NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

November 4, 2026

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of November 12, 2026 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the November 2026 meeting of the Participants Committee will be held **in person on Thursday, November 12, 2026, at 2:00 p.m. at the Hilton Boston Back Bay, located at 40 Dalton Street, Boston, MA 02115**, **following individual, modified Sector meetings with the ISO Board and with State Officials as follows:**

- 9:00 am – 10:15 am Sector Meetings Session I
- 10:30 am – 11:45 am Sector Meetings Session II
- 11:45 am – 12:30 pm Lunch
- 12:30 pm – 1:45 pm Sector Meetings Session III
- 2:00 pm – conclusion of business NPC General Business

A schedule of planned Sector meetings is included in this supplemental notice.

The Participants Committee meeting, which is scheduled to begin at **2:00 p.m.** following those Sector meetings, will be held for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

To join the meeting using the enhanced Webex interface, please **download the Webex app** to your desktop or to your phone (whichever device you will be using) **in advance of the meeting** and use the app to join the meeting. You may also access the meeting through the ISO's Webex meetings page by clicking https://iso-newengland.webex.com/webappng/sites/iso-newengland/meeting/home and selecting the meeting (event password = **nepool**).

Please also note that the ISO Board will conduct a public meeting on Tuesday, November 10, 2026, from 1:00 p.m. to approximately 4:30 p.m., at the same venue (the Hilton Boston Back Bay). For your convenience, we have included with this package the ISO's Notice of its Open Board Meeting, which also can be downloaded here.

Looking forward, please make sure that your calendars reflect the upcoming NEPOOL Annual Meeting, which will be held on **Thursday, December 3, 2026, at the Colonnade Hotel in Boston**. There are a limited number of rooms available for the night before the December 3 meeting at the rate of $259.00 per night, on a first-come, first-served basis through **Tuesday, November 10, 2026**. Please contact Laura Clark on or before that cut-off date to secure a room in the block.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the October 2, 2026 Participants Committee meeting. A copy of the draft minutes is included and posted with this supplemental notice. Please provide us with any comments on those minutes no later than **noon on Tuesday, November 10, 2026**.

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

2A. To consider and take action, as appropriate, on conforming changes to Tariff Section IV.A, Schedule 2, to note the exclusion of Storage as Transmission-Only Asset (SATOA) activities from Energy Transaction Units. Background material and a draft resolution is included with this supplemental notice and posted with the meeting materials.

3. To receive an ISO Chief Executive Officer Report. No Board or Board Committee meeting summaries are included with this supplemental notice as there have been no Board or Board Committee meetings since the October 2 Participants Committee meeting.

4. To receive a System and Market Operations Report and Winter Analysis Update. The November System and Market Operations Report, reflecting October data, and Winter Analysis Update will be circulated and posted in advance of the meeting.

5. To consider and take action, as appropriate, on Tariff changes related to the integration of large loads, proposed in response to the FERC's June 18, 2026 *New England Large and Co-Located Loads Show Cause Order*:

   a. Section I.2.2 (Definitions) and Section II of the Open Access Transmission Tariff (OATT), including (i) new Sections II.56-II.63, new Attachments S-V, and new Schedule 9A; and (ii) conforming changes to Sections II.20.2, II.20.3, and II.21.2, and to Schedules 1, 2, 16, 17, 22 and 23, as considered by the ***Transmission Committee*** at its November 3 meeting;

   b. Sections I.2.2 and III.12.1 (Installed Capacity Requirement) of the Tariff, as considered by the ***Reliability Committee*** at its November 3 meeting; and

   c. Section I.2.2 and Section III (Market Rule 1), including Sections III.1.10.5A, III.1.7.19.2.2.2, III.1.8.1, III.2.5, III.2.6.1, and III.15.8.5.2.1, as considered by the ***Markets Committee*** at its November 3 meeting.

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

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

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

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

8. Administrative matters.

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

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.

2026 Open Meeting of the ISO New England Board of Directors
November 10, 2026
Boston, Massachusetts

The ISO New England Board of Directors will conduct an open meeting in Boston on Tuesday, November 10, 2026 from 1:00 p.m. to approximately 4:30 p.m.

Location: The meeting will take place in-person at the Hilton Boston Back Bay (40 Dalton Street, Boston, MA 02115). A virtual attendance option will also be available.

Preliminary Agenda: The program will begin with opening remarks from the chair of the ISO New England Board of Directors, Cheryl LaFleur. The Board will conduct its regular business, which will include a management update on the ISO Strategic Plan from ISO New England CEO and President, Vamsi Chadalavada, and updates on large load integration and the outlook for the upcoming winter season. A listening session will follow. The ISO may post a final agenda prior to the meeting.

Written Comments: The public can submit written comments to the ISO Board of Directors either in advance of or after the meeting. Please submit written comments by email to the following email address: BoardofDirectors@iso-ne.com. Written comments provided by November 30 will be compiled and posted to the ISO website.

Listening Session: The Board is conducting this open session to give the public an opportunity to observe the Board's discussions firsthand. The format of this meeting is not a public hearing. A limited number of timeslots will be available for those who want to address the Board directly. Meeting details, including how to sign up for the listening session, are available on the ISO Calendar Event Page.

Registration: The public will have options to attend in-person and virtually. Virtual attendance is not limited and virtual meeting information is available on the ISO event page. The meeting space can accommodate approximately 150 in-person attendees. Because in-person space is limited, we urge people to register early. Advanced registration is required to attend in-person and is available on the ISO Calendar Event Page.

Recording: After the meeting, ISO-NE will post a video recording for the benefit of members of the public who are not able to attend the meeting live.

Accessibility: If you have requests for accommodations, you may reach out to Gae Warman-Gold via email (gwarmangold@iso-ne.com).

About ISO New England: ISO New England is the independent, private, nonprofit entity that serves as the Regional Transmission Organization ("RTO") for New England. The ISO

operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement ("TOA") with the New England Participating Transmission Owners ("PTO"). As the RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to plan and operate the system according to reliability standards established by the ISO, the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC").

For more information about ISO New England, please visit www.iso-ne.com, or www.ISONewswire.com.

About the ISO New England Board of Directors: An independent Board of Directors oversees the management of ISO New England. For information on ISO governance, including profiles of the individual members of the ISO New England Board of Directors, please visit: https://www.iso-ne.com/about/corporate-governance.

NEPOOL
NEW ENGLAND POWER POOL

PARTICIPANTS COMMITTEE NOVEMBER 12, 2026 MEETING
Hilton Boston Back Bay, Boston, MA
MEETING SCHEDULE**

SECTOR/GROUP	Session I 9:00 – 10:15 a.m.	Session II 10:30 – 11:45 a.m.	Lunch 11:45 – 12:30 p.m.	Session III 12:30 – 1:45 p.m.	General Business 2:00 p.m. - adjournment
Generation / Long	ISO Board Panel 1 ***(Maverick A)***	*Open*	Lunch (*Ballroom*)	State Officials Panel 2 ***(Washington)***	Lunch (All) ***Belvidere Ballroom***
Transmission	ISO Board Panel 2 ***(Maverick B)***	*Open*	Lunch (*Ballroom*)	State Officials Panel 1 ***(Copley)***	
Supplier / Short (LSE)	*Open*	State Officials Panel 2 ***(Washington)***	Lunch (*Ballroom*)	ISO Board Panel 2 ***(Maverick B)***	
Publicly Owned Entity	State Officials Panel 1 ***(Copley)***	ISO Board Panel 2 ***(Maverick B)***	Lunch (*Ballroom*)	*Open*	
AR	State Officials Panel 2 ***(Washington)***	ISO Board Panel 1 ***(Maverick A)***	Lunch (*Ballroom*)	*Open*	
End User	*Open*	State Officials Panel 1 ***(Copley)***	Lunch (*Ballroom*)	ISO Board Panel 1 ***(Maverick A)***	
ISO Board Panel 1	Generation / Long ***(Maverick A)***	AR ***(Maverick A)***	Lunch (*Ballroom*)	End User ***(Maverick A)***	
ISO Board Panel 2	Transmission ***(Maverick B)***	Publicly Owned Entity ***(Maverick B)***	Lunch (*Ballroom*)	Supplier / Short (LSE) ***(Maverick B)***	
State Officials Panel 1**	Publicly Owned Entity ***(Copley)***	End User ***(Copley)***	Lunch (*Ballroom*)	Transmission ***(Copley)***	
State Officials Panel 2**	AR ***(Washington)***	Supplier / Short (LSE) ***(Washington)***	Lunch (*Ballroom*)	Generation / Long ***(Washington)***	

ISO Board Panel 1: Caren Anders, Mike Curran, Craig Ivey, Cheryl LaFleur, Mark Vannoy

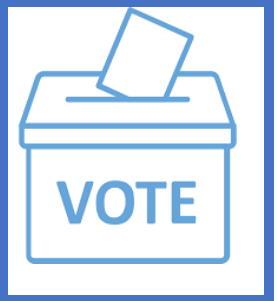
ISO Board Panel 2: Steve Corneli, Catherine Flax, Kathryn Guarini, Mel Williams, and Vamsi Chadalavada

State Officials Panel 1: ** Kerrick Johnson, Pat Scully (remote), Liz Anderson, Ed McNamara (remote/tentative), Dan Phelan, David Arconti (tentative), Michael Haskell, Gregg Wade, Matt Young , Bob Snook (remote), Heather Hunt, Sheila Keane, Nathan Forster, Josh Walters (remote), Kelly Porter

State Officials Panel 2: ** Andy Frank, Carrie Gilbert (remote), Weezie Nuara, Karen Bradbury, Holly Cheeseman (tentative), George Twigg, Todd Bianco, Ethan Tremblay (remote), Bruce Blair, Ron Guay (remote), Shannon Beale, Lou Cecere (remote), Eric Annes, Jeff Bentz

** Subject to Change

1 October 2, 2026 Minutes



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To approve the draft minutes of the October 2, 2026 Participants Committee meeting.

RESOLVED, that the Participants Committee approves the preliminary minutes of the October 2, 2026 meeting, as circulated in advance of this meeting, with additional non-material clarifications, as the final minutes of the October 2, 2026 meeting.

Nov 12, 2026 Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, October 2, 2026, at the AC Hotel Portsmouth Downtown/Waterfront in Portsmouth, New Hampshire. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting.

Mr. Dave Cavanaugh, Acting Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and guests who were present.

APPROVAL OF SEPTEMBER 3, 2026 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the September 3, 2026 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, subject to additional non-material clarifications, with an abstention by Mr. Jon Lamson noted.

CONSENT AGENDA

Mr. Cavanaugh then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting, with Item No. 3 (PP5-6 Revisions) removed at the request of the ISO. Following motion duly made and seconded, the Consent Agenda, with Item No. 3 removed, was unanimously approved, with an abstention by Mr. Lamson noted.

PLANNING PROCEDURE NO. 5-6 REVISIONS

Mr. Nick Gangi, Reliability Committee (RC) Chair, referred the Committee to proposed revisions to ISO New England Planning Procedure No. 5-6 (Interconnection Planning Procedure for Generation and Elective Transmission Upgrades) (PP5-6 Revisions). He explained that the revisions were intended to clarify requirements for resources participating in the first Cluster Study and included three new model acceptance tests to evaluate the conformance of inverter-based resources with ISO-adopted provisions of IEEE 2800-2022. He said that the RC had considered the revisions over the course of three meetings and had unanimously recommended Participants Committee support for the PP5-6 Revisions.

Mr. Gangi reported that, following the RC's recommendation, the ISO identified the need to correct the short-circuit-ratio parameter for Test 17 in Appendix C-2. The corrected test parameter would specify short-circuit ratios of 2.5 and 20, consistent with similar model acceptance tests. He explained that the correction would not materially affect how the new test would be performed.

There being no further questions or discussion, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the PP5-6 Revisions, as circulated to the Participants Committee in advance of its October 2, 2026 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

The motion was unanimously approved, with an abstention by Mr. Lamson noted.

ISO BOARD & BOARD COMMITTEE SUMMARIES

Mr. Cavanaugh then referred the Committee to the summaries of the ISO Board and Board Committee meetings held since the last Participants Committee meeting, which had been circulated and posted in advance of the meeting. He noted that the summaries included the Board's committee assignments and the reappointment of Ms. Cheryl LaFleur as Chair of the ISO Board.

In response to a question regarding the Board Markets Committee's review of management's response to recommendations in the External Market Monitor's (EMM) annual report, Mr. Matthew White, ISO Chief Economist and Vice President of Market Development and Settlements, explained that the ISO had compared the recommendations with the projects identified in the Annual Work Plan. He added that the recommendations related to Capacity Auction Reforms (CAR) were being addressed through that project and that the EMM was broadly supportive of those efforts.

Mr. Cavanaugh also noted the ISO's ongoing strategic planning initiative and advised that it would be addressed further during the Annual Work Plan discussion and at the November Sector and Participants Committee meetings.

ISO SYSTEM & MARKET OPERATIONS REPORT

Mr. Stephen George, ISO Vice President of System & Market Operations and Capital Projects, referred the Committee to the October System & Market Operations Report (Report), which had been circulated and posted in advance of the meeting. He reviewed highlights from the Report, noting that its data waseare through September 27, 2026. Those highlights included: (i) the Peak Hour for September 2026, with 18,669 MW of Revenue Quality Metered (RQM) Data, occurred on September 10, 2026 during the hour ending at 7:00 p.m.; (ii) September

averages for Day-Ahead Hub Locational Marginal Price (LMP) ($41.79/MWh), Real-Time Hub LMP ($39.51/MWh), and natural gas prices ($1.78/MMBtu); (iii) an Energy Market value for September 2026 of $404 million, down 34% from August 2026 and up 26% from September 2025; (iv) an Ancillary Services Market value of $6 million, down 31% from August 2026 and up 26% from September 2025; (v) average Day-Ahead cleared physical energy during peak hours as a percentage of forecasted load, which was higher than in September 2025 but lower than in August 2026; (vi) Net Commitment Period Compensation (NCPC) payments for September totaled $1.3 million (representing 0.3% of September's monthly Energy Market value), comprised of $1.3 million in First Contingency payments (including $496,000 in Dispatch Lost Opportunity Costs, $81,000 in Rapid Response Pricing Opportunity Costs, $52,000 paid to resources at external locations, down $43,000 from August, and $29,000 paid to Real-Time Deviations); and (vii) a Forward Capacity Market (FCM) value of $77 million.

Using slides from the Report, Mr. George then (i) reviewed the effects of a late-September nor'easter that produced coastal and offshore wind gusts of approximately 70 miles per hour, caused one transmission-line outage in southeastern Massachusetts and approximately 57,000 customer outages at peak, and resulted in high-wind-speed cutouts at the region's offshore wind facilities; (ii) noted the ISO's plans to implement recently approved Day-Ahead Ancillary Services (DAAS) adjustments on October 22, 2026, for the October 23, 2026, Operating Day; (iii) highlighted continued growth in wind production, noting that offshore wind reached a record output of approximately 1,100 MW on September 24, 2026, combined onshore and offshore wind reached approximately 2,000 MW on September 27, 2026, and average hourly wind supply was a record approximately 900 MWh during September 2026; and (iv) described

continuing enhancements to the Report, including the addition of a monthly Key Takeaways slide.

In response to questions regarding offshore wind that went offline during the nor'easter, Mr. George explained that the facilities did not go offline simultaneously. Rather, output declined in stages over approximately three to four hours, remained near zero for approximately two to three hours while wind speeds exceeded turbine operating limits, and then returned to service over several hours. He stated that the event had been forecasted and did not require additional out-of-market resource commitments, although operators had to prepare for the associated changes in net load and potentially carry additional regulation capability. Mr. George confirmed that the ISO monitored both increases and decreases in wind output and expected to report offshore and onshore wind separately once the offshore facilities became fully commercial.

In response to other questions, Mr. George stated that the hour of the September RQM peak had been inadvertently omitted from the Report and would be restored the following month. He confirmed that the approximately 57,000 customer outages reported during the nor'easter represented aggregated distribution-system outages rather than direct transmission outages. He also agreed to consider: (i) identifying on planned-project slides whether projects would be subject to aAsset Ccondition Rreview; (ii) adding Regional Greenhouse Gas Initiative (RGGI) information to future market reporting; and (iii) retaining certain DAAS slides in the monthly Report. He noted that more timely and complete DAAS information was also available through the ISO's weekly and monthly market reports.

Turning to planned transmission and generation outages, Mr. George highlighted scheduled work involving Phase 2, the New England Clean Energy Connect, Cross-Sound Cable,

and the ties with New Brunswick and New York. Each outage was expected to affect transfer capability into or out of New England. In response to a question regarding a scheduled outage of Line 398 line between Connecticut and New York, Mr. George explained that the outage would require Phase 2 imports to be limited to 1,400 MW because of the potential effect of a Phase 2 contingency on the remaining New York ties. He confirmed that the restriction applied to imports, not exports.

Mr. George then reported that the ISO's winter -preparation activities were underway, stating that oil inventory levels were a few percentage points higher than at the same time in 2025, although the ISO continued to monitor potential delays in fuel replenishment. The ISO was contacting larger oil-fired resources regarding their expected pre-winter inventories and supply-chain arrangements and expected to present its W~~w~~inter 2026/27 outlook at the November Participants Committee meeting.

ISO DRAFT 2027 ANNUAL WORK PLAN

Ms. Allison DiGrande, ISO Executive Director of Participant Relations and Services, referred the Committee to the ISO's draft 2027 Annual Work Plan (Work Plan), which had been circulated and posted in advance of the meeting. She explained that the Work Plan reflected the ISO's current priorities and could be updated as scope, external requirements, and stakeholder priorities evolved. Any new work resulting from the ISO's longer-range strategic planning initiative would be incorporated into the first-quarter update.

Ms. DiGrande identified the Work Plan's principal anchor projects as CAR implementation, conforming changes, and follow-on work; Large and Co-Located Loads compliance and resource adequacy work; development of an Operating Reserves Demand Curve; implementation of the Asset Condition Reviewer function; *Order 1920* compliance and

transmission right-sizing; and IT implementation of CAR and next-generation market systems. She also identified notable initiatives involving longer-term transmission planning, *Order 2023* process enhancements, surplus interconnection service, dispatch enhancements, integrated market simulation, probabilistic forecasting, synchrophasor measurements, cloud computing, cybersecurity, and artificial intelligence.

Focusing on CAR follow-on work, Ms. DiGrande stated that the ISO expected in 2027 to assess issues including the Balancing Ratio cap, gas constraints, correlated outages, and storage accreditation and modeling. The ISO would prioritize the work according to the deadlines applicable to the first seasonal auction but did not expect to complete every assessment or implement every resulting change during 2027. ISO representatives stated that resource constraints were not expected to prevent consideration or implementation of an alternative Balancing Ratio approach within the identified scope. They also stated that the listed CAR follow-on topics were illustrative rather than exhaustive and acknowledged member interest in tools for load participation, managing increased price volatility, and alternative storage-modeling software.

Regarding other anchor projects, ISO representatives explained that the Large and Co-Located Loads work was principally being driven by the FERC show-cause ~~proceeding~~ order and the need to establish a comprehensive regional process, rather than by a large volume of pending New England applications. The ISO continued to monitor load growth in neighboring regions because of its potential effect on import availability. The Operating Reserves Demand Curve project had shifted from late 2026 to the second quarter of 2027 because of competing priorities. The ISO expected to begin with the scope described in its March memorandum; a

broader review of Reserve-Constraint Penalty Factors (RCPFs) would require a separate prioritization discussion.

Members also discussed coordination between *Order 1920* compliance and the ISO's existing Longer-Term Transmission Planning (LTTP) process, the timing of lessons-learned discussions, and the possibility of avoiding duplicative work. ISO representatives expected LTTP lessons learned discussions to begin at the Planning Advisory Committee (PAC), with any resulting Tariff changes considered by the Transmission Committee (TC). The ISO was targeting completion of the first phase of surplus interconnection service work by the second quarter of 2027, depending on the project's start date, and planned thereafter to consider *Order 2023* process enhancements. The ISO also expected by the end of 2026 to adjust the Unit Dispatch System look-ahead for fast-ramping resources and to consider broader ramping and dispatch-signal enhancements in 2027.

In response to questions regarding market-system technology, ISO representatives confirmed that the Day-Ahead component of the next-generation market-clearing engine had been implemented previously, ~~r~~Real-~~t~~Time multi-interval improvements had been implemented in July 2026, and the next phase would address single-interval functions. They agreed that the faster platform could support consideration of a later Day-Ahead Market offer deadline but stated that any change would require prioritization and more extensive work than a simple schedule adjustment. Members also emphasized the need for stakeholder outreach and readiness before implementation of the new capacity auction design.

2027 ISO AND NESCOE BUDGETS

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated and posted in advance of the meeting regarding the proposed 2027

ISO and New England States Committee on Electricity (NESCOE) budgets. He reported that B&F had considered the 2027 budgets and that no objections had been raised with respect to those budgets. He also noted the 2027 budget presentations and discussion at the previous Participants Committee meeting and the additional information provided afterward in response to State and stakeholder comments.

2027 ISO Budgets

In response to a question regarding the growing volume of external inquiries concerning system operations and market design, Ms. Kelly C. Reyngold, ISO Vice President, Chief Financial Officer, explained that the ISO considered those demands in its ongoing review of staffing needs and had reflected the associated staffing levels in its 2027 budget projections.

There being no further questions or comments, the following motion was duly made, seconded, and approved unanimously, with abstentions by Cross-Sound Cable and Mr. Lamson noted:

> RESOLVED, that the Participants Committee supports the Year 2027 operating and capital budgets proposed by the ISO, as presented at this meeting.

2027 NESCOE Budget

Ms. Heather Hunt, NESCOE Executive Director, was available by telephone to address any questions regarding the proposed 2027 NESCOE budget. No questions were asked. The following motion was then duly made, seconded and approved unanimously, with an abstention by Mr. Lamson noted:

> RESOLVED, that the Participants Committee supports the Year 2027 NESCOE budget, as presented at this meeting.

ENVIRONMENTAL LEAGUE OF MASSACHUSETTS MEMBERSHIP APPLICATION

Mr. Brian Thomson, Membership Subcommittee Chair, referred the Committee to materials circulated in advance of the meeting regarding the application of Environmental League of Massachusetts, Inc. (ELM) for Governance Only Small End User membership. He explained that the application was before the Participants Committee because an End User Sector representative had opposed it, preventing the Subcommittee from approving the application without Participants Committee action.

Mr. Patrick Gerity, NEPOOL Counsel, supplemented Mr. Thomson's introduction with additional context regarding the Subcommittee's review, the basis for treating the application as one for Small End User membership, and the application-specific considerations. He stated that ELM had submitted sufficient evidence to qualify as a Small End User Participant. He also identified other End Users admitted on similar grounds and described the proxy restriction that would apply to ELM if approved.

Ms. Erin Smith, ELM Energy and Grid Policy Director, explained that ELM was a Massachusetts 501(c)(3) nonprofit organization whose mission included promoting a sustainable energy system and that ELM sought to participate and vote on matters affecting the sustainability of Massachusetts' energy system.

While the following main motion was pending, two End User members (Opposing Members), referring to materials they had circulated and posted in advance of the meeting, offered their view that evidence of electricity consumption (by way of an electric bill) should not be accepted in and of itself as sufficient evidence/eligibility of a nonprofit organization's eligibility as an End User Sector Participant. They asked that action on ELM's application be deferred so that the Membership Subcommittee, a working group, or NEPOOL leadership could

further consider the applicable eligibility standards. Mr. Cavanaugh acknowledged that those standards could be reviewed separately but noted that such a broader review was not before the Committee.

A motion to defer consideration of ELM's application was duly made and seconded. Mr. Lombardi advised the Committee that approval of the motion to defer would require a two-thirds vote. The motion was put to a vote and failed by a show of hands, with only Opposing Members, Green Oceans and Vistra in favor, and abstentions by FirstLight, Shell, Competitive Power Ventures, and Mr. Lamson noted.

After the motion to defer failed, the Committee resumed consideration of the following main motion, which had been duly made and seconded:

> RESOLVED, that the Participants Committee approves the application of the Environmental League of Massachusetts, Inc. to be a Governance Only Small End User subject to the following conditions: (1) that NEPOOL Counsel and the ISO find ELM's Application complete; (2) that ELM sign and return the Standard Membership Conditions, Waivers and Reminders letter; and (3) that ELM execute an Indemnification Agreement to permit an expedited membership effective date.

The Committee then voted on the unamended motion by a show of hands. The motion was approved, with the Opposing Members and Green Oceans opposed and abstentions by FirstLight Power, Shell, Vistra, and Mr. Lamson noted.

LITIGATION REPORT

Mr. Gerity referred the Committee to the October 1, 2026 Litigation Report that had been circulated and posted before the meeting. He reported that the FERC had accepted the Balancing Ratio Cap Compliance Changes, ~~the Day-Ahead Ancillary Services (~~DAAS~~)~~ Adjustments, and the System-Backed Export Charge Proposal previously supported by the Committee. He also

reported that the ISO had notified the FERC that the effective date for the previously filed and approved MW-dependent fuel price adjustments would be September 23, 2027.

Continuing, Mr. Gerity stated that the Asset Condition Reviewer Role proceeding remained pending before the FERC. Reply briefs regarding the base return on equity (ROE) had been filed after the FERC denied a request by the New England Transmission Owners for additional time, and an order was expected in or around November. He also summarized the FERC's order finding that the Tariff was unjust and unreasonable because it lacked a correction mechanism for certain settlement errors. The FERC had largely accepted the ISO's proposed approach, and the ISO expected to make a compliance filing by January 8, 2027, following stakeholder review.

Finally, Mr. Gerity reported that several generators participating in the Transition Cluster Study had filed a complaint alleging that the assignment of network upgrade costs violated the Tariff and FERC's cost-causation principles and a waiver of certain Tariff provisions in case the FERC did not act on the complaint by October 16, 2026, as requested. The complainants requested expedited action and comment periods, and the ISO had opposed the requested expedited comment periods. He stated that NEPOOL Counsel would continue to monitor and report on developments.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Ben Griffiths, MC Vice-Chair, reported that the next MC meeting would be held in person at the DoubleTree Hotel in Westborough, MA, the following week, with most of the meeting focused on CAR stakeholder amendments. He also noted that the MC was scheduled to meet during the first week of November, before the November

Participants Committee meeting, at which the MC was expected to vote on CAR, related amendments, and Large Loads.

Reliability Committee (RC). Mr. Frank Ettori, RC Vice-Chair, reported that the next RC meeting would be held in person at the DoubleTree Hotel in Westborough, MA, on October 20, 2026. Topics for consideration included Hydro-Québec Interconnection Capability Credits and Installed Capacity Requirement and related values for the third Annual Reconfiguration Auction for the 2027-2028 Capacity Commitment Period (ARA3), Operating Procedure (OP) updates, continued discussion of revisions to Planning Procedure Nos. 4 and 7, non-performance factor Ten~~10~~- and Thirty~~30~~-M~~m~~inute R~~r~~eserve R~~r~~equirements, and the start of the Load Forecasting Subcommittee cycle.

Transmission Committee (TC). Mr. Nick Gangi, TC Chair, reported that a joint TC/RC/MC meeting would be held in person at the DoubleTree Hotel in Westborough, MA, on October 14, 2026, to discuss Large Loads. The TC also expected to discuss *Order ~~No.~~ 1920* compliance and potentially the disposition of Transition Cluster Study withdrawal penalties. Additional joint meetings were scheduled for October 27 and November 3, 2026, at the DoubleTree Hotel in Westborough, MA. Both meetings were expected to include discussion of Large Loads, with a vote on the Large Loads proposal expected at the November 3 ~~joint~~ meeting.

Membership Subcommittee. Mr. Brian Thomson, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held virtually on October 13, 2026, with four membership applications and one termination expected to be on the agenda. He encouraged all those interested to participate.

ADMINISTRATIVE MATTERS

Mr. Lombardi reminded the Committee that the next meeting would be held in person, on Thursday, November 12, 2026, at the Hilton Boston Back Bay. Sector meetings with ISO Board panels and State officials were expected to begin at approximately 9:00 a.m.; the Participants Committee meeting would follow at 2:00 p.m.

Looking further ahead, Mr. Lombardi said that the December 3, 2026 Annual Meeting would be held in person at the Colonnade Hotel in Boston. He noted that FERC Chairman Laura V. Swett had been invited to participate and expressed hope that her participation in the Annual Meeting and other New England meetings that week would soon be confirmed.

Mr. Lombardi also reminded each Sector to identify its 2027 Participants Committee Officer by October 21, 2026. Following confirmation of those selections, balloting for the 2027 Participants Committee Chair would begin.

There being no other business, the meeting adjourned at 12:17 p.m.

Respectfully submitted,

_____
Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE OCTOBER 2, 2026 MEETING

(W) = Webex

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso (W)		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton (W)	
AR Large RG Group Member	AR-RG		Aidan Foley (W)	
Ashburnham Municipal Light Plant	Publicly Owned Entity			Dan Murphy
AVANGRID (CMP/UI)	Transmission	Alan Trotta (W)	Jason Rauch	
Bath Iron Works	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		Michael Lazorchak
Boylston Municipal Light Department	Publicly Owned Entity			Dan Murphy
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity	Dave Cavanaugh		Michael Lazorchak
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Canal Marketing LLC	Generation		Bill Fowler	
Chester Municipal Light Department	Publicly Owned Entity		Dan Murphy	
Chicopee Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Clear River Electric	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
CLEAResult Consulting Inc.	AR-DG	Tamera Oldfield (W)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (W)		
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	
Conservation Law Foundation	End User			Claire Lang-Ree (W)
Constellation Energy Generation (Constellation)	Supplier	Andy Gillespie (W)	Gretchen Fuhr (W)	Bill Fowler
CPV Towantic, LLC	Generation	Richard Bratton		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Dartmouth Power Associates, L.P.	Generation			Sarah Yasutake (W)
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Earthjustice	End User			Jennifer Yun (W)
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
Eversource Energy	Transmission		Dave Burnham (W)	Dave Norman
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Fiscal Alliance Foundation, Inc.	End User			Lisa Linowes
Gabel Associates, Inc.	Supplier	Sarah Yasutake (W)		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (W)	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Steve Kirk	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Green Oceans	End User		Lauren Knight	Lisa Linowes
Groton Electric Light Department	Publicly Owned Entity			Dan Murphy
Grid United LLC	Provisional Member	Mike Spector		
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Doug Hurley
High Liner Foods (USA) Inc.	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Holyoke Gas & Electric Department	Publicly Owned Entity			Dan Murphy
H.Q. Energy Services (US)	AR-RG	Louis Guilbault (W)		
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Industrial Wind Action Corp	End User	Lisa Linowes		

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE OCTOBER 2, 2026 MEETING

(W) = Webex

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ipswich Municipal Light Department	Publicly Owned Entity			Dan Murphy
Lamson, Jon	End User	Jon Lamson (W)		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (W)		
Mansfield Municipal Electric Department	Publicly Owned Entity			Dan Murphy
Marblehead Municipal Light Department	Publicly Owned Entity			Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihrle	Jamie Donovan	Chris Modlish (W)
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Mass. Department of Capital Asset Management	End User		Paul Lopes (W)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity		Dan Murphy	
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Midcoast Regional Redevelopment Authority	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Moore Company	End User			Bill Short
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson		
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (W)
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum	Don Kreis	
NextEra Energy Resources, LLC	Generation	Michelle Gardner (W)		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
NRG Business Marketing, LLC	Supplier	Ben Griffiths		
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity			Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity			Dan Murphy
PowerOptions, Inc.	End User			Doug Hurley
Princeton Municipal Light Department	Publicly Owned Entity			Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
RENEW Northeast, Inc.	Assoc. Non-Voting	Francis Pullaro (W)		Carter Scott
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Russell Municipal Light Dept.	Publicly Owned Entity			Dan Murphy
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity			Dan Murphy
South Hadley Electric Light Department	Publicly Owned Entity			Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity			Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Veolia Flexible Energy Services North America	AR-LR	Doug Hurley		
Vermont Electric Company	Transmission	Frank Ettori		
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (W)		
Vermont Energy Investment Corp.	AR-LR			Doug Hurley
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (W)
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		

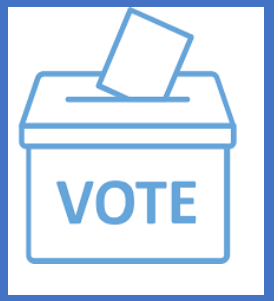
ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE OCTOBER 2, 2026 MEETING

(W) = Webex

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Vistra (Dynegy Marketing and Trade, Inc.)	Generation	Ryan McCarthy		
Vitol Inc.	Supplier	Seth Cochran (W)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity			Dan Murphy
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
West Boylston Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User			Bill Short

2 Consent Agenda



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1. Revisions to PP-7 (Revisions to Align with Potential *Order 881* Extension and/or Limited Waiver Requests)
2. HQICCs and ICR Values for 2027-2028 ARA 3
3. ICR and Related Values for 2027-2028 ARA 3

RESOLVED, that the Participants Committee approves the Consent Agenda as circulated in advance of this meeting.

CONSENT AGENDA

Reliability Committee (RC)

*From the previously-circulated notice of RC actions at the **October 20, 2026 RC Meeting**, dated October 20, 2026.*[1]

1. Revisions to PP-7 (Revisions to Align with Potential Order No. 881 Extension and/or Limited Waiver Requests)

Support proposed revisions to ISO New England Planning Procedure (PP) No. 7 (Procedures for Determining and Implementing Transmission Facility Ratings in New England),[2] as recommended by the RC at its October 20, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

2. HQICCs and ICR Values for 2027-2028 ARA 3

Support the following Hydro-Québec Interconnection Capability Credit (HQICC) values for the Third Annual Reconfiguration Auction (ARA) for the 2027-28 Capacity Commitment Period (CCP), as recommended by the RC at its October 20, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair:

Month	2027-2028 HQICC Values (MW)
June	1,004
July	1,004
August	1,004
September	1,004
October	1,004
November	1,004
December	1,004
January	1,004
February	1,004
March	1,004
April	1,004
May	1,004

The motion to recommend Participants Committee support was approved, with one opposition (Supplier Sector) and 5 abstentions (4 Supplier, 1 End User) noted.

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

[2] Revising PP7 to (i) accommodate extensions/waivers of *Order 881* compliance; (ii) clarify processing of submitted methodologies; and (iii) correct the Season 12 OH Conductors Celsius temperature in Appendix A Table 1A.

3. ICR and Related Values for 2027-2028 ARA 3

Support, for the 3rd ARA for the 2027-28 CCP, the following New England Installed Capacity Requirement (ICR) and Net ICR, Maine (ME) Maximum Capacity Limit (MCL), Northern New England (NNE) MCL values:

	2027-2028 ARA 3 ICR values (MW)
ICR	30,674
Net ICR	29,670
ME MCL	4,345
NNE MCL	8,695

and the following Marginal Reliability Impact (MRI) Capacity Demand Curves – System-Wide, ME Export-Constrained Capacity Zone, and NNE Export-Constrained Capacity Zone

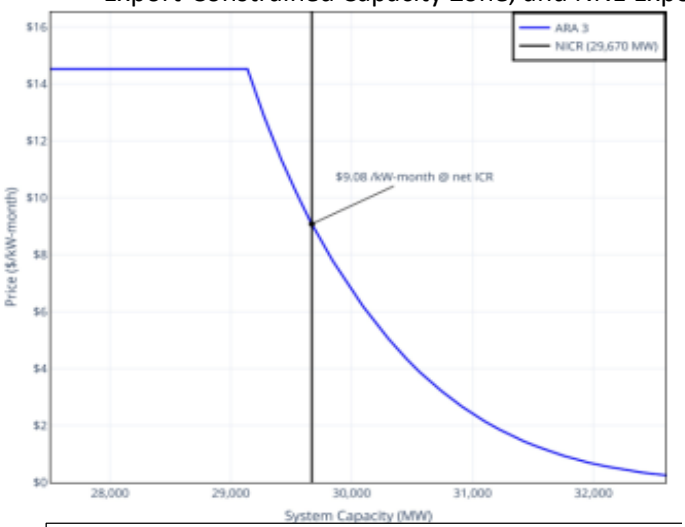


Figure 1: 2027-28 CCP ARA3 System-Wide MRI Capacity Demand Curve

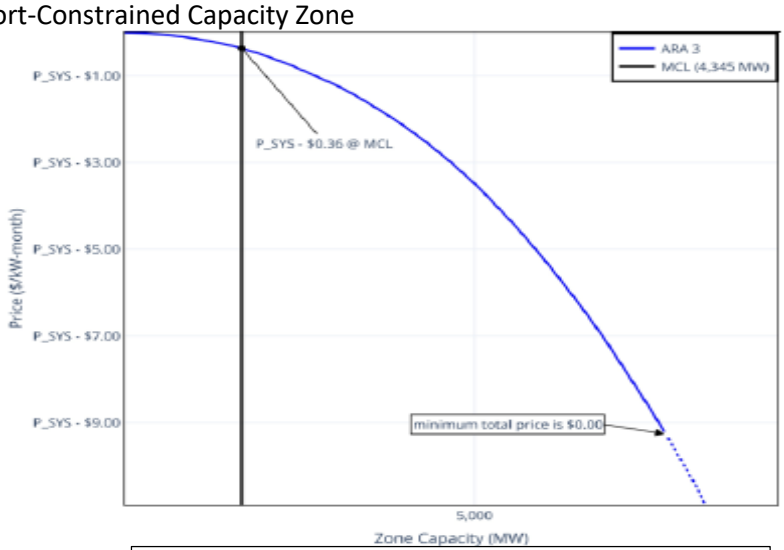


Figure 2: 2027-28 CCP ARA3 ME Export-Constrained MRI Capacity Demand Curve

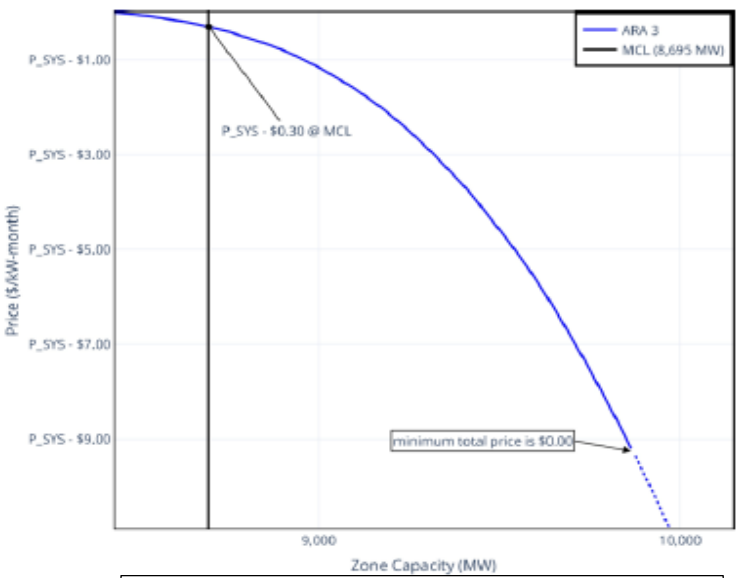
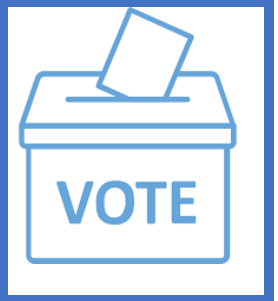


Figure 3: 2027-28 CCP ARA3 NNE Export-Constrained MRI Capacity Demand Curve

each as recommended by the RC at its October 20, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved, with one opposition (Supplier Sector) and 5 abstentions (4 Supplier, 1 End User) noted.

2A SATOA Conforming Changes to Tariff Section IV.A, Schedule 2



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To consider and take action, as appropriate, on conforming changes to Tariff Section IV.A, Schedule 2, to note the exclusion of Storage as Transmission-Only Asset (SATOA) activities from Energy Transaction Units.

RESOLVED, that the Participants Committee supports the updates to Section IV.A, Schedule 2 of the Tariff to exclude the operation of Storage as Transmission-Only Assets from the calculation of Energy Transaction Units, as reflected in the materials 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 of the Budget & Finance Subcommittee.

Nov 12, 2026 Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: November 4, 2026

RE: Conforming Changes to Section IV.A, Schedule 2 of the Tariff Related to Storage as Transmission-Only Assets (SATOAs)

At the November 12, 2026 Participants Committee meeting, you will be asked to vote on a proposed conforming revision to Section IV.A, Schedule 2 of the Tariff to exclude the operation of SATOAs[1] from the calculation of Energy Transaction Units (TUs). The ISO is targeting a December 2026 filing and a March 1, 2027 effective date. Included with this memorandum are the following supporting materials:

- Attachment A: ISO-NE's Redlined Tariff Sheets
- Attachment B: ISO-NE's October 9, 2026 Presentation

BACKGROUND & OVERVIEW

Except for charging and discharging necessary to perform their transmission functions, which are settled through ISO-NE's Real-Time Energy Market, SATOAs do not participate in the wholesale markets. SATOA owners recover their costs through the Annual Transmission Revenue Requirements under Attachment F of the Tariff, with net energy-market costs and revenues charged or credited to transmission ratepayers.[2]

Section II.51.3 of the OATT provides that transmission service charges, including Ancillary Services charges, and charges assessed or revenues allocated under Schedules 1, 2, 3, and 5 of Section IV.A do not apply to SATOA operations. The ISO's review of settlement calculations identified that Real-Time SATOA Obligations would currently affect the calculation of Schedule 2 Energy TUs. To conform that calculation to OATT Section II.51.3, the ISO proposes to specify that Energy TUs are calculated without reference to contributions from the operation of a SATOA, alongside the existing exclusion for Coordinated External Transactions.

[1] A SATOA is electric storage equipment approved as a regulated transmission solution. ISO-NE manually dispatches SATOAs only to address the transmission system needs for which they were planned, avoid or mitigate load shedding after dispatching all available resources capable of providing effective relief, or support system restoration.

[2] *ISO New England Inc.*, 185 FERC ¶ 61,044, at PP 9–14 (2023). FERC accepted the SATOA Tariff revisions on Oct. 19, 2023, and those provisions became effective on Sept. 1, 2026. *Id.* at P 1.

STAKEHOLDER PROCESS TO DATE

The ISO presented its proposed revisions at the October Budget & Finance (B&F) Subcommittee meeting. No B&F Subcommittee member present expressed opposition to the proposed conforming changes. Although the B&F Subcommittee considered the revisions at only one meeting, members present did not object to advancing them to the Participants Committee for consideration.

The following form of resolution may be used for Participants Committee action:

RESOLVED, that the Participants Committee supports the updates to Section IV.A, Schedule 2 of the Tariff to exclude the operation of Storage as Transmission-Only Assets from the calculation of Energy Transaction Units, as reflected in the materials 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 of the Budget & Finance Subcommittee.

SECTION IV.A

RECOVERY OF ISO ADMINISTRATIVE EXPENSES

IV.A.8 Collection of Commission Annual Charges

Schedule 1 Scheduling, System Control and Dispatch Service

Schedule 2 Energy Administration Service

Schedule 3 Reliability Administration Service

Schedule 4 Collection of Commission Annual Charges

Schedule 5 Collection of NESCOE Budget

Schedule 2
Energy Administration Service

Energy Administration Service ("EAS") is the Service provided by the ISO to administer the Energy Market.

The ISO's expenses are based on the functions required to provide EAS and include, but are not limited to:

- Core operation of the Energy Market;
- Generation and demand dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Market power monitoring and mitigation for the Energy Market;
- Sanctions activities;
- Operation of FTR auctions;
- Market assessment and reports; and
- Formulation of additional market rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (Energy TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

Energy TU Based Charges: For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions or operation of a SATOA. Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:

(1) $0.86039 times the Customer's first 12,500 Energy TUs for that month; plus

(2) $0.78217 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus

(3) $0.70396 times the amount of Energy TUs that exceed 39,500.

Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids shall pay, in arrears, amounts equal to:

(1) $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus

(2) $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.

Volumetric Measure Based Charges: A Customer shall be considered an EAS VM Customer if the sum of Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (measured in megawatthours, MWh and excluding Coordinated External Transactions) assessed to that Customer during the month exceeds zero (0), in which case, the total EAS VM charges for that Customer shall be equal to the sum of:

(1) Monthly Real-Time Load Obligation (MWh), excluding Monthly Real-Time Load Obligation associated with Coordinated External Transactions;

(2) Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs, and provided further that Monthly Real-Time Generation Obligation associated with Coordinated External Transactions shall be excluded; and

(3) Monthly Real-Time Demand Reduction Obligation (MWh).

Subject to the foregoing, each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:

(a) $0.58201 per MWh for the first 250,000 MWh of EAS VM for that month; plus

Storage as Transmission-Only Assets (SATOAs) Exclusion from ISO Tariff Section IV.A

Conforming Changes to Section IV.A – "ISO Self Funding Tariff"

John Waggoner

MANAGER, BUDGET & FINANCE REPORTING



Storage as Transmission-Only Assets (SATOAs) Exclusion from ISO Tariff Section IV.A

Proposed Effective Date: March 1, 2027

- Previous tariff changes defined the treatment of SATOAs
- The ISO is proposing conforming revisions to Section IV.A, Schedule 2 of the Tariff, to note the exclusion of SATOA activities from Energy Transaction Units (TU)
- The ISO welcomes feedback on the proposed changes

Background

- On December 29, 2022 the ISO made a FERC filing for tariff revisions to enable the treatment of SATOA's[1]
  - On October 19, 2023 the FERC accepted the ISO's SATOA tariff filing revisions[2]
  - SATOA tariff language become effective on September 1, 2026 [3]
- A summary of tariff related changes for SATOAs that have been made includes:
  - SATOA and Real-Time SATOA Obligation definitions as noted on slide 4 of this presentation
  - Section II, Open Access Transmission Tariff, includes new Section II.51 with SATOA rules related to planning and operations
    - Section II.51.3 – limits the charges that are applicable to a SATOA
      - "Transmission Service Associated with SATOA Operation: Transmission service charges including charges for Ancillary Services, and charges assessed or revenues allocated under Schedules 1, 2, 3, and 5 of Section IV.A of the Tariff are not applicable to the operation of a SATOA."
  - Section III.1.7.21, Market Rule 1, contains market-related rules to limit a SATOAs participation in New England Markets
  - Transmission Operating Agreement (TOA) adds definition of a SATOA and includes it as a Category A facility

[1] 12/29/2022 SATOA filing - Part 1 and Part 2

[2] 10/19/2023 FERC Order Accepting SATOA related tariff revisions - FERC Order for SATOA

[3] 02/07/2025 SATOA effective date filing Metered Quantity for Settlement Rules and Notice of SATOA Effective Date

Background (cont.)

- A *SATOA* is defined in Section I of the ISO Tariff as electric storage equipment that:
  - Is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher;
  - The ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and
  - Is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities
- Market Rule 1 provides how SATOAs participate in the Real-Time markets (Real-Time SATOA Obligations)
  - Section III.3.2.1(b) of the ISO Tariff provides that "Each PTO shall have for each settlement interval a Real-Time SATOA Obligation for energy at each Location equal to the sum of: (1) the MWhs of energy, where such MWhs of energy shall have positive value, provided by SATOAs at that Location; and (2) the MWhs of load, where such MWhs of load shall have a negative value, consumed by SATOAs at that Location"

Proposal and Rationale

- Per review and analysis of settlement calculations, Real-Time SATOA Obligation would currently impact the calculation of a Section IV.A, Schedule 2 Energy Transaction Unit (TU)
- To conform with the existing tariff language discussed in this presentation, the ISO proposes conforming revisions to Section IV.A, Schedule 2 of the Tariff, to note the exclusion of SATOA activities from Energy TUs:
  - In conformity with Section II.51.3 of the Open Access Transmission Tariff as noted on slide 3
    - Since a SATOA is not subject to Transmission and Ancillary Service charges, has limited market participation, and cannot submit market offers it was determined there would be no charges assessed or revenues allocated under Section IV.A Recovery of ISO Administrative Expenses

Summary of Proposed Tariff or Manual Changes[4]

Section	Tariff or Manual Change	Reason for Change
Addition to the first sentence of Section IV.A, Schedule 2 "Energy Administration Service" for Energy TU Based Charges	"For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions or operation of a SATOA. Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:"	Addition of conforming language to explicitly provide that SATOAs are excluded from charges under Tariff Section IV.A, Schedule 2, Energy TU-Based Charges consistent with the treatment of Coordinated External Transactions

[4] Section IV.A redlines are being provided with these materials

Conclusion

- The ISO proposes conforming changes to add language explicitly excluding SATOAs from charges under Tariff Section IV.A, Schedule 2, Energy Transaction Units (TUs)
- The ISO is targeting a December 2026 FERC filing with a planned effective date of March 1, 2027 for the proposed conforming changes.
  - SATOA rules became operative on September 1, 2026, but as outlined in prior ISO filings, six months (i.e., March 1, 2027) is the earliest feasible timeframe to implement the software and system to support the operation and settlement of SATOAs[5]

[5] See Page 11 of 02/07/2025 SATOA effective date filing letter Metered Quantity for Settlement Rules and Notice of SATOA Effective Date

Stakeholder Schedule[6]

Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee October 9, 2026 [7]	Introduce the proposed Section IV.A Schedule 2 changes and address any clarifying questions
Participants Committee November 12, 2026	Vote on the Tariff Section IV.A Schedule 2 changes

[6] The Budget and Finance Subcommittee was previously briefed on SATOA-related tariff changes in August 2022 - August 2022 SATOA Presentation to B&F Subcommittee

[7] Should an additional Budget and Finance Subcommittee discussion be necessary, the Subcommittee may continue discussions at its November 20, 2026 meeting

Questions



About the Presenter

John Waggoner

Manager, Budget & Finance Reporting

ISO New England

jwaggoner@iso-ne.com

2026 Open Meeting

ISO New England Board of Directors



3 CEO Report



ISO NEW ENGLAND'S STRATEGIC PLAN

Vamsi Chadalavada
President & CEO, ISO-NE



Nov 12, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

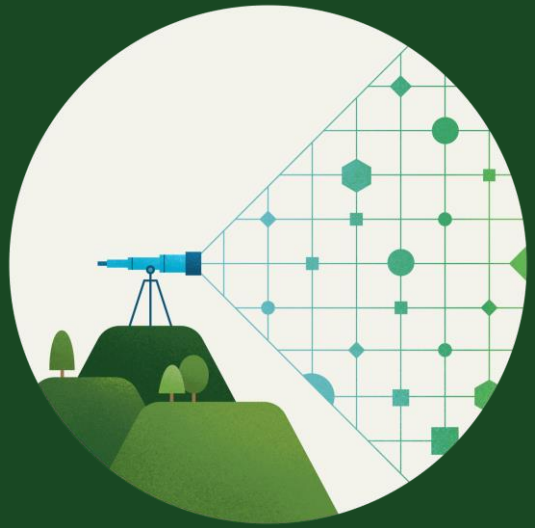
ISO NEW ENGLAND'S STRATEGIC PLAN

Vamsi Chadalavada
President & CEO, ISO-NE

Our Mission is Unchanged



Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity



Our Vision

We aspire to be indispensable to New England by delivering trusted, independent, and innovative services and solutions that reliably power the region's evolving energy future



Strategy Statement

Drive increasing value for the region through exceptional, cost-effective core services, and by developing new high-impact solutions that we are uniquely positioned to deliver



Mission

Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity



Vision

We aspire to be indispensable to New England by delivering trusted, independent, and innovative services and solutions that reliably power the region's evolving energy future



Strategy

Drive increasing value for the region through exceptional, cost-effective core services, and by developing new high-impact solutions that we are uniquely positioned to deliver

OUR 2032 ASPIRATIONS

ISO-NE Is a Valued Partner to the Region

We set the standard for cost-effective design and operation of wholesale electricity markets and transmission infrastructure

We are trusted by states and stakeholders to deliver objective information and tools that drive meaningful and lasting impact



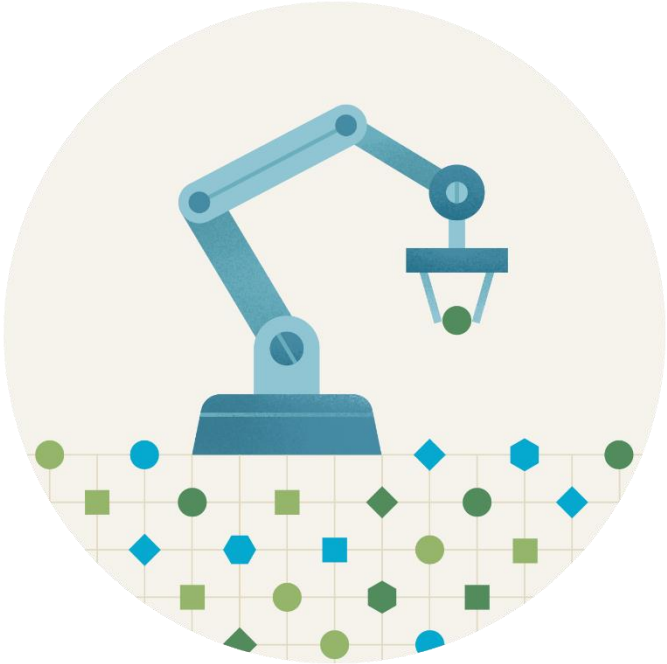
OUR 2032 ASPIRATIONS

Reliability Is Powered by Competitive Markets

We maintain reliability despite uncertainty regarding both supply and demand

An innovative, expanding suite of market products reliably integrates new energy supply and demand technologies

The competitive wholesale markets inspire the confidence of private investors and ensure a highly reliable generation fleet



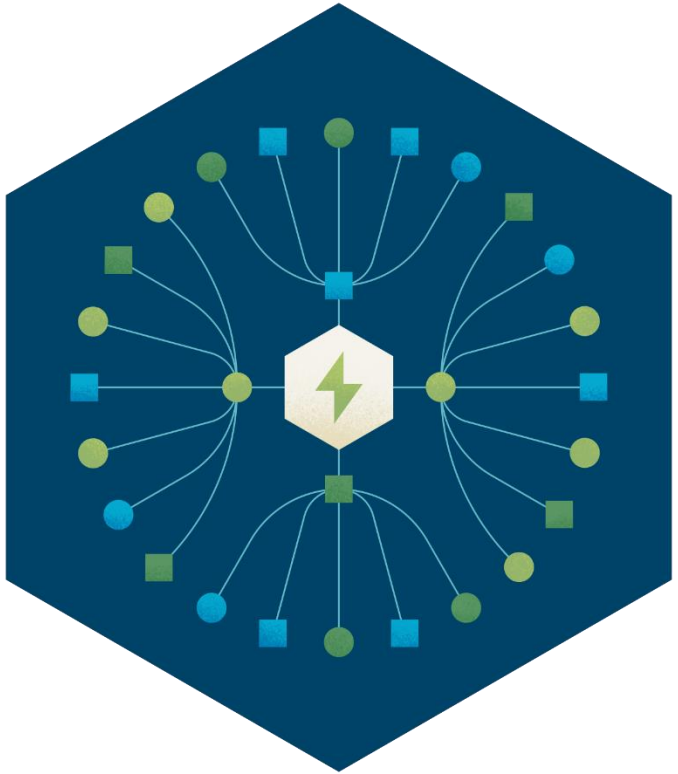
OUR 2032 ASPIRATIONS

ISO-NE Is Where Outstanding People Do Their Best Work

We attract and retain talented people through an environment where all feel valued

We operate as a results-oriented, innovative, and collaborative organization committed to continuous improvement

Modernized and dependable tools and AI significantly accelerate innovation and organizational efficiency



Our Strategic Beliefs

Attracting and retaining top talent will require a strong sense of purpose, a high-performing culture, and compelling career growth opportunities

Wholesale markets will continue to provide incentives to maintain the existing fleet and attract new entry while managing major disruptions such as large loads and siting constraints

Even as the region's resource mix transitions, **existing resources will remain essential** to reliability for the foreseeable future

Affordability will remain front and center as the region navigates an evolving energy future

Our Strategic Beliefs



AI and emerging technologies will impact how we work and how the grid operates



Persistent policy and regulatory uncertainty will require agile, disciplined navigation of often-competing federal, state, regional, and local priorities



Demonstrating and substantiating the increasing value we deliver will be critical to strengthening stakeholder trust and public confidence

Our Strategic Opportunities

Elevate the Core

- Implement Capacity Auction Reforms
- Implement Temporally Optimized Pricing and Dispatch
- Bolster Operational Capabilities of the Existing Fleet

Protect the Core

- Create Resource Adequacy Probabilistic Tool
- Establish Universal Data Platform

Change the Game

- Maximize Demand Flexibility
- Deploy Asset Condition Reviewer
- Modernize Forward Transactions Market Platform

OPPORTUNITY:

Implement Capacity Auction Reforms

Compensate capacity resources commensurate with their contribution to system reliability as New England's resource mix continues to evolve



Why It's Important

Procure a more cost-effective mix of capacity resources, now and for the future

Align regional reliability benefits with costs as the power system's resources evolve

Incentivize investment in diverse technologies that have greater reliability benefits

OPPORTUNITY:

Implement Temporally Optimized Pricing and Dispatch

Revise the real-time markets to efficiently manage ever-greater demands on the power grid as the sun rises and sets each day



Why It's Important

Enhance system reliability when the grid's load increases rapidly as the sun sets

Enable more cost-effective real-time dispatch by accounting for upcoming swings in solar output

Better employ new storage technologies and accommodate growing intermittent energy sources in New England

OPPORTUNITY:

Bolster Operational Capabilities of the Existing Fleet

Assess expansion of dual-fuel capability to strengthen near-term resource and winter energy adequacy



Why It's Important

Expanding and enhancing existing generating resources will bolster system capacity

Improve reliability and market efficiency when regional gas system is constrained

OPPORTUNITY:

Create Resource Adequacy Probabilistic Tool

Provide more granular insight into potential high-impact, low-probability energy shortfall and loss-of-load events from three to 10 years into the future



Why It's Important

Provide a platform to access ISO-NE resource adequacy models

Allow generation developers, suppliers, and the states to model scenarios to make informed decisions on investment and policy design

OPPORTUNITY:

Establish Universal Data Platform

Give market participants self-service access to structured, high-quality data using analytics tools and / or pre-built dashboards and reports



Why It's Important

Enhance transparency, insight, and operational efficiency

Promote broader innovation, for which data plays a key role

Gain efficiencies by minimizing ad hoc custom reporting

OPPORTUNITY:

Maximize Demand Flexibility

Strengthen ISO-NE's ability to ensure reliability amid constrained regional energy supply and infrastructure, and design cost-effective transmission plans



Why It's Important

Optimizing wholesale and retail demand response improves system efficiency

Demand flexibility during peak hours reduces need for new infrastructure

Demand flexibility plays a key role in managing short duration energy shortages, which supports reliability

OPPORTUNITY:

Deploy Asset Condition Reviewer

Perform advisory reviews of asset condition project proposals to replace or reconstruct aging transmission facilities, in a role requested by the New England states and stakeholders



Why It's Important

Create a consistent and transparent review framework for asset condition projects across the region

Provide independent advisory findings to strengthen stakeholder understanding of project need, scope, alternatives, and cost considerations

OPPORTUNITY:

Modernize Forward Transactions Market Platform

Create a voluntary, transparent, open, and centrally-cleared futures platform for capacity and other ISO-NE products



Why It's Important

Support greater cost certainty and reduced risk for wholesale buyers and sellers, which benefits consumers

Foster transparent multi-year price signals to guide new resource investment

Provide competitive capacity cost benchmarks for retail rate regulators in New England

STRATEGIC TOOLS:

Scale Technology & Artificial Intelligence

Leverage AI responsibly, enabling faster decisions, deeper insights, and greater impact

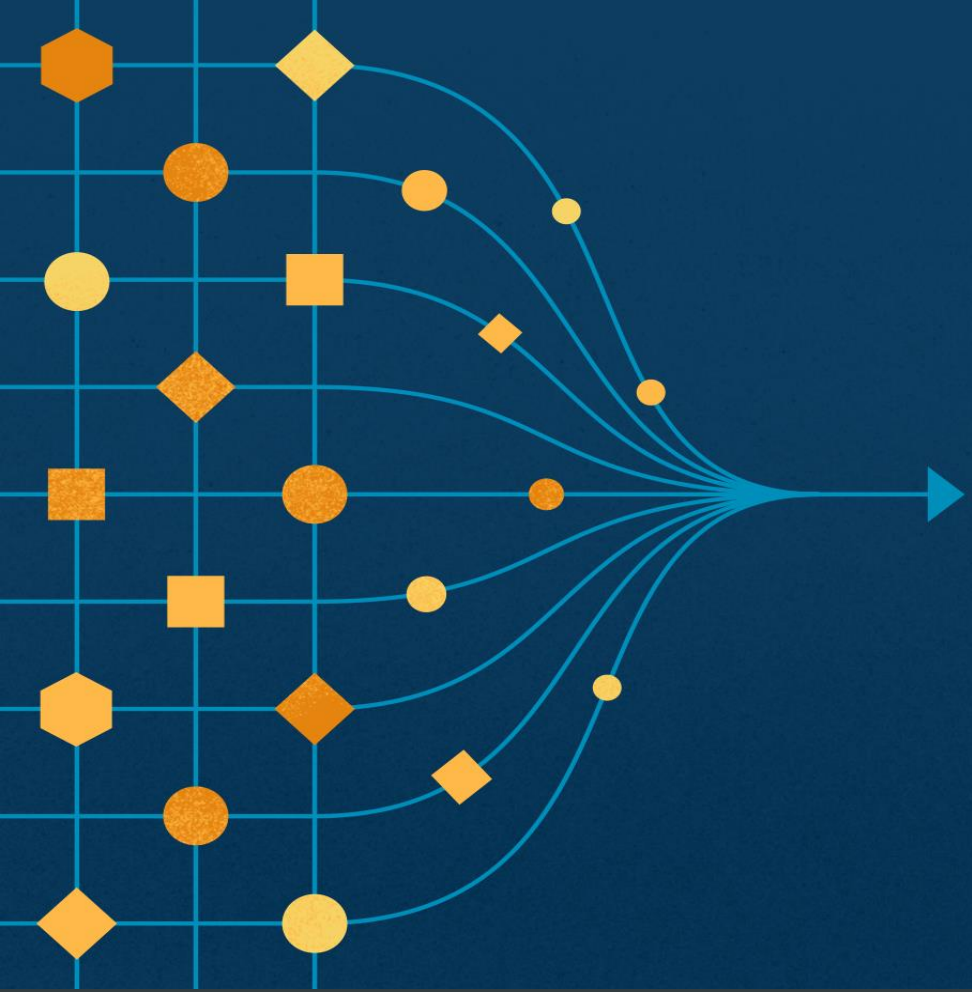


Why It's Important

Accelerate project timelines and more efficiently execute system studies, models, and operational analyses

Allow workforce to focus on high-value, complex work

Deliver quicker and impactful business outcomes to benefit the region



External launch of strategy in Q1 2027

4 Winter Outlook and Nov 2026 System & Market Operations Report

REPORT

NOVEMBER 12, 2026| HILTON BOSTON BACK BAY, BOSTON, MA

NEPOOL PARTICIPANTS COMMITTEE | 11/12/2026
Meeting Agenda Item #4

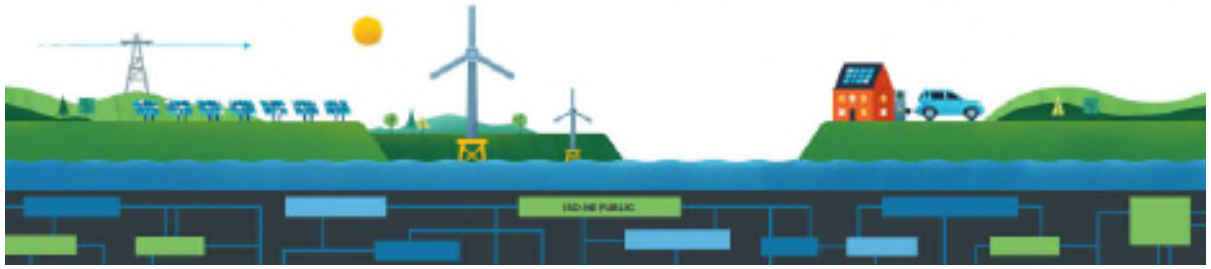
ISO new england

NEPOOL Participants Committee

Winter Outlook and System & Market Operations Report – November 2026

Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



Nov 12, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

NEPOOL PARTICIPANTS COMMITTEE | 11/12/2026
Meeting Agenda Item #4

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Winter Outlook and System & Market Operations Report – November 2026

Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



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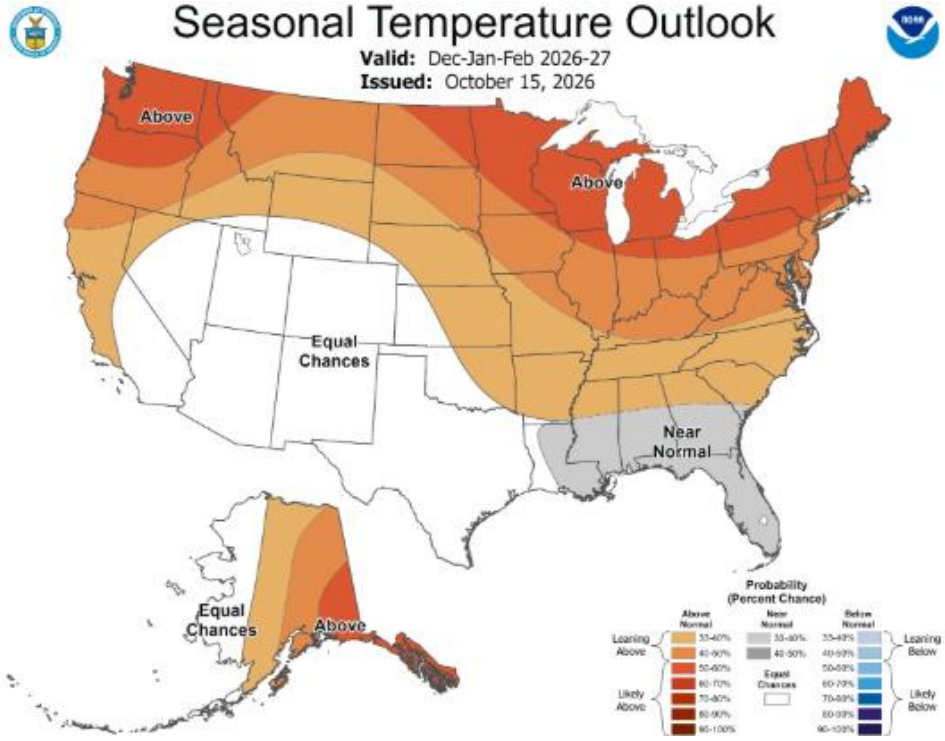
2026/2027 WINTER OUTLOOK

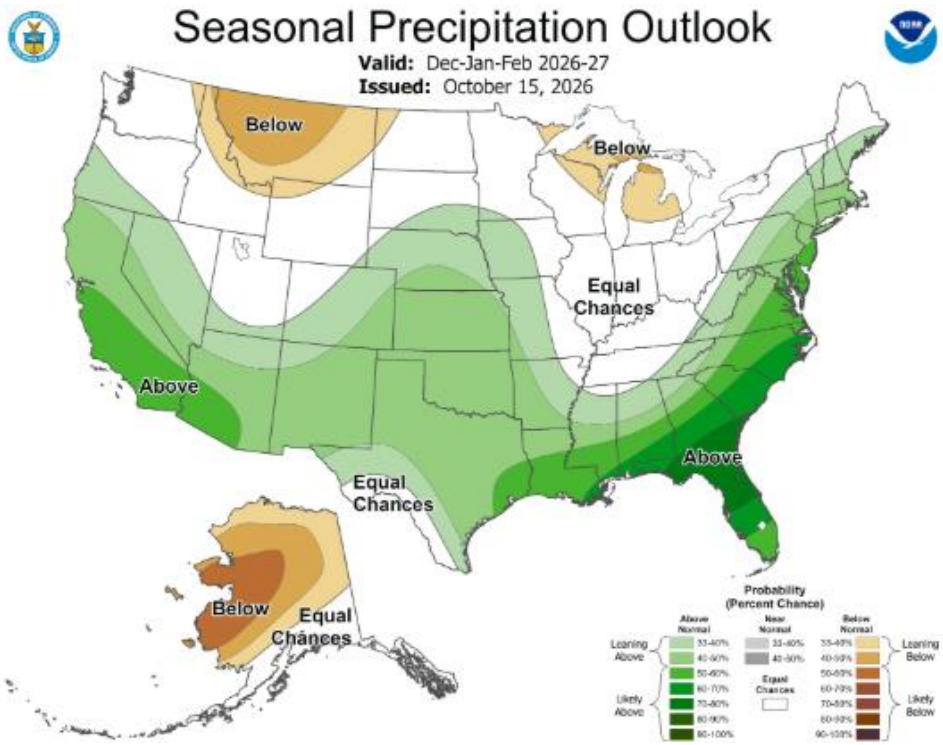
2026/2027 Winter Outlook Highlights

- Seasonal outlooks show a 50-60% probability of above-normal temperatures and a 33-50% probability of above-normal precipitation across most of New England
- Winter peak demand forecasts are slightly higher than last year
- Newly commercial offshore wind facilities are expected to bolster winter operations
- Fuel oil supplies are expected to start the winter higher than last year, with more replenishment anticipated in the next month
- Sufficient capacity and energy are expected this winter
  - Lowest capacity margin is forecasted for the week beginning January 9[1]
  - Energy shortfall risk from extreme winter events does not exceed the Regional Energy Shortfall Threshold (REST), given the existing resource mix and expected loads

1 - Based on ISO's November 2, 2026 Annual Maintenance Schedule

Winter Temperature and Precipitation Outlook





Winter Expectations

- Demand Forecast
  - 50/50 winter peak demand forecast of 20,483 MW, which is ~112 MW (~0.6%) higher than the 2025/26 forecast
  - 90/10 winter peak demand forecast of 21,457 MW, which is ~11 MW (~0.1%) higher than the 2025/26 forecast
  - The Winter 2025/2026 peak demand of 20,182 MW occurred on January 25, 2026
- Scheduled Generation and Transmission Outages
  - Generation and transmission outages have been coordinated to minimize any adverse impacts; no significant generation or transmission outages are currently scheduled
- Transfer Capability
  - Per the normal protocol, transfer capability on the New York Northern AC ties has been increased (effective 11/1/26) from 1,400 to 1,600 MW for the winter period

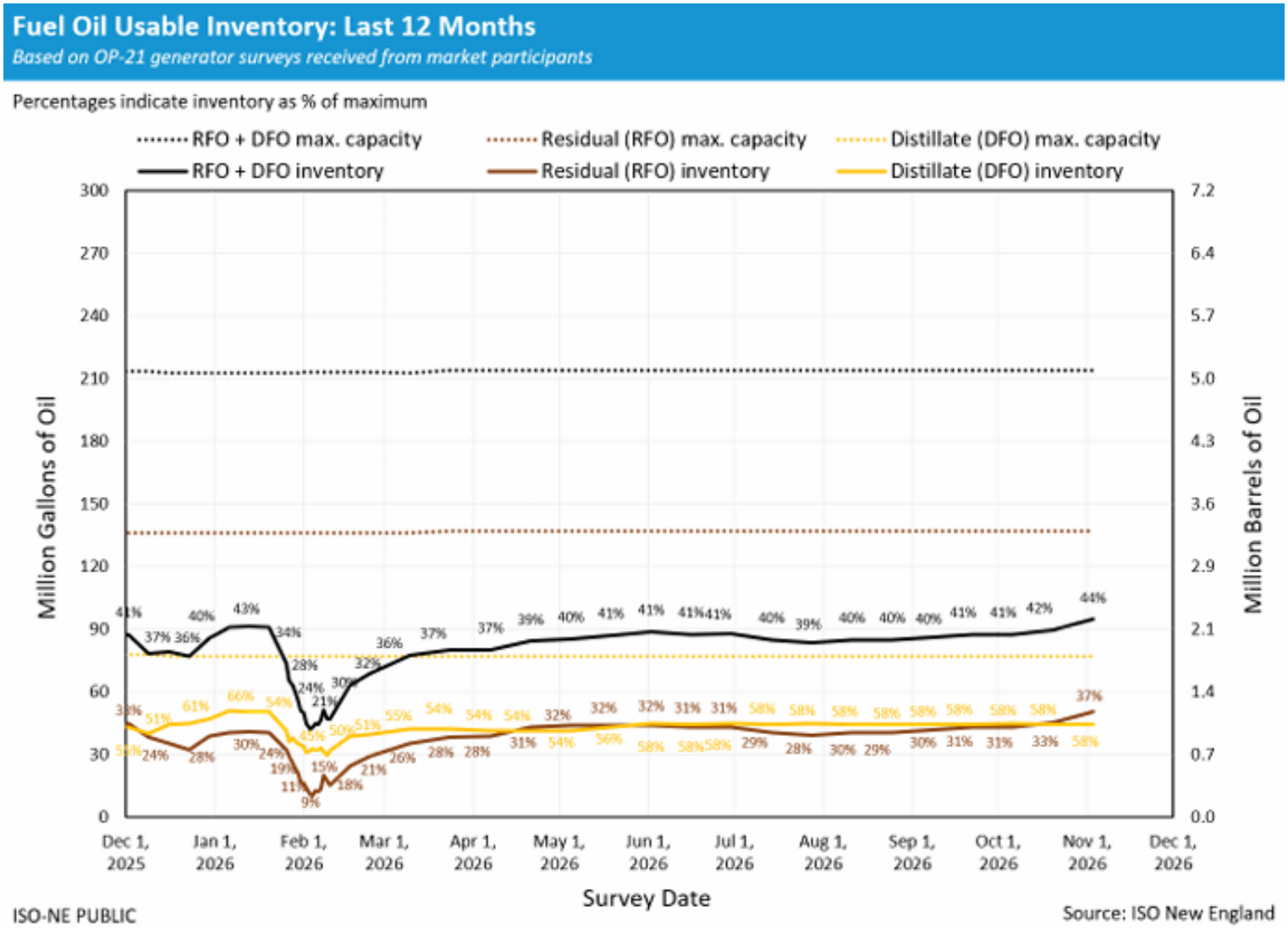
Winter Expectations, cont.

- Natural Gas Deliverability
  - ISO will monitor natural gas deliverability using its normal operating protocols
  - As in past winters, ISO assumes approximately 3,900–4,800 MW of gas-only generation may be unavailable on the coldest days due to constrained natural gas pipelines
- Capacity Outlook
  - The lowest projected capacity margins are ~3,100 MW (50/50 forecast) and ~2,100 MW (90/10 forecast), both for the week beginning January 9
  - Extended cold weather could quickly deplete stored fuel, and ISO's capacity outlook and 21-day energy assessments will be adjusted accordingly

LNG and Fuel Oil Expectations

- Current fuel oil inventory is ~94.5 M gallons (~44% of maximum storage capacity)
- Pre-winter fuel oil replenishment is underway with more expected in the next month
- Saint John LNG tanks are expected to be full (~10 Bcf) heading into the winter
- Fuel oil delivery times are expected to be longer than normal though supplies are expected to be adequate; ISO staff remains attentive to geopolitical factors that may impact fuel supply chains

Total Usable Fuel Oil in New England



Winter Energy Analysis

- Extreme weather events were studied to evaluate the region's energy shortfall risk this winter
  - Studies were performed using ISO's Probabilistic Energy Adequacy Tool (PEAT) and results were compared to the Regional Energy Shortfall Threshold (REST)
- Similar to the methodology employed for ISO's prior PEAT-based analysis, the events studied were those identified as having the most significant shortfall risk
- Each weather event was studied 720 times (*i.e.*, "cases"); each case represented different combinations of fuel oil inventories, LNG inventories, imports, and generator forced outages

Winter Energy Analysis, cont.

- Key Assumptions
  - Existing resource mix, including Revolution Wind, Vineyard Wind, and New England Clean Energy Connect (NECEC), in-service
  - ~9 GW of behind-the-meter (BTM) PV nameplate capacity
  - Up to 1.3 Bcf/d of LNG injection capability from Saint John LNG and the Everett Marine Terminal (EMT)
    - EMT is expected to be available to aid in meeting LDC demand; ISO assumes that in extreme weather conditions when prices are very high, EMT will sell gas to electric power generation

Energy Analysis Results Show Minimal Risk When Compared Against REST Criteria

- The REST criteria is defined as follows:
  - acceptable shortfall **magnitude** of **3%**
  - acceptable shortfall **duration** of **18 hours**
  - magnitude and duration must **both** be exceeded for the REST to be violated
- ISO's PEAT-based evaluation of extreme events for this winter resulted in shortfall magnitude of 0.1% and shortfall duration of 0.33 hours, **both well below the established REST criteria**
- Study results are consistent with the existing resource mix and ISO's expectations for load this winter

Winter Preparations

- ISO staff hosted the Generator Winter Readiness Seminar with Market Participants on October 27, 2026
- Winter Generator Readiness Surveys responses are due by December 1, 2026
- Annual Natural Gas Critical Infrastructure Surveys were completed earlier in 2026, ensuring that critical gas infrastructure is not part of automatic or manual load shed schemes
- Dual fuel audits of ~30 generators totaling ~6,700 MW of capacity are to be completed prior to December 1, 2026
- Generator Fuel and Emissions Surveys and 21-Day Energy Assessments will be performed weekly (or daily, if required) during the winter season

SYSTEM & MARKET OPERATIONS REPORT

November 2026

System & Market Operations Report Enhancements

- This month's report carries forward several clarity and usability improvements first introduced in the June 2026 System & Market Operations Report (see slide 7 of the June report for a summary)
- To streamline the report, several slides are now marked with footnotes noting that they will be removed in future reports since the information is part of ISO's routine reporting and is readily available elsewhere; in addition to the slides previously noted, these slides to be removed in future reports now also include:
  - Slide 71, DA and RT NCPC Charges
  - Slide 72, NCPC Charges by Type
  - Slide 73, NCPC Charges by Type as a Percent of Energy Market Value
  - Slide 74, NCPC Charge Allocations
  - Slide 75, RT First Contingency Paid Allocated to RTLO/RTGO
  - Slide 76, RT First Contingency Charges to Deviation Type
- Slide 55, Average Hourly DAAS Prices, has been retained in response to feedback received at last month's committee meeting.
- Further enhancements are planned in the coming months to continue simplifying and improving the report

HIGHLIGHTS

System & Market Operations Report Key Takeaways

- October peak demand (RQM) was ~1% higher than in October 2025 and ~14% lower than in September 2026 (see slide no. 20)
- October total market value was ~13% lower than in October 2025 and ~6% lower than in September 2026 (see slide no. 21)
- Day-Ahead Ancillary Services (DAAS) post-implementation adjustments, including the Forecast Energy Requirement (FER) Demand Quantity Adjustment and the Strike Price Adjustment, took effect with the October 22 Day-Ahead market
- As reviewed at the October 20 Reliability Committee meeting, the ISO made two changes effective with the November 1 operating day:
  - Reduced the reserve Non-Performance Factor (NPF) from 115% to 110%
  - Shortened the normal Unit Dispatch System (UDS) Look Ahead from 15 to 10 minutes
- Several significant transmission and generation outages are scheduled to finish before winter (see slide no. 34 for a summary)

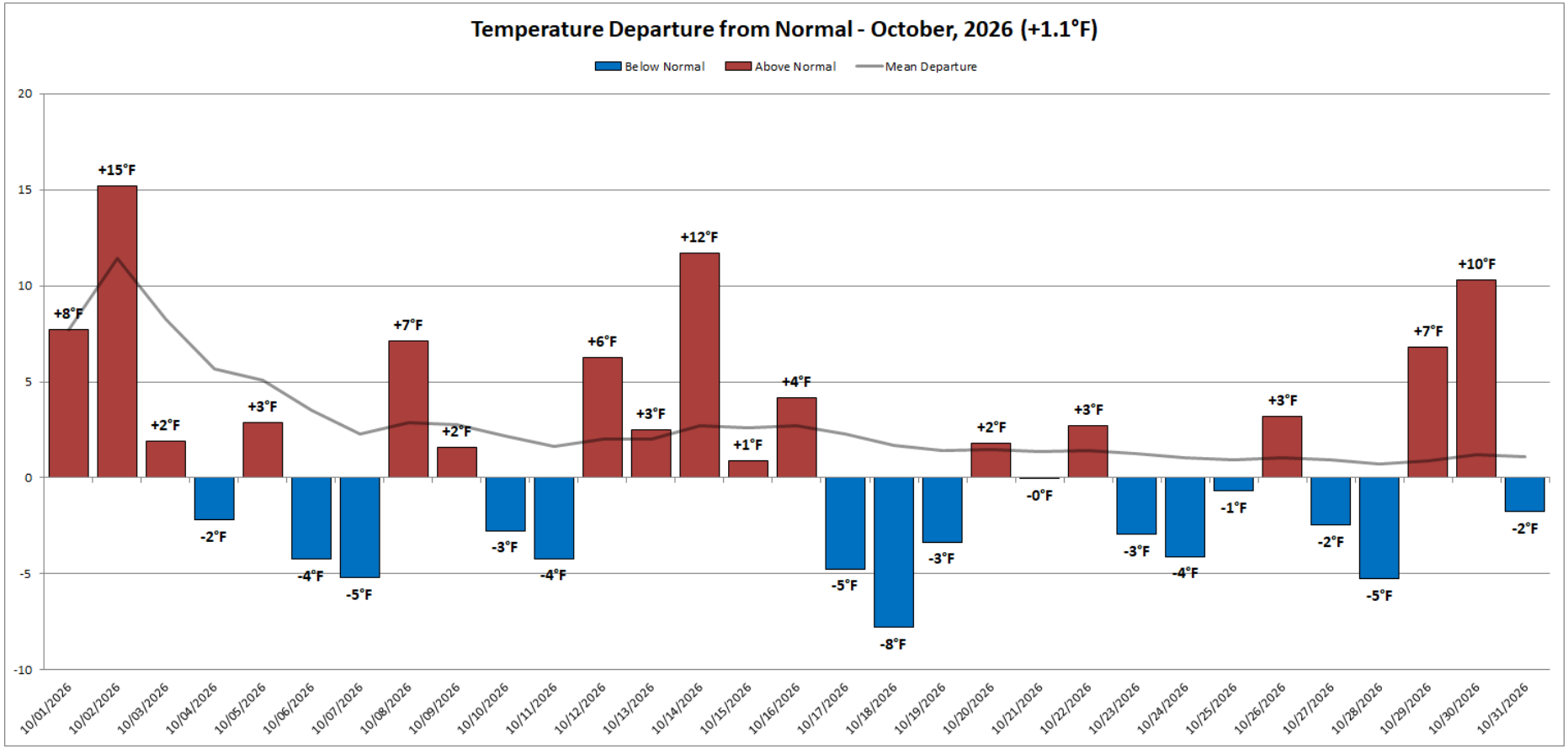
Weather At-a-Glance

October 2026

New England Weather	**OCT 2026**	**Change M-O-M**	**Change Y-O-Y**
Avg Hourly Temperature (°F) ***(23-City Weighted)***	52.5°	-10.2° ↓	-1.0° ↓
Boston Weather			
Temperature Departure from Normal (°F)	1.4°	2.4° ↑	-.2° ↓
Maximum Temperature (°F)	87.0°	0.0° —	3.0° ↑
Minimum Temperature (°F)	37.0°	-12.0° ↓	-3.0° ↓
Avg Hourly Temperature (°F)	56.2°	-8.4° ↓	-.2° ↓
Precipitation Departure from Normal (inches)	-1.95"	-3.74" ↓	-2.88" ↓
Precipitation (inches)	2.08"	-3.27" ↓	-2.88" ↓
Hartford Weather			
Temperature Departure from Normal (°F)	1.1°	1.9° ↑	0.1° ↑
Maximum Temperature(°F)	88.0°	1.0° ↑	3.0° ↑
Minimum Temperature(°F)	28.0°	-15.0° ↓	-1.0° ↓
Avg Hourly Temperature (°F)	54.1°	-9.9° ↓	0.1° ↑
Precipitation Departure from Normal (inches)	-2.14"	-3.33" ↓	-2.24" ↓
Precipitation (inches)	2.38"	-3.20" ↓	-2.24" ↓

Weather At-a-Glance, cont.

New England 23-City Temperature Departure From Normal – October 2026



Markets At-a-Glance: Demand

*Data through October 31, 2026**

Average Hourly Net Energy for Load (MWh)[a]	**Oct 2026**	**% Change M-O-M**	**% Change Y-O-Y**	
Revenue Quality Metered (RQM)	11,627	-6.7% ↓	-0.04% ↓	
Telemetered	11,114	-7.2% ↓	-0.6% ↓	
Max/Min Hourly System Load (MW)				
Maximum RQM	16,106	-13.7% ↓	1.1% ↑	Fri, Oct 2, 2026 in HE18
Maximum Telemetered	15,881	-13.1% ↓	0.2% ↑	Fri, Oct 2, 2026 in HE18
Minimum Telemetered	6,964	-5.4% ↓	-5.7% ↓	Sat, Oct 10, 2026 in HE13
Year-To-Date Hourly Peak Load (MW)[b]				
RQM	25,832	0.0%	-2.9% ↓	Thu, Jul 2, 2026 in HE19
Telemetered	25,361	0.0%	-2.5% ↓	Thu, Jul 2, 2026 in HE19
Forward Capacity Market (FCM) Load[c]	25,303	0.0%	-2.6% ↓	Thu, Jul 2, 2026 in HE19
Other RT Load (Average Hourly MW)				
Scheduled Exports	1,505	-19% ↓	-5% ↓	
Energy Storage Load	308	14% ↑	19% ↑	

*Based on available settled days.
[a] RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SORs). Telemetered loads as monitored by the Control Room. Both are 'net energy for load' concepts and therefore include transmission losses. Neither of reflect storage load. Due to the difference in metering quality, derivation, and the impact of SORs, the RQM and Telemetered peaks can occur on different days and/or hours.
[b] Y-T-D % Change Y-O-Y is based on like periods (i.e., through similar months). Y-T-D values are available in the Weekly Market Report found on the ISO website.
[c] FCM load values reflect the sum of active, normal load assets that are non-dispatchable (it excludes storage load), are included in the FCM settlement and do not reflect any transmission losses. FCM Load is Revenue Quality Metered.

Markets At-a-Glance: Payments and Prices

*Data through October 31, 2026**

Market Value ($ millions)[a]	Oct 2026	% Change M-O-M	% Change Y-O-Y
Energy Market Value[b]	412	-8% ↓	-12% ↓
Ancillary Services[c]	10	41% ↑	-42% ↓
Forward Capacity Market (FCM)	78	0%	-13% ↓
Net Commitment Period Compensation (NCPC)	3	100% ↑	23% ↑
Total	**502**	**-6% ↓**	**-13% ↓**
Average Power Prices ($/MWh)			
DA Hub LMP	39.26	-5% ↓	-3% ↓
DA Hub LMP Plus Forecast Energy Requirement (FER) Price	41.62	-3% ↓	-11% ↓
RT Hub LMP	37.48	-5% ↓	-8% ↓
Average Generation Fuel Prices ($/MMBtu)			
Natural Gas (MA Avg.)	1.46	-16% ↓	-38% ↓
Diesel	37.66	1% ↑	115% ↑
No. 6 Oil	17.92	2% ↑	68% ↑
Regional Greenhouse Gas (RGGI) Spot Price[d]	2.32	1% ↑	65% ↑
MA Electricity Generator Emissions Limits (MA EGEL) Price[d]	0.73	-45% ↓	15% ↑

*Based on available settled days. Complete month data for Energy Market Value, Capacity Value, and LMPs are available in the Monthly Market Report published circa the 15th of the month found on the ISO website.

[a] Market Value totals are converted to 'equivalent month' values before doing the comparisons to prior months.

[b] Energy Market Value includes net costs associated with satisfying the FER constraint.

[c] Ancillary Services (A/S) = Day-Ahead and Real-Time Reserves, Regulation, less Marginal Loss Revenue Fund.

[d] Assumes an emissions rate of 117 lbs/MMBtu.

Underlying natural gas data furnished by: ICE Global markets in clear view

Markets At-a-Glance: Supply

*Data through October 31, 2026**

Average Hourly RQM Supply[a]	**Oct 2026 (MWh)**	**% Change M-O-M**	**% Change Y-O-Y**
Total RQM Supply	13,440	-8% ↓	-0.15%
Natural Gas	5,509	-10% ↓	-21% ↓
Nuclear	2,524	-24% ↓	-12% ↓
Solar	632	4% ↑	17% ↑
Hydro	473	8% ↑	3% ↑
Wind	1,163	37% ↑	77% ↑
Onshore Wind	590	38% ↑	25% ↑
Offshore Wind	573	35% ↑	214% ↑
Other[b]	462	-22% ↓	4% ↑
Hybrid/Solar	79	8% ↑	19% ↑
Oil	4	413% ↑	-38% ↓
Batteries	34	10% ↑	58% ↑
Demand Response Resources (DRRs)	0.04	-69% ↓	-71% ↓
Scheduled Imports	2,559	1% ↑	78% ↑
Average Hourly Behind-The-Meter (BTM) Solar[c]	**1,193**	**-4% ↓**	**17% ↑**

*Based on available settled days.
[a] Supply is RQM quality and includes both Modeled and Settlement Only Resources (SORs) and includes DRR and imports. Differs from NEL load due to not being adjusted for exports, Dispatchable Asset Related Demand (DARDs) and inadvertent tie flows.
[b] Other generation includes landfill gas, methane, wood, coal and refuse.
[c] BTM Solar is an average hourly (all hours) estimate. Historically, the majority (~2/3rd) of BTM solar is distributed solar and is not captured in RQM supply numbers.

System Planning Highlights

- The ISO posted the preferred Longer-Term Transmission Solution on 8/14/26, and notified the Qualified Transmission Project Sponsors (QTPSs) they were selected
  - The QTPSs executed all Selected QTPS Agreements by 10/15/26, and they are posted on the ISO website
- CELT 2027 forecast discussions began at the October 23 Load Forecast Committee meeting
- The next LFC meeting will be held on December 11

Forward Capacity Market (FCM) Highlights

- CCP 17 (2026-2027)
  - The ISO filed the ICR and related values with FERC, for the ARA3 that was conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.
  - The third annual reconfiguration auction (ARA3) was held March 2-4, 2026. Results were posted on March 31, 2026.
- CCP 18 (2027-2028)
  - The second annual reconfiguration auction (ARA2) was held August 3-5, 2026 and results were posted on September 2, 2026.
  - The ISO presented the assumptions for the ICR and related values studies for the ARA3 at the August PSPC meeting.
  - The ISO reviewed the proposed tie benefits values for the ARA3 at the September 17, PSPC meeting.
  - At the October 15 PSPC meeting and October 20 RC meeting, the ISO presented proposed ICR and related values for the ARA 3 that will be conducted in 2027. RC voted to approve the values.

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

FCM Highlights, cont.

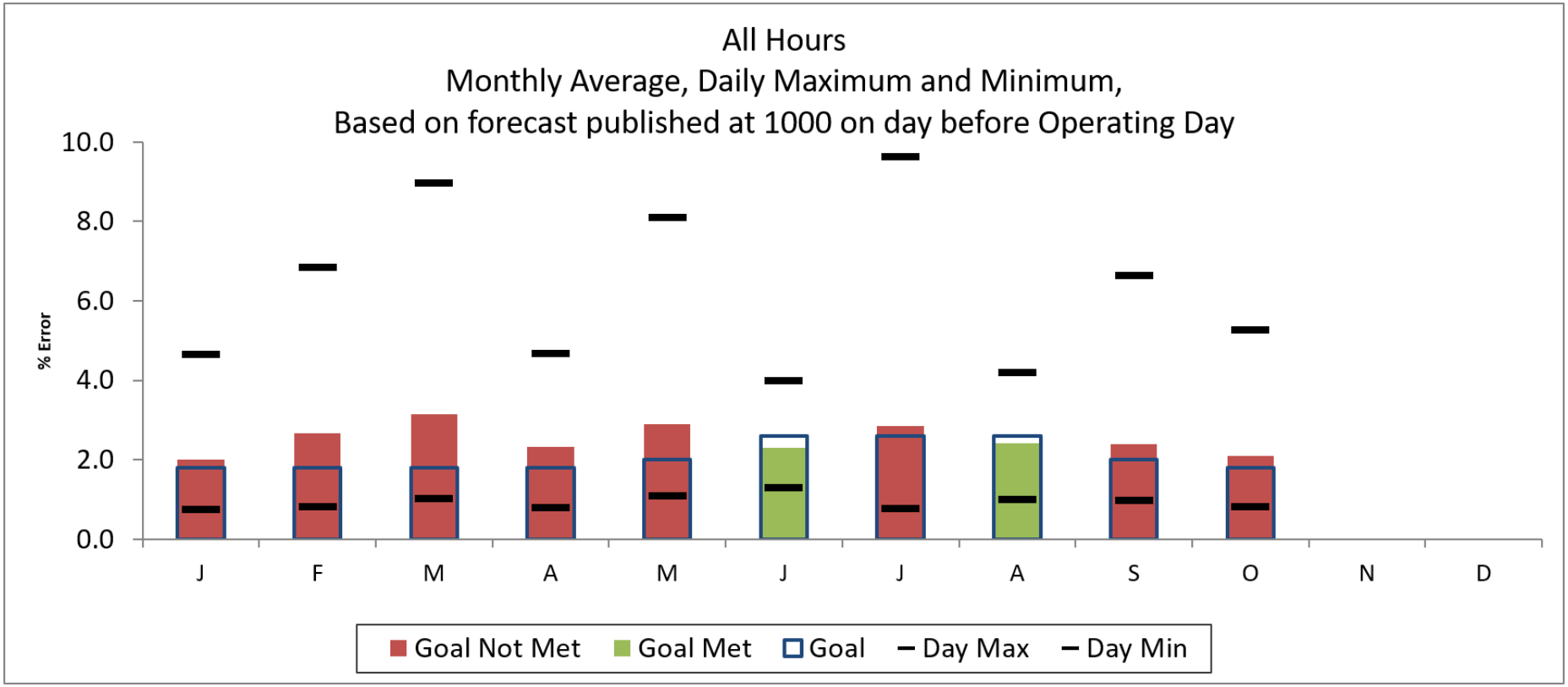
- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
    - On May 20, 2024 FERC issued an order accepting the additional delay
    - 2024 interim RA qualification process completed on November 1, 2024
      - A total of 1,389 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
    - 2025 interim RA qualification process completed on November 3, 2025
      - A total of 1,455 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
      - The Transitional CNR Group Study was completed with the completion of the 2025 interim RA qualification process
    - 2026 interim RA qualification process
      - The New Capacity Qualification Package (NCQP) submission window was open June 15-23, 2026
      - Qualification Determination Notifications were issued on October 16, 2026 and Qualified Capacities will be finalized on November 2, 2026.
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

SYSTEM OPERATIONS

NPCC Simultaneous Activation of Ten-Minute Reserve Events

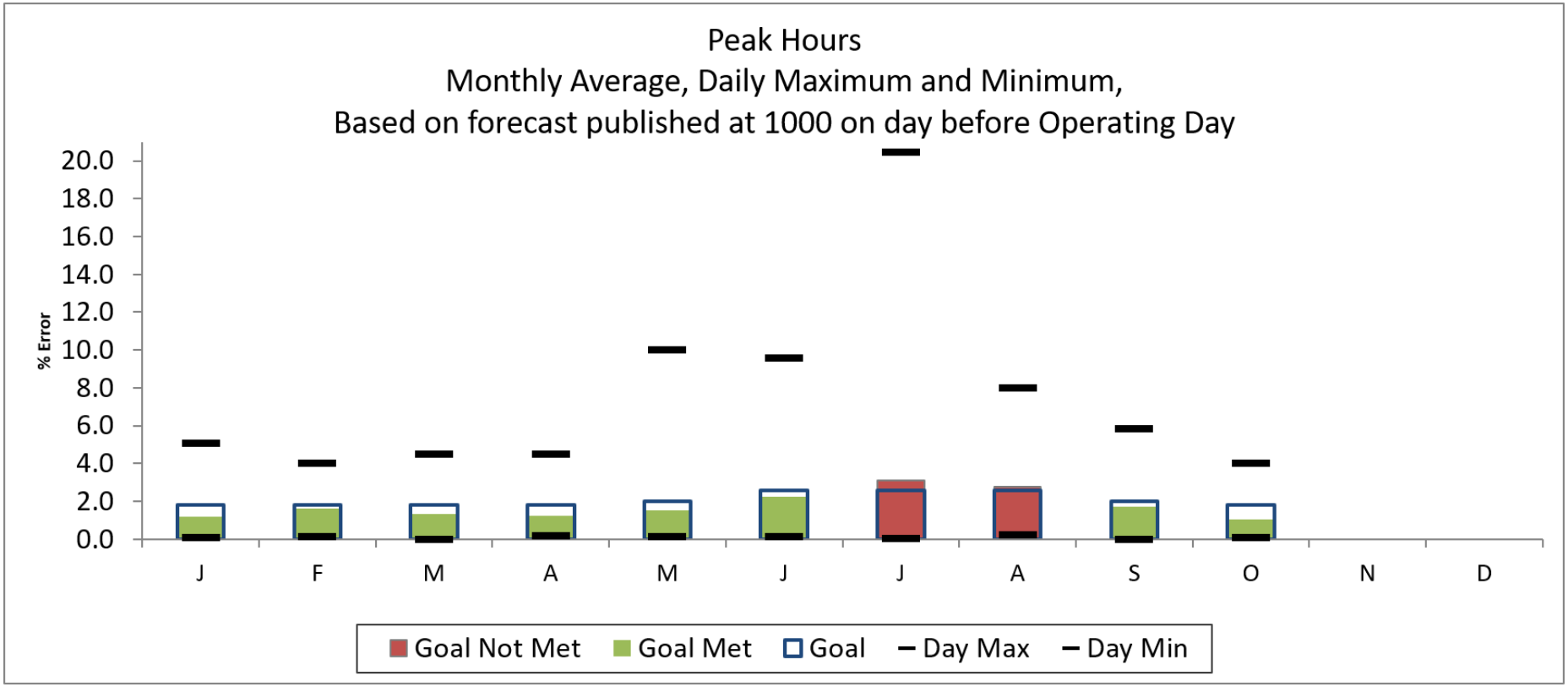
Date	Area	MW Lost
10/13/2026	NYISO	650
10/21/2026	NYISO	1000

2026 Load Forecast Accuracy



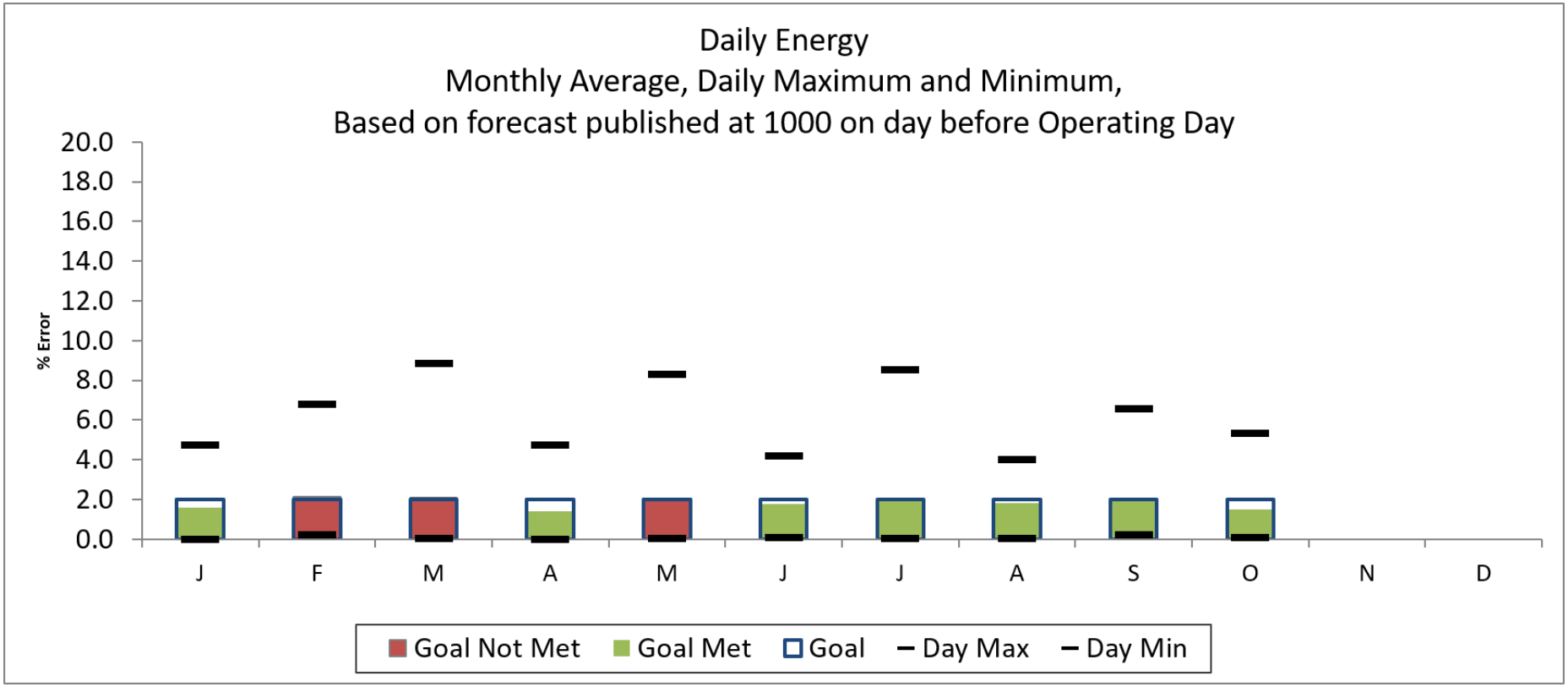
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.65	6.85	8.96	4.67	8.09	3.99	9.64	4.19	6.64	5.28			9.64
Day Min	0.76	0.82	1.01	0.80	1.09	1.29	0.77	1.01	0.98	0.81			0.76
MAPE	2.00	2.66	3.14	2.33	2.90	2.30	2.86	2.41	2.40	2.10			2.51
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2026 Load Forecast Accuracy, cont.



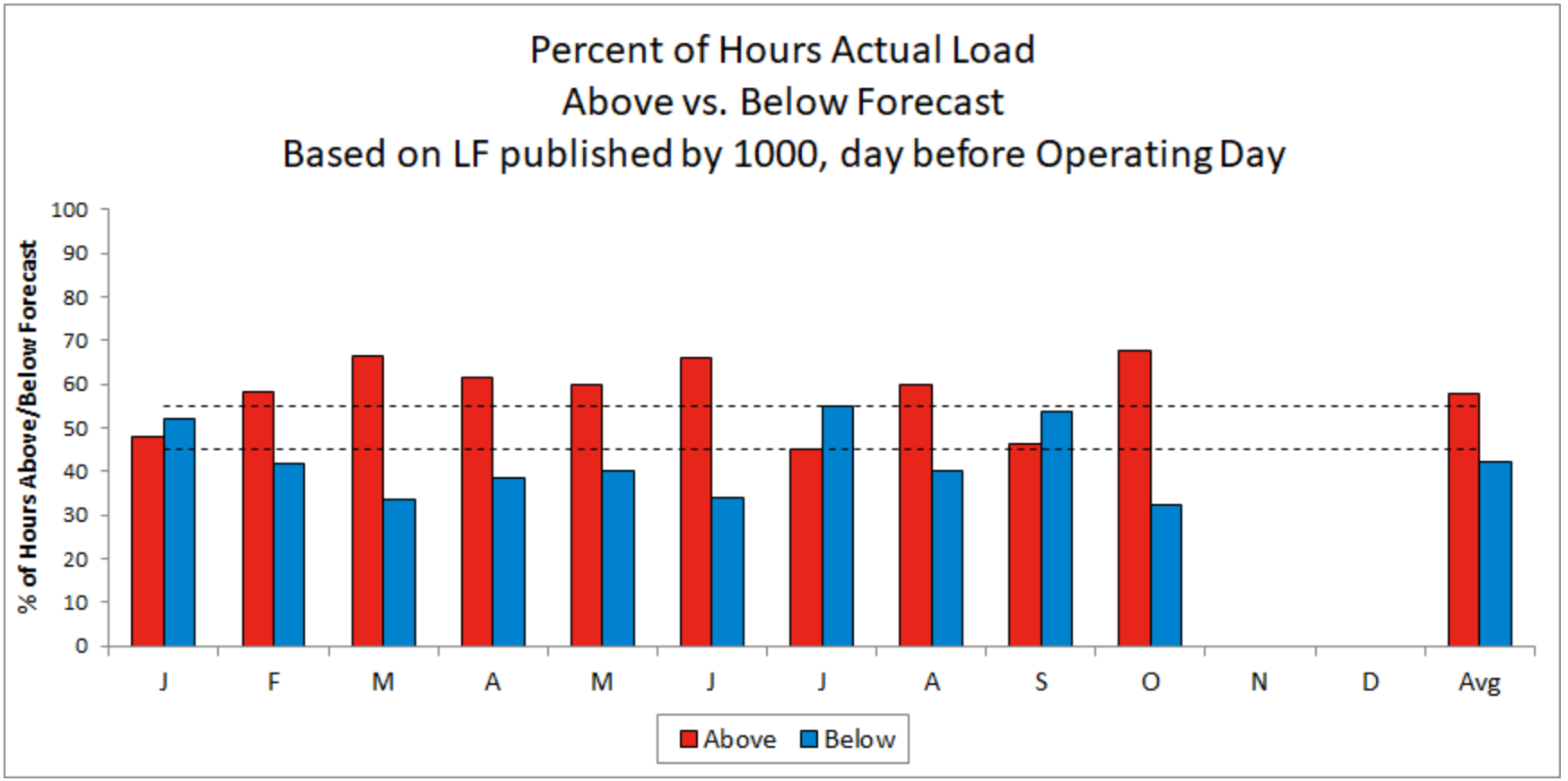
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05	4.02	4.51	4.51	10.02	9.58	20.46	8.02	5.82	4.00			20.46
Day Min	0.08	0.12	0.01	0.16	0.11	0.14	0.03	0.24	0.01	0.07			0.01
MAPE	1.17	1.64	1.34	1.24	1.52	2.23	3.08	2.77	1.71	1.06			1.78
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2026 Load Forecast Accuracy, cont.



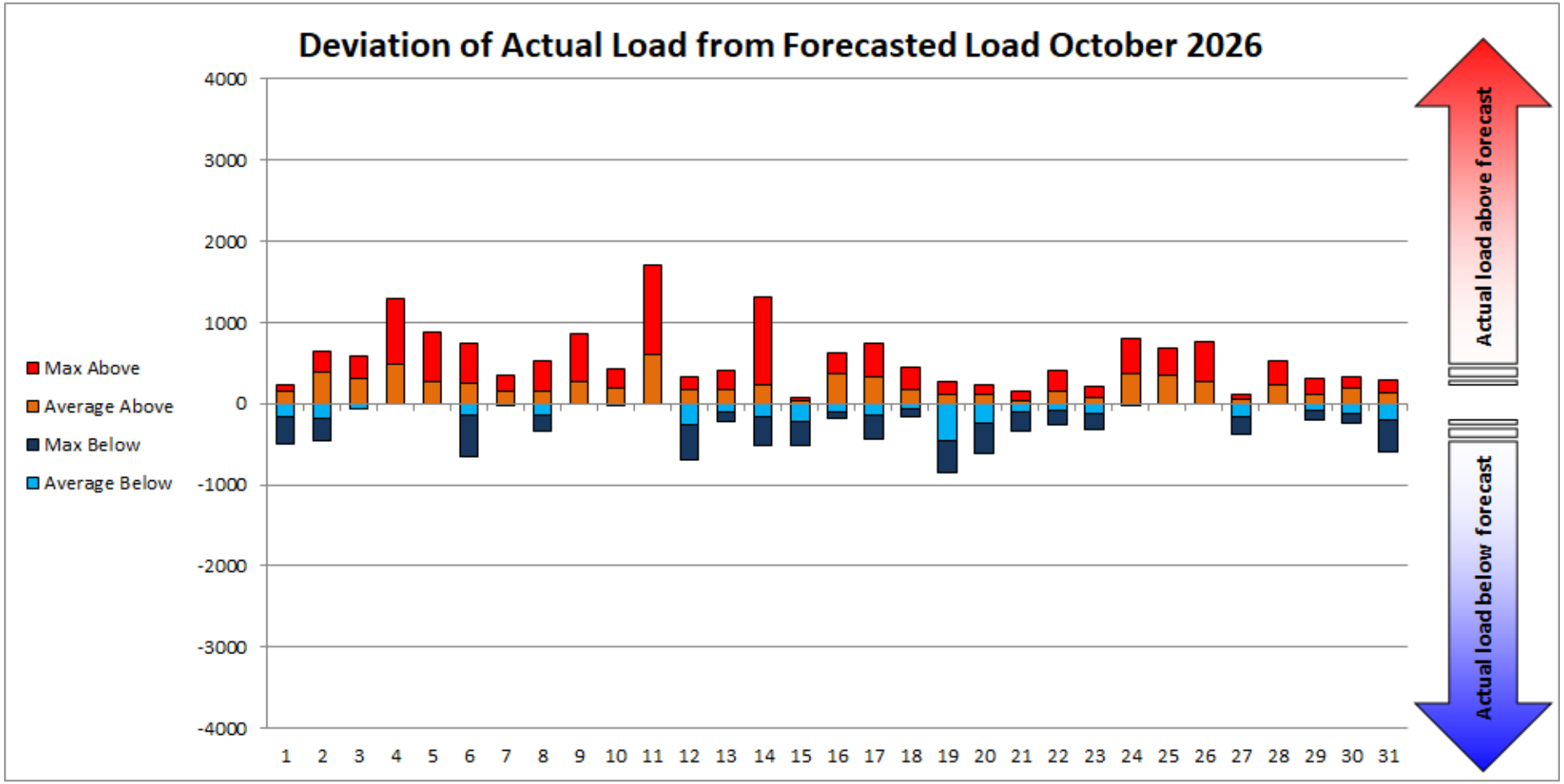
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74	6.81	8.85	4.75	8.32	4.17	8.54	4.03	6.57	5.32			8.85
Day Min	0.01	0.22	0.03	0.00	0.06	0.07	0.03	0.05	0.24	0.07			0.00
MAPE	1.57	2.12	2.11	1.42	2.06	1.75	1.94	1.82	1.95	1.48			1.82
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00			

2026 Load Forecast Accuracy, cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	47.8	58.2	66.4	61.4	59.7	66.1	44.9	59.9	46.2	67.7			58
Below %	52.2	41.8	33.6	38.6	40.3	33.9	55.1	40.1	53.8	32.3			42
Avg Above	203	299.6	325	240.4	296.5	304	259.1	298.3	210.4	222			325
Avg Below	-233.3	-271.5	-290.0	-157.2	-194.4	-160.0	-432.7	-256.5	-210.6	-110.1			-433
Avg All	-20	59	130	91	106	138	-139	51	2	115			53

2026 Load Forecast Accuracy, cont.



Wind and Solar Power Forecast Error Statistics

- Beginning with the April 2026 System & Market Operations Report, ISO included links to wind and solar forecast error statistics
- Solar forecast error statistics are for front-of-meter solar resources only
- These statistics are updated monthly and published on the ISO-NE external website
- Wind Generation Forecast Error Statistics
- Solar Power Forecast Error Statistics

Notable Planned Transmission Outages

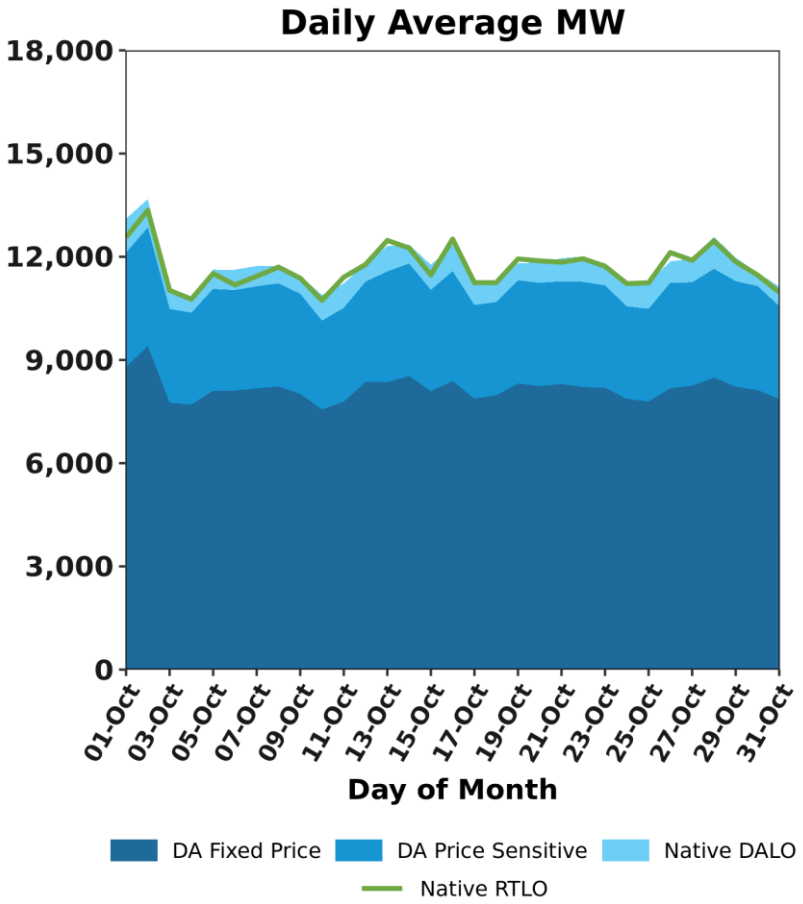
- The table below highlights select longer-duration planned outages that impact transfer capability; it is not a comprehensive list of all outages

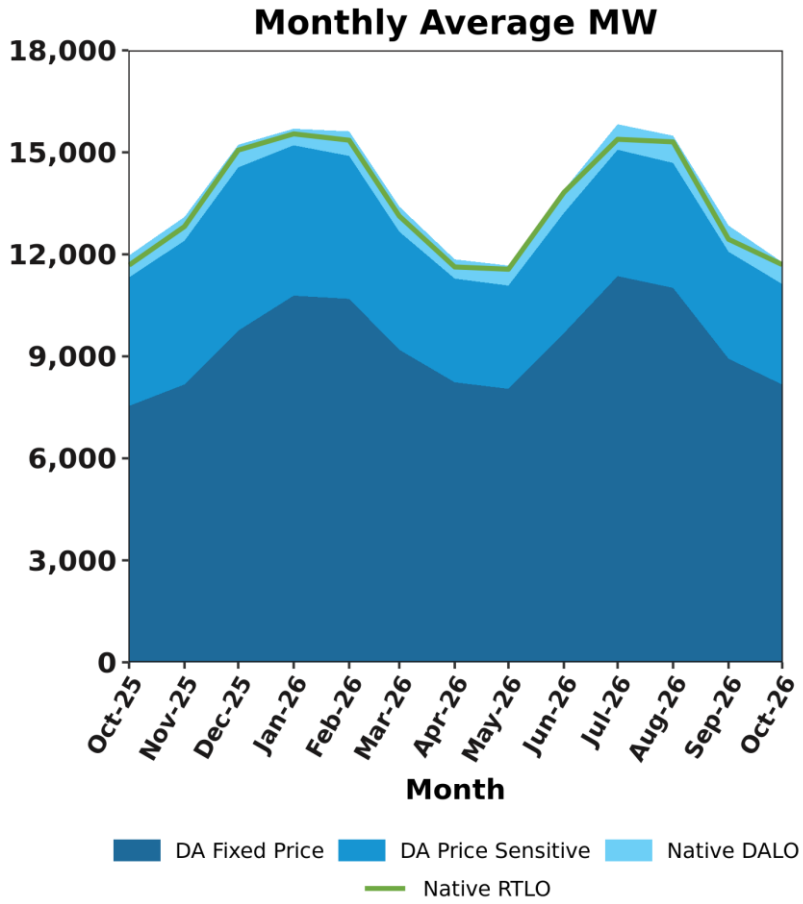
Outage	Start	Planned End	Total Transfer Capability (TTC) Impacts
NECEC	11-05-2026	11-17-2026	TTC = 0 MW
390/3016	11-16-2026	11-20-2026	New Brunswick-New England = 575 MW New England-New Brunswick = 0 MW
393	11-17-2026	11-19-2026	New York – New England = 800 MW New England – New York = 600 MW NNC = 0 MW in both directions
398	11-21-2026	11-24-2026	New York – New England = 1000 MW New England – New York = 600 MW NNC = 60 MW in both directions Phase 2 – New England = 1400 MW

MARKET OPERATIONS

Supply and Demand Volumes

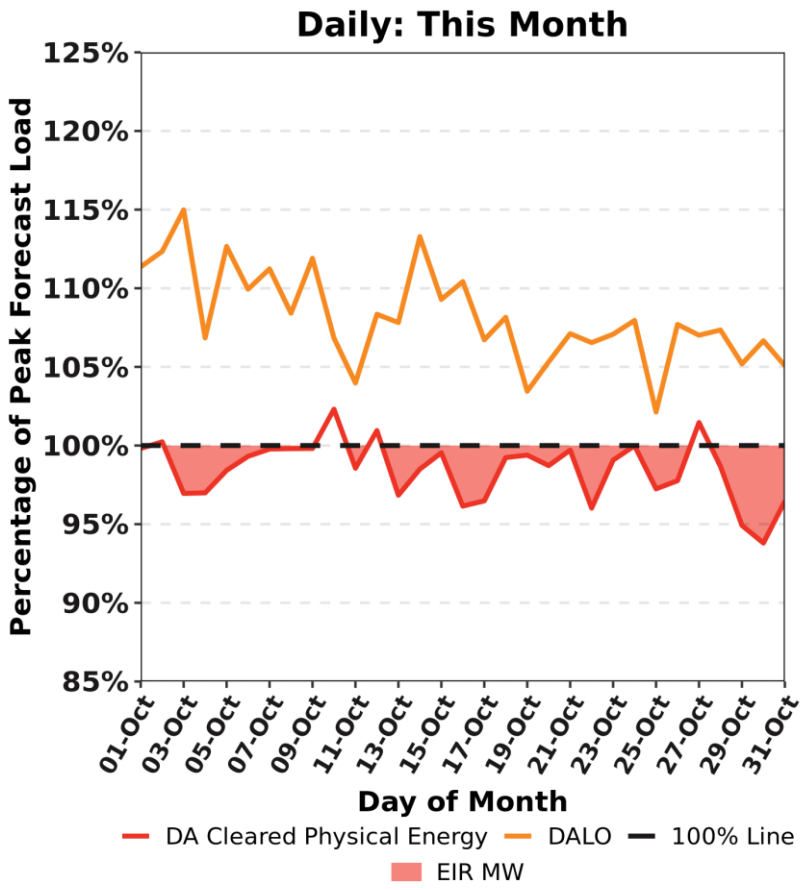
DA Cleared Native Load by Composition Compared to Native RT Load

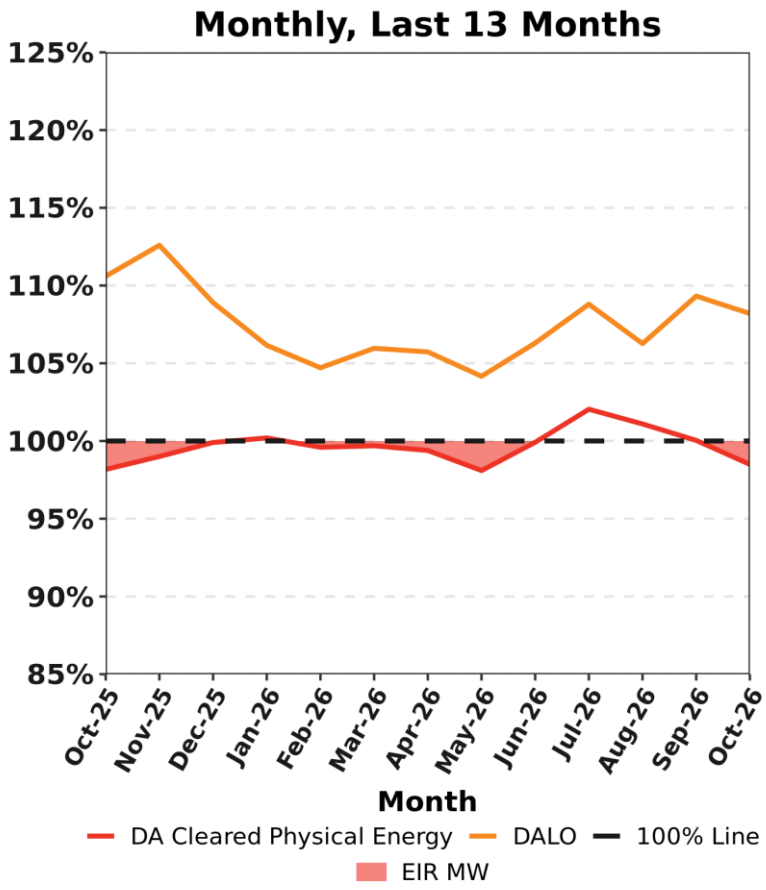




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these charts.

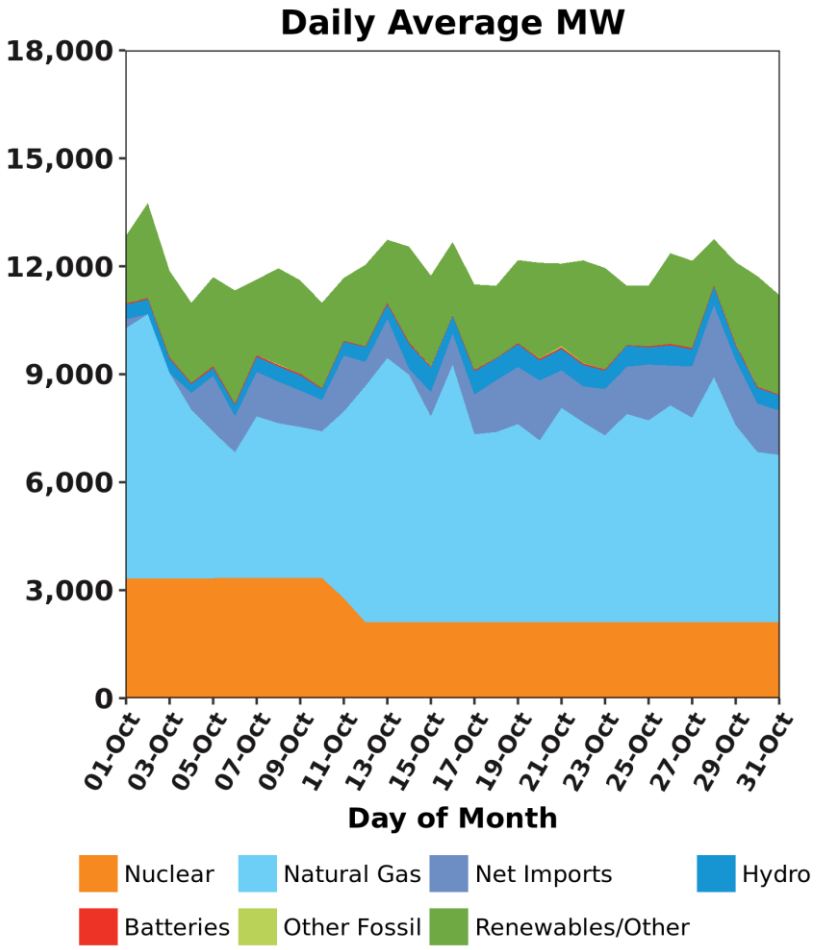
DA Volumes as % of Forecast in Peak Hour

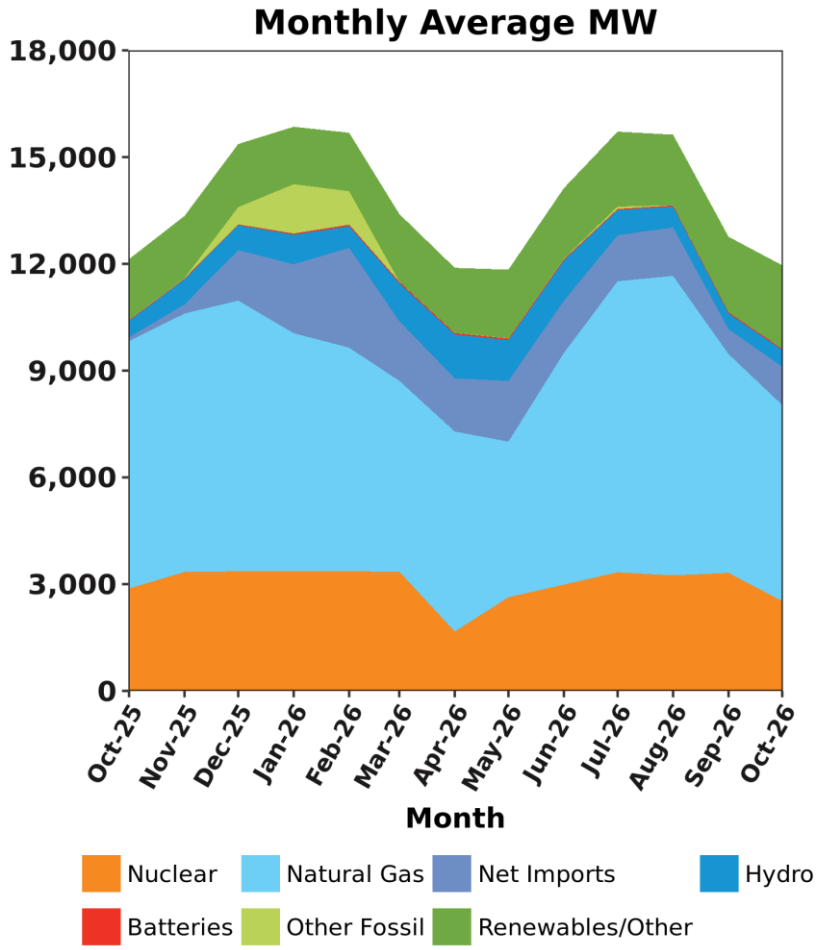




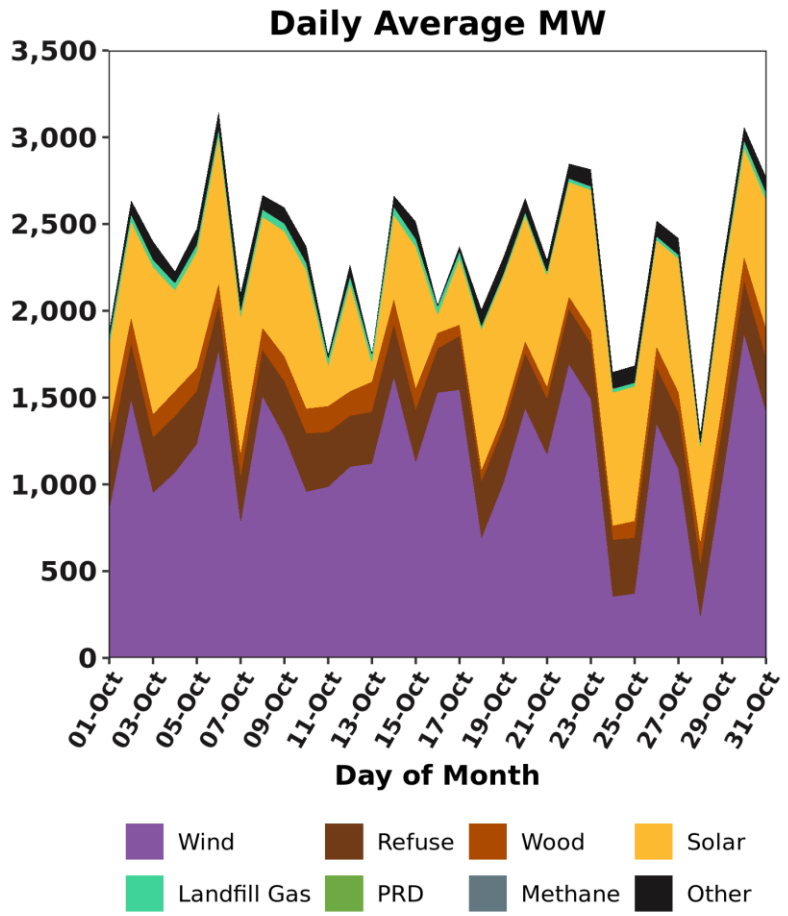
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

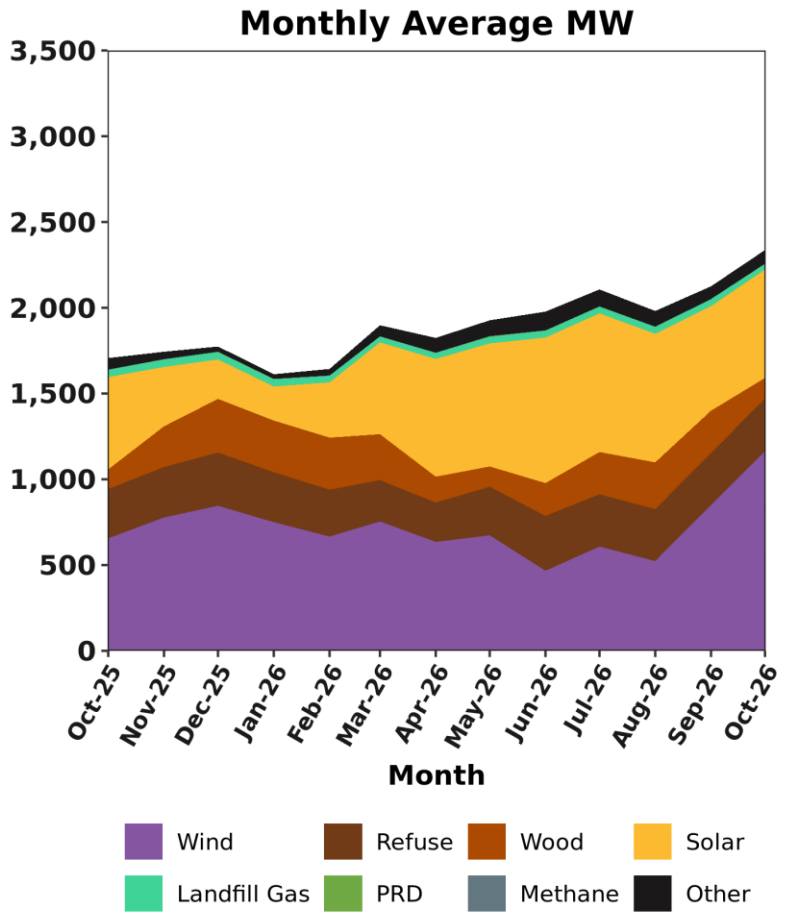
Resource Mix





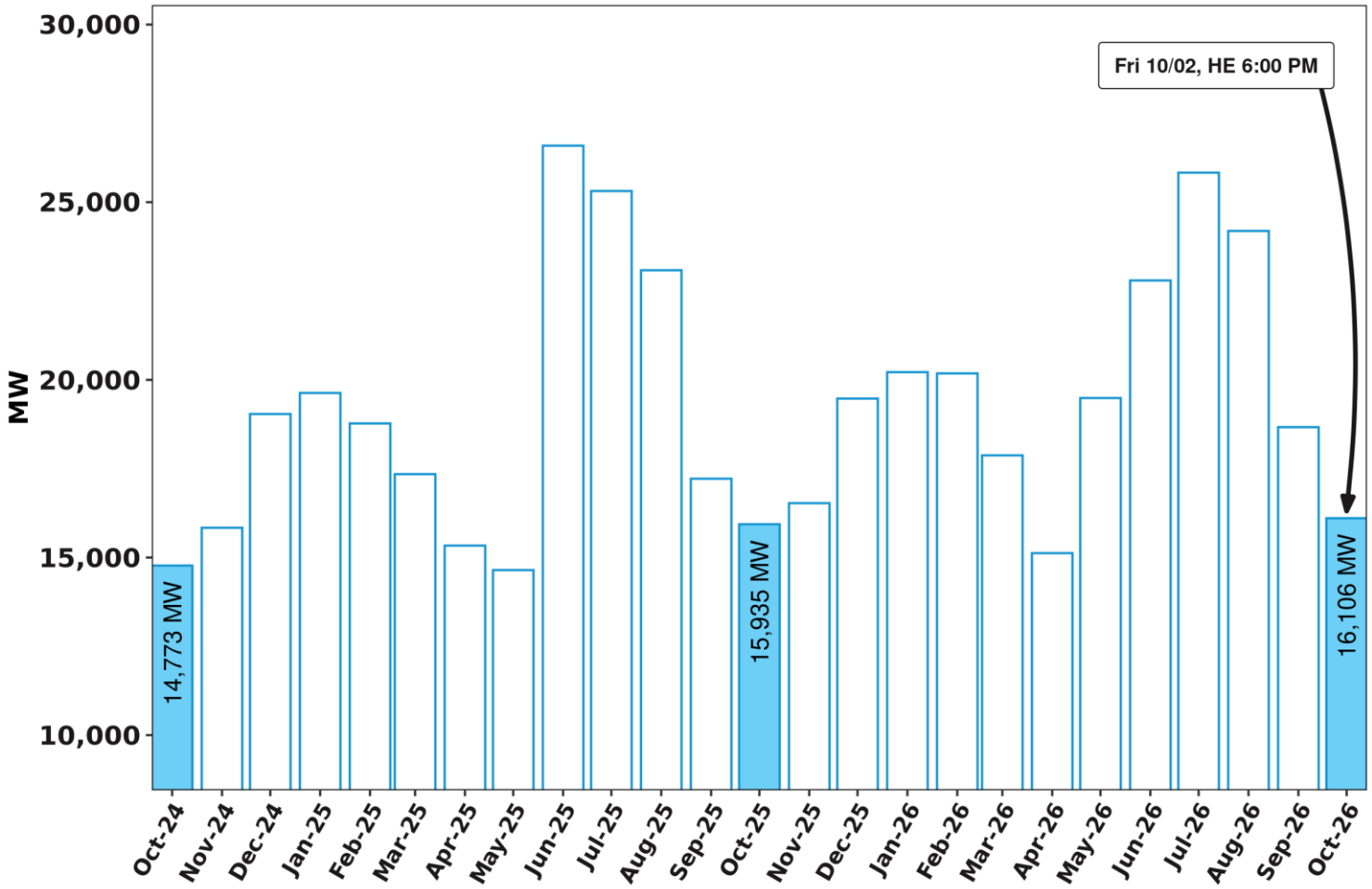
Renewable/Other Generation by Fuel Type





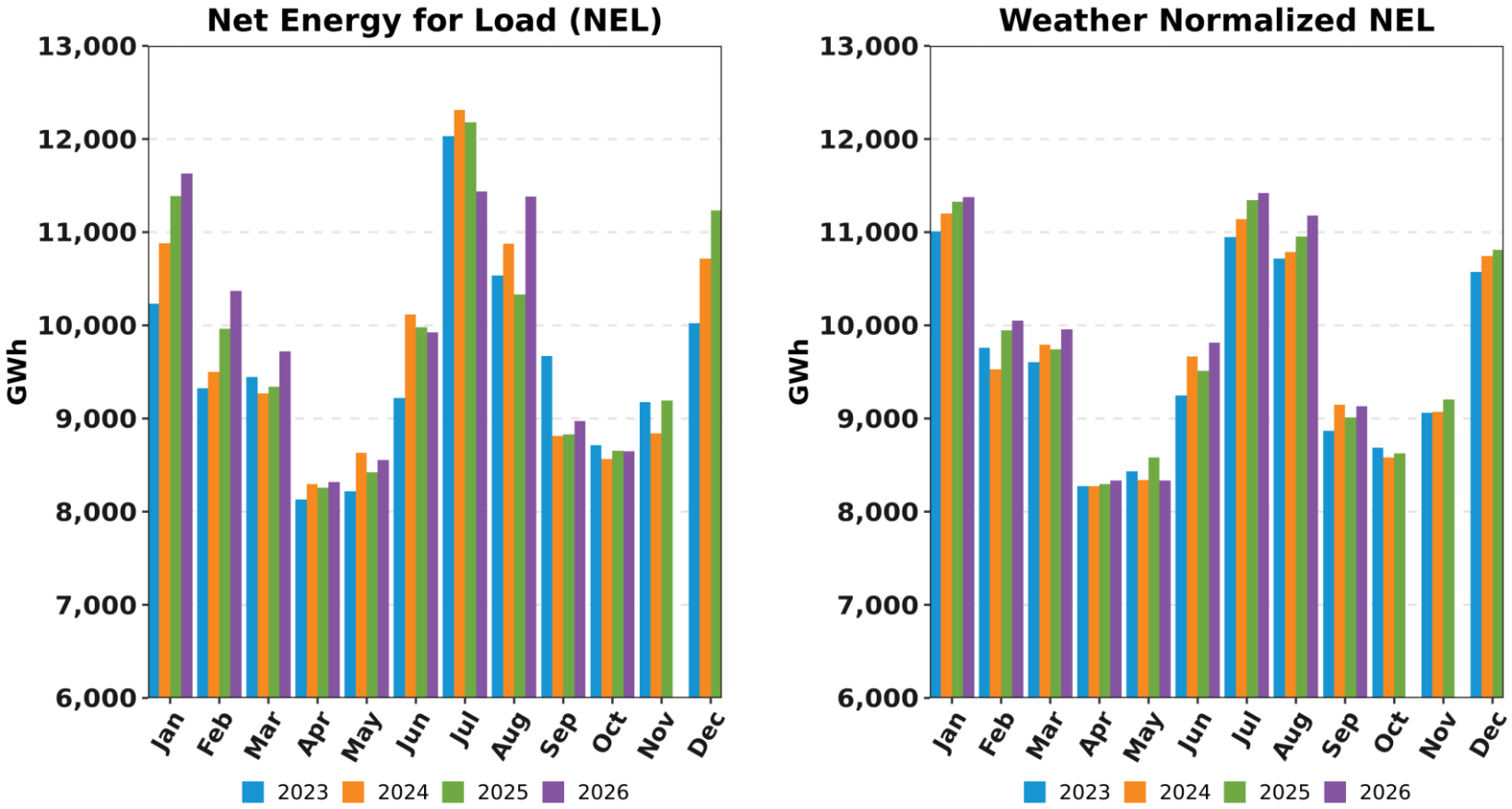
"Other" currently only contains Hybrid Solar/Battery; PRD=Demand Response Resources (DRR)

RQM System Peak Load MW by Month



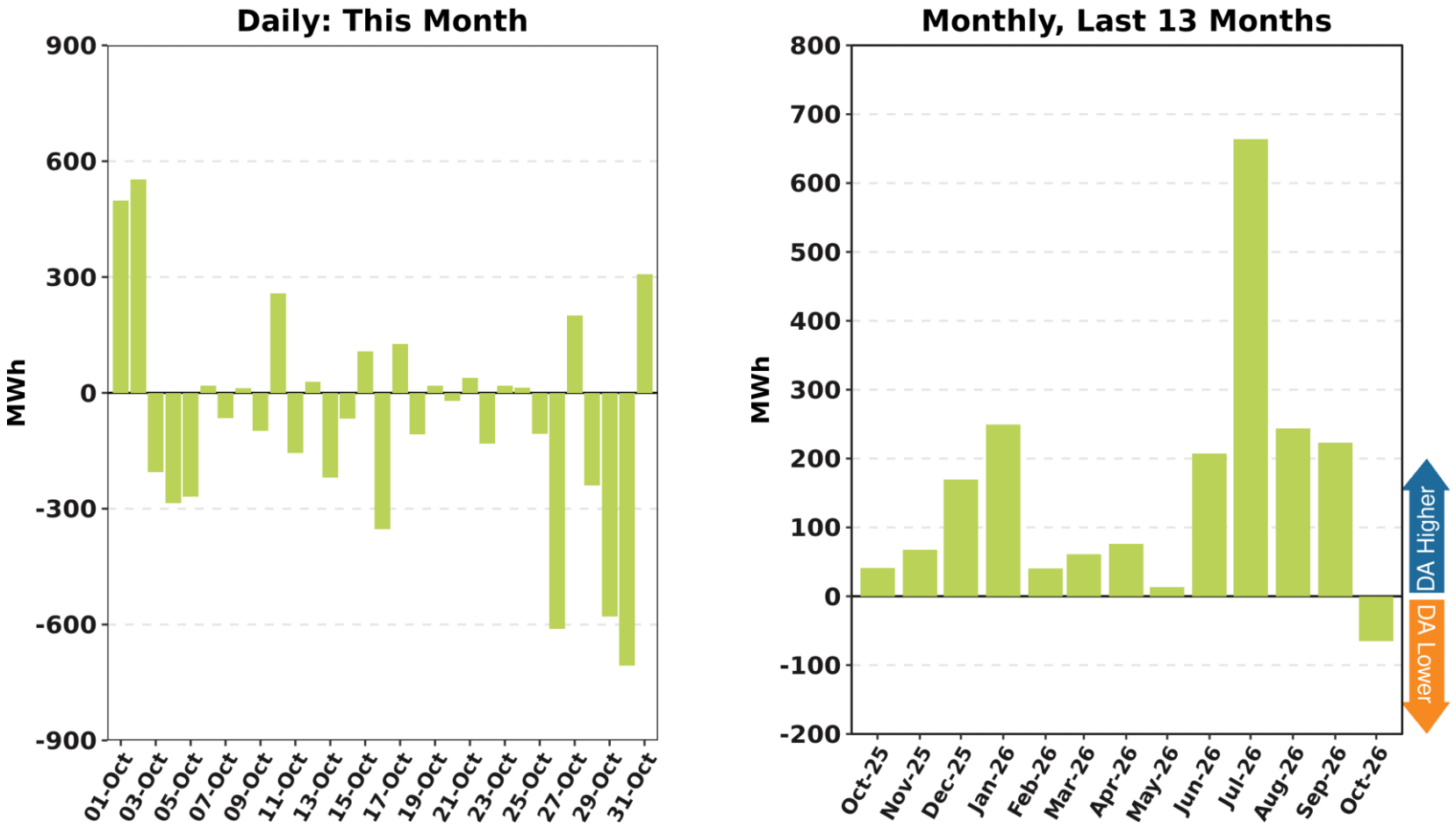
Shaded columns highlight current month and the same month over the prior two years

Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



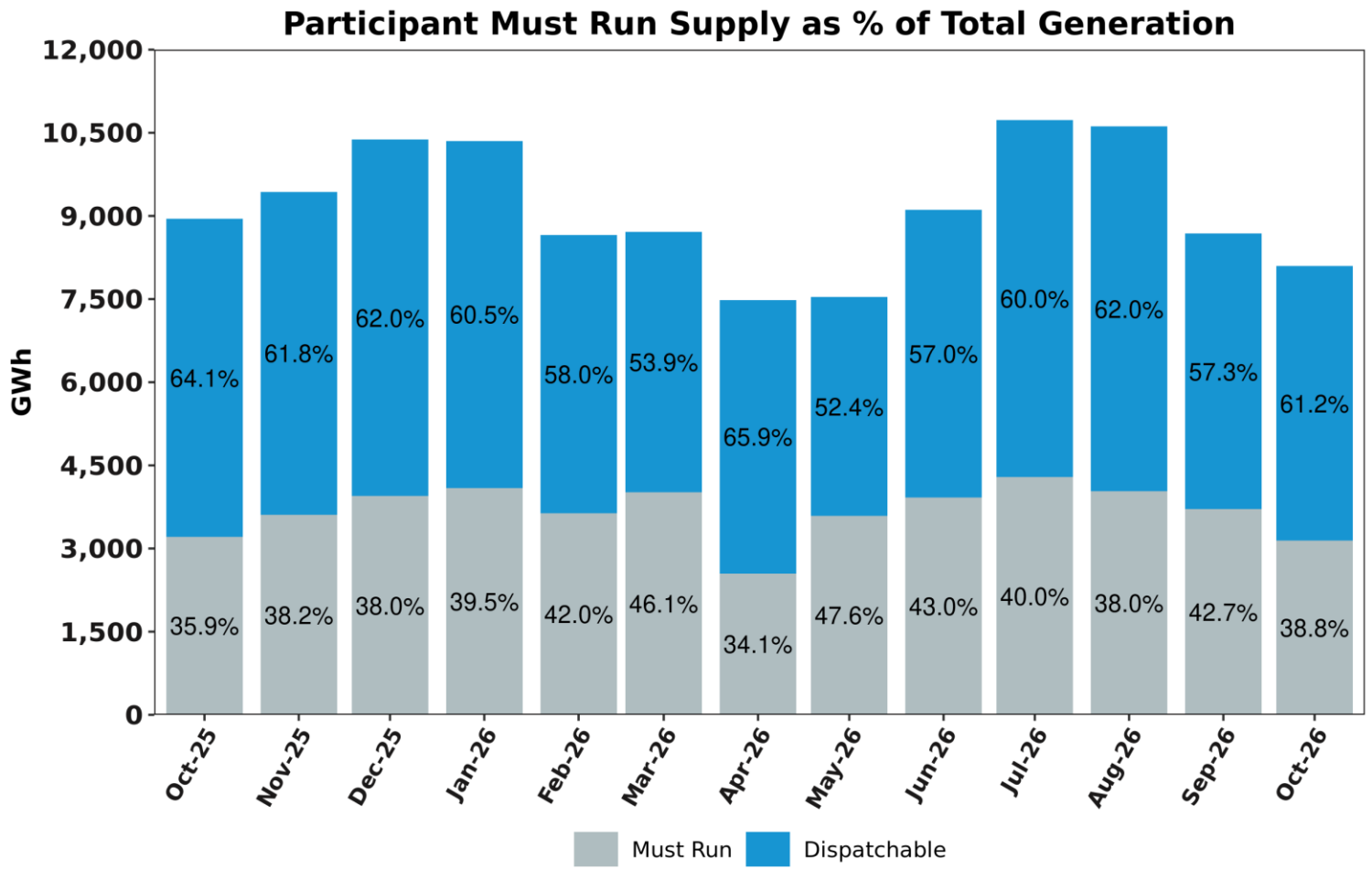
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL is typically reported on a one-month lag.

DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour



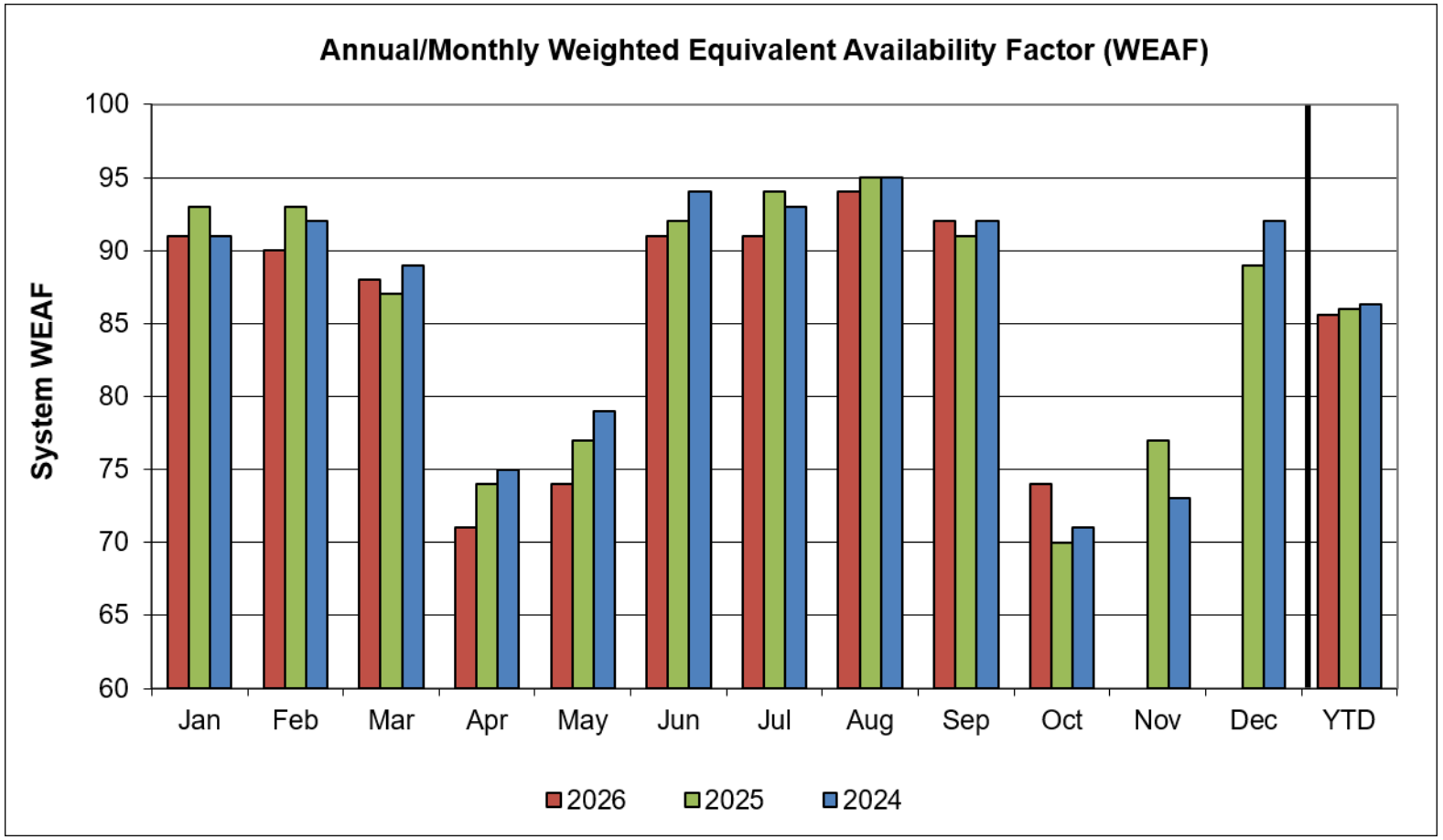
Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

RT Generation Output Offered as Must Run vs Dispatchable



Includes generation and DRR. Must Run (non-dispatchable) category reflects full output of Settlement Only Resources (SOG) as well as must run offers from modeled units

System Unit Availability



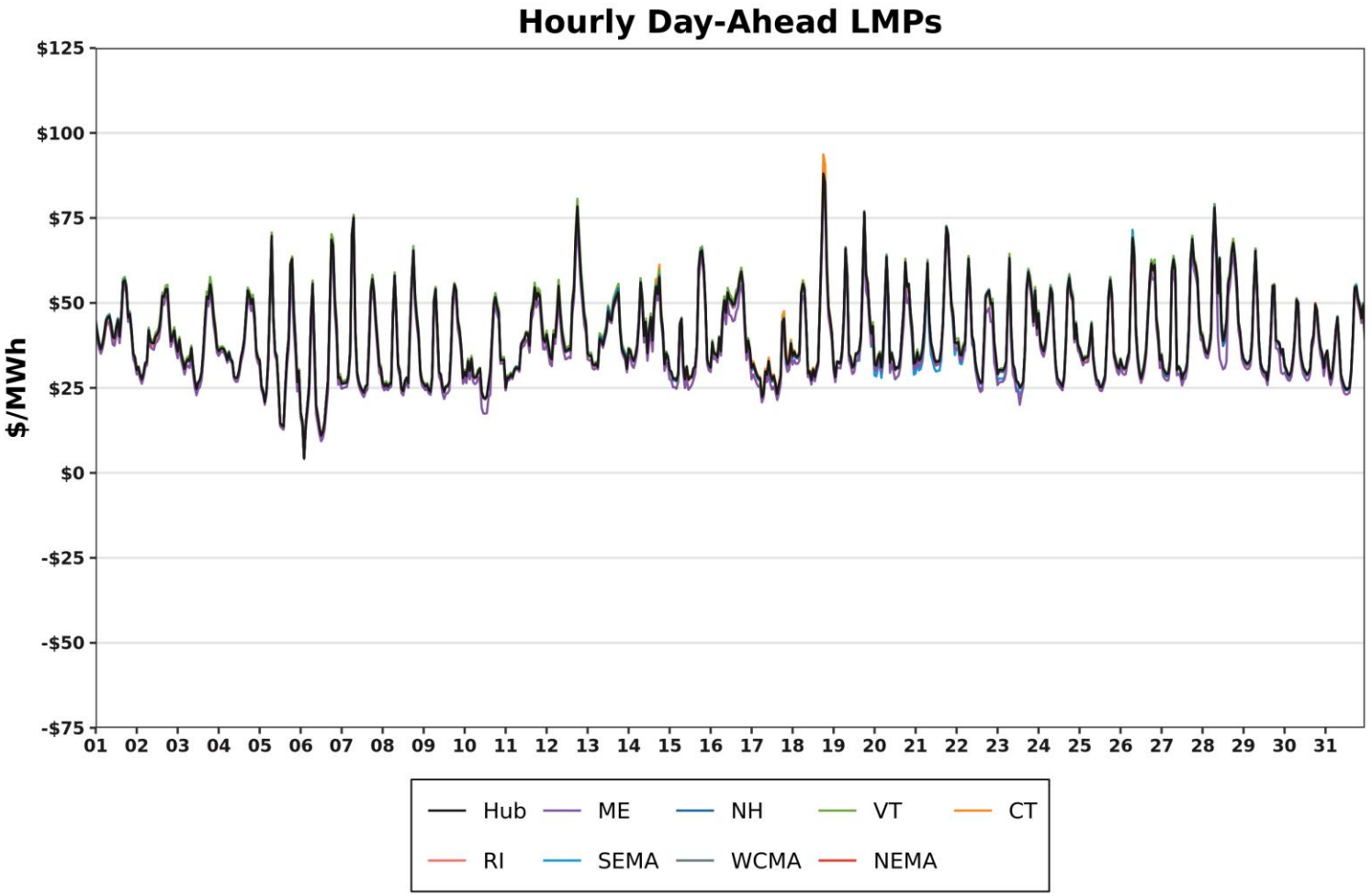
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2026	91	90	88	71	74	91	91	94	92	74			86
2025	93	93	87	74	77	92	94	95	91	70	77	89	86
2024	91	92	89	75	79	94	93	95	92	71	73	92	86

Data as of 11/2/26

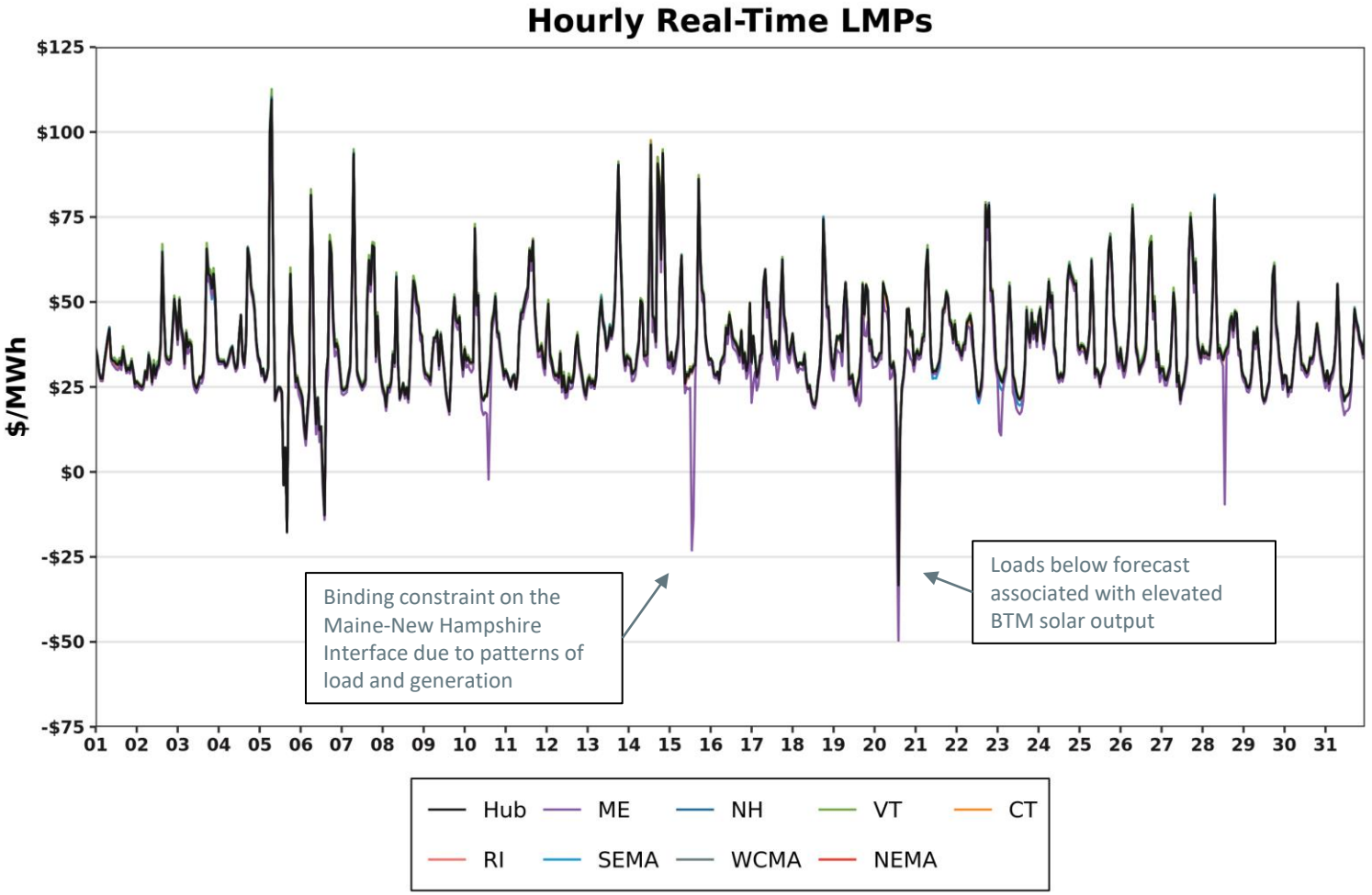
MARKET OPERATIONS

Market Pricing

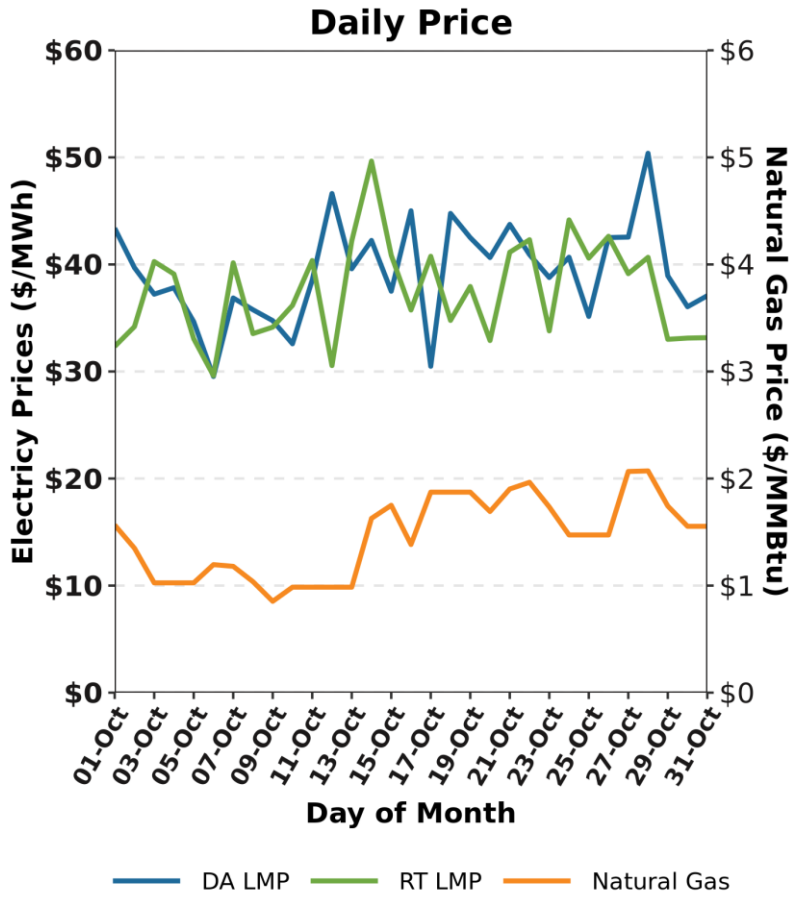
Hourly DA LMPs, October 1-31, 2026

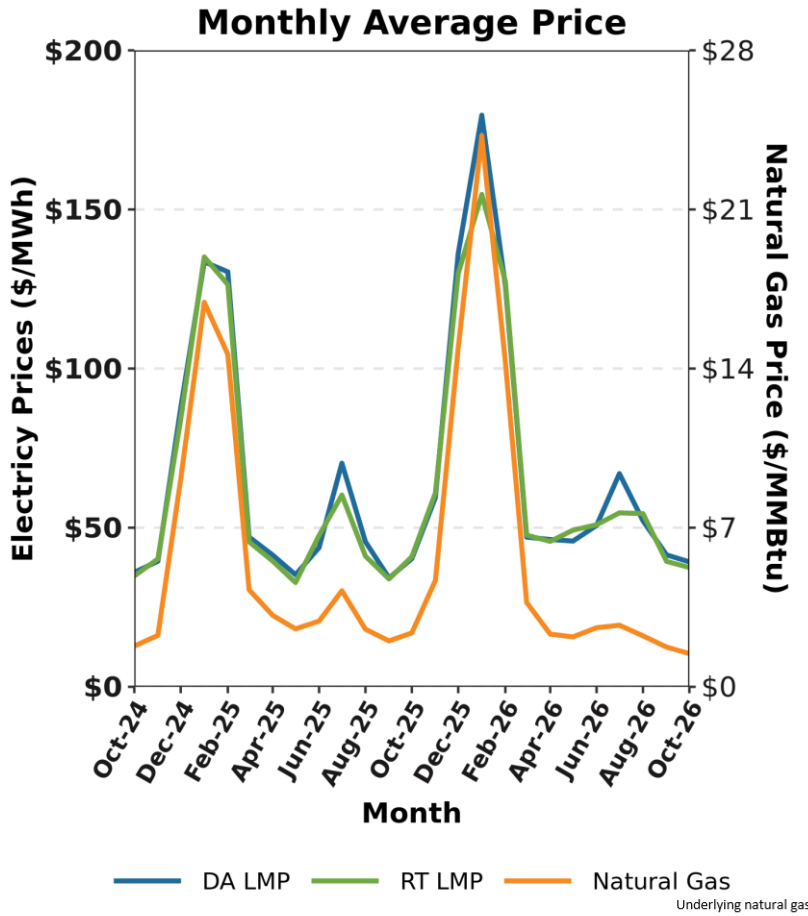


Hourly RT LMPs, October 1-31, 2026



Wholesale Electricity vs Natural Gas Price by Month

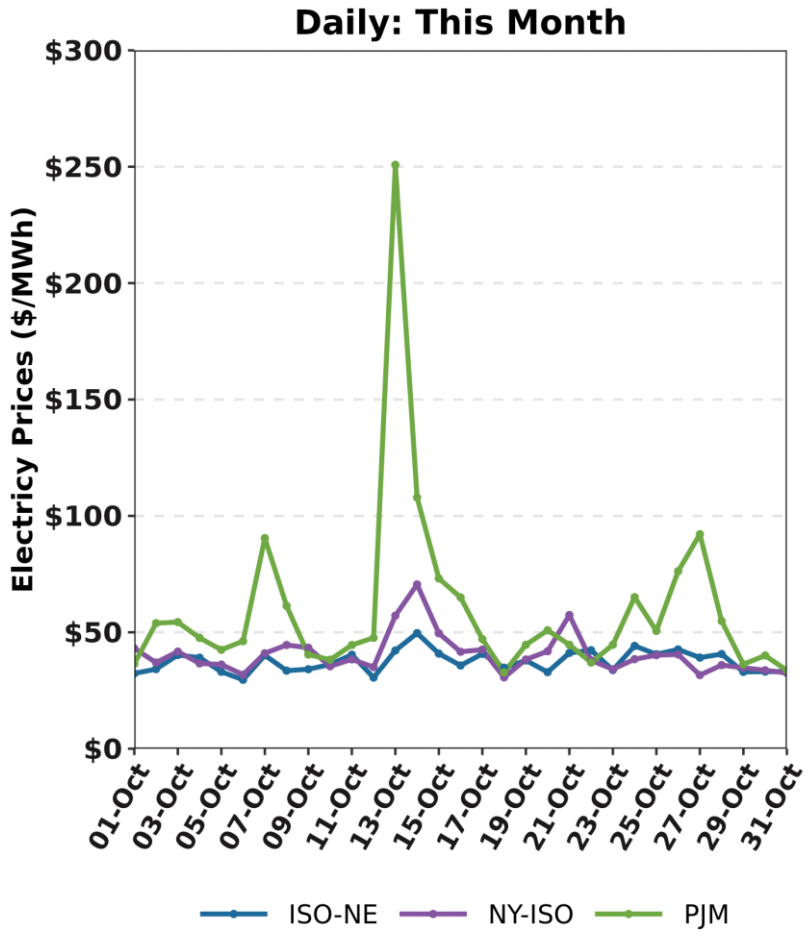


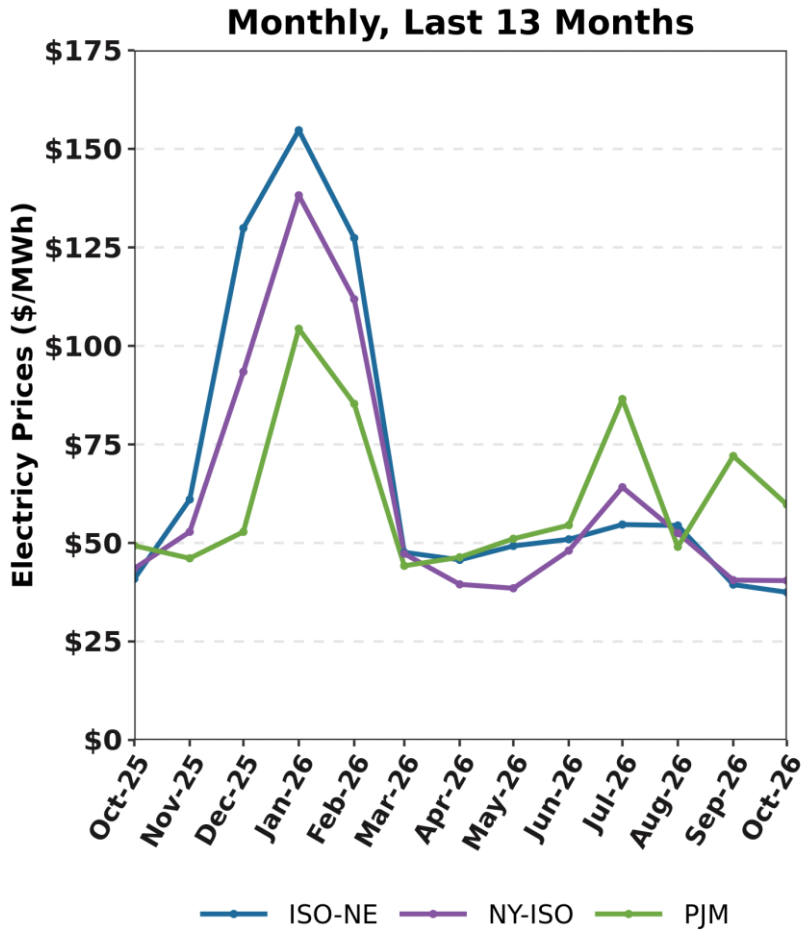


Gas price is average of Massachusetts delivery points

Underlying natural gas data furnished by:
ice Global markets in clear view

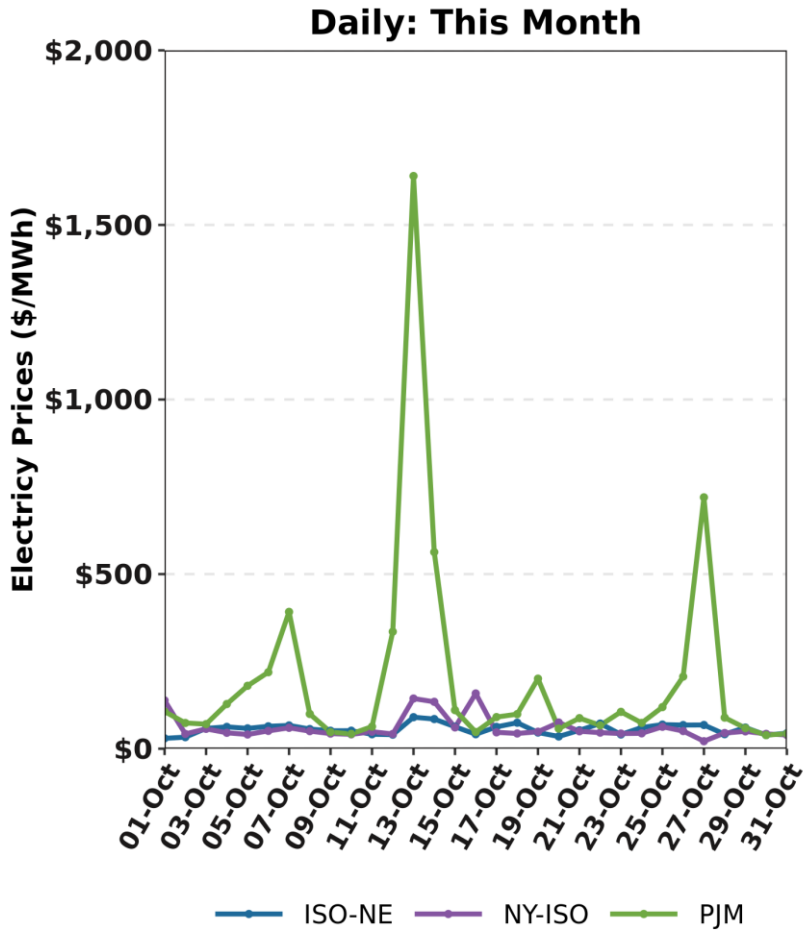
New England, NY, and PJM Hourly Average RT Prices by Month

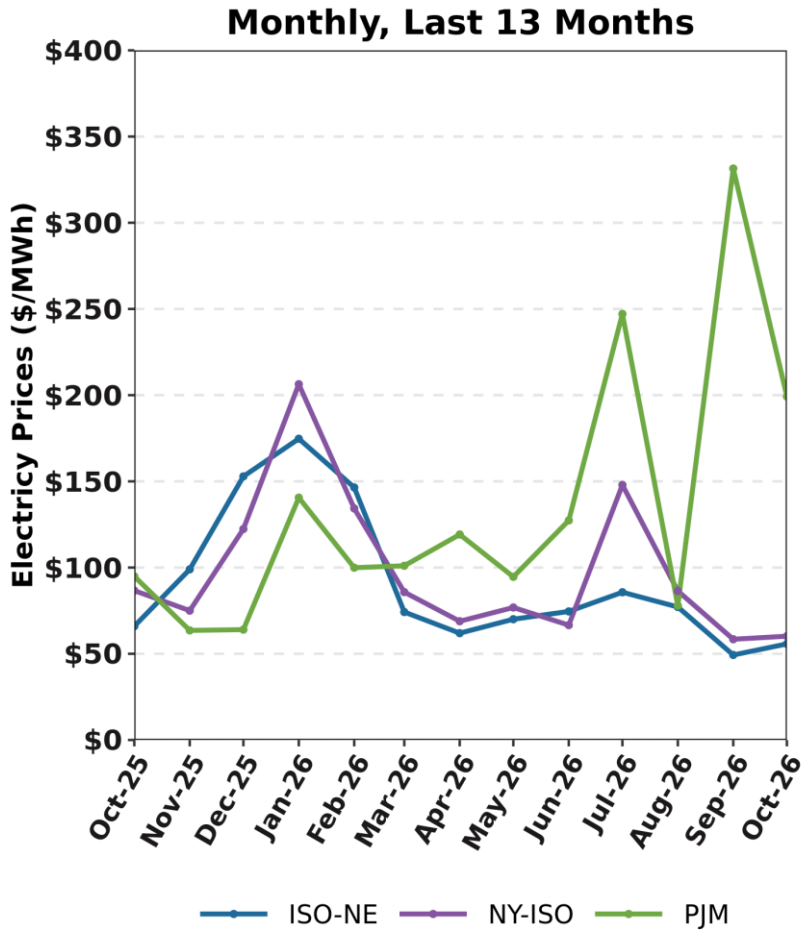




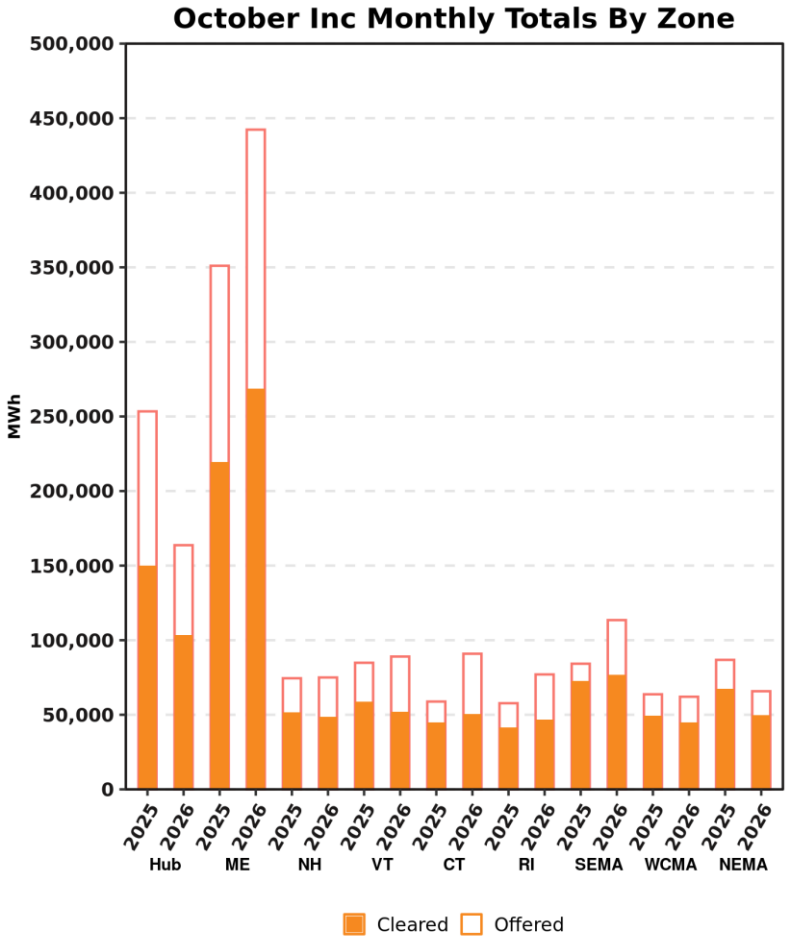
Hourly average prices are shown

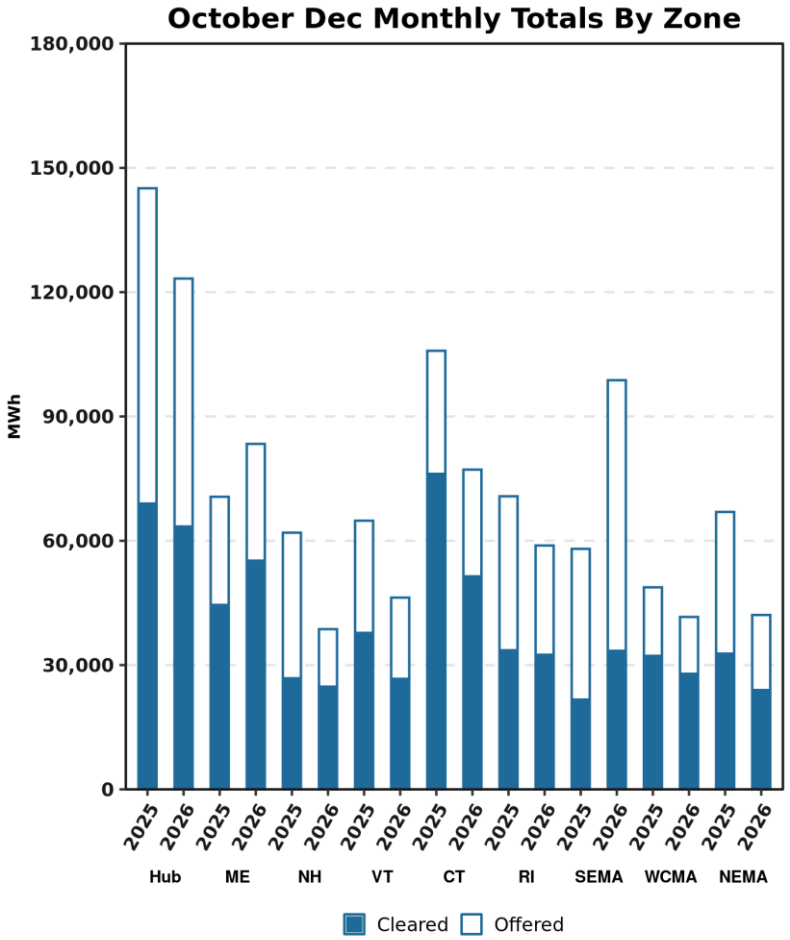
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





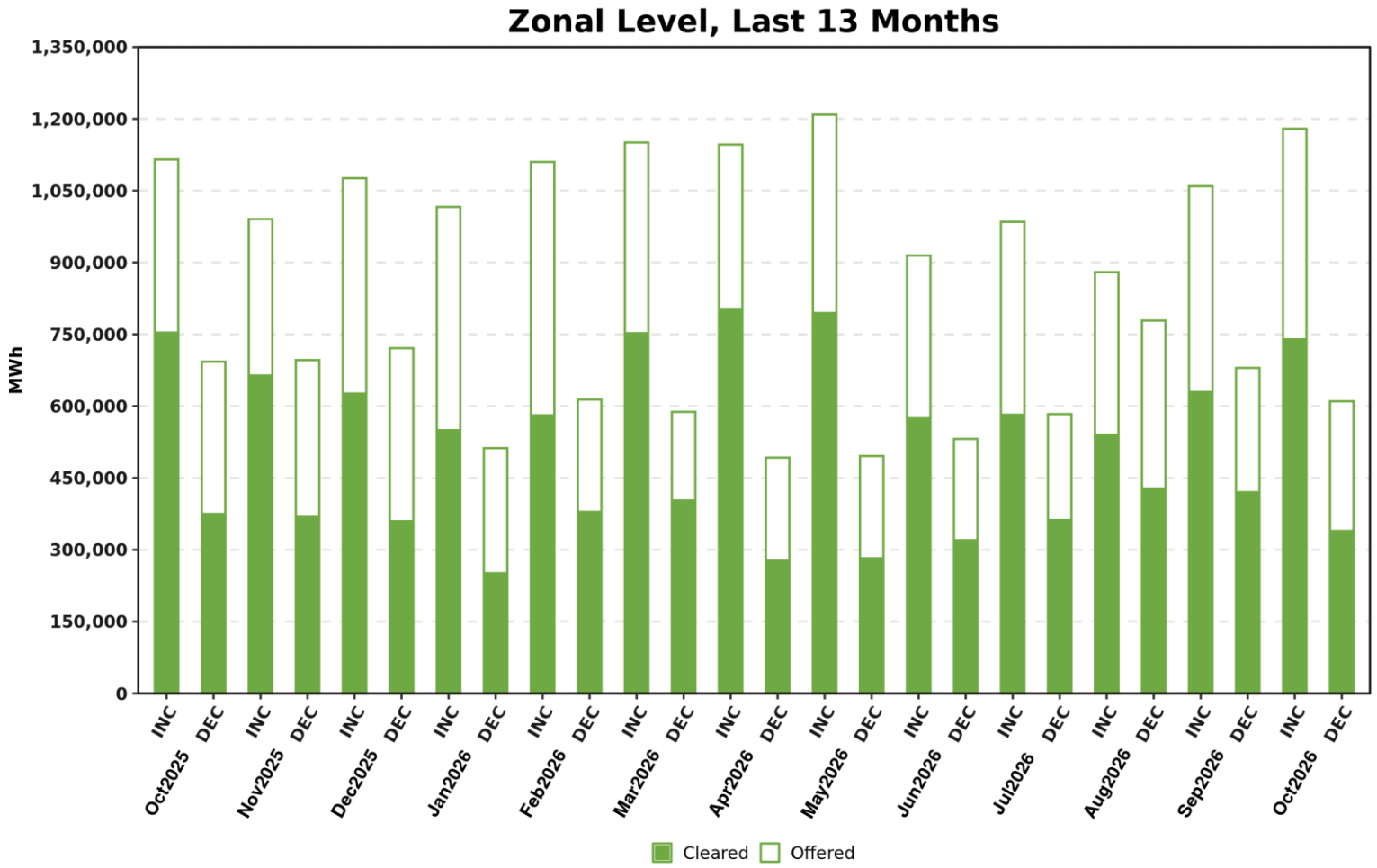
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

DAY-AHEAD ANCILLARY SERVICES (DAAS)

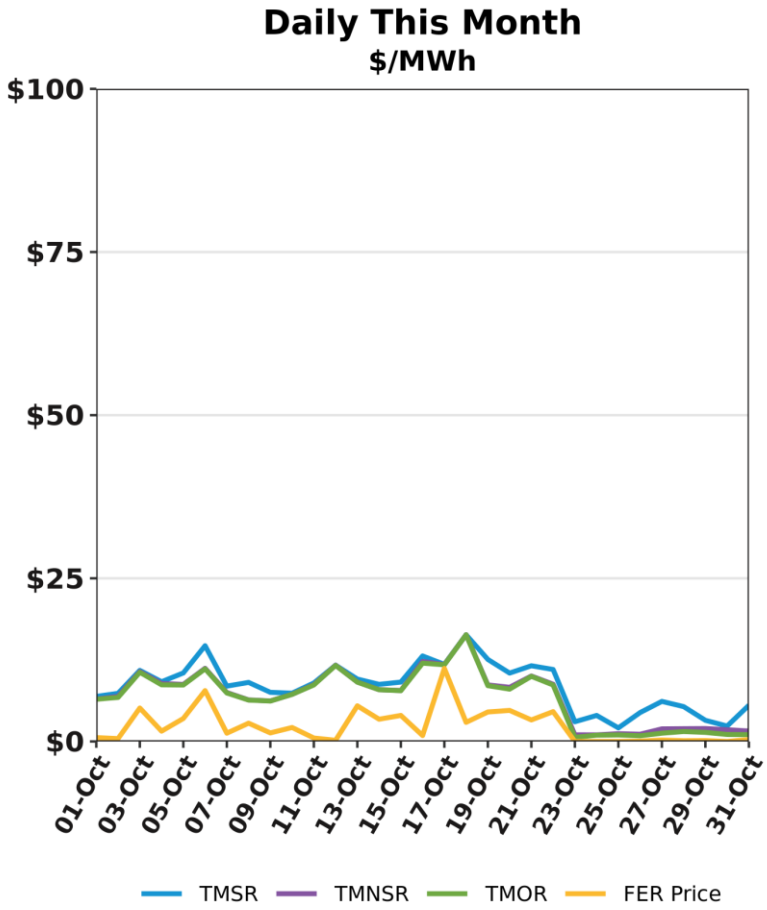
DAAS Results

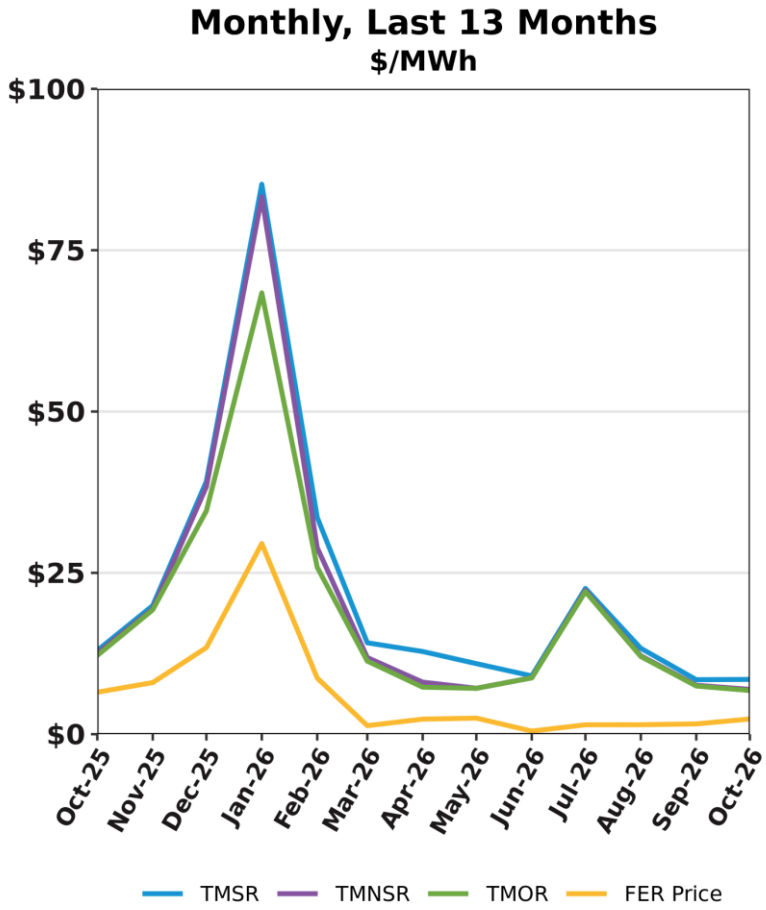
Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg. Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
10/01/2025	$15.5M	$719K	$478K	$8.21	3.1%	$1,911K	202K	$6.50	12.3%	209
11/01/2025	$24.8M	$1,123K	$458K	$7.85	1.9%	$2,550K	210K	$8.00	10.3%	135
12/01/2025	$60.9M	$2,131K	$1,053K	$18.20	1.7%	$4,916K	227K	$13.42	8.1%	107
01/01/2026	$91.1M	$4,617K	$3,241K	$55.53	3.6%	$12,042K	203K	$29.54	13.2%	127
02/01/2026	$55.1M	$1,678K	$857K	$14.78	1.6%	$3,369K	157K	$8.70	6.1%	104
03/01/2026	$17.4M	$667K	$357K	$6.43	2.1%	$422K	91K	$1.32	2.4%	32
04/01/2026	$15.4M	$463K	$119K	$2.23	0.8%	$641K	107K	$2.34	4.2%	81
05/01/2026	$15M	$425K	-$187K	-$3.40	-1.2%	$674K	133K	$2.49	4.5%	101
06/01/2026	$19.3M	$483K	$63K	$1.17	0.3%	$186K	60K	$0.48	1.0%	17
07/01/2026	$32.1M	$1,161K	$784K	$14.55	2.4%	$649K	126K	$1.46	2.0%	35
08/01/2026	$22.1M	$665K	$418K	$7.78	1.9%	$642K	114K	$1.47	2.9%	31
09/01/2026	$15M	$417K	$342K	$6.29	2.3%	$484K	126K	$1.59	3.2%	61
10/01/2026	$13.1M	$390K	$349K	$6.48	2.7%	$665K	122K	$2.36	5.1%	72

About the Table:
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)
- *'Avg Daily Energy MWh Paid FER Price' reflects Cleared DA Physical Gen and DRR MWh during non-zero FER prices

Additionally:
- FER Credits are included in the Monthly Market Operations Report (see Section 7.1.1) found on the ISO website. Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

Average Hourly DAAS Prices





This information is available in the Monthly Market Report found on the ISO website and is scheduled for removal from this deck at a future date.

BACK-UP DETAIL

NEW GENERATION

New Generation Update

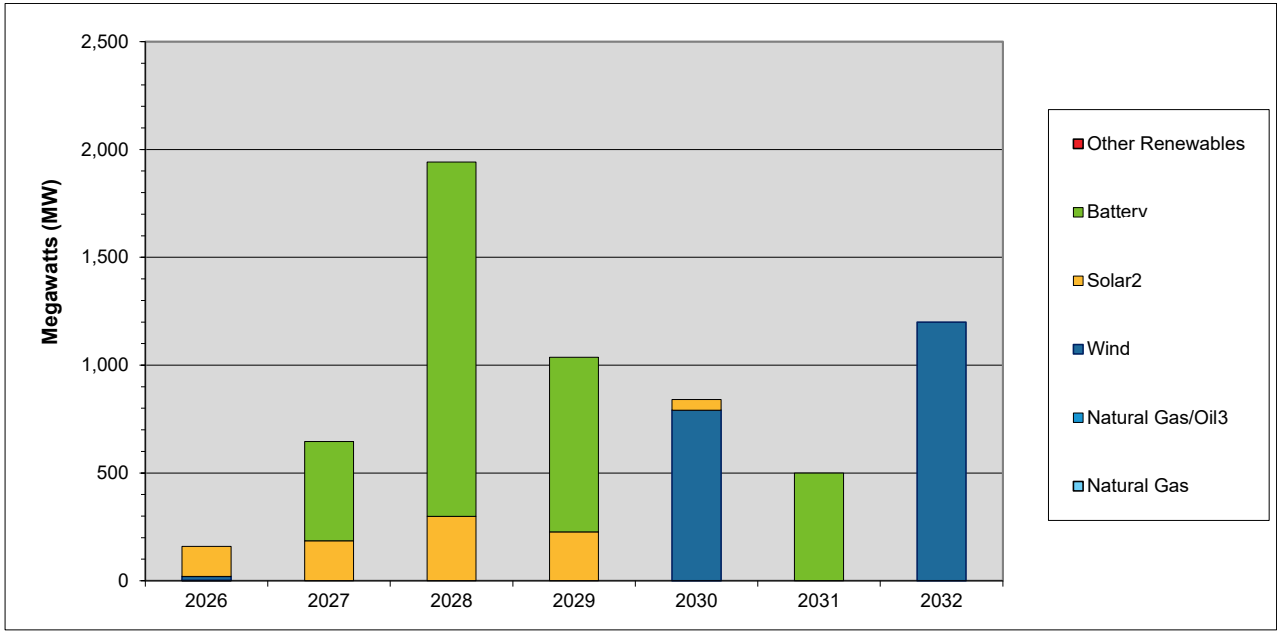
Based on Queue as of 11/02/26

- In total, 38* generation projects are currently being tracked by the ISO, totaling approximately 7,524 MW

* Total does not include CNR Only requests

Projected Annual Capacity Additions

By Supply Fuel Type



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	0	461	1,643	810	0	500	0	3,414	54.0
Solar[2]	140	185	299	227	50	0	0	901	14.2
Wind	18	0	0	0	791	0	1,200	2,009	31.8
Natural Gas/Oil[3]	0	0	0	0	0	0	0	0	0.0
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	**158**	**646**	**1,942**	**1,037**	**841**	**500**	**1,200**	**6,324**	**100.0**

[1] Sum may not equal 100% due to rounding

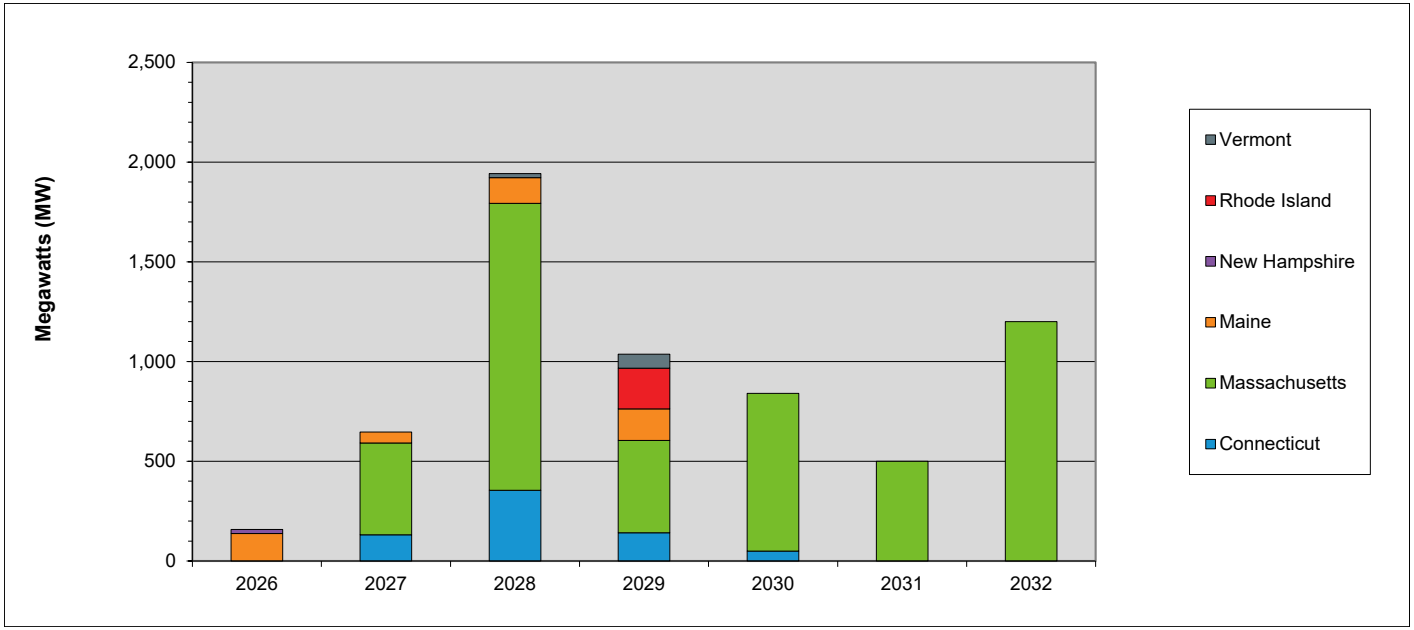
[2] This category includes both solar-only, and co-located solar and battery projects

[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

Chart is based on the dates listed in the interconnection queue and in many cases does not reflect accurately achievable dates for proposed projects

Projected Annual Generator Capacity Additions

By State



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Vermont	0	0	20	70	0	0	0	90	1.4
Rhode Island	0	0	0	205	0	0	0	205	3.2
New Hampshire	20	0	0	0	0	0	0	20	0.3
Maine	138	54	129	157	0	0	0	478	7.6
Massachusetts	0	461	1,438	463	791	500	1,200	4,853	76.7
Connecticut	0	131	355	142	50	0	0	678	10.7
Totals	**158**	**646**	**1,942**	**1,037**	**841**	**500**	**1,200**	**6,324**	**100.0**

[1] **Sum may not equal 100% due to rounding**

Chart is based on the dates listed in the interconnection queue and in many cases does not reflect accurately achievable dates for proposed projects

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	15	3,414	2	454	13	2,960
Fuel Cell	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Natural Gas/Oil	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0
Solar	19	901	3	136	16	765
Wind	4	3,209	1	18	3	3,191
Total	38	7,524	6	608	32	6,916

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	0	0	0	0	0	0
Intermediate	0	0	0	0	0	0
Peaker	34	4,315	5	590	29	3,725
Wind Turbine	4	3,209	1	18	3	3,191
Total	38	7,524	6	608	32	6,916

- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	15	3,414	0	0	0	0	15	3,414	0	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	19	901	0	0	0	0	19	901	0	0
Wind	4	3,209	0	0	0	0	0	0	4	3,209
Total	38	7,524	0	0	0	0	34	4,315	4	3,209

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35	589.882	-175.468	504.466	-85.416	437.780	-66.686
	Passive Demand	2,557.256	2,579.120	21.864	2,574.367	-4.753	2,568.703	-5.664
Demand Total		**3,322.606**	**3,169.002**	**-153.604**	**3,078.833**	**-90.169**	**3,006.483**	**-72.350**
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624	26,503.730	-139.649	26,049.059	-454.671
	Intermittent	1,178.933	1,146.783	-32.15	989.265	-157.518	912.376	-76.889
Generator Total		**27,983.936**	**27,790.162**	**-193.774**	**27,492.995**	**-297.167**	**26,961.435**	**-531.560**
Import Total		**1,503.842**	**1,247.601**	**-256.241**	**1,244.601**	**-3.000**	**1,234.800**	**-9.801**
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**	**31,816.429**	**-390.336**	**31,202.718**	**-613.711**
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**	**30,775**	**190**	**30,300**	**-475**

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	622.854	584.913	-37.941	492.363	-92.550	384.960	-107.403
	Passive Demand	2,316.815	2,314.068	-2.747	2,314.705	0.637	2,254.722	-59.983
Demand Total		**2,939.669**	**2,898.981**	**-40.688**	**2,807.068**	**-91.913**	**2,639.682**	**-167.386**
Generator	*Non-Intermittent*	26,507.420	26,715.489	208.069	26,271.866	-443.623	26,314.531	42.665
	Intermittent	1,356.084	1,286.589	-69.495	1,310.622	24.033	1,205.314	-105.308
Generator Total		**27,863.504**	**28,002.078**	**138.574**	**27,582.488**	**-419.59**	**27,519.845**	**-62.643**
Import Total		**566.998**	**564.079**	**-2.919**	**636.310**	**72.231**	**409.310**	**-227.000**
Grand Total*		**31,370.171**	**31,465.138**	**94.967**	**31,025.866**	**-439.272**	**30,568.837**	**-457.029**
Net ICR (NICR)		**30,305**	**30,395**	**90**	**30,600**	**205**	**30,050**	**-550**

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 18

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	543.580	403.884	-139.696	410.941	7.057		
	Passive Demand	2,070.498	2,851.331	780.833	2,010.568	-840.763		
Demand Total		**2,614.078**	**3,255.215**	**641.137**	**2,421.509**	**-833.706**		
Generator	*Non-Intermittent*	27,026.635	25,822.288	-1,204.347	26,192.205	369.917		
	Intermittent	1,450.872	890.415	-560.457	1,479.423	589.008		
Generator Total		**28,477.507**	**26,712.703**	**-1,764.804**	**27,671.628**	**958.925**		
Import Total		**464.835**	**1,234.800**	**769.965**	**614.235**	**-620.565**		
Grand Total*		**31,556.420**	**31,202.718**	**-353.702**	**30,707.372**	**-495.346**		
Net ICR (NICR)		**30,550.000**	**30,415.000**	**-135.000**	**29,855.000**	**-560.000**		

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3,596.056**	**323.058**	**3,919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	**3,092.648**	**229.958**	**3,322.606**
2026-27	Active	615.369	7.485	622.854
	Passive	2,194.172	122.643	2,316.815
	Grand Total	**2,809.541**	**130.128**	**2,939.669**
2027-28	Active	543.58	0.0	543.58
	Passive	1,965.515	104.983	2070.498
	Grand Total	**2,509.095**	**104.983**	**2,614.498**

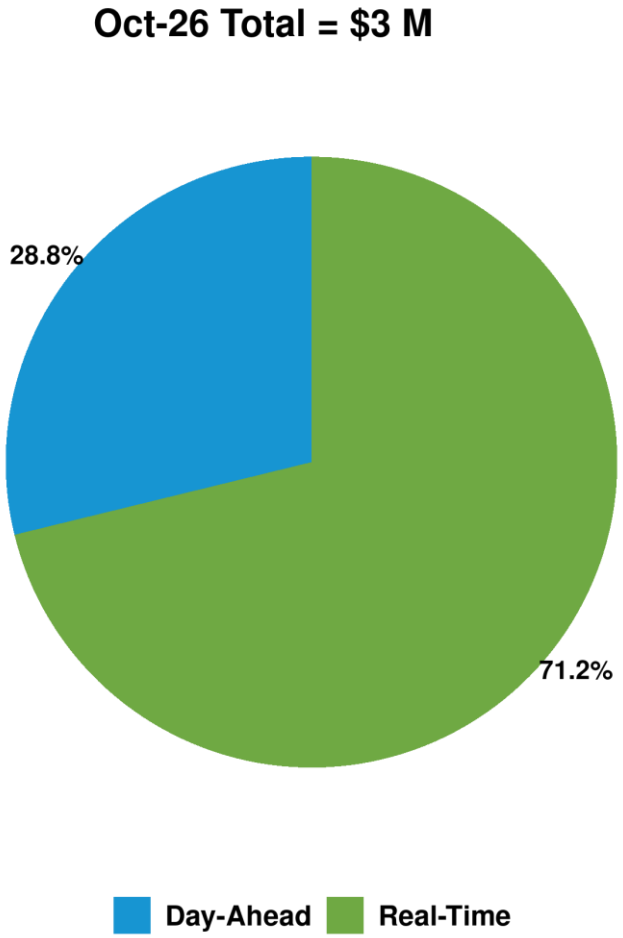
NET COMMITMENT PERIOD COMPENSATION

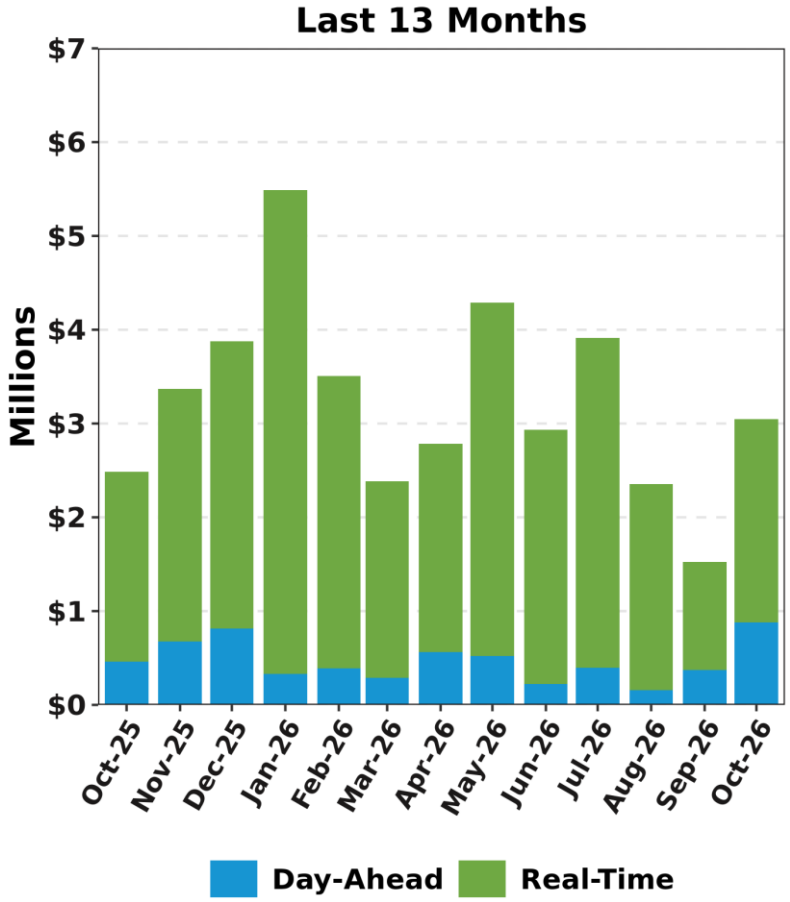
NCPC Highlights

- **Net Commitment Period Compensation (NCPC)** total $3M
  - Represents 0.7% of monthly Energy Market value
  - First Contingency $3M
    - Dispatch Lost Opportunity Cost (DLOC) - $521K; Rapid Response Pricing (RRP) Opportunity Cost - $156K; Posturing - $0; Generator Performance Auditing (GPA) - $775K
    - $394K paid to resources at external locations, up $185K from September
      - $391K charged to Day-Ahead Load Obligation (DALO) at external locations; <$1K to Day-Ahead Generation Obligation (DAGO) at external locations; $3K to RT Deviations
  - 2nd Contingency, Distribution and Voltage were zero

This information is available in the Monthly Market Report found on the ISO website and is scheduled for removal from this deck at a future date.

DA and RT NCPC Charges





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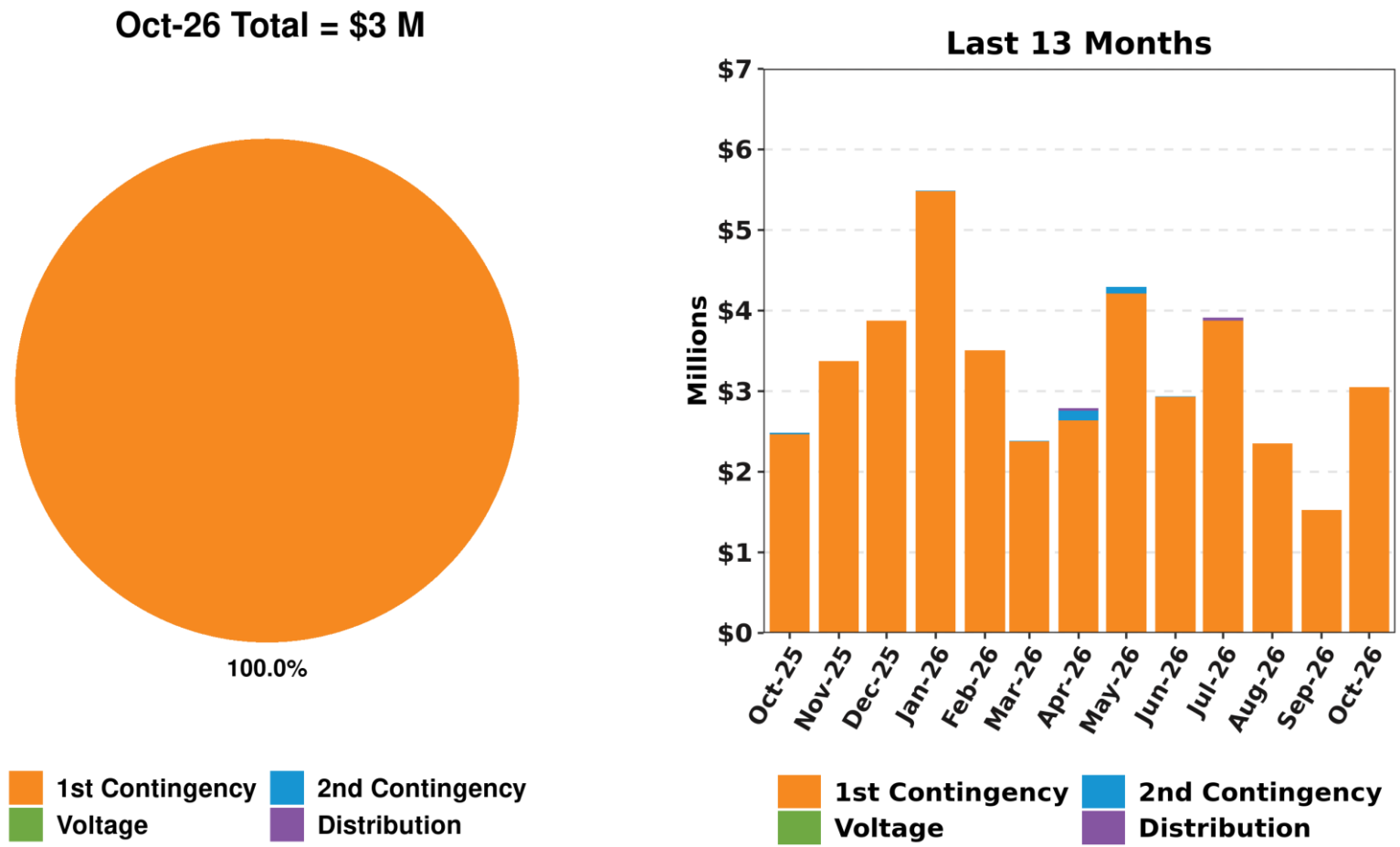
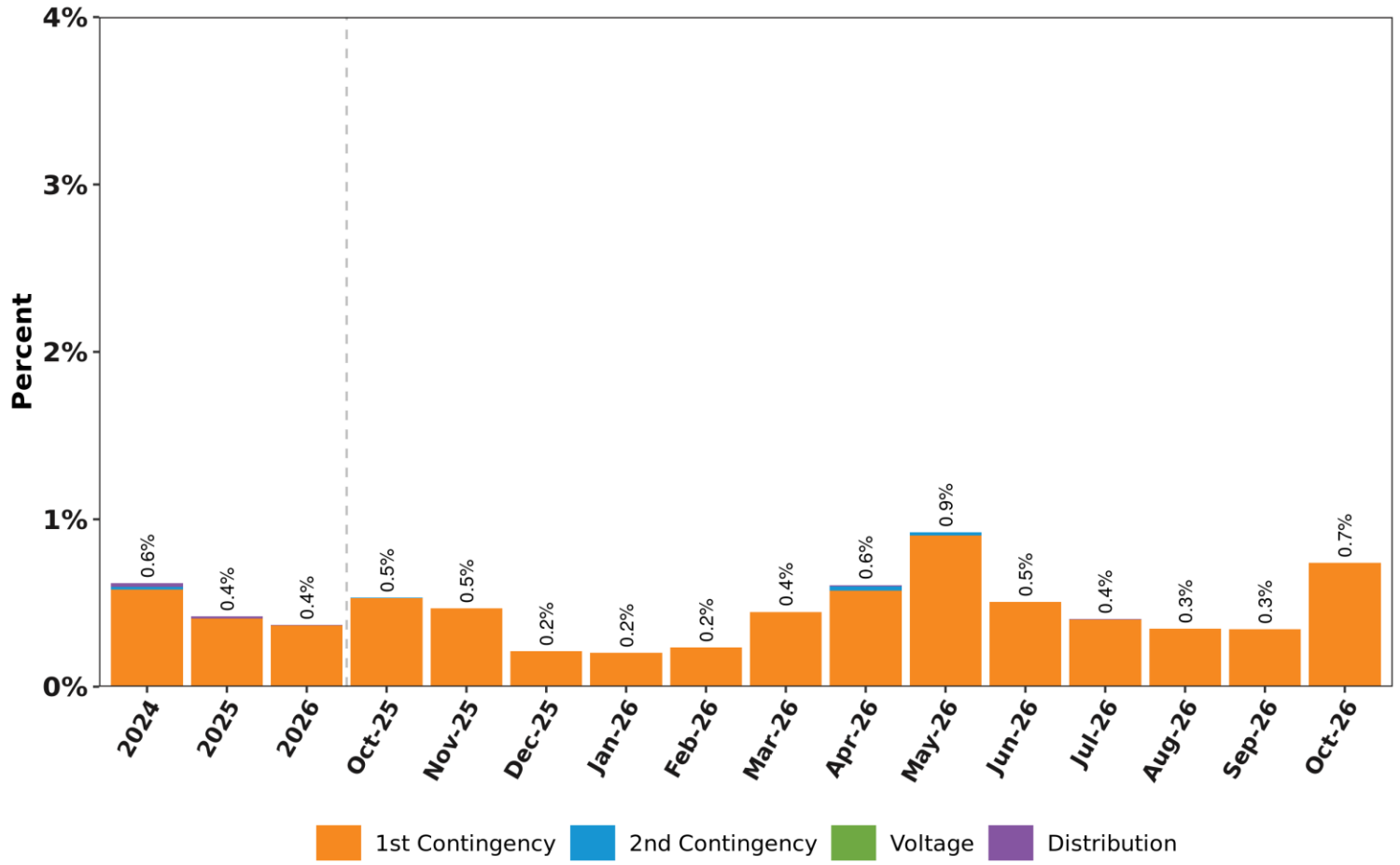
NCPC Charges by Type



This information is available in the Monthly Market Report found on the ISO website and is scheduled for removal from this deck at a future date.

NCPC Charges by Type as Percent of Energy Market Value



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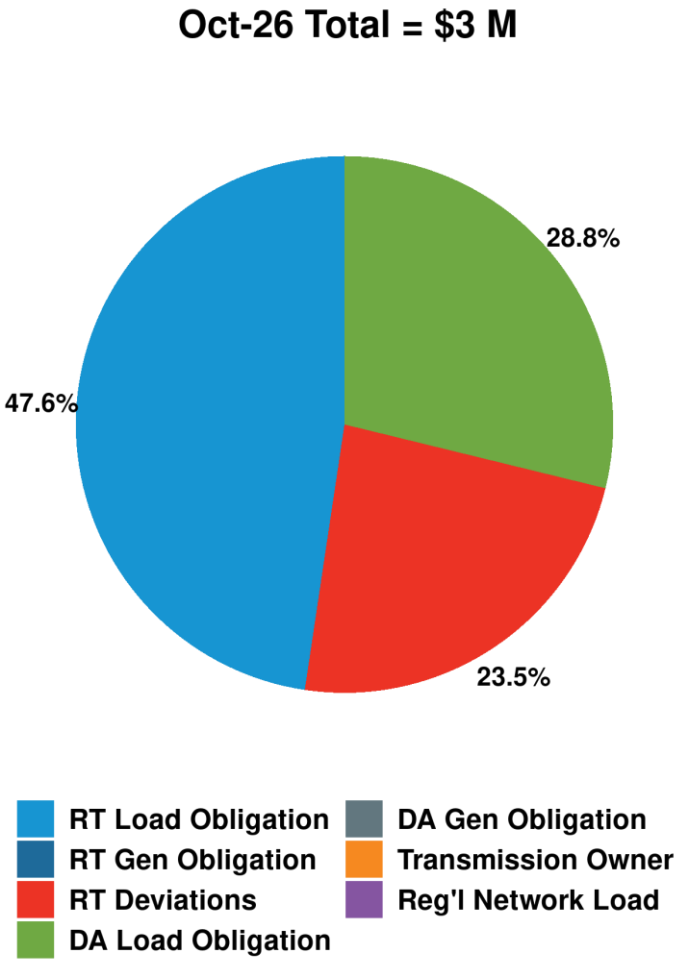
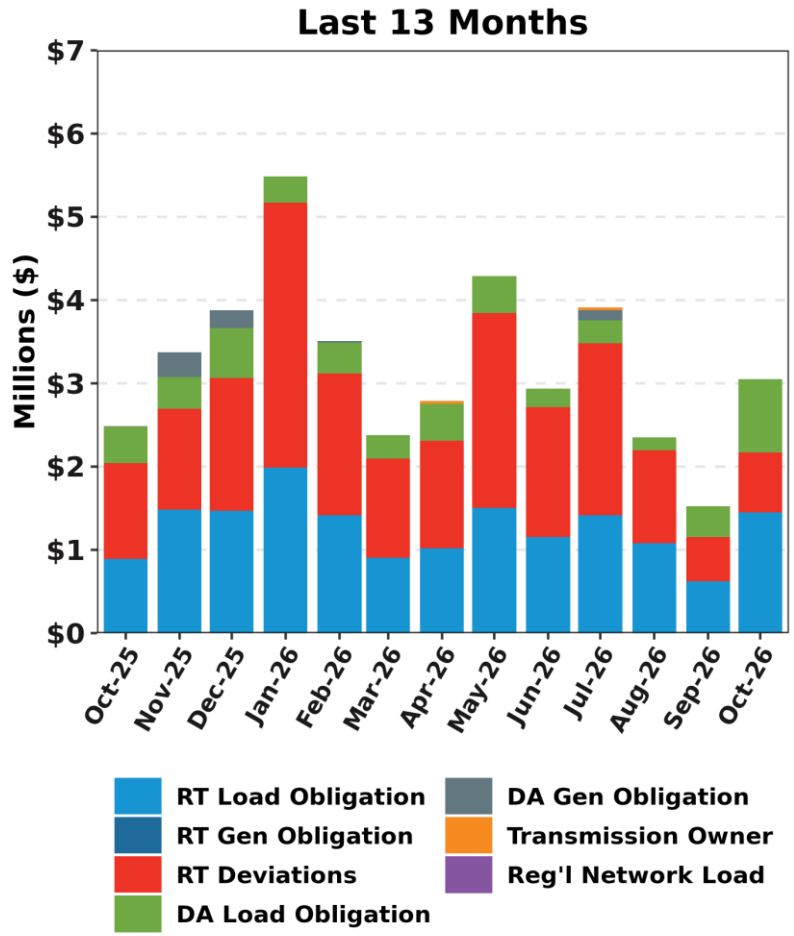
NCPC Charge Allocations





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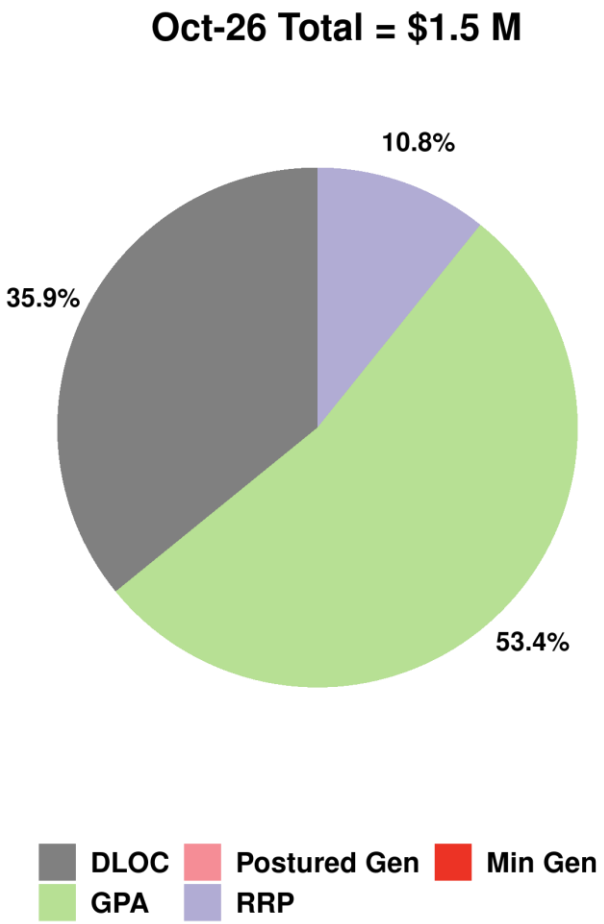
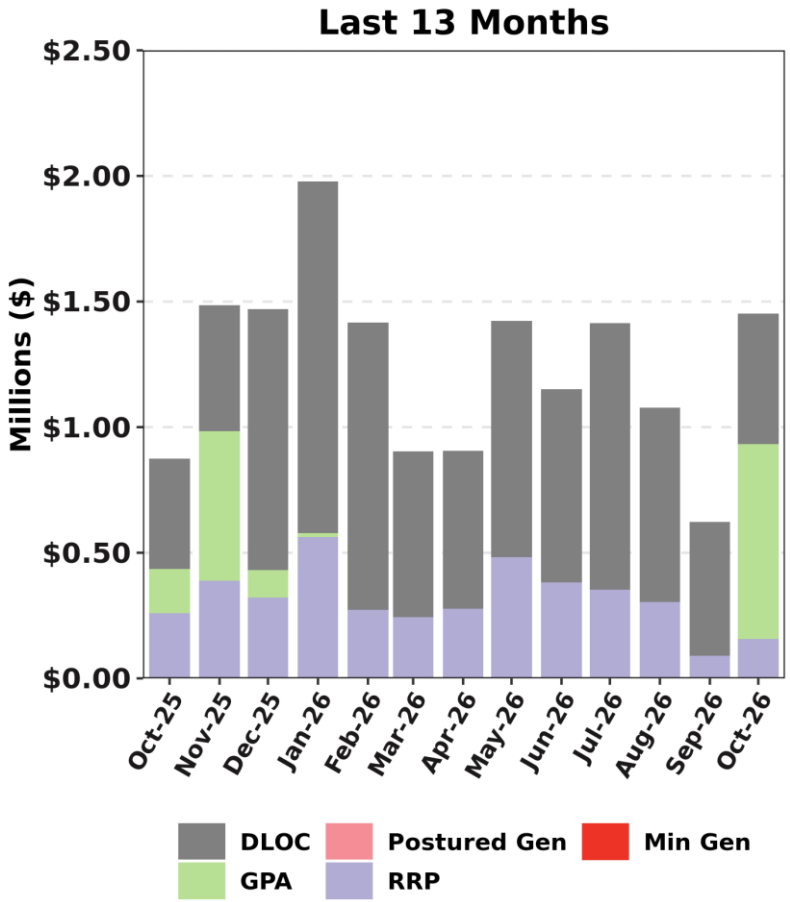
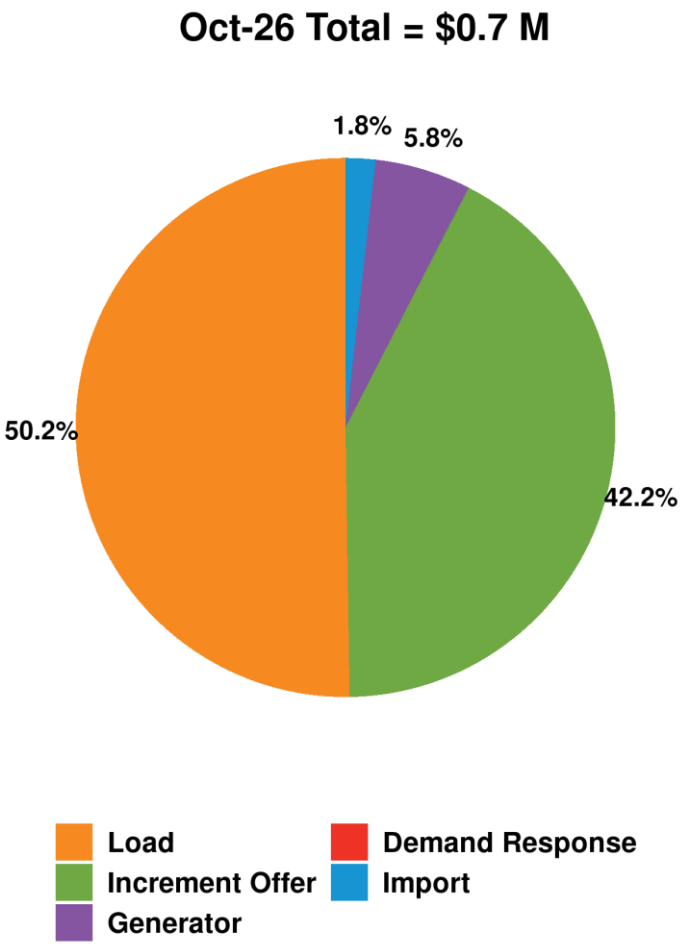
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

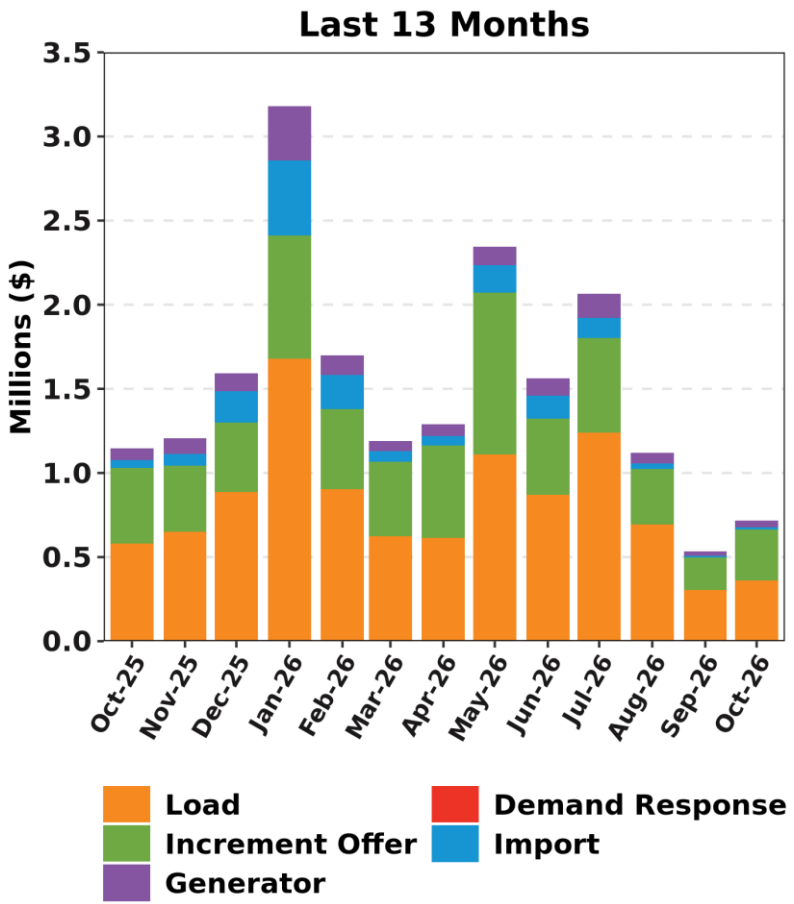




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.
This information is available in the Monthly Market Report found on the ISO website and is scheduled for removal from this deck at a future date.

RT First Contingency Charges by Deviation Type





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REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- November 18 PAC Meeting Tentative Agenda Topics (note that the agenda is still under review)*
  - Asset Condition Projects
    - Otter River #615 Substation Asset Replacement (NGRID)
    - Line 330 ACR Project (Eversource)
  - 2026 Economic Study – Follow-up on the Stakeholder-Requested Scenario
  - 2026 Economic Study – Final Benchmark Scenario Results
  - 2026 Economic Study – Policy Scenario Assumptions
  - Transmission Planning Guide Process Update

* Agenda topics are subject to change. Visit https://www.iso-ne.com/committees/planning/planning-advisory for the latest PAC agendas.

Economic Studies: 2026 Study

- The 2026 Economic Study was launched in January
  - The ISO presented results of the public survey, as part of a lessons learned, and Benchmark Scenario assumptions at PAC
  - The ISO opened the Stakeholder-Requested scenario window through July 24, and one stakeholder submitted a request. ISO will provide feedback at the November PAC.
  - The preliminary Benchmark results were presented at PAC this summer. The final Benchmark, Policy assumptions, and Stakeholder-Requested requests will be discussed in November.
    - Results from the latter scenarios will come out over the next 3-6 months, followed by the System Efficiency Needs Scenario in Q2-Q3 2027

2025 Longer-Term Transmission Planning (LTTP) RFP

- On 12/13/24, NESCOE provided its LTTP RFP request describing the needs to be addressed by 2035:
  - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
  - Increase the Surowiec-South interface capacity to at least 3,200 MW
  - Develop new infrastructure (e.g., substation) at Pittsfield, Maine that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind
- The ISO issued the RFP on 3/31/25, with proposals due by 9/30/25
- The ISO presented the preliminary preferred Longer-Term Transmission Solution at the July 2026 PAC meeting, posted the preferred Longer-Term Transmission Solution on 8/14/26, and notified the Qualified Transmission Project Sponsors (QTPSs) they were selected
  - The QTPSs executed all Selected QTPS Agreements by 10/15/26 and they are posted on the ISO website

2025 Longer-Term Transmission Planning (LTTP) RFP, cont.

- Transmission Initiative Down East (TIDE) project (was designated as LTP A1 during the 2025 LTTP RFP) RSP IDs: 1940-1977
  - Lead QTPS: Central Maine Power (CMP)
  - Joint Proposal: Yes, w/ Public Service of New Hampshire (PSNH) and NSTAR (Eversource)
  - Type: AC transmission in ME and NH
  - Cost Containment: Yes
  - Projected Benefit-to-Cost Ratio: 2.10
  - Construction Start: Q1 2029, In-Service Date: Q4 2032
  - Design Summary
    - Wind interconnection POI: Pittsfield
    - New 345 kV lines: Pittsfield-Coopers Mills & Buxton-Deerfield (70 mi total)
    - Rebuild Larrabee Rd-Surowiec 115 kV line to operate at 345 kV
    - Several reconductored 345 & 115 kV lines
    - Retire ME Yankee 345 kV substation, build new adjacent Old Ferry Rd 345 kV
    - New STATCOMs: Eight 400 MVAR @ 345 kV
    - New Phase Angle Regulators: Four 750 MVA @ 345 kV
    - Minor corollary upgrade: Three upgraded 115 kV breakers at Orrington

Permanent Asset Condition Reviewer

- ISO engaged with the Transmission Committee (TC) and the PTO Administrative Committee (PTO-AC) regarding the development of this new role. The proposal was the product of robust discussion and incorporated numerous stakeholder-suggested revisions
- Final changes to the Transmission Operating Agreement (TOA) and ISO's Open Access Transmission Tariff (OATT) were filed on August 17, 2026
- On October 16, 2026, FERC issued an Order fully accepting the revisions to establish the ISO as the New England region's Asset Condition Reviewer (ACR), effective January 1, 2027
- Interim project reviews underway to inform permanent design
- ISO is working on staffing and implementation towards January 2027 go-live

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

Note: The listings in this section focus on major transmission line construction and rebuilding.

SEMA/RI Reliability Projects

Status as of 10/26/2026

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Oct-20	4
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Oct-20	4
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 10/26/2026

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Dec-29	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Jul-27	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

*Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 10/26/2026

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	4
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Jul-27	3

SEMA/RI Reliability Projects, cont.

Status as of 10/26/2026

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Nov-25	4
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

* Does not include the reconductoring work over the Cape Cod canal

** Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 10/26/2026

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	May-22	4
1724	Replace the Kent County 345/115 kV transformer	Mar-22	4
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Upper Maine Solution Projects

Status as of 10/26/2026

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland-Coopers Mills 115 kV line	Aug-24	4
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-29	2
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-29	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-30	2
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Aug-25	4

Upper Maine Solution Projects, cont.

Status as of 10/26/2026

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Nov-24	4
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jul-24	4
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Dec-26	3

* Cancelled per the Upper Maine Solutions Study Addendum that was published on January 11, 2024

Boston 2033 Solutions Study

Status as of 10/26/2026

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1933	Install one 80 MVAR shunt reactor at the 115 kV Electric Avenue Substation	Dec-28	1
1934	Protection systems modification associated with the Stoughton RAS at three 345 kV substations (Stoughton, West Walpole and Holbrook) and two 115 kV substations (Hyde Park and K-Street)	Mar-27	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1940	New P-C - A new 38.5 mile overhead 345 kV line between Coopers Mills substation (Windsor, ME) and the new Pittsfield substation (Pittsfield, ME)	Dec-32	1
1941	3023 - Reconductor 17.4 miles of overhead 345 kV line between Albion Road substation (Benton, ME) and new Pittsfield substation (Pittsfield, ME), split this line and terminate into the new Pittsfield substation	Dec-32	1
1942	3026 - Relocate 3.4 mile section of overhead 345 kV line between the Larrabee Road substation (Lewiston, ME) and the Surowiec substation (Pownal, ME)	Dec-32	1
1943	374 - Reconductor 26.5 miles of overhead 345 kV line between Surowiec substation (Pownal, ME) and Buxton substation (Buxton, ME)	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1944	3038 - Reconductor 26.5 miles of overhead 345 kV line between Surowiec substation (Pownal, ME) and Buxton substation (Buxton, ME)	Dec-32	1
1945	391-ME - Rebuild 30.6 miles of overhead 345 kV line on monopoles between Buxton substation (Buxton, ME) and the ME/NH border	Dec-32	1
1946	385-ME - Replace 0.24 miles of overhead structures between Buxton substation (Buxton, ME) and the ME/NH border	Dec-32	1
1947	New B-D-ME - Build new 30.6 mile overhead 345 kV line between Buxton substation (Buxton, ME) and the ME/NH border	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1948	64 - Convert 16.4 miles of existing overhead line 64 from 115 kV to 345 kV between Larrabee Road substation (Lewiston, ME) and Surowiec substation (Pownal, ME)	Dec-32	1
1949	81 - Reconductor 28.5 miles of overhead 115 kV line between Mason substation (Wiscasset, ME) and Surowiec substation (Pownal, ME)	Dec-32	1
1950	200 - Rebuild 13.8 miles of overhead 115 kV line between Larrabee Road substation (Lewiston, ME) and Leeds substation (Leeds, ME)	Dec-32	1
1951	167 - Reconductor 16.3 miles of overhead 115 kV line between Surowiec substation (Pownal, ME) and Section 167A Tap (Westbrook, ME)	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1952	257 - Rebuild 21.1 miles of overhead 115 kV line on a double-circuit with line 258 between Coopers Mills substation (Windsor, ME) and Albion Road substation (Benton, ME)	Dec-32	1
1953	258 - Rebuild 21.1 miles of overhead 115 kV line on a double-circuit with line 257 between Coopers Mills substation (Windsor, ME) and Albion Road substation (Benton, ME)	Dec-32	1
1954	67 - Rebuild 21.1 miles of overhead 115 kV line in a double circuit configuration with the new P-C line between Albion Road substation (Benton, ME) and Pittsfield substation (Pittsfield, ME)	Dec-32	1
1955	Bypass 345 kV S388 Series Capacitor	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1956	Bypass 345 kV S3023 Series Capacitor	Dec-32	1
1957	Old Ferry Road - Retire existing Maine Yankee substation (Wiscasset, ME) and build new 345 kV substation called Old Ferry Road (Wiscasset, ME) in a breaker-and-a-half configuration - 345 kV Maine Yankee substation Decommissioned - Reterminate 392, 3027, 378, 377, 375 345 kV lines and existing STATCOM into new substation - Add two 345 kV Phase Angle Regulators (PAR) on Line 377 at Old Ferry Road substation - Add two 345 kV Phase Angle Regulators (PAR) on Line 375 at Old Ferry Road substation	Dec-32	1
1958	Pittsfield - Build new 345 kV air-insulated substation called Pittsfield (Pittsfield, ME) in a breaker-and-a-half configuration, terminate split 3023 line and new P-C 345 kV line into the station	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1959	Surowiec - Expand Surowiec substation (Pownal, ME) with additional 345 kV bay, upgrading eight existing 345 kV breakers, installing five new 345 kV breakers, and reterminate 64 line into 345 kV station	Dec-32	1
1960	Larrabee Road - Upgrade/Expand existing Larrabee Road substation (Lewiston, ME) with upgrading two existing 345 kV breakers, installing two new 345 kV breakers, and reterminate 64 line into 345 kV station	Dec-32	1
1961	Buxton - Upgrade Buxton substation (Buxton, ME) with additional 345 kV bay, upgrading 11 existing 345 kV breakers, installing two new 345 kV breakers, and terminate new B-D-ME 345 kV line into the station	Dec-32	1
1962	Albion Road - Upgrade Albion Road substation (Benton, ME) with upgrading two existing 345 kV breakers and installing one new 345 kV series breaker	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1963	Coopers Mills - Upgrade Coopers Mills substation (Windsor, ME) with additional 345 kV bay, installing five new 345 kV breakers, and terminate new P-C 345 kV line into the station	Dec-32	1
1964	South Gorham - Upgrade South Gorham substation (South Gorham, ME) with two new 345 kV breakers and uprates of existing T1 and T2 autotransformers	Dec-32	1
1965	Surowiec STATCOM - Install new 345 kV +/-400 MVAR STATCOM near Surowiec substation (Pownal, ME)	Dec-32	1
1966	Coopers Mills STATCOM - Install new 345 kV +/-400 MVAR STATCOM at Coopers Mills substation (Windsor, ME)	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1967	Old Ferry Road STATCOM - Install new 345 kV +/-400 MVAR STATCOM at Old Ferry Road substation (Wiscasset, ME)	Dec-32	1
1968	Pittsfield STATCOM - Install new 345 kV +/-400 MVAR STATCOM at Pittsfield substation (Pittsfield, ME)	Dec-32	1
1969	Woburn (Woburn, MA) - Construction, installation and interconnection of a 400 MVAR STATCOM	Dec-32	1
1970	New B-D-NH - New overhead 345 kV line from Deerfield substation (Deerfield, NH) to the NH/ME state line	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1971	391-NH - Reconstruction of existing portion of the 345 kV 391 line between Deerfield substation (Deerfield, NH) and the NH/ME state line	Dec-32	1
1972	373 - Reconductoring of existing 345 kV 373 line between Deerfield substation (Deerfield, NH) and Scobie Pond substation (Londonderry, NH)	Dec-32	1
1973	N133 - Reconductoring of a portion of the existing 115 kV N133 line between Bolt Hill tap (Eliot, ME) and Three Rivers substation (Eliot, ME)	Dec-32	1
1974	Deerfield (Deerfield, NH) - Construction, installation and interconnection of two 400 MVAR STATCOMs; including new 345 kV bay, installing three new 345 kV breakers and upgrading four existing 345 kV breakers, and terminate the new B-D-NH line	Dec-32	1

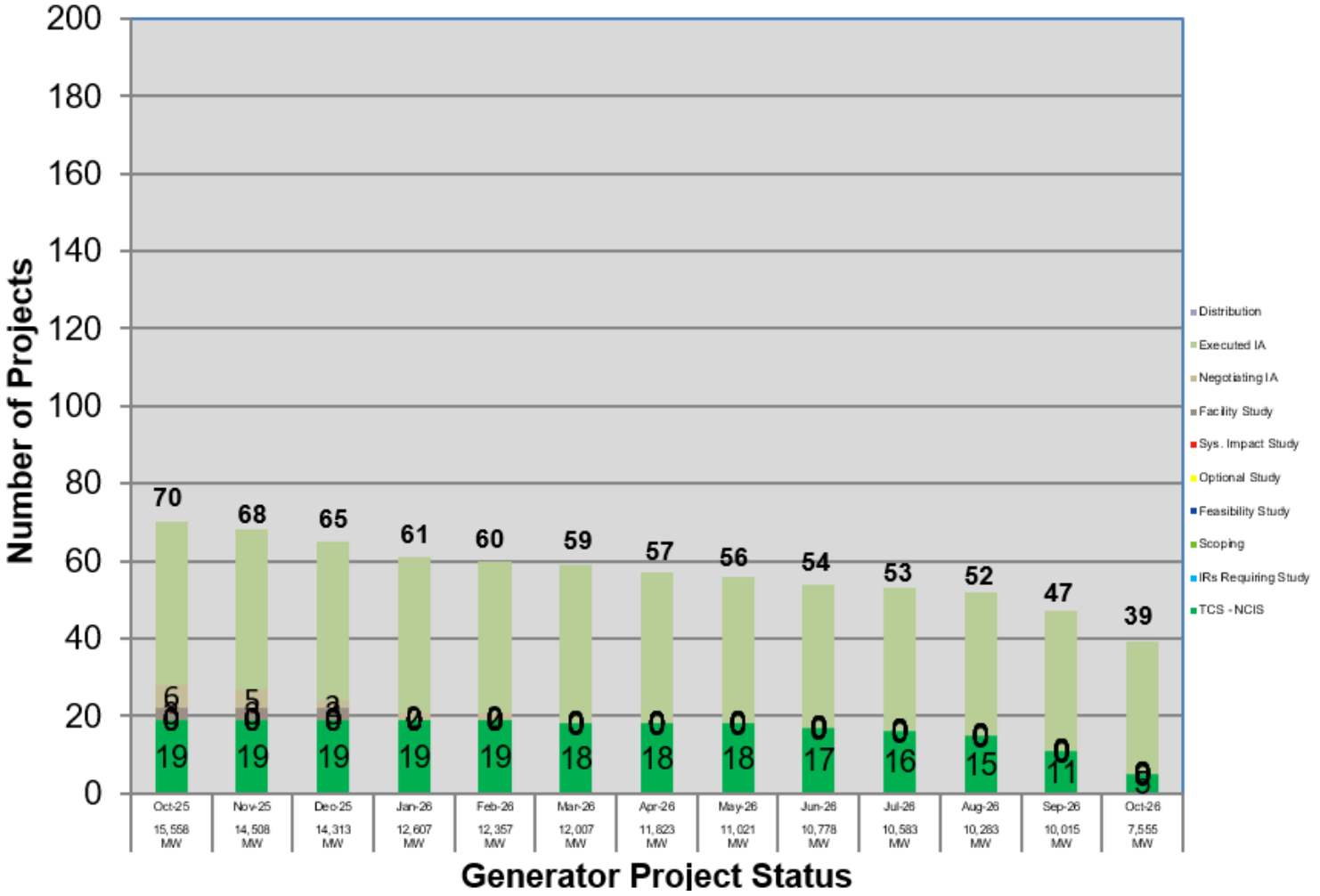
Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1975	Scobie Pond (Londonderry/Derry, NH) - Construction, installation and interconnection of a 400 MVAR STATCOM; including new 345 kV bay, installing two new 345 kV breakers, and upgrading four existing 345 kV breakers	Dec-32	1
1976	Three Rivers (Eliot, ME) - Termination of reconductored N133 line	Dec-32	1
1977	Upgrade of three existing 115 kV breakers at Orrington substation (Orrington, ME)	Dec-32	1

Status of Tariff Studies as of November 2, 2026



ETUs: 0 in TCS – NCIS, 0 Negotiating IA, and 1 with Executed IA
Transmission Service Requests needing study: 0
https://irtt.iso-ne.com/external.aspx

Additional notes provided on next slide

Status of Tariff Studies as of November 2, 2026, cont.

- Additional Notes
  - The final Transitional Cluster Study Report was issued on August 6, 2026
  - The Cluster Request Window for the first regular Cluster Study opens on October 5, 2026 and will be open for 45 Calendar Days
  - The interconnection queue has been closed since June 13, 2024

OPERABLE CAPACITY ANALYSIS

Fall 2026 Analysis

Fall 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov - 2026[2] CSO (MW)	Nov - 2026[2] SCC (MW)
Operable Capacity MW [1]	27,106	29,545
Active Demand Capacity Resource (+) [5]	340	274
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	334	334
Non Commercial Capacity (+)	16	16
Non Gas-fired Planned Outage MW (-)	3,859	4,668
Gas Generator Outages MW (-)	1,269	1,379
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,068	20,522
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,623	17,623
Operating Reserve Requirement MW	2,000	2,000
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,623	19,623
Operable Capacity Margin	-555	899

[1]Operable Capacity is based on data as of **October 23, 2026** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **October 23, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 7, 2026.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Fall 2026 Operable Capacity Analysis

90/10 Load Forecast	Nov - 2026[2] CSO (MW)	Nov - 2026[2] SCC (MW)
Operable Capacity MW [1]	27,106	29,545
Active Demand Capacity Resource (+) [5]	340	274
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	334	334
Non Commercial Capacity (+)	16	16
Non Gas-fired Planned Outage MW (-)	3,859	4,668
Gas Generator Outages MW (-)	1,269	1,379
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,068	20,522
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,461	18,461
Operating Reserve Requirement MW	2,000	2,000
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,461	20,461
Operable Capacity Margin	-1,393	61

[1]Operable Capacity is based on data as of **October 23, 2026** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **October 23, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 7, 2026.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Fall 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 2026 - 50-50 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in November.

Report created: 10/23/2026

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/7/2026	27106	340	334	16	3859	1269	3600	0	19068	17623	2000	19623	-555	Y	Fall 2026
11/14/2026	27106	340	334	16	3168	1280	3600	0	19748	17941	2000	19941	-193	N	Fall 2026
11/21/2026	27106	340	334	16	676	0	3600	1370	22150	18621	2000	20621	1529	N	Fall 2026

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2026 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 110% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.
15. Operable Capacity Season Label: Applicable season and year.

Fall 2026 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 2026 - 90/10 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in November.

Report created: 10/23/2026

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/7/2026	27106	340	334	16	3859	1269	3600	0	19068	18461	2000	20461	-1393	Y	Fall 2026
11/14/2026	27106	340	334	16	3168	1280	3600	0	19748	18794	2000	20794	-1046	N	Fall 2026
11/21/2026	27106	340	334	16	676	0	3600	1535	21985	19506	2000	21506	479	N	Fall 2026

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2026 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 110% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.
15. Operable Capacity Season Label: Applicable season and year.

***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

OPERABLE CAPACITY ANALYSIS

Winter 2026/27 Analysis

Winter 2026/27 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan - 2027[2] CSO (MW)	Jan - 2027[2] SCC (MW)
Operable Capacity MW [1]	27,429	29,545
Active Demand Capacity Resource (+) [5]	348	274
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	98	98
Non Gas-fired Planned Outage MW (-)	598	931
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,728	4,136
Net Capacity (NET OPCAP SUPPLY MW)	21,158	22,459
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,483	20,483
Operating Reserve Requirement MW	2,000	2,000
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,483	22,483
Operable Capacity Margin	-1,325	-24

[1]Operable Capacity is based on data as of **October 23, 2026** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **October 23, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 9, 2027.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2026/27 Operable Capacity Analysis

90/10 Load Forecast	Jan - 2027[2] CSO (MW)	Jan - 2027[2] SCC (MW)
Operable Capacity MW [1]	27,429	29,545
Active Demand Capacity Resource (+) [5]	348	274
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	98	98
Non Gas-fired Planned Outage MW (-)	598	931
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,539	5,066
Net Capacity (NET OPCAP SUPPLY MW)	20,347	21,529
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,457	21,457
Operating Reserve Requirement MW	2,000	2,000
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,457	23,457
Operable Capacity Margin	-3,110	-1,928

[1]Operable Capacity is based on data as of **October 23, 2026** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **October 23, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 9, 2027.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2026/27 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 2026 - 50-50 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in December through March.

Report created: 10/23/2026

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/28/2026	27106	340	334	16	482	0	3600	1662	22052	19285	2000	21285	767	N	Winter 2026/2027
12/5/2026	27578	348	261	97	760	822	3200	982	22520	19469	2000	21469	1051	N	Winter 2026/2027
12/12/2026	27578	348	261	97	851	0	3200	2368	21865	19735	2000	21735	130	N	Winter 2026/2027
12/19/2026	27578	348	261	97	648	0	3200	2745	21691	19746	2000	21746	-55	N	Winter 2026/2027
12/26/2026	27578	348	261	97	607	0	3200	3134	21343	19803	2000	21803	-460	N	Winter 2026/2027
1/2/2027	27429	348	409	98	598	0	2800	3733	21153	20055	2000	22055	-902	N	Winter 2026/2027
1/9/2027	27429	348	409	98	598	0	2800	3728	21158	20483	2000	22483	-1325	Y	Winter 2026/2027
1/16/2027	27429	348	409	98	599	0	2800	3583	21302	20483	2000	22483	-1181	N	Winter 2026/2027
1/23/2027	27429	348	409	98	599	0	2800	3134	21751	20483	2000	22483	-732	N	Winter 2026/2027
1/30/2027	27429	348	409	98	359	0	3100	2835	21990	20278	2000	22278	-288	N	Winter 2026/2027
2/6/2027	27429	348	409	98	349	0	3100	2536	22299	20032	2000	22032	267	N	Winter 2026/2027
2/13/2027	27429	348	409	98	406	0	3100	2237	22541	20006	2000	22006	535	N	Winter 2026/2027
2/20/2027	27429	348	409	98	379	0	3100	1788	23017	19764	2000	21764	1253	N	Winter 2026/2027
2/27/2027	27429	348	409	98	765	263	2200	1226	23830	18854	2000	20854	2976	N	Winter 2026/2027
3/6/2027	27429	348	409	98	780	906	2200	0	24398	18533	2000	20533	3865	N	Winter 2026/2027
3/13/2027	27429	348	409	98	1286	600	2200	0	24198	18353	2000	20353	3845	N	Winter 2026/2027
3/20/2027	27429	348	409	98	1268	794	2200	0	24022	18017	2000	20017	4005	N	Winter 2026/2027
3/27/2027	27213	349	409	98	1741	693	2700	0	22935	17496	2000	19496	3439	N	Winter 2026/2027

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.

5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2026 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

11. Operating Reserve Requirement MW: 110% of first largest contingency plus 50% of the second largest contingency.

12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)

13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

14. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

15. Operable Capacity Season Label: Applicable season and year.

Winter 2026/27 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 2026 - 90/10 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in December through March.

Report created: 10/23/2026

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/28/2026	27106	340	334	16	482	0	3600	2576	21138	20201	2000	22201	-1063	N	Winter 2026/2027
12/5/2026	27578	348	261	97	760	822	3200	1970	21532	20394	2000	22394	-862	N	Winter 2026/2027
12/12/2026	27578	348	261	97	851	0	3200	3355	20878	20673	2000	22673	-1795	N	Winter 2026/2027
12/19/2026	27578	348	261	97	648	0	3200	3864	20572	20684	2000	22684	-2112	N	Winter 2026/2027
12/26/2026	27578	348	261	97	607	0	3200	4280	20197	20744	2000	22744	-2547	N	Winter 2026/2027
1/2/2027	27429	348	409	98	598	0	2800	4408	20478	21008	2000	23008	-2530	N	Winter 2026/2027
1/9/2027	27429	348	409	98	598	0	2800	4539	20347	21457	2000	23457	-3110	Y	Winter 2026/2027
1/16/2027	27429	348	409	98	599	0	2800	4331	20554	21457	2000	23457	-2903	N	Winter 2026/2027
1/23/2027	27429	348	409	98	599	0	2800	4032	20853	21457	2000	23457	-2604	N	Winter 2026/2027
1/30/2027	27429	348	409	98	359	0	3100	4032	20793	21242	2000	23242	-2449	N	Winter 2026/2027
2/6/2027	27429	348	409	98	349	0	3100	3583	21252	20984	2000	22984	-1732	N	Winter 2026/2027
2/13/2027	27429	348	409	98	406	0	3100	3284	21494	20957	2000	22957	-1463	N	Winter 2026/2027
2/20/2027	27429	348	409	98	379	0	3100	2686	22119	20703	2000	22703	-584	N	Winter 2026/2027
2/27/2027	27429	348	409	98	765	263	2200	1974	23082	19751	2000	21751	1331	N	Winter 2026/2027
3/6/2027	27429	348	409	98	780	906	2200	405	23993	19414	2000	21414	2579	N	Winter 2026/2027
3/13/2027	27429	348	409	98	1286	600	2200	606	23592	19225	2000	21225	2367	N	Winter 2026/2027
3/20/2027	27429	348	409	98	1268	794	2200	0	24022	18873	2000	20873	3149	N	Winter 2026/2027
3/27/2027	27213	349	409	98	1741	693	2700	0	22935	18328	2000	20328	2607	N	Winter 2026/2027

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2026 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 110% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.
15. Operable Capacity Season Label: Applicable season and year.

***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes	125 [3]

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 [3]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**2,520**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: November 4, 2026

RE: Vote on Large Load Revisions

At the November 12, 2026, Participants Committee meeting, you will be asked to vote on large load integration Tariff revisions ("Large Load Revisions") proposed by ISO-NE and the Participating Transmission Owners ("PTOs") as a Section 205 proposal in response to the FERC's June 18, 2026, show cause order in EL26-72 ("Show Cause Order"). The Large Load Revisions primarily came through the Transmission Committee, but pieces of the proposal also came through the Markets and Reliability Committees. Each of the three Technical Committees has recommended Participants Committee support for the Large Load Revisions for which each Committee has primary responsibility. The ISO plans to file the Large Load Revisions on November 12 and request an effective date of November 13, 2026. Assuming the vote at the Participants Committee follows the Technical Committees' recommendations, NEPOOL will join the filing as a supporting party. Additional materials for this agenda item have been included or posted with this memorandum.

Background

By way of brief background, on June 18, 2026, the FERC issued six tailored show cause orders under Section 206 of the Federal Power Act, one to each RTO/ISO, relating to integrating large loads such as data centers. In the order directed to ISO-NE and the PTOs (Docket No. EL26-72, 195 FERC ¶ 61,215), the FERC preliminarily found the ISO-NE Tariff unjust, unreasonable, or unduly discriminatory or preferential because it does not address large and co-located loads clearly or specifically enough.[1] The FERC said it had less concern about New England because not much large load development has occurred so far, but it still found the existing rules, built for conventional loads, inadequate for the speed and scale of demand growth. Reforms will apply prospectively only and should include a reasonable implementation and transition period. The Commission expects reforms in five areas:

1. *Transmission service application and study procedures*: A definition of large load, a pro forma transmission service agreement, rolling applications with a non-refundable fee, a 60–90 day study timeline, and ongoing operational requirements.

2. *Cost transparency and cost shifting*: Public posting of large load additions, planned network upgrades, and cost estimates, and a pro forma cost recovery agreement

[1] NEPOOL counsel's memo summarizing the Show Cause Order is available here.

requiring a minimum contribution toward the transmission owner's revenue requirement.

3. *Co-location arrangements and behind-the-meter generation ("BTMG")*: Clear interconnection and service rules for co-located load, with appropriate allocation of transmission and ancillary service costs.

4. *New transmission services for flexible large loads*: interim non-firm network service, firm contract demand service, and non-firm contract demand service.

5. Generator interconnection for facilities serving electrically proximate or co-located large loads, including load-matched or expedited interconnection options.

The FERC also required an informational report on resource adequacy for serving new large loads by July 20, 2026,[2] and strongly encouraged a Section 205 filing over a Section 206 response.

On August 3, 2026, ISO-NE and the PTO Administrative Committee jointly moved to hold the Section 206 proceeding in abeyance for 90 days, starting from the August 17, 2026 response deadline. They committed to a Section 205 filing addressing all five reform categories and the order's briefing questions.[3] ISO-NE also said it would put Eligible Customers on notice that large loads must bring their own new capacity and will be excluded from the Installed Capacity Requirement, with detailed rules to be filed in 2027. The FERC granted the motion on August 14, 2026. A Section 205 filing addressing the FERC's preliminary findings will obviate the need for ISO-NE and the PTOs to respond directly to the Show Cause Order.

NEPOOL Stakeholder Process

From early August through November 3, ISO-NE and the PTOs brought forward elements of the Section 205 proposal and the Transmission, Markets and Reliability Committees reviewed and provided input on those elements and specific Tariff revisions. This work was a rapid response to a tight deadline and required collaboration among ISO-NE, the PTOs and NEPOOL.

During the stakeholder discussions one primary issue involved the ISO-NE proposal to use price-based re-dispatch as the means to effectuate non-firm transmission service to large loads. The FERC's Show Cause Order expects that the transmission provider will make available to large loads a form of non-firm transmission service. ISO-NE has proposed to treat large loads like a Dispatchable Asset-Related Demand and effectively curtail service to the large load at an energy

[2] ISO-NE made this filing on July 20, 2026, and the filing is available here. A NEPOOL counsel memo summarizing the filing is available here.

[3] The anticipated filing would include a large load definition based on load size and interconnection voltage; an application and study process; operational requirements (hourly forecasts, telemetry, remote disconnection, and ramp-rate/ride-through); a pro forma transmission service agreement; systematic posting of network upgrade needs and costs and a pro forma cost recovery agreement; co-location rules, including that BTMG cannot be netted against load for Regional Network Service charges; interim and permanent flexible load services; and a study process for generators serving proximate and co-located loads.

price at or above $250/MWh. The New England Power Generators Association ("NEPGA") and some individual generators have contested both the use of an administratively set price as well as the specific price proposed by the ISO for re-dispatch of flexible large loads.[4] The ISO provided the rationale for its re-dispatch price proposal in a memo and presentations.[5] NEPGA had originally expressed its intent to offer an amendment on this issue but ultimately chose to not offer the amendment for a vote.

The ISO and the PTOs discussed the large load proposal with NEPOOL's three Technical Committees over the course of several meetings, responding to Participant input. On November 3, each of the Technical Committees voted on the ISO's and the PTO's proposed Large Load Revisions for which each committee has primary responsibility, with no Participant amendments offered.

Technical Committee Votes

The ***Transmission Committee*** voted to recommend Participants Committee support for the Large Load Revisions for which it has primary responsibility.[6] Based on a show of hands, the motion passed with five opposed (3 Generators, 1 Supplier, 1 Alternative Resource) and two abstentions (2 End Users).

The ***Reliability Committee*** voted to recommend Participants Committee support for the Large Load Revisions for which it has primary responsibility.[7] Based on a show of hands, the motion passed with two opposed (1 Generation, 1 Supplier) and four abstentions (1 Generation, 1 Supplier, 1 Alternative Resource, 1 End User).

The ***Markets Committee*** voted to recommend Participants Committee support for the Large Load Revisions for which it has primary responsibility.[8] The motion passed with a vote of 71.11% in favor.[9]

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[4] NEPGA's most recent presentation on this issue is available here. A related FirstLight presentation is available here.

[5] The memo is available here. The presentations are available here and here.

[6] Large Load Revisions reviewed and voted on by the Transmission Committee included: Sections I.2.2 (Definitions) and Section II of the Open Access Transmission Tariff (OATT), including (i) new Sections II.56-II.63, new Attachments S-V, and new Schedule 9A; and (ii) conforming changes to Sections II.20.2, II.20.3, and II.21.2, and to Schedules 1, 2, 16, 17, 22 and 23.

[7] Sections I.2.2 and III.12.1 (Installed Capacity Requirement) of the Tariff.

[8] Large Load Revisions reviewed and voted on by the Markets Committee included: Sections I.2.2 and Section III (Market Rule 1), including Sections III.1.10.5A, III.1.7.19.2.2.2, III.1.8.1, III.2.5, III.2.6.1, and III.15.8.5.2.1.

[9] The individual Sector votes were Generation (2.78% in favor, 13.89% opposed, 0 abstentions), Transmission (16.67% in favor, 0.00% opposed, 0 abstentions), Supplier (8.33% in favor, 8.33% opposed, 4 abstentions), Publicly Owned Entity (16.67% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (10.00% in favor, 6.67% opposed, 0 abstentions), and End User (16.67% in favor, 0.00% opposed, 2 abstentions).

Proposed Resolutions for Participants Committee Votes

For action by the Participants Committee on November 12, we have suggested separate resolutions for each Technical Committee's recommendation, recognizing different applicable voting thresholds.

- **Transmission Committee (66.67% Vote)**

  RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Transmission Committee, and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

- **Reliability Committee (60% Vote)**

  RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Reliability Committee, and as reflected in the materials distributed to the Participants 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 Reliability Committee.

- **Markets Committee (60% Vote)**

  RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Markets Committee, and as reflected in the materials distributed to the Participants 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.

ISO new england

memo

To: NEPOOL Transmission, Markets, and Reliability Committees

From: ISO New England, Inc.

Date: October 29, 2026

Subject: New England Large Load Show Cause Order (EL26-72) Voting Memo

The ISO and Participating Transmission Owners (PTOs) are requesting votes on their proposal in response to the New England Large Load show cause order (EL26-72). The proposal incorporates efficient study processes, provides cost transparency, accommodates co-location arrangements, provides new transmission services tailored for flexible large loads, and integrates large loads into generation studies.

By way of background, the Federal Energy Regulatory Commission (FERC) issued a show cause order instituting a proceeding under Section 206 of the Federal Power Act related to the integration of large loads and co-located load arrangements. In response, as required in the show cause order, the ISO filed an informational report on resource adequacy on July 20, 2026. On August 3, 2026, as allowed for in the show cause order, the ISO and the PTOs jointly requested a 90-day abeyance for the Section 206 proceeding. FERC issued an order on August 14, 2026 holding the proceeding in abeyance for 90 days, resulting in a November 16, 2026 deadline for a Section 205 filing to meet the directives in the show cause order.

The ISO's proposal addresses FERC's Large Load show cause order and can be implemented in a timely manner. The proposal includes a definition of Large Load (which contains rules for exemptions and transitions that respect commercial arrangements), introduces three new transmission services for Large Loads, and establishes a robust study process for Large Loads, co-located loads, and electrically proximate loads. It also introduces operating requirements for Large Loads, such as forecasting, telemetry, communications requirements, ramp rate requirements, and outage coordination requirements to maintain reliability. In addition, to establish the new non-firm transmission services, the proposal includes a price-based redispatch mechanism. Finally, the proposal introduces a settlement structure for Large Loads, as well as a new Cost Recovery Agreement (CRA) that addresses cost shifting to protect ratepayers.

In addition to addressing the show cause order, the proposal addresses resource adequacy concerns. The ISO has included a new requirement that provides notice that Large Loads must "bring your own new capacity" (BYONC) and that Large Loads will be excluded from the Installed Capacity Requirement (ICR). In 2027, the ISO will further develop these resource adequacy-related provisions with valued input from its stakeholder process.

THE COMMONWEALTH OF MASSACHUSETTS
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ANDREA JOY CAMPBELL
ATTORNEY GENERAL

(617) 727-2200
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To: NEPOOL Participants Committee
From: Massachusetts Attorney General's Office
Cc: ISO-NE, New England States Committee on Electricity
Date: November 10, 2026
Re: FERC Docket No. EL26-72 (New England Large and Co-Located Loads Show Cause Order) Compliance; November 12, 2026 Participants Committee Meeting Agenda Item No. 5

On Thursday, November 12, 2026, the NEPOOL Participants Committee will consider and take action on changes to ISO-NE's Transmission, Markets, and Services Tariff ("Tariff") proposed by ISO-NE and the Participating Transmission Owners Administrative Committee ("PTO-AC") in response to Federal Energy Regulatory Commission's ("FERC") June 18, 2026 *New England Large and Co-Located Loads Show Cause Order* (FERC Docket No. EL26-72) (the "Show Cause Order"), as recommended by the Technical Committees on November 3, 2026. Consistent with Robert's Rules of Order, the Massachusetts Attorney General's Office ("MA AGO") will **move to divide** a portion of the vote on the Transmission Committee's recommendation (i.e., Agenda Item No. 5(a)). Specifically, the MA AGO will move to divide from the vote, for separate consideration, the **PTO-AC-proposed Attachment V** to the Open Access Transmission Tariff ("OATT").[1]

Attachment V is the PTO-AC's proposed "Large Load Cost Recovery Agreement," and it includes the PTO-AC's proposed "Cost Recovery Charge" (i.e., Appendix C-2).

The MA AGO plans to make this procedural motion to preserve its opportunity to support ISO-NE's proposed changes and the remainder of the PTO-AC's proposed changes in response to the Show Cause Order, notwithstanding its opposition to portions of the PTO-AC's proposed "Large Load Cost Recovery Agreement" (i.e., Attachment V). If the Participants Committee supports the MA AGO's motion to divide this vote / question, there would be separate votes for (a) the PTO-AC's proposed Attachment V and (b) the remainder of the OATT changes as recommended by the Transmission Committee at its November 3, 2026 meeting. Members will have the opportunity to support both portions of the vote (consistent with the single vote taken by the Transmission Committee at its November 3, 2026 meeting) *or* to support one or the other portions of ISO-NE's and the PTO-AC's proposals.

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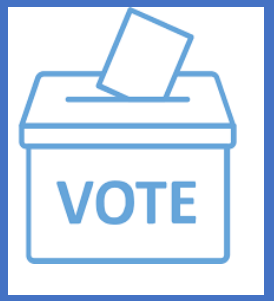
[1] The remainder of the vote will include changes to Section I.2.2 (Definitions) and Section II of the OATT, including (i) new Sections II.56-II.63, new Attachments S-U, and new Schedule 9A; and (ii) conforming changes to Sections II.20.2, II.20.3, and II.21.2, and to Schedules 1, 2, 16, 17, 22 and 23.

5.a Vote on Large Load Revisions: TC-Recommended Changes



66.67%

To consider and take action, as appropriate, on Tariff changes related to the integration of large loads, proposed in response to the FERC's June 18, 2026 New England Large and Co-Located Loads Show Cause Order: Section I.2.2 (Definitions) and Section II of the Open Access Transmission Tariff (OATT), including (i) new Sections II.56-II.63, new Attachments S-V, and new Schedule 9A; and (ii) conforming changes to Sections II.20.2, II.20.3, and II.21.2, and to Schedules 1, 2, 16, 17, 22 and 23, as recommended by the Transmission Committee at its November 3 meeting.

RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Transmission Committee, and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

Nov 12, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

New England Large Load Show Cause Order (EL26-72)

Tariff Revisions

Dennis Cakert, Alex Rost, and Nic Baldenko



Project Title: New England Large Load Show Cause Order (EL26-72)	WMPP ID: 196

Proposed Effective Date: November 2026
Proposed Implementation Date: June 1, 2027 (Application & Study Process), June 1, 2028 (Transmission Services)

- This project covers the ISO's and Participating Transmission Owners' (PTOs) response to the Federal Energy Regulatory Commission's (FERC) June 18, 2026 show cause order (Order)
  - See the ISO's conceptual design presentation from August 18-19, 2026, detailed design presentations from September 15, 2026, additional detail from October 14, 2026, and incremental updates from October 27, 2026

Project Title: New England Large Load Show Cause Order (EL26-72)

WMPP ID: 196

Proposed Effective Date: November 2026
Proposed Implementation Date: June 1, 2028

- Today's presentation discusses the final draft Tariff provisions for TC vote
- Revisions include the following sections:
  - Section I.2.2
  - OATT Table of Contents
  - New Part II.J of the OATT
  - Attachment S of the OATT
  - Attachment T of the OATT
  - Attachment U of the OATT
  - Attachment V of the OATT
  - Schedule 1 of the OATT
  - Schedule 2 of the OATT
  - Schedule 16 of the OATT
  - Schedule 17 of the OATT
  - Schedule 9A of the OATT
  - Schedule 22 of the OATT
  - Schedule 23 of the OATT
  - Section II.B of the OATT

MINOR UPDATES TO TARIFF REDLINES

Minor Updates to Tariff Redlines

- Various other minor typographical or clarifying edits have been made to previously presented Tariff redlines and are highlighted in teal in posted materials

Section	Tariff or Manual Change	Reason for Change
Part II.J	Added statement “Such terms and conditions are not intended to supersede any applicable state or local laws or regulations nor do they authorize operations that would violate state or local laws and regulations” to the introduction to Part II.J	Clarifying no violation of state and local laws
Section II.60.2	Added statement "As described in ISO New England Planning Procedures, the Large Load System Impact Study shall recognize the unique operational characteristics of Large Loads associated with Non-Firm Contract Demand Service or Interim Contract Demand Service that are willing and able to limit their energy withdrawals under certain conditions, as well as any applicable Non-Firm Large Load Generator Arrangement, which may lessen or avoid the need for certain network upgrades."	Clarifying treatment of non-firm services in Large Load System Impact Study
Section II.63.2(c)	Corrected typo of “reequipments” to “requirements”	Correction

SUMMARY OF PROPOSED TARIFF CHANGES: TRANSMISSION COMMITTEE

Definition Changes for Transmission Committee Vote

Section	Summary of Change
Section I.2.2	**New Definitions:** Co-Located Large Load, Electrically Proximate Large Load, Firm Contract Demand Service, Interim Contract Demand Service, Large Load, Large Load Affected Party, Large Load Affected System, Large Load Base Cases, Large Load Co-Located Generator, Large Load Contingent Facilities, Large Load Cost Recovery Agreement, Large Load Distribution Upgrades, Large Load Electrically Proximate Generator, Large Load Eligible Customer, Large Load Entity, Large Load Facilities Study, Large Load Facilities Study Agreement, Large Load Internal Affected Party, Large Load Internal Affected System, Large Load Interconnection Facilities, Large Load Interconnection Transmission Owner, Large Load Interconnecting Transmission Owner's Interconnection Facilities, Large Load Material Modification, Large Load Network Upgrades, Large Load Point of Change of Ownership, Large Load Queue Position, Large Load Scoping Meeting, Large Load Service Commencement Date, Large Load Site Control, Large Load Study Cases, Large Load Sufficiently Under Construction, Large Load System Impact Study, Large Load System Impact Study Agreement, Large Load Transmission Customer, Large Load Transmission Customer's Interconnection Facilities, Large Load Transmission Service Agreement, Large Load Transmission Service Application, Non-Firm Contract Demand Service, Non-Firm Large Load Generator Arrangement

Tariff Changes for Transmission Committee Vote
New Part II.J of the OATT

Section	Summary of Change
Section II.56-II.57	Details the transmission services available for Large Loads
Section II.58	Details the Large Load Transmission Application process and the posting of Large Load Network Upgrade information for transparency purposes
Section II.59	Details the designation of new capacity for Firm Contract Demand Service

Tariff Changes for Transmission Committee Vote
New Part II.J of the OATT (cont.)

Section	Summary of Change
Section II.60	Details on the Large Load Study procedures
Section II.61	Details on redispatch and load shedding
Section II.63	Details on the operational arrangements

Tariff Changes for Transmission Committee Vote
New Attachments to Part II.J of the OATT

Section	Summary of Change
Attachment S	Large Load Transmission Service Agreement
Attachment T	Large Load System Impact Study Agreement
Attachment U	Large Load Facilities Study Agreement

Tariff Changes for Transmission Committee Vote
Conforming Changes to Section II.B

Section	Summary of Change
Section II.20.2	Adds Large Load Transmission Customer's use of the pool transmission facility (PTF) on behalf of its Large Loads to provision prohibiting undue discrimination for the PTO's use of the PTF
Section II.20.3	Adds Large Load Transmission Customers to cost responsibility for relieving transmission constraints
Section II.21.2	Adds Large Load Transmission Customers to the determination of Network Customer's monthly Regional Network Load

Tariff Changes for Transmission Committee Vote
OATT Related Changes

Section	Summary of Change
Schedule 2	Determination and allocation of VAR Service Charges and establishes that this service is supplied to Large Load Transmission Customers
Schedule 16	Large Load Transmission Customers are charged for Blackstart Service based on their pro-rata share of Monthly Regional Network Load and demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service as determined in Section II.62 of the OATT
Schedule 17	The ISO will allocate to, invoice, and collect from Transmission Customers that receive Regional Network Service and/or Through or Out Service IROL-CIP Costs, and Large Load Transmission Customers that receive Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service
Schedule 22	Additions to the Large Generator Interconnection Procedures (LGIP) to include the study process for Large Load Co-Located Generator and Large L Electrically Proximate Generator
Schedule 23	Additions to the Small Generator Interconnection Procedures (LGIP) to include the study process for Large Load Co-Located Generator and LL Electrically Proximate Generator

Tariff Changes for Transmission Committee Vote
PTO's Provisions

Section	Summary of Change
Attachment V	New Cost Recovery Agreement (CRA)
Schedule 9A	Large Load Transmission Services
Section II.62	Provides the determination of demand for the Large Load transmission services
Section II.21	Includes Large Load Transmission Customers' load in determination of the hour of Local Network Monthly Peak
Schedule 1	Establishes that Large Load Transmission Customers are charged for transmission service and that demand for Large Load Transmission Customers for transmission services are determined in OATT Section II.62.

CONCLUSION & NEXT STEPS

Conclusion & Next Steps

- Today's presentation describes Tariff redlines associated with New England's Large Load show cause order (EL26-72)
- These redlines should be understood as complete for the purpose of voting
- The filing will be submitted to the Commission shortly after the Participants Committee vote on November 12, 2026
- The ISO will begin detailed discussion on BYONC rules in 2027

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Transmission Committee (MC Invited) **July 16, 2026**	Overview of abeyance request, timing for Section 205 process, and informational filing content
Joint Reliability and Transmission Committee (MC Invited) **August 18-19, 2026**	Overview of conceptual design proposal for Section 205 filing
Joint Transmission, Markets, and Reliability Committee **September 15, 2026**	Review of details on proposed Large Load study process, operational requirements, market design and settlements, introduction to CRA and initial Tariff redlines
Joint Transmission, Markets, and Reliability Committee **October 14, 2026**	Review of remaining design details and incremental updates to the ISO and PTO AC proposals based on stakeholder feedback, including any incremental Tariff language; Introduction of stakeholder amendments
Joint Transmission, Markets, and Reliability Committee **October 27, 2026**	Review of final proposals and associated Tariff language, focusing on any design refinements in response to stakeholder feedback and initial amendments; Review of stakeholder amendments
Transmission Committee **November 3, 2026**	Vote on TC jurisdictional redlines associated with ISO and PTO AC proposals, and any stakeholder amendments
Reliability Committee **November 3, 2026**	Vote on RC jurisdictional redlines associated with ISO proposal, and any stakeholder amendments
Markets Committee **November 3, 2026**	Vote on MC jurisdictional redlines associated with ISO proposal, and any stakeholder amendments
Participants Committee* **November 12, 2026**	Vote on ISO proposal and any stakeholder amendments

*PTO AC action will be required ahead of the PC vote and FERC filing

Technical Committee Focus on Large Loads Tariff Revisions

TC

- Section I.2.2 Defined Terms
- Section II (Open Access Transmission Tariff)

MC

- Section I.2.2 Defined Terms
- Section III (Market Rule 1)

RC

- Section I.2.2 Defined Terms
- Section III.12.1 (Installed Capacity Requirement)

Questions



I.2 Rules of Construction; Definitions

I.2.2. Definitions:

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

Co-Located Large Load is a configuration where a Large Load's Point of Delivery is located on the Interconnection Facilities of an existing or planned Generating Facility.

Electrically Proximate Large Load is a configuration where a Large Load's Point of Delivery is located at (or directly connected radially through dedicated facilities to) the same substation and voltage level as a Generating Facility's Point of Interconnection (or to the Generating Facility's radially dedicated facilities that connect between the substation and its Point of Interconnection), such that the Generating Facility's Point of Interconnection is sufficiently electrically close to the associated Large Load's Point of Delivery, such that the impact on the transmission system of the combination of the Generating Facility and the Large Load, with the exception of the transmission facilities between the two, will be effectively the same as if they were located at the same point.

Firm Contract Demand Service is a type of transmission service for Large Loads described in Section II.57.1.1 of the OATT.

Interim Contract Demand Service is a type of transmission service for Large Loads described in Section II.57.1.2 of the OATT

Large Load is a commercial or industrial customer, located at a single site behind one or more points of delivery, and that has a gross peak demand of 50 MW or greater, relative to its exempt demand as described in Part II.J of the OATT, interconnects to the transmission system, either directly or through a system primarily designed to serve the customer, at a voltage level of greater than 60 kV. Excluded from this definition are: electrical energy support resources such as storage resources (*e.g.*, pumped storage and battery energy storage systems); emergency and municipal services resources such as hospitals, major medical complexes and water treatment facilities; transportation and infrastructure resources other than dedicated electric vehicle charging facilities, such as railroads and airports; and campus facilities that do not have an aggregate exceeding 50 MW of dedicated computational, industrial or commercial process loads each 1 MW or greater, including but not limited to a university campus without a major data center.

Large Load Affected Party is the entity that owns, operates or controls a Large Load Affected System, or any other entity that otherwise may be a necessary party to the Large Load study process.

Large Load Affected System is any electric system that is outside the New England Control Area that may be affected by the proposed provision of transmission service to a Large Load.

Large Load Base Cases are the set of initial cases used to evaluate the impact of Large Loads, including: (1) the latest available case used for performing Needs Assessments; and (2) the latest available case used for a completed Cluster Study or an ongoing Cluster Study.

Large Load Co-Located Generator is a Generating Facility that is associated with a Co-Located Large Load through a Non-Firm Large Load Generator Arrangement.

Large Load Contingent Facilities are those unbuilt Interconnection Facilities, Large Load Interconnection Facilities, Network Upgrades, and Large Load Network Upgrades or a transmission project that is planned or proposed for the New England Transmission System upon which the Large Load Transmission Customer's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Large Load Transmission Service Application or a reassessment of the Large Load Interconnection Facilities and/or Large Load Network Upgrades and/or costs and timing.

Large Load Cost Recovery Agreement is the agreement in the form of Attachment V to the OATT.

Large Load Distribution Upgrades are the additions, modifications, and upgrades to the Large Load Interconnecting Transmission Owner's distribution system (i.e., facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances) at or beyond the Point of Delivery to facilitate interconnection of the Large Load and render the transmission service necessary to serve the Large Load. Large Load Distribution Upgrades do not include Large Load Interconnection Facilities.

Large Load Electrically Proximate Generator is a Generating Facility that is associated with an Electrically Proximate Large Load through a Non-Firm Large Load Generator Arrangement

Large Load Eligible Customer is the Eligible Customer that submits an application for Firm Contract Demand Service or Non-Firm Contract Demand Service on behalf of a Large Load.

Large Load Entity is the entity that owns or controls the Large Load.

Large Load Facilities Study is the study for Large Loads conducted pursuant to Section II.60 of the OATT.

Large Load Facilities Study Agreement is the agreement described in Section II.60 of the OATT.

Large Load Internal Affected Party is the entity that owns, operates or controls a Large Load Internal Affected System, or any other entity operating within the New England Control Area that otherwise may be a necessary party to the Large Load study process.

Large Load Internal Affected System is any electric system that is within the New England Control Area that may be affected by the proposed provision of service to the Large Load.

Large Load Interconnection Facilities are Large Load Interconnecting Transmission Owner's Interconnection Facilities and Large Load Transmission Customer's Interconnection Facilities. Collectively, Large Load Interconnection Facilities include all facilities and equipment between the Large Load and the Point of Delivery, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Large Load to the Administered Transmission System. Large Load Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Large Load Network Upgrades.

Large Load Interconnecting Transmission Owner is the Transmission Owner that owns, leases or otherwise possesses the controlling interest in the portion of the Administered Transmission System at the Point of Delivery for the Large Load.

Large Load Interconnecting Transmission Owner's Interconnection Facilities are all facilities and equipment owned, controlled, or operated by Large Load Interconnecting Transmission Owner from the Large Load Point of Change of Ownership to the Point of Delivery as identified in Appendix A to the Large Load Transmission Service Agreement, including any modifications, additions or upgrades to such facilities and equipment. Large Load Interconnecting Transmission Owner's Interconnection Facilities are

sole use facilities and shall not include Large Load Distribution Upgrades and Large Load Network Upgrades.

Large Load Material Modification is defined in Section II.60 of the OATT.

Large Load Network Upgrades are those upgrades to the New England Transmission System, any Large Load Affected Systems and Large Load Internal Affected Systems as identified in a Large Load System Impact Study.

Large Load Point of Change of Ownership is the point, as set forth in Appendix A to the Large Load Transmission Service Agreement, where Large Load Transmission Customer's Interconnection Facilities connect to the Large Load Interconnecting Transmission Owner's Interconnection Facilities.

Large Load Queue Position is the order of a valid Large Load Transmission Service Application in the New England Control Area, relative to all other pending Large Load Transmission Service Application(s) in the New England Control Area, that is established based upon the date and time of receipt of such application by the ISO.

Large Load Scoping Meeting is the meeting between representatives of the ISO, the Large Load Eligible Customer, and the Transmission Owner(s), or any Large Load Internal Affected Party as deemed appropriate by the ISO in accordance with applicable codes of conduct and confidentiality requirements, conducted for the purpose of discussing the proposed Large Load Transmission Service Application, exchanging information, and refining information and models provided by Large Load Eligible Customer.

Large Load Service Commencement Date is the date transmission service is to begin pursuant to the terms of a Large Load Transmission Service Agreement that has been executed or filed unexecuted.

Large Load Site Control is the exclusive right to develop, construct, operate and maintain the Large Load. Large Load Site Control may be demonstrated by documentation establishing that, over the expected term of the Large Load operations, the entity proposing the Large Load will hold ownership or other exclusive rights over the property allowing for the construction, operation and maintenance of the Large Load in the form of either: (a) fee simple ownership of real property ; (b) an easement; (c) a valid written leasehold or other contractual interest in real property; (d) a duly executed written contract to purchase, acquire an easement, a license or leasehold interest in real property; or (e) for any federal or

state property, has filed applications for required permits or authorizations to construct, operate and maintain the Large Load.

Large Load Study Cases are the cases defined in Section II.60.2 of the OATT.

Large Load Sufficiently Under Construction is a load that is determined by the ISO to have provided sufficient evidence that it received major permits necessary for construction of the project, achieved project financing closing, ordered major equipment necessary for the construction of the project, and has started construction activities on the project site.

Large Load System Impact Study is the study for Large Loads conducted pursuant to Section II.60 of the OATT.

Large Load System Impact Study Agreement is the agreement described in Section II.60 of the OATT.

Large Load Transmission Customer is the Large Load Eligible Customer that has completed the large load service application and study procedures set forth in Sections II.58 and II.60 of the OATT, and executed a Large Load Transmission Service Agreement and receives Firm Contract Demand Service, Interim Contract Demand Service, or Non-Firm Contract Demand Service on behalf of a Large Load.

Large Load Transmission Customer's Interconnection Facilities are all facilities and equipment, as identified in Appendix A of the Large Load Transmission Service Agreement, that are located between the Large Load and the Large Load Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Large Load Transmission Customer to the Administered Transmission System. Large Load Transmission Customer's Interconnection Facilities may be sole use facilities or subject to shared use pursuant to arrangements filed with and approved by the Commission.

Large Load Transmission Service Agreement is the form of transmission service agreement applicable to a Large Load Transmission Service Application pertaining to a Large Load, that is included as Attachment R to the OATT.

Large Load Transmission Service Application is a Large Load Eligible Customer's application, in the form available on the ISO website.

Non-Firm Contract Demand Service is a type of transmission service for Large Loads described in Section II.57.1.3 of the OATT.

Non-Firm Large Load Generator Arrangement is an arrangement between a Co-located Load or Electrically Proximate Load and the applicable Co-Located Generator or Electrically Proximate Generator which supports the Large Load taking Interim Contract Demand Service or Non-Firm Contract Demand Service.

II.J TRANSMISSION SERVICES FOR LARGE LOADS

Capitalized terms used in this Part II.J but not defined in Section I.2.2 of the Tariff shall have the meanings ascribed to them in Schedule 22 to the OATT.

The MW value of exempt demand for a load in operation or determined by the ISO to be a Large Load Sufficiently Under Construction prior to June 18, 2026 shall be determined as the greater of: (i) its measured maximum observed hourly gross peak in the ten (10) years prior to June 18, 2026; or (ii) the MW value specified in a service or operational agreement with the applicable utility or ISO as of June 18, 2026. As of the effective date of this provision, exempt demand shall not be treated as a Large Load and shall not be subject to Part II.J of the OATT. An existing load or a Large Load Sufficiently Under Construction as of June 18, 2026 shall be defined as a Large Load when its gross peak demand increases by 50 MW or more relative to its exempt demand. Transmission service for the exempt demand shall transition to Firm Contract Demand Service and the load shall be subject to Section II.63 of the OATT, but shall be exempt from the application and study process in Part II.J of the OATT and the requirements of Section II.59 of the OATT. The increased demand relative to exempt demand shall be subject to all requirements in Part II.J of the OATT.

A load that is not in operation or is determined by the ISO to not be a Large Load Sufficiently Under Construction as of June 18, 2026 shall be treated as a Large Load if and when it meets the Large Load definition. A Large Load that is not in operation or is determined by the ISO to not be a Large Load Sufficiently Under Construction but has a system impact study agreement with the applicable Large Load Interconnecting Transmission Owner prior to June 1, 2027 shall not be subject to the study requirements of Part II.J of the OATT, but shall be subject to all other requirements of Part II.J of the OATT.

Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service shall be provided by the ISO pursuant to the applicable terms and conditions of this OATT starting on June 1, 2028. Such terms and conditions are not intended to supersede any applicable state or local laws or regulations nor do they authorize operations that would violate state or local laws and regulations.

II.56 Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service

II.56.1 Provision of Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service: A Large Load Eligible Customer may apply for the provision of Firm Contract Demand Service and Non-Firm Contract Demand Service. The ISO shall deem a Large Load Transmission Service Application for Firm Contract Demand Service sufficient to support a related need for Interim Contract Demand Service under Section II.57.1.2 of the OATT.

II.56.2 Eligibility to Receive Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service: Upon completion of the application, study and service agreement requirements set forth in Section II.58 of the OATT, Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service shall be taken and paid for by each Large Load Transmission Customer that obtains the service on behalf of a Large Load.

II.57 Nature of Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service

II.57.1 Scope of Service: Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service are the transmission services that the ISO provides to a Large Load Transmission Customer and allow a Large Load Transmission Customer to serve a Large Load located in the New England Control Area.

II.57.1.1 Firm Contract Demand Service is a firm transmission service provided to a Large Load Transmission Customer for a specific contracted MW value that can never be exceeded. All identified Large Load Network Upgrades shall be in service before a Large Load Transmission Customer can be provided Firm Contract Demand Service for a Large Load. Firm Contract Demand Service shall be provided after meeting the requirements of Section II.59 of the OATT.

II.57.1.2 Interim Contract Demand Service is a temporary, non-firm transmission service provided to a Large Load Transmission Customer requesting Firm Contract Demand Service before Large Load Network Upgrades are completed and placed into service, and before the Large Load Transmission Customer has designated, or has caused to be designated, sufficient

capacity resources to serve the Large Load pursuant to Section II.59 of the OATT. Interim Contract Demand Service shall be available for a term of no more than seven years, or the length of time required to place the required Large Load Network Upgrades in-service, whichever is longer.

II.57.1.3 Non-Firm Contract Demand Service is non-firm transmission service provided to Large Load Transmission Customers. Large Load Transmission Customers shall not be required to designate capacity resources for a Large Load that is provided Non-Firm Contract Demand Service.

II.57.1.4 Price-Based Redispatch of Non-Firm Large Loads: A Large Load Transmission Customer receiving Interim Contract Demand Service or Non-Firm Contract Demand Service for a Large Load shall be subject to the price-based redispatch provisions of Section III.1.10.5A of the Tariff.

II.57.1.5 Compliance With Other Applicable OATT Requirements: A Large Load Transmission Customer taking Firm Contract Demand Service, Interim Contract Demand Service, or Non-Firm Contract Demand Service shall: (i) obtain or provide Ancillary Services pursuant to Section II.4 of this OATT; (ii) comply with all applicable creditworthiness and financial assurance requirements set forth by the ISO and Large Load Interconnecting Transmission Owner, including but not limited to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy; and (iii) pay for real power losses associated with its scheduled service as calculated and recovered through the Loss Component of the Locational Marginal Prices as further provided for in the ISO New England Operating Documents.

II.57.2 ISO and PTO Responsibilities: As provided in the TOA and this OATT, the ISO and the PTOs shall plan, construct, operate, and maintain the PTF in accordance with Good Utility Practice and their obligations in Attachment K in order to allow the ISO to provide Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service for the Large Load.

II.57.3 Restrictions on Use of Service: A Large Load Transmission Customer shall be entitled to use Firm Contract Demand Service, Interim Contract Demand Service, or Non-Firm Contract Demand Service for any of the uses specified in Part II.J of this OATT.

II.58 Initiating Service

The ISO shall begin accepting Large Load Transmission Service Applications under this Section II.58 of the OATT starting on June 1, 2027.

II.58.1 Conditions Precedent for Receiving Service: Subject to the terms and conditions of Part II.J of this OATT, Firm Contract Demand Service, Interim Contract Demand Service, or Non-Firm Contract Demand Service shall be provided where (i) the Large Load Eligible Customer completes a Large Load Transmission Service Application available on the ISO website, (ii) the Large Load Eligible Customer provides, or causes to be provided, the deposits required under Part II.J of this OATT; (iii) the ISO completes the study process described under Part II.J of this OATT; (iv) the Large Load Eligible Customer and the ISO complete the technical arrangements set forth in Sections II.58.5 and II.58.6 of this OATT; (iii) the Large Load Eligible Customer executes a Large Load Transmission Service Agreement in the form of Attachment S to this OATT for service under Part II.J of this OATT or requests in writing that the ISO file a proposed unexecuted Large Load Transmission Service Agreement with the Commission; and (iv) the Large Load Eligible Customer executes a Large Load Cost Recovery Agreement in the form of Attachment V to the OATT. With the completion of each of these requirements, a Large Load Eligible Customer that has executed a Large Load Transmission Service Agreement shall be considered the Large Load Transmission Customer for purposes of the receipt of Firm Contract Demand Service, Interim Contract Demand Service, or Non-Firm Contract Demand Service, as applicable.

II.58.2 Application Procedures: A Large Load Eligible Customer requesting Firm Contract Demand Service or Non-Firm Contract Demand Service under this OATT shall submit to the ISO a Large Load Transmission Service Application. The Large Load Eligible Customer shall provide, or cause to be provided, the deposits described below. Completed Large Load Transmission Service Applications shall be assigned a Large Load Queue Position according to the date and time the Large Load Transmission Service Application is received in full and deemed complete by the ISO, with the earliest Large Load Transmission Service Application receiving the highest Large Load Queue Position. The Large Load Queue Position shall be used to determine: (i) the order of

performing the Large Load System Impact Studies; and (ii) the cost responsibility for the facilities and Large Load Network Upgrades necessary to accommodate the Large Load Transmission Service Application.

A Large Load Transmission Service Application shall include the following information:

(a) The identity, address, telephone number, and electronic mail address of the party requesting service.
(b) A statement that the party requesting service is, or will be upon commencement of service, a Large Load Transmission Customer under this OATT.
(c) The Large Load's gross peak demand (MW).
(d) The Large Load's requested transmission service level for each type of transmission service.
(e) The proposed Large Load Point of Delivery.
(f) Documentation demonstrating Large Load Site Control.
(g) Large Load Interconnecting Transmission Owner's interconnecting facilities study report for the Large Load.
(h) All technical data as required under Appendix 1 to the Large Load Transmission Service Application.
(i) All simulation models and accompanying model acceptance testing documentation, as required in applicable ISO New England Planning Procedures.
(j) An affidavit from the Large Load Eligible Customer (or Large Load Entity on its behalf) stating that there are no duplicative applications associated with the same proposed Large Load in the form of Appendix 2 to the Large Load Transmission Service Application.

For a Large Load Transmission Service Application to be complete, the Large Load Eligible Customer shall post or cause to be posted:

(a) An initial, non-refundable application fee of $50,000, in the form of an irrevocable letter of credit or cash;
(b) A study deposit of $150,000, in the form of an irrevocable letter of credit or cash; and

The ISO shall accept Large Load Transmission Service Applications on a rolling basis. If the Large Load Transmission Service Application is complete, then the ISO shall notify the Large Load Eligible Customer within twenty (20) days of receipt. The ISO shall tender a Large Load System Impact Study Agreement to the Large Load Eligible Customer with such notice. If a Large Load Transmission Service Application fails to meet the requirements of this section, including any deficiencies identified for the provided technical information, models or model acceptance testing documentation, the ISO shall notify the Large Load Eligible Customer requesting service within twenty (20) days of receipt and specify the reasons for such failure. The Large Load Eligible Customer shall have fifteen (15) days to cure the deficiency. If the Large Load Eligible Customer fails to cure the deficiency, then the ISO shall deem the Large Load Transmission Service Application withdrawn. A Large Load Eligible Customer may withdraw its Large Transmission Service Application at any time. A Large Load Transmission Service Application that is withdrawn or is deemed withdrawn will result in the loss of its Large Load Queue Position and the loss of the non-refundable application fee. The ISO shall update the OASIS to reflect Large Load Transmission Service Applications that are withdrawn or deemed withdrawn.

II.58.3 OASIS Posting:

The ISO shall maintain on its OASIS a list of all Large Load Transmission Service Applications in its Control Area. With the exception of any information that has been classified as Critical Energy Infrastructure Information or designated by the Large Load Eligible Customer as Confidential Business Information, the list shall identify, for each Large Load Interconnection Application: (i) the Large Load's gross peak demand; (ii) the Large Load location by county and state; (iii) the status of the Large Load Transmission Service Application, including Large Load Queue Position; (iv) the types of transmission service being requested (*i.e.*, Firm Contract Demand Service or Non-Firm Contract Demand Service); and (v) the date of the Large Load Transmission Service Application. The ISO shall post to its OASIS Large Load System Impact Study reports subsequent to the meeting between the ISO, Large Load Interconnecting Transmission Owner, and Large Load Eligible Customer to discuss the applicable study report.

II.58.4 Cost of Large Load Network Upgrades Posting:

The ISO shall develop, maintain and post on its website, in an easily accessible, searchable and fillable format: (1) a cumulative list reflecting the Large Load Network Upgrades identified for each Large Load, categorized by upgrade type; and (2) costs estimates for each identified Large Load Network Upgrade for each Large Load.

II.58.5 Technical Arrangements to be Completed Prior to Commencement of Service: Firm Contract Demand Service, Interim Contract Demand Service and Non-Firm Contract Demand Service -to the Large Load Transmission Customer shall not commence until the Large Load Interconnecting Transmission Owner and Large Load Transmission Customer (or Large Load Entity on its behalf), consistent with Good Utility Practice, have completed installation of all equipment including direct connection facilities and protection systems -necessary for the Large Load to reliably withdraw energy at the Point of Delivery and any additional requirements imposed under this OATT and the ISO New England Planning Procedures in order to ensure the reliable operation of the New England Transmission System. The ISO shall exercise reasonable efforts, in coordination with the Large Load Transmission Customer (or Large Load Entity on its behalf) and the Large Load Interconnecting Transmission Owner -to complete such arrangements as soon as practicable taking into consideration the Large Load Service Commencement Date.

II.58.6 Completion of Large Load Facilities: The Large Load Transmission Customer shall construct, install, operate and maintain or shall cause to be constructed, installed, operated and maintained all facilities on the Large Load side of the Point of Delivery. The provision of Firm Contract Demand Service, Interim Contract Demand Service, and Non-Firm Contract Demand Service shall be conditioned upon the construction, installation, operation and maintenance of all facilities on the Large Load side of each Point of Delivery necessary to reliably deliver capacity and energy from the New England Transmission System to the Large Load.

II.59 Large Load Designated Capacity

II.59.1 Designation of New Capacity for a Firm Contract Demand Service Large Load: To receive the requested amount of Firm Contract Demand Service for a Large Load, the Large Load Eligible Customer shall designate, or cause to be designated, sufficient new capacity resources to meet the requested amount of Firm Contract Demand Service for the Large Load. Interim Contract Demand Service shall be provided for the amount of requested Firm Contract Demand Service until such sufficient capacity resources are designated and achieve commercial operation.

II.60 Large Load Study Procedures

II.60.1 Large Load Scoping Meeting

Within fifteen (15) days of the ISO's notice to the Large Load Eligible Customer that its Large Load Transmission Service Application is complete, the ISO shall hold a Large Load Scoping Meeting that includes the ISO, the Large Load Eligible Customer, the Large Load Interconnecting Transmission Owner, any Large Load Affected Party, and any Large Load Internal Affected Party as deemed appropriate by the ISO in accordance with applicable codes of conduct and confidentiality requirements.

The purposes of the Large Load Scoping Meeting shall be (i) to discuss the estimated timeline for completing the Large Load System Impact Study, (ii) to exchange pertinent information, (iii) to analyze such information, and (iv) to discuss any other information necessary to facilitate the administration of the Large Load System Impact Study procedures. The Parties will bring to the meeting personnel and other resources as may be reasonably required to accomplish the purposes of the meeting in the time allocated for the meeting. The duration of the meeting shall be sufficient to accomplish its purposes.

The Large Load Eligible Customer shall execute the Large Load System Impact Study Agreement within seven (7) days after the Large Load Scoping Meeting is held, or else the ISO shall deem the related Large Load Transmission Service Application withdrawn.

II.60.2 Scope of Large Load System Impact Study

The Large Load System Impact Study shall evaluate the impact of the proposed Large Load on the reliability and operation of the New England Transmission System. The Large Load System Impact Study shall consider the Large Load Base Cases as well as all Large Load facilities, any capacity designated under Section II.59 of the OATT that is available at the time of the Large Load System Impact Study, and any associated Large Load Co-Located Generators or Large Load Electrically Proximate Generators (and with respect to (iii) below, any identified Large Load Network Upgrades associated with such higher queued Large Load facilities) that, on the date the Large Load System Impact Study is commenced: (i) are directly interconnected to the

New England Transmission System; (ii) are interconnected to Large Load Affected Systems and may have an impact on the Large Load Transmission Service Application; (iii) have a pending higher queued Large Load Transmission Service Application to receive service from the New England Transmission System and may have an impact on the Large Load Transmission Service Application; and (iv) have no Queue Position but have executed a Large Load Transmission Service Agreement or requested that an unexecuted Large Load Transmission Service Agreement be filed with the Commission (the "Large Load Study Cases" for the Large Load System Impact Study).

The Large Load System Impact Study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, including thermal analysis and voltage analysis, a system protection and controls analysis, an electromagnetic transient screening, a Cluster and other study coordination screening, and any other analyses that the ISO deems necessary in consultation with the Large Load Interconnecting Transmission Owner. Analyses performed for the Large Load System Impact Study shall meet all Applicable Reliability Standards and other requirements contained in ISO New England Planning Procedures, including those related to ride-through, ramp rates and control technologies and/or protection schemes, as applicable. As described in ISO New England Planning Procedures, the Large Load System Impact Study shall recognize the unique operational characteristics of Large Loads associated with Non-Firm Contract Demand Service or Interim Contract Demand Service that are willing and able to limit their energy withdrawals under certain conditions, as well as any applicable Non-Firm Large Load Generator Arrangement, which may lessen or avoid the need for certain network upgrades. The Large Load System Impact Study report shall state the assumptions upon which it is based and the results of the analyses, and provide the requirements or potential impediments to providing the requested transmission service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the transmission service. The Large Load System Impact Study report shall provide (i) a list of facilities that are required as a result of the Large Load Transmission Service Application and a non-binding good faith estimate of cost responsibility; (ii) a non-binding good faith estimated time to construct; (iii) a protection and controls assessment to determine the required protection upgrades and controls; and may provide

(iv) identification of the likely permitting and siting process including easements and environmental work.

The Large Load System Impact Study shall evaluate the use of static synchronous compensators, static VAR compensators, advanced power flow control devices, transmission switching, synchronous condensers, voltage source converters, advanced conductors, and tower lifting. The ISO shall evaluate each identified alternative transmission technology and determine, in the manner described in the ISO New England Planning Procedures, whether the above technologies should be used, consistent with Good Utility Practice, Applicable Reliability Standards, and Applicable Laws and Regulations. The ISO shall include an explanation of the results of its evaluation for each technology in the Large Load System Impact Study report.

II.60.3 Large Load System Impact Study Procedures

The ISO shall coordinate the Large Load System Impact Study with the Large Load Interconnecting Transmission Owner, any Large Load Affected Party, and any Large Load Internal Affected Party as deemed appropriate by the ISO. The ISO and Large Load Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when they perform the study. The ISO and the Large Load Interconnecting Transmission Owner shall use reasonable efforts consistent with Good Utility Practice to complete the Large Load System Impact Study within ninety (90) days after the receipt of the Large Load Eligible Customer executed Large Load System Impact Study Agreement in the form of Attachment T to this OATT.

At the request of the Large Load Eligible Customer or at any time the ISO or Large Load Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Large Load System Impact Study, the ISO shall notify the Large Load Eligible Customer as to the schedule status of the Large Load System Impact Study. If the ISO and Large Load Interconnecting Transmission Owner are unable to complete the Large Load System Impact Study within the time period, the ISO shall notify the Large Load Eligible Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. In such circumstances, upon request, the ISO and Large Load Interconnecting

Transmission Owner shall provide all supporting documentation, workpapers and relevant Large Load Study Cases power flow, short circuit and stability databases that have been developed for the Large Load System Impact Study to any third-party consultant retained by the Large Load Eligible Customer. The recipient(s) of such information shall be subject to the confidentiality provisions of the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/disclosure requirements, such information may be provided directly to the Large Load Eligible Customer.

If the electromagnetic transient screening uncovers the need for additional electromagnetic transient analysis, the ISO shall publish a preliminary Large Load System Impact Study report within the 90-day timeline that includes the results of the stability analysis, steady state analysis, short circuit analysis, protection analysis, electromagnetic transient screening analysis, and Large Load Network Upgrades and preliminary cost estimates. The ISO shall use reasonable efforts consistent with Good Utility Practice to complete a full electromagnetic transient analysis and issue a final Large Load System Impact Study report within 120 days of publishing the preliminary Large Load System Impact Study report.

II.60.4 Cluster and Other Study Coordination

The 90-day Large Load System Impact Study period will include a Cluster and other study coordination screening to determine whether additional study is required to account for the combined impacts of a Cluster under study according to Schedules 22, 23 and 25 of the OATT, other studies as described in ISO New England Planning Procedures, and a Large Load System Impact Study. If the Cluster and other study coordination screening uncovers the need for additional analysis, then the ISO shall publish a preliminary Large Load System Impact Study report within the 90-day timeline that includes the results of the stability analysis, steady state analysis, short circuit analysis, protection analysis, electromagnetic transient screening analysis, and Large Load Network Upgrades and preliminary cost estimates If the Cluster and other study coordination screening determines that there are combined impacts that need to be studied in detail, then the ISO shall use reasonable efforts consistent with Good Utility Practice to complete

the additional Cluster and other study coordination analysis and publish a final Large Load System Impact Study report within 120 days of publishing the preliminary Large Load System Impact Study report.

II.60.5 Large Load System Impact Study Report Review Meeting

Within seven (7) days of the issuance of the final Large Load System Impact Study report (or a preliminary Large Load System Impact Study report if additional electromagnetic transient analysis or analysis of impacts of a Cluster or other study are needed), the ISO shall hold a Large Load System Impact Study report review meeting that includes the ISO, the Large Load Eligible Customer, the Large Load Interconnecting Transmission Owner, any Large Load Affected Party, and any Large Load Internal Affected Party as deemed appropriate by the ISO in accordance with applicable codes of conduct and confidentiality requirements. The Large Load Eligible Customer shall review the final Large Load System Impact Study report (or a draft Large Load System Impact Study report) within fifteen (15) days of the meeting.

II.60.6 Large Load Facilities Study Procedures

If a Large Load System Impact Study indicates that Large Load Network Upgrades to the New England Transmission System are needed to supply the Large Load Eligible Customer's service or to mitigate indirect impacts on MTF or OTF facilities, the ISO, within thirty (30) days of the issuance of the final Large Load System Impact Study report, shall tender to the Large Load Eligible Customer a Large Load Facilities Study Agreement in the form of Attachment U to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Large Load Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s) and pursuant to which the Large Load Eligible Customer shall agree to reimburse (or cause to reimburse) the ISO and any affected PTO(s) for performing the required Large Load Facilities Study. For a Large Load Transmission Service Application to remain a Completed Application, within fifteen (15) days, the Large Load Eligible Customer shall execute the Large Load Facilities Study Agreement and return it to the ISO, or elect in writing to waive the Large Load Facilities Study. If the Large Load Eligible Customer neither elects to execute a Large Load Facilities Study Agreement nor waives the Large Load Facilities Study, then its Large Load Transmission Service Application shall be deemed withdrawn and its deposit, if any

(less the reasonable Administrative Costs incurred by the ISO and any affected entities), shall be returned with Interest. Upon receipt of an executed Large Load Facilities Study Agreement, the ISO and any affected PTO(s), will use reasonable efforts to complete the required Large Load Facilities Study within ninety (90) days. If the ISO and any affected PTO(s) are unable to complete the Large Load Facilities Study in the allotted time period, the ISO shall notify the Large Load Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost, along with an explanation of the reasons that additional time is required to complete the study. When completed, the Large Load Facilities Study report will include a +/- 20% good faith estimate of (i) the Large Load Eligible Customer's appropriate share of the cost of any required Large Load Network Upgrades, and (ii) the time required to complete such construction and initiate the requested service. The Large Load Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected PTO(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code.

II.60.7 Large Load Transmission Service Agreement Negotiation and Execution

Within twenty (20) days of the ISO's issuance of the final Large Load System Impact Study report or final Large Load Facilities Study report, whichever is later, the ISO shall tender a Large Load Transmission Service Agreement to the Large Load Eligible Customer. The ISO, the Large Load Interconnecting Transmission Owner and the Large Load Eligible Customer shall have sixty (60) days to negotiate the Large Load Transmission Service Agreement. At the end of the sixty (60) day period, the Large Load Eligible Customer shall either request to execute the Large Load Transmission Service Agreement or request the filing of an unexecuted Large Load Transmission Service Agreement, otherwise the ISO shall deem the Large Load Transmission Service Application withdrawn.

II.60.8 Large Load Material Modification

The following shall constitute a Large Load Material Modification: (1) a decrease of more than 60% of the total transmission service; (2) any increase to the total level of transmission service requested, or any increase to the level of transmission service requested as Firm Contract

Demand Service; (3) any change to a Non-Firm Large Load Generator Arrangement that impacts the Large Load; (4) a modification to the Point of Delivery that is not agreed upon by the ISO, the Large Load Interconnecting Transmission Owner, and the Large Load Eligible Customer; (5) a commencement date for Firm Contract Demand Service or Non-Firm Contract Demand Service that extends for more than three (3) years from the original commencement date or a commencement date that is more than seven (7) years from the date of the Large Load Transmission Service Application, unless an extension request is made to the ISO and the ISO deems the extension to be non-material; (6) during the study period, a decrease of the total transmission service requested, or any modifications to the Large Load, Large Load Co-Located Generator, or Large Load Electrically Proximate Generator models that take more than fifteen (15) days to address; and (7) after the study period, any modifications that significantly alter the performance of the studied project. A Large Load Material Modification shall require a new Large Load Transmission Service Application.

II.60.9 Coordination of Studies to Support a Non-Firm Large Load Generator Arrangement

The ISO may perform studies to support the interconnection of a Large Load Co-Located Generator or a Large Load Electrically Proximate Generator to support a Non-Firm Large Load Generator Arrangement with a Co-Located Load or an Electrically Proximate Load concurrent with the applicable Large Load System Impact Study. Such studies shall meet the requirements for a Large Load Co-Located Generator or Large Load Electrically Proximate Generator of Schedule 22 and Schedule 23 of the OATT. The Large Load Eligible Customer shall identify the Large Load Co-Located Generator or Large Load Electrically Proximate Generator and specify the details of the Non-Firm Large Load Generator Arrangement in order to reflect the Large Load Co-Located Generator or Large Load Electrically Proximate Generator and the details of the Non-Firm Large Load Generator Arrangement in the studies performed to support Interim Contract Demand Service or Non-Firm Contract Demand Service. The Large Load Eligible Customer shall be responsible for 50% of all Large Load System Impact Study ~~work~~costs if the study includes a Large Load Co-Located Generator or Large Load Electrically Proximate Generator.

II.61 Redispatch and Load Shedding

II.61.1 Procedures: Prior to the Large Load Service Commencement Date, the ISO and the Large Load Transmission Customer shall establish redispatch and Load Shedding procedures pursuant to Section II.63 of this OATT with the objective of responding to contingencies on the New England Transmission System. The parties shall implement such programs during any period when the ISO determines that a system contingency exists and such procedures are necessary to alleviate such contingency, up to and including the capability to coordinate the remote disconnection of the Large Load. The ISO shall notify all affected Large Load Transmission Customers in a timely manner of any scheduled reduction of service.

II.61.2 Transmission Constraints: During any period when the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of the New England Transmission System, the ISO shall take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent the ISO determines that the reliability of the system can be maintained by redispatch reduction of Interim Contract Demand Service or Non-Firm Contract Demand Service, the ISO will initiate procedures pursuant to Section II.63 of this OATT to redispatch Large Loads without regard to ownership.

II.61.3 Load Shedding: To the extent that a system contingency exists on the New England Transmission System and the ISO determines that it is necessary for Large Load Transmission Customers taking Firm Contract Demand Service to shed load, the Parties shall shed load in accordance with the ISO New England Operating Documents.

II.61.4 System Reliability: Notwithstanding any other provisions of this OATT, the ISO reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to effect a redispatch reduction of Non-Firm Contract Demand Service and Interim Contract Demand Service, or reduction of Firm Contract Demand Service without liability on the part of the ISO or the Transmission Owners for the purpose of making necessary adjustments to, changes in, or repairs on the Large Load Interconnecting Transmission Owners' lines, substations

and facilities, and in cases where the continuance of Non-Firm Contract Demand Service, Interim Contract Demand Service, or Firm Contract Demand Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the New England Transmission System or on any other system(s) directly or indirectly interconnected with the New England Transmission System, the ISO, consistent with Good Utility Practice, also may effect a redispatch reduction of Non-Firm Contract Demand Service and Interim Contract Demand Service, or reduction of Firm Contract Demand Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The ISO shall give the Large Load Transmission Customer taking Firm Contract Demand Service as much advance notice as is practicable in the event of such reduction. Any redispatch reduction of Non-Firm Contract Demand Service and Interim Contract Demand Service, or reduction of Firm Contract Demand Service shall be not unduly discriminatory relative to the Large Load Transmission Customers' use of the Transmission System on behalf of its Large Loads.

II.62 Determination of Large Load Transmission Customer's Demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service

II.62.1 Billing and Charges: Each Large Load Transmission Customer which takes Firm Contract Demand Service, Non-Firm Contract Demand Service, or Interim Contract Demand Service for a month shall be subject to the applicable provisions of Part II.J of this OATT and shall pay to the ISO for such month an amount equal to its Firm Contract Demand, Monthly Non-Firm Contract Demand, and/or Monthly Interim Contract Demand, as defined below, for the month times the applicable rate as determined in accordance with Schedule 9A of this OATT, except that any exempt demand which transitions to Firm Contract Demand Service pursuant to the earlier provisions of this Part II.J and can be separately metered by the Large Load Interconnecting Transmission Owner from any additional demand above the exempt demand shall be billed at the rate established for such exempt demand as of June 18, 2026, as later amended or revised.

II.62.2 Firm Contract Demand: is the amount of Firm Contract Demand Service requested by the Large Load Eligible Customer on its Large Load Transmission Service Application.

II.62.3 Monthly Non-Firm Contract Demand: is the Large Load Transmission Customer's hourly load associated with the provision of Non-Firm Contract Demand Service coincident with the coincident aggregate load of all Network Customers and Large Load Transmission Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak"). Large Load Transmission Customer's Monthly Non-Firm Contract Demand shall include all load associated with the provision of Non-Firm Contract Demand Service to Large Loads, including load offset by any resources, regardless of whether the resources are registered as Generator Assets. The Monthly Non-Firm Contract Demand of all Large Load Transmission Customers within a Local Network shall be calculated by the associated PTO.

II.62.4 Monthly Interim Contract Demand: shall be calculated in the same manner as Monthly Non-Firm Contract Demand.

II.63 Operating Arrangements

II.63.1 Large Load Transmission Customer Obligation: The Large Load Transmission Customer shall plan, construct, operate and maintain, or shall cause to be planned, constructed, operated and maintained, all of its equipment and facilities connected to the New England Transmission System in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, the ISO New England Operating Documents and requirements of the Electric Reliability Organization (ERO) as defined in 18 C.F.R § 39.1 and NPCC.

II.63.2 General Network Operating Terms and Conditions: The terms and conditions under which the Large Load Transmission Customer shall (or shall cause to) operate its facilities and the technical and operational matters associated with the implementation of Part II.J of the OATT are specified in Section II.63 of this OATT, and in the ISO New England Operating Documents. The ISO, the applicable PTO(s) and the Large Load Transmission Customer shall (i) operate and maintain equipment necessary for integrating the Large Load Transmission Customer within the New England Transmission System (including, but not limited to, remote terminal units, metering, monitoring, communications equipment and relaying equipment), (ii) transfer data among the ISO, the PTO(s) and the Large Load Transmission Customer (including, but not limited to, operational characteristics ,demand schedules, demand consumption for redispatch required under Section II.61 of this OATT, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted demand necessary for near and long-term planning over specified time horizons, including hourly, and (v) address any other technical and operational considerations required for implementation of Part II.J of this OATT, including scheduling protocols. The Large Load Transmission Customer shall meet these requirements or cause them to be met. The Large Load Transmission Customer shall (or shall cause to) satisfy its Control Area requirements by contracting with the ISO and all the applicable PTOs. In the alternative, the Large Load Transmission Customer may (or may cause to) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, in a manner which satisfies ERO and NPCC requirements

and receives any necessary ERO and NPCC approvals, subject to applicable federal and state regulatory approvals and subject to the development and implementation of a reasonable transition plan that, inter alia, satisfies applicable established system reliability criteria.

(a) **Electrical Supply:** The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty-hertz alternating current at a voltage class determined by mutual agreement of the ISO, the applicable PTO(s) and the Large Load Transmission Customer.

(b) **Ramp Rate:** The Large Load Transmission Customer shall (or shall cause to) comply with the ramp rate requirements specified in the ISO New England Operating Procedures.

(c) **Ride-Through:** The Large Load Transmission Customer shall (or shall cause to) comply with all ride-through requirements ~~reequipments~~specified in ISO New England Planning Procedures and ISO New England Operating Procedures.

(c) **Automatic Control Technologies Limiting Withdrawals:** The Large Load Transmission Customer shall (or shall cause to) comply with all reequipments specified in the Large Load Transmission Service Agreement and all ISO New England Operating Procedures with regard to the operation and maintenance of necessary control technologies and/or protection systems to limit withdrawals from the transmission system.

(d) **Maintenance Outage Procedures:** The ISO and the applicable PTO(s) will utilize the ISO New England Operating Procedures with respect to the timing of scheduled maintenance of the New England Transmission System and Large Loads.

(f) **Reporting Obligations**: The Large Load Transmission Customer shall (or shall cause to) provide all information required by the ERO, NPCC, the applicable

PTO(s) or the ISO. The Large Load Transmission Customer shall (or shall cause to) respond promptly and completely to the ISO's and the applicable PTO(s)'reasonable requests for information, including but not limited to, data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

For Large Loads:

- Submission of hourly demand consumption forecasts as required
- Redispatch capability
- Load power factor or reactive power injection/withdrawal performance
- Underfrequency load shedding capability
- Block load shedding capability
- Disturbance/interruption reports
- Protection system setting conformance
- Protection system testing and maintenance conformance
- Planned changes to protection systems
- Metering testing and maintenance conformance
- Monitoring equipment testing and maintenance conformance
- Planned changes in transformation capability
- Conformance to induced sub-synchronous oscillations, harmonic, ride-through, ramp rate and voltage fluctuation limits
- Dead station tripping conformance

Failure by the Large Load Transmission Customer to do so may constitute default and permits the ISO to terminate the Large Load Transmission Service Agreement, in accordance with Commission requirements. Delinquency in responding shall result in a suspension of service as described in Section II.63.3 below.

The Large Load Transmission Customer shall (or shall cause to) supply accurate and reliable telemetered information to the system operators regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information

deemed necessary by the ISO and the applicable PTO(s) for reliable operation. Information shall be gathered for electronic communication using a methodology acceptable to the ISO. All equipment used for metering, monitoring SCADA, RTU, RAPR, and communications must be approved by the ISO and the applicable PTO(s).

(g) **Operational Obligations:** The Large Load Transmission Customer (or the Large Load Entity on its behalf) and the Large Load Interconnecting Transmission Owner shall request permission from the ISO prior to opening and/or closing circuit breakers per applicable ISO New England Operating Procedures. The Large Load Transmission Customer shall (or shall cause to) carry out all switching orders from the ISO or the applicable PTO(s) in a timely manner.

The Large Load Transmission Customer shall (or shall cause to) balance the load at the Point(s) of Delivery such that the difference in the individual phase currents are acceptable to the ISO as specified in the ISO New England Operating Procedures.

The Large Load Transmission Customer's or Large Load Entity's equipment shall conform with any harmonic distortion and voltage fluctuation standards specified in ISO New England Operating Procedures. The Large Load Transmission Customer's equipment shall comply with all environmental requirements to the extent they impact the operation of the New England Transmission System. The Large Load Transmission Customer shall (or shall cause to) operate all of its equipment and facilities connected to the New England Transmission System in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of the ISO, the applicable PTO(s) and NPCC.

(h) **Notice of Transmission Service Interruptions**: If at any time, in the reasonable exercise of the ISO's judgment, operation of the Large Load Transmission Customer's or Large Load Entity's equipment adversely affects the quality of

service or interferes with the safe and reliable operation of the New England Transmission System, the ISO may discontinue transmission service, consistent with Section II.61 of the OATT, until the condition has been corrected.

(i) **Access and Control:** Properly accredited representatives of the ISO shall at all reasonable times have access to the Large Load facilities to make reasonable inspections and obtain information required in connection with this OATT. Such representatives shall make themselves known to the applicable personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Large Load.

(j) **Point(s) of Delivery:** Firm Contract Demand Service, Interim Contract Demand Service, or Non-Firm Contract Demand Service shall be delivered by the ISO at the Point(s) of Delivery specified in the Large Load Transmission Customer's Large Load Transmission Service Agreement. Each Point of Delivery shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and, the actual, or if not currently in service, the projected in-service year.

(k) **Maintenance of Equipment:** The ISO may request that the Large Load Transmission Customer conduct or cause to be conducted testing, calibration, verification or validation of the data link, metering, monitoring, data acquisition, transmission, protective, or other equipment or software consistent with the routine obligation to maintain equipment and facilities or for the purposes of trouble shooting problems on the network facilities. The Large Load Transmission Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software. The ISO shall have the right to inspect the tests, calibrations, verifications and validations of the data link, metering, monitoring, data acquisition, transmission, protective, or other equipment or other software connected to the New England Transmission System. The Large Load Transmission Customer, at the ISO's request, shall (or shall cause to) supply the

ISO with a copy of the installation, test, and calibration records of the data link, metering, monitoring, data acquisition, transmission, protective or other equipment or software connected to the New England Transmission System. The ISO shall have the right, at the Large Load Transmission Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, monitoring, data acquisition, transmission, protective or other equipment or software connected to the ISO's system.

(l) **Emergency System Operations**: The Large Load Transmission Customer's or Large Load Entity's equipment and facilities shall be subject to all applicable emergency operation standards required of and by the ISO to operate in an interconnected transmission network. The ISO reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of the New England Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

(m) **Cost Responsibility:** The Large Load Transmission Customer shall be responsible for all costs incurred by the ISO relative to the Large Load Transmission Customer's Large Load.

II.63.3 Default: If the Large Load equipment fails to perform consistent with the obligations specified in this OATT, then the Large Load Transmission Customer shall be deemed to be in default and service may be suspended immediately and subject to a termination through an ISO filing with the Commission. If the information required in Section II.63.2 (f) is not provided- in a timely manner, then the ISO shall issue a notice of such failure to the Large Load Transmission Customer. If the information is not provided or the issues related to providing the information are not resolved within the timeframe established by the ISO, then the ISO may suspend service until the information is provided or the issue is resolved.

ATTACHMENT S
LARGE LOAD TRANSMISSION SERVICE AGREEMENT

This Large Load Transmission Service Agreement ("Agreement"), dated as of _____, is entered into, by and between ISO New England ("ISO"), and _____ ("Large Load Transmission Customer"). Capitalized terms used but not defined in this Agreement shall have the meanings ascribed to them in the ISO New England Transmission, Markets, and Services Tariff ("Tariff").

PART I – General Terms and Conditions

1. The Large Load Transmission Customer has submitted a Completed Application for the following transmission services under the ISO Open Access Transmission Tariff ("OATT") (check all that apply):

   [ ] Firm Contract Demand Service

   [ ] Non-Firm Contract Demand Service

2. Check if applicable:

   [ ] The Large Load is the result of an increment to a load that did not previously meet the definition of Large Load. This Large Load will receive transmission service as described in Part II.J of the OATT.

3. The Large Load Transmission Customer agrees to supply, or shall cause to be supplied, information the ISO deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

4. The ISO agrees to provide and the Large Load Transmission Customer agrees to take and pay for the transmission services selected in Section I.1 of this Agreement, and Interim Contract Demand Service, as applicable, in accordance with the provisions of the ISO New England Operating Documents and this Large Load Transmission Service Agreement.

5. Large Load Transmission Customer agrees to pay all applicable charges under Section IV of the Tariff.

6. Any notice or request made to or by either party regarding this Large Load Transmission Service Agreement shall be made to the representative of the other party as indicated below.

The ISO:

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

Large Load Transmission Customer:

7. The Tariff is incorporated herein and made a part hereof.

8. General description of Large Load served by the Large Load Transmission Customer

a. Total gross peak demand (must match the sum of all services covered in this Agreement):

b. Point(s) of Delivery:

c. Project Name:

d. Location:

e. Transformer nameplate rating:

f. Additional facilities and/or associated equipment:

9. Termination of Agreement. This Agreement may be terminated by the Large Load Transmission Customer, after giving the ISO thirty (30) days written notice. To resume provision of services, the Large Load Transmission Customer shall submit a new Large Load Transmission Service Application. The ISO may terminate this Agreement pursuant to Part II.J of the OATT. The Large Load Transmission Customer shall be responsible for any charges or costs incurred up to the date of termination, or as a result of termination.

PART II – Firm Contract Demand Service

1. The ISO has determined that the Large Load Transmission Customer has a Completed Application for Firm Contract Demand Service under the OATT.

2. Service shall commence on the later of: (l) _____, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Large Load Network Upgrades are completed, or (3) the date on which sufficient capacity resources have been designated for the Large Load and achieve commercial operation pursuant to Section II.59.1 of the OATT.

   For a Large Load or a portion of a Large Load that is converting existing service to Firm Contract Demand Service as the result of an increment to a load that did not previously meet the definition of Large Load, service shall comment on: _____

3. Specifications for Firm Contract Demand Service.
   a. Total gross peak demand served by Firm Contract Demand Service (MW and MVAR):

   b. Term of Service:

   c. Point(s) of Delivery:

   d. Description of designated capacity resource(s):

PART III – Interim Contract Demand Service

1. The ISO has determined that the Large Load Transmission Customer has a Completed Application for Firm Contract Demand Service under the OATT.

2. Service shall commence on _____ and shall expire on the later of: (1) 7 years from the date service commences, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or Large Load Network Upgrades are completed. Should Interim Contract Demand Service expire without meeting the requirements of Firm Contract Demand Service, then the service will transition to Non-Firm Contract Demand

Service. The ISO shall provide Non-Firm Contract Demand Service until the Large Load Transmission Customer requests termination of the service.

3. Specifications for Interim Contract Demand Service.

a. Total gross peak demand served by Interim Contract Demand Service:

b. Term of Service:

c. Point(s) of Delivery:

d. Description of a Non-Firm Large Load Generator Arrangement (if applicable):

PART IV – Non-Firm Contract Demand Service

1. The ISO has determined that the Large Load Transmission Customer has a Completed Application for Non-Firm Contract Demand Service under the OATT.

2. Service shall commence on the later of: (l) _____, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or Large Load Network Upgrades are completed. The ISO shall provide Non-Firm Contract Demand Service until the Large Load Transmission Customer requests termination of the service.

3. Specifications for Non-Firm Contract Demand Service.

a. Total gross peak demand served by Firm Contract Demand Service (MW and MVAR):

b. Term of Service:

c. Point(s) of Delivery:

d. Description of a Non-Firm Large Load Generator Arrangement (if applicable):

IN WITNESS WHEREOF, the Parties have caused this Large Load Transmission Service Agreement to be executed by their respective authorized officials.

Large Load Transmission Customer:

By: _____ _____ _____

Name Title Date

ISO:

By: _____ _____ _____

Name Title Date

APPENDIX A TO LARGE LOAD TRANSMISSION SERVICE AGREEMENT

1. **Large Load Interconnection Facilities**:

a. **Point of Delivery and Large Load Point of Change of Ownership**. The Point of Delivery shall be at the point where [*insert description of location*]. See Appendix A-[*insert*], which drawing is attached hereto and made part hereof.

The Large Load Point of Change of Ownership shall be at the point where *[insert description of location]*. See Appendix A-[*insert*], which drawing is attached hereto and made part hereof.

If not located at the Point of Delivery, the metering point(s) shall be located at: [*insert location*].

b. **Large Load Transmission Customer's Interconnection Facilities (including metering equipment)**. The Large Load Transmission Customer shall construct [*insert Large Load Transmission Customer's Interconnection Facilities*]. See Appendix A-[*insert*], which drawing is attached hereto and made part hereof.

c. **Large Load Interconnecting Transmission Owner's Interconnection Facilities (including metering equipment)**. The Large Load Interconnecting Transmission Owner shall construct [*insert Large Load Interconnecting Transmission Owner's Interconnection Facilities, including any Cluster Enabling Transmission Upgrades*]. See Appendix A-[*insert*], which drawing is attached hereto and made part hereof.

2. **Large Load Network Upgrades**:

3. **Large Load Distribution Upgrades**. [*insert Distribution Upgrades*]

4. **Large Load Network Upgrades to Large Load Affected Systems and/or Large Load Internal Affected Systems** . [*insert Large Load Affected System Upgrades*]

5. **Large Load Contingent Facilities**: [*insert list of Contingent Facilities*]

6. **Description of Automatic Control Technologies Limiting Withdrawals**: [*insert a description of the automatic control technologies used to limit Large Load withdrawals at the Point of Delivery*]

ATTACHMENT T
LARGE LOAD SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of _____, 20__ by and between _____, a _____ organized and existing under the laws of the State of _____ ("Large Load Eligible Customer"), ISO New England Inc., a non-stock corporation existing under the laws of the State of Delaware ("ISO"), and _____, a _____ organized and existing under the laws of the State of _____ ("Large Load Interconnecting Transmission Owner"), and, if applicable, _____, a _____ organized and existing under the laws of the State of _____ ("Interconnection Customer" for: [ ] a Large Load Co-Located Generator or [ ] a Large Load Electrically Proximate Generator). Large Load Large Load Eligible Customer, ISO, and Large Load Large Load Interconnecting Transmission Owner, and Interconnection Customer (if applicable) may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Large Load Eligible Customer submitted a Large Load Transmission Service Application dated _____ to ISO; and

WHEREAS, Large Load Eligible Customer has requested ISO to perform a Large Load System Impact Study to assess the impact of providing [ ] Firm Contract Demand Service / [ ] Non-Firm Contract Demand Service to the Large Load with the Large Load Queue Position number [ ].

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO New England Transmission, Markets, and Services Tariff.

2.0 Large Load Eligible Customer elects and ISO shall cause to be performed a Large Load System Impact Study consistent with Part II.J of the OATT.

3.0 The scope of the Large Load System Impact Study shall be subject to the assumptions set forth in Appendix A to this Agreement.

4.0 The Large Load System Impact Study will be based upon the results of the Large Load Interconnecting Transmission Owner's study to identify Large Load Interconnection Facilities, and the technical information provided by Large Load Eligible Customer in the Large Load Transmission Service Application, subject to any modifications in accordance with Section II.60.8 of the OATT. ISO and Large Load Interconnecting Transmission Owner reserve the right to request additional technical information from Large Load Eligible Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Large Load System Impact Study. If Large Load Eligible Customer modifies the Large Load's designated Point of Delivery, Large Load Transmission Service Application, or the technical information provided therein is modified, as allowed by Section II.60.8 of the OATT, the time to complete the Large Load System Impact Study may be extended.

5.0 The Large Load System Impact Study report shall provide the following information:

- identification of any circuit breaker or other facility short circuit capability limits exceeded as a result of the requested transmission service;
- identification of any thermal overload of any transmission facility or system voltage limit violations resulting from the requested transmission service;
- initial review of grounding requirements and electric system protection;
- identification of any instability or inadequately damped response to system disturbances resulting from the requested transmission service; and
- description and non-binding, good faith estimated cost of and the time to construct the facilities required to provide the requested transmission service to the Large Load and to address the identified short circuit, instability, and power flow issues.

6.0 The Large Load Eligible Customer is providing, or is causing to be provided, a deposit in the amount of $150,000.

The deposit shall be applied toward the cost of the Large Load System Impact Study and the development of this Large Load System Impact Study Agreement and its

attachment(s). Large Load Interconnecting Transmission Owner's and ISO's good faith estimate for the time of commencement and completion of the Large Load System Impact Study is [insert date], unless screening steps in the study indicate that additional time is needed, at which time the ISO will provide an updated good faith estimate for the completion of the study.

The total estimated cost of the performance of the Large Load System Impact Study consists of $_____ which is comprised of the ISO's estimated cost of $_____ and the Large Load Interconnecting Transmission Owner's estimated cost of $_____.

Any difference between the deposit and the actual cost of the Large Load System Impact Study shall be paid by, or caused to be paid by, or refunded to the Large Load Eligible Customer, as appropriate. Any additional payments or refunding under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT.

Upon receipt of the Large Load System Impact Study, ISO and Large Load Interconnecting Transmission Owner shall charge and the Large Load Eligible Customer shall pay, or cause to be paid, the actual costs of the Large Load System Impact Study. ISO and Large Load Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Large Load Eligible Customer on a monthly basis for the work to be conducted on the Large Load System Impact Study each month. Large Load Eligible Customer shall pay, or caused to be paid, any invoiced amounts within thirty (30) Calendar Days of receipt of the invoice.

Where the Large Load System Impact Study includes a Large Load Co-Located Generator or Large Load Electrically Proximate Generator, the Large Load Eligible Customer shall be allocated 50% of the cost of the Large Load System Impact Study (with the remaining 50% to be paid by the Interconnection Customer for the Large Load Co-Located Generator or Large Load Electrically Proximate Generator under Schedules 22 or 23 of the OATT).

In accordance with Part II.J of the OATT, in performing the Large Load System Impact Study, ISO and Large Load Interconnecting Transmission Owner shall coordinate with

Large Load Affected Parties and Large Load Internal Affected Parties, shall receive and incorporate input from such entities into its study, and shall provide copies of the final study report to such entities.

7.0 Miscellaneous.

7.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.

7.2 Disclaimer of Warranty. In preparing and/or participating in the Large Load System Impact Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, beyond the commitment to use reasonable efforts in preparing and/or participating in the Large Load System Impact Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the Large Load System Impact Study), as applicable, no Party nor any subcontractor consultant employed by it makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy of the information considered in conducting the Large Load System Impact Study, the content of the Large Load System Impact Study, or the conclusions of the Large Load System Impact Study. Large Load Eligible Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

7.3 Force Majeure, Liability and Indemnification.

7.3.1 Force Majeure. Neither ISO, Large Load Interconnecting Transmission Owner nor a Large Load Eligible Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder. However, an entity whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Agreement, and shall promptly notify the ISO, the Large Load Interconnecting Transmission Owner or the Large Load Eligible Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

7.3.2 Liability. ISO shall not be liable for money damages or other compensation to the Large Load Eligible Customer for action or omissions by ISO in performing its obligations under this Agreement, except to the extent such act or omission by ISO is found to result from its gross negligence or willful misconduct. Large Load Interconnecting Transmission Owner shall not be liable for money damages or other compensation to the Large Load Eligible Customer for action or omissions by Large Load Interconnecting Transmission Owner in performing its obligations under this Agreement, except to the extent such act or omission by Large Load Interconnecting Transmission Owner is found to result from its gross negligence or willful misconduct. To the extent the Large Load Eligible Customer has claims against ISO or Large Load Interconnecting Transmission Owner, the Large Load Eligible Customer may only look to the assets of ISO or Large Load Interconnecting Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of ISO or Large Load Interconnecting Transmission Owner or Affiliate of either who, the Large Load Eligible Customer acknowledges and agrees, have no personal or other liability for obligations of ISO or Large Load Interconnecting Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of ISO or Large Load Interconnecting Transmission Owner or Affiliate of either. In no event shall ISO, a Large Load Interconnecting Transmission Owner or any Large Load Eligible Customer be liable for any

incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance under this Agreement. Notwithstanding the foregoing, nothing in this section shall diminish a Large Load Eligible Customer's obligations under the Indemnification section below.

7.3.3 Indemnification. Large Load Eligible Customer shall at all times indemnify, defend, and save harmless ISO and the Large Load Interconnecting Transmission Owner and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities ("Losses") by or to third parties arising out of or resulting from the performance by ISO or Large Load Interconnecting Transmission Owner under this Agreement, any bankruptcy filings made by the Large Load Eligible Customer, or the actions or omissions of the Large Load Eligible Customer in connection with this Agreement, except in the case of ISO, to the extent such Losses arise from the gross negligence or willful misconduct by ISO or its directors, officers, members, employees or agents, and, in the case of Large Load Interconnecting Transmission Owner, to the extent such Losses arise from the gross negligence or willful misconduct by Large Load Interconnecting Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost, damage or liability. The obligations of Large Load Eligible Customer to indemnify ISO and Large Load Interconnecting Transmission Owner shall be several, and not joint or joint and several. The liability provisions of the Transmission Operating Agreement or other applicable operating agreements shall apply to the relationship between the ISO and the Large Load Interconnecting Transmission Owner.

7.4 Third-Party Beneficiaries. Without limitation of Sections 7.2 and 7.3 of this Agreement, the Parties agree that subcontractor consultants hired by them to conduct, participate in, or review, or to assist in the conducting, participating in, or reviewing of, a Large Load System Impact Study shall be deemed third party beneficiaries of Sections 7.2 and 7.3.

7.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 7.5, shall continue in effect for a term of one year or until the Large Load System Impact Study is completed. This Agreement shall automatically terminate upon the withdrawal of the Large Load Transmission Service Application under Part II.J of the OATT. The ISO or the Large Load Interconnecting Transmission Owner may terminate this Agreement fifteen (15) days after providing written notice to the Large Load Eligible Customer that it has breached one of its obligations hereunder, if the breach has not been cured within such fifteen (15) day period.

7.6 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the state where the Point of Delivery is located without regard to any choice of law provisions.

7.7 Severability. In the event that any part of this Agreement is deemed as a matter of law to be unenforceable or null and void, such unenforceable or void part shall be deemed severable from this Agreement and the Agreement shall continue in full force and effect as if each part was not contained herein.

7.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.

7.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing and signed by the Parties hereto.

7.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.

7.11 Independent Contractor. Each of the Parties shall at all times be deemed to be an independent contractor of the other Parties, and none of its employees or the employees of its subcontractors shall be considered to be employees of the other Parties as a result of this Agreement.

7.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to insist or rely on any such provision, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

7.13 Successors and Assigns. This Agreement may not be assigned, by operation of law or otherwise, without the prior written consent of the other Parties hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, this Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns, to the extent the same are authorized hereunder.

7.14 Due Authorization. Each Party to this Agreement represents and warrants that it has full power and authority to enter into this Agreement and to perform its obligations hereunder, that execution of this Agreement will not violate any other agreement with a third party, and that the person signing this Agreement on its behalf has been properly authorized and empowered to enter into this Agreement.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

ISO	Large Load Interconnecting Transmission Owner
By:	By:
Title:	Title:
Date:	Date:

[Insert name of Large Load Eligible Customer]

By:

Title:

Date:

Appendix A
To Attachment T
Large Load System Impact
Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE LARGE LOAD SYSTEM IMPACT STUDY

The Large Load System Impact Study will be based upon the results of the Large Load Interconnecting Transmission Owner's study to identify Interconnection Facilities, the technical information provided by Large Load Eligible Customer in the Large Load Transmission Service Application, and the following assumptions:

Designation of Point of Delivery and configuration to be studied.

Where applicable, the information provided by the Interconnection Customer for the Large Load Co-Located Generator or Large Load Electrically Proximate Generator in its application submitted pursuant to Schedules 22 or 23 of the OATT.

[Above assumptions to be completed by Large Load Eligible Customer and other assumptions to be provided by Large Load Eligible Customer, ISO, and Large Load Interconnecting Transmission Owner]

ATTACHMENT U
LARGE LOAD FACILITIES STUDY AGREEMENT

This Large Load Facilities Study Agreement ("Agreement"), dated _____, 20__, is entered into by _____ (the " Large Load Eligible Customer") and ISO New England Inc. ("ISO") for the purpose of setting forth the terms, conditions, and costs for conducting a Large Load Facilities Study (the "Study") on [both] the systems of _____ [and] _____ ("the Transmission Operator(s)") relative to [the Large Load Eligible Customer's proposed _____ project (the "Project") to be located in _____, _____,] [or] [the transmission service requested in the Large Load Eligible Customer's Large Load Transmission Service Application] in accordance with the Open Access Transmission Tariff (the "OATT") included in the ISO Transmission, Markets and Services Tariff on file with the Federal Energy Regulatory Commission. The ISO and the Large Load Eligible Customer are sometimes referred to herein together as the "Parties" and individually as a "Party."

1. Purposes and Elements of the Study

The Study will determine the detailed engineering, design and cost of the facilities, upgrades, and special protection systems necessary to [satisfy the Large Load Eligible Customer's interconnection for the Project] [or] [provide the transmission service] as indicated by the Large Load System Impact Study (the "LLSIS").

2. Information Requirements

The Large Load Eligible Customer agrees to provide, or cause to be provided, in a timely and complete manner, all required information and technical data necessary for the ISO or its designated agent to conduct the Study. Where such information and technical data were previously provided, or caused to be provided, by the Large Load Eligible Customer for purposes of the LLSIS, or otherwise, the Large Load Eligible Customer should review and update, or cause to be reviewed and updated, the information and provide the ISO with current information, as required. The ISO will advise the Large Load Eligible Customer of additional information or studies that may be deemed necessary to complete the Study. Any such additional information or studies shall be obtained or conducted only if required by Good Utility Practice and shall be subject to the Large Load Eligible Customer's consent to proceed, such consent not to be unreasonably withheld. The cost of such additional studies shall be paid for by the Large Load Eligible Customer.

3. Representatives

All work pertaining to the Study that is the subject of this Agreement will be approved only through designated and authorized representatives of the Large Load Eligible Customer and the ISO, as they are identified in Article 14.5 hereof.

4. Scope, Duration, and Results of Study

The Scope of Work for the Study is set forth in Exhibit 1, entitled "Scope of Work." The ISO estimates that the Study will require approximately _____ (__) [time period] to complete, as more fully set forth in Exhibit 2, entitled "Study Timetable." The Large Load Eligible Customer understands and agrees that such time periods are only an estimate and that the ISO makes no representations or warranties, either express or implied, that the Study will be completed within these time periods. The ISO will provide the Large Load Eligible Customer with periodic status reports, which describe preliminary Study results, if available. Upon completion of the Study, the ISO will provide a report on the Study to the Large Load Eligible Customer based on the information provided and developed as a result of this effort. The Large Load Eligible Customer understands and acknowledges that any use of the Study results by the Large Load Eligible Customer or its agents, whether in preliminary or final form, prior to the ISO's approval pursuant to Sections I.3.9 and I.3.10 of the Transmission, Markets and Services Tariff is completely at the Large Load Eligible Customer's sole risk.

5. Payment and Nature of Costs

(a) The estimated costs contained within this Agreement are the ISO's good faith estimate of its costs to perform the Study contemplated by this Agreement. The ISO does not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Large Load Eligible Customer by the ISO may change as set forth in this Agreement. Prepayment will be required for all costs and expenses (including, without limitation, labor, materials, overheads, and administrative and general costs) the ISO will incur to perform its obligations under this Agreement, including, without limitation, all study, analysis, design, monitoring, and review work performed by the ISO or its designated agent's personnel under the terms of this Agreement ("Study Costs").

(b) The estimated Study Costs required to be paid by, or caused to be paid by, the Large Load Eligible Customer to the ISO are shown on Exhibit 3, entitled "Prepayment

Schedule." The initial prepayment requirement is ($), which the Large Load Eligible Customer agrees to pay, or cause to be paid, to the ISO upon execution of this Agreement. The initial prepayment and any subsequent prepayments will be applied against all Study Costs incurred by the ISO for work performed under this Agreement. The ISO will invoice the Large Load Eligible Customer for the costs and expenses that the ISO will incur as stated in Exhibit 3. Each invoice will show the detail of the work performed, the difference between the actual costs for such work and the prepayment amount for such work, and the amount of the prepayment for the costs of the expected work. The Large Load Eligible Customer shall pay, or cause to be paid, the invoiced amount to the ISO within thirty (30) days of the Large Load Eligible Customer's receipt of the ISO's invoice. During the term of this Agreement, the ISO will, in writing, advise the Large Load Eligible Customer in advance of any changes in the cost estimate for work to be performed if the total amount increases by ten percent (10%) or more. Any such change to the Study Costs for the ISO's work performed under this Agreement shall be subject to the Large Load Eligible Customer's consent, such consent not to be unreasonably withheld. The Large Load Eligible Customer shall, within thirty (30) days of the ISO's notice of a cost increase, either authorize such cost increase and make, or caused to be made, payment in the amount set forth in such notice, or the ISO will suspend its performance and may terminate this Agreement. Payments for work performed by the ISO shall not be subject to refunding to the Large Load Eligible Customer except in accordance with Section 5(d) below.

(c) The ISO will invoice Large Load Eligible Customer for pre-contract Study Costs incurred by the ISO prior to the effective date of this Agreement. To the extent such pre-contract Study Costs exceed Large Load Eligible Customer's pre-contract cost deposit balance, the Large Load Eligible Customer will reimburse, or cause to be reimbursed, the ISO within twenty (20) days after receipt of the ISO's invoice. Pre-contract costs shall include, without limitation, costs for study, analysis and review work performed in connection with the Study and all costs associated with the development and negotiation of all associated agreements. Payment for pre-contract Study Costs shall not be subject to refunding to the Large Load Eligible Customer.

(d) If the actual Study Costs for the work exceed prepaid estimated costs, the Large Load Eligible Customer shall make, or cause to be made, payment to the ISO for such actual Study Costs within thirty (30) days of the date of the invoice for such costs. If the actual costs for the work are less than that prepaid, the ISO will credit such difference toward its expected additional costs, or in the event there will be no additional billed costs, will refund to Large Load Eligible Customer the amount of the overpayment. Any additional payments or refunding under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT.

(e) Within one (1) year following the issuance of a final bill under this Agreement, the Large Load Eligible Customer shall have the right to audit the ISO's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. The ISO reserves the right to assess a reasonable fee to compensate for the use of its personnel's time in assisting any inspection or audit of its books, records or accounts by the Large Load Eligible Customer or its designated agent.

6. No Interconnection or Wheeling Rights; No Interruption of Service

(a) Nothing in this Agreement shall be interpreted to give the Large Load Eligible Customer the right to have electricity wheeled over, or to interconnect with, the ISO's or the Transmission Operator's transmission or distribution system. Such rights may be provided for under separate agreement.

(b) Before the ISO will take any portion of the transmission system out of service to accommodate any work by, or on behalf of, the Large Load Eligible Customer, such action must first be fully evaluated and approved by the ISO and the Transmission Operator.

7. Indemnification

The indemnification and liability provisions in Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the "Large Load Eligible Customer" under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

8. Disclaimer of Damages

NO PARTY SHALL BE LIABLE TO ANY OTHER PARTY(IES) FOR ANY INDIRECT, CONSEQUENTIAL, EXEMPLARY, SPECIAL, INCIDENTAL OR PUNITIVE DAMAGES, INCLUDING WITHOUT LIMITATION LOSS OF USE OR LOST BUSINESS, REVENUE, PROFITS OR GOODWILL, ARISING IN CONNECTION WITH THIS AGREEMENT, THE STUDY PROVIDED HEREUNDER, AND/OR THE INTENDED USE THEREOF, UNDER ANY THEORY OF TORT, CONTRACT, WARRANTY, STRICT LIABILITY OR NEGLIGENCE. The Parties agree this Section 8 will survive expiration, cancellation, or any termination of the Agreement.

9. Duration

This Agreement will remain in effect for a period of one (1) year from its effective date (the "Term") and is subject to extension automatically if the final Study report has not been completed or by mutual agreement of the Parties.

10. Termination

(a) In addition to other termination provisions provided for herein, the ISO may terminate this Agreement immediately, upon notice to the Large Load Eligible Customer, if the ISO is unable to obtain or maintain any governmental license, waiver, consent, registration or approval needed to conduct the Study hereunder.

(b) The ISO or the Large Load Eligible Customer may terminate this Agreement upon thirty (30) days' written notice to the other Party or seven (7) days after providing written notice to the other Party that it has breached one it its obligations hereunder, if the breach has not been cured within such seven day period.

11. Dispute Resolution and Voluntary Arbitration

The dispute resolution provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the "Large Load Eligible Customer" under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

12. Commission Jurisdiction Over Certain Disputes; Equitable Relief

(a) Nothing in this Agreement shall preclude, or be construed to preclude, any Party from filing a petition or complaint with the Federal Energy Regulatory Commission "Commission" with respect to any matter over which the Commission has jurisdiction.

(b) The Parties specifically reserve the right to seek a temporary restraining order, preliminary or permanent injunction, or other similar equitable relief with respect to (i) violations of confidentiality provisions of this Agreement, (ii) any failures by the Parties to comply with any applicable post-termination obligations for which monetary compensation would not be adequate, or (iii) to preserve the status quo or prevent irreparable harm.

13. Confidential Information

(a) During and after the term of this Agreement, neither Party or its employees or agents shall divulge or use for any purpose other than as specified in this Agreement Confidential Information received from the other Party (the "Disclosing Party"). "Confidential Information" shall mean all of the following except to the extent excluded below: (i) all information about the Disclosing Party whether furnished before or after the date hereof, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, which is marked "Confidential" or "Proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (ii) all reports, summaries, compilations, analyses, notes or other information which are based on, contain or reflect any Confidential Information; (iii) any and all Confidential Information as that term is defined in the ISO New England Information Policy; and (iv) any information which, if disclosed by a transmission function employee of a utility regulated by the Commission to a market function employee of the same utility system, other than by public posting, would violate the Commission's open access same time information regulations.

(b) The foregoing restrictions on use and disclosure of Confidential Information do not apply to information that: (i) is already in the possession of the Party receiving the information (the "Receiving Party") at the time of the information's disclosure hereunder and not otherwise subject to obligations of confidentiality; (ii) is, or becomes publicly known,

through no wrongful act or omission of the Receiving Party or breach of this Agreement; (iii) is received by the Receiving Party without restriction from a third party free to disclose it without obligation to the Disclosing Party; (iv) is developed independently by the Receiving Party without reference to the Confidential Information or other information of the Disclosing Party; or (v) is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel. In addition, nothing in this Section 13 shall prohibit the Large Load Eligible Customer from disclosing Confidential Information to its lenders, consultants, agents, directors, officers, employees, and attorneys (the "Representatives") for the purpose of advising the Large Load Eligible Customer, provided that the Representatives shall be informed by the Large Load Eligible Customer that such information is Confidential Information and shall agree to treat it confidentially in accordance with this Section 13.

(c) At the Disclosing Party's option, the Receiving Party shall promptly either destroy all Confidential Information in tangible form in its possession, or return all such copies, and in either event, provide a written officer's certification confirming the same promptly upon the earlier of: (i) the Disclosing Party's written request; or (ii) the expiration or earlier termination of this Agreement.

14. Miscellaneous

14.1 Assignment. The Large Load Eligible Customer may not assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the ISO, which consent shall not be unreasonably withheld. Any attempted assignment without such prior written consent shall be void. Notwithstanding the foregoing, the Large Load Eligible Customer may assign this Agreement as collateral security under its financing documents and the ISO hereby consents to such assignment.

14.2 Governing Law. This Agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts, and with Part II of the Federal Power Act, 16 U.S.C. §§ 824d, et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. Part 35, each as may be modified from time to time.

14.3 Enforceability. If any section or clause of this Agreement shall be held to be invalid or unenforceable by any body or entity of competent jurisdiction, then the remainder of the Agreement shall remain in full force and effect and the Parties shall promptly negotiate a replacement provision or agree that no replacement is necessary.

14.4 No Waiver. Any term or provision of this Agreement may be waived only in writing by the Party who is entitled to the benefits being waived. No waiver by any Party shall operate as a waiver of any future exercise of that right, nor shall any single or partial exercise of any right hereunder preclude any other or future exercise of that right or any other right hereunder. All rights and remedies evidenced hereby are in addition to and cumulative to rights and remedies available at law.

14.5 Notice. Any notice required to be given under this Agreement shall be in writing and transmitted via email to the Parties at the email addresses below or such other email addresses as may be specified by written notice. Notice sent in accordance with this Section shall be deemed effective when received.

14.6 Force Majeure. The force majeure provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the "Large Load Eligible Customer" under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

14.7 Use of Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of subcontractors, as it deems appropriate, to perform its obligations under this Agreement. Notwithstanding the foregoing, each Party shall remain responsible for the accuracy of such work performed by its subcontractors.

14.8 No Third Party Beneficiary. Nothing in this Agreement, express or implied, is intended to confer on any person, other than the Parties, any rights or remedies under or by reason of this Agreement.

14.9 Entire Agreement. This Agreement, including the Attachments, constitutes the entire agreement between the Parties with respect to its subject matter. No amendment to this Agreement shall be valid unless in writing and signed by all Parties.

14.10 Signature Authorization. The Parties have duly executed and agreed to be bound by this Agreement as evidenced by the signatures of their authorized representatives below. Each Party represents and warrants to the other that the signatory identified beneath its name below has full authority to execute this Agreement on its behalf.

14.11 Definitions. Capitalized terms not defined herein shall have the meanings ascribed to them in the Transmission, Markets and Services Tariff.

14.12 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

[LARGE LOAD ELIGIBLE CUSTOMER]

Name:_____

Title:_____

Date:_____

ISO NEW ENGLAND INC.

Name:_____

Title:_____

Date:_____

Exhibit 1

Scope of Work

Exhibit 2

Study Timetable

Exhibit 3

Prepayment Schedule

ATTACHMENT V

LARGE LOAD COST RECOVERY AGREEMENT

LARGE LOAD COST RECOVERY AGREEMENT

~~**LARGE LOAD COST RECOVERY AGREEMENT**~~

by and among

[Large Load Entity/Large Load Interconnecting Transmission Owner/Large Load Eligible Customer-]

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THIS LARGE LOAD COST RECOVERY AGREEMENT ("Agreement") is made and entered into this [DAY] day of [MONTH] [YEAR], by and among [Large Load Entity legal name] ("Large Load Entity"), [Large Load Interconnecting Transmission Owner] ("Large Load Interconnecting Transmission Owner" or "LLITO"), and [Large Load Eligible Customer legal name; if the Large Load Entity is not the Large Load Eligible Customer ("Large Load Eligible Customer"). Each may be referred to as a "Party" and collectively as the "Parties." ~~[DRAFTING NOTE: Confirm the full legal names, capacities, and notice information for each Party.]~~

RECITALS

WHEREAS, Large Load Interconnecting Transmission Owner owns, operates, or controls portions of the New England Transmission System and will plan, construct, own, operate, and maintain the LLITO's Network Upgrades and Direct Assignment Facilities needed to serve the Large Load Facility and address the system and reliability impacts thereof; and

WHEREAS, Large Load Entity intends to develop, own, lease, control, and/or operate the Large Load Facility described in Appendix A ("Large Load Facility") at the site and with the service characteristics identified in this Agreement; and

WHEREAS, Large Load Eligible Customer intends to procure regional and local transmission service from Large Load Interconnecting Transmission Owner and ISO-NE under the ISO-NE OATT on behalf of Large Load Entity and to bill the applicable costs to Large Load Entity under Large Load Eligible Customer's applicable retail tariff or an approved retail special contract;

[Use the following when the Large Load Entity is the Large Load Eligible Customer: **WHEREAS**, Large Load Entity is ~~an~~a Large Load Eligible Customer under the ISO-NE OATT and intends to procure regional and local transmission service from Large Load Interconnecting Transmission Owner and ISO-NE under the ISO-NE OATT;]

and

WHEREAS, the Parties have agreed to enter into this Agreement to establish Large Load Entity's Cost Responsibility, credit support, revenue-requirement crediting, stranded-cost protection, payment obligations, and operational requirements associated with the Required Facilities, while protecting existing transmission customers from costs attributable to the Large Load Facility;

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

When used in this Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the ISO-NE OATT or the Article in which they are used, as applicable.

ARTICLE 1. DEFINITIONS

The definitions contained in this Article 1 apply throughout this Agreement. Capitalized terms not defined in this Article 1 have the meanings given in the ISO New England Inc. ("ISO-NE") Transmission, Markets, and Services Tariff ("Tariff") ~~–~~the ISO New England Operating Documents as defined in the Tariff, or the applicable Article, as the context requires. If a definition in this Agreement conflicts with a mandatory definition in the Tariff, the Tariff definition controls ~~to the extent of the conflict~~.

Credit Support shall mean any and all security and financial assurance described in Article 10 and Appendix D to this agreement.

Direct Assignment Facilities shall mean all facilities and equipment owned, controlled, or operated by Large Load Interconnecting Transmission Owner as identified in Appendix A to this agreement, including any modifications, additions or upgrades to such facilities and equipment, necessary to interconnect the Large Load Facility to the Administered Transmission System. Direct Assignment Facilities are sole use facilities and shall not include Large Load Network Upgrades.

Firm Contract Demand Service or FCDS shall mean the type of transmission service for Large Loads described in Section II.57.1.1 of the Part II of the Tariff ("the ISO-NE OATT").

Interim Contract Demand Service or ICDS shall mean the type of transmission service for Large Loads described in Section II.57.1.2 of the ISO-NE OATT.

Large Load Commercial Operation Date shall mean the beginning date of the commercial operation of the Large Load Facility.

Large Load Entity's Interconnection Facilities or LLEIF shall mean all facilities and equipment, as identified in Appendix A of this Agreement, owned and operated by the Large Load Entity, including any

modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Large Load Facility to the Direct Assignment Facilities or Administered Transmission System as applicable.

LLITO's Network Upgrades shall mean those Large Load Network Upgrades identified in the Large Load System Impact Study for the Large Load Eligible Customer that are within LLITO's service territory, as described in Appendix A to this Agreement.

Large Load Network Upgrades shall mean those upgrades to the New England Transmission System, any Large Load Affected Systems and Large Load Internal Affected Systems as identified in the Large Load Eligible Customer's Large Load System Impact Study.

Non-Firm Contract Demand Service or NFCDS shall mean the type of transmission service for Large Loads described in Section II.57.1.3 of the ISO-NE OATT.

Reasonable Efforts shall mean efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Required Facilities shall mean the Direct Assignment Facilities and LLITO's Network Upgrades.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 Effective Date. This Agreement shall become effective upon execution by the Parties, subject to acceptance by the Commission if required~~, or,~~. Any Party may request the Agreement be filed unexecuted at the Commission, and if filed unexecuted, the Agreement will be effective upon the date specified by the Commission. Large Load Interconnecting Transmission Owner shall promptly make any filing required by Article 3.1, and Large Load Eligible Customer and Large Load Entity shall reasonably cooperate with those filings.

2.2 Term of Agreement. Subject to Articles 2.3 and 2.4, this Agreement shall remain in effect for ~~the longer of 1) thirty (30~~1) forty (40) Years ~~or 2) a period coextensive with the depreciable life of the LLITO's Network Upgrades and other Required Facilities identified in Appendix A and Appendix C 2, measured from the date the applicable facilities are placed in service~~ ("Initial Term"). Unless otherwise agreed to in writing by the Parties or termination of this Agreement consistent with this Article 2, following the end of the Initial Term this Agreement shall be renewed on an annual basis. ~~Consistent with Appendix A and Appendix C 2, the longest applicable depreciable life of the LLITO's Network Upgrades and other Required Facilities is [XX] years.~~

2.3 Termination Procedures.

2.3.1 Voluntary Termination. Large Load Entity or Large Load Eligible Customer may request termination of this Agreement by giving ~~ISO NE and~~ all other Parties at least ninety (90) Calendar Days' advance written notice. A termination so requested ~~by Large Load Entity~~ shall not be effective until Large Load Entity has paid all amounts then due, the applicable Exit Fee, and any other ongoing cost ~~responsibility~~obligations assigned to Large Load Entity under this Agreement. Any continuing transmission-service obligations under the ISO-NE OATT or the Large Load Transmission Service Agreement shall remain in effect until the applicable service is properly terminated under those instruments. Any continuing retail-service obligations under a retail tariff or special contract shall remain in effect until the applicable service is properly terminated under that instrument. Any such voluntary termination prior to the permanent cessation of operation of the Large Load Facility shall only be effective by the consent of all other Parties, such consent not to be unreasonably withheld. Following the permanent cessation of operation of the Large Load Facility, Large Load Interconnecting Transmission Owner may terminate this agreement on ninety (90) Calendar Days' advance written notice.

2.3.2 Default. Each Party may terminate this Agreement in accordance with Article 16. Large Load Interconnecting Transmission Owner~~,~~ or Large Load Eligible Customer may also suspend or terminate the Large Load Entity's applicable services, to the extent permitted by the ISO-NE OATT and the Large Load Transmission Service Agreement, following an Event of Default or an exceedance of the contract demand quantity for the transmissions service reserved by the Large Load Eligible Customer.

2.3.3 Regulatory Effect of Termination. Notwithstanding this Article 2, no termination shall become effective until the Parties have complied with Applicable Laws and Regulations, including any required filing with or acceptance by the Commission. Termination shall not relieve a Party of obligations that accrued before the effective termination date or of any OATT, safety, retirement, or other operational instruction or deactivation requirement that survives under its governing instrument.

2.4 Termination Costs. Upon termination, disconnection, suspension, or abandonment of the Large Load project, Large Load Entity shall remain responsible for ~~its~~ all costs incurred or committed by the Large Load Interconnecting Transmission owner before the effective date of the termination or change.

2.4.1 Termination Prior to Large Load Commercial Operation Date. In the event the Agreement is terminated prior to the Large Load Commercial Operation Date, Large Load Entity shall ~~be responsible for~~pay all costs incurred by the Large Load Interconnecting Transmission Owner prior to the effective date of the termination, including but not limited to costs for design, engineering, procurement, and construction of the Direct Assignment Facilities and LLITO's Network Upgrades.

2.4.1.1 With respect to any portion of Direct Assignment Facilities or LLITO's Network Upgrades to the extent covered by this Agreement, that have not yet been constructed or installed, Large Load Interconnecting Transmission Owner shall ~~to the extent possible and~~ with Large Load Entity's authorization use Reasonable Efforts to cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities so long as such Reasonable Efforts do not require Large Load Interconnecting Transmission Owner to incur additional costs or liabilities; provided that in the event Large Load Entity elects not to authorize such cancellation, Large Load Entity shall assume all payment obligations with respect to such materials, equipment, and contracts, and Large Load Interconnecting Transmission Owner shall deliver such material and equipment, and, if necessary, and to the extent possible, assign such contracts, to Large Load Entity as soon as practicable, at Large Load

Entity's expense. To the extent that Large Load Entity has already paid Large Load Interconnecting Transmission Owner for any or all such costs of materials or equipment not taken by Large Load Entity, either (i) in the case of overpayment, Large Load Interconnecting Transmission Owner shall promptly refund such amounts to Large Load Entity, less any costs, including penalties incurred by Large Load Interconnecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts, or (ii) in the case of underpayment, Large Load Entity shall promptly pay such amounts still due plus any costs, including penalties incurred by Large Load Interconnecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

~~If a Large Load Entity terminates this Agreement, it shall remain responsible for all costs incurred in association with that Large Load Entity's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any LLITO's Network Upgrades for which a Constructing Party has incurred expenses.~~

2.4.1.2. The Large Load Interconnecting Transmission Owner applicable may, at its option, retain any portion of such materials, equipment, or facilities that Large Load Entity chooses not to accept delivery of, in which case Large Load Interconnecting Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.1.3. With respect to any portion of the Direct Assignment Facilities or LLITO's Network Upgrades and any other facilities already installed or constructed pursuant to the terms of this Agreement, Large Load Entity shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.4.2 Termination Following Large Load Commercial Operation Date. In the event of termination of the Agreement following the Large Load Commercial Operation Date, Large Load Entity shall be responsible for all outstanding amounts due under the

Agreement, including the Exit Fee and any costs associated with the disconnection of the Large Load Facility described in Article 2.5.

2.5 Cessation of Service and Disconnection. Upon termination of this Agreement, Large Load Interconnecting Transmission Owner may cease the provision of any applicable transmission service to the Large Load Eligible Customer and Large Load Eligible Customer may cease procuring or billing any transmission service on behalf of Large Load Entity, in each case subject to the ISO-NE OATT, the Large Load Transmission Service Agreement, Applicable Laws and Regulations, and any required regulatory approval. The Parties shall coordinate any reduction, disconnection, retirement, or removal of facilities in a safe and reliable manner. Large Load Entity shall bear the costs required to effectuate the cessation or disconnection, except to the extent another Party is responsible under this Agreement or its default caused the costs.

2.6 Survival. This Agreement shall continue after termination to the extent necessary to administer all billings and payments under this Agreement (including but not limited to the Cost Recovery Charge, the Exit Fee, the costs for any Direct Assignment Facilities or LLITO's Network Upgrades due under this Agreement), credit support, security draws or returns, audits, confidentiality, indemnification, dispute resolution, and liabilities arising from acts or events occurring while this Agreement was in effect, and to permit safe access, disconnection, removal, or salvage of facilities.

ARTICLE 3. REGULATORY FILINGS

3.1 Filing. The Large Load Interconnecting Transmission Owner shall ~~jointly~~ file this Agreement (and any amendment hereto) with the appropriate Governmental Authority, if required, in accordance Applicable Laws and Regulations. Large Load Entity or Large Load Eligible Customer may request that any information so provided be subject to the confidentiality provisions of Article 21. If the Large Load Entity or Large Load Eligible Customer has executed this Agreement, or any amendment thereto, the Large Load Entity shall reasonably cooperate with the Large Load Interconnecting Transmission Owner with respect to such filing and to provide any information reasonably requested by Large Load Interconnecting Transmission Owner needed to comply with applicable regulatory requirements.

ARTICLE 4. ENGINEERING, PROCUREMENT, AND CONSTRUCTION

4.1 Large Load Interconnecting Transmission Owner Engineering, Procurement, and Construction. The Large Load Interconnecting Transmission Owner shall design, procure, and construct the Direct Assignment Facilities and LLITO's Network Upgrades using Reasonable Efforts to complete construction and placing in service such facilities by the dates set forth in Appendix B (Milestones). The Large Load Interconnecting Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Large Load Interconnecting Transmission Owner reasonably expects that it will not be able to complete Direct Assignment Facilities and LLITO's Network Upgrades by the specified dates, Large Load Interconnecting Transmission Owner shall promptly provide written notice to the Large Load Entity and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

4.2 Equipment Procurement. Large Load Interconnecting Transmission Owner shall commence design of the LLITO's Network Upgrades and Direct Assignment Facilities and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

4.2.1 If applicable, the Large Load Interconnecting Transmission Owner has completed the Facilities Study pursuant to the Facilities Study Agreement;

4.2.2 Large Load Interconnecting Transmission Owner has received written authorization to proceed with design and procurement from the Large Load Entity by the date specified in Appendix B (Milestones); and

4.2.3 The Large Load Entity has provided ~~security~~Credit Support to Large Load Interconnecting Transmission Owner in accordance with Article ~~[XX]~~10 and Appendix ~~C~~D by the dates specified in Appendix B ~~(Milestones).~~.

4.3 Construction Commencement. Large Load Interconnecting Transmission Owner shall commence construction of the LLITO's Network Upgrades and Direct Assignment Facilities as soon as practicable after the following additional conditions are satisfied:

4.3.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

4.3.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the LLITO's Network Upgrades and Direct Assignment Facilities;

4.3.3 Large Load Interconnecting Transmission Owner has received written authorization to proceed with construction from the Large Load Entity by the date specified in Appendix B (Milestones); and

4.3.4 The Large Load Entity has provided ~~security~~Credit Support to Large Load Interconnecting Transmission Owner in accordance with Article ~~[XX]~~10 and Appendix D by the dates specified in Appendix B (Milestones).

4.4 Large Load Entity's Interconnection Facilities ("LLEIF"). Large Load Entity shall, at its expense, design, procure, construct, own and install the LLEIF, as set forth in Appendix A.

4.4.1 LLEIF Specifications. Large Load Entity shall submit initial specifications for the LLEIF, including System Protection Facilities, to Large Load Interconnecting Transmission Owner at least one hundred eighty (180) Calendar Days prior to the Service Commencement Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Service Commencement Date. Large Load Interconnecting Transmission Owner shall review ~~such~~initial and final specifications to ensure that the LLEIF are compatible with the technical specifications, operational control, and safety requirements of Large Load Interconnecting Transmission Owner and comment on such specifications within thirty (30) Calendar Days of Large Load Entity's

submission. All specifications provided hereunder shall be deemed confidential and shall also be marked as Critical Energy Infrastructure Information as appropriate.

4.4.2 Large Load Interconnecting Transmission Owner's Review. Large Load Interconnecting Transmission Owner's review of Large Load Entity's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Load Facility or the LLEIF. Large Load Entity shall make such changes to the LLEIF as may reasonably be required by Large Load Interconnecting Transmission Owner, in accordance with Good Utility Practice, to ensure that the LLEIF are compatible with the technical specifications, operational control, and safety requirements of ~~Large Load Interconnecting Transmission Owner.~~, as well as applicable Reliability Standards, Applicable Laws and Regulations, and the ISO-NE Operating Documents..

4.4.3 LLEIF Construction. The LLEIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Large Load Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Large Load Entity shall deliver to Large Load Interconnecting Transmission Owner "as-built" drawings, information and documents for the LLEIF including but not limited a one-line diagram, a site plan showing the Large Load Facility and the LLEIF, plan and elevation drawings showing the layout of the LLEIF, a relay functional diagram, and any other information reasonably requested by the Large Load Interconnecting Transmission Owner consistent with Good Utility Practice.

4.5 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at the incremental cost to another Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents if allowed under the applicable agency agreement, that are necessary to enable the Access Party solely to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Load Facility with the Administered Transmission System; (ii) operate and maintain the Large Load Facility, the Interconnection Facilities and the New England Transmission System; and (iii) disconnect or

remove the Access Party's facilities and equipment upon termination of this Agreement. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

4.6 Large Load Identification. The Large Load Facility's site location and legal description, initial requested load, initial Contract Demand, Maximum Forecast Demand, and Interconnection Point information shall be as set forth in Appendix A. These details shall control unless changed through an approved Large Load Service Request and an amendment to this Agreement or other filing required under the ISO-NE OATT.

4.7 Updates and Material Changes. Large Load Entity shall promptly notify ISO-NE, Large Load Interconnecting Transmission Owner, and Large Load Eligible Customer~~,~~ (if the Large Load Entity is not the Large Load Eligible Customer~~,~~), of any material change to the Large Load Facility, its load forecast, operating characteristics, development schedule, or Transmission Service Level. No such change shall 1) increase the contract demand quantity for any transmission service provided to the Large Load Eligible Customer ~~or modify the Required Facilities without a new or amended Large Load Service Request and any required tariff, regulatory, or Agreement approval~~; 2) materially modify the electrical characteristics of the Large Load Facility; or 3) modify the Direct Assignment Facilities or Large Load Network Upgrades without written consent of the Large Load Interconnecting Transmission Owner as well as compliance with any requirement consistent with the ISO-NE Operating Documents, Applicable Reliability Standards, or Applicable Laws and Regulations.

4.7 Service Milestones. The Parties shall maintain in Appendix B the requested Service Commencement Date, any phased-service dates, material project milestones, security-posting dates, payment milestones, and the dates for required regulatory approvals. A milestone change does not modify ~~Contract Demand, Cost Responsibility, or the Term~~any other obligations of the Large Load Entity unless expressly approved under this Agreement and the ISO-NE OATT.

4.9 Taxes.

~~[under development]~~

4.9.1 Taxability of Customer Payments. Large Load Entity is developing a project which is not a generator as defined by IRS Notice 2016-36 the Parties recognize that under current federal and state income tax laws all payments or property transfers made by Large Load Entity to a Large Load Interconnecting Transmission Owner that is not tax exempt for the installation of the Direct Assignment Facilities shall be taxable, as contributions in aid of construction under the Internal Revenue Code (IRC) Section 118(b) and any applicable state income tax laws.

4.9.2 Tax Gross-Up Amount. To the extent applicable, Large Load Interconnecting Transmission Owner shall include any amounts paid by Large Load Entity for the Direct Assignment Facilities in U.S. federal and state taxable income. Large Load Entity's liability for the cost consequences of any tax liability under this Article 4.9 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Large Load Entity will pay Large Load Interconnecting Transmission Owner, in addition to the amount paid for the Direct Assignment Facilities, an amount equal to (1) the current taxes imposed on Large Load Interconnecting Transmission Owner ("Current Taxes") on the excess of (a) the gross income realized by Large Load Interconnecting Transmission Owner as a result of payments or property transfers made by Large Load Entity to Large Load Interconnecting Transmission Owner under this Agreement (without regard to any payments under this Article 4.9) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit the Large Load Interconnecting Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Large Load Interconnecting Transmission Owner's composite federal and state tax rates at the time the payments or property transfers are received and Large Load Interconnecting Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Large Load Interconnecting Transmission Owner's anticipated tax depreciation deductions as a result of such payments or property transfers by Large Load Interconnecting Transmission Owner's current weighted average cost of capital. Thus, the formula for calculating Large Load Entity's liability to

Large Load Interconnecting Transmission Owner pursuant to this Article 4.9.2 can be expressed as follows: (Current Tax Rate x (Gross Income Amount - Present Value Depreciation Amount))/(1 - Current Tax Rate).

4.9.3 Private Letter Ruling or Change or Clarification of Law or Administrative Practice. At Large Load Entity's request and expense, Large Load Interconnecting Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Large Load Entity to Large Load Interconnecting Transmission Owner under this Agreement are subject to federal income taxation. Large Load Entity will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Large Load Entity's knowledge. Large Load Interconnecting Transmission Owner and Large Load Entity shall cooperate in good faith with respect to the submission of such request. Large Load Interconnecting Transmission Owner shall file the request in its name and have final authority, exercised in good faith after reasonable consultation with Large Load Entity, to determine the content of its request and its representation.

Large Load Interconnecting Transmission Owner shall keep Large Load Entity fully informed of the status of such request for a private letter ruling and shall allow Large Load Entity to participate in all substantive discussion with IRS officials, including a conference of right, should such a conference be held, about the request and shall permit Large Load Entity to prepare the initial drafts of any follow-up communications in connection with the request. Large Load Interconnecting Transmission Owner shall have final authority, exercised in good faith after reasonable consultation with Large Load Entity, to determine the content of substantive discussions and any follow-up communications.

In the event of a change in law or the expansion of the safe-harbor of Notice 2016-36, or any successor published guidance of the IRS, that makes the Large Load Entity's payments or property transfers made by Large Load Entity to Large Load Interconnecting Transmission Owner for the installation of the Direct Assignment Facilities under this agreement non-taxable upon Large Load Entity's written request and sole expense, Large Load Interconnecting Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 4.9.

4.9.4 Contests. Large Load Interconnecting Transmission Owner reserves the right to make all decisions with regard to any claim for refund and its prosecution, including the selection of counsel and compromise or settlement of the claim, but Large Load Interconnecting Transmission Owner shall keep Large Load Entity informed, shall consider in good faith suggestions from Large Load Entity about the pursuit of the refund claim, and shall reasonably permit Large Load Entity or a Large Load Entity representative to attend proceedings related to the claim.

Large Load Entity shall pay to Large Load Interconnecting Transmission Owner on a periodic basis, as invoiced by Large Load Interconnecting Transmission Owner, Large Load Interconnecting Transmission Owner's documented reasonable costs of prosecuting such claim for refund.

4.9.5 Refund. In the event that (a) a private letter ruling is issued to Large Load Interconnecting Transmission Owner which holds that any amount paid or the value of any property transferred by Large Load Entity to Large Load Interconnecting Transmission Owner under the terms of this Agreement is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Large Load Interconnecting Transmission Owner in good faith that any amount paid or the value of any property transferred by Large Load Entity to Large Load Interconnecting Transmission Owner under the terms of this Agreement is not taxable to Large Load Interconnecting Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Large Load Entity to Large Load Interconnecting Transmission Owner are not subject to federal income tax, or (d) if Large Load Interconnecting Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Large Load Entity to Large Load Interconnecting Transmission Owner pursuant to this Agreement, Large Load Interconnecting Transmission Owner shall promptly refund to Large Load Entity the following:

(i) Any payment made by Large Load Entity under this Article 4.9 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) Interest on any amounts paid by Large Load Entity to Large Load Interconnecting Transmission Owner for such taxes which Large Load Interconnecting Transmission Owner did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date payment was made by Large Load Entity to the date Large Load Interconnecting Transmission Owner refunds such payment to Large Load Entity, and

(iii) With respect to any such taxes paid by Large Load Interconnecting Transmission Owner, any refund or credit Large Load Interconnecting Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to the Large Load Interconnecting Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Large Load Interconnecting Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Large Load Interconnecting Transmission Owner will remit such amount promptly to Large Load Entity only after and to the extent that Large Load Interconnecting Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to the Large Load Interconnecting Transmission Owner's Direct Assignment Facilities.

The intent of this provision is to leave both the Large Load Entity and Large Load Interconnecting Transmission Owner, to the extent practicable, in the event that no taxes are due with respect to any payment for the Direct Assignment Facilities hereunder, in the same position they would have been in had no such tax payments been made. Large Load Entity shall bear the economic burden to the extent a complete refund of taxes and interest is not obtained.

4.9.6 Taxes Other Than Income Taxes. Upon the timely request by Large Load Entity, and at Large Load Entity's sole expense, Large Load Interconnecting Transmission Owner shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Large Load Interconnecting Transmission Owner for which Large Load Entity may be required to reimburse Large Load Interconnecting Transmission Owner under the terms of this Agreement. Large Load

Entity shall pay to Large Load Interconnecting Transmission Owner on a periodic basis, as invoiced by Large Load Interconnecting Transmission Owner, Large Load Interconnecting Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Large Load Entity and Large Load Interconnecting Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Large Load Entity to Large Load Interconnecting Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Large Load Entity will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Large Load Interconnecting Transmission Owner.

4.10 Modification.

4.10.1 General. Either Large Load Entity or Large Load Interconnecting Transmission Owner may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities or the New England Transmission System, that Party shall provide to the other Parties: (i) sufficient information regarding such modification so that the other Party(ies) may evaluate the potential impact of such modification prior to commencement of the work; and (ii) such information as may be required by the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Load Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party(ies) at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed. Notwithstanding the foregoing, no Party shall be obligated to proceed with a modification that would constitute a Large Load Material Modification and therefore require a new ~~transmission service~~Large Load Transmission Service Application request under the ISO-NE OATT.

In the case of Large Load Facility or Large Load Entity's Interconnection Facility modifications ~~that do~~ not ~~require~~requiring a new Large Load ~~Entity to submit a~~

Transmission Service ~~Request~~Application, Large Load Interconnecting Transmission Owner shall provide, within ~~thirty (30~~sixty (60) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the New England Transmission System, Direct Assignment Facilities or Large Load Network Upgrades necessitated by such Large Load Entity modification and a good faith estimate of the costs thereof.

4.10.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this Agreement and Good Utility Practice.

4.10.3 Modification Costs. Large Load Entity shall not be directly assigned for the costs of any additions, modifications, or replacements that Large Load Interconnecting Transmission Owner makes to Direct Assignment Facilities or the New England Transmission System to facilitate the interconnection of a third party to Direct Assignment Facilities or the New England Transmission System, or to provide transmission service to a third party under the Tariff, except as provided for under the Tariff or any other applicable tariff. Large Load Entity shall be responsible for the costs of any additions, modifications, or replacements to the Large Load Facility or Large Load Entity's Interconnection Facilities that may be necessary to maintain or upgrade such Large Load Entity's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

4.11 No Service. The Large Load Interconnecting Transmission Owner and Large Load Eligible Customer are not providing any form of electrical service, including transmission service, distribution service, wholesale service, or retail service to the Large Load Entity pursuant to this Agreement.

ARTICLE 5. TESTING AND INSPECTION

5.1 Pre-Large Load Commercial Operation Date Testing and Modifications. Prior to the Large Load Commercial Operation Date, Large Load Interconnecting Transmission Owner shall test Direct Assignment Facilities and LLITO's Network Upgrades and Large Load Entity shall test the Large Load Facility and the Large Load Entity's Interconnection Facilities to ensure their safe

and reliable operation in accordance with ISO-NE Operating Documents and Applicable Reliability Standards (including NERC CLO-003-1 and MOD-026-2). ~~Similar testing~~Testing may be required by the Large Load Interconnecting Transmission owner at any time after initial operation, including but not limited to a material change in the Large Load Facility, a significant outage of the Large Load Facility, or at the request of the ISO-NE, Large Load Eligible Customer, or Large Load Interconnecting Transmission Owner. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Large Load Entity shall bear the cost of all such testing and modifications.

5.2 Post-Large Load Commercial Operation Date Testing and Modifications. Large Load Entity and Large Load Interconnecting Transmission Owner shall each at its own expense perform routine inspection and testing of its facilities and equipment in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, as may be necessary to ensure the continued interconnection of the Large Load Facility to the Administered Transmission System in a safe and reliable manner. The Large Load Entity and Large Load Interconnecting Transmission Owner each shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Large Load Entity acknowledges and agrees that the ISO-NE may also perform testing of Large Load Entity's facilities and equipment in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

5.3 Right to Observe Testing. Each Party shall notify the other Parties in advance of its performance of tests of ~~its Interconnection~~the Direct Assignment Facilities and LLEIF. The other Parties have the right, at its own expense, to observe such testing.

5.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment; (ii) review and inspect the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review and examine the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Each Party may exercise these rights from time to time as it deems

necessary upon reasonable notice to the other Parties. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement, acceptance, or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article ~~6~~5.4 shall be governed by Article 21.

ARTICLE 6. METERING

6.1 General. Each Party shall comply with the ISO-NE OATT, ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, regarding metering. Large Load Entity shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment described in Appendix A of this Agreement, including spare Metering Equipment that are necessary to address equipment failure. Large Load Entity shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Tariff and any applicable retail tariffs and to communicate the information to the ISO-NE. Unless otherwise agreed, such equipment shall remain the property of Large Load Interconnecting Transmission Owner.

6.2 Check Meters. Large Load Entity, at its option and expense, may install and operate, on its premises and on its side of the Interconnection Point, one or more check meters to check Large Load Interconnecting Transmission Owner's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this Agreement, except as provided in Article ~~7~~6.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Large Load Interconnecting Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Large Load Entity in accordance with Good Utility Practice.

6.3 Standards. Large Load Interconnecting Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards and the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

6.4 Testing of Metering Equipment. Large Load Interconnecting Transmission Owner shall inspect and test all Large Load Interconnecting Transmission Owner-owned Metering Equipment upon installation and thereafter as specified in the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Large Load Interconnecting Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Large Load Entity may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Large Load Entity's expense, in order to provide accurate metering. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than the values specified within ISO New England Operating Documents, or successor documents, from the measurement made by the standard meter used in the test, Large Load Interconnecting Transmission Owner shall adjust the measurements, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

6.5 Metering Data. At Large Load Entity's expense, metered data shall be telemetered to locations designated by ISO-NE, Large Load Interconnecting Transmission Owner, and Large Load Eligible Customer. The metering required by the ISO-NE OATT and ISO New England Operating Documents shall be the official measurement of the Large Load Facility's demand and energy withdrawals at the Interconnection Point for transmission charges, Contract Demand monitoring, and reconciliation.

ARTICLE 7. COMMUNICATIONS

7.1 Large Load Entity Obligations. Large Load Entity shall maintain ~~satisfactory~~continuous and reliable operating communications with the ISO-NE, Large Load Eligible Customer, and Large Load Interconnecting Transmission Owner in accordance with applicable provisions of ISO New England Operating Documents, Applicable Reliability Standards, Applicable Laws and Regulations, or successor documents. Such communications shall include the capability to receive and respond to real-time operating instructions and shall identify personnel authorized to act on behalf of the Large Load Entity. The Large Load Entity shall promptly notify ISO-NE and Interconnecting Transmission Owner of any loss or material degradation of required operating

communications and shall maintain backup communications capability as required by the applicable ISO New England Operating Documents.

7.2 Telemetry and Remote Terminal Unit. No later than the date specified in Appendix B and, in any event, before the Service Commencement Date, a Remote Terminal Unit, or equivalent data-collection and transfer equipment acceptable to ISO-NE, Large Load Interconnecting Transmission Owner, and Large Load Eligible Customer shall be installed by Large Load Entity or Large Load Interconnecting Transmission Owner at Large Load Entity's expense. The equipment shall gather the accumulated, interval, and instantaneous data required for Large Load Entity's service and shall telemeter that data through dedicated circuits or other approved communications facilities to the locations designated by ISO-NE, Large Load Interconnecting Transmission Owner, and Large Load Eligible Customer. The communications protocol shall comply with the ISO-NE OATT and ISO New England Operating Documents.

Each Party shall promptly advise the other Parties if it detects or otherwise learns of a metering, telemetry, or communications-equipment error or malfunction requiring attention or correction. The Party owning the equipment shall correct the error or malfunction as soon as reasonably feasible and shall provide any replacement data required for billing or reliability purposes.

7.3 No Annexation. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

ARTICLE 8. OPERATIONS AND COMPLIANCE

8.1 General. Each Party shall comply with applicable provisions of ISO New England Operating Documents, Reliability Standards, or successor documents, regarding operations. Each Party shall provide to the other Party(ies) all information that may reasonably be required by the other Party(ies) to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

~~**8.2 Control Area Notification.** Before the Service Commencement Date, the Large Load Entity shall notify the ISO-NE and Large Load Interconnecting Transmission Owner in writing in accordance with ISO New England Operating Documents, Reliability Standards, or successor documents. If the Large Load Entity elects to have the Large Load Facility dispatched and operated from a remote Control Area other than the Control Area in which the Large Load Facility is physically located, and if permitted to do so by the relevant transmission tariffs and ISO New England Operating Documents, Reliability Standards, or successor documents, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this Agreement, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Load Facility in the other Control Area for dispatch and operations.~~

~~**8.3 Large Load Interconnecting Transmission Owner and ISO-NE Obligations.**~~**8.2 Large Load Interconnecting Transmission Owner Obligations.** Large Load Interconnecting Transmission Owner shall operate, maintain and control the Direct Assignment Facilities in a safe and reliable manner and in accordance with this Agreement and ISO New England Operating Documents, Reliability Standards, or successor documents. Large Load Interconnecting Transmission Owner may provide operating instructions to Large Load Entity consistent with this Agreement, ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Large Load Interconnecting Transmission Owner's operating protocols and procedures as they may change from time to time. Large Load Interconnecting Transmission Owner will consider changes to their operating protocols and procedures proposed by Large Load Entity.

8.4~~**3**~~ **Large Load Entity Obligations.** In addition to any payments required by this Agreement, in express consideration for the construction of the Direct Assignment Facilities and LLITO's Network Upgrades Large Load Entity shall at its own expense operate, maintain and control the Large Load Facility and the Large Load Entity's Interconnection Facilities in a safe and reliable manner and in accordance with this Agreement, the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and accepts full and exclusive responsibility for the Large Load Facility's compliance with those documents.

8.~~5~~4 Large Load Eligible Customer Obligations. Large Load Eligible Customer agrees to provide all information reasonably necessary to each other Party in order to facilitate the construction of the Interconnection Facilities and the LLITO's Network Upgrades. Large Load Eligible Customer likewise agrees to provide to each other Party all information necessary to calculate the Cost Recovery Charge described in Article 10 and Appendix C-2 of this Agreement. Large Load Eligible Customer shall provide this information consistent with Reasonable Efforts.

8.~~6~~5 Start-Up and ~~Synchronization~~Energization and Ramp Rate. The Large Load Entity is responsible for the proper start-up and energization of the Large Load Facility to the New England Transmission System in accordance with Applicable Laws and Regulations, ISO New England Operating Documents, Applicable Reliability Standards, ~~or successor documents.~~applicable LLITO Operating Procedures, applicable state tariffs or special contracts, or successor documents, including any applicable ramp-rate, load-change, or operating limitations established pursuant to the ISO New England Operating Documents.

8.7 Outages and Interruptions.

8.7.1 Outages.

8.7.1.1 Outage Authority and Coordination. Large Load Entity agrees and acknowledges that the ISO-NE shall have the authority to coordinate and direct facility outages, including outages of the Large Load Facility, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Each Party may in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, in coordination with the other Party(ies), remove from service any of its respective facilities or LLITO's Network Upgrades that may impact the other Party's(ies') facilities as necessary to perform maintenance or testing or to install or replace equipment, subject to the oversight of ISO-NE in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

8.7.1.2 Outage Schedules. Outage scheduling~~, and any related compensation,~~ shall be in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

8.7.2 Interruption of Service. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, the ISO-NE or Large Load Interconnecting Transmission Owner may require Large Load Entity to interrupt or reduce deliveries of electricity if such ~~delivery~~demand of electricity could adversely affect ISO-NE's or Large Load Interconnecting Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the New England Transmission System.

8.7.3 Under-Frequency and Over Frequency Conditions. Large Load Entity shall implement under-frequency and over-frequency relay set points for the Large Load Facility as required by the applicable provisions of ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Large Load Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with ISO-NE and Large Load Interconnecting Transmission Owner in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

8.7.4 System Protection and Other Control Requirements. Large Load Entity shall, at its expense, install, operate, and maintain System Protection Facilities as a part of the Large Load Facility or the Large Load Entity's Interconnection Facilities in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, Large Load Interconnecting Transmission Owner's operational requirements, or successor documents. Large Load Interconnecting Transmission Owner shall install at Large Load Entity's expense, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, Large Load Interconnecting Transmission Owner's operational requirements, or successor documents, and consistent with Good Utility Practice any System Protection Facilities that may be required on the Direct Assignment Facilities or the New England Transmission System as a result of the interconnection of the Large Load

Facility and the Large Load Entity's Interconnection Facilities. Large Load Entity shall not make a material change to System Protection Facilities, protection settings, control schemes, or other equipment that could affect the New England Transmission System or Direct Assignment Facilities without providing notice to and coordinating with the System Operator and Interconnecting Transmission Owner as required by applicable ISO New England Operating Documents.

8.8 Switching and Tagging Rules. Each Party shall provide the other Party(ies) with a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment. The Interconnecting Transmission Owner shall retain operating authority over its facilities and shall have authority to direct or coordinate switching of the Large Load Entity's Interconnection Facilities where such switching may affect the Direct Assignment Facilities or the New England Transmission System. The Large Load Entity shall not perform switching that may energize, de-energize, parallel, isolate, or otherwise materially affect the Interconnecting Transmission Owner's facilities or the New England Transmission System without prior authorization or coordination with the Interconnecting Transmission Owner and, where applicable, the System Operator.

The Parties shall establish and maintain clearly defined operating jurisdiction, switching authority, equipment identification, communication protocols, and clearance/tagging responsibilities at the points of interconnection

8.9 Use of Interconnection Facilities by Third Parties.

8.~~8~~9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Direct Assignment Facilities and the Large Load Entity Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Load Facility to the Administered Transmission System and shall be used for no other purpose.

8.~~8~~9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use the Direct Assignment Facilities, or any part thereof, Large Load Entity will be entitled to compensation for the capital expenses it incurred in connection with the ~~Interconnection~~Direct Assignment Facilities based upon the pro rata use of the ~~Interconnection~~Direct Assignment Facilities by Large Load Interconnecting Transmission Owner, all third party users, and Large Load Entity, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the ~~Interconnection~~Direct Assignment Facilities, will be allocated between Large Load Entity and any third party users based upon the pro rata use of the Direct Assignment Facilities ~~and Large Load Entity Interconnection Facilities~~ by Large Load Interconnecting Transmission Owner, all third party users, and Large Load Entity, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to the Commission for resolution.

8.~~9~~10 Real-Time Operational Obligations. Large Load Entity shall maintain the capability to receive acknowledge, and ~~comply with~~implement real-time operating instructions ~~and dispatch signals from~~issued by ISO-NE ~~and~~, Large Load Eligible Customer, or Interconnecting Transmission Owner~~, including~~ in accordance with applicable ISO New England Operating Documents. Such instructions ~~to reduce, interrupt, or restore~~may include reducing or interrupting load, ~~within the design and safety limitations of the~~limiting increases in load, maintaining load at or below an instructed level, or restoring load. Large Load ~~Facility.~~Entity shall promptly notify ISO-NE, Large Load Eligible Customer, and Interconnecting Transmission Owner of any condition that prevents or materially limits its ability to comply with an operating instruction. Large Load Entity shall maintain demand within its Contract Demand, provide required operating data, and promptly report any condition that could materially affect the New England Transmission System ~~or~~, the ~~Required~~Direct Assignment Facilities, or the Large Load Network Upgrades.

ARTICLE 9. MAINTENANCE

9.1 Large Load Interconnecting Transmission Owner and Large Load Entity Obligations. Large Load Interconnecting Transmission Owner and Large Load Entity shall each maintain their respective facilities in a safe and reliable manner and in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.2 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Large Load Entity shall be responsible for all reasonable expenses including overheads, associated with owning, operating, maintaining, repairing, and replacing the Direct Assignment Facilities, consistent with Appendix C-1 of this Agreement.

ARTICLE 10. PERFORMANCE OBLIGATION, COST RECOVERY, AND CREDIT SUPPORT

10.1 Large Load Entity's Interconnection Facilities. Large Load Entity shall design, procure, construct, install, own and/or control the Large Load Entity's Interconnection Facilities described in Appendix A at its sole expense.

10.2 Direct Assignment Facilities. Large Load Interconnecting Transmission Owner shall design, procure, construct, install, own and/or control Direct Assignment Facilities described in Appendix A at the sole expense of the Large Load Entity.

10.3 LLITO's Network Upgrades. Large Load Interconnecting Transmission Owner shall design, procure, construct, install, and own LLITO's Network Upgrades described in Appendix A. The Large Load Entity shall be responsible for all payments consistent with this Article 10 and Appendix C-2 in consideration for the construction of ~~these~~ LLITO's Network Upgrades.

10.4 Cost Recovery for LLITO's Network Upgrades. Each Large Load Interconnecting Transmission Owner shall include the costs of LLITO's Network Upgrades that meet the

definitions of PTF or non-PTF through the ISO-NE's and applicable Transmission Owner's formula rates for Regional or Local Service (as appropriate), as established under the Settlement Agreement dated June 15, 2020 in Docket Nos. EL16-19-0000 and ER20-2054-000 approved by FERC, as modified and approved from time to time. For avoidance of doubt, each Large Load Interconnecting Transmission Owner finances and constructs the applicable LLITO's Network Upgrades and recovers return on investment, depreciation expense, financing charges, income taxes, operation and maintenance costs, property taxes, administrative expenses, and other ownership costs, including ancillary services, through the formula rate. Costs recovered through the formula rate shall be reduced by the Cost Recovery Charge and any Exit Fee as described in ~~Sections~~Articles 10.~~6~~5 and 10.9 below, as well as in Appendix C-2.

10.5 Cost Recovery Charge. Consistent with Appendix C-2 of this Agreement, in consideration for the construction of the LLITO's Network Upgrades ~~and Interconnection Facilities~~ necessary to facilitate the interconnection of the Large Load Facility to the Administered Transmission System, Large Load Entity agrees to pay the Cost Recovery Charge described in Appendix C-2.

10.6 Initial Provision of Credit Support Prior to Large Load Commercial Operation Date. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of any LLITO's Network Upgrades and Direct Assignment Facilities or any part thereof, Large Load Entity shall provide to Large Load Interconnecting Transmission Owner financial assurance consistent with Appendix D ~~("Credit Support").~~of this Agreement ("Credit Support"). Such Credit Support must be provided in a form reasonably acceptable to the Large Load Interconnecting Transmission Owner and, consistent with the milestones described in Appendix B, be sufficient to cover the costs of the Direct Assignment Facilities and LLITO's Network Upgrades.

~~10.7~~10.7 Credit Support Following the Large Load Commercial Operation Date. Following the Large Load Commercial Operation Date, consistent with Appendix D of this Agreement, Large Load Entity shall provide, in a form reasonably acceptable to the Large Load Interconnecting Transmission Owner, Credit Support sufficient to cover the cost of the Exit Fee described in Appendix C-2 of this Agreement as well as any ongoing amounts due under the Agreement.

10.8 **Maintenance of Credit Support.** Large Load Entity agrees to maintain sufficient Credit Support consistent with Appendix D. and this Article 10. Failure to maintain sufficient Credit Support shall be deemed a Breach consistent with Article 16.

10.89 **Exit Fee.** If, prior to the expiration of or at the end of the Term of the Agreement, the Agreement is terminated or the Large Load Entity disconnects or otherwise ceases operation of the Large Load Facility, Large Load Entity shall, within 30 days of such termination, disconnection, or cessation of operation, pay to Large Load Interconnecting Transmission Owner the Net Book Value of the LLITO's Network Upgrades plus any additional unrecovered costs associated with removal, retirement, decommissioning, site restoration, or other termination-related costs attributable to such facilities, net of any salvage value, as determined by Appendix C-2, as of the date of such termination, disconnection, or cessation of operation ("Exit Fee"). Large Load Interconnecting Transmission Owner shall effectively apply the Exit Fee to reduce the remaining Net Book Value of the LLITO's Network Upgrades. Payment of the Exit Fee shall be in addition to any other costs associated with termination described in this Agreement, including Article 2.4 and Article 16.

10.910 **Reconciliation and No Double Recovery.** Amounts collected from Large Load Entity under this Agreement shall be reconciled against amounts recovered through the ISO-NE OATT, the Large Load Transmission Service Agreement, applicable formula rates, and any retail tariff or special contract. Large Load Interconnecting Transmission Owner and Large Load Eligible Customer shall use Reasonable Efforts to prevent duplicate recovery of the same cost and shall promptly credit or refund any over-collection identified through the applicable reconciliation.

10.1011 **Special Provisions for Affected Systems.** Large Load Entity shall enter into separate agreements to address any Large Load Network Upgrades to any and all Large Load Affected System(s) and Large Load Internal Affected System(s) that are necessary for safe and reliable interconnection of the Large Load Facility as identified by the Large Load Eligible Customer's Large Load System Impact Study.

10.12 **Large Load Distribution Upgrades.** Large Load Entity shall enter into separate agreements to pay for and construct any Large Load Distribution Upgrades identified by the Large Load Eligible Customer's Large Load System Impact Study as described in Appendix A of this Agreement.

ARTICLE 11. INVOICE

11.1 General. Each Party shall submit to the other Party(ies), on a monthly basis, invoices of amounts due for the preceding month, including the Cost Recovery Charge described in Appendix C-2. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party(ies) under this Agreement, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

11.2 Final Invoice for Direct Assignment Facilities. Within six months after completion of the construction of Direct Assignment Facilities, Large Load Interconnecting Transmission Owner shall provide an invoice of the final cost of the construction of Direct Assignment Facilities and shall set forth such costs in sufficient detail to enable Large Load Entity to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Large Load Interconnecting Transmission Owner shall refund to Large Load Entity any amount by which the actual payment by Large Load Entity for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice. Large Load Entity shall pay to Large Load Interconnecting Transmission Owner any amount by which the actual payment by Large Load Entity for estimated costs falls short of the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice. Following the Final Invoice, Large Load Entity is still responsible for all operation, maintenance, and replacement charges consistent with Article 9 and Appendix C-1 of this Agreement.

11.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix ~~F~~FE. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by any Party will not constitute a waiver of any rights or claims the other Party(ies) may have under this Agreement.

11.4 Disputes. In the event of a billing dispute between Large Load Entity and any other Party, any such other Party shall continue to fulfill its obligations under this Agreement so long as the Large Load Entity: (i) continues to make all payments not in dispute; and (ii) pays to such other Party or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Large Load Entity fails to meet these two requirements for continuation of service, then such other Party may provide notice to Large Load Entity of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in the Commission's Regulations at 18 CFR § 35.19a(a)(2)(iii).

11.5 Late Payment Interest Charge. Any charge amounts due hereunder not paid when due shall bear interest at the rate set forth in 18 CFR § 35.19a(a)(2)(iii) from the date such amount was due until date of payment.

ARTICLE 12. EMERGENCIES

12.1 Obligations. Each Party shall comply with the Emergency Condition procedures of ~~the~~ ISO-NE in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

12.2 Notice. Large Load Interconnecting Transmission Owner shall notify Large Load Entity promptly when it becomes aware of an Emergency Condition that affects Direct Assignment Facilities or the New England Transmission System that may reasonably be expected to affect Large Load Entity's operation of the Large Load Facility or the Large Load Entity's Interconnection Facilities. Large Load Entity acknowledges that ISO-NE may also notify Large Load Entity of any such Emergency Condition and such notification will be deemed to meet the requirement of Large Load Interconnecting Transmission Owner to notify Large Load Entity of such Emergency Condition pursuant to this Article 12.2. Large Load Entity shall notify Large Load Interconnecting Transmission Owner and ISO-NE promptly when it becomes aware of an Emergency Condition that affects the Large Load Facility or the Large Load Entity's Interconnection Facilities that may reasonably be expected to affect the New England

Transmission System or Direct Assignment Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Large Load Entity's or Large Load Interconnecting Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall not be delayed pending availability of complete information and be followed as soon as practicable with written notice.

12.3 Immediate Action. Unless, in Large Load Entity's reasonable judgment, immediate action is required to address an Emergency Condition, Large Load Entity shall obtain the consent of Large Load Interconnecting Transmission Owner and ISO-NE prior to performing any manual switching operations at the Large Load Facility or the Large Load Entity's Interconnection Facilities in response to an Emergency Condition either declared by Large Load Interconnecting Transmission Owner or the ISO-NE or otherwise regarding the New England Transmission System. Where such action involves switching of facilities that may affect the New England Transmission System or Direct Assignment Facilities, Large Load Entity shall notify ISO-NE and Interconnecting Transmission Owner as soon as practicable and shall coordinate subsequent switching and restoration with them.

12.4 Large Load Interconnecting Transmission Owner's Authority.

12.4.1 General. Large Load Interconnecting Transmission Owner may take whatever actions or inactions with regard to the New England Transmission System or Direct Assignment Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the New England Transmission System or Direct Assignment Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Large Load Interconnecting Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Load Facility or the Large Load Entity's Interconnection Facilities. ISO-NE and Large Load Interconnecting Transmission Owner may, on the basis of technical considerations, require the Large Load Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to,

directing Large Load Entity to ~~shut down, start up, increase~~reduce or ~~decrease the real~~interrupt load, limit increases in load, maintain load at or below a specified level, manage reactive power ~~output of~~ or power factor within applicable facility capabilities, disconnect the Large Load Facility~~; implementing a reduction or disconnection pursuant to Article 13.4.2; directing the Large Load Entity to assist with black start (if available) or~~, coordinate restoration ~~efforts;~~of load or altering the outage schedules of the Large Load Facility and the Large Load Entity's Interconnection Facilities. Large Load Entity shall comply with all of ISO-NE's and Large Load Interconnecting Transmission Owner's operating instructions concerning Large Load Facility real power ~~and reactive power output~~ within the manufacturer's design limitations of the Large Load Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

12.4.2 Reduction and Disconnection. Large Load Interconnecting Transmission Owner may reduce Interconnection Service or disconnect the Large Load Facility or the Large Load Entity's Interconnection Facilities when such reduction or disconnection is necessary in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. ~~These rights are separate and distinct from any right of curtailment of the ISO-NE and Large Load Interconnecting Transmission Owner pursuant to the Tariff.~~ When Large Load Interconnecting Transmission Owner can schedule the reduction or disconnection in advance, ~~-~~Large Load Interconnecting Transmission Owner shall notify Large Load Entity of the reasons, timing and expected duration of the reduction or disconnection. Large Load Interconnecting Transmission Owner shall coordinate with the Large Load Entity in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Any reduction or disconnection by Large Load Interconnecting Transmission Owner shall continue only for so long as reasonably necessary in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The Parties shall cooperate with each other to restore the Large Load Facility and the New England Transmission System to their normal operating state as soon as practicable in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

12.5 Large Load Entity Authority. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents and the Agreement, the Large Load Entity may take whatever actions or inactions with regard to the Large Load Facility or the Large Load Entity's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Load Facility or the Large Load Entity's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Large Load Entity shall use Reasonable Efforts to minimize the effect of such actions or inactions on the New England Transmission System and Direct Assignment Facilities. Large Load Interconnecting Transmission Owner shall use Reasonable Efforts to assist Large Load Entity in such actions.

12.6 Large Load Eligible Customer Authority. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents and the Agreement, the Large Load Eligible Customer may, consistent with Good Utility Practice take whatever actions or inactions with regard to the Large Load Facility or the Large Load Entity's Interconnection Facilities during an Emergency Condition in order to protect Large Load Eligible Customer's system and facilities.

12.7 ISO-NE Authority. Each Party acknowledges that the ISO-NE shall have the authority to take action in an Emergency Condition consistent with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, including the curtailment or disconnection of the Large Load Facility. Large Load Entity shall comply with any ~~lawful order~~directive issued or action required by ISO-NE in an Emergency Condition.

12.8 Limited Liability. Except as otherwise provided in this Agreement, a Party shall not be liable to another Party for any action it or the ISO-NE takes in responding to an Emergency Condition so long as such action is made in good faith and in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 13. REGULATORY REQUIREMENTS, OATT AND GOVERNING LAW

13.1 Regulatory Requirements. Each Party's obligations under this Agreement are subject to receipt of any approval, certificate, permit, acceptance, or authorization required by a Governmental Authority and the ISO-NE OATT. Each Party shall in good faith use Reasonable Efforts to obtain required approvals and shall not take action inconsistent with a mandatory Commission order, the ISO-NE OATT, or Applicable Laws and Regulations. If a regulatory condition materially impairs performance, the Parties shall negotiate in good faith to address it, subject to the Commission's jurisdiction.

13.2 Governing Law.

13.2.1. The validity, interpretation, and performance of this Agreement and each of its provisions shall be governed by the laws of the State in which the Interconnection Point is located, without regard to its conflict-of-laws principles, except to the extent federal law or the Commission's jurisdiction controls.

13.2.2. This Agreement is subject to the Federal Power Act, the Commission's rules and orders, the ISO-NE OATT, the Large Load Transmission Service Agreement, applicable retail tariffs or approved retail special contracts, and all other Applicable Laws and Regulations.

13.2.3. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any law, order, rule, regulation, tariff provision, or determination of a Governmental Authority, subject to the Federal Power Act and Applicable Laws and Regulations.

13.3 OATT Incorporation by Reference. The applicable provisions of the ISO-NE OATT, including provisions governing ~~transmission service,~~ Direct Assignment Facilities, Large Load Network Upgrades, creditworthiness, metering, operations, outage coordination, rate recovery, and dispute resolution, are incorporated into this Agreement by reference, as amended from time to time and accepted by the Commission. If this Agreement conflicts with a mandatory provision of the ISO-NE OATT, the mandatory OATT provision controls to the extent of the conflict.

ARTICLE 14. NOTICES

14.1 General. Unless otherwise provided in this Agreement, any notice, demand, or request required or permitted to be given by a Party to another Party, and any instrument required or permitted to be tendered or delivered in writing, shall be effective when delivered by recognized national courier, certified or registered mail, personal delivery, or another method permitted by this Agreement, addressed to the Party at the address set out in Appendix ~~F~~E (Addresses for Notices and Billings).

A Party may change the notice information in this Agreement by giving five (5) Business Days written notice prior to the effective date of the change.

14.2 Billings and Payments. Billings and payments shall be sent to the addresses and remittance contacts set out in Appendix ~~F~~E and administered in accordance with Article ~~5~~11.

14.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to another Party and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix ~~F~~E.

14.4 Operations and Maintenance Notice. Each Party shall notify the other Parties in writing of the identity of the person or persons it designates as the point of contact for implementing Articles ~~10~~8 and ~~11~~9.

ARTICLE 15. FORCE MAJEURE

15.1 Force Majeure.

15.1.1 Economic hardship is not considered a Force Majeure event.

15.1.2 A Party shall not be considered to be in Default with respect to an obligation other than the obligation to pay money when due if prevented from fulfilling that obligation by Force Majeure. The affected Party shall notify the other Parties of the Force Majeure and its

particulars as soon as reasonably possible, confirm any telephone notice in writing, and exercise due diligence to remove the disability with reasonable dispatch. The affected Party shall not be required to accept terms that are unsatisfactory to it to settle a strike or other labor disturbance.

ARTICLE 16. DEFAULT, EVENTS OF DEFAULT AND REMEDIES

16.1 Events of Default.

16.1.1 General. An Event of Default occurs when a Party fails to perform a material obligation under this Agreement, the ISO-NE OATT, the Large Load Transmission Service Agreement, or an applicable retail special contract and the failure is not excused by Force Majeure or the act or omission of another Party. Failure to pay money when due is not excused by Force Majeure. An Event of Default includes any event described in ~~Sections~~Articles 16.1.2 through 16.1.4.

16.1.2 Large Load Entity Events of Default. Each of the following is an Event of Default by Large Load Entity: (i) failure to pay an amount due under this Agreement or ~~the~~under any applicable ~~retail arrangement~~tariff or rate schedule of, or agreement with Large Load Eligible Customer; (ii) failure to post, maintain, replace, or replenish~~, or replace~~ required Credit Support; (iii) actual demand for the Large Load Facility exceeding ~~Contract Demand~~the amount of Large Load Eligible Customer's reserved FCDS, ICDS, or NFCDS for the Large Load Facility as applicable or failure to comply with a lawful operating instruction issued by another Party or ISO-NE; (iv) a material misrepresentation or failure to provide required project, load, financial, or operating information; (v) unauthorized assignment; (vi) insolvency, bankruptcy, or an assignment for the benefit of creditors; or (vii) cancellation, suspension, downsizing, or abandonment of the Large Load project without paying the any resulting ~~Cost Responsibility and Stranded Cost Responsibility~~amounts due under the Agreement, including the Exit Fee.

16.1.3 Large Load Interconnecting Transmission Owner, Large Load Eligible Customer, or ISO-NE Events of Default. To the extent applicable and permitted by the ISO-NE OATT, the Large Load Transmission Service Agreement, and Applicable Laws and Regulations, a material failure by Large Load Interconnecting Transmission Owner, Large Load Eligible

Customer, or ISO-NE to perform an obligation expressly assigned to it under this Agreement, after the applicable cure period, is an Event of Default by that Party. A tariff-directed action, outage, curtailment, or emergency action taken in accordance with the ISO-NE OATT, the Large Load Transmission Service Agreement, Applicable Reliability Standards, or a Commission order is not an Event of Default.

16.1.4 Notice and Cure. A failure to pay any obligation under this Agreement or replenish Credit Support shall be cured within five (5) Business Days after written notice, unless the applicable tariff or security instrument requires a shorter period. Any other curable failure shall be cured within thirty (30) Calendar Days after written notice; provided that, if the failure cannot reasonably be cured within thirty (30) Calendar Days, the Breaching Party shall begin cure within that period and diligently complete it within ninety (90) Calendar Days. ~~An~~Notwithstanding the foregoing, upon an insolvency or bankruptcy event affecting the Large Load Entity, unauthorized assignment, ~~or~~ demand exceedance, or failure of the Large Load Entity to provide or maintain required Credit Support, the Large Load Entity shall not be subject to the foregoing cure periods, and the Large Load Interconnecting Transmission Owner may ~~be treated as~~ immediately ~~actionable to the extent permitted by Applicable Laws and Regulations and the ISO-NE OATT~~exercise the remedies available under Article 16.2.

16.2 Remedies. If an Event of Default is not cured within the applicable period, the non-defaulting Party may, subject to the ISO-NE OATT, the Large Load Transmission Service Agreement, Applicable Laws and Regulations, and any required Commission approval, (i) suspend or terminate the affected service; (ii) terminate this Agreement; (iii) recover all amounts due, including the Exit Fee, and documented costs of enforcement; (iv) seek damages, specific performance, injunctive relief, or other relief at law or in equity; and (v) exercise any additional right under the ISO-NE OATT, the Large Load Transmission Service Agreement, or an applicable retail arrangement. The non-defaulting Party shall use Reasonable Efforts to mitigate avoidable losses.

16.3 Draw on Security. Large Load Interconnecting Transmission Owner may draw on or apply Credit Support upon an Event of Default to satisfy any amounts due or reasonably expected to become due, including the Exit Fee, termination costs, or any other obligations of Large Load Entity. Any draw shall be credited against the amount owed but shall not limit Large Load Entity's obligation to replenish the Credit Support or pay any remaining balance.

16.4 FERC Complaints and Regulatory Remedies. Nothing in this Article limits a Party's right to file a complaint, petition, or other pleading with the Commission under Section 206 or Section 306 of

the Federal Power Act, 16 U.S.C. §§ 824e and 825e, or to seek relief under any other applicable provision of the Federal Power Act. A Party may request Commission action concerning rates, terms, conditions, cost recovery, security, service termination, or any other matter within the Commission's jurisdiction, and no informal process or ADR procedure is a condition to exercising that right where immediate regulatory relief is appropriate.

16.5 Cumulative Remedies and Survival. The remedies in this Article are cumulative and are in addition to remedies available under the ISO-NE OATT, the Large Load Transmission Service Agreement, an applicable retail tariff or special contract, the Federal Power Act, or other Applicable Laws and Regulations. The payment, security, indemnity, audit, confidentiality, dispute, and cost-responsibility provisions shall survive termination to the extent necessary to enforce accrued or surviving obligations.

ARTICLE 17. INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

Notwithstanding any other provision of this Agreement, the liability, indemnification, and insurance provisions of the Transmission Operating Agreement, the ISO-NE OATT, and the Large Load Transmission Service Agreement or other applicable operating agreements govern the relationship between Large Load Interconnecting Transmission Owner and Large Load Eligible Customer, and the liability, indemnification, and insurance provisions of ~~the ISO-NE OATT, the Large Load Transmission Service Agreement, and~~ applicable ~~retail arrangements~~state tariffs and special contracts govern the corresponding relationships involving Large Load Eligible Customer and Large Load Entity, except to the extent this Agreement expressly provides otherwise.

17.1 Indemnity. Each Party shall at all times indemnify, defend, and hold the other Parties harmless from ~~Loss~~any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties arising out of the indemnifying Party's performance or non-performance of its obligations under this Agreement, except to the extent caused by the gross negligence or intentional wrongdoing of an indemnified Party~~. Without limiting the foregoing, Large Load Entity shall indemnify and hold harmless Large Load Eligible Customer, if applicable, for Loss caused by Large Load Entity's failure to comply with Article 4 or Article 10.~~ ("Loss")..

17.1.1 Indemnified Person. If an Indemnified Person is entitled to indemnification under this Article ~~17~~ as a result of a third-party claim and the Indemnifying Party fails, after notice and a reasonable opportunity, to assume the defense, or if the Indemnifying Party is not permitted to assume the defense as provided below, the Indemnified Person may, at the Indemnifying Party's expense, contest, settle, consent to judgment, or pay the claim.

17.1.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold an Indemnified Person harmless under this Article ~~17~~, the amount owing shall be the Indemnified Person's actual Loss, net of insurance or other recovery.

17.1.3 Indemnity Procedures. Promptly after receipt by an Indemnified Person of any written claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 17.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

~~The~~If the Indemnifying Party acknowledges in writing its responsibility for the Loss resulting from the claim or proceeding, the Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional ~~attorney~~law firm to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in which event the Indemnifying Party shall pay the reasonable costs and expenses (including legal fees) of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

17.2 Consequential Damages. Except for amounts expressly payable as Exit Fees, security replenishment, or other agreed payment obligations, no Party shall be liable under this Agreement for special, indirect, incidental, consequential, or punitive damages, including loss of profit or revenue, loss of use of equipment, cost of capital, or cost of temporary equipment or services, whether based in contract, tort, negligence, strict liability, or any other theory. Damages recoverable under another agreement shall not be treated as consequential damages under this ~~Section~~Article.

17.3 Insurance. Large Load Interconnecting Transmission Owner and Large Load Entity shall, at their own expense, maintain in force throughout the Term and until released by the other Parties the minimum insurance coverages stated in this Article ~~17~~.3, with insurers authorized to do business in the State in which the Interconnection Point is located:

17.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the State in which the Interconnection Point is located.

17.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage

(including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death, and property damage.

17.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

17.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

17.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party(ies), its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this Agreement against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

17.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only

one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

17.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

17.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

17.3.9 Within ten (10) days following execution of this Agreement, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this Agreement, executed by each insurer or by an authorized representative of each insurer.

17.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 17.3.2 through 17.3.8 to the extent it maintains a self-insurance program, provided that such Party's senior secured debt is rated at investment grade, or better, by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 17.3.2 through 17.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 17.3.2 through 17.3.9. In the event that a Party is permitted to self-insure pursuant to this Article, it shall notify the other Party(ies) that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 17.3.9.

17.3.11 The Parties agree to report to each other in writing as soon as ~~practical~~practicable any and all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Agreement.

ARTICLE 18. ASSIGNMENT

18.1 Assignment. This Agreement may be assigned by any Party only with the written consent of the other Parties; provided that the Parties may assign this Agreement without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority, operational authority, and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Large Load Entity shall have the right to assign this Agreement, without the consent of any other Party, for collateral security purposes to aid in providing financing for the Large Load Facility, provided that the Large Load Entity will promptly notify all other Parties of any such assignment. Any financing arrangement entered into by the Large Load Entity pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify each other Party of the date and particulars of any such exercise of assignment right(s), including providing Large Load Interconnecting Transmission Owner with proof that it meets all the requirements of this Agreement. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 19. SEVERABILITY

19.1 Severability. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

ARTICLE 20. COMPARABILITY

20.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

ARTICLE 21. CONFIDENTIALITY

21.1 Confidentiality. Confidential Information shall include, without limitation, all information governed by the ISO New England Information Policy, Critical Energy Infrastructure Information, all information obtained from third parties under confidentiality agreements, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by a Party to another prior to the execution of this Agreement.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by a Party, the other Party(ies) shall provide, in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

21.1.1 Term. During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article 21, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

21.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Agreement; or (6) is required, in accordance with Article 21.1.7 of the Agreement, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party(ies) that it no longer is confidential.

21.1.3 Release of Confidential Information. A Party shall not release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or are considering providing financing to or equity participation with Large Load Entity, or to potential purchasers or assignees of Large Load Entity, on a need-to-know basis in connection with this Agreement, unless such person has first been advised of the confidentiality provisions of this Article 21 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 21.

21.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party(ies). The disclosure by each Party to the other Party(ies) of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

21.1.5 No Warranties. By providing Confidential Information, a Party does not make any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, a Party does not obligate itself to provide any particular information or Confidential Information to the other Party(ies) nor to enter into any further agreements or proceed with any other relationship or joint venture.

21.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party(ies) under this Agreement or its regulatory requirements.

21.1.7 Order of Disclosure. If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party(ies) with prompt notice of such request(s) or requirement(s) so that the other Party(ies) may seek an appropriate protective order or waive compliance with the terms of this Agreement. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

21.1.8 Termination of Agreement. Upon termination of this Agreement for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party(ies), use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party(ies)) or return to the other Party(ies), without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party(ies).

21.1.9 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's(ies') Breach of its obligations under this Article 21. Each Party accordingly agrees that the other Party(ies) shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 21, which equitable relief shall be granted without bond or proof of damages, and the receiving Parties shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 21, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 21.

21.1.10 Disclosure to the Commission, its Staff, or a State. Notwithstanding anything in this Article 21 to the contrary, and pursuant to 18 CFR. section 1b.20, if the Commission or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to the Commission or its staff, within the time provided for in the request for information. In providing the information to the Commission or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by the Commission and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party(ies) to this Agreement prior to the release of the Confidential Information to the Commission or its staff. The Party shall notify the other Party(ies) to the Agreement when it is notified by the Commission or its staff that a request to release Confidential Information has been received by the Commission, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

21.1.11 Subject to the exception in Article 21.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this Agreement ("Confidential Information") shall not be disclosed by the other Party(ies) to any person not employed or retained by the other Party(ies), except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party(ies), such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Agreement or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party(ies) in writing of the information it claims is confidential. Prior to any disclosures of the other Parties' Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party(ies) in writing and agrees to assert confidentiality and cooperate with the other Party(ies) in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 22. ENVIRONMENTAL RELEASES

22.1 Each Party shall notify the other Parties, first orally and then in writing, of the release of any Hazardous Substances, asbestos or lead abatement activities, or remediation activities related to the Large Load Facility, the LLEIF, or the Required Facilities that may reasonably be expected to affect another Party. The notifying Party shall provide notice as soon as practicable, using a good-faith effort to notify the other Parties no later than twenty-four (24) hours after becoming aware of the occurrence, and shall promptly furnish copies of publicly available reports filed with Governmental Authorities.

ARTICLE 23. INFORMATION REQUIREMENTS

23.1 Information Acquisition. Subject to confidentiality, code-of-conduct, and cybersecurity restrictions, each Party shall provide information reasonably necessary to 1) administer the ISO-NE OATT and this Agreement; 2) plan and operate the New England Transmission System, LLITO's Network Upgrades, the Direct Assigned Facilities, and the LLEIF; 3) calculate any charges, payments, or amounts due under this Agreement; 4) monitor contract demand quantities for transmission service; and 5) comply with Applicable Reliability Standards.

23.2 Information Submission by Large Load Interconnecting Transmission Owner. Upon request, Large Load Interconnecting Transmission Owner shall provide Large Load Entity and Large Load Eligible Customer the tariff, operating, facility, schedule, cost, and service information reasonably necessary to construct the Direct Assignment Facilities and LLITO's Network Upgrades. Upon request, Large Load Interconnecting Transmission Owner shall provide periodic status reports addressing scope, progress, expected in-service dates, costs incurred, and projected costs.

23.3 Information Submission by Large Load Entity. Large Load Entity shall submit and certify current information reasonably required by ISO-NE, Large Load Interconnecting Transmission Owner, and Large Load Eligible Customer no later than 60 days prior to the Service Commencement Date and thereafter upon request or material change. The submission shall include the Large Load Facility's site, facility type, Contract Demand, Maximum Forecast Demand, load forecasts, operating characteristics, power-quality characteristics, metering and telemetry configuration, use of onsite or behind-the-meter resources, development schedule, and information required under the applicable the ISO-NE OATT data requirements. Large Load Entity shall also submit to ISO New England and Large Load Eligible Customer any information or data necessary to procure transmission service under the ISO-NE OATT.

23.3.1 Changed Data and Additional Analysis. If information provided by Large Load Entity differs materially from information used to establish the Large Load Service Request, Contract Demand, or Required Facilities, ISO-NE or Large Load Interconnecting Transmission Owner may require additional planning, reliability, metering, or cost analyses at Large Load Entity's expense. Large Load Entity shall not increase its service level or operate outside its approved configuration until any required analysis is complete and all necessary approvals have been obtained. Large Load Entity agrees to provide any

such data requested by the ISO-NE or the Large Load Interconnecting Transmission Owner.

23.4 Information Supplementation. Before the Service Commencement Date and periodically thereafter, Large Load Entity shall provide current as-built, as-operated, as-tested, and metering information that differs from prior submissions, or written confirmation that no material differences exist. Large Load Entity shall provide additional information and perform tests reasonably required by ISO-NE, Large Load Interconnecting Transmission Owner, Large Load Eligible Customer, Good Utility Practice, the ISO-NE OATT, or Applicable Reliability Standards.

23.5 Material Equipment Changes. Large Load Entity shall provide ISO-NE, Large Load Interconnecting Transmission Owner, and Large Load Eligible Customer information regarding proposed equipment replacement, repair, adjustment, expansion, or control changes that could affect load, metering, protection, power quality, service level, Contract Demand, or the Required Facilities. Large Load Interconnecting Transmission Owner shall provide information regarding changes to Large Load Interconnecting Transmission Owner-owned facilities that could affect Large Load Entity's equipment ratings, protection, metering, or operating requirements. The Parties shall provide and update this information in accordance with this Article 23 and the ISO-NE OATT.

ARTICLE 24. INFORMATION ACCESS AND AUDIT RIGHTS

24.1 Information Access. Each Party shall make available to the other Parties information in its possession that is reasonably necessary to verify costs, invoices, workpapers, amounts due, any charges under this Agreement, supplemental payments, security amounts, and compliance with this Agreement, the ISO-NE OATT, the Large Load Transmission Service Agreement, and applicable retail arrangements. Information shall be used only to administer or enforce those instruments and shall remain subject to Article 21.

24.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party(ies) when the notifying Party becomes aware of its inability to comply with the

provisions of this Agreement for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle the Party receiving such notification to allege a cause for anticipatory Breach of this Agreement.

24.3 Audit Rights. Subject to Article 21, each Party may, during normal business hours and upon reasonable notice, audit at its own expense another Party's accounts and records relating to performance or satisfaction of obligations under this Agreement, the ISO-NE OATT, the Large Load Transmission Service Agreement, or an applicable retail arrangement. Audit rights include costs and invoices for Required Facilities and Direct Assignment Facilities, formula-rate calculations, Revenue Requirement Credits, supplemental payments, security and Exit Fee calculations, ~~allocations to other customers~~, metering data, outage and emergency actions, and compliance with Contract Demand and operating requirements. Audits shall be limited to relevant records and shall not unreasonably disrupt operations.

24.4 Audit Rights Periods.

24.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, financing, and construction of Required Facilities, including Direct Assignment Facilities and LLITO's Network Upgrades, shall be subject to audit for twenty-four (24) months after Large Load Interconnecting Transmission Owner's final invoice or true-up under Article 11.2, or after the applicable facilities are placed in service, whichever is later.

24.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to a Party's performance or satisfaction of all obligations under this Agreement other than those described in Article 24.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four (24) months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit

rights period shall be twenty-four (24) months after the event for which the audit is sought.

24.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party(ies) together with those records from the audit which support such determination.

ARTICLE 25. SUBCONTRACTORS

25.1 General. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party(ies) for the performance of such subcontractor.

25.2 Responsibility of Principal. The creation of a subcontract relationship shall not relieve the hiring Party of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor it hires as if no subcontract had been made. Any obligation imposed on the hiring Party shall be equally binding upon, and construed to apply to, its subcontractors.

25.3 No Limitation by Insurance. The obligations under this Article 25 shall not be limited by any limitation of a subcontractor's insurance.

ARTICLE 26. DISPUTES

26.1 Submission and Informal Resolution. In the event of a dispute or claim arising out of or relating to this Agreement, the disputing Party shall provide the other Parties with a written Notice of Dispute. The dispute shall be referred promptly to designated senior representatives for informal resolution. The representatives shall meet or confer within ten (10) Business Days and shall use

Reasonable Efforts to resolve the matter within thirty (30) Calendar Days after receipt of the Notice of Dispute. This informal process is not a condition to seeking emergency relief, filing a FERC complaint, or invoking any ADR processes.

26.2 Alternative Dispute Resolution. If a dispute is not resolved informally, any Party may request Alternative Dispute Resolution ("ADR") to the extent contemplated by the ISO-NE OATT. The Parties shall use the ADR procedures, neutral-selection process, confidentiality protections, and timing requirements specified in the ISO-NE OATT or applicable Commission rules. ADR shall be conducted by persons knowledgeable in electric utility, transmission, and FERC matters and shall not alter a jurisdictional rate, term, or condition unless accepted or approved by the Commission.

26.3 FERC Complaints and Other Rights. Any Party may instead file a complaint, petition, or other pleading with the Commission under Section 206 or Section 306 of the Federal Power Act, seek relief under Section 205 or another applicable provision, or exercise rights under the ISO-NE OATT, the Large Load Transmission Service Agreement, an applicable retail arrangement, or Applicable Laws and Regulations. No Party's participation in informal negotiations or ADR waives or limits its right to seek Commission action. A final ADR determination affecting jurisdictional rates, terms, conditions, charges, Required Facilities, or LLITO's Network Upgrades shall be filed with the Commission if required.

26.4 Costs and Interim Performance. Unless otherwise determined through ADR, the Parties shall bear their own costs and share neutral costs as specified by the applicable ADR procedure. During a dispute, each Party shall continue performing undisputed payment and operational obligations, and shall pay undisputed amounts when due. A dispute shall not prevent a Party from taking action authorized by the ISO-NE OATT, ISO-NE Operating Documents, the Large Load Transmission Service Agreement, Applicable Reliability Standards, or an Emergency Condition procedure.

ARTICLE 27. REPRESENTATIONS, WARRANTIES AND COVENANTS

27.1 General. Each Party makes the following representations, warranties and covenants:

27.1.1 Good Standing. Such Party is duly organized, validly existing, and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; is qualified to do business in the state or states in which the Large Load Facility and Required Facilities owned by such Party are located; and has the corporate power and authority to own its properties, carry on its business, enter into this Agreement, and perform the covenants and obligations assigned to it.

27.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a Party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

27.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

27.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

ARTICLE 28. MISCELLANEOUS

28.1 Binding Effect. This Agreement and the rights and obligations hereof shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

28.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendix, exhibit, or schedule, the body of this Agreement shall prevail as the final intent of the Parties. A mandatory provision of the ISO-NE OATT, a Commission order, or Applicable Laws and Regulations shall control over any conflicting provision of this Agreement.

28.3 Rules of Interpretation. Unless a clear contrary intention appears: (1) the singular includes the plural and vice versa; (2) a reference to a person includes its permitted successors and assigns; (3) a reference to an agreement, document, instrument, tariff, or rule means that instrument as amended and in effect from time to time in accordance with its terms and Applicable Laws and Regulations; (4) a reference to Applicable Laws and Regulations means those laws and regulations as amended, modified, codified, or reenacted; (5) a reference to an Article, Section, Appendix, or schedule means the corresponding provision of this Agreement or the ISO-NE OATT, as applicable; (6) "hereunder," "hereof," "herein," and similar terms refer to this Agreement as a whole; (7) "including" means including without limitation; and (8) "from," "to," and "through" have the inclusive or exclusive meanings stated in the context.

28.4 Entire Agreement. Except for the ISO-NE OATT, ISO New England Operating Documents, Applicable Reliability Standards, the Large Load Transmission Service Agreement, applicable retail tariffs or approved retail special contracts, related facilities agreements, and Commission orders, this Agreement, including its Appendices, constitutes the entire agreement among the Parties concerning its subject matter and supersedes prior contemporaneous understandings or agreements concerning that subject matter. No other representation, warranty, or covenant forms part of the consideration for a Party's obligations unless stated in this Agreement or a governing instrument identified in this ~~Section~~Article 28.4.

28.5 No Third Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

28.6 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty. Termination or Default of this Agreement for any reason shall not waive a Party's rights under the ISO-NE OATT, the Large Load Transmission Service Agreement, an applicable retail arrangement, the Federal Power Act, or other Applicable Laws and Regulations. Any waiver shall, if requested, be provided in writing.

28.7 Headings. The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

28.8 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

28.9 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

28.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

28.11 Reservation of Rights. Consistent with the ISO-NE OATT, the Federal Power Act, and the Commission's rules, Large Load Interconnecting Transmission Owner Large Load Eligible Customer, and Large Load Entity reserve all rights to make filings with the Commission under Section 205, Section 206, Section 306, or any other applicable provision of the Federal Power Act concerning this Agreement, rates, terms, conditions, charges, classifications of service, security,

cost recovery, or service termination. Each Party may protest or participate fully in any proceeding concerning another Party's filing. Nothing in this Agreement limits the rights of a Party or the Commission, except to the extent the Parties may lawfully agree otherwise and the Commission accepts or approves that agreement.

28.12 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

[signature page follows]

IN WITNESS WHEREOF, the Parties have executed this Agreement in triplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

[SIGNATURE BLOCKS]

Appendices

[table of contents to come]

APPENDIX A

Large Load Identification and Required Facilities

1. Large Load Identification:

a. Site, Interconnection Point, and Service Characteristics

b. **Large Load Entity and Large Load Facility Details**

~~c. Large Load Interconnecting Transmission Owner and Large Load Eligible Customer Service, Ownership, and Billing Details~~

2. Direct Assignment Facilities:

a.

b.

c.

3. LLITO's Network Upgrades:

4. Large Load Distribution Upgrades:

5. Large Load Entity Interconnection Facilities:

6. Metering Equipment:

APPENDIX A-1

Required Facilities and Interconnection Point Diagram

Contains Critical Energy Infrastructure Information – Do Not Release

APPENDIX A-2

Interconnection Point and Ownership Diagram

Contains Critical Energy Infrastructure Information – Do Not Release

APPENDIX B

Milestones

Item No.	Milestone Description	Responsible Party	Date	Reference
1	Provide LLITO with ~~Initial Security~~Credit Support pursuant to Article 10~~.7~~ and Appendix D	Large Load Entity	Within 15 Business Days of Agreement ("LLCRA") execution OR at least 30 Calendar Days prior to Milestone 3 Notice to Proceed design & long lead material procurement	
2	Provide certificate of insurance	Large Load Entity and Large Load Interconnecting Transmission Owner	Within 10 Calendar Days of execution of LLCRA	
3	Provide LLITO with Notice To Proceed with Engineering and Design Activities and ordering of long lead time material for Direct Assignment Facilities and LLITO's Network Upgrades	Large Load Entity	Date:	
4	Provide siting & permitting approval for Large Load Facility and LLEIF to Large Load Interconnecting Transmission Owner	Large Load Entity & Large Load Interconnecting Transmission Owner	Prior to Milestone 8	

5	Obtain necessary real property rights and rights-of-way for the construction of the Direct Assignment Facilities and LLITO's Network Upgrades	Large Load Entity and/or Large Load Interconnecting Transmission Owner	Date:	
6	Provide LLITO with ~~Additional Security~~additional Credit Support pursuant to Article 10~~.7~~ and Appendix D	Large Load Entity	30 Calendar Days prior to ~~[~~Milestone 7~~]~~	
7	Provide to Large Load Interconnecting Transmission Owner written authorization to proceed with equipment procurement and construction for all Direct Assignment Facilities and LLITO's Network Upgrades	Large Load Entity	Date:	
8	Provide initial design, engineering and specification for Large Load Entity's Interconnection Facilities to Large Load Interconnecting Transmission Owner	Large Load Entity	Date:	

9	Provide comments on initial design, engineering and specifications for Large Load Entity's Interconnection Facilities	Large Load Interconnecting Transmission Owner	Within 30 Calendar Days of receipt	
10	Provide final design, engineering and specifications for Large Load Entity's Interconnection Facilities to Large Load Interconnecting Transmission Owner	Large Load Entity	Within 180 calendar days prior to ~~ISD~~In Service Date of the LLITO Network Upgrades and Direct Assignment Facilities	
11	Provide comments on final design, engineering and specification for Direct Assignment Facilities	Large Load Interconnecting Transmission Owner	Within 30 Calendar Days of receipt	
~~12~~	~~Deliver to Transmission Owner "as built" drawings, information and documents regarding Large Load Entity's Interconnection Facilities~~	~~Large Load Entity~~	~~At least 120 Calendar Days prior to In Service Date of Interconnection Facilities and LLITO's Network Upgrades [Milestone 17]~~	
~~13~~12	Provide protective relay settings to Large Load Interconnecting Transmission Owner for coordination and verification	Large Load Entity	At least 90 Calendar Days prior to In Service Date of ~~Interconnection~~Direct Assignment Facilities and LLITO's Network Upgrades ~~[Milestone 17]~~	

~~14~~13	Provide LLITO with 100% ~~security~~Credit Support associated with LLITO's Network Upgrades~~-~~, Exit Fee, and Cost Recovery Charge consistent with Article 10 and Appendix D.	Large Load Entity	At least 30 Calendar days prior to ~~Commencement~~commencement of ~~Construction [Milestone 15]~~construction	
~~15~~14	Commencement of construction of Direct Assignment Facilities and LLITO's Network Upgrades	Interconnecting Transmission Owner	Date:	
16	Commencement of Construction of Large Load Facility and /or LLEIF	Large Load Entity	Date:	
17	In Service Date of Direct Assignment Facilities and LLITO's Network Upgrades	Large Load Interconnecting Transmission Owner	Date:	
18	Submit all supplemental and/or updated ~~data~~ "as -built~~/as-tested""~~ information for Large Load Facility or LLEIF	Large Load Entity	Prior to Large Load Commercial Operation Date	
19	Large Load Commercial Operation Date of Large Load Facility	Large Load Entity	Date:	

20	Deliver to ~~Interconnection Customer~~Large Load Entity "as built" drawings, information and documents regarding ~~Large Load Interconnecting Transmission Owner's Interconnection~~Direct Assignment Facilities	Large Load Interconnecting Transmission Owner	If requested, within 120 Calendar Days after Large Load Commercial Operation Date	
21	Provide Large Load Entity with final cost invoices for Direct Assignment Facilities. Release ~~Financial Security~~any Credit Support for Direct Assignment Facilities.	Large Load Interconnecting Transmission Owner	Within ~~10~~6 months of completion of construction ~~of Large Load Interconnecting Transmission Owner Interconnection~~Direct Assignment Facilities	
~~22~~	~~Commencement of cost recovery for LLITO's Network Upgrades~~	~~Large Load Interconnecting Transmission Owner~~	~~Upon LLITO placing LLITO's Network Upgrades in service [Milestone 17]~~	

APPENDIX C

FACILITY DETAILS

1. Large Load Project and Service Description: ~~[DRAFTING NOTE: Insert the facility type, site description, requested service date, and service configuration.]~~

2. Large Load Facility and Demand:

3. Required Facilities and Applicable Study:

4. Metering and Telemetry:

5. Permits and Site Rights:

APPENDIX C-1

Annual Facilities Charge and Capital Replacement Reimbursement for Direct Assignment Facilities

~~[TO specific]~~

[To be determined by the individual LLITO]

APPENDIX C-2

Cost Recovery Charge

Purpose:

The purpose of the Cost Recovery Agreement ("CRA") is ~~the mechanism used~~ to ensure that the Large Load ~~Customer~~Entity is financially responsible for~~,~~ and pays ~~the~~Large Load ~~Customer~~ Revenue Requirements ("~~LCRRs~~LLRR") associated with the Large Load ~~Customer's~~Entity's cost of ~~the Required Facilities~~LLITO's Network Upgrades on the Large Load Interconnecting Transmission Owner's ~~("ITO")~~ system~~. The CRA ensures~~ such that there is no ~~cost shifting to~~rate impact caused by the LLRR on other transmission customers ~~because of the LCRR.~~. The Large Load Eligible Customer taking transmission service on behalf of the Large Load Entity, as applicable, will have ~~-~~two transmission services to select from~~,~~: Firm Contract Demand Service ("FCDS") ~~or~~Non~~or~~ Non-Firm Contract Demand Service ("NFCDS"). Interim Contract Demand ("ICDS") is applicable before Large Load Network Upgrades are completed and placed into service, and before the Large Load ~~Transmission~~Eligible Customer has designated, or has caused to be designated, sufficient capacity resources to serve the Large Load.

The Cost Recovery Charge ("CRC"):

The CRC is a make-whole provision that covers the difference between ~~LCRR~~LLRR and the amount to be paid by the Large Load Eligible Customer through the selected transmission service (FCDS, NFCDS, and/or ICDS~~).~~) to eliminate the rate impact of the LLRR on other transmission customers. The CRC is paid by the Large Load ~~Customer~~Entity to the ~~ITO~~LLITO and applied as a credit against the ~~ITO's~~LLITO's applicable regional and/or local revenue requirements. ~~The obligation is imposed to ensure~~ In the event that ~~incremental costs of serving~~ the Large Load Entity and the Large Load Eligible Customer are ~~not shifted to existing or other customers.~~ the same entity, that entity pays the CRC.

FCDS CRC Calculation:

~~The ITO~~Annually the LLITO establishes the regional and/or local ~~LCRR~~LLRR for the Large Load ~~Customer's share of the~~Entity's gross cost of ~~the Required Facilities~~LLITO's Network Upgrades, based on the ~~ITO's~~LLITO's annual carrying charge factor (pursuant to the ~~ITO's~~LLITO's FERC approved annual transmission formula rate), while the Large Load Eligible Customer provides a Firm Contract Demand ("FCD") requirement. If the Large Load ~~Customer's share of the LCRR~~Entity's LLRR exceeds the payments expected to be collected from the Large Load Eligible Customer under its FCDS based on the applicable annual RNS or LNS rate, the difference is a supplemental CRC payment. If the Large Load Eligible Customer's FCDS payment based on the applicable RNS or LNS rate is equal to or exceeds the ~~LCRR~~LLRR, there is no supplemental CRC required.

- **Step 1: Calculate LLRR**

LLRR = Gross cost of LLITO's Network Upgrades × LLITO Regional or Local Carrying Charge Factor

- **Step 2: Calculate FCDS Charge**
  FCDS Charge = FCD × RNS or LNS Rate

- **Step 3: Calculate Annual CRC**
  Annual CRC = LLRR − FCDS Payment if LLRR > (FCDS Payment)
  0 if LLRR ≤ FCDS Payment

- **Step 4: Calculate Monthly CRC**
  Monthly CRC = Annual CRC/12

LLRR = Large Load Entity's Local or Regional Cost Responsibility Revenue Requirement
LLITO Carrying Charge Factor = Annual Regional or Local network service rate carrying charge factor as established under the Settlement Agreement dated June 15, 2020 in Docket Nos. EL16-19-0000 and ER20-2054-000 approved by FERC, as modified and approved from time to time.
FCDS Payment = Large Load Eligible Customer's Firm contract demand times RNS or LNS Rate in effect for service year.
FCD = Large Load Eligible Customer's Firm Contract Demand (MW)
RNS/LNS Rate = Applicable annual Regional Network Service or Local Network Service rate ($/MW-year)

NFCDS CRC Calculation:

~~The ITO~~Annually, the LLITO establishes the regional and/or local ~~LCRR~~LLRR for the Large Load ~~Customer's share of the~~Entity's gross cost of ~~the Required Facilities~~LLITO's Network Upgrades based on the ~~ITO's~~LLITO's annual carrying charge factor (pursuant to the ~~ITO's~~LLITO's FERC approved annual transmission formula rate), while the Large Load Eligible Customer provides or causes the provision of an estimate of Non-Firm Contract Demand ("NFCD"). If the Large Load ~~Customer's share of the LCRR~~Entity's LLRR exceeds the actual payments collected from the Large Load Eligible Customer under its NFCD based on the applicable annual RNS or LNS rate, the difference is a supplemental CRC payment. The CRC, under the NFCDS, will be subject to true-ups based on actual demand/charges to ensure full recovery of the ~~LCRR~~LLRR. If the Large Load Eligible Customer's NFCDS payment based on the applicable RNS or LNS rate is equal to or exceeds the ~~LCRR~~LLRR there is no supplemental CRC required.

- **Step 1: Calculate LLRR**
  LLRR = Gross cost of LLITO's Network Upgrades × LLITO Regional or Local Carrying Charge Factor

- **Step 2: Calculate NFCDS Charge**
  NFCDS Charge = NFCD × RNS or LNS Rate

- **Step 3: Calculate Annual CRC**
  Annual CRC = LLRR − NFCDS Payment if LLRR > (NFCDS Payment)
  0 if LLRR ≤ NFCDS Payment

- **Step 4: Calculate Monthly CRC**
  Monthly CRC = Annual CRC/12

LLRR = Large Load Entity's Local or Regional Cost Responsibility Revenue Requirement
LLITO Carrying Charge Factor = Annual Regional or Local network service rate carrying charge factor as established under the Settlement Agreement dated June 15, 2020 in Docket Nos. EL16-19-0000 and ER20-2054-000 approved by FERC, as modified and approved from time to time.
NFCD = Large Load Eligible Customer's Non-Firm Contract Demand (MW)

NFCDS Payment = Large Load Eligible Customer's NFCD times RNS or LNS Rate in effect for service year.
RNS/LNS Rate = Applicable annual Regional Network Service or Local Network Service rate ($/MW-year)

ICDS CRC Calculation:

ICDS will be available to the Large Load Eligible Customer during the interim period prior to ~~completion of~~receiving FCDS consistent with the ~~Required Facilities. During this interim period~~OATT. While the Large Load Eligible Customer is receiving ICDS, Large Load Entity will be billed ~~as~~pursuant to the NFCDS ~~and~~methodology outlined above. Once the Large Load Eligible Customer is receiving FCDS, Large Load Entity will then be ~~converted~~billed pursuant to the FCDS ~~upon completion of the Required Facilities~~methodology.

Take-or-Pay Structure and Annual Updates:

~~Together, the payments under the selected transmission service, either FCDS, NFCDS and/or ICDS and the~~ The CRC ~~and, if applicable, create~~creates a take-or-pay obligation under which the Large Load ~~Customer~~Entity bears 100% cost responsibility for ~~its share of~~ the ~~LCRR~~CRC. The ~~LCRR~~LLRR and CRC shall be updated annually, in January to reflect the upcoming years updated RNS/LNS rate updates~~, ITO's~~ and LLITO's annual carrying charge factor, over the term of the Agreement.

~~Annual CRC~~**Exit Fee Calculation**~~:~~

1	**Calculation of Annual Cost Recovery Charge**		
2	Input Cells are Shaded Yellow		
3	**Load Customer Revenue Requirements (LCRR) and Demand**		**Source**
4	Gross Cost of Required Facilities [1]		Transmission Owner/Transmission Provider (fixed)
5	ITO RNS/LNS Carrying Charge Factor		RNS - Att 3 - Att F - App B - Att 1 (Regional) - W/S 4, Line 28 LNS - Att 3 - Att F - App B - Att 2 (Local) - W/S 3, Line 19
6	Load Customer Revenue Requirements (LCRR)	-	Line 4 x Line 5
7	Load Customer Firm/Non-Firm Contract Demand kW		Large Load Customer
8			
9	**Large Load Payments**		
10	Load Customer Firm/Non-Firm Contract Demand kW	-	Line 7
11	RNS/ITO LNS Current Rate		RNS - Att 1 - Sch 9 - Line 3 LNS - Att 2 - ITO specific Local Network Service Rate
12	**FCDS/NFCDS Charge**	-	Line 10 x Line 11
13	Load Customer Revenue Requirements (LCRR)	-	Line 6
14	**Annual Cost Recovery Charge (CRC)** [2]	-	Line 13 less Line 12 (If <0 =0)
15	Monthly Cost Recovery Charge (CRC)	-	Line 14 / 12

[1] Gross Cost will be reduced for individual components (if applicable) of the total required faciliites that have reached end of useful life.
[2] NFCDS will be billed based on actuals and CRC may require true-up to cover LCRR.

~~**Net Book Value for Exit Fee**~~

~~The Net Book Value for the Exit Fee shall be calculated based on the current depreciated value of the Network Upgrades, including cost of removal, as of the effective date of the termination of the Agreement. The formula for calculating the Net Book Value and Exit Fee is as follows:~~

Calculation of Exit Fee

Input Cells are Shaded Yellow					
In-Service Date	1/1/2026	1/1/2026	1/1/2026	1/1/2026	
Exit Date	1/1/2056	1/1/2056	1/1/2056	1/1/2056	
	NETWORK UPGRADE #1	NETWORK UPGRADE #2	NETWORK UPGRADE #3	CAPITAL REPLACEMENTS	TOTAL NETWORK UPGRADE AND CAPITAL REPLACEMENT COST
Transmission Asset Class Useful Life (Years) [1]	0	0	0	0	
Gross Cost of Required Facilities [2]	$ -	$ -	$ -	$ -	$ -
FERC Approved Depreciation Rate	0.00%	0.00%	0.00%	0.00%	
Elapsed Contract Term (Months)	360	360	360	360	
Remaining Contract Term (Months)	-360	-360	-360	-360	
Gross Exit Fee	$ -	$ -	$ -	$ -	$ -
(Less) Salvage Value	$ -	$ -	$ -	$ -	$ -
Net Book Value Exit Fee	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Calculation of Exit Fee

Line:	Exit Fee Components:	Source:
1	Transmission Asset Class Useful Life (Years) [1]	Useful life of applicable Network Upgrades per Appendix A, Item #3
2	Gross Cost of Required Facilities [2]	Transmission Owner/Transmission Provider (fixed)
3	FERC Approved Depreciation Rate	Appendix D to Attachment F of the ISO-NE OATT
4	Elapsed Contract Term (Months)	Billing periods recovered from contract in-service date through exit date
5	Remaining Contract Term (Months)	(Line 1 * 12) - Line 4
6	Gross Exit Fee	Line 5 * Line 3 / 12 * Line 2
7	Salvage Value	Transmission Owner/Transmission Provider
8	Net Book Value Exit Fee	Line 6 - Line 7

[1] *Useful life shall be the longer of 30 years or a period coextensive with the depreciable life of the applicable Required Facilities identified in Appendix A*

[2] *Gross Cost will be reduced to zero for individual components of the total applicable Required Facilities that have reached end of useful life*

Pursuant to Article 10.8, the Net Book Value for the Exit Fee represents the remaining unrecovered investment in LLITO's Network Upgrades constructed specifically to serve the Large Load Entity if service is terminated prior to the end of the Initial Term, at the end of the Initial Term, or otherwise agreed upon pursuant to Article 2.2. In addition to the recovery of the remaining unrecovered investment, the Exit Fee shall include any additional unrecovered costs associated with removal, retirement, decommissioning, site restoration, or other termination-related costs attributable to such facilities, net of any salvage value ("Decommissioning Costs").

Exit Fee = NBV + Decommissioning Costs

NBV = The Net Book Value of the Required Facilities based on the general ledger books and records of the LLITO.

Decommissioning Costs = Any additional unrecovered costs associated with removal, retirement, decommissioning, site restoration, or other termination-related costs attributable to such facilities, net of any salvage value

APPENDIX D

CREDIT SUPPORT

~~[INDIVIDUAL TO SECTION]~~

[Specifics to be determined by the individual LLITO]

APPENDIX E

~~**SERVICE COMMENCEMENT AND MILESTONE CERTIFICATION**~~

~~[DRAFTING NOTE: Describe the certification required before the Large Load Facility begins service, including compliance with Contract Demand, metering, telemetry, operating communications, and applicable ISO-NE and Large Load Interconnecting Transmission Owner approvals.]~~

~~APPENDIX F~~

Addresses for Notices and Billings~~:~~

Large Load Entity:

Large Load Interconnecting Transmission Owner:

Large Load Eligible Customer:

Billings and Payments:

Alternative Notice Methods (telephone, facsimile, or email):

Schedule 9A

LARGE LOAD TRANSMISSION SERVICES

ISO New England Inc. Open Access Transmission Tariff (OATT)

A Large Load Transmission Customer which obtains Firm Contract Demand Service to serve a Large Load in the New England Control Area shall pay to the ISO each month for Firm Contract Demand Service the amount determined in accordance with the following formula:

Amount to be Paid = ((RNS Rate per kilowatt-year) x (Large Load Transmission Customers Firm Contract Demand **(a)**) x (1/12))

A Large Load Transmission Customer which obtains Non-Firm Contract Demand Service to serve a Large Load in the New England Control Area shall pay to the ISO each month for Non-Firm Contract Demand Service the amount determined in accordance with the following formula:

Amount to be Paid = ((RNS Rate per kilowatt-year) x (Large Load Transmission Customers Monthly Non-Firm Contract Demand **(a)**) x (1/12))

A Large Load Transmission Customer which obtains Interim Contract Demand Service to serve a Large Load in the New England Control Area shall pay to the ISO each month for Interim Contract Demand Service the amount determined in accordance with the following formula:

Amount to be Paid = ((RNS Rate per kilowatt-year) x (Large Load Transmission Customers Monthly Interim Contract Demand **(a)**) x (1/12))

Notes:

(a) As used in this Schedule, "Firm Contract Demand," "Monthly Non-Firm Contract Demand," and "Monthly Interim Contract Demand" each has the meaning specified in Section II.61.1 of this OATT**,** except that any customer for which exempt demand has been converted to Firm Contract Demand Service consistent with II.J of this OATT and continues to be separately metered and billed at the rate established for the exempt demand as of June 18, 2026, as later amended or revised, shall have the appropriate portion of its Firm Contract Demand exempted for the purposes of this Schedule.

(b) The RNS Rate is calculated in accordance with Schedule 9 to the OATT

(bc) The Large Load Transmission Customer shall also be obligated to pay any ancillary charges and any charges required to be paid pursuant to Market Rule 1 and this tariff.

II.20 Load Shedding and Curtailments

II.20.1 Procedures: Prior to the Service Commencement Date, the ISO and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.22 of this OATT with the objective of responding to contingencies on the PTF. The parties will implement such programs during any period when the ISO determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The ISO will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

II.20.2 Transmission Constraints: During any period when the ISO determines that a transmission constraint exists on the PTF, MTF or OTF, and such constraint may impair the reliability of the New England Transmission System, the ISO will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent the ISO determines that the reliability of the system can be maintained by redispatching resources, the ISO will initiate procedures pursuant to Section II.22 of this OATT to redispatch the appropriate resources and the Transmission Customers' own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the PTO's use of the PTF on behalf of their Native Load Customers, any Large Load Transmission Customer's use of the PTF on behalf of its Large Loads, and any Network Customer's use of the PTF to serve its designated Regional Network Load.

II.20.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the ISO implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Customers and Large Load Transmission Customers will bear the costs of such redispatch in accordance with ISO New England Operating Documents.

II.20.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the PTF, MTF or OTF cannot be relieved through the implementation of least-cost redispatch procedures and the ISO determines that it is necessary to effect a Curtailment of scheduled deliveries, such schedule shall be curtailed in accordance with Section II.22 of this OATT.

II.20.5 Allocation of Curtailments: The ISO shall on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent

with Good Utility Practice, any Curtailment will be shared by the customers taking MTF Service, OTF Service and/or Through or Out Service and Network Customers on a nondiscriminatory basis. The ISO shall not direct the Network Customer to effect a Curtailment of its schedules to an extent greater than the ISO would effect a Curtailment of the Transmission Owner's or Schedule 20 Service Provider's schedules under similar circumstances. Notwithstanding the preceding provisions of this Section, Real-Time External Transactions shall be scheduled and curtailed in accordance with Section II.44 of this OATT.

II.20.6 Load Shedding: To the extent that a system contingency exists on the PTF, OTF and/or MTF and the ISO determines that it is necessary for the customers taking MTF Service, OTF Service and/or Through or Out Service and Network Customers to shed load, the Parties shall shed load in accordance with the ISO New England Operating Documents.

II.20.7 System Reliability: Notwithstanding any other provisions of this OATT, the ISO reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to effect a Curtailment of Regional Network Service without liability on the part of the ISO or the Transmission Owners for the purpose of making necessary adjustments to, changes in, or repairs on the Transmission Owners' lines, substations and facilities, and in cases where the continuance of Regional Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the PTF or on any other system(s) directly or indirectly interconnected with the PTF, the ISO, consistent with Good Utility Practice, also may effect a Curtailment of Regional Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The ISO will give the Transmission Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Regional Network Service will be not unduly discriminatory relative to the Transmission Owners' or Schedule 20 Service Provider's use of the Transmission System on behalf of their Native Load Customers. Section II.22 of this OATT shall specify the rate treatment and all related terms and conditions applicable in the event that the Transmission Customer fails to respond to established Load Shedding and Curtailment procedures.

II.21 Rates and Charges

II.21.1 Regional Network Service: Each Transmission Customer which has a load in the New England Control Area and takes Regional Network Service for a month shall be subject to the applicable provisions of Part II.B. of this OATT and shall pay to the ISO for such month an amount equal to its Monthly Regional Network Load for the month times the applicable Local Network RNS Rate (except as provided for in Section II.21.3), and shall pay in addition any amount which it is required to pay for the service pursuant to Section II.18.3 and Schedules 13 and 14 of this OATT. It shall also be obligated to pay for any Direct Assignment Facilities and its share of any new facilities or upgrades required to provide the requested service including applicable study costs to the extent they are consistent with Commission policy and Schedules 11 and 12, and any ancillary service charges and other charges and/or costs required to be paid pursuant to the Transmission, Markets and Services Tariff. The applicable Local Network RNS Rate shall be the rate, determined in accordance with Schedule 9 to this OATT, which is applicable to (i) a delivery to load in the particular Local Network in which the load served by the Transmission Customer is located, or (ii) to the extent that the ISO, after consultation with the affected PTOs, at the request of a PTO who owns the Local Network where the Regional Network Load is located, recognizes Regional Network Load to be the responsibility of another PTO, the applicable Local Network RNS Rate shall be the Local Network RNS Rate of the PTO responsible for such Regional Network Load. In the event the Transmission Customer serves Regional Network Load located on more than one Local Network, the amount to be paid by it shall be separately computed for the Regional Network Load located on each Local Network.

II.21.2 Determination of Network Customer's Monthly Regional Network Load: Network Customer's "Monthly Regional Network Load" is its hourly load (including its designated Regional Network Load not physically interconnected with the PTF under Section II.18.3 of this OATT) coincident with the coincident aggregate load of all Network Customers and Large Load Transmission Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak"). Network Customer's Monthly Regional Network Load shall exclude (i) load offset by any resource that is not a Generator Asset, and (ii) load offset by the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset. For Regional Network Load located within the New England Control Area, the Monthly Regional Network Load of all Network Customers within a Local Network shall be calculated by the associated PTO. For Regional Network Load located outside of the New England Control Area, the Monthly Regional

Network Load of all Network Customers shall be calculated by the associated PTO (in consultation with the ISO and the associated Balancing Authority).

II.21.3 Exception to Payment for Regional Network Service: Regional Network Service charges associated with an Electric Storage Facility's charging load: The applicable Local Network RNS Rate shall be reduced to zero for monthly Regional Network Load associated with the charging load of an Electric Storage Facility. The reduction to zero of the applicable Local Network RNS Rate shall only apply to the Schedule 9 charges. This discount will only be applied to Electric Storage Facility charging load that (a) is reported under a separately identified Regional Network Load that does not include station service load or any other load and (b) is providing one or more of the following services to the ISO: reactive power voltage support, operating reserves, regulation and frequency response, balancing energy supply and demand, or addressing a reliability concern. Electric Storage Facilities shall be considered to be balancing energy supply and demand when they are responding to ISO dispatch instructions in the Real-Time Energy Market. The applicable Local Network RNS Rate will be applied to Electric Storage Facility charging load unless it is reported as described in (a) above and is providing one or more services as described in (b) above.

II.22 Operating Arrangements

II.22.1 Network Customer Obligation: The Network Customer shall plan, construct, operate and maintain all of its equipment and facilities connected to the New England Transmission System in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, the ISO New England Operating Documents and requirements of the Electric Reliability Organization (ERO) as defined in 18 C.F.R § 39.1 and NPCC.

II.22.2 General Network Operating Terms and Conditions: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part II.B of the OATT are specified in Section II.22 of this OATT, and in the ISO New England Operating Documents. The ISO, the applicable PTO(s) and the Network Customer shall (i) operate and maintain equipment necessary for integrating the Network Customer within the PTF (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data among the ISO, the PTO(s) and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the PTF, interchange schedules, unit outputs for redispatch required under Section II.20 of this OATT, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part II.B of this OATT, including scheduling protocols. The Network Customer shall satisfy its Control Area requirements by contracting with the ISO and all the applicable PTOs. In the alternative, the Network Customer may satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, in a manner which satisfies ERO and NPCC requirements and receives any necessary ERO and NPCC approvals, subject to applicable federal and state regulatory approvals and subject to the development and implementation of a reasonable transition plan that, inter alia, satisfies applicable established system reliability criteria.

(a) **Electrical Supply:** The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty-hertz alternating current at a voltage class determined by mutual agreement of the ISO, the applicable PTO(s) and the Network Customer.

(b) **Maintenance Outage Procedures:** The ISO and the applicable PTO(s) will utilize the ISO New England Operating Procedures with respect to the timing of scheduled maintenance of the New England Transmission System and Network Resources.

(c) **Reporting Obligations**: The Network Customer shall be responsible for all information required by the ERO, NPCC, the applicable PTO(s) or the ISO. The Network Customer shall respond promptly and completely to the ISO's and the applicable PTO(s)'reasonable requests for information, including but not limited to, data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

For Regional Network Loads:

- ten-year coincident, seasonal (summer, winter) annual peak load forecast, aggregated by geographic distribution area
- load power factor performance by geographic distribution area
- Underfrequency load shedding capability aggregated by geographic distribution area
- Block load shedding capability aggregated by geographic distribution area
- Disturbance/interruption reports
- Protection system setting conformance
- Protection system testing and maintenance conformance
- Planned changes to protection systems
- Metering testing and maintenance conformance
- Planned changes in transformation capability
- Conformance to harmonic and voltage fluctuation limits
- Dead station tripping conformance
- Voltage reduction capability conformance

For Network Resources and interconnected generators:

- Ten-year forecast of generation capacity retirements, deactivations, and additions, if applicable
- Generator reactive capability verification
- Generator underfrequency relaying conformance
- Protection system testing and maintenance conformance
- Planned changes to protection system

- Planned changes to generation parameters
- Metering testing and maintenance conformance

Failure by the Network Customer to do so may constitute default and permits the ISO to terminate the TSA, in accordance with Commission requirements. Delinquency in responding by the Network Customer will result in a fine as described in Section II.22.5 below.

The Network Customer shall supply accurate and reliable information to the system operators regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by the ISO and the applicable PTO(s) for reliable operation. Information shall be gathered for electronic communication using a methodology acceptable to the ISO. All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by the ISO and the applicable PTO(s).

(d) **Operational Obligations:** The Network Customer and Transmission Owner shall request permission from the ISO prior to opening and/or closing circuit breakers per applicable ISO New England Operating Procedures. The Network Customer shall carry out all switching orders from the ISO or the applicable PTO(s) in a timely manner.

The Network Customer shall balance the load at the Point(s) of Delivery such that the difference in the individual phase currents are acceptable to the ISO as specified in the ISO New England Operating Procedures.

The Network Customer’s equipment shall conform with any harmonic distortion and voltage fluctuation standards specified in ISO New England Operating Procedures. The Network Customer’s equipment must comply with all environmental requirements to the extent they impact the operation of the New England Transmission System. The Network Customer shall operate all of its equipment and facilities connected to the New England Transmission System in a safe and efficient manner and in accordance with manufacturers’ recommendations, Good Utility Practice, applicable regulations, and requirements of the ISO, the applicable PTO(s) and NPCC.

(e) **Notice of Transmission Service Interruptions**: If at any time, in the reasonable exercise of the ISO’s judgment, operation of the Network Customer’s equipment adversely affects

the quality of service or interferes with the safe and reliable operation of the New England Transmission System, the ISO may discontinue transmission service, consistent with Section II.20, until the condition has been corrected.

(f) **Access and Control:** Properly accredited representatives of the ISO shall at all reasonable times have access to the Network Customer's facilities to make reasonable inspections and obtain information required in connection with this OATT. Such representatives shall make themselves known to the Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Network Customer's facilities.

(g) **Point(s) of Delivery:** Regional Network Service will be delivered by the ISO at the Point(s) of Delivery specified in the Network Customer's application referred to in Section II.16.2 of this OATT (a blank form of which is posted on the OASIS), as approved and amended from time to time. Each Point of Delivery shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and, the actual, or if not currently in service, the projected in-service year.

(h) **Maintenance of Equipment:** The ISO may request that the Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software consistent with the Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of trouble shooting problems on the network facilities. The Network Customer will be responsible for the cost to test, calibrate, verify or validate the equipment or software. The ISO shall have the right to inspect the tests, calibrations, verifications and validations of the data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to the New England Transmission System. The Network Customer, at the ISO's request, shall supply the ISO with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software connected to the New England Transmission System. The ISO shall have the right, at the Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software connected to the ISO's system.

(i) **Emergency System Operations**: The Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by the ISO to operate in an interconnected transmission network. The ISO reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of the New England Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

(j) **Cost Responsibility:** The Network Customer shall be responsible for all costs incurred by the ISO relative to the Network Customer's facilities. Some costs may be allocated to several Network Customers. If the method for allocating costs is not clearly defined, then the method for allocation will be at the ISO's discretion.

II.22.3 Network Resource Obligations: The following obligations of the Network Customer are specific to a generator Network Resource.

(a) **Voltage or Reactive Control Requirements**: Unless directed otherwise, the Network Customer will operate its existing interconnected generation facility(ies) with an automatic voltage regulator(s). The voltage regulator will control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by the ISO.

At the discretion of the ISO, the Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with the requirements specified in the ISO New England Operating Procedures and shall be provided and compensated as specified in Schedule 2 of this OATT.

(b) If the Network Customer has not installed capacity sufficient to operate its generation facility consistent with recommendations of the ISO resulting from the System Impact and Facilities Studies or fails to operate at such capacity, applicable PTO(s) may install, at the Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

(c) **Station Service:** When the Network Customer's generation facility is producing electricity, the Network Customer must supply its own station service power. If and when the Network Customer's generation facility is not producing electricity, the Network Customer must obtain station service capacity and energy from another supplier or another of its resources.

(d) **Protection Requirements:** The Network Customer must meet protection requirements as defined in the ISO New England Operating Documents, and ERO and NPCC documents, as may be adopted or amended from time to time.

(e) **Coordination of Operations:** All operations (including start-up, shutdown and determination of hourly generation) will be coordinated by the ISO.

II.22.4 Obligations for Delivery to Load: The following obligations are specific to delivery to load.

(a) Power Factor Requirement: The Transmission Customer agrees to maintain an overall load power factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by the ISO New England Operating Procedures which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total New England load. The Network Customer agrees to maintain load power factor and reactive power requirements within the range specified by the ISO for the sub-area based on total New England load during that hour. The ISO may revise the power factor limits required from time to time. If the Network Customer lacks the capability to maintain the load power factor within the ranges specified, the applicable PTO(s) may:

i) install, at the Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery;

ii) charge the Network Customer.

(b) **Protection Requirements:** The Network Customer's relay and protection systems must comply with all applicable ISO New England Operating Procedures and ERO and NPCC

criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

(c) **Operational Obligations:** The Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to the New England Transmission System or others' interconnected systems and complies with ISO New England Operating Procedures, and ERO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to:

- voltage reduction load shedding
- underfrequency load shedding
- block load shedding
- dead station tripping
- transferring load between point(s) of delivery
- implementing voluntary load reductions including interruptible customers
- starting stand-by generation
- permitting transmission owner controlled service restoration following supply delivery contingencies on transmission owner facilities.

II.22.5 Default: If the Network Customer's equipment fails to perform consistent with the obligations specified in this OATT , then the Network Customer will be deemed to be in default and service may be suspended immediately and subject to a termination through an ISO filing with the Commission. If the Network Customer fails to provide the information required in Section II.22.2(c) in a timely manner, the ISO shall be permitted to assess a penalty of $100 per day until such information is provided in its entirety to the ISO.

II.23 Application of Part II.B to Transmission Customers

If the Transmission Customer is a Market Participant, in order to receive Regional Network Service, it must be party to a Market Participant Service Agreement and a service agreement for Local Network Service.

If the Transmission Customer is not a Market Participant, in order to receive Regional Network Service, it must be party to a Transmission Service Agreement (Attachment B to this OATT) and a service agreement for Local Network Service.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. Local level service is provided by the PTOs under Schedule 21 to this OATT. For transmission service under this OATT, this Ancillary Service can be provided only by the ISO and the Transmission Customer and Large Load Transmission Customer must purchase this service from the ISO. Charges for Scheduling, System Control and Dispatch Service are to be based on the expenses incurred by the ISO, and by the individual PTOs in the operation of Local Control Center dispatch centers or otherwise, to provide these services. The expenses incurred by the ISO in providing these services recovered under Section IV of the OATT. A surcharge for the expenses incurred by PTOs in the provision of these services for transmission service over the PTF will be added to the Through or Out Service rate and to the Regional Network Service rate. Any Scheduling, System Control and Dispatch Service expenses for the provisions of these services for MTF Service shall be determined separately and assessed to Transmission Customers receiving MTF Service, in accordance with the arrangements between the Transmission Customers receiving MTF Service and the MTF Provider.

The expenses incurred in providing Scheduling, System Control and Dispatch Service for transmission service over the PTF for each PTO will be determined by an annual calculation based on the previous calendar year's data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report. The surcharge shall be redetermined annually as of June 1 in each year and shall be in effect for the succeeding twelve (12) months. The rate surcharge per kilowatt for each month is one-twelfth of the amount derived by dividing the total annual PTO expenses for providing the service by the sum of the average of the coincident Monthly Peaks (as defined in Section II.21.2) of all Local Networks for the prior calendar year.

Each Transmission Customer which is obligated to pay the rate for Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its Monthly Network Load (as defined in Section II.21.2 of this OATT) for the month. Each Transmission Customer which is obligated to pay the rate for Through or Out Service for the applicable period shall pay the surcharge on the basis of the

highest amount of its Reserved Capacity for each transaction scheduled as Through or Out Service for such period. Each Large Load Transmission Customer that is obligated to pay for the Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service, as determined in Section II.62 of the OATT for the month

The details for implementation of Schedule 1 for transmission service over the PTF shall be established in accordance with the Implementation Rule for Schedule 1 attached to this OATT.

SCHEDULE 1 IMPLEMENTATION RULE

This rule provides detail with respect to the calculation of the rate surcharge each year for Scheduling, System Control and Dispatch Service, which is defined in the OATT as the service required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities ("PTF"). This service also includes the dispatch and security analysis of the system. Scheduling, System Control and Dispatch Service for transmission service over transmission facilities other than PTF is provided under Schedule 21 of the OATT. For transmission service under the OATT, this Ancillary Service will be provided by the ISO, and rates collected under Schedule 1 are based on expenses incurred by the Local Control Centers, and the PTOs (as described herein) in providing the necessary elements of this service to the ISO. All of the costs of the ISO for the provision of service under Schedule 1 will be recovered under Section IV of the Transmission, Markets and Services Tariff. Schedule 1 of the OATT is for collection only of the revenue requirements for Local Control Centers and PTOs for System Control and Dispatch Service. Any Transmission Customer taking Regional Network Service or Through or Out Service shall be subject to the rate surcharge calculated under Schedule 1 of the OATT as described in more detail in this rule below.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Schedule 1 rate surcharge to be utilized by the ISO in the billing of Schedule 1 Ancillary Service that will be in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs would file corrections to the informational filing. At least thirty (30) days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the RTO NE website. The filing of the informational filing does not

reopen the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing. The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term "agreed-upon procedures" shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms used in this rule that are not defined in the Tariff have the following definitions:

Scheduling and Dispatch Surcharge Rate shall equal the rate surcharge that is determined for the applicable period beginning on June 1, 1999, in accordance with Section II of this rule below.

PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the PTO from REMVEC II, CONVEX/ESCC, and the Maine Local Control Center as recorded in each PTO's FERC Form 1, Account Nos. 561-561.4, excluding any charges recorded in this account that were incurred under the OATT or Schedule 21 of the OATT. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the PTO for providing scheduling and dispatch services, excluding any revenues recorded in this account that where received as a result of charges under the OATT.

REMVEC II is a Local Control Center of the ISO providing security analysis of PTF.

Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each PTO's expenses as recorded in FERC Account Nos. 561-561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in these accounts, that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer, multiplied by the PTF Transmission Plant Allocator, (2) NSTAR Electric Company (East) SCADA-related expenses as calculated in accordance with Appendix A of this Rule, (3) the Central Maine Power Company Local Control Center revenue requirements as calculated in accordance with Appendix B of this Rule, and (4) the CL&P Dispatch Center Revenue Requirement as calculated in accordance with Appendix C of the Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and Non-PTF as determined for the applicable period pursuant to Attachment F of the OATT.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers and Large Load Transmission Customers

For Network Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Network Customer's Regional Monthly Network Load, as defined in Section II.21.2 of the OATT, multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

For Large Load Transmission Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Large Load Transmission Customers' demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service, as determined in Section II.62 of the OATT, multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

B. Surcharge for Through or Out Customers

For Through or Out Service Customers, the Scheduling and Dispatch Surcharge shall equal the Transmission Customer's Reserved Capacity for each transaction scheduled for the month multiplied by the applicable Monthly or Hourly Scheduling and Dispatch Surcharge Rate, as determined in accordance with Section II.C below.

C. Scheduling and Dispatch Surcharge Rate

The Scheduling and Dispatch Surcharge Rate will be the surcharge rate in effect from time to time for the applicable period, determined pursuant to the formula described below based on the prior calendar year's data. The Scheduling and Dispatch Surcharge Rate shall be redetermined each year, with the new Surcharge Rate going into effect on June 1 of each year, and be effective for the succeeding twelve months.

In the case of PTOs which are subject to the Commission's jurisdiction, the data used shall be as identified in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1. When FERC Form 1 data is not the direct source of the data used in the formula, the worksheets used to develop the inputs will reflect Appendix A, Appendix B, and Appendix C of this Rule.

The Scheduling and Dispatch Surcharge Rate shall be equal to the sum of (1) PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense, (2) Local PTF Transmission Related Scheduling

and Dispatch Expense, (3) less Schedule 1 revenues from the prior year surcharges for Short-Term Point-To-Point Transactions, and divided by the annual average of the sum of all Regional Network Customers Monthly Peak Load, as defined in Section II.21.2 of the OATT, from the prior calendar year plus the Long-Term Firm Point-To-Point Service Reserved Capacity, from the prior calendar year, plus all Large Load Transmission Customers' demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service, as defined in Section II.62 of the OATT from the previous calendar year.

The Monthly Scheduling and Dispatch Surcharge Rate shall equal one-twelfth of the Scheduling and Dispatch Surcharge Rate.

The Hourly Scheduling and Dispatch Surcharge Rate shall be the annual rate divided by 8760.

APPENDIX A TO SCHEDULE 1 IMPLEMENTATION RULE

NSTAR ELECTRIC COMPANY (EAST) SCADA

This service is required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (PTF). Service under this schedule represents the contribution to that service provided by the PTO's own Dispatch Center, commonly referred to as SCADA. These costs are excluded from costs in Attachment F.

The PTF Revenue Requirement for the scheduling, system control and dispatch service that is based on data for the calendar year 2004 or later shall include an allocated PTF-related amount of Incremental Return and Associated Income Taxes on SCADA-related transmission plant investments included in the Regional System Plan and placed in-service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Dispatch Center Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be based on actual data in lieu of allocated data if specifically identified in NSTAR Electric's (East) accounting records.

Definitions: Dispatch Center Wages and Salaries Allocation Factor: Ratio of Dispatch Center Related Direct Wages and Salaries to NSTAR Electric's (East) total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Dispatch Center Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Plant in service.

Dispatch Center Transmission Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Investment in Transmission Plant.

ADIT Worksheet shall mean the worksheet set forth in Appendix D to Schedule 1 Implementation Rule.

The PTF Revenue Requirement for the Scheduling System Control and Dispatch Service shall equal the sum of the PTO's: (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment), (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Related Amortization of Investment Tax Credits, (D) Dispatch Center Related Municipal Tax Expense, (E) Dispatch Center Related Payroll Tax Expense (F) Dispatch Center Operation and Maintenance Expense, (G) Dispatch Center Related Administrative and General Expense, and (H) Dispatch Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities; multiplied by the PTF Transmission Plant Allocation Factor.

The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be calculated using the Dispatch Center investment base components specifically identified in Section A.1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post–2003 Dispatch Center Investment, the Dispatch Center Investment Base will only include items (a), (d) and (e) under Section (A)(1), calculated in the manner indicated.

1. **The Dispatch Center Investment Base** will consist of (a) Dispatch Center Plant in FERC accounts 350-359, plus (b) Dispatch Center Related General Plant, plus (c) Dispatch Center Plant Held for Future Use, less (d) Dispatch Center Related Depreciation Reserve, less (e) Dispatch Center Related Accumulated Deferred Taxes, plus or minus (f) Other Regulatory Assets/Liabilities, plus (g) Dispatch Center Prepayments, plus (h) Dispatch Center Materials and Supplies, plus (i) Dispatch Center Related Cash Working Capital.

a. Dispatch Center Plant will equal the year-end balance of the PTO's Investment in Dispatch Center per FERC accounts 350 through 359. Dispatch Center Plant Investment is not included in PTF investment in the Attachment F revenue requirement. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Post-2003 Dispatch Center Plant shall be separately identified.

b. Dispatch Center Related General Plant shall equal the PTO's year-end balance of Investment in General Plant multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

c. Dispatch Center Plant Held for Future Use shall equal the year-end balance of Transmission related Dispatch Center Investment in FERC account 105.

d. Dispatch Center Related Depreciation Reserve shall equal the year-end balance of Transmission Dispatch Center Depreciation Reserve, plus the year-end balance of Dispatch Center Related General Depreciation Reserve. Dispatch Center Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Dispatch Center Wages and Salaries Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Dispatch Center Depreciation Reserve associated with the Post-2003 Dispatch Center Investment, shall equal the balance of the Dispatch Center Depreciation Reserve multiplied by the ratio of Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

e. Dispatch Center Related Accumulated Deferred Taxes shall equal the year-end balance of Total Accumulated Deferred Income Taxes, multiplied by the Dispatch Center Plant Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Total Accumulated Deferred Income Taxes associated with the Post-2003 Dispatch Center Investment, shall equal the balance of total property-related accumulated deferred income taxes as recorded in FERC Accounts 281 and 282, multiplied by the Dispatch Center Plant Allocation Factor, further multiplied by the ratio of the Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

f. Other Regulatory Assets/Liabilities shall equal the year-end balance of FAS 106 multiplied by the Dispatch Center Wages and Salaries Allocation Factor described in Section (A) (2) (b) above and the year-end balance of FAS 109, net of FAS 109 liability, multiplied by the Dispatch Center Plant Allocation Factor, plus or minus Dispatch Center Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities in FERC Account Nos. 182.3 and 254 as a result of changes in Federal, State, or Local income tax rates, as calculated in the ADIT Worksheet, multiplied by the Dispatch Center Transmission Plant Allocation Factor.

g. Dispatch Center Prepayments shall equal the year-end balance of Prepayments multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

h. Dispatch Center Materials and Supplies shall equal the year-end balance of Transmission Plant Materials and Supplies multiplied times the Dispatch Center Plant Allocation Factor described above.

i. Dispatch Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Dispatch Center Transmission Related Operation and Maintenance Expense and Dispatch Center Transmission Related Administrative and General Expense.

2. The Cost of Capital Rate shall equal (a) the Weighted Cost of Capital, plus (b) Federal Income Taxes, plus (c) State Income Taxes.

a. the Weighted Cost of Capital will be calculated based upon the PTO's capital structure at the end of each year and will equal the sum of (i), (ii) and (iii) below.

The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, shall only reflect item (iii) below and shall apply in the manner indicated below.

i. the Long Term Debt Component, which equals the product of the actual weighted average embedded cost to maturity of Long Term Debt then outstanding and the ratio that Long-Term Debt is to Total Capital.

ii. the Preferred Stock Component, which equals the product of the actual weighted average embedded cost to maturity of Preferred Stock then outstanding and the ratio that Preferred Stock is to Total Capital.

iii. the Return on Equity Component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that Common Equity is to Total Capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental return on equity shall be the product of 1.00% and the ratio of Common Equity to Total Capital.

b. Federal Income Taxes shall equal

$$\frac{A + [(B+C+D)/E]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Sections A.2.(a)(ii) and (iii) above, B is Dispatch Center Related Amortization of Investment Tax Credits, as determined in Section II.D. below, C is the Equity AFUDC component of Dispatch Center Depreciation Expense, as defined in Section B., D is Dispatch Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities, as defined in Section II.H., below, and E is Dispatch Center Investment Base, as determined in A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental Federal Income Tax shall equal:

$$(A'*FT)/(1-FT)$$

Where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above.

c. State Income Taxes shall equal

$$\frac{(A + [(B+C+D)/E] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Section A.2.(a)(ii), and Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above, B is Dispatch Center Amortization of Investment Tax Credits, as determined in Section II.C. below, C is the Equity AFUDC component of Dispatch Center Depreciation Expense, as defined in Section B. below, D is Dispatch Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes

Regulatory Assets and Liabilities, as defined in Section II.H., below, and E is Dispatch Center Investment Base, as determined in A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental State Income Tax shall equal:

(A'+ Federal Income Tax)*ST/(1-ST)

Where ST is the State Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above.

B. Dispatch Center Depreciation Expense shall equal the sum of Transmission Depreciation Expense for Dispatch Center Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Dispatch Center Wages and Salaries Allocation Factor, described in Section (A)(1)(b) above.

C. Dispatch Center Related Amortization of Investment Tax Credits shall equal the PTO's Amortization of Investment Tax Credits multiplied by the Dispatch Center Plant Allocation Factor described above.

D. Dispatch Center Related Municipal Tax Expense shall equal the PTO's total Municipal Tax Expense multiplied by the Dispatch Center Plant Allocation Factor described above.

E. Dispatch Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Dispatch Center Wages and Salaries Allocation Factor, described above.

F. Dispatch Center Operation and Maintenance Expense shall equal all expenses related to SCADA operation charged to FERC Account Number 561 through 561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in this Account that were incurred under this OATT or the Local Service Schedules of this OATT as a Transmission Customer.

G. Dispatch Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Dispatch Center Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Dispatch Center Plant Allocation Factor, and (3)

Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Dispatch Center Plant Allocation Factor, plus any other Federal and State Dispatch Center related expenses or assessments, plus specific Dispatch Center related expenses included in Account 930.1 plus Transmission Merger-Related Costs multiplied by the Dispatch Center Transmission Plant Allocation Factor.

H. Dispatch Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities shall equal the Company's expenses and credits as recorded in FERC Account Nos. 410.1 or 411.1 solely related to any deficient or excess deferred income taxes as a result of changes to Federal, State, or Local income tax rates, as calculated in the ADIT Worksheet, multiplied by the Dispatch Center Transmission Plant Allocation Factor.

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

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center PTF Allocation Factor shall equal the ratio of the Local Control Center PTF Direct Wages and Salaries to the total Local Control Center Transmission Direct Wages and Salaries.

4. Local Control Center Plant Allocation Factor shall equal the ratio of the Total Investment in Local Control Center Plant to Total Plant in service.

B. TERMS

ADIT Worksheet shall mean the worksheet set forth in Appendix D to Schedule 1 Implementation Rule.

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1

Other Regulatory Assets/Liabilities -FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities -FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No. 105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing PTF Local Control Center services as recorded in FERC Account No. 561.

Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal the PTO's expenses recorded in FERC Account Nos. 556, 561-561.4, & 581, less any costs included in FERC

Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of the Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

Local Control Center Plant Depreciation Reserve shall equal the PTO's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account No. 108.

Materials and Supplies shall equal the PTO's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal the PTO's depreciation expense for Local Control Center Related Plant as recorded in FERC Account No. 403.

Local Control Center Related Plant shall equal the PTO's gross plant balances used for system control and dispatch purposes as recorded in FERC Account Nos. 303-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining annual transmission revenue requirements pursuant to the billing rule which implements Attachment F of the OATT.

Local Control Center Support Revenues shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of the OATT or the PTO's Local Service Schedule.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Loss on Reacquired Debt shall equal the PTO's balance as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account No. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirements based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on Central Maine's local control center investments included in the Regional System Plan and placed in service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Central Maine's accounting records.

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Investment), (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Amortization of Investment Tax Credits, (E) Municipal Tax Expense, (F) Payroll Tax Expense, (G) Operations and Maintenance Expense, (H) Administrative and General, (I) Local Control Center Amortization of Deficient or Excess Accumulated Deferred Income Tax Regulatory Assets and Liabilities minus (J) Support Revenues.

The Incremental Return and Associated Income Taxes for Post-2003 Investment shall be calculated using the investment base components specifically identified in Section A.1. of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate reflected in the PTO's Attachment F formula of the OATT. To calculate the Incremental Return and Associated Income Taxes for Post 2003 Investment, Local Control Center Investment Base shall only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

1. Local Control Center Investment Base

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, plus (b) Plant Held for Future Use, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Loss on Reacquired Debt, plus or minus (f) Other Regulatory Assets/Liabilities, plus (g) prepayments, plus (h) Materials and Supplies, plus (i) Cash Working Capital.

(a) Local Control Center Related Plant shall equal the balance of the PTO's Investment in Local Control Center Plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Post 2003 Local Control Center Plant shall be separately identified.

(b) Local Control Center Related Plant Held for Future Use shall equal the balance of Plant Held for Future Use multiplied by the Local Control Center Plant Allocation Factor.

(c) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve for the PTO's investment in Local Control Center plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Depreciation Reserve shall equal the Depreciation Reserve for the PTO's Local Control Center Plant identified in (a) above.

(d) Local Control Center Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Accumulated Deferred Taxes shall equal the PTO's balance of total property related accumulated deferred income taxes recorded in FERC account 281and 282 multiplied by the Local Control Center Plant Allocation Factor and further multiplied by the ratio of Post-2003 Investment to Total Local Control Center Related Plant.

(e) Local Control Center Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Local Control Center Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor, plus or minus Local Control Center Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities in FERC Account Nos. 182.3 and 254 as a result of changes in Federal, State, or Local income tax rates, as calculated in the ADIT Worksheet, multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(h) Local Control Center Related Materials and Supplies shall equal the PTO's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(i) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense, Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Investment shall only reflect item (iii) below and shall apply in the manner indicated below

(b) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(c) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(d) the return on equity component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that common equity is to the PTO's total capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental return on equity shall be the product of Central Maine's incremental return on equity of 1.0% and the ratio that common equity is to the PTO's total capital.

(e) Federal Income Tax shall equal

$$\frac{(A+[(B + C+ D)/E]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is Local Control Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities, as defined in Section II.I., below, and E is Local Control Center Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(f) State Income Tax shall equal

$$\frac{(A+[(B + C+ D)/E] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is Local Control Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities, as defined in Section II.I., below, and E is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Local Control Center Depreciation Expense shall equal the Local Control Center Plant Depreciation Expense and Accumulated Amortization.

C. Local Control Center Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric balance of Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

D. Local Control Center Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

E. Local Control Center Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

F. Local Control Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

G. Local Control Center Operation and Maintenance Expense shall equal the PTO's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

H. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

I. Local Control Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities shall equal the PTO's expenses and credits as recorded in FERC Account Nos. 410.1 or 411.1 solely related to any deficient or excess deferred income taxes as a result of changes to Federal, State, or Local income tax rates, as calculated in the ADIT Worksheet, multiplied by the Local Control Center Plant Allocation Factor. Amortization will be multiplied by a factor of 1/(1 – T), where T is the effective combined Federal Income Tax Rate and the Corporate Income Tax Rate of Maine in effect at the applicable time.

J.. Transmission Support Revenues shall equal the PTO's revenue received for providing system control and dispatch service.

III. CALCULATION OF LOCAL CONTROL CENTER TRANSMISSION REVENUE REQUIREMENTS

The Total Local Control Center Revenue Requirements derived in Section II. above are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2. above to determine the transmission related revenue requirement, and further multiplied by the Local Control enter

PTF Allocation Factor defined in Section I. A. 3. above, to determine the PTF Transmission related revenue requirements to be included in Schedule I of the OATT.

APPENDIX C TO SCHEDULE 1 IMPLEMENTATION RULE
CL&P DISPATCH CENTER REVENUE REQUIREMENT

This appendix calculates the CL&P Dispatch Center Revenue Requirement for use in calculating part (4) of the Local PTF Transmission-Related Scheduling and Dispatch expenses in the Schedule 1 Implementation Rule. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT and as used in this appendix have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch center Plant as recorded in FERC Account Nos. 281-283 and 190.

Other Regulatory Assets/Liabilities shall equal the year-end balance of Dispatch Center Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities in FERC Account Nos. 182.3 and 254 as a result of changes in Federal, State, or Local income tax rates, as calculated in the ADIT Worksheet.

ADIT Worksheet shall mean the worksheet set forth in Appendix D to Schedule 1 Implementation Rule.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period June 1, 2008 through May 31, 2009, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the Convex Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, (D) Dispatch Center Municipal Tax Expense, and (E) Dispatch Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities. "CONVEX Agreements" refers to the agreements between The Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Appendix C.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of:

(a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes, plus or minus (d) Other Regulatory Assets/Liabilities.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums,

discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

AxBxC

where: A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TC/(1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.1.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

E. Dispatch Center Amortization of Deficient or Excess Accumulated Deferred Income Taxes Regulatory Assets and Liabilities shall equal the company's Dispatch Center expenses and credits as recorded in FERC Account Nos. 410.1 or 411.1 solely related to

any deficient or excess deferred income taxes as a result of changes to Federal, State, or Local income tax rates, as calculated in the ADIT Worksheet. Amortization will be multiplied by a factor of 1/(1 – T), where T is the effective combined Federal Income Tax and the Corporate Income Tax Rate of Connecticut in effect at the applicable time.

APPENDIX D TO SCHEDULE 1 IMPLEMENTATION RULE

WORKSHEET 1

ADIT WORKSHEET

Company Name
Annual Transmission Revenue Requirements (ATRR)
(Excess)/Deficient ADIT Worksheet
Worksheet_
For costs in 20__

Input Cells are Shaded Yellow

Line No.	Description (c)	FERC Account Nos. FERC Account No. - ADIT	FERC Account No. - Deficient / Excess ADIT	FERC Account No. - Amortization Expense	(A) 20__ Year End Unamortized (Excess)/Deficient ADIT Protected	(B) Unprotected	(C) Gross-Up (b)	(D) = (A) + (B) + (C) 1231__ Balance	(E) Amortization Periods (f) Protected	(F) Unprotected	(G) Amortization Expense (d) Protected	(H) Unprotected	(I) Gross-Up (h)	(J) Protected	(K) Other Adjustments (e) Unprotected
1a								-							
1b								-							
1c								-							
1d								-							
1e								-							
1.1								-							
2	Total (Sum Lines 1a thru 1.1) (c)				-	-	-	-			-	-	-	-	-
3	Deficient ADIT – Regulatory Asset		182.3		FF1Page 232_										
4	Excess ADIT – Regulatory Liability		254		FF1Page 278_										
5	Deficient/(Excess) Deferred Income Tax Regulatory Asset/(Liability) (Line 3 + Line 4)							-							
6	Total Protected and Unprotected Amortization Expense (Line 2(G) + Line 2(H))											-			
7	Transmission Allocation (Plant Allocator or Direct Assigned (DA))														
8	Transmission-related Amortization Expense (Line 6 x Line 7)											-	(j)		

Notes:

(a) Enter credit balances as negatives.
(b) Total equals the sum of sublines a through (L where (L is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.
(c) Upon a change in Federal, State or Local income tax rates, the Company remeasures its affected accumulated deferred income tax (ADIT) assets and liabilities to reflect the new applicable corporate income tax rate. The affected ADIT accounts are remeasured by comparing ADIT on cumulative temporary differences for each item in accounts 190, 282, and 28 net change in regulatory assets (account 182.3) and regulatory liabilities (account 254) to reflect the resulting deficient or excess ADIT balances to be recovered/returned from/to customers, respectively. See Worksheet 2 for additional detail of the remeasurement.
(d) Deficient ADIT is amortized to Account 410.1; Excess ADIT is amortized to Account 411.1.
(e) PTO will provide explanation for "other adjustments," where applicable.
(f) The amortization periods of the deficient or excess ADIT being returned or recovered through rates are as follows:

Company	Protected	Unprotected (years)	
CLSP	ARAM	10, 5	For CLSP, unprotected deficient/(excess) ADIT balances will be amortized over 10 years for pension and other post-retirement benefits and over 5 years for all other amounts, except property-related deficient/(excess)
CMP	ARAM	10, 5	For CMP, unprotected deficient/(excess) ADIT will be amortized over 10 years and unprotected excess ADIT will be amortized over 5 years.
NSTAR Elec	ARAM	10, 5	For NSTAR Elec, unprotected deficient/(excess) ADIT balances will be amortized over 10 years for pension and other post-retirement benefits and over 5 years for all other amounts, except property-related deficient/(ex

(g) Relates to the Federal Income Tax rate change associated with the 2017 Tax Cuts and Jobs Act.
(h) Tax gross up calculated using the Composite Tax Rate (1) ÷ Composite Tax Rate) in effect for the applicable period.
(i) Notwithstanding anything to the contrary in Attachment F, the New England Transmission Owners will be permitted to reflect the amortization of excess or deficient ADIT in enhanced rates under the Settled Formula Rate.
(j) PTO will add footnotes below to identify excess or deficient ADIT from future Federal, State and Local income tax rate changes.
(k) (l)

(L)	(M) = (A) – (G) – (J)	(N) = (B) – (H) – (K)	(O) = (C) – (I) – (L)	(P) = (M) + (N) + (O)	(O)
	20__ Year End Unamortized (Excess)/Deficient ADIT				
Gross-Up (h)	**Protected**	**Unprotected**	**Gross-Up (h)**	**12/31/__ Balance**	**Reference**
	-	-	-	-	
	-	-	-	-	
	-	-	-	-	
	-	-	-	-	
	-	-	-	-	
	-	-	-	-	
-	-	-	-	-	
	FF1Page 232_				
	FF1Page 278_				
				-	

Internal Records for the period 1/1/2020 to 12/31/2021; Beginning on 1/1/2022, Appendix A, WS 5, Line 12 or Direct Assigned (DA)

3 at the current Federal, State & Local income tax rate to ADIT balances at the historical Federal, State & Local income tax rates. The difference between the two represents the deficient or excess ADIT balances. The result of this remeasurement is a change

Notes
ADIT which will be amortized using ARAM
xcess) ADIT which will be amortized using ARAM

APPENDIX D TO SCHEDULE 1 IMPLEMENTATION RULE

WORKSHEET 2

REMEASUREMENT WORKSHEET

Company Name
Annual Transmission Revenue Requirements
(Excess)/Deficient ADIT Worksheet
Remeasurement Support
Worksheet__
For Costs in 20__

Line No.	Description	FERC Account No.	(A) Gross Temporary Difference at December 31, 20__ (a), (b)	(B) = (A)* __% ADIT @ __%	(C) = (A)* __% ADIT @ __%	(D) = (B) - (C) (Excess)/Deficient ADIT at December 31, 20__ due to Rate Change	(E) Adjustments Post Remeasurement (d)	(F) = (D) - (E) (Excess)/Deficient ADIT due to Rate Change at 20__	(G) Protected	(H) Unprotected
1a				-	-	-		-		-
1b				-	-	-		-		-
1c				-	-	-		-		-
1d				-	-	-		-		-
1e				-	-	-		-		-
1[ ]										
2	Total (Sum Lines 1a thru 1[]) (c)		-	-	-	-	-	-	-	-

Notes
(a) Enter credit balances as negatives.
(b) Company records.
(c) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. PTO may add or remove sublines without a FPA Section 205 filing.
(d) Represents the impact of the 2018 Return to Accrual adjustments and other miscellaneous adjustments on the excess ADIT balance from the initial remeasurement.

SCHEDULE 2

REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE

In order to maintain transmission voltages on the New England Transmission System (for voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures) within acceptable limits, Qualified Reactive Resources are operated to produce (or absorb) reactive power. Thus, VAR Service must be provided to support Regional Network Service and Through or Out Service on the New England Transmission System (both of which services have a direct impact on voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures). The amount of VAR Service that must be supplied with respect to a Transmission Customer's Regional Network Service and Through or Out Service and Large Load Transmission Customer's Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service will be determined based on the degree of dynamic reactive power support necessary to maintain transmission voltages within limits that are consistently adhered to in the operation of the New England Transmission System. Additional detailed requirements regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 are described in the Ancillary Service Schedule 2 Business Procedure posted on the ISO website. Transmission Customers taking Local Service, MTF Service or OTF Service may also need to acquire voltage support services not otherwise provided under this Schedule 2 pursuant to Schedules 18, 20A or 21 to this OATT, as appropriate.

I. DEFINITIONS

Whenever used in this Schedule, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.2.2. of the Tariff.

II. ELIGIBILITY FOR PAYMENT UNDER SCHEDULE 2

A. Qualified Generator Reactive Resources

Qualified Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. A Qualified Generator Reactive Resource shall be offered into the Real-Time Energy Market at a MW level of at least its Economic Min in all hours of the month whenever the resource is physically available, and

be eligible for commitment by the ISO for the purpose of providing reactive power voltage support to the New England Transmission System. Qualified Generator Reactive Resources are subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures for the purpose of providing reactive power voltage support to the New England Transmission System. In addition, any generator that is dispatched by ISO for the purpose of providing voltage support to the New England Transmission System shall be eligible to recover its Lost Opportunity Costs ("LOC"), Cost of Energy Consumed ("CEC"), and Cost of Energy Produced ("CEP") pursuant to Sections IV.B-D of this Schedule 2.

A generator is eligible to be designated as a Qualified Generator Reactive Resource by the ISO if it meets the criteria listed below, and a Qualified Generator Reactive Resource designation may be retained as long as the criteria listed below continues to be met:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;

2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;

3. the generator provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulating equipment status telemetered to the ISO and the applicable Local Control Center;

4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents;

5. the installation of the generator shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor or successor provisions under the New England regional transmission arrangements; and

6. the Market Participant provides accurate reactive capability data to the ISO as specified in ISO New England Operating Documents.

B. Qualified Non-Generator Reactive Resources

Qualified Non-Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. However, to the extent that cost recovery for the dynamic reactive power capability of a non-generator resource could occur under the PTF cost recovery mechanism, it shall occur only under such cost recovery mechanism and not under this Schedule 2.

A non-generator is eligible to be designated as a Qualified Non-Generator Reactive Resource by the ISO if it meets the criteria listed below, and a Qualified Non-Generator Reactive Resource designation may be retained as long as the criteria listed below continues to be met:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;

2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;

3. the type of dynamic reactive power equipment is within a category of equipment that has been approved by the ISO, with advisory input from the Reliability Committee;

4. the dynamic reactive power equipment is subject to the Operating Authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment are in place;

5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulating equipment status telemetered to the ISO and the applicable Local Control Center;

6. the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents;

7. the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor provisions under the New England regional transmission arrangements; and

8. the Market Participant provides accurate reactive capability data to the ISO as specified in ISO New England Operating Documents.

C. Non-Dynamic Reactive Resources

Nothing in this Schedule 2 is intended to preclude, or provide support for, the cost recovery under a separate schedule to the Tariff, filed with the Commission pursuant to the requirements of Sections 205 or 206 of the Federal Power Act, for non-generator, non-dynamic reactive resources that are interconnected to and provide VAR Service to the New England Transmission System but do not meet the criteria to be deemed either Qualified Non-Generator Reactive Resources or PTF.

III. DETERMINATION AND ALLOCATION OF VAR SERVICE CHARGES

Transmission Customers and Large Load Transmission Customers must purchase VAR Service from the ISO for the support of transmission voltages on the New England Transmission System. With the exception of VAR Service charges related to high voltage conditions, the hourly charge for VAR Service shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service and each Large Load Transmission Customer that receives Firm Contract Demand Service, Non-Firm Contract Demand Service, and/or Interim Contract Demand Service. In the event that VAR Service charges for an hour are exclusively related to service provided to meet reliability criteria that address high voltage conditions in one or more Reliability Regions, then the VAR Service charges associated with high voltage conditions for that hour are allocated to each Transmission Customer within the affected Reliability Regions that receives Regional Network Service based on its pro rata share of Regional Network Load and Firm Contract Demand Service, Non-Firm Contract Demand Service, and/or Interim Contract Demand Service within the affected Reliability Regions, and to each Large Load Transmission Customer that receives Firm Contract Demand Service, Non-Firm Contract Demand Service, and/or Interim Contract Demand Service based on its pro rata share of Regional Network Load and demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and/or Interim

Contract Demand Service within the affected Reliability Regions as determined in Section II.62 of the OATT. VAR Service charges are determined pursuant to the following formula:

$$CH = (CC + LOC_O + CEC_O + CEP_O)\ \left(\frac{HL_1 + RC_1}{HL + RC}\right)$$

$$+ (LOC_{HV} + CEC_{HV} + CEP_{HV}) \left(\frac{HLR_1}{HLR}\right)$$

in which the inputs to the formula have the following meaning:

CH = the amount to be paid by the Transmission Customer and/or Large Load Transmission Customer for the hour;

CC = the Capacity Costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC_{HV} = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that supplies VAR Service to meet reliability criteria in the Transmission Customer's and/or Large Load Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

LOC_O = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that provides VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service that is supplied exclusively to address high voltage conditions;

CEP_{HV} = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria in the Transmission Customer's and/or Large Load Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEP_O = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

CEC_{HV} = the Cost of Energy Consumed which is the cost of energy used in the hour by a dynamic reactive power resource in order to supply VAR Service to meet reliability criteria in the Transmission Customer's and/or Large Load Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEC_O = the Cost of Energy Consumed which is the cost of Energy used in the hour by a dynamic reactive power resource in order to provide VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

HL_1 = the Regional Network Load of the Transmission Customer or demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and/or Interim Contract Demand Service for the Large Load Transmission Customer as determined in Section II.62 of the OATT for the hour;

HL = the aggregate of the Regional Network Loads of all Transmission Customers and demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and/or Interim Contract Demand Service for ~~the~~ all Large Load Transmission Customers as determined in Section II.62 of the OATT for the hour;

HLR_1 = that portion of the Regional Network Load of the Transmission Customer and demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and/or Interim Contract Demand Service for the Large Load Transmission Customer as determined in Section II.62 of the OATT that is within a Reliability Region where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

HLR = the aggregate of all the Regional Network Loads of all Transmission Customers- and demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and/or Interim Contract Demand Service for ~~the~~ all Large Load Transmission Customers as determined in Section II.62 of the OATT within Reliability Regions where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

RC_1 = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour, excluding any Coordinated External Transaction Reserved Capacity for Through or Out Service; and

RC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour, excluding all Coordinated External Transaction Reserved Capacity for Through or Out Service.

IV. DETERMINING A QUALIFIED REACTIVE RESOURCE'S PAYMENT UNDER THIS SCHEDULE

The compensation to be paid to resources providing VAR Service shall be as set forth below.

A. Capacity Cost (CC)

1. A Qualified Reactive Resource shall be eligible to receive VAR Payments under the Capacity Cost component of this Schedule 2 for the capability to provide VAR Service.

2. Payment for VAR Service is intended to compensate a Qualified Generator or Non-Generator Reactive Resource for VAR Service at the resource's Point of Interconnection. For those resources interconnected under an agreement other than the Interconnection Agreement established pursuant to Schedules 22, 23, or 25 and without a defined Point of Interconnection, the resource will be compensated for VAR Service at the point where the resource interconnected to the existing Administered Transmission System.

3. Payment for VAR Service associated with lagging capability is not intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the

generator step-up transformer. Payment for VAR Service associated with leading capability is intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer.

4. The "VAR CC Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the Adjusted CC Rate * Min (1, (1.2*Forecast Peak Adjusted Reference Load for the year/(SUM of all Qualified Reactive Resources' Summer Seasonal Claimed Capability))).

5. The "Base CC Rate" shall be $2.19/kVAR-yr effective January 1, 2012.

6. The Adjusted CC Rate shall be a single rate applied over the full range of leading and lagging capability of a Qualified Reactive Resource and shall be determined as described below. The Base CC Rate shall be converted into an Adjusted CC Rate, expressed in the form of $/kVARyr, representing the amount to be paid for leading and lagging capability. The Adjusted CC Rate shall be calculated in accordance with the following formula: Adjusted CC Rate (CCRateadjusted) shall equal: (the Base CC Rate (CCRatebase) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The basis of each such formula element and methodology for calculation is set forth in the Schedule 2 VAR Payment Implementation Rule. The details of the Schedule 2 VAR Payment Implementation Rule may be modified by the ISO without a filing under the Federal Power Act, provided that: (i) the modifications are consistent with the requirements of this Schedule 2; and (ii) the modifications receive the support of at least two-thirds of the voting percentage of the Transmission Committee members.

7. The "Forecast Peak Adjustment Reference Load" shall be the value published in the then-most recently published Forecast Report of Capacity, Energy, Loads and Transmission (the "CELT Report") at the time the VAR CC Rate is established for a year.

8. "Seasonal Claimed Capability" for Qualified Reactive Resources shall be determined as follows:

a. A "Qualified Generator Reactive Resource's Seasonal Claimed Capability" shall be the Seasonal Claimed Capability of each Qualified Generator applicable for the season in which the ISO Forecast Peak Adjusted Load is forecast to occur. The Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit (or ISO approved combination of units in accordance with ISO New England Operating Procedures). Claimed Capability Ratings are the maximum dependable load carrying ability, in megawatts to three decimal places, of such unit or units, excluding capacity required for station use. SCC-S and SCC-W are the MW values of the Resource that will be used as billing determinants under this Tariff.

b. A "Qualified Non-Generator Reactive Resource's Seasonal Claimed Capability" shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability in megawatts to three decimal places.

9. The "VAR Revenue Requirement" shall be the sum over a month of all Qualified Reactive Resources' VAR Payments.

10. A Qualified Reactive Resource's VAR Payment shall equal (1/12) * (VAR CC Rate*Qualified VARs).

11. Qualified Reactive Resources will be paid their VAR Payment under this Section for each month of a calendar year starting with the month in which the resource is approved as a Qualified Reactive Resource.

12. "Qualified VARs" shall be determined as follows:

(a) In accordance with the ISO New England Operating Procedures, the Qualified VARs of a Qualified Reactive Resource shall:

i. be determined through actual testing in accordance with the then-applicable VAR testing procedures set forth in the ISO New England Operating Procedures. At least every five (5) years after that initial test, an ongoing test of the capability of a

Qualified Reactive Resource to supply VAR Service in both leading and lagging capability shall be conducted.

ii. use the average value of the reactive output or absorption during the lagging or leading test respectively, except that if any recorded value is less than 75% of the average value, the Qualified VARs shall be based upon that minimum value.

iii. equal the sum total of the absolute values of the leading and lagging VAR capability of the resource determined pursuant to this section.

(b) Qualified VARs of a Qualified Generator Reactive Resource:

- The Qualified VARs of a Qualified Generator Reactive Resource that i) has not yet performed an initial Reactive Capability Audit; or ii) has been granted a waiver under the Ancillary Service Schedule 2 Business Procedure of the audit-based calculation of Qualified VARs shall be equal to the sum of the absolute values of the:
    i) lagging VAR capability (adjusted downward for reactive power absorbed between the resource and its Point(s) of Interconnection):
        a) At 90% of the Summer Network Resource Capability for Intermittent Power Resources, Continuous Storage Facilities, and Qualified Generator Reactive Resources without a Summer Seasonal Claimed Capability, or,
        b) At the Summer Seasonal Claimed Capability for non-intermittent Generator Reactive Resources;

        -and-

    ii) leading VAR capability (adjusted upward for reactive power absorbed between the resource and its Point(s) of Interconnection) at Economic Min with all generating units of the Qualified Generator Reactive Resource online.

(c) The Qualified VARs of a Qualified Non-Generator Reactive Resource that i) has not yet performed an initial Reactive Capability Audit; or ii) has been granted a waiver under the Ancillary Service Schedule 2 Business Procedure of the audit-based calculation of Qualified VARs shall be equal to the sum of the absolute values of the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point and the leading VAR capability at the corresponding Economic Min point or an

equivalent point as indicated on the Qualified Non-Generator Reactive Resource's reactive capability data, as required in ISO Operating Documents, that is submitted to and approved by the ISO and then in effect adjusted for reactive power absorbed between the resource and its Point(s) of Interconnection.

B. Lost Opportunity Cost (LOC)

1. The LOC for generators that are dispatched down by, or at the request of, the ISO, or a Local Control Center for the purpose of providing VAR Service will be calculated pursuant to Market Rule 1.

2. Qualified Non-Generator Reactive Resources shall be eligible for payment of the LOC for Qualified Non-Generator Reactive Resources that are dispatched down (pursuant to the authority established within written operating protocols developed under Section II.B.4) at the request of the ISO or a Local Control Center for the purpose of providing VAR Service. The LOC of such Qualified Non-Generator Reactive Resources will be calculated pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

C. Cost of Energy Consumed (CEC)

1. The CEC associated with resources that are producing or absorbing reactive power at zero real power output at the request of the ISO or a Local Control Center for the purpose of providing VAR Service will equal the cost of the additional Energy to produce the reactive power and will be calculated in each hour as follows: CEC = (MWhUnit * (LMP or actual Energy cost), where the MWh Unit are calculated pursuant to the Ancillary Service Schedule 2 Business Procedure. The actual Energy cost applies only if the Energy is purchased through a bilateral contract.

2. For the Chester SVC, or any other non-generator reactive resource, recovering its costs under another Tariff schedule, the CEC will be set to zero ($0), and the cost of Energy to supply reactive supply and voltage control from the resource will be treated as losses on the New England Transmission System.

D. Cost of Energy Produced (CEP)

1. The CEP associated with generating units that are brought on-line by the ISO or a Local Control Center for the purpose of providing VAR Service shall equal the portion of the total NCPC (as defined in Market Rule 1) to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.

2. Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEP incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEP of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

V. ALTERNATIVE PAYMENT FOR VAR SERVICE

Where a non-generator source of VAR Service (i) responds to identified needs for dynamic reactive power on the New England Transmission System, as identified in the Regional System Plan, and (ii) is confirmed by the ISO as a dynamic reactive power resource that will meet the identified need, and (iii) such non-generator source of VAR Service meets the criteria to be a Qualified Non-Generator Reactive Resource but cannot recover its costs of providing dynamic reactive power under Schedule 2, such non-generator may submit a separate schedule to the ISO OATT to be filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act for a rate to be paid to allow such resource to recover its costs related to providing VAR Service. In such case, it shall not be considered a Qualified Non-Generator Reactive Resource under this Schedule 2 and its provision of VAR Service and payment shall be governed solely by such separate schedule filed with the Commission.

SCHEDULE 2 VAR PAYMENT IMPLEMENTATION RULE

This rule describes the steps to be taken to calculate the VAR CC Rate in accordance with Section IV.A. of Schedule 2. On an annual basis, the Base CC Rate shall be converted into a VAR CC Rate, expressed in the form of $/kVAR-yr, representing the amount to be paid for leading and lagging capability.

The following calculations shall be done in December of each year to calculate the VAR CC Rate for the next year of VAR Payments for leading and lagging reactive power capability in the following year. As described below, the VAR CC Rate shall be updated on an annual basis utilizing the most current leading and lagging test results, and it is expected to take three years to test all of the Qualified Reactive Resources in leading mode.

1. Calculate the "Current Total Aggregate Lagging VARs", which shall equal the "Current Net Aggregate Tested Lagging VARs" plus the "Current Net Aggregate Non-Tested Lagging VARs"; Where:

   a. the Current Net Aggregate Tested Lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful lagging VAR test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of a Schedule 2 Qualified Reactive Resource as taken from its lagging VAR test results adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection, (i.e., gross lagging VARs test results adjusted down for losses); and

   b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of a Schedule 2 Qualified Reactive Resource as taken from its reactive capability (and line and transformer impedance, where needed to calculate losses) data, submitted to and approved by the ISO, at the points defined in IV.12, adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection (i.e., gross lagging VARs reactive capability data, as required in ISO Operating Documents, at SCC adjusted down for losses).

   c. Increase and decrease limiters shall be applied to potential increases or decreases in the Current Total Aggregate Lagging VARs as follows:

   i. Current Total Aggregate Lagging VARs Limiters for 2010:
   • The Current Total Aggregate Lagging VARs value shall not be limited for 2010.

ii. Current Total Aggregate Lagging VARs Limiters for 2011 and beyond:

• Current Total Aggregate Lagging VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 130% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and

• Current Total Aggregate Lagging VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010.

2. Calculate the Current Total Aggregate Leading VARs which shall equal the Current Net Aggregate Tested Leading VARs plus the Current Net Aggregate Non-Tested Leading VARs;

Where:

a. the Current Net Aggregate Tested Leading VARs shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful Leading VAR Test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its leading VAR test results adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection (i.e., gross leading VARs test results adjusted up for losses);

b. the Current Net Aggregate Non-Tested Leading VARs: shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful Leading VAR Test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website. This value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its reactive capability data, as required in the ISO Operating Documents, (and line and transformer impedance, where needed to calculate losses) data at the points defined in IV.12, adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection, (i.e., gross leading

VARs reactive capability data, as required in the ISO Operating Documents, at Economic Min adjusted up for losses).

c. Current Total Aggregate Leading VARs Limiters

i. Current Total Aggregate Leading VARs Limiters for 2010:
• The Current Total Aggregate Leading VARs value shall not be limited for 2010.

ii. Current Total Aggregate Leading VARs Limiters for 2011 and beyond:

• Current Total Aggregate Leading VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 130% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and

• Current Total Aggregate Leading VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no less than 70% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010.

3. Calculate the Adjusted CC Rate ($CCRate_{adjusted}$): shall equal (the Base CC $Rate_e$ * Current Total Aggregate Lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs).

4. VAR CC Rate ("VARCCRate"): shall equal (the Adjusted CC Rate) * (the lesser of 1 or (1.2 * "Forecast Peak Adjusted Reference Load" for the year / the sum of the "Qualified Reactive Resources' Seasonal Claimed Capability"));

Where:

a. the "Forecast Peak Adjusted Reference Load" for the year shall equal the amount specified as "Adjusted Reference Load" for the applicable year in *Section I.1 -Summaries – Summer* from the most current *Forecast Report of Capability, Energy, Loads and Transmission (CELT Report)*;

b. The sum of the "Qualified Reactive Resources' Seasonal Claimed Capability" shall equal the Qualified Generator Reactive Resources' Seasonal Claimed Capability plus the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability;

Where:

i. the Qualified Generator Reactive Resources' Seasonal Claimed Capability is reflected in the VAR Annual Capacity Cost Rate Report; and

ii. the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability is reflected in the VAR Annual Capacity Cost Rate Report.

5. Monthly VAR Payment for a Qualified Reactive Resource in a particular month shall equal the (VARCCRate / 12 * (its Monthly Net Lagging VARs for that month + its Monthly Net Leading VARs for that month)), as reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.

a. Monthly Net Lagging VARs: Qualified Reactive Resource's Monthly Net Lagging VARs value shall equal its VAR value based on (a) its most recent successful Lagging VAR test or (b) if it has not yet completed such a test, its VAR value at SCC, or equivalent point, based on its submitted and ISO accepted reactive capability data, as required in the ISO Operating Documents, and line and transformer impedance data. The Qualified VAR Resource's Monthly Net Lagging VARs value shall be reflected in the applicable monthly VAR Status Summary Report that is posted on the ISO website.

b. Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at Economic Min, or equivalent point, based on its submitted and ISO accepted reactive capability data, as required in the ISO Operating Documents, and line and transformer impedance data. The Qualified Reactive Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly VAR Status Summary Report that is posted on the ISO website.

SCHEDULE 16
Blackstart Service

Introduction and Description of Service

Blackstart Service is necessary to facilitate a stable and orderly system restoration following a partial or complete shutdown of the New England Transmission System. Resources are offered by Blackstart Owners to provide Blackstart Service and, if selected by the ISO, are modified (if required), maintained, tested and operated by a Market Participant, or its designee, in accordance with this Schedule 16. The ISO shall select those resources whose locations and capabilities support the New England System Restoration Plan. Following agreement between the owner and the ISO, such selected resources ("Designated Blackstart Resources") shall provide and are eligible to receive compensation for providing Blackstart Service. Blackstart Service is provided by Blackstart Owners via Designated Blackstart Resources, arranged for through the ISO, and utilized by Transmission Customers and Large Load Transmission Customers. Transmission Customers are charged for Blackstart Service based on their pro-rata share of Monthly Regional Network Load and demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service as determined in Section II.62 of the OATT. Large Load Transmission Customers are charged for Blackstart Service based on their pro-rata share of Monthly Regional Network Load and demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service as determined in Section II.62 of the OATT.

1. Eligibility Requirements:

A resource must meet the eligibility requirements listed below, as detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), to be considered for compensation as a Designated Blackstart Resource.

1.1. The Blackstart Owner offers the resource to provide Blackstart Service;

1.2. The offered resource must be selected by the ISO to provide Blackstart Service, based on the technical requirements to satisfy NERC, NPCC and ISO restoration criteria;

1.3. The ISO accepts the Blackstart Owner's offer to provide Blackstart Service;

1.4. The Blackstart Owner and resource meet the following Blackstart Service Minimum Criteria:

1.4.1. the resource is located within the ISO New England Reliability Coordinator Area;

1.4.2. the resource is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System;

1.4.3. the resource is capable of starting and remaining energized without support from either offsite power or another Designated Blackstart Resource until such time as additional load is directed to be picked up pursuant to instruction from the ISO or Local Control Center;

1.4.4. the resource is capable of closing its output circuit breaker to a de-energized bus;

1.4.5. the resource is maintained and staffed in a manner that allows it to be brought online and available for loading by the ISO or Local Control Center within a specified time period, with such period being measured from the initiation of the startup instruction from the ISO or Local Control Center;

1.4.6. the resource has the ability to maintain frequency within a prescribed range and is able to operate in a mode with zero governor droop or the equivalent;

1.4.7. the resource has an automatic voltage regulator capable of being placed in automatic voltage control mode;

1.4.8. the resource has the ability to provide lead and lag power factor capability;

1.4.9. the resource has access to a fuel supply during a shutdown of the New England Transmission System that will allow it to, in accordance with ISO or Local Control Center dispatch instruction, run at full capacity for a specified minimum amount of time;

1.4.10. the Blackstart Owner maintains a communication capability from the resource to either the Local Control Center or the ISO, as directed by the ISO, that is independent of a public telephone or cellular phone communication network and is confirmed to be capable of operating during a shutdown of the New England Transmission System; and

1.5. A Blackstart Service Commitment is established between the Blackstart Owner and the ISO.

2. Term of Blackstart Service

2.1. Term of Blackstart Service Commitment:

The Designated Blackstart Resource's term of Blackstart Service Commitment, as established under OP 11, shall start on the effective date of the resource's Blackstart Service Commitment and, for a resource that:

2.1.1. does not establish a Specified-Term Blackstart Capital Payment, the Blackstart Service Commitment shall continue until terminated in accordance with Section 2.3. The Blackstart Owner and the ISO by mutual agreement may establish a minimum period for the open term, which shall not be greater than the number of years of the recovery period, as shown in Table 4a of Appendix A, that corresponds to the age of the Designated Blackstart Resource on the effective date of the Blackstart Service Commitment.

2.1.2. establishes a Specified-Term Blackstart Capital Payment, the term of Blackstart Service Commitment shall equal the number of years of the recovery period, as shown in Table 4a of Appendix A, that corresponds to the age of the Designated Blackstart Resource on the effective date of the Blackstart Service Commitment (i.e., the "specified term"). The age of the resource shall be calculated based on the "In-Service Date", as stated in the ISO's "Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report)."

At the expiration of the specified term of Blackstart Service Commitment and unless otherwise terminated in accordance with Section 2.3, a Designated Blackstart Resource will commence a new term of Blackstart Service Commitment in accordance with Section 2.1 and OP 11.

2.2 Termination:

2.2.1. Mutual Termination: The Blackstart Service Commitment may be terminated at any time by mutual agreement of the Blackstart Owner and ISO. If the Blackstart Service Commitment is terminated under this provision, then the Designated Blackstart Resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments.

2.2.2. Unilateral Termination:

2.2.2.1. Either the Blackstart Owner or the ISO may terminate the Blackstart Service Commitment upon at least two (2) years' written notice to the other party following the effective date of the Blackstart Service Commitment. In the event of a Force Majeure, the two-year written notice requirement shall be waived.

2.2.2.1.1. If the Blackstart Owner terminates the Blackstart Service Commitment under this provision, then the Designated Blackstart Resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments, except as provided for in Section 2.3.2.1.2.

2.2.2.1.2. A Blackstart Owner may terminate the Blackstart Service Commitment of a Designated Blackstart Resource that establishes a Specified-Term Blackstart Capital Payment in order to retire or deactivate the Designated Blackstart Resource if such retirement or deactivation has been approved or required under the Tariff. The payment of the Blackstart O&M Payment shall cease on the first day of the month following the day, as recognized by ISO, that the Designated Blackstart Resource stopped providing Blackstart Service.

If the Blackstart Resource is retired or deactivated in compliance with this Section, then it shall receive a single lump-sum payment in the month following the effective date of the retirement or deactivation that equals the Lump Sum Blackstart Capital Payment as determined in Section 5.4.

2.2.2.1.3. If the ISO terminates a Blackstart Service Commitment under this provision for reasons other than provided in Section 2.3.2.2, then:

2.2.2.1.3.1. the Designated Blackstart Resource's Blackstart O&M Payment will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated; and

2.2.2.1.3.2. the Blackstart Resource shall receive a single lump-sum payment in the month following the effective date of the termination that equals the Lump Sum Blackstart Capital Payment as determined in Section 5.4.

2.2.2.2. Regardless of the term length, the ISO may terminate the Blackstart Service Commitment:

2.2.2.2.1. with ninety (90) days' notice to the Blackstart Owner following the issuance by the ISO to the Blackstart Owner of a Failure to Maintain Blackstart Capability notice. The ISO shall not terminate the Blackstart Service Commitment if the Blackstart Owner corrects the failure within this ninety-day notice period; or

2.2.2.2.2. with ninety (90) days notice to the Blackstart Owner following the issuance by the ISO to the Blackstart Owner of a Failure to Perform During a System Restoration notice.

The ISO shall not terminate the Blackstart Service Commitment if the Failure to Perform During a System Restoration was determined by the ISO to be due to an event of Force Majeure.

2.2.2.2.3. If the ISO terminates the Blackstart Service Commitment under either Section 2.2.2.2.1 or Section 2.2.2.2.2, then any remaining Designated Blackstart Resource Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments.

3. Rights and Obligations

3.1. The Blackstart Owner shall follow ISO and Local Control Center operating dispatch instructions during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System, in accordance with the Designated Blackstart Resource's Blackstart Service obligations, as stated in this Section 3, and Blackstart Service Minimum Criteria.

3.2. The Blackstart Owner shall not subject the Designated Blackstart Resource to any agreement, arrangement or procedure that conflicts with the resource's ability to provide Blackstart Service, including any agreement, arrangement or procedure that would prevent the resource from following ISO or Local Control Center dispatch instructions during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

3.3. The Blackstart Owner shall maintain the ability of the Designated Blackstart Resource to perform in accordance with ISO New England Operating Documents.

3.4. The Blackstart Owner shall, at least once every 12 months, ensure that the Designated Blackstart Resource passes all Blackstart Capability Tests and complies with all reporting requirements, in accordance with OP 11.

3.5. The ISO shall have the right to be present during the performance of a Blackstart Capability Test and to inspect the Designated Blackstart Resource and the Blackstart Owner's procedures and records that pertain to the operation and maintenance of Blackstart Service to confirm the resource's ability to provide Blackstart Service and assess the accuracy of information provided to the ISO and Local Control Centers.

3.6. A Blackstart Owner that desires to submit a request to retire or deactivate or modify equipment that would diminish the ability of a Designated Blackstart Resource to provide

Blackstart Service may submit the request if it simultaneously submits a notice of Blackstart Service Commitment termination to the ISO in accordance with Section 2.3. The notice of Blackstart Service Commitment termination may be conditional on the ISO's approval of the request to retire, deactivate, or modify.

3.7. The terms and conditions of Schedule 16 shall apply to the Designated Blackstart Resource, whether or not it has a Capacity Supply Obligation, while the Designated Blackstart Resource is committed to provide Blackstart Service.

3.8. The Blackstart Owner shall be entitled to take the Designated Blackstart Resource out of operation in accordance with the schedule for planned outages as established by the ISO, provided that the ISO has the right, working with the Blackstart Owner and the Local Control Center, to reposition the outage for reliability reasons with respect to Blackstart Service when establishing the planned outage schedule.

3.9. The Blackstart Owner shall inform the ISO and Local Control Center of any planned outage of equipment under the Blackstart Owner's control that affects the Designated Blackstart Resource's ability to provide Blackstart Service.

3.10. The Blackstart Owner shall maintain documentation of its procedures and training for starting the resource, energizing a de-energized bus and maintaining voltage and frequency during restoration, and provide this documentation to the ISO, upon request.

4. Failure to Meet Blackstart Service Obligations

4.1. A Blackstart Owner shall notify the ISO and Local Control Center as soon as practicable and within 15 minutes of identifying a failure or inability of a Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria and Blackstart Service obligations specified in Schedule 16 and in the ISO New England Operating Documents pertaining to Blackstart Service. Such conditions include any forced outage of equipment under the Blackstart Owner's control that affects the Designated Blackstart Resource's ability to provide Blackstart Service, or that might constitute a Failure to Maintain Blackstart Capability or a Failure to Perform During a System Restoration.

4.2. Upon receipt of the notice described in Section 4.1, the ISO shall assess all available information associated with a Designated Blackstart Resource's inability to meet its Blackstart Service Minimum Criteria and Blackstart Service obligations, and provide notice to the Blackstart Owner that a Failure to Maintain Blackstart Capability or a Failure to Perform During a System

Restoration event has occurred (collectively or individually, a "Failure") if the ISO determines based on that assessment that a Failure has occurred.

4.3. The Blackstart Owner shall exercise diligence to correct the condition that caused the Failure promptly and provide notice to the ISO when the Failure has been corrected. The ISO shall review and provide prompt acknowledgement of such notice. If the Blackstart Owner determines that the Failure will continue for a period greater than 30 days from the date of the Failure, the Blackstart Owner shall submit a correction plan for approval by the ISO.

4.4. Suspension of Payments as a result of a Failure to Maintain Blackstart Capability.

4.4.1. If a Failure to Maintain Blackstart Capability has not been corrected within 30 days from date of the Failure, regardless of whether an ISO-approved correction plan is in place, then the ISO shall set the Designated Blackstart Resource's Blackstart O&M Payment to zero effective on the date of the Failure.

4.4.2. If a Failure to Maintain Blackstart Capability has not been corrected within 60 days from the date of the Failure or on a date established by the ISO based on a Blackstart Owner's submitted correction plan (whichever is later), then the ISO shall set the Designated Blackstart Resource's Total Blackstart Capital Payment to zero beginning on the day following the date that the correction was to be completed.

4.5. Suspension of Payments as a result of a Failure to Perform During a System Restoration: Following a Failure to Perform During a System Restoration event, the ISO shall set the Designated Blackstart Resource's Blackstart O&M Payment and Total Blackstart Capital Payment to zero effective on the date of the Failure to Perform During a System Restoration. The ISO shall not suspend a Designated Blackstart Resource's Blackstart O&M Payment and Total Blackstart Capital Payment, if the Failure to Perform During a System Restoration was determined by the ISO to be due to an event of Force Majeure.

4.6. Resumption of Suspended Payments: Following the suspension of a Blackstart O&M Payment or Total Blackstart Capital Payment, the payment(s) shall resume upon the date, as recognized by the ISO, on which the Failure was corrected, *provided, however*, that the ISO retains its rights to terminate under the circumstances described in Section 2.3.2.2.

4.7. Suspension of Payments or a Resumption of Suspended Payments: A suspension of payments or a resumption of suspended payments under Section 4 shall result in a pro rata

adjustment of the resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, for the month(s) in which the suspension is applied or removed.

5. Blackstart Service Payments

A Blackstart Owner is eligible to receive payment for the provision of Blackstart Service from a Designated Blackstart Resource based on either the Blackstart Standard Rate Payment established in accordance with Section 5.1 or a Blackstart Station-specific Rate Payment established in accordance with Section 5.2. Unless stated otherwise, a Designated Blackstart Resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, shall start on the first day of the month following the effective day of the Blackstart Service Commitment, and shall cease on the first day of the month following the day that the Blackstart Service Commitment is terminated.

5.1. Blackstart Standard Rate Payment

5.1.1. General Provisions

The Blackstart Standard Rate Payment utilizes the payment parameters contained within Appendix A to Schedule 16 – Blackstart Standard Rate Components and Capital Recovery Factors ("Appendix A"). The ISO utilizes Appendix A, the ISO's CELT Report and documentation provided by the Blackstart Owner to determine the Blackstart Standard Rate Payment that a Designated Blackstart Resource is to receive for Blackstart Service.

5.1.1.1. Designated Blackstart Resources that the ISO recognizes as requiring the addition of Blackstart Equipment to meet Blackstart Service Minimum Criteria may elect to establish the Specified-Term Blackstart Capital Payment for a single term determined in accordance with Section 2.1.2.

5.1.1.2. Designated Blackstart Resources may establish one (and only one) of the following: Station-level Standard Blackstart Capital Payment, an individual Additional Resource Standard Blackstart Capital Payment, a Station-level Specified-Term Blackstart Capital Payment or an individual Additional Resource Specified-Term Blackstart Capital Payment.

5.1.1.3. The values in Tables 1, 2, 3, and 7 of Appendix A shall be adjusted on an annual basis in accordance with the most recent "Handy-Whitman Index of Public Utility Construction Costs" and then rounded to the nearest dollar. The annual adjustment calculation shall become effective on January 1 of the next year. The ISO shall post on its website the updated Appendix A.

The adjustment of the values in Table 1 and Table 7 shall be derived based on the Handy-Whitman index values for the North Atlantic Region for July for "Common Labor" at Table B-1, line 19 (or its successor).

The adjustment of the values in Table 2 and Table 3 shall be derived based on the Handy-Whitman index values for the North Atlantic Region for July for "Total Other Production Plant" at Table E-1, line 28 (or its successor).

5.1.2. A Designated Blackstart Resource at a Blackstart Station shall be entitled to Blackstart Service compensation in a month based on the following formula, Blackstart Owner-submitted data and values from Appendix A.

Blackstart Standard Rate Payment $_{individual}$ = (Blackstart O&M Payment $_{station}$ + Total Blackstart Capital Payment $_{station}$) / 12 * Designated Blackstart Resource $_{individual}$ nameplate MVA value / Σ Designated Blackstart Resource $_{individual}$ nameplate MVA values at the Blackstart Station

Where:

Total Blackstart Capital Payment $_{station}$ = Standard Blackstart Capital Payment $_{station}$ + Specified-Term Blackstart Capital Payment $_{station}$

5.1.2.1. Blackstart O&M Payment $_{station}$: The Blackstart O&M Payment provides compensation to Blackstart Stations for the operating and maintenance expenses associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station, and is derived based on the following formula using data from Tables 1 and 5 of Appendix A.

Blackstart O&M Payment $_{station}$ = Station-level Blackstart O&M Payment + ΣAdditional Resource Blackstart O&M Payment for each additional Designated Blackstart Resource at the Blackstart Station.

Where:

The Station-level Blackstart O&M Payment is determined by selecting from Table 1 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the largest applicable Station-level Blackstart O&M Payment value for the Designated Blackstart Resource(s) located at the Blackstart Station; and

The Additional Resource Blackstart O&M Payment is determined by selecting from Table 1 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the applicable payment values associated with each additional Designated Blackstart Resource(s) located at the Blackstart Station and excludes the Designated Blackstart Resource used to determine the Station-level Blackstart O&M Payment.

5.1.2.2. Standard Blackstart Capital Payment $_{station}$ or Specified-Term Blackstart Capital Payment $_{station}$: The Standard Blackstart Capital Payment $_{station}$ or Specified-Term Blackstart Capital Payment $_{station}$, but not both, provides compensation to Blackstart Stations for the capital cost associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station.

5.1.2.2.1. The Standard Blackstart Capital Payment $_{station}$ is derived based on the following formula using data from Tables 2 and 5 of Appendix A.

Standard Blackstart Capital Payment $_{station}$ = Station-level Standard Blackstart Capital Payment + Σ Additional Resource Standard Blackstart Capital Payment for each additional Designated Blackstart Resource at the Blackstart Station that is eligible to establish such a payment.

Where:

The Station-level Standard Blackstart Capital Payment is determined by selecting from Table 2 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the largest applicable Station-level Standard Blackstart Capital Payment value for the Designated Blackstart Resource(s) located at the Blackstart Station that are eligible to receive a Station-level Standard Blackstart Capital Payment. The Station-level Standard Blackstart Capital Payment shall be set to zero if any Designated Blackstart Resource located at the Blackstart Station is recovering a Station-level Specified-Term Blackstart Capital Payment.

The Additional Resource Standard Blackstart Capital Payment is determined by selecting from Table 2 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the applicable payment value associated with each additional Designated Blackstart Resource (s) located at the Blackstart Station that establishes an Additional Resource Standard Blackstart Capital Payment and excludes (i) the Designated Blackstart Resource located at the Blackstart Station that is used to

establish the Station-level Standard Blackstart Capital Payment or Station-level Specified-Term Blackstart Capital Payment and (ii) the Designated Blackstart Resources located at the Blackstart Station that establish an Additional Resource Specified-Term Blackstart Capital Payment.

5.1.2.2.2. The Specified-Term Blackstart Capital Payment $_{station}$ is derived based on the following formula using data from Tables 3, 4a and 5.

Specified-Term Blackstart Capital Payment $_{station}$ = Station-level Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor + Σ Additional Resource Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor for each additional Designated Blackstart Resource at the Blackstart Station that is eligible to establish such a payment.

Where:

The Station-level Specified-Term Blackstart Capital Payment is determined by selecting, based on Tables 3 and 4a of Appendix A, the largest "Station-level Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor" value for the Designated Blackstart Resource(s) located at the Blackstart Station that are eligible to receive a Station-level Specified-Term Blackstart Capital Payment.

The Additional Resource Specified-Term Blackstart Capital Payment is determined by selecting, based on Tables 3 and 4a of Appendix A, the "Additional Resource Specified-Term Blackstart Capital Cost* the appropriate capital recovery factor" associated with each additional Designated Blackstart Resource(s)located at the Blackstart Station that establishes an Additional Resource Specified-Term Blackstart Capital Payment and excludes (i) the Designated Blackstart Resource located at the Blackstart Station that is used to establish the Station-level Standard Blackstart Capital Payment or Station-level Specified-Term Blackstart Capital Payment and (ii) the Designated Blackstart Resources located at the Blackstart Station that establish an Additional Resource Standard Blackstart Capital Payment.

The capital recovery factor is based on Table 4a of Appendix A and reflects the age of the Designated Blackstart Resource that is recovering a Specified-Term Blackstart Capital Payment, where the age is determined by the resource's "In-Service Date", as stated in the CELT Report.

5.2. Blackstart Station-specific Rate Payment

The Blackstart Station-specific Rate Payment provides compensation to Blackstart Stations for the operation, maintenance and capital expenses associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station, and is established by Commission acceptance of a Blackstart Owner's filing, under Section 205 of the Federal Power Act, to establish or revise Blackstart Station-specific Rate Payment reflecting cost-based Blackstart Service compensation.

5.2.1. The rate schedule shall specify two categories of Blackstart Service payments (Blackstart O&M Payment and Total Blackstart Capital Payment) of a Blackstart Station that are to be recovered annually for the provision of Blackstart Service.

5.2.2. The Blackstart Owner is responsible for making all appropriate filings with the Commission and Blackstart Service compensation shall be governed solely by the Commission-approved rate schedule.

5.2.3. A Designated Blackstart Resource shall be entitled to compensation in a month based on the following formula:

Blackstart Station-specific Rate Payment $_{individual}$ = (Blackstart O&M Payment $_{station}$ + Total Blackstart Capital Payment $_{station}$) / 12 * Designated Blackstart Resource $_{individual}$ nameplate MVA value / Σ Designated Blackstart Resource $_{individual}$ nameplate MVA values at the Blackstart Station.

Where:

Blackstart O&M Payment $_{station}$ = the Commission-accepted annual Blackstart O&M Payment for the Blackstart Station, which shall include operations and maintenance compensation for the provisions of Blackstart Service and for compliance with all associated NERC Critical Infrastructure Protection Reliability Standards.

Total Blackstart Capital Payment $_{station}$ = the Commission-accepted annual Blackstart Capital Payment for the Blackstart Station.

5.3. Non-Designated Blackstart Resource Study Cost Payments

If a Market Participant undertakes, at the direction of the ISO, a study to assess the viability of converting an offered resource to a Designated Blackstart Resource and the ISO issues a final determination not accepting a resource as a Designated Blackstart Resource, then the Market

Participant(s) with Ownership Shares in the resource shall be reimbursed for either (i) the Non-Designated Blackstart Resource Study Cost Payment in Table 7 to Appendix A or (ii) Commission-accepted compensation for study costs. This payment provides compensation for study costs that were incurred after the date that the Blackstart Owner and ISO agreed that studies to determine the technical feasibility of the resource to provide Blackstart Service should be undertaken through the date of the final determination, including expenses incurred to fulfill information requests. Such study cost compensation shall be made within a single monthly payment and charged to Transmission Customers based upon their pro-rata Monthly Regional Network Load share in the month in which the compensation is paid.

5.4. Lump Sum Blackstart Payment

A Lump Sum Blackstart Payment provides compensation for Designated Blackstart Resources that are retired, deactivated, or terminated under Section 2.3.2.1.2 or Section 2.3.2.1.3, respectively, and shall be paid to the retired, deactivated, or terminated Designated Blackstart Resource as a single lump-sum payment in the month following the effective date of the retirement, deactivation, or termination. A Lump Sum Blackstart Payment reflects the present value of the remaining Standard Blackstart Capital Payments due the eligible, retiring or terminated Designated Blackstart Resource(s).

5.4.1. The Lump Sum Blackstart Payment $_{individual}$ is derived based on the following formula.

Lump Sum Blackstart Payment $_{individual}$ = (Lump Sum Blackstart Capital Payment $_{station}$) * Designated Blackstart Resource $_{individual}$ nameplate MVA value of the retiring or terminated Designated Blackstart Resource / Σ all the retiring or terminated Designated Blackstart Resource $_{individual}$ nameplate MVA values at the Blackstart Station.

5.4.1.1. For eligible retiring or terminated Designated Blackstart Resource(s) receiving Blackstart Standard Rate Payment under Section 5.1, the Lump Sum Blackstart Payment $_{station}$ is derived based on the following formula using data from Tables 2, 3, 4a, 4b, and 5 of Appendix A that is in effect on the retirement, deactivation, or termination date.

5.4.1.1.1. At a Blackstart Station where (i) one of the Designated Blackstart Resources being retired, deactivated, or terminated establishes a Station-level Standard Blackstart Capital Payment, (ii) has a minimum period associated with its open-term Blackstart Service Commitment and (iii) the effective date of retirement, deactivation, or termination is within the

minimum period, the Lump Sum Blackstart Capital Payment $_{station}$ shall equal the present value of the monthly Station-level Standard Blackstart Capital Payment, using data from Tables 2, 4a, 4b and 5, for the remaining months of the minimum period associated with the open-term Blackstart Service Commitment.

5.4.1.1.2. At a Blackstart Station comprised of more than one Designated Blackstart Resource, where one of the Designated Blackstart Resources being retired, deactivated, or terminated establishes a Specified-Term Blackstart Capital Payment $_{station}$, the Lump Sum Blackstart Capital Payment station shall equal the present value of the monthly Specified-Term Blackstart Capital Payment, using data from Tables 3, 4a, 4b and 5, for the remaining months of the term of Blackstart Service Commitment.

5.4.1.1.3. The Lump Sum Blackstart Capital Payment $_{station}$ that is calculated pursuant to Section 5.4.1.1.1 or Section 5.4.1.1.2 shall be adjusted by: (a) adding, if any and as applicable, for any other Designated Blackstart Resources are being retired, deactivated, or terminated and that have a minimum period associated with the open-term Blackstart Service Commitment, the present value of the Additional Resource Standard Blackstart Capital Payment(s), using data from Tables 2, 4a, 4b and 5, for the remaining months of the applicable minimum period of Blackstart Service Commitment; (b) adding, if any and as applicable, for any other Designated Blackstart Resources are being retired, deactivated, or terminated and that have a specified-term associated with their Blackstart Service Commitment, the present value of the Additional Resource Specified-Term Blackstart Capital Cost(s), using data from Tables 3, 4a, 4b and 5, for the remaining months of the applicable specified-term Blackstart Service Commitment; (c) subtracting, if any and as applicable, for any Designated Blackstart Resources are continuing in service and that have a minimum periods associated with their open-term Blackstart Service Commitments, the present value of the new Station-level Standard Blackstart Capital Payment, using data from Tables 2, 4a, 4b and 5, for the remaining months of the applicable minimum period; and (d) subtracting, if any and as applicable, for any Designated Blackstart Resources are continuing in service and that have a specified-term Blackstart Service Commitment, the present value of the new Station-level Specified-Term Blackstart Capital Cost, using data from Tables 3, 4a, 4b and 5, for the remaining months of the applicable specified-term of Blackstart Service Commitment.

5.4.1.2. For eligible, retiring or terminated Designated Blackstart Resource(s) receiving Blackstart Station-specific Rate Payment under Section 5.2, the Lump Sum Blackstart Payment $_{individual}$, Lump Sum Blackstart Capital and Payment $_{station}$ is derived in accordance with the Lump

Sum Blackstart Payment provisions included in the applicable Blackstart Owner's Section 205 Blackstart Station-specific Rate Payment filing, as approved by FERC.

5.5. Equipment Damage Reimbursement

Blackstart Owners are eligible for Equipment Damage Reimbursement under Schedule 16 for equipment damage to a Designated Blackstart Resource: (1) that resulted from operating such equipment in response to operating dispatch instructions from the ISO during the restoration of the New England Transmission System, (2) for which reasonably available and customary insurance was sought and not available for the damages incurred and (3) that would not have occurred but for the Blackstart Owner's provision of Blackstart Service from that Designated Blackstart Resource. The burden of making such showings will be upon the Blackstart Owners and it is the responsibility of the Blackstart Owners to seek Commission approval under Section 205 of the Federal Power Act for any reimbursement under this Section. Equipment Damage Reimbursement $_{individual}$ shall equal the Commission-approved Equipment Damage Reimbursement for a Designated Blackstart Resource.

5.6. Total Blackstart Service Payments

The Total Blackstart Service Payments in a month shall be based on the following formula:

Total Blackstart Service Payments $_{month}$ = Σ Blackstart Standard Rate Payment $_{individual}$ + Σ Blackstart Station-specific Rate Payment $_{individual}$ + Σ Non-Designated Blackstart Resource Study Cost Payments for the month + Σ Lump Sum Blackstart Payments $_{individual}$ + Σ Equipment Damage Reimbursement $_{individual}$.

6. Monthly Blackstart Service Charge

Each Transmission Customer and Large Load Transmission Customer shall pay a charge for Blackstart Service in a month, which is calculated using the following formula:

Blackstart Service Charge $_{month}$ for Transmission Customer = Blackstart Service Payments $_{month}$ * (Transmission Customer's Monthly Regional Network Load for the month / (Sum of all Transmission Customer's Monthly Regional Network Load for the month plus the sum of all Large Load Transmission Customer demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service as determined in Section II.62 of the OATT for the month).

Blackstart Service Charge $_{month}$ for Large Load Transmission Customer = Blackstart Service Payments $_{month}$ * (Large Load Transmission Customer demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service as determined in Section II.62 of the OATT for the month / (Sum of all Transmission Customer's Monthly Regional Network Load for the month plus the sum of all Large Load Transmission Customer demand for Firm Contract Demand Service, Non-Firm Contract Demand Service, and Interim Contract Demand Service as determined in Section II.62 of the OATT for the month).

Appendix A to Schedule 16

Blackstart Standard Rate Components and Capital Recovery Factors

Table 1 - Blackstart O&M Payments

Designated Blackstart Resource ("DBR") Type	Station-level Blackstart O&M Payment ($/year for the first DBR)	Additional Resource Blackstart O&M Payment ($/year for each additional DBR)
Fossil Resources:		
MVA <= 10	$71,100	$11,050
10 < MVA <= 60	$77,700	$11,950
60 < MVA <= 90	$80,200	$12,750
90 < MVA <= 300, Small Starting Requirement (Simple Cycle)	$113,900	$15,450
90 < MVA <= 300, Small Starting Requirement (Combined cycle)	$416,300	$25,150
90 < MVA <= 300, Medium Starting Requirement	$672,400	$34,050
90 < MVA <= 300, Large Starting Requirement	$676,400	$34,150
300 < MVA, Large Starting Requirement	$819,700	$50,250
Hydroelectric Resources:		
10 < MVA <= 60	$77,700	$11,950
60 < MVA <= 90	$80,200	$12,750

Table 2 - Standard Blackstart Capital Payments

Designated Blackstart Resource ("DBR") Type	Proxy Unit Type	Configuration	Station-level Blackstart Capital Payment ($/year for the first DBR)	Additional Resource Blackstart Capital Payment ($/year for each additional DBR)
Fossil Resources:				
MVA <= 10	Wartsilla 34DF	1 x SCGT	$239,400	$32,300
10 < MVA <= 60	LM2500	1 x SCGT	$253,200	$32,300
60 < MVA <= 90	LM6000	1 x SCGT	$253,200	$32,300
90 < MVA <= 300, Small Starting Requirement (Simple Cycle)	LMS100	1 x SCGT	$332,000	$32,300
90 < MVA <= 300, Small Starting Requirement (Combined cycle)	GE 7EA	2 x CCGT	$1,637,300	$32,700
90 < MVA <= 300, Medium Starting Requirement	Siemens 501F	2 x CCGT	$2,488,300	$32,700
90 < MVA <= 300, Large Starting Requirement	GE 7FA	2 x CCGT	$2,488,300	$32,700
300 < MVA, Large Starting Requirement	GE HA.02	2 x CCGT	$2,997,900	$32,700
Hydroelectric Resources:				
10 < MVA <= 60	LM2500	1 x SCGT	$253,200	$32,300
60 < MVA <= 90	LM6000	1 x SCGT	$253,200	$32,300

Note: Standard Blackstart Capital Payments are calculated using Specified-Term Blackstart Capital Costs from Table 3 and a 25 Year capital recovery factor from Table 4a., rounded to nearest $100.

Table 3 - Specified-Term Blackstart Capital Cost

Designated Blackstart Resource ("DBR") Type	Configuration	Station-level Specified-Term Blackstart Capital Cost ($ for the first DBR)	Additional Resource Specified-Term Blackstart Capital Cost ($ for each additional DBR)
Fossil Resources:			
MVA <= 10	1 x SCGT	$2,170,722	$292,700
10 < MVA <= 60	1 x SCGT	$2,295,886	$292,700
60 < MVA <= 90	1 x SCGT	$2,295,886	$292,700
90 < MVA <= 300, Small Starting Requirement (Simple Cycle)	1 x SCGT	$3,010,809	$292,700
90 < MVA <= 300, Small Starting Requirement (Combined cycle)	2 x CCGT	$14,847,052	$296,300
90 < MVA <= 300, Medium Starting Requirement	2 x CCGT	$22,564,862	$296,300
90 < MVA <= 300, Large Starting Requirement	2 x CCGT	$22,564,862	$296,300
300 < MVA, Large Starting Requirement	2 x CCGT	$27,186,123	$296,300
Hydroelectric Resources:			
10 < MVA <= 60	Multi-unit Plant	$2,295,886	$292,700
60 < MVA <= 90	Multi-unit Plant	$2,295,886	$292,700

Table 4a - Blackstart Capital Recovery Factors

Designated Blackstart Resource Age	Recovery Period (years)	Capital Recovery Factor
$X \leq 5$ years	25	0.1103
$5 < X \leq 10$ years	20	0.1199
$10 < X \leq 15$ years	15	0.1371
15 years < X	10	0.1626

Table 4b - Weighted Average Cost of Capital

Weighted Average Cost of Capital	10.01%	

Table 5 - Designated Blackstart Resource Classes

Designated Blackstart Resource Type	Proxy Generating Units
Fossil Resources:	
MVA <= 10	Diesels (Wartsila)
10 < MVA <= 60	LM2500
60 < MVA <= 90	LM6000
90 < MVA <= 300 Small Starting Requirement Simple Cycle	LMS100
90 < MVA <= 300 Small Starting Requirement Combined Cycle	GE 7EA
90 < MVA <= 300 Medium Starting Requirement	Siemans 501F
90 < MVA <= 300 Large Starting Requirement	GE 7FA
300 < MVA Large Starting Requirement	GE HA.02
Hydro Resources:	
10 < MVA <= 60	LM2500
60 < MVA <= 90	LM6000

Table 6 - Reserved

Table 7 - Non-Designated Blackstart Resource Study Payment

Non-Designated Blackstart Resource Study Payment ($)	$115,560

SCHEDULE 17
RECOVERY OF CRITICAL INFRASTRUCTURE PROTECTION COSTS BY FACILITIES CRITICAL TO THE DERIVATION OF INTERCONNECTION RELIABILITY OPERATING LIMITS

Introduction

NERC Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization ("CIP-002-5.1") requires the identification, assessment and categorization of facilities that NERC defines as Bulk Electric System ("BES") Cyber Systems and associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that their loss, compromise, or misuse could have on the reliable operation of the BES. Criterion 2.6 in Attachment 1 – Impact Rating Criteria to CIP-002-5.1 assigns a medium impact rating to generation and transmission facilities that the ISO identifies as critical to the derivation of Interconnection Reliability Operating Limits and their associated contingencies ("IROL-Critical Facilities"). In accordance with CIP-002-5.1, an owner of an IROL-Critical Facility ("IROL-Critical Facility Owner") must comply with the controls included in the NERC CIP Reliability Standards corresponding to the medium impact category.

This Schedule 17 provides for the recovery of an IROL-Critical Facility Owner's incremental capital, operation and maintenance, and associated administrative and regulatory costs paid to comply with the NERC CIP Reliability Standards corresponding to the medium impact category (collectively, "IROL-CIP Costs"), as approved by the Commission's acceptance of the IROL-Critical Facility Owner's filing pursuant to Section 205 of the Federal Power Act, at one or more IROL-Critical Facilities to the extent cost recovery for the IROL-CIP Costs is not provided for under another provision of the Tariff or a contractual arrangement to which the IROL-Critical Facility Owner is a party. Eligible IROL-CIP Costs are above and beyond the costs paid by the IROL-Critical Facility Owner to comply with NERC CIP Reliability Standards corresponding to low impact requirements. Nothing in this Schedule 17 shall restrict or limit the rights of an IROL-Critical Facility Owner to make a filing with the Commission pursuant to Section 205 of the Federal Power Act to recover IROL-CIP Costs through a means other than this Schedule 17.

Under this Schedule 17, the ISO will act as the billing and collection agent on behalf of the IROL-Critical Facility Owners for recovery of their Commission-approved IROL-CIP Costs. The ISO will allocate to, invoice, and collect from Transmission Customers that receive Regional Network Service and/or Through or Out Service IROL-CIP Costs~~,~~ and Large Load Transmission Customers that receive Firm Contract

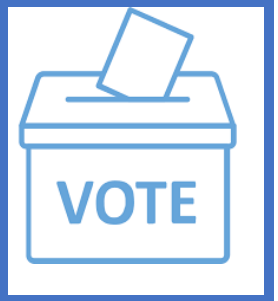
Schedule 22 Redlines

Schedule 22 redlines can be accessed here.

Schedule 23 Redlines

Schedule 23 redlines can be accessed here.

5.b Vote on Large Load Revisions: RC-Recommended Changes



60%

To consider and take action, as appropriate, on Tariff changes related to the integration of large loads, proposed in response to the FERC's June 18, 2026 New England Large and Co-Located Loads Show Cause Order: Sections I.2.2 and III.12.1 (Installed Capacity Requirement) of the Tariff, as considered by the Reliability Committee at its November 3 meeting

RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Reliability Committee, and as reflected in the materials distributed to the Participants 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 Reliability Committee.

Nov 12, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

New England Large Load Show Cause Order (EL26-72)

Tariff Revisions

Dennis Cakert, Alex Rost, and Nic Baldenko



Project Title: New England Large Load Show Cause Order (EL26-72)	WMPP ID: 196

Proposed Effective Date: November 2026
Proposed Implementation Date: June 1, 2027 (Application and Study Process), June 1, 2028 (Transmission Services)

- This project covers the ISO's and Participating Transmission Owners' (PTOs) response to the Federal Energy Regulatory Commission's (FERC) June 18, 2026 show cause order (Order)
  - See the ISO's conceptual design presentation from August 18-19, 2026, detailed design presentations from September 15, 2026, additional detail from October 14, 2026, and incremental updates from October 27, 2026

Project Title: New England Large Load Show Cause Order (EL26-72)	WMPP ID: 196

Proposed Effective Date: November 2026
Proposed Implementation Date: June 1, 2028

- Today's presentation discusses the final draft Tariff provisions for RC vote
- Revisions include the following sections:
  - Section I.2.2
  - Section III.12

SUMMARY OF PROPOSED TARIFF CHANGES: RELIABILITY COMMITTEE

Definition Changes for Reliability Committee Vote

Section	Summary of Change
Section I.2.2	**New Definitions**: Interim Contract Demand Service, Non-Firm Contract Demand Service

Tariff Changes for Reliability Committee Vote

Section	Summary of Change
Section III.12.1 – Installed capacity Requirement	Large Loads receiving Interim Contract Demand Service or Non-Firm Contract Demand Service shall be excluded from the calculation of the Installed Capacity Requirement and related values.

CONCLUSION & NEXT STEPS

Conclusion & Next Steps

- Today's presentation describes Tariff redlines associated with New England's Large Load show cause order (EL26-72)
- These redlines should be understood as complete for the purpose of voting
- The filing will be submitted to the Commission shortly after the Participants Committee vote on November 12, 2026
- The ISO will begin detailed discussion on BYONC rules in 2027

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Transmission Committee (MC Invited) **July 16, 2026**	Overview of abeyance request, timing for Section 205 process, and informational filing content
Joint Reliability and Transmission Committee (MC Invited) **August 18-19, 2026**	Overview of conceptual design proposal for Section 205 filing
Joint Transmission, Markets, and Reliability Committee **September 15, 2026**	Review of details on proposed Large Load study process, operational requirements, market design and settlements, introduction to CRA and initial Tariff redlines
Joint Transmission, Markets, and Reliability Committee **October 14, 2026**	Review of remaining design details and incremental updates to the ISO and PTO AC proposals based on stakeholder feedback, including any incremental Tariff language; Introduction of stakeholder amendments
Joint Transmission, Markets, and Reliability Committee **October 27, 2026**	Review of final proposals and associated Tariff language, focusing on any design refinements in response to stakeholder feedback and initial amendments; Review of stakeholder amendments
Transmission Committee **November 3, 2026**	Vote on TC jurisdictional redlines associated with ISO and PTO AC proposals, and any stakeholder amendments
Reliability Committee **November 3, 2026**	Vote on RC jurisdictional redlines associated with ISO proposal, and any stakeholder amendments
Markets Committee **November 3, 2026**	Vote on MC jurisdictional redlines associated with ISO proposal, and any stakeholder amendments
Participants Committee* **November 12, 2026**	Vote on ISO proposal and any stakeholder amendments

*PTO AC action will be required ahead of the PC vote and FERC filing

Technical Committee Focus on Large Loads Tariff Revisions

TC

- Section I.2.2 Defined Terms
- Section II (Open Access Transmission Tariff)

MC

- Section I.2.2 Defined Terms
- Section III (Market Rule 1)

RC

- Section I.2.2 Defined Terms
- Section III.12.1 (Installed Capacity Requirement)

Questions



I.2 Rules of Construction; Definitions

I.2.2. Definitions:

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

Interim Contract Demand Service is a type of transmission service for Large Loads described in Section II.57.1.2 of the OATT

Non-Firm Contract Demand Service is a type of transmission service for Large Loads described in Section II.57.1.3 of the OATT.

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Large Loads receiving Interim Contract Demand Service or Non-Firm Contract Demand Service shall be excluded from the calculation of the Installed Capacity Requirement and related values. Prior to each Annual Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for the Capacity Commitment Period associated with that Annual Capacity Auction in accordance with this Section III.12.1. Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall calculate an Installed Capacity Requirement for the New England Control Area for such Capacity Commitment Period in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a "resource" shall mean any Capacity Resource eligible to receive Capacity Base Payments in the Annual or Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Annual Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement. Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity

Commitment Period beginning on June 1, 2027, the ISO shall determine a system-wide Marginal Reliability Impact value for such Capacity Commitment Period.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Annual Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for the Capacity Commitment Period associated with that Annual Capacity Auction.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Annual Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

(a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Resource Adequacy Requirement for the import-constrained Capacity Zone Z shall be determined in accordance with the following formula:

$$LRA_Z = Resources_z + Proxy\ Units_z - (Proxy\ Units\ Adjustment_z(1-FOR_z)) - (Firm\ Load\ Adjustment_z(1-FOR_z))$$

In which:

LRA_Z	=	MW of Local Resource Adequacy Requirement for Capacity Zone Z;
$Resources_z$	=	MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;
$Proxy\ Units_z$	=	MW of proxy unit additions in Load Zone Z;
Firm Load $Adjustment_z$	=	MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and
FOR_z	=	Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z,

		including any proxy unit additions to Capacity Zone Z.
Proxy Units Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1 days/year.

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2. Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

(a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.

(b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.

(c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.

(d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element

with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Annual Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

(a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less

than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{RestofNewEngland}}$$

In which:

$\text{Maximum Capacity Limit}_Y$ = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

$\text{LRA}_{\text{RestofNewEngland}}$ = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.
Prior to each Annual Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit. Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall determine zonal Marginal Reliability Impact values for each export-constrained Capacity Zone for such Capacity Commitment Period.

III.12.3 Consultation and Filing of Capacity Requirements.

(a) **Capacity Requirements Filing.** At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for the Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act at least 90 days prior to the Annual Capacity Auction for the Capacity Commitment Period. For the capacity requirements that the ISO will determine for the Capacity Commitment Period beginning on June 1, 2027 described in Sections III.12.1 and III.12.2, the ISO shall file such Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Commission pursuant to Section 205 of the Federal Power Act at least 90 days prior to the third annual reconfiguration auction for such Capacity Commitment Period.

(b) **New Capacity Zone Filing.** The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given Annual Capacity Auction, any new Capacity Zone must be accepted by the Commission prior to the Deactivation Notification Deadline of the applicable Annual Capacity Auction.

III.12.4. Capacity Zones.

For each Annual Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will publish the Capacity Zones modeled for the Annual Capacity Auction publicly on its website prior to conducting the auction, in accordance with Section III.15.9:

(a) The ISO shall model in the Annual Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the Resource Adequacy Assessment Qualified Capacity and potential new capacity that could qualify to be procured in the export constrained Capacity Zone, including potential Import Capacity Resources on the export-constrained side of the interface.

(b) The ISO shall model in the Annual Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the Resource Adequacy Assessment Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all capacity for which a Deactivation Notification has been submitted for the relevant Capacity Commitment Period.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Annual Capacity Auction.

III.12.4A. Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location of Active Demand Capacity Resources. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the Deactivation Notification Deadline of the applicable Annual Capacity Auction, and those Dispatch Zones shall remain in place through the end of the Capacity Commitment Period for which they were established. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity

Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward and Annual Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include:

(a) For the relevant Capacity Commitment Period, the network model shall include:

(i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3 for the Forward Capacity Market, and other than those for which a Deactivation Notification has been submitted for the Annual Capacity Market;

(ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and

(iii) in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the Capacity Demonstration Deadline for the Annual Capacity Auction or first day of the relevant Capacity Commitment Period for the Forward Capacity Auction.

(b) Prior to each Annual Capacity Auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section

III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model for such third annual reconfiguration auction.

III.12.6.1. Process for Establishing the Network Model.

(a) The ISO shall establish an initial network model prior to the Annual Capacity Auction that only includes transmission infrastructure, including Internal Elective Transmission Upgrades, that is already in service at the time that the initial network model is developed.

(b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.

(c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission

project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner or Elective Transmission Upgrade Interconnection Customer has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner or Elective Transmission Upgrade Interconnection Customer concurs that the schedule is achievable, and it is the intent of the Transmission Owner or Elective Transmission Upgrade Interconnection Customer to build the proposed transmission project in accordance with that schedule. The Transmission Owner or Elective Transmission Upgrade Interconnection Customer may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the

Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3. Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.6.4. Transmission Solutions Selected Through the Competitive Transmission Process.

For a transmission solution, which may consist of single or multiple proposals, selected through the competitive transmission process pursuant to Sections 4.3, 4A, 16 or 17 of Attachment K, such transmission solution, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement(s). The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement(s) to determine whether to include the transmission solution, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission solution includes an upgrade(s) located on a PTO's existing transmission system where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s) being upgraded, the process for establishing the in-service date and determining whether to include the upgrade(s) on the existing transmission system, or relevant portion thereof, in the network model for the Capacity Commitment Period shall be as described in Section III.12.6.1.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2. Capacity.

(a) For calculations made in relation to the Capacity Commitment Period beginning on June 1, 2028 and Capacity Commitment Periods thereafter, the resources included in the calculation of the Installed

Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include all Capacity Resources that cleared in any previous Annual Capacity Auction or Forward Capacity Auction but shall exclude (i) Import Capacity Resources that are not backed by a multiyear contract to provide capacity in the New England Control Area that requires delivery of capacity for the Capacity Commitment Period for which the calculations are made and (ii) capacity from Capacity Resources for which a Deactivation Notification has been submitted that will be in effect for the relevant Capacity Commitment Period.

The rating of Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the Resource Adequacy Assessment Qualified Capacity for the upcoming Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the Resource Adequacy Assessment Qualified Capacity process.

(b) For calculations made in relation to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

(i) all Existing Generating Capacity Resources,

(ii) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(iii) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and

(iv) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

(v) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

(vi) capacity de-listed or retired as a result of Permanent De-List Bids, Retirement De-List Bids, or substitution auction demand bids that cleared in previous Forward Capacity Auctions, and

(vii) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand Capacity Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Capacity Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process.

III.12.7.3. Resource Availability.

(a) For calculations made in relation to the Capacity Commitment Period beginning on June 1, 2028, and Capacity Commitment Periods thereafter, the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

(i) For Generating Capacity Resources, the most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. For Generating Capacity Resources that do not have sufficient data to calculate an availability metric using the most recent five-year moving average of EFORd, class average data for similar resource types shall be used.

(ii) For Active Demand Capacity Resources, historical performance data for those resources shall be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(iii) For Distributed Energy Capacity Resources, the availability metric for each underlying technology type shall be applied in the same manner as it would be applied if the Distributed Energy Capacity Resource were qualified as a generator or demand response resource.

(b) For calculations made in relation to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

(i) For Existing Generating Capacity Resources:
the most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(ii) For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsection (a) above, class average data for similar resource types shall be used.

(iii) For existing Active Demand Capacity Resources:
historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to 1% of (the 90/10 forecasted seasonal net peak loads minus all Demand Capacity Resources).

(b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.

(c) **Maintain an adequate amount of ten-minute synchronized reserves**. The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a zone shall be the zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. To ensure that Demand Response Resources, On-Peak Demand Capacity Resources, and Seasonal Peak Demand Capacity Resources are not reflected as reductions in the load forecast, the ISO shall reflect them in historical loads as specified below.

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO.

(b) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction or Annual Capacity Auction, as appropriate, for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction or Annual Capacity Auction, as appropriate, for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

As necessary prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for

interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Annual Capacity Auction and Annual Reconfiguration Auction; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Annual Capacity Auction using the calculation methodology in this Section III.12.9. Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall calculate tie benefits for such Capacity Commitment Period using the calculation methodology in this Section III.12.9.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using a probabilistic resource adequacy simulation program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for each qualifying individual interconnection or group of interconnections using the methodology in Section

III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, "at criterion" system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

The ISO will review annually NPCC's assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring

Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

A. External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.

(i) The transmission system will be modeled using the following conditions:

1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
2. Qualified Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
3. Qualified Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction or Annual Capacity Auction, as appropriate;
4. Qualified Distributed Energy Capacity Resources reflecting their existing Qualified Capacity for the Capacity Commitment Period;
5. Transfers on the transmission system that impact the transfer capability of the interconnection under study.

(ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.

(iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

B. In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

A. Adding Proxy Units within New England when the New England system is short of capacity. In modeling New England as part of the interconnected system, if New England is short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.

B. Removing capacity from New England when the New England system is surplus of capacity. In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the Resource Adequacy Assessment Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. For the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios

described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

C. **Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity**. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.

D. **Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity**. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.

E. Maintaining the neighboring Control Area's locational resource requirements. In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

A. The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.

B. Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.

C. Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie

benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated

in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For each Annual Capacity Auction and the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively.

A. Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.

B. If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of

interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).

C. The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.

D. The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.

E. For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Annual Capacity Auction shall be any Import Capacity Resources previously cleared in a Forward Capacity Auction or Annual Capacity Auction backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the relevant Capacity Commitment Period. The capacity imports applicable for determining tie benefits for the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, are those Import Capacity Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for such annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for each Annual Capacity Auction and the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation.

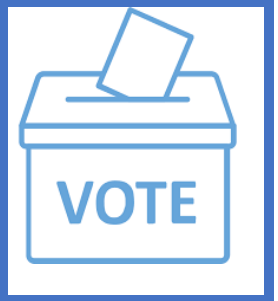
III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Annual Capacity Auction.

For external interfaces, Import Capacity Resources shall be allowed in the Annual Capacity Auction and the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

5.c Vote on Large Load Revisions: MC-Recommended Changes



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To consider and take action, as appropriate, on Tariff changes related to the integration of large loads, proposed in response to the FERC's June 18, 2026 New England Large and Co-Located Loads Show Cause Order: Section I.2.2 and Section III (Market Rule 1), including Sections III.1.10.5A, III.1.7.19.2.2.2, III.1.8.1, III.2.5, III.2.6.1, and III.15.8.5.2.1, as considered by the Markets Committee at its November 3 meeting.

RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Markets Committee, and as reflected in the materials distributed to the Participants 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.

Nov 12, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

New England Large Load Show Cause Order (EL26-72)

Tariff Revisions

Dennis Cakert, Alex Rost, and Nic Baldenko



Project Title: New England Large Load Show Cause Order (EL26-72)	WMPP ID: 196

Proposed Effective Date: November 2026
Proposed Implementation Date: June 1, 2027 (Application and Study Process), June 1, 2028 (Transmission Services)

- This project covers the ISO's and Participating Transmission Owners' (PTOs) response to the Federal Energy Regulatory Commission's (FERC) June 18, 2026 show cause order (Order)
  - See the ISO's conceptual design presentation from August 18-19, 2026, detailed design presentations from September 15, 2026, additional detail from October 14, 2026, and incremental updates from October 27, 2026

Project Title: New England Large Load Show Cause Order (EL26-72)	WMPP ID: 196

Proposed Effective Date: November 2026
Proposed Implementation Date: June 1, 2027 (Application and Study Process), June 1, 2028 (Transmission Services)

- Today's presentation discusses the final draft Tariff provisions for MC vote
- Revisions include the following sections:
  - Section I.2.2
  - Section III Table of Contents
  - Section III.1
  - Section III.2
  - Section III.15

MINOR UPDATES TO TARIFF REDLINES

Minor Updates to Tariff Redlines

- The ISO proposes an incremental redline to:
  - Clarify a defined term

Section	Tariff or Manual Change	Reason for Change
III.1.10.5A(c)(ii)	"Send a Dispatch Instruction to re-dispatch all or a portion of the Large Load's Interim Contract Demand Service and/or Non-Firm Contract Demand Service based on the Large Load's applicable Locational Marginal Price and the ~~Non-Firm~~ Large Load Re-Dispatch Price."	Use defined term

SUMMARY OF PROPOSED TARIFF CHANGES: MARKETS COMMITTEE

Definition Changes for Markets Committee Vote

Section	Summary of Change
Section I.2.2	**New Defined Terms:** Behind-the-Meter Generation, Firm Contract Demand Service, Interim Contract Demand Service, Large Load, Large Load Co-Located Generator, Large Load Electrically Proximate Generator, Large Load Re-Dispatch Price, Large Load Transmission Customer, Large Load Transmission Service Agreement, Large Load Transmission Service Application, Non-Firm Contract Demand Service

Tariff Changes for Markets Committee Vote

Section	Summary of Change
Section III.1.10.5A	Establishes what a Large Load Transmission Customer and the ISO shall do with respect to a Large Load and establishes what the Assigned Meter Reader shall do with respect to a Large Load for Revenue Quality Metering
Section III.1.7.19.2.2.2	A Large Load is ineligible to provide Real-Time Reserves
Section III.1.8.1	A Large Load is ineligible to provide Day-Ahead Ancillary Services (*i.e.*, Day-Ahead reserves)

Tariff Changes for Markets Committee Vote (cont.)

Section	Summary of Change
Section III.2.5	Re-dispatchable load (such as Large Loads with Interim Contract Demand Service and Non-Firm Contract Demand Service) can set Real-Time LMP
Section III.2.6.1	Re-dispatchable load (such as Large Loads with Interim Contract Demand Service and Non-Firm Contract Demand Service) can set Day-Ahead LMP
Section III.15.8.5.2.1	Excludes Interim Contract Demand Service and Non-Firm Contract Demand Service from capacity cost allocation

CONCLUSIONS & NEXT STEPS

Conclusion & Next Steps

- Today's presentation describes Tariff redlines associated with New England's Large Load show cause order (EL26-72)
- These redlines should be understood as complete for the purpose of voting
- The filing will be submitted to the Commission shortly after the Participants Committee vote on November 12, 2026
- The ISO will begin detailed discussion on Bring Your Own New Capacity (BYONC) rules in 2027

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Transmission Committee (MC Invited) **July 16, 2026**	Overview of abeyance request, timing for Section 205 process, and informational filing content
Joint Reliability and Transmission Committee (MC Invited) **August 18-19, 2026**	Overview of conceptual design proposal for Section 205 filing
Joint Transmission, Markets, and Reliability Committee **September 15, 2026**	Review of details on proposed Large Load study process, operational requirements, market design and settlements, introduction to CRA and initial Tariff redlines
Joint Transmission, Markets, and Reliability Committee **October 14, 2026**	Review of remaining design details and incremental updates to the ISO and PTO AC proposals based on stakeholder feedback, including any incremental Tariff language; Introduction of stakeholder amendments
Joint Transmission, Markets, and Reliability Committee **October 27, 2026**	Review of final proposals and associated Tariff language, focusing on any design refinements in response to stakeholder feedback and initial amendments; Review of stakeholder amendments
Transmission Committee **November 3, 2026**	Vote on TC jurisdictional redlines associated with ISO and PTO AC proposals, and any stakeholder amendments
Reliability Committee **November 3, 2026**	Vote on RC jurisdictional redlines associated with ISO proposal, and any stakeholder amendments
Markets Committee **November 3, 2026**	Vote on MC jurisdictional redlines associated with ISO proposal, and any stakeholder amendments
Participants Committee* **November 12, 2026**	Vote on ISO proposal and any stakeholder amendments

*PTO AC action will be required ahead of the PC vote and FERC filing

Technical Committee Focus on Large Loads Tariff Revisions

TC

- Section I.2.2 Defined Terms
- Section II (Open Access Transmission Tariff)

MC

- Section I.2.2 Defined Terms
- Section III (Market Rule 1)

RC

- Section I.2.2 Defined Terms
- Section III.12.1 (Installed Capacity Requirement)

Questions



I.2 Rules of Construction; Definitions

I.2.2. Definitions:

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

Behind-the-Meter Generation is generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, and is not separately metered in wholesale markets from the end-use customer load.

Co-Located Large Load is a configuration where a Large Load's Point of Delivery is located on the Interconnection Facilities of an existing or planned Generating Facility.

Electrically Proximate Large Load is a configuration where a Large Load's Point of Delivery is located at (or directly connected radially through dedicated facilities to) the same substation and voltage level as a Generating Facility's Point of Interconnection (or to the Generating Facility's radially dedicated facilities that connect between the substation and its Point of Interconnection), such that the Generating Facility's Point of Interconnection is sufficiently electrically close to the associated Large Load's Point of Delivery, such that the impact on the transmission system of the combination of the Generating Facility and the Large Load, with the exception of the transmission facilities between the two, will be effectively the same as if they were located at the same point.

Firm Contract Demand Service is a type of transmission service for Large Loads described in Section II.57.1.1 of the OATT.

Interim Contract Demand Service is a type of transmission service for Large Loads described in Section II.57.1.2 of the OATT

Large Load is a commercial or industrial customer, located at a single site behind one or more points of delivery, and that has a gross peak demand of 50 MW or greater, relative to its exempt demand as described in Part II.J of the OATT, interconnects to the transmission system, either directly or through a system primarily designed to serve the customer, at a voltage level of greater than 60 kV. Excluded from this definition are: electrical energy support resources such as storage resources (*e.g.*, pumped storage and battery energy storage systems); emergency and municipal services resources such as hospitals, major

medical complexes and water treatment facilities; transportation and infrastructure resources other than dedicated electric vehicle charging facilities, such as railroads and airports; and campus facilities that do not have an aggregate exceeding 50 MW of dedicated computational, industrial or commercial process loads each 1 MW or greater, including but not limited to a university campus without a major data center.

Large Load Affected Party is the entity that owns, operates or controls a Large Load Affected System, or any other entity that otherwise may be a necessary party to the Large Load study process.

Large Load Affected System is any electric system that is outside the New England Control Area that may be affected by the proposed provision of transmission service to a Large Load.

Large Load Base Cases are the set of initial cases used to evaluate the impact of Large Loads, including: (1) the latest available case used for performing Needs Assessments; and (2) the latest available case used for a completed Cluster Study or an ongoing Cluster Study.

Large Load Co-Located Generator is a Generating Facility that is associated with a Co-Located Large Load through a Non-Firm Large Load Generator Arrangement.

Large Load Contingent Facilities are those unbuilt Interconnection Facilities, Large Load Interconnection Facilities, Network Upgrades, and Large Load Network Upgrades or a transmission project that is planned or proposed for the New England Transmission System upon which the Large Load Transmission Customer's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Large Load Transmission Service Application or a reassessment of the Large Load Interconnection Facilities and/or Large Load Network Upgrades and/or costs and timing.

Large Load Cost Recovery Agreement is the agreement in the form of Attachment V to the OATT.

Large Load Distribution Upgrades are the additions, modifications, and upgrades to the Large Load Interconnecting Transmission Owner's distribution system (i.e., facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances) at or beyond the Point of Delivery to facilitate interconnection of the Large Load and render

the transmission service necessary to serve the Large Load. Large Load Distribution Upgrades do not include Large Load Interconnection Facilities.

Large Load Electrically Proximate Generator is a Generating Facility that is associated with an Electrically Proximate Large Load through a Non-Firm Large Load Generator Arrangement

Large Load Eligible Customer is the Eligible Customer that submits an application for Firm Contract Demand Service or Non-Firm Contract Demand Service on behalf of a Large Load.

Large Load Entity is the entity that owns or controls the Large Load.

Large Load Facilities Study is the study for Large Loads conducted pursuant to Section II.60 of the OATT.

Large Load Facilities Study Agreement is the agreement described in Section II.60 of the OATT.

Large Load Internal Affected Party is the entity that owns, operates or controls a Large Load Internal Affected System, or any other entity operating within the New England Control Area that otherwise may be a necessary party to the Large Load study process.

Large Load Internal Affected System is any electric system that is within the New England Control Area that may be affected by the proposed provision of service to the Large Load.

Large Load Interconnection Facilities are Large Load Interconnecting Transmission Owner's Interconnection Facilities and Large Load Transmission Customer's Interconnection Facilities. Collectively, Large Load Interconnection Facilities include all facilities and equipment between the Large Load and the Point of Delivery, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Large Load to the Administered Transmission System. Large Load Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Large Load Network Upgrades.

Large Load Interconnecting Transmission Owner is the Transmission Owner that owns, leases or otherwise possesses the controlling interest in the portion of the Administered Transmission System at the Point of Delivery for the Large Load.

Large Load Interconnecting Transmission Owner's Interconnection Facilities are all facilities and equipment owned, controlled, or operated by Large Load Interconnecting Transmission Owner from the Large Load Point of Change of Ownership to the Point of Delivery as identified in Appendix A to the Large Load Transmission Service Agreement, including any modifications, additions or upgrades to such facilities and equipment. Large Load Interconnecting Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Large Load Distribution Upgrades and Large Load Network Upgrades.

Large Load Material Modification is defined in Section II.60 of the OATT.

Large Load Network Upgrades are those upgrades to the New England Transmission System, any Large Load Affected Systems and Large Load Internal Affected Systems as identified in a Large Load System Impact Study.

Large Load Point of Change of Ownership is the point, as set forth in Appendix A to the Large Load Transmission Service Agreement, where Large Load Transmission Customer's Interconnection Facilities connect to the Large Load Interconnecting Transmission Owner's Interconnection Facilities.

Large Load Queue Position is the order of a valid Large Load Transmission Service Application in the New England Control Area, relative to all other pending Large Load Transmission Service Application(s) in the New England Control Area, that is established based upon the date and time of receipt of such application by the ISO.

Large Load Re-Dispatch Price is $250/MWh.

Large Load Scoping Meeting is the meeting between representatives of the ISO, the Large Load Eligible Customer, and the Transmission Owner(s), or any Large Load Internal Affected Party as deemed appropriate by the ISO in accordance with applicable codes of conduct and confidentiality requirements, conducted for the purpose of discussing the proposed Large Load Transmission Service Application, exchanging information, and refining information and models provided by Large Load Eligible Customer.

Large Load Service Commencement Date is the date transmission service is to begin pursuant to the terms of a Large Load Transmission Service Agreement that has been executed or filed unexecuted.

Large Load Site Control is the exclusive right to develop, construct, operate and maintain the Large Load. Large Load Site Control may be demonstrated by documentation establishing that, over the expected term of the Large Load operations, the entity proposing the Large Load will hold ownership or other exclusive rights over the property allowing for the construction, operation and maintenance of the Large Load in the form of either: (a) fee simple ownership of real property ; (b) an easement; (c) a valid written leasehold or other contractual interest in real property; (d) a duly executed written contract to purchase, acquire an easement, a license or leasehold interest in real property; or (e) for any federal or state property, has filed applications for required permits or authorizations to construct, operate and maintain the Large Load.

Large Load Study Cases are the cases defined in Section II.60.2 of the OATT.

Large Load Sufficiently Under Construction is a load that is determined by the ISO to have provided sufficient evidence that it received major permits necessary for construction of the project, achieved project financing closing, ordered major equipment necessary for the construction of the project, and has started construction activities on the project site.

Large Load System Impact Study is the study for Large Loads conducted pursuant to Section II.60 of the OATT.

Large Load System Impact Study Agreement is the agreement described in Section II.60 of the OATT.

Large Load Transmission Customer is the Large Load Eligible Customer that has completed the large load service application and study procedures set forth in Sections II.58 and II.60 of the OATT, and executed a Large Load Transmission Service Agreement and receives Firm Contract Demand Service, Interim Contract Demand Service, or Non-Firm Contract Demand Service on behalf of a Large Load.

Large Load Transmission Customer's Interconnection Facilities are all facilities and equipment, as identified in Appendix A of the Large Load Transmission Service Agreement, that are located between the Large Load and the Large Load Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Large Load Transmission Customer to the Administered Transmission System. Large Load Transmission

Customer's Interconnection Facilities may be sole use facilities or subject to shared use pursuant to arrangements filed with and approved by the Commission.

Large Load Transmission Service Agreement is the form of transmission service agreement applicable to a Large Load Transmission Service Application pertaining to a Large Load, that is included as Attachment R to the OATT.

Large Load Transmission Service Application is a Large Load Eligible Customer's application, in the form available on the ISO website.

Non-Firm Contract Demand Service is a type of transmission service for Large Loads described in Section II.57.1.3 of the OATT.

Non-Firm Large Load Generator Arrangement is an arrangement between a Co-located Load or Electrically Proximate Load and the applicable Co-Located Generator or Electrically Proximate Generator which supports the Large Load taking Interim Contract Demand Service or Non-Firm Contract Demand Service.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied Supplied Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

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

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

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

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset’s or Settlement Only Distributed Energy Resource Aggregation’s ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset’s or Settlement Only Distributed Energy Resource Aggregation’s capability to perform under specified summer and winter conditions for a specified duration.

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) A Seasonal DRDERA Audit value determines the ability of a Demand Response Distributed Energy Resource Aggregation to perform during specified months for a specified duration.

(v) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's Establish Claimed Capability Audit value, the Demand Response Resource's Seasonal DR Audit value or the Demand Response Distributed Energy Resource Aggregation's Seasonal DRDERA Audit value.

(b) The Claimed Capability Audit value of a Generator Asset or Settlement Only Distributed Energy Resource Aggregation shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.

(b) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(c) For a newly commercial Generator Asset or Settlement Only Distributed Energy Resource Aggregation:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and

3. Intermittent Generator Assets or intermittent Settlement Only Distributed Energy Resource Aggregations

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation.

(d) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.

(ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset or the sum of the maximum energy injection capabilities of the Settlement Only Distributed Energy Resource Aggregation’s constituent Distributed Energy Resources.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

(g) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset’s net output to increase from the current operating level to its Real-Time High Operating Limit or the Settlement Only Distributed Energy Resource Aggregation’s net output to increase from the current operating level to its maximum energy injection capability.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

(i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2 (h) or a Settlement Only Distributed Energy Resource Aggregation consisting of a single technology type not listed in Section III.1.5.1.2 (h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.

(b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets and Settlement Only Distributed Energy Resource Aggregation except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation or Settlement Only Distributed Energy Resource Aggregation's.

(d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(e) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset or Settlement Only Distributed Energy Resource Aggregation for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2
Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage) Hydraulic Turbine-Other	2
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

(k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(l) A Generator Asset or Settlement Only Distributed Energy Resource Aggregation that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset or Settlement Only Distributed Energy Resource Aggregation to perform

a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset or Settlement Only Distributed Energy Resource Aggregation during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.3.2 Seasonal DRDERA Audits.

(a) A Seasonal DRDERA Audit may be performed only for a Demand Response Distributed Energy Resource Aggregation.

(b) A Seasonal DRDERA Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DRDERA Audit must be conducted by all Demand Response Distributed Energy Resource Aggregations:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DRDERA Audit must be conducted by all Demand Response Distributed Energy Resource Aggregations:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DRDERA Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DRDERA Audit:

(i) The ISO shall perform the Seasonal DRDERA Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DRDERA Audit by issuing a Dispatch Instruction ordering the Demand Response Distributed Energy Resource Aggregation to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DRDERA Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.2 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DRDERA Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DRDERA Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DRDERA Audit as provided in this Section III.1.5.1.3.2 may be used to fulfill the Seasonal DRDERA Audit obligation of a Demand Response Distributed Energy Resource Aggregation.

(h) An ISO-Initiated Claimed Capability Audit fulfills the Seasonal DRDERA Audit obligation of a Demand Response Distributed Energy Resource Aggregation.

(i) Each Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation is evaluated during the Seasonal DRDERA Audit of the Demand Response Distributed Energy Resource Aggregation.

(j) Any Distributed Energy Resource on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DRDERA Audit value (summer or winter) of a Demand Response Distributed Energy Resource Aggregation resulting from the Seasonal DRDERA Audit shall be the sum of the load reductions demonstrated during the audit by each of the Demand Response Distributed Energy Resource Aggregation's constituent Distributed Energy Resources plus the energy injected by the Demand Response Distributed Energy Resource Aggregation during the audit period.

(l) If a Distributed Energy Resource is added to or removed from a Demand Response Distributed Energy Resource Aggregation between audits, the Demand Response Distributed Energy Resource Aggregation's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Distributed Energy Resource, such that at any point in time the summer or winter Seasonal DRDERA Audit value of a Demand Response Distributed Energy Resource Aggregation shall equal the sum of the most recent valid like-season audit values of its constituent Distributed Energy Resources.

(m) The Seasonal DRDERA Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

The summer or winter audit value of a Distributed Energy Resource shall be set to zero at the end of the Capability Demonstration Year if the Distributed Energy Resource did not perform a Seasonal DRDERA Audit for that season as part of a Demand Response Distributed Energy Resource Aggregation during that Capability Demonstration Year.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource, shall replace either the summer or winter Seasonal DRDERA Audit value for a Demand Response Distributed Energy Resource Aggregation, and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability or equivalent interconnection agreements for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a

mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation location.

(c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit, Settlement Only Distributed Energy Resource Aggregation to its maximum energy injection capability, the Demand Response Resource to its Maximum Reduction, or the Demand Response Distributed Energy Resource Aggregation to its MaximumReduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(iv) For Settlement Only Distributed Energy Resource Aggregations, begin the audit with the first full clock hour after sufficient time has been allowed for the net output of the Settlement Only Distributed Energy Resource Aggregation to increase from the current operating level to its maximum energy injection capability.

(v) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(vi) For Demand Response Distributed Energy Resource Aggregations, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit

Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource or Demand Response Distributed Energy Resource Aggregations	1
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer, or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation to provide energy or reserves.

(b) Generator Asset audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) Demand Response Distributed Energy Resource Aggregation audits shall be performed using the following methods:

(i) **MaximumReduction**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to start deviating demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Distributed Energy Resource Aggregation was not previously deviating demand.

(v) **CLAIM10**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5

(e) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator, Demand Response Resource , or Demand Response Distributed Energy Resource Aggregation performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator, Demand Response Resource , or Demand Response Distributed Energy Resource Aggregation performance in response to Dispatch Instructions.

(f) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation for the parameters being audited.

(g) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(h) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer, or other operating parameter values that are not representative of the actual capability of the Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation, the values for the Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation shall be restricted to those values that are supported by the audit.

(i) In the event that a Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;

2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

(i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

(ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:

(i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;

(ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or

(iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch. The ISO shall use a joint optimization process to serve Day-Ahead Market energy requirements and Day-Ahead Ancillary Services requirements, as described in Section III.1.10.8(a).

(b) [Reserved].

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 LMP-Based Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.9A Day-Ahead Ancillary Services Prices.

The prices paid by the ISO for the provision of Day-Ahead Ancillary Services in the New England Markets will reflect Day-Ahead Ancillary Services clearing prices determined by the ISO in accordance with the ISO New England Filed Documents.

III.1.7.10 Other Transactions.

Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the

obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.

b. For a Generator Asset that is off-line and not available for commitment shall be zero.

c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

III.1.7.13 Seasonal DECR Audit Value.

(a) A Seasonal DECR Audit Value must be established and maintained for all Distributed Energy Capacity Resources. A summer Seasonal DECR Audit Value is established for use from June 1 through September 30 and a winter Seasonal DECR Audit Value is established for use from October 1 through May 31.

(b) The Seasonal DECR Audit Value of Distributed Energy Capacity Resources is the sum of: the Seasonal Claimed Capabilities of Distributed Energy Resource Aggregations participating as a Generator Asset or a Settlement Only Distributed Energy Resource Aggregation; the Seasonal DR Audit value of a Distributed Energy Resource Aggregation participating as a Demand Response Resource; and the Seasonal DRDERA Audit values of the Demand Response Distributed Energy Resource Aggregations comprising the Distributed Energy Capacity Resource.

(c) The Seasonal Claimed Capability of a Settlement Only Distributed Energy Resource is:

a. Based upon review of historical data for non-intermittent daily cycle hydro.

b. The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities as reflected in hourly revenue metering data.

c. For all other Settlement Only Distributed Energy Resources, the minimum of: (1) the Settlement Only Distributed Energy Resource’s current Establish Claimed Capability Audit value and (2) the Settlement Only Distributed Energy Resource’s current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

The Seasonal DRDERA Audit value for Distributed Energy Resource Aggregations participating as Demand Response Distributed Energy Resource Aggregations is the value of the audit for the aggregation performed pursuant to Section III.1.5.1.3.2**.**

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, Demand Response Distributed Energy Resource Aggregation, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to potential referral under Section III.A.19.

III.1.7.19 Real-Time Reserve Designation.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

III.1.7.19.1 Eligibility.

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

(a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

(c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.

For a Dispatchable Asset Related Demand associated with a Large Load, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).

(c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

III.1.7.19.2.3 Demand Response Resources and Demand Response Distributed Energy Resource Aggregations.

For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

III.1.7.19.2.3.1 Dispatched.

(a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource or Demand Response Distributed Energy Resource

Aggregation that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).

(c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is not being dispatched that is not a Fast Start Demand Response Resource or Fast Start Demand Response Distributed Energy Resource Aggregation, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource or a Fast Start Demand Response Distributed Energy Resource Aggregation that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource or a Fast Start Demand Response Distributed Energy Resource Aggregation that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's or Demand Response Distributed Energy Resource Aggregation's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

(c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's or Demand Response Distributed Energy Resource Aggregation's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource or Demand Response Distributed Energy Resource Aggregation pursuant to subsection (b) above.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, demand reduction levels of Generator Assets, DARDs, Demand Response Resources or Demand Response Distributed Energy Resource Aggregations;, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

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

III.1.8 Day-Ahead Ancillary Services and Forecast Energy Requirement.

III.1.8.1 Day-Ahead Ancillary Services Offers.

Market Participants may submit Day-Ahead Ancillary Services Offers for the Operating Day in the Day-Ahead Ancillary Services Market as specified in this Section III.1.8.1.

(a) Each Day-Ahead Ancillary Services Offer shall be associated with a specific Generator Asset, Demand Response Resource, Demand Response Distributed Energy Resource Aggregation, or DARD for which the Market Participant has submitted a corresponding Supply Offer, Demand Reduction Offer, or

Demand Bid in the Day-Ahead Energy Market for the same hour of the Operating Day, ~~,~~ ~~excluding~~ Dispatchable Asset Related Demand associated with a Large Load.

(b) Each Day-Ahead Ancillary Services Offer shall specify: (i) the hour of the Operating Day for which the Day-Ahead Ancillary Services Offer applies; (ii) product-specific offer prices, in $/MWh, that are greater than or equal to zero for the Day-Ahead Ancillary Services; and (iii) a single offer quantity, in MWh, that is greater than or equal to zero. The offer prices for the Day-Ahead Ancillary Services shall not exceed the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer, the Maximum Reduction specified in the associated Demand Reduction Offer, or the Maximum Consumption Limit specified in the associated Demand Bid.

(c) As part of its Day-Ahead Ancillary Services Offer, a Market Participant is permitted to specify a Maximum Daily Award Limit quantity, in MWh, that is greater than or equal to zero.

(d) For each hour of the Operating Day, a Market Participant may submit only one Day-Ahead Ancillary Services Offer associated with a specific Generator Asset, Demand Response Resource, Demand Response Distributed Energy Resource Aggregation, or DARD.

(e) Day-Ahead Ancillary Services Offers shall be submitted by the offer submission deadline for the Day-Ahead Market specified in Section III.1.10.1A of this Market Rule 1. A Day-Ahead Ancillary Services Offer shall not remain in effect for subsequent Operating Days.

III.1.8.2 Day-Ahead Ancillary Services Strike Price.

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of the values calculated in accordance with subsections (1) and (2) below:

(1) the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero; and

(2) a floor value derived in accordance with subsection (c) below.

(b) The value calculated in subsection (a)(1) above shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly-available forecasting algorithm to

Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO's forecasting algorithm prior to implementing such revisions.

(c) The floor value in subsection (a)(2) above shall be determined daily based on the marginal cost of supplying energy by an efficient, distillate-fired combustion turbine generator, reflecting regional emissions costs and the lowest-priced distillate fuel available. The ISO shall describe to Market Participants the heat rate, emissions cost, and fuel prices that it uses to determine the value in subsection (a)(2).

(d) In the event that the ISO is not able to utilize the methods in subsections (a) through (c) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast and floor value available and shall disclose the use of such substitute method to Market Participants as soon as practicable.

III.1.8.3 Day-Ahead Flexible Response Services Demand Quantities.

The Day-Ahead Ancillary Services Market shall endeavor to procure the Day-Ahead Flexible Response Services Demand Quantities specified in this Section III.1.8.3.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Ten-Minute Spinning Reserve Requirement projected Day-Ahead.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Ten-Minute Reserve Requirement projected Day-Ahead.

(c) For each hour of the Operating Day, the Day-Ahead Minimum Total Reserve Demand Quantity shall be equal to the Minimum Total Reserve Requirement projected Day-Ahead.

(d) For each hour of the Operating Day, the Day-Ahead Total Reserve Demand Quantity shall be equal to the Total Reserve Requirement projected Day-Ahead.

III.1.8.4 Forecast Energy Requirement Demand Quantity.

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be:

(1) the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1, less

(2) the greater of (i) the forecast of front-of-the-meter dispatchable wind and solar resources' total real-time energy supply, as adjusted for any expected operating conditions, less the total energy supply and ancillary services from such resources forecast to clear in the Day-Ahead Market and (ii) zero.

III.1.9 Pre-scheduling.

III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers, and Demand Reduction Offers above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers and Demand Reduction Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each Generator Asset as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement the Day-Ahead Market and a Real-Time Energy Market.

(b) The Day-Ahead Market shall enable Market Participants to purchase and sell energy and sell ancillary services through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO’s forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets or Demand

Response Resources, or Demand Response Distributed Energy Resource Aggregations with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers, or Demand Reduction Offers.

III.1.10.1A Energy and Day-Ahead Ancillary Services Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead Market until 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the applicable Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in

accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the

Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource and Demand Response Distributed Energy Resource Aggregation Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources or Demand Response Distributed Energy Resource Aggregations may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource or Demand Response Distributed Energy Resource Aggregation and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets or the Demand Response Distributed Energy Resource Aggregation's operational Distributed Energy Resources.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource or the Demand Response Distributed Energy Resource Aggregation's Offer Data to reflect the physical operating characteristics and/or availability of the Distributed Energy Resources.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources or Demand Response Distributed Energy Resource Aggregations

exceeds the cost to load associated with compensating Demand Response Resources or Demand Response Distributed Energy Resource Aggregations for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th}X - \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, Deviation Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment

Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

(l) **Settlement Only Distributed Energy Resource Aggregation Supply Offers and/or Demand Bids –** Market Participants selling into the New England Markets from Settlement Only Distributed Energy Resource Aggregations and/or purchasing from the New England Markets for Settlement Only Distributed Energy Resource Aggregations may submit Supply Offers and /or Demand Bids, which will apply only to the Day-Ahead Energy Market. Such offers and/or bids must specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered and/or bid by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis

(m) **Day-Ahead Ancillary Services Offers** – Market Participants selling into the New England Markets from Generator Assets Demand Response Resources, or Demand Response Distributed Energy Resource Aggregation, or participating in the New England Markets with DARDs, and that have submitted Supply Offers, Demand Reduction Offers, or Demand Bids for the following Operating Day, as described in subsections (c), (d), and (e) of this Section III.1.10.1A, may submit Day-Ahead Ancillary

Services Offers for the following Operating Day. Day-Ahead Ancillary Services Offers shall be submitted to the ISO in accordance with Section III.1.8.1 of this Market Rule 1.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs, Demand Response Resources, or Demand Response Distributed Energy Resource Aggregations committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption, ancillary services, and related services, Start-Up Fees, No-Load Fees, Interruption Cost, and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy and ancillary services from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, ancillary services offers and requirements, and the Forecast Energy Requirement Demand Quantity.

(c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation shall not be Self-Scheduled.

III.1.10.4 External Resources.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

(i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;

(ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.5A Large Load.

(a) The Large Load Transmission Customer shall, or shall cause to

(i) Register the Large Load as a Dispatchable Asset Related Demand

(ii) Comply with all applicable requirements in the ISO New England Operating Documents including, but not limited to, forecasting, telemetry, ramp rates, and following Dispatch Instructions.

(b) The Large Load Transmission Customer may, or may cause to

(i) Submit Demand Bids in the Day-Ahead and Real-Time Energy Markets on behalf of the Large Load

(ii) Use energy supply from a Large Load Co-Located Generator or Large Load Electrically Proximate Generator to achieve all or a portion of re-dispatch requirements for Interim Contract Demand Service and/or Non-Firm Contract Demand Service pursuant to Section III.1.10.5A(c)(ii).

(c) The ISO shall

(i) Schedule the Large Load to withdraw energy based on the lesser of the Large Load's forecasted demand and the sum of the Large Load's transmission services MW pursuant to the Large Load's Transmission Service Agreement,

(a) If the Large Load Transmission Customer elects to submit Demand Bids pursuant to Section III.1.10.5A(b)(i), the ISO shall schedule the Large Load to withdraw energy based on the lesser of the Large Load's Demand Bid MW and the sum of the Large Load's transmission services MW pursuant to the Large Load Transmission Service Agreement,

(ii) Send a Dispatch Instruction to re-dispatch all or a portion of the Large Load's Interim Contract Demand Service and/or Non-Firm Contract Demand Service based on the Large Load's applicable Locational Marginal Price and the ~~Non-Firm~~ Large Load Re-Dispatch Price.

(d) The Assigned Meter Reader for the Large Load shall

(i) Submit Revenue Quality Metering for hourly and monthly settlement that represents gross demand quantities for the Large Load, such that the Large Load's Revenue Quality Metering is not netted by other physical load, supply, or Behind-the-Meter Generation,

(ii) Submit Revenue Quality Metering for hourly and monthly settlement that represents gross supply quantities for Large Load Co-Located Generators and/or Large Load Electrically Proximate Generators associated with a Large Load, such that the generator's Revenue Quality Metering is not netted with any other load or supply.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity and storing the energy for later injection of electricity into the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

(i) comprise one or more storage facilities at the same point of interconnection;

(ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;

(iii) be directly metered;

(iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;

(v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;

(vi) settle its injection of electricity to the grid as a Generator Asset and any receipt of electricity from the grid as a DARD;

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility; and

(ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and

(iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(j) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) In clearing the Day-Ahead Energy Market, the ISO will respect Electric Storage Facility Initial State of Charge, Round Trip Efficiency, Maximum State of Charge, and Minimum State of Charge.

(e) A storage facility incapable of receiving and storing electricity from the grid may participate in the New England Markets as a Continuous Storage Facility, so long as that facility satisfies all Continuous Storage Facility registration and participation requirements that are not solely related to consumption capability. Notwithstanding Section III.1.10.6(a), Section III.1.10.6(c), and any other related provisions, such non-consuming storage facilities shall not be required to:

(i) be capable of consuming at least 0.1 MW from the grid; or

(ii) be capable of modifying consumption responsive to Dispatch Instructions.

(f) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging energy.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

(g) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(h) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(i) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered

and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(j) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(k) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone, as determined in accordance with Section III.12.4, that experienced price separation in the Annual Capacity Auction as determined in accordance with Section III.15.4.2.2(j) of Market Rule 1;

(2) The External Transaction is directly associated with an Export Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The External Node associated with the unobligated Export Offer Segment is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) Annual Capacity Auction Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Offer Segment is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale’s megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward or Annual Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated Transaction Scheduling.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production

costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated e-Tag ID at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 Scheduling Considerations.

(a) In scheduling the Day-Ahead Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (i) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (ii) Day-Ahead Ancillary Services Offers to satisfy the Day-Ahead Flexible Response Services Demand Quantities; and (iii) Supply Offers, Demand Reduction Offers, External Transactions, and Day-Ahead Ancillary Services Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determination specified in this subsection (a), the ISO shall take into account, as applicable: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for ancillary services; (vi) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics and parameters specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid and any audited values of such operating characteristics and parameters; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination.

In scheduling the Day-Ahead Market, the following limitations shall apply:

(i) For purposes of satisfying the Day-Ahead Flexible Response Services Demand Quantities specified in Sections III.1.8.3(a) through (d), the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the Generator Asset, Demand Response Resource, Demand Response Distributed Energy Resource Aggregation, or DARD associated with the Day-Ahead Ancillary Services Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(ii) For purposes of satisfying the Forecast Energy Requirement Demand Quantity specified in Section III.1.8.4, the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the offer is associated with a Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation that meets the following conditions:

(1) The Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation is, for the applicable hour, either scheduled for energy in the Day-Ahead Energy Market or is a Fast Start Generator, Fast Start Demand Response Resource, or Fast Start Demand Response Distributed Energy Resource Aggregation.

(2) The Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation is not designated as constrained by transmission limitations, as described in Section III.1.7.19.1(3).

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead energy and ancillary services schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Market cannot be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and

other Resources, transmission constraints, and other relevant factors. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy and ancillary services scheduled in the Day-Ahead Market based upon applicable Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is

made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will

honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.10.10 Local Second Contingency Protection Resources

III.1.10.10.1 [Reserved.]

III.1.10.10.2 Day-Ahead and Real-Time Energy Market.

When establishing operating schedules, the ISO will select and identify Local Second Contingency Protection Resources on a not unduly discriminatory basis in accordance with the procedures defined in the ISO New England Manuals. Appendix A will determine which, if any, Supply Offers will be adjusted. The ISO will also record, in an auditable log, the reason the Resource was selected.

III.1.10.10.2.1 Special Constraint Resources.

When establishing operating schedules, at the request of a Transmission Owner or distribution company in order to maintain area reliability, the ISO will commit and dispatch Generator Assets to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or the ISO's operating procedures in accordance with the procedures defined in the ISO New England Manuals. The ISO will also record, in an auditable log, the designation of such a Generator Asset as a

Special Constraint Resource and the name of the requesting Transmission Owner or distribution company. Any NCPC Charge associated with the Real-Time operation of the Special Constraint Resource is charged in accordance with the provisions of Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.1.10.10.3 [Reserved.]

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Settlement Only Distributed Energy Resource Aggregations, and Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, and nuclear-powered Resources, all Resources must be Dispatchable Resources in the

Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) All wind and hydro Intermittent Power Resources are required to be DNE Dispatchable Generators, with the exception of wind and hydro Intermittent Power Resources with an injection capability of less than 5 MW that are connected through transmission facilities rated at less than 115 kV. A Distributed Energy Resource Aggregation is required to be a DNE Dispatchable Generator if it 1) consists entirely of wind or hydro Intermittent Power Resources or a combination of wind and hydro Intermittent Power Resources, and 2) participates as a Generator Asset.

(i) A Market Participant may elect to have a wind or hydro Intermittent Power Resource with an injection capability less than 5 MW that is connected through transmission facilities rated at less than 115 kV be a DNE Dispatchable Generator.

(ii) A Market Participant may elect to have a hydro Intermittent Power Resource or a Distributed Energy Resource Aggregation consisting entirely of hydro Intermittent Power Resources and participating as a Generator Asset be a DDP Dispatchable Resource if it is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range.

(f) The ISO may request that dual-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel

Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

(c) Wind and solar Generator Assets that are not Settlement Only Resources shall electronically transmit meteorological and forced outage data, as specified below, to the ISO, over a secure network, using the protocol specified in the ISO Operating Documents, for the development and deployment of wind and solar power production forecasts.

Wind Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: wind speed, and wind direction;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, and standard deviation of ambient air relative humidity;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, Wind High Limit, wind turbine counts; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Wind Plant Future Availability.

Solar Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: irradiance;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, standard deviation of ambient air relative humidity, wind speed, and wind direction;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, and Solar High Limit; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Solar Plant Future Availability.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the

Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

III.2 Day-Ahead Prices, Real-Time Prices, and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day. Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price shall be calculated for each hour of the Operating Day, as specified in Section III.2.6.2, as part of the joint optimization of energy and ancillary services in the Day-Ahead Market.

III.2.2 General.

The ISO shall determine the least cost security-constrained economic commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price will be calculated based on the joint optimization process described in Section III.1.10.8(a) utilizing the prices of offers and bids, the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) when applicable, and Reserve Constraint Penalty Factors as specified in Section III.2.6.2(c) when applicable. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.7A when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding electric output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of resources supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices, Real-Time Reserve Clearing Prices, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Offer Data, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and zonal Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England

Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time, or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time, or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed $2,000/MWh.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

(f) If the Rapid Response Pricing Asset is a Fast Start Demand Response Distributed Energy Resource Aggregation that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(g) If the Rapid Response Pricing Asset is a Fast Start Demand Response Distributed Energy Resource Aggregation that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, Demand Response Distributed Energy Resource Aggregations, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume

an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.7A(c); and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids and re-dispatchable non-firm large load that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of Day-Ahead Prices.

III.2.6.1 Calculation of Day-Ahead Locational Marginal Prices.

(a) Day-Ahead Locational Marginal Prices shall be determined on the basis of the Day-Ahead Market security-constrained economic commitment and dispatch described in Section III.1.10.8(a) and in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market. Such prices shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the

Day-Ahead Market by applying a joint optimization method consistent with Section III.1.10.8(a), given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer, energy bid, re-dispatchable non-firm large load, or Day-Ahead Ancillary Services Offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource and the effect on ancillary service costs associated with increasing the output of the Resource or reducing consumption of the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and supply. The cost of serving an increment of load at a Node or External Node, calculated in this manner, shall determine the Day-Ahead Locational Marginal Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of all Day-Ahead fixed Demand Bids cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available supply at the Generator Asset's Economic Maximum Limit, demand reduction at the Demand Response Resource's Maximum Reduction, and deviation at the Demand Response Distributed Energy Resource Aggregation's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction Offer, or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line Generator Assets, dispatched Demand Response Resources, dispatched Demand Response Distributed Energy Resource Aggregations, Increment Offers or External Transaction purchases; and

(ii) If power balance is not achieved after step (i), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line Generator Assets (excluding Settlement Only Resources), dispatched Demand Response Resources, dispatched Demand Response Distributed Energy Resource Aggregations, Increment Offers or External Transaction purchases or the price from step (i), whichever is higher.

(c) System-level excess energy conditions. If the total cleared energy supply in the Day-Ahead Energy Market exceeds the total bid-in demand, then the following steps shall be performed to achieve energy balance:

(i) The Day-Ahead security-constrained economic dispatch process will be performed such that all committed Generator Assets shall be dispatched no lower than their respective Emergency Minimum Limits and each such Generator Asset will be treated as offering its output below its Economic Minimum Limit at the Energy Offer Floor; and

(ii) If power balance is not achieved in step (i), the Day-Ahead security-constrained economic dispatch process will be performed such that (a) all committed Generator Assets shall be dispatched no lower than zero, each such Generator Asset will be treated as having an unlimited downward ramp rate, and each such Generator Asset will be treated as offering its output below its Economic Minimum Limit at the Energy Offer Floor; and (b) all committed Demand Response Resources and Demand Response Distributed Energy Resource Aggregations shall be dispatched no lower than zero, each such Demand Response Resource and Demand Response Distributed Energy Resource Aggregation will be treated as having an unlimited

downward ramp rate, and each such Demand Response Resource and Demand Response Distributed Energy Resource Aggregation will be treated as offering its demand reduction below its Minimum Reduction at the Energy Offer Floor.

(d) Local excess energy conditions. If a transmission limit is violated in the Day-Ahead Energy Market, the following steps shall be performed:

(i) The Day-Ahead security-constrained economic dispatch process will be performed such that all Generator Assets contributing to the transmission limit violation shall be dispatched no lower than their respective Emergency Minimum Limits, and each such Generator Asset will be treated as offering its output below its Economic Minimum Limit at the Energy Offer Floor; and

(ii) If the transmission limit violation is not resolved in step (i), the Day-Ahead security-constrained economic dispatch process will be performed such that (a) all Generator Assets contributing to the transmission limit violation shall be dispatched no lower than zero, each such Generator Asset will be treated as having an unlimited downward ramp rate, and each such Generator Asset will be treated as offering its output below its Economic Minimum Limit at the Energy Offer Floor; and (b) all Demand Response Resources and Demand Response Distributed Energy Resource Aggregations contributing to the transmission limit violation shall be dispatched no lower than zero, each such Demand Response Resource and Demand Response Distributed Energy Resource Aggregation will be treated as having an unlimited downward ramp rate, and each such Demand Response Resource and Demand Response Distributed Energy Resource Aggregation will be treated as offering its demand reduction below its Minimum Reduction at the Energy Offer Floor.

III.2.6.2 Calculation of Additional Day-Ahead Prices.

The ISO shall calculate hourly Day-Ahead Prices for additional requirements in the Day-Ahead Market as described in this Section III.2.6.2.

(a) **Day-Ahead Flexible Response Services Clearing Prices.**

(i) The clearing price for Day-Ahead Thirty-Minute Operating Reserve shall be the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy:

(1) the next increment of Day-Ahead Minimum Total Reserve Quantity, if the cost of such next increment is greater than or equal to the Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Reserve Demand Quantity; or,

(2) if Section III.2.6.2(a)(i)(1) is inapplicable, the next increment of Day-Ahead Total Reserve Demand Quantity.

(ii) The clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve shall be the sum of (1) the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and (2) the clearing price for Day-Ahead Thirty-Minute Operating Reserve.

(iii) The clearing price for Day-Ahead Ten-Minute Spinning Reserve shall be the sum of (1) the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of Day-Ahead Ten-Minute Spinning Reserve, and (2) the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve.

(iv) If the Day-Ahead Market does not clear sufficient Day-Ahead Flexible Response Services to satisfy one or more of the Day-Ahead Flexible Response Services Demand Quantities, the Day-Ahead Flexible Response Services clearing prices shall be set based upon the applicable Reserve Constraint Penalty Factors, as described by Section III.2.6.2(c)(i) through (iv).

(b) **Forecast Energy Requirement Price**.

(i) The Forecast Energy Requirement Price shall be the marginal cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of the Forecast Energy Requirement Demand Quantity.

(ii) The Forecast Energy Requirement Price shall be based upon the Forecast Energy Requirement Penalty Factor specified by Section III.2.6.2(d) when any one or some combination of the following occurs:

(1) The Day-Ahead Market does not clear sufficient energy and Day-Ahead Energy Imbalance Reserve to satisfy the Forecast Energy Requirement Demand Quantity.

(2) The Day-Ahead Locational Marginal Prices are set pursuant to Section III.2.6.1(b).

(c) **Reserve Constraint Penalty Factors in the Day-Ahead Market**. The Day-Ahead Market scheduling pursuant to Section III.1.10.8(a), and the Day-Ahead Prices specified in Section III.2.6, shall respect the applicable Reserve Constraint Penalty Factors specified below:

(i) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Spinning Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(ii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Minimum Total Reserve Demand Quantity shall be equal to the Real-Time Minimum Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iv) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Reserve Demand Quantity shall be equal to the Real-Time Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(d) **Forecast Energy Requirement Penalty Factor**. The Day-Ahead Market scheduling pursuant to Section III.1.10.8(a), and the Day-Ahead Prices specified in Section III.2.6, shall respect the Forecast Energy Requirement Penalty Factor applicable to the Forecast Energy Requirement Demand Quantity. The Forecast Energy Requirement Penalty Factor shall be set at $2,575/MWh.

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, adjusted for generation modeled at load Nodes, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node is greater than 75 percent of the total load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to

avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(c) If there is insufficient Operating Reserve in Real-Time available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the

applicable Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factors:

Real-Time Requirement	Reserve Constraint Penalty Factor
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	$1500/MWh
Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	$50/MWh

The Reserve Constraint Penalty Factors shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed for every five-minute interval, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes

within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation clearing prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-

Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Market Results

(a) Day-Ahead Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Market results for an Operating Day or if no Day-Ahead Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Market results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.15. Annual Capacity Market.

(a) Annual Capacity Market Overview.

The ISO shall administer an annual market for capacity (Annual Capacity Market) in accordance with the provisions of this Section III.15. For each one-year period from June 1 through May 31, starting with the period June 1, 2028 to May 31, 2029, for which Capacity Supply Obligations are assumed and payments are made in the Annual Capacity Market ("Capacity Commitment Period"), the ISO shall conduct an Annual Capacity Auction in accordance with the provisions of Section III.15.4 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Annual Capacity Auction, a resource must have Qualified Capacity resulting from the Annual Capacity Auction qualification process in accordance with the provisions of Sections III.15.2 and III.15.3. Obligations associated with the Annual Capacity Market may be traded during ISO-administered Monthly Reconfiguration Auctions and monthly bilateral transactions, in accordance with Section III.15.5 and Section III.15.6, respectively. The obligations of resources with Capacity Supply Obligations resulting from the Annual Capacity Auction, Monthly Reconfiguration Auctions, and monthly bilateral transactions are set forth in Section III.15.7. Payments and charges resulting from participation in the Annual Capacity Market, Monthly Reconfiguration Auctions, and bilateral transactions are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.

(b) Capacity Auction Calendar.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, the ISO shall publish a calendar of dates and deadlines for the administration of the Capacity Market, with the dates and deadlines being consistent for each Annual Capacity Auction cycle. The Capacity Auction Calendar shall include specific dates and deadlines for all such Capacity Market dates and deadlines defined in this Section III.15 and related Tariff provisions. The following defines several milestone dates and deadlines.

(1) the Qualification Data Submission Deadline for the Annual Capacity Auction shall occur during the month of February;

(2) the Capacity Demonstration Deadline for the Annual Capacity Auction shall occur during the month of April; and

(3) the Annual Capacity Auction shall occur during the month of May.

(c) Modification of Capacity Auction Calendar.

The ISO may, on a prospective basis, reasonably revise any date or deadline in the Capacity Auction Calendar with written notice of such revision to each Governance Participant in the manner specified in Section 17.11(b) of the Participants Agreement prior to the occurrence of the date or deadline being revised. In the event a Market Participant fails to meet a deadline in the Capacity Auction Calendar for submission of information or data, the ISO shall extend such deadline for that Market Participant upon receipt of an order from the Commission granting the Market Participant's request for a waiver of such deadline for good cause shown. In no event shall a date or deadline be extended, prospectively by the ISO or retroactively by filing of a Market Participant, should doing so interfere with the ISO's effective administration of the Capacity Market.

(d) Effectiveness for the 2028-2029 Capacity Commitment Period and Thereafter.

The provisions of this Section III.15 are effective for the Capacity Commitment Period that runs from June 1, 2028 through May 31, 2029 and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated, the provisions of Section III.13 are not applicable to the Annual Capacity Market, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.

III.15.A. Non-Commercial Capacity Transition Rules.

All Capacity Resources that are on critical path schedule monitoring pursuant to Section III.13.3 as of June 1, 2028 are subject to the provisions of this Section III.15.A.

The ISO shall monitor the Non-Commercial Capacity resource's compliance with its critical path schedule from the time the ISO approves the request until the resource achieves FCM Commercial Operation, is terminated pursuant to Section III.15.A.2.1, or withdraws from critical path schedule monitoring pursuant to Section III.15.A.2.3.

III.15.A.1. Non-Commercial Capacity Resource Critical Path Schedule Reports.

For each resource that is being monitored for compliance with its critical path schedule, the Lead Market Participant for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Lead Market Participant does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Each critical path schedule report shall include a complete updated version of the critical path schedule as described in Section III.15.A.1.1 through Section III.15.A.1.3.

III.15.A.1.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.15.A.1, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule must clearly indicate if the Lead Market Participant is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Lead Market Participant must also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.15.A.1.2. Documentation of Milestones Achieved.

(a) For all new resources (except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW,

which are discussed in Section III.15.A.1.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Lead Market Participant shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.15.A.1.2(a)(v).

(iv) **Substantial Site Construction.** The Lead Market Participant shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity subject to critical path schedule monitoring in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Lead Market Participant shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity subject to critical path schedule monitoring. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Lead Market Participant is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. The Lead Market Participant shall provide documentation showing that all interconnection facilities and upgrades identified for the project associated with the resource in a Transitional Cluster Study, Cluster Study, or Cluster Restudy (conducted pursuant to Section 7.5 of Schedule 22, Section 7.5 of Schedule 23, or Section 7.5 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff), or interconnection request or agreement under applicable state tariff, rules or procedures, have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market

Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Lead Market Participant shall provide documentation showing the resource will be capable of providing its total offered demand reduction value as described in the New Demand Capacity Resource Qualification Package by the proposed Commercial Operation Date reported in the critical path schedule report.

(ii) **Additional Requirements**. For each customer and each prospective customer the Lead Market Participant shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Lead Market Participant shall also provide the Asset identification number.

III.15.A.1.3. Additional Relevant Information.

The Lead Market Participant must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule.

III.15.A.2. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Lead Market Participant proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.15.A.1), then the ISO shall consult with the Lead Market Participant to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Lead Market Participant to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Lead Market Participant does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.15.A.1.

III.15.A.2.1. Termination of Critical Path Schedule Monitoring.

If a Lead Market Participant fails to comply with the requirements of Sections III.15.A.1 or III.15.A.2, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Lead Market Participant, shall have the right, through a filing with the Commission, to terminate the resource's status on critical path schedule monitoring, provided that, where a Lead Market Participant voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.15.A.2.3 no filing with the Commission shall be necessary. Upon Commission ruling, the Lead Market Participant shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource and instead permits the Lead Market Participant to continue on critical path schedule monitoring, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource, and subject to continued reporting by the Lead Market Participant in accordance with Section III.15.A.1.

III.15.A.2.2. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's ability to remain on critical path schedule monitoring, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. The ISO shall also reduce the resource's assigned capacity interconnection service (or equivalent for resources not subject to the ISO Interconnection Procedures).

III.15.A.2.3. Withdrawal from Critical Path Schedule Monitoring.

A Lead Market Participant may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO.

III.15.A.3. Financial Assurance.

The financial assurance requirements for Designated FCM Participants offering Non-Commercial Capacity into the Forward Capacity Auction, as described in Section VII.B.2.b the ISO New England Financial Assurance Policy, shall continue to apply to all Capacity Resources that are subject to the provisions of this Section III.15.A.

Once a resource with Non-Commercial Capacity achieves commercial operation, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as a resource that has achieved Capacity Market Commercial Operation, as governed by the ISO New England Financial Assurance Policy.

If a Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any financial assurance that is forfeited pursuant to Section III.15.A shall be used to reduce charges incurred by load in the relevant Capacity Zone.

III.15.A.4. Demonstrating FCM Commercial Operation

All Capacity Resources subject to the provisions of this Section III.15.A shall achieve commercial operation, for purposes of ending critical path schedule monitoring, in accordance with the FCM Commercial Operation requirements specified in Section III.13.3.8.

III.15.A.5. Settlement of Qualification Process Cost Reimbursement Deposit.

Upon the date on which the entire resource is no longer on critical path schedule monitoring, the ISO shall provide the Lead Market Participant with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff. All Capacity Resources that are subject to the provisions of this Section III.15.A shall be subject to the Forward Capacity Market payment and refund requirements as set forth in Section III.13.1.9.3.2 of the Tariff.

III.15.1. Auction Demand Curves and Other Auction Inputs.

III.15.1.1. Annual Capacity Auction Demand Curves.

The total amount of capacity cleared in the Annual Capacity Auction pursuant to Section III.15.4 shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the Capacity Zones modeled for the Annual Capacity Auction.

III.15.1.1.1. System-Wide Capacity Demand Curve.

The System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.15.1.1.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

III.15.1.1.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

III.15.1.1.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.15.1.1.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.15.1.2. Capacity Auction Offer Price Cap and the Cost of New Entry.

III.15.1.2.1. Calculation of Capacity Auction Offer Price Cap, CONE, and Net CONE.

(a) The Capacity Auction Offer Price Cap shall be the greater of (i) 1.6 multiplied by Net CONE; and (ii) CONE. References in this Section III.15 and Sections III.A.21 and III.A.24 to the Capacity Auction Offer Price Cap shall mean the Capacity Auction Offer Price Cap for the Annual Capacity Auction associated with the relevant Capacity Commitment Period.

(b) To determine the CONE and Net CONE for the Annual Capacity Auctions associated with the Capacity Commitment Period beginning on June 1, 2028 and the Capacity Commitment Period beginning on June 1, 2029, the ISO shall make interim-year adjustments as described in Section III.15.1.2.2 to the following CONE and Net CONE calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025:

(i) CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $12.400/kW-month.

(ii) Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $7.468/kW-month.

(c) The ISO shall recalculate CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2030. Thereafter, CONE and Net CONE shall be recalculated no less often than once every four years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders, and the new values will be filed with the Commission prior to the Annual Capacity Auction in which the new value is to apply.

III.15.1.2.2. Interim-Year Adjustments to CONE and Net CONE.

(a) For years in which no full recalculation is performed pursuant to Section III.15.1.2.1, CONE and Net CONE shall be adjusted for each Annual Capacity Auction with the following updates to the capital

budgeting model used to calculate the CONE and Net CONE values set forth above in this Section III.15.1.2:

(1) Each line item associated with capital costs that is included in the capital budgeting model shall be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114).

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the CONE and Net CONE values set forth in Section III.15.1.2.1. The value of each line item associated with capital costs in the capital budgeting model will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE, for each month of the Capacity Commitment Period to which the updated value will apply.

(4) The annual adjustment to CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning June 1, 2028, shall use a cost of debt of 6.85% and a cost of equity of 13.80%. These values shall also be used for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2029.

(5) If any of the values required for the calculations described in this Section III.15.1.2.2 are unavailable, then comparable values, prices or sources shall be used.

(b) The CONE and Net CONE values adjusted pursuant to this Section III.15.1.2.2 will be published on the ISO’s website.

III.15.2. Capacity Resource Qualification.

Each resource, or portion thereof, must qualify as a Generating Capacity Resource, an Import Capacity Resource, a Demand Capacity Resource, or a Distributed Energy Capacity Resource. Each resource must be at least 100 kW in size to participate in an Annual Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of Section III.13 became effective. The summer period of a Capacity Resource's Seasonal Qualified Capacity Values shall be the months of June through September and the winter period shall be the months of October through May, except in the case of Demand Capacity Resources, where the summer period shall be the months of April through November and the winter period shall be the months of December through March.

This Section III.15.2 details the requirements of the qualification process for the Annual Capacity Auction, as well as certain requirements related to Monthly Reconfiguration Auctions and Capacity Supply Obligation Bilateral transactions. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in an Annual Capacity Auction, are set forth in Section III.15.2.1. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in a Monthly Reconfiguration Auction are set forth in Section III.15.2.2. Qualification requirements with respect to interconnection service are addressed in Section III.15.2.3. Qualification requirements with respect to resources that have previously counted as capacity and have materially changed are addressed in Section III.15.2.4. Following the Annual Capacity Auction's Qualification Data Submission Deadline, the ISO calculates and provides to Lead Market Participants Advisory Qualified Capacity Values for each Capacity Resource, per Section III.15.2.5. Lead Market Participants then have until the Capacity Demonstration Deadline to demonstrate that their Capacity Resources have achieved Commercial Operation, per Section III.15.2.6. Thereafter, the ISO calculates Seasonal Qualified Capacity Values for each Capacity Resource, per Section III.15.2.7, which values are subject to the challenge process addressed therein. Lead Market Participants are then permitted to submit Composite Offers in accordance with Section III.15.2.8, and load serving entities are permitted to submit self-supply designations in accordance with III.15.2.9. Final Qualified Capacity values for each Capacity Resource are calculated by the ISO one Business Day prior to the opening of the Annual Capacity Auction Offer Window in accordance with Section III.15.2.10. The publication of offer information during the qualification process and after the Annual Capacity Auction is addressed in Section III.15.2.11.

Resources seeking to qualify for an Annual Capacity Auction may be subject to buyer-side market power review and mitigation pursuant to Section III.A.21 and must abide by the applicable submission

requirements and timelines set forth therein prior to seeking to qualify for an Annual Capacity Auction. To the extent not already established for the purposes of the submission requirements of Section III.A.21.1.5, all capacity suppliers seeking to qualify for an Annual Capacity Auction must be Market Participants prior to the Qualification Data Submission Deadline. The Lead Market Participant for a resource participating in an Annual Capacity Auction may not change during the period beginning 15 Business Days prior to the opening of the Annual Capacity Auction Offer Window and ending with the posting of the results of the Annual Capacity Auction.

III.15.2.1. Qualification Data Submission Requirements.

III.15.2.1.1. Qualification Data Submission Package.

(a) For a resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for participation in an Annual Capacity Auction, a Lead Market Participant must submit the following information to the ISO by the Qualification Data Submission Deadline, as applicable:

(i) the resource name;

(ii) the Lead Market Participant's contact information;

(iii) the date by which the resource is expected to complete its capacity demonstration pursuant to III.15.2.6(c) or to update its as-built data pursuant to III.15.2.6(d);

(iv) the resource address or location, and if available, asset identification number;

(v) whether the resource has ever previously had a Capacity Supply Obligation;

(vi) the location of the resource's interconnection;

(vii) the estimated Seasonal Qualified Capacity Values of the resource, as well as an estimate of any incremental Seasonal Qualified Capacity Values (in MW) (for Generating Capacity Resources and Import Capacity Resources);

(viii) the estimated total summer and winter demand reduction value (for Demand Capacity Resources and Distributed Energy Capacity Resources) or net injection capability values per facility (for Distributed Energy Capacity Resources);

(ix) a description of the resource, including (for Generating Capacity Resources and Import Capacity Resources) a general description of the resource's equipment configuration and a description of the resource technology type, and (for Demand Capacity Resources) a description of the resource's Demand Capacity Resource type and measure type, and (for Distributed Energy Capacity Resources) a description of the project and its configuration, including the types of generation and demand response composing the project, and (for

Generating Capacity Resources and Distributed Energy Capacity Resources comprising generation) a one-line diagram of the resource's configuration;

(x) for resources supported by an Internal Elective Transmission Upgrade, all unique project identifiers associated with the Internal Elective Transmission Upgrade;

(xi) for Generating Capacity Resources with a contract to export capacity from the New England Control Area during the Capacity Commitment Period, the interface over which the capacity will be exported and the contract associated with the export capacity;

(xii) Additional requirements for Import Capacity Resources, the interface over which the capacity will be imported and one of the following submissions documenting the source of the imported capacity, as further detailed in Section III.15.2.1.1.1: (i) documentation of a contract entered into before the Qualification Data Submission Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for one or more years encompassing the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iii) documentation for system-backed import capacity that the Import Capacity Resource will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load.

(xiii) Additional requirements for Demand Capacity Resources, as further detailed in Section III.15.2.1.1.2: resource technical and credit/financial contacts; Measurement and Verification Plan (for On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources); Load Zone and Dispatch Zone (for Active Demand Capacity Resources);

(xiv) Additional requirements for Distributed Energy Capacity Resources, as further detailed in Section III.15.2.1.1.3: expected nameplate capacity by technology type per facility; installation date of facilities that are part of the project and already constructed, installed, or in commercial operation; indication of whether the project elects Intermittent Power Resource treatment; resource technical and credit/financial contacts; Load Zone, Dispatch Zone and DRR Aggregation Zone;

(xv) Additional requirements for resources with capacity impacted by ambient air conditions between 90 degrees and 100 degrees, as further detailed in Section III.15.2.1.5; and

(xvi) Additional requirements for resources seeking ISO-estimated Seasonal Qualified Capacity Values, as further detailed in III.15.2.6(d): the Qualification Data Submission Package shall satisfy the technical data requirements associated with such resources and be supplemented with the as-built status of the resource on the date of the relevant Capacity Demonstration Deadline.

(b) By submitting the required qualification information, the Lead Market Participant certifies that a Capacity Offer from the resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Tariff.

(c) The ISO may waive the submission of any information not required for evaluation of the resource.

III.15.2.1.1.1. Additional Import Capacity Resource Requirements.

Import Capacity Resources must be backed by one or more External Resources or by an external Control Area for the duration of the relevant Capacity Commitment Period. An external demand resource may not be an Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff. For the purposes of the qualification process, all Import Capacity Resources shall be treated as if they had never previously participated as capacity and must submit the materials described pursuant to this Section III.15.2.1.1 for each Capacity Commitment Period for which the Import Capacity Resource seeks to qualify capacity. Import Capacity Resources backed by an External Control Area that does not have a Coordination Agreement with the ISO shall be ineligible to participate in the Annual Capacity Market. No single Import Capacity Resource may qualify capacity in excess of the external interface limits as described in Section III.12.10.

An Elective Transmission Upgrade with Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall have its external node modeled in the Annual Capacity Auction after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Annual Capacity Auction qualification requirements of this Section III.15.2.1 and demonstration requirements of III.15.2.6. The Qualified Capacity of all Import Capacity Resources associated with an Elective Transmission Upgrade shall not exceed the Elective Transmission Upgrade’s Capacity Network Import Capability.

Capacity Offers for Import Capacity Resources shall be subject to rationing except for Capacity Offers priced above the Capacity Offer Price Threshold for Import Capacity resources associated with an Elective Transmission Upgrade, which must obtain a Capacity Supply Obligation or not in whole unless the Capacity Offer indicated that it may be rationed as described in III.15.4.1.

III.15.2.1.1.1.1. Imports Backed by External Resources.

If the Import Capacity Resource will be backed by one or more External Resources, the Lead Market Participant shall submit a description of how the Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify. The description must indicate specifically which External Resources will back the Import Capacity Resource during the Capacity Commitment Period and contain the relevant historical performance data for each resource. If those External Resources are not owned or controlled directly by the Lead Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.15.2.1.1.1.2. Imports Backed by an External Control Area.

If the Import Capacity Resource will be backed by an external Control Area, the Lead Market Participant shall submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the Import Capacity Resource.

III.15.2.1.1.1.3. Imports Crossing Intervening Control Areas.

Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) for imports crossing a single intervening Control Area, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the Qualification Data Submission Deadline, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing; (2) for imports crossing more than one intervening Control Area, in addition to the requirements above, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals,

by the Qualification Data Submission Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load; and (3) the Lead Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.15.2.1.1.2. Additional Demand Capacity Resource Requirements.

A Demand Capacity Resource may be an Active Demand Capacity Resource, On-Peak Demand Capacity Resource, or Seasonal Peak Demand Capacity Resource, and may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area.

For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource for the Capacity Commitment Period beginning June 1, 2028, the measure or measures contained in the resource must not have been in-service prior to June 1, 2024. For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in the Annual Capacity Auction or Monthly Reconfiguration Auction, as relevant, for or during the Capacity Commitment Period beginning June 1, 2029, and all Capacity Commitment Periods thereafter, the measure or measures contained in the resource must have been placed in-service or previously qualified as capacity no more than six months before the prior Annual Capacity Auction's Capacity Demonstration Deadline.

III.15.2.1.1.2.1. Measurement and Verification of Demand Capacity Resources.

(a) To demonstrate the demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the Lead Market Participant of such a resource participating in the Annual Capacity Auction, Capacity Supply Obligation Bilaterals, or Monthly Reconfiguration Auctions shall submit to the ISO Measurement and Verification Documents in accordance with this Section III.15.2.1.1.2.1 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.15.2.1.1.2.1 and the ISO New England Manuals.

(b) Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall: (1) serve as the basis for the claimed demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; (2) document the measurement and verification performed to verify the achieved demand reduction value of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; and (3) contain a projection of the On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's demand reduction value for each month of the Capacity Commitment Period and, for those Demand Capacity Resources composed of energy efficiency measures, over the expected Measure Lives. An On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours. If an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

(c) The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Annual Capacity Auction qualification process, as described in this Section III.15.2.1.1.2.1, and monthly Measurement and Verification data submitted during the Capacity Commitment Period. The monthly Measurement and Verification data shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan.

Such monthly Measurement and Verification data shall document the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, and the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, for all measures in operation as of the end of the previous month. The monthly Measurement and Verification data shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Lead Market Participants. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

(d) Lead Market Participants for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity Resource for which the Lead Market Participant is requesting compensation continues to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than ten Business Days before the Qualification Data Submission Deadline.

(e) For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources comprising customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Lead Market Participants shall maintain records of retail customers served, including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Lead Market Participant shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction values and measures installed by Load Zone and meter domain. Lead Market Participants shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is retired or deactivated from the Annual Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

(f) The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Annual Capacity Auction qualification

process as described in Section III.15.2 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.15.2.1.1.3. Additional Distributed Energy Capacity Resource Requirements.

(a) Distributed Energy Capacity Resources. A facility connected at a point of interconnection that is 5 MW or greater cannot be a part of a Distributed Energy Capacity Resource. A Distributed Energy Capacity Resource comprises one or more Distributed Energy Resource Aggregations located in a single Capacity Zone and a single DRR Aggregation Zone, except that (a) a Settlement Only Distributed Energy Resource Aggregation may not participate in a Distributed Energy Capacity Resource with any other type of Distributed Energy Resource Aggregation, and (b) an end-use customer facility participating as part of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with measures other than Energy Efficiency may not participate in a Distributed Energy Capacity Resource. Distributed Energy Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area. For purposes of this Section III.15.2.1.1.3: (i) if a facility is expected to interconnect at a point of interconnection, its net injection capability is the generation capability of the installed generation technology at the point of interconnection; (ii) if a facility is expected to interconnect at a Retail Delivery Point and does not plan to participate in the aggregation as a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, the net injection capability is the lesser of the generation less the load profile measured at the location of the end-use customer meter or the amount the facility is contractually able to inject.

(b) Demand Response Resource in Distributed Energy Capacity Resources. If the Distributed Energy Capacity Resource includes Demand Response Resources, the completed Qualification Data Submission Package shall include the following additional information: the estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); the estimated total summer and winter demand reduction value of the Demand Response Resource (which must be consistent with the baseline calculation methodology in Section

III.8.2); and supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values.

(c) Net Injection of 5 MW or Greater. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility with net injection of 5 MW or greater at a Retail Delivery Point, then the completed Qualification Data Submission Package for such a resource shall include the following additional information: the Pnode and service address at which the end-use facility is located; nameplate MW and net injection capability; non-coincident peak load (MW) of the facility without generation; technology type; and the Market Participant's portion of generation requested to be included as Qualified Capacity.

(d) Net Injection Greater Than or Equal to 1 MW and less than 5 MW. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility that has net injection capability at the point of interconnection of 1 MW or greater and less than 5 MW, then the completed Qualification Data Submission Package for such a facility shall include the following additional information: distribution bus; technology type; nameplate MW; one-line diagram of the plant and station facilities, including any known transmission facilities; if the facility is intermittent, the requested contribution of Qualified Capacity and supporting site-specific data; if an interconnection agreement is required under state requirements, the date when the interconnection request was submitted and the status of that interconnection request.

III.15.2.1.2. Market Power Review.

Lead Market Participants seeking to qualify a Capacity Resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or that is otherwise treated as if it had never done so pursuant to this Section III.15.2, must comply with the market power review provisions of Section III.A.21 by the Annual Capacity Auction Qualification Data Submission Deadline.

III.15.2.1.3. Capacity Commitment Period Election.

For the Annual Capacity Auctions for the 2028-2029, 2029-2030 and 2030-2031 Capacity Commitment Periods, a Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource must specify by the Qualification Data Submission Deadline whether it elects to continue to have the associated Capacity Supply Obligation and Capacity Clearing Price apply in Annual Capacity Auctions for the balance of the period permitted for

such Capacity Resource pursuant to Section III.13.1.1.2.2.4. Should a Lead Market Participant elect to terminate Section III.13.1.1.2.2.4 treatment for its Capacity Resource, it may not re-elect such treatment for any future Annual Capacity Auctions.

A Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource which has not achieved Capacity Market Commercial Operation as defined in Section III.15.2.6 of Market Rule 1 may not participate in the Annual Capacity Auction for the 2028-2029 Capacity Commitment Period and shall not have the previously elected Capacity Supply Obligation and Capacity Clearing Price apply for the 2028-2029 Capacity Commitment Period. Should such resource achieve Capacity Market Commercial Operation in time for participation in the Annual Capacity Auction for the 2029-2030 Capacity Commitment Period, or the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period, it may elect to have the Capacity Supply Obligation and Capacity Clearing Price it received pursuant to Section III.13.1.1.2.2.4 apply for the balance of the period permitted for such Capacity Resource pursuant to Section III.13.1.1.2.2.4, and in no event after the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period.

III.15.2.1.4. Material Deficiency in Data Submission.

In its review of a Lead Market Participant's data submission under this Section III.15.2.1, the ISO may consult with the Lead Market Participant, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO determines that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Lead Market Participant may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

In the event the ISO determines that a Lead Market Participant's data submission under Section III.15.2.1 is materially deficient, it shall notify the participant of such deficiencies at least ten Business Days prior to publication of the Advisory Seasonal Qualified Capacity Values, and the Lead Market Participant shall have five Business Days from the date of notification to cure the deficiencies. Should a Lead Market Participant fail to cure such deficiencies by the end of the cure period, it shall not be permitted to participate in the Annual Capacity Auction. In the event of such a rejection, the ISO shall provide the

Lead Market Participant with a written explanation of the reason for the rejection within ten Business Days of the close of the cure period.

III.15.2.1.5. Additional Qualification Requirements for Ambient Air Condition Impacts.

In the Qualification Data Submission Package, a Lead Market Participant may submit documentation indicating that a portion of its resource's capacity will not be physically available due to an ambient air condition. The size of such ambient air condition is calculated as the difference between the summer Qualified Capacity at 90 degrees and the rating of the resource at 100 degrees. The ISO shall verify during the qualification process the size of the ambient air condition.

III.15.2.2. Monthly Reconfiguration Auction Qualification.

For a resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for the purpose of participation in a Monthly Reconfiguration Auction pursuant to Section III.15.5 or bilateral activities pursuant to Section III.15.6, prior to the Capacity Demonstration Deadline for the relevant month a Lead Market Participant must: (1) submit the Qualification Data Submission Package as described in Section III.15.2.1 (except for the information described at Section III.15.2.1.2) by the Capacity Demonstration Deadline for the relevant month, except that an Import Capacity Resource or a Resource seeking ISO-estimated Seasonal Qualified Capacity Values pursuant to Section III.15.2.6(d) must submit its Qualification Data Submission Package 30 calendar days prior to the Capacity Demonstration Deadline; and (2) complete a capacity demonstration pursuant to Section III.15.2.6.

III.15.2.3. Deliverability Review.

A Generating Capacity Resource, Active Demand Capacity Resource, Import Capacity Resource associated with an External Elective Transmission Upgrade, and Distributed Energy Capacity Resource must satisfy the deliverability review requirements described in this Section III.15.2.3 in order to qualify capacity for participation in an Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction above the deliverability value associated with the resource's qualification for any previous Forward Capacity Auction, Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction. None of the provisions of this Section III.15.2, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder.

III.15.2.3.1. Deliverability Review for Capacity Resources Associated with Generating Facilities or External Elective Transmission Upgrades Subject to Schedule 22, 23, or 25 of Section II of the Tariff.

A Generating Facility or External Elective Transmission Upgrade subject to Schedules 22, 23 or 25 of Section II of the Tariff must complete the applicable interconnection processes set forth therein and have been assigned, as applicable, either Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, as necessary to support the delivery of the associated Capacity Resource's Qualified Capacity.

III.15.2.3.2. Deliverability Review for Capacity Resources Associated with Resources Not Subject to Schedule 22, 23, or 25 of Section II of the Tariff.

For a Generating Capacity Resource, Active Demand Capacity Resource, or Distributed Energy Capacity Resource not subject to Schedules 22, 23, or 25 of Section II of the Tariff, the ISO shall perform a deliverability review based on: (1) the information provided in the resource's Qualification Data Submission Package; and (2) the results of the ISO's most recent deliverability analysis, performed consistent with the criteria and conditions conducted as described in the ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that such a resource cannot deliver any of the requested incremental capacity, then the resource or incremental portion thereof shall not qualify for participation in the Capacity Market as reflected in the Seasonal Qualified Capacity Values issued pursuant to Section III.15.2.7; otherwise, the ISO shall determine that the requested Qualified Capacity of the Capacity Resource is deliverable, and the Capacity Resource shall be eligible to continue to proceed with the remainder of the processes described in this Section III.15.2.

III.15.2.4. Resources Previously Counted as Capacity.

Resources that have previously counted as capacity shall, for the purposes of Section III.15.2, be treated as if they had never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction if: (1) there is a material change to the Capacity Resource as described in III.15.2.4.1, or (2) if a deactivated or retired resource seeks to re-enter the Capacity Market pursuant to III.15.2.4.2.

III.15.2.4.1. Material Change to a Capacity Resource.

(a) A Lead Market Participant that materially changes a Capacity Resource that has previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or plans to do so prior to the relevant Capacity Demonstration Deadline, may, by the relevant Qualification Data

Submission Deadline or monthly Capacity Demonstration Deadline, inform the ISO of that material change, update the information provided under Section III.15.2.1.1 to reflect the change to the Capacity Resource, and demonstrate its updated Commercial Capacity pursuant to Section III.15.2.6. The updated Qualified Capacity of the resource, accounting for the change, shall be calculated in accordance with Section III.15.3.1 for the subsequent Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. The Seasonal Qualified Capacity of a Capacity Resource that notifies the ISO of a material change but does not demonstrate pursuant to III.15.2.6 shall remain unmodified until demonstration of the material change occurs.

(b) For purposes of this Section III.15.2.4, a material change to a Capacity Resource is a change to the design or operating characteristics of the resource, including its interconnection facilities, that may have a significant effect on the reliability or operating characteristics associated with the Capacity Resource, and shall include, but not be limited to, changing the resource technology type, making a change to the Capacity Resource that increases or decreases the resource's Annual Qualified Capacity by greater than the lesser of 5 MW or 10 percent, or any change to the resource that requires a material modification to its interconnection agreement. No less than 30 calendar days prior to the Qualification Data Submission Deadline or Monthly Capacity Demonstration Deadline, as relevant, a Lead Market Participant may request, and the ISO shall within 20 calendar days provide, a determination regarding whether a change qualifies as a material change to a Capacity Resource pursuant to this Section III.15.2.4 and requires submission of the materials required pursuant to Section III.15.2.1.1.

III.15.2.4.2. Treatment of Previously Deactivated or Retired Resources.

In order to qualify for participation in the Capacity Market, a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) must: (1) have reached its deactivation date and reduced its Capacity Network Resource Capability pursuant to Section II.48.3; (2) if the resource was compensated for delaying deactivation through a Commission-approved cost-of-service agreement, have refunded to the ISO all costs subject to refund under the claw-back provision set forth in Section II.54.1; and (3) have satisfied the provisions of Section III.15.2, including submission of the Qualification Data Submission Package described in Section III.15.2.1 and completed the capacity interconnection service requirements described in Section III.15.2.3, as if the resource had never previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction.

III.15.2.5. Calculation of Advisory Qualified Capacity Values.

Following the Qualification Data Submission Deadline, by a date in the month of February published on the Capacity Auction Calendar, the ISO shall calculate and provide to Lead Market Participants summer and winter Advisory Qualified Capacity Values for each resource that has met the data submission requirements in Section III.15.2.1. The Advisory Qualified Capacity Values of any resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as if it had not done so, shall equal its demonstrated Commercial Capacity determined in accordance with Section III.15.2.6; except that in the event that a resource has not yet demonstrated a portion of its Commercial Capacity, its Advisory Qualified Capacity Values shall equal the sum of its Commercial Capacity and the estimated incremental Seasonal Qualified Capacity Values of the resource as submitted pursuant to Section III.15.2.1. For all other resources, the Advisory Qualified Capacity Values shall equal the Capacity Resource's summer and winter Qualified Capacity as calculated pursuant to Section III.15.3.

During the period beginning with the ISO's issuance of Advisory Qualified Capacity Values and ending with the conclusion of the Annual Capacity Auction, any change to a capacity resource or the information submitted in a Qualification Data Submission Package shall not impact the resource's Seasonal Qualified Capacity Values for that Annual Capacity Auction unless the change has already been accounted for in the submitted Qualification Data Submission Package, or is made pursuant to Section III.15.2.1.4 or Section III.15.2.7.

III.15.2.6. Capacity Commercial Operation Demonstration Requirement.

To participate in an Annual Capacity Auction, Monthly Reconfiguration Auctions, or a Capacity Supply Obligation Bilateral transaction, a Capacity Resource must first demonstrate that its capacity is commercially operational by meeting the demonstration requirements in this Section III.15.2.6 by the applicable Capacity Demonstration Deadline. A resource that meets the demonstration requirements of this Section III.15.2.6 shall be deemed to have achieved Capacity Market Commercial Operation.

(a) Demonstration must be completed (i) prior to a Capacity Resource's initial participation in the Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction, and (ii) when a Capacity Resource that has previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction materially changes or reactivates pursuant to Section III.15.2.4.

(b) The Capacity Demonstration Deadline for each Annual Capacity Auction shall be during the month of April preceding the relevant Annual Capacity Auction, as published on the Capacity Auction

Calendar; for each Monthly Reconfiguration Auction and Capacity Supply Obligation Bilateral window, the Capacity Demonstration Deadline shall precede the relevant Obligation Month by approximately two weeks, as published on the Capacity Auction Calendar.

(c) To demonstrate commercial capacity, a resource must perform an audit by the relevant Capacity Demonstration Deadline, using the following audit requirements:

(i) For Generating Capacity Resources that are not Intermittent Power Resources, each Generator Asset must perform an Establish Claim Capability Audit pursuant to Section III.1.5.1.2, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.2(d)(iv).

(ii) For Generating Capacity Resources that are Intermittent Power Resources, each Generator Asset must perform a Seasonal Claim Capability Audit pursuant to Section III.1.5.1.3, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.3(i).

(iii) For Active Demand Capacity Resources, each Demand Response Asset must perform a Seasonal DR Audit pursuant to III.1.5.1.3.1, as specified by season in III.15.7.1.5.3(c), requested by the Lead Market Participant, and have its audit value become effective pursuant to Section III.1.5.1.3.1(m).

(iv) For Demand Capacity Resources that are not Active Demand Capacity Resources, each Demand Capacity Resource must perform a Passive DR Audit pursuant to III.15.7.1.5.4, as specified by season in III.15.7.1.5.3(c), at the request of the Lead Market Participant, and have its audit value become effective pursuant to Section III.15.7.1.5.4(f).

(v) For Distributed Energy Capacity Resources, each asset comprising the Distributed Energy Capacity Resource must meet the demonstration requirement in sub-sections (i) through (iii) above for its corresponding asset type.

(vi) For Import Capacity Resources, demonstration is achieved through provision of performance data in the resource’s Qualification Data Submission Package in accordance with Section III.15.2.1, except that Import Capacity Resources associated with an external Elective

Transmission Upgrade must demonstrate the ability to transfer power between regions pursuant to Schedule 25, Article 6.

(d) For those resources identified in Sections III.15.2.6(c)(ii), III.15.2.6(c)(iv), and III.15.2.6(c)(v) providing asset-level meter-based performance data by the Capacity Demonstration Deadline that is, as determined by the Lead Market Participant, of insufficient duration to establish accurate Seasonal Qualified Capacity Values, or for a period inconsistent with the audit described in Section III.15.2.6(c), the Lead Market Participant may request that the ISO determine Seasonal Qualified Capacity Values based on the lesser of: (1) the Seasonal Qualified Capacity Values requested for qualification by the Lead Market Participant; or (2) the Seasonal Qualified Capacity Values estimated by the ISO. In no instance shall the Seasonal Qualified Capacity Values developed pursuant to this Section III.15.2.6(d) exceed a resource's seasonal Capacity Network Resource Interconnection Service, or its equivalent.

The ISO-estimated Seasonal Qualified Capacity Values shall be based on technical data requirements for recently commercial resources identified in the Qualification Data Submission Package. The Qualification Data Submission Package of resources seeking ISO-estimated Seasonal Qualified Capacity Values shall include a description of the as-built status of the resource at time of submission, including whether the resource is fully or partially operational. For those resources seeking ISO-estimated Seasonal Qualified Capacity Values, the Qualification Data Submission Package must be submitted to the ISO by the Lead Market Participant by the Qualification Data Submission Deadline for the Annual Capacity Auction, or 30 days prior to the relevant monthly Capacity Demonstration Deadline, with the submission updated at the time of the Capacity Demonstration Deadline to reflect the as-built status of the resource. Resources satisfying the provisions of this Section III.15.2.6(d) shall be deemed to have demonstrated Commercial Capacity.

Resources seeking ISO-estimated Seasonal Qualified Capacity Values that have completed the relevant audit described in III.15.2.6(c) for only one season may elect to use the ISO-estimated Seasonal Qualified Capacity Values for one or both seasons. The ISO-estimated Seasonal Qualified Capacity Values may constitute a resource's Seasonal Qualified Capacity Value for up to one year after issuance, but shall be valid for no longer than one year after a resource becomes fully operational. A Lead Market Participant may request replacement of ISO-estimated Seasonal Qualified Capacity Values once the relevant seasonal audit has been completed.

III.15.2.7. Seasonal Qualified Capacity Values and Challenge Process.

(a) Following the April Capacity Demonstration Deadline, for each Capacity Resource qualified to participate in an Annual Capacity Auction, the ISO shall notify the Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity, calculated in accordance with Section III.15.3, and the Load Zone in which the resource is located. This notification will be provided by the Seasonal Qualified Capacity Notification Date specified in the Capacity Auction Calendar.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for a Capacity Resource, then the Lead Market Participant must notify the ISO within five calendar days of the Seasonal Qualified Capacity Notification Date.

(c) If a Capacity Resource's summer Qualified Capacity has been subject to a significant decrease pursuant to Section III.15.3.6, the Lead Market Participant may submit a restoration plan in accordance with Section III.15.3.6(b) within five calendar days of the Seasonal Qualified Capacity Notification Date.

(d) The ISO shall notify the Lead Market Participant of the outcome of any challenge submitted under (b) above or of its determination regarding the sufficiency of a restoration plan submitted under (c) above, by the date specified in the Capacity Auction Calendar for such responses. In assessing the sufficiency of a restoration plan, the ISO shall determine whether the plan provides sufficient information to support the reasonable likelihood of the resource providing capacity consistent with its summer Qualified Capacity value by the start of the Capacity Commitment Period.

III.15.2.8. Offers Composed of Separate Resources (Composite Offers).

Separate resources seeking to participate together in an Annual Capacity Auction shall submit a Composite Offer Form no later than the Composite Offer Deadline, which shall be approximately two business days prior to the auction as specified in the Capacity Auction Calendar, with the exception that Distributed Energy Capacity Resources may not participate in composite offers. Composite offers may not be modified or withdrawn after the Composite Offer Deadline. Composite offers must meet the following conditions:

(a) In all months of the summer period of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources combined meet the amount of the offer in all

months of the winter period; and (ii) to combine for a month, that month must be a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of a composite offer must qualify in accordance with all of the provisions of Section III.15.2 applicable to that resource type. A composite offer participates in the Annual Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period.

(c) The summer Qualified Capacity of a composite offer shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.15.3.7 shall apply, even where one or more of the resources that are part of the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the composite offer in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) Composite offers are subject to the locational restrictions specified in the following table:

		Location of Summer Resource			
		Import-Constrained Capacity Zone	Rest-of-Pool Capacity Zone	Export-Constrained Capacity Zone	Nested Export-Constrained Capacity Zone
Location of Winter Resource	Import-Constrained Capacity Zone	Eligible (within same Capacity Zone)	Eligible	Eligible	Eligible
	Rest-of-Pool Capacity Zone	Ineligible	Eligible	Eligible	Eligible
	Export-Constrained Capacity Zone	Ineligible	Ineligible	Eligible (within same Capacity Zone)	Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located)

	Nested Export-Constrained Capacity Zone	Ineligible	Ineligible	Ineligible	Eligible (within same Capacity Zone)

III.15.2.9. Self-Supplied Capacity.

Where a load serving entity elects to designate all or a portion of its Capacity Load Obligation as self-supplied, the load serving must make such designation to the ISO during the self-supply designation window, as published in the Capacity Auction Calendar on the ISO's website. The load serving entity's designation shall specify the MW amount and Lead Market Participant providing the self-supplied capacity. During the Annual Capacity Auction Offer Window, the Lead Market Participant supplying such capacity shall confirm the load serving entity's self-supply designation by specifying each Self-Supplied Capacity Resource and the MW amount of self-supplied capacity in its Capacity Offer. A Generating Capacity Resource or an Import Capacity Resource may be designated as a Self-Supplied Capacity Resource. A Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied Capacity Resource. All self-supplied capacity shall be subject to the eligibility and locational requirements in this Section III.15.2.9. If designated as a Self-Supplied Capacity Resource the resource will clear in the Annual Capacity Auction as described in Section III.15.4 and, with the exception of demand programs for Self-Supplied Capacity Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.15.2. All designations as a Self-Supplied Capacity Resource in the Annual Capacity Auction qualification process are binding.

III.15.2.9.1. Self-Supplied Capacity Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied Capacity Resource, it shall also maintain its status as a Generating Capacity Resource, Import Capacity Resource, or Distributed Energy Capacity Resource and must satisfy the Annual Capacity Auction qualification process requirements set forth in the remainder of Section III.15.2 applicable to that resource type, in addition to the requirements of this Section III.15.2.9.1. Where a Capacity Offer composed of separate resources is submitted for a Self-Supplied Capacity Resource, all of the requirements and deadlines specified in Section III.15.2.8 shall apply to that offer, in addition to the requirements of this Section III.15.2.9. The total quantity of capacity that a load serving entity designates as self-supplied capacity

may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period, which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied Capacity Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.15.2.9.2. Locational Requirements for Self-Supplied Capacity Resources.

In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource for a load in an import-constrained Capacity Zone, the Self-Supplied Capacity Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied Capacity Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied Capacity Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.15.2.10. Publication of Annual Qualified Capacity Values for Annual Capacity Auction.

The ISO shall provide Annual Qualified Capacity values to Lead Market Participants of each Capacity Resource participating in an Annual Capacity Auction one business day before the opening of the Annual Capacity Auction Offer Window.

III.15.2.11. Publication of Offer Information.

(a) For each Capacity Offer, the quantity and Load Zone (or interface, as applicable) in which the resource is located will be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(b) For Capacity Offers from Import Capacity Resources, the name of submitter, quantity, and interface shall be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(c) The name of each Lead Market Participant submitting Capacity Offers, as well as the number of Capacity Offers submitted by each Lead Market Participant, shall be published to the ISO's website no later than 15 calendar days after the issuance of Advisory Qualified Capacity Values. Authorized Persons

of Authorized Commissions will be provided confidential access to full information about posted Capacity Offers upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.15.3. Capacity Resource Accreditation.

Pursuant to the provisions of this Section III.15.3, the ISO shall determine a summer Qualified Capacity, a winter Qualified Capacity, an Annual Qualified Capacity and, where applicable, a Monthly Qualified Capacity for each Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource. A Capacity Resource's Seasonal Qualified Capacity Values shall not exceed its seasonal Capacity Network Resource Interconnection Service or equivalent, or Capacity Network Import Interconnection Service, as applicable. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall not exceed the resource's highest previously received Capacity Supply Obligation unless the resource has demonstrated and qualified the additional capacity pursuant to Section III.15.2.4.1.

Qualified Capacity values for resources that have never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Section III.15.3.1. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Sections III.15.3.2 through III.15.3.5.

III.15.3.1. Qualified Capacity for Resources Never Previously Counted as Capacity.

III.15.3.1.1. Resources Never Previously Counted as Capacity.

The summer and winter Qualified Capacity of a Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as such pursuant to the terms of this Section III.15, shall be determined in accordance with the capacity demonstration requirements set forth in Section III.15.2.6, as specified below.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is not an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant to Section III.15.2.6(c)(i), the ISO shall use the Section III.1.5.1.2(c) audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(ii), the ISO shall use the Section III.1.5.1.3 audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and Section III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iii), the ISO shall use the Section III.1.5.1.3.1 audit results. To determine the Seasonal Qualified Capacity Values of a Demand Capacity Resource other than an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iv), the ISO shall use the Section III.15.7.1.5.4 audit results. The annual and Monthly Qualified Capacity of such resources shall be determined pursuant to Sections III.15.3.4.2 and III.15.3.4.3, respectively.

To determine the Seasonal Qualified Capacity Values of a Distributed Energy Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(v), the ISO shall use the audit results specified therein for the corresponding asset type. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.5.2 and III.15.3.5.3, respectively.

To determine the Seasonal Qualified Capacity Values of an Import Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(vi), the ISO shall use the performance data results specified therein. The annual and monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.3.

To determine the Seasonal Qualified Capacity Values of a resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and that has elected to demonstrate commercial capacity pursuant Section III.15.2.6(d), the ISO shall use the values developed pursuant to Section III.15.2.6(d). The annual Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3, Section III.15.3.4.2, or Section III.15.3.5.2, as applicable to

the relevant resource type. The Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.4, III.15.3.4.3, or Section III.15.3.5.3, as applicable to the relevant resource type.

III.15.3.2 Qualified Capacity for Generating Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Generating Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.2.

III.15.3.2.1. Summer Qualified Capacity.

(a) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline each year, with only positive summer ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive summer ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the summer Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all summer period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

III.15.3.2.2. Winter Qualified Capacity.

(a) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the winter Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all winter period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

III.15.3.2.3. Annual Qualified Capacity.

The Annual Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The Annual Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.15.3.2.4. Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Generating Capacity Resource shall be the resource's most recent Seasonal Claimed Capability value for the season applicable to the relevant month; for those Generating Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

III.15.3.3. Qualified Capacity for Import Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by an External Control Area shall be based on the values and data submitted during the qualification process, subject to ISO review and verification. The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be based on the data submitted during the qualification process, subject to ISO review and verification, and calculated based on the summer and winter Qualified Capacity of the resources underlying the Import Capacity Resource, in accordance with Sections III.15.3.2.1 and III.15.3.2.2.

III.15.3.4. Qualified Capacity for Demand Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Demand Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.4.

III.15.3.4.1. Summer and Winter Qualified Capacity.

(a) For Demand Capacity Resources composed of Energy Efficiency measures, the summer (or winter, as applicable) Qualified Capacity shall equal the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Capacity Demonstration Deadline (excluding any capacity that will retire or deactivate, or whose Measure Life will expire, prior to the start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses).

(b) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the median of the resource's Seasonal DR Audit value or Passive DR Audit value from the five most recent years, for the relevant season, increased by average avoided peak transmission and distribution losses. Where a Demand Capacity Resource has fewer than five summer or winter Seasonal Audit Values, as applicable, then the summer (or winter) Qualified Capacity for that Demand Capacity Resource shall be equal to the median of all the resource's previous

summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

III.15.3.4.2. Annual Qualified Capacity.

The Annual Qualified Capacity of a Demand Capacity Resource shall equal the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.15.3.4.3 Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Demand Capacity Resource, other than a resource composed of Energy Efficiency measures, shall equal its most recent Seasonal DR Audit value or Passive DR Audit value for the season applicable to the relevant month; for those Demand Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

The Monthly Qualified Capacity of a Demand Capacity Resource composed of Energy Efficiency measures shall equal the most recently-determined summer or winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire, deactivate, or whose Measure Life will expire, prior to the start of the relevant Obligation Month, and increased by average avoided peak transmission and distribution losses).

III.15.3.5. Qualified Capacity of Distributed Energy Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Distributed Energy Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.5.

III.15.3.5.1. Summer and Winter Qualified Capacity.

The summer (or winter, as applicable) Qualified Capacity of a Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer (or winter) Seasonal Audit Value from the five most recent years, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation. Where a Distributed Energy Capacity Resource has fewer than five summer (or winter) Seasonal Audit Values, then the summer (or winter) Qualified Capacity for that Distributed Energy Capacity Resource shall be

equal to the median of the resource's previous summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

The summer or winter Qualified Capacity of Distributed Energy Capacity Resources that are Intermittent Power Resources shall be determined in accordance with the rules for Generating Capacity Resources that are Intermittent Power Resources in Section III.15.3.2.

III.15.3.5.2. Annual Qualified Capacity.

Annual Qualified Capacity for a Distributed Energy Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, unless the Distributed Energy Capacity Resource is an Intermittent Power Resource, in which case the Annual Qualified Capacity shall be equal to the resource's summer Qualified Capacity.

III.15.3.5.3. Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Distributed Energy Capacity Resource shall equal the most recent Seasonal DECR Audit for the season applicable to the relevant month; for those Distributed Energy Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

III.15.3.6. Adjustment for Significant Decreases in Capacity.

For a Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Distributed Energy Capacity Resource, or Demand Capacity Resource, if the most recent summer Seasonal Claimed Capability rating, summer season Import Capacity Resource performance data submitted pursuant to Section III.15.2.1.1.1, summer Seasonal DECR Audit Value, summer Seasonal DR Audit Value, or summer Passive DR Audit Value as of the Annual Capacity Auction's Capacity Demonstration Deadline is below the resource's Qualified Capacity by more than the threshold defined in the following formula:

$$Threshold = min[max(10\% \times QC_{Summer}, 2\ MW), 10\ MW]$$

Where,

QC_{Summer} = the resource's summer Qualified Capacity

then the Lead Market Participant must elect one of the two treatments set forth in this Section III.15.3.6 by the close of the Seasonal Qualified Capacity Challenge and Restoration Plan Submission Window. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.15.3.6(b) and fails to meet the associated requirements, then the treatment described in Section III.15.3.6(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Annual Capacity Auction only, to have the resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability rating, summer Seasonal DECR Audit Value, Seasonal DR Audit Value, or Passive DR Audit Value as of the Capacity Demonstration Deadline, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a restoration plan describing the measures that will be taken and showing that the Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 by the start of the relevant Capacity Commitment Period; and (ii) to have the Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 for the Annual Capacity Auction. The ISO shall review submitted restoration plans in accordance with the requirements and timelines set forth in Section III.15.2.7.

III.15.3.7. Resources Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where a Generating Capacity Resource (other than an Intermittent Power Resource), Demand Capacity Resource, or Import Capacity Resource has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.15.3, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, in accordance with Section III.15.2.8; or (ii) have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

Where a Distributed Energy Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this

Section III.15.3, then that resource must have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.15.4. Annual Capacity Auction.

III.15.4.1 Capacity Offers.

Lead Market Participants submitting Capacity Offers in the Annual Capacity Auction shall submit Capacity Offers for the Capacity Commitment Period associated with the Annual Capacity Auction as specified in this Section III.15.4.1.

(a) Each Capacity Offer shall be associated with a Capacity Resource for which an Annual Qualified Capacity value has been established for the Annual Capacity Auction through the Annual Capacity Auction qualification process set forth in Sections III.15.2 and III.15.3.

(b) Capacity Offers must be submitted during the Annual Capacity Auction Offer Window, the dates of which will be specified as published in the Capacity Auction Calendar. Capacity Offers are not considered final until the close of the Annual Capacity Auction Offer Window and may be amended or corrected as necessary until such time as the window closes.

(c) If a Lead Market Participant fails to submit a Capacity Offer for a resource subject to the requirements of Section III.A.22.1, the ISO shall enter a Capacity Offer for the resource into the Annual Capacity Auction in accordance with Section III.A.22.1(d).

(d) Each Capacity Offer must specify at least one price-quantity pair, which consists of one price, denominated in $/kW-month to an accuracy of at most three digits to the right of the decimal point, and a quantity value, expressed in MW to an accuracy of up to three decimal places. The Capacity Offer may specify up to ten price-quantity pairs, where each such pair represents the total amount of capacity offered from the Capacity Resource at the price specified. If more than one price-quantity pair is submitted, the price-quantity pairs must specify prices and quantity values in such a way that, when the price-quantity pairs are ordered from lowest price to highest price, the quantity value in each price-quantity pair increases with each successive, higher-priced price-quantity pair. The price-quantity pair with the greatest specified price must include the Capacity Resource's total Annual Qualified Capacity. The Capacity Offer must not contain any offer prices less than $0.00/kW-month or greater than the Capacity Auction Offer Price Cap, unless otherwise allowed pursuant to Section III.A.22.2.3 and subsection (e) of this Section III.15.4.1 or required by Section III.A.21 and subsection (f) of this Section III.15.4.1. The Capacity Offer must not specify a total MW quantity value that exceeds the Capacity Resource's Annual Qualified Capacity.

(e) A price-quantity pair in a Capacity Offer must not specify a price above the Capacity Offer Price Threshold, except under the following circumstances:

(i) the Lead Market Participant for the Capacity Resource submitted the price-quantity pair to the Internal Market Monitor as part of a Proposed Capacity Offer, pursuant to Section III.A.22.2.2;

(ii) the Internal Market Monitor determined an Allowable Capacity Offer Price relative to the price-quantity pair pursuant to Section III.A.22.2.3; and

(iii) the specified price in the Capacity Offer does not exceed the price specified in the price-quantity pair reviewed by the Internal Market Monitor.

(f) For capacity included in a Capacity Offer that is subject to a Capacity Offer Floor Price pursuant to Section III.A.21.3, the price specified must not be less than the Capacity Offer Floor Price.

(g) A Capacity Offer may specify a Rationing Minimum Limit up to which the offer may not be rationed and must be accepted or rejected in whole. Without such indication, offers shall be rationable up to the total MW quantity in the offer that is priced at or below the Capacity Offer Price Threshold, subject to the auction clearing constraint described in Section III.15.4.2.2(d). The lowest priced price-quantity pair in a Capacity Offer that specifies a Rationing Minimum Limit must specify a quantity value equal to or greater than the specified Rationing Minimum Limit. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only specify a Rationing Minimum Limit pursuant to this subsection (g) if the Import Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(h) If the Capacity Offer specifies any price above the Capacity Offer Price Threshold, the Capacity Offer may elect to have the Above-Threshold Offer Segment be treated as rationable, subject to any Rationing Minimum Limit specified pursuant to subsection (g). Without such an election, the Above-Threshold Offer Segment will be treated as non-rationable and accepted or rejected in whole. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only elect rationability for the Above-Threshold Offer Segment pursuant to this subsection (h) if the Import

Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(i) In order to give effect to a self-supply designation made by a load serving entity pursuant to Section III.15.2.9 for any portion of the Capacity Resource's Annual Qualified Capacity, the Capacity Offer for such resource must (i) identify the load serving entity for which its capacity will serve as self-supplied capacity and the MW quantity of self-supplied capacity and (ii) include a price-quantity pair with an offer price of $0.00/kW-month that includes the amount of such capacity, unless such capacity is subject to a Capacity Offer Floor Price. If the self-supplied capacity is subject to a Capacity Offer Floor Price, then the price specified in the price-quantity pair including the self-supplied capacity must equal the Capacity Offer Floor Price.

(j) A Capacity Offer for a Generating Capacity Resource with a contract to export capacity during the Capacity Commitment Period must specify an Export Offer Segment and the interface over which the Export Offer Segment will be exported.

(k) A Lead Market Participant for a Capacity Resource that is subject to delayed deactivation pursuant to Sections II.52 and II.53 shall not enter a Capacity Offer for any capacity supplied by the Capacity Resource that is subject to delayed deactivation. The ISO shall enter such Capacity Resource's capacity subject to delayed deactivation into the Annual Capacity Auction at a price of $0.00/kW-month.

(l) If a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the Capacity Resource had been made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 for a Forward Capacity Auction, the Capacity Offer submitted for such Capacity Resource must include a price-quantity pair with an offer price of $0.00/kW-month that includes the total amount of the resource's capacity that cleared subject to such election.

III.15.4.2. Conduct of the Annual Capacity Auction.

The ISO shall determine Capacity Supply Obligations and Capacity Clearing Prices for the Capacity Commitment Period by conducting the Annual Capacity Auction as described in this Section III.15.4.2.

III.15.4.2.1. Replacement of Specified Prices for Mitigation Purposes.

After the Annual Capacity Auction Offer Window, the ISO shall replace specified prices in submitted Capacity Offers as necessary, pursuant to Section III.A.22.2.4(c). Any such adjusted Capacity Offers shall be inputs for the Annual Capacity Auction.

III.15.4.2.2. Clearing of the Annual Capacity Auction.

(a) In determining Capacity Supply Obligations and Capacity Clearing Prices, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear Capacity Offers, capacity entered into the auction by the ISO as described in Section III.15.4.1(k), and any Proxy Capacity Offers against the capacity demand curves calculated in accordance with Section III.15.1.1. In clearing Capacity Offers, the optimization algorithm shall take into account, as applicable, the inputs and constraints set forth in this Section III.15.4.2.2.

(b) The optimization algorithm shall take into account the following: (i) all price-quantity pairs in Capacity Offers for the Annual Capacity Auction submitted pursuant to Section III.15.4.1, subject to any adjustments made pursuant to Section III.15.4.2.1 and the constraint described in subsection (c) of this Section III.15.4.2.1; (ii) any Rationing Minimum Limits and rationability elections specified in Capacity Offers pursuant to Section III.15.4.1(g) and Section III.15.4.1(h), respectively; (iii) capacity from a Capacity Resource subject to delayed deactivation pursuant to Sections II.52 and II.53 at a default price of $0.00/kW-month; (iv) the set of distinct Capacity Zones determined to be modeled in the Annual Capacity Auction pursuant to Section III.12.4; (v) the System-Wide Capacity Demand Curve calculated in accordance with Section 15.1.1.1; (vi) any Capacity Zone Demand Curves for import-constrained and export-constrained Capacity Zones, calculated in accordance with Sections 15.1.1.2 and 15.1.1.3, respectively; (vii) external interface limits calculated pursuant to Section III.12.10; and (viii) any Proxy Capacity Offers for the Annual Capacity Auction as determined pursuant to Section III.A.24.7, which shall be treated as non-rationable.

(c) The optimization algorithm shall not take into account price-quantity pairs in Capacity Offers that specify a price that exceeds the Capacity Auction Offer Price Cap.

(d) Capacity entered into the Annual Capacity Auction at a price of $0.00/kW-month shall clear the auction.

(e) A Capacity Offer that specifies a Rationing Minimum Limit pursuant to Section III.15.4.1(g) shall not clear at quantities less than the specified Rationing Minimum Limit, and Above-Threshold Offer

Segments that are non-rationable pursuant to Section III.15.4.1(h) shall not clear at quantities less than the MW quantity of the segment.

(f) For an Export Offer Segment specified in a Capacity Offer that indicates a Generating Capacity Resource's contract to export capacity over an external interface connected to an import-constrained Capacity Zone from another Capacity Zone, or over an external interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone, the ISO shall model the Export Offer Segment as though that quantity of capacity were located in the Capacity Zone where the external interface identified in the Capacity Offer is located and adjust Capacity Zone Demand Curves as necessary to reflect such modeling.

(g) In determining the clearing result that accounts for auction inputs and satisfies all applicable constraints, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including clearing results where a Capacity Offer with a specified price below the Capacity Clearing Price does not clear.

(h) Where the clearing of the Annual Capacity Auction either system-wide or in a single Capacity Zone results in a tie (that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs), the following rules shall apply in sequence, as necessary, to determine clearing: (i) if multiple Capacity Offers may be rationed, they will be rationed proportionately; and (ii) the Capacity Offer associated with the Lead Market Participant having the lower market share in the capacity auction shall be cleared.

(i) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be the price specified by the System-Wide Capacity Demand Curve for the system-wide capacity entered into the Annual Capacity Auction that maximizes social surplus. In no case, however, shall the Capacity Clearing Price for the Rest-of-Pool Capacity Zone be less than the highest price specified in an offer for capacity that clears the auction, excluding any capacity that, due to its specified price, would not have cleared but for the fact that it is located within an import-constrained Capacity Zone that has a cleared quantity of capacity equal to or less than the truncation point for the zone's Capacity Zone Demand Curve.

(j) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an import-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the import-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the import-constrained Capacity Zone and that clears the auction.

(k) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(l) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(m) The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for an import-constrained Capacity Zone shall not exceed the Capacity Auction Offer Price Cap. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

(n) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an interface between the New England Control Area and an external Control Area shall be equal to:

(i) if the quantity of capacity over the external interface that clears the auction is equal to the external interface limit for such interface, the highest price specified in a Capacity Offer for capacity that is supplied from a resource offering capacity over such external interface and that clears the auction; or

(ii) if the quantity of capacity over the external interface that clears the auction is less than the external interface limit for such interface, the Capacity Clearing Price for the Capacity Zone associated with the external interface.

III.15.4.2.3. Results of the Annual Capacity Auction.

(a) Annual Capacity Supply Obligations shall be awarded to Capacity Resources in accordance with the results of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2. For Intermittent Power Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.15.2) shall be adjusted based on the winter Qualified Capacity as determined pursuant to Section III.15.3.2.2. Additional Capacity Supply Obligations may be awarded in accordance with Section III.15.4.2.4.

(b) The Capacity Clearing Prices in each Capacity Zone modeled in the Annual Capacity Auction shall be the clearing prices determined as a result of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2.

III.15.4.2.4. Additional Clearing of Auction in the Event of Cleared Proxy Offers.

If any Proxy Capacity Offer entered into the Annual Capacity Auction clears and receives a Capacity Supply Obligation, the ISO shall conduct an additional run of the auction. This additional run shall use the same methodology described in Section III.15.4.2.2, except that the additional run shall (i) exclude all Proxy Capacity Offers and (ii) enter all other capacity that cleared in the primary run of the Annual Capacity Auction at a price of $0.00/kW-month. The additional run of the auction shall not affect the Capacity Clearing Prices of the primary run of the Annual Capacity Auction pursuant to Section III.15.4.2.2. Capacity (other than capacity still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receives a Capacity Supply Obligation as a result of the primary run of the Annual Capacity Auction shall be paid the Capacity

Clearing Price in the Capacity Zone associated with the capacity during the associated Capacity Commitment Period. Where the additional run of the auction procures additional capacity, that additionally procured capacity shall be paid the price resulting from the additional run in the Capacity Zone associated with that additional capacity during the associated Capacity Commitment Period, and such price shall be equal to or greater than the price resulting from the primary run of the Annual Capacity Auction in that Capacity Zone.

III.15.4.3. Publication of Annual Capacity Auction Results.

As soon as practicable after the Annual Capacity Auction is complete, the ISO shall publish the results of that Annual Capacity Auction publicly on its website, including the set of Capacity Zones modeled in the auction, the Capacity Clearing Prices in each of those Capacity Zones, and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. The published information shall identify Proxy Capacity Offers that cleared, if any, in the primary run of the Annual Capacity Auction.

III.15.5. Monthly Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct Monthly Reconfiguration Auctions as described in this Section III.15.5. Monthly Reconfiguration Auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in the Monthly Reconfiguration Auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Section III.15.5.1) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.15.5.1. Capacity Zones Included in Monthly Reconfiguration Auctions.

Each Monthly Reconfiguration Auction associated with a Capacity Commitment Period shall include each of, and only, the Capacity Zones and external interfaces modeled in the Annual Capacity Auction for that Capacity Commitment Period in accordance with Section III.15.4.2.2.

III.15.5.2. Participation in Monthly Reconfiguration Auctions.

Each supply offer and demand bid in a Monthly Reconfiguration Auction must be associated with a specific resource and must satisfy the requirements of this Section III.15.5.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.13.2, supply offers and demand bids submitted for Monthly Reconfiguration Auctions shall not be subject to mitigation by the Internal Market Monitor. Offers composed of separate resources may not participate in reconfiguration auctions. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in reconfiguration auctions, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. The offer and bid deadline for each Monthly Reconfiguration Auction shall be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.15.5.2.

III.15.5.2.1. Supply Offers in Monthly Reconfiguration Auctions.

(a) All supply offers in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, denominated in $/kW-month.

(b) A resource may not submit a supply offer for a Monthly Reconfiguration Auction unless a Monthly Qualified Capacity value has been established for the resource for the month associated with the Monthly Reconfiguration Auction pursuant to the qualification processes described in Sections III.15.2 and III.15.3.

(c) The amount of capacity up to which a resource may submit a supply offer in a Monthly Reconfiguration Auction shall be the difference (but in no case less than zero) between (i) the resource's Monthly Qualified Capacity for the month associated with the auction, as determined pursuant to Section III.15.3 during the most recent qualification process for the resource; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

III.15.5.2.2. Demand Bids in Monthly Reconfiguration Auctions.

(a) All demand bids in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant and shall specify the amount of capacity bid in MW and the price, denominated in $/kW-month.

(b) To submit a demand bid in a Monthly Reconfiguration Auction, a resource must have a Capacity Supply Obligation for the month associated with that Monthly Reconfiguration Auction.

(c) Where capacity associated with a Self-Supplied Capacity Resource that cleared in the Annual Capacity Auction for the Capacity Commitment Period is offered in a Monthly Reconfiguration Auction, a resource acquiring a Capacity Supply Obligation in that Monthly Reconfiguration Auction shall not as a result become a Self-Supplied Capacity Resource.

(d) Each demand bid submitted to the ISO for a Monthly Reconfiguration Auction shall be no greater than the amount of the resource's capacity that is already obligated for the month associated with that Monthly Reconfiguration Auction as of the offer and bid deadline for the auction.

III.15.5.3. Clearing Offers and Bids in Monthly Reconfiguration Auctions.

All supply offers and demand bids are rationable and may be cleared in whole or in part in Monthly Reconfiguration Auctions.

III.15.5.4. Conduct of Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a Monthly Reconfiguration Auction for whole-month capacity commitments during that month. For each Monthly Reconfiguration Auction, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear the supply offers against demand bids submitted for the auction. The truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.15.1.1.2 and Section III.15.1.1.3 and external interface limits established pursuant to Section III.12 shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in Monthly Reconfiguration Auctions.

III.15.5.5. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be increased by the amount of capacity that clears. For each demand bid that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be decreased by the amount of capacity that clears.

III.15.6. Bilateral Capacity Contracts.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, and Capacity Performance Bilaterals in accordance with this Section III.15.6, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation. To the extent necessary for the ISO's review and approval of any of the bilateral contracts described in this Section III.15.6, the ISO shall apply the Capacity Zones and external interfaces modeled as inputs and constraints in the Annual Capacity Auction for the applicable Capacity Commitment Period, as described in Section III.15.4.2.2. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in Capacity Supply Obligation Bilaterals or Capacity Performance Bilaterals, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1.

III.15.6.1. Capacity Supply Obligation Bilaterals.

A Capacity Transferring Resource having a Capacity Supply Obligation and seeking to shed that obligation may enter into a Capacity Supply Obligation Bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part, to a Capacity Acquiring Resource, or portion thereof, for a whole-month period during the Capacity Commitment Period, as described in this Section III.15.6.1.

III.15.6.1.1. Terms of and Participation in Capacity Supply Obligation Bilaterals.

(a) Capacity Supply Obligation Bilaterals are available for monthly periods, and a Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) The qualification of Capacity Acquiring Resources for participation in Capacity Supply Obligation Bilaterals is determined in the same manner as the qualification of resources submitting supply offers for Monthly Reconfiguration Auctions as specified in Section III.15.5.2.1(b). A resource that does not have a Monthly Qualified Capacity value established for the month covered by the Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that month.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Monthly Qualified Capacity of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral. For the purpose of this subsection (c), unobligated Monthly Qualified Capacity refers to the Monthly Qualified Capacity that was

determined pursuant to Section III.15.3 in the most recent qualification process for the resource prior to the submission of the Capacity Supply Obligation Bilateral to the ISO and that is not subject to a Capacity Supply Obligation.

(d) A resource, or a portion thereof, that has been designated as a Self-Supplied Capacity Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied Capacity Resource as a result of the transaction.

(e) Capacity Supply Obligation Bilaterals are allowed between a Capacity Transferring Resource and a Capacity Acquiring Resource that are located within different Capacity Zones and across external interfaces modeled as part of the Annual Capacity Auction for the Capacity Commitment Period of the relevant monthly period, subject to the transmission interface limits between Capacity Zones and external interface limits, as described in Section III.15.6.1.4(b).

(f) Participation in any Capacity Supply Obligation Bilateral is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of submission to the ISO.

III.15.6.1.2. Timing of Submission and Prior Notification to the ISO.

The Lead Market Participant for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals in the Capacity Auction Calendar. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.15.6.1.3. Contents of Submission to the ISO.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, denominated in $/kW-

month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.15.6.1.4. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral and shall reject the Capacity Supply Obligation Bilateral if any of the submission and participation requirements described in this Section III.15.6.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the submittal window, the ISO shall conduct a review to determine the deliverability of the submitted Capacity Supply Obligation Bilaterals. In its review, the ISO shall model as constraints the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Sections III.15.1.1.2 and III.15.1.1.3 and external interface limits established pursuant to Section III.12 for the applicable Capacity Commitment Period. The ISO shall reject Capacity Supply Obligation Bilaterals that are not fully deliverable up to their specific MW values without violating transmission transfer limits between Capacity Zones or external transfer limits. Transactions will only be accepted or rejected in their entirety. The ISO shall approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected, the Lead Market Participant for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the basis for such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.15.6.1.5. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply

Obligation of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.15.6.2. Capacity Load Obligations Bilaterals.

A Capacity Load Obligation Transferring Participant seeking to shed its Capacity Load Obligation may enter into a Capacity Load Obligation Bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone to a Capacity Load Obligation Acquiring Participant seeking to acquire a Capacity Load Obligation, as described in this Section III.15.6.2.

III.15.6.2.1. Terms of and Participation in Capacity Load Obligation Bilaterals.

A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.15.6.2.2. Timing of Submission to the ISO.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial daily settlements of payments and charges associated with the Annual Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 p.m. on the first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.15.6.2.3. Contents of Submission to the ISO.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following: (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant

and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.15.6.2.4. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section III.15.6.2 are not met.

III.15.6.2.5. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral.

III.15.6.3. Capacity Performance Bilaterals.

A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.15.6.3.

III.15.6.3.1. Terms of and Participation in Capacity Performance Bilaterals.

If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval through a Capacity Performance Bilateral, so long as both resources were subject to the same Capacity Scarcity Condition. The Lead Market Participant for the transferring resource may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for such five-minute interval to the receiving resource. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.

III.15.6.3.2. Timing of Submission to the ISO.

A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Annual Capacity Market for the month associated with the Capacity

Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 p.m. on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).

III.15.6.3.3. Contents of Submission to the ISO.

The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW amount of Capacity Performance Score being transferred; and (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.

III.15.6.3.4. ISO Review.

The ISO shall review the information provided in the submission of the Capacity Performance Bilateral and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.15.6.3 are not met.

III.15.6.3.5. Effect of Capacity Performance Bilateral.

A Capacity Performance Bilateral does not affect either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Condition subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.15.8.2.

III.15.7. Obligations of Capacity Suppliers.

Resources assuming a Capacity Supply Obligation through an Annual Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a Monthly Reconfiguration Auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.15.7 for each Capacity Commitment Period.

III.15.7.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through an Annual Capacity Auction, Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.15.7.1.1. Generating Capacity Resources with Capacity Supply Obligations.

III.15.7.1.1.1. Energy Market Offer Requirements.

(a) A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.15.7.1.1.1(a)(i) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.15.7.1.1.3. [Reserved.]

III.15.7.1.1.4. [Reserved.]

III.15.7.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas; and

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-

scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.1.2. Import Capacity Resources with Capacity Supply Obligations.

III.15.7.1.2.1. Energy Market Offer Requirements.

A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(a) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;
(b) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;
(c) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

III.15.7.1.2.2. Additional Requirements for Import Capacity Resources.

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(a) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;
(b) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

III.15.7.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.15.7.1.3.1. Energy Market Offer Requirements.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market consistent with the Market Participant's expectation of the output of the resource in Real-Time. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.3.2. [Reserved.]

III.15.7.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources with Capacity Supply Obligations are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

III.15.7.1.4. [Reserved.]

III.15.7.1.5. Demand Capacity Resources with Capacity Supply Obligations.

III.15.7.1.5.1. Energy Market Offer Requirements.

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

(i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.15.7.1.5.3. Additional Requirements for Demand Capacity Resources.

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) An Energy Efficiency measure may be added to an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been associated with an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the measure may not be transferred to a different resource.

(c) For purposes of confirming Capacity Market Commercial Operation as described in Section III.15.2.6, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year.

(d) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall in addition: (i) comply with the ISO’s measurement and verification requirements pursuant to Section

III.15.2.1.1.2.1. and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.15.7.1.5.4 and III.15.7.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.15.7.1.5.5 and the ISO New England Manuals.

III.15.7.1.5.4. On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource Auditing Requirements.

(a) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource in every Capacity Commitment Period during which the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).

(c) Passive DR Audit values shall be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.

(d) The audit value of an On-Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Capacity Resource during the Demand Resource On-Peak Hours.

(e) The audit value of a Seasonal Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the

Seasonal Peak Demand Capacity Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.

(g) For On-Peak Demand Capacity Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Capacity Resources consisting of Energy Efficiency measures, the ISO shall calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. Such an audit shall not satisfy the Passive DR Audit requirement.

III.15.7.1.5.5. Additional Demand Capacity Resource Audits.

The ISO may perform one or both of the following additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures.

(a) Level 1 Audit: the ISO shall establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent

like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

III.15.7.1.6. DNE Dispatchable Generator.

III.15.7.1.6.1. Energy Market Offer Requirements.

DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.15.7.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.

III.15.7.1.7.1. Energy Market Offer Requirements.

(a) A Market Participant with a Distributed Energy Capacity Resource having a Capacity Supply Obligation shall submit offers for its Distributed Energy Resource Aggregations into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.7.1; for purposes of the following comparisons, the portion of any Demand Reductions Offers or Baseline Deviation Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the offers must be equal to or greater than the Distributed Energy Capacity Resource's Capacity Supply Obligation whenever the Distributed Energy Resource Aggregations are physically available. If the Distributed Energy Resource Aggregations are physically available at a level less than the Distributed Energy Capacity Resource's Capacity Supply Obligation, the sum of the offers must equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each offer from a Distributed Energy Resource Aggregation made into the Day- Ahead Energy Market shall also meet the following requirement:

(i) the sum of the resource's notification time plus start-up time plus Minimum Run Time (or Minimum Deviation Time or Minimum Reduction Time) plus Minimum Down Time (or Minimum Time Between Deviations or Minimum Time Between Reductions) is less than or equal to 72 hours.

(b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource Aggregations, it is not obligated to submit Supply Offers into the Day-Ahead Energy Market and may not submit Supply Offers into the Real-Time Energy Market.

III.15.7.1.7.2. Requirement that Offers Reflect Accurate Distributed Energy Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the then-known capability of the resource.

III.15.7.1.7.3. Additional Requirements for Distributed Energy Capacity Resources.

Distributed Energy Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) A Market Participant may not associate an Asset with a non-commercial Distributed Energy Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Distributed Energy Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) Distributed Energy Capacity Resources shall comply with the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

(c) Distributed Energy Capacity Resources shall comply with the auditing and rating requirements as detailed in this Market Rule 1 and the ISO New England Manuals.

(d) For Distributed Energy Capacity Resources, the Seasonal DECR Audit Value shall be established pursuant to Section III.1.7.13.

III.15.7.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.15.7.2 and shall not be subject to the requirements set forth in Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.15.7.2.1. Generating Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.2.2. Distributed Energy Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.2.1. Energy Market Offer Requirements.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation is not required to submit offers for the resource into the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant with a Settlement Only Distributed Energy Resource Aggregation is not permitted to submit an offer for that resource into the Real-Time Energy Market.

III.15.7.2.2.2. Day-Ahead Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation may submit an offer into the Day- Ahead Energy Market. If any portion of the offer clears in the Day-Ahead Energy Market, the entire offer, up to the maximum capability offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market so long as it is not a Settlement Only Distributed Energy Resource Aggregation.

III.15.7.2.2.3. Real-Time Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit an offer in the Real-Time Energy Market so long as the resource is not a Settlement Only Distributed Energy Resource Aggregation, and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.2.4. Additional Requirements for Distributed Energy Capacity Resources Having No Capacity Supply Obligation.

Distributed Energy Capacity Resources without a Capacity Supply Obligation shall comply with the requirements in Section III.15.7.1.7.3.

III.15.7.2.3. Intermittent Power Resources without a Capacity Supply Obligation.

III.15.7.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.15.7.2.4. [Reserved.]

III.15.7.2.5. Demand Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.5.1. Energy Market Offer Requirements.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.15.7.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.15.7.1.5.5 and the ISO New England Manuals;

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as detailed in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.3. Exporting Resources.

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.15.7.3 and the ISO New England Manuals. Intermittent Power Resources and Demand Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7 and Section III.1.10.7.A, as applicable.

III.15.7.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource, a Generating Capacity Resource, or a Distributed Energy Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under this Section III.15 by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.15.7.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.15.7.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.15.8. Capacity Payments and Charges.

Revenue in the Annual Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.15.8.1 and Capacity Performance Payments as described in Section III.15.8.2, adjusted as described in Section III.15.8.3 and Section III.15.8.4. Market Participants with a Capacity Load Obligation shall be subject to charges as described in Section III.15.8.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.15 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.15.8.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.15.8.1.1.

III.15.8.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in an Annual Capacity Auction, except for the portion of resources designated as Self-Supplied Capacity Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.15.8.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Annual Capacity Auction**. For a resource whose offer has cleared in an Annual Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the

Forward Capacity Auction in which the offer cleared, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, and subject to the limitations set forth in Section III.15.2.1.3.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in a Monthly Reconfiguration Auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and the price associated with the Capacity Supply Obligation Bilateral.

III.15.8.1.2 Export Capacity

If there are any unobligated Export Offer Segments from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Annual Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x [Cleared MWs of Export Offer Segment]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x [Cleared MWs of Export Offer Segment]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.15.8.5.2.

III.15.8.2. Capacity Performance Payments.

III.15.8.2.1. Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.15.8.2.2. Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.15.8.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided

for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.15.8.2.2(c), for any On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.15.8.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response

Baseline of the Demand Response Asset or Distributed Energy Resource associated with the Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.15.8.2.3. Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.15.8.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in

Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

III.15.8.2.4. Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Capacity Resource or a Seasonal Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.15.8.2.5. Capacity Performance Payment Rate.

The Capacity Performance Payment Rate shall be $9337/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.15.8.2.6. Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity

Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.15.8.3. Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.15.8.3.1 and Section III.15.8.3.2 below.

III.15.8.3.1. Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the product of the applicable Capacity Auction Offer Price Cap multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

III.15.8.3.2. Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (ACAcp – ACAsp) – (12 months x ACAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

ACAcp = the Capacity Clearing Price for the relevant Annual Capacity Auction.

ACAsp = the Annual Capacity Auction Offer Price Cap for the relevant Annual Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the

Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.15.8.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.15.8.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.15.8.3.2(b).

III.15.8.4. Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.15.8.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.15.8.4(a) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss cap described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result

of the application of the stop-loss mechanism described in Section III.15.8.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.15.8.4(b)

III.15.8.5. Charges to Market Participants with Capacity Load Obligations.

III.15.8.5.1. Calculation of Capacity Charges.

For purposes of this Section III.15.8.5.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in rate component (b) of Sections III.15.8.5.1.1 through III.15.8.5.1.8 shall be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.1.1. Annual Capacity Auction Charge.

The ACA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone ACA Costs divided by Zonal Capacity Obligation.

Where:

Capacity Zone ACA Costs, for each Capacity Zone, are the Total ACA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total ACA Costs are the sum of, for all Capacity Zones, Capacity Supply Obligations in each zone (the total obligation awarded to resources in the Annual Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.15.8.5.1.5) multiplied by the applicable clearing price from the auction in which the obligation was awarded to the resource.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.15.8.5.1.2. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where:

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.3. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where:

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections III.15.8.5.1.1(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b), and III.15.8.5.1.8(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.15.8.5.1.4. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where:

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied Capacity Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections III.15.8.5.1.1.(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b) and III.15.8.5.1.8(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.15.8.5.1.5. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where:

Intermittent Power Resource Seasonal Variance is the difference between the ACA payments for Intermittent Power Resources in the Obligation Month and the base ACA payments for Intermittent Power Resources.

ACA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to Intermittent Power Resources in the Annual Capacity Auction process for the Obligation Month pursuant to Section III.15.4.2.3, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base ACA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Annual Qualified Capacity procured from Intermittent Power Resources in the Annual Capacity Auction process, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.6. CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where:

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.15.8.5.4.1(f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.15.8.5.1.7. CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2.

Where:

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.15.8.5.4.2(b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.8. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were

terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.15.8.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Annual Capacity

Auction pursuant to Section III.12.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

The Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year one year prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year one year prior to the start of the Capacity Commitment Period.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied Capacity Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

III.15.8.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Annual Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals. The adjustment to a load serving entity's Coincident Peak Contribution resulting from a Dispatchable Asset Related Demand associated with a Large Load shall be based on the Large Load's Interim Contract Demand Service and Non-Firm Contract Demand Service.

III.15.8.5.3. Excess Revenues.

Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3, shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.15.8.5.4. Capacity Transfer Rights.

III.15.8.5.4.1. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price in the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price in the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.4.2. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Annual Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.15.2.9. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%

Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Annual Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (collectively, "WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.5. Annual Capacity Market Net Charge Amount.

The Annual Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; and (c) any applicable export charges.

III.15.9. Information Publication and Reporting.

III.15.9.1. Publication of Certain Data Prior to the Annual Capacity Auction.

For each Annual Capacity Auction, no later than one Business Day before the opening of the Annual Capacity Auction Offer Window, the ISO shall publish publicly on its website:

a. which Capacity Zones shall be modeled in the Annual Capacity Auction;
b. the transmission interface limits as determined pursuant to Section III.12.5;
c. which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Annual Capacity Auction;
d. determinations on which new resources have been rejected due to deliverability impacts pursuant to Section III.15.2.3;
e. the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Annual Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;
f. for each resource that submitted a Load-Side Relationship Certification, the following information: the resource technology type; which qualifying circumstance in Section III.A.21.1.4 was asserted in the Load-Side Relationship Certification; the relevant state policy asserted in the Load-Side Relationship Certification, if any; whether the ISO accepted or rejected the Load-Side Relationship Certification; and, consequently, whether the resource was subject to a review for the exercise of buyer-side market power; and
g. which resources are qualified to participate in the Annual Capacity Auction, including resource type, Capacity Zone, and Annual Qualified Capacity.

III.15.9.2. Publication of Certain Data After Conducting the Annual Capacity Auction

In addition to the Annual Capacity Auction results information identified by Section III.15.2.11 and Section III.15.4.3 of Market Rule 1, within 15 days of conducting the Annual Capacity Auction, the ISO shall publish publicly on its website:

a. which Capacity Offers, satisfying the requirements of Section III.A.21.1 of Market Rule 1, were not reviewed for an exercise of buyer-side market power because of one of the conditions described in Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.4 of Market Rule 1; and the condition met by each such resource;
b. the Internal Market Monitor’s determinations made as part of any buyer-side market power review conducted pursuant to Section III.A.21.2 and any Capacity Offer Floor Price determinations made pursuant to Section III.A.21.3 with regard to capacity not previously cleared

in an Annual Capacity Auction or Forward Capacity Auction, and the basis for any such determinations; except that offer price information and any information employed by the Internal Market Monitor in making these determinations related to the potential impact of a Capacity Resource's offer on Capacity Clearing Prices shall not be published publicly;

c. the Internal Market Monitor's determinations regarding Proposed Capacity Offers, including whether the Internal Market Monitor accepted or rejected prices specified in a resource's Proposed Capacity Offer that were subject to Internal Market Monitor review and whether the Internal Market Monitor accepted or rejected the cost components of the resource' offer, which are set forth in Section III.A.22.2.3(a). No offer prices, cost components, or other underlying data shall be published; and,

d. which resources offering capacity not previously offered into an Annual Capacity Auction or Forward Capacity Auction were qualified to participate in the Annual Capacity Auction (this information will include a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations).

6 Litigation Report



Nov 12, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of November 11, 2026

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated October 1, 2026 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

Executive Orders / Executive Memos / Agency Directives

*	1	Executive Proclamation: Adjusting Imports of Wind Turbines and Their Parts and Components Into the US	Oct 22	President directs trade negotiations and a report by ***April 20, 2027***
	2	Executive Memo: Presidential Determinations for Energy Infrastructure	Oct 19	DOE commits up to $42 million in DPA funding to advance Constitution Pipeline development and permitting
	3	Revolution Wind and Vineyard Wind Stop-Work Orders	Oct 29, Nov 5	Revolution Wind, Vineyard Wind announce commercial operation
	4	Executive Orders: Nuclear Energy Deployment and Reforms (EOs 14302, 14301, 14300, 14299)	Oct 26, Nov 3	NRC finalizes two rules under EO 14300

I. Complaints/Section 206 Proceedings

	6	Transition Cluster Study Upgrade Cost Allocation Complaint and Waiver Request (EL26-112)	Oct 5	ISO-NE, Flatiron, CT DEEP, MPUC, MA DOER, NH DOE, Strata oppose Waiver Request; RENEW supports Waiver Request
			Oct 6-13	Interventions only filed by NEPOOL, National Grid, MOPA, RI Energy, MA AG, Avangrid, Eversource, SEIA, Longroad Development, Agawam Energy
			Oct 13	Comments opposing the Complaint filed by: ISO-NE, Flat Iron Energy, CT DEEP, MPUC, MA DOER, NH DOE, Strata Solar Development; comments supporting the Complaint filed by RENEW
			Oct 14	TCS Project Companies' answer the protests by ISO-NE, NH DOE and Strata Solar Development
			Oct 15	ISO-NE answers TCS Project Companies' Oct 14 reply
			Oct 16	FERC denies Waiver Request
			Oct 30	Answers to and comments on the Complaint filed by ISO-NE AEU, MA DOER, NESCOE, Public Systems, RENEW, Walden
			Nov 9	Project Companies answer ISO-NE Oct 30 Answer
	7	ME Agencies RTO ROE Adder Complaint (EL26-103)	Oct 6	Maine State Agencies answer CMP/MEPCO motion to dismiss
			Oct 15	CMP/MEPCO submit abeyance request pending outcome of Federal Litigation
			Oct 29	Maine Agencies oppose abeyance request
	10	State Consumer Advocates' Eversource X-178 Complaint (EL26-66)	Nov 2	K. Pastoriza submits drone inspection images and reports
			Nov 9	K. Pastoriza submits pre-filed direct testimony from NH SEC proceeding

II. Rate, ICR, FCA, Cost Recovery Filings

*	16	PBOP Collections Report (RI Energy) (ER27-408)	Nov 3	RI Energy files to refund an over-recovery of ***$969,852*** in transmission-related PBOP expenses; comment deadline ***Nov 24, 2026***
*	16	PBOP Collections Report (Eversource) (ER27-348)	Oct 30	Eversource files to refund an over-recovery of ***$179,779*** in transmission-related PBOP expenses; comment deadline ***Nov 19, 2026***
*	16	GMP Updated Depreciation Rates (ER27-181)	Oct 16	GMP files updates to its stated depreciation rates in the ISO-NE OATT
*	17	2027 NESCOE Budget (ER27-164)	Oct 15 Oct 29	ISO-NE files materials for funding NESCOE's 2027 operations NEPOOL files comments supporting 2027 NESCOE Budget
*	17	2027 ISO-NE Administrative Costs and Capital Budgets (ER26-158)	Oct 15 Oct 19	ISO-NE files its 2027 administrative costs and capital budgets NEPOOL files comments supporting 2027 ISO-NE Budgets
	18	CIP-IROL Cost Recovery Filing: Cross-Sound Cable (ER26-3737)	Oct 23	FERC accepts rate schedule revisions that will allow CSC to recover ***$791,687*** in CIP-IROL Costs incurred between Jan 1, 2024 and Dec 31, 2025

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

*	20	Waiver Request: Schedule 22 Section 5.1.1.2 (Brough Storage LLC) (ER27-142)	Oct 8	Brough Storage requests a limited waiver, to the extent necessary, of Tariff Section 5.1.1.2 and Schedule 22 to permit it to change its elected service from CNRIS to NRIS
			Oct 14	ISO-NE intervenes, opposes request for shortened comment period, and signals opposition to waiver request
			Oct 15	Brough Storage answers ISO-NE Oct 14 motion
			Oct 16	FERC denies shortened comment period request
			Oct 19	ISO-NE protests Waiver Request
			Oct 29	Brough Storage answers ISO-NE Protest; MA DOER submits comments; NEPOOL intervenes

IV. OATT Amendments / TOAs / Coordination Agreements

*	21	Eversource PTOs' Att F Appendix A PBOP Revisions (ER27-340)	Oct 30	Eversource PTOs file proposed revisions to Appendix A to Attachment F of the ISO-NE OATT to address their continuing over recovery of PBOP expenses; comment deadline ***Nov 20, 2026***
*	21	Waiver Request: Indicated TOs (Order 881 Implementation) (ER27-214)	Oct 16	Indicated TOs request a waiver of the ISO-NE Tariff's *Order 881*-implementing (Ambient Adjusted Ratings) provisions through Dec 31, 2028
	21	Asset Condition Reviewer Role (ER26-3533; ER26-3534)	Oct 6	AEU submits limited answer to reiterate and clarify its unconditional support for the ACR Revisions
			Oct 16	FERC accepts ACR Revisions, eff. *Jan. 1, 2027*
	22	Notice of Nov 17, 2026 Effective Date for *Order 881* ISO-NE Tariff Compliance Changes (ER22-2357; ER25-410)	Oct 23	ISO-NE files a notice that the effective date of the Tariff's *Order 881* revisions (addressing Ambient Adjusted Ratings) will be moved up to ***Nov 17, 2026***

V. Financial Assurance/Billing Policy Amendments

	22	*Opinion 594* ROE Refund-Related FAP Changes (ER27-134)	Oct 14	ISO-NE and NEPOOL file changes to provide FAP reqs. specific to refunds directed by the FERC in *Opinion 594*
			Nov 3	Eversource intervenes

VI. Schedule 20/21/22/23 Changes & Agreements

No Activity to Report

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	23	Capital Projects Report – 2026 Q3 (ER27-166)	Oct 15	ISO-NE files 2026 Q3 Report
			Oct 19	NEPOOL files comments supporting the Q3 Report
	23	Capital Projects Report – 2026 Q2 (ER26-3471)	Oct 7	FERC accepts 2026 Q2 Report, eff. *Jul 1, 2026*
*	23	LFTR Implementation: 72nd Quarterly Status Report (ER07-476)	Oct 15	ISO-NE files its 72nd quarterly report
*	24	IMM Quarterly Markets Report (Summer 2026) (ZZ27-4)	Nov 5	IMM files Summer 2026 Report

IX. Membership Filings

*	24	Nov 2026 Membership Filing (ER27-331)	Oct 29	***New Members***: First Commodities International Inc. and Green.ai Inc.; ***Termination***: Manchester Street, L.L.C.; comment deadline ***Nov 19, 2026***
*	24	ELM Membership Filing (ER27-92)	Oct 9	***New Member***: Environmental League of Massachusetts
	24	Sep 2026 Membership Filing (ER26-3646)	Oct 26	FERC accepts (i) the membership of SESCO Enterprises LLC; and (ii) the termination of the Participant status of Uncia Energy, LP - Series G

X. Misc. - ERO Rules, Filings; Reliability Standards

*	25	Revised Reliability Standard: TPL-001-6 (RD27-2)	Nov 2	NERC files proposed Reliability Standard TPL-001-6; comment deadline ***Dec 2, 2026***
*	25	Revised Reliability Standards: FAC-011-5 and TOP-003-9 (RD27-1)	Nov 2	NERC files proposed Reliability Standards FAC-011-5 and TOP-003-9; comment deadline ***Dec 2, 2026***
	26	2027 NERC/NPCC Business Plans and Budgets (RR26-3)	Oct 15	FERC approves NERC (including NPCC) 2027 Budget and Business Plans

XI. Misc. - of Regional Interest

*	26	203 Application: Kendall Green (EC27-8)	Oct 21	Kendall Green requests authorization for a transaction pursuant to which Forge Buyer will indirectly acquire 100% of the membership interests in Franklin Holdco, which indirectly owns 100% of the membership interests of Kendall Green; comment deadline ***Nov 12, 2026***

	26	203 Application: NextEra/Dominion (EC26-131)	Oct 15 Oct 15-16 Oct 30 Nov 4 Nov 5	Applicants answer comments and protests Applicants respond to Deficiency Letter VA AG answers Applicants' Oct 15 answer ISO-NE IMM submits additional detail regarding its suggested condition to merger approval EDF, PJM IMM, VA AG answer Applicants' DL response
	27	203 Application: Hull Street/ FirstLight Power Management et. al. (EC26-110)	Oct 15 Nov 2	FERC authorizes Hull Street's indirect acquisition of FirstLight Transaction consummated
	27	203 Application: Vistra/Cogentrix (Nautilus Power et al.) (EC26-63)	Oct 30	Transaction consummated
*	28	Rate Incentive: CL&P Huntsbrook Project (ER27-460)	Nov 10 Nov 10	CL&P requests abandonment rate incentive for its Huntsbrook Project, a portion of the Power Up Project; comment deadline ***Dec 1, 2026*** NESCOE intervenes
*	28	NSTAR 3-Year Software Depreciation Rate (ER27-430)	Nov 6	NSTAR proposes to establish a 3-year depreciation rate for Account 351.2 (Computer Software); comment deadline ***Nov 27, 2026***
	28	NSTAR (MMWEC)-HQUS Use Rights Transfer Agreement (ER26-3445)	Oct 30	Use Rights Transfer Agreement accepted, eff. *Oct 31, 2026*
	28	NSTAR (CMEEC)-Vitol Use Rights Transfer Agreement (ER26-3440)	Oct 30	Use Rights Transfer Agreement accepted, eff. *Oct 31, 2026*
	28	Wholesale Distribution Tariff – Rhode Island Energy (ER26-3084)	Oct 8	WDT accepted, eff. *Sep 1, 2026*

XII. Misc. – Administrative & Rulemaking Proceedings

31	*Order 917*: Revisions to EQR Data Collection and Filing Process (RM23-9)	Nov 3	FERC issues notice of Feb 9-10, 2027 hybrid tech. conf. at FERC HQ

XIII. FERC Enforcement Proceedings

Natural Gas-Related Enforcement Actions

33	Rover Pipeline, LLC and ETP (CPCN Show Cause Order) (IN19-4)	Oct 30	FERC terminates this proceeding
33	Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)	Nov 6	FERC approves Agreement that resolves OE's investigation into whether Rover violated Section 7(e) of the NGA; FERC Regulations, and FERC's Certificate Order; Rover agreed to pay a civil penalty of ***$10 million***

XIV. Natural Gas Proceedings

34	Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)	Oct 29	FERC issues Algonquin a certificate of public convenience and necessity to abandon its existing facilities and construct (within 3 years) its Cape Cod Canal Pipeline Project
34	Iroquois ExC Project (CP20-48)	Oct 29	Iroquois requests extension of time, to Mar 25, 2029, to complete construction of its ExC Project; comment deadline ***Nov 24, 2026***

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

36	*Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (5th Cir. – 25-60055 et al.)	Nov 4	Court hears oral argument
37	Opinion 531-A Compliance Filing Undo / *Opinion 594* Review (20-1329, 26-1123, 26-1150, 26-1173)	Oct 19 Nov 4	Court sets briefing schedule Vermont Transco moves to dismiss its petition
38	Avangrid/NextEra NECEC Civil Suit (D.MA) (Case No. 3:24CV30141)	Nov 11	Avangrid seeks status conference; NextEra opposes
39	Allco PURPA Enforcement Petition (D.CT) (Case No. 3:25CV01321)	Oct 6-7 Oct 20 Oct 28	Allco seeks reconsideration and leave to amend Court schedules argument on State Agency Defendants' motion to dismiss for ***Nov 18, 2026*** Defendants oppose motion to amend

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Joan Bosma, NEPOOL Counsel

DATE: November 11, 2026

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through November 11, 2026. In addition, in the opening Section immediately below, we continue to summarize recent Executive Orders issued by the President of the United States and Executive Agency directives related to the energy industry. If you have questions on any of these summaries, please contact us.

Executive Orders / Agency Directives

Questions concerning any of the Executive Orders ("EO") or Agency Directives summarized below can be directed to Joan Bosma (617-345-4651; jbosma@daypitney.com).

- **Executive Proclamation: Adjusting Imports of Wind Turbines and Their Parts and Components into the United States**

On October 22, 2026, President Trump issued a Proclamation under section 232 of the Trade Expansion Act of 1962 concurring with the Secretary of Commerce's finding that imports of wind turbines and their components and subcomponents threaten to impair national security.[2] The Proclamation cites concerns with cybersecurity vulnerabilities, radar interference, grid reliability, and reliance on foreign suppliers. It directs the Secretary of Commerce and the U.S. Trade Representative to jointly pursue or continue negotiations with foreign trading partners to address the identified national security threats and provide the President with an update within 180 days (***April 20, 2026***). The Secretary of Commerce must continue monitoring imports and advise the President of circumstances warranting further action under section 232. The Proclamation does not impose new tariffs or modify existing tariffs.

- **Executive Order: Declaring a National Emergency To Secure the US BPS (EO 14421)**

On August 26, 2026, President Trump issued an EO declaring a national emergency regarding national security and supply chain risks associated with foreign-produced bulk power system ("BPS") electric equipment. The EO authorizes the Department of Energy ("DOE") to prohibit or impose conditions on the acquisition, importation, transfer, or installation of foreign-produced BPS equipment where DOE determines that the equipment has ties to a "Covered Foreign Entity" and poses an unacceptable risk to the security or reliability of the U.S. electric grid. The EO applies to transactions initiated after August 26, 2026 and covers a broad range of equipment. The DOE may also impose conditions on foreign-produced equipment already installed or operating, including requirements to monitor, secure, replace, or remove equipment posing an unacceptable risk. The EO directs the DOE to issue implementing rules or regulations by ***December 24, 2026*** and to identify potentially high-

[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] Proclamation 11074, 91 FR 68001 (Oct. 22, 2026).

risk equipment and develop recommendations for its identification, monitoring, isolation, or replacement. On September 9, 2026, the DOE issued a Request for Information seeking comments on covered equipment and transactions; country-of-origin and supply-chain tracing; software and remote access; existing equipment; mitigation, licensing, and vendor prequalification; domestic manufacturing; and potential cost and reliability effects. Comments were due on or before October 9, 2026.

- **NRC: Review of NextEra-Dominion License Transfers**

On August 27, 2026, the Nuclear Regulatory Commission ("NRC") published notice that it is considering an application filed by NextEra, Dominion and certain Dominion subsidiaries seeking approval for the indirect transfer of control of multiple NRC licenses in connection with the proposed NextEra-Dominion merger. The requested transfers include the licenses for Millstone Power Station Units 1, 2 and 3 in Connecticut, as well as licenses for the Surry, North Anna, and V.C. Summer nuclear facilities and related spent fuel storage installations. The NRC will determine whether the proposed transfer would affect the licensees' qualifications or otherwise be inconsistent with applicable law and NRC requirements.

- **DOE National Transmission Needs Study**

On July 9, 2026 the DOE released its draft 2026 National Transmission Needs Study, which evaluates transmission constraints and potential needs across the United States. For New England, the Draft Study identifies transmission constraints in northern Maine that limit the interconnection of new generation and identifies the ISO-NE and NYISO interface as a potentially high-value opportunity for additional interregional transmission, particularly during winter periods when New England's natural gas system is constrained. The Draft Study also notes that prior transmission investment has reduced congestion within ISO-NE, but contributed to comparatively high regional transmission rates. Comments on the draft Study were due on or before September 8, 2026.

- **Executive Memo: Presidential Determinations for Energy Infrastructure**

On April 20, 2026, President Trump issued five Presidential Determinations authorizing the Secretary of Energy to use the DOE's authority pursuant to section 303 of the Defense Production Act ("DPA") to support domestic energy production, infrastructure, and related supply chains. The Determinations waive the requirements of section 303(a)(1)-(a)(6) of the DPA and were issued in the context of the national energy emergency declared in Executive Order 14156.[3] The Determinations cover: (i) coal supply chains and baseload power generation capacity; (ii) development, manufacturing, and deployment of large-scale energy and energy-related infrastructure; (iii) grid infrastructure, equipment, and supply chain capacity; (iv) domestic petroleum production, refining, and logistics capacity; and (v) natural gas transmission, processing, storage, and liquefied natural gas capacity. Each Determination makes the findings necessary to authorize expedited DOE support under DPA section 303, including through purchases, purchase commitments, and financial support. On June 4, 2026, the Department of Energy announced that it plans to use $500 million in DPA funds to support 13 coal-fired power plants and new coal export infrastructure. On June 15, 2026, the DOE issued a request for information seeking information on how distribution-transformer efficiency standards affect domestic manufacturing, equipment availability, national security, and grid-supply-chain resilience.[4] In line with this memo, on September 8, 2026, President Trump issued Executive Order 14427,[5] which amends EO 13603 to allow both the Secretaries of Energy and the Interior to exercise certain DPA priority and allocation authorities independently for forms of energy under their respective authority. On October 19, 2026, the DOE announced a commitment of up to $42 million in DPA Title III funding to support development and permitting of Constitution Pipeline, a proposed 125-mile natural

[3] Exec. Order 14156, 90 FR 8433 (Jan. 20, 2025) ("Declaring a National Emergency").

[4] *Energy Conservation Program: Energy Conservation Standards for Distribution Transformers*, Proposed Rule, 91 FR 35903 (June 15, 2026).

[5] Exec. Order No. 14427, 91 FR 58,007 (Sep. 11, 2026).

gas pipeline from Pennsylvania to New York. The DOE stated that, after permits are obtained, remaining funds will support deployment of complementary natural gas infrastructure.[6]

- **Proclamation: Ratepayer Protection Pledge**

On March 4, 2026, President Trump issued a proclamation announcing the "Ratepayer Protection Pledge," under which seven major technology companies[7] committed that electricity demand associated with their data centers will not increase household electricity costs. The Proclamation states that the participating companies will build, bring, or buy the new generation resources needed to serve their data centers, pay for all required power delivery infrastructure upgrades, negotiate separate rate structures with utilities and relevant State governments, and pay those rates and infrastructure costs whether the electricity is used or not. The Proclamation also states that the participating companies will invest in local communities and coordinate with grid operators to support grid reliability, and frames domestic data center development as important to the United States' economic, technological, and national security interests.

- **Revolution Wind and Vineyard Wind Stop-Work Orders**

***Revolution Wind Stop-Work Order and Litigation*.** On August 22, 2025, the Bureau of Ocean Energy Management (BOEM) issued an order directing Revolution Wind to halt all activities related to the Revolution Wind Project on the Outer Continental Shelf and not resume activities until BOEM completed its review. On September 4, 2025, Revolution Wind filed suit in the U.S. District Court for the District of Columbia challenging the order and moved for a stay pending review and preliminary injunction. On September 22, 2025, Revolution Wind's request to temporarily block BOEM from enforcing the order while the lawsuit continues was granted.[8]

***Stop-Work Order II and Litigation*.** On December 22, 2025, the BOEM's Acting Director issued a second order related to Revolution Wind (as well as to 4 other offshore wind projects, including Vineyard Wind) ordering Ørsted, among others, to suspend all ongoing activities related to the Revolution Wind Project for the next 90 days for reasons of national security ("the Second Stop Work Order").[9] The national security risks, BOEM states, were identified by the Defense Department (Department of War) in recently completed classified reports.[10] In response, Ørsted moved for leave to supplement its pending complaint and moved to preliminarily enjoin the Second Stop Work Order. The State of Rhode Island, State of Connecticut, and Katie Dykes ("State Plaintiffs") filed a motion for (i) stay pending review and (ii) a preliminary injunction. Other parties also challenged the Second Stop Work Order in federal court (e.g. Dominion in the US District for the Eastern District of Virginia, in connection with the CVOW – Commercial project). On January 12, 2026, U.S. District Court (D.C.) Judge Royce Lamberth granted a stay and preliminary injunction against enforcement of the Second Stop Work Order as it applied to Revolution Wind. On January 15, 2026, Vineyard Wind filed suit to enjoin the BOEM's Second Stop Work Order.[11] On January 27, 2026, U.S. District Court (Mass.) Judge Brian Murphy blocked the Second Stop Work Order as it applied to Vineyard Wind, allowing construction to proceed while the lawsuits remain pending; and on May 28, 2026, the Judge stayed the Vineyard Wind federal stop-work case until August 26, 2026 with a joint status report

[6] DOE Fact Sheet, updated Oct. 21, 2026, available at https://www.energy.gov/articles/fact-sheet-energy-department-advancing-constitution-pipeline-strengthen-national-security.

[7] Amazon, Google, Meta, Microsoft, OpenAI, Oracle, and xAI signed the Ratepayer Protection Pledge.

[8] *Revolution Wind, LLC v. Burgum*, No. 1:25-cv-02999 (D.D.C. Sept. 22, 2025), order granting preliminary injunction available at https://www.courthousenews.com/wp-content/uploads/2025/09/judge-lamberth-revolution-wind-preliminary-injunction-order.pdf.

[9] *See* https://www.doi.gov/pressreleases/trump-administration-protects-us-national-security-pausing-offshore-wind-leases.

[10] Unclassified US Government reports have found that the movement of massive turbine blades and the highly reflective towers create radar interference called "clutter." The clutter caused by offshore wind projects obscures legitimate moving targets and generates false targets in the vicinity of the wind projects. A 2024 DOE report stated that a radar's threshold for false alarm detection can be increased to reduce some clutter, but an increased detection threshold could cause the radar to "miss actual targets."

[11] *Vineyard Wind 1 LLC v. U.S. Dept of the Interior*, 1:26-cv-10156 (D. Mass.).

due August 28, 2026. On September 1, 2026, Judge Murphy granted the parties' joint status report and motion to extend the stay until ***November 30, 2026*** with an additional status report due at that time.

Project Status and Vineyard Wind/GE Vernova Litigation. In March of this year, the 700-MW Revolution Wind project began delivering power to the New England grid,[12] and the 800-MW Vineyard Wind 1 project's construction was completed. In April, Massachusetts announced activation of the Vineyard Wind contracts, which the state reported will provide stable prices and save Massachusetts customers a projected $1.4 billion over 20 years.[13] Separately, on April 17, 2026, Massachusetts Superior Court Judge Peter Krupp issued a preliminary injunction to prevent GE Vernova/GE Renewables (contractor on the Vineyard Wind Project) from terminating its Turbine Supply Agreement with Vineyard Wind.[14] On May 29, 2026, Judge Krupp denied GE Vernova's request for reconsideration, upheld the preliminary injunction requiring GE Vernova to remain on the project, and denied GE Vernova's motion to stay the case and compel arbitration. On September 16, 2026, Vineyard Wind and GE Vernova announced a settlement resolving their outstanding litigation. GE Vernova withdrew its termination notice, and the parties agreed to dismiss all pending legal claims; the settlement terms are confidential.[15] Since the last Report, both projects have reached full commercial operation; Vineyard Wind 1 reached full commercial operations on October 29, 2026, and on November 5, 2026, Ørsted reported that Revolution Wind achieved commercial operations in October under its offtake contracts with utilities in Connecticut and Rhode Island.

- **Executive Order: Ending Market Distorting Subsidies for Unreliable, Foreign Controlled Energy Sources (EO 14315)**

On July 7, 2025, following the signing of the One Big Beautiful Bill Act ("OBBB"), President Trump issued an EO directing the Secretary of the Treasury to implement provisions of the OBBB aimed at eliminating federal support for wind and solar energy and directing the Department of the Interior to review and revise any policies that provide preferential treatment to wind and solar energy sources, by August 21, 2025. Specifically, the EO requires the Treasury to issue guidance to enforce the OBBB's termination of Sections 45Y and 48E tax credits, including restricting safe harbor provisions and "beginning of construction" standards. On March 9, 2026, the Treasury and Internal Revenue Service issued Notice 2026-15 proposing guidance and regulations to implement the OBBB's enhanced Foreign Entity of Concern restrictions.[16]

- **Executive Orders: Nuclear Energy Deployment and Reforms (EOs 14302, 14301, 14300, 14299)**

On May 23, 2025, President Trump issued four Executive Orders[17] intended to accelerate the development, testing, licensing, deployment, and export of nuclear energy technology. The EOs direct the DOE, DoD, NRC, and other federal agencies to: (i) facilitate 5 GW of uprates to existing reactors and the start of construction on ten new large reactors by 2030; (ii) streamline DOE environmental reviews and establish a pilot program for test reactors; (iii) reform NRC licensing with expedited review timelines; and (iv) accelerate advanced nuclear deployment for national security missions, including AI/data center and military installation needs. The NRC issued a proposed rule to revise 10 CFR Parts 50 and 53 to facilitate NRC review of reactor designs previously authorized and tested by the DOE or DoD (comments were due on or before May 4, 2026), and the DOE announced that construction of the National Reactor Innovation Center's Demonstration of Microreactor

[12] *See* https://revolution-wind.com/news/2026/03/revolution-wind-begins-delivering-power-to-new-england (Mar. 13, 2026).

[13] *See* Massachusetts Executive Office of Energy and Environmental Affairs Press Release, available at: https://www.mass.gov/news/vineyard-wind-contracts-lower-electricity-prices-for-massachusetts-customers (Apr. 27, 2026).

[14] *Vineyard Wind 1, LLC v. GE Renewables US LLC*, No. 26-1041-BLS1 (Mass. Super. Ct. Apr. 17, 2026).

[15] Vineyard Wind Press Release, available at https://www.vineyardwind.com/press-releases/2026/9/16-resolution-of-commercial-litigation.

[16] Notice 2026-15 is available at https://www.irs.gov/pub/irs-drop/n-26-15.pdf.

[17] The referenced executive orders, which were included separately in the last Report, are: "Reinvigorating the Nuclear Industrial Base" (EO 14302); "Reforming Nuclear Reactor Testing at the Department of Energy" (EO 14301); "Ordering the Reform of the Nuclear Regulatory Commission" (EO 14300); and "Deploying Advanced Nuclear Reactor Technologies for National Security" (EO 14299).

Experiments ("DOME") test bed and its first-of-its-kind facility is complete. On May 14, 2026, the DOE announced the selection of eight companies to receive more than $94 million in federal funding to support near-term deployment of advanced light-water small modular reactors. On June 4, 2026, the DOE announced that Antares Nuclear's Mark-0 advanced reactor design successfully completed a zero-power fueled criticality demonstration at Idaho National Laboratory as part of DOE's Reactor Pilot Program. On July 21, the Marine Minerals Administration ("MMA") and the NRC signed a MOU that establishes how the agencies will work together in the event there is a proposal for nuclear energy projects on the U.S. Outer Continental Shelf. On August 11, the NRC issued a direct final rule implementing portions of EO 14300, effective as of October 26, 2026. On September 24, 2026, the NRC issued a proposed rule implementing EO 14300, which revises requirements related to reactor licensing, decommissioning, and operational oversight. Comments on the proposed rule were due on or before November 9, 2026.[18] On October 26, 2026, the NRC published a final rule, [19] to be effective ***November 25, 2026***, allowing applicants to use information from prior DOE or DoD authorizations of demonstration reactors to support commercial reactor license applications. On November 3, 2026, the NRC published a final rule,[20] to be effective ***December 3, 2026***, streamlining contested licensing proceedings. The rule applies to contested proceedings noticed on or after the effective date.

- **Executive Order: Zero-Based Regulatory Budgeting to Unleash American Energy (EO 14270)**

On April 9, 2025, President Trump issued an EO directing the FERC, along with DOE, EPA, and the NRC, to incorporate conditional sunset provisions into specified "Covered Regulations" that requires these regulations expire after one year unless extended at the agency's discretion for a period of up to five years. The agencies must provide the public with an opportunity to comment on the costs and benefits of each such regulation prior to its expiration. For the FERC, the EO applies to regulations promulgated under the FPA, Natural Gas Act ("NGA"), and the Powerplant and Industrial Fuel Use Act. On October 1, 2025, the FERC issued a direct final rule (*Order 914*) and a related NOPR, in response to EO 14270, to sunset 53 regulations identified as outdated or unnecessary. *Order 914* establishes a one-year sunset from its effective date (45 days after *Order 914*'s publication in the Federal Register), after which the regulations will be removed from the U.S. Code of Federal Regulations and the FERC will no longer treat them as effective.[21] On May 29, 2026 the DOE published a direct final rule to insert sunset provisions into certain DOE regulations under this EO. The rule was scheduled to become effective July 13, 2026; however, the DOE received adverse comments during the public comment period and withdrew its final rule on July 9, 2026. The proposed rule was sent to the Office of Management and Budget ("OMB") on November 2, 2026 for review, and it remains pending.

- **Executive Order: Strengthening the Reliability and Security of the United States Electric Grid (EO 14262)**

On April 8, 2025, President Trump issued an EO directing the Secretary of the DOE to strengthen use of emergency authority under Section 202(c) of the FPA and to implement a new national methodology for assessing electric reliability. The EO requires the DOE to streamline and expedite the issuance of 202(c) emergency orders during forecasted supply interruptions and to develop, within 30 days, a uniform framework for evaluating reserve margins across all FERC-jurisdictional regions. This framework will be used to identify regions with insufficient capacity and determine which generation resources are critical to reliability. The DOE is further directed to use the methodology to prevent the retirement or fuel conversion of any resource over 50 MW that would cause a net reduction in accredited capacity. While the FERC is not directly tasked under EO 14262, implementation of its provisions may influence FERC-jurisdictional processes.

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[18] *Regulatory Enhancements for Reactor Licensing, Decommissioning, and Operational Oversight*, Proposed Rule, 91 Fed. Reg. 60,702 (Sep. 24, 2026).

[19] NRC Reviews of Reactor Designs Previously Authorized by U.S. Department of Energy or Department of War, Final Rule, 91 FR 67195 (Oct. 26, 2026).

[20] Streamlining Contested Adjudications in Licensing Proceedings, Final Rule, 91 FR 69446 (Nov. 3, 2026).

[21] *See infra* Section XII.

DOE Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid ("DOE RA Report"). On July 7, 2025, the DOE released a Report in response to Section 3(b) of EO 14262 (which directed the DOE to develop a uniform methodology for analyzing current and anticipated reserve margins in FERC-regulated regions of the bulk power system). The DOE RA Report provides an assessment of the U.S. grid's ability to meet projected load growth through 2030 using a deterministic approach that simulates system stress in all hours of the year and incorporates grid conditions and scenarios based on historical data.[22] Overall highlights from the DOE RA Report include conclusions that: (i) the status quo is unsustainable; (ii) grid growth must match the pace of AI innovation; (iii) with projected load growth, retirements increase the risk of power outages by 100 times in 2030; (iv) planned supply falls short, reliability at risk; and (v) old tools won't solve new problems.

Not New England. The DOE RA Report identifies several regions facing acute reliability issues in the near future, though not New England. The DOE RA Report cites sharp load growth from electrification, AI, and data centers as the key drivers of resource adequacy concerns. Noting the absence of additional AI/data center load growth in New England, the DOE RA Report concludes that no additional capacity in New England would be necessary to meet the study's reliability standards.

Request for Rehearing – DOE RA Report. On August 6, 2025, Clean Energy Organizations,[23] concluding that the DOE RA Report is a rule subject to rehearing, despite being styled as a report, requested rehearing of the DOE RA Report, asserting that the Report "fails to account for [] important aspects of the resource adequacy puzzle."[24] Clean Energy Organizations request that DOE "withdraw the Resource Adequacy Protocol or otherwise address the errors contained in it."

I. Complaints/Section 206 Proceedings

- **Transition Cluster Study Upgrade Cost Allocation Complaint and Waiver Request (EL26-112)**

On September 30, 2026, TCS Project Companies[25] filed a complaint against ISO-NE alleging that implementation of the first Transition Cluster Study was "unjust and unreasonable, and its results must be corrected" ("Complaint"). Specifically, the TCS Project Companies allege that ISO-NE's assignment of $3.2 billion in Upgrade costs to the Interconnecting Customers ("ICs") remaining in the TCS violates the FERC's cost causation principles (by assigning $3.2 billion in upgrade costs that did not result from interconnection of the projects) and ISO-NE's Tariff (by requiring ICs to bear the full cost of upgrades that they assert otherwise should be allocated to load). TCS Project Companies urged the FERC to act "before Interconnection Customers are forced to execute LGIAs and post deposits based on a flawed and unlawful study." Project Companies concurrently filed a limited

[22] The DOE RA Report employs three different 2030 cases: a Plant Closures Case (which assumes all announced retirements occur), a No Plant Closures Case (which assumes no announced retirements proceed and mature additions), and a Required Build Case (which compares impacts of retirements on perfect capacity additions necessary to return 2030 to current level of reliability). In the Plant Closures Case, only New England and NYISO met the reliability thresholds, while all other regions failed. ISO-NE's peak demand is projected to grow from 28 GW in 2024 to 31 GW by 2030, with capacity rising from 40 GW to 45.5 GW in the No Plant Closures case and to 42.8 GW in the Plant Closures case.

[23] "Clean Energy Organizations" are, for the purposes of this matter, the American Clean Power Association ("ACPA"), Advanced Energy United ("AEU"), and American Council on Renewable Energy ("ACORE").

[24] Clean Energy Organizations assert that DOE's analysis "fails to take account of (or simply mischaracterizes) major developments that will affect resource adequacy in the next half-decade and beyond, primarily the pace of new resource development, the retirement of existing resources, and the well-established regulatory and market mechanisms that connect these threads. The [Report] also excludes mention of President Trump's own policies aimed at making the headline outcomes of the [Report] highly unlikely.

[25] "TCS Project Companies" are: Moraga Storage, LLC ("Moraga Storage") and River Mill Storage, LLC ("River Mill Storage") (together, the "Segue Companies"), Hecate Energy Medway Energy Center LLC ("Medway Energy Center") (the "Hecate Company" or "Hecate Energy"), Brough Storage, LLC ("Brough Storage") and Partridge Storage, LLC ("Partridge Storage") (together, the "CleanCapital Companies").

request for waiver of certain Schedule 22 provisions[26] in case the FERC did not act on the Complaint by ***October 16, 2026***[27] as requested ("Waiver Request").

Request for Shortened Comment Periods (Partially Granted). Project Companies requested the FERC set a 10-day comment period on the Waiver Request and a 20-day comment period on the Complaint, both of which ISO-NE opposed. On October 5, 2026, the FERC partially granted Project Companies' request for shortened comment periods, setting the deadline for filing comments pertaining to the Waiver Request to October 13, 2026 and the deadline for ISO-NE's answer to the Complaint or comments pertaining to the Complaint to October 30, 2026.

Waiver Request. On October 13, 2026, answers and comments opposing the Waiver Request were filed by: ISO-NE, Flatiron Energy, CT DEEP, MPUC, MA DOER, NH DOE, and Strata Solar Development ("Strata"); comments supporting the Waiver were filed by RENEW. On October 14, 2026, Project Companies answered ISO-NE's Waiver Answer, NH DOE's protest, and Strata's comments. ISO-NE answered Project Companies answer on October 15, 2026. On October 16, 2026, the FERC denied the Waiver Request,[28] finding that the Waiver Request did not meet the FERC's criteria[29] for granting waiver of tariff provisions.

Complaint. On October 30, answers to and protests and comments on the Complaint were filed by ISO-NE, AEU, MA DOER, NESCOE, Public Systems,[30] RENEW, and Walden Renewable Development ("Walden"). Project Companies answered ISO-NE's October 30 answer on November 9, 2026.

Other Intervenors. In addition to the parties that filed comments on the Waiver and/or the Complaint, intervenors include: NEPOOL, National Grid, MOPA, RI Energy, MA AG, Avangrid, Eversource, SEIA, Longroad Development and Agawam Energy.

The Complaint is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ME Agencies RTO ROE Adder Complaint (EL26-103)**

Maine ("ME") Agencies[31] filed a complaint on September 1, 2026 against Central Maine Power ("CMP"), Versant Power ("Versant"), and Maine Electric Power Company ("MEPCO") (collectively, "Maine TOs") and ISO-NE seeking an order (i) finding unjust and unreasonable the continued collection by Maine TOs of the previously-authorized 50 basis point Return on Equity ("ROE") Adder for participation in ISO-NE ("RTO ROE Adder"); (ii) directing a compliance filing terminating the adder; and (iii) directing a refund of any adder-related charges imposed after the refund effective date of the Complaint. Comments on the Complaint were due on or before

[26] Schedule 22 §§ 11.2 (LGIA Negotiation and Execution -- those provisions requiring that negotiations for a draft LGIA last no more than 60 calendar days after ISO-NE's tender of the draft LGIA and that the interconnection customer is deemed withdrawn if it has not executed the LGIA within that same 60-day time period); 11.3.1.1 (requiring a 20% deposit of the estimated network upgrade costs identified in the draft LGIA minus the commercial readiness deposit provided with the interconnection request; and § 5.1.1.2 (application of withdrawal penalties).

[27] The First Cluster Study process will not commence until Jan. 19, 2027, when ISO-NE is required to "lock in" its base reference case.

[28] *Moraga Storage, LLC et al. v. ISO New England Inc.*, 197 FERC ¶ 61,041 (Oct. 16, 2026) ("*Order Denying TCS Cost Allocation Waiver Request*").

[29] The FERC has granted waiver of tariff provisions where: (1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties. *See, e.g.*, *Citizens Sunrise Transmission LLC*, 171 FERC ¶ 61,106, at P 10 (2020); *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,059, at P 13 (2016).

[30] For purposes of this proceeding, "Public Systems" are: CMEEC, MMWEC, NHEC, and VPPSA.

[31] "ME Agencies" are: the Maine Office of the Public Advocate ("MOPA"), Maine Public Utilities Commission ("MPUC"), and the Maine Department of Energy Resources ("ME DOER").

September 21, 2026. CMP and MEPCO answered the Complaint. Comments supporting the Complaint were filed by NESCOE and Consumer Advocates.[32] Comments opposing the Complaint were filed by EEI. On October 6, 2026, Maine State Agencies[33] answered the September 21 CMP/MEPCO answer. Doc-less interventions only were filed by PSEG, RI Energy (out-of-time), and Public Citizen.

Abeyance Motion. On October 15, 2026, CMP and MEPCO asked the FERC to hold this proceeding in abeyance pending the outcome of pending litigation in the US District Court for the District of Maine where the TOs have challenged the lawfulness of the Maine RTO requirement that is at the core of the RTO ROE Adder Complaint ("Federal Litigation"). On October 29, 2026, ME Agencies opposed the abeyance motion.

This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CT Agencies RTO ROE Adder Complaint (EL26-79)**

As previously reported, CT Agencies[34] filed a complaint on June 11, 2026 against Eversource, UI and ISO-NE seeking an order (i) finding unjust and unreasonable the continued collection by Eversource and UI of the previously-authorized 50 basis point Return on Equity ("ROE") Adder for participation in ISO-NE ("RTO ROE Adder"); (ii) directing a compliance filing terminating the adder; and (iii) directing a refund of any adder-related charges imposed after the refund effective date of the Complaint.

Comments on the Complaint were due on or before July 1, 2026. CL&P and UI ("CT TOs") moved to hold the proceeding in abeyance pending final resolution of related federal district court litigation ("Abeyance Request") and separately moved to dismiss and answered the Complaint ("CT TOs' Motion to Dismiss/Answer"). Comments were filed by the MA AG, MMWEC, NESCOE, New England Consumer Advocates, NH OCA, Connecticut Industrial Energy Consumers ("CT IEC"), EEI and WIRES. Doc-less interventions were filed by MA AG, ME OPA, NH OCA, PSEG, RI Energy, RI PUC, MA DPU, MPUC, MD OPC, WIRES, and Public Citizen. On July 6, 2026, CT Agencies opposed CT TOs' request for a shortened response period on the abeyance motion. On July 14, 2026, the FERC granted motion to extend until August 5, 2026 the deadline to answer CT TO's Motion to Dismiss/Answer. On July 16, 2026, the CT Agencies opposed the Abeyance Request, asserting that an abeyance would unduly delay resolution of the Complaint and jeopardize refund protection. On August 5, 2026, CT Agencies answered CT TOs' Motion to Dismiss/Answer ("CT Agencies' Answer") arguing that CT's new RTO participation requirement lawfully makes the CT TOs' continued participation in ISO-NE mandatory, is not preempted by federal law, and renders their continued receipt of the RTO ROE Adder unjust and unreasonable. On September 30, 2026, CT TOs answered CT Agencies' August 5 Answer and other comments, maintaining that the Complaint should be dismissed, arguing that the RTO ROE Adder is not controlled by subsequent section 219 precedent, that Connecticut's RTO participation requirement does not necessarily make their participation involuntary, and that the requested relief is barred by federal preemption and the filed rate doctrine.

ISO-NE Party Status. On June 26, 2026, ISO-NE moved to be dismissed as a party and, alternatively, answered the Complaint, taking no position on its merits and committing to comply with any FERC-directed Tariff amendments or refunds (on July 9, 2026, CT State Agencies stated that they did not oppose ISO-NE's dismissal in light of its commitment to comply with any FERC decision).

This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[32] "Consumer Advocates" are: the MA AGO, RI DPUC, NH OCA, and the CT OCC.

[33]

[34] "CT Agencies" are: the Conn. Dept. of Energy and Environ. Protection ("CT DEEP"), Conn. Office of Consumer Counsel ("CT OCC"), Conn. Pub. Utils. Regulatory Authority ("CT PURA"), and William Tong, Conn. Atty. General ("CT AG").

- **New England Large and Co-Located Loads Show Cause Order (EL26-72)**

On June 18, 2026, the FERC issued a unanimous order instituting a Section 206 proceeding (with each Commissioner separately attaching a statement), preliminarily finding that the ISO-NE Tariff appears to be unjust, unreasonable, or unduly discriminatory or preferential because it does not adequately address the challenges associated with integrating large and co-located loads onto the transmission system.[35] The *New England Large and Co-Located Loads Show Cause Order* directs ISO-NE and the PTOs, on or before ***August 17, 2026***, to either show cause why the Tariff remains just and reasonable and not unduly discriminatory or preferential or explain what Tariff changes would remedy the FERC's concerns regarding: (i) the application, study, and ongoing operational requirements for transmission service to large loads; (ii) transparency and cost recovery for network upgrades needed to serve large loads, including a pro forma cost recovery agreement intended to mitigate cost shifting; (iii) the rates, terms, and conditions applicable to co-location arrangements; (iv) transmission services for co-located loads, loads with behind-the-meter generation, and flexible large loads; and (v) the rates, terms, and conditions applicable to interconnection customers serving electrically proximate large loads. The FERC said that ISO-NE and the PTOs could request, on or before August 3, 2026, an up to a 90-day abeyance to develop a Section 205 filing addressing the identified concerns. The FERC also directed ISO-NE to submit, on or before July 20, 2026, an informational report addressing resource adequacy and how sufficient generation will be available to serve existing and new large loads ("July 20 Informational Report"). NEPOOL Counsel presented a summary of the *New England Large and Co-Located Loads Show Cause Order* at the June 24, 2026 Transmission Committee meeting.

Interventions were due on or before July 9, 2026. Many parties doc-lessly intervened, including NEPOOL, NESCOE, NECPUC, state commissions and consumer advocates, and other Market Participants and stakeholders. On June 22, 2026, Vermont Electric Cooperative ("VEC") requested issuance of an errata to remove it as a named Party; the FERC issued the requested errata on July 9, 2026. Out-of-time interventions were later filed by the Technology Industry Council and Capital Power Corp.

July 20 Informational Report. On July 20, 2026, ISO-NE submitted the required informational report. The July 20 Informational Report summarizes New England's resource adequacy outlook, and addresses existing and potential new proposals to meet upcoming challenges. ISO-NE emphasized that the proposals rely on New England's existing competitive markets as the most cost-effective and efficient means of ensuring resource adequacy in New England (which ISO-NE said requires both maintaining sufficient revenue for the existing fleet to remain commercially viable, and providing sufficient incentives for new resource investment). Responses to the July 20 Informational Report were due on or before August 19, 2026; none were filed.

Compliance Abeyance Request – Responses or Section 205 Filing Due on or Before November 16, 2026. As permitted by the *New England Large and Co-Located Loads Show Cause Order,* ISO-NE and the TOs requested on August 3, 2026 that the FERC hold this proceeding in abeyance for 90 days, or until ***November 16, 2026***. ISO-NE and the PTOs said that the abeyance would allow them to work through the stakeholder process to develop and refine a FPA Section 205 filing that will address the issues raised in the *New England Large and Co-Located Loads Show Cause Order*. ISO-NE and the PTOs committed to submit a FPA Section 205 filing on or before November 16, 2026. NESCOE supported the Compliance Abeyance Request.

On August 14, 2026, the FERC granted the Compliance Abeyance Request.[36] The FERC will hold this proceeding in abeyance, in full, for 90 days, with responses to the *New England Large and Co-Located Loads Show Cause Order* due on ***November 16, 2026***, and answers to responses due on ***December 16, 2026***. The submission of

[35] *ISO New England Inc.*, 195 FERC ¶ 61,215 (June 18, 2026) ("*New England Large and Co-Located Loads Show Cause Order*"). The FERC issued parallel, region-specific show cause orders for each of the six RTO/ISO markets in lieu of taking final action on the pending Large Load ANOPR (RM26-4).

[36] *ISO New England Inc. et al.*, 196 FERC ¶ 61,132 (Aug. 14, 2026) ("*Order Granting Compliance Abeyance Request*").

a FPA section 205 filing[37] on or before November 16, 2026 will suspend the obligation of filers to respond to the *New England Large and Co-Located Loads Show Cause Order* and the FERC will continue to hold this proceeding in abeyance pending further FERC directive. Noting its expectation that ISO-NE and/or Participating Transmission Owners ("PTOs") will implement tariff revisions as expeditiously as possible, the FERC encouraged ISO-NE and/or PTOs to propose an effective date that takes into account the necessary time to implement the proposed Tariff revisions and accommodate existing commercial arrangements. ISIO-NE's and the PTOs' proposed revisions in response to the *New England Large and Co-Located Loads Show Cause Order* were recommended by the Technical Committees on November 3 and will be voted at the November 12 Participants Committee meeting.

If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **State Consumer Advocates' Eversource X-178 Complaint (EL26-66)**

On May 12, 2026, State Consumer Advocates[38] filed a complaint alleging that Eversource illegally categorized the X-178 transmission upgrade as an asset management project under section 3.08(f) of the TOA (rather than as a regional transmission project under section 2.06 of the TOA) ("Eversource X-178 Complaint"). If properly categorized as an asset management project, State Consumer Advocates seek either modifications to the TOA or the establishment of a process for FERC review of challenges to a PTO's classification of a project as an asset condition project under section 3.08(f).

Answers to and comments on the Eversource X-178 Complaint were due on or before June 1, 2026. On June 1, 2026, ***Eversource*** moved to dismiss the Complaint asserting that the Complaint fails to identify any violation of the TOA or ISO-NE OATT, relies on an incorrect reading of TOA section 3.08(f), and ignores other TOA provisions that Eversource asserts preserve PTO authority. ***Indicated NETOs***[39] filed an answer opposing the requested TOA changes, taking no position on the X-178 Project, but arguing that the Complaint does not satisfy the section 206 burden, would improperly alter PTO rights and obligations, and could impair PTOs' ability to maintain reliability. Comments were filed by: ***NESCOE*** (without taking a position on the Complaint, stating that the region needs additional oversight of asset condition projects and the Eversource X-178 Complaint exemplifies the need for reform), ***MMWEC*** (without taking a position on the Eversource X-178 Project, but sharing concerns that asset condition projects are displacing the regional transmission planning process), **CLF** and ***MPUC*** (each separately supporting the Complaint), the MA AG (providing additional context and support for the issues and concerns identified in the Petition), and ***Kris Pastoriza*** (one of two individual complainants on a previously-unsuccessful complaint that sought an investigation into the need and costs of the Project,[40] supported the Complaint in late-filed comments and additional materials). Doc-less interventions only were filed by ISO-NE, EEI, Public Citizen, and the Easton NH Selectboard.

On June 15, 2026, ***State Consumer Advocates*** answered Eversource's Motion to Dismiss (arguing that the TOA provisions cited by Eversource preserve its authority to maintain its facilities but do not authorize regional cost recovery outside the regional planning process, and that those provisions are no longer just and reasonable if they permit such recovery). On June 16, 2026, the ***MPUC*** separately responded to Eversource and the Indicated NETOs (requesting that the FERC deny the Motion to Dismiss and either hold a hearing or audit the X-178 Project,

[37] To the extent that ISO-NE and/or Participating Transmission Owners intend to request in their FPA section 205 filing that the show cause proceeding be terminated in full or in part if the Commission accepts the filing, the FERC "encourage[d] ISO-NE and/or Participating Transmission Owners to explain, with specificity, which of their proposed Tariff revisions they believe resolve all or some of the Commission's preliminary findings in the Show Cause Order, and whether the Commission should terminate the Show Cause Order, in full or in part." (*Id.* at P 10.)

[38] "State Consumer Advocates" are: the ME OPA, CT OCC, RI Division, NH OCA and VT DPS.

[39] "Indicated NETOs" are: CMP, MEPCO, National Grid, RI Energy, UI, and Versant Power.

[40] *See Kristina Pastoriza and Ruth Ward v. Pub. Srvc. Co. of New Hampshire*, 194 FERC ¶ 61,156 (Mar 2, 2026) ("PSNH Rebuild Complaint Order") (summarized in the Mar 4, 2026 Litigation Report).

arguing that portions of the project constitute upgrades subject to regional planning). On June 29, 2026, ***Eversource*** answered the State Consumer Advocates, MPUC, NESCOE, and MA AGO filings (asserting that they do not cure the Complaint's defects, improperly narrow the scope of permissible asset condition projects, and misinterpret the TOA and Mobile-Sierra doctrine). On July 9, 2026, the ***State Consumer Advocates*** answered Eversource's June 29 answer (clarifying that they do not challenge Eversource's authority to maintain its facilities but rather its right to recover certain project costs regionally outside the regional planning process). Letters were submitted by US Senator Richard Blumenthal (D-CT) (urging the FERC to act in the best interest of consumers and establish a mechanism for greater oversight of asset condition projects) and K. Pastoriza (urging the FERC not to make any determination in this proceeding that rests on an assumption that the New Hampshire Site Evaluation Committee ("NH SEC") will assess Eversource's X-178 project for prudence or need). Since the last Report, K. Pastoriza submitted for the record drone photos and inspection reports as well as pre-filed testimony from the NH SEC proceeding.

The State Consumer Advocates' Eversource X-178 Complaint is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO-NE Tariff Correction Mechanism Show Cause Order (EL26-45)**

As previously reported, the FERC issued a show cause order, on March 10, 2026, finding that the ISO-NE Tariff may be unjust and unreasonable because it lacks provisions that would enable ISO-NE to correct for improper or erroneous charges or payments made to Market Participants ("Correction Mechanism").[41] The *Correction Mechanism Show Cause Order* directed ISO-NE to either: (i) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential given its lack of a Correction Mechanism or (ii) explain how it will revise the Tariff to remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential and, therefore, proceeds to establish replacement Tariff provisions. The FERC also stated that ISO-NE could instead submit a Section 205 filing to propose revisions to the Tariff and seek abeyance of this proceeding while such revisions are under consideration by the FERC. Interventions were due on or before March 31, 2026 and were filed by NEPOOL, Avangrid (out-of-time), Brookfield, Constellation, Dynegy (Vistra), Eversource, National Grid, NEPGA, Public Systems,[42]and Public Citizen.

ISO-NE Response. On May 8, 2026, ISO-NE responded to the *Correction Mechanism Show Cause Order* by (i) explaining potential changes to the Billing Policy that, if adopted, would address the majority of the issues that the FERC raised in the Show Cause Order ("Proposed Compliance Changes"), (ii) explaining why it is not appropriate to modify certain, discrete, market settlement provisions related to Capacity Performance Payment errors ("Capacity Performance Payment Errors"), and (iii) requesting that the FERC provide guidance with respect to adding a provision to the ISO's Tariff to enable the extension of settlement deadlines by FERC action to address settlement errors ("Settlement Deadline Extension").[43] ISO-NE requested that, if changes described in (i) above would be sufficient, it be given 120 days in any order on its response to submit a compliance filing with specific Billing Policy changes. On June 8, Public Systems[44] submitted comments (supporting Tariff changes that permit ISO-NE to accept and re-distribute repayments of erroneously or otherwise improperly received funds, but reserving comment on the specific Tariff changes and its implementation until they have had an opportunity to review the Tariff language and ISO-NE's implementation in specific cases).

[41] *ISO New England Inc.*, 194 FERC ¶ 61,187 (Mar. 10, 2026) ("*Correction Mechanism Show Cause Order*").

[42] "Public Systems" for purposes of this proceeding are Mass. Municipal Wholesale Electric Co. ("MMWEC"), Conn. Municipal Electric Energy Coop. ("CMEEC"), New Hampshire Electric Coop., Inc. ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

[43] ISO-NE reviewed its plans for its May 9 response with the Budget & Finance Subcommittee ("B&F") at the B&F's April 17 meeting.

[44] For purposes of this proceeding, "Public Systems" are: MMWEC, CMEEC and VPPSA.

Order Directing Compliance Filing. On September 10, 2026, the FERC found that the Tariff is unjust and unreasonable due to its lack of a Correction Mechanism.[45] Accordingly, it directed ISO-NE to submit, on or before ***January 8, 2027***, a compliance filing with the Proposed Compliance Changes. Agreeing with ISO-NE's response regarding the complexities and drawbacks related to correcting Capacity Performance Payment Errors, the FERC found the current Tariff "just and reasonable as it relates to the settlement of Capacity Performance Payments,"[46] so no further action is required on this issue. Finally, the FERC declined to provide the requested guidance with respect to a possible Settlement Deadline Extension, instead encouraging ISO-NE to "submit whatever section 205 filing it believes is appropriate" for future FERC evaluation.[47]

Tariff language implementing the Proposed Compliance Changes will be reviewed with the B&F Subcommittee (at its November 20, 2026 meeting) and the Participants Committee. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **BP Phantom Load Complaint (EL26-5)**

On October 14, 2025, as supplemented October 17, BP Energy Retail Company ("BP") filed a complaint seeking relief from invoices issued by ISO-NE for July, August, and September of 2024 based on phantom load shifted from the NEMA to the SEMA zone, which BP asserts was incorrectly assigned to BP by Eversource (NSTAR) due to an IT system error. Answers, comments and interventions were due on or before December 12, 2025.

Answers and comments in response to the BP Complaint were filed by **ISO-NE** (opposing the Complaint and BP waiver request, asserting that the alleged error constitutes a Meter Data Error and that BP requested relief would require resettlement of final bills outside the ISO-NE Tariff and Manual M-28 settlement timelines), **Eversource** (supporting BP's request for waiver of the Market Rule 1 time limitations and requesting that the FERC direct ISO-NE to complete billing adjustments for July, August, and September 2024 based on updated data, with any resettlement extending to all affected Market Participants), and the Retail Energy Supply Association ("**RESA**") (supporting the Complaint, stating that phantom load errors harm Market Participants and requesting that any resettlement ordered by the FERC extend to all Market Participants) filed answers/comments. ISO-NE answered the December 8 comments of Eversource and BP on December 26. On December 29, BP opposed Eversource's motion to dismiss and replied to ISO-NE's December 12 answer and December 26 response (reiterating its request that the FERC direct ISO-NE to correct the July through September 2024 invoices). ISO-NE answered BP's December 29 answer on January 9, 2026. Interventions only were filed by Calpine, ENGIE, National Grid, NRG, and Public Citizen.

Supplement. On March 3, 2026, BP advised the FERC that NSTAR had concluded working with the MA DOER to update data that provides the basis for renewable portfolio standard ("RPS") compliance, and that BP's MA RPS had been re-determined based on this data, reducing BP's RPS obligation to $6 million ("BP Supplement"). In the Supplement, BP stated that it has been unable to determine whether NSTAR intends to adjust BP's load allocation for settlement charges, and it continues to seek relief with respect to the remaining disputed amount under FERC jurisdiction. On March 6, 2026 NSTAR answered the BP Supplement. NSTAR asserted that, should the FERC determine—as ISO-NE argued—that the filed-rate doctrine and Market Rule 1's finality provisions bar reopening past invoices, then the Complaint must be dismissed. "If ISO-NE cannot lawfully grant relief, [BP] likewise cannot obtain relief from Eversource or NSTAR, which have no authority to provide what the tariff forbids."[48] On March 19, 2026, RESA filed an answer supporting BP's Complaint and Supplement, asserting that

[45] ISO New England Inc., 196 FERC ¶ 61,185 (Sep. 10, 2026) ("*Correction Mechanism Compliance Order*").

[46] *Id.* at P 35.

[47] *Id.* at P 40.

[48] Motion for Leave to Answer and Answer of Eversource Energy and NSTAR Elec. Co., *BP Energy Retail Co. LLC v. ISO New England Inc., et al.*, Docket No. EL26-5-000 (filed Mar. 6, 2026).

ISO-NE should be ordered to make the settlement corrections and that any relief granted should be extended to all affected Market Participants, not just BP.

This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Local Transmission Planning Complaint (EL25-44)**

Still pending is the complaint filed more than 15 months ago (December 19, 2024), by a group of "Consumer Complainants,"[49] against all FERC-jurisdictional public utility transmission providers with local planning tariffs (including ISO-NE and the remaining ISO/RTOs), asserting that the transmission providers' tariffs, which authorize individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above ("Local Planning") without regard to whether such Local Planning approach is the more efficient or cost-effective transmission project for the interconnected transmission grid and cost-effective for electric consumers, coupled with the absence of an independent transmission system planner, "are unjust and unreasonable, having produced inefficient planning and projects that are not cost-effective, resulting in unjust and unreasonable rates for both individual projects and cumulative regional transmission plans and portfolios." Specifically, the Consumer Complainants asserted that the FERC must mandate (i) revision of local and regional planning tariffs to (a) prohibit individual transmission owner planning of FERC-jurisdictional transmission facilities 100 kV and above; and (b) require exclusive regional planning of all transmission facilities 100 kV and above, utilizing existing *Order 1000* regions; and (ii) that all regional planning must be conducted through an Independent Transmission Planner as described in their Complaint.

Answers, interventions, comments, and protests to the Consumers RTP Complaint were filed by, among others, ISO-NE, New England Transmission Owners ("NETOs"),[50] AEU, CT OCC, NECPUC, NESCOE, MA AG, NH OCA (supporting the Complaint), MPUC (urging the FERC to reject the remedies proposed by the Complainants and open its own investigations pursuant to Section 206 of the FPA), EEI, NARUC, Public Interest Organizations,[51] and WIRES. Interventions only were filed by more than 100 parties, including NEPOOL. On April 4, 2025, ISO-NE answered certain comments and reiterated its request that it be dismissed as a respondent to the proceeding. Answer and reply comments were also filed by Complainants (requesting FERC grant the Complaint and deny the motions to dismiss), NESCOE (addressing the standard of review that may apply to certain reforms), MOPA (asking FERC to reject motions to dismiss and open an investigation), MPUC (requesting FERC accept its motion for to leave to answer and consider its answer), and AMP (asking FERC to deny motions to dismiss). On May 20, 2025, ISO-NE responded to Complainant's Answer and the responses of NESCOE, MPUC, and MOPA, again requesting it be dismissed as a respondent to the proceeding as a matter of law and because the Complainants failed to meet their burden under FPA Section 206. On June 30, 2025, Complainants answered the May 22 answer by "Southeast Respondents"[52] and on July 25, 2025 ATC answered Complainants April 24, 2025 answer. The Industrial Energy

[49] "Consumer Complainants" are Industrial Energy Consumers of America ("IECA"), American Forest & Paper Assoc., R Street Institute, Glass Packaging Institute, Public Citizen, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, Assoc. of Businesses Advocating for Tariff Equity, Carolina Utility Customers Assoc., PA Energy Consumer Alliance, Resale Power Group of Iowa, Wisconsin Industrial Energy Group, Multiple Intervenors (NY), Arkansas Elec. Energy Consumers, Inc., Public Power Assoc. of NJ, OK Industrial Energy Consumers, Large Energy Group of Iowa, Industrial Energy Consumers of PA, MD Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Consumer Advocate Div. of the Public Service Commission of WV, and Missouri Industrial Energy Consumers.

[50] For purposes of this proceeding, "NETOs" are: Eversource Energy Service Company on behalf of The Connecticut Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), and NSTAR Elec. Co. ("NSTAR", and together with CL&P and PSNH, "Eversource"); Central Maine Power Co. ("CMP"), Maine Elec. Power Co., Inc. ("MEPCO"), and The United Illuminating Co. ("UI"); New England Power Co. d/b/a National Grid; The Narragansett Elec. Co. d/b/a Rhode Island Energy ("RI Energy"); Vermont Electric Power Co., Inc. ("VELCO") and Vermont Transco LLC ("VTransco"), and Versant.

[51] "Public Interest Organizations" or "PIOs" are Earthjustice, Natural Resources Defense Council ("NRDC"), Sustainable FERC Project, and the Southern Environmental Law Center.

[52] Complainants defined "Southeast Respondents" as: Dominion Energy South Carolina, Inc. ("DESC"), Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, and Duke Energy Florida, LLC (together, "Duke Energy"), Louisville Gas and Electric Co. and Kentucky Utilities Co.

Consumers of America submitted comments in November rebutting utilities' opposition to competitive transmission development. The IECA submitted supplemental comments highlighting points made in the Complaint, including the rise of electricity rates tied to electric transmission, and requested that the FERC grant the Complaint. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Allco PP5 Complaint (EL25-43)**

Still pending is the December 19, 2024 complaint by Allco Finance Limited ("Allco") asking the FERC to (i) direct ISO-NE to abolish its Planning Procedure No. 5 ("PP5") procedures by (ii) finding that PP5's procedures are unjust and unreasonable and unduly discriminatory and/or preferential in violation of section 206 of the FPA; and (iii) find that ISO-NE has violated the FPA by forcing on State jurisdictional interconnections, such as Allco's, the requirement to pay for transmission level interconnection studies, to pay for Power Systems Computer Aided Design ("PSCAD") models in connection with such studies, and by causing delays to the execution by distribution utilities of State jurisdictional generator interconnection agreements (particularly for Allco's 2 MW Winsted solar energy project). ISO-NE answered the Allco PP5 Complaint on January 15, 2025 (as corrected on January 30, 2025). On January 23, 2025, Allco answered ISO-NE's January 15 Answer. On February 7, 2025, ISO-NE answered Allco's January 23 Answer and on February 25, 2025 Allco answered ISO-NE's February 7 Answer. Doc-less interventions only were filed by NEPOOL, Calpine, National Grid, the MA DPU, and Public Citizen. There has been no activity in this proceeding since Allco's February 24, 2025 answer. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **206 Proceeding: TO Initial Funding Show Cause Order (EL24-83)**

As previously reported, on June 13, 2024, the FERC instituted a Section 206 proceeding finding that the ISO-NE Tariff appears to be unjust, unreasonable, and unduly discriminatory or preferential because it includes provisions for transmission owners to unilaterally elect transmission owner ("TO") Initial Funding (the funding of network upgrade capital costs that the TO incurs to provide interconnection service to an interconnection customer, with the network upgrade capital costs subsequently recovered from the interconnection customer through charges that provide a return on and of those network upgrade capital costs).[53] TO Initial Funding, the FERC found, may increase the costs of interconnection service without corresponding improvements to that service, may unjustifiably increase costs such that it results in barriers to interconnection, and may result in undue discrimination among interconnection customers.[54] The FERC also found that there may be no risks associated with owning, operating, and maintaining network upgrades for which transmission owners are not already otherwise compensated.[55] Accordingly, ISO-NE was directed, on or before September 11, 2024, to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory.[56] The refund effective date for this proceeding is June 24, 2024.[57] A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and was reviewed with, the Transmission Committee.

(together, "LG&E/KU"), Tampa Electric Co. ("TEC"), Florida Power and Light ("FPL"), and Alabama, Georgia and Mississippi Power Companies.

[53] *ISO New England Inc. et al.,* 187 FERC ¶ 61,170 (June 13, 2024) ("*TO Initial Funding Show Cause Order*").

[54] *Id.* at P 1.

[55] *Id.*

[56] *Id.* at P 2.

[57] Notice of this 206 proceeding was published in the *Fed. Reg.* on June 24, 2024 (Vol. 89, No. 121) pp. 52,454-52,455.

Interventions were due on or before July 5, 2024 and were filed by the following New England-related parties:[58] NEPOOL, Advanced Energy United ("AEU"), Avangrid, Calpine, CMEEC (out-of-time), EDP Renewables, Eversource, Invenergy, MA AG, National Grid, NESCOE, NextEra, NRDC, PPL, Maine Public Utilities Commission ("MPUC"), Massachusetts Department of Public Utilities ("MA DPU"), American Clean Power Association ("ACPA"), American Council on Renewable Energy ("ACRE"), Edison Electric Institute ("EEI"), Electric Power Supply Association ("EPSA"), RENEW Northeast ("RENEW"), Solar Energy Industries Association ("SEIA"), WIRES, Cordelio Services, and Public Citizen.

NE Response to Show Cause Order (Attaching Substantive Response by NETOs). On September 11, 2024, ISO-NE submitted a response ("NE Response") explaining that, because the rules identified in the *TO Initial Funding Show Cause Order*[59] fall within the exclusive purview of, and are implemented by, the Participating Transmission Owners ("PTOs") under the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs, it had requested that the PTOs respond to the *TO Initial Funding Show Cause Order* and attached the response of Indicated New England Transmission Owners ("NETOs")[60] to the NE Response. NETOs' response identified several reasons why the FERC's proposal is in their view beyond the FERC's authority and power.

Responses to the September NE Response were due on or before October 25, 2024. Responses from ISO-NE-related parties to this joint proceeding were filed by, among others: NE TOs, Invenergy, Public Interest Organizations, Public Systems, Clean Energy Associations, EEI, WIRES, and the Harvard Law Initiative. ISO-NE IMM filed comments in the MISO version of this proceeding to urge the FERC to reject MISO's request for a broad, and what the IMM asserts is an inappropriately limited, declaration on the authority of an IMM to monitor long-term transmission planning for impacts on the wholesale markets and assumed efficiency improvements to those markets. Each of the regional matters, including the New England-specific docket, remain pending before the FERC.

Federal Court Appeals. On August 30, 2024, certain parties[61] filed a petition for review of the FERC's orders in this proceeding in the 8th Circuit, since challenged by the FERC. Developments on the federal court appeals will be reported in Section XVI below. In the meantime, if you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

As previously reported, the FERC issued *Opinions 594* and *594-A,*[62] which addressed long-running challenges to the New England Transmission Owner's ("NETOs") return on equity ("Base ROE") for regional transmission service. *Opinion 594-A* sustained *Opinion 594* in full: the NETOs' prior 11.14% base ROE remains unjust and unreasonable, the 9.57% replacement base ROE stands, and the NETOs must pay refunds, with interest, for both the 15-month refund period (October 1, 2011, through December 31, 2012) and the period

[58] The notice instituting this 206 proceeding was issued in the following four unconsolidated dockets (which resulted in some parties intervening in all four proceedings): EL24-80 (MISO); EL24-81 (PJM); EL24-82 (SPP); and EL24-83 (ISO-NE).

[59] The rules identified in the *Order to Show Cause* were those that establish the methodology to recover costs associated with interconnection-related upgrades, and the related financial obligations of the PTO or the interconnecting party – in New England, set forth in Article 11.3 of the LGIA, Article 5.2 of the SGIA, and Article 11.3 of the ETU IA, as well as Schedule 11 of the OATT.

[60] The NETOs, for purposes of this proceeding, are: Eversource; CMP; UI; National Grid; RI Energy; Fitchburg Gas and Electric Light Co. ("Unitil"); and Versant.

[61] The parties to the 8th Circuit Appeal are: Ameren Services Co., Ameren Illinois Co., Union Elec. Co. d/b/a Ameren Missouri, Ameren Trans. Co. of IL, American Trans. Co. LLC, Duke Energy Corp., Duke Energy Business Services, LLC, Duke Energy Ohio, Inc., Duke Energy KY, Inc., Duke Energy IN, LLC, Exelon Corp., Atlantic City Elec. Co., Baltimore Gas and Elec. Co., Commonwealth Edison Co., Delmarva Power & Light Co., PECO Energy Co., Potomac Elec. Power Co., Northern Indiana Pub. Srvc. Co. LLC, Xcel Energy Services Inc., Northern States Power Co., a MN Corp., Northern States Power Co., a WI Corp., and Southwestern Pub. Srvc. Co. ("8th Circuit Parties").

[62] *Coakley, Mass. Attorney Gen., et al. v. Bangor Hydro-Electric Co. et al.*, Opinion No. 594, 194 FERC ¶ 61,208 (Mar. 19, 2026) ("*Opinion 594*"), *reh'g denied*, 196 FERC ¶ 61,232 (Sep. 24, 2026) ("*Opinion 594-A*").

from October 16, 2014, through March 19, 2026. A more detailed summary of *Opinion 594-A* was provided to the Tranmission Committee. Petitions for review of the orders and opinions issued in these proceedings have been filed with the D.C. Circuit and consolidated (case no. 26-1150).[63] The deadline to complete the *Opinion 594* refunds is ***May 20, 2027*** and the deadline to submit the associated refund reports is ***June 4, 2027***.[64]

Versant Refund Procedural Modification/Extension. Also as previously reported, Versant moved to extend its refund deadline and modify the refund procedure associated with its ROE refund obligation. Specifically, Versant proposed to reduce all retail transmission charges beginning January 1, 2027 (from what they otherwise would be under Schedule 21-VP) in a manner that, based on current best estimates of Versant's retail refund liability and 2027 transmission use, will pay to retail transmission customers over calendar year 2027 the full amount of monies that would otherwise be payable as refunds to retail transmission customers (with interest). The charges would then be adjusted as of July 1, 2027, up or down, based on the final refund calculations issued by ISO-NE in May 2027. Versant's request remains pending before the FERC.

If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com), Margaret Czepiel (202-218-3906; mczepiel@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **PBOP Collections Report (RI Energy) (ER27-408)**

On November 3, 2026, The Narragansett Electric Company d/b/a Rhode Island Energy Inc. ("RI Energy") filed a report identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT. The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F.[65] No changes to the filed rate were sought. The report shows an over-recovery, after interest, of ***$969,852***. If accepted, the PBOP figures will be used in RIE's 2027 Annual Update. Comments on this filing are due on or before ***November 24, 2026***. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PBOP Collections Report (Eversource) (ER27-348)**

On October 30, 2026, Eversource filed a report identifying planned collection activity related to the over recovery of PBOP under Appendix A to Attachment F to the ISO-NE OATT. The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F. No changes to the filed rate were sought. The report shows an over-recovery, after interest, of ***$179,779***. If accepted, the PBOP figures will be used in Eversource's 2026 Annual Update. Comments on this filing are due on or before ***November 19, 2026***. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **GMP Updated Depreciation Rates (ER27-181)**

On October 16, 2026, Green Mountain Power ("GMP") filed updates to its stated depreciation rates in the ISO-NE OATT (Appendix D of Attachment F and Attachment E-2 of Schedule 21-GMP). The proposed updates conform the stated depreciation rates for GMP's transmission, distribution and general plant accounts to the same depreciation rates used in GMP's retail rates recently approved by the State of Vermont Public Utility

[63] *See infra* Section XVI.

[64] Notice of Extension of Time, *Coakley v. Bangor Hydro-Electric Co.*, Docket Nos. EL11-66-001 *et al.* (issued Apr. 14, 2026).

[65] A Report is required when "the absolute value of [(Cumulative Under/(Over) Recovery, including Current Year interest)] is greater than $100,000 and the absolute value of [(Cumulative Under/(Over) recovery, including Current Year interest, as a percent of transmission-related PBOP expense)] is greater than 20%. See ISO-NE OATT, Attachment F, Appendix A, Worksheet 9, Note (j).

Commission ("VT PUC"). GMP estimated that the updated depreciation rates would increase GMP's Annual Transmission Revenue Requirements under the formula rate in Attachment F by approximately 0.78%. GMP requested a December 1, 2026 effective date for the changes. Comments on this filing were due on or before November 6, 2026; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **2027 NESCOE Budget (ER26-164)**

On October 15, 2026, ISO-NE, joined by NESCOE, filed Tariff changes for the funding of NESCOE's 2027 operations. The 2027 Operating Expense Budget for NESCOE is $2,978,711. The amount to be recovered reflects true-ups from 2025 (over-collections of $814,301). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00942 per kilowatt ("kW") of Monthly Network Load (a $0.00136/kW increase from 2026). The 2027 NESCOE budget was supported by the Participants Committee at its October 2, 2026 meeting (Agenda Item #6b). Comments and any interventions were on or before November 5, 2026. On October 29, 2026, NEPOOL submitted comments supporting NESCOE's 2027 Budget. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2027 ISO-NE Administrative Costs and Capital Budgets (ER27-158)**

Also on October 15, 2026, ISO-NE filed for recovery of its 2027 administrative costs (the "2027 Revenue Requirement") and submitted its capital budget for calendar year 2027 ("2027 Capital Budget", and together with the 2027 Revenue Requirement, the "2027 ISO Budgets"). The 2027 ISO Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 15, 2026 filing, ISO-NE reported that the 2027 Revenue Requirement is $354.0 million (a $24 million or 7.3% increase over 2026), which decreases to $346.4 million after the overcollection for 2025 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2027 Core Operating Budget) comprise $302.38 million; depreciation and amortization of regulatory assets total $51.7 million; and a $7.6 million true-up decrease for 2025 over-collections. An effective date of January 1, 2027 was requested.

ISO-NE further reported that the 2027 Capital Budget is $45 million, an increase of $2.5 million or 5.9% over the 2026 Capital Budget, and is comprised of the following (with 2027 projected costs and target completion dates, if available, in parentheses):

Next-Generation Electronic Dispatch & Reliability Voice Network (Mar 2028)	($1.4 million)	Electromagnetic Transient Model Repository (Jun 2028)	($1.1 million)
MW Dependent Fuel Price Adjustment (Sep 2027)	($1 million)	Settlement Market System (SMS) Technology Upgrade (Jul 2027)	($600,000)
Integrated Market Simulator Usability (Jun 2027)	($400,000)	Total Transfer Capability Utility (TTCU) Implementation for Resource Outage Coordination (Mar 2027)	($200,000)
Enterprise Resource Planning (ERP) Enhancements (Jun 2027)	($100,000)	Microsoft 365 Phase III (Mar 2027)	($100,000)
Single Interval MCE Improvements (SIMI) (Dec 2028)	($5 million)	EMP 3.5 Upgrade – GridOS (Sep 28)	($4 million)
Space Utilization Phase II (Mar 2028)	($3 million)	Migration of MIS FTP Server to Cloud (Apr 2027)	($100,000)
Advanced Technology Initiatives (Dec 2027)	($3 million)	2027 Issue Resolution Projects (Dec 2027)	($1.5 million)

Capacity Management Tracking System for CAR Phase I (Jun 2027)	($1.5 million)	GridOS Connect (Dec 2027)	($1.4 million)
Settlement & Financial Assurance for Capacity Auction Reform (Mar 2028)	($1.2 million)	Capacity Management Tracking System for CAR Phase II (Mar 2028)	($1 million)
Performance Audit Changes for CAR (Mar 2028)	($1 million)	Resource Adequacy Assessment & Accreditation for CAR (Jun 2027)	($900,000)
Auctions Clearing Engine for CAR (Jun 2028)	($800,000)	Circuit Inventory Management Platform Phase II (Dec 2027)	($600,000)
Replace Employee & Pager Application (Dec 2027)	($500,000)	Atlassian to Cloud Phase II (Dec 2027)	($500,000)
Distributed Energy Resources – *Order 2222* Phase II (Jun 2027)	($500,000)	DASI Benchmark Calculation Versioning Enhancements – IMM (Dec 2027)	($500,000)
PowerGADS Update for Capacity Auction Reforms (Jun 2027)	($400,000)	CIP Electronic Security Perimeter Network Services (Sep 2027)	($300,000)
Non-Project Capital Expenditures	($7.5 million)	Other Emerging Work	($3.8 million)
Capitalized Interest	($1.2 million)		

Comments were due on or before November 5, 2026. On October 19, 2026, NEPOOL filed comments in support of the 2027 ISO Budgets, noting that the Participants Committee unanimously supported the Operating and Capital Budgets at its October 2, 2026 meeting (with abstentions). This matter is pending before FERC. If there are any questions on this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **CIP-IROL Cost Recovery Filing: Cross-Sound Cable (ER26-3737)**

On October 23, 2026, the FERC accepted, effective November 9, 2026, Cross Sound Cable Company ("CSC") rate schedule revisions that will allow CSC to recover ***$791,687*** of eligible CIP-IROL Costs incurred between January 1, 2024 and December 31, 2025.[66] Unless the October 233 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **New Base ROE (11.39%) - Attachment F Revisions (ER26-2389)**

On June 29, 2026, the FERC accepted, subject to the outcome of further proceedings, the Participating Transmission Owners Administrative Committee's ("PTO-AC") proposed 11.39% Base ROE.[67] Based on its preliminary finding that the proposed Base ROE had not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful, the FERC suspended the proposed Base ROE for five months, to become effective *November 30, 2026*, and established paper hearing procedures concerning PTO-AC's application of the FERC's revised ROE methodology under *Opinion Nos. 569 et seq.* and *594*.

[66] *Cross-Sound Cable Co., LLC*, Docket No. ER26-3737-000 (Oct. 23, 2026) (unpublished letter order).

[67] *Eversource and ISO-NE*, 195 FERC ¶ 61,258 (June 29, 2026) ("*New Base ROE Initial Order*"). As previously reported, the PTO-AC had filed proposed revisions to the Annual Transmission Revenue Requirements ("ATRR") Template found in Appendix A to Attachment F of the ISO-NE OATT on Apr. 30, 2026. The proposal included an increase of the Base ROE to 11.39%, ("Attachment F Revisions"). The Attachment F Revisions were reviewed, but not supported, by the Participants Committee at its special April 30, 2026 Webex meeting.

Initial briefs were due on or before August 28, 2026, and were submitted by: NETOs, Acadia Center, Consumer Advocates,[68] FERC Trial Staff, NECOS, Public Systems,[69] and State Entities.[70] Responses to the initial briefs were filed on September 28, 2026[71] by: NETOs, Acadia, Consumer Advocates, FERC Trial Staff, NECOS, Public Systems, and State Entities. No additional answers or briefs will be permitted.[72] This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joan Bosma (jbosma@daypitney.com; 617-345-4651).

- **Transmission Rate (2027) Annual Update/Informational Filing (ER20-2054)**

On July 31, 2026, the PTO AC submitted its annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff for 2027. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2025 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2025 and 2026, as well as the Annual True-up including associated interest. The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $183.60/kW-year effective January 1, 2027, an increase of $5.97 /kW-year from the charges that went into effect on January 1, 2026. In addition, the filing includes updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.87 kW-year (effective June 1, 2026 through May 31, 2027), a $0.36/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2026.

While this filing will not be noticed for public comment, this filing triggers the commencement of an Information Exchange Period and a Review Period under the Protocols. Interested Parties have until ***September 15, 2026*** to submit information and document requests, and the PTOs are required to make a good faith effort to respond to all requests within 15 calendar days, but by no later than ***October 16, 2026***. During the Review Period, Interested Parties have until ***November 17, 2026*** to submit Informal Challenges to the PTOs, and the PTOs are required to make a good faith effort to respond to any Informal Challenges no later than ***December 15, 2026***. Interested Parties have until ***February 2, 2027*** to file a Formal Challenge with the FERC.

- **Transmission Rate (2026) Supplement (*Opinion 594* Updates) (ER20-2054)**

On June 30, 2026, the PTO AC submitted updated rates and associated revenue requirements to reflect *Opinion 594* changes to the data inputs in its July 31, 2025 annual information filing. The changes result in a Pool RNS Rate of $177.63/kW-year effective January 1, 2026 through December 31, 2026 (a decrease of $6.12/kW-year from the 2026 Pool RNS Rate of $183.75/kW-year that was submitted on July 31, 2025). The PTOs presented the changes at the July 16, 2026 Joint RC/TC meeting and at a Technical Session on July 22, 2026. Under the Protocols, Interested Parties have until ***September 15, 2026*** to submit information and document requests, and the PTOs are required to make a good faith effort to respond to all requests within 15 calendar days, but by no later than ***October 16, 2026***. During the Review Period, Interested Parties have until November 17, 2026 to submit Informal Challenges to the PTOs, and the PTOs are required to make a good faith effort to respond to any Informal Challenges no later than ***December 15, 2026***. Interested Parties have until ***February 2, 2027*** to file a Formal Challenge with the FERC.

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[68] "Consumer Advocates" or "CANE" are: . the MA Attorney General's Office ("MA AGO"), the CT Office of Consumer Counsel ("CT OCC"), MOPA, NH OCA, and the Rhode Island Division of Public Utilities and Carriers ("RI DPUC").

[69] "Public Systems" are MMWEC and NHEC.

[70] "State Entities" are the CT PURA, CT DEEP, CT AG, MPUC, and MA DPU.

[71] Although NETOS requested that the FERC grant a one-month extension for reply briefs to be filed in this proceeding, many parties opposed that request (including Acadia, : Consumer Advocates; MMWEC/NHEC; NESCOE; NECOS/ENE; MA DPU) and the FERC denied the NETOs' request (Notice Denying Extension of Time, Eversource Energy and ISO New England Inc., Docket No. ER26-2389 (Sep. 16, 2026).

[72] *New Base ROE Initial Order* at P 48.

- **Transmission Rate (2026) Annual Filing Formal Challenge (NESCOE Eversource Challenge) (ER20-2054)**

On April 1, 2026, NESCOE filed a formal challenge to the rate schedules of CL&P, NSTAR Electric Company (East) ("NSTAR East"), NSTAR Electric Company (West) ("NSTAR West"), and PSNH (together with CL&P, NSTAR East, and NSTAR West, "Eversource"). As with its CMP Formal Challenge, NESCOE challenged Eversource's recovery through its formula rates of incentive compensation based on financial performance targets that benefit only utility shareholders ("NESCOE Eversource Formal Challenge"). NESCOE requested that the FERC either (i) direct that those costs be removed from the Eversource rate schedules and customers reimbursed for such costs collected to date; or (ii) initiate a Section 206 proceeding *sua sponte* to revise the formula rate to make it clear that costs for incentive compensation that are based on financial targets are not recoverable from customers. On April 22, NH OAC submitted comments supporting NESCOE's Eversource Formal Challenge, and Eversource responded to that Challenge. On May 7, NESCOE answered Eversource's April 22 response. On May 22, Eversource answered NESCOE's May 7 answer. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Transmission Rate (2026) Annual Filing Formal Challenge (NESCOE CMP Challenge) (ER20-2054)**

As previously reported, NESCOE filed, on February 9, 2026, a formal challenge to CMP's rate schedules included in the PTO AC's 2025-26 Annual Update, challenging CMP's recovery through its formula rates of incentive compensation based on financial performance targets that benefit only utility shareholders ("NESCOE CMP Formal Challenge"). Following a 21-day extension of time granted by the FERC, CMP answered the NESCOE CMP Formal Challenge on March 23, 2026, moving to dismiss or have the FERC reject the Formal Challenge.[73] NESCOE answered the March 23 CMP answer on April 7, 2026. On June 4, 2026, CMP filed an errata to its March 23 motion to dismiss and response to NESCOE's February 9 Formal Challenge, submitting revised privileged materials to correct an erroneous Annual Performance Award incentive compensation plan objective and to make minor conforming edits (there were no changes to the text available in the public version of its response). This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **Waiver Request: Schedule 22 Section 5.1.1.2 (Brough Storage LLC) (ER27-142)**

On October 8, 2026, CleanCapital Holdings LLC and Brough Storage LLC (together, "Brough Storage")[74] requested waiver (before October 20, 2026) of Section 5.1.1.2 of OATT Schedule 22 ("Waiver Request") to permit Brough Storage to change its requested service, elected as required at the time of executing a Transitional Cluster Study ("TCS") Agreement, from Capacity Network Resource Interconnection Service ("CNRIS") to Network Resource Interconnection Service ("NRIS"). Brough Storage stated that an NRIS election would reduce the upgrade costs allocated to Brough Storage ($304.9 million, an amount that exceeds Brough Storage's entire construction budget) by nearly 80% and meets the FERC's standard for granting a waiver request. Brough Storage requested a shortened comment period, which was opposed by ISO-NE and denied by the FERC; comments on the Brough Storage Waiver Request were due on or before October 29, 2026.

ISO-NE protested the Waiver Request, arguing that the request is "retroactive in nature and prohibited by the filed rate doctrine" and "[does] not satisfy the Commission's criteria for granting waiver." ISO-NE asserted that granting the Waiver Request "would disrupt [ISO-NE's] administration of its [TCS], cause harm to

[73] CMP argued that "there is nothing unusual about CMP's incentive compensation plans and, like similar utility incentive programs, they are balanced pay-at-risk mechanisms used to align workforce performance with utility goals… NESCOE has not raised a prudence challenge to these expenses or otherwise demonstrated why disallowance is appropriate in this case. Accordingly, the Commission should reject NESCOE's Challenge and decline to initiate a Section 206 proceeding." Motion to Dismiss and Response of Central Maine Power Co., Docket No. ER20-2054-000 (filed Mar. 23, 2026).

[74] Brough anticipates developing a 290 MW AC battery energy storage facility, designed to resolve renewable intermittency, improve grid stability, reduce peak electricity costs and enhance resilience, while reducing emissions.

Interconnection Customers participating in the TCS, and constitute undue preferential treatment for [Brough Storage]". On October 29, 2026, Brough Storage answered the ISO-NE protest and the MA DOER submitted comments "to underscore the importance of storage resources to Massachusetts' long-term energy strategy and to support the Petitioners' request for a Limited Waiver." NEPOOL filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275¬0533; pmgerity@daypitney.com).

- **Syncarpha Solar Entities Refund Report (QF26-468 et al.)**

On July 9, 2026, ISO-NE requested that the FERC direct it to accept ***$45,996.94*** from Marie's Way Solar 1 and ***$17,509.13*** from Syncarpha North Adams (representing capacity market revenues received prior to effectiveness of QF status plus interest) and approve an allocation of the refund amounts to FCM Capacity Load Obligation ("CLO") for January 2026. On June 9, 2026, Marie's Way Solar and Syncarpha North Adams filed a refund report identifying ISO-NE FCM capacity market revenues received before submitting self-certifications as qualifying small power production facilities ("QF") (QF wholesale sales made without a prior exemption from FPA Section 205 must be refunded).[75] The Refund Report and ISO-NE's request remain pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Waiver Request: Indicated TOs (*Order 881* Implementation) (ER27-214)**

On October 16, 2026, Indicated TOs[76] requested a waiver of the Tariff's *Order 881*-implementing (Ambient Adjusted Ratings) provisions through ***December 31, 2028***, citing delays by unforeseen hardware and software implementation issues (noting that, for the same reasons, NYISO and MISO TOs have already received similar waivers of those regions' *Order 881*-implementing provisions). The TOs added that, should any of them complete their remaining work ahead of December 31, 2028, they will implement the *Order 881* OATT requirements at the earliest practicable opportunity, and provide notice to the FERC and ISO-NE at least 30 days prior to doing so. Comments on the waiver request were due on or before November 6, 2026; none were filed. The waiver request is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Eversource PTOs' Att F Appendix A PBOP Revisions (ER27-340)**

On October 30, 2026, the Eversource PTOs proposed revisions to Appendix A to Attachment F of the ISO-NE OATT to address its continuing over recovery of PBOP expenses and more accurately reflect the going forward expense levels. Specifically, the Eversource PTOs revised the amount currently listed in footnote (e) of Worksheet 9 to Appendix A of Attachment F to $(871,000) for CL&P, $(3,070,000) for NSTAR (East), $(137,000) for NSTAR (West), and $(189,000) for PSNH. The Eversource PTOs stated that setting their fixed transmission-related PBOP expense amount to these updated levels more accurately reflects their expected expense levels and will result in reduced rates for customers. Comments on this filing are due on or before ***November 20, 2026***. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Asset Condition Reviewer Role (ER26-3533; ER26-3534)**

On October 16, 2026, the FERC accepted, effective *January 1, 2027*, the revisions to the OATT (ER26-3533) and the TOA (ER26-3534) that establish ISO-NE as the New England region's Asset Condition Reviewer ("ACR") and

[75] *See* 16 U.S.C. § 824d; 18 C.F.R. § 35.19a; *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139 at p. 61,980, *order on reh'g*, 65 FERC ¶ 61,081 (1993).

[76] "Indicated TOs" for purposes of this proceeding are: CMP, Eversource (CL&P, NSTAR, PSNH), MEPCO, National Grid, RI Energy, and UI.

the process for ISO-NE to execute the ACR role (collectively, the "ACR Revisions").[77] It is worth highlighting the concurrences by Commissioners Rosner and Chang, which in part "call[ed] on other regions to take note of this model and the spirit of collaboration that made it possible"[78] and "commend[ed] the New England stakeholders on their collaborative development of this important new role for the region and [urged] others to adopt similar processes that will provide transparency into these types of transmission projects",[79] respectively. Unless the *ACR Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Notice of Nov 17, 2026 Effective Date for Order 881 ISO-NE Tariff Compliance Changes* (Transmission Line Rating Calculation and Submittal Timeframe Implementation Details) (ER22-2357; ER25-410)**

On October 23, 2026, ISO-NE provided notice that the effective date of the Tariff's *Order 881* revisions (addressing Ambient Adjusted Ratings) will be moved up to ***November 17, 2026.*** If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- ***Opinion 594* ROE Refund-Related FAP Changes (ER27-134)**

On October 14, 2026, ISO-NE and NEPOOL jointly proposed Tariff revisions to the ISO-NE Financial Assurance Policy ("FAP") to provide financial assurance requirements specific to refunds directed by the FERC in *Opinion 594*. The Tariff Revisions were unanimously supported by the Participants Committee at its September 3, 2026 meeting. ISO-NE requested an effective date of December 14, 2026. Comments on this filing were due on or before November 4, 2026; none were filed. Eversource file a doc-less motion to intervene. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

VI. Schedule 20/21/22/23 Changes & Agreements[80]

No Activity to Report

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports[81]

- **Capital Projects Report – 2026 Q3 (ER27-166)**

On October 15, 2026, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule for the third quarter ("Q3") of calendar year 2026 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects:

[77] *ISO New England Inc.*, 197 FERC ¶ 61,042 (Oct. 16, 2026) ("*ACR Order*")

[78] *Id.* Rosner, Commissioner, concurring at P3.

[79] *Id.* Chang, Commissioner, concurring at P1.

[80] Reporting on the following Time Value Refunds Reports, which have each been pending before the FERC for more than a year and a half, has been suspended and will be continued if and when there is new activity to report: Schedule 21-VP: Versant/Jonesboro LSA (ER24-24); Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804); and Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035). Reporting has also been suspended and will be continued if and when there is new activity to report on the notice of cancellation of the Green Mountain Power/Hardwick NITSA under Schedule 21-GMP (ER25-298).

[81] Reporting on the *Opinion 531* Refund Reports (EL11-66) has been suspended and will be continued if and when there is new activity to report.

(i) MW Dependent Fuel Price Adjustment ($2,230,900); (ii) Next-Generation Electronic Dispatch & Reliability Voice Networks ($2,071,000); (iii) Electromagnetic Transient Model Repository (EMTR) ($1,631,900); (iv) Enterprise Resource Planning (ERP) Enhancements ($1,133,200); (v) Integrated Market Simulator Usability ($748,400); (vi) Foundation Out of the Box (FootB) ($651,800); and (vii) Tie Line Telemetry Replacement Phase I ($409,100). Projects placed in service this quarter include: nGEM Real-Time Market Clearing Engine Implementation; Application and Infrastructure Portfolio; 2026 Issue Resolution Project Phase I; and Migration of Spring Boot BTM PV Microservices to AWS ECS. And one project reported to have a significant change in funds -- Oracle Platform Replacement (reduced by $375,900). Comments on this filing were due on or before November 5, 2026. On October 19, 2026, NEPOOL filed comments in support of the Report. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Capital Projects Report – 2026 Q2 (ER26-3471)**

On October 7, 2026, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2026 (the "Report"), effective *July 1, 2026*.[82] Report highlights included the following new projects: (i) Interconnection Request Tracking Upgrade ($2,411,800); (ii) Settlement Market System ("SMS") Technology Upgrade ($1,191,700); (iii) Total Transfer Capability Utility ("TTCU") Implementation for Resource Outage Coordination ("ROC") ($1,144,400); (iv) Atlassian Cloud Migration ($994,300); (v) Application and Infrastructure Portfolio ($762,600); (vi) Migration of Market Information System ("MIS") File Transfer Protocol ("FTP") Server to Cloud ($525,000); (vii) Security System Software Upgrade 2026 ($431,900); and (viii) 2026 Issue Resolution Project Phase II ($284,000). Four projects were completed this quarter: (i) Upgrade SMS Application Technology Phase II; (ii) Pool Control Error Calculator ("PCEC") Upgrade; (iii) Voltage Ampere Reactive ("VAR") Capability Testing; and (iv) Solver Performance Study. Projects with significant budget changes included: Oracle Platform Replacement (decrease of $640,000 to $1,969,400); Unified Data Platform Cloud (decrease of $472,400 to $1.582 million); and Storage as Transmission Only Asset ("SATOA") (decrease of $305,000 to $968,600). Significant budget changes for projects in planning included a decrease of $500,000 for the Solar Do Not Exceed Dispatch Phase III project, which has been deferred due to higher-priority initiatives. ISO-NE's non-project capital spending budget increased by $436,400 for total costs of $1,636,400, reflecting updated project spending forecasts and changes in project in-service dates (which increased the amount of capitalized interest and loan fees associated with the capital program). NEPOOL filed comments supporting the Report. The October 7 order was not challenged and is final and unappealable. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **LFTR Implementation: 72nd Quarterly Status Report (ER07-476)**

ISO-NE filed the 72nd of its quarterly status reports regarding LFTR implementation on October 15, 2026. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

[82] *ISO New England Inc.*, Docket No. ER26-3471-000 (Oct. 7, 2026) (unpublished letter order).

- ***Order 1920* Compliance Status Reports (RM21-17)**

On August 14, 2026, ISO-NE submitted its *Order 1920* Information Report (describing the stakeholder process schedule and its engagement with Relevant State Entities).[83] If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **IMM Quarterly Markets Report – Summer 2026 Report (ZZ27-4)**

On November 5, 2026, the IMM filed with the FERC its Summer 2026 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under…Appendix A and analysis of such market data," as required pursuant to Section 17.2.2 of Appendix A to Market Rule 1. The Report covers the period from June 1, 2026 through August 31, 2026. The Summer 2026 Report will be reviewed with the Markets Committee at its December 8, 2026 meeting. These filings are not noticed for public comment by the FERC.

IX. Membership Filings

Questions concerning any of the Membership Filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Nov 2026 Membership Filing (ER27-331)**

On October 29, 2026, NEPOOL requested that the FERC accept: (i) the NEPOOL memberships of First Commodities International and Green.ai (each, Supplier Sector); and (ii) the termination of the Participant status of Manchester Street, L.L.C. [Related Person to Vistra/Dynegy Marketing & Trade (Generation Sector). Comments on this filing are due on or before ***November 19, 2026***.

- **ELM Membership Filing (ER27-92)**

On October 9, 2026, NEPOOL requested that the FERC accept the NEPOOL membership of the Environmental League of Massachusetts (End User Sector), eff. October 12, 2026. This matter is pending before the FERC.

- **Oct 2026 Membership Filing (ER26-3897)**

On September 30, 2026, NEPOOL requested that the FERC accept the NEPOOL memberships of Atlantic Grid LLC (Supplier Sector); Energetick LLC (Supplier Sector); Nabla Technologies Europe, LLC (Supplier Sector); and ZPD-PT Solar Project 2017-040 LLC [Related Person to the Agilitas Energy Companies (AR Sector, DG Sub-Sector)]. This matter is pending before the FERC.

- **Sep 2026 Membership Filing (ER26-3646)**

On October 26, 2026, the FERC accepted: (i) NEPOOL membership of SESCO Enterprises LLC (Supplier Sector); and (ii) the termination of the Participant status of Uncia Energy, LP - Series G [Related Person to Trafigura Trading (Supplier Sector)].[84] Unless the October 26 order is challenged, this proceeding will be concluded.

[83] *See* Notice of Extension of Time, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 191 FERC ¶ 61,129 (2025) (accepting the Filing Parties' proposal that ISO-NE submit an informational filing and status reports).

[84] *New England Power Pool Participants Comm.*, Docket No. ER26-3646-000 (Oct. 26, 2026) (unpublished letter order).

X. Misc. - ERO Rules, Filings; Reliability Standards[85]

Questions concerning any of the ERO Reliability Standards or ERO-related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Revised Reliability Standard: TPL-001-6 (RD27-2)**

On November 2, 2026, NERC requested FERC approval of proposed Reliability Standard TPL-001-6 (Transmission System Planning Performance Requirements). TPL-001-6 was developed in response to *Order 901*'s directive to submit new or revised standards enhancing system planning requirements for Inverter-Based Resources ("IBRs") by November 4, 2026. TPL-001-6 is intended to improve how Planning Coordinators and Transmission Planners account for IBRs and Distributed Energy Resources ("DERs") in their annual Planning Assessments. Under the proposed Implementation Plan, TPL-001-6 would become effective on the later of: (i) the first day of the first calendar quarter that is 18 months after the effective date of the FERC's order approving MOD-032-2 (i.e., October 1, 2029); or (ii) the first day of the first calendar quarter that is six months after the effective date of the FERC's order approving TPL-001-6. Comments on TPL-001-6 are due on or before ***December 2, 2026***.

- **Revised Reliability Standards: FAC-011-5 and TOP-003-9 (RD27-1)**

Also on November 2, 2026, NERC requested FERC approval of proposed Reliability Standards FAC-011-5 (System Operating Limits Methodology for the Operations Horizon) and TOP-003-9 (Transmission Operator and Balancing Authority Data and Information Specification and Collection). FAC-011-5 and TOP-003-9 were developed in response to *Order 901* and are to ensure that Reliability Coordinators, Transmission Operators, and Balancing Authorities are collecting IBR and DER data so it can be incorporated into their operations planning studies and real-time monitoring and analysis responsibilities. NERC stated that these proposed Reliability Standards "are an integral part of NERC's proposed framework to address IBR reliability issues in a comprehensive and holistic manner". Under the proposed Implementation Plan, FAC-011-5 and TOP-003-9 would become effective on the later of: (i) the first day of the first calendar quarter that is 18 months after the effective date of the FERC's order approving MOD-032-2 (i.e., October 1, 2029); or (ii) the first day of the first calendar quarter that is six months after the effective date of the FERC's order approving , FAC-011-5 and TOP-003-9. Comments on the proposed FAC-011-5 and TOP-003-9 are also due on or before ***December 2, 2026***.

- **Wildfire Report: Wildfire Prevention, Detection, and Mitigation Best Practices (RD25-9)**

On May 1, 2026, NERC issued, as directed,[86] a wildfire report that identified best practices to reduce wildfire ignition risk from the Bulk-Power System ("BPS"), including vegetation management, hazardous fuel removal, engineering approaches, operational practices, and emerging technologies ("Wildfire Report").[87] On June 1, 2026, EEI responded to the Wildfire Report with general and specific comments. On July 10, 2026, NERC submitted a supplement to its Wildfire Report, providing its Wildfire Action Plan outlining how NERC plans to implement and support the recommendations in the Wildfire Report. No comments on the Wildfire Report supplement were filed by the July 24, 2026 comment deadline. This matter is pending before the FERC.

[85] Reporting on the following ERO Reliability Standards or related rule-making proceedings has been suspended and will be continued if and when there is new activity to report: NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2); *Order 901*: IBR Reliability Standards (RM22-12); and 2024 Reliability Standards Development Plan (RM05-17 *et al.*).

[86] *N. Am. Elec. Rel. Corp.*, 192 FERC ¶ 61,212 at P 1 (Sep. 10, 2025).

[87] NERC's report and informational filing are available at: https://www.nerc.com/globalassets/who-we-are/legal--regulatory/filings--orders/nerc-filings-to-ferc/2026/wildfire-report-filing_signed.pdf.

- **2027 NERC/NPCC Business Plans and Budgets (RR26-3)**

On October 15, 2026, the FERC accepted NERC's proposed 2027 Business Plan and Budget, as well as the 2027 Business Plans and Budgets for the six Regional Entities,[88] including NPCC.[89] NERC reported that its 2027 funding requirement represents an increase of 9.1% from 2026 with a total budget and funding requirement of approximately $140 million. The NPCC U.S. allocation of NERC's net funding requirement is $17.65 million. NPCC requested $24.7 million in total U.S. statutory funding (a U.S. assessment per kWh (2025 NEL) of $0.0000918) and $1.2 million for non-statutory functions. NERC will allocate to NPCC $14.9 million of its 2027 assessment. Unless the *NERC 2027 Budget Order* is challenged, this proceeding will be concluded.

XI. Misc. - of Regional Interest

- **203 Application: Kendall Green (EC27-8)**

On October 21, 2026, Kendall Green Energy LLC ("Kendall Green") asked for authorization for a transaction pursuant to which Forge Buyer, LLC ("Buyer") will indirectly acquire 100% of the membership interests in Franklin Holdco, which indirectly owns 100 percent of the membership interests of Kendall Green, making Kendall Green, through common upstream ownership, a Related Person to CPV Towantic and its Related Persons. CL&P requested authorization by ***January 21, 2027***. Comments on the 203 application are due on or before ***November 12, 2026***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: CMEEC/CL&P (EC26-144)**

On August 6, 2026, CL&P asked for authorization to re-purchase from the Connecticut Transmission Municipal Electric Energy Cooperative ("CTMEEC") the "M-N Segment" (a 10.2 mile section of a 345 kV line that runs from CL&P's Beseck substation in Wallingford south to CL&P's East Devon substation in Milford and various 345 kV and 115 kV "reconfigurations" around Beseck substation and certain dead-end structures within the Beseck substation, located primarily within the Wallingford, CT retail service area).[90] CL&P requested authorization by ***November 30, 2026***. Comments on the 203 application were due on or before August 27, 2026. CTMEEC filed comments urging the FERC to authorize the transaction as requested. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: NextEra/Dominion (EC26-131)**

On July 15, 2026, as supplemented on July 17, 2026, NextEra and Dominion (together, "Applicants") requested authorization for their proposed combination, following which the combined company will be owned approximately 74.5% by NextEra shareholders and 25.5% by Dominion shareholders. Applicants requested authorization by ***January 11, 2027***.

Comments and protests were filed by: Eversource, MPUC, NESCOE, PIOs, State Parties, PJM IMM, NC Elec. Membership Corp., Carolina Industrial Group for Fair Utility Rates, Old Dominion Elec. Coop., MD OPC, VA OAG, Central Electric Power Coop., and an individual citizen (C. Abboud). Comments requesting the FERC deny NextEra's application have been submitted by two U.S. Senators -- MA Senator Markey (on August 13) and CT Senator Blumenthal (Sep 2). Doc-less interventions only were filed by: ISO-NE, ISO-NE IMM, CLF, CMEEC, CT OCC, EDF, Eversource, MA AG, MOPA, NRDC, NH OCA, RI DPUC, CT AG, CT DEEP, MA DPU, ME AG, ME DOER, MPUC, RI AG, AEP, AMP, Carolina Industrial Group For Fair Utility Practices, Central Electric Power Cooperative, Corporate

[88] The Regional Entities are Midwest Reliability Organization ("MRO"), Northeast Power Coordinating Council, Inc. ("NPCC"), ReliabilityFirst Corporation ("ReliabilityFirst"), SERC Reliability Corporation ("SERC"), Texas Reliability Entity ("Texas RE"), and Western Electricity Coordinating Council ("WECC").

[89] *N. Am. Elec. Rel. Corp.*, 197 FERC ¶ 61,023 (Oct. 15, 2026) ("*NERC 2027 Budget Order*").

[90] The M-N Segment was constructed by CL&P as part of the Middletown-to-Norwalk Project, which went into service in Dec. 2008. CL&P transferred the M-N Segment portion of that Middletown-to-Norwalk Project to CTMEEC in 2011.

Energy Buyer's Association, Florida Municipal Power Agency, Maryland Office of People's Counsel, North Carolina Justice Center, City of Orangeburg (South Carolina), PJM, PJM IMM, National Rural Electric Cooperative Association ("NRECA"), Rockland Electric, South Carolina Coastal Conservation League, South Carolina Office of Regulatory Staff, Southern Alliance for Clean Energy, Tri-County Electric Cooperative, Virginia Municipal Electric Association No. 1, and Public Citizen. On October 15, 2026, Applicants answered the comments and protests filed. On October 30, 2026, the VA AG and the ISO-NE IMM answered Applicants' October 15, 2026 answer. The ISO-NE IMM's answer included additional detail regarding its suggested condition to merger approval to which Applicants appeared to have conceded (namely, an agreement to a cost-based review 'administered by the IMM, subject to existing oversight by the External Market Monitor, and ultimate review by the FERC if required,' to ensure any resource deactivation proposed by Applicants for the June 2028 through June 2033 Capacity Commitment Periods is economic on a standalone basis).

Deficiency Letter. As previously reported, on September 23, 2026, the Office of Energy Market Regulation issued a deficiency letter ("DL"), requesting Applicants provide additional information to permit processing of the application. Applicants submitted that information, including supplemental workpapers, on October 15-16, 2026. Answers to and comments on the DL were filed by EDF, the PJM IMM and the VA AG.

The Application is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Hull Street/FirstLight Power Management et. al. (EC26-110)**

On October 15, 2026, the FERC authorized a transaction pursuant to which HSE FirstLight, LLC, an entity owned by affiliates of Hull Street Energy, acquired 100% of the ownership interests in PSP FL USA LLC, which indirectly owns FirstLight Power Management LLC, FirstLight CT Housatonic LLC, FirstLight MA Hydro LLC, and Northfield Mountain LLC (the "FirstLight Companies").[91] The transaction was consummated on *November 2, 2026*. The FirstLight Companies and their generation, including the approximately 1,168 MW Northfield Mountain pumped-storage facility and hydroelectric facilities in Connecticut and Massachusetts, are now indirect wholly owned subsidiaries of Hull Street affiliates. Accordingly, FirstLight is now a Related Person and will vote together with Pawtucket Power Holdings (another Hull Street affiliate) in the Generation Sector. Pursuant to the *FirstLight/Hull Street Order*, Applicants must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Vistra/Cogentrix (Nautilus Power et al.) (EC26-63)**

As previously reported, the FERC authorized[92] on August 5, 2026, a transaction (the "Vistra/Cogentrix Transaction") pursuant to which Vistra Operations Company LLC, an indirect wholly-owned subsidiary of Vistra, acquire 100% of the voting equity interests in the Cogentrix Public Utilities (including Nautilus Power, LLC and its Related Persons[93]; collectively, the "Applicants").[94] The Vistra/Cogentrix Transaction was consummated on *October 30, 2026*. Vistra Operations Company LLC now indirectly owns and controls the Cogentrix Public Utilities, making Nautilus Power and Dynegy Marketing and Trade Related Persons, which will together have a single vote in the Generation Sector. Pursuant to the *Vistra/Cogentrix Order*, Applicants must file a notice within 10 days of

[91] *FirstLight Power Management LLC, et al.*, 197 FERC ¶ 61,025 (Oct. 15, 2026) ("*FirstLight/Hull Street 203 Order*").

[92] *Bridgeport Energy LLC, et al.*, 196 FERC ¶ 61,107 (Aug. 5, 2026) ("*Vistra/Cogentrix Order*").

[93] Nautilus Power's Related Persons include: Acadia Renewable Energy (which is not part of the 203 application), Essential Power Massachusetts, Essential Power Newington, and Revere Power.

[94] Applicants include: Bridgeport Energy LLC, Essential Power Massachusetts, LLC, Essential Power Newington, LLC, Essential Power OPP, LLC, Essential Power Rock Springs, LLC, Hamilton Liberty LLC, Hamilton Patriot LLC, Hamilton Projects Acquiror, LLC, Lakewood Cogeneration, L.P., Nautilus Power, LLC , Revere Power, LLC, Rumford Power LLC, Tiverton Power LLC, and Vistra Corp.

consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Rate Incentive: CL&P Huntsbrook Project (ER27-460)**

On November 10, 2026, CL&P requested approval of an Abandoned Plant Incentive in connection with its investment in a transmission project at the Huntsbrook Junction in eastern Connecticut ("Huntsbrook Project"), a part of the Power Up New England Project ("Power Up Project").[95] CL&P requested a January 10, 2027 effective date for the Abandoned Plant Incentive. Comments on the Abandoned Plant Incentive request are due on or before ***December 1, 2026***. Thus far, NESCOE has filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NSTAR 3-Year Software Depreciation Rate (ER27-430)**

On November 6, 2026, NSTAR proposed to establish a 3-year depreciation rate for Account 351.2 (Computer Software) because, for the first time, NSTAR has a computer software asset with a 3-year depreciable life. The depreciation rate will be set forth in NSTAR's Appendix D to Attachment F of the ISO-NE OATT and is estimated to increase NSTAR's depreciation expense by approximately ***$56,388*** over the life of the asset. Comments are due on or before ***November 27, 2026***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NSTAR (MMWEC)-HQUS Use Rights Transfer Agreement (ER26-3445)**

On October 30, 2026, the FERC accepted an Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") between NSTAR and H.Q. Energy Services (U.S.) Inc.("HQUS").[96] The Transfer Agreement reflects NSTAR's transfer of transmission capacity Use Rights previously held by the Massachusetts Municipal Wholesale Electric Company ("MMWEC") on the HQ Interconnection. The Use Rights Transfer Agreement was accepted effective October 31, 2026, as requested. Unless the October 30 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NSTAR (CMEEC)-Vitol Use Rights Transfer Agreement (ER26-3440)**

Also on October 30, 2026, the FERC accepted a Transfer Agreement that transfers CMMEC's Use Rights to Vitol.[97] The Use Rights Transfer Agreement was accepted effective October 31, 2026, as requested. Unless the October 30 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Wholesale Distribution Tariff – Rhode Island Energy (ER26-3084)**

On October 8, 2026, the FERC accepted RIE's new Wholesale Distribution Tariff ("WDT").[98] The RIE WDT provides for RIE's recovery of costs associated with the provision of Wholesale Distribution Service ("WDS") to customers who own electric energy storage systems ("ESS") connected to RIE's distribution system. The WDT allows such customers to utilize RIE's distribution system when charging their ESS for the purpose of participating in the wholesale (New England) market. The WDT was accepted effective September 1, 2026, as requested. The October 8 order was not challenged and is final an unappealable. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[95] The Huntsbrook Project is a forward-looking transmission investment designed to expand the hosting capacity of the New England transmission system and enable the interconnection of up to 2,400 MW of new generation resources, which also increases transfer capability on critical transmission interfaces in Connecticut and the New England region. The Huntsbrook Project as a key component of the Power Up New England portfolio for a federal funding award.

[96] *NSTAR Electric Co.*, Docket No. ER26-3445-000 (Oct. 30, 2026) (unpublished letter order).

[97] *NSTAR Electric Co.*, Docket No. ER26-3440-000 (Oct. 30, 2026) (unpublished letter order).

[98] *The Narragansett Electric Co.*, 197 FERC ¶ 61,016 (Oct. 8, 2026).

- **CMP ESF Rate (ER24-1177)**

On August 4, 2025, the FERC approved the settlement agreement that resolves all issues set for settlement in this proceeding,[99] effective August 4, 2025.[100] CMP was directed to make a compliance filing with revised tariff records in eTariff format on or before September 3, 2025, reflecting that effective date and the FERC's action in the Settlement Order. CMP submitted that compliance filing on September 3, 2025, with any comments due on or before September 24, 2025; none were filed. On September 15, 2025, CMP submitted a refund report confirming the $365,000 was refunded to Rumford ESS, LLC. Comments on the refund report were due on or before October 6, 2025; none were filed. The refund report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[101]

- **ISO/RTO Petition for CEII Protections Rulemaking (AD26-9; RM26-14)**

On June 3, 2026, ISO-NE and other Indicated ISOs/RTOs,[102] together with transmission-owning utilities,[103] (together, the "Petitioners") filed a petition for rulemaking requesting that the FERC consider improvements to its protections for Critical Energy/Electric Infrastructure Information ("CEII") and related sensitive electric infrastructure information. Petitioners asserted that current CEII rules generally apply to information submitted to or generated by the FERC, but do not provide uniform protections for CEII and CEII-like information exchanged among ISOs/RTOs, transmission providers, market participants, interconnection and transmission customers, consultants, and others. Petitioners cited increasing cyber threats, growing requests for CEII, and inconsistent regional requirements, and asked the FERC to convene a technical conference or other record-building proceeding and then initiate a rulemaking to consider stronger and more uniform protections. As of the date of this Report, the Petition has not been noticed for public comment and the FERC has not issued a NOPR as requested.

- **Technical Conf: PJM Governance and Stakeholder Reforms (AD26-7)**

On Thursday, ***July 23, 2026***, the FERC convened a technical conference to discuss PJM's governance and stakeholder processes, with a particular focus on identifying and evaluating concrete, actionable reforms to improve PJM's ability to address operational and market needs in a timely and efficient manner. The conference explored specific governance features and stakeholder processes in PJM that impact timely action on operational and market needs. It is noteworthy that, in comments and during the technical conference, many features of New England's governance arrangements and processes were identified as potential models for improvements. The FERC invited the filing of post-conference comments by all interested persons. Post-technical conference comments were due on or before August 21, 2026 and were filed by, among others: PJM, AEU, Capital Power, Constellation, Dominion, ENGIE, National Grid, Shell, Vitol, Public Interest Organizations,[104] and R Street.

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[99] *See Central Maine Power Co.,* 187 FERC ¶ 61,002 (Apr. 1, 2024) ("*CMP ESF Rate Order*") (accepting, subject to refund and settlement judge procedures, CMP's rate schedule for distribution services for electric storage facilities ("ESFs") seeking to participate in the ISO-NE Market ("ESF Rate")).

[100] *Central Maine Power Co.,* 192 FERC ¶ 61,110 (Aug. 4, 2025) ("*CMP ESF Rate Settlement Order*").

[101] Reporting on the following administrative and rulemaking proceedings has been suspended and will be continued if and when there is new activity to report: Annual Reliability Technical Conference (AD25-8); Tech Conf: Meeting the Challenge of Resource Adequacy in ISO/RTOs (AD25-7); Large Loads Co-Located at Generating Facilities (AD24-11); Annual Reliability Tech. Conf. (AD24-10); Innovations and Efficiencies in Generator Interconnection (AD24-9); and ANOPR: Implementation of Dynamic Line Ratings (RM24-6).

[102] The "Indicated ISO/RTO" are the Alberta Electric System Operator ("AESO"); the Independent Electricity System Operator ("IESO") of Ontario; ISO New England Inc. ("ISO-NE"); Midcontinent Independent System Operator, Inc. ("MISO"); New York Independent System Operator, Inc. ("NYISO"); and Southwest Power Pool, Inc. ("SPP").

[103] The "transmission-owning utilities" are Central Hudson Gas & Elec. Corp.; Consolidated Edison Co. of New York, Inc.; Niagara Mohawk Power Corp. d/b/a National Grid; the New York Power Authority, New York State Elec. & Gas Corp.; Orange & Rockland Utilities, Inc.; Rochester Gas & Elec., and Tucson Elec. Power Co.

[104] "Public Interest Organizations" are: RMI, Sierra Club, Earthjustice, NRDC, and Southern Environmental Law Center.

Dispute Resolution Services Forum (Sep 1-3). From September 1-3, 2026, the FERC's Director of Dispute Resolution Services ("DRS") convened a forum to facilitate interest-based discussions on proposed reforms to PJM's governance and stakeholder processes. The stated objective of the forum is to gather feedback from PJM members and stakeholders, identify areas of consensus and divergence, and evaluate actionable reforms to inform a future filing.

Preliminary Term Sheet. In its Forum notice, the FERC directed PJM to prepare preliminary governance and stakeholder process reforms focused on major themes of a July 23 FERC technical conference. PJM filed with the FERC and presented to its stakeholders on August 19 a framework of eight governance reforms to be addressed in connection with the FERC-mediated discussions ("Term Sheet"). Specific Term Sheet terms proposed by PJM include:

- Expanding PJM Section 205 filing rights to include energy and ancillary services markets and the Regional Transmission Expansion Planning protocol;
- Changing PJM's stakeholder process to advisory rather than binding voting and providing for expedited consideration of issues;
- Extending the PJM Board of Managers terms of service from three to nine years;
- Granting the Organization of PJM States, Inc. ("OPSI"), access to Section 205 filing rights on certain matters of resource adequacy subject to certain conditions including a Member vote and a reliability safety valve; and
- Adding state-appointed representatives to the Nominating Committee for the PJM Board of Managers.

PJM has also proposed a Memorandum of Understanding ("States MOU") Framework Between the PJM States and PJM, which would establish reliability and resource adequacy as shared responsibilities, and delineates wholesale and retail roles and responsibilities.

We understand that there are stakeholder-proposed alternatives to the Term Sheet and States MOU that have been prepared and are under discussion in the DRS process. PJM discussed a package of reforms at its September 24, 2026 Members Committee meeting and took action on that package of reforms at a special September 30, 2026 meeting.

- **Joint Federal-State Current Issues Collaborative[105] (AD24-7)**

2026-27 NECPUC Representatives. On August 25, 2026, NARUC provided notice of the two state commission representatives from each of the NARUC regions for the 2026-27 term.[106] The FERC issued a notice announcing those appointments on September 8, 2026. As previously reported, MPUC Commissioner Carrie Gilbert and NH PUC Commissioner Pradip Chattopadhyay were elected as NECPUC representatives.[107]

[105] *Joint Federal-State Task Force on Elec. Transmission and Federal and State Current Issues Collaborative*, 186 FERC ¶ 61,189 (Mar. 21, 2024) ("*Order Establishing Collaborative*"). The Collaborative will provide a venue for federal and state regulators to share perspectives, increase understanding, and, where appropriate, identify potential challenges and coordination on matters that impact specific state and federal regulatory jurisdiction, including (but not limited to) the following: electric reliability and resource adequacy; natural gas-electric coordination; wholesale and retail markets; new technologies and innovations; and infrastructure. The Collaborative will be comprised of all FERC Commissioners as well as representatives from 10 state commissions, who will be nominated for and serve one-year terms from the date of appointment by the FERC. The FERC will issue notices announcing the time, place and agenda for each meeting of the Collaborative, after consulting with members of the Collaborative and considering suggestions from state commissions. Collaborative meetings will be on the record, and open to the public for listening and observing. The Collaborative will expire 3 years after its first public meeting but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

[106] Commission representatives from each of the five NARUC regions serve a one-year term from the date of appointment for no more than three consecutive terms.

[107] The 2026-27 Commission representatives are: Chair Christine Guhl-Sadovy, NJ BPU and Commr. Kathryn Zerfuss, PA PUC (MACRUC); Chair Sarah Martz, IA UC and Commr. Stacey Paradis, IL CC (MARC); Commr. Carrie Gilbert, MPUC and Commr. Pradip

- ***Order 917*: Revisions to EQR Data Collection and Filing Process (RM23-9)**

On March 19, 2026, the FERC issued *Order 917* adopting revisions to the data collection and filing process requirements for Electric Quarterly Reports ("EQRs").[108] The FERC stated that the *Order 917* changes are intended to update data collection, improve data quality, increase market transparency, reduce filing costs over time, and streamline compliance with future filing changes. Among other things, *Order 917* adopts eXtensible Business Reporting Language-Comma-Separated Values ("XBRL-CSV") as the standard for EQR filings, amends the FERC's regulations to require RTOs and ISOs to produce reports containing market participant transaction data, modifies existing EQR reporting requirements, and extends the quarterly filing window to four months after the end of the quarter.[109] *Order 917* includes EQR Data Dictionary Version 4.0, which reflects the revised reporting framework and new data fields. *Order 917* became effective May 26, 2026.[110] While compliance with *Order 917* is mandatory, the actual timeline for compliance with *Order 917* remains to be seen. The FERC said that "industry participants will be afforded a reasonable amount of time to develop their software and we will make available a platform for filers to test their submissions. We plan to allow a reasonable amount of time following the technical conference process for software evaluation, development, implementation, and testing."[111]

Request for Rehearing/Clarification. A request for rehearing and/or clarification was filed on April 17, 2026 by Energy Compliance Consulting, LLC ("ECC"). On May 18, 2026, the FERC issued an *Allegheny Notice*, noting that ECC's request may be deemed denied by operation of law, but noting that the ECC's request will be addressed in a future order.[112] The FERC issued that order on July 20, 2026,[113] modifying the discussion in *Order 917*, setting aside *Order 917*, in part, and clarifying *Order 917*. Specifically, the FERC agreed with ECC's arguments regarding: (i) the definition of Transaction Identifier data field; (ii) the elimination of certain allowable reporting options for Rate Units; and (iii) the need to modify the definition of FERC Tariff Reference. The FERC provided clarification regarding: (a) the implementation for eliminating certain reporting requirements; (b) the Notes data field; (c) the Agent's role in filing EQRs; (d) the Rate Description data field; and (e) the Type of Rate data field, directing FERC Staff to discuss the Type of Rate data field at the future technical conference(s) to be held in this proceeding.

Notice of New Webpage and Staff Guidance on Initial Implementation. On May 5, 2026, the FERC issued a "Notice of New Webpage and Staff Guidance on Initial Implementation of Order No. 917", stating that "to help inform filers about how to implement the initial changes to the EQR reporting requirements set forth in Order No. 917, [FERC] staff has developed a under new webpage with filing guidance.[114] Going forward, this webpage will

Chattopadhyay, NH PUC (NECPUC); Chair Doyle Webb, AK PSC and Chairman Gabriella Passidomo Smith FL PSC and (SEARUC); and Commr. Greg Nibert, NM PRC and Chair Brian Rybarik, WA UTC (WESTERN).

[108] *Filing Process and Data Collection for the Electric Quarterly Report*, 194 FERC ¶ 61,195 (Mar. 19, 2026) ("*Order 917*").

[109] Specifically, *Order 917*: (a) Adopts a single collection method for EQR reporting based on the XBRL-CSV standard; (b) amends the FERC's regulations to extend the quarterly filing window to four months after the end of the quarter; (c) amends the FERC's regulations to require RTOs and ISOs to produce reports containing market participant transaction data in XBRL-CSV format that adheres to the FERC EQR taxonomies, which Sellers can use to prepare their EQR submissions; (d) provides the option to file data on a rolling basis before the close of the filing window; (e) retains the EQR refiling policy to require re-filings for up to 12 quarters when there are material corrections or material omissions to previously filed EQRs; (f) eliminates the requirement for Sellers to report transmission capacity reassignment information in the EQR; (g) eliminates the requirement for Sellers to identify the index price publisher(s) to which they report transactions in the EQR; (h) eliminates the requirement for Sellers to identify which exchange or broker was used to consummate transactions; (i) improves data quality and transparency by adopting new data fields and clarifies the definitions and requirements of certain data fields; and (j) streamlines the EQR filing process by eliminating certain data that Sellers must submit each quarter with their EQRs.

[110] *Order 917* was published in the *Fed. Reg.* on Mar. 24, 2026 (Vol. 91, No. 56) pp. 14,306-14,348.

[111] *Order 917* at P 39.

[112] *Filing Process and Data Collection for the Elec. Quarterly Rpt.*, 195 FERC ¶ 62,103 (May 18, 2026) ("*Order 917 Allegheny Notice*").

[113] *Filing Process and Data Collection for the Elec. Quarterly Rpt.*, 196 FERC ¶ 61,045 (July 20, 2026).

[114] The webpage is available at https://www.ferc.gov/order-917.

also help inform filers and other interested parties of future changes to the EQR filing process and reporting requirements Order No. 917." Additionally, the FERC said that "to stay up-to-date with developments in this rulemaking proceeding, you may join our contact list."

Notice of Technical Conference. On November 3, 2026, the FERC issued a notice that Staff will convene a technical conference, February 9-10, 2027, at FERC HQ. The conference will take place in hybrid format to allow both in-person and virtual attendance. Prior to the technical conference, a detailed agenda and registration information will be published in a supplemental notice in this proceeding and posted on the FERC's *Order 917* webpage.

If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **American Efficient Show Cause Order (IN24-2)**

As previously reported, the FERC issued on December 16, 2024 a show cause order[115] in which it directed American Efficient, LLC, its various subsidiary companies,[116] and its corporate parents[117] (collectively, "American Efficient") to show cause why they should not be found to have violated (i) Section 222 of the FPA and § 1c.2 of the FERC's regulations through a manipulative scheme and course of business in PJM and MISO that extracted millions of dollars in capacity payments for a purported energy efficiency project that did not actually cause reductions in energy use;[118] and (ii) provisions of MISO's and PJM's Tariffs for failure to satisfy the tariff requirements for participation as an Energy Efficiency Resource ("EER").[119] American Efficient was also directed to show cause why they should not (i) ***disgorge $2,116,057 and $250,937,821***, back to MISO and PJM, respectively (in each case plus interest); (ii) ***disgorge additional unjust profits*** received between April 2024 and the date of any future FERC order directing disgorgement back to PJM; and (iii) pay a ***$722 million*** civil penalty. American Efficient could have sought a modification of these amounts consistent with FPA § 31(d)(4).[120]

On March 17, 2025, American Efficient answered the show cause order explaining that American Efficient did not violate a tariff or commit fraud, requesting the FERC dismiss the proceeding and close its investigation without further action. OE replied to American Efficient's answer on April 15, 2025 and American Efficient subsequently responded to OE's April 15 reply, supplemented its answer with financial information, and provided

[115] *American Efficient, LLC et al.,* 189 FERC ¶ 61,196 (Dec. 16, 2024) ("*American Efficient Show Cause Order*").

[116] Affirmed Energy LLC, Wylan Energy L.L.C., Midcontinent Energy LLC, and Maple Energy LLC.

[117] Modern Energy Group LLC and MIH LLC.

[118] OE concludes that "[w]hat American Efficient passes off as energy efficiency in its capacity supply offers really is just market research. It buys sales data of energy efficient products from large retailers like The Home Depot, Lowes, and Costco and then figures out how many MWs of electricity would be saved if end-use customers installed those products and used them in accordance with predictive models. It then bids those energy savings into the capacity markets as if it caused the savings. But American Efficient does not cause the energy savings."

[119] OE's Report notes that American Efficient initially cleared 10.6 MWs (worth $518,000) in an ISO-NE Forward Capacity Auction. When American Efficient sought to expand its Program in ISO-NE from 10.6 MWs to 189 MWs, "ISO-NE and its IMM sent a series of emails and letters critiquing the Program and then disqualified the Company from expanded participation in the FCA. In one of those letters, ISO-NE explained that it never would have qualified any of American Efficient's capacity if it had understood the true nature of the Program from the beginning." Similar disqualification occurred in MISO. American Efficient expressly kept information about those disqualifications from PJM and expanded the Program in PJM. No disgorgement with respect to American Efficient's New England activity is contemplated.

[120] Under Section 31(d)(4) of the FPA, 16 U.S.C. § 823b(d)(4), the Commission may "compromise, modify, or remit, with or without conditions, any civil penalty which may be imposed . . . at any time prior to a final decision by the court of appeals . . . or by the district court."

updates on some related federal court developments, each of which it asserted weigh against rushing if not issuing a penalty order. On July 10, 2025, American Efficient filed another letter supporting its position that this "proceeding should be terminated without further action."

On November 3, 2025, American Efficient requested that the FERC conclude its Order to Show Cause proceeding by declining the Office of Enforcement and Regulatory Accounting's ("OERA") request for an Order Assessing Penalties and closing out this investigation. FERC's OERA Litigation Staff replied to the November 3 motion on November 24, 2025. On December 12, 2025, American Efficient requested that the FERC terminate this proceeding. On January 16, 2026, American Efficient requested that the FERC not issue an Order assessing a penalty before the Supreme Court has rendered a decision in *AT&T, Inc v. FCC (asserting that a decision from the Supreme Court will implicate the constitutionality of FERC's civil penalty authority)*.

Order Assessing Civil Penalties. On April 15, 2026, the FERC issued an Order Assessing Civil Penalties[121] finding that American Efficient, LLC and its various subsidiary companies violated the PJM and MISO tariffs, section 222 of the FPA, and the FERC's Anti-Manipulation Rule in connection with their energy efficiency resource program. The FERC directed American Efficient to disgorge approximately ***$410 million*** in profits and pay a civil penalty of ***$722 million*** by ***June 15, 2026***, and for PJM and MISO to submit to the FERC a proposal for the allocation of disgorgement funds to the harmed participants. American Efficient did not respond to the Order Assessing Civil Penalties.

If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

- **Rover Pipeline, LLC and Energy Transfer Partners, L.P. (CPCN Show Cause Order) (IN19-4)**

On October 30, 2026, the FERC issued an order terminating this proceeding.[122] As has been reported for quite some time, the procedural schedule in this proceeding has been suspended for more than four years.[123] In terminating the proceeding, the FERC cited the delay occasioned by the Northern District's stay and the unique circumstances of this proceeding.

- **Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)**

On November 6, 2026, the FERC approved a Stipulation and Consent Agreement ("Agreement") between the Office of Enforcement and Regulatory Accounting ("Enforcement") and Rover Pipeline, LLC ("Rover Pipeline") and Energy Transfer, LP ("Energy Transfer", and together with Rover Pipeline, "Rover").[124] The Agreement resolves Enforcement's investigation into whether Rover violated NGA section 7(e), FERC Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order[125] by: (i) intentionally including diesel fuel and other toxic substances and unapproved additives in the drilling mud during its horizontal directional drilling ("HDD") operations under the

[121] *American Efficient, LLC et. al.*, 195 FERC ¶ 61,043 (Apr. 15, 2026) ("*American Efficient Penalties Order*").

[122] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 197 FERC ¶ 61,070 (Oct. 30, 2026) ("*Order Terminating Proceeding*").

[123] On May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, FERC ALJ Joel DeJesus suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule. That stay was never lifted. On Oct. 23, 2026, Rover and the FERC jointly moved to dismiss the Northern District proceeding and on Oct. 26, 2026, the Northern District granted the motion.

[124] *Rover Pipeline, LLC and Energy Transfer Partners, L.P.*, 197 FERC ¶ 61,100 (Nov. 6, 2026).

[125] *Rover Pipeline LLC,* 158 FERC ¶ 61,109 (2017), *order on clarification & reh'g*, 161 FERC ¶ 61,244 (2017), *Petition for Rev.*, *Rover Pipeline LLC v. FERC*, No. 18-1032 (D.C. Cir. Jan. 29, 2018) ("*Certificate or Certificate Order*").

Tuscarawas River in Stark County, Ohio, in connection with the Rover Pipeline Project;[126] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. Under the Agreement, Rover agreed to pay or cause to be paid a civil penalty of ***$10 million***.

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

New England Pipeline Proceedings
The following New England pipeline projects are currently under construction or before the FERC:

- **PNGTS Facilities Increase (CP26-553)**
  - Project to increase the certificated capacity on Portland Natural Gas Transmission System's ("PNGTS") wholly-owned north system from Pittsburg, New Hampshire to Westbrook, Maine ("Northern Facilities") by 14,160 Mcf/d, and to increase the mainline certificated capacity on the system it jointly owns with Maritimes & Northeast Pipeline, L.L.C. ("MNE") from Westbrook, Maine to Dracut, Massachusetts ("Joint Facilities"), by 14,514 Mcf/d to accommodate new firm upstream deliveries at the interconnect with TransCanada Pipelines Limited in Pittsburg, New Hampshire. PNGTS said that the increase in certificated capacity does not involve any construction nor additional cost.
  - On September 22, 2026, as corrected on September 23, the MPUC submitted comments supporting the request

- **Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)**
  - Project to relocate and rebuild the Sagamore and Bourne meter and regulation ("M&R") stations to continue providing uninterrupted natural gas transportation service to National Grid to supply end users on both sides of the Cape Cod Canal. The proposed Project will not result in new or incremental capacity and is therefore not an expansion of the Algonquin system.
  - Abbreviated Application for a Certificate of Public Convenience and Necessity ("CPCN") and for Related Authorizations and Order Approving Abandonment ("Application") filed September 29, 2025. Application includes authorizations to (i) construct, install, own, operate, and maintain approximately 5.24 miles of pipeline; (ii) abandon by removal approximately 0.75 miles of existing pipeline; (iii) abandon by removal 2 existing M&R stations; and (iv) construct, install, own, operate, and maintain 4 new M&R stations.
  - On October 29, 2026, the FERC issued a certificate of public convenience and necessity to Algonquin authorizing it to abandon its existing facilities and to construct its Cape Cod Canal Project, subject to: (i) completion of the proposed facilities and making them available on or before October 29, 2029; (ii) compliance with all applicable regulations under the Natural Gas Act; and (iii) compliance with the environmental conditions appended to the order.[127]

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).

[126] The Rover Pipeline Project is an approximately 711-mile-long interstate natural gas pipeline designed to transport gas from the Marcellus and Utica shale supply areas through West Virginia, Pennsylvania, Ohio, and Michigan to outlets in the Midwest and elsewhere.

[127] *Algonquin Gas Transmission, LLC*, 197 FERC ¶ 61,063 (Oct. 29, 2026) ("*Algonquin Cape Cod Canal Certificate Order*").

- On February 19, 2025, the FERC granted a requested two-year extension of time, to March 25, 2027, to construct the project and place it into service.[128]
- Three-year construction project; service now requested for ***March 25, 2029***.
- On August 14, 2026, as supplemented on August 21 and 27 and September 4, 2026, Iroquois requested authorization to proceed with construction of natural gas compression and gas cooling facilities at three existing compressor stations on Iroquois' system (the Athens, Dover, and Milford Compressor Stations in Greene and Dutchess Counties, New York, and New Haven County, Connecticut) as part of the ExC Project. Comments opposing (D. Myers, Sierra Club, Save the Sound, and K. (not T.) Swift) and supporting (National Grid, ConEd) the request were filed.
- On September 23, 2026, Iroquois was granted the requested permission to proceed by the Chief, Gas Branch 1 Division of Gas – Environment and Engineering, FERC Office of Energy Projects.
- On October 29, 2026, Iroquois requested an extension of time until March 25, 2029, to complete the construction of its ExC Project and place the ExC Project facilities into service, citing permitting delays outside of its control for its Brookfield, CT Compressor Station. Comments on Iroquois' request are due on or before ***November 24, 2026***.

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Offshore Wind Orders Challenge (26-1910)**
  Case Title: State of New York et al. v. U.S. Dept. of Interior et al.
  Underlying Proceeding: BOEM/DOI lease cancellation and settlement
  Status: Briefing underway

On June 2, 2026, New York, New Jersey, Connecticut, Maine, Massachusetts, Rhode Island, and Vermont (the "States") filed a complaint in the U.S. District Court for the District of Columbia challenging the U.S. Department of the Interior's cancellation of BOEM Lease No. OCS-A 0538 and the related settlement agreement between the U.S. and Attentive Energy LLC. The Complaint seeks declaratory relief, vacatur of the lease cancellation and settlement agreement, and temporary, preliminary, and permanent injunctive relief. The New England plaintiff states allege that cancellation of the lease could affect New England by constraining NYISO's ability to export power to ISO-NE. A Standing Order was entered on June 4, 2026. On August 6, the Court granted the parties' joint request for leave to file an amended complaint and to revise the briefing schedule. On August 14, 2026, the States filed an amended complaint asking the Court to overturn the lease cancellation on grounds it is arbitrary and capricious, contrary to law and procedurally defective, and overturn the settlement agreement on grounds it is unlawful, as well as require the federal government to comply with OCSLA. On September 29, 2026, the parties jointly requested a revised scheduling order after the States received consent to file a second amended complaint adding new constitutional and statutory claims and revising existing claims. The Court granted the request, vacating the August 6 scheduling order, and set the following schedule: the States' second amended

[128] *Iroquois Gas Transmission System, L.P.*, 190 FERC ¶ 61,112 (Feb. 19, 2025).

complaint was filed on October 2, 2026; Defendants' responses are due ***December 11, 2026***; the States' responses to any motions are due ***February 5, 2027***; and Defendants' replies are due ***March 5, 2027***. The Court also granted the parties' request for additional briefing pages.

- ***Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (5th Circuit – 25-60055 et al.) (consolidated)**
  Case Title: Leeward *v. FERC*
  Underlying FERC Proceeding: RM22-22[129]
  Status: Briefing Complete; Oral Argument Held; Awaiting Decision

Appeals of *Order 904* have been transferred to and consolidated in the 5th Circuit Court of Appeals, with 25-60055 as the lead docket. A briefing schedule was established on November 18, 2025 following the filing of a certified list in lieu of the administrative record, triggering the following specific dates for the approved briefing schedule: (Procedural Motions (December 2, 2025); Petitioners' Briefs (February 19, 2026); FERC's Brief (April 17, 2026); Response Brief Intervenors in Support of FERC (May 1, 2026); Petitioners' Reply Briefs (July 6, 2026; updated from June 1, 2026); Deferred Joint Appendix (June 8, 2026); and Final Briefs (June 15, 2026)). The FERC filed its appellee brief on May 20, 2026; a joint Respondent-Intervenors brief was filed in support of FERC, by MISO TOs, PJM, certain state consumer advocate offices, among others. The Court deemed the intervenor brief deadline satisfied and updated Petitioners' reply brief deadline to July 6, 2026. The Court received the required paper copies of the parties' briefs. On October 3, 2026, the Court granted Petitioners' unopposed request for additional oral argument time and to divide argument among three groups of Petitioners. On October 30, 2026, the FERC filed a FRAP 28(j) letter identifying supplemental authority, and certain Petitioners responded on November 2, 2026. Oral argument was held on November 4, 2026. This matter is now pending a decision by the Court.

- ***Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)**
  Case Title: *Appalachian Voices v. FERC*
  Underlying FERC Proceeding: RM21-17[130]
  Status: Briefing Completed; Oral Argument Held; Pending Court Decision

As previously reported, on July 18, 2024, AEU/ACPA/SEIA and Invenergy petitioned the DC Circuit Court of Appeals for review of the FERC's *Order 1920*.[131] Petitions were also filed in the First, Second, Fourth, Fifth, Sixth, Seventh, Ninth, and Eleventh Circuits. The Judicial Panel on Multidistrict Litigation randomly selected the Fourth Circuit as the Circuit in which to consolidate the petitions for review. The DC Circuit ordered that its cases be transferred to the 4th Circuit. The 4th Circuit lead case no. is 24-1650. On August 26, 2024, the 4th Circuit granted the FERC's motion to hold the petitions for review in abeyance. On September 10, 2025, Appalachian Voice et al submitted their opening brief. FERC's opening brief was filed on January 5, 2026. Intervenor briefs and amicus curiae briefs were filed on February 6, 2026, and a motion to reconsider the order granting filing of amicus curiae briefs was filed February 9, 2026. Petitioners' and Intervenors' reply briefs were filed February 25, 2026. On March 4, 2026, the Fourth Circuit extended by two days the deadline for submission of the Joint Appendix (from March 4, 2026 to March 6, 2026) and final briefs from (March 11, 2026 to March 13, 2026). The Joint Appendix was filed on March 6, 2026. On March 13, 2026, final briefs were filed, including the respondent's brief, petitioners' and intervenors' final briefs, and *amicus curiae* briefs, including one filed by the Commonwealth of Massachusetts. On August 4, the FERC submitted supplemental authority under Rule 28(j) referencing and attaching the D.C. Circuit's decision issued on July 31, 2026 upholding Order 2023.[132] On August 7, the FERC submitted a consent motion scheduling oral argument for September 15, 2026 with proposed oral argument

[129] *Compensation for Reactive Power Within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (Oct. 17, 2024).

[130] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*"); *Constellation Mystic Power, LLC*, 186 FERC ¶ 62,048 (Feb. 5, 2024) ("*Second CapEx Info Filing Order Allegheny Notice*").

[131] Petitioners for review of *Order 1920* have also been filed in the 1st, 4th, 5th, and 9th Circuits.

[132] *Advanced Energy United v. FERC*, No. 23-1282 (D.C. Cir. July 31, 2026) (denying petitions for review).

format in all consolidated appeal dockets.[133] Also on August 7, Clean Air Task Force, Earthjustice, NRDC, Sierra Club, Southern Enviro Law Center, and Invenergy submitted supplemental authority and response to the FERC's August 4 letter. On August 21, the Court set the consolidated appeals' oral argument for September 15, 2026 and limited the argument times to 60 minutes per side with a directive to adjust proposals accordingly. As directed, the FERC resubmitted its proposal, and the Court accepted it on August 31, 2026. On September 15, 2026, the Court heard oral argument. This matter is now pending a decision by the Court.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Case Title: *Sierra Club, et al. v. FERC*
  Underlying FERC Proceeding: ER18-619[134]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance; Fifth Abeyance Request Filed Mar 2, 2026

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance now five times, with the most recent request filed March 2, 2026. The Court granted Petitioners' request, on March 18, 2026, to hold the case in abeyance; and the Court amended its order, on March 19, 2026, to clarify that motions to govern future proceedings are due by ***April 3, 2028***.

- ***Opinion 531-A* Compliance Filing Undo / *Opinion 594* Petitions for Review (20-1329, 26-1150, 26-1123, 26-1173) (consolidated)**
  Case Title: *Central Maine Power Co., et al. v. FERC*
  Underlying FERC Proceeding: ER15-414[135] **and EL11-66, et. al.**
  Petitioners: TOs (CMP et al.)
  Status: Briefing Underway

On August 28, 2020, the TOs[136] petitioned the DC Circuit Court of Appeals for review of the FERC's October 6, 2017 order rejecting the TOs' filing that sought to reinstate their transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[137] decision. As previously reported, this case has been held in abeyance since On October 2, 2020.

On May 18, 2026, NETOs filed a petition in case no. 26-1123 seeking review of *Opinion 594*. The Court held 26-1123 in abeyance and consolidated it with case 20-1329 on May 21, 2026. On June 5, 2026, NETOs filed a separate petition for review in case no. 26-1150 seeking review of *Opinion 594* and the FERC's May 21, 2026 Allegheny Notice (*see* Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64), Section II above). On June 8, 2026, the Court consolidated this case with case nos. 20-1329 and 26-1123 and directed Petitioners to file a

[133] In this case, the consolidated dockets are the following: 24-1650, 24-1748, 24-1756, 24-1758, 24-1760, 24-1765, 24-1770, 24-1785, 24-1804, 24-1857, 24-1862, 24-1867, 24-1876, 24-1885, 24-1887, 24-1979, 24-1991, 24-2162, 24-2163, 25-1073, 25-1080, 25-1197, 25-1349.

[134] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

[135] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

[136] The "TOs" are CMP; Eversource Energy Service Co., on behalf of its affiliates CL&P, NSTAR and PSNH; National Grid; New Hampshire Transmission; UI; Unitil and Fitchburg; VTransco; and Versant Power.

[137] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

docketing statement and statement of issues in case 26-1150 by July 8, 2026. Petitioners filed that docketing statement on July 8, 2026.

On June 15, Petitioners moved to stay *Opinion 594*'s refund obligations. That motion was opposed by the FERC and by a group comprised of the CT PURA, MA AGO, NHEC, MMWEC, MA DPU, CT AG, NH DOE, NH OCA, RI AG and RI DPUC. On July 23, Petitioners filed a 120-day status report. The Court granted the Respondent's unopposed motion for extension of time to respond to the June 15, 2026 motion to stay until July 15, 2026; the Court granted the motions to intervene by CT OCC, CT PURA, and CT AG's Office and separately, granted a motion to intervene by various New England state entities and public utilities.[138] On August 28, 2026, the Court denied the motion to stay in No. 26-1150, and ordered Nos. 20-1329, 26-1123, and 26-1173 be returned to the Court's active docket, and ordered the respondent file the certified index to the record by September 28, 2026. On September 28, 2026, Petitioners submitted an unopposed motion on proposed briefing format for the consolidated cases. On October 19, 2026, the Court established a briefing schedule for the consolidated cases: Petitioners' opening briefs are due ***November 13, 2026***; the FERC's brief is due ***February 11, 2027***; Intervenors' brief in support of the FERC is due ***March 4, 2027***; Petitioners' reply briefs are due ***March 19, 2027***; the deferred appendix is due ***March 26, 2027***; and final briefs are due ***April 2, 2027***. On November 3, 2026, Vermont Transco moved without opposition to voluntarily dismiss its petition in No. 26-1173.

- ***Avangrid/NextEra NECEC Civil Suit*** **(D.MA) (Case No. 3:24CV30141)**
  Case Title: ***Avangrid, Inc. et al. v. NextEra Energy, Inc. et al.***
  Status: Federal Anti-Trust Claims Dismissed; State Law Claims Remain Pending

On November 12, 2024, Avangrid sued NextEra in US District Court for the District of Massachusetts ("D.MA") claiming NextEra's illegal use political and regulatory channels to delay or prevent Avangrid from obtaining the approvals needed to construct the NECEC project resulted in damages in excess of $350 million. Specifically, Avangrid alleged NextEra violations of US (Sherman Act) and MA Anti-Trust laws (alleging actual, attempted, and conspiracy to monopolize the markets) (the "Anti-Trust Claims"), as well as state law violations related to NextEra's: (i) conspiracy with others (to perpetuate an attack campaign based on false and misleading claims against NECEC using dark money in violation of campaign finance law, and to intervene without basis in NECEC's permitting process for unlawful purpose), (ii) intentional interference with CMP contracts, (iii) unjust enrichment; and (iv) unfair business practices (together the "State Law Claims").

On September 22, 2025, the presiding US District Judge, Mark Mastroianni, dismissed Avangrid's Antitrust Claims, noting that NextEra's motion to dismiss as to the State Law Claims remains under advisement. On October 6, 2025, Avangrid and NextEra submitted a joint request for a second oral argument to cover the remaining claims after the September 22 order, and Avangrid submitted an unopposed request for a status conference to discuss how to seek relief from the monopolizations claims in the September 22 order (either by seeking leave to amend or request for an appeal). A status conference was scheduled for and held on October 16, 2025. A hearing on NextEra's motion to dismiss the State Law Claims was held on December 18, 2025 and an official transcript was filed. On November 11, 2026, Avangrid moved for a status conference; and NextEra opposed the request the same day. The State Law Claims remain pending before the Court.

[138] The motions for leave to intervene were filed by: MOPA, Taunton Municipal Lighting Plant, Concord Municipal Light Plant, Pascoag Utility District, Reading Municipal Light Department, Middleborough Gas, Electric Department, Braintree Electric Light Department, Hingham Municipal Lighting Plant, Belmont Municipal Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Middleton Electric Light Department, Rowley Municipal Lighting Plant, Wellesley Municipal Light Plant, Norwood Municipal Light Department, Littleton Electric Light & Water Department, NHEC, MA DPU, NH OCA, RI DPUC, MA AGO, NH DOE, RI AG's Office, Green Mountain Power Corporation, and MMWEC.

- **Allco PURPA Enforcement Petition (D.CT) (Case No. 3:25CV01321)**
  Case Title: *Allco Finance Limited Inc. v. Dykes et al.*
  Status: Private Defendants Dismissed; Reconsideration and Amendment Motions Pending; State Agency Defendants' Motion to Dismiss Pending

Following a FERC notice[139] that it had decided not to act on Allco's PURPA Complaint related to Connecticut's[140] implementation under section 210 of PURPA of its Shared Clean Energy Facility ("SCEF") Program,[141] Allco brought an enforcement action against Connecticut in federal district court in Connecticut.[142] *Allco Finance Limited Inc. v. Dykes et al.* (case no. 3:25CV01321). On November 24, 2025, Defendants[143] filed a motion to dismiss the Complaint and stay discovery. DEEP Commissioner, Katie S. Dykes, PURA Commissioners, David Arconti, Michael Caron, and Marissa Gillett,[144] and DOAG Commissioner, Bryan P. Hurlburt, (the "State Agency Defendants") also filed a joint motion to dismiss the Complaint; and on December 9, 2025, Allco filed a memo in opposition to the motion to dismiss filed by the Defendants and the State Agency Defendants. On December 23, 2025, a motion to dismiss the complaint was filed by the Defendants and a joint motion to dismiss was filed by the State Agency Defendants. On January 7, 2026, the Court granted the unopposed Motions to Stay Discovery by the State Agency Defendants and Defendants, respectively, pending the resolution of the Defendants Motions to Dismiss. On March 31, 2026, the State Agency Defendants filed a notice of supplemental authority in support of their joint motion to dismiss. On April 13, 2026, Allco responded to the State Agency Defendants' notice of supplemental authority and filed a petition for rehearing or rehearing *en banc*. On August 31, 2026, the Defendants submitted supplemental authority relevant to their pending motion to dismiss citing the July 9, 2026 Connecticut Superior Court's decision.[145] On September 29, 2026, the Court granted the Private Defendants' motion to dismiss. The State Agency Defendants' motion to dismiss remains pending. On October 6, 2026, Allco moved for reconsideration of the September 29 dismissal order, and on October 7, 2026, Allco moved to amend its Complaint. The Private Defendants and State Agency Defendants opposed the motion to amend on October 28, 2026, and Allco filed replies to both oppositions on November 11, 2026. The Court scheduled oral argument on the State Agency Defendants' motion to dismiss for ***November 18, 2026***.

- **RENEW Northeast, et. al. APA Challenge (D. Mass. – Case No. 1:25CV13961)**
  Case Title: *Renew Northeast, et al. v. U.S. Department of Interior, et al.*
  Status: Preliminary Injunction granted; Summary judgement briefing scheduled

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[139] *Allco Finance Limited*, 192 FERC ¶ 61,116 (Aug. 4, 2025).

[140] For purposes of this proceeding, "Connecticut" is the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), Connecticut Public Utilities Regulatory Authority ("CT PURA"), and the Connecticut Department of Agriculture ("CT DoA").

[141] Allco asserted that CT is improperly implementing PURPA by requiring the following criteria for participation in the Shared Clean Energy Facility ("SCEF") program: (i) that no more than 10% of the project site contains slopes greater than 15%; (ii) that separate QFs on the same parcel cannot receive a contract even when the total of the two QFs is less than 5MWs; (iii) documentation of "community outreach and engagement" regarding the bid for a contract; (iv) restrictions related to "Prime Farmland" location; (v) a QF cannot have been constructed or started construction; (vi) a workforce development program, and for certain projects a community benefits agreement; (vii) a contract that includes renewable energy credits; and (viii) a bidder must bear costs related to a utility's voluntarily seeking to re-sell the QF's energy in the ISO-NE market, if the utility chooses not to use the energy to supply its own customers. Allco argues that the criteria are neither objective nor reasonable and are unrelated to a QF's commercial viability or financial commitment. Allco further contends that some of CT's SCEF program requirements violate its constitutional rights. Allco also states that bids it submitted in 2024 and 2025 were rejected on the basis of these unlawful requirements.

[142] 16 U.S.C. § 824a-3(h)(2)(B).

[143] Defendants are UI, Avangrid Networks, Inc., Avangrid, Iberdrola, S.A., Charlotte Ancel, and Pedro Azagra Blázquez.

[144] Marissa Gillett resigned her position as chair of PURA, effective Oct. 10, 2025.

[145] *Allco Finance Ltd. v. PURA*, No. HHB-CV-25-6095406-S (Conn. Super. Ct. July 9, 2026) (dismissing Allco's appeal).

On December 23, 2025, RENEW Northeast and several other clean energy trade associations[146] filed suit against certain federal agencies[147] challenging the agencies' actions affecting wind and solar project permitting. Plaintiffs alleged that the challenged agency actions concerning wind and solar development, which followed federal executive actions including the January 20, 2025 Presidential Memorandum temporarily withdrawing outer continental shelf areas from offshore wind permitting and Executive Order 14315 directing the DOI to eliminate preferential treatment for wind and solar resources, violated the Administrative Procedure Act (5 U.S.C. §§ 551 *et seq.*).

On January 12, 2026, Plaintiffs filed an amended complaint, adding Green Energy Consumers Alliance ("GECA") as a plaintiff, and moved for a preliminary injunction. Plaintiffs sought to enjoin five agency actions: (1) DOI's review procedures memorandum for wind and solar actions; (2) USFWS's restriction on wind and solar projects' use of the IPaC database; (3) DOI's "capacity density" Land Order; (4) the Army Corps' memorandum prioritizing permit applications for higher-capacity-density projects; and (5) DOI's Zerzan M-Opinion concerning OCSLA § 8(p)(4). Defendants opposed the preliminary injunction motion on February 10, 2026, and the Court held a hearing on March 4, 2026. On March 16, 2026, Defendants moved to dismiss the amended complaint; Plaintiffs opposed that motion on March 24, 2026. On April 21, 2026, the Court granted Plaintiffs' motion for a preliminary injunction as to the five agency actions, with respect to GECA and the Regional Organization Plaintiffs' members.

On June 16, 2026, finding that Plaintiffs are likely to succeed on the merits of their claims, the Court allowed Plaintiffs' Motion for a Preliminary Injunction. Accordingly, Defendants are enjoined from implementing (1) the DOI Review Procedures Memo or otherwise taking any steps to require agency action related to wind and solar energy facilities to be submitted to the Office of the Executive Secretariat and Regulatory Affairs, subsequently reviewed by the Office of the Deputy Secretary and finally reviewed by the Office of the Secretary as a prerequisite of said action; (2) the Wind and Solar IPaC Ban or otherwise taking any action to prevent solar and wind projects from utilizing the Information for Planning and Consultation website based upon completion of the review procedure outlined DOI Review Procedures Memo; (3) Defendants are enjoined from implementing § 4 of the DOI Land Order or otherwise taking any action to limit permitting of energy projects based on a project's comparative "capacity density"; (4) § 4(c) of the Corps' Memo or otherwise taking any action to prioritize processing Clean Water Act and Rivers and Harbor Act permit applications based on whether a project would generate the most annual potential energy generation per acre over projects with low potential generation per acre; and (5) the Zerzan M-Opinion (M-Opinion 37086) or otherwise taking any action to treat M-Opinion 37059 as binding and authoritative or to re-evaluate agency action taken in reliance upon M-Opinion 37067.

On July 30, 2026, Defendants responded to the Amended Complaint for Declaratory and Injunctive Relief. On September 14, 2026, the parties filed a joint statement and proposed schedule for the scheduling conference. On September 21, 2026, the Court held the virtual scheduling conference and adopted the parties' proposed schedule for production of the administrative record and summary judgment briefing. The administrative record is due ***November 20, 2026***, and any motions concerning the record are due ***January 15, 2027***. Plaintiffs' motion for summary judgment is due ***January 22, 2027***; Defendants' cross-motion and opposition are due ***March 5, 2027***; Plaintiffs' opposition is due ***April 16, 2027***; and Defendants' reply is due ***May 7, 2027***. The Court scheduled a hearing on the summary judgment motions for ***June 9, 2027***.

[146] Plaintiffs include: RENEW Northeast, Mid-Atlantic Renewable Energy Coalition Action, Alliance for Clean Energy New York, Renewable Northwest, Southern Renewable Energy Association, Interwest Energy Alliance, Clean Grid Alliance, Carolinas Clean Energy Business Association, and the Green Energy Consumers Alliance, Inc. (added in the subsequent amended complaint).

[147] Defendants include: Department of Interior ("DOI"), Bureau of Land Management, Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, U.S. Fish and Wildlife Service ("USFWS"), U.S. Army Corps of Engineers ("Army Corp"), and related federal officials.

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Admin Matters

Nov 12, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee