

November 25, 2025

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of December 4, 2025 Participants Committee Annual Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the 2025 Annual Meeting of the Participants Committee will be held **in person on Thursday, December 4, 2025, at 10:00 a.m. in Boston, MA at the Colonnade Hotel (120 Huntington Avenue)** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. Please note the following:

- **Holiday Breakfast:** A holiday breakfast, providing attendees with an opportunity to begin the day by sharing a few moments of the holiday season, will begin at 9:00 a.m., one hour before the meeting begins.
- **Sector Changes:** Participants wishing to change Sector membership for 2026 must provide us with written notice of that request before the Annual Meeting. Under Section 6.3 of the NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective at the first annual meeting following that request.

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**).

Immediately following the meeting, there will be an Appreciation Luncheon for Gordon van Welie in the Boston Ballroom (one floor up from the Huntington Ballroom and front desk). Please plan on a little extra time for that luncheon, which will include remarks on Gordon's time and efforts steering the region these past 25 years. Those who have not yet RSVPed are asked to urgently do so; all will be asked to express a plated lunch entrée preference.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the November 6, 2025 Participants Committee meeting. A copy of the draft minutes are included with this supplemental notice and posted with the meeting materials.
2. [There is no Consent Agenda for this meeting.]
3. To receive remarks from Commissioner David Rosner, Federal Energy Regulatory Commission.
4. To receive an ISO Chief Executive Officer report. The December CEO report is included with this supplemental notice and posted with the meeting materials.
5. To receive an ISO Chief Operating Officer report. The December COO Report will be circulated and posted in advance of the meeting.
6. To receive the 2025 NEPOOL Annual Report.
7. To elect NEPOOL Participants Committee Officers for 2026. A draft resolution reflecting the outcome of the balloting for Participants Committee Chair, as well as candidates for Secretary and Assistant Secretary, is included with this supplemental notice and posted with the meeting materials.
8. To adopt a NEPOOL Budget for 2026. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.
9. To consider and take action, as appropriate, on changes to the Financial Assurance Policy to align more accurately the timing of Financial Assurance obligations with the duration of the associated payment risks. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.
10. To consider and take action, as appropriate, on Capacity Auction Reforms – Prompt/Deactivation (CAR-PD)-related Tariff changes to:
 - a. Section I.2.2 (Definitions) and Section III (Market Rule 1), including new Section III.15 and reflecting NEPGA’s Amendment, Tariff Section I.2.2, Market Rule 1, including new Section III.15 and NEPGA’s Amendment, as well as Sections II.52-55 of the Open Access Transmission Tariff (OATT), all as recommended by the **Markets Committee**;
 - b. Sections I.2.2 and Section III.12 (Calculation of Capacity Requirements) of the Tariff, all as recommended by the **Reliability Committee**; and
 - c. Sections I.2.2, I.3.9 (Review of Market Participant’s Proposed Plans), OATT Sections II.22 (Operating Arrangements), II.48 (Interconnection Service Capabilities), II.52-55 (Deactivation), and to OATT Attachments K (Regional System Planning Process) and N (Procedures for Regional System Plan Upgrades), and Schedule 16 (Blackstart Service), all as recommended by the **Transmission Committee**.

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

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.

Final Agenda (cont.)

11. To consider, and take action, as appropriate, on a proposed NEPOOL Policy Statement regarding GIS Waiver Requests. A final version of that Policy Statement (along with a redlined version marked to show the changes made to the draft discussed at the November 6 meeting) and a draft resolution are included with this supplemental notice and posted with the meeting materials.
12. 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.
13. To receive reports from Committees, Subcommittees and other working groups:
 - Markets Committee
 - Reliability Committee
 - Transmission Committee
 - Budget & Finance Subcommittee
 - Membership Subcommittee
 - Joint Nominating Committee
 - Others
14. Administrative matters.
15. To transact such other business as may properly come before the meeting.

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November 6, 2025 Minutes



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RESOLVED, that the Participants Committee approves the preliminary minutes of the November 6, 2025 meeting, as circulated in advance of this meeting, with additional non-material clarifications, as the final minutes of the November 6, 2025 meeting.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 2:00 p.m. on Thursday, November 6, 2025 at the Hilton Boston Logan Airport Hotel, in Boston, MA. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by Webex.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates, ISO and State officials, and guests who were present.

APPROVAL OF OCTOBER 9, 2025 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the October 9, 2025 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 in advance of the meeting, with an abstention by Mr. Jon Lamson noted.

CONSENT AGENDA

Ms. Bresolin then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved, with oppositions by CSC, HQUS, and LIPA, and abstentions by BP, DTE, Galt, Mercuria, Calpine, Emera Energy Services, the Generation Bridge Companies, Nautilus, Wheelabrator, and Mr. Lamson noted. The oppositions, as well as most of the abstentions, were specifically attributed to the HQICC and/or the ICR and Related Values for the

Annual Reconfiguration Auctions (ARAs) for the 2026-27 and 2027-28 Capacity Commitment Periods (Consent Agenda Items 3 and 4). Further explaining their votes, the representative for a number of those abstaining explained that, notwithstanding the fact that the values appeared to have been calculated in accordance with the Tariff's formulas, the resulting tie benefits number embedded in the values were, in their view, unreasonably high and produced an illogical outcome. The representatives for CSC and LIPA stated that their oppositions stemmed from their long-standing objections to the ISO's determination that the Cross-Sound Cable has no capacity import capability into New England, disregarding what they asserted is the project's demonstrated reliability benefits to Connecticut and the region, particularly through the procurement of emergency energy over the facility.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the relatively short November CEO Report, which had been circulated and posted with the materials for the meeting. There were no questions or comments on that summary.

ISO COO REPORT

Operations Report

Dr. Vamsi Chadavalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his November operations report, which had been circulated and posted in advance of the meeting. Dr. Chadavalavada noted that the data in the report was through October 29, 2025, unless otherwise noted. The November report highlighted: (i) that the Peak Hour for October, with 15,935 MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on October 6, 2025 during the hour ending 7:00 p.m.; (ii) October averages

for Day-Ahead Hub LMP (\$33.38/MWh), Real-Time Hub LMP (\$40.38/MWh), and natural gas prices (\$2.31/MMBtu); (iii) Energy Market value for October 2025 was \$429 million, up from \$350 million in October 2024 and up from the updated September 2025 Energy Market value of \$358 million; (iv) Ancillary Services Markets value (\$16.9 million) was up from October 2024 (\$8 million); (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 98.3% during October (down from 98.6% reported for September 2025); (vi) Daily Net Commitment Period Compensation (NCPC) payments for October totaled \$2.4 million (representing just 0.6% of October's monthly Energy Market value), comprised of (a) \$2.4 million in First Contingency payments (including \$414,000 in Dispatch Lost Opportunity Costs, \$250,000 in Rapid Response Pricing Opportunity Costs, and \$64,000 paid to resources at external locations), (b) \$18,000 in Second Contingency and no voltage or distribution payments; and (vii) a Forward Capacity Market (FCM) value of \$88.8 million.

Referring to questions asked previously and off-line, Dr. Chadalavada reported that, through the end of October 2025, New England had experienced 122 "duck curve days" (when demand during the middle of the day is lower than it is in the evening), compared to 89 through the same period in 2024. He noted also that, for the first time in 13 years, the region had a monthly net export (exporting approximately 102 GWh of electricity to Hydro-Québec and New York, with the vast majority of those exports going to New York). With respect to outages, Dr. Chadalavada said that, other than the usual forced and planned outages across the generation fleet, there was nothing noteworthy to report.

Addressing Day-Ahead Ancillary Service (DAAS) market costs, Dr. Chadalavada explained that October's higher Forecasted Energy Requirement (FER) costs were the result of reduced supply (due to between 6-8 GWh of planned maintenance outages and 2-3.5 GWh of forced outages) and the resulting reduced number of DAAS offered into the market. He cautioned members against viewing the higher FER costs in isolation, noting that because of co-optimization, higher Day-Ahead FER costs resulted in lower Day-Ahead LMPs. He noted that there would be an opportunity for further analysis and discussion with the Internal Market Monitor on the results of the DAAS market at the December Markets Committee meeting.

Dr. Chadalavada reported on the results of the recent transitional Capacity Network Resource (CNR) Group Study that closed on November 3. He said that 64 resources qualified (34 generation; 30 Demand Response resources) totaling approximately 1,450 MW of Summer Qualified Capacity.

2025/26 Winter Outlook

Dr. Chadalavada highlighted that the results of the Winter 2025/26 Energy Analysis, which showed that there was minimal risk that the REST criteria (a shortfall magnitude exceeding 3% and a shortfall duration exceeding 18 hours) would be violated. He said that the ISO's Winter 2025-26 evaluation showed a shortfall magnitude of 0.1% and shortfall duration of 0.7 hours, far short of a potential violation. Notwithstanding, he noted a low probability and worst-case risk that, due to a confluence of adverse conditions (low supplies of liquefied natural gas (LNG) and fuel oil, a low level of imports and a high level of forced outages), the maximum 21-day energy shortfall could be approximately 168,000 MWh (or roughly 2% of the total 21-day energy demand). If faced with that scenario, he explained that the energy shortfall was likely to begin on day 14 or later in the 21-day period, would be spread out over four to five

days, and would thus allow for plenty of lead time for additional Participant actions (including expediting delivery of LNG or oil supplies, or the sourcing of gas supplies) and ISO preventative actions (including reducing exports and/or scheduling additional imports, generator posturing, seeking waivers of emissions or air permit limitations, and coordinated conservation appeals). In response, some members expressed a continuing unease with scenarios in which the region nears the REST threshold and reiterated requests for continuing discussion on this topic.

In response to questions on system-wide usable heavy oil inventory, Dr. Chadalavada confirmed that the drop in maximum available inventory (roughly 30 million gallons as of June 1) was attributable to the fact that a unit with on-site heavy oil storage was no longer reflected in the calculations.

ORDER 898 COMPLIANCE REVISIONS

Mr. Nick Gangi, Transmission Committee (TC) Chair, referred the Committee to the materials circulated in advance of the meeting regarding proposed revisions to Appendix A (Transmission Formula Rate Template) to OATT Attachment F (Annual Transmission Revenue Requirements) in response to the requirements of FERC *Order 898* (Accounting and Reporting Treatment of Certain Renewable Energy Assets) (the *Order 898* Compliance Revisions). Mr. Gangi explained that the *Order 898* Compliance Revisions would accommodate new FERC plant accounts and provide references that would better align with FERC Forms 1 and 3-Q. He explained that the *Order 898* Compliance Revisions were unanimously supported by the Transmission Committee at its October 28, 2025 meeting.

Without discussion, the following motion was duly made, seconded, and approved unanimously, with an abstention by Mr. Lamson:

RESOLVED, that the Participants Committee supports the Order 898 Revisions, as recommended by the Transmission Committee and as circulated to the Participants Committee in advance of its November 6, 2025, meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

REFERRAL TO GIS WORKING GROUP: FURTHER DISCUSSION ON GIS ACCOUNT-LINKING ENHANCEMENT

Ms. Bresolin referred the Committee to the materials circulated in advance of the meeting regarding a proposed enhancement to the NEPOOL Generation Information System (GIS) and the GIS Operating Rules that would allow a single GIS login to be linked to and access multiple GIS accounts. She reported that although the Markets Committee had recommended Participants Committee approval of the requested enhancement, there had been an expressed desire by some Participants for further discussion on the matter before final Participants Committee action. She noted that the original proponent of this GIS Rule change did not oppose that request. Accordingly, she asked that the motion directing the GIS Operating Rules Working Group to reconvene for further discussion on this GIS proposal be moved for Committee action.

Without discussion, the following motion was duly made, seconded, and approved unanimously, with abstentions by the AR Sector's Large Renewable Generation (RG) Group Member, Eversource, Harvard, and Mr. Lamson:

RESOLVED, that the Participants Committee refers to the NEPOOL Generation Information System (GIS) Operating Rules Working Group for further consideration of the request by Vistra Corp. to change the NEPOOL GIS to allow a NEPOOL GIS login to be linked and have access to multiple NEPOOL accounts and to report back to this Committee on the outcome of that consideration.

PROPOSED NEPOOL POLICY STATEMENT: GIS WAIVER REQUESTS

Referring the Committee to the draft policy statement regarding GIS waiver requests (Policy Statement) circulated and posted with the meeting materials, Mr. Lombardi provided context describing the impetus for, the intent and essence of, and welcomed questions and feedback on, the draft Policy Statement. He noted that, while no action was being sought at this meeting, the goal was to consider and take action as appropriate on the Policy Statement at a subsequent Participants Committee meeting, preferably the December 4 Annual Meeting.

In response to questions, Mr. Lombardi explained that the purpose of the Policy Statement is to provide a policy framework for how NEPOOL will, as a process matter, address any future requests for waiver of the GIS Operating Rules and GIS Administration Agreement. He said that the Policy Statement was designed to reinforce predictability and fairness in the administration of GIS Operating Rules, while appropriately deferring to the States' jurisdiction in the area of Renewable Portfolio Standard (RPS) compliance. As a general rule, the Policy Statement clarifies that NEPOOL will not formally consider GIS waiver requests going forward unless two conditions were satisfied, namely that (1) the requesting party has formally sought relief from, and received a determination by, the relevant state regulatory authority and (2) the relevant state regulatory body has expressly indicated support for NEPOOL's review and consideration of the matter. He noted that establishing this general policy protocol would preserve NEPOOL's intended limited role and would avoid substituting NEPOOL's judgement for that of the relevant state authority. Mr. Lombardi emphasized that GIS Account Holders and State regulators could, and would still be encouraged to, address GIS Certificate-related issues outside of the NEPOOL process where and as appropriate.

In response to Participant questions and comments, Mr. Lombardi provided further clarification and thanked members for their comments and suggested clarifications. Those expressing support believed that the Policy Statement would provide clarity of approach and would minimize the efforts involved both for the Committee and for those seeking relief through a waiver of the GIS Rules. One member emphasized that, notwithstanding sympathy around the NEPOOL table for some of the situations underlying prior waiver requests, it is, as a process matter, more appropriately the role of the States, and not NEPOOL, to review and adjudicate those situations, consistent with both rate payer interests and state policy goals. Mr. Lombardi re-emphasized that the draft Policy Statement was consistent with that view.. Others, expressing appreciation for the work done, offered potential clarifications to the Policy Statement.

Concluding the discussion, Ms. Bresolin reminded the Committee that action on the Policy Statement would be taken at a subsequent Participants Committee meeting, likely at the December Annual Meeting, and a revised Policy Statement, with adjustments reflecting comments and questions received, would be circulated with the materials for such meeting.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the November 5, 2025 Litigation Report that had been circulated and posted before the meeting. He highlighted the following two items: (1) that Ms. Laura Swett and Mr. David LaCerte had been sworn in as the new Chair and a Commissioner, respectively, of the FERC; and (2) that the FERC had invited comments on a U.S. Department of Energy-proposed Advance Notice of Proposed Rulemaking (ANOPR) concerning standardized procedures for the interconnection of large loads to the interstate transmission system. He reported that certain state organizations had requested and supported an extension of the initial comment deadline on the proposed ANOPR and recommended

Participants interested in submitting comments to be on the lookout for a FERC order addressing that request and potentially granted additional time to comment (and to submit reply comments). He encouraged those with questions on these or any matter in the Litigation Report to reach out to NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee (MC). On behalf of Mr. Ben Griffiths, MC Vice-Chair, Ms. Bresolin reported that the next MC meeting would be on November 12-13, 2025 at the DoubleTree Hotel in Westborough, MA. The MC would vote on the first day on the Capacity Auction Reform's (CAR) prompt market design and related deactivation changes (CAR-PD) and would on the second day discuss seasonal accreditation under the CAR project (CAR-SA).

Reliability Committee. For Mr. Bob Stein, RC Vice-Chair, Ms. Bresolin reported that the next RC meeting would be held on November 18, 2025 at the DoubleTree Hotel in Westborough, MA. She said that the RC would vote on the elements of CAR-PD under its purview, as well as discuss passive Demand Response, Active Demand Capacity Resource Modeling (ADCR) and accreditation and seasonal tie benefits modeling.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the next TC meeting would be held virtually on November 20, 2025. He said that the TC would vote on the elements of the CAR-PD proposal under its purview and further discuss the ISO's proposed *Order 2023*-related changes to formalize equivalent Capacity Network Resource Capability (CNRC) for resources not subject to ISO Interconnection Procedures.

Budget & Finance Subcommittee (B&F). For Mr. Tom Kaslow, B&F Chair, Ms. Bresolin reported that the next B&F meeting was scheduled for November 14, at which the B&F

would receive its usual reports and consider the proposed 2026 NEPOOL Budget as well as ISO-proposed updates to the Financial Assurance Policy.

Membership Subcommittee. Mr. Brad Swalwell, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held by Zoom on November 10, 2025. He encouraged all those interested to participate and to reach out to him or NEPOOL Counsel for the Zoom information.

Joint Nominating Committee (JNC). Ms. Bresolin indicated that the JNC process would kick-off following the December Annual Participants Committee meeting, and would include a search for a proposed new Board member to replace Mr. Brook Colangelo, whose third and final three-year term on the ISO Board of Directors would be completed at the end of September 2026. ISO Board members, Messrs. Craig Ivey and Mark Vannoy, would each be eligible for election to a third and final three-year term.

ADMINISTRATIVE MATTERS

On behalf of NECPUC and NESCOE, Mr. George Twigg, NECPUC Executive Director, thanked Participants for the opportunity to meet with the Sectors earlier that day, as well as for the thoughtfulness of the preparatory materials provided in connection with those meetings, which the State Officials found contributed to a productive and informative dialogue.

Mr. Lombardi reported that the December Participants Committee Annual Meeting would be held at the Colonnade Hotel in Boston, MA. The Annual Meeting would be preceded by the traditional holiday breakfast, would include remarks by FERC Commissioner David Rosner and a vote on CAR-PD, and would be followed by a luncheon of appreciation for Mr.

van Welie upon the occasion of his retirement as the ISO's CEO. Ms. Bresolin encouraged all members to attend that luncheon and to RSVP when requested.

There being no other business, the meeting adjourned at 2:57 pm.

Respectfully submitted,

Sebastian Lombardi, Secretary

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE NOVEMBER 6, 2025 MEETING**

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Assoc. Non-Voting		Alex Lawton	
AR Large RG Group Member	AR-RG	Aidan Foley		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
AVANGRID (CMP/UI)	Transmission	Alan Trotta	Jason Rauch	
Bath Iron Works	End User		Howard Plante	Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity	Dave Cavanaugh		
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Clear River Electric	Publicly Owned Entity		Dave Cavanaugh	
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield (W)		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (W)		
Connecticut Office of Consumer Counsel	End User	Claire Coleman	Jamie Talbert-Slagle	
Conservation Law Foundation	End User	Phelps Turner		
Constellation Energy Generation (Constellation)	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Earthjustice	End User	Christine Powell (W)	Ada Statler (W)	
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Andy Gillespie		Bill Fowler
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Gabel Associates, Inc.	Supplier	Sarah Yasutake		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (W)	
Garland Manufacturing Company	End User		Howard Plante	Bill Short
Generation Bridge Companies	Generation		Steve Kirk	Bill Fowler
Generation Group Member	Generation		Abby Krich (W)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Granite Shore Companies	Generation			Bob Stein
Grid United LLC	Provisional Member	Mike Spector		
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault (W)	Bob Stein	
Hammond Lumber Company	End User		Howard Plante	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	
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy

(W) = Webex

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PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Icetec Energy Services, LLC	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (W)	
Lamson, Jon	End User	Jon Lamson (W)		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Kilgoar (W)	
Maine Power LLC	Supplier	Jeff Jones (W)		
Maine Public Advocate's Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihle		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network (MCAN)	End User			Abby Krich (W)
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	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	
Midcoast Regional Redevelopment Authority	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User		Howard Plante	Bill Short
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tm Brennan	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (W)
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
PowerOptions, Inc.	End User		Zach Gray-Traverso	Doug Hurley
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RENEW Northeast, Inc.	Assoc. Non-Voting	Francis Pullaro		
Rhode Island Division (RI DPUC)	End User	Linda George		
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	Dan Murphy
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User		Howard Plante	Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Tangent Energy	AR-LR	Brad Swalwell		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	

(W) = Webex

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PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Union of Concerned Scientists	End User	Susan Muller (W)		
Vermont Electric Company	Transmission	Frank Ettori		
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		
Vistra (Dynegy Marketing and Trade, Inc.)	Supplier	Ryan McCarthy		Bill Fowler
Vitol Inc.	Supplier	Seth Cochran (W)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User			Bill Short

3

FERC Commissioner David Rosner Remarks

REPORT

**Sworn In**

June 17, 2024

Term Expires

June 30, 2027

David Rosner joined FERC as a Commissioner in June 2024. He served as Chairman from August 13, 2025, until October 23, 2025. Rosner has nearly two decades of experience across energy technologies, market design and energy policy issues, both in and outside of government. Prior to his service as a Commissioner, he was an energy industry analyst for FERC and spent two years on detail to the U.S. Senate Energy and Natural Resources Committee staff. During his time as a staff member at FERC, he led efforts related to the Commission's work on electric transmission, fuel security, energy storage resources, and natural gas-electric coordination.

Commissioner Rosner was previously a senior policy advisor for the U.S. Department of Energy's Office of Energy Policy and Systems Analysis and an associate director at the Bipartisan Policy Center's energy project. He holds master's degrees in economics and public policy from American University and a Bachelor of Arts degree in economics from Tufts University.

Commissioner Rosner resides in the Washington, DC area, with his family.



Sworn In

June 17, 2024

Term Expires

June 30, 2027

Contact

Telephone: [202-502-6500](tel:202-502-6500)

[Request a Meeting](#) →

Staff

C.J. OSMAN

Senior Advisor

RICHARD LEHFELDT

Legal Advisor

HENRY ENGELSTEIN

Legal Advisor

ROBERT FARES

Technical Advisor

ARIELLE SCHWARTZ

Technical Advisor

ALEXANDER DE TABOADA

Special Advisor

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Commissioner Rosner resides in the Washington, DC area, with his family.

This page was last updated on October 24, 2025

4

CEO Report



Dec 4, 2025
Meeting

Summary of ISO New England Board and Committee Meetings

December 4, 2025 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee each met on November 4. The Board of Directors met on November 4 and 5. All of the meetings were held in Boston, Massachusetts.

The Audit and Finance Committee began with an executive session to review the proposed corporate goals for 2026. The Committee then continued in regular session with an annual update on the availability of an internet- and telephone-based tool for anonymously reporting compliance issues. The Committee was provided with a report on current budget performance, along with an update on interest rates. The Committee reviewed and approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. The Committee reviewed a proposal for financing the purchase and construction of an additional facility at Whiting Farms Road, and after considering the financing options, the impact on consumers (which should be negligible given the pay-off of the Company's debt related to the Windsor facility) and management's proposed approach of obtaining tax-exempt debt, agreed to recommend resolutions for the Board's approval. Next, the Committee met with representatives of KPMG, the Company's external auditors, to discuss the scope and preliminary results of the 2025 System and Organization Controls Report and resulting unqualified audit opinion. KPMG also provided an overview of work plans and timing for the financial statements audit. The Committee met with KPMG in executive session to ensure that the auditors had the opportunity to make any necessary reports without management present. Next, the Committee received a report on the 2024 Benefit Plan Audits results from Meyers Brothers Kalicka, the Company's external benefit plan auditor. The Committee then received a report on internal audit activities. The Committee also met with the Company's Market and Credit Risk Department regarding the risk of Market Participant defaults. The Committee then undertook its biennial review of its charter to confirm the Committee's compliance with the charter's terms and assess whether any revisions are necessary. Finally, the Committee reviewed its calendar for the upcoming year.

The Compensation and Human Resources Committee discussed key dates and deliverables for 2026 goal setting and conducting the corporate performance review for 2025. The Committee also received a report on employee compliance with the Code of Conduct following the annual collection of certificates. Next, the Committee reviewed its calendar for the upcoming year, and discussed opportunities for employee outreach. During an executive session, the Committee discussed executive compensation benchmarking reviews prepared by Mercer, the Company's compensation consultant.

The Markets Committee was provided with a summary of market performance for the 2025 summer season from the internal and external market monitors, including Pay for Performance scarcity events, and noted highlights of a six-month review of the Day-Ahead Ancillary Services market. The Committee received an update on the Capacity

Auctions Reforms project including stakeholder and regulatory updates, and an overview of the proposed capacity accreditation process. The Committee discussed proposed changes to the agreement with Potomac Economics as the Company extends the current agreement with the External Market Monitor for another three-year period, and reviewed its calendar for the upcoming year. Following that discussion, the Committee held an executive session to consider the proposed corporate goals for 2026.

The Nominating and Governance Committee discussed the 2026 Joint Nominating Committee process, the candidate profile, and conversations with members of the Board about the incumbents who are eligible for re-election. Next, the Committee discussed possible site visits and potential guest speakers for the Board in 2026 as part of the Board's continuing education program. The Committee then reviewed its calendar for the upcoming year and held an executive session.

The System Planning and Reliability Committee reviewed the winter operations outlook for the 2025/2026 season. The Committee also reviewed key operations and planning metrics, as well as reliability standards compliance. The Committee received updates on various operations and planning activities, including longer-term transmission planning RFP responses, compliance with the Federal Energy Regulatory Commission's Order No. 2023, including the transitional cluster study, and winter preparedness. The Committee was provided with a preview of major activities through the end of 2025 and early 2026. The Committee also reviewed its calendar for the upcoming year, and received an update on the development of an Asset Condition Reviewer. Finally, the Committee held an executive session to discuss the proposed corporate goals for 2026.

The Board of Directors convened in executive session to receive a report from the Compensation and Human Resources Committee. Following the executive session, the Board received the report of the CEO, including an update on achievement of corporate goals to date, the Department of Energy's proposed rulemaking on large load growth, and changes at the Federal Energy Regulatory Commission. In addition, the Board recognized Robert Ludlow and Gordon van Welie upon their upcoming retirements, and congratulated both. The Board received reports from the standing committees, and reviewed its calendar for the next year.

The next day, the Board reconvened and prepared for its meetings with the NEPOOL sectors and the states, as well as the annual open meeting/Regional System Plan public meeting of the Board. Separately, the Board then met with the NEPOOL sectors and the states, and conducted its open meeting.

5

COO Report



NEPOOL Participants Committee Report

December 2025



Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

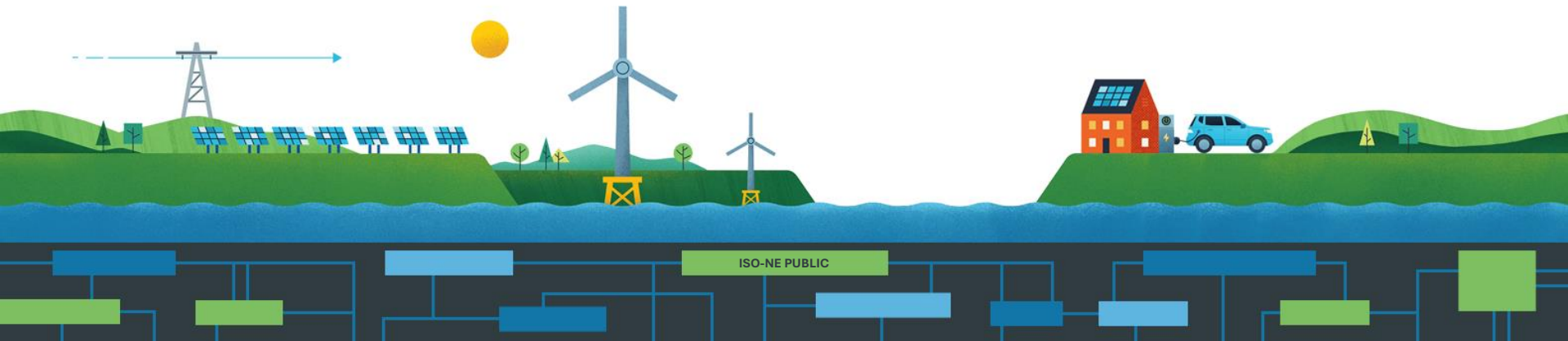
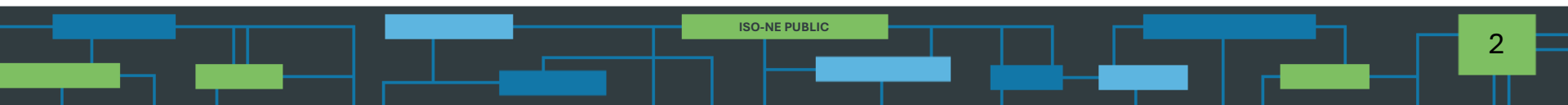


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Regular Operations Report - Highlights



Highlights: November 2025

Settled data through November 24th

- **Peak Hour** on November 17
 - 16,526 MW system peak (Revenue Quality Metered/RQM); hour ending 6:00 P.M.
- **Minimum Telemetered Load**
 - 7,998 MW; hour ending 12:00 P.M. on Sunday, November 2
- **Average Pricing**
 - Day-Ahead (DA) Hub Locational Marginal Price (LMP): \$58.65/MWh
 - Real-Time (RT) Hub LMP: \$61.88/MWh
 - Natural Gas: \$4.16/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value \$572M up from \$410M in November 2024
 - Ancillary Markets* value \$15.9M, up from \$6.2M in November 2024
 - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 98.9% during November, up from 98.2% during October
 - Updated October Energy Market value: \$468M
- **Net Commitment Period Compensation (NCPC)** total \$3.1M
 - Represents 0.5% of monthly Energy Market value
 - First Contingency \$3.1M
 - Dispatch Lost Opportunity Cost (DLOC) - \$426K; Rapid Response Pricing (RRP) Opportunity Cost - \$373K; Posturing - \$0; Generator Performance Auditing (GPA) - \$525K
 - \$346K paid to resources at external locations, up \$273K from October
 - \$47K charged to Day-Ahead Load Obligation (DALO) at external locations; \$292K to Day-Ahead Generation Obligation (DAGO) at external locations; \$7K to RT Deviations
 - 2nd Contingency, Distribution and Voltage was zero
- **Forward Capacity Market (FCM)** market value \$88.8M
 - FCM peak observed in 2025 is currently 26,086 MWh
 - **OP-4 and Capacity Scarcity Conditions (CSC) occurred on November 23**

Underlying natural gas data furnished by:

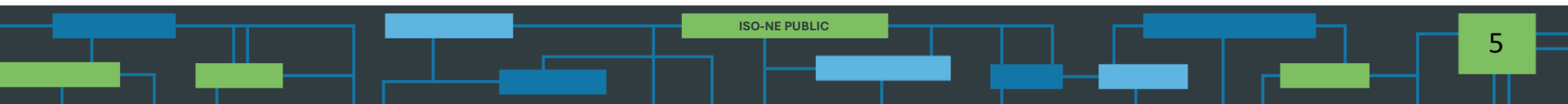


*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund **DA cleared physical energy is the sum of generation, DRR, and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **26,024 MW**
 - hour ending 7:00 P.M. on Tuesday, June 24
- RQM System Peak Load: **26,586 MW**
 - hour ending 6:00 P.M. on Tuesday, June 24
- FCM Peak Load: **26,086 MW**
 - hour ending 7:00 P.M. on Tuesday, June 24
 - At this hour, the capacity zone-level FCM peak loads were 3,357 MW in Northern New England, 2,026 MW in Maine, 9,920 MW in Rest-of-Pool, and 10,783 MW in Southeast New England.

*Telemetered loads are as reported by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SOG). Due to the difference in calculation methodologies and the impact of SOGs, these values can occur on different days and/or hours. Both are 'net energy for load' concepts and include transmission losses. FCM load values reflect the sum of active, normal load assets that are non-dispatchable, are included in the FCM settlement and do not include transmission losses.



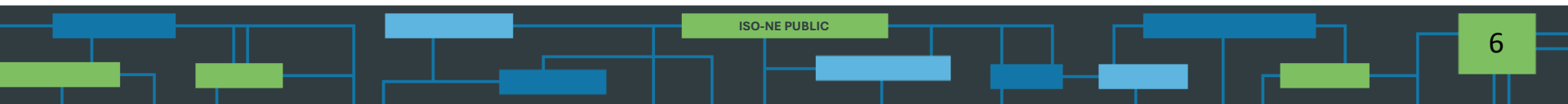
Day-Ahead Ancillary Services (DAAS) Results

- Average daily total DA E&AS Market value: **\$24.6M**
- DAAS Settlements:
 - Average daily Gross (pre-closeout) DAAS Credits: **\$1.15M**
 - Includes EIR, TMOR, TMNSR, and TMOR
 - Net (post-closeout) DAAS Credits per MWh Cleared: **\$6.91/MWh**
 - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **1.6%**
- FER Credits* as % of total DA E&AS Market Value: **10.8%**
- Energy Gap:
 - Average hourly cleared EIR MWh: **132 MWh**
 - Average hourly cleared FER Price: **\$8.22/MWh**

DA E&AS refers to DA Energy and Ancillary Services

*FER credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR)

FER credits are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)



DAAS Results (continued)...

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
3/1/2025	\$17.3M	\$466K	\$202K	\$3.35	1.2%	\$982K	177K	\$3.26	6.2%	176
4/1/2025	\$13.9M	\$332K	\$175K	\$3.23	1.3%	\$760K	128K	\$2.66	5.8%	97
5/1/2025	\$11.0M	\$190K	\$52K	\$0.94	0.5%	\$563K	164K	\$2.06	5.2%	155
6/1/2025	\$20.2M	\$885K	\$173K	\$2.97	0.9%	\$1,287K	156K	\$3.15	6.6%	125
7/1/2025	\$35.8M	\$1,704K	\$1,139K	\$19.53	3.2%	\$1,277K	97K	\$3.06	3.7%	55
8/1/2025	\$20.2M	\$747K	\$544K	\$9.57	2.7%	\$1,292K	143K	\$3.02	6.4%	94
9/1/2025	\$12.3M	\$320K	\$184K	\$3.21	1.5%	\$587K	134K	\$1.94	4.8%	104
10/1/2025	\$15.5M	\$719K	\$478K	\$8.21	3.1%	\$1,911K	203K	\$6.50	12.3%	209
11/1/2025	\$24.6M	\$1,154K	\$402K	\$6.91	1.6%	\$2,664K	205K	\$8.22	10.8%	132

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
- Data prior to August (denoted by the line) may not match settlement quality data provided in the Monthly Market Report

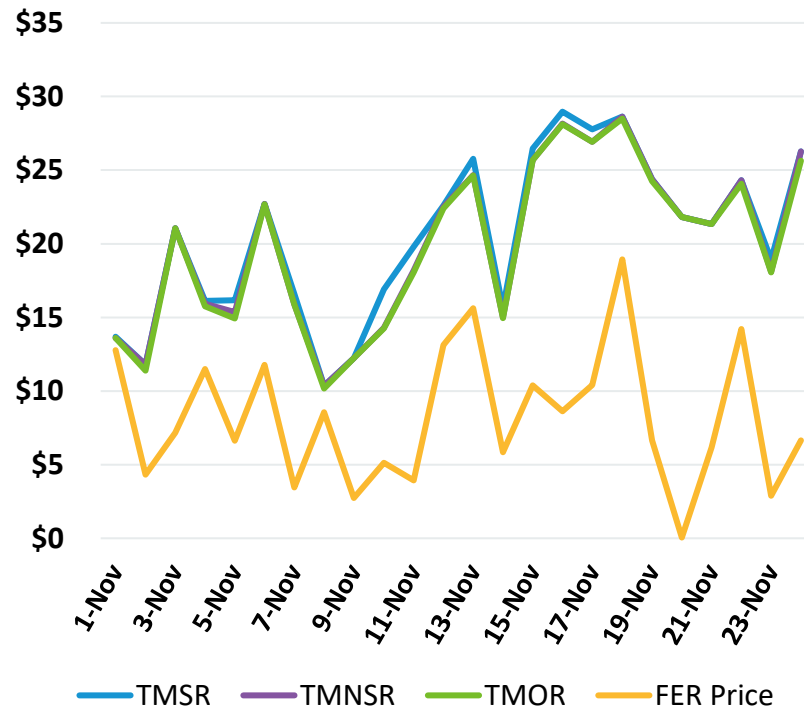
Additionally:

- FER Credits are included in the Monthly Market Report (see Section 7.1.1) found on the ISO Website [here](#). Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

Average Hourly DAAS Prices

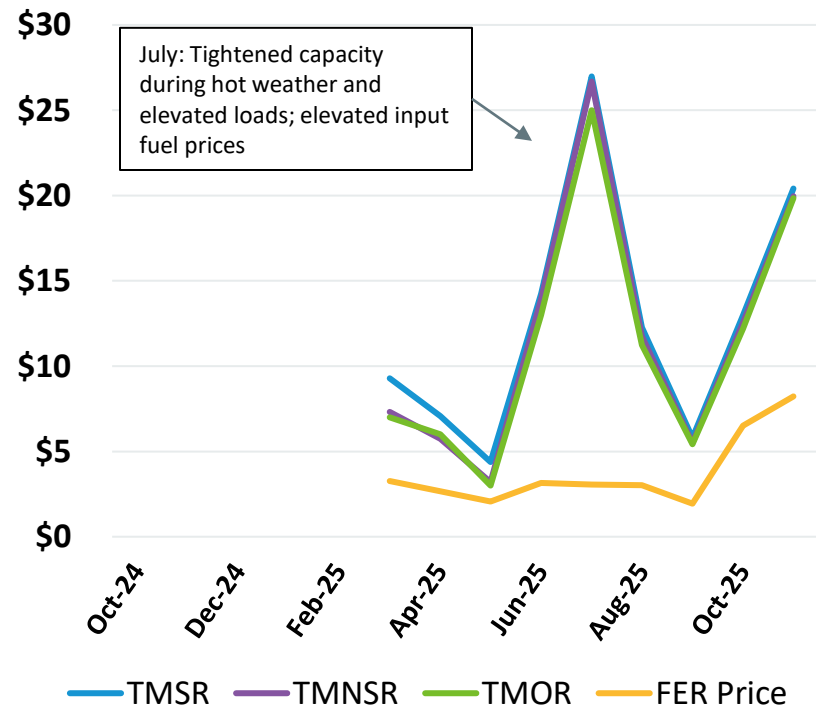
Daily This Month

\$/MWh



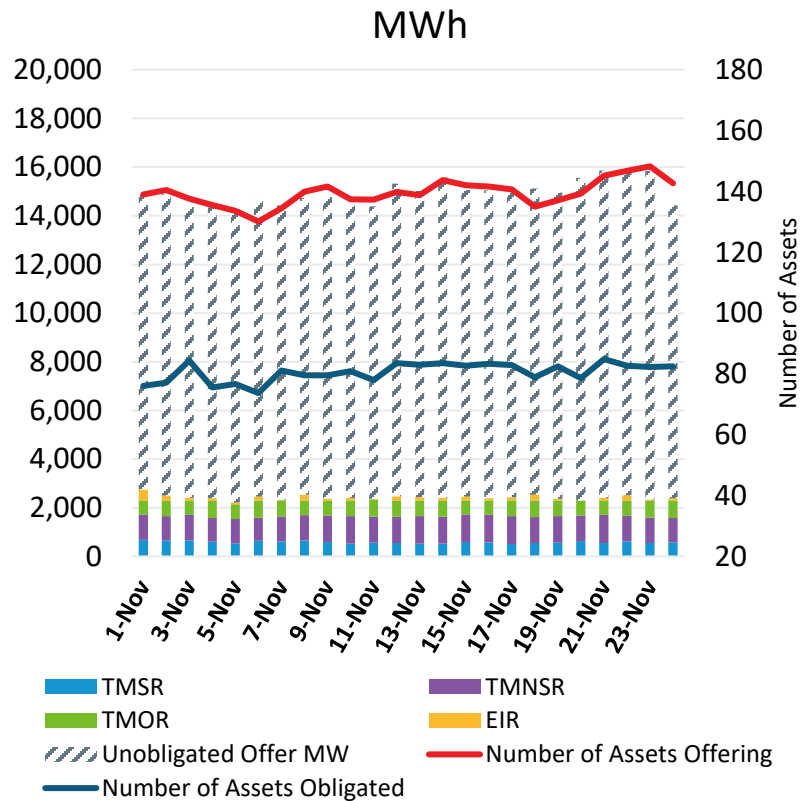
Monthly, Last 13 Months

\$/MWh

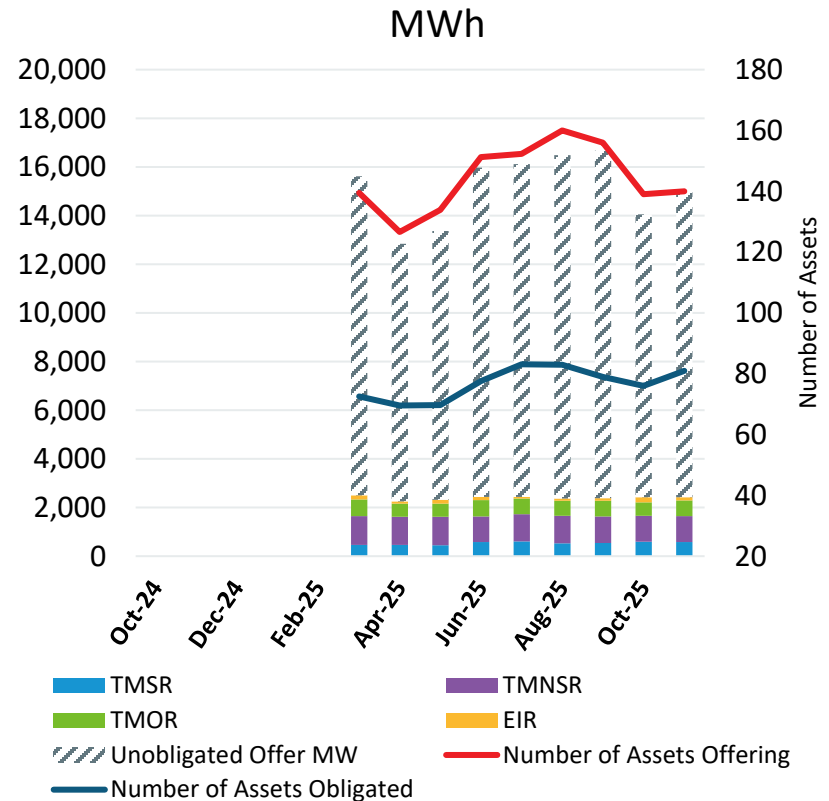


Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



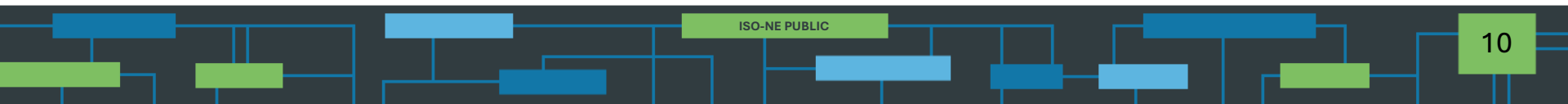
Monthly, Last 13 Months



*Unobligated Offer MWh reflect the raw, as-offered DAAS MW amounts that remained unobligated (received no MW reward). This supply does not consider additional unit parameter or dispatch constraints and should not be equated with actual capacity available in the dispatch solution.

Highlights

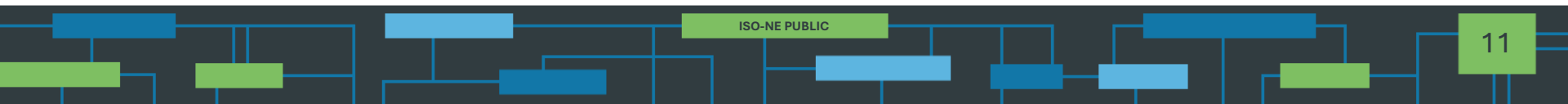
- The ISO is evaluating all LTTP RFP submissions and expects to provide an update on the initial review of proposals in late 2025/early 2026
- The 2026 forecast cycle formally began in September
- Stakeholder discussions related to CELT 2026 will continue at the next Load Forecast Committee on December 12



Forward Capacity Market (FCM) Highlights

- CCP 16 (2025-2026)
 - The third annual reconfiguration auction (ARA3) was held March 3-5 and results were posted on April 1
- CCP 17 (2026-2027)
 - The second annual reconfiguration auction (ARA2) was held August 1-5 and results were posted on September 2
 - The ISO filed the ICR and related values for the ARA3 to be conducted in 2026 with FERC on November 21, with a requested effective date of January 21, 2026
- CCP 18 (2027-2028)
 - The first annual reconfiguration auction (ARA1) was held June 2-4 and results were posted on July 2
 - The ISO filed the ICR and related values for the ARA2 to be conducted in 2026 with FERC on November 21, with a requested effective date of January 21, 2026

CCP – Capacity Commitment Period



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
 - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

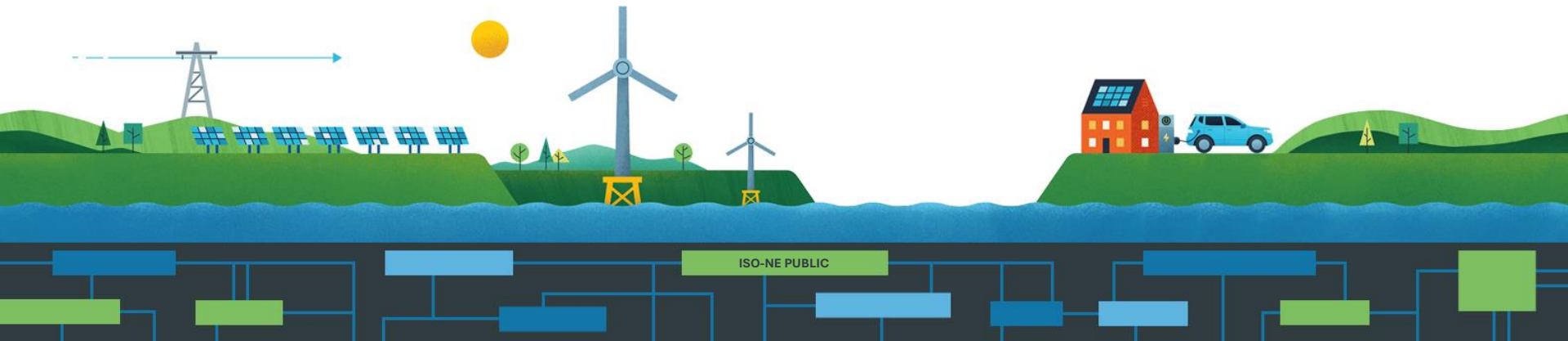
DECEMBER 4, 2025 | NEPOOL PARTICIPANTS COMMITTEE

November 23 OP-4 Event and Capacity Scarcity Condition



Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT & CHIEF OPERATING OFFICER



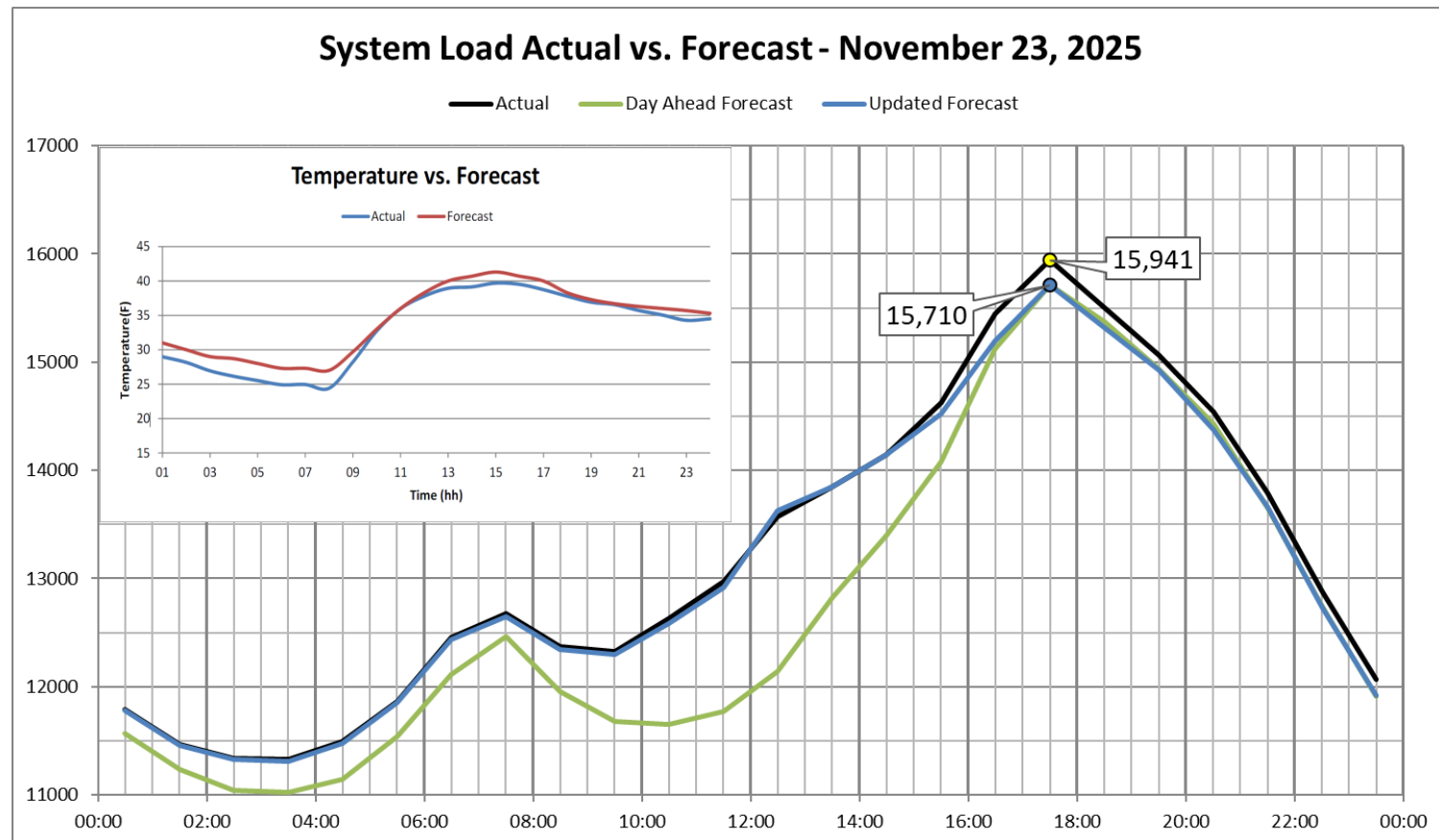
OP-4 and Capacity Scarcity Condition

Sunday, November 23, 2025

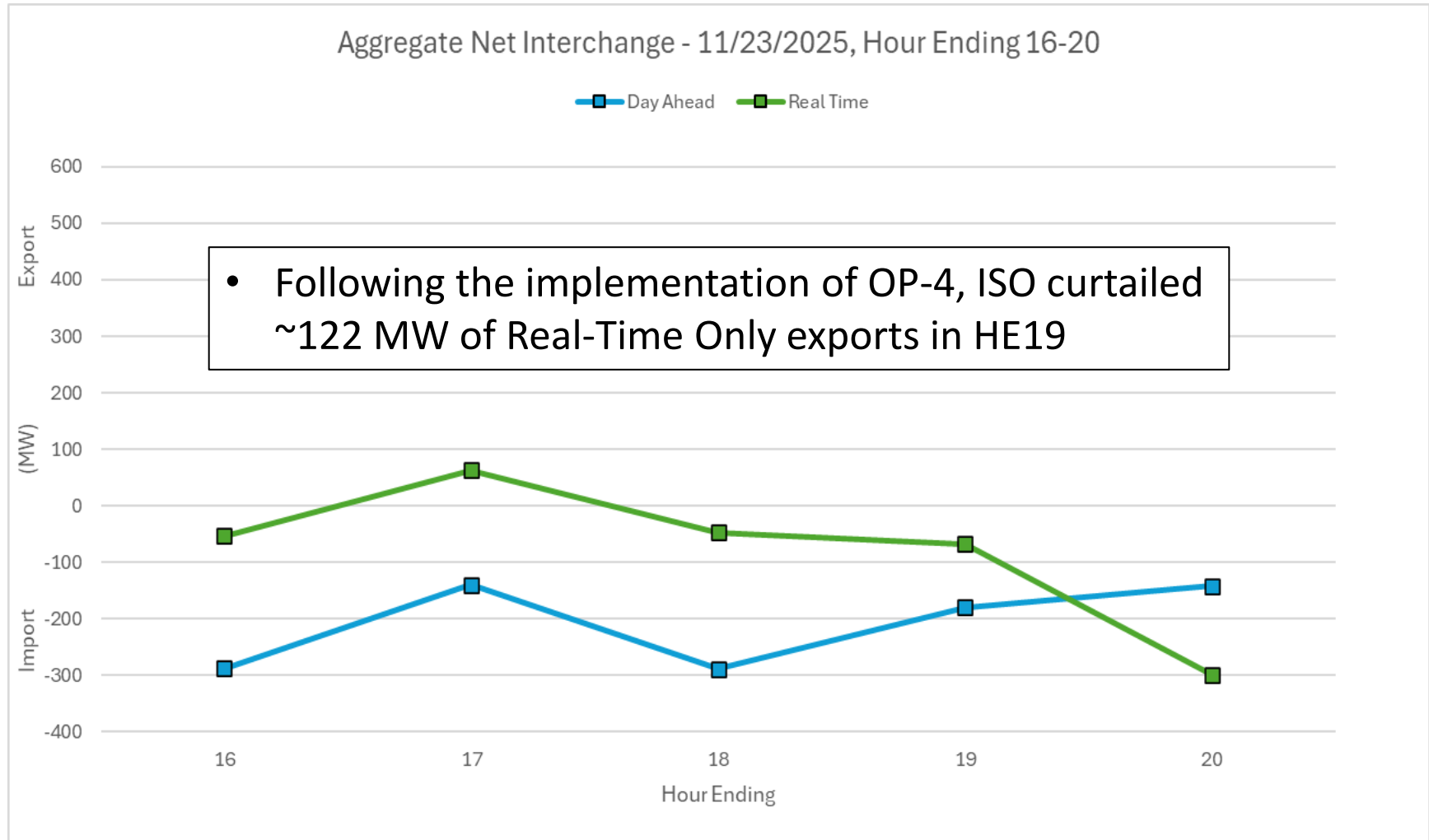
- ISO's November 23, 2025, [Operational Capacity Update Report](#) (published at noon) estimated a peak hour capacity margin of 958 MW based on a forecasted load of 15,710 MW
- Based on system conditions, ISO implemented M/LCC-2, Abnormal Conditions Alert, from 17:41 to 21:00 and OP-4 Actions 1 & 2 from 17:41 to 19:00
 - At 17:38 a large thermal resource tripped offline followed minutes later by the loss of two additional smaller resources; reduction in generator capacity totaled ~900 MW
 - Additional factors contributing to the capacity deficiency included load exceeding forecast by ~230 MW and net imports ~250 MW less than expected during the peak hour
- The 10-minute and 30-minute Reserve Constraint Penalty Factor (RCPF) violated for the 17:50-18:05 intervals; the 30-minute RCPF was also violated for the 18:10-18:15 intervals

Actual Peak Load of 15,941 MW (in HE18) Exceeded ISO's Forecasted Peak Load by ~230 MW

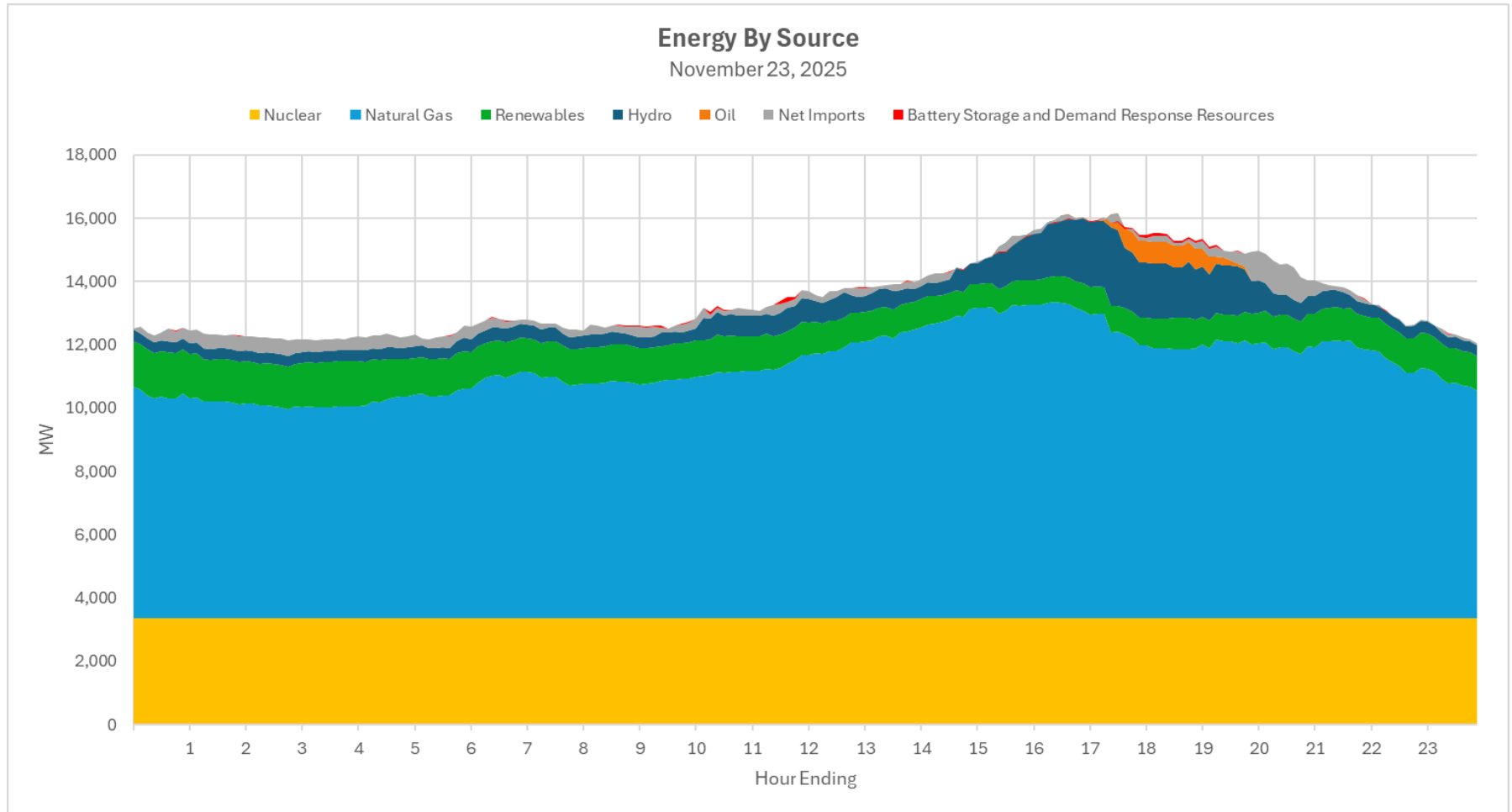
- Lower than forecasted behind-the-meter (BTM) PV resulted in higher loads during daylight hours while lower than forecasted temperatures drove higher loads in non-daylight hours



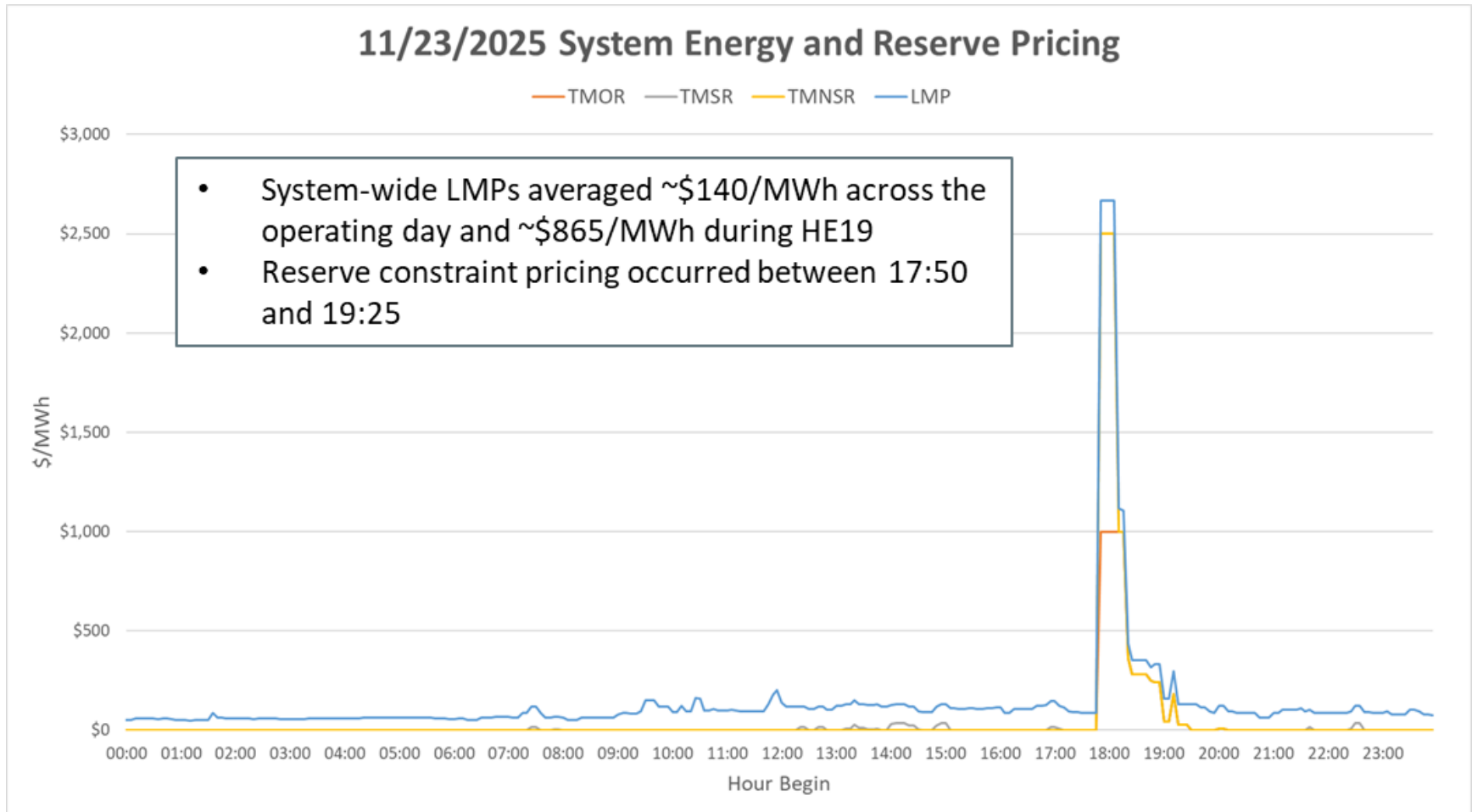
Net Imports During the Peak Hour Were ~250 MW Less Than Expected



Energy Supplies By Source – November 23, 2025



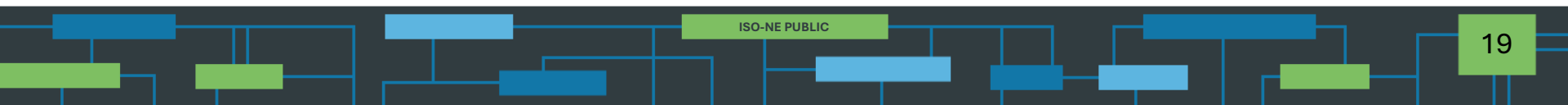
Real-Time System Energy and Reserve Pricing



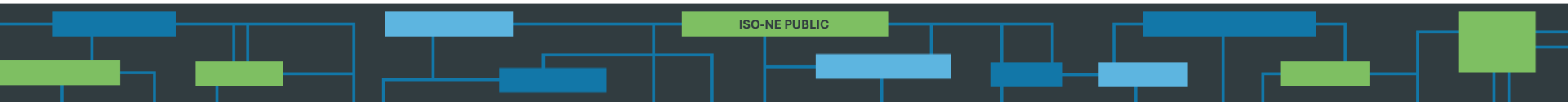
Summary of Capacity Scarcity Condition Intervals

5-Minute Intervals	System 30 Min Reserve Constraint Penalty Factor (\$1,000 MW/hr)	System 10 Min Reserve Constraint Penalty Factor (\$1,500 MW/hr)
17:50 – 18:05 (4 Intervals)	Violated	Violated
18:10 – 18:15 (2 Intervals)	Violated	N/A

- A Capacity Scarcity Condition results from the **violation** of the System 30 Minute Operating Reserve constraint or the System 10 Minute Operating Reserve constraint in any one 5-minute interval



SYSTEM OPERATIONS



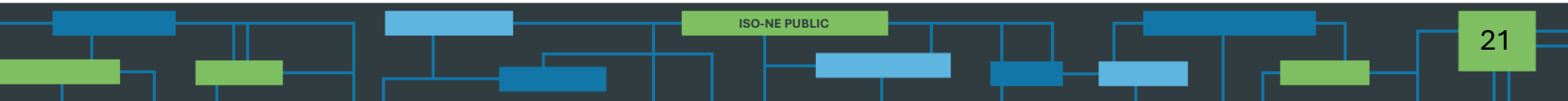
System Operations

<u>Weather Patterns</u>	Boston	Temperature: Below Normal (-0.5°F) Max: 63°F, Min: 31°F Precipitation: 1.75" - Below Normal Normal: 3.66" Snow: Trace	Hartford	Temperature: Below Normal (-1.2°F) Max: 64°F, Min: 22°F Precipitation: 1.95" - Below Normal Normal: 3.51" Snow: Trace

<u>Peak Load:</u>	16,389 MW	November 17, 2025	18:00 (ending)
<u>Mid-Day Minimum Load - Month:</u>	7,998 MW	November 2, 2025	12:00 (ending)
<u>Mid-Day Minimum Load - Historical:</u>	5,318 MW	April 20, 2025	14:00 (ending)

Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

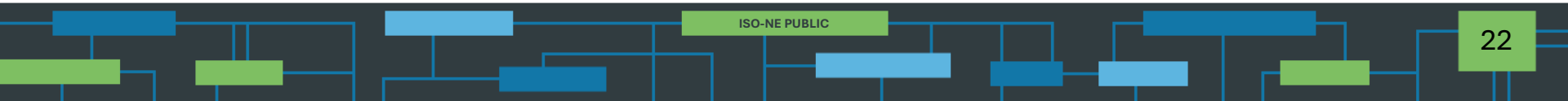
Procedure	Declared	Cancelled	Note
OP-4	11/23/2025 17:41	11/23/2025 19:00	Capacity
M/LCC 2	11/23/2025 17:41	11/23/2025 21:00	Capacity



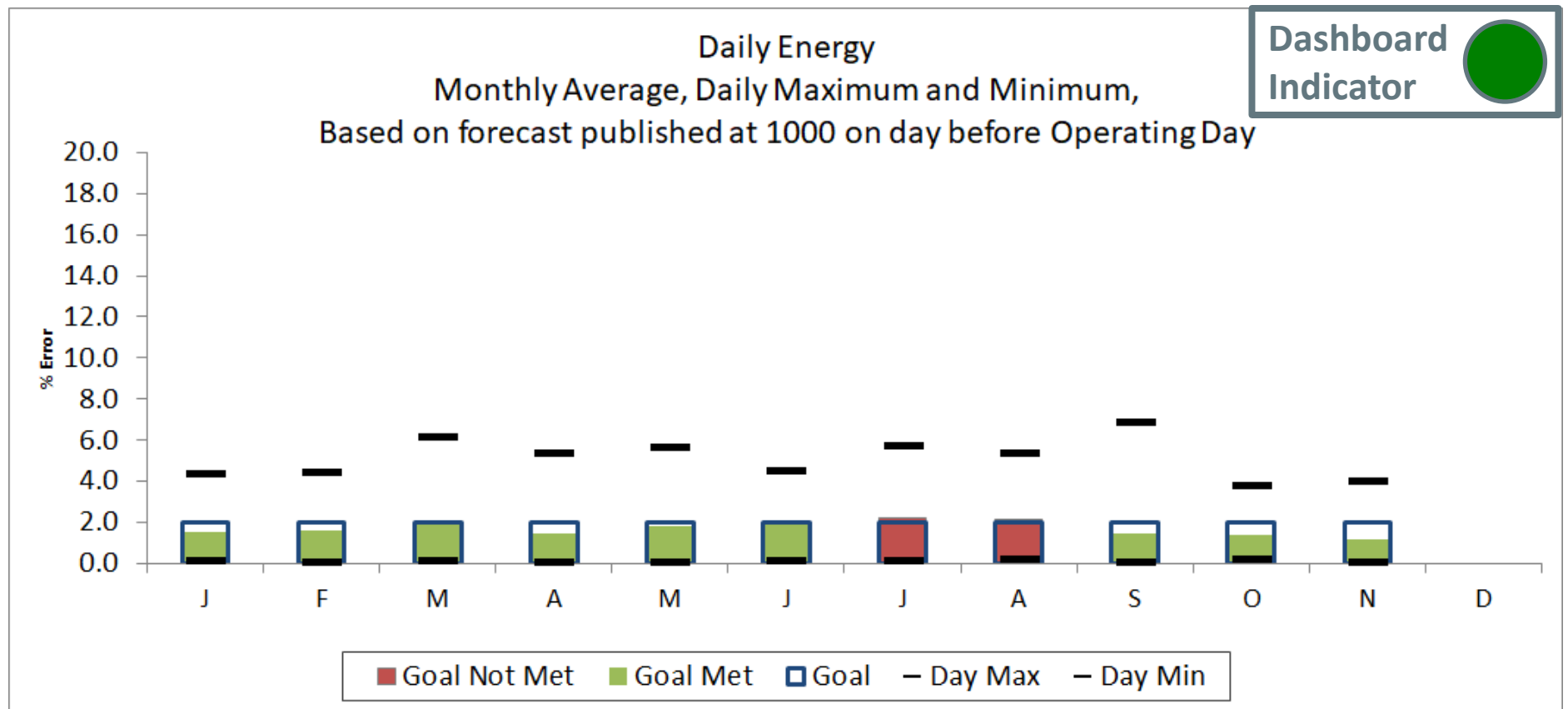
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
11/10/2025	NBPSO	350
11/23/2025	ISO-NE	800
11/25/2025	NYISO	560

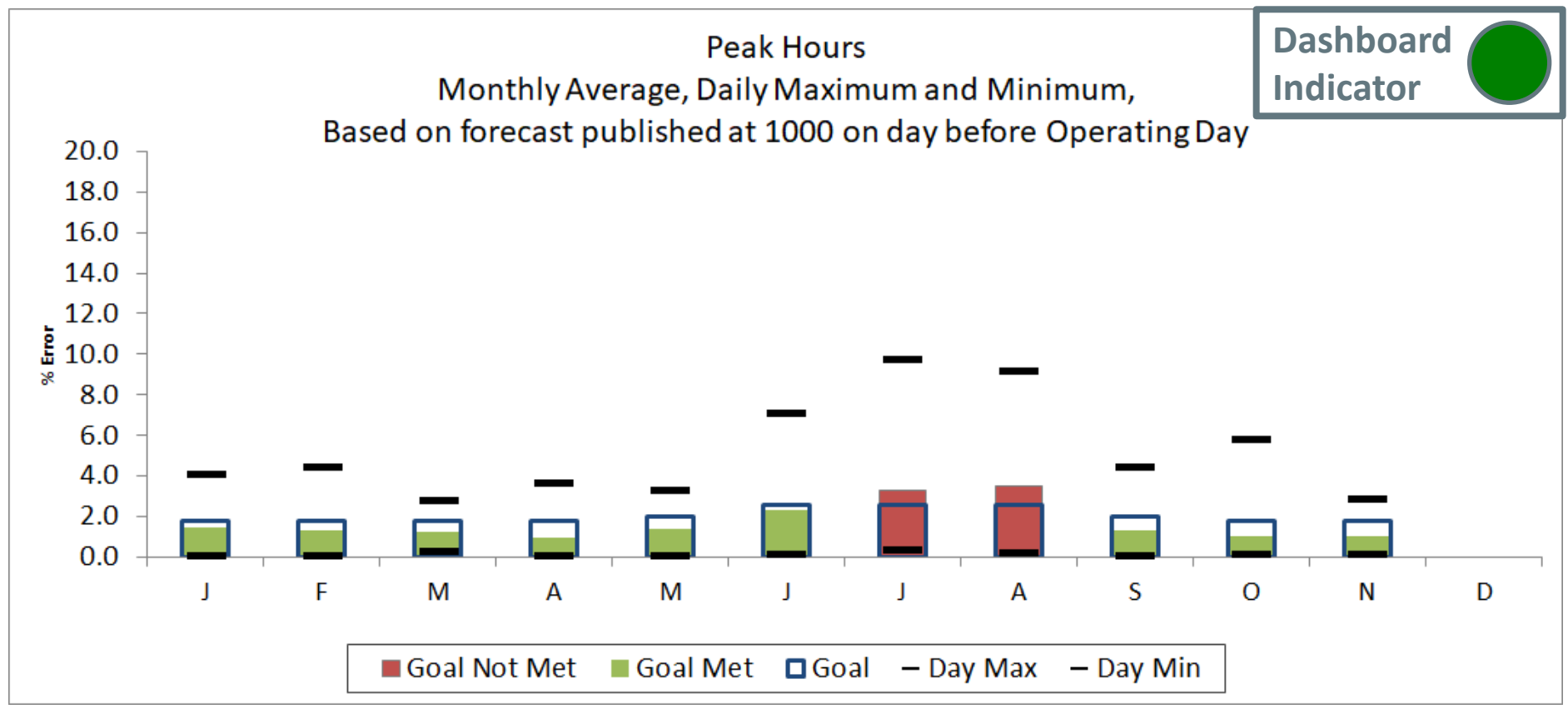


2025 System Operations - Load Forecast Accuracy cont.



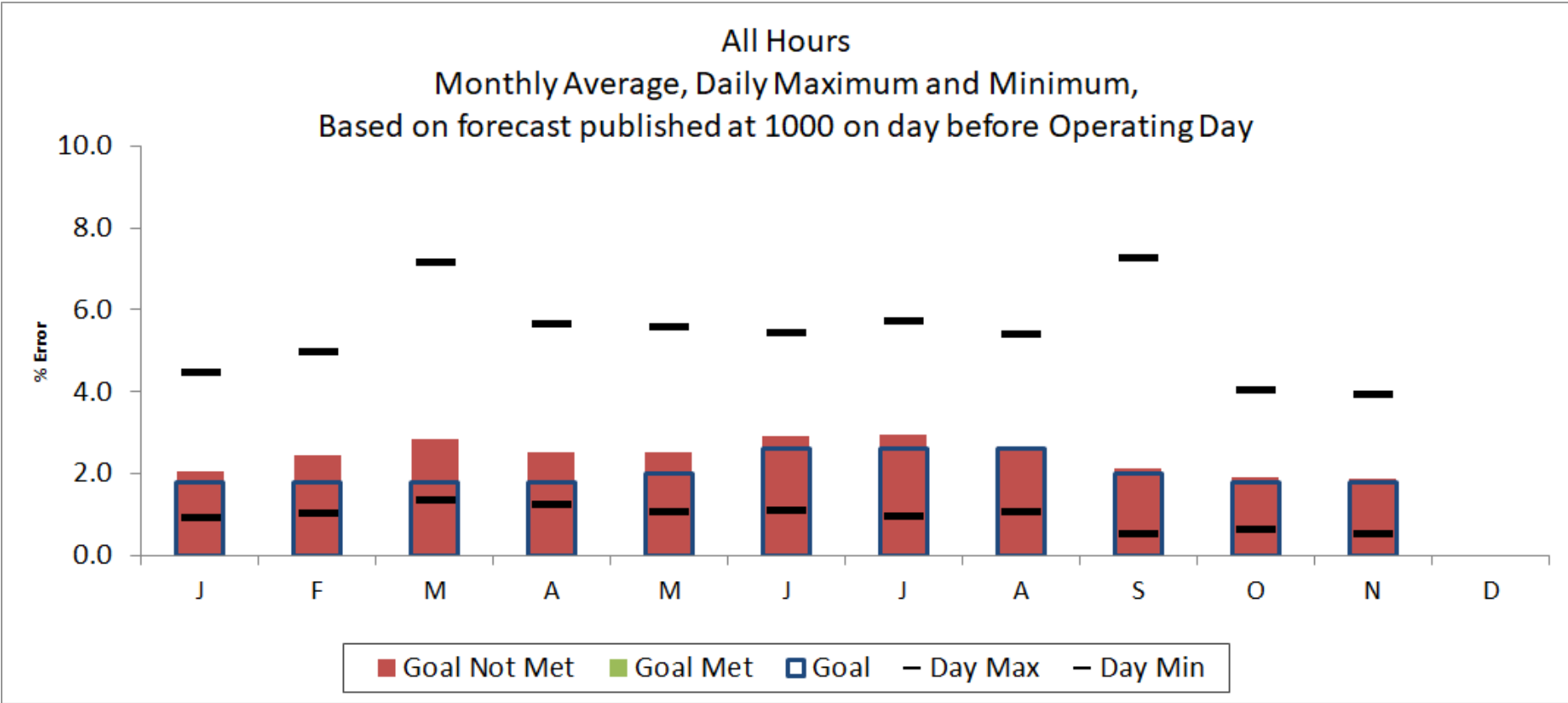
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	4.44	6.10	5.36	5.61	4.48	5.70	5.34	6.81	3.73	3.97		6.81
Day Min	0.12	0.04	0.12	0.05	0.06	0.08	0.11	0.16	0.05	0.18	0.03		0.03
MAPE	1.54	1.62	1.89	1.45	1.80	1.98	2.24	2.12	1.46	1.39	1.21		1.70
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00		

2025 System Operations - Load Forecast Accuracy cont.



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.41	2.77	3.63	3.29	7.08	9.71	9.15	4.43	5.77	2.84		9.71
Day Min	0.03	0.06	0.24	0.03	0.06	0.11	0.34	0.15	0.05	0.12	0.07		0.03
MAPE	1.48	1.34	1.29	1.00	1.41	2.30	3.28	3.48	1.30	1.02	1.04		1.73
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

2025 System Operations - Load Forecast Accuracy cont.

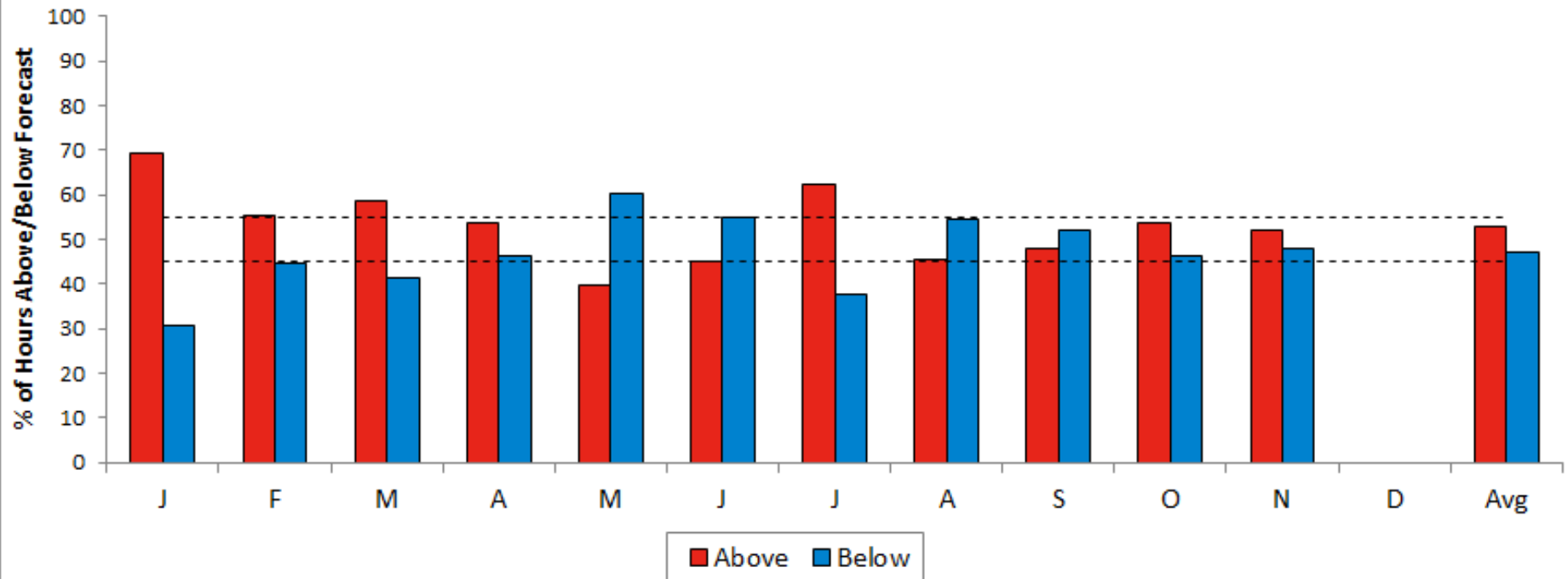


Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.46	4.98	7.13	5.65	5.57	5.44	5.72	5.41	7.24	4.01	3.91		7.24
Day Min	0.90	1.02	1.33	1.23	1.07	1.11	0.95	1.07	0.52	0.64	0.50		0.50
MAPE	2.07	2.47	2.83	2.53	2.53	2.93	2.94	2.68	2.13	1.92	1.88		2.45
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

2025 System Operations - Load Forecast Accuracy cont.

Percent of Hours Actual Load
Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day

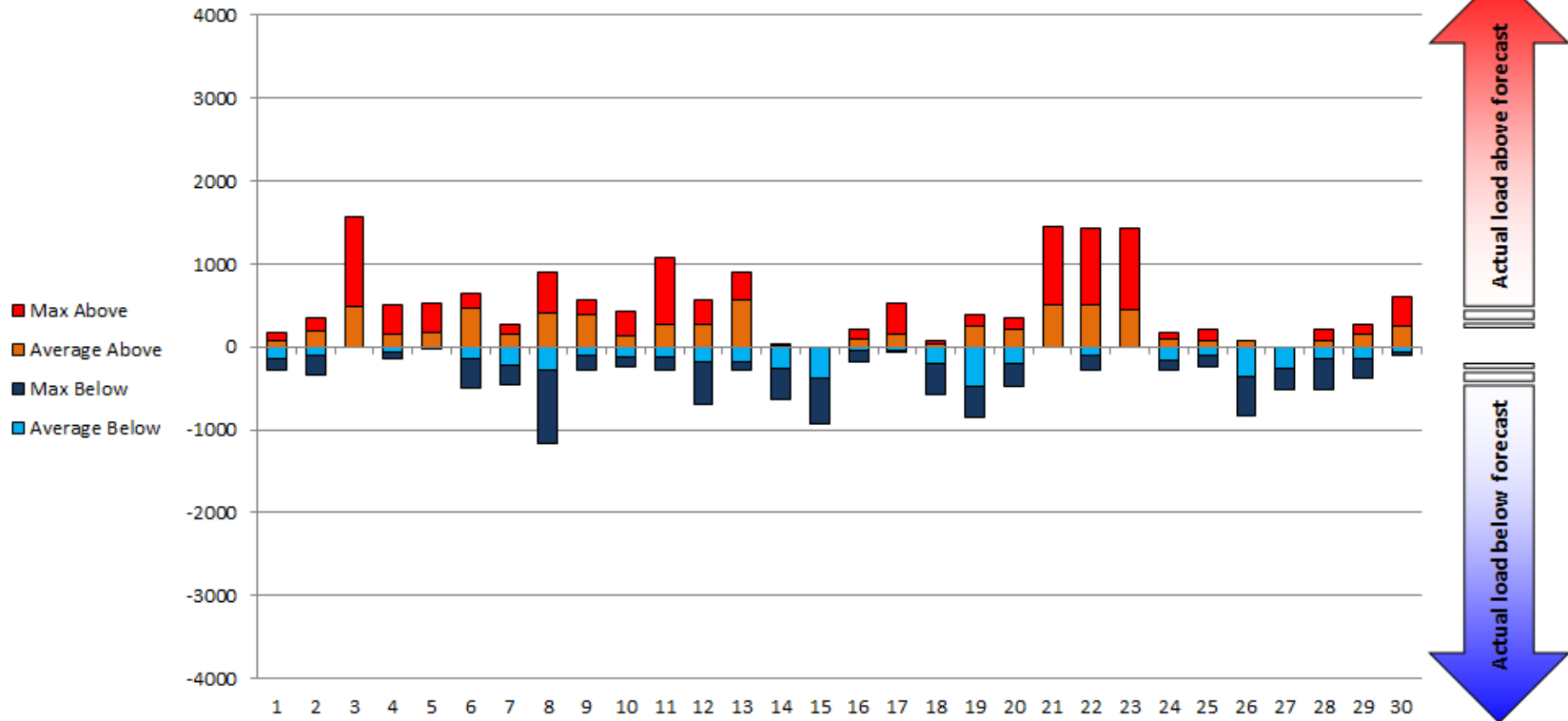
Target = 50%
Plus/Minus = 5%



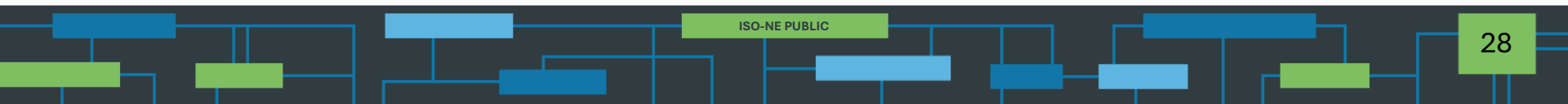
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	69.2	55.2	58.5	53.5	39.8	45.1	62.5	45.3	48.1	53.5	51.9		53
Below %	30.8	44.8	41.5	46.5	60.2	54.9	37.5	54.7	51.9	46.5	48.1		47
Avg Above	280.5	282.1	246.5	255.8	164.5	307.8	397.3	225.4	213.7	161.8	222.3		397
Avg Below	-178.6	-287.9	-273.2	-190.7	-254.1	-310.2	-270.0	-308.7	-179.5	-157.1	-154.8		-310
Avg All	138	24	12	49	-82	-24	145	-81	1	12	35		21

2025 System Operations - Load Forecast Accuracy

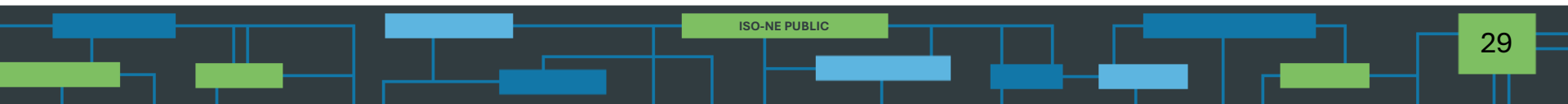
Deviation of Actual Load from Forecasted Load November 2025



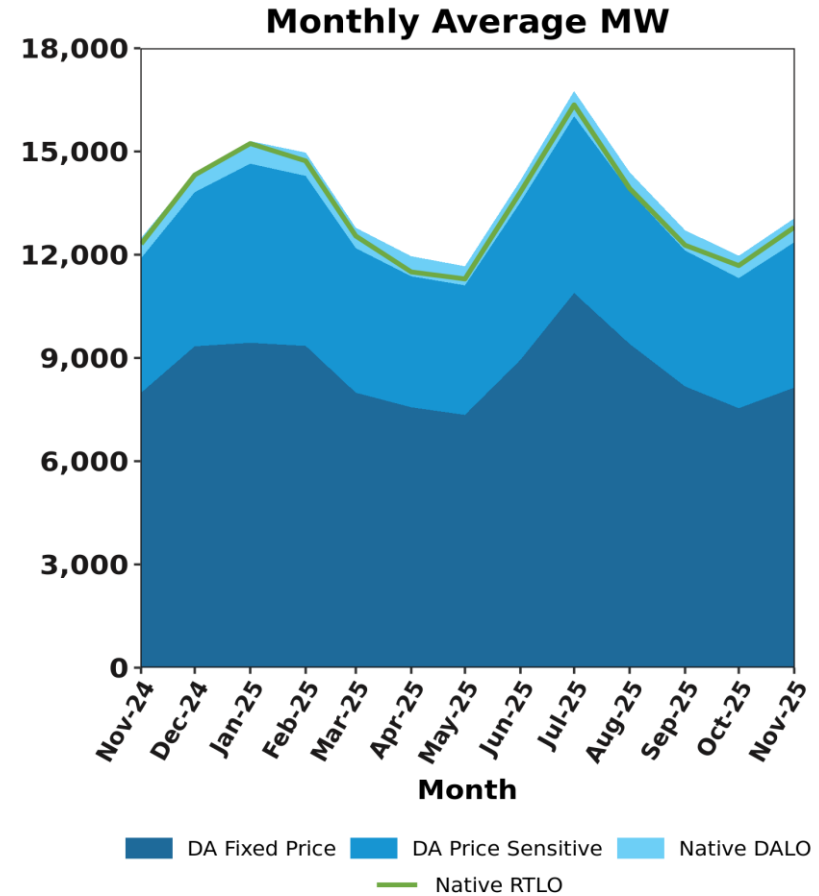
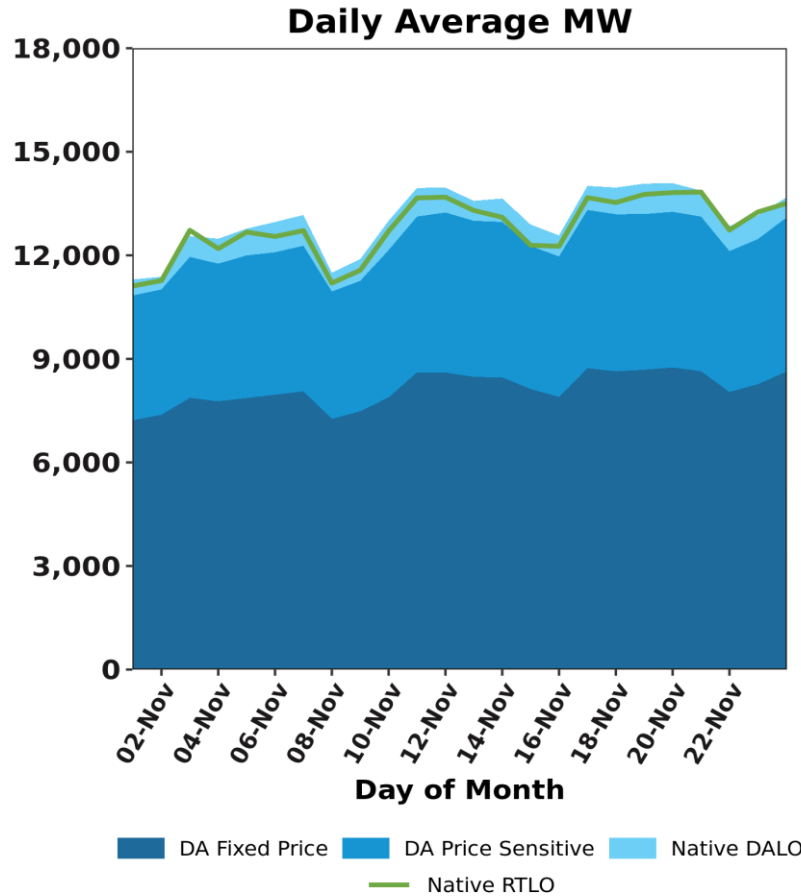
MARKET OPERATIONS



SUPPLY AND DEMAND VOLUMES

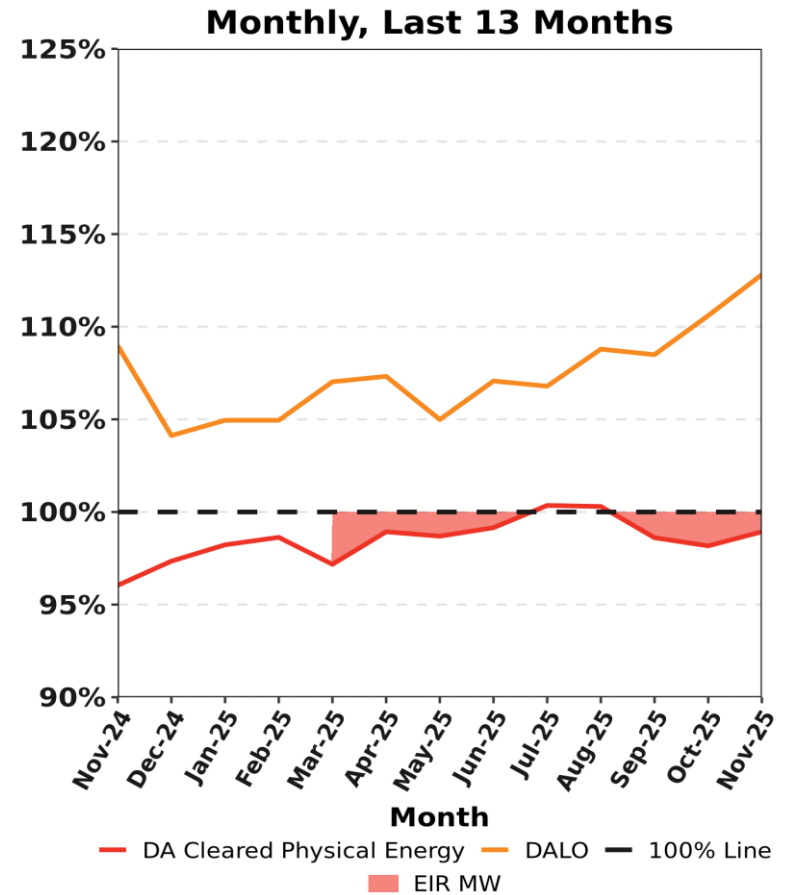
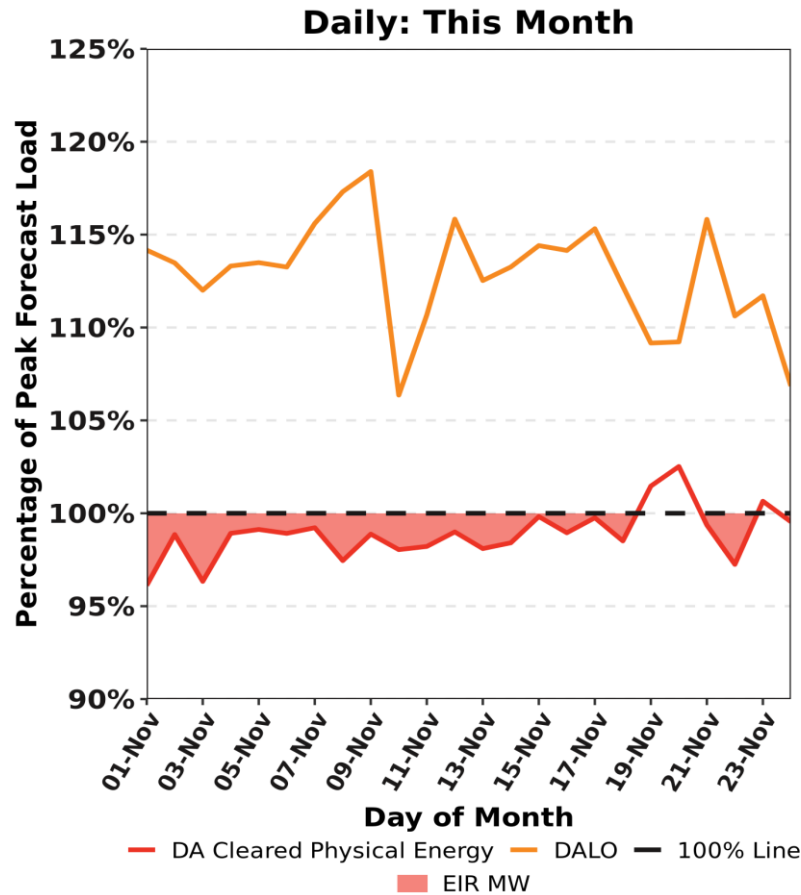


DA Cleared Native Load by Composition Compared to Native RT Load



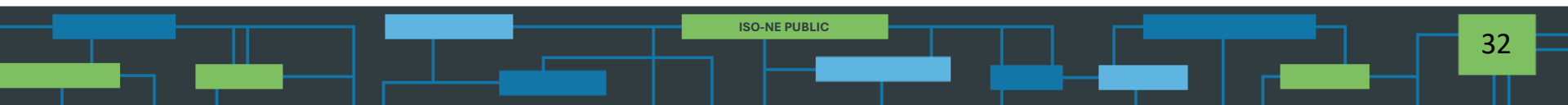
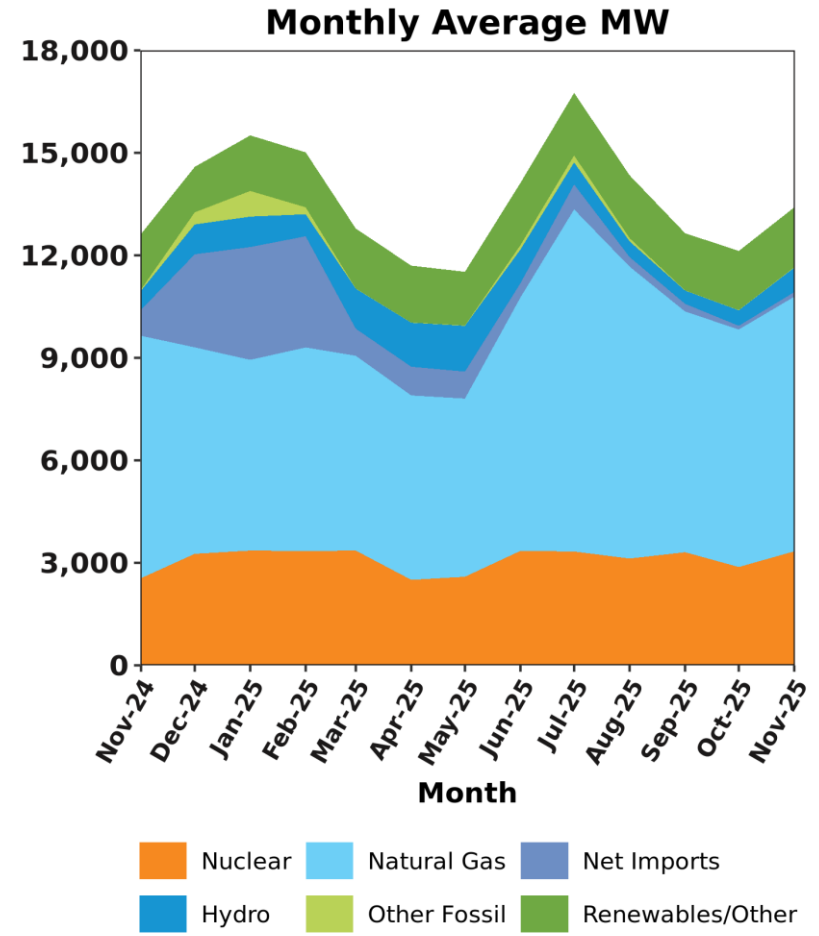
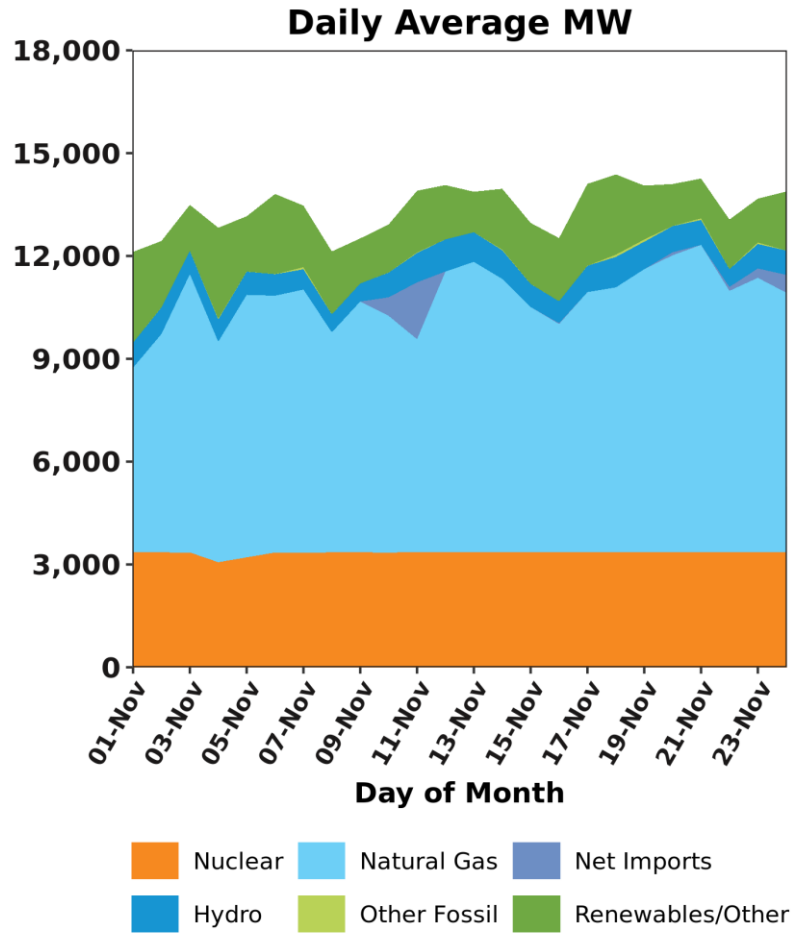
Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

DA Volumes as % of Forecast in Peak Hour

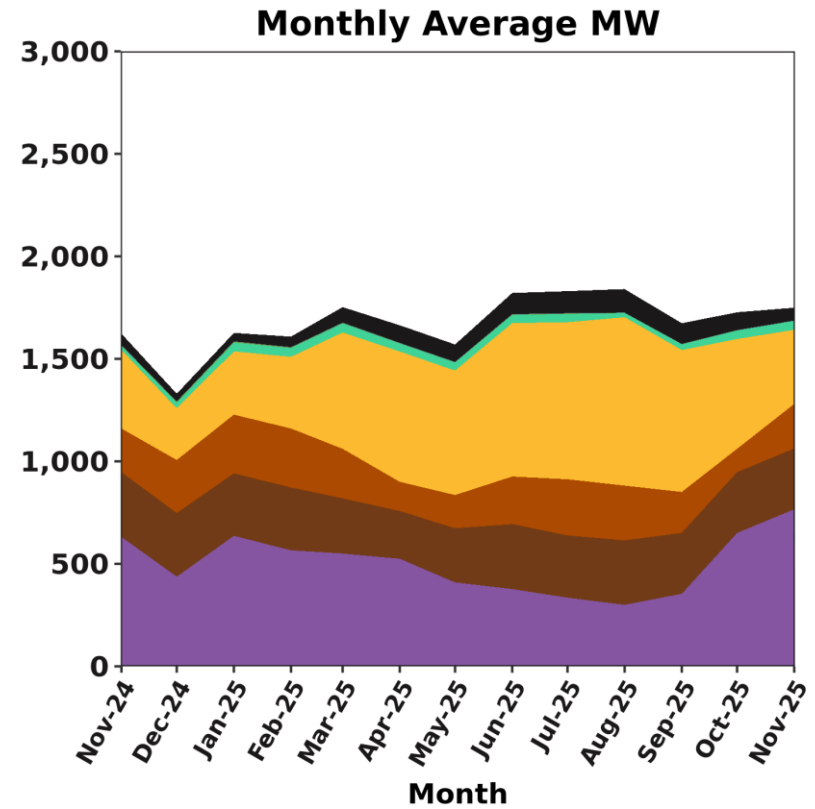
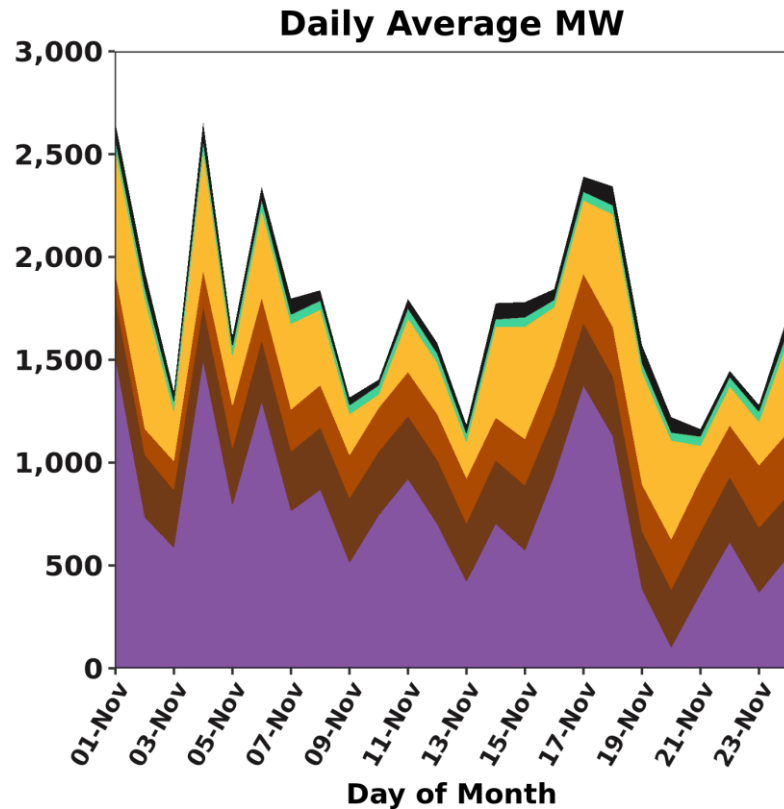


*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Resource Mix

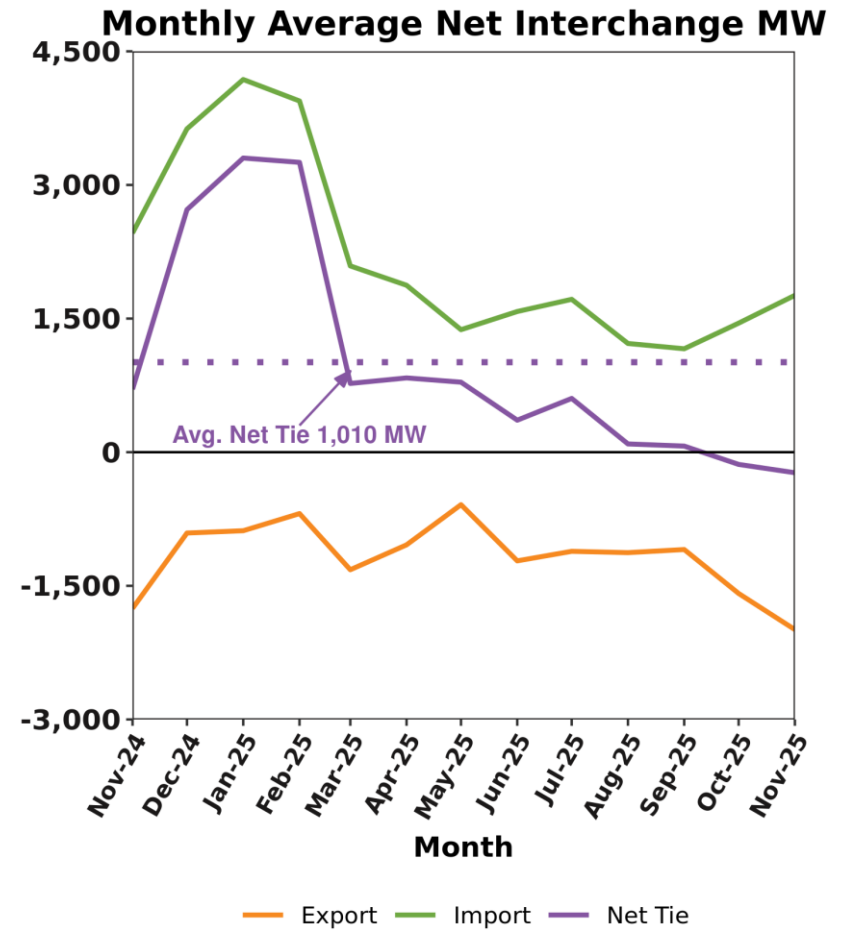
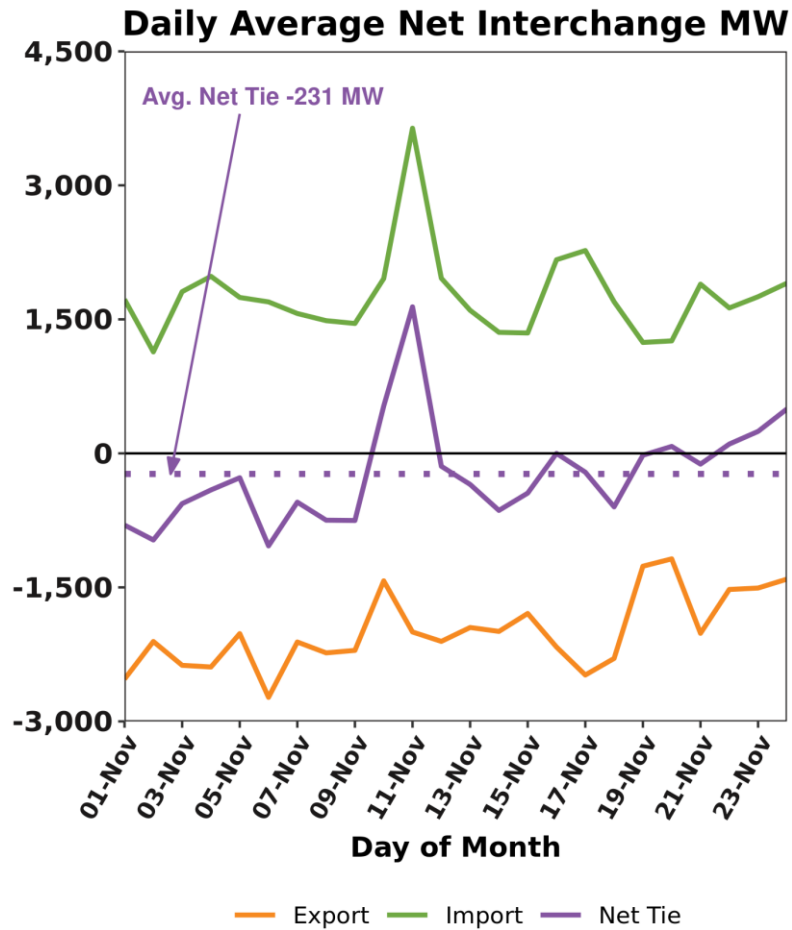


Renewable Generation by Fuel Type



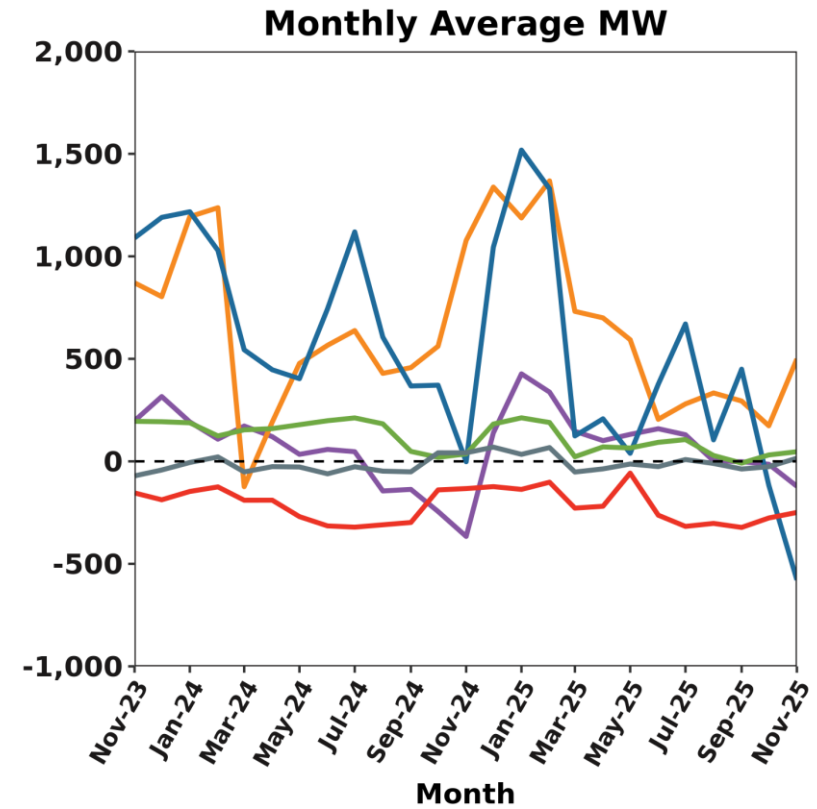
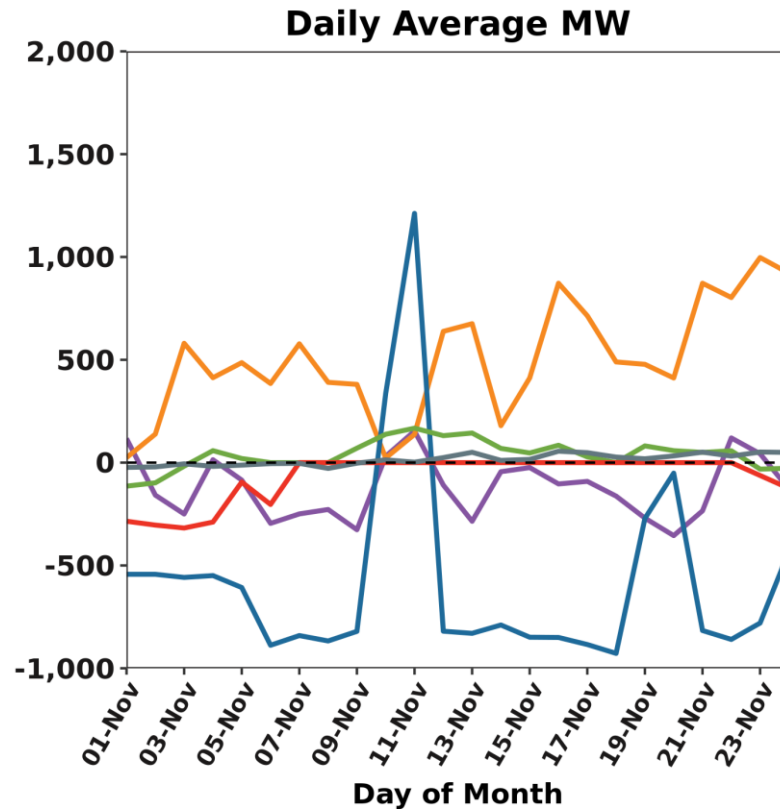
CSF = Continuous Storage Facilities (a.k.a. Batteries); PRD=Demand Response Resources (DRR)

RT Net Interchange



Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

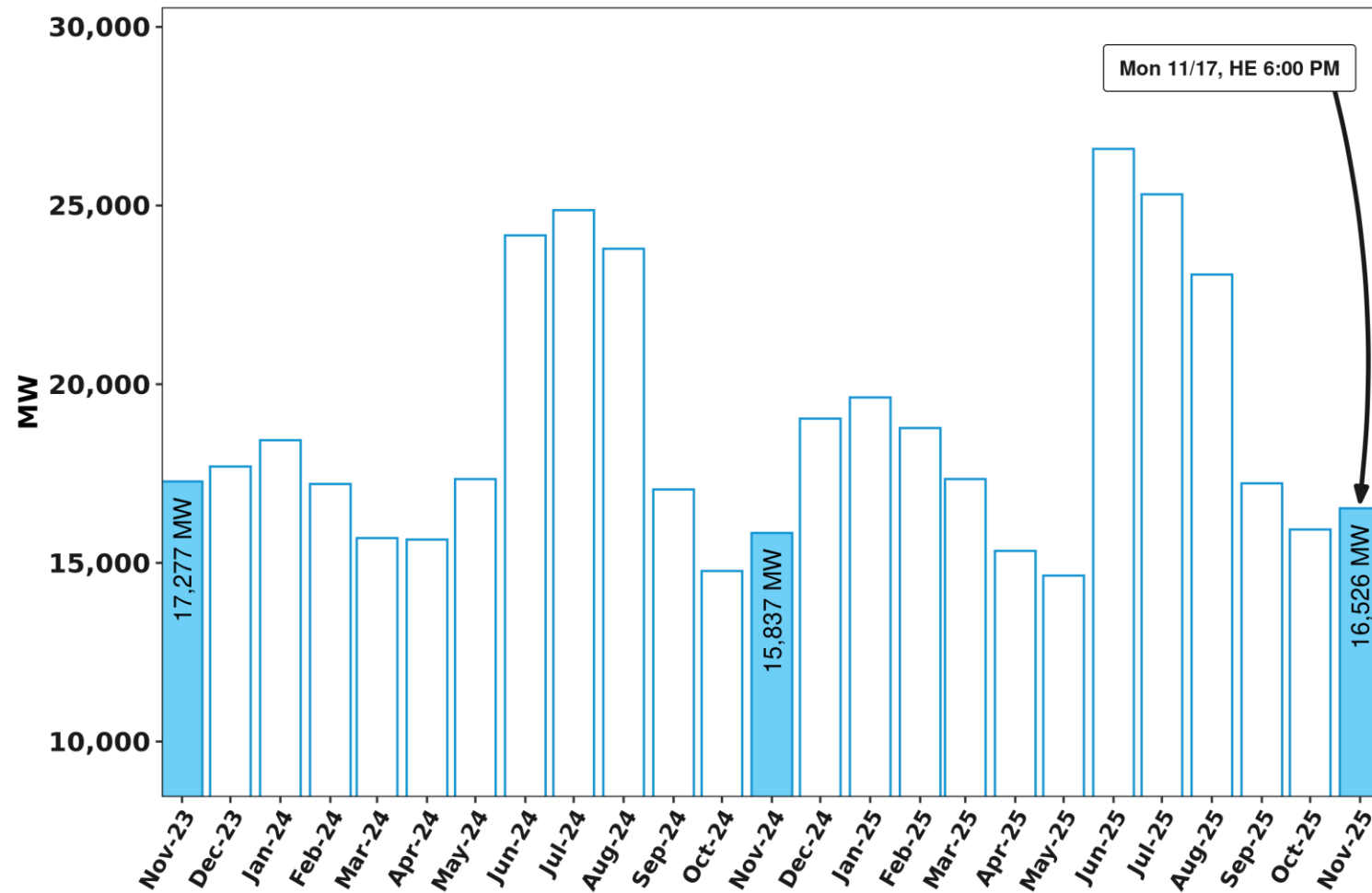
RT Net Interchange by External Interface



NB HQ-Ph2 NY-CSC
NY-NAC HQ HG NY-NNC

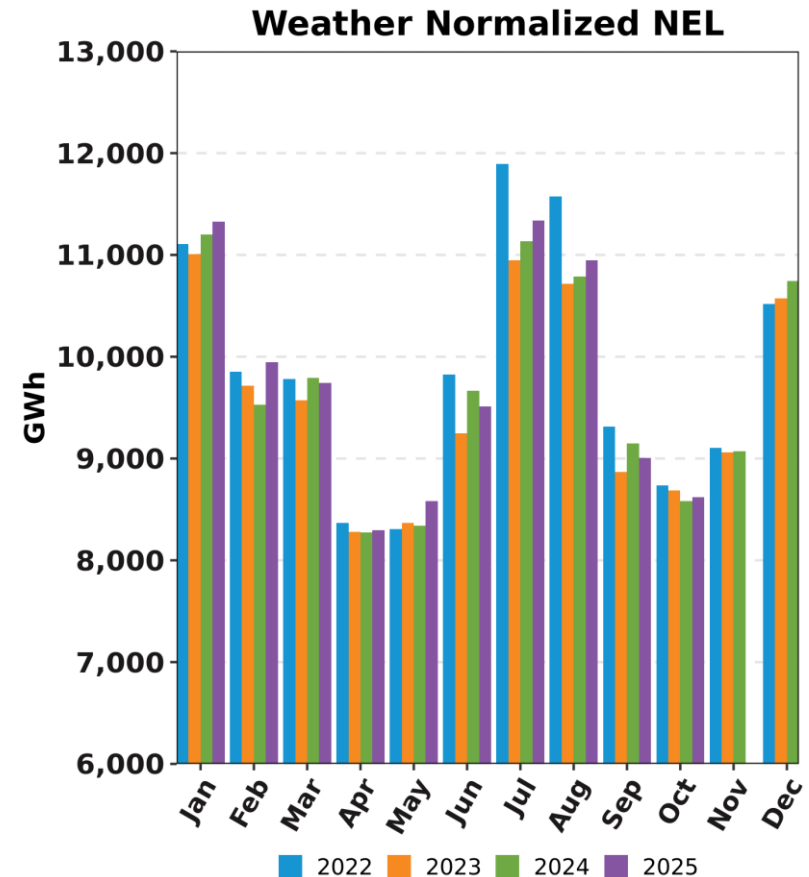
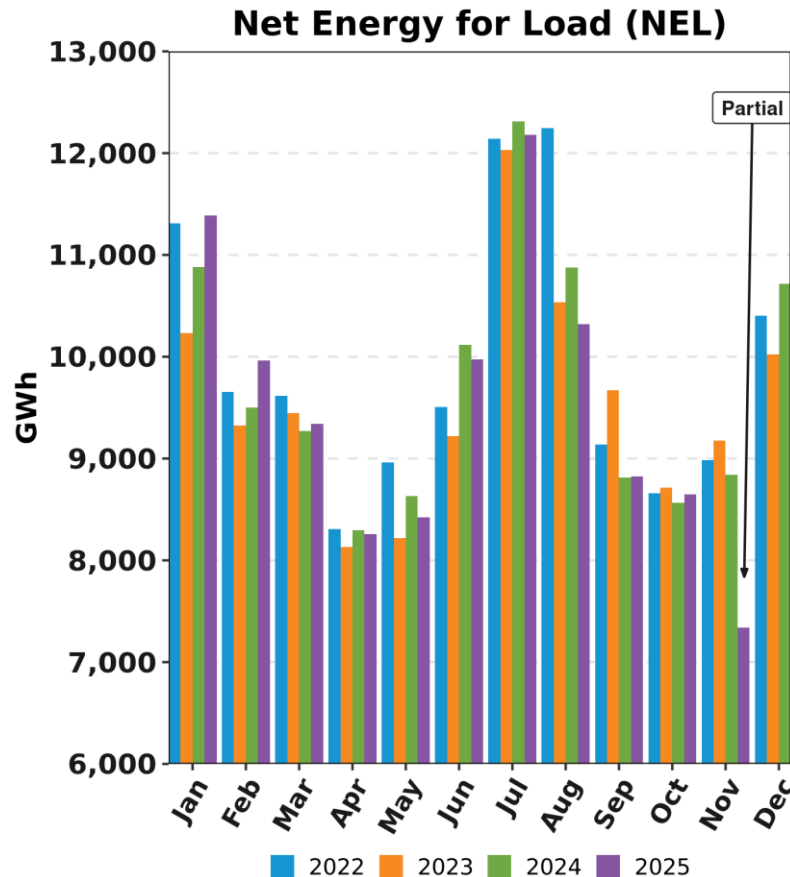
NB HQ-Ph2 NY-CSC
NY-NAC HQ HG NY-NNC

RQM System Peak Load MW by Month



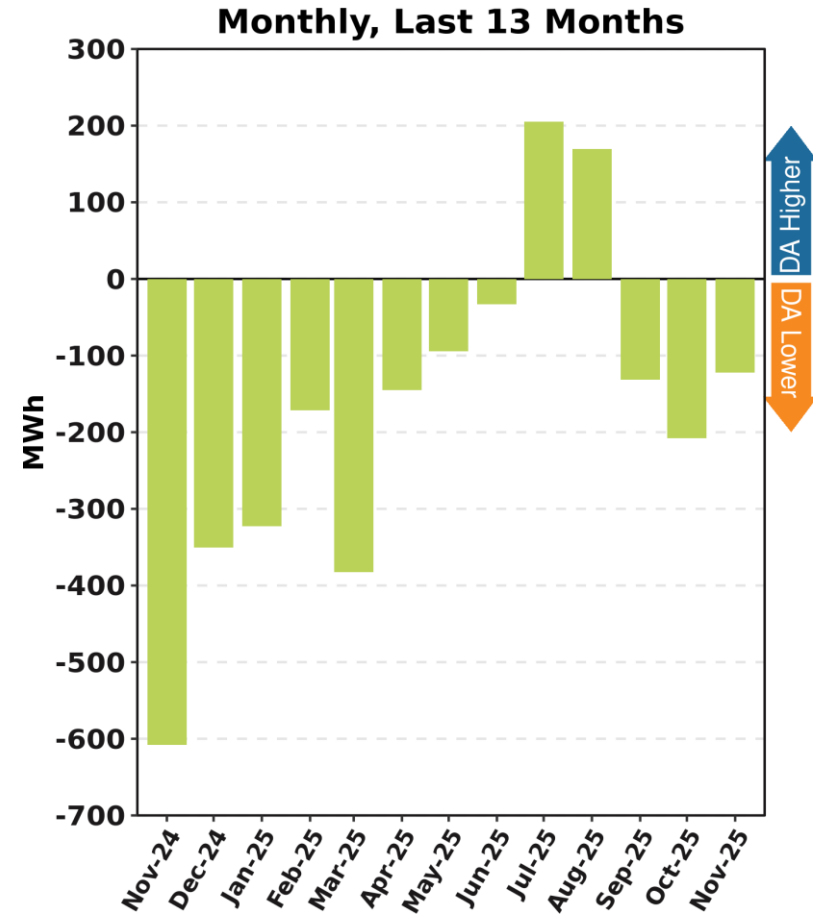
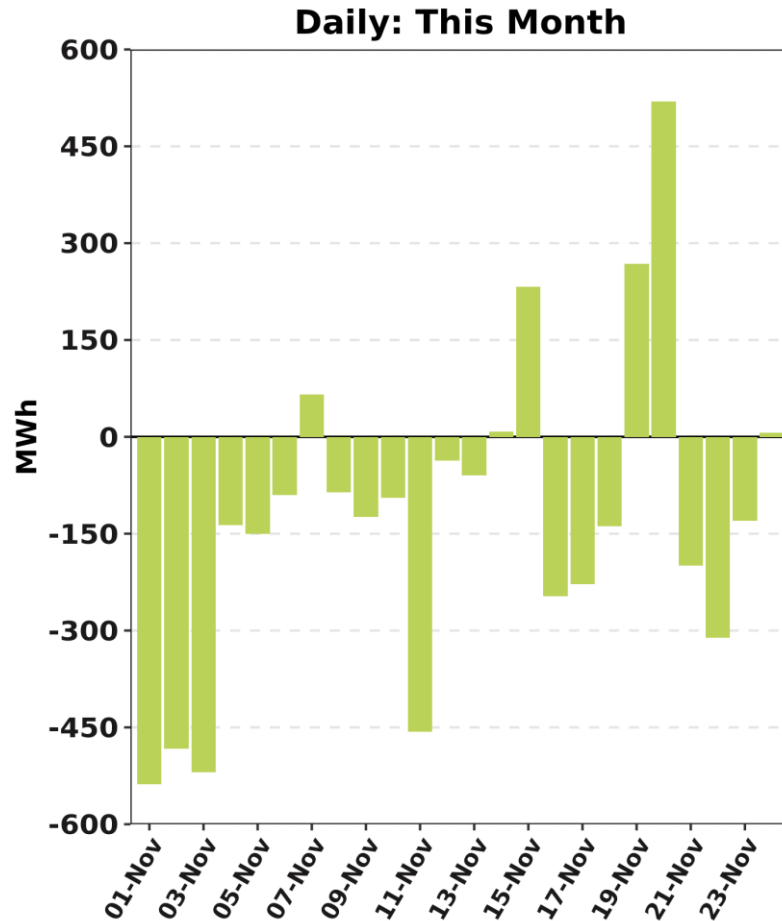
Shaded columns highlight current month and the same month over the prior two years

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



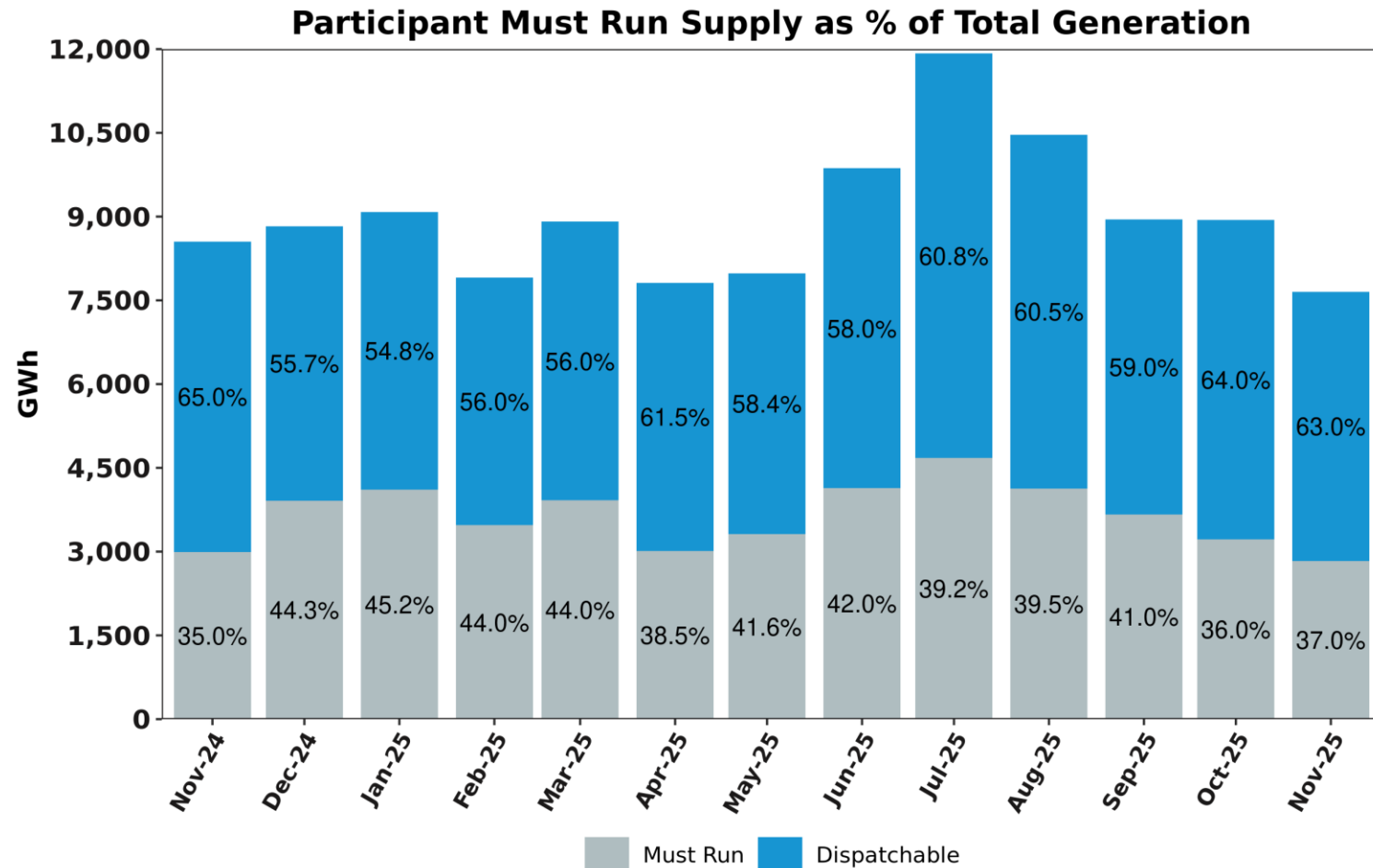
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

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



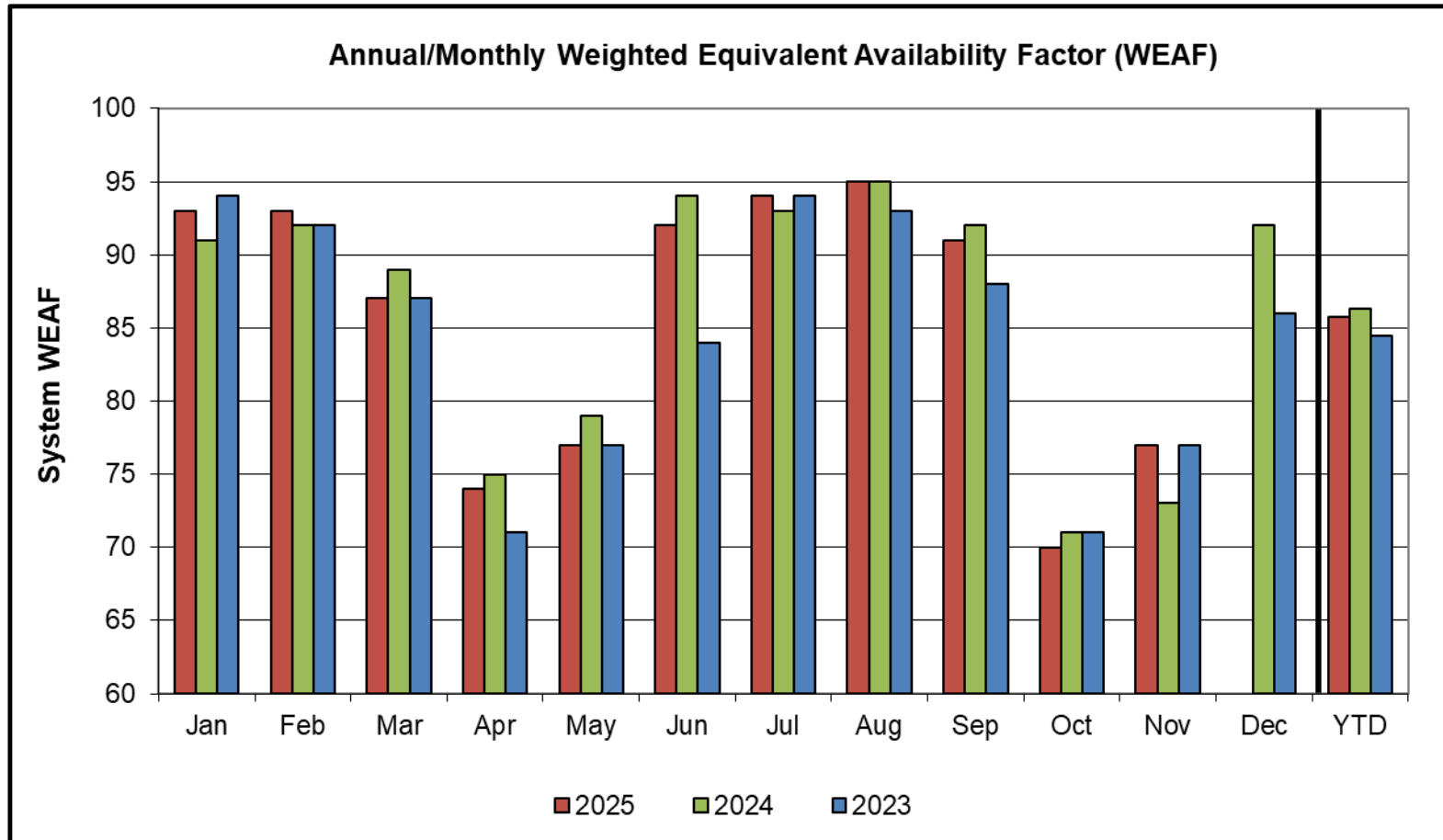
Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

RT Generation Output Offered as Must Run vs Dispatchable



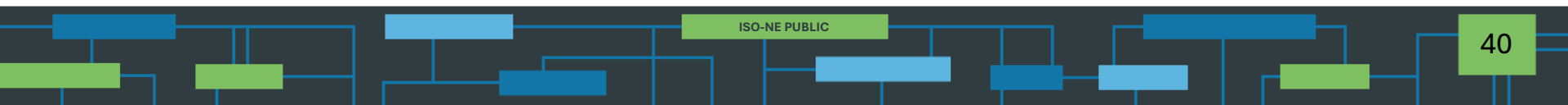
Includes generation and DRR. Must Run (non-dispatchable) category reflects full output of Settlement Only Resources (SOG) as well as must run offers from modeled units

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2025	93	93	87	74	77	92	94	95	91	70	77		86
2024	91	92	89	75	79	94	93	95	92	71	73	92	86
2023	94	92	87	71	77	84	94	93	88	71	77	86	85

Data as of 11/21/25



MARKET PRICING



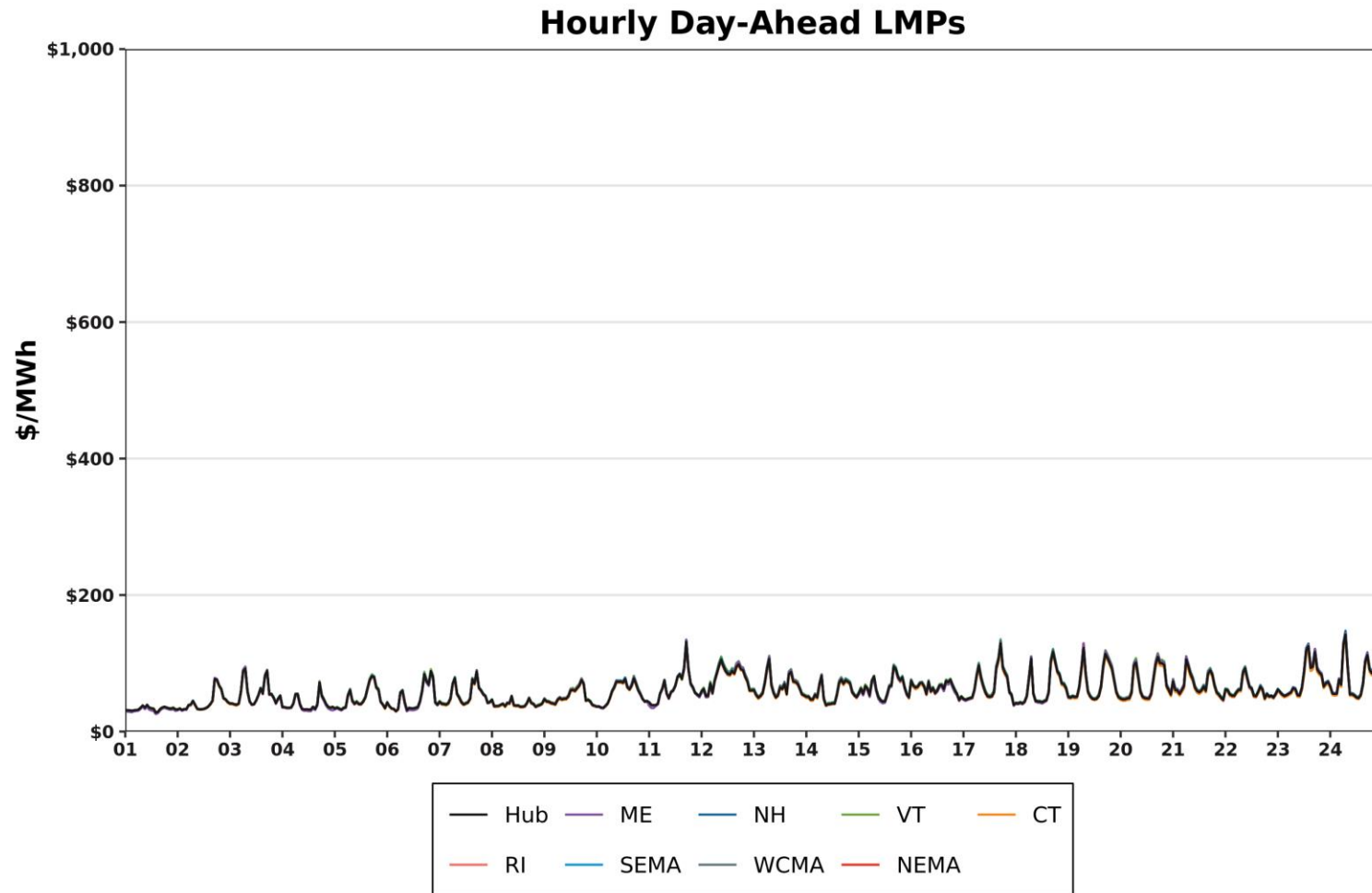
DA vs. RT LMPs (\$/MWh)

Arithmetic Average

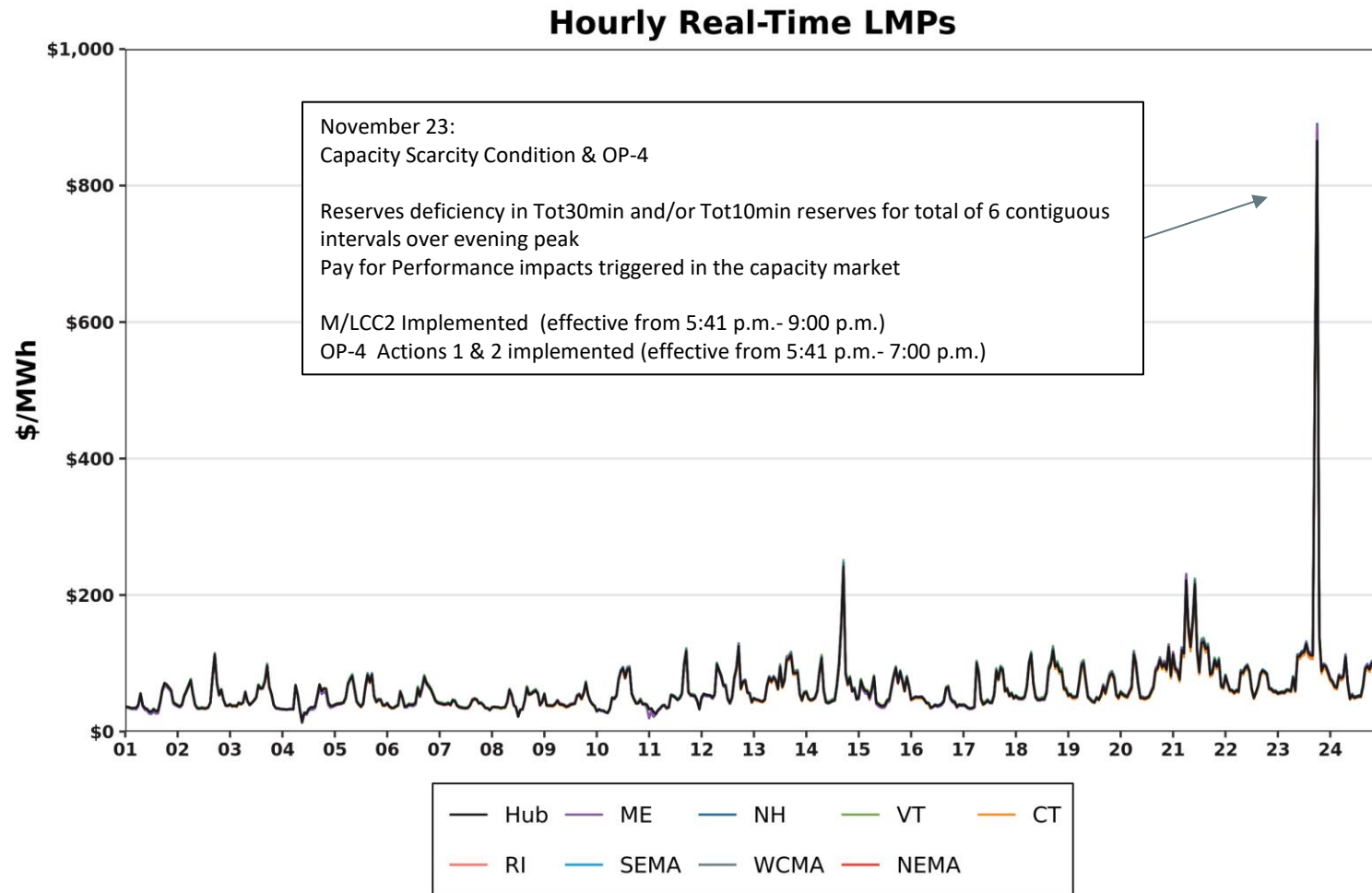
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$37.04	\$36.59	\$37.22	\$36.78	\$36.25	\$36.89	\$37.34	\$37.07	\$37.35
Real-Time	\$35.91	\$35.36	\$36.05	\$35.55	\$35.26	\$35.71	\$36.17	\$35.92	\$36.21
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$41.35	\$41.07	\$41.72	\$41.11	\$40.17	\$41.28	\$41.70	\$41.37	\$41.91
Real-Time	\$39.37	\$38.79	\$39.65	\$39.23	\$38.46	\$39.17	\$39.62	\$39.37	\$39.77
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%

November-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$39.50	\$40.86	\$40.75	\$39.21	\$36.87	\$39.39	\$39.84	\$39.46	\$40.75
Real-Time	\$40.23	\$40.97	\$41.25	\$40.42	\$38.32	\$39.88	\$40.27	\$40.21	\$41.10
RT Delta %	1.85%	0.27%	1.23%	3.09%	3.93%	1.24%	1.08%	1.90%	0.86%
November-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$58.65	\$58.46	\$59.72	\$60.41	\$56.90	\$57.68	\$58.64	\$58.75	\$59.43
Real-Time	\$61.88	\$61.64	\$63.01	\$63.80	\$60.13	\$60.83	\$61.69	\$61.97	\$62.65
RT Delta %	5.51%	5.44%	5.51%	5.61%	5.68%	5.46%	5.20%	5.48%	5.42%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	48.48%	43.07%	46.55%	54.07%	54.33%	46.43%	47.19%	48.88%	45.84%
Yr over Yr RT	53.82%	50.45%	52.75%	57.84%	56.92%	52.53%	53.19%	54.12%	52.43%

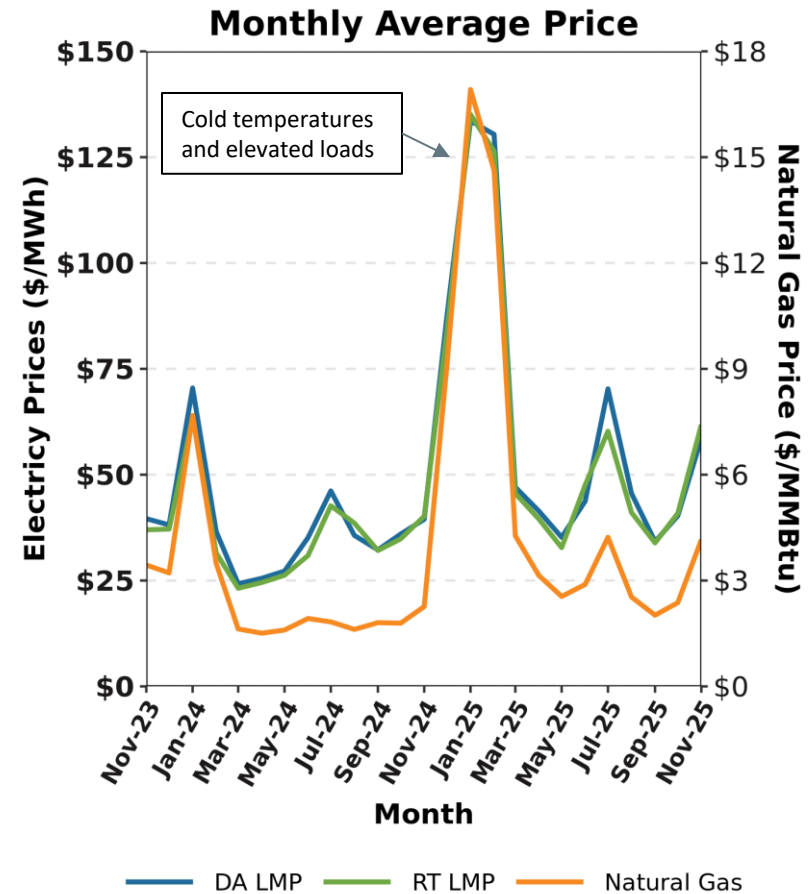
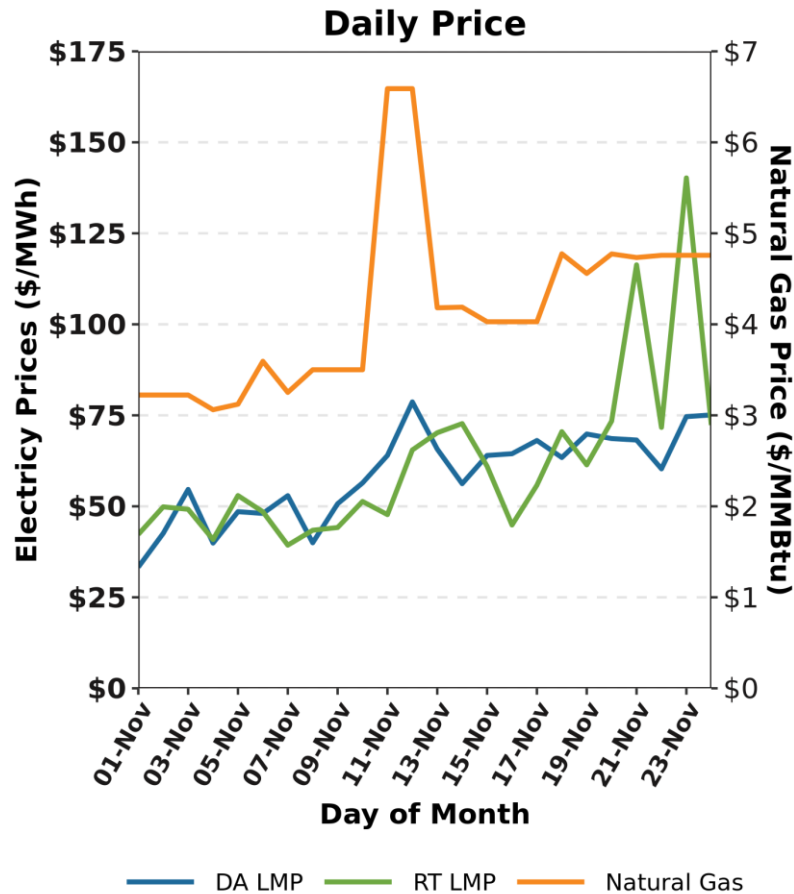
Hourly DA LMPs, November 1-24, 2025



Hourly RT LMPs, November 1-24, 2025



Wholesale Electricity vs Natural Gas Price by Month

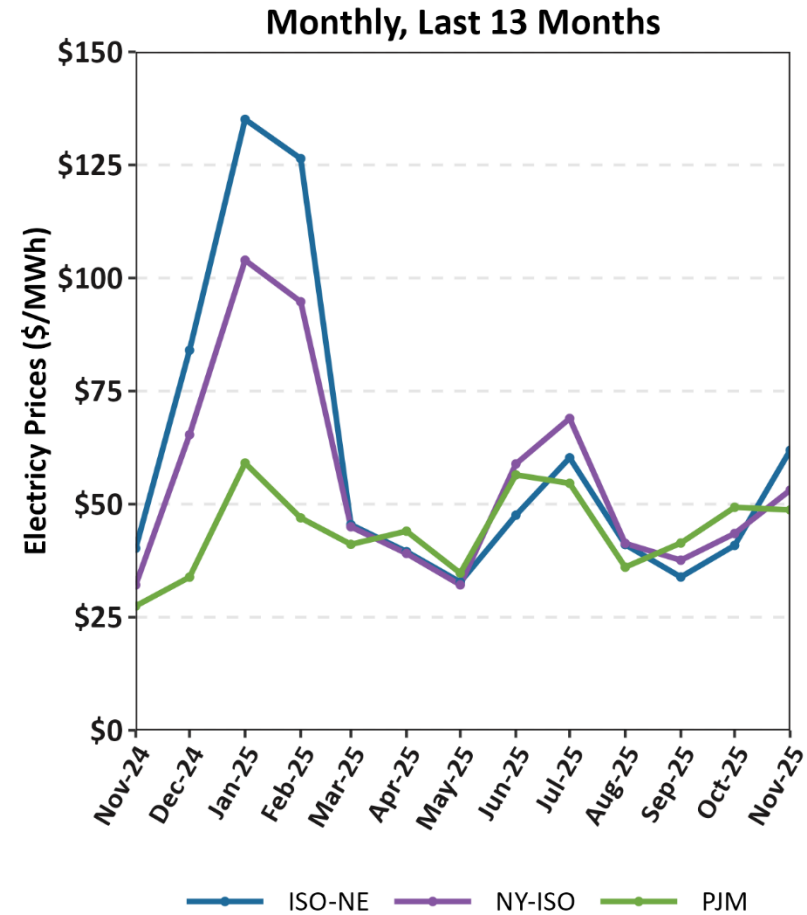
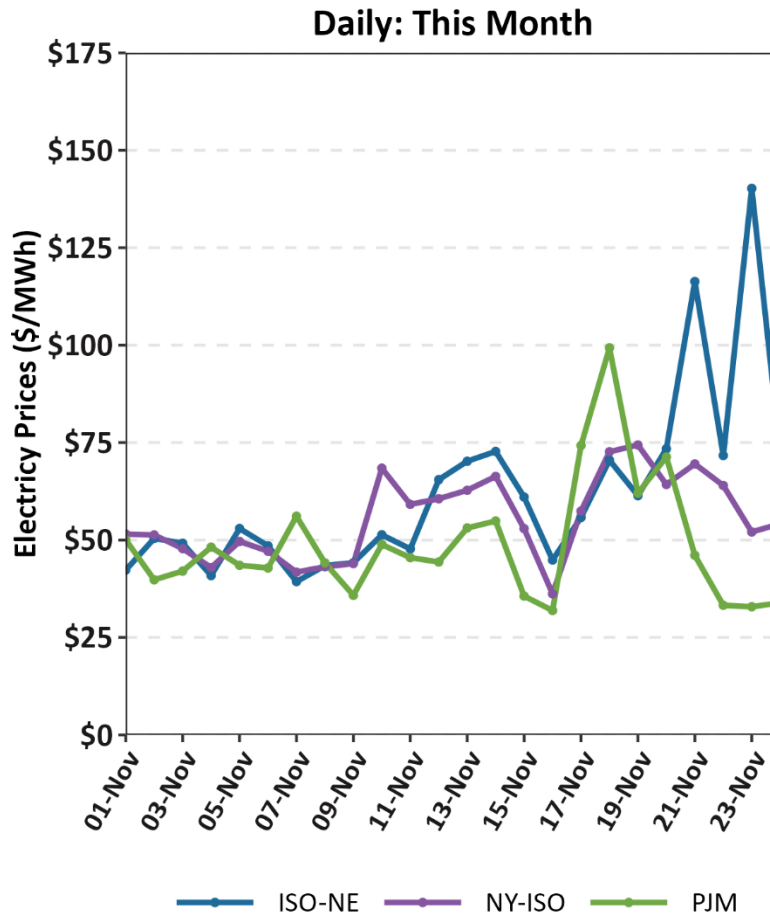


Gas price is average of Massachusetts delivery points

Underlying natural gas data furnished by:

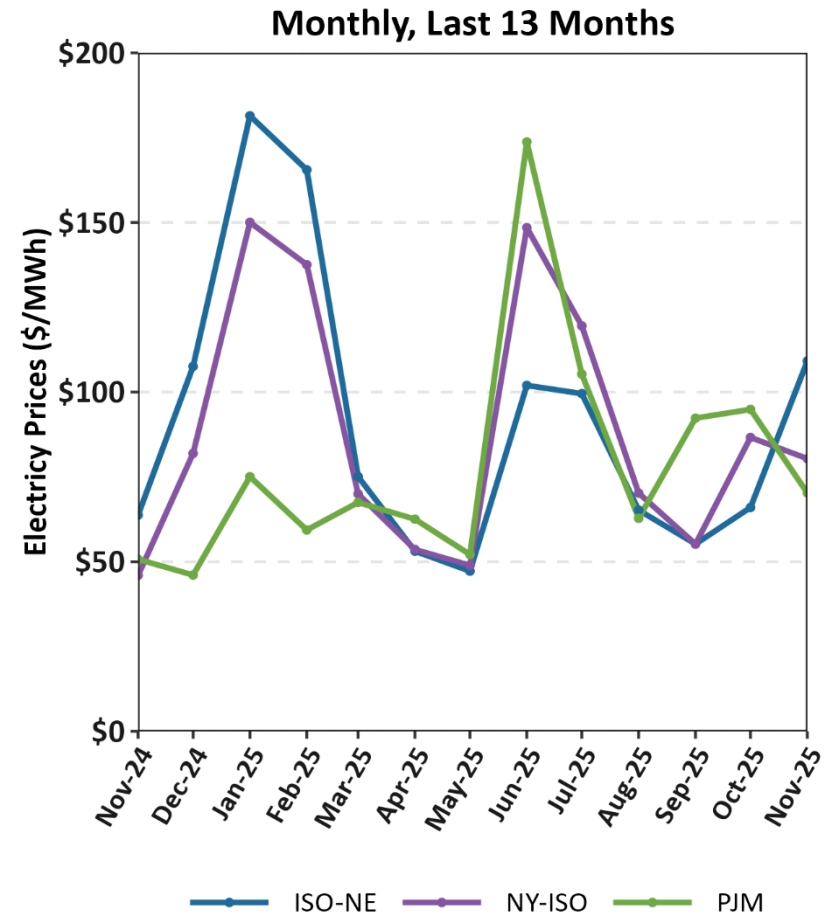
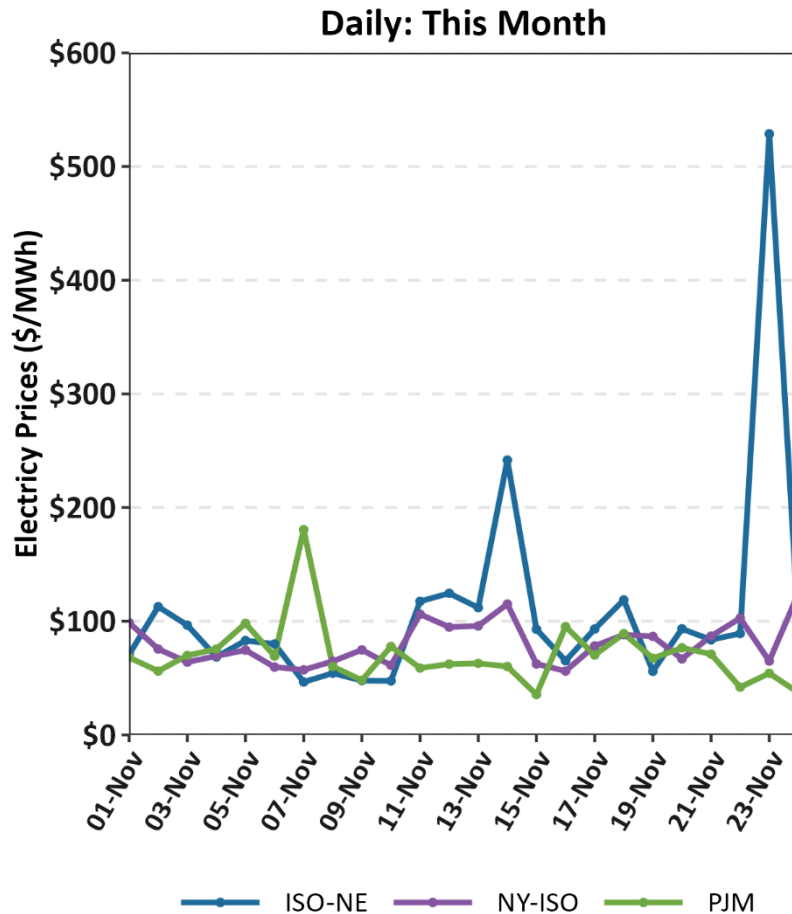


New England, NY, and PJM Hourly Average RT Prices by Month



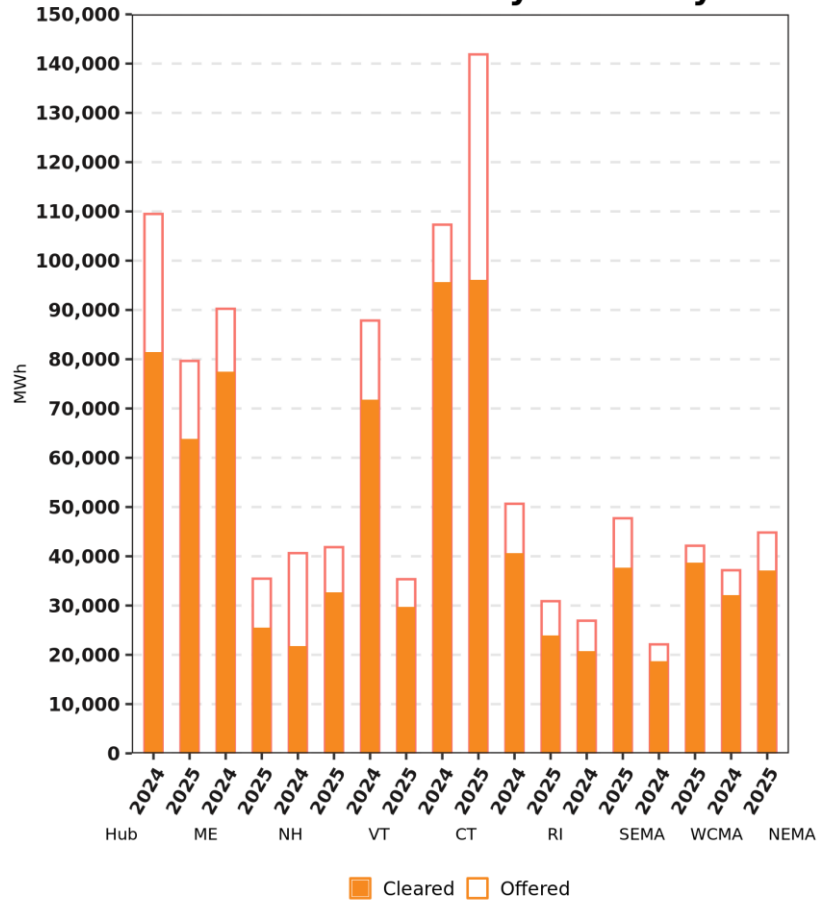
Hourly average prices are shown

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

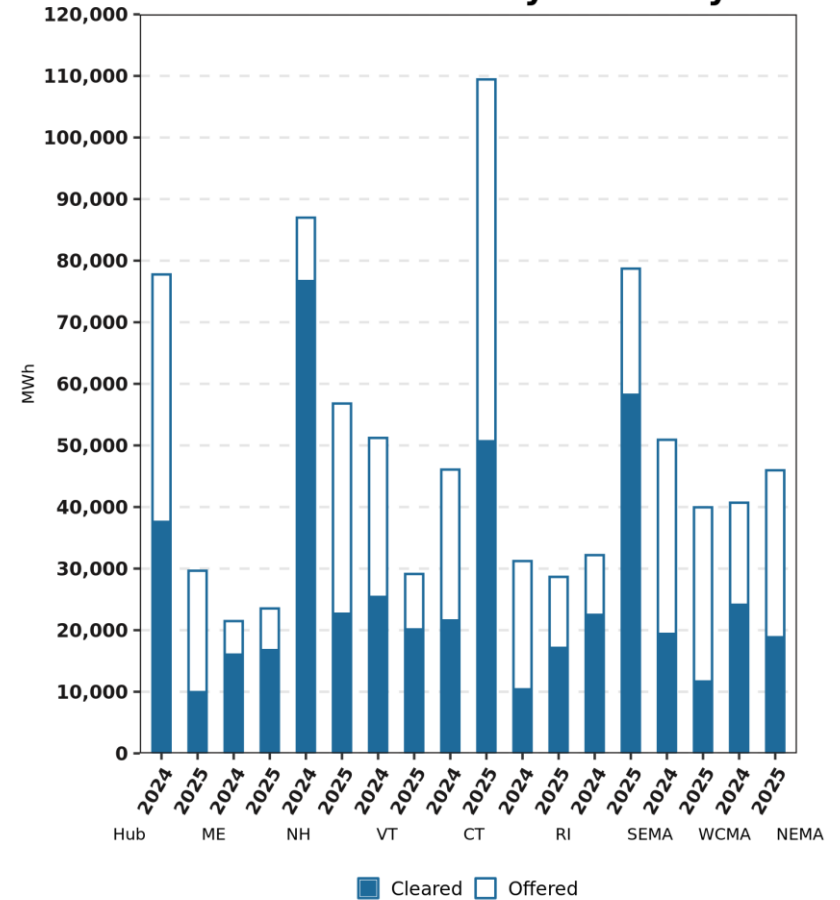


Zonal Increment Offers and Decrement Bid Amounts

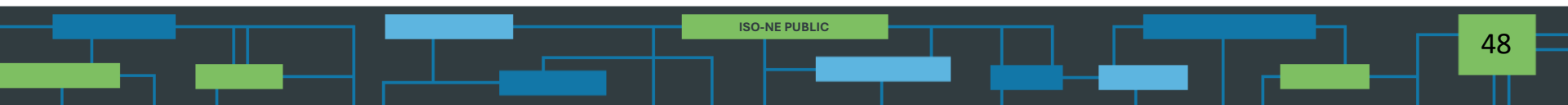
November Inc Monthly Totals By Zone



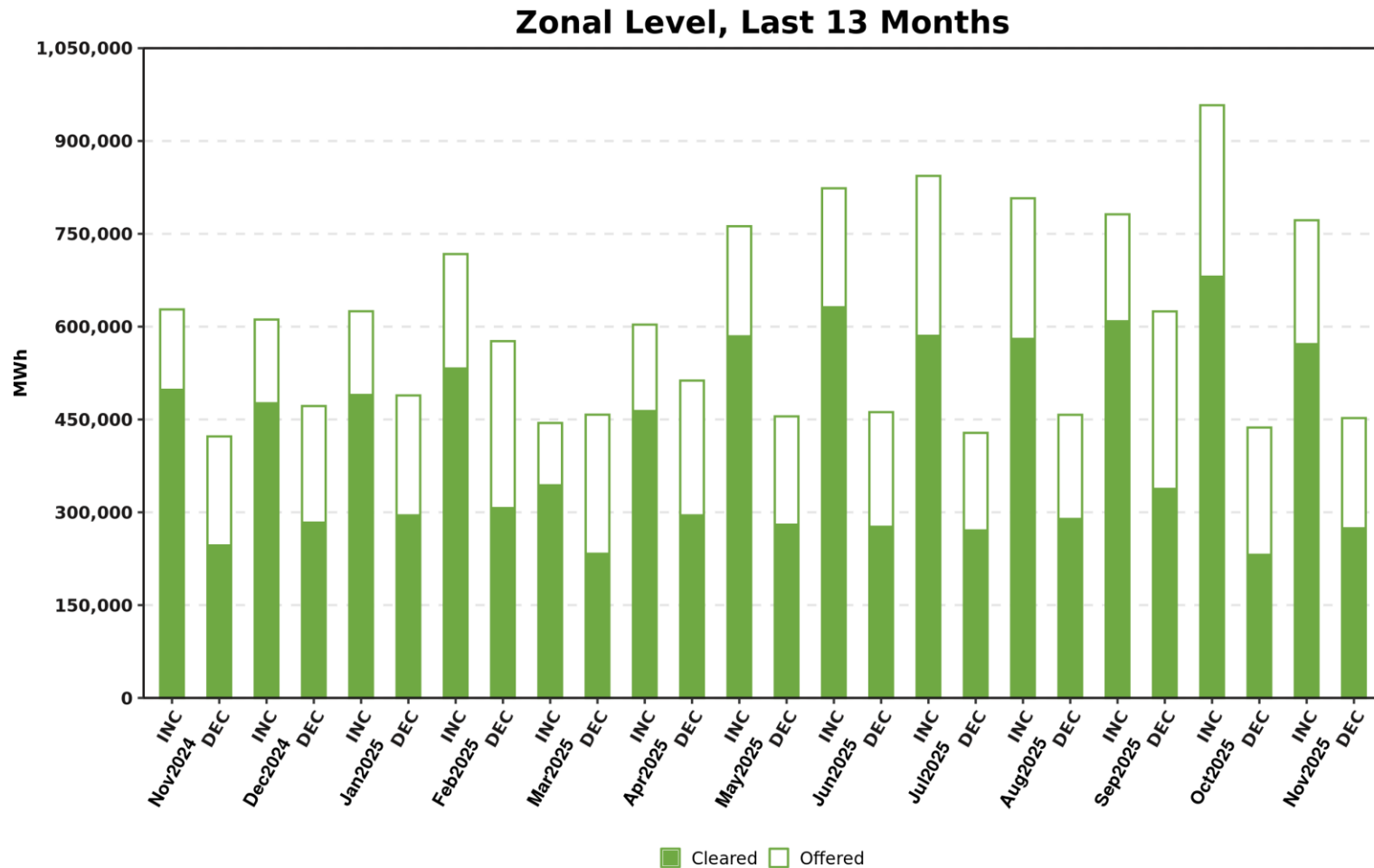
November Dec Monthly Totals By Zone



Includes nodal activity within the zone; excludes external nodes

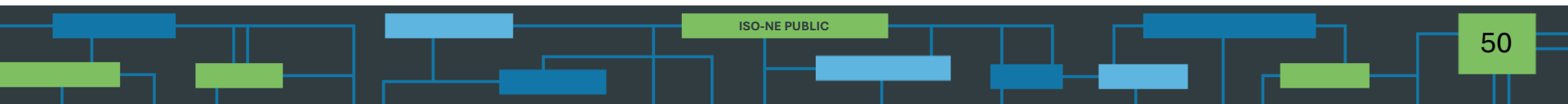


Total Increment Offers and Decrement Bids

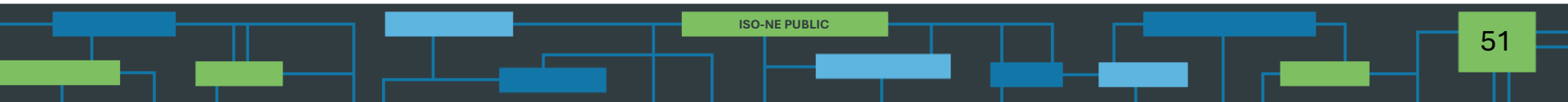


Includes nodal activity within the zone; excludes external nodes

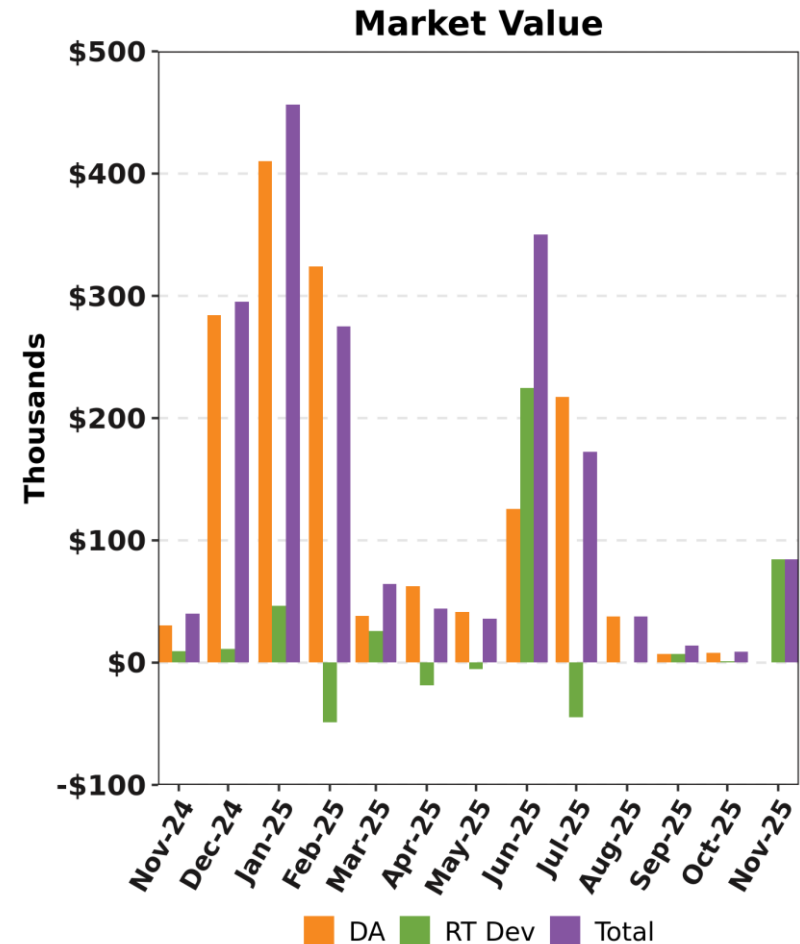
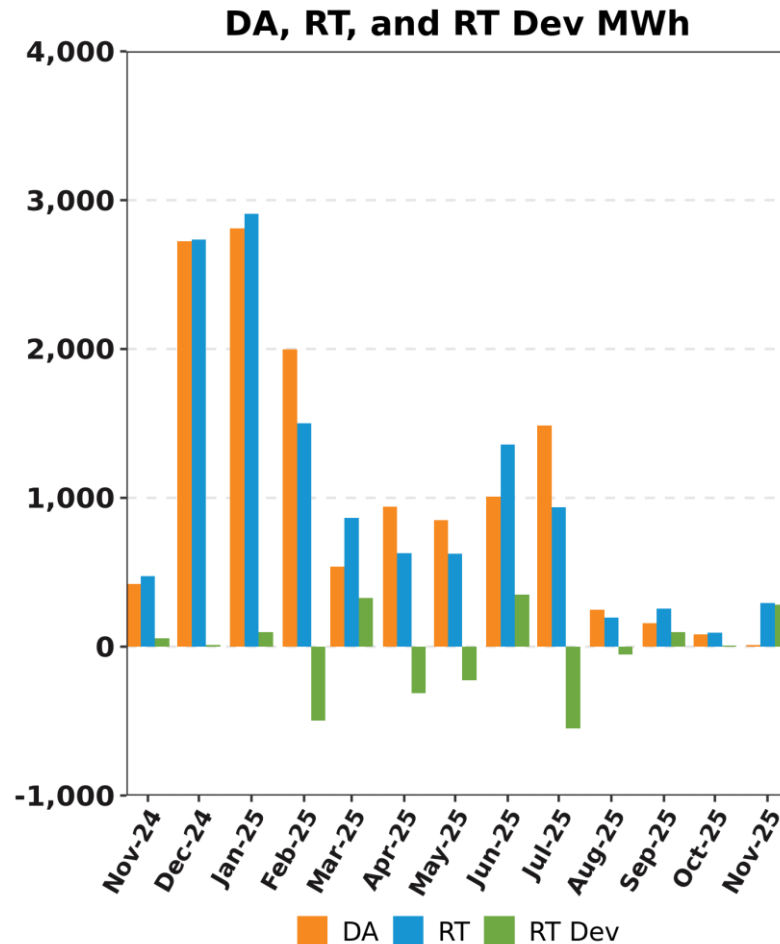
BACK-UP DETAIL



DEMAND RESPONSE

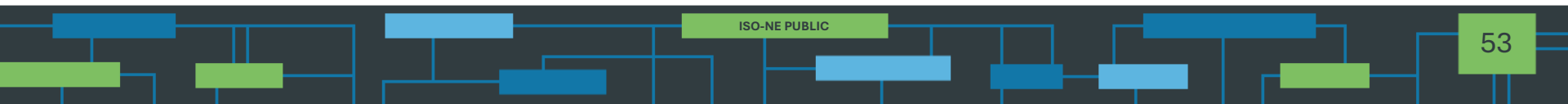


Demand Response Resource (DRR) Energy Market Activity by Month



DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.

NEW GENERATION

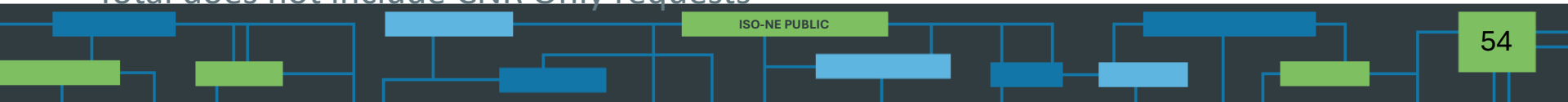


New Generation Update

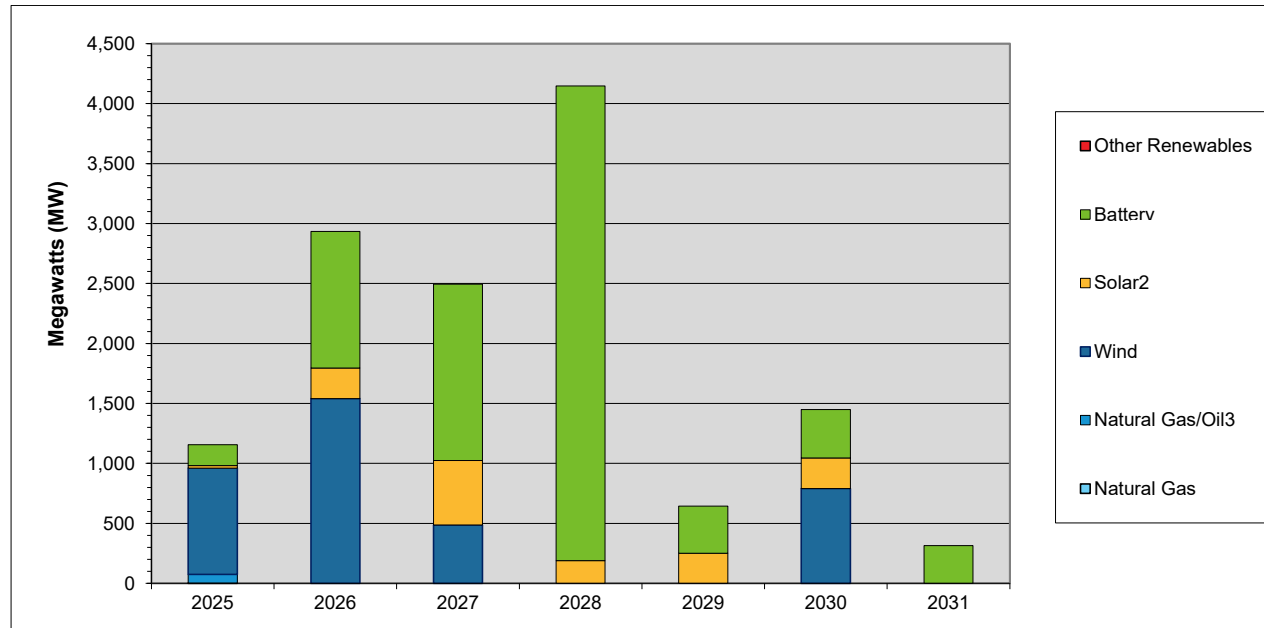
Based on Queue as of 12/01/25

- The interconnection queue has been updated to reflect the projects that have submitted the required materials to participate in the Order No. 2023 Transitional Cluster Study
- In total, 69* generation projects are currently being tracked by the ISO, totaling approximately 15,559 MW

* Total does not include CNR Only requests



Projected Annual Capacity Additions *By Supply Fuel Type*



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total ¹
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	175	1,140	1,471	3,957	392	404	315	7,854	59.8
Solar ²	20	255	537	190	252	254	0	1,508	11.5
Wind	886	1,540	487	0	0	791	0	3,704	28.2
Natural Gas/Oil ³	73	0	0	0	0	0	0	73	0.6
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	1,154	2,935	2,495	4,147	644	1,449	315	13,139	100.0

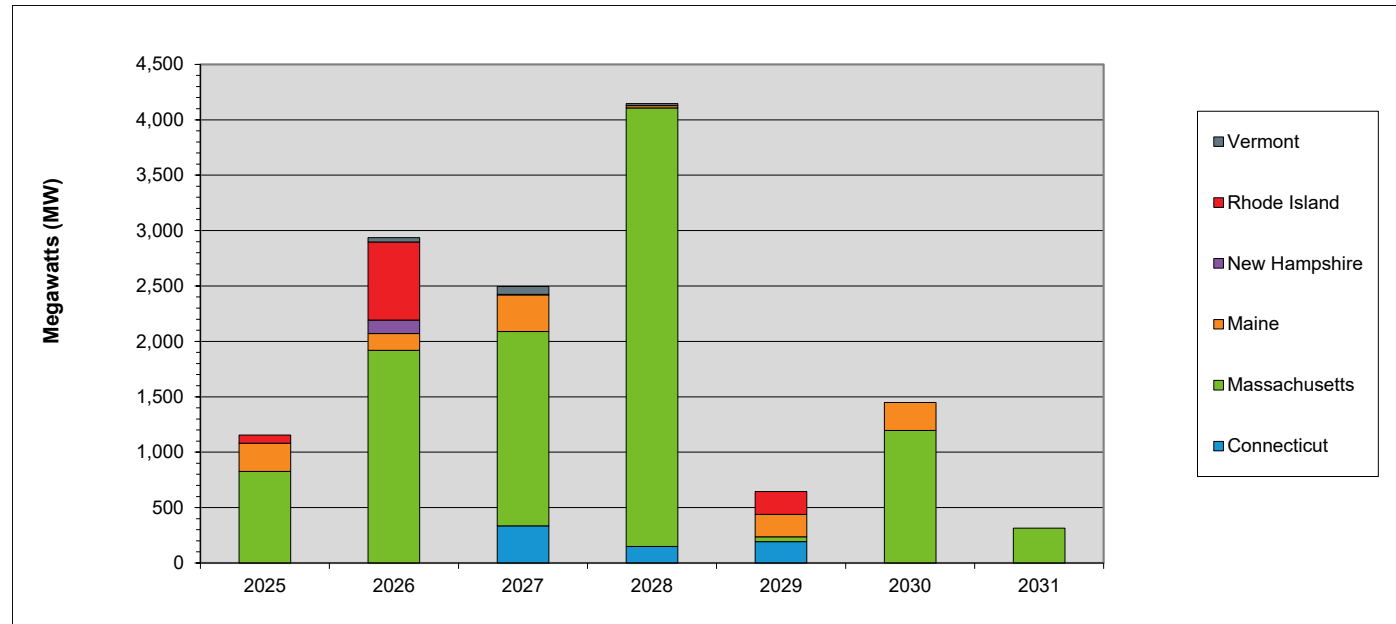
¹ Sum may not equal 100% due to rounding

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



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total ¹
Vermont	0	38	70	20	0	0	0	128	1.0
Rhode Island	73	704	0	0	205	0	0	982	7.5
New Hampshire	0	122	5	0	0	0	0	127	1.0
Maine	254	151	331	20	202	254	0	1,212	9.2
Massachusetts	827	1,920	1,753	3,957	45	1,195	315	10,012	76.2
Connecticut	0	0	336	150	192	0	0	678	5.2
Totals	1,154	2,935	2,495	4,147	644	1,449	315	13,139	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	31	7,854	2	425	29	7,429
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	1	73	0	0	1	73
Nuclear	0	0	0	0	0	0
Solar	27	1,528	4	76	23	1,452
Wind	10	6,104	3	877	7	5,227
Total	69	15,559	9	1,378	60	14,181

- 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	1	73	0	0	1	73
Peaker	58	9,382	6	501	52	8,881
Wind Turbine	10	6,104	3	877	7	5,227
Total	69	15,559	9	1,378	60	14,181

- 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

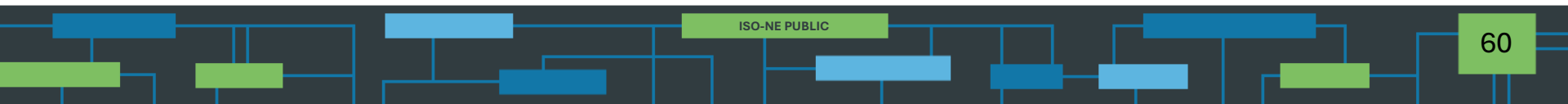
New Generation Projection

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	31	7,854	0	0	0	0	31	7,854	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	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	27	1,528	0	0	0	0	27	1,528	0	0
Wind	10	6,104	0	0	0	0	0	0	10	6,104
Total	69	15,559	0	0	1	73	58	9,382	10	6,104

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

FORWARD CAPACITY MARKET



Capacity Supply Obligation FCA 15

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	677.673	673.401	-4.272	579.692	-93.709	461.416	-118.276
	Passive Demand	3,212.865	3,211.403	-1.462	3,134.652	-76.751	3,113.332	-21.32
Demand Total		3,890.538	3,884.804	-5.734	3,714.344	-170.460	3,574.748	-139.596
Generator	Non-Intermittent	28,154.203	27,714.778	-439.425	27,081.653	-633.125	27,132.413	50.76
	Intermittent	1,089.265	1,073.794	-15.471	1,056.601	-17.193	865.694	-190.907
Generator Total		29,243.468	28,788.572	-454.896	28,138.254	-650.318	27,998.107	-140.147
Import Total		1,487.059	1297.132	-189.927	1,249.545	-47.587	1,193.583	-55.962
Grand Total*		34,621.065	33,970.508	-650.557	33,102.143	-868.365	32,766.438	-335.705
Net ICR (NICR)		33,270	31,775	-1,495	31,545	-230	31,380	-165

* 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 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		
	Passive Demand	2,316.815	2,314.068	-2.747	2,314.705	0.637		
Demand Total		2,939.669	2,898.981	-40.688	2,807.068	-91.913		
Generator	Non-Intermittent	26,507.420	26,715.489	208.069	26,271.866	-443.623		
	Intermittent	1,356.084	1,286.589	-69.495	1,310.622	24.033		
Generator Total		27,863.504	28,002.078	138.574	27,582.488	-419.59		
Import Total		566.998	564.079	-2.919	636.310	72.231		
Grand Total*		31,370.171	31,465.138	94.967	31,025.866	-439.272		
Net ICR (NICR)		30,305	30,395	90	30,600	205		

* 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				
	Passive Demand	2,070.498	2,851.331	780.833				
Demand Total		2,614.078	3,255.215	641.137				
Generator	Non-Intermittent	27,026.635	25,822.288	-1,204.347				
	Intermittent	1,450.872	890.415	-560.457				
Generator Total		28,477.507	26,712.703	-1,764.804				
Import Total		464.835	1,234.800	769.965				
Grand Total*		31,556.420	31,202.718	-353.702				
Net ICR (NICR)		30,550.000	30,415.000	-135.000				

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

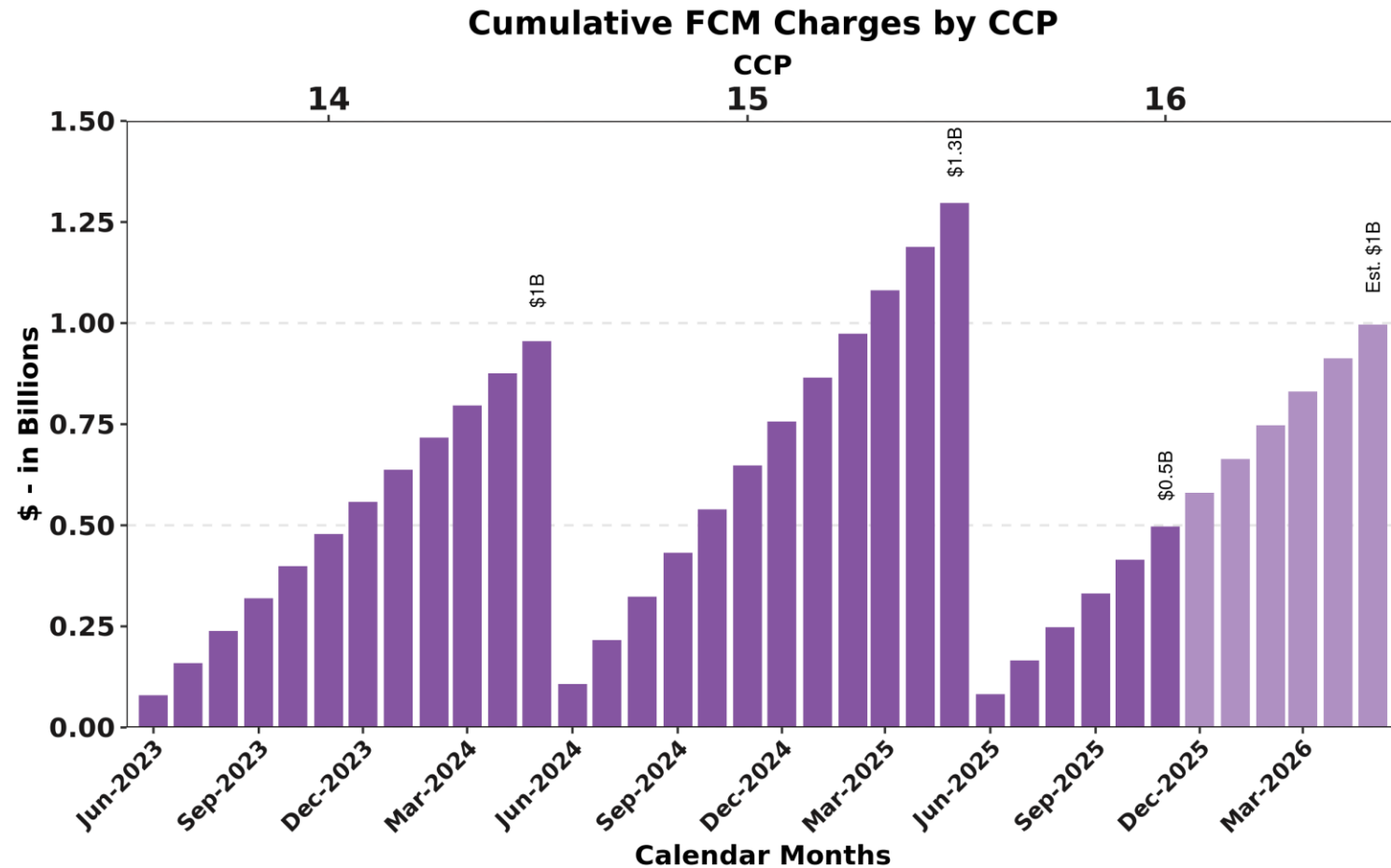
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes 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

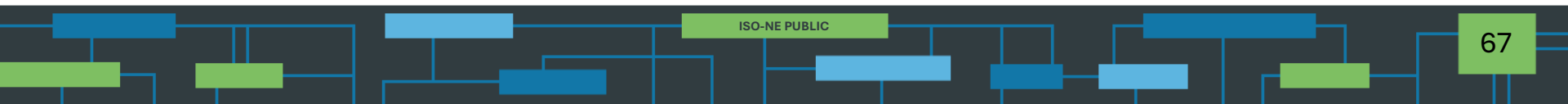
Commitment Period	Active/Passive	Existing	New	Grand Total
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3,085.734	514.072	3,599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3,386.703	653.541	4,040.244
2023-24	Active	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

Forward Capacity Market Auctions



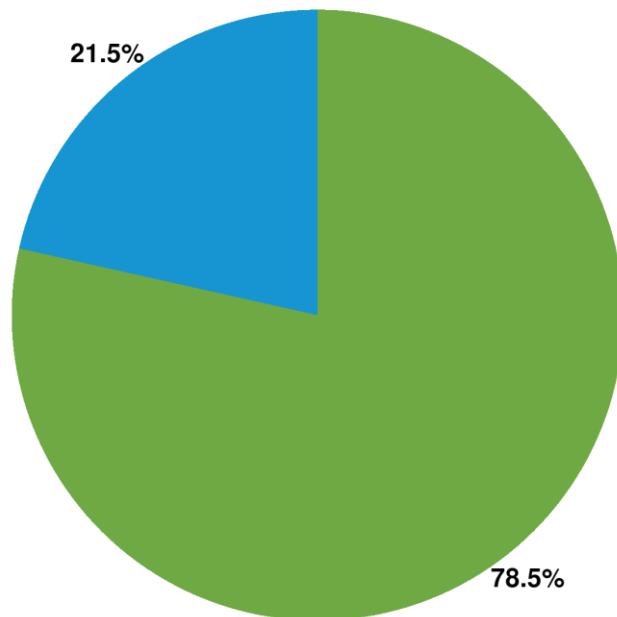
The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

NET COMMITMENT PERIOD COMPENSATION



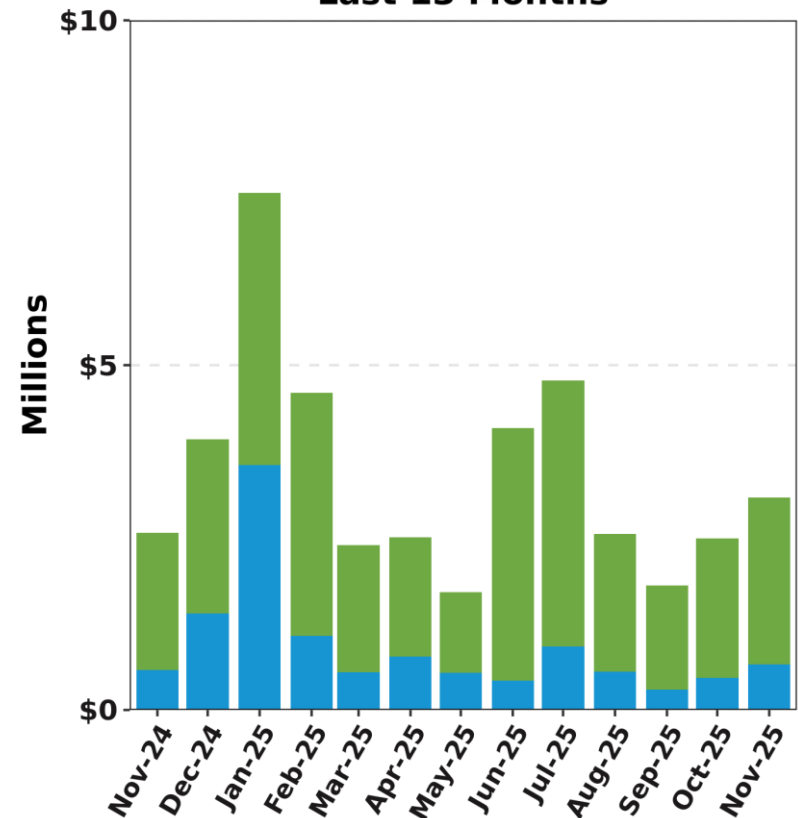
DA and RT NCPC Charges

Nov-25 Total = \$3.1 M



Day-Ahead Real-Time

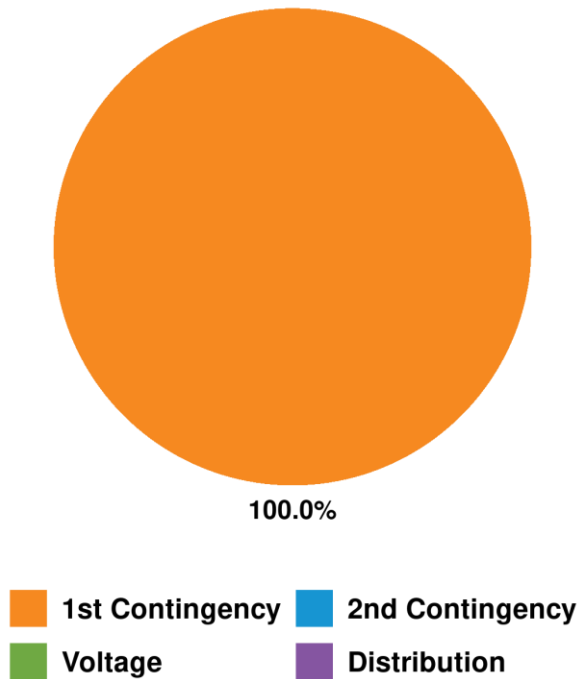
Last 13 Months



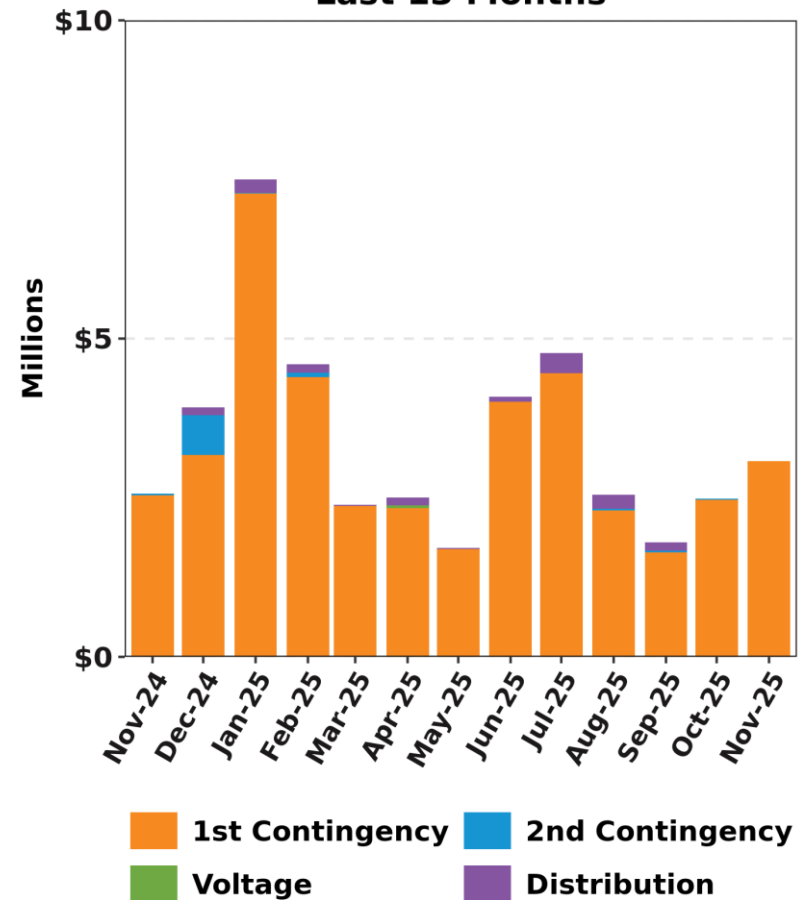
Day-Ahead Real-Time

NCPC Charges by Type

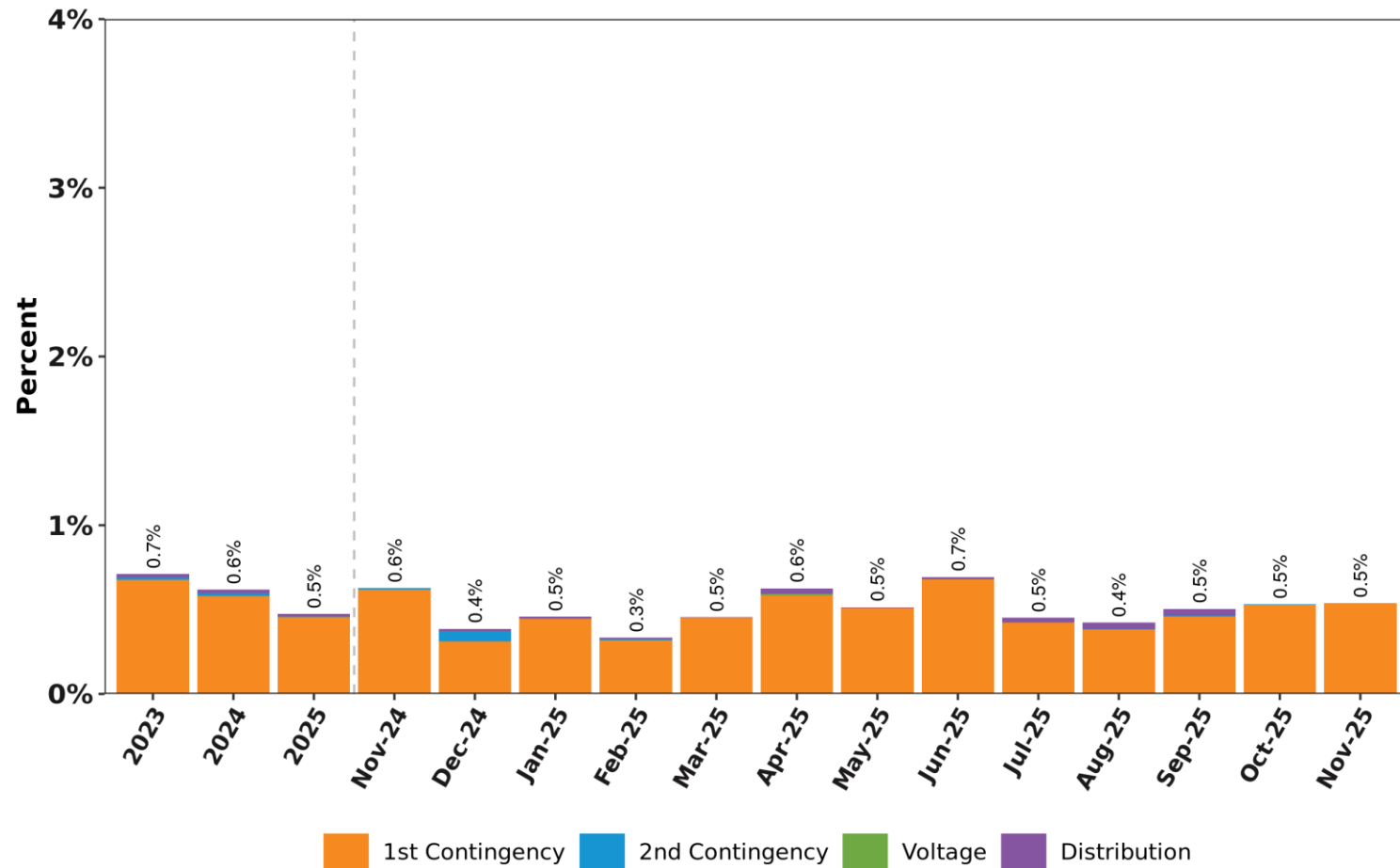
Nov-25 Total = \$3.1 M



Last 13 Months

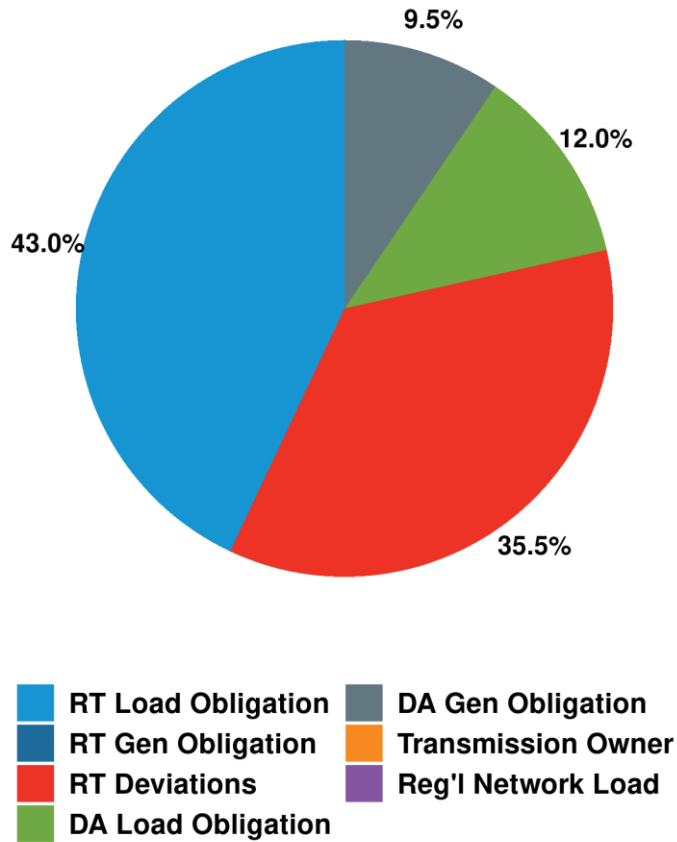


NCPC Charges by Type as Percent of Energy Market Value

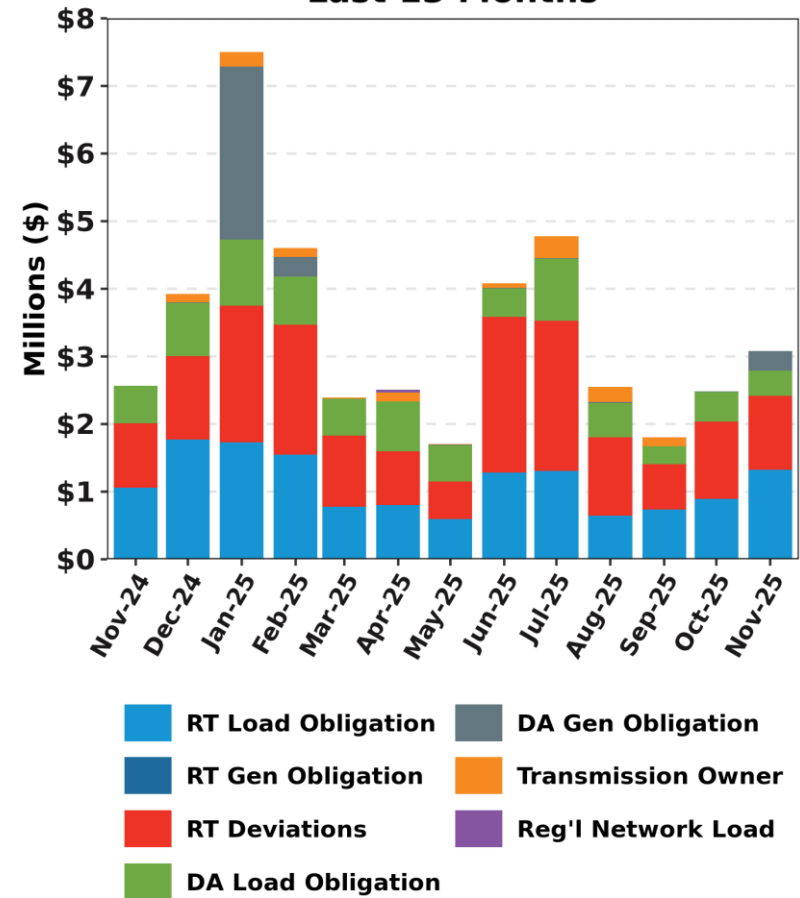


NCPC Charge Allocations

Nov-25 Total = \$3.1 M

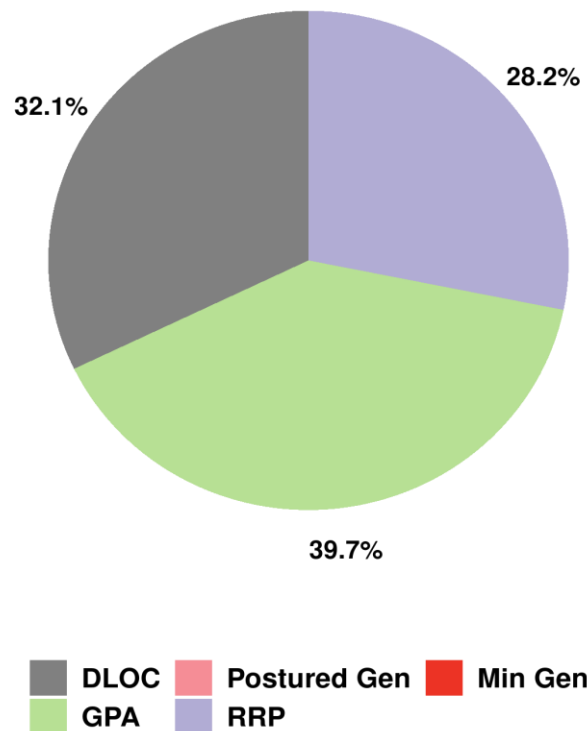


Last 13 Months

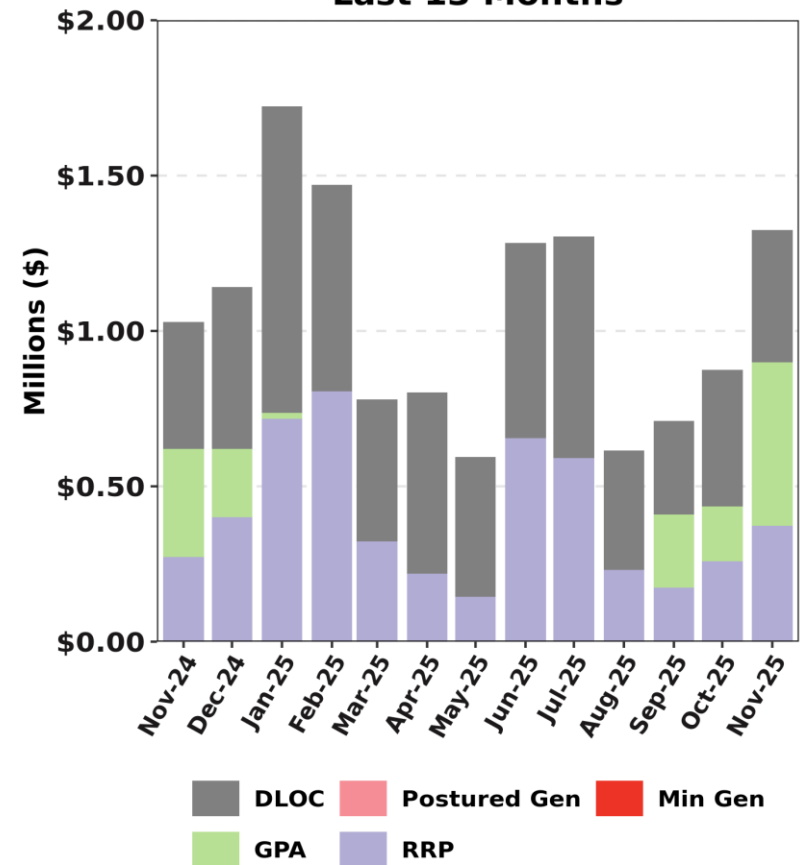


RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

Nov-25 Total = \$1.3 M



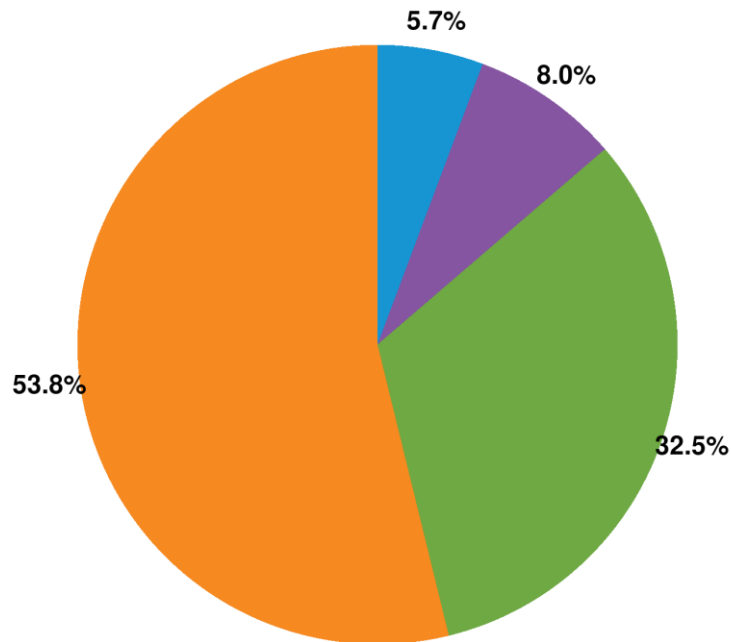
Last 13 Months



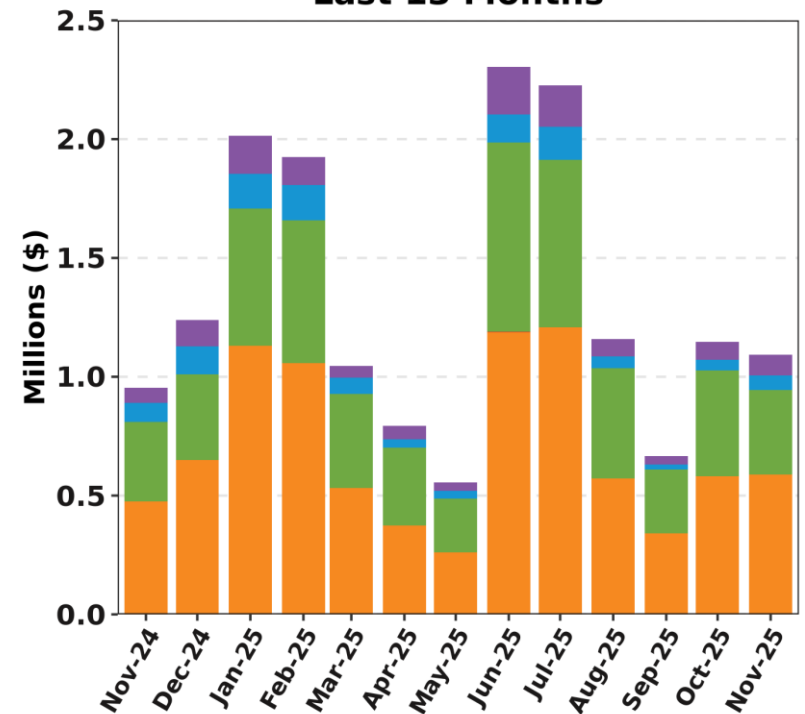
The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

RT First Contingency Charges by Deviation Type

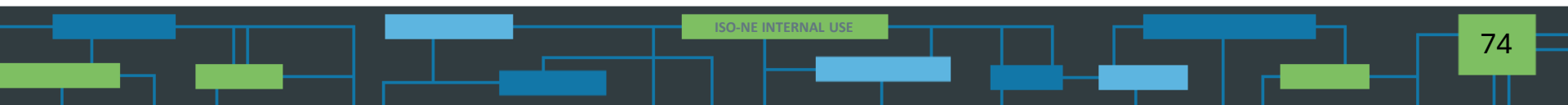
Nov-25 Total = \$1.1 M



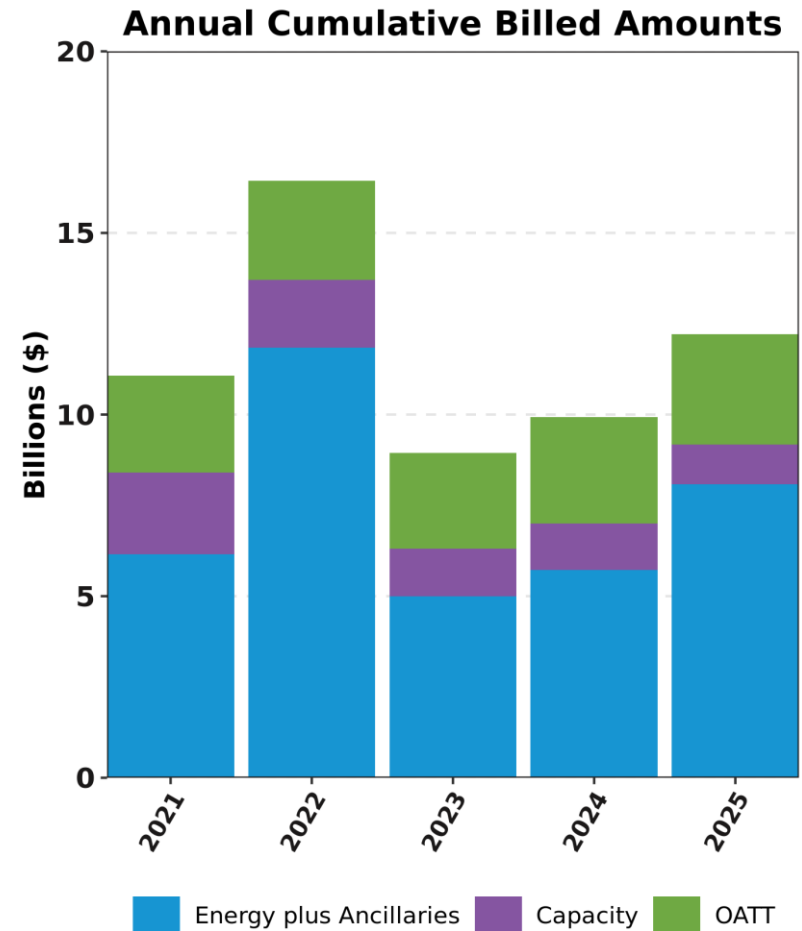
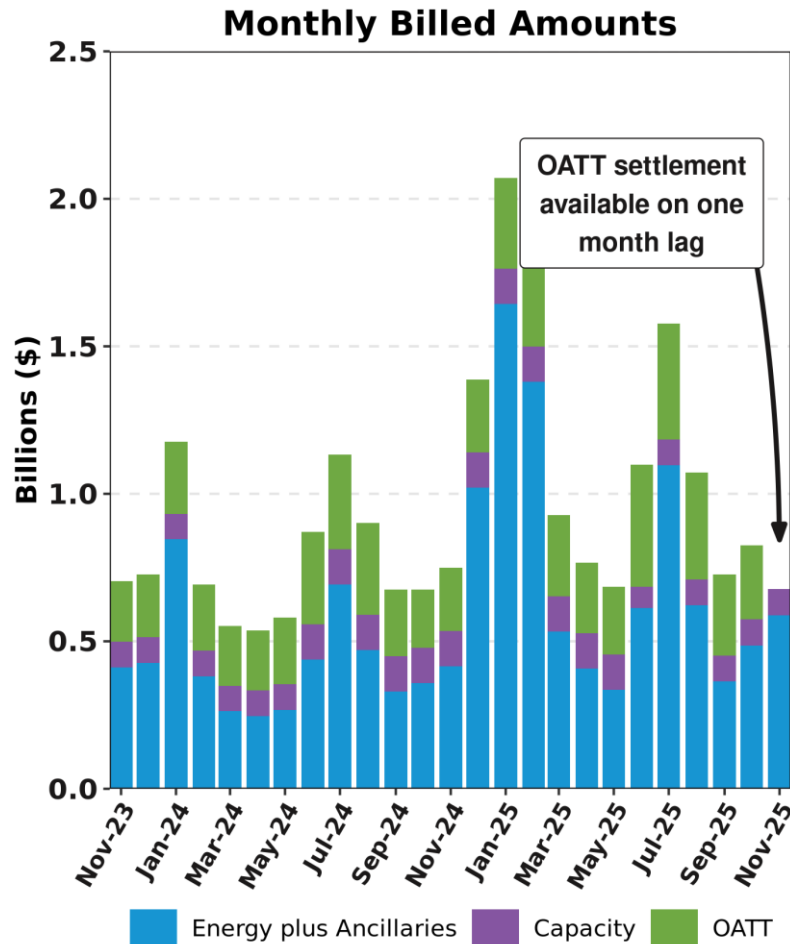
Last 13 Months



ISO BILLINGS

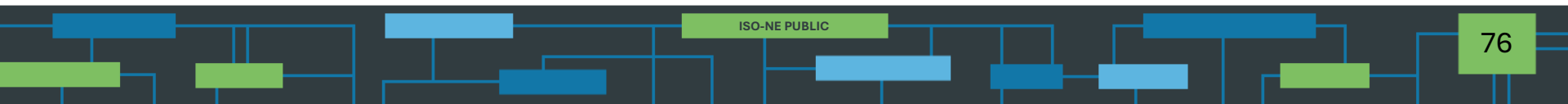


Total ISO Billings



Ancillaries = Reserves, Regulation, NCPC, minus Marginal Loss Revenue Fund. OATT = RNS, Through and Out, Schedule 9

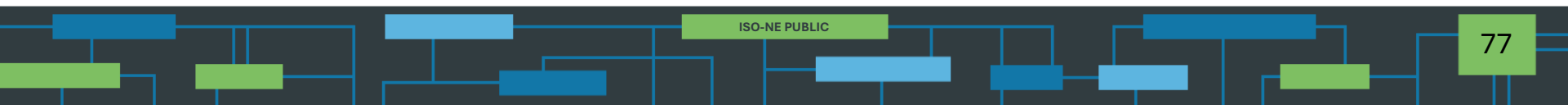
REGIONAL SYSTEM PLAN (RSP)



Planning Advisory Committee (PAC)

- December 17 PAC Meeting Agenda Topics*
 - Asset Condition Projects
 - Singer 345 kV Substation – Flood Mitigation Project Update
 - Eversource Telecommunications Asset Strategy
 - Eversource Line 1803, Optical Ground Wire Installation Project
 - E-183W Process Discussion
 - ACL 430: E-183W 115 kV Line Rebuild Update
 - Moody's Macroeconomic Outlook
 - 2024 Economic Studies: System Efficiency Needs Scenario (SENS) Sensitivity Results

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



2025 Longer-Term Transmission Planning (LTP) RFP

- On 12/13/24, NESCOE provided its LTP 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 is evaluating all submissions and expects to provide an update on the initial review of proposals in late 2025/early 2026

* Unless a bidder can demonstrate supply chain issues that warrant a later in-service date

** Bidders may propose alternate locations which would be more efficient and cost-effective

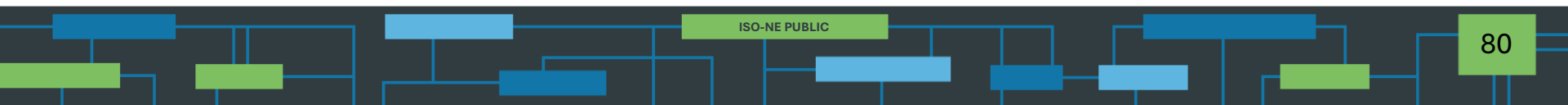
2025 Longer-Term Transmission Planning (LTP) RFP, cont.

- Total of 6 Longer-Term Proposals submitted
 - 4 are joint proposals
- Total of 4 different lead QTPSs (3 non-incumbents, 1 incumbent)
 - 4 additional QTPSs are participating as part of joint proposals (all are incumbents)
- Project Designs
 - 3 primarily AC transmission
 - 3 primarily HVDC transmission
 - All designs claim they support 1200 MW of northern ME wind
 - Claimed Surowiec-South Limits: 3200-3800 MW (3200 MW target)
 - Claimed Maine-New Hampshire Limits: 3000-3600 MW (3000 MW target)
- Project Installed Costs*
 - Low of \$0.96B
 - High of \$4.04B
- In-Service Dates: Q4 2032 to Q3 2035 (12/31/2035 target)

* Costs may include estimates for corollary upgrades

Economic Studies: 2024 Study

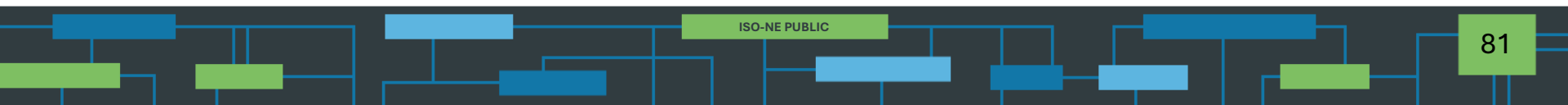
- 2024 Economic Study
 - This study is the first use of new Economic Study Process Tariff language
 - The study was initiated at the January 2024 PAC meeting and will be completed this year unless a Request for Proposal is triggered
 - Benchmark, Policy and Stakeholder-Requested Scenarios are complete and the report and factsheet were issued in September
 - There was also a public webinar in September
 - System Efficiency Needs Scenario is being analyzed between now and Q4 2025
 - Economic Study Phase 2 Tariff changes were accepted by FERC on 6/20/25, with an effective date of 6/23/25



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 11/24/2025

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

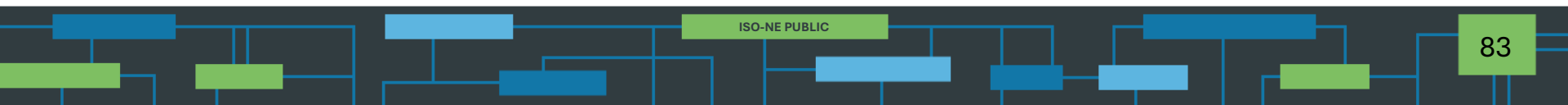
SEMA/RI Reliability Projects, cont.

Status as of 11/24/2025

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	Jun-28	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	Dec-26	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

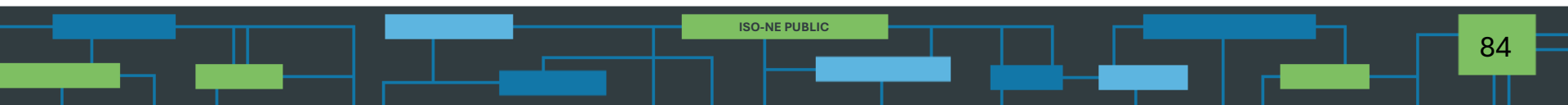


SEMA/RI Reliability Projects, cont.

Status as of 11/24/2025

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	Dec-26	2



SEMA/RI Reliability Projects, cont.

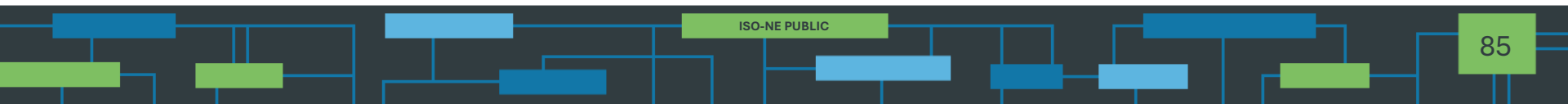
Status as of 11/24/2025

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	Dec-25	3
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

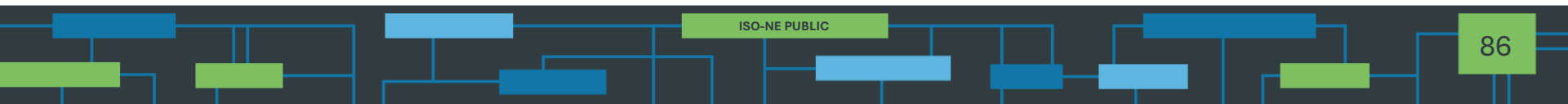


SEMA/RI Reliability Projects, cont.

Status as of 11/24/2025

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

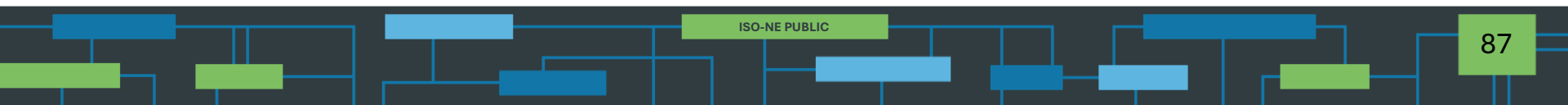


Upper Maine Solution Projects

Status as of 11/24/2025

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	Jul-28	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Jul-28	1
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



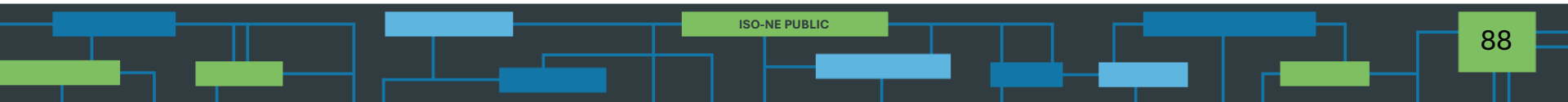
Upper Maine Solution Projects, cont.

Status as of 11/24/2025

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	Jun-26	2

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

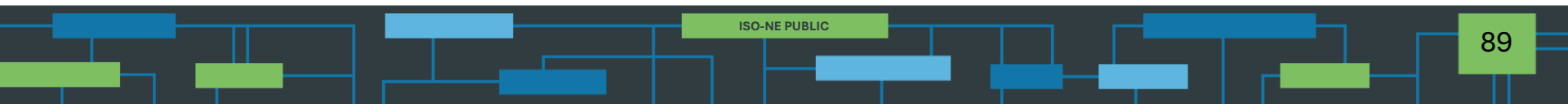


Boston 2033 Solutions Study

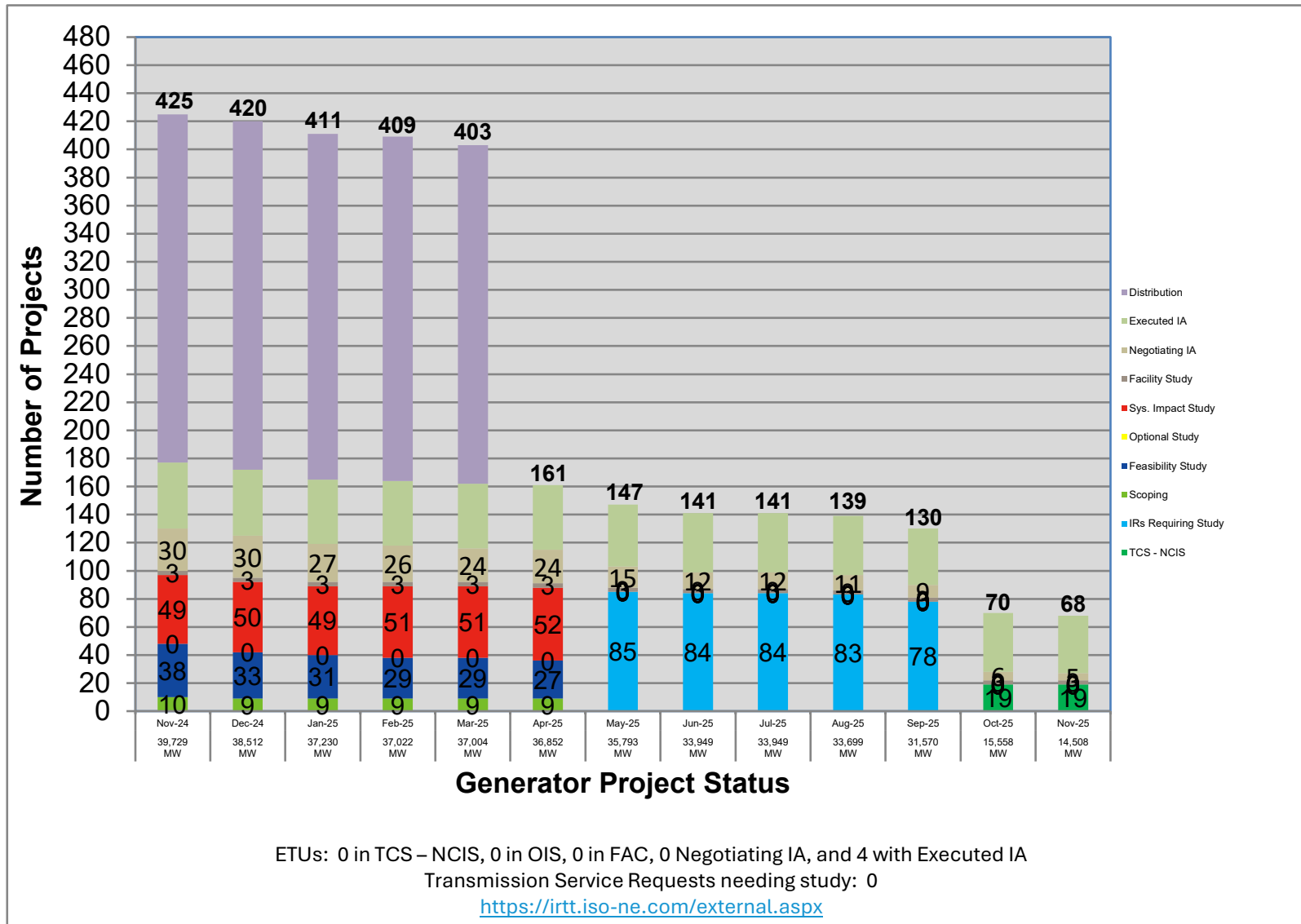
Status as of 11/24/2025

Project Benefit: Addresses system needs in the Boston area

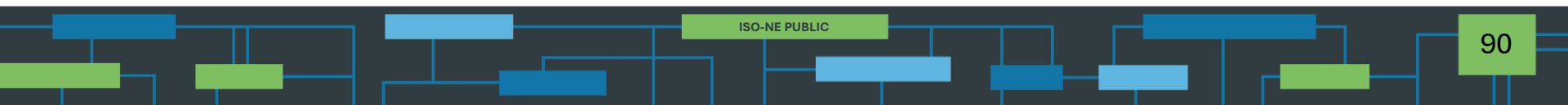
RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1933	Install one 80 MVAR shunt reactor at the 115 kV Electric Avenue Substation	Dec-28	1
1934	Protection systems modification associated with the Stoughton RAS at three 345 kV substations (Stoughton, West Walpole and Holbrook) and two 115 kV substations (Hyde Park and K-Street)	May-26	1



Status of Tariff Studies as of November 24, 2025



Additional Notes provided on next slide



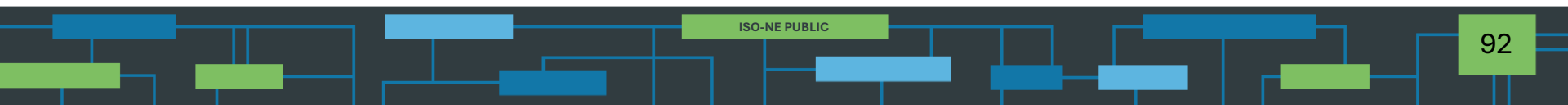
Status of Tariff Studies as of November 24, 2025, cont.

Additional Notes:

- *As of April 2025, the ISO is no longer tracking Distribution Projects in its interconnection queue.*
- *The values starting in May 2025 reflect that, as a result of the Order No. 2023 response from FERC, the ISO is no longer performing serial interconnection studies.*
- *The “TCS – NCIS” category represents projects that did not complete a system impact study before April 4, 2025 and require study in the Transitional Cluster Study (TCS) according to the Network Capability Interconnection Standard (NCIS). Such projects may also be studied in the TCS according to the Capacity Capability Interconnection Standard (CCIS). There are additional projects in the TCS that are seeking to augment their Network Resource Interconnection Service (NRIS) to Capacity Network Resource Interconnection Service (CNRIS) (and thus will only be studied in the TCS according to the CCIS), but are included in the Executed IA/Negotiating IA totals.*

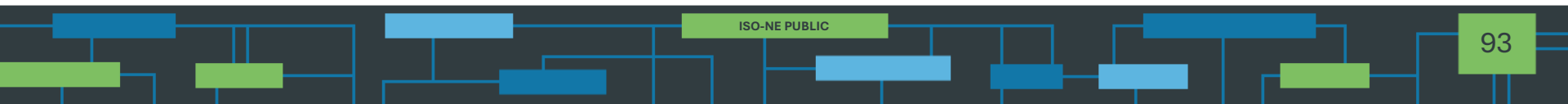
Note on Air Emissions Slides

- For more timely reporting and stakeholder convenience, the data and information included in this report on air emissions can now be found by visiting the ISO website, under System Planning > Plans and Studies > Environmental and Emissions Reports
 - <https://www.iso-ne.com/system-planning/system-plans-studies/emissions>
- Monthly and year-to-date emissions by fuel type are reported in the ISO Newswire article series, [Monthly Wholesale Electricity Prices and Demand in New England](#) (link can be found on the page above)



OPERABLE CAPACITY ANALYSIS

Winter 2025/26 Analysis



Winter 2025/26 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan - 2026 ² CSO (MW)	Jan - 2026 ² SCC (MW)
Operable Capacity MW ¹	26,640	29,773
Active Demand Capacity Resource (+) ⁵	399	292
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	318	318
Non Gas-fired Planned Outage MW (-)	43	1,171
Gas Generator Outages MW (-)	0	33
Allowance for Unplanned Outages (-) ⁴	2,800	2,800
Generation at Risk Due to Gas Supply (-) ³	3,583	3,936
Net Capacity (NET OPCAP SUPPLY MW)	22,166	23,678
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	20,056	20,056
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,181	22,181
Operable Capacity Margin	-15	1,497

¹Operable Capacity is based on data as of **November 21, 2025** 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 **November 21, 2025**.

² Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 10, 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.

Winter 2025/26 Operable Capacity Analysis

90/10 Load Forecast	Jan - 2026 ² CSO (MW)	Jan - 2026 ² SCC (MW)
Operable Capacity MW ¹	26,640	29,773
Active Demand Capacity Resource (+) ⁵	399	292
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	318	318
Non Gas-fired Planned Outage MW (-)	43	1,171
Gas Generator Outages MW (-)	0	33
Allowance for Unplanned Outages (-) ⁴	2,800	2,800
Generation at Risk Due to Gas Supply (-) ³	4,331	4,795
Net Capacity (NET OPCAP SUPPLY MW)	21,418	22,819
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	21,125	21,125
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,250	23,250
Operable Capacity Margin	-1,832	-431

¹Operable Capacity is based on data as of **November 21, 2025** 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 **November 21, 2025**.

² Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 10, 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.

Winter 2025/26 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

November 21, 2025 - 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 January through March.

Report created: 11/21/2025

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
12/6/2025	27114	288	596	189	209	878	3200	1490	22410	19324	2125	21449	961	N	Winter 2025/2026
12/13/2025	27114	288	596	189	133	333	3200	2412	22109	19334	2125	21459	650	N	Winter 2025/2026
12/20/2025	27114	288	896	189	49	0	3200	3134	22104	19390	2125	21515	589	N	Winter 2025/2026
12/27/2025	27114	288	896	189	44	0	3200	3733	21510	19390	2125	21515	-5	N	Winter 2025/2026
1/3/2026	26640	399	1235	318	22	0	2800	3728	22042	19637	2125	21762	280	N	Winter 2025/2026
1/10/2026	26640	399	1235	318	43	0	2800	3583	22166	20056	2125	22181	-15	Y	Winter 2025/2026
1/17/2026	26640	399	1235	318	116	162	2800	2972	22542	20056	2125	22181	361	N	Winter 2025/2026
1/24/2026	26640	399	1235	318	49	162	2800	2673	22908	20056	2125	22181	727	N	Winter 2025/2026
1/31/2026	26390	399	1235	568	23	0	3100	2536	22933	19855	2125	21980	953	N	Winter 2025/2026
2/7/2026	26390	399	1235	568	20	0	3100	2237	23235	19615	2125	21740	1495	N	Winter 2025/2026
2/14/2026	26390	399	1235	568	20	0	3100	1788	23684	19589	2125	21714	1970	N	Winter 2025/2026
2/21/2026	26390	399	1235	568	56	0	3100	1489	23947	19352	2125	21477	2470	N	Winter 2025/2026
2/28/2026	26390	399	1235	568	370	0	2200	414	25608	18461	2125	20586	5022	N	Winter 2025/2026
3/7/2026	26390	399	1235	568	352	0	2200	308	25732	18147	2125	20272	5460	N	Winter 2025/2026
3/14/2026	26390	399	1235	568	342	426	2200	0	25624	17970	2125	20095	5529	N	Winter 2025/2026
3/21/2026	26390	399	1235	568	485	426	2200	0	25481	17641	2125	19766	5715	N	Winter 2025/2026
3/28/2026	26233	399	1235	568	500	1580	2700	0	23655	17132	2125	19257	4398	N	Winter 2025/2026

Column Definitions

- CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
- 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 participate in the Day-Ahead and Real-Time Energy Markets.
- External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
- Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
- 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.
- 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.
- 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.
- 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.
- CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
- Peak Load Forecast MW:** Provided in the annual 2025 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).
- Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
- CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
- CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
- Operable Capacity Season Label:** Applicable season and year.
- Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2025/26 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS November 21, 2025 - 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 January through March.

Report created: 11/21/2025

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	
12/6/2025	27114	288	596	189	209	878	3200	2477	21423	20354	2125	22479	-1056	N	Winter 2025/2026
12/13/2025	27114	288	596	189	133	333	3200	3531	20990	20365	2125	22490	-1500	N	Winter 2025/2026
12/20/2025	27114	288	896	189	49	0	3200	4280	20958	20424	2125	22549	-1591	N	Winter 2025/2026
12/27/2025	27114	288	896	189	44	0	3200	4408	20835	20424	2125	22549	-1714	N	Winter 2025/2026
1/3/2026	26640	399	1235	318	22	0	2800	4539	21231	20684	2125	22809	-1578	N	Winter 2025/2026
1/10/2026	26640	399	1235	318	43	0	2800	4331	21418	21125	2125	23250	-1832	Y	Winter 2025/2026
1/17/2026	26640	399	1235	318	116	162	2800	3870	21644	21125	2125	23250	-1606	N	Winter 2025/2026
1/24/2026	26640	399	1235	318	49	162	2800	3870	21711	21125	2125	23250	-1539	N	Winter 2025/2026
1/31/2026	26390	399	1235	568	23	0	3100	3583	21886	20914	2125	23039	-1153	N	Winter 2025/2026
2/7/2026	26390	399	1235	568	20	0	3100	3284	22188	20661	2125	22786	-598	N	Winter 2025/2026
2/14/2026	26390	399	1235	568	20	0	3100	2686	22786	20633	2125	22758	28	N	Winter 2025/2026
2/21/2026	26390	399	1235	568	56	0	3100	2237	23199	20384	2125	22509	690	N	Winter 2025/2026
2/28/2026	26390	399	1235	568	370	0	2200	1311	24711	19446	2125	21571	3140	N	Winter 2025/2026
3/7/2026	26390	399	1235	568	352	0	2200	1206	24834	19114	2125	21239	3595	N	Winter 2025/2026
3/14/2026	26390	399	1235	568	342	426	2200	0	25624	18928	2125	21053	4571	N	Winter 2025/2026
3/21/2026	26390	399	1235	568	485	426	2200	0	25481	18582	2125	20707	4774	N	Winter 2025/2026
3/28/2026	26233	399	1235	568	500	1580	2700	0	23655	18045	2125	20170	3485	N	Winter 2025/2026

Column Definitions

- CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
- 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 participate in the Day-Ahead and Real-Time Energy Markets.
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- 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.
- 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.
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- CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8-9)
- Peak Load Forecast MW:** Provided in the annual 2025 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).
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- CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
- CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
- Operable Capacity Season Label:** Applicable season and year.
- Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

*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

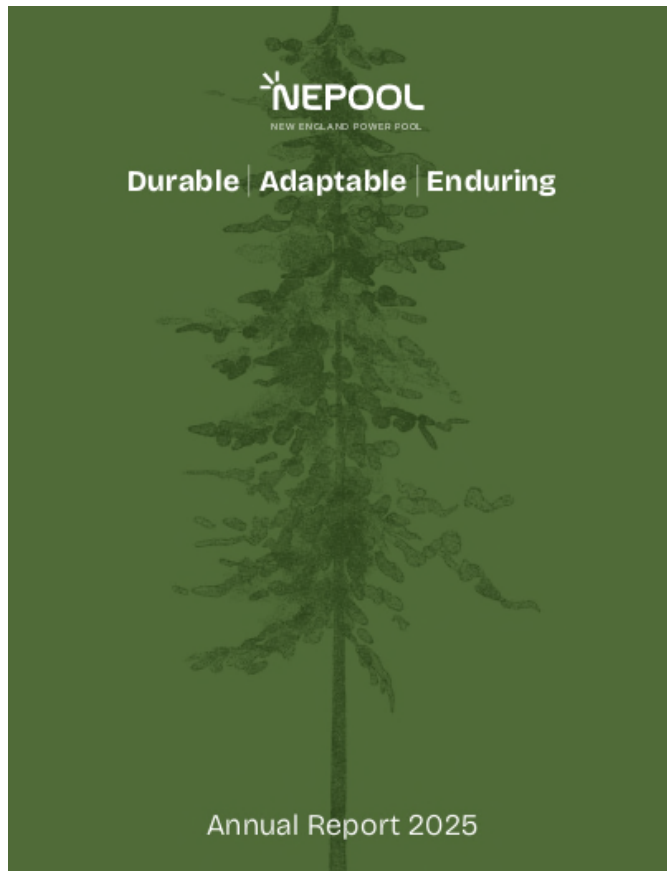
OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 ³
9	Transmission Customer 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

6

2025 NEPOOL Annual Report



Dec 4, 2025
Meeting

7

2026 NPC Officer Election



66.67%

Dec 4, 2025
Meeting

To elect NEPOOL Participants Committee Officers for 2026.

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2026 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Sarah Bresolin
Vice-Chair	Jackie Bihrlé
Vice-Chair	Dave Cavanaugh
Vice-Chair	Steve Kirk
Vice-Chair	Aleks Mitreski
Vice-Chair	Dave Norman
Secretary	Sebastian Lombardi
Assistant Secretary	Pat Gerity

**NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING**

December 4, 2025

RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2026

WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and

WHEREAS, pursuant to those procedures the individuals indentified in the following resolution were nominated and elected for 2026 to the offices of Chair and Vice-Chair, as set forth opposite their names; and

WHEREAS Section 7.1 of the Second Restated NEPOOL Agreement provides that officers be elected at the Annual Meeting of the Participants Committee.

NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2026 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Sarah Bresolin
Vice-Chair	Jackie Bihrlle
Vice-Chair	Dave Cavanaugh
Vice-Chair	Steve Kirk
Vice-Chair	Aleks Mitreski
Vice-Chair	Dave Norman
Secretary	Sebastian Lombardi
Assistant Secretary	Pat Gerity

8

Estimated Budget for 2026 Participant Expenses



66.67%

To adopt a NEPOOL Budget for 2026.

RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2026 as presented at this meeting.

Dec 4, 2025
Meeting

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Tom Kaslow, Chair, NEPOOL Budget & Finance Subcommittee
Rosendo Garza, NEPOOL Counsel

DATE: November 25, 2025

RE: Estimated Budget for 2026 Participant Expenses

At its December 4 meeting, the Participants Committee will be asked to approve the estimated NEPOOL expense budget for 2026 (2026 Budget), included as Attachment A. Consistent with prior years, the proposed 2026 Budget estimates are compared to both the current-year estimated expenses approved by the Participants Committee at its last annual meeting and the current forecast of actual expenses for this year.¹

Consistent with prior years' practice, NEPOOL Counsel, the GIS Administrator, the ISO, and NEPOOL's Independent Financial Advisor collaborated to develop the recommended 2026 Budget. The NEPOOL Budget & Finance Subcommittee discussed the proposed 2026 Budget at its November 14 meeting. Although a few background questions regarding the allocation of Participant Expenses were raised during discussion, no Subcommittee member expressed any objection to the proposed 2026 Budget.

The following form of resolution may be used in acting on the 2026 Budget:

RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2026 as presented at this meeting.

¹ An estimated projection of a Participant's share of the 2026 Budget expenses, including a comparison to 2025 per-Participant expense shares, will be circulated under separate cover.

**ESTIMATED 2026 NEPOOL BUDGET COMPARED TO
2025 NEPOOL BUDGET AND 2025 PROJECTED ACTUAL EXPENSES**

<u>Line Items</u>	<u>2025 Approved Budget</u>	<u>2026 Proposed Budget</u>	<u>2025 Current Forecast</u>
NEPOOL Counsel Fees (1)	\$ 4,500,000	\$ 4,500,000	\$ 4,500,000
NEPOOL Counsel Disbursements (1)	\$ 30,000	\$ 30,000	\$ 30,000
Independent Financial Advisor Fees and Disbursements (2)	\$ 48,000	\$ 48,000	\$ 46,000
Committee Meeting Expenses (1) (3)	\$ 960,000	\$ 1,050,000	\$ 1,150,000
Generation Information System (5)	\$ 1,183,624	\$ 1,347,300	\$ 1,329,698
Credit Insurance Premium (4)	\$ 604,500	\$ 561,700	\$ 543,000
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (6)	\$ 0	\$ 0	\$ 0
SUBTOTAL EXPENSES	\$ 7,326,124	\$ 7,537,000	\$ 7,598,698
<u>Revenue</u>			
NEPOOL Membership Fees (4)	(\$ 2,500,000)	(\$ 2,500,000)	(\$ 2,493,200)
Generation Information System (5) (7)	(\$ 1,183,624)	(\$ 1,347,300)	(\$ 1,329,698)
Credit Insurance Premium (4) (8)	(\$ 604,500)	(\$ 561,700)	(\$ 543,000)
TOTAL REVENUE	(\$ 4,288,124)	(\$ 4,409,000)	(\$ 4,365,898)
TOTAL NEPOOL EXPENSES	\$ 3,038,000	\$ 3,128,000	\$ 3,232,800

Notes

- (1) Day Pitney LLP, NEPOOL Counsel, provided the proposed 2026 estimate.
- (2) Michael M. Mackles, NEPOOL's Independent Financial Advisor, provided the 2026 proposed estimate, reflecting the review of meeting and travel expenses. The 2025 Current Forecast is lower than the 2025 Approved Budget due to the cancellation of some Budget & Finance Subcommittee meetings.
- (3) The 2025 Current Forecast for Committee Meeting Expenses captures higher meeting costs that exceeded the 2025 estimates for each Principal Committee meeting, along with strong attendance at the Summer Meetings.
- (4) ISO New England Inc. provided the 2026 proposed estimate.
- (5) Based on fee arrangement set forth in the Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the projected annualized fixed fee for 2026 is \$1,347,300. This amount includes \$15,000 for ISO-NE's administrative GIS-related costs. The estimate assumes that NEPOOL will remain in the 140,000–149,999 tier of total Account Holders and Generators for the first four months of the year (January through April), increase to the 150,000–159,999 tier for the following five months (May through September), and then increase to the 160,000–169,999 tier for the final three months of the year (October through December), resulting in a higher annual fee.

The 2025 Current Forecast is higher than the 2025 Approved Budget because the number of Account Holders and Generators increased more rapidly than projected in 2024 and several GIS-related changes approved in 2025 were not anticipated in the 2024 projections.
- (6) If NEPOOL determines that an audit should be performed in 2026, funding for that audit will be addressed separately.
- (7) GIS costs are paid by "GIS Participants" pursuant to the Allocation of Costs Related to Generation Information System, as approved by the NEPOOL Participants Committee on June 21, 2001 and amended on May 6, 2016.
- (8) Credit insurance premiums are paid by Qualifying Market Participants in accordance with the methodology set forth in Section IX of the ISO New England Financial Assurance Policy.

ESTIMATED BREAKDOWN OF PROJECTED 2026 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

(2025 figures as projected and budgeted at 2024 Annual Meeting)

CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS			
		2026	2025
A.	Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately)	5,628,000	5,538,000
B.	Projected NEPOOL Membership Fees	2,500,000	2,500,000
C.	Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B)	3,128,000	3,038,000
D.	Projected Amount to be paid by all Market Participant End Users (based on highest hourly load in any month in preceding calendar year) (figure used here for 2024 is based on 2023 peak loads of MPEU members)	38,625	39,625
E.	Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2024 is estimated amount based on 2023 membership data)	107,202	103,772
F.	[Reserved]	0	0
G.	Large Renewable Generation Sub-Sector Share (C-(D+E)) x RG%	298,217	289,460
H.	Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors (“Remaining Sectors”) (C – (D+E+G))	2,683,956	2,605,143

CALCULATION OF SECTOR ALLOCATIONS			
		2026	2025
I.	Amount to be allocated to each of the Remaining Sectors ($H \div 4$)	670,989	651,286
J.	Total Amount paid by Related Person Suppliers (3 voting members) ($I \div s_y$) x rps_y	9,007	9,238
K.	Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers ($(I \times 2) + G - J$)	1,631,189	1,582,794
L.	[Reserved]	0	0
M.	Remainder of Aggregate Share to be paid, on a per member basis, by voting members in the Generation Sector, Supplier Sector (excluding Related Person Suppliers), and Large Renewable Generation Resource Providers ($K \div (g_y + (s_y - rps_y) + lrg_y)$)	9,484	9,593
N.	Transmission Sector Share per full voting member ($I \div t_y$)	111,832	108,548
O.	[Reserved]	0	0
P.	Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members) ⁱ ($I \div poe_y$)	11,183	11,039

ANNUAL VARIABLES			
		2026	2025
s_y	# Supplier Sector voting members	149	141
rps_y	# Supplier Sector Related Person Suppliers	2	2
g_y	# Generation Sector voting members	15	15
lrg_y	# AR Sector Large Renewable Generation Resource Providers	11	11
RG%	Lesser of ($lrg_y \times 2\%$) or 10%	10%	10%
t_y	# Transmission Sector voting members	6	6
poe_y	# Publicly Owned Entity voting members	60	59

9

FAP Revisions: Obligation Roll-Off Timing



66.67%

To consider, and take action, as appropriate, on changes to the Financial Assurance Policy (“FAP”) to align more accurately the timing of Financial Assurance obligations with the duration of the associated payment risks.

RESOLVED, that the Participants Committee supports the revisions to the ISO New England Financial Assurance Policy 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.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates
FROM: Rosendo Garza, NEPOOL Counsel
DATE: November 25, 2025
RE: Updates to the Financial Assurance Policy

At the December 4, 2025 Participants Committee meeting, you will be asked to vote on proposed updates to the Financial Assurance Policy (FAP) to align more accurately the timing of Financial Assurance (FA) obligations with the duration of the associated payment risks. Included with this memorandum are the following materials:

- Attachment A: ISO-NE's Redlined FAP Sheets
- Attachment B: ISO-NE's November 14, 2025 Presentation

BACKGROUND & OVERVIEW

ISO-NE conducted an analysis of the FAP and identified gaps that create a two-day period during which ISO-NE may lack sufficient collateral to mitigate the risk of a Market Participant's default on its financial obligations. As described in Attachment B, the current definition of "MCC" (or the "monthly capacity charge")¹ sets the MCC to zero for FA purposes on the date ISO-NE issues the invoice, rather than two business days later when the payment is made. This two-day lag creates a potential gap in posted FA to cover the unpaid charge. Similarly, the Settlement Financial Assurance requirement² for Financial Transmission Rights transactions sets the FA obligation to zero for FA purposes on the date ISO-NE issues the invoice, producing the same two-day exposure. ISO-NE proposes to address these issues by revising the MCC definition and adding clarifying language to the Settlement Financial Assurance requirement, as shown in Attachment A.

STAKEHOLDER PROCESS TO DATE

At the November 14 Budget & Finance Subcommittee (B&F) meeting, ISO-NE presented its proposed revisions to the FAP. No Subcommittee member present expressed opposition or concerns with the proposal. Although the revisions were presented and considered at only one B&F meeting, the Subcommittee members present agreed that the revisions are ready for Participants Committee consideration.

¹ The MCC is a component of the Forward Capacity Market Delivery FA calculation that collateralizes Pay-for-Performance and failure to cover charges in the prior month.

² This requirement collateralizes settled Financial Transmission Rights (FTR) transactions and is a component of the overall FTR FA requirement.

The Participants Committee may use the following form of resolution for action:

RESOLVED, that the Participants Committee supports the revisions to the ISO New England Financial Assurance Policy 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.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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Overview

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 - 5. Additional Eligibility Requirements
 - 6. Prior Uncured Defaults
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- III. MARKET PARTICIPANTS' REQUIREMENTS
 - A. Determination of Financial Assurance Obligations

C. Settlement Financial Assurance

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide “Settlement Financial Assurance.” The amount of a Designated FTR Participant’s Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement. Additionally, when the Designated FTR Participant is invoiced and the net of the charges incurred by such Designated FTR Participant for FTR transactions and the amount due to such Market Participant for FTR transactions results in a net charge, the amount of the net charge shall be added to the Designated FTR Participant’s Settlement Financial Assurance until the invoice is paid.

D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a “Designated FCM Participant”), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the “FCM Financial Assurance Requirements”). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a “Corporate Liquidity Assessment” as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant’s FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant’s Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

$$\text{FCM Delivery Financial Assurance} = [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF}] - \text{IMC} - \text{MCC}$$

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

$$\text{FCM Delivery Financial Assurance} = [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF}] - \text{IMC} - \text{MCC}$$

Corporate Liquidity Assessment Result: Medium Risk

$$\text{FCM Delivery Financial Assurance} = [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF}] - \text{IMC} - \text{MCC} - \text{Peak Monthly Stop-loss} \times \max[(\text{ABR} - \text{CWAP}), 0.1]$$

Corporate Liquidity Assessment Result: High Risk

$$\begin{aligned} \text{FCM Delivery Financial Assurance} = & [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF}] - \text{IMC} - \text{MCC} - \text{Peak Monthly Stop-loss} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \\ & - \text{Second Largest Monthly Stop-loss} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \end{aligned}$$

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant~~but not yet billed~~. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

NOVEMBER 14, 2025 | HOLYOKE, MA

NEPOOL PARTICIPANTS COMMITTEE
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Recommendation to Update the Financial Assurance Policy to Address Obligation Roll-Off Timing

NEPOOL Budget and Finance Subcommittee Meeting

Zach Shell

LEAD MARKET AND CREDIT RISK ANALYST



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ISO recommends two updates to the FAP to accurately align the timing of FA obligations with the actual duration of associated payment risks

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Executive Summary

- Following a detailed analysis of FAP, the ISO identified instances where certain Financial Assurance (FA) obligations are released prematurely—before the underlying obligation has been fully paid by the Market Participant (MP)
- Specifically, the review identified issues with the early roll-off of:
 - **Monthly Capacity Charge FA**
 - **FTR Settlement FA**
- This presentation outlines the ISO's findings, explains the potential risk exposure created by the unintended gap in the current policy, and presents a recommended approach to ensure FA obligations remain in place until the corresponding payments have been made

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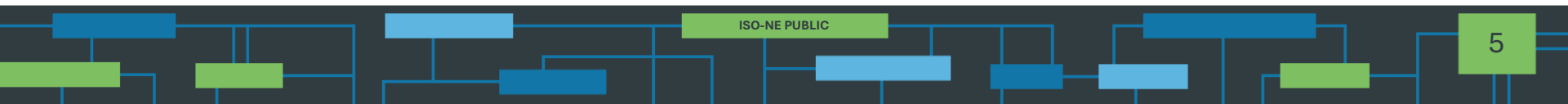
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What is MCC and what role does it play in the FAP?

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- MCC is a component of the Forward Capacity Market (FCM) Delivery Financial Assurance calculation which collateralizes Pay-for-Performance Charges and Failure to Cover Charges incurred in prior months
 - MCC is defined as monthly capacity payments that have been incurred in previous months but have not yet been billed
- MCC is initially estimated from the first day of the current delivery month. This estimate is then replaced by the actual settled MCC value once settlement is complete.
- Once the monthly bill is issued, typically on the first Monday after the ninth day of the month, the MCC subsequently reverts to zero and is no longer collateralized
- The current FAP definition of MCC causes a FA shortfall during a 2-day period between bill issuance and bill payment which needs to be remediated



Explain the issue regarding the timing gap in the collateralization of MCC

- The MCC definition within the FAP refers to charges incurred in previous months that are “not yet billed”
 - *“MCC equals monthly capacity payments incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.”*
- This language sets the FA obligation for the MCC to zero on the invoice issuance date, rather than 2 business days later when payment is made
- Accordingly, there exists a 2-day period during which the ISO may lack sufficient collateral to mitigate the risk of a potential default by the MP on these obligations
- We believe this was an unintentional outcome. In 2018, the ISO updated the definition of the MCC to account for the fact that MCC amounts could be positive (credits) or negative (charges). As part of that change, the MCC definition was revised from Monthly Capacity Payments “incurred in previous months, but not yet paid” to “incurred in previous months, but not yet billed” because the term “paid” only referred to negative amounts. Switching to the term “billed” had the unintended consequence described herein.

How do we remediate the 2-day collateral gap before invoice payment?

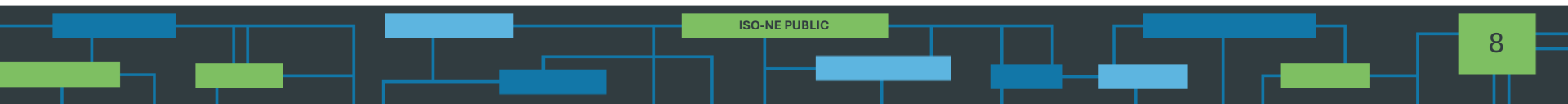
- The ISO recommends revising the FAP definition of MCC to maintain the obligation until payment, rather than upon billing
- Current FAP definition: “MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.”
- Revised FAP definition: “MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, **which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant**. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.”

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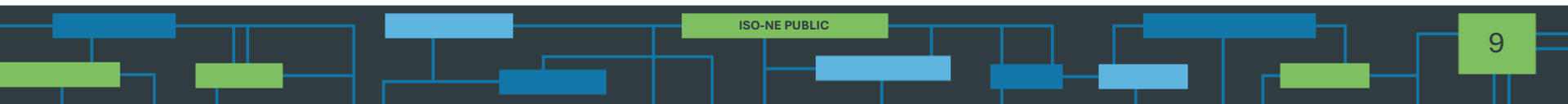
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What is FTR Settlement FA and what role does it play in the FAP?

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- FTR Settlement FA collateralizes settled FTR transactions and is one component of the overall FTR Financial Assurance Requirements
 - Once the monthly bill is issued, typically on the first Monday after the ninth day of the month, the FTR Settlement FA for the settlement days included on that month's bill is then set to zero and no longer collateralized
- In the FAP, FTR Settlement FA is calculated as the amount of any settled but uninvoiced Charges incurred for FTR transactions less the settled but uninvoiced amounts due to such MP for FTR transactions
 - These amounts include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement
- The current FAP definition of FTR Settlement FA causes a FA shortfall during a 2-day period between bill issuance and bill payment which needs to be remediated



Explain the issue regarding the timing gap in the collateralization of FTR Settlement FA

- The FTR Settlement FA definition within the FAP refers to “settled but uninvoiced Charges”
 - *“The amount of a Designated FTR Participant’s Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement.”*
- This language sets the FA obligation for FTR Settlement FA to zero on the invoice issuance date, rather than 2 business days later when payment is made
- Accordingly, there exists a 2-day period during which the ISO may lack sufficient collateral to mitigate the risk of a potential default by the MP on these obligations

How do we remediate the 2-day collateral gap before invoice payment?

- The ISO recommends revising the FAP definition of FTR Settlement FA to maintain the obligation until payment, rather than upon billing
- Current FAP definition: “A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide “Settlement Financial Assurance.” The amount of a Designated FTR Participant’s Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement.”
- Revised FAP definition: “A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide “Settlement Financial Assurance.” The amount of a Designated FTR Participant’s Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement. **Additionally, when the Designated FTR Participant is invoiced and the net of the charges incurred by such Designated FTR Participant for FTR transactions and the amount due to such Market Participant for FTR transactions results in a net charge, the amount of the net charge shall be added to the Designated FTR Participant’s Settlement Financial Assurance until the invoice is paid.”**

Can you provide an example that illustrates the recommended policy change?

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Day	Obligation Status	FTR Credit (\$)	FTR Charge (\$)	FA Obligation (\$) (Current Policy)	FA Obligation (\$) (Updated Policy)
1	Settled but Uninvoiced	10	-12	-2	-2
2	Settled but Uninvoiced	10	-12	-2	-2
3	Settled but Uninvoiced	10	-12	-2	-2
4	Invoiced but Not Paid	10	-12	0	-2
5	Invoiced but Not Paid	10	-12	0	-2
6	Paid	0	0	0	0

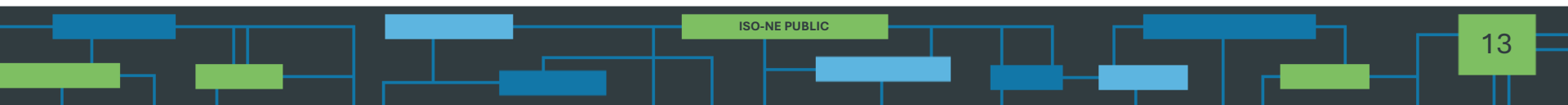
The updated policy will simply hold the FA obligation for 2 additional days in situations where the net FTR transactions result in a charge

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FAP Redline: Monthly Capacity Charge (FAP Section VII.A.1)

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- MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant ~~but not yet billed~~. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

FAP Redline: FTR Settlement FA (FAP Section VI.C)

- *A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide “Settlement Financial Assurance.” The amount of a Designated FTR Participant’s Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement. Additionally, when the Designated FTR Participant is invoiced and the net of the charges incurred by such Designated FTR Participant for FTR transactions and the amount due to such Market Participant for FTR transactions results in a net charge, the amount of the net charge shall be added to the Designated FTR Participant’s Settlement Financial Assurance until the invoice is paid.*

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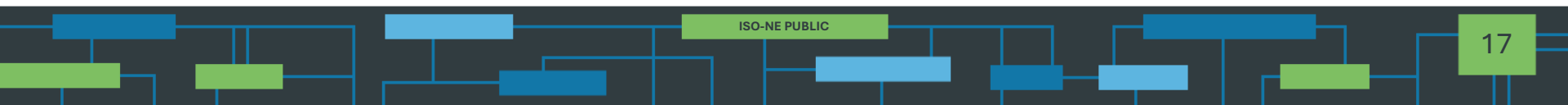
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Stakeholder Process and Next Steps

ISO-NE POOL PARTICIPANTS COMMITTEE
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Steps	Timeline
Presentation of Redlines	November 14th*
Vote at the Participants Committee	December 4th*
Estimated FERC Filing Date	January or February 2026
Effective Date	60 days from FERC filing

*If an additional Budget and Finance Subcommittee meeting is necessary, the Subcommittee can continue discussions during the December 11, 2025 meeting and the Participants Committee can take action at the January 8, 2026 meeting.



10

CAR-PD Proposal



60.00%

60.00%

Dec 4, 2025
Meeting

To consider, and take action, as appropriate, on Capacity Auction Reforms – Prompt/Deactivation (CAR-PD)-related Tariff changes.

RESOLVED, that the Participants Committee supports ISO-NE's CAR-PD Proposal, including related revisions to: Tariff Section I.2.2, Market Rule 1, including new Section III.15 and NEPGA's Amendment, as well as Sections II.52-55 of the Open Access Transmission Tariff (OATT), as **recommended by the Markets Committee** at its November 2025 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.

RESOLVED, that in connection with ISO-NE's CAR-PD Proposal, the Participants Committee supports the changes to Sections I.2.2 and Section III.12 (Calculation of Capacity Requirements) of the Tariff, all as **recommended by the Reliability Committee** at its November 2025 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.

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CAR-PD Proposal (cont.)



66.67%

Dec 4, 2025
Meeting

To consider, and take action, as appropriate, on Capacity Auction Reforms – Prompt/Deactivation (CAR-PD)-related Tariff changes.

RESOLVED, that in connection with ISO-NE's CAR-PD Proposal, the Participants Committee supports the changes to Sections I.2.2, I.3.9 (Review of Market Participant's Proposed Plans), Open Access Transmission Tariff (OATT) Sections II.22 (Operating Arrangements), II.48 (Interconnection Service Capabilities), II.52-55 (Deactivation), and to OATT Attachments K (Regional System Planning Process) and N (Procedures for Regional System Plan Upgrades), and Schedule 16 (Blackstart Service), all as ***recommended by the Transmission Committee*** at its November 2025 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.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates
FROM: NEPOOL Counsel
DATE: November 25, 2025
RE: CAR-PD Proposal

At its December 4, 2025 Annual Meeting, the Participants Committee will be asked to consider and vote to support a package of revisions to the ISO New England Inc. (ISO-NE or the ISO) Tariff that would transition the Forward Capacity Market (FCM) to a prompt annual market construct as part of ISO-NE's Capacity Auction Reforms (CAR) initiative (CAR-PD Proposal).¹ This memorandum provides a high-level overview of the proposal and includes the following attachments:

- Attachment A: Section I.2.2, Sections II.52–55, and Section III, as recommended by the Markets Committee
- Attachment B: Section I.2.2 and Section III.12, as recommended by the Reliability Committee
- Attachment C: Section I.2.2, Section I.3.9, Sections II.22, II.48, II.52–55, Attachments K and N, and Schedule 16, as recommended by the Transmission Committee
- Attachment D: ISO-NE's voting memorandum to the Technical Committees, dated November 5, 2025
- Attachment E: ISO-NE's memorandum to the Participants Committee, dated November 25, 2025
- Attachment F: ISO-NE's November 12–13, 2025 Presentation
- Attachment G: Markets Committee Notice of Actions, dated November 13, 2025

BACKGROUND

In 2023, the ISO and stakeholders began discussing and assessing the potential transition of the region's capacity market design to a prompt and/or seasonal capacity market construct with accompanying accreditation reforms. To assist in this evaluation, the ISO engaged the Analysis Group to prepare a report with a recommendation. The final report, presented to the Markets Committee in January 2024, recommended that New England develop and implement a prompt seasonal market design.²

¹ After the Technical Committees' votes, the ISO identified various non-substantive edits and typographical errors in the Tariff redlines. The ISO also determined that it needed to renumber the proposed deactivations provisions because Section II.51 of the Open Access Transmission Tariff (OATT) is reserved for SATOAs, which have not yet become effective. *See Revisions to Enable the Treatment of Storage as Transmission-Only Assets*, Docket Nos. ER23-739 & ER23-743, at 7 (filed Dec. 29, 2022).

² Analysis Group, *Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets* (Jan. 2024), https://www.iso-ne.com/static-assets/documents/100007/a08b_mc_2024_01_09_11_agi_updated_report.pdf.

Following that recommendation, and later in 2024, NEPOOL joined ISO-NE's filing³ to delay further Forward Capacity Auction (FCA) 19 to 2028.⁴ As explained in the filing letter, the purpose of the delay was to allow the region to develop rules for the transition to a prompt seasonal construct to be implemented in time for the Capacity Commitment Period 2028/2029 (CCP 28/29) as part of what would become the CAR initiative.⁵

Throughout 2024, the ISO led discussions on the scope of the CAR project and considered stakeholder feedback, including written comments. In the fall of 2024, the ISO presented its plan to transition to a prompt seasonal capacity market construct in two phases. The first phase, known as CAR-PD, would include Tariff revisions to move the FCM to a prompt annual market with accompanying retirement reforms. CAR-PD is intended to stand on its own and serve as the foundation for the second phase, CAR-SA (Seasonal and Accreditation), which will develop rules to move from an annual construct to a seasonal one with accompanying accreditation reforms.⁶

HIGH-LEVEL OVERVIEW OF THE CAR-PD PROPOSAL

The CAR-PD proposal consists of two major sets of changes. The first concerns updates to the auction processes and administration to facilitate a prompt capacity auction that would procure a year of capacity approximately one month before the delivery period. A key change from the current FCM construct is that only commercial resources would be permitted to participate in the auction. Because of this change, the timeline for completing pre-auction activities, such as qualifying capacity resources and establishing Qualified Capacity values, is streamlined and shortened. In addition, moving to a prompt capacity auction would eliminate the Annual Reconfiguration Auctions, although the CAR-PD proposal retains monthly reconfiguration auctions that would run about a week before each delivery month. Another important change to the auction mechanics is the adoption of a sealed-bid format in place of the descending-clock auction format currently used in the FCA. The ISO also proposes conforming changes to Installed Capacity Requirement provisions.

The second major set of revisions for the CAR-PD Proposal concerns reforms to the process for exiting the markets. Currently referred to as "retirements" but, under CAR-PD restructured as "deactivations," the deactivation process would be decoupled from the capacity

³ ISO New England Inc. & New England Power Pool, Revisions to ISO New England Transmission, Markets and Services Tariff to Further Delay the Nineteenth Forward Capacity Auction and Related Capacity Markets Activities, Docket No. ER24-1710 (filed Apr. 05, 2024).

⁴ By way of background, in late 2023, NEPOOL and ISO-NE jointly filed a proposal to delay FCA 19 for one year (to February 2026) to provide the region with sufficient time to develop a new resource capacity accreditation methodology in advance of the capacity auction. ISO New England Inc. & New England Power Pool, *Market Rule Changes to Delay Nineteenth Forward Capacity Auction and Related Capacity Market Activities*, Docket No. ER23-339, at 2 (filed Nov. 3, 2023). The Commission accepted that proposal. *ISO New England Inc.*, 186 FERC ¶ 61,001 (2024).

⁵ In May 2024, the Commission accepted that proposal to delay FCA 19 further. *ISO New England Inc.*, 187 FERC ¶ 61,083 (2024).

⁶ Discussions on CAR-SA are ongoing and are expected to continue through 2026.

market offer process. Under the revised process, a resource could reduce or eliminate interconnection service MW through the deactivation mechanism.⁷ Under CAR-PD, the current four-year lead time to retire under a forward market would be replaced with a requirement that a resource submit a binding, irrevocable deactivation notice one year in advance of the start of the delivery period. The deactivation date could be accelerated under certain circumstances. Within 90 days of submission, the ISO would analyze all deactivations for local transmission security and market power impacts, including, if necessary, using a Proxy Capacity Offer to mitigate potential market power in the context of a deactivation. The ISO would publish the results of all submitted deactivations shortly after completing its review.

With respect to CAR-PD's market mitigation design, the proposed changes to the seller- and buyer-side mitigation constructs are conforming in nature. For example, the ISO updated naming conventions, such as replacing "Dynamic De-List Bid Threshold" with the "Capacity Offer Price Threshold (COPT)," adjusted the timing of certain reviews, and revised inputs to the cost workbook. One notable revision is the ISO's proposed removal of the Tariff's so-called "ambient air de-list" provision, which, under the FCM rules, allows a resource to de-list MW that it cannot produce at ambient temperatures between 90 degrees to 100 degrees Fahrenheit. The ISO has indicated that it will conduct a broader evaluation of the mitigation design after completion of the overall CAR project.⁸

SUMMARY OF STAKEHOLDER PROCESS

Because the CAR-PD Proposal included Tariff revisions to the Market Rules (including Section III.12), the OATT, and defined terms in Section I.2.2,⁹ NEPOOL's three Technical Committees discussed and vetted successive iterations of the CAR-PD Proposal to transition the FCM to a prompt-annual market design, along with various Participant-sponsored ideas and proposals.

Markets Committee Review

After months of review and discussion, the Markets Committee, at its November 12–13 meeting, considered the Tariff revisions under its purview related to the CAR-PD proposal.

⁷ Because the CAR-PD proposal would move the deactivation process outside the capacity auction, the existing retirement in Market Rule 1 are relocated to corresponding proposed deactivation provisions in the OATT. In addition to incorporating the proposed deactivation rules to the OATT, the ISO made conforming changes throughout that tariff. See Attachment C. Notably, if the Commission approves the CAR-PD Proposal, the Participants Agreement's so-called jump ball provision would no longer apply to the proposed deactivation provisions because they would reside in the OATT.

⁸ See ISO New England Inc., *CAR – Prompt, Market Power and Mitigation Design for the Prompt Capacity Auction*, at 4 (July 8–9, 2024), https://www.iso-ne.com/static-assets/documents/100025/a04.2a_mc_2025_07-08-09_july_mitigation_iso_presentation.pdf.

⁹ At the Markets Committee's request, NEPOOL Counsel reviewed the CAR-PD Tariff revisions and concluded that they reasonably reflect the ISO's proposed market design. Memorandum from NEPOOL Counsel to NEPOOL Markets Committee Members and Alternates 1 (Oct. 31, 2025), https://www.iso-ne.com/static-assets/documents/100028/a03.1.b_mc_2025_11_12_13_nepool_counsel_assessment_carpd_tariff_changes_memo.pdf.

Specifically, it reviewed revisions to the following Tariff sections, which are provided in Attachment A: (1) Section I.2.2; Sections II.52–55;^{10, 11} and (3) Section III, including the new Section III.15. The Markets Committee also considered three amendments the ISO’s un-amended CAR-PD Proposal,¹² which are summarized below. The first amendment failed with a 56.67% Vote in favor,¹³ and the second amendment failed with a 52.82% Vote in favor.¹⁴ The third amendment passed with an 83.33% Vote in favor,¹⁵ as did the once-amended main motion, with a 97.92% Vote in favor.¹⁶ Because the ISO had indicated that, if the third amendment received broad stakeholder support, it would consider incorporating that amendment into its un-amended CAR-PD proposal,¹⁷ the ISO did not request a separate vote for its un-amended proposal.

As noted above, the Markets Committee considered three motions to amend the ISO’s CAR-PD Proposal at its November 2025 meeting. Those amendments are summarized below.

1. Jericho Power – Fixing the COPT Value for CCP 28/29 Amendment

Using a formula that incorporated the most recent clearing prices from the two ARAs held in the summer of 2025, Jericho Power proposed an amendment that would apply a revised COPT value of \$4.984/kW-month for CCP 28/29. As noted above, this amendment did not receive the Markets Committee support, falling short by less than four percentage points.¹⁸

¹⁰ See note 1.

¹¹ The Markets Committee vetted the proposed Sections II.52–II.55 rules because those deactivation provisions were revised from the existing Market Rule 1 retirement provisions. *See also* Memorandum from the Technical Committee Chairs and Vice-Chairs to the Technical Committees (Oct. 31, 2025), https://www.iso-ne.com/static-assets/documents/100028/a03.1.d_mc_2025_11_12_13_car-pd_voting_process_memo.pdf.

¹² Throughout the stakeholder process, two Participants introduced amendments that sought to modify, in one way or another, different components of the CAR-PD Proposal. Ultimately, these amendments either remained at the conceptual stage or were not offered for Markets Committee consideration. The Participants elected not to advance their amendments due to assurances from ISO-NE that the issues raised would either be addressed outside the CAR initiative or had been incorporated by the ISO in some form. Please click on the entity’s name to review that Participant’s final presentation to the Markets Committee: [FirstLight Power Inc.](#); [Jericho Power 1](#); [Jericho Power 2](#); and [Jericho Power 3](#).

¹³ See Markets Committee Notice of Actions, Attachment G, at 1–2.

¹⁴ *Id.* at 2.

¹⁵ *Id.* at 3.

¹⁶ *Id.*

¹⁷ See Memorandum from ISO New England Inc. to the NEPOOL Technical Committees (Nov. 5, 2025), https://www.iso-ne.com/static-assets/documents/100029/a03.1.c_mc_tc_2025_11_12_13_car-pd_iso_amendments_feedback_final.pdf.

¹⁸ To view Jericho Power’s presentation on its COPT amendment, click [here](#).

2. Calpine Corporation – Changing the COPT Methodology Amendment

Calpine proposed an alternative COPT methodology that differed from the ISO's by calculating the common value component as the product of the Balancing Ratio, the Performance Payment Rate, and the hours of expected Capacity Scarcity Conditions. Calpine's amendment failed to pass at the Markets Committee by slightly more than seven percentage points.¹⁹

3. NEPGA – Ambient Air De-list Amendment

In response to the ISO's proposed removal of the ambient air de-list exemption, NEPGA proposed an amendment that would, in effect, retain that exemption under CAR-PD. As noted above, NEPGA's amendment received broad stakeholder support, passing with nearly an 85 percent Vote in favor.

Consistent with past practice, Participants are reminded that neither NEPOOL nor ISO-NE will raise procedural objections at the FERC should any amendments that were considered but not supported be presented directly to FERC, notwithstanding that such amendments were not brought to the Participants Committee for a vote. With this understanding, Jericho Power and Calpine informed us that they do not intend to seek a Participants Committee vote on their amendments that did not receive Markets Committee support.

Reliability Committee Review

The Reliability Committee considered the portions of the CAR-PD Proposal under its purview over the course of two meetings. Those revisions, provided in Attachment B, included changes to Section I.2.2 and Section III.12 of the Tariff. At its November 18 meeting, the Reliability Committee voted unanimously to recommend Participants Committee support for provisions of the CAR-PD Proposal under its purview.

Transmission Committee Review

The Transmission Committee considered the Tariff sections of the CAR-PD Proposal under its purview over the course of two meetings. Those revisions, as provided in Attachment C, included two sets: the first set included proposed revisions to Section II.52–55²⁰ regarding deactivation rules, and the second set included proposed revisions to Sections I.2.2, I.3.9, Section II.22, II.48 and Section II, Attachments K and N, and Schedule 16 of the Tariff. At its November 12 joint meeting with the Markets Committee, the Transmission Committee voted unanimously to recommend Participants Committee support for the new deactivation rules in Section II.52–55, and then at its November 20 meeting, the Transmission Committee voted unanimously to recommend Participants Committee support for the rest of the CAR-PD revisions under its purview.

¹⁹ Calpine's presentation can be accessed [here](#).

²⁰ See note 1.

PLANNED PROCESS FOR PARTICIPANTS COMMITTEE ACTION

Following its usual process, the starting point at the December 4 Participants Committee meeting will be consideration of whether to support the Markets Committee-recommended Tariff revisions, which modified the ISO's CAR-PD proposal by incorporating NEPGA's amendment, together with the Tariff revisions supported by the Reliability and Transmission Committees. In light of the vote outcomes at the Technical Committees, the Participants Committee may consider the CAR-PD Proposal in a single action. The proposal would require a 66.67 percent Vote in favor to receive Participants Committee support. As indicated in the ISO's November 25 memorandum (included as Attachment E), ISO-NE will incorporate NEPGA's amendment in its proposal should it "receive broad support" at the Participants Committee.

The following forms of resolution, either in a single action or in separate actions, may be used for Participants Committee action on the CAR-PD Proposal Tariff revisions:

RESOLVED, that the Participants Committee supports ISO-NE's CAR-PD Proposal, including related revisions to: Tariff Section I.2.2, Market Rule 1, including new Section III.15 and NEPGA's Amendment, as well as Sections II.52-55 of the Open Access Transmission Tariff (OATT), as recommended by the Markets Committee at its November 2025 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.

RESOLVED, that in connection with ISO-NE's CAR-PD Proposal, the Participants Committee supports the changes to Sections I.2.2 and Section III.12 (Calculation of Capacity Requirements) of the Tariff, all as recommended by the Reliability Committee at its November 2025 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.

RESOLVED, that in connection with ISO-NE's CAR-PD Proposal, the Participants Committee supports the changes to Sections I.2.2, I.3.9 (Review of Market Participant's Proposed Plans), Open Access Transmission Tariff (OATT) Sections II.22 (Operating Arrangements), II.48 (Interconnection Service Capabilities), II.52-55 (Deactivation), and to OATT Attachments K (Regional System Planning Process) and N (Procedures for Regional System Plan Upgrades), and Schedule 16 (Blackstart Service), all as recommended by the Transmission Committee at its November 2025 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.

the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Advisory Qualified Capacity Values are the advisory summer and winter Qualified Capacity values, calculated pursuant to Section III.15.2.5.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Allowable Capacity Offer Price is a price determined by the Internal Market Monitor as part of its review of Proposed Capacity Offers pursuant to Section III.A.22.2.3.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Capacity Auction (ACA) is the Annual Capacity Market auction process carried out pursuant to Section III.15.4 of Market Rule 1.

Annual Capacity Auction Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

Annual Capacity Auction Offer Window is the period described in the Capacity Auction Calendar during which Capacity Offers must be submitted for an Annual Capacity Auction.

Annual Capacity Market is the annual market for procuring capacity in the New England Control Area, as set forth in Section III.15 of Market Rule 1.

Annual Qualified Capacity is the Qualified Capacity calculated pursuant to Section III.15.3 that is used in an Annual Capacity Auction.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction associated with the Forward Capacity Market that may be used in accordance with Section -III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, a Distributed Energy Resource participating as part of a Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an ~~Existing~~ Generating Capacity Resource, calculated for the asset in the same manner as the net costs of ~~Existing~~ Generating Capacity Resources as described in Section III. ~~13.1.2.3.2.1.1.1~~ A.22 (for an asset ~~with a Static De List Bid or an Export Bid~~ associated with a Capacity Offer price subject to Internal Market Monitor review) or Section III. ~~A.24~~ 13.1.2.3.2.1.1.2 (for an asset ~~with a Permanent De List Bid or Retirement De List Bid~~ submitting a Deactivation Notification).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Available Energy is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

Available Storage is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand [Capacity](#) Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand [Capacity](#) Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand [Capacity](#) Resource's or Seasonal Peak Demand [Capacity](#) Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section [III.15.2.1.1.2.1](#) or Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand [Capacity](#) Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand [Capacity](#) Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 [or Section III.15.2.1.1.2.1](#) of Market Rule 1 and the ISO New England Manuals.

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

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Benchmark Scenario is an Economic Study reference scenario that is described in Section 17.2(a) of Attachment K to the OATT.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

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

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the

provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day); and (8) with respect to Day-Ahead Ancillary Services Offers administered by the ISO, a quantity with a related price for Day-Ahead Ancillary Services (Day-Ahead Ancillary Services Offers may contain multiple prices for each hour).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section

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:

Above-Threshold Offer Segment is the total MW quantity of a Capacity Offer that is priced above the Capacity Offer Price Threshold, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward or Annual Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 or Section III.15 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 or Section III.15.8.2.2 of Market Rule 1.

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

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

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

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

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

Administrative Export De-List Bid is a bid ~~that may be~~ submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of

III.15.6.1, or; (2) ~~an annual or monthly~~ reconfiguration auction, as described in Section III.13.4-or Section III.15.5.

Capacity Auction Calendar is a calendar published on the ISO's website, as described in Section III.15, detailing dates and deadlines associated with Annual Capacity Market participation, Monthly Reconfiguration Auction participation, and monthly Capacity Supply Obligation Bilateral transactions.

Capacity Auction Offer Price Cap is determined pursuant to Section III.15.1.2.1 of Market Rule 1 prior to the Annual Capacity Auction for each Capacity Commitment Period and is the highest price at which capacity may be offered into the Annual Capacity Auction, unless otherwise expressly allowed by the Tariff.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the ~~Forward~~ Capacity Market, as described in Section III.13.7.2.3 or III.15.8.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market or Annual Capacity Market as described in Section III.13.7.1 or Section III.15.8.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price ~~infer~~ a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1 or resulting from the Annual Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.15.4.2.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market and Annual Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Demonstration Deadline is a monthly deadline described in the Capacity Auction Calendar for completion of the capacity demonstration requirement set forth in Section III.15.2.6 prior to participation in the Annual Capacity Auction, a Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral transaction.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 or Section III.15.8.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 or Section III.15.6.2 of Market Rule 1.

~~**Capacity Network Import Capability (CNI Capability)** is as defined in Section I of Schedule 25 of the OATT.~~

~~**Capacity Network Import Interconnection Service (CNI Interconnection Service)** is as defined in Section I of Schedule 25 of the OATT.~~

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 or Section III.15.6 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 or Section III.15.6.2 of Market Rule 1.

Capacity Market is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1, or the annual market for procuring capacity in the New England Control Area, as described in Section III.15 of Market Rule 1.

Capacity Market Commercial Operation is defined in Section III.15.2.6 of Market Rule 1.

Capacity Market Deactivation is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from the Capacity Market, or the permanent reduction in Capacity Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Offer is an offer submitted for inclusion in the Annual Capacity Auction as set forth in Section III.15.4.1 of Market Rule 1.

Capacity Offer Floor Price is defined in Section III.A.21.3 of Market Rule 1.

Capacity Offer Price Threshold (COPT) is the price specified in Section III.A.22.2.1 of Market Rule 1 associated with the submission, review, and mitigation of prices specified in Capacity Offers submitted for the Annual Capacity Auction.

Capacity Offer Review Submission Deadline is the deadline described in the Capacity Auction Calendar by which proposed Capacity Offers and accompanying documentation must be submitted to the Internal Market Monitor in accordance with Section III.A.22.2.2.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 [or Section III.15.6.3](#) of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 [or Section III.15.8.2](#) of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 [or Section III.15.8.2.5](#) of Market Rule 1.

[Capacity Resource is a type of resource eligible to participate in the Annual Capacity Auction. There are four types of Capacity Resources: Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource.](#)

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 [or Section III.15.8.2.4](#) of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the ~~Forward~~ Capacity Market, as described in Section III.13.7.2.1 [or III.15.8.7.2.1](#) of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2 [or an Annual Capacity Auction in accordance with Section III.15.4](#), a reconfiguration auction in accordance with Section III.13.4 [or Section III.15.5](#), or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 [or Section III.15.6.1](#) of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 [or Section III.15.6.1](#) of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4 [or Section III.15.8.5.4](#).

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) ~~an annual or monthly~~ reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the ~~Forward~~ Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3 and in Sections III.15.1.1.2 and III.15.1.1.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

Cluster has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Request Window has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Cluster Restudy has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Cluster Study has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation or Capacity Market Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only ~~by the clearing of the Static De-List Bids, Capacity Offer the Permanent De-List Bids, or the Retirement De-List Bids of none of all the Existing~~ Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity Commitment Period, or by the acceptance of the Deactivation Notification of all Generating Capacity Resources composing the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite ~~FCM~~ Capacity Market Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction or Annual Capacity Auction in which multiple ~~Designated FCM~~ Lead Market Participants provide capacity, as described in Section III.13.1.5 or Section III.15.2.8 of Market Rule 1.

Composite Offer Deadline is the deadline for submission of the Composite Offer Form described at Section III.15.2.8.

Composite Offer Form is a form submitted by Lead Market Participants for separate resources seeking to participate as a single composite Capacity Resource in the Annual Capacity Auction, as described in Section III.15.2.8.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

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

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

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost-Based Reference Price is a price determined by the Internal Market Monitor for comparison to a price in a Proposed Capacity Offer submitted pursuant to Section III.A.22.2.3.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry (\$/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4 and for each Annual Capacity Auction pursuant to Section III.15.1.2.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailement is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Cyber Security Exigency is a suspicious or malicious electronic act or event that compromises or attempts to compromise, or disrupts or attempts to disrupt, the ongoing operation of the ISO, the New England Markets, or reliability within the New England Control Area or other electrical facilities directly or indirectly connected to the New England Transmission System and (i) whose severity or nature

reasonably requires that the ISO obtain expert assistance not normally called upon to counter such an electronic act or resolve such an event or (ii) whose nature requires the ISO to report such an electronic act or event pursuant to NERC Critical Infrastructure Protection Reliability Standards or applicable regulations promulgated by the Department of Homeland Security, the Department of Energy, or a federal agency with similar cybersecurity responsibilities (or any of their respective successor organizations or agencies).

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Ancillary Services means Day-Ahead Flexible Response Services and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Ancillary Services Avoidable Input Cost is defined in Section III.A.8.2.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Benchmark Level is defined in Section III.A.8.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Day-Ahead Ancillary Services Offer. Blocks of the Day-Ahead Ancillary Services Offer in effect for each hour will be totaled to determine the quantity of Day-Ahead Ancillary Services Offer Block-Hours for a given day.

Day-Ahead Ancillary Services Expected Close-Out Component is defined in Section III.A.8.2.1 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Market means the sale of and payment for Day-Ahead Ancillary Services developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Ancillary Services Offer is an offer that may be submitted by Market Participants in the Day-Ahead Ancillary Services Market in accordance with Section III.1.8.1 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as described in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ancillary Services Strike Price is specified in Section III.1.8.2 of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.4 of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Flexible Response Services means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Flexible Response Services Demand Quantities means Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, Day-Ahead Total Ten-Minute Reserve Demand Quantity, Day-Ahead Minimum Total Reserve Demand Quantity, and Day-Ahead Total Reserve Demand Quantity.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Market means the jointly optimized Day-Ahead Energy Market and Day-Ahead Ancillary Services Market.

Day-Ahead Minimum Total Reserve Demand Quantity is described in Section III.1.8.3(c) of Market Rule 1.

Day-Ahead Prices means the prices resulting from the Day-Ahead Market as described in Section III.2.6 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.3(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is described in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Total Ten-Minute Reserve Demand Quantity is described in Section III.1.8.3(b) of Market Rule 1.

Day-Ahead Total Reserve Demand Quantity is described in Section III.1.8.3(d) of Market Rule 1.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Deactivation Notification is a notification of the planned New England Market Deactivation or Capacity

Market Deactivation of a resource, External Elective Transmission Upgrade, or portion thereof, submitted to the ISO by the applicable Lead Market Participant.

Deactivation Notification Deadline is the deadline for submission of a Deactivation Notification and a Deactivation Notification Package, as discussed in Section II.52.1 of the OATT.

Deactivation Notification Package is information submitted to the ISO, as specified in Section II.52.3 of the OATT, by a resource or External Elective Transmission Upgrade seeking a determination regarding a Deactivation Notification.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is \$2,000/MWh.

Demand Capacity Resource ~~is a type of resource that may participate in the Capacity Market, means an Existing Demand Capacity Resource or a New Demand Capacity Resource.~~ There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Capacity Resources, and Seasonal Peak Demand Capacity Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of “unavailable” for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Distributed Energy Resource Aggregation (DRDERA) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator

Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Energy Capacity Resource (DECR) ~~means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource~~ is a type of Capacity Resource that participates in the Capacity Market and composes one or more Distributed Energy Resource Aggregations.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

Distributed Generation means 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, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid ~~that may be~~ submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, Existing Demand Capacity Resources, and Existing Distributed Energy Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the

output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study or Economic Studies are studies described in Section 17 of Attachment K to the OATT that are used to examine situations where potential regulated transmission solutions, market responses, or investments could result in (i) a net reduction in total production cost to supply system load based on the factors specified in Attachment N of the OATT, (ii) reduced congestion, or (iii) the integration of new resources or loads, or both, on an aggregate or regional basis.

Effective Offer is the Supply Offer, Demand Reduction Offer, Demand Bid or Day-Ahead Ancillary Services Offer that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the

Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative \$150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, Day-Ahead Ancillary Services Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORD) means the portion of time a unit is in demand, but is unavailable due to forced outages.

~~**Estimated Capacity Load Obligation** is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.~~

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid ~~that may be~~ submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Export Offer Segment is the total MW quantity of a Capacity Offer that is subject to a contract to export capacity outside the New England Control Area during the Capacity Commitment Period associated with the Capacity Offer, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England

Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is \$2,000/MWh for External Transactions other than Coordinated External Transactions and \$1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative \$1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

~~**FCA Cleared Export Transaction** is defined in Section III.1.10.7(f)(ii) of Market Rule 1.~~

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without

limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Energy Requirement Demand Quantity is described in Section III.1.8.4 of Market Rule 1.

Forecast Energy Requirement Penalty Factor is a rate, in \$/MWh, that is used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of forecast energy requirement shortages and is defined in Section III.2.6.2(d) of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(b) of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1. [The final Forward Capacity Auction was for the Capacity Commitment Period beginning on June 1, 2027.](#)

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

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

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

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

Forward Reserve Offer Cap is \$7,100/megawatt-month.

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

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1. As described in Section III.9.1, the final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

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

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

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

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

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

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

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

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a “Non-Market Participant FTR Customers” and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC’s Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a ~~New-Generating Capacity Resource or an Existing Generating Capacity Resource~~ type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource ~~means an Existing Import Capacity Resource or a New Import Capacity Resource is a type of resource offered-participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2 by providing to provide capacity in the New England Control Area from an external Control Area.~~

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section II.54.5 of the OATT, I.13.2.5.2.5.2 of ~~Market Rule 1.~~

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Initial State of Charge is the State of Charge that an Electric Storage Facility offers at the start of hour one of the Day-Ahead Energy Market.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement” pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures,” the “Small Generator Interconnection Procedures,” or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource or an aggregation of wind, solar, run of river hydro and other renewable resources that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market or Annual Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids, Demand Reduction Offers, Baseline Deviation Offers, or Day-Ahead Ancillary Services Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource. For purposes of the Annual Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of a Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not

limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load-Side Relationship Certification is a certification described in Section III.A.21.1.43 that a ~~Project Sponsor~~Lead Market Participant submits as part of ~~the New Capacity Qualification Package, New Demand Capacity Resource Qualification Package, or New Distributed Energy Capacity Resource Qualification Package~~submission of information pursuant to Section III.A.21.1.5 to demonstrate that ~~the New Capacity Resource~~certain capacity should not be subject to buyer-side market power review.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA.

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Longer-Term Transmission Upgrade is any addition, modification, and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the

construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Section 16 of Attachment K to the OATT.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 and Section 10 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Longer-Term Proposal is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 16.4(b) of Attachment K to the OATT.

Longer-Term Transmission Solution is the Longer-Term Proposal identified as the preferred solution pursuant to Section 16 of Attachment K to the OATT.

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

Longer-Term Transmission Upgrade is an addition, modification, and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Longer-Term Transmission Upgrade PTF classification specified in the OATT and has been included in the Regional System Plan and RSP Project List as a Longer-Term Transmission Upgrade pursuant to the procedures described in Section 16 of Attachment K of the OATT.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

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

Market Efficiency Needs Scenario is an Economic Study reference scenario that is described in Section 17.2(b) of Attachment K to the OATT.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Award Limit is a parameter that may be submitted as part of a Day-Ahead Ancillary Services Offer, as described in Section III.1.8.1, that expresses the maximum total megawatt-hours of Day-Ahead energy offered or bid and Day-Ahead Ancillary Services offered for the next Operating Day.

Maximum Daily Energy Limit is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Maximum State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, above which the ISO shall not schedule the Electric Storage Facility to receive electricity from the grid.

Measure Life is the estimated time an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction, Annual Capacity Auction, or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an ~~Existing~~ On-Peak Demand Capacity Resource or ~~Existing~~ Seasonal Peak Demand Capacity Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section III.13.1.4.3.1 and Section III.15.2.1.1.2.1 of Market Rule 1 that are submitted by On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1, or as part of the qualification process for the Annual Capacity Auction

pursuant to the requirements of Section III.15.2.1.1.2.1 of Market Rule 1, and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with the monthly settlement report for the Forward Capacity Market or Annual Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MG TSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MG TSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, below which the ISO shall not schedule the Electric Storage Facility to inject electricity to the grid.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the ~~Forward~~-Capacity Market payment described in Section III.13.7.3 or Section III.15.8.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly Qualified Capacity is the amount of a resource's Qualified Capacity eligible to participate in a Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral during the applicable month.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Reconfiguration Auction is the reconfiguration auction conducted by the ISO each month as described in Section III.13.4.7 for those Monthly Reconfiguration Auctions held for months prior to the Capacity Commitment Period beginning on June 1, 2028 and in Section III.15.5 for those Monthly Reconfiguration Auctions held for months subsequent to the start of the Capacity Commitment Period beginning on June 1, 2028.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the ninth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

Net Regional Clearing Price is described in Section III.13.7.5 [or Section III.15.8.5](#) of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired or deactivated; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired or deactivated, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, New Demand Capacity Resource, or New Distributed Energy Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is a form applicable to the Forward Capacity Market described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time applicable to the Forward Capacity Market during which a Project Sponsor may submit a New Capacity Show of Interest Form, a New Demand Capacity Resource Show of Interest Form, or a New Distributed Energy Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is [a form applicable to the Forward Capacity Market](#) described in Section III.13.1.4.1.1.1 of Market Rule 1.

New Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

New Distributed Energy Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource.

New Distributed Energy Capacity Resource Show of Interest Form is [a form applicable to the Forward Capacity Market](#) described in Section III.13.1.4A.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

[New England Markets Deactivation](#) is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from all New England Markets, or the permanent reduction in Capacity Network Import Capability and Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

~~**New Resource Offer Floor Price** is defined in Section III.A.21.3.~~

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.~~2.1 4-3~~ or Section III.15.8.5.2.1.

Non-Commercial Capacity is the capacity of a ~~New Capacity Resource~~ that cleared in a Forward Capacity Auction for periods prior to the Annual Capacity Auction associated with the Capacity

Commitment Period beginning on June 1, 2028, or otherwise acquired a Capacity Supply Obligation and remains on Critical Path Schedule monitoring as of June 1, 2028, for some or all of its capacity that acquired a Capacity Supply Obligation~~or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.~~

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer” also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to

the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption

of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Capacity Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4 or Section III.15.7.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Permanent De-list Bid is a bid ~~that may be~~ submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference

between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability.

Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Policy Scenario is an Economic Study reference scenario that is described in Section 17.2(c) of Attachment K to the OATT.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource, New Demand Capacity Resource, or New Distributed Energy Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proposed Capacity Offer is an offer submitted to the Internal Market Monitor for its review pursuant to Section III.A.22.2.3.

Proxy Capacity Offer is a type of offer used in the Annual Capacity Market.

Proxy De-List Bid was a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Data Submission Deadline is a date specified in the Capacity Auction Calendar by which a Lead Market Participant seeking to have a resource participate in the Annual Capacity Auction must submit qualification materials pursuant to Section III.15.2.1.1.

Qualification Data Submission Package is the package submitted to the ISO by a Lead Market Participant seeking to qualify a resource for the Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral pursuant to Section III.15.2.1.1.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1 and shall apply to all resources subject to Section III.15.A of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes, or, for the 2028-2029 Capacity Commitment Period and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes.

Qualified Capacity Challenge and Restoration Plan Submission Window is the period set forth in the Capacity Auction Calendar during which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in a Seasonal Qualified Capacity value of a Capacity Resource.

Qualified Capacity Challenge and Restoration Plan Submission Deadline is a date set forth in the Capacity Auction Calendar by which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in Qualified Capacity of a Capacity Resource.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is ~~the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which an offer or bid may not be rationed in the Forward Capacity Auction~~ the MW quantity below which a Capacity Offer may not be rationed in the Annual Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in ~~Section III.13.2.8.2 and Section III.13.2.8.3.~~

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time

over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

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

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

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

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

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

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy

Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

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

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

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 or Section III.15.7.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

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

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Reference Level is defined in Section III.A.7 of Appendix A of Market Rule 1.

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

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

necessary for such non-designated load. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, the Annual Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in \$/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1, and that are used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Flexible Response Services shortages and defined in Section III.2.6.2(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

Resource Adequacy Assessment Qualified Capacity is the amount of summer and winter Qualified Capacity determined pursuant to Section III.15.3 of Market Rule 1 for all Capacity Resources identified in Section III.12.7.2(a) of Market Rule 1, at the start of the Resource Adequacy Assessment process that begins in June of the year preceding the relevant Capacity Commitment Period.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid in the Forward Capacity Market to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily

terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

Round-Trip Efficiency is a percentage expressing the megawatt-hours of energy that an Electric Storage Facility injects onto the grid per megawatt-hour of energy it receives from the grid.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Capacity Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Seasonal Qualified Capacity Notification Date is a date described in the Capacity Auction Calendar by which the ISO shall notify Market Participants of their Seasonal Qualified Capacity for the upcoming Capacity Commitment Period.

Seasonal Qualified Capacity Values are the summer and winter Qualified Capacity calculated by the ISO pursuant to Section 15.2.7.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two Solution, Stage Two Solution, or Longer-Term Proposal that has been identified

by the ISO as the preferred Phase Two Solution, Stage Two Solution, or Longer-Term Transmission Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction in the Day-Ahead Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction subject to the conditions specified in Section III.1.10.1A(b)(iii) and (iv). For an External Transaction in the Real-Time Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Self-Supplied Capacity Resource is described in Section III.15.2.9.1 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Distributed Energy Resource Aggregation (SODERA) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a ~~New Capacity~~ Resource, each asset of which: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy asset under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the asset receives the revenue source.

Stage One Proposal is a first round submission, as defined in Section 4A.6 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.8 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stakeholder-Requested Scenario is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

State of Charge is the total quantity of megawatt-hours available to be injected by an Electric Storage Facility onto the grid.

State-identified Requirement refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid ~~that may be~~ submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity

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

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

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only ~~by the clearing of the Static De List Bids Capacity Offer, the Permanent De List Bids or the Retirement De List Bids of all the Existing if none of the~~ Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity Commitment Period, or by deactivating all Generating Capacity Resources composing the Station.

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

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

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

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

Substation Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

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

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) or Section III.15.3.2.1(b) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the ~~Forward~~ Capacity Market as specified in Section III.13.2.2 or Section III.15.1.1.1.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control

Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

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

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of

the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

Transitional Cluster Study has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Transitional CNR Group Study has the meaning specified in Section I of Schedule 22, Section I of 23, and Section I of 25 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than \$0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1, and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is \$2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) or Section III.15.3.2.2(b) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 [and Section III.15.8.5.2](#) of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

SECTION II

ISO NEW ENGLAND OPENACCESS TRANSMISSION TARIFF

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II.I. DEACTIVATION

II.52 Deactivation Notification Process: The Deactivation Notification process described in Section II.I shall be effective for Deactivation Notifications associated with deactivations occurring during the Capacity Commitment Period beginning on June 1, 2028 and all subsequent Capacity Commitment Periods.

II.52.1 Deactivation Notification Deadline: The Deactivation Notification Deadline shall be the first Business Day occurring within 12 months of the first day of each Capacity Commitment Period. Deactivation Notifications shall be subject to the reliability review process described in this Section II.I and shall be reviewed by the Internal Market Monitor pursuant to Section III.A.24.

II.52.2 Deactivations Requiring Deactivation Notification: On or before the Deactivation Notification Deadline for the relevant Capacity Commitment Period, a Lead Market Participant seeking to permanently remove all or a portion of a resource from the Capacity Market shall submit a Deactivation Notification specifying whether the Lead Market Participant is seeking: (a) a Capacity Market Deactivation; or (b) a New England Markets Deactivation, for the resource. No Deactivation Notification may result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit unless the Deactivation Notification is for the entire resource. No Deactivation Notification may result in a resource's or External Elective Transmission Upgrade's final CNR Capability or CNI Capability exceeding its final NR Capability or NI Capability, respectively. For the purposes of this Section II.I, the entity authorized to submit a Deactivation Notification on behalf of an External Elective Transmission Upgrade shall be treated as the Lead Market Participant and the External Elective Transmission Upgrade shall be treated as the deactivating resource.

A resource that has never held Capacity Network Resource Interconnection Service shall not be required to submit a Deactivation Notification and may deactivate by notifying the ISO in writing of its election to deactivate and the date of deactivation. The interconnection rights for the resource will terminate and the status of the resource will be converted to deactivated on the date of deactivation. The date specified for deactivation is subject to the limit for resource inactivity described below.

A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be deactivated regardless of whether a Deactivation Notification was submitted. The

interconnection rights for the resource will terminate and the status of the resource will be converted to deactivated on the date of deactivation. Where a resource has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three-year period will be calculated from the last day of commercial operation of the resource.

II.52.3 Deactivation Notification Package: All Deactivation Notifications must be detailed in a Deactivation Notification Package submitted by the Lead Market Participant associated with a deactivation to the ISO no later than the Deactivation Notification Deadline. Deactivation Notifications may not be modified or withdrawn after the Deactivation Notification Deadline. The Deactivation Notification Package requirements shall be published on the ISO's website, subject to update, and shall include the following information: (1) the name of the entity submitting the Deactivation Notification, including its affiliates and ultimate parent company; (2) the resource subject to the Deactivation Notification, including the resource's name and resource identification number; (3) whether the Deactivation Notification is for a Capacity Market Deactivation or a New England Markets Deactivation; (4) the MW amount deactivating, and whether it is a full or partial deactivation; (5) the final amount of CNR Capability or CNI Capability, and NR Capability or NI Capability resulting from a New England Markets Deactivation, or the final amount of CNR Capability or CNI Capability resulting from a Capacity Market Deactivation; and (6) the date of the resource's planned deactivation. For Deactivation Notifications subject to review by the Internal Market Monitor pursuant to Section III.A.24, Lead Market Participants must include in their Deactivation Notification Package the relevant cost workbooks and supporting information described in Section III.A.24. The Deactivation Notification Package shall also include an affidavit executed by a corporate officer attesting to the accuracy of its content, including reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments, cash flows, opportunity costs, and risk premiums, and shall be subject to audit upon request by the Internal Market Monitor.

II.52.4 Publication of Deactivation Notifications: No later than ten Business Days after the Deactivation Notification Deadline, the ISO shall post on its website information concerning submitted

Deactivation Notifications, including the resource name, reduction in Interconnection Service (MW Quantity) that would result from acceptance of the Deactivation Notification, and the resource's planned deactivation date. Planned deactivation dates shall be updated for those resources accelerating deactivation pursuant to Section II.55.3.

II.53 Deactivation Notification Reliability Review

II.53.1 Deactivation Notification Reliability Review: For each Capacity Commitment Period corresponding to a given Deactivation Notification Deadline, the ISO shall within 90 calendar days of the Deactivation Notification Deadline review all Deactivation Notifications of 20 MW or more and determine whether a resource associated with any Deactivation Notification is needed for reliability reasons. The capacity associated with a Deactivation Notification shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. The capacity associated with a Deactivation Notification shall be deemed needed for reliability only for the sole purpose of addressing a local transmission reliability issue. If review of a Deactivation Notification results in the identification of a reliability need, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. If delaying the deactivation of one or more resources will resolve the identified reliability need, the ISO shall determine based on a review of net going forward costs (as determined pursuant to Section III.A.24), and in consultation with the Reliability Committee, whether a resource may be eligible for delayed deactivation. The Lead Market Participant associated with a resource eligible for delayed deactivation shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Deactivation Notification is eligible for delayed deactivation. The Lead Market Participant for a resource eligible for delayed deactivation must respond to the ISO within 30 calendar days indicating whether it accepts the delayed deactivation.

II.53.2 Publication of Delayed Deactivations: No later than 90 calendar days after the Deactivation Notification Deadline, the ISO shall post on its website its determinations regarding any Deactivation Notification where the resource elected to delay deactivation to satisfy a reliability need.

II.54 Compensation of Resources Delaying Deactivation

II.54.1 Compensation Election of Resources Delaying Deactivation: If the ISO determines that a resource is eligible for delayed deactivation and the Lead Market Participant associated with that resource accepts the delayed deactivation pursuant to Section II.53, the resource shall be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved net going forward costs for the relevant Capacity Commitment Period as determined and filed pursuant to Section III A.24, instead of the Capacity Clearing Price; or (ii) in instances where an entire resource is electing to delay deactivation, under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within 30 days of the ISO's notification that the resource is eligible for delayed deactivation. A resource that elects delayed deactivation that does not notify the ISO of its compensation election as described in this Section II.54 will be paid on the basis of the resource's net going forward costs. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. Cost-of-service agreements must include a claw-back provision addressing the obligation of a resource delaying deactivation that later seeks to return to New England Markets to refund to the ISO with interest all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the resource while the resource was subject to a cost-of-service agreement; credits associated with any refund shall be allocated in the same manner as the charges associated with the cost-of-service agreement. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Deactivation Notification was submitted. A resource that has delayed deactivation due to a reliability need shall deactivate as of the first day of the first Capacity Commitment Period in which they are no longer necessary for reliability. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the deactivation was delayed, payment will continue to be pursuant to this Section II.54. Resources that elect payment based on the Commission-approved net going forward costs may file with the Commission pursuant to Section 205 of the Federal Power Act to update its net going forward costs if the resource is retained for reliability for a period longer than the Capacity Commitment Period for which the deactivation was initially delayed.

II.54.2 Allocation of Costs Associated with Delayed Deactivation: The difference between payments based on resource net going forward costs or cost-of-service compensation as detailed in this Section II.54

and payments based on the market clearing price for the Capacity Market under Section III.15 shall be allocated to Regional Network Load within the affected Reliability Region.

II.54.3 Compensation for Delayed Deactivation of Stations Having Common Costs: If a deactivation that is associated with a Station having Common Costs is delayed for reliability reasons, the Generating Capacity Resource will be paid as follows: (i) if one or more Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Capacity Auction and one or more Generating Capacity Resource deactivations are delayed for reliability, then the Generating Capacity Resource deactivations delayed for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets composing the Generating Capacity Resource subject to delayed deactivation; or (ii) if no Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Capacity Auction and one or more Generating Capacity Resource deactivations are delayed for reliability, then each Generating Capacity Resource deactivation delayed for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Generating Capacity Resources delaying deactivation for reliability purposes).

II.54.4 Amended Obligations of a Cost of Service Agreement: If the ISO is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of a Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, the ISO shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

II.54.5 Incremental Cost of Reliability Service for Resources Delaying Deactivation: In cases where a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource has delayed deactivation for reliability reasons pursuant to Section II.53, and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

- (a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO:** A resource seeking to avail itself of the recovery mechanism provided in this Section II.54.5 must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.
- (b) **Required Showing Made to the Federal Energy Regulatory Commission:** In order to receive just and reasonable compensation for a capital expenditure under this Section II.54.5, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section II.54.1, the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.
- (c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.
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II.55 Deactivation Acceptance

II.55.1 Notification to Lead Market Participant: No later than 90 days after the Deactivation Notification Deadline, the ISO shall notify the Lead Market Participant: (1) that the Deactivation Notification has been accepted; (2) whether a resource associated with the Deactivation Notification is eligible for delayed deactivation; and (3) whether the Deactivation Notification represents a failure of the conduct test that may be subject to a Proxy Capacity Offer. Lead Market Participants identified pursuant to Section III.A.24 as submitting a Deactivation Notification in order to exercise market power to the benefit of a portfolio may be subject to referral to the Commission's Office of Enforcement and the capacity associated with their Deactivation Notification shall be subject to a Proxy Capacity Offer during the Capacity Commitment Period associated with the Deactivation Notification pursuant to Section III.15.4.

II.55.2 Accepted Deactivation Notifications: A resource, or portion thereof, that has had a Deactivation Notification accepted by the ISO shall be ineligible to participate in the Capacity Market coincident with the commencement of the Capacity Commitment Period identified in the Deactivation Notification. The interconnection rights, or relevant portion thereof, for the resource will terminate on the deactivation date and the status of the resource, or portion thereof, will be converted to deactivated on the date of deactivation, consistent with the provisions of Section II.48.3 and Schedules 22, 23, and 25 of the OATT. For those resources that specified Capacity Market Deactivation in their Deactivation Notification, only the CNR Capability or CNI Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Capacity Market Deactivation, consistent with Section II.48.3 and the relevant provisions of Schedules 22, 23, and 25 of the OATT. Resources that have submitted a Deactivation Notification shall continue participation in New England Markets consistent with the rights and obligations described in Section III.15.7 until the date specified in the resource's accepted Deactivation Notification.

II.55.3 Accelerated Deactivation: A resource, or portion thereof, that is to be deactivated pursuant to Section II.55.2 may deactivate the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Deactivation Notification was submitted if: (1) the Lead Market Participant has received the notification accepting the Deactivation Notification and responds to request a deactivation date earlier than 12 months after the Deactivation Notification Deadline; (2) the Lead Market Participant sought and received written notification from the Internal Market Monitor confirming eligibility for accelerated deactivation; and (3) the resource is able to transfer any of its remaining Capacity Supply

Obligation to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.15.6 or Monthly Reconfiguration Auctions as described in Section III.15.5. A resource, or portion thereof, electing accelerated deactivation pursuant to this Section II.55.3 that has satisfied the above-described obligations must notify the ISO in writing of its election to deactivate and the date of deactivation. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to deactivated on the date of deactivation, consistent with the treatment of accepted Deactivation Notifications described in Section II.55.2.

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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, Capacity Performance 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-Capacity](#) 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.1.4.2 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, Capacity Performance 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-Capacity](#) 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.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to 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 its 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.
- (a) 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:
 - (a) 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).
- (b) 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.
- (c) 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.
- (d) 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.
- (e) 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.
- (f) 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.)

- (g) 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.
- (h) 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 ~~cleared~~ experienced price separation in the ~~Forward Annual~~ Capacity Auction ~~with price separation~~, as determined in accordance with ~~Section III.12.4 and Section III.13.2.3.4~~ Section III.15.4.2.2(j) of Market Rule 1;

(2) The External Transaction is directly associated with ~~an Export Bid or Administrative Export De List Bid~~ Capacity Offer ~~Export Offer Segment~~ that ~~cleared~~ did not receive a Capacity Supply Obligation in the ~~Forward 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 ~~cleared Export Bid~~;

(3) The External Node associated with the unobligated Export Offer Segment ~~cleared Export Bid or Administrative Export De List Bid~~ 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 unobligated Export Offer Segment ~~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) FAnnual 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 Bid or an Administrative Export De List Bid~~ Export Offer Segment that ~~cleared~~ did not receive a Capacity Supply Obligation in the ~~Forward 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~~cleared Export Bid~~;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Offer Segment ~~Export Bid or Administrative Export De List Bid~~ 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 [FCA-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](#)~~FCA~~ Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and [FCA-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.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity (“Forward Capacity Market”) in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011 and ending with the period June 1, 2027 to May 31, 2028, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market (“Capacity Commitment Period”), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 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 Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1. The final Forward Capacity Auction was held in February 2024 for Capacity Supply Obligations associated with the Capacity Commitment Period beginning June 1, 2027 and no Forward Capacity Auctions shall be held thereafter.

III.13.A Forward Capacity Market Interim Provisions.

~~III.13.A.1 Interim Forward Capacity Auction Schedules.~~

~~Notwithstanding any other any dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Operating Documents, for the nineteenth through thirty-seventh Forward Capacity Auctions (associated with the 2028-2029 through 2046-2047 Capacity Commitment Periods, respectively), the following provisions apply.~~

~~III.13.A.1.1 [Reserved.]Nineteenth Forward Capacity Auction Delayed~~

~~For the nineteenth Forward Capacity Auction (associated with the 2028-2029 Capacity Commitment Period), the dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Operating Documents shall not apply and shall be delayed by three calendar years.~~

~~III.13.A.1.2 First Annual Reconfiguration Auction Suspension~~

~~For the nineteenth through thirty-sixth Forward Capacity Auctions (associated with the 2028-2029 through 2045-2046 Capacity Commitment Periods, respectively), the first annual reconfiguration auction~~

as specified in Section III.13.4 that is typically held in the month of June, approximately 24 months before the start of the applicable Capacity Commitment Period, shall not be conducted.

III.13.A.1.3 ~~Second Annual Reconfiguration Auction Suspension~~

~~For the nineteenth through twenty-seventh Forward Capacity Auctions (associated with the 2028-2029 through 2036-2037 Capacity Commitment Periods, respectively), the second annual reconfiguration auction as specified in Section III.13.4 that is typically held in the month of August, approximately 10 months before the start of the applicable Capacity Commitment Period, shall not be conducted.~~

III.13.A.1.4 ~~Third Annual Reconfiguration Auction Suspension~~

~~For the nineteenth through twenty-first Forward Capacity Auctions (associated with the 2028-2029 through 2030-2031 Capacity Commitment Periods, respectively), the third annual reconfiguration auction as specified in Section III.13.4 that is typically held in the month of March, approximately three months before the start of the applicable Capacity Commitment Period, shall not be conducted.~~

III.13.A.1.5 ~~Accelerated Qualification Period and Auctions~~

~~For the twentieth through thirty-seventh Forward Capacity Auctions (associated with the 2029-2030 through 2046-2047 Capacity Commitment Periods, respectively), the Forward Capacity Auction, and the qualification process for each such auction, shall be conducted under a 10-month timeline in accordance with the key dates set forth in the schedule below. For each Forward Capacity Auction specified in the table below, the ISO shall publish the dates, date ranges and deadlines for activities related to the respective Forward Capacity Auction no later than six months before the applicable notification to Lead Market Participants of their Existing Capacity Resource's summer Qualified Capacity and winter Qualified Capacity values as specified in Section III.13.1.2.3(a).~~

Capacity Commitment Period	Forward Capacity Auction Date	Revised annual reconfiguration auction Dates (as applicable)
2028-2029	February 2028	No reconfiguration auctions
2029-2030	December 2028	No reconfiguration auctions
2030-2031	October 2029	No reconfiguration auctions
2031-2032	August 2030	Third annual reconfiguration auction March 2031
2032-2033	June 2031	Third annual reconfiguration auction March 2032

~~2033-2034~~	~~April 2030~~	~~Third annual reconfiguration auction March 2033~~
~~2034-2035~~	~~February 2033~~	~~Third annual reconfiguration auction March 2034~~
~~2035-2036~~	~~December 2033~~	~~Third annual reconfiguration auction March 2035~~
~~2036-2037~~	~~October 2034~~	~~Third annual reconfiguration auction March 2036~~
~~2037-2038~~	~~August 2035~~	~~Second annual reconfiguration auction August 2036; Third annual reconfiguration auction March 2037~~
~~2038-2039~~	~~June 2036~~	~~Second annual reconfiguration auction August 2037; Third annual reconfiguration auction March 2038~~
~~2039-2040~~	~~April 2037~~	~~Second annual reconfiguration auction August 2038; Third annual reconfiguration auction March 2039~~
~~2040-2041~~	~~February 2038~~	~~Second annual reconfiguration auction August 2039; Third annual reconfiguration auction March 2040~~
~~2041-2042~~	~~December 2038~~	~~Second annual reconfiguration auction August 2040; Third annual reconfiguration auction March 2041~~
~~2042-2043~~	~~October 2039~~	~~Second annual reconfiguration auction August 2041; Third annual reconfiguration auction March 2042~~
~~2043-2044~~	~~August 2040~~	~~Second annual reconfiguration auction August 2042; Third annual reconfiguration auction March 2043~~
~~2044-2045~~	~~June 2041~~	~~Second annual reconfiguration auction August 2043; Third annual reconfiguration auction March 2044~~
~~2045-2046~~	~~April 2042~~	~~Second annual reconfiguration auction August 2044; Third annual reconfiguration auction March 2045~~
~~2046-2047~~	~~February 2043~~	~~Regular annual reconfiguration auction schedule applies~~

~~The ISO may adjust any published date, date range and/or deadline for Forward Capacity Auction activities by 10 Business Days if needed, and shall publish a revised date, date range and/or deadline no later than 30 days in advance of such adjustment.~~

III.13.A.2. Interim Reconfiguration Auction Qualification.

- (a) Notwithstanding any other provision of the ISO New England Operating Documents, a New Capacity Resource that has not already acquired a Capacity Supply Obligation and intends to achieve Commercial Operation as defined in Section III.13.1.1.2.2.2(h) before June 1, 2028, may

qualify for the annual reconfiguration auction, monthly reconfiguration auction and bilateral activities described in Section III.13.4 and Section III.13.5 occurring in 2025, 2026, 2027 and 2028 for the 2024-2025 Capacity Commitment Period associated with the fifteenth Forward Capacity Auction, 2025-2026 Capacity Commitment Period associated with the sixteenth Forward Capacity Auction, 2026-2027 Capacity Commitment Period associated with the seventeenth Forward Capacity Auction and 2027-2028 Capacity Commitment Period associated with the eighteenth Forward Capacity Auction as, applicable, under this section providing the following conditions are met:

- (1) The Project Sponsor submits qualification materials as described in Section III.13.1, including a New Capacity Show of Interest Form in April 2024 and a New Capacity Qualification Package in June 2024. The ISO shall post a list of the required materials on its website and a complete schedule for their submittal at least 60 days in advance; and
- (2) The Project Sponsor requests that the ISO monitor the New Capacity Resource's compliance with its critical path schedule as described in Section III.13.3.1.1 by November 1, 2024.

(b) Notwithstanding any other provision of the ISO New England Operating Documents, a New Capacity Resource that has not already acquired a Capacity Supply Obligation, and intends to achieve Commercial Operation as defined in Section III.13.1.1.2.2.2(h) before June 1, 2028, may qualify for the annual reconfiguration auction, monthly reconfiguration auction and bilateral activities described in Section III.13.4 and Section III.13.5 occurring in 2026, 2027, and 2028 for the 2025-2026 Capacity Commitment Period associated with the seventeenth Forward Capacity Auction, and the 2027-2028 Capacity Commitment Period associated with the eighteenth Forward Capacity Auction, as applicable, under this section providing the following conditions are met:

- (1) The Project Sponsor submits qualification materials as described in Section III.13.1, including a New Capacity Show of Interest Form in April 2025 and a New Capacity Qualification Package in June 2025. The ISO shall post a list of the required materials on its website and a complete schedule for their submittal at least 60 days in advance; and
- (2) The Project Sponsor requests that the ISO monitor the New Capacity Resource's compliance with its critical path schedule as described in Section III.13.3.1.1 by the first Business Day occurring in November 2025.

(c) Notwithstanding any other provision of the ISO New England Operating Documents, a New Capacity Resource that has not already acquired a Capacity Supply Obligation and intends to achieve Commercial Operation as defined in Section III.13.1.1.2.2.2(h) before June 1, 2028, may qualify for the annual reconfiguration auction, monthly reconfiguration auction and bilateral activities described in Section III.13.4 and Section III.13.5 occurring in 2027 and 2028 for the 2026-2027 Capacity Commitment Period associated with the seventeenth Forward Capacity Auction, and the 2027-2028 Capacity Commitment Period associated with the eighteenth Forward Capacity Auction, as applicable, under this section providing the following conditions are met:

- (1) The Project Sponsor submits qualification materials as described in Section III.13.1, including a New Capacity Show of Interest Form in April 2026 and a New Capacity Qualification Package in June 2026. The ISO shall post a list of the required materials on its website and a complete schedule for their submittal at least 60 days in advance; and
- (2) The Project Sponsor requests that the ISO monitor the New Capacity Resource's compliance with its critical path schedule as described in Section III.13.3.1.1 by the first Business Day occurring in November 2026.

III.13.A.3. Interim Provisions Regarding Demand Capacity Resources.

Notwithstanding any other provision of the ISO New England Operating Documents, for the nineteenth Forward Capacity Auction (associated with the 2028-2029 Capacity Commitment Period), a New Demand Capacity Resource is an Active Demand Capacity Resource that has not cleared in a previous Forward Capacity Auction, or an On-Peak Demand Resource consisting of measures that have not been in service prior to June 1, 2024, or a Seasonal Peak Demand Resource consisting of measures that have not been in service prior to June 1, 2024.

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:

		<u>Location of Summer Resource</u>			
		<u>Import- Constrained Capacity Zone</u>	<u>Rest-of-Pool Capacity Zone</u>	<u>Export- Constrained Capacity Zone</u>	<u>Nested Export- Constrained Capacity Zone</u>
<u>Location of Winter Resource</u>	<u>Import- Constrained Capacity Zone</u>	<u>Eligible (within same Capacity Zone)</u>	<u>Eligible</u>	<u>Eligible</u>	<u>Eligible</u>
	<u>Rest-of-Pool Capacity Zone</u>	<u>Ineligible</u>	<u>Eligible</u>	<u>Eligible</u>	<u>Eligible</u>
	<u>Export- Constrained Capacity Zone</u>	<u>Ineligible</u>	<u>Ineligible</u>	<u>Eligible (within same Capacity Zone)</u>	<u>Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located)</u>

	<u>Nested Export- Constrained Capacity Zone</u>	<u>Ineligible</u>	<u>Ineligible</u>	<u>Ineligible</u>	<u>Eligible (within same Capacity Zone)</u>

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_{location of the interface} - Capacity Clearing Price_{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_{location of the interface} - Capacity Clearing Price_{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:

$$\frac{(\text{Load} + \text{Reserve Requirement})}{\text{Total Capacity Supply Obligation}}$$

(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:

$$\text{MaxCSO} \times [3 \text{ months} \times (\text{ACAcP} - \text{ACA}_{\text{Sp}}) - (12 \text{ months} \times \text{ACAcP})]$$

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.

ACA_{Sp} = 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.

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.

	<u>Millstone 3</u>	<u>Seabrook</u>	<u>Stonybrook</u> <u>GT 1A</u>	<u>Stonybrook</u> <u>GT 1B</u>	<u>Stonybrook</u> <u>GT 1C</u>	<u>Stonybrook</u> <u>2A</u>	<u>Stonybrook</u> <u>2B</u>	<u>Wyman 4</u>
<u>Danvers</u>	<u>0.2627%</u>	<u>1.1124%</u>	<u>8.4569%</u>	<u>8.4569%</u>	<u>8.4569%</u>	<u>11.5551%</u>	<u>11.5551%</u>	<u>0.0000%</u>
<u>Georgetown</u>	<u>0.0208%</u>	<u>0.0956%</u>	<u>0.7356%</u>	<u>0.7356%</u>	<u>0.7356%</u>	<u>1.0144%</u>	<u>1.0144%</u>	<u>0.0000%</u>
<u>Ipswich</u>	<u>0.0608%</u>	<u>0.1066%</u>	<u>0.2934%</u>	<u>0.2934%</u>	<u>0.2934%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>
<u>Marblehead</u>	<u>0.1544%</u>	<u>0.1351%</u>	<u>2.6840%</u>	<u>2.6840%</u>	<u>2.6840%</u>	<u>1.5980%</u>	<u>1.5980%</u>	<u>0.2793%</u>
<u>Middleton</u>	<u>0.0440%</u>	<u>0.3282%</u>	<u>0.8776%</u>	<u>0.8776%</u>	<u>0.8776%</u>	<u>1.8916%</u>	<u>1.8916%</u>	<u>0.1012%</u>
<u>Peabody</u>	<u>0.2969%</u>	<u>1.1300%</u>	<u>13.0520%</u>	<u>13.0520%</u>	<u>13.0520%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>
<u>Reading</u>	<u>0.4041%</u>	<u>0.6351%</u>	<u>14.4530%</u>	<u>14.4530%</u>	<u>14.4530%</u>	<u>19.5163%</u>	<u>19.5163%</u>	<u>0.0000%</u>
<u>Wakefield</u>	<u>0.2055%</u>	<u>0.3870%</u>	<u>3.9929%</u>	<u>3.9929%</u>	<u>3.9929%</u>	<u>6.3791%</u>	<u>6.3791%</u>	<u>0.4398%</u>
<u>Ashburnham</u>	<u>0.0307%</u>	<u>0.0652%</u>	<u>0.6922%</u>	<u>0.6922%</u>	<u>0.6922%</u>	<u>0.9285%</u>	<u>0.9285%</u>	<u>0.0000%</u>
<u>Boylston</u>	<u>0.0264%</u>	<u>0.0849%</u>	<u>0.5933%</u>	<u>0.5933%</u>	<u>0.5933%</u>	<u>0.9120%</u>	<u>0.9120%</u>	<u>0.0522%</u>
<u>Braintree</u>	<u>0.0000%</u>	<u>0.6134%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>
<u>Groton</u>	<u>0.0254%</u>	<u>0.1288%</u>	<u>0.8034%</u>	<u>0.8034%</u>	<u>0.8034%</u>	<u>1.0832%</u>	<u>1.0832%</u>	<u>0.0000%</u>
<u>Hingham</u>	<u>0.1007%</u>	<u>0.4740%</u>	<u>3.9815%</u>	<u>3.9815%</u>	<u>3.9815%</u>	<u>5.3307%</u>	<u>5.3307%</u>	<u>0.0000%</u>
<u>Holden</u>	<u>0.0726%</u>	<u>0.3971%</u>	<u>2.2670%</u>	<u>2.2670%</u>	<u>2.2670%</u>	<u>3.1984%</u>	<u>3.1984%</u>	<u>0.0000%</u>
<u>Holyoke</u>	<u>0.3194%</u>	<u>0.3096%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>2.8342%</u>	<u>2.8342%</u>	<u>0.6882%</u>

<u>Hudson</u>	<u>0.1056%</u>	<u>1.6745%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.3395%</u>
<u>Hull</u>	<u>0.0380%</u>	<u>0.1650%</u>	<u>1.4848%</u>	<u>1.4848%</u>	<u>1.4848%</u>	<u>2.1793%</u>	<u>2.1793%</u>	<u>0.1262%</u>
<u>Littleton</u>	<u>0.0536%</u>	<u>0.1093%</u>	<u>1.5115%</u>	<u>1.5115%</u>	<u>1.5115%</u>	<u>3.0607%</u>	<u>3.0607%</u>	<u>0.1666%</u>
<u>Mansfield</u>	<u>0.1581%</u>	<u>0.7902%</u>	<u>5.0951%</u>	<u>5.0951%</u>	<u>5.0951%</u>	<u>7.2217%</u>	<u>7.2217%</u>	<u>0.0000%</u>
<u>Middleboroug h</u>	<u>0.1128%</u>	<u>0.5034%</u>	<u>2.0657%</u>	<u>2.0657%</u>	<u>2.0657%</u>	<u>4.9518%</u>	<u>4.9518%</u>	<u>0.1667%</u>
<u>North Attleborough</u>	<u>0.1744%</u>	<u>0.3781%</u>	<u>3.2277%</u>	<u>3.2277%</u>	<u>3.2277%</u>	<u>5.9838%</u>	<u>5.9838%</u>	<u>0.1666%</u>
<u>Pascoag</u>	<u>0.0000%</u>	<u>0.1068%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>
<u>Paxton</u>	<u>0.0326%</u>	<u>0.0808%</u>	<u>0.6860%</u>	<u>0.6860%</u>	<u>0.6860%</u>	<u>0.9979%</u>	<u>0.9979%</u>	<u>0.0000%</u>
<u>Shrewsbury</u>	<u>0.2323%</u>	<u>0.5756%</u>	<u>3.9105%</u>	<u>3.9105%</u>	<u>3.9105%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.4168%</u>
<u>South Hadley</u>	<u>0.5755%</u>	<u>0.3412%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>
<u>Sterling</u>	<u>0.0294%</u>	<u>0.2044%</u>	<u>0.7336%</u>	<u>0.7336%</u>	<u>0.7336%</u>	<u>1.1014%</u>	<u>1.1014%</u>	<u>0.0000%</u>
<u>Taunton</u>	<u>0.0000%</u>	<u>0.1003%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0000%</u>
<u>Templeton</u>	<u>0.0700%</u>	<u>0.1926%</u>	<u>1.3941%</u>	<u>1.3941%</u>	<u>1.3941%</u>	<u>2.3894%</u>	<u>2.3894%</u>	<u>0.0000%</u>
<u>Vermont Public Power Supply Authority</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>2.2008%</u>	<u>2.2008%</u>	<u>2.2008%</u>	<u>0.0000%</u>	<u>0.0000%</u>	<u>0.0330%</u>
<u>West Boylston</u>	<u>0.0792%</u>	<u>0.1814%</u>	<u>1.2829%</u>	<u>1.2829%</u>	<u>1.2829%</u>	<u>2.3041%</u>	<u>2.3041%</u>	<u>0.0000%</u>

<u>Westfield</u>	<u>1.1131%</u>	<u>0.3645%</u>	<u>9.0452%</u>	<u>9.0452%</u>	<u>9.0452%</u>	<u>13.5684%</u>	<u>13.5684%</u>	<u>0.7257%</u>

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.

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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's 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).

SECTION III

MARKET RULE 1

APPENDIX A

**MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION**

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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 - III.A.21.1.1. ~~Resources with~~ Capacity Not Exceeding 5 MW
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~~EXHIBIT 1~~ [Reserved]

~~EXHIBIT 2~~ [Reserved]

~~EXHIBIT 3~~ [Reserved]

~~EXHIBIT 4~~ [Reserved]

~~EXHIBIT 5~~ [Reserved]

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

* * *

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this **Appendix A** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule I (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this **Appendix A**. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this **Appendix A**, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential referral under Section III.A.19.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.8, III.A.10, ~~and~~ III.A.11, [III.A.21](#), [III.A.22](#), and [III.A.24](#) below.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Day-Ahead Ancillary Services Offers, Demand Bids, ~~and~~ Decrement Bids, [and Capacity Offers](#), as well as to the scheduling or operation of a generation unit or transmission facility.

* * *

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the ~~Forward~~ Capacity Market.

In accordance with the following provisions of this ~~Appendix A~~ Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the ~~Forward~~ Capacity Market and the exit of certain resources, in the form of deactivations, from the Capacity Market. Section III.13 of Market Rule 1 Sections III.A.21, III.A.22, III.A.23, and III.A.24 of this ~~Appendix A~~ specify the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

~~(a) [Reserved].~~

~~(b) Section III.13.1.2.3.1.6.3 Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.~~

~~(c) Section III.13.1.2.3.2 Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.~~

~~(d) Section III.13.1.3.3A(d) Review by Internal Market Monitor of offers from Existing Import Capacity Resources.~~

~~(e) Section III.13.1.3.5.6 Review by Internal Market Monitor of Offers from New Import Capacity Resources.~~

~~(f) Section III.13.1.7 Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.~~

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the ~~Forward~~ Capacity Market.

Sections III.13.4 and III.15.5 of Market Rule 1 address reconfiguration auctions in the ~~Forward~~ Capacity Market. As addressed in Sections III.13.4.2 and III.15.5.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility and Resource Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities and is supplemented by Operating Procedure No. 5, which addresses outage scheduling for transmission

facilities and Resources. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners and Resource Lead Market Participants. The Internal Market Monitor shall have the right to request that each Transmission Owner or Resource Lead Market Participant provide information to the Internal Market Monitor concerning the Transmission Owner or Resource Lead Market Participant's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner or Resource Lead Market Participant shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this **Appendix A**. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

* * *

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

* * *

III.A.17.2.3. Reporting on General Performance of the ~~Forward~~ Capacity Market.

The performance of the ~~Forward~~ Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. ~~No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the~~ Internal Market Monitor shall report on the functioning of the ~~Forward~~ Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this **Appendix A**.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the ~~Forward~~ Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

* * *

III.A.21. ~~Review of Offers from New Resources in the Forward Capacity Market~~Buyer-Side Market Power Review for the Capacity Market.

(a) ~~The Internal Market Monitor shall review offers from certain New Capacity Resources. Any capacity that has not been previously offered into the an Annual Capacity Auction~~ ~~Forward Capacity Auction~~ and that will be included in a Capacity Offer once it satisfies the necessary auction qualification requirements in Sections III.15.2 and III.15.3 of Market Rule 1 is subject to the provisions of this Section III.A.21, as described in this Section III.A.21. The Internal Market Monitor shall conduct a buyer-side market power review and determine a resource-specific Capacity Offer Floor Price for such capacity unless such capacity is exempted as described in this Section III.A.21. Capacity for which the Internal Market Monitor determines a Capacity Offer Floor Price pursuant to this Section III.A.21 remains subject to the provisions of this Section III.A.21 until the capacity is awarded a Capacity Supply Obligation through an Annual Capacity Auction.

(b) –For the purposes of this Section III.A.21, capacity not previously offered into an Annual Capacity Auction includes the following:

(i) capacity supplied from a resource that has never been offered into an Annual Capacity Auction;

(ii) capacity supplied from a resource previously offered into an Annual Capacity Auction, where such capacity represents an increase in the resource's total capacity as compared to the highest Capacity Supply Obligation (measured in MW) awarded to the resource in a prior Annual Capacity Auction or Forward Capacity Auction, and the increase is associated with a material change in the resource as defined in Section III.15.2.4.1(b); and

(iii) capacity supplied from a previously deactivated or retired resource, or portion thereof, that seeks to re-enter the Capacity Market pursuant to Section III.15.2.4 and that has not been offered into an Annual Capacity Auction since deactivation or retirement.

(c) For the purposes of this Section III.A.21, capacity not previously offered into an Annual Capacity Auction does not include the following:

(i) capacity supplied from an Import Capacity Resource that is (1) backed by a multi-year contract and (2) previously offered into an Annual Capacity Auction or Forward Capacity Auction while backed by that contract; or

(ii) for the purpose of the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, capacity for which a Capacity Supply Obligation had been awarded in a Forward Capacity Auction and not subsequently de-listed pursuant to a Permanent De-List Bid or a Retirement De-List Bid.

~~The provisions of Sections III.A.21.1 and III.A.21.2 are not applicable to offers from New Import Capacity Resources that are subject to the pivotal supplier test in Section III.A.23.~~

(d) A Lead Market Participant must be designated for a resource that will supply the capacity that is subject to the provisions of this Section III.A.21, notwithstanding the development or commercialization status of the resource.

III.A.21.1. Applicability of Buyer-Side Market Power Review.

The Internal Market Monitor will not conduct a buyer-side market power review of New Capacity Resources that meet the criteria. Review submission requirements for capacity subject to the Internal Market Monitor's buyer-side market power review and exemptions from the Internal Market Monitor's buyer-side market power review are described in this Section III.A.21.1.

III.A.21.1.1. ~~Resources with~~ Capacity Not Exceeding 5 MW.

~~A New Capacity Resource~~ Capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer ~~is~~ not ~~be~~ subject to the Internal Market Monitor's buyer-side market power review ~~or a Capacity Offer Floor Price~~ if the ~~amount of the capacity project's expected auction capacity (in MW) at the time of the qualification process for the Forward Capacity Auction~~ does not exceed an Annual Qualified Capacity of 5 MW.

~~If a New Capacity Resource's expected auction capacity exceeds 5 MW at the time of the qualification process for the Forward Capacity Auction, but the final FCA Qualified Capacity for the New Capacity Resource does not exceed 5 MW, an offer from the New Capacity Resource will not be mitigated pursuant to Section III.A.21.2.3, notwithstanding any buyer-side market power review that may have been conducted at the time of the qualification process.~~

III.A.21.1.2. ~~Passive Demand Response Resources.~~

~~Capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer~~ ~~New Demand Capacity Resources that consist solely of~~ ~~and that is supplied from an On-Peak Demand~~ ~~Capacity~~ Resources or Seasonal Peak Demand ~~Capacity~~ Resources ~~is~~ not ~~be~~ subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price.

III.A.21.1.3 ~~Import Capacity Not Associated with Transmission Investments.~~

Import capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer ~~is~~ not ~~be~~ subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price, unless the import capacity is either:

- (i) supplied from a single new External Resource, and the External Resource or import capacity supplied by the External Resource is controlled by or receiving out-of-market revenues (as defined in Section III.A.21.3(a)(ii)) from an entity or individual that (a) made or is making an investment in transmission that increases New England's import capability or (b) has a contractual arrangement with such an entity or individual, or

(ii) is controlled by or receiving out-of-market revenues (as defined in Section III.A.21.3(a)(ii)) from an Elective Transmission Upgrade Interconnection Customer as defined in Section II.47.5, Affiliate of an Elective Transmission Upgrade Interconnection Customer, or sponsor of an Elective Transmission Upgrade.

For the purposes of this Section III.A.21.1.3, the term “controlled” has the meaning set forth in Section III.A.23.4.

III.A.21.1.43. CapacityResources Supported by a Qualifying Load-Side Relationship Certification.

Capacity not previously offered in an Annual Capacity Auction that will be included in a Capacity Offer ~~New Capacity Resources~~ will not be subject to the Internal Market Monitor’s buyer-side market power review or a Capacity Offer Floor Price if the Lead Market Participant ~~Project Sponsor~~ for the resource supplying the capacity complies with the submission requirements described in Section III.A.21.1.5 and submits a Load-Side Relationship Certification, ~~as described in this Section III.A.21.1.3,~~ demonstrating one of the following qualifying circumstances:

(a) the ~~Project Sponsor~~ Lead Market Participant and its Affiliates or partners, if any, are not load serving entities and are neither receiving nor expecting to receive any revenues from a load serving entity, state, or political subdivision of a state that relate to the development, operation, control, or output of the ~~resource supplying the capacity~~ New Capacity Resource (excepting any revenues earned through an ISO-administered market); or

(b) the ~~resource supplying the capacity~~ New Capacity Resource is a Sponsored Policy Resource.

For the purpose of this Section III.A.21, a load serving entity is any entity that has or is the type of entity that could acquire a Capacity Load Obligation in the ~~Forward~~ Capacity Market.

To demonstrate such circumstances, the ~~Project Sponsor~~ Lead Market Participant must include as part of the Load-Side Relationship Certification a sworn affidavit from an officer or principal for the ~~Project Sponsor~~ Lead Market Participant -that includes factual detail sufficient to explain the qualifying circumstances. The ~~Project Sponsor~~ Lead Market Participant must submit the Load-

Side Relationship Certification to the ISO concurrent with the submission of information made pursuant to Section III.A.21.1.5, with the New Capacity Qualification Package, described in Section III.13.1.1.2.2, the New Demand Capacity Resource Qualification Package, described in Section III.13.1.4.1.1.2, or the New Distributed Energy Capacity Resource Qualification Package, described in Section III.13.1.4A.1.1.2. If the ISO is unable to determine from the Load-Side Relationship Certification that one of the qualifying circumstances exists, the capacityNew Capacity Resource's offer shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

III.A.21.1.5. Submission of Information for Exemption or Internal Market Monitor Review.

(a) The Lead Market Participant for a resource supplying capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer must submit to the ISO the following, unless the capacity meets the exemption requirements of Section III.A.21.1.1, Section III.A.21.1.2, or Section III.A.21.1.3:

(i) the qualification data described and referenced in Section III.15.2.1.1(a);

(ii) the name of any Affiliates of the Lead Market Participant that are load serving entities;

(iii) for capacity supplied from a resource previously offered into an Annual Capacity Auction as described in Section III.A.21(b)(ii), information identifying any changes to the resource's design or operating characteristics and the impact of such changes on the resource's total capacity;

(iv) for capacity that satisfies either of the qualifying circumstances set forth in Section III.A.21.1.4, a Load-Side Relationship Certification as described in Section III.A.21.1.4;

(v) for capacity that does not satisfy either of the qualifying circumstances set forth in Section III.A.21.1.4, the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and sufficient documentation and information for a buyer-side market power review pursuant to Section III.A.21.2.

Such documentation and information **must** include all financial estimates, projected revenues, and cost projections for the resource supplying the capacity, including the resource's pro-forma financing support data and anticipated out-of-market revenues (as defined in Section III.A.21.3(a)(ii)). For capacity that has achieved commercial operation prior to the submission of this information, such documentation **must** also include all financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation.

(b) With the exception of capacity that will be offered into the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 or the Capacity Commitment Period beginning on June 1, 2029, the Lead Market Participant may submit the information required by subsection (a) as early as the first Business Day of January of the third calendar year prior to the first Annual Capacity Auction for which the capacity may be eligible to be offered, as determined with reference to the capacity's proposed commercial operation date. For capacity that will be offered into the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 or the Capacity Commitment Period beginning on June 1, 2029, the earliest submission date will be the first Business Day of June 2026.

(c) If not already submitted pursuant to subsection (b), the Lead Market Participant must submit the information required by subsection (a) no later than the first Business Day of June of the calendar year prior to the first Annual Capacity Auction into which the capacity will be offered pursuant to Section III.A.22.1.

(d) By the end of the fifth calendar month following the month during which the submission of information pursuant to subsection (a) was made, the ISO shall notify the Lead Market Participant **of** any ISO determination as to whether the capacity is exempt from buyer-side market power review pursuant to Section III.A.21.1.4 and the basis for such determination, any Capacity Offer Floor Price for the capacity, and any Internal Market Monitor determinations regarding whether a requested lowest offer price submitted pursuant to subsection (a) must be mitigated, as described in Section III.A.21.2.3. The ISO and the Internal Market Monitor shall not disclose to the Lead Market Participant any information or analysis regarding the potential impact on Capacity Clearing Prices of any offer of the capacity into the Annual Capacity Auction.

(e) A Lead Market Participant that submits a Load-Side Relationship Certification must be prepared to provide both (1) the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and (2) the documentation and information described in subsection (a)(v), in the event that the ISO determines that the Load-Side Relationship Certification does not meet the requirements of Section III.A.21.1.4. If the ISO rejects a Load-Side Relationship Certification, the Lead Market Participant must promptly provide this information, and the capacity shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

(f) A Lead Market Participant that submits a Load-Side Relationship Certification is under a continuing obligation through the time of the Annual Capacity Auction to withdraw the Load-Side Relationship Certification if, at any point through the time of the Annual Capacity Auction, the capacity ceases to satisfy the qualifying circumstances set forth in Section III.A.21.1.4 that provided the basis of the Load-Side Relationship Certification. If at the time of withdrawal, the Lead Market Participant submits a substitute Load-Side Relationship Certification demonstrating alternate qualifying circumstances that the ISO determines meets the requirements of Section III.A.21.1.4, then the capacity will continue to be exempt from the Internal Market Monitor's buyer-side market power review pursuant to Section III.A.21.1.4. If no substitute Load-Side Relationship Certification is submitted at the time of withdrawal and the capacity is not exempt from buyer-side market power review pursuant to Section III.A.21.1.1, Section III.A.21.1.2, or Section III.A.21.1.3, then the following shall apply:

(i) If the withdrawal occurs no later than the first Business Day of June of the calendar year prior to the Annual Capacity Auction, the Lead Market Participant must submit concurrently with the withdrawal both (1) the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and (2) the documentation and information described in subsection (a)(v). The capacity shall then be subject to buyer-side market power review pursuant to Section III.A.21.2, unless a Capacity Offer Floor Price already has been calculated for the capacity subject to review. If a Capacity Offer Floor Price already has been calculated, no additional review is required.

(ii) If the withdrawal occurs later than the first Business Day of June of the calendar year prior to the Annual Capacity Auction, the capacity shall be treated as though no

submission of information was made pursuant to Section III.A.21.1.5 and be assigned a Capacity Offer Floor Price as described in Section III.A.21.3(g).

(g) A Lead Market Participant that submitted a requested lowest offer price pursuant to subsection (a) is under a continuing obligation through the time of the Annual Capacity Auction to submit a Load-Side Relationship Certification if, at any point through the time of the Annual Capacity Auction, circumstances change such that either of the qualifying circumstances set forth in Section III.A.21.1.4 can be demonstrated for the capacity associated with the requested lowest offer price. If the Load-Side Relationship Certification is submitted no less than 21 days prior to the Annual Capacity Auction Offer Window and the ISO determines that the Load-Side Relationship Certification meets the requirements of Section III.A.21.1.4, then the capacity will not be subject to a Capacity Offer Floor Price, notwithstanding the results of any previously conducted buyer-side market power review.

(h) If a Lead Market Participant fails to provide a submission pursuant to subsection (a) as required pursuant to this Section III.A.21.1.5, the capacity that would be the subject of the submission will be assigned a Capacity Offer Floor Price as described in Section III.A.21.3(g).

III.A.21.2. Review for the Exercise of Buyer-Side Market Power.

With the exception of New Capacity Resources that meet the criteria described in Section III.A.21.1, the Internal Market Monitor shall review requested lowest offer prices submitted pursuant to Section III.A.21.1.5 from New Capacity Resources, as described in Sections III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), and III.13.1.4A.1.1.2.6(a), for the potential exercise of buyer-side market power following the process described in this Section III.A.21.2 and will determine a Capacity Offer Floor Price for the capacity that is the subject of the submission.

III.A.21.2.1. Conduct Test.

The Internal Market Monitor will perform a conduct test by reviewing the information ~~described in~~ submitted pursuant to Sections ~~III.A.21.1.5~~ III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), and III.13.1.4A.1.1.2.6(a) and determining a ~~New Resource Offer Floor Price break-even price~~, as described in Section III.A.21.3, for the capacity subject to review ~~New Capacity Resource~~. A requested lowest offer price ~~for from a New Capacity Resource~~ capacity subject to review fails the conduct test if the Internal Market Monitor determines ~~that the New Resource Offer Floor Price~~ break-even price that exceeds the requested lowest offer price.

III.A.21.2.2. Demonstration of Lack of Incentive to Exercise Buyer-Side Market Power.

If the ~~Lead Market Participant~~Project Sponsor ~~does not submit~~ fails to demonstrate either of the qualifying circumstances set forth in Section III.A.21.1.4 to the ISO through a Load-Side Relationship Certification ~~(or the ISO rejects the Project Sponsor's Load-Side Relationship Certification)~~ because the ~~Project Sponsor~~Lead Market Participant is or is affiliated with a load serving entity or because the ~~Project Sponsor~~Lead Market Participant receives or expects to receive revenues outside of ISO-administered markets from a load serving entity, the ~~Lead Market Participant~~Project Sponsor is entitled to submit documentation and information as part of the ~~New Capacity Qualification Package, the New Demand Capacity Resource Qualification Package, or New Distributed Energy Capacity Resource Qualification Package~~ submission of information pursuant to Section III.A.21.1.5 to demonstrate that, notwithstanding such a relationship with a load serving entity with regard to the resource supplying the capacity subject to review~~New Capacity Resource~~, such load serving entity would be unlikely to realize a material, net financial benefit from any reduction in ~~Annual~~Forward Capacity Auction clearing prices resulting from entry of the ~~capacity~~New Capacity Resource in the ~~Annual~~Forward Capacity Market. If, after consideration of such documentation and information, the Internal Market Monitor determines that a load serving entity as described in this Section III.A.21.2.2 would be unlikely to realize such a material, net financial benefit ~~from any reduction in Forward Capacity Auction clearing prices resulting from entry of the New Capacity Resource in the Forward Capacity Market~~, then the Internal Market Monitor will not subject the requested lowest offer price to the mitigation described in Section III.A.21.2.3. For the avoidance of doubt, a ~~Lead Market Participant~~Project Sponsor may not utilize the provisions of this Section III.A.21.2.2 if it receives or expects to receive any revenues from a state, or from a political subdivision of a state that is not also a load serving entity, that relate to the development, operation, control, or output of the resource supplying the capacity~~New Capacity Resource~~.

As part of the documentation and information the ~~Lead Market Participant~~Project Sponsor submits pursuant to this Section III.A.21.2.2, the ~~Lead Market Participant~~Project Sponsor must include in its documentation and information a disclosure of any and all direct or indirect relationships or arrangements with a load serving entity regarding the resource supplying the capacity~~New Capacity Resource~~ and any other information necessary for the Internal Market Monitor to make the determination described in this Section III.A.21.2.2.

III.A.21.2.3. Consequence of Failing the Conduct Test and Failing to Rebut Presumed Incentive.

If a requested lowest offer price for capacity subject to review from a New Capacity Resource fails the conduct test and the Internal Market Monitor does not determine the lack of a material, net financial benefit to a load serving entity, as described in Section III.A.21.2.2, the New Resource Offer Floor Price ~~Internal Market Monitor-determined break-even price~~ -calculated as part of the conduct test shall be ~~used in the Forward Capacity Auction~~ the Capacity Offer Floor Price, as described in Section III.A.21.3(d) ~~13.2.3.2~~.

~~As described in Section III.A.21.1.1, the mitigation described in this Section III.A.21.2.3 will not apply to a New Capacity Resource with an FCA-Qualified Capacity that does not exceed the capacity threshold set forth in Section III.A.21.1.1, notwithstanding the results of any buyer-side market power review.~~

III.A.21.3. ~~New Resource Offer Floor Prices~~ Capacity Offer Floor Prices.

For capacity not previously offered into an Annual Capacity Auction ~~any New Capacity Resource~~ for which the Internal Market Monitor is required to ~~determine~~ calculate a Capacity Offer Floor Price ~~New Resource Offer Floor Price~~, the Internal Market Monitor shall use the ~~calculation~~ methodology described in this Section III.A.21.3 to make such a determination.

~~A resource having a New Resource Offer Floor Price determined pursuant to this Section III.A.21.3 that is higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.~~

(a) When determining a Capacity Offer Floor Price ~~calculating a New Resource Offer Floor Price~~ for any capacity not previously offered into an Annual Capacity Auction ~~New Capacity Resource~~, the Internal Market Monitor shall determine a break-even price for the capacity by entering all relevant resource capital and operating costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into a capital budgeting model and ~~shall calculate~~ ing the break-even contribution required from the Annual ~~Forward~~ Capacity Market to yield a discounted cash flow with a net present value of zero for the project.

~~(i)~~ The default model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under

contract (i.e., a contract negotiated at arm's length between two unrelated parties). The model horizon shall be longer or shorter than 20 years for a resource's ~~New Resource Offer Floor Price~~ break-even contribution calculation, if sufficiently documented in the offer information submitted pursuant to Sections III.~~A.21.1.5~~~~13.1.1.2.2.3~~, ~~III.13.1.4.1.1.2.8~~, or ~~III.13.1.4A.1.1.2.6~~. Adjustments to the model and calculation methodology will be made for capacity supplied from certain types of ~~New~~ Demand Capacity Resources and ~~New~~ Distributed Energy Capacity Resources as ~~described below in this subsection (a)~~ follows:

~~(1)~~ For Demand Response Assets or Distributed Energy Resources with demand reduction capability, the Internal Market Monitor will model discounted cash flows over the contract life.:-

(1)

~~(2)~~

~~(3)~~ For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are large commercial or industrial customers that use pre-existing equipment or strategies, the Internal Market Monitor will include new equipment costs and annual operating costs, such as customer incentives and sales representative commissions, as incremental costs.

(2)

~~(4)~~

~~(5)~~(3) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are residential or small commercial customers that do not use pre-existing equipment or strategies, the Internal Market Monitor will include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs as incremental costs.

~~(b) — The Internal Market Monitor shall compare the requested lowest offer price to the capacity price estimate calculated pursuant to subsection (a), and the resource's New Resource Offer Floor Price shall be determined as follows:~~

(ii) In calculating the break-even contribution for the capacity, ~~The~~ Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used ~~to evaluate the~~

- ~~requested offer price for such calculation.~~ Out-of-market revenues are any revenues that are:
- (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner.
- Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the ~~Annual Forward~~ Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the ~~Lead Market Participant~~ ~~Project Sponsor~~ shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.
- (iii) For ~~capacity supplied from a New~~ Demand Capacity Resource or ~~New~~ Distributed Energy Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource or Distributed Energy Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource or Distributed Energy Resource Aggregation, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).
- (iv) For ~~capacity not previously offered into an Annual Capacity Auction~~ ~~a New Capacity Resource~~ that has achieved commercial operation prior to the ~~submission of information pursuant to Section III.A.21.1.5 New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate~~, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for

inflation. For any such capacity resource, the prevailing market conditions will be those that were in place at the time of the decision to construct or change the design or operating characteristics of the resource supplying the capacity.

(b) ~~(iv)~~ Sufficient documentation and information must be included in the resource's qualification package (as described in Sections III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), or III.13.1.4A.1.1.2.6(a)) submission of information pursuant to Section III.A.21.1.5 to allow the Internal Market Monitor to make the determinations described in this Section III.A.21.3. If the supporting documentation and information is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Lead Market Participant~~Project Sponsor~~ to gather further information as necessary to complete its analysis. If after consultation, the Lead Market Participant~~Project Sponsor~~ does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the capacity subject to review shall be treated as though no submission of information was made pursuant to Section III.A.21.1.5 and be assigned a Capacity Offer Floor Price ~~resource's New Resource Offer Floor Price shall be equal to the Forward Capacity Auction as described in Section III.A.21.3(g) Starting Price.~~

(c) ~~(v)~~ If the Internal Market Monitor determines that the requested offer price is consistent with the equal to or greater than the Internal Market Monitor-determined break-even price's capacity price estimate, then the ~~resource's New Resource Offer Floor Price~~Capacity Offer Floor Price shall be equal to the requested offer price.

(d) ~~(vi)~~ If the Internal Market Monitor determines that the requested offer price is not consistent with less than the Internal Market Monitor-determined break-even price and the Internal Market Monitor does not determine the lack of a material, net financial benefit to a load serving entity, as described in Section III.A.21.2.2's capacity price estimate, then the ~~New Resource Offer Floor Price~~Capacity Offer Floor Price shall be equal to set to a level that is consistent with the capacity price estimate~~Internal Market Monitor-determined break-even price, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c).~~

~~(e)~~ After the Seasonal Qualified Capacity Values are determined for the resource supplying the capacity subject to the Capacity Offer Floor Price, the Internal Market Monitor may recalculate the break-even price as necessary to update a Capacity Offer Floor Price such that it reflects the Seasonal Qualified Capacity Values. During this recalculation, the Internal Market Monitor shall change only inputs and

assumptions used in the initial determination of the break-even price that depend on resource capacity values. The Internal Market Monitor shall notify the Lead Market Participant of any update to the Capacity Offer Floor Price concurrently with the Seasonal Qualified Capacity Notification Deadline. The Internal Market Monitor may further update the Capacity Offer Floor Price as necessary to reflect changes in a resource's Seasonal Qualified Capacity Values that occur after the Seasonal Qualified Capacity Notification Date and shall notify the Lead Market Participant of any such further update on the same date as any notifications made by the ISO pursuant to Section III.15.2.7(d).

(f) In accordance with Section III.15.4.2.2(c), capacity having a Capacity Offer Floor Price determined pursuant to this Section III.A.21.3 that is higher than the Capacity Auction Offer Price Cap shall not be taken into account in the clearing of the Annual Capacity Auction.

(g) If a Lead Market Participant fails to provide a submission of information by the deadline set forth in Section III.A.21.1.5(c) and the capacity is not exempt from buyer-side market power review pursuant to Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.3, the capacity will be subject to a Capacity Offer Floor Price in each Annual Capacity Auction into which the capacity is being offered that equals the Capacity Auction Offer Price Cap calculated for such Annual Capacity Auction, unless a Capacity Offer Floor Price is calculated pursuant to subsection (h)(i) of this Section III.A.21.3.

(h) Capacity for which a Capacity Offer Floor Price has been determined pursuant to this Section III.A.21.3 will remain subject to that Capacity Offer Floor Price until the capacity clears and is awarded a Capacity Supply Obligation in an Annual Capacity Auction, except as follows:

(i) If the capacity for which a Capacity Offer Floor Price has been determined does not clear the first Annual Capacity Auction into which it is offered, the Lead Market Participant may submit a request to the Internal Market Monitor to recalculate the Capacity Offer Floor Price for a subsequent Annual Capacity Auction if either (1) the cost or expected revenue assumptions for the resource have changed from those same assumptions reflected in the most recent submission of information pursuant to Section III.A.21.1.5(a) in a way that will impact the Capacity Offer Floor Price determination or (2) the Capacity Offer Floor Price had been set to the Capacity Auction Offer Price Cap. The request must be made by the submission deadline for the subsequent Annual Capacity Auction set forth in Section III.A.21.1.5(c) and must include all of the information and documentation required by Section III.A.21.1.5(a). If the request is made on the grounds of a change in cost or expected

revenue assumptions, the request must clearly and specifically identify the changed assumptions and the supporting documentation for such assumptions, and must explain how the changed assumptions will impact the Capacity Offer Floor Price calculation. The Internal Market Monitor, at its discretion, may reject a request to recalculate that does not clearly and specifically identify the changed assumptions or the supporting documentation for such assumptions, or explain the impact on the Capacity Offer Floor Price calculation.

(ii) If the capacity satisfies the requirements of Section III.A.21.1.1, then the capacity will not be subject to a Capacity Offer Floor Price, even if the Internal Market Monitor previously determined a Capacity Offer Floor Price for the capacity.

(iii) If the capacity satisfies the requirements of Section III.A.21.1.5(g), then the capacity will not be subject to a Capacity Offer Floor Price, even if the Internal Market Monitor previously determined a Capacity Offer Floor Price for the capacity.

III.A.21.4. — Offer Prices for New Import Capacity Resources.

~~(a) — All New Import Capacity Resources (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be subject to the pivotal supplier test in Section III.A.23.~~

~~(b) — For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 that does not seek to specify a price below which it would not accept a Capacity Supply Obligation that is at or above the Dynamic De List Bid Threshold, the resource's offer price shall be \$0.00/kW-month, subject to the provisions of Section III.13.2.3.2(a)(v).~~

~~(c) — For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and seeks to specify a price below which it would not accept a Capacity Supply Obligation that is at or above the Dynamic De List Bid Threshold, the Internal Market Monitor shall calculate an Internal Market Monitor determined offer price for the resource using the methodology for calculating New Resource Offer Floor Prices set forth in Section III.A.21.3. For any New Import Capacity Resource that is not subject to the pivotal supplier test in Section III.A.23, the Internal Market Monitor shall calculate a~~

~~New Resource Offer Floor Price using the methodology set forth in Section III.A.21.3, if such a calculation is required for the resource under Section III.A.21.2 above.~~

~~(d) — For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found to be associated with a pivotal supplier, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7, the resource's offer prices shall be reduced to equal the lower of (1) the prices determined by the Internal Market Monitor pursuant to subsection (c); or (2) the offer prices as revised pursuant to Section III.13.1.3.5.7. For any New Import Capacity Resource that is subject to the pivotal supplier test and is found not to be associated with a pivotal supplier, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7, the resource's offer prices shall be reduced to the prices revised pursuant to Section III.13.1.3.5.7.~~

III.A.22. Supply-Side Market Power Review for the Capacity Market.~~[Reserved.]~~

III.A.22.1. Capacity Market Offer Requirement.

~~(a) — With the exception of resources for which the ISO has accepted a Deactivation Notification that will be in effect for the relevant Capacity Commitment Period, a resource that has previously held a Capacity Supply Obligation or has had a Capacity Offer submitted on its behalf in a prior Annual Capacity Auction is required to participate in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3.~~

~~(b) — A resource that has not previously held a Capacity Supply Obligation or has not had a Capacity Offer submitted on its behalf in a prior Annual Capacity Auction is required to participate in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3 if the resource (1) has CNR Capability at the time of the Qualification Data Submission Deadline and (2) is in commercial operation or has a Commercial Operation Date in its interconnection agreement earlier than April 1 of the same calendar year as the Annual Capacity Auction.~~

~~(c) — A Capacity Offer must be submitted to the ISO during the Annual Capacity Auction Offer Window for a resource that participates in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3 and receives an Annual Qualified Capacity greater than 0 MW. The Capacity Offer must include a total quantity that is equal to the resource's Annual Qualified Capacity.~~

(d) If a Capacity Offer is not submitted to the ISO during the Annual Capacity Auction Offer Window for a resource subject to subsection (c), the ISO shall enter a Capacity Offer for the resource into the Annual Capacity Auction with the resource's Annual Qualified Capacity priced at either (i) \$0.00/kW-month or (ii) for any capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 supplied by the resource, the Capacity Offer Floor Price.

III.A.22.2. Capacity Offer Price Review for Economic Withholding.

The Internal Market Monitor shall review Proposed Capacity Offers from resources that will submit Capacity Offers in the Annual Capacity Auction as described in this Section III.A.22.2.

III.A.22.2.1. Capacity Offer Price Threshold.

For each Annual Capacity Auction, a Capacity Offer Price Threshold shall be calculated as described below in this Section III.A.22.2.1 and shall be published to the ISO's website no later than one month before the Capacity Offer Review Submission Deadline. This publication shall include the preliminary value calculated pursuant to subsection (a) below, whether the preliminary value was constrained by either of the limitations described in subsection (b) below, the margin value as calculated pursuant to subsection (c) below, and the final value as calculated pursuant to subsection (d) below.

(a) Subject to the limitations described in subsection (b) and to subsection (e) below, a preliminary value of the Capacity Offer Price Threshold shall be calculated as the average of: (i) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone from the immediately preceding Annual Capacity Auction (provided, however, that if there is a second run of the primary auction-clearing process pursuant to Section III.15.4.2.4, the resulting Rest-of-Pool Capacity Zone clearing price from that run shall be used instead); and (ii) the price at which the total amount of capacity clearing in the immediately preceding Annual Capacity Auction intersects the System-Wide Capacity Demand Curve for the upcoming Annual Capacity Auction that is filed with the Commission pursuant to Section III.12.3(a) in advance of the upcoming Annual Capacity Auction.

(b) The preliminary value of the Capacity Offer Price Threshold shall not be higher than 75 percent of the Net CONE value for the upcoming Annual Capacity Auction. The preliminary

value of the Capacity Offer Price Threshold shall not be lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.A.22.2.1, except as needed to ensure that it is not higher than 75 percent of the Net CONE value for the upcoming Annual Capacity Auction.

(c) A margin value shall be calculated using the following formula:

$$\text{Margin} = \$1/kW\text{-month} \times \left[\frac{(0.75 \times \text{Net CONE}_{\text{upcoming ACA}}) - \text{COPT}_{\text{preliminary}}}{(0.75 \times \text{Net CONE}_{\text{upcoming ACA}})} \right]$$

(d) The final value of the Capacity Offer Price Threshold for the upcoming Annual Capacity Auction shall be equal to the preliminary value of the Capacity Offer Price Threshold calculated pursuant to Sections III.A.22.2.1(a) and III.A.22.2.1(b) plus the margin value calculated pursuant to Section III.A.22.2.1(c).

(e) For the purpose of determining a preliminary value of the Capacity Offer Price Threshold for the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, the “immediately preceding Annual Capacity Auction” shall mean the Forward Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2027.

III.A.22.2.2. Applicability of Capacity Offer Price Review.

(a) Except with regard to capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 and Capacity Offers that will meet the requirements set forth in subsection (d) below, a Lead Market Participant that seeks to submit a Capacity Offer that specifies prices above the Capacity Offer Price Threshold for the Annual Capacity Auction must submit a Proposed Capacity Offer to the Internal Market Monitor for review pursuant to Section III.A.22.2.3 and must include the additional documentation described in that section. With the submission of a Proposed Capacity Offer, the Lead Market Participant must notify the ISO if the resource for which the Proposed Capacity Offer is submitted will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests) if it is not awarded a Capacity Supply Obligation for the Capacity Commitment Period.

(b) The Proposed Capacity Offer and all documentation required for the Internal Market Monitor’s review must be submitted no later than the Capacity Offer Review Submission

Deadline established for the Annual Capacity Auction. If a Lead Market Participant does not submit a Proposed Capacity Offer and the required supporting documentation to the Internal Market Monitor by the Capacity Offer Review Submission Deadline, the Capacity Offer submitted for the resource during the Annual Capacity Auction Offer Window must not specify any prices above the Capacity Offer Price Threshold.

(c) A price in a Capacity Offer specified for capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 is not subject to the Internal Market Monitor's review pursuant to Section III.A.22.2.3, but the specified price may only be greater than the Capacity Offer Floor Price if the price is below the Capacity Offer Price Threshold. If the Capacity Offer Floor Price is at or above the Capacity Offer Price Threshold, the specified price must equal the Capacity Offer Floor Price.

(d) Notwithstanding subsection (a) above, a Lead Market Participant that seeks to submit a Capacity Offer that specifies a price above the Capacity Offer Price Threshold for the Annual Capacity Auction is not required to submit a Proposed Capacity Offer if (i) the Capacity Offer will not contain more than one price-quantity pair that has a specified price above the Capacity Offer Price Threshold and (ii) the difference between the MW quantity of such price-quantity pair and the MW quantity of the price-quantity pair that specifies the next lowest price is equal to or less than the ambient air condition MW verified through the process set forth in Section III.15.2.1.5. For the purposes of Sections III.15.4.1, any Capacity Offer that qualifies for this exemption from the Proposed Capacity Offer submission requirement shall be deemed to have met the requirements set forth in (i) through (iii) of Section III.15.4.1(e) and to have been determined an Allowable Capacity Offer Price of \$0.01/kW-month greater than the Capacity Auction Offer Price Cap for the price-quantity pair. Such price-quantity pair will not be subject to the mitigation set forth in Sections III.A.22.2.4(c) and (d). Nothing in this subsection (d), however, shall limit or prevent the Internal Market Monitor from reviewing any ambient air condition adjustment or any Capacity Offer that qualifies for the exemption set forth in this subsection (d) for the potential exercise of market power, or to request additional information from the Lead Market Participant submitting the Capacity Offer to enable the Internal Market Monitor to make such a determination and take any appropriate steps.

III.A.22.2.3. Review of Capacity Offer Prices Exceeding Threshold.

(a) The Internal Market Monitor shall review each Proposed Capacity Offer with a price above the Capacity Offer Price Threshold to determine whether the offer is consistent with the following: (1) the resource's net going forward costs; (2) reasonable expectations about the resource's Capacity Performance Payments; (3) reasonable risk premium assumptions; and (4) the resource's reasonable opportunity costs, all as determined pursuant to this Section III.A.22.2.3. Sufficient documentation and information about each offer component must be included in the Section III.A.22.2.2(a) submittal to allow the Internal Market Monitor to make the requisite determinations about each cost component. The Section III.A.22.2.2(a) submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a resource with a Capacity Supply Obligation, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments, cash flows, opportunity costs, and risk premiums, and shall be subject to audit upon request by the ISO. The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) at any time to address any questions or concerns regarding the data submitted, as appropriate. In determining the consistency of Proposed Capacity Offer prices with the foregoing cost components, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio. In its review of the Proposed Capacity Offer, the Internal Market Monitor shall treat ambient air condition MW verified through the process set forth in Section III.15.2.1.5, if any, as physically unavailable and make its determinations pursuant to this Section III.A.22.2.3 accordingly.

(b) The Internal Market Monitor shall review each Proposed Capacity Offer and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop Cost-Based Reference Prices for comparison with the prices specified in the Proposed Capacity Offer that are above the Capacity Offer Price Threshold. The Internal Market Monitor shall calculate the Cost-Based Reference Prices in a manner that is consistent with the sum of the resource's net going forward costs plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable risk premium assumptions plus reasonable opportunity costs. The Internal Market Monitor's comparison of the Cost-Based Reference Prices to the prices specified in the Proposed Capacity Offer will result in Allowable Capacity Offer Prices as

follows:

(i) For each price-quantity pair in the Proposed Capacity Offer that specifies a price above the Capacity Offer Price Threshold, the Internal Market Monitor shall calculate a Cost-Based Reference Price for the MW quantity specified in the price-quantity pair.

(ii) If the price specified in the price-quantity pair of the Proposed Capacity Offer is equal to or less than 110 percent of the Cost-Based Reference Price for such price-quantity pair, then the Allowable Capacity Offer Price for the price-quantity pair shall be equal to the price specified for the price-quantity pair. If the price specified for the price-quantity pair is more than 110 percent of the Cost-Based Reference Price, then the Allowable Capacity Offer Price for the price quantity pair shall be equal to the Cost-Based Reference Price.

(iii)-If replacement of the prices specified for price-quantity pairs in the Proposed Capacity Offer with the Allowable Capacity Offer Prices determined pursuant to (i) and (ii) would result in a Capacity Offer that does not comply with the requirements of Section III.15.4.1(d), the Internal Market Monitor, after consultation with the Lead Market Participant, may adjust the Allowable Capacity Offer Price for any price-quantity pair as necessary to ensure that the Proposed Capacity Offer, if submitted pursuant to Section III.15.4.1 and mitigated pursuant to Section III.A.22.2.4(c), would comply with the requirements of Section III.15.4.1(d).

(c) If the Internal Market Monitor establishes an Allowable Capacity Offer Price for a price-quantity pair that does not equal the price specified by the Lead Market Participant for the price-quantity pair in the Proposed Capacity Offer, an explanation of the Allowable Capacity Offer Price based on the Internal Market Monitor review shall be provided to the Lead Market Participant at the time the Internal Market Monitor notifies the Lead Market Participant of the results of the Internal Market Monitor's Proposed Capacity Offer price review. Such explanation shall explain the Internal Market Monitor's determinations with respect to the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.A.22.2.3.1. Net Going Forward Costs.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall report expected net going forward costs for the applicable Capacity Commitment Period in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. A Proposed Capacity Offer price shall be evaluated for consistency with the capacity's net going forward costs based on a review of the data submitted in the following formula:

$$\begin{aligned} \text{Net Going Forward Costs} = & \\ & \frac{(GFC - IMR)}{(CQ_{\text{Summer, kW}} \times (12 \text{ months}))} \end{aligned}$$

Where:

GFC = annual going forward costs, in dollars. These are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Proposed Capacity Offer that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period if it is not awarded a Capacity Supply Obligation for the Capacity Commitment Period. Expenses, including financial obligations, incurred prior to the capacity auction that cannot be recovered, reimbursed, compensated, waived, or cancelled should the resource not be awarded a Capacity Supply Obligation are considered unavoidable and shall not be included. The expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the

New England Control Area, and expected transmission costs associated with importing to the New England Control Area may be included for Import Capacity Resources.

$CQ_{\text{Summer}} \text{ kW}$ = capacity, in kilowatts, for which the price specified in the Proposed Capacity Offer is above the Capacity Offer Price Threshold. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = expected annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Proposed Capacity Offer that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all submitted cost data representing the cumulative expected cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the resource's total ISO market revenues. In the case of a resource that has indicated that the resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be \$0.00.

III.A.22.2.3.2. Expected Capacity Performance Payments.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.A.22.2.3.3. Risk Premium.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall also provide documentation separately detailing any risk premium included in the price. This documentation must address all components of physical and financial risk reflected in the price, including, for example, catastrophic events, a higher-than-expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.A.22.2.3.1 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer

attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Annual Capacity Market is consistent with the participant's corporate risk management practices.

III.A.22.2.3.4. Opportunity Costs.

To the extent that a Capacity Resource submitting a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the price, the Lead Market Participant must include in the submission to the Internal Market Monitor evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.15.3.6, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.A.22.2.3.5. Review as Applied to Stations having Common Costs.

Where a resource at a Station having Common Costs elects to submit a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold, the provisions of this Section III.A.22.2.3.5 shall apply.

(a) **Submission of Cost Data.** In addition to the information required elsewhere in this Section III.A.22.2.3, a Proposed Capacity Offer submitted by a resource that is associated with a Station having Common Costs must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

(b) **Internal Market Monitor Review of Stations having Common Costs.** The Internal Market Monitor will review each price specified in the Proposed Capacity Offer that is above the Capacity Offer Price Threshold from a resource that is associated with a Station having Common Costs pursuant to the following methodology:

- (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
- (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the asset offer order.
- (iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive failure to clear the Annual Capacity Auction by each individual asset in asset offer order.
- (iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of Capacity Offer price-quantity pairs as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The Capacity Offer price-quantity pairs of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable price-quantity pair for use in the Annual Capacity Auction.

The Internal Market Monitor will compare a Capacity Offer price developed using the adjusted composite costs to the price specified in the Proposed Capacity Offer submitted by the resource that is associated with a Station having Common Costs and determine an Allowable Capacity Offer Price as described in Section III.A.22.2.3(b).

III.A.22.2.3.6. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall use the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent, when relevant to its review pursuant to this Section III.A.22.2.3.

<u>Age of Existing Resource (years)</u>	<u>Remaining Life (years)</u>	<u>Annual Rate of Capital Cost Recovery</u>
<u>1 to 5</u>	<u>30</u>	<u>0.106</u>
<u>6 to 10</u>	<u>25</u>	<u>0.110</u>
<u>11 to 15</u>	<u>20</u>	<u>0.117</u>
<u>16 to 20</u>	<u>15</u>	<u>0.131</u>
<u>21 to 25</u>	<u>10</u>	<u>0.163</u>
<u>25 plus</u>	<u>5</u>	<u>0.264</u>

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, along with its documentation submitted pursuant to Section III.A.22.2.2(b). The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\text{Cost Of Capital}}{(1 - (1 + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the resource, based on the age of the resource, as indicated in the table above.

III.A.22.2.4 Results of Capacity Offer Price Review.

(a) Concurrent with the Seasonal Qualified Capacity Notification Date for the Annual Capacity Auction, the ISO shall notify the Lead Market Participant that submitted a Proposed Capacity Offer concerning the result of the Internal Market Monitor's Proposed Capacity Offer

price review conducted pursuant to Section III.A.22.2.3 and include the information described in Section III.A.22.2.3(c).

(b) After the notification described in subsection (a), the Internal Market Monitor may redetermine any Allowable Capacity Offer Price, as necessary, to reflect changes in a resource's Seasonal Qualified Capacity Values that occur after the Seasonal Qualified Capacity Notification Date or to correct any errors in the initial determination of the Allowable Capacity Offer Price. The Internal Market Monitor shall notify the Lead Market Participant of any such redetermination on the same date as any notifications made by the ISO pursuant to Section III.15.2.7(d).

(c) For resources for which an Allowable Capacity Offer Price was established pursuant to Section III.A.22.2.3, the ISO shall replace a price specified in a price-quantity pair of the resource's Capacity Offer in the Annual Capacity Auction with a price as set forth in subsection (d), under the following circumstances:

(i) the resource is associated with a pivotal supplier, as determined pursuant to the pivotal supplier test set forth in Section III.A.23; and

(ii) the price specified in the price-quantity pair exceeds the greater of the Allowable Capacity Offer Price established for such price-quantity pair and the Capacity Offer Price Threshold determined pursuant to Section III.A.22.2.1.

(d) For the purposes of subsection (c), the ISO shall replace a price specified in a price-quantity pair of the Capacity Offer with the greater of (i) the Allowable Capacity Offer Price established for the price-quantity pair and (ii) the Capacity Offer Price Threshold.

III.A.22.3. Request for Additional Capacity Cost Recovery.

If as a result of mitigation applied to a Capacity Offer pursuant to Section III.A.22.2.4(c) a Lead Market Participant believes that it will not recover the costs to its Capacity Resource of meeting the Capacity Supply Obligation for the Capacity Commitment Period, as reflected in the Capacity Offer submitted for the resource, the Lead Market Participant may submit a filing to the Commission pursuant to Section 205 of the Federal Power Act in accordance with this Section III.A.22.3.

III.A.22.3.1. Threshold Conditions for Filing a Request.

To be eligible to make a Section 205 filing pursuant to this Section III.A.22.3, the following threshold conditions must have been met:

- (a) the Capacity Offer submitted by the Lead Market Participant for the Capacity Resource in the Annual Capacity Auction must have at least one price-quantity pair that was submitted as part of a Proposed Capacity Offer and for which the Internal Market Monitor determined an Allowable Capacity Offer Price pursuant to Section III.A.22.2.3;
- (b) the price specified in such price-quantity pair must have been replaced pursuant to Section III.A.22.2.4(c) prior to entry of the Capacity Offer into the Annual Capacity Auction; and
- (c) some portion of the MW quantity specified in such price-quantity pair that is also included in the Capacity Offer's Above-Threshold Offer Segment must have been awarded a Capacity Supply Obligation in the Annual Capacity Auction.

III.A.22.3.2. Relief Available Through Filing.

- (a) The Section 205 filing may request the following relief from the Commission:
 - (i) additional costs associated with the Capacity Supply Obligation awarded to the Capacity Resource in the Annual Capacity Auction, to be paid on a kW-month basis, at a price that is measured as the positive difference between (1) the lowest price specified in the Capacity Offer for the amount of MW of the Capacity Supply Obligation for which the Lead Market Participant seeks additional cost recovery and (2) the Capacity Clearing Price applicable to the Capacity Supply Obligation; and
 - (ii) regulatory costs associated with the filing.
- (b) A Lead Market Participant may not request a cost recovery rate that exceeds a rate calculated in accordance with subsection (a)(i). Notwithstanding subsection (a)(i), the Commission is not required to use a price specified in the Capacity Offer for the determination of a cost recovery rate if the Capacity Resource's costs of meeting its Capacity Supply Obligation are, on a kW-month basis, lower than such price.

III.A.22.3.3. Timing of Filing.

A Section 205 filing made pursuant to this Section III.A.22.3 must be made within sixty days after the ISO publicly publishes the results of the Annual Capacity Auction in accordance with Section III.15.4.3.

III.A.22.3.4. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include the following:

- (a) the Proposed Capacity Offer, all documentation and information submitted to the Internal Market Monitor pursuant to Section III.A.22.2, and any additional documentation and information relevant to the Proposed Capacity Offer that was submitted to the Internal Market Monitor during any consultation with the Internal Market Monitor before, during, or after the formal review process described in Sections III.A.22.2 and III.A.22.3;
- (b) the Internal Market Monitor's notification pursuant to Section III.A.22.2.4(a) and any explanation provided as part of that notification pursuant to Section III.A.22.2.3(c);
- (c) all price-quantity pairs and other parameters in the Capacity Offer submitted to the ISO for entry into the Annual Capacity Auction;
- (d) identification of the price-quantity pairs contained in the Capacity Offer that the Lead Market Participant claims have been improperly mitigated pursuant to Section III.A.22.2.4(c);
- (e) identification of the amount of MW of the Capacity Supply Obligation for which the Lead Market Participant seeks additional cost recovery;
- (f) an explanation as to the alleged error committed by the Internal Market Monitor in determining the Cost-Based Reference Price for the MW amount identified pursuant to subsection (e);
- (g) the Internal Market Monitor's written response to the request for relief, provided pursuant to Section III.A.22.3.5; and
- (h) all requested regulatory costs in connection with the filing.

III.A.22.3.5. Review by Internal Market Monitor Prior to Filing.

Within twenty days after the ISO publicly publishes the results of the Annual Capacity Auction, a Lead Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.22.3 shall submit to the Internal Market Monitor a complete, advance copy of the filing with all of the material described in Section III.A.22.3.4, with the exception of the material described in Section III.A.22.3.4(g). Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the request for additional cost recovery. The Lead Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing, as described in Section III.A.22.3.4(g).

III.A.22.3.6. Payments and Charges Related to the Additional Cost Recovery.

(a) In the event that the Commission accepts a filing for cost recovery under this section, the ISO shall adjust the Capacity Resource's monthly capacity payment calculated pursuant to Section III.15.8.1.1(a) to reflect the additional cost recovery rate for the portion of the Capacity Resource's Capacity Supply Obligation to which additional cost recovery applies. With respect to monthly capacity payments made prior to implementation of a Commission-accepted additional cost recovery rate, the ISO shall issue a single lump sum payment reflecting the additional cost recovery rate.

(b) The ISO shall allocate costs associated with payments made pursuant to subsection (a) in accordance with the cost allocation provisions in Section III.15.8.5.1 that apply to Annual Capacity Auction costs. Charges for the lump sum payment made pursuant to subsection (a) shall be determined in a way that is consistent with a Market Participant's Capacity Load Obligation during each Obligation Month covered by the lump sum payment.

(c) With respect to any regulatory costs accepted by the Commission, the ISO shall apportion the sum total of such regulatory costs equally among the twelve months of the Capacity Commitment Period. Each monthly amount shall be added to the Capacity Resource's monthly capacity payment, and any monthly amounts applicable to monthly capacity payments made prior to implementation of a Commission-accepted additional cost recovery rate shall be added to the lump sum payment set forth in subsection (a). The ISO shall allocate costs associated with

payments of such regulatory costs consistent with the allocation methodology set forth in subsection (b).

III.A.23. Pivotal Supplier Test for ~~Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market~~the Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to conducting the ~~commencement of the Forward Annual~~ Capacity Auction at the system level and for each import-constrained Capacity Zone. For the purpose of performing the pivotal supplier test as described in this Section III.A.23.1, the Capacity Resources that will be included in the calculations described herein are the Capacity Resources that will be entered into the Annual Capacity Auction for which the test is being performed.

~~An Existing Capacity Resource or New Import Capacity Resource~~ A Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's ~~FCA-Qualified Capacity~~Annual Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. ~~Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.~~

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

III.A.23.1.1. System-Level Requirement.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total ~~Annual~~FCA Qualified Capacity from all ~~Existing~~ Generating Capacity Resources and ~~Existing~~ Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of:

- (1) the total Annual FCA-Qualified Capacity from all Existing-Generating Capacity Resources and Existing-Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual FCA-Qualified Capacity from Import Capacity Resources over the interface, and;
 - (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled nested export-constrained Capacity Zone, the lesser of:
- (1) the total Annual FCA-Qualified Capacity from all Existing-Generating Capacity Resources and Existing-Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual FCA-Qualified Capacity from Import Capacity Resources over the interface, and;
 - (2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;
- (d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:
- (1) the total Annual FCA Qualified Capacity from all Existing-Generating Capacity Resources and Existing-Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total Annual FCA Qualified Capacity from Existing Generating Capacity Resources and Existing-Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

- (2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), ~~and~~;

(a) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:

- (1) the capacity transfer limit of the interface (net of tie benefits), and;
(2) the total amount of AnnualFCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.1.2. Import-Constrained Capacity Zone Requirement.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(~~a1~~) The total AnnualFCA Qualified Capacity from all ~~Existing~~ Generating Capacity Resources and ~~Existing~~ Demand Capacity Resources located within the import-constrained Capacity Zone; and

(~~b2~~) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of AnnualFCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

AnnualFCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's AnnualFCA Qualified Capacity in an export-constrained Capacity Zone ~~or nested export-constrained Capacity Zone~~ does not change the quantity calculated in Section III.A.23.1.1(c) ~~or Section III.A.23.1.1(d)~~ for that export-constrained Capacity Zone ~~or nested export-constrained Capacity Zone~~, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's AnnualFCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1.1(~~ed~~) for

that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's AnnualFCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1.2(4) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only AnnualFCA Qualified Capacity is a single capacity resource with a Capacity Offerbid that (i) is not subject to rationing ~~under Section III.13.1.2.3.1 or III.13.2.6~~, and (ii) contains only one price-quantity pair for the entire AnnualFCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers that are determined to be pivotal and subject to the mitigation described in Section III.A.22.2.4(c) as soon as practicable after the close of the Annual Capacity Auction Offer Window and before the Annual Capacity Auction results are determined~~no later than seven days prior to the start of the Forward Capacity Auction.~~

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the AnnualFCA Qualified Capacity of a supplier includes the capacity of ~~Existing~~ Generating Capacity Resources, ~~Existing~~ Demand Capacity Resources, and Existing Import Capacity Resources, ~~and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade)~~ that is controlled by the supplier or its Affiliates.

~~For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.~~

For purposes of determining the ~~Annual~~[FCA](#) Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the ~~Forward~~ Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. ~~Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market~~[Deactivation Notification Package Submission and Review.](#)

[III.A.24.1. Deactivation Notifications Requiring Workbook Submission and Review.](#)

[A Lead Market Participant seeking to permanently remove all or part of a resource from the Annual Capacity Market or from all New England Markets must follow the Deactivation Notification process pursuant to Section II.52, including the timely and complete submission of a Deactivation Notification Package. For each ~~Deactivations~~ Notification representing the deactivation of greater than 20 MW, the Deactivation Notification Package shall include the cost workbooks and supporting materials described in Section III.A.24.2 for review by the Internal Market Monitor. If more than one Deactivation Notification is submitted by a single Lead Market Participant or its Affiliates \(as used in Section III.A.24.6\) and the sum of all such Deactivation Notifications in aggregate is greater than 20 MW, then the Lead Market Participant must timely submit each such Deactivation Notification Package, including the cost workbooks and supporting materials described in Section III.A.24.2, as if each deactivation were greater than 20 MW. The Internal Market Monitor has no obligation to review a Deactivation Notification Package if the Deactivation Notification provides notice of either: \(a\) deactivation of the only resource controlled by a Lead Market Participant or its Affiliates participating in the Annual Capacity Market; or \(b\) deactivation of all resources controlled by a Lead Market Participant or its Affiliates participating in the Annual Capacity Market, where the term “control” has the meaning set forth in Section III.A.24.6.](#)

[Resources requiring review under Section III.A.24.1 that deactivate without submitting the complete information required by Section III.A.24.2 by the Deactivation Notification Deadline set forth in Section II.52.1 may be subject to referral to the Commission’s Office of Enforcement in accordance with Section III.A.19 if the Internal Market Monitor has reason to believe a Market Violation has occurred. In instances where a resource deactivates without submitting the complete information required by Section III.A.24.2, the Internal Market Monitor will determine the Proxy Capacity Offer of the resource pursuant to Section III.A.24.7 and include the Proxy Capacity Offer in the](#)

deactivation determinations filing pursuant to Section III.A.24.9.

III.A.24.2. Submission of Cost Workbooks and Supporting Materials.

Lead Market Participants submitting a Deactivation Notification Package subject to review under Section III.A.24.1 shall submit completed cost workbooks based on the latest Deactivation Notification cost workbooks posted to the ISO's website. The submitted cost workbooks shall include or be accompanied by sufficient documentation and information about each cost workbook component to allow the Internal Market Monitor to make the requisite determinations regarding their validity and the economic viability of the deactivating resource. Lead Market Participants submitting a Deactivation Notification Package shall include in their submission identifying information relating to all Annual Qualified Capacity that the Lead Market Participant and its Affiliates control (as that term is defined in Section III.A.24.6) including all capacity the control of which it has contracted to a third party.

Lead Market Participants may elect to submit the relevant cost workbooks and supporting materials for a completeness determination by the Internal Market Monitor no earlier than 90 days, but no later than 30 days, before the Deactivation Notification Deadline. No later than ten business days before the Deactivation Notification Deadline, the Internal Market Monitor shall notify those Lead Market Participants submitting materials for a completeness determination that either: (a) the submission has been determined to be complete; or (b) the submission has been determined to be incomplete, and identifying any aspects of the workbook or supporting materials that are deemed incomplete. Submission of a cost workbook and supporting materials for a completeness determination is optional and does not eliminate the requirement to submit a Deactivation Notification and Deactivation Notification Package on or immediately before the Deactivation Notification Deadline.

III.A.24.3. Internal Market Monitor Review of Deactivation Notification Package.

The Internal Market Monitor shall review all Deactivation Notification Packages requiring review pursuant to Section III.A.24.1 that the Internal Market Monitor determines contain a complete submission of cost workbooks and supporting material submitted on or before the Deactivation Notification Deadline for the relevant Capacity Commitment Period. The Internal Market Monitor is under no obligation to review Deactivation Notifications that it deems to be incomplete at the time of the Deactivation Notification Deadline due to incomplete cost workbooks and supporting materials.

The Internal Market Monitor shall review each timely-submitted and complete Deactivation Notification Package requiring review pursuant to Section III.A.24.1 to determine whether the economic basis for the

deactivation is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.A.24.4.1); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.A.24.4.2); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.A.24.4.3). The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the submission is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the Deactivation Notification Deadline for resources requiring review under Section III.A.24 to address any questions or concerns regarding the data submitted, as appropriate.

III.A.24.4. Net Present Value of Expected Cash Flows.

For those Capacity Resources subject to Internal Market Monitor review pursuant to Section III.A.24.1, the net present value of a Capacity Resource's expected cash flows shall be determined as described in this Section III.A.24.4.

III.A.24.4.1. Net Present Value of Expected Cash Flows Formula.

The Lead Market Participant for a Capacity Resource that submits a Deactivation Notification that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values. The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values. The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Capacity Resource's expected cash flows as follows:

The net present value of the Capacity Resource's expected cash flows is equal to (i) the net present value of the Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined below) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and 12 months.

The Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life (i.e., the Capacity Commitment Period associated with the Deactivation Notification) is the resource's expected annual net operating profit, including expected capacity revenues, less its expected capital expenditures in the Capacity Commitment Period.

The Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is deactivated may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource deactivations, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any

other assumptions used to develop the forecasted expected capacity prices in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with the Internal Market Monitor's estimate thereof in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with deactivating the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with deactivating the resource at the end of the resource's economic life plus the net present value of the Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.A.24.4.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Capacity Resource adjusted for risk. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Capacity Resource adjusted for risk. If the Internal Market Monitor determines the Lead Market Participant has

not provided adequate supporting documentation for the weighted average cost of capital for the Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.A.24.4 or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

The Internal Market Monitor shall calculate the Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years with year one being the Capacity Commitment Period associated with the Deactivation Notification. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Internal Market Monitor's estimate of the Capacity Auction Offer Price Cap and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the evaluation period in which a resource's net present value is maximized.

III.A.24.4.2. Expected Capacity Performance Payments.

The Lead Market Participant for a Capacity Resource that submits a Deactivation Notification that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.A.24.4.3. Opportunity Costs.

To the extent that a Capacity Resource submitting Deactivation Notification has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the bid, the Lead Market Participant must include evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.15.3.6, capital projects required to operate the plant as a capacity resource or for other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other

independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.A.24.4.4. Stations Having Common Costs.

Deactivation Notifications submitted by a Generating Capacity Resource that is associated with a Station having Common Costs and seeking to deactivate must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs. The Internal Market Monitor will review each Deactivation Notification from a Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

- (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
- (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred deactivation order.
- (iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive deactivation of each individual asset in preferred deactivation order.
- (iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically nonincreasing set of prices as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The price of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Capacity Auction.

The Internal Market Monitor will compare a price developed using the adjusted composite costs to the Deactivation Notification submitted by the Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the

submitted price is greater than the price developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will establish an Internal Market Monitor-calculated price as described in Section III.A.24.5 and, if the resource is determined to be deactivating to the benefit of a portfolio pursuant to III.A.24.6, the Internal Market Monitor shall use the Internal Market Monitor calculated price as the Proxy Capacity Offer Price pursuant to III.A.24.7.

III.A.24.5. Conduct Test.

The Internal Market Monitor shall review those Deactivation Notifications submitted pursuant to Section III.A.24.1 to determine whether the economic basis for a Deactivation Notification and associated cost workbooks are consistent with the reasonable net present value of the resource's expected cash flows, reasonable expectations about the resource's Capacity Performance Payments, and the resource's reasonable opportunity costs. After due consideration and consultation with the Lead Market Participant, as appropriate, the Internal Market Monitor shall develop a first-year break-even price based on the cost workbooks and supporting materials submitted by the Lead Market Participant. The Internal Market Monitor shall also calculate a first-year break-even price based on the Internal Market Monitor's reasonable expectations regarding net present value of the resource's expected cash flows, the resource's Capacity Performance Payments, and the resource's opportunity costs. If the first-year expected Capacity Clearing Price submitted by the Lead Market Participant is more than 10% greater than the first-year break-even price calculated based on the Internal Market Monitor's reasonable expectations regarding the net present value of the resource's expected cash flows, the resource's Capacity Performance Payments, and the resource's opportunity costs, then that resource fails the conduct test. For those resources failing the conduct test, the Internal Market Monitor shall perform a further review of the Lead Market Participant's portfolio pursuant to III.A.24.6. Resources that do not fail the conduct test shall deactivate consistent with the terms of their Deactivation Notification unless delaying deactivation pursuant to Section II.53.

III.A.24.6. Portfolio Benefit Test.

The ~~retirement~~ portfolio benefit test is performed for each Lead Market Participant submitting a Deactivation Notification subject to Internal Market Monitor review that has failed the conduct test set forth in Section III.A.24.56 ~~prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid.~~ The test will be performed as follows:

If

- i. The annual capacity revenue from the Lead Market Participant's total FCAnnual Qualified Capacity, not including the FCAnnual Qualified Capacity associated with the Permanent De List Bid or Retirement De List Bid Deactivation Notification, is greater than
- ii. the annual capacity revenue from the Lead Market Participant's total FCAnnual Qualified Capacity, including the FCAnnual Qualified Capacity associated with the Permanent De List Bid or Retirement De List Bid Deactivation Notifications for resources controlled by the Lead Market Participant that failed the conduct test as calculated pursuant to subsection v. below, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio benefit test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCAnnual Qualified Capacity not including the FCAnnual Qualified Capacity associated with the Permanent De List Bid or Retirement De List Bid Deactivation Notification is calculated as the product of (a) the Lead Market Participant's total FCAnnual Qualified Capacity not including the FCAnnual Qualified Capacity associated with the Permanent De List Bid or Retirement De List Bid Deactivation Notification that is the subject of the review and (b) the Internal Market Monitor-simulatedestimated eCapacity Cclearing Pprice not including the FCAnnual Qualified Capacity associated with the Permanent De List Bid or Retirement De List BidDeactivation Notification.
- v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCAnnual Qualified Capacity including the FCAnnual Qualified Capacity associated with the Permanent De List Bid or Retirement De List BidDeactivation Notification is calculated as the product of (a) the Lead Market Participant's total FCAnnual Qualified Capacity including the FCAnnual Qualified Capacity associated with the Permanent De List Bid or Retirement De List BidDeactivation Notification that is the subject of the review and (b) the Internal Market Monitor-estimated-simulated eCapacity eClearing pPrice including the FCAnnual Qualified Capacity associated with the Permanent De List Bid or Retirement De List Bid Deactivation Notification.

- vi. For purposes of subsections iv. and v. above, the Internal Market Monitor-~~simulated~~ ~~estimated e~~Capacity ~~e~~Clearing ~~p~~Price, not to exceed the ~~Forward Capacity Auction Starting Price Capacity Auction Offer Price Cap~~, is based on ~~the parameters of the~~ System-Wide Capacity Demand Curve, ~~and~~ Capacity Zone Demand Curves as specified in Section III.15.13.2.2., ~~and the supply curve developed from the most recent Annual Capacity Auction.~~

For purposes of the test performed in this Section III.A.24, the ~~FCA-Annual~~ Qualified Capacity of a Lead Market Participant includes the capacity of ~~Existing~~ Capacity Resources that ~~is~~ are controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the ~~FCA-Annual~~ Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the ~~Annual~~ ~~Forward~~ Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.24.6 and all capacity the control of which it has contracted to a third party.

III.A.24.7. Proxy Capacity Offer.

For those deactivations the Internal Market Monitor determines have failed both the conduct test set forth in Section III.A.24.5 and the portfolio benefit test set forth in Section III.A.24.6, the first-year break-even price calculated based on the Internal Market Monitor’s reasonable expectations regarding net present value of the resource’s expected cash flows, the resource’s Capacity Performance Payments, and the resource’s opportunity costs, determined in accordance with Section III.A.24.3, shall be used as that resource’s Proxy Capacity Offer price. The deactivation determination filing made to the Commission as described in Section III.A.24.9 shall include an explanation of the resource’s Proxy Capacity Offer price. Unless the Commission determines otherwise, the ISO shall enter Proxy Capacity Offers into the Capacity Auction pursuant to Section III.15.4.

III.A.24.8. Deactivation Determination Notification.

No later than 90 days after the Deactivation Notification Deadline, the Internal Market Monitor shall provide written notification to the Lead Market Participant that submitted each Deactivation Notification concerning the result of the Internal Market Monitor’s conduct test conducted pursuant to Section

III.A.24.5.

III.A.24.9. Deactivation Determinations Filing.

No later than 120 days after the Deactivation Notification Deadline, the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act confidentially describing the determinations made by the Internal Market Monitor with respect to each Deactivation Notification failing the conduct test, including the supporting documentation for each such determination. The filing shall identify to the extent possible the components of the Deactivation Notification which were accepted as justified, and shall also identify to the extent possible the components of the Deactivation Notification which were not justified and which resulted in the Internal Market Monitor identifying the resource as requiring a Proxy Capacity Offer. The deactivation determinations filing shall identify the Proxy Capacity Offer price that, pursuant to Section III.15.4, will be entered into the Annual Capacity Auction on behalf of the Lead Market Participant during the Capacity Commitment Period in question if the Commission accepts the deactivation determinations filing. In the event that no Deactivation Notification failed the conduct test associated with a particular Deactivation Notification Deadline, the filing shall state that outcome.

In the event that a Lead Market Participant elects pursuant to Section II.53 to delay a resource's deactivation for reliability reasons, and elects pursuant to Section II.54.1 to be compensated based on net going forward costs, the deactivation determinations filing shall include a description of the resource's net going forward costs and all supporting materials necessary to arrive at the resource's net going forward costs, including a description of any instances in which the Internal Market Monitor-determined net going forward costs differ from the net going forward costs that may be arrived at based solely on the resource's cost workbook submission.

I.2.2. Definitions:

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

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward [or Annual](#) Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 [or Section III.15](#) of Market Rule 1.

Annual Capacity Auction (ACA) is the [Annual Capacity Market auction process carried out pursuant to Section III.15.4 of Market Rule 1.](#)

Annual Capacity Market is the [annual market for procuring capacity in the New England Control Area, as set forth in Section III.15 of Market Rule 1.](#)

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market [and Annual Capacity Market.](#)

Capacity Demonstration Deadline is a [monthly deadline described in the Capacity Auction Calendar for completion of the capacity demonstration requirement set forth in Section III.15.2.6 prior to participation in the Annual Capacity Auction, a Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral transaction.](#)

Capacity Resource is a [type of resource eligible to participate in the Annual Capacity Auction. There are four types of Capacity Resources: Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource.](#)

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2 [or an Annual Capacity Auction in accordance with Section III.15.4](#), a reconfiguration auction in accordance with Section III.13.4 [or Section III.15.5](#), or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 [or Section III.15.6.1](#) of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the ~~Forward~~ Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3 and in Sections III.15.1.1.2 and III.15.1.1.3.

Deactivation Notification is a notification of the planned New England Market Deactivation or Capacity Market Deactivation of a resource, External Elective Transmission Upgrade, or portion thereof, submitted to the ISO by the applicable Lead Market Participant.

Deactivation Notification Deadline is the deadline for submission of a Deactivation Notification and a Deactivation Notification Package, as discussed in Section II.52.1 of the OATT.

Demand Capacity Resource ~~is a type of resource that may participate in the Capacity Market; means an Existing Demand Capacity Resource or a New Demand Capacity Resource.~~ There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Capacity Resources, and Seasonal Peak Demand Capacity Resources.

Distributed Energy Capacity Resource (DECR) ~~means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource~~ is a type of Capacity Resource that participates in the Capacity Market and composes one or more Distributed Energy Resource Aggregations.

Dynamic De-List Bid is a bid ~~that may be~~ submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, Existing Demand Capacity Resources, and Existing Distributed Energy Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Export Bid is a bid ~~that may be~~ submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1. The final Forward Capacity Auction was for the Capacity Commitment Period beginning on June 1, 2027.

Generating Capacity Resource means a ~~New Generating Capacity Resource or an Existing Generating Capacity Resource~~ type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2.

Import Capacity Resource ~~means an Existing Import Capacity Resource or a New Import Capacity Resource~~ is a type of resource offered participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2 by providing to provide capacity in the New England Control Area from an external Control Area.

Lead Market Participant, for purposes other than the Forward Capacity Market or Annual Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids, Demand Reduction Offers, Baseline Deviation Offers, or Day-Ahead Ancillary Services Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource. For purposes of the Annual Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of a Capacity Resource.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired or deactivated; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired or deactivated, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned,

purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Capacity Show of Interest Submission Window is the period of time [applicable to the Forward Capacity Market](#) during which a Project Sponsor may submit a New Capacity Show of Interest Form, a New Demand Capacity Resource Show of Interest Form, or a New Distributed Energy Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

On-Peak Demand [Capacity](#) Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined ~~as determined prior to the 2028-2029 Capacity Commitment Period~~ in the Forward Capacity Market qualification processes, [or, for the 2028-2029 Capacity Commitment Period and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes.](#)

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 [or Section III.15.7.4](#) of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

[Resource Adequacy Assessment Qualified Capacity](#) is the amount of summer and winter [Qualified Capacity determined pursuant to Section III.15.3 of Market Rule 1 for all Capacity Resources identified in Section III.12.7.2\(a\) of Market Rule 1, at the start of the Resource Adequacy Assessment process that begins in June of the year preceding the relevant Capacity Commitment Period.](#)

Seasonal Peak Demand [Capacity](#) Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use

customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Static De-List Bid is a bid ~~that may be~~ submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

System-Wide Capacity Demand Curve is the demand curve used in the ~~Forward~~ Capacity Market as specified in Section III.13.2.2 or Section III.15.1.1.1.

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each ~~Annual~~Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for ~~each upcoming Capacity Commitment Period through~~ the Capacity Commitment Period associated with that ~~Annual~~Forward 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~~include generating resources, demand resources, and import capacity resources~~ 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~~Forward 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 ~~AnnualForward~~ 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 ~~each upcoming Capacity Commitment Period through~~ the Capacity Commitment Period associated with that ~~AnnualForward~~ 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 ~~AnnualForward~~ 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~~[Forward](#) 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:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{Rest of New England}}$$

In which:

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

LRA_{Rest of New England} = 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 Forward~~ 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 ~~each upcoming Capacity Commitment Period through~~ 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 ~~each upcoming Capacity Commitment Period through~~ the ~~relevant~~ Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act at least 90 days prior to the ~~AnnualForward~~ 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) _____

(a)(c) **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 AuctionFCA, any new Capacity Zone must be accepted by the Commission prior to the Deactivation NotificationExisting Capacity Qualification Deadline of the applicable Annual Capacity AuctionFCA.

III.12.4. Capacity Zones.

For each ~~AnnualForward~~ 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](#)~~include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):~~

(a) The ISO shall model in the [AnnualForward](#) 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](#)~~existing~~ Qualified Capacity and ~~potential~~[proposed](#) new capacity that could qualify to be procured in the export constrained Capacity Zone, including ~~potential~~[existing and proposed new](#) Import Capacity Resources on the export-constrained side of the interface.

(b) The ISO shall model in the [AnnualForward](#) 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](#)~~existing~~ 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](#)~~Retirement De List Bids and Permanent De List Bids (including any received for the current Forward Capacity Auction at the time of this calculation), substitution auction demand bids submitted for the current Forward Capacity Auction, rejected for reliability Static De List Bids from the most recent previous Forward Capacity Auction, and rejected for reliability Dynamic De List Bids from the most recent previous Forward Capacity Auction.~~

(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 [AnnualForward](#) 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 beginning of the New Capacity Show of Interest Submission Window~~ of the applicable ~~Annual~~ ~~Forward~~ 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 [AnnualForward](#) Capacity Auction ~~and each annual reconfiguration 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 [AnnualForward](#) 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:

(ia) all Existing Generating Capacity Resources,

(ib) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(~~iii~~e) 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~~d) 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,

(e) ~~all Existing Distributed Energy Capacity Resources,~~

but shall exclude:

(~~v~~f) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

(~~vi~~g) 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~~h) 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. ~~The rating of Distributed Energy Capacity Resources shall be the existing Qualified Capacity for the Capacity Commitment Period being evaluated.~~

~~III.12.7.2.1.~~ ~~[Reserved.]~~

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, tThe 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:

(a) 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.

(b) [Reserved.]

(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.

~~For Distributed Energy Capacity Resources:~~

~~For each Distributed Energy Capacity Resource, the availability metric for each underlying technology type will 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.~~

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 ~~Existing~~ 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) ~~[Reserved.]~~

~~(c)~~ ~~[Reserved.]~~

~~(d)~~ 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~~ 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 AnnualForward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the AnnualForward Capacity Auction ~~and the third annual reconfiguration 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. For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

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 ~~the General Electric Multi-area Reliability Simulation (MARS)~~ 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 ~~Existing~~ Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
 3. Qualified ~~Existing~~ Demand Capacity Resources reflecting their Capacity Supply ————Obligation received in the most recent Forward Capacity Auction or Annual Capacity Auction, as appropriate;
 4. Qualified ~~Existing~~ 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](#)~~existing~~ 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 the Forward 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. ~~For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.~~

- 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 Forward Capacity Auction shall be anythe Qualified Existing 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, ~~and~~ 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,annual reconfiguration auctions 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 suchthe 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 eachthe Annual Forward 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. ~~In addition, for the first and second annual reconfiguration auctions, any changes to the import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.~~

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~~Forward Capacity Auction ~~and Reconfiguration Auctions~~.

For external interfaces, Import Capacity Resources shall be allowed in the ~~Annual~~Forward 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, reconfiguration auctions~~ 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.

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:

Annual Capacity Auction (ACA) is the [Annual Capacity Market auction process carried out pursuant to Section III.15.4 of Market Rule 1.](#)

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand [Capacity](#) Resource or Seasonal Peak Demand [Capacity](#) Resource, a Distributed Energy Resource participating as part of [a Demand Response Distributed Energy Resource Aggregation](#), a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of ~~an Existing~~ Generating Capacity Resource, calculated for the asset in the same manner as the net costs of ~~Existing~~ Generating Capacity Resources as described in Section III.~~13.1.2.3.2.1.1.1~~[A.22](#) (for an asset ~~with a Static De List Bid or an Export Bid~~[associated with a Capacity Offer price subject to Internal Market Monitor review](#)) or Section III.~~A.24~~[13.1.2.3.2.1.1.2](#) (for an asset ~~with a Permanent De List Bid or Retirement De List Bid~~[submitting a Deactivation Notification](#)).

Capacity Clearing Price is the clearing price ~~infer~~ a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1 [or resulting from the Annual Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.15.4.2.](#)

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market [and Annual Capacity Market.](#)

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 [or Section III.15.8.5.2](#) of Market Rule 1.

Capacity Market is the [forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1, or the annual market for procuring capacity in the New England Control Area, as described in Section III.15 of Market Rule 1.](#)

Capacity Market Deactivation is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from the Capacity Market, or the permanent reduction in Capacity Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 or Section III.15.8.2 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2 or an Annual Capacity Auction in accordance with Section III.15.4, a reconfiguration auction in accordance with Section III.13.4 or Section III.15.5, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 or Section III.15.6.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 or Section III.15.6.1 of Market Rule 1.

Common Costs are those costs associated with a Station that are avoided only ~~by the clearing of the Static De-List Bids, Capacity Offer, the Permanent De-List Bids, or the Retirement De-List Bids~~ if ~~none of all~~ the ~~Existing~~ Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity Commitment Period, or by the acceptance of the Deactivation Notification of all Generating Capacity Resources composing the Station.

Deactivation Notification is a notification of the planned New England Market Deactivation or Capacity Market Deactivation of a resource, External Elective Transmission Upgrade, or portion thereof, submitted to the ISO by the applicable Lead Market Participant.

Deactivation Notification Deadline is the deadline for submission of a Deactivation Notification and a Deactivation Notification Package, as discussed in Section II.52.1 of the OATT.

Deactivation Notification Package is information submitted to the ISO, as specified in Section II.52.3 of the OATT, by a resource or External Elective Transmission Upgrade seeking a determination regarding a Deactivation Notification.

Demand Capacity Resource ~~is a type of resource that may participate in the Capacity Market, means an Existing Demand Capacity Resource or a New Demand Capacity Resource.~~ There are three Demand

Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand [Capacity](#) Resources, and Seasonal Peak Demand [Capacity](#) Resources.

Distributed Energy Capacity Resource (DECR) ~~means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource~~ is a type of Capacity Resource that participates in the Capacity Market and composes one or more Distributed Energy Resource Aggregations.

Dynamic De-List Bid is a bid ~~that may be~~ submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, Existing Demand Capacity Resources, and Existing Distributed Energy Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1. The final Forward Capacity Auction was for the Capacity Commitment Period beginning on June 1, 2027.

Generating Capacity Resource means a ~~New Generating Capacity Resource or an Existing Generating Capacity Resource~~ type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2.

Import Capacity Resource ~~means an Existing Import Capacity Resource or a New Import Capacity Resource~~ is a type of resource offered participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2 by providing to provide capacity in the New England Control Area from an external Control Area.

Incremental Cost of Reliability Service is described in Section II.54.5 of the OATT. ~~I.13.2.5.2.5.2 of Market Rule 1.~~

Lead Market Participant, for purposes other than the Forward Capacity Market or Annual Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids, Demand Reduction Offers, Baseline Deviation Offers, or Day-Ahead Ancillary Services Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource. For purposes of the Annual Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of a Capacity Resource.

Monthly Reconfiguration Auction is the reconfiguration auction conducted by the ISO each month as described in Section III.13.4.7 for those Monthly Reconfiguration Auctions held for months prior to the Capacity Commitment Period beginning on June 1, 2028 and in Section III.15.5 for those Monthly Reconfiguration Auctions held for months subsequent to the start of the Capacity Commitment Period beginning on June 1, 2028.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired [or deactivated](#); (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired [or deactivated](#), provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Capacity Show of Interest Form is [a form applicable to the Forward Capacity Market](#) described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time [applicable to the Forward Capacity Market](#) during which a Project Sponsor may submit a New Capacity Show of Interest Form, a New Demand Capacity Resource Show of Interest Form, or a New Distributed Energy Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New England Markets Deactivation is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from all New England Markets, or the permanent reduction in Capacity Network Import Capability and Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

Permanent De-list Bid is a bid ~~that may be~~ submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Proxy Capacity Offer is a type of offer used in the Annual Capacity Market.

Qualification Data Submission Deadline is a date specified in the Capacity Auction Calendar by which a Lead Market Participant seeking to have a resource participate in the Annual Capacity Auction must submit qualification materials pursuant to Section III.15.2.1.1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes, or, for the 2028-2029 Capacity Commitment Period and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes.

Rationing Minimum Limit is ~~the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which an offer or bid may not be rationed in the Forward Capacity Auction~~ the MW quantity below which a Capacity Offer may not be rationed in the Annual Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

Retirement De-List Bid is a bid in the Forward Capacity Market to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Static De-List Bid is a bid ~~that may be~~ submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

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

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only ~~by the clearing of the Static De-List Bids~~ Capacity Offer, the Permanent De-List Bids or the Retirement De-List

Bids of all the Existing if none of the Generating Capacity Resources composing the Station acquire a
Capacity Supply Obligation for the Capacity Commitment Period, or by deactivating all Generating Capacity
Resources composing the Station.

I.3 Obligations of Market Participants and Other Customers

The ISO acts as Counterparty for sales to its Customers of Regional Transmission Service, and for agreements and transactions with its Customers, including but not limited to assignments involving Customers, and agreements and transactions with Customers involving sale to the ISO and/or purchase from the ISO of energy, capacity, reserves, regulation, Ancillary Services, FTRs and involving other products, service and transactions, all as specified in Sections II and III of the Tariff (collectively, the “Products”).

To the extent permitted by applicable law, any warranties provided by the sellers or assignors to the ISO of the Products which cover the Products, whether express or implied, are hereby passed to the Customers on a “pass through basis” and to the extent not passed through, any such warranties are hereby assigned by ISO to Customers. Sellers and assignors to the ISO and Customers acknowledge that warranties on such Products are limited to that offered by the seller or assignor to the ISO and will exist, if at all, solely between the seller or assignor to the ISO and the Customer. AS BETWEEN CUSTOMER AND ISO AS COUNTERPARTY, NO EXPRESS OR IMPLIED WARRANTIES ARE MADE BY THE ISO REGARDING THE PRODUCTS SOLD BY THE ISO AS COUNTERPARTY, AND ANY SUCH PRODUCTS ARE PROVIDED ON AN “AS IS” AND “AS AVAILABLE” BASIS. THE ISO MAKES NO WARRANTY OR REPRESENTATION THAT THE PRODUCTS WILL BE UNINTERRUPTED OR ERROR FREE. THE CUSTOMER HEREBY WAIVES, AND THE ISO HEREBY DISCLAIMS, ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY WARRANTY OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, TITLE AND NON-INFRINGEMENT. THE ISO DOES NOT WARRANT THAT THE PRODUCTS OFFERED WILL MEET CUSTOMER’S REQUIREMENTS. NO ORAL OR WRITTEN INFORMATION OR ADVICE GIVEN BY THE ISO OR ANY AUTHORIZED REPRESENTATIVE OF THE ISO SHALL CREATE A WARRANTY OR IN ANY WAY INCREASE THE SCOPE OF ANY PASS THROUGH OR ASSIGNED WARRANTY. SOME JURISDICTIONS DO NOT ALLOW THE EXCLUSION OF IMPLIED WARRANTIES IN CERTAIN CIRCUMSTANCES, SO THE ABOVE EXCLUSION APPLIES ONLY TO THE EXTENT PERMITTED BY APPLICABLE LAW.

I.3.1. Service Agreement:

Receipt of service under this Tariff requires the execution of a Market Participant Service Agreement in the form specified in Attachment A or Attachment A-1, as applicable, to this Tariff unless the Customer seeks transmission service only and does not participate in the New England Markets (in which case the Customer must execute a Transmission Service Agreement). Receipt of Local Service under Section II of

this Tariff requires the execution of a Transmission Service Agreement in the form specified in Attachment A to Schedule 21 of Section II of this Tariff for Local Service and shall be subject to the requirements of Schedule 21. Receipt of OTF Service under Section II of this Tariff requires the execution of a Transmission Service Agreement in the appropriate form specified under Schedule 20 of Section II of this Tariff and shall be subject to the requirements of Schedule 20.

I.3.2. Assets:

Each Market Participant shall, to the fullest extent practicable, cause all of the Assets it owns or operates to be designed, constructed, maintained and operated in accordance with Good Utility Practice and the provisions of this Tariff, the ISO New England Operating Procedures, and the ISO New England Planning Procedures.

I.3.3. Maintenance and Repair:

Each Market Participant shall, to the fullest extent practicable: (a) cause Assets owned or operated by it to be withdrawn from operation for maintenance and repair only in accordance with maintenance schedules reported to, and approved and published by the ISO in accordance with the ISO New England Operating Procedures, (b) restore such Assets to good operating condition with reasonable promptness, and (c) in emergency situations, accelerate maintenance and repair at the reasonable request of the ISO in accordance with the ISO New England Planning Procedures.

I.3.4. Central Dispatch:

Each Market Participant shall, to the fullest extent practicable, subject each of the Assets it owns or operates to central dispatch by the ISO; provided, however, that each Market Participant shall at all times be the sole judge as to whether or not and to what extent safety requires that at any time any of such facilities will be operated at less than their full capacity.

I.3.5. Provision of Information:

The Customers shall provide the ISO with any and all information within their custody or control that the ISO deems necessary to perform its obligations under this Tariff, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. Each Customer shall ensure that the ISO has an accurate list of the Customer's Affiliates. The ISO will compile a list that shall be considered definitive. It will be the Customer's responsibility to regularly review the list and to promptly (and in advance of Affiliate changes, where possible) provide the ISO with additions and/or corrections to the list and, when requested, relevant supporting documentation.

I.3.6. Records and Information:

Each Customer shall keep such records as may reasonably be required by the ISO, and shall furnish to the ISO such records, reports and information (including forecasts) as it may reasonably require, provided that confidentiality thereof is protected in accordance with the ISO New England Information Policy.

I.3.7. Payment of Invoices; Compliance with Policies:

Each Customer is obligated to pay when due in accordance with this Tariff, the ISO New England Financial Assurance Policy and the ISO New England Billing Policy all amounts invoiced to it pursuant to this Tariff, and to comply with those terms, conditions and policies in all respects. If a Customer fails to meet the requirements specified in the ISO New England Financial Assurance Policy and ISO New England Billing Policy, the ISO may take such actions as are specified in those policies.

I.3.8. Protective Devices for Transmission Facilities:

Each Market Participant shall install, maintain and operate such protective equipment and switching, voltage control, load shedding and emergency facilities as the ISO and the applicable Transmission Owner may determine to be required in order to assure continuity of service and the stability of the New England Transmission System.

I.3.9. Review of Market Participant's Proposed Plans:

I.3.9.1 Submission and Review of Proposed Plan Applications:

Each Market Participant and Transmission Owner shall submit to the ISO at least sixty (60) days prior to the proposed in service date in such form, manner and detail as the ISO may reasonably prescribe, (i) any new or materially changed plan for additions to or changes to any generating and demand resources or transmission facilities rated 69 kV or above subject to control of such Market Participant or Transmission Owner, and (ii) any new or materially changed plan for any other action to be taken by the Market Participant or Transmission Owner, except for [deactivations of](#), retirements [of](#), ~~or~~ or reductions in the capacity of a generating resource or a demand resource, which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant. In the case of changes to transmission facilities developed through the Solutions Study process or the competitive solution process, no significant action (other than engineering reasonably necessary to support the Solutions Study or competitive solution process) shall be taken.

Unless the ISO notifies the Market Participant or Transmission Owner in writing within sixty (60) days of the submittal (or ninety (90) days if the ISO determines that it requires additional time), that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner shall be free to proceed.

The ISO shall maintain on its website a list of such applications that are currently under review and the status of each such application. The ISO shall provide notice of any action taken with respect to any such applications, including an explanation of its reasons for such action, to each Market Participant or Transmission Owner as soon as reasonably practicable after such action is taken. The time limits provided by this section may be changed with respect to any such submission by agreement between the ISO and the Market Participant or Transmission Owner.

I.3.9.2 Additional Review of Additions of or Changes to Generating Resources:

Proposals for new generating resources or modifications to existing generating resources are also subject to the terms set out in Schedule 22, the Large Generator Interconnection Procedures and Agreement, and Schedule 23, the Small Generator Interconnection Procedures and Agreement, to Section II of the Tariff.

I.3.9.3 Reliability Review of Deactivations, Retirements, or Reductions in Capacity of an Existing Demand Capacity Resource, or Existing Generating Capacity Resource, Distributed Energy Capacity Resource, or External Elective Transmission Upgrade:

Proposals for the permanent reduction of Capacity Network Resource Capability or Capacity Network Import Capability from an Existing Demand Capacity Resource, or an Existing Generating Capacity Resource, a Distributed Energy Capacity Resource, or an External Elective Transmission Upgrade ~~below its Qualified Capacity amount for the relevant Capacity Commitment Period~~, including unit retirement or deactivation, are reviewed for reliability impact pursuant to the terms set out in Section III.13.2.5.2.5 or Section II.53 of the Tariff. Once a ~~demand resource or generating resource resource or~~ External Elective Transmission Upgrade has a cleared de-list bid or Deactivation Notification accepted pursuant to Section II.14 of the Tariff it may permanently reduce its capacity consistent with the terms of its de-list bid or Deactivation Notification ~~for all or any part of the Capacity Commitment Period of the approved de-list~~ without further reliability review. However, any proposed physical modification to a de-listed retired or deactivated generating facility must comply with the requirements, including the reliability review process, set out in Schedules 22, ~~or~~ 23, or 25, as applicable.

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SECTION II

ISO NEW ENGLAND OPENACCESS TRANSMISSION TARIFF

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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).

* * *

II.48 Interconnection Service Capabilities

II.48.1 Establishing CNR Capability and CNI Capability

(a) CNR Capability shall be established as follows: Section 5.2.3 of Schedule 22 and Section 5.2.3 of Schedule 23 of this OATT describe the establishment of CNR Capability for a Generating Facility that was treated as an Existing Generating Capacity Resource in the fourth Forward Capacity Auction. For a Generating Facility newly obtaining or increasing CNR Interconnection Service in the fourth Forward Capacity Auction through Forward Capacity Market activities prior to September 4, 2025, summer CNR Capability shall be established as the highest MW quantity of Capacity Supply Obligation obtained by the Generating Capacity Resource for the summer period and winter CNR Capability shall be established as the higher of (1) the highest MW quantity of Capacity Supply Obligation obtained by the associated Generating Capacity Resource for the winter period and (2) the Generating Facility's summer CNR Capability multiplied by the ratio of the Generating Capacity Resource's winter Qualified Capacity to summer Qualified Capacity for the auction in which the entry occurred. Commencing September 4, 2025, the summer and winter CNR Capability for a Generating Facility shall be established as the amounts requested in the Generating Facility's Interconnection Request, for which all of the requirements in the Interconnection Procedures have been completed, and which shall not exceed the maximum net MW electrical output at the Point of Interconnection at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter.

Notwithstanding the requirements contained in this section, a Generating Facility that did not secure a Capacity Supply Obligation prior to September 4, 2024, may establish CNR Interconnection Service through the process described in Section III.13.A.2 - Interim Reconfiguration Auction Qualification, conducted between January 1, 2025 and January 1, 2026, provided that the Generating Facility (1) has a completed System Impact Study or Interconnection Agreement establishing NR Interconnection Service on or before April 4, 2025 and (2) has a Commercial Operation Date prior to June 1, 2028.

(b) CNI Capability shall be established as follows: Summer and winter CNI Capability for an External ETU with CNI Interconnection Service pursuant to Schedule 25 of this OATT shall be established as the amounts requested in the External ETU's Interconnection Request for which all of the requirements of the interconnection process have been completed.

Notwithstanding the requirements contained in this section, an External ETU that did not secure a Capacity Supply Obligation prior to September 4, 2025, may establish CNI Interconnection Service through the process described in Section III.13.A.2 - Interim Reconfiguration Auction Qualification, conducted between January 1, 2025 and January 1, 2026, provided that the External ETU (1) has a completed System Impact Study or Interconnection Agreement establishing NI Interconnection Service on or before April 4, 2025.

At the time of its establishment pursuant to the preceding paragraph, the CNI Capability shall not exceed the maximum net MW electrical capability at the Point of Interconnection and shall not exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures.

II.48.2 Establishing NR Capability and NI Capability

(a) NR Capability shall be established in the manner described in Schedules 22 and 23 of this OATT.

Summer and winter NR Capability for a Generating Facility shall be established as the Generating Facility's maximum net MW electrical output at the Point of Interconnection at an ambient temperature at or above 50 degrees F for summer and at or above 0 degrees F for winter. A Generating Facility's summer and winter NR Capability shall be equal to or greater than its summer and winter CNR Capability, respectively.

(b) NI Capability shall be established as follows: For an External ETU with NI Interconnection Service pursuant to Schedule 25 of this OATT, summer and winter NI Capability shall be established as the maximum net MW electrical capability at the Point of Interconnection and shall not exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures. An External ETU's summer and winter NI Capability shall be equal to or greater than its summer and winter CNI Capability, respectively.

II.48.3 Reductions to CNR Capability and CNI Capability: CNR Capability and CNI Capability shall be reduced as follows upon partial or full exit from the ~~Forward~~ Capacity Market as a result of any of the following actions: (1) a voluntary or mandatory termination pursuant to Section III.13.3.4A or Section III.15.A.2.1 of the Tariff results in a reduction to summer and winter CNR Capability (or summer and winter CNI Capability) equal to the respective reduction to summer and winter Qualified Capacity described in III.13.3.4A or Section III.15.A.2.1; (2) a failure to operate commercially for a period of three

calendar years resulting in retirement pursuant to Section III.13.2.5.2.5.3(d) or deactivation pursuant to Section II.52.2 of the Tariff results in a reduction of summer and winter CNR Capability (or summer and winter CNI Capability) to zero; (3) a full exit from the ~~Forward~~ Capacity Market as the result of the operation of a Retirement De-List Bid or a Permanent De-List Bid, described in Section III.13.2.5.2.5.3, or an accepted Deactivation Notification as described in Section II.55 of the Tariff, ~~and/or a substitution auction demand bid, described in Section III.13.2.8 of the Tariff, results results~~ in a reduction of summer and winter CNR Capability (or summer and winter CNI Capability) to zero; and a partial exit from the ~~Forward~~ Capacity Market as the result of the operation of a Retirement De-List Bid or a Permanent De-List Bid ~~and/or a substitution auction demand bid, or the operation of an accepted Deactivation Notification that~~ results in a reduction of CNR Capability (or CNI Capability) as described below.

(a) Summer CNR/CNI Capability Following Partial Exit Resulting From De-List Bid or Partial Deactivation Resulting from Deactivation Notification and/or Substitution Auction Demand

~~Bid~~: Following the partial permanent exit from the ~~Forward~~ Capacity Market of a Generating Capacity Resource (or an Import Capacity Resource associated with an External ETU) as a result of the operation of a de-list bid ~~and/or a substitution auction demand bid~~ or an accepted Deactivation Notification, the summer CNR Capability of the associated Generating Facility (or the summer CNI Capability of the associated External ETU) shall be reduced to equal the final amount of summer CNR Capability or summer CNI Capability resulting from the operation of the de-list bid or acceptance of the Deactivation Notification ~~(1) the associated summer Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated summer Qualified Capacities) for the Forward Capacity Auction in which the partial exit occurred minus (2) the MW quantity that exited the Forward Capacity Market.~~

(b) Winter CNR/CNI Capability Following Partial Exit Resulting From De-List Bid or Partial Deactivation Resulting from Deactivation Notification and/or Substitution Auction Demand

~~Bid~~: Following the partial permanent exit from the ~~Forward~~ Capacity Market of a Generating Capacity Resource (or an Import Capacity Resource associated with an External ETU) as a result of the operation of a de-list bid ~~and/or a substitution auction demand bid~~ or an accepted Deactivation Notification, the winter CNR Capability of the associated Generating Facility (or the winter CNI Capability of the associated External ETU) shall be reduced to equal the final amount of winter CNR Capability or winter CNI Capability resulting from the operation of the de-list bid or acceptance of the Deactivation Notification ~~(1) the Generating Facility's summer CNR Capability (or the External ETU's summer CNI Capability) reduced as described in subsection (a) of this Section II.48.3~~

~~multiplied by (2) the ratio of the associated winter Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated winter Qualified Capacities) to the associated summer Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated summer Qualified Capacities) for the Forward Capacity Auction in which the partial exit occurred; provided that a different winter CNR Capability value may be established to account for winter capability remaining after the removal of summer capability if the ISO determines that engineering information submitted no later than 10 calendar days after the conclusion of the Forward Capacity Auction supports the use of the different value.~~

II.48.4 Reductions to NR Capability and NI Capability: NR Capability and NI Capability shall be reduced as follows for Generating Facilities and External ETUs as a result of any of the following actions: (1) a partial or full voluntary retirement or deactivation results in partial or full reduction of NR Capability or NI Capability for a resource that has never held Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service; (2) a failure to operate commercially for a period of three calendar years (as described in Section III.13.2.5.2.5.3(d) or II.52.2 of the Tariff) results in a reduction of NR Capability or NI Capability to zero; (3) a full retirement or deactivation of a Generating Facility or an External ETU as the result of the operation of a Retirement De-List Bid or an unconditional Permanent De-List Bid (as described in Section III.13.1.2.4.1(a) and Section III.13.2.5.2.5.3 of the Tariff) ~~and/or a substitution auction demand bid (as described in Section III.13.2.8 of the Tariff), or accepted~~ Deactivation Notification, that results in a reduction of NR Capability or NI Capability to zero; and a partial retirement or deactivation as the result of the operation of a Retirement De-List Bid or an unconditional Permanent De-List Bid ~~and/or a substitution auction demand bid, or an accepted~~ Deactivation Notification, that results in a reduction of NR Capability or NI Capability as described below.

(a) Summer NR/NI Capability Following Partial Retirement Resulting From De-List Bid ~~and/or Substitution Auction Demand Bid~~ or Partial Deactivation Resulting from Deactivation Notification: Following the partial retirement or deactivation of a Generating Facility (or an External ETU) as a result of the operation of a de-list bid ~~and/or a substitution auction demand bid or an~~ accepted Deactivation Notification, the summer NR Capability of the Generating Facility (or summer NI Capability of the External ETU) shall be reduced to equal the final amount of summer NR Capability or summer NI Capability resulting from operation of the de-list bid or acceptance of the Deactivation Notification. ~~(1) the Generating Facility's summer CNR Capability (or the External~~

~~ETU's summer CNI Capability) reduced as described in subsection (a) of Section II.48.3 multiplied by (2) the ratio of the Generating Facility's summer NR Capability (or the External ETU's summer NI Capability) prior to the Forward Capacity Auction to the Generating Facility's summer CNR Capability (or the External ETU's summer CNI Capability) prior to the Forward Capacity Auction.~~

(b) Winter NR/NI Capability Following Partial Retirement Resulting From De-List Bid or Partial

Deactivation Resulting from Deactivation Notification: Following the partial retirement or deactivation of a Generating Facility (or an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid or an accepted Deactivation Notification, the winter NR Capability of the Generating Facility (or winter NI Capability of the External ETU) shall be reduced to equal the final amount of winter NR Capability or winter NI Capability resulting from the operation of the de-list bid or acceptance of the Deactivation Notification. ~~(1) the Generating Facility's summer NR Capability (or the External ETU's summer NI Capability) reduced as described in subsection (a) of this Section II.48.4 multiplied by (2) the ratio of the Generating Facility's winter NR Capability (or the External ETU's winter NI Capability) prior to the Forward Capacity Auction to the Generating Facility's summer NR Capability (or the External ETU's summer NI Capability) prior to the Forward Capacity Auction; provided that a different winter NR Capability value may be established to account for winter capability remaining after the removal of summer capability if the ISO determines that engineering information submitted no later than 10 calendar days after the conclusion of the Forward Capacity Auction supports the use of the different value.~~

However, if the resulting winter NR Capability (or winter NI Capability) is less than the Generating Facility's winter CNR Capability (or External ETU's winter CNI Capability), the winter NR Capability (or winter NI Capability) will be set equal to the winter CNR Capability (or winter CNI Capability).

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II.I. DEACTIVATION

II.52 Deactivation Notification Process: The Deactivation Notification process described in Section II.I shall be effective for Deactivation Notifications associated with deactivations occurring during the Capacity Commitment Period beginning on June 1, 2028 and all subsequent Capacity Commitment Periods.

II.52.1 Deactivation Notification Deadline: The Deactivation Notification Deadline shall be the first Business Day occurring within 12 months of the first day of each Capacity Commitment Period. Deactivation Notifications shall be subject to the reliability review process described in this Section II.I and shall be reviewed by the Internal Market Monitor pursuant to Section III.A.24.

II.52.2 Deactivations Requiring Deactivation Notification: On or before the Deactivation Notification Deadline for the relevant Capacity Commitment Period, a Lead Market Participant seeking to permanently remove all or a portion of a resource from the Capacity Market shall submit a Deactivation Notification specifying whether the Lead Market Participant is seeking: (a) a Capacity Market Deactivation; or (b) a New England Markets Deactivation, for the resource. No Deactivation Notification may result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit unless the Deactivation Notification is for the entire resource. No Deactivation Notification may result in a resource's or External Elective Transmission Upgrade's final CNR Capability or CNI Capability exceeding its final NR Capability or NI Capability, respectively. For the purposes of this Section II.I, the entity authorized to submit a Deactivation Notification on behalf of an External Elective Transmission Upgrade shall be treated as the Lead Market Participant and the External Elective Transmission Upgrade shall be treated as the deactivating resource.

A resource that has never held Capacity Network Resource Interconnection Service shall not be required to submit a Deactivation Notification and may deactivate by notifying the ISO in writing of its election to deactivate and the date of deactivation. The interconnection rights for the resource will terminate and the status of the resource will be converted to deactivated on the date of deactivation. The date specified for deactivation is subject to the limit for resource inactivity described below.

A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be deactivated regardless of whether a Deactivation Notification was submitted. The

interconnection rights for the resource will terminate and the status of the resource will be converted to deactivated on the date of deactivation. Where a resource has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three-year period will be calculated from the last day of commercial operation of the resource.

II.52.3 Deactivation Notification Package: All Deactivation Notifications must be detailed in a Deactivation Notification Package submitted by the Lead Market Participant associated with a deactivation to the ISO no later than the Deactivation Notification Deadline. Deactivation Notifications may not be modified or withdrawn after the Deactivation Notification Deadline. The Deactivation Notification Package requirements shall be published on the ISO's website, subject to update, and shall include the following information: (1) the name of the entity submitting the Deactivation Notification, including its affiliates and ultimate parent company; (2) the resource subject to the Deactivation Notification, including the resource's name and resource identification number; (3) whether the Deactivation Notification is for a Capacity Market Deactivation or a New England Markets Deactivation; (4) the MW amount deactivating, and whether it is a full or partial deactivation; (5) the final amount of CNR Capability or CNI Capability, and NR Capability or NI Capability resulting from a New England Markets Deactivation, or the final amount of CNR Capability or CNI Capability resulting from a Capacity Market Deactivation; and (6) the date of the resource's planned deactivation. For Deactivation Notifications subject to review by the Internal Market Monitor pursuant to Section III.A.24, Lead Market Participants must include in their Deactivation Notification Package the relevant cost workbooks and supporting information described in Section III.A.24. The Deactivation Notification Package shall also include an affidavit executed by a corporate officer attesting to the accuracy of its content, including reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments, cash flows, opportunity costs, and risk premiums, and shall be subject to audit upon request by the Internal Market Monitor.

II.52.4 Publication of Deactivation Notifications: No later than ten Business Days after the Deactivation Notification Deadline, the ISO shall post on its website information concerning submitted

Deactivation Notifications, including the resource name, reduction in Interconnection Service (MW Quantity) that would result from acceptance of the Deactivation Notification, and the resource's planned deactivation date. Planned deactivation dates shall be updated for those resources accelerating deactivation pursuant to Section II.55.3.

II.53 Deactivation Notification Reliability Review

II.53.1 Deactivation Notification Reliability Review: For each Capacity Commitment Period corresponding to a given Deactivation Notification Deadline, the ISO shall within 90 calendar days of the Deactivation Notification Deadline review all Deactivation Notifications of 20 MW or more and determine whether a resource associated with any Deactivation Notification is needed for reliability reasons. The capacity associated with a Deactivation Notification shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. The capacity associated with a Deactivation Notification shall be deemed needed for reliability only for the sole purpose of addressing a local transmission reliability issue. If review of a Deactivation Notification results in the identification of a reliability need, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. If delaying the deactivation of one or more resources will resolve the identified reliability need, the ISO shall determine based on a review of net going forward costs (as determined pursuant to Section III.A.24), and in consultation with the Reliability Committee, whether a resource may be eligible for delayed deactivation. The Lead Market Participant associated with a resource eligible for delayed deactivation shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Deactivation Notification is eligible for delayed deactivation. The Lead Market Participant for a resource eligible for delayed deactivation must respond to the ISO within 30 calendar days indicating whether it accepts the delayed deactivation.

II.53.2 Publication of Delayed Deactivations: No later than 90 calendar days after the Deactivation Notification Deadline, the ISO shall post on its website its determinations regarding any Deactivation Notification where the resource elected to delay deactivation to satisfy a reliability need.

II.54 Compensation of Resources Delaying Deactivation

II.54.1 Compensation Election of Resources Delaying Deactivation: If the ISO determines that a resource is eligible for delayed deactivation and the Lead Market Participant associated with that resource accepts the delayed deactivation pursuant to Section II.53, the resource shall be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved net going forward costs for the relevant Capacity Commitment Period as determined and filed pursuant to Section III A.24, instead of the Capacity Clearing Price; or (ii) in instances where an entire resource is electing to delay deactivation, under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within 30 days of the ISO's notification that the resource is eligible for delayed deactivation. A resource that elects delayed deactivation that does not notify the ISO of its compensation election as described in this Section II.54 will be paid on the basis of the resource's net going forward costs. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. Cost-of-service agreements must include a claw-back provision addressing the obligation of a resource delaying deactivation that later seeks to return to New England Markets to refund to the ISO with interest all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the resource while the resource was subject to a cost-of-service agreement; credits associated with any refund shall be allocated in the same manner as the charges associated with the cost-of-service agreement. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Deactivation Notification was submitted. A resource that has delayed deactivation due to a reliability need shall deactivate as of the first day of the first Capacity Commitment Period in which they are no longer necessary for reliability. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the deactivation was delayed, payment will continue to be pursuant to this Section II.54. Resources that elect payment based on the Commission-approved net going forward costs may file with the Commission pursuant to Section 205 of the Federal Power Act to update its net going forward costs if the resource is retained for reliability for a period longer than the Capacity Commitment Period for which the deactivation was initially delayed.

II.54.2 Allocation of Costs Associated with Delayed Deactivation: The difference between payments based on resource net going forward costs or cost-of-service compensation as detailed in this Section II.54

and payments based on the market clearing price for the Capacity Market under Section III.15 shall be allocated to Regional Network Load within the affected Reliability Region.

II.54.3 Compensation for Delayed Deactivation of Stations Having Common Costs: If a deactivation that is associated with a Station having Common Costs is delayed for reliability reasons, the Generating Capacity Resource will be paid as follows: (i) if one or more Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Capacity Auction and one or more Generating Capacity Resource deactivations are delayed for reliability, then the Generating Capacity Resource deactivations delayed for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets composing the Generating Capacity Resource subject to delayed deactivation; or (ii) if no Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Capacity Auction and one or more Generating Capacity Resource deactivations are delayed for reliability, then each Generating Capacity Resource deactivation delayed for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Generating Capacity Resources delaying deactivation for reliability purposes).

II.54.4 Amended Obligations of a Cost of Service Agreement: If the ISO is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of a Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, the ISO shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

II.54.5 Incremental Cost of Reliability Service for Resources Delaying Deactivation: In cases where a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource has delayed deactivation for reliability reasons pursuant to Section II.53, and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

- (a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO:** A resource seeking to avail itself of the recovery mechanism provided in this Section II.54.5 must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.
- (b) **Required Showing Made to the Federal Energy Regulatory Commission:** In order to receive just and reasonable compensation for a capital expenditure under this Section II.54.5, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section II.54.1, the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.
- (c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.
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II.55 Deactivation Acceptance

II.55.1 Notification to Lead Market Participant: No later than 90 days after the Deactivation Notification Deadline, the ISO shall notify the Lead Market Participant: (1) that the Deactivation Notification has been accepted; (2) whether a resource associated with the Deactivation Notification is eligible for delayed deactivation; and (3) whether the Deactivation Notification represents a failure of the conduct test that may be subject to a Proxy Capacity Offer. Lead Market Participants identified pursuant to Section III.A.24 as submitting a Deactivation Notification in order to exercise market power to the benefit of a portfolio may be subject to referral to the Commission's Office of Enforcement and the capacity associated with their Deactivation Notification shall be subject to a Proxy Capacity Offer during the Capacity Commitment Period associated with the Deactivation Notification pursuant to Section III.15.4.

II.55.2 Accepted Deactivation Notifications: A resource, or portion thereof, that has had a Deactivation Notification accepted by the ISO shall be ineligible to participate in the Capacity Market coincident with the commencement of the Capacity Commitment Period identified in the Deactivation Notification. The interconnection rights, or relevant portion thereof, for the resource will terminate on the deactivation date and the status of the resource, or portion thereof, will be converted to deactivated on the date of deactivation, consistent with the provisions of Section II.48.3 and Schedules 22, 23, and 25 of the OATT. For those resources that specified Capacity Market Deactivation in their Deactivation Notification, only the CNR Capability or CNI Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Capacity Market Deactivation, consistent with Section II.48.3 and the relevant provisions of Schedules 22, 23, and 25 of the OATT. Resources that have submitted a Deactivation Notification shall continue participation in New England Markets consistent with the rights and obligations described in Section III.15.7 until the date specified in the resource's accepted Deactivation Notification.

II.55.3 Accelerated Deactivation: A resource, or portion thereof, that is to be deactivated pursuant to Section II.55.2 may deactivate the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Deactivation Notification was submitted if: (1) the Lead Market Participant has received the notification accepting the Deactivation Notification and responds to request a deactivation date earlier than 12 months after the Deactivation Notification Deadline; (2) the Lead Market Participant sought and received written notification from the Internal Market Monitor confirming eligibility for accelerated deactivation; and (3) the resource is able to transfer any of its remaining Capacity Supply

Obligation to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.15.6 or Monthly Reconfiguration Auctions as described in Section III.15.5. A resource, or portion thereof, electing accelerated deactivation pursuant to this Section II.55.3 that has satisfied the above-described obligations must notify the ISO in writing of its election to deactivate and the date of deactivation. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to deactivated on the date of deactivation, consistent with the treatment of accepted Deactivation Notifications described in Section II.55.2.

ATTACHMENT K
REGIONAL SYSTEM PLANNING PROCESS

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2. Planning Advisory Committee

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2.3 Membership

There are no membership requirements to become part of the Planning Advisory Committee. Meetings are open to members of any entity, including State regulators or agencies and NESCOE, subject to the Critical Energy Infrastructure Information (“CEII”) policy as further described in Section 2.4(d) of this Attachment. ~~To be added to the Planning Advisory Committee email distribution list, an email address shall be provided to the Secretary of the Committee.~~ Throughout this Attachment K, a member of the Planning Advisory Committee refers to any individual, whether they attend Planning Advisory Committee meetings or are included on the email distribution list.

* * *

4. Procedures for the Conduct of Needs Assessments, Treatment of Market Responses and Evaluation of Regulated Transmission Solutions

4.1 Needs Assessments

The regional system planning process established in this Attachment K has four different processes. Except as otherwise provided in Section 16 of this Attachment, the reliability planning process established in Section 4 of this Attachment K shall apply to all transmission solutions adopted to resolve a reliability need, and the system efficiency planning process established in Section 17 of this Attachment K shall apply to all transmission solutions adopted to resolve a system efficiency need. The public policy planning process established in Section 4A of this Attachment K shall apply to all transmission solutions adopted to resolve a public policy need. The longer-term transmission planning procedures established in Section 16 of this Attachment K shall apply to all transmission solutions adopted to resolve a longer-term need, and may apply to a non-time-sensitive reliability or system efficiency need to the extent identified by the ISO and combined with longer-term needs in a request for proposal(s) requested by NESCOE in accordance with Section 16.4(a) of this Attachment K.

For needs identified initially as reliability, system efficiency or public policy needs, the collateral benefits of potential solutions to those needs shall not change the planning process applicable to those identified needs; notwithstanding the foregoing, the ISO shall report its views as to whether a project or preferred

solution may also satisfy identified reliability needs of the system as described in Section 4A.8 of this Attachment K.

Sections 4.1 through 4.3 of this Attachment are not applicable to the planning of Public Policy Transmission Upgrades, which is governed instead by Section 4A of this Attachment. Sections 4.1 through 4A of this Attachment are not applicable to the planning of Longer-Term Transmission Upgrades, which is governed instead by Section 16 of this Attachment. Sections 4.1 to 4.3 of this Attachment K are not applicable to the planning of System Efficiency Transmission Upgrades, which is governed instead by Section 17 of this Attachment K.

On a regular and ongoing basis, the ISO, in coordination with the PTOs and the Planning Advisory Committee, shall conduct assessments (i.e., Needs Assessments) of the adequacy of the PTF system, as a whole or in part, to maintain the reliability of such facilities. A Needs Assessment shall analyze whether the PTF in the New England Transmission System: (i) meet applicable reliability standards; (ii) have adequate transfer capability to support local, regional, and inter-regional reliability; (iii) are sufficient to integrate new resources and loads on an aggregate or regional basis; or (iv) otherwise examine various aspects of its performance and capability. A Needs Assessment shall also identify: (i) the location and nature of any potential problems with respect to the PTF and (ii) situations that significantly affect the reliable and efficient operation of the PTF along with any critical time constraints for addressing the needs of the PTF to facilitate the development of market responses and to initiate the pursuit of regulated transmission solutions.

(a) Triggers for Needs Assessments

The ISO, in coordination with the PTOs and the Planning Advisory Committee, shall perform Needs Assessments, inter alia, as needed to:

- Assess compliance with reliability standards and criteria (including those established by the ISO, NERC, and NPCC) consistent with the long-term needs of the system.
- Assess the adequacy of the transmission system capability, such as transfer capability, to support local, regional and interregional reliability.

- Assess sufficiency of the system to integrate new resources and loads on an aggregate or regional basis as needed for the reliable and efficient operation of the system.
- Analyze various aspects of system performance. (Including but not limited to, transient network analysis, small signal analysis, electromagnetic transients program analysis, or delta P analysis).
- Examine short circuit performance of the system.
- Assess the ability to efficiently operate and maintain the transmission system.

• ~~Address system performance in consideration of de-list bids and cleared demand bids, and Deactivation Notifications consistent with sections 4.1(c) and 4.1(f) of Attachment K.~~

- Address system performance as otherwise deemed appropriate by the ISO.

(b) [RESERVED]

(c) Reliability Committee Update Regarding Delayed Deactivations ~~Conduct of a Needs Assessment for Rejected De-List Bids~~

~~(i) In the case of a rejected Static De List Bid or Dynamic De List Bid, the ISO may as warranted, with advisory input from the Reliability Committee, examine the unavailability of the resource(s) with the rejected bid as a sensitivity in a Needs Assessment, or examine the unavailability of the resource(s) in the base representation in a Needs Assessment. The ISO may as warranted, with advisory input from the Reliability Committee, initiate a Needs Assessment for the purpose of modeling rejected Static De List Bids or Dynamic De List Bids where the ISO believes that the initiation of such a study is warranted.~~

~~(ii) Prior to the annual start of each New Capacity Show of Interest Qualification Data Submission Window Deadline, the ISO shall present to the Reliability Committee the status of any prior rejected Dynamic De List Bids, Static De List Bids, Permanent De List Bids or~~

~~Retirement De List Bids~~resources delaying deactivation that are being studied in the regional system planning process.

(d) Notice of Initiation of Needs Assessments

Prior to its commencement, the ISO shall provide notice of the initiation of a Needs Assessment to the Planning Advisory Committee consistent with Section 2 of this Attachment.

(e) Preparation of Needs Assessment

Needs Assessments may examine transmission adequacy, and other relevant factors as may be agreed upon from time to time. Needs Assessments shall also consider the views, if any, of the Planning Advisory Committee, State regulators or agencies, NESCOE, the Market Advisor to the ISO Board of Directors, and the ISO Board of Directors. A corresponding assessment shall be performed by the PTOs to identify any needs relating to the Non-PTF transmission facilities (of whatever voltage) that could affect the provision of Regional Transmission Service over the PTF.

(f) Treatment of Market Responses in Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

In performing Needs Assessments, the ISO shall rely on certain resources to prevent the identification of system needs. Specifically, the ISO shall incorporate or update information regarding future resources, with the exception of imports across external tie lines, in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction or Annual Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Needs Assessments. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study, (ii) have been selected in, and are contractually bound by, a state-sponsored request for

proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service, for the relevant period, all submitted Deactivation Notifications, submitted Retirement De-List Bids, submitted and Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out of service rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which an Elective Transmission Upgrade Interconnection Agreement has been executed and, to the extent required, filed and accepted by the Commission, or filed unexecuted and accepted by the Commission ~~and for which the certification has been accepted in accordance with Section III.12 of the Tariff.~~ In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which an Elective Transmission Upgrade Interconnection Agreement has been executed, and, to the extent required, filed and accepted by the Commission, or filed unexecuted and accepted by the Commission ~~for which the certification has been accepted in accordance with Section III.12 of the Tariff.~~

* * *

4.2 Evaluation of Regulated Transmission Solutions in Solutions Studies, Where Competitive Solution Process of Section 4.3 Is Not Applicable

The procedures described in this Section 4.2 shall be utilized for the evaluation of regulated transmission solutions for reliability needs where the requirements of Sections 4.1(i) and/or (j) of this Attachment are satisfied. Otherwise, the procedures of Section 4.3 shall be utilized for that purpose.

(a) Evaluation and Development of Regulated Transmission Solutions in Solutions Studies for Reliability Transmission Upgrades

In the case of Reliability Transmission Upgrades, the ISO, in coordination with the proponents of regulated transmission solutions and other interested or affected stakeholders, shall conduct or participate in studies (“Solutions Studies”) to evaluate whether proposed regulated transmission solutions meet the PTF system needs identified in Needs Assessments. The ISO, in coordination with affected stakeholders shall also identify regulated transmission projects for addressing the needs identified in Needs Assessments.

The ISO may form ISO-led targeted study groups to conduct Solutions Studies. Such study groups will include representatives of the proponents of regulated transmission solutions and other interested or affected stakeholders. Through this process, the ISO may identify the solutions for the region that offer the best combination of electrical performance, cost, future system expandability, and feasibility to meet a need identified in a Needs Assessment in the required time frame. These solutions may differ from a transmission solution proposed by a transmission owner.

Proponents of regulated transmission proposals in response to Needs Assessments shall also identify any LSP plans that require coordination with their regulated transmission proposals addressing the PTF system needs.

(b) Notice of Initiation of a Solutions Study

The ISO shall provide notice of the initiation and scope of a Solutions Study to the Planning Advisory Committee.

(c) Classification of Regulated Transmission Solutions as Reliability Transmission Upgrades

As described in Section 3.1 and 3.6(a) of this Attachment, proposed regulated transmission solutions determined by the ISO, in consultation with the Planning Advisory Committee, to address needs identified in Needs Assessments shall be classified as a Reliability Transmission Upgrade pursuant to the standards set forth in Attachment N of this OATT.

(d) Evaluation Factors Used for Identification of the Preferred Solution

Factors to be considered during the evaluation process for identification of the preferred solution may include, but are not limited to, the following which are listed in no particular order:

- Installed cost;
- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements [or deactivations](#);
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards; and
- Impact on NPCC Bulk Power System classification.

* * *

4.3 Competitive Solution Process for Reliability Transmission Upgrades

(a) Initiating the Competitive Solution Process

The ISO will publicly issue a request for proposal for which, pursuant to Section 4.1(i) of this Attachment, a competitive solution process will be utilized. The request for proposal will indicate that a Qualified Transmission Project Sponsor may submit an individual or joint Phase One Proposal(s) offering a solution that addresses the identified needs or address a subset of those needs. In the case where a joint Phase One Proposal is submitted, all parties must be Qualified Transmission Project Sponsors. A Qualified Transmission Project Sponsor may propose a comprehensive solution to address the identified needs, or a subset thereof, that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

A PTO or PTOs identified by the ISO as the Backstop Transmission Solution provider(s) shall submit an individual or joint Phase One Proposal (if more than one PTO is identified) as a Backstop Transmission Solution to comprehensively address all of the needs identified in the request for proposal that would be solved by a project located within or connected to its/their existing electric system, and which it/they would therefore have an obligation to build under Schedule 3.09(a) of the TOA. Such PTOs may recover the costs of preparing the Backstop Transmission Solution in accordance with the mechanisms reflected in the OATT and the terms of the TOA.

A member of the Planning Advisory Committee that is not a Qualified Transmission Project Sponsor but would like the ISO to consider a Phase One Proposal reflecting its concept for a project in response to a request for proposal (that is, a project that is "unsponsored") must, before

the deadline for the submission of Phase One Proposals, identify a Qualified Transmission Project Sponsor willing to submit a corresponding Phase One Proposal and Phase Two Solution (and to develop and construct the project, if selected in the competitive solution process) in order for the unsponsored project to be submitted in response to an ISO solicitation in Phase One. Upon request by the pertinent Planning Advisory Committee member for assistance in identifying a sponsor, the ISO shall post on its website and distribute to the Planning Advisory Committee a notice that solicits expressions of interest by Qualified Transmission Project Sponsors for sponsorship of the member's conceptual project. All expressions of interest shall include a detailed explanation of why the Qualified Transmission Project Sponsor is best qualified to construct, own and operate the unsponsored project. If only one Qualified Transmission Project Sponsor expresses interest, the ISO shall designate it as the Qualified Transmission Project Sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the Qualified Transmission Project Sponsor. In either case, the designated Qualified Transmission Project Sponsor shall thereafter comply with the requirements of this Attachment K and the ISO Tariff with respect to the project. If no Qualified Transmission Project Sponsor expresses interest, the unsponsored project may not be submitted as a Phase One Proposal.

(b) Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(c) Information Required for Phase One Proposals; Study Deposit; Timing
Phase One Proposals shall provide the following information:

- (i) a detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;
- (ii) a detailed explanation of the identified needs that are addressed, how the proposed solution addresses those identified needs, a description of those needs which have not been addressed, and a description of the impact of the Phase One Proposal on those needs which have not been addressed;
- (iii) the proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;
- (iv) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained; and
- (v) the estimated installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate and any cost containment or cost cap measures.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a \$100,000 study deposit per submitted Phase One Proposal to support the cost of Phase One Proposal and Phase Two Solution study work by the ISO. The study deposit of \$100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Phase One Proposal and Phase Two Solution.

Phase One Proposals must be submitted by the deadline specified in the public posting by the ISO of the request for proposal described in Section 4.3(a) of this Attachment, which shall not be less than 60 days from the posting date of the request for proposal. The ISO may reject submittals which are insufficient or not adequately supported.

(d) LSP Coordination

Qualified Transmission Project Sponsors of Phase One Proposals shall also identify any LSP plans that require coordination with their Phase One Proposals.

(e) Review of Phase One Proposals by ISO

If any identified need is only solved by the Backstop Transmission Solution, the ISO shall proceed under Section 4.2 of this Attachment, rather than pursuant to the procedures set forth in the remainder of this Section 4.3.

If all of the identified needs are solved by more than one Phase One Proposal, the ISO shall perform a review of each proposal to determine whether the proposed solution:

- (i) provides sufficient data and that the data is of sufficient quality to satisfy Section 4.3(c) of this Attachment;
- (ii) satisfies one or more of the needs as identified in Section 4.3(c)(ii);
- (iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and
- (iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities, or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

(f) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies in meeting the requirements of Section 4.3(e) in the information provided in connection with a proposed Phase One Proposal, the ISO will notify the submitting Phase One Proposal Qualified Transmission Project Sponsor and provide an opportunity for the sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Phase One Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed

Phase One Proposals. This identification and notification will occur prior to the publication by the ISO of any Phase One Proposals. In providing information under this subsection (f), or in Phase Two Solutions, the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its Phase One Proposal. Phase Two Solutions reflecting a material modification to a Phase One Proposal or representing a new project will be rejected.

(g) Listing of Qualifying Phase One Proposals or Groups of Phase One Proposals

The ISO will provide the Planning Advisory Committee with, and post on the ISO's website, a listing of Phase One Proposals that meet the criteria of Section 4.3(e). The listing will contain Phase One Proposals, either individually or as a group, that solve all of the identified needs. A meeting of the Planning Advisory Committee will be held thereafter in order to solicit stakeholder input on the listing, and the listed proposals. The ISO with input from the Planning Advisory Committee may exclude Phase One Proposals, from the list, and from consideration in Phase Two Solutions, based on a determination that the Phase One Proposal is not competitive with other Phase One Proposals, that have been submitted in terms of cost, electrical performance, future system expandability, or feasibility. Information on Phase One Proposals containing CEII will be posted on the ISO's protected website consistent with Section 2.4(d) of this Attachment. The ISO may amend its listing based on stakeholder input. The ISO shall post on its website an explanation of why it has determined to exclude a Phase One Proposal from consideration in the Phase Two Solution process.

(h) Information Required for Phase Two Solutions; Identification and Reporting of Preliminary Preferred Phase Two Solution

Qualified Transmission Project Sponsors of Phase One Proposals reflected on the final listing developed pursuant to Section 4.3(g) of this Attachment shall provide the following information in their proposed Phase Two Solutions:

- (i) updates of the information provided in Phase One Proposals, or a certification that the information remains current and correct;
- (ii) list of required major Federal, State and local permits;

- (iii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the Phase Two Solution and their respective durations, and possible constraints;
- (iv) project schedule, with additional detail compared with Phase One Proposals, as specified by the ISO;
- (v) detailed cost component itemization and life-cycle cost including any clarifications to cost containment or cost cap measures that were not included as part of the Phase One Proposal;
- (vi) description of the financing being used;
- (vii) design and equipment standards to be used;
- (viii) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;
- (ix) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;
- (x) status of acquisition of right, title, and interest in rights of way, substations, and other property or facilities, if any, that are necessary for the proposed Phase Two Solution;
- (xi) detailed explanation of project feasibility and potential constraints and challenges;
- (xii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and
- (xiii) detailed explanation of potential future expandability.

Phase Two Solutions must be submitted to the ISO by the deadline specified in the posting of the final listing (following stakeholder input) of Phase One Proposals described in Section 4.3(g). The deadline for submittal of Phase Two Solutions shall not be less than 60 days from the posting date of the final listing. The ISO may reject Phase Two Solution submittals which are insufficient or not adequately supported.

The ISO will identify the Phase Two Solution, individually or as a group, that offers the best combination of electrical performance, cost, future system expandability and feasibility to comprehensively address all of the needs in the required timeframe as the preliminary preferred Phase Two Solution in response to each request for proposal. The ISO will report the preliminary preferred Phase Two Solution, together with explanatory materials, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred Phase Two Solution.

The ISO will consider several factors during the evaluation process for identification of the preliminary preferred Phase Two Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements [or deactivations](#);
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;

- Replacement of aging infrastructure;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities.

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4A. Public Policy Transmission Studies; Public Policy Transmission Upgrades

* * *

4A.3 Public Policy Transmission Studies

(a) Conduct of Public Policy Transmission Studies; Stakeholder Input

With input from Planning Advisory Committee and potentially impacted PTOs, the ISO will perform the initial phase of the Public Policy Transmission Study to develop a rough estimate of the costs and benefits of high-level concepts that could meet transmission needs driven by Public Policy Requirements. The study's results will be posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the results of the initial phase of the study, and the scope, parameters and assumptions (including resource assumptions) for any follow-on phase of the study. The ISO may – as a follow-on phase of the Public Policy Transmission Study – perform more detailed analysis and engineering work on the high-level concepts.

(b) Treatment of Market Solutions in Public Policy Transmission Studies

The ISO shall reflect proposed market responses in the Public Policy Transmission Study. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), Merchant Transmission Facilities and Elective Transmission Upgrades.

In performing Public Policy Transmission Studies, the ISO shall rely on certain resources to prevent the identification of transmission needs driven by Public Policy Requirements.

Specifically, the ISO shall incorporate in the Public Policy Transmission Study information regarding future resources, with the exception of imports across external tie lines, that have been proposed and (i) have cleared in a Forward Capacity Auction [or Annual Capacity Auction](#) pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually

bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Public Policy Transmission Studies. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service, for the relevant period, all ~~accepted~~submitted Deactivation Notifications, submitted Retirement De-List Bids, ~~submitted and~~ Permanent De-List Bids, ~~and demand bids that have cleared in a substitution auction, and may model out of service rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.~~ With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate information regarding a proposed Merchant Transmission Facility or Elective Transmission Upgrade in a Public Policy Transmission Study at a time after the studies corresponding to the Merchant Transmission Facility or Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), and a commercial operation date has been ascertained, with the exception of Elective Transmission Upgrades that are proposed in conjunction with the interconnection of a resource, which shall be considered at the same time as the proposed resource is considered in the Public Policy Transmission Study.

* * *

4A.8 Information Required for Stage Two Solutions; Identification and Reporting of Preliminary Preferred Stage Two Solution

Qualified Transmission Project Sponsors of Stage One Proposals listed pursuant to Section 4A.6(e) of this Attachment shall provide the following information in their proposed Stage Two Solutions:

- (i) updates of the information provided in Stage One Proposals, or a certification that the information remains current and correct;
- (ii) list of required major Federal, State and local permits;
- (iii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the Stage Two Solution and their respective durations, and possible constraints;
- (iv) project schedule, with additional detail compared with Stage One Proposals, as specified by the ISO;
- (v) detailed cost component itemization and life-cycle cost including any clarifications to cost containment or cost cap measures that were not included as part of the Stage One Proposal;
- (vi) description of the financing being used;
- (vii) design and equipment standards to be used;
- (viii) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;
- (ix) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;

- (x) status of acquisition of right, title, and interest in rights of way, substations, and other property or facilities, if any, that are necessary for the proposed Stage Two Solution;
- (xi) detailed explanation of project feasibility and potential constraints and challenges;
- (xii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and
- (xiii) detailed explanation of potential future expandability.

Stage Two Solutions must be submitted to the ISO by the deadline specified in the posting of the final listing (following stakeholder input) of Stage One Proposals described in Section 4A.6(e). The deadline for submittal of Stage Two Solutions shall not be less than 60 days from the posting date of the final listing. The ISO may reject Stage Two Solution submittals which are insufficient or not adequately supported.

The ISO will consider several factors during the evaluation process for identification of the preliminary preferred Stage Two Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements [or deactivations](#);
- Interface impacts;
- Future expandability;

- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities

The ISO will report the preliminary preferred Stage Two Solution(s), along with its views as to whether the preliminary preferred solution(s) also satisfies identified reliability needs of the system, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred Stage Two Solution(s).

* * *

14. Annual Assessment of Transmission Transfer Capability

Each year, the ISO shall issue the results of the annual assessment of transmission transfer capability, conducted pursuant to applicable NERC, NPCC and ISO New England standards and criteria and the identification of potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Each annual assessment will identify those portions of the New England system, along with the associated interface boundaries, that should be considered in the assessment of Capacity Zones to be modeled in the Forward Capacity Market [or Annual Capacity Market](#) pursuant to ISO Tariff Section III.12. This report will be posted on the ISO website. Each annual assessment will model out-of-service resources associated with the following ~~bids~~, if the ISO determines the removal of the resource is likely to have an impact on the transmission transfer limits for the relevant period: [Deactivation Notifications](#), Retirement De-List Bids, [and](#) Permanent De-List Bids, ~~demand bids submitted for the upcoming substitution auction, and rejected for reliability~~ [Static De-List Bids and rejected for reliability](#) [Dynamic De-List Bids from the most recent Forward Capacity Auction](#).

* * *

16.4 Competitive Solution Process for Longer-Term Transmission Upgrades

(a) Identification of Longer-Term Needs; Request for Proposal Determination

At the request of NESCOE, the ISO will consult with and provide technical support to NESCOE on possible longer-term needs that may be addressed through one or more request for proposal(s) in connection with a Longer-Term Transmission Study or a follow-on study. During this consultation, the ISO, at its sole discretion, may also identify for NESCOE's consideration known non-time-sensitive reliability or system efficiency needs that could be combined with longer-term needs in a request for proposal(s). NESCOE determines which potential needs will be included in a request for proposal(s) and whether to move forward with such a request(s). If the ISO receives from NESCOE a written list identifying the specific needs that NESCOE may be interested in including in one or more potential request for proposal(s), the ISO will post the list on the ISO's website. A meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the needs. Members of the Planning Advisory Committee shall direct all comments related to the NESCOE-identified needs to the ISO for consideration by NESCOE.

Any time following NESCOE's receipt and consideration of Planning Advisory Committee input but prior to NESCOE submitting a request to initiate a subsequent Longer-Term Transmission Study, NESCOE may submit a written request for the ISO to publicly issue, via a posting on the ISO's website, a request for proposal(s) inviting Qualified Transmission Project Sponsors to submit proposals offering a comprehensive solution that addresses the needs specified in NESCOE's request for the ISO to initiate a request for proposal(s).

Notwithstanding any other provision to the contrary, if a non-time-sensitive reliability or system efficiency need that the ISO identified for NESCOE's consideration under this Section 16.4(a) is combined with longer-term needs included in a request for proposal(s), then the reliability or system efficiency need and the development of regulated transmission solutions for that need shall be subject to the procedures for longer-term transmission planning in Section 16. If any non-time-sensitive reliability or system efficiency needs are not included in the needs selected by NESCOE to be addressed in a request for proposal(s), then those non-time-sensitive reliability or system efficiency needs shall be addressed pursuant to Sections 4.3 or 17.12 of this Attachment K. If the longer-term process is terminated pursuant to Section 16.6 of this Attachment K or corresponding Longer-Term Transmission Upgrade is removed from the RSP Project List pursuant to Section 3.6(c), then: (1) in the case of a system efficiency need, the ISO shall initiate the process under Section 17.12 of this Attachment K, and (2), in the case of a reliability need,

notwithstanding any other provisions to the contrary, the ISO shall: (i) assess the reliability need and its time-sensitivity, as appropriate; (ii) determine whether a solution is needed to solve the reliability need in three years or less from the completion of the assessment in this Section 16.4(a); and (iii) initiate the applicable process pursuant to Sections 4.1-4.3 of this Attachment K.

(b) Issuance of Request for Proposal

The ISO will publicly post on its website a request for proposal(s) inviting Qualified Transmission Project Sponsors to submit (by the deadline specified in the request for proposal, which shall not be less than 60 days from the date of posting the request for proposal) a Longer-Term Proposal offering a comprehensive solution that addresses all the needs identified in the request. The request for proposal will indicate that a Qualified Transmission Project Sponsor may submit an individual or joint Longer-Term Proposal(s). In the case where a joint proposal is submitted, all parties must be Qualified Transmission Project Sponsors.

(c) Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(a) Information Required for Longer-Term Proposals; Study Deposit; Timing

The following information must be provided as part of the Longer-Term Proposal:

- (i) detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;
- (ii) detailed explanation of how the proposed solution addresses the identified need(s);
- (iii) list of required major Federal, State and local permits

- (iv) proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;
- (v) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained;
- (vi) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;
- (vii) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;
- (viii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the proposed solution and their respective duration, and possible constraints;
- (ix) detailed cost component itemization and life-cycle cost, including cost containment or cost cap measures;
- (x) description of the financing being used;
- (xi) design and equipment standards to be used;
- (xii) detailed explanation of project feasibility and potential constraints and challenges;
- (xiii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and
- (xiv) detailed explanation of potential future expandability.

A Qualified Transmission Project Sponsor may submit a proposed solution that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a \$100,000 study deposit per submitted Longer-Term Proposal to support the cost of Longer-Term Proposal evaluation by the ISO. The study deposit of \$100,000 shall be applied toward the costs incurred by the ISO associated with the evaluation of the Longer-Term Proposal. Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the evaluation of a Longer-Term Proposal shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the ISO Tariff.

Longer-Term Proposals must be submitted by the deadline specified in the public posting by the ISO of the request for proposal. The ISO may reject submittals which are insufficient or not adequately supported.

(e) LSP Coordination

Qualified Transmission Project Sponsors of Longer-Term Proposals shall also identify any LSP plans that require coordination with their Longer-Term Proposals.

(f) Review of Longer-Term Proposals

Upon receipt of Longer-Term Proposals, the ISO shall perform a review of each proposal to determine whether the proposal:

- (i) provides sufficient data and that the data is of sufficient quality to satisfy Section 16.4(d);
- (ii) satisfies the needs identified in the request for proposal;
- (iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and;

- (iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

For each Longer-Term Proposal that satisfies the criteria specified in this Section 16.4(f), the ISO shall also perform an independent capital cost estimate, using a consistent capital cost estimating methodology, to ensure consistency in its review of the Longer-Term Proposals and their cost estimates.

(g) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies (compared with the requirements of Section 16.4(d)) in the information provided in connection with a Longer-Term Proposal, the ISO will notify the Qualified Transmission Project Sponsor that submitted the Longer-Term Proposal and provide an opportunity for the Qualified Transmission Project Sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Longer-Term Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed solutions. In providing information under this subsection (g), the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its Longer-Term Proposal.

(h) Identification and Reporting of Preliminary Preferred Longer-Term Transmission Solution; Stakeholder Input

The ISO will identify the Longer-Term Transmission Solution that offers the best combination of electrical performance, cost, future system expandability and feasibility to comprehensively address all of the needs in the timeframes specified in the request for proposal(s) as the preliminary preferred Longer-Term Transmission Solution in response to each request for proposal.

The ISO will consider several factors during the evaluation process for identification of the preliminary preferred Longer-Term Transmission Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements [or deactivations](#);
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities

The ISO will determine the financial benefits associated with Longer-Term Proposals that meet the needs identified in the request for proposal(s) and are competitive in terms of electrical performance, cost, future system expandability and feasibility. These financial benefits will consider factors that include, but are not limited to, the following which are listed in no particular order:

- Production cost and congestion savings;
- Avoided capital cost of local resources needed to serve demand;
- Avoided transmission investment;
- Reduction in losses; and

- Reduction in expected unserved energy

To be eligible for consideration as the preliminary preferred Longer-Term Transmission Solution, the Longer-Term Proposal must provide a benefit-to-cost ratio of greater than 1.0. Longer-Term Proposals with a benefit-to-cost ratio of 1.0 or less shall not be eligible for consideration as the preliminary preferred Longer-Term Transmission Solution. The benefit-to-cost ratio shall equal financial benefits divided by project costs. For the purpose of this calculation, financial benefits will be set equal to the present value of all financially quantifiable benefits provided by the project projected for the first 20 years of the project's life and project costs will be set equal to the present value of the annual revenue requirements projected for the first 20 years of the project's life.

The ISO will report the preliminary preferred Longer-Term Transmission Solution to the Planning Advisory Committee and seek input on the preliminary preferred Longer-Term Transmission Solution. Members of the Planning Advisory Committee may provide comments to the ISO on the preliminary preferred Longer-Term Transmission Solution.

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17.10 Treatment of Market Responses in System Efficiency Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

In performing System Efficiency Needs Assessments, the ISO shall incorporate or update information regarding future resources, with the exception of imports across external tie lines, in System Efficiency Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction [or Annual Capacity Auction](#) pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in System Efficiency Needs Assessments. For

imports, if a tie line from an external area has an associated energy contract, the minimum energy interchange will be respected. Otherwise, imports and exports will be reflective of the least cost economic dispatch. The ISO will model out-of-service, for the relevant period, all submitted Deactivation Notifications, submitted Retirement De-List Bids, and submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected for reliability Static De-List Bids and rejected for reliability, Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a System Efficiency Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which an Elective Transmission Upgrade Interconnection Agreement has been executed, and, to the extent required, filed and accepted by the Commission, or filed unexecuted and accepted by the Commission~~the certification has been accepted in accordance with Section III.12 of the Tariff.~~ In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the System Efficiency Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained,~~and for which the certification has been accepted in accordance with Section III.12 of the Tariff and for which an Elective Transmission Upgrade Interconnection Agreement has been executed and, to the extent required, filed and accepted by the Commission, or filed unexecuted and accepted by the Commission.~~

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17.12 Competitive Solution Process for System Efficiency Transmission Upgrades

(a) Initiating the Competitive Solution Process

The ISO will publicly post on its website a request for proposal(s) inviting Qualified Transmission Project Sponsors to submit (by the deadline specified in the request for proposal, which shall not be less than 60 days from the date of posting the request for proposal) a System Efficiency Transmission Upgrade offering a solution that addresses the minimum threshold of needs identified in the request. The request for proposal will indicate that a Qualified Transmission Project Sponsor may submit an individual or joint System Efficiency Transmission Upgrade Proposal(s). In the case where a joint proposal is submitted, all parties must be Qualified Transmission Project Sponsors.

(b) Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(c) Information Required for System Efficiency Transmission Upgrade Proposals; Study Deposit; Timing

The following information must be provided as part of the System Efficiency Transmission Upgrade Proposal:

- (i) detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;
- (ii) detailed explanation of how the proposed solution addresses the identified need(s);
- (iii) list of required major Federal, State and local permits
- (iv) proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;
- (v) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained;

- (vi) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;
- (vii) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;
- (viii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the proposed solution and their respective duration, and possible constraints;
- (ix) detailed cost component itemization and life-cycle cost, including cost containment or cost cap measures;
- (x) description of the financing being used;
- (xi) design and equipment standards to be used;
- (xii) detailed explanation of project feasibility and potential constraints and challenges;
- (xiii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and
- (xiv) detailed explanation of potential future expandability.

A Qualified Transmission Project Sponsor may submit a proposed solution that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a \$100,000 study deposit per submitted System Efficiency Transmission Upgrade Proposal to support the cost of System Efficiency Transmission Upgrade Proposal evaluation by the ISO. The study deposit of \$100,000 shall be applied toward the costs incurred by the ISO associated with the evaluation of the System Efficiency Transmission Upgrade Proposal. Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the evaluation of a System Efficiency Transmission

Upgrade Proposal shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the ISO Tariff.

System Efficiency Transmission Upgrade Proposals must be submitted by the deadline specified in the public posting by the ISO of the request for proposal. The ISO may reject submittals which are insufficient or not adequately supported.

(c) LSP Coordination

Qualified Transmission Project Sponsors of System Efficiency Transmission Upgrade Proposals shall also identify any LSP plans that require coordination with their System Efficiency Transmission Upgrade Proposals.

(e) Review of System Efficiency Transmission Upgrade Proposals

Upon receipt of System Efficiency Transmission Upgrade Proposals, the ISO shall perform a review of each proposal to determine whether the proposal:

- (i) provides sufficient data and that the data is of sufficient quality to satisfy Section 17.12(c);
- (ii) satisfies the needs identified in the request for proposal;
- (iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and;
- (iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

For each System Efficiency Transmission Upgrade Proposal that satisfies the criteria specified in this Section 17.12(e), the ISO shall also perform an independent capital cost estimate, using a consistent capital cost estimating methodology, to ensure consistency in its review of the System Efficiency Transmission Upgrade Proposals and their cost estimates.

(f) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies (compared with the requirements of Section 17.12(c) in the information provided in connection with a System Efficiency Transmission Upgrade Proposal, the ISO will notify the Qualified Transmission Project Sponsor that submitted the System Efficiency Transmission Upgrade Proposal and provide an opportunity for the Qualified Transmission Project Sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of System Efficiency Transmission Upgrade Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed solutions. In providing information under this subsection (f), the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its System Efficiency Transmission Upgrade Proposal.

(g) Identification and Reporting of Preliminary Preferred System Efficiency Transmission Upgrade Solution; Stakeholder Input

The ISO will identify the System Efficiency Transmission Upgrade Solution that offers the best combination of electrical performance, cost, future system expandability and feasibility to comprehensively address all of the needs in the timeframes specified in the request for proposal(s) as the preliminary preferred System Efficiency Transmission Upgrade Solution in response to each request for proposal.

The ISO will consider several factors during the evaluation process for identification of the preliminary preferred System Efficiency Transmission Upgrade Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;

- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements [or deactivations](#);
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities

The ISO will determine the financial benefits associated with System Efficiency Transmission Upgrade Proposals that meet the needs identified in the request for proposal(s) and are competitive in terms of electrical performance, cost, future system expandability and feasibility. These financial benefits will consider the following factors, which are listed in no particular order:

- Production cost savings;
- Avoided transmission costs; and
- Reduced transmission losses.

To be eligible for consideration as the preliminary preferred System Efficiency Transmission Upgrade Solution, the System Efficiency Transmission Upgrade Proposal must provide a benefit-to-cost ratio of greater than 1.0. System Efficiency Transmission Upgrade Proposals with a benefit-to-cost ratio of 1.0 or less shall not be eligible for consideration as the preliminary preferred System Efficiency Transmission Upgrade Solution. The benefit-to-cost ratio shall equal financial benefits divided by project costs. For the purpose of this calculation, financial benefits will be equal to the present value of one year's financial benefits for the project, ten years from the initiation of the System Efficiency Needs Assessment. For the

purpose of this calculation, cost will be equal to the present value of the yearly carrying cost of the project for one year, ten years from the initiation of the System Efficiency Needs Assessment.

The ISO will report the preliminary preferred System Efficiency Transmission Upgrade Solution to the Planning Advisory Committee and seek input on the preliminary preferred System Efficiency Transmission Upgrade Solution. Members of the Planning Advisory Committee may provide comments to the ISO on the preliminary preferred System Efficiency Transmission Upgrade Solution.

* * *

ATTACHMENT K APPENDIX 3

LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

The entities listed in this Appendix 3 are those approved by ISO-NE as Qualified Transmission Project Sponsors as of the date the revisions to this Appendix 3 were filed with the Commission. The most current list of entities approved as Qualified Transmission Project Sponsors is available on the ISO-NE website. This Appendix 3 will be updated to reflect any subsequent enrollments as part of unrelated OATT filings at the time ISO-NE undertakes such unrelated filings.

Anbaric Development Partners, LLC

Avangrid Networks, Inc.

Central Maine Power Company

Connecticut Transmission Municipal Electric Cooperative

[energyRe Giga-Projects USA, LLC](#)

Eversource Energy Transmission Ventures, Inc.

NGV US Transmission Inc.

Hudson Light and Power Department

LS Power Grid Northeast, LLC

Maine Electric Power Company

Massachusetts Municipal Wholesale Electric Company

Middleboro Gas & Electric Department

Narragansett Electric Company d/b/a Rhode Island Energy

New England Power Company

New Hampshire Transmission, LLC

Norwood Municipal Light Department

NSTAR Electric Company

PPL Translink, Inc.

Public Service Company of New Hampshire

Taunton Municipal Light Plant

The City of Holyoke Gas and Electric Department

The Connecticut Light and Power Company

Town of Braintree Electric Light Department

United Illuminating Company

Vermont Transco, LLC

Versant Power

Viridon New England LLC

SCHEDULE 16

Blackstart Service

* * *

2. Term of Blackstart Service

2.2 Termination:

* * *

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.

* * *

3. Rights and Obligations

* * *

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.

* * *

5. Blackstart Service Payments

* * *

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.

$$\text{Lump Sum Blackstart Payment}_{\text{individual}} = (\text{Lump Sum Blackstart Capital Payment}_{\text{station}}) * \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA value of the retiring or terminated Designated Blackstart Resource} / \Sigma \text{ all the retiring or terminated Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA values at the Blackstart Station.}$$

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.

* * *

ATTACHMENT N

PROCEDURES FOR REGIONAL SYSTEM PLAN UPGRADES

I. INTRODUCTION

* * *

II. STANDARDS FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, SYSTEM EFFICIENCY TRANSMISSION UPGRADES, PUBLIC POLICY TRANSMISSION UPGRADES AND LONGER-TERM TRANSMISSION UPGRADES

A. Identification of Reliability Transmission Upgrades

Reliability Transmission Upgrades are those upgrades necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards. In applying the applicable reliability standards, some of the considerations that will be taken into account are as follows:

- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources, and new, retired, [deactivated](#) or unavailable generators);
- load growth;
- acceptable stability response;
- acceptable short circuit capability;
- acceptable voltage levels;
- adequate thermal capability; and
- acceptable system operability and responses (e.g. automatic operations, voltage changes).

To identify the transmission system facilities required to maintain reliability and system performance consistent with the applicable reliability standards, the ISO shall:

- determine whether the above factors are met using reasonable assumptions for certain amounts of forecasted load growth, and generation and transmission facility availability (due to maintenance, forced outages, or other unavailability); and
- rely on Good Utility Practice, applicable reliability standards, and the ISO System Rules.

A Reliability Transmission Upgrade is not an upgrade required by the interconnection of a generator except to the extent determined under the terms of Schedule 11 of the OATT. A Reliability Transmission Upgrade may also provide system efficiency benefits.

B. Identification of System Efficiency Transmission Upgrades

* * *

1. Base Economic Evaluation Model

In supporting the evaluation of financial benefits, the ISO may take into account applicable economic factors in its base economic evaluation model, such as:

- energy costs;
- Capacity Costs;
- cost of supplying total operating reserve;
- system losses;
- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources and new, retired, [deactivated](#), or unavailable generators);
- load growth;
- fuel costs;
- fuel availability;
- generator availability;
- release of bottled generating resources;

The modeled system will consist of the projected New England Transmission System, the forecasted New England energy demand, and the expected resource mix within New England given inclusion factors in Section 17.10 of Attachment K. In an Economic Study cycle, for external areas' demand, external

resource mixes, and interregional transmission topology, when possible, a consistent external data source will be used to model economic and contracted interchange between neighboring regions.

* * *



memo

To: NEPOOL Markets, Reliability, and Transmission Committees

From: ISO New England, Inc.

Date: November 5, 2025

Subject: Capacity Auction Reforms – Prompt / Deactivation (CAR-PD) (WMPP ID: 184)

The ISO is requesting votes on the first phase of its proposed Capacity Auction Reforms (CAR). The CAR-PD proposal transitions the capacity auction from a three-year forward market to a prompt market and decouples retirement decisions from the capacity auction, balancing reliability considerations with efficiency under the new deactivation notification process. Together, these changes will help the region reflect more accurate information and more efficiently determine capacity awards.

By way of background, for 18 years, the ISO administered a Forward Capacity Market (FCM), using annual auctions to secure commitments from resources more than three years in advance. Following significant discussion and broad support from stakeholders, FERC accepted the ISO's proposed delay to Forward Capacity Auction 19 (FCA 19) to allow for time to develop a prompt and seasonal market with accreditation reforms.

The CAR-PD proposal transitions the FCM to a prompt market that will utilize more up-to-date and accurate information, providing better price signals. The region will have the most recent load forecasts as auction inputs and participants will have more representative values for their assets. Further, the new requirement to be commercial before participating in the capacity market will help prevent cases where resources sell capacity that can't ultimately deliver (*i.e.*, the phantom entry concern).

The proposed deactivation revisions will require resources that wish to discontinue their market participation to submit a deactivation notification. Separating the former capacity retirement process from market outcomes in favor of a shift to deactivations is expected to help foster efficient individual deactivation decisions by maximizing the amount of relevant market information available to participants before the decision is made and creates a straightforward path for resources wishing to exit the market.

The ISO proposal is the product of robust discussion with stakeholders and incorporates numerous stakeholder suggested revisions. The ISO began presenting on its CAR-PD proposal in January 2025 and has since summarized the key content areas and hyperlinked to the presented detailed design in the [CAR Proposal Information Summary](#). The ISO is proposing an effective date in early March 2026, and the CAR-PD proposal will serve as the foundation for the next phase of the CAR project, Seasonal / Accreditation.



memo

To: NEPOOL Participants Committee (PC)
From: ISO New England, Inc.
Date: November 25, 2025
Subject: ISO New England's CAR-PD Proposal Update

In preparation for the December PC, the ISO is providing clarity on its Capacity Auction Reforms – Prompt/Deactivation (CAR-PD) proposal following the votes at the November Technical Committees.

As noted in our early November memo, the ISO would not be opposed to incorporating the NEPGA ambient air de-list bid amendment into its CAR-PD proposal if it received broad stakeholder and state support.¹ At the November Markets Committee meeting, this amendment and the once-amended main motion were both widely supported by stakeholders and the states.² If this amendment continues to receive broad support at the PC, the ISO plans to incorporate it into its proposal.

¹ ISO New England, "ISO New England's Position on CAR-PD Amendments," memo to the NEPOOL Technical Committees (November 5, 2025), https://www.iso-ne.com/static-assets/documents/100029/a03.1.c_mc_tc_2025_11_12_13_car-pd_iso_amendments_feedback_final_.pdf

² NEPOOL Markets Committee Secretary, "Actions of the Markets Committee," memo to the Participants Committee (November 13, 2025), https://www.iso-ne.com/static-assets/documents/100029/a00_mc_2025_11-12-13_actions_letter.pdf

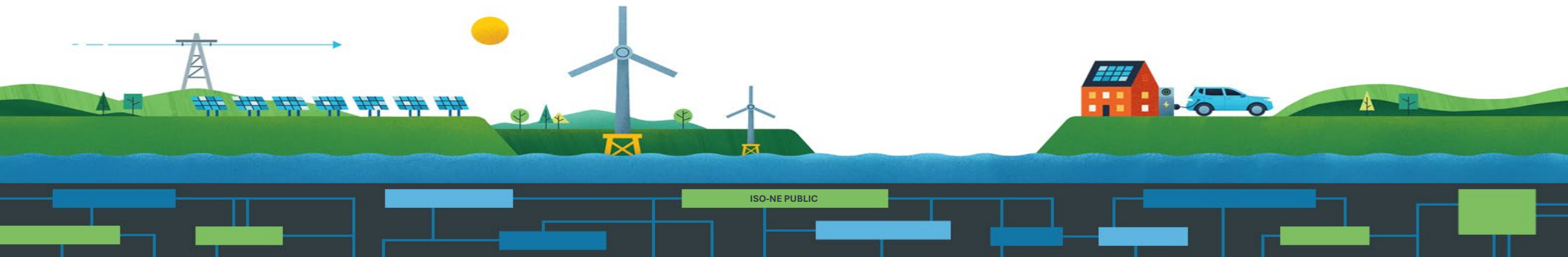
Capacity Auction Reforms: Prompt/Deactivation (CAR-PD)

CAR-PD Proposal Summary



Chris Geissler

DIRECTOR, ECONOMIC ANALYSIS



Proposed Effective Date: Early March 2026

- CAR-PD includes changes to run the capacity auction shortly before the start of the delivery period and reform the process by which resources exit from the ISO markets
- This presentation provides a final overview of the changes proposed under CAR-PD in the appendix
- The next few slides highlight the key benefits of the proposal

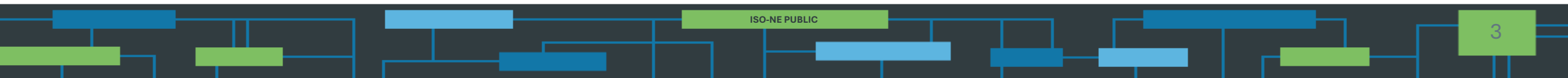
Summaries and links to the CAR-PD design details can be accessed through the [CAR Proposal Information Summary](#)



The Capacity Auction Reforms – Prompt / Deactivation (CAR-PD) Package Moves the Region Ahead

NEPOOL PARTICIPANTS COMMITTEE
DEC 4, 2025 MEETING, AGENDA ITEM #10
Attachment F

- The ISO aims to ensure power system reliability and cost-efficiency better as New England's resource mix evolves
- The CAR-PD proposal transitions the capacity auction from a three-year forward market to a prompt market and decouples retirement decisions from the capacity auction, balancing reliability considerations with efficiency under the new deactivation notification process
- Together, these changes will help the region reflect more accurate information and more efficiently determine capacity awards

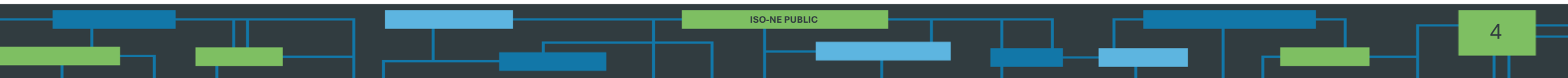


The CAR-PD Package Moves the Region Ahead (Cont.)

ISO-NE POOL PARTICIPANTS COMMITTEE
DEC 4, 2025 MEETING, AGENDA ITEM #10
Attachment F

Prompt:

- The CAR-PD proposal transitions the FCM to a prompt market that will utilize more up-to-date and accurate information, providing price signals that better reflect capacity's reliability value
 - The load forecast used to inform capacity demand will better reflect expected conditions
 - Participants can more accurately reflect expected market conditions in their priced supply offers since the timing will no longer require a company to project what conditions may be like in ~four years
 - On quantity, participants will be given more up-to-date Qualified Capacity (QC) values
- The new requirement to be commercial before participating in the capacity market will help prevent cases where resources sell capacity that they cannot ultimately deliver (*i.e.*, the phantom entry concern)

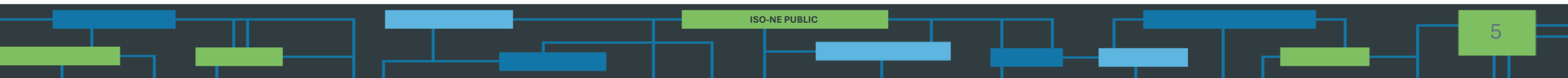


The CAR-PD Package Moves the Region Ahead (Cont.)

INTEGRATED PARTICIPANTS COMMITTEE
DEC 4, 2025 MEETING, AGENDA ITEM #10
Attachment F

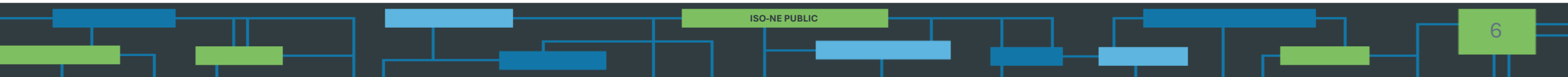
Deactivations:

- The proposed deactivation revisions will require resources that wish to discontinue their market participation to submit a deactivation notification
- Shortening the timeframe in which a resource gives a deactivation notification to one year increases the information that it has available when making this determination, and therefore, may lead to more efficient deactivation decisions



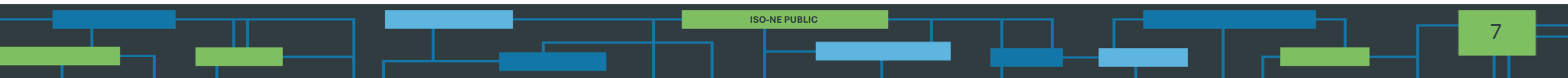
Stakeholder Process and Next Steps

- The ISO proposal is the product of robust discussion with stakeholders and incorporates numerous stakeholder-suggested revisions
 - The ISO has valued feedback and incorporated numerous suggestions and points of feedback that have improved the proposal, including, but not limited to:
 - The deactivation notification timeframe
 - The deactivation mitigation structure to include a proxy bid for resources exercising market power
 - Clarifications to the Tariff language
 - Clarifications and improvements to design and process for qualification, auction schedule, outage coordination, mitigation, offer PQ pairs, CPS monitoring, and many more
- The product of the work done together on CAR-PD will serve as the foundation for the next phase of the CAR project: Seasonal / Accreditation



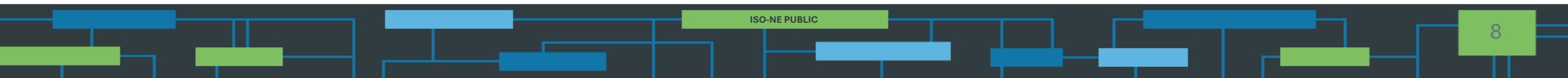
APPENDIX

*Material from August MC Summer Meeting Summarizing the CAR-PD
Background and Design*



Background: Region's Decision to Pursue CAR

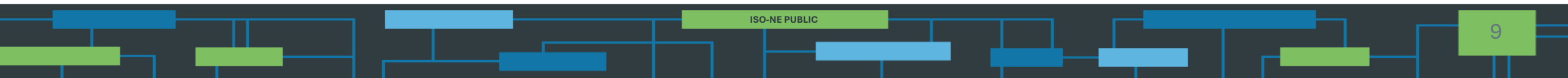
- The ISO began exploring the move to a prompt auction during its earlier efforts in Resource Capacity Accreditation (RCA), which found synergies between the accreditation changes and other capacity market reforms, including prompt and seasonal markets
- In evaluating how to proceed, the ISO asked the Analysis Group (AGI) to assess the merits of moving to a prompt and seasonal auction
- AGI's analysis found numerous benefits to such reforms



AGI's Analysis Supported Move to a Prompt and Seasonal Capacity Market

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Attachment F

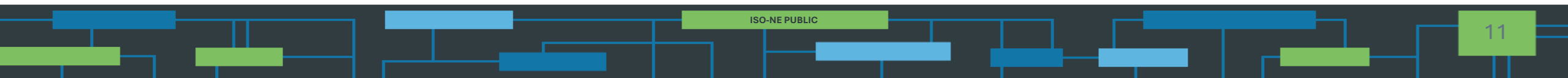
- AGI's analysis found several benefits associated with moving to a prompt timeframe related to the improved information available to the ISO and market participants, including:
 - Reduced risk for capacity sellers due to having better information about market conditions and operational characteristics ([ISO's April 2024 MC presentation](#) expanded on this to show how this could improve market efficiency, see slides 10 to 12)
 - Numerous benefits associated with ensuring all participating capacity is commercial
- AGI estimated that this reduction in risk may lead to lower capacity market prices and costs across a range of conditions
- More detail is available in [AGI's report](#)



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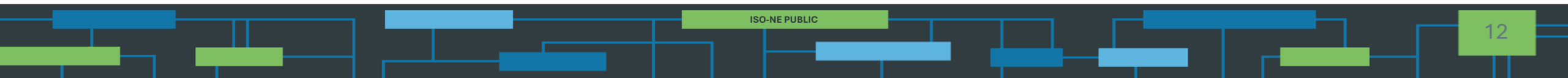
CAR Schedule

- Upon FERC approval of the Further Delay Filing, the ISO began working with stakeholders to develop capacity market reforms
 - Scoping discussions began in Q3 of 2024
 - Detailed discussion of the proposal began in Q1 of 2025
- Plan to split CAR components into two filings:
 1. CAR-PD: Includes the move to a prompt auction and deactivation reforms
 - Targeted filing: late 2025
 2. CAR-SA: Includes the seasonal commitment periods and accreditation enhancements
 - Targeted filing: late 2026
- Provides the opportunity to get feedback from FERC in response to the first filing



Themes from Scope Discussions

- Keep scope narrow where possible
 - Even with a narrow scope, ISO is proposing three very significant changes, each of which is its own large body of work
 - CAR reforms must be completed in time to be in effect for CCP 19
 - The ISO plans to continue pursuing capacity market enhancements after the initial CAR filings are submitted
- Prioritize ‘bang for buck’ in design items
 - Means not focusing on design elements that are not strictly necessary and are expected to materially change under CAR-SA
- Simplicity



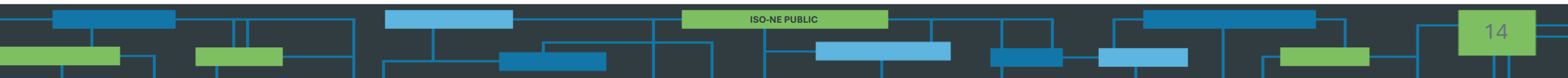
Key Design Changes Under CAR-PD

- Development of a new deactivation process for exiting the capacity market
- Qualification rules require resources to be commercial in order to sell capacity
 - Reactivation rules outline how a resource that has deactivated may return to the capacity market
- Competitive offer and price formation; mitigation rules
- Auction format and process, including:
 - Move from a descending clock auction to a sealed bid auction
 - Elimination of reliability reviews for resources that do not sell capacity, but are not being deactivated
- Creation of a new capacity market activity schedule
- Changes align with CAR-PD topic areas introduced at the [December 2024 Markets Committee](#)

Key Benefit: Prompt Auction Improves Auction Efficiency Through More Accurate Inputs

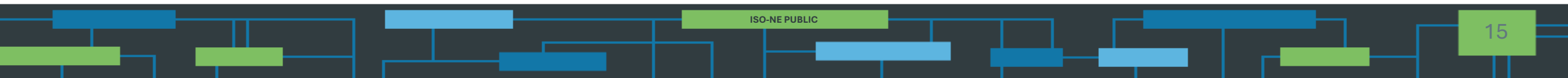
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Attachment F

- A prompt auction allows the ISO to derive capacity demand using up-to-date forecasts and information
- Capacity sellers can develop offers based on more recent information about resource capabilities and market conditions
- Particularly important with the rate of technological change and evolving public policies



Key Benefit: Prompt Auction Addresses Phantom Entry Concern

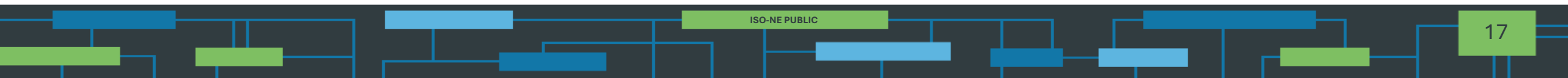
- Requiring resources to be operational to sell capacity eliminates concerns regarding phantom or delayed entry, where the region may have procured capacity that is not available for the commitment period
- Phantom entry adversely impacts:
 - Buyers via the purchase of capacity not received
 - Other sellers via depressed capacity prices
 - Market efficiency as it may prevent other cost-effective capacity providers from selling capacity



Key Benefits: Additional Perspectives

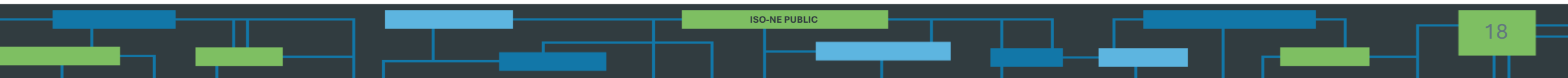
- [AGI report](#) and [summary presentation](#)
- [IMM memo](#) and [comments on further delay filing](#)
- [EMM memo](#), [comments on further delay filing](#), and [Annual Markets Report \(AMR\)](#)
 - Changes help address several AMR recommendations
 - Move to prompt addresses one of EMM's 'high benefit' recommendations (2021-1)
 - Developing a sealed bid auction structure, as proposed under CAR-PD, will address another EMM recommendation (2015-7)
 - Accreditation reforms being pursued under CAR-SA will address another 'high benefit' recommendation (2020-2)

DEACTIVATING RESOURCES



Prompt Auction Allows for More Efficient Deactivation Design

- Under the forward market, resources considering deactivation give notice to the market more than four years ahead of their intended deactivation date
- Key prompt benefit: Allows resources to make this determination much closer to the intended deactivation date
- Participants can consider more up-to-date information about resource operating characteristics and market conditions in deactivation decisions, leading to more efficient outcomes
- The ISO's deactivation proposal includes several changes and enhancements based on valuable stakeholder feedback

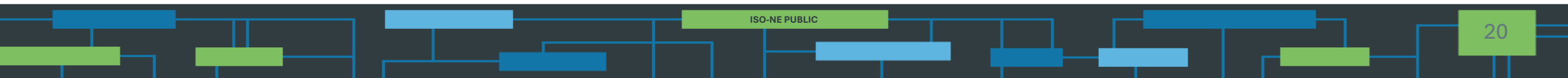


CAR-PD Proposes a One-Year Deactivation Notification Timeline

- Participants would give Deactivation Notification one year ahead of the intended commitment period
- In response to stakeholder feedback, timing was shortened (originally proposed a two-year notice) to reflect further consideration of tradeoffs between:
 - Longer deactivation timeline, which gives the market time to respond and may reduce the duration of any RMRs, and
 - Shorter deactivation timeline, which allows participants to use better information about market conditions and resource operational capabilities to make a deactivation decision
- The shortened notification timeline leverages the benefits of the improved information available to the market ahead of a prompt capacity auction

Deactivating Resource Reliability Reviews are Similar to Today

- If a resource that submits a Deactivation Notification is needed for local transmission security, the ISO will seek to retain the resource via an out-of-market contract to allow time for a solution to be developed before the resource deactivates
- At the end of the resource's contract, it would deactivate
- This process would be similar to the current rules
- *Note: As discussed later, the ISO is proposing under CAR-PD to discontinue reliability reviews for resources participating in the prompt auction that are not proposing to deactivate*

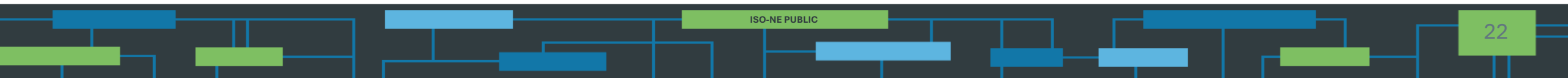


Market Power Assessment for Deactivating Resources is Similar to Today

- Review includes two distinct components:
 1. **Conduct Test:** Assessment will look at whether deactivation appears to be economically sensible. The results of this assessment are confidentially filed with FERC
 2. **Impact Test:** Whether a market participant has an incentive to physically withhold the deactivating resource
- If a resource fails both tests, a proxy supply offer at the competitive price is entered on behalf of the deactivating resource, like today
 - Competitive price considers costs that would be avoided if the resource deactivates, much like with the current proxy Retirement De-List bid
- Use of proxy supply came after stakeholder feedback on the earlier Market Power Charge design concept
 - Use of proxy supply protects the market from higher prices in cases where an exercise of market power is suspected, but does not provide a price signal reflecting the resource's exit to the market

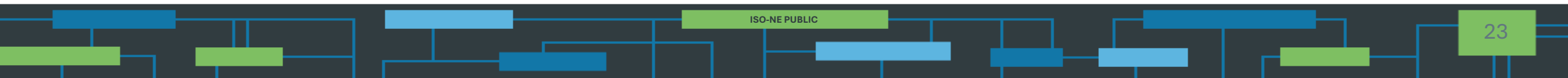
CAR-PD Deactivation Proposal: Other Key Mechanics

- Deactivations cannot be revoked
 - Shortening the deactivation notification timeline to one year, and the allowance of reactivations (discussed further in the next section), helps to reduce any impacts associated with making deactivations irrevocable
 - Allows the market to respond to deactivations with more certainty
 - Allowing revocability would raise several challenging design questions related to interconnection service, study assumptions, allocation of costs, etc.
- Deactivations can be accelerated if the resource does not have any outstanding CSO positions, if it is not needed for reliability, and if it is not deemed to be exercising market power

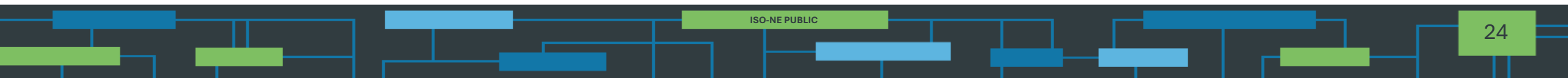


CAR-PD Deactivation Proposal: Market Impacts

- Many elements of deactivation align with current retirement rules, including:
 - Assessment of market power and remedy, if found
 - Reliability review criteria and remedy
- Key changes include timing and that the retirement/deactivation decision is made well ahead of the auction
- The ISO does not expect these changes to lead to systematically higher or lower capacity market prices and costs
 - If CAR-PD's shorter notification timeline leads a resource that would otherwise exit to remain in the market and sell capacity, this could decrease capacity prices and costs
 - If CAR-PD's shorter notification timeline leads a resource that would otherwise remain in the market and sell capacity to exit, this could increase capacity prices and costs

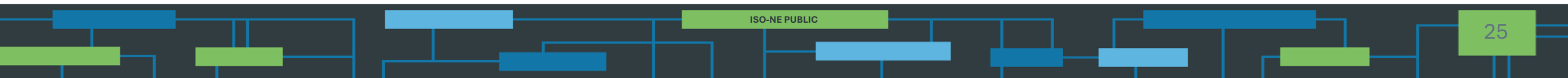


QUALIFICATION RULES



CAR-PD: Qualification Overview

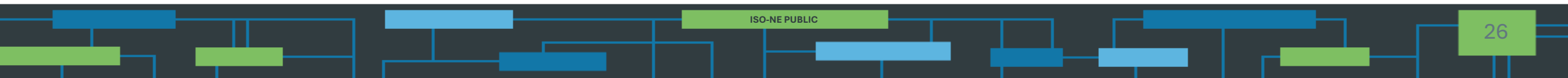
- Interconnection service will generally be established outside of (and ahead of) the capacity market, as outlined in FERC Order No. 2023
- Process to establish QC will broadly be consistent with current rules, and in many cases, will be based on the resource's Seasonal Claimed Capability (SCC) ratings from recent audits
- Two key changes:
 1. Timing: QC values will be established closer to the CCP given the prompt auction timing
 2. Basis: QC values for all resources are established using observed resource performance



Key Benefit: A Prompt Auction Allows Qualification to Better Align with Resource Capabilities

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- Timing allows for QC values to more accurately reflect resource capabilities leading into the CCP
- Requiring all resources to be commercial addresses an existing concern regarding phantom capacity, where the forward auction procures capacity from non-commercial resources that do not become commercial for the CCP
 - Phantom capacity results in consumers paying for capacity that does not provide reliability value to the region
- Improves market efficiency and system reliability
- Also reduces risk to capacity suppliers



CAR-PD Enhances Ability of Deactivated Resources to Reactivate

- Resources that have chosen to deactivate and wish to re-enter can do so
 - No longer subject to an investment threshold
- With the elimination of the new versus existing distinction under CAR-PD, concerns about ‘togglng’ no longer exist
- Any reactivating resources that had a Cost-of-Service Agreement (COSA) would be subject to a claw-back provision regarding certain payments associated with the COSA
- Must follow the same process as other new resources, including:
 - Go through a cluster study to establish CNRC
 - Demonstrate that they are commercial
- Reduces barriers to entry, which improves market efficiency

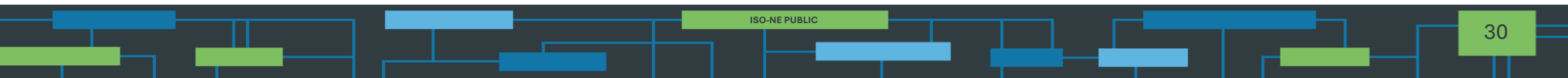
Repowering Provisions

- Participants can continue to modify an interconnection agreement as allowed under current rules
 - Enables the participant to transfer the portion of the CNRC/CNRIS that is not being modified from the old resource to the new resource
 - These provisions, which relate to the interconnection process, are not impacted by CAR
- Resources that undergo a material change, including repowering, will need to meet the same criteria as all other resources before participating in a prompt auction
 - Establish interconnection service
 - Demonstrate commerciality to get a QC value
- Resources that repower in the interconnection space will no longer be subject to an investment threshold in the capacity market, thereby reducing barriers to entry
- For more information, see the [ISO's March 2025 memo on repowering](#) and the August detailed design deck on qualification

CAR PD Qualification Rules: Market and Reliability Impacts

- Establishing QC values shortly before the CCP will improve market efficiency by more accurately aligning how much capacity resources can sell with their actual capability
- This could increase or decrease market prices and costs
 - If using more accurate data allows resources to sell more capacity (e.g., improved performance or new resources that become commercial ahead of schedule), this will tend to decrease prices and costs
 - If using more accurate data leads resources to sell less capacity (decreased performance or phantom entry), this will tend to increase prices and costs
- Using more accurate qualification values will decrease the risk that system reliability is adversely impacted by phantom entry

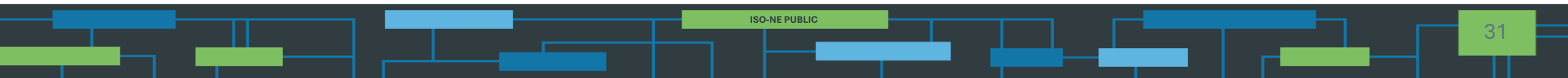
COMPETITIVE OFFER AND PRICE FORMATION AND MITIGATION



Stakeholders Identified Competitive Offer and Price Formation as a Priority Item in CAR-PD Discussions

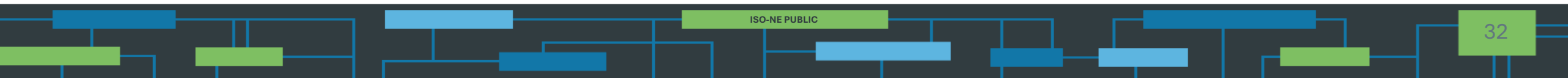
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- A number of stakeholders across a range of sectors highlighted competitive offer and price formation as key items to discuss as part of CAR-PD
- ISO noted this priority in its scope discussions
 - See [August 2024 MC presentation](#)



ISO Assessment: Competitive Offers

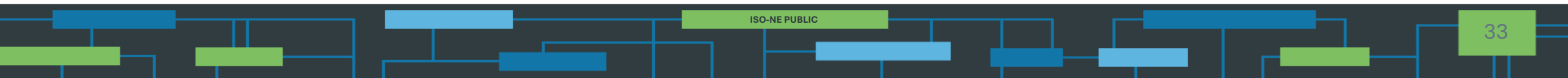
- The same logic that informs competitive offers under a forward auction applies to a prompt auction
- Competitive offers are based on the resource's next best alternative
- This may consider capacity costs that can be avoided as well as opportunity costs (e.g., forgone PFP revenues due to having a CSO)
- Importantly, competitive offers should not include costs that can no longer be avoided
- Like today, Market Participants may need to forecast expected future costs and revenues when making long-term investment decisions
- Discussed in ISO's [March 2024 MC presentation](#), slides 25 through 39



ISO Assessment: Competitive Capacity Clearing Prices

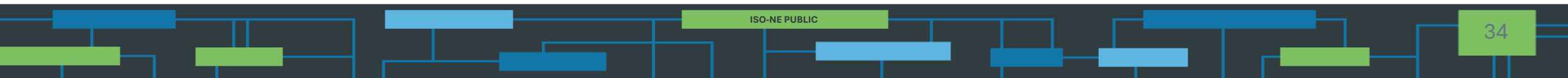
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- Some resources may offer their capacity at lower prices in a prompt market if costs that would have been avoidable in a forward setting are now sunk (if incurred)
- However, the ISO does not expect capacity clearing prices to be systematically higher or lower in a prompt market
- Resources will continue to make investments if they expect to recover these costs through the energy and capacity markets
- The capacity market demand curve will continue to be derived based on capacity's Marginal Reliability Impact (MRI)
- In other words, the ISO expects the same resources to sell capacity in a prompt or forward setting, and this would result in similar capacity prices
- Discussed in [ISO's March 2025 MC presentation](#), slides 40 through 53



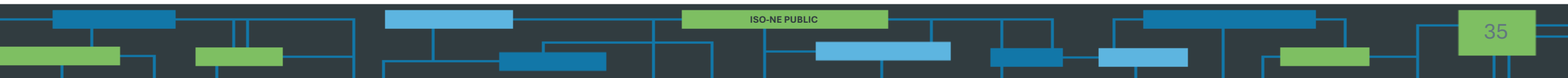
Seller-Side Market Power: Cost Workbook

- Capacity sellers submitting a price at or offer above the Capacity Offer Price Threshold (COPT) (discussed further in a couple of slides) will be required to submit a cost workbook that supports this price
- The cost workbook will continue to use the logic that a competitive offer price is based on the change in costs/revenues if the resource did not sell capacity and instead pursued its next best alternative
- Market Participants will have the opportunity to consult with the IMM with the aim of reaching an agreement on the cost workbook ahead of submission



Seller-Side Market Power: Pivotal Supplier Test

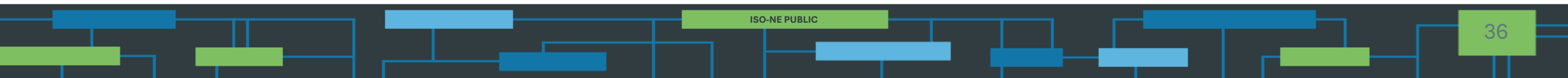
- Like today, if the IMM concludes that a resource's submitted offer ceiling price exceeds its competitive value, it conducts a pivotal supplier test (PST)
- The PST assesses if the Market Participant's portfolio is sufficiently large that, without it, the ISO would procure less capacity than its Net Installed Capacity Requirement (NICR) or relevant Capacity Zone's Local Sourcing Requirement
- If a resource fails both tests, its offer price is replaced with the IMM's determination of its competitive offer price
- As part of the post-CAR roadmap, the ISO plans to assess whether further changes to the PST (e.g., to an impact test) should be pursued



Buyer-Side Market Power: Nature of Review is Unchanged

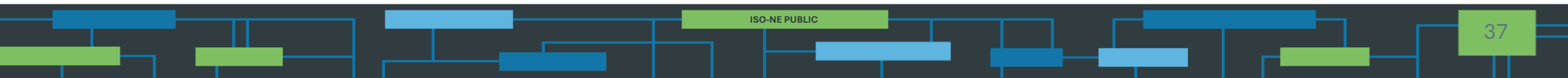
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- The ISO is not proposing to change the set of resources subject to buyer-side market power (BSMP) review (Lane 3)
 - Have not previously sold capacity
 - Above 5 MW threshold
 - Not a sponsored policy resource
 - Not Seasonal Peak DR or On-Peak DR
 - Participant and its Affiliates or partners are a load serving entity or are receiving out-of-market revenues from a load serving entity
 - Appendix includes more information on the criteria governing lanes
- Such resources will be subject to an offer floor price based on the estimated competitive costs of developing the resource



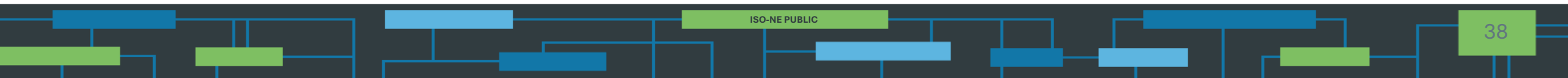
Buyer-Side Market Power: Timing

- Currently, the BSMP process is conducted in advance of the forward auction
- Moving to a prompt auction affords more flexibility for when this determination would occur
 - Aligns with the fact that resources will have different development timelines
- With the prompt design, the ISO will allow resources to submit cost information and receive their offer floor price nearly as early as under the current rules (3+ years ahead of the CCP), but will also allow participants to request their offer floor price up until one year before the start of the CCP
 - Allows resources that can be developed over shorter timeframes to get an offer floor price that more accurately reflects their expected costs and revenues



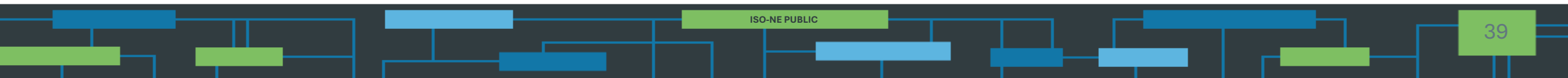
Buyer-Side Market Power: Determination of Lanes

- Lane 1: New resources that are less than 5 MW or are passive demand
- Lane 2: Competitive entrants or Sponsored Policy Resources
- Lane 3: New resources that do not fit into Lane 1 or Lane 2
- For more information on lanes, see the [ISO's May 2025 presentation on mitigation](#), slides 10 to 14



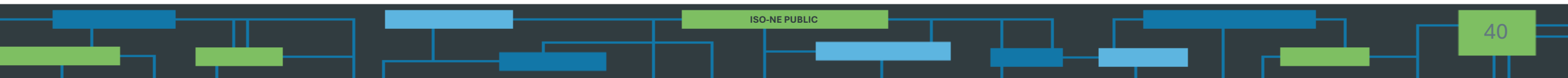
Other Mitigation Mechanics

- All resources that have qualified to participate in the prompt auction are effectively existing resources because of the requirement to achieve commercial operation ahead of the auction
- Therefore, all resources are subject to the seller-side market power review process
- The IMM will review offers if they are priced at or above the COPT, which will be developed in a manner consistent with the current Dynamic Delist Bid Threshold (DDBT)

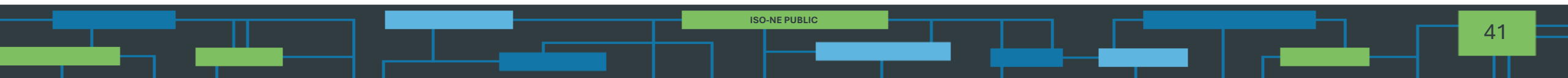


CAR-PD: Offer/Price Formation and Mitigation Market Impacts

- As explained in earlier materials, the ISO does not expect changes in the offer timing to materially impact capacity prices
 - If the timing reduces risks for capacity suppliers because of improved information regarding market conditions or operational capabilities, this could result in lower costs due to the corresponding efficiency gains
- The mitigation rules are largely consistent with those that exist today and are not expected to materially impact market outcomes relative to current rules

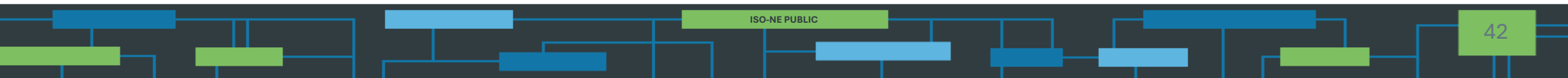


AUCTION MECHANICS AND ACTIVITY SCHEDULE



Move to a Sealed Bid Auction

- Under CAR-PD, the ISO would discontinue the use of a Descending Clock Auction (DCA) structure
- This change in auction format impacts how resource offers to sell capacity are collected
 - Auction clearing and pricing rules are unchanged from those used today with the DCA
- Not expected to materially impact market outcomes, although this could reduce the likelihood that participants can exercise market power to increase capacity prices by leveraging information made available during the auction
- This change is consistent with the EMM's recommendation, is responsive to stakeholder input regarding the auction structure, and simplifies elements of the auction administration



Priced Capacity Offers

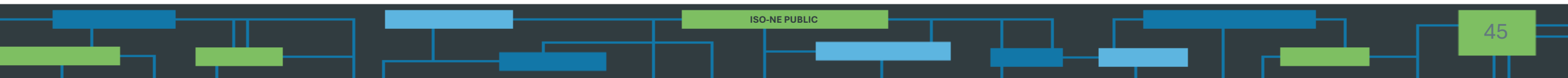
- All participating resources are expected to make priced offers
- Will allow resources to submit up to 10 price-quantity pairs
 - Increase from the five price-quantity pairs initially proposed (and used today)
 - This increased functionality was requested by stakeholders
- Numerous rules are consistent with those used today, including:
 - If a participating resource does not submit an offer, it is (generally) treated as a price taker in the auction (e.g., it is willing to sell its capacity at any price)
 - Allowance of self-supply (though timing is updated to allow maximum flexibility to use this provision)
 - Allowance of composite offers
 - Treatment of deactivating resources retained for local transmission security

Eliminate Reliability Reviews from Primary and Monthly Auctions

- The change in auction timing allows the ISO to leverage its outage coordination process as the basis for reliability reviews
 - The ISO will continue to work closely with participants to schedule outages during periods that address their needs while maintaining system reliability
 - The ISO cannot require a resource to reschedule an outage if it does not have a CSO
 - Eliminates the need for outage blackout periods
- Decoupling reliability reviews from the capacity market also allows the auctions (annual and monthly) to be held closer to the delivery period
 - Helps facilitate more participation and allows resources to use more up-to-date information
- Reliability reviews will continue for deactivation notifications that would otherwise result in the resource permanently exiting the capacity market

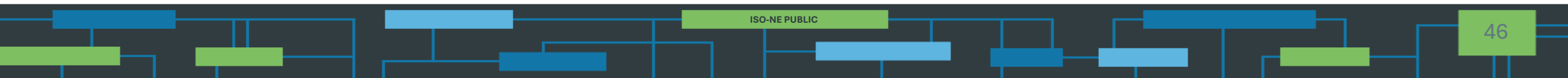
Discontinue Annual Reconfiguration Auctions

- No longer necessary with the move to a prompt auction
- The ISO understands that some participants are interested in exploring additional opportunities to trade CSO MW before the prompt auction within the commitment period
- The ISO plans to assess further as part of the post-CAR roadmap
- See [July 2025 Markets Committee](#) materials for further discussion of trading opportunities



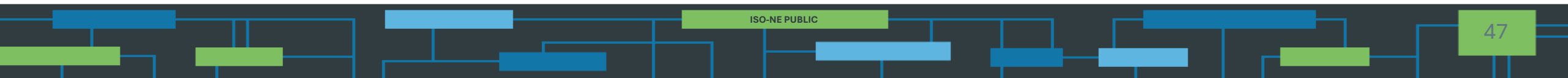
Information Publication and Filings

- Proposal continues with several FERC filings, including:
 - Market power review associated with deactivations
 - ICR and related values
- The ISO will continue to provide information regarding auction parameters and results through public postings
- Allows for a shorter pre-auction activity schedule and for the auction to be run as close to the commitment period as possible
- Helps facilitate the benefits of moving to prompt
 - Most up-to-date inputs and information used for the auction
 - Supports participation of recently commercial resources
- Will also help as the ISO moves to seasonal auctions



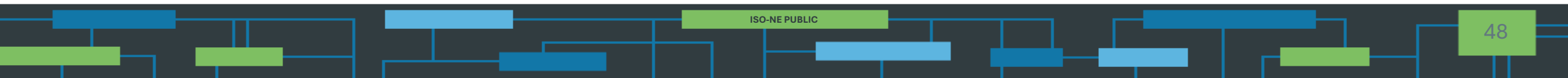
Capacity Activity Schedule

- Order No. 2023 means the interconnection process is largely separate from the capacity market
 - Resources will generally obtain CNRC before participating in the capacity auction
- Pre-auction activity schedule includes many of the same activities and processes that occur with today's 3+ year forward FCA, including:
 - Buyer-side market power review (1 to 3.5 years ahead of CCP)
 - Deactivation notifications (1 year ahead of CCP)
 - Development of ISO-administered auction demand parameters such as Net ICR, MRI-based demand curves, zonal modeling determinations (15 months to 6 months ahead of CCP)
 - Determination of ISO-administered supply parameters, including the COPT, Capacity Auction Offer Price Cap and resource qualification values (9 months to 2 months ahead of CCP)
 - Participant-submitted supply parameters, including priced supply offers, self-supply and composite offer designations (4 months to 1 month ahead of CCP)
- Prompt auction is run <1 month before the start of the CCP
- Monthly reconfiguration auctions are run ~1 week ahead of the relevant month



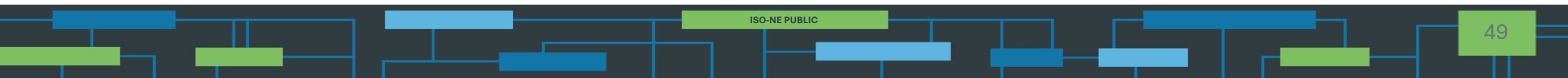
Stakeholder Feedback is Valued

- Feedback has been appreciated and has been incorporated throughout the CAR-PD process. The following examples are not an exhaustive list of contributions to the design but show the ISO's continued collaboration and openness:
 - Shortening the deactivation notification timeframe
 - Changing the market power charge for deactivations to proxy-bid treatment
 - Changing the deactivation nomenclature for ease of stakeholder reference
 - Updating buyer-side market power timeline to reflect resource development timelines
 - Continuing CPS monitoring
 - Increasing the number of price quantity pairs that can be submitted

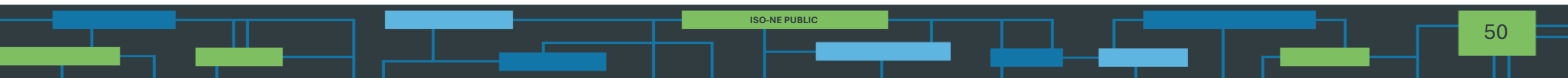


Conclusion

- The ISO is finalizing its CAR-PD proposal
- The proposal has been discussed across a number of NEPOOL meetings and has benefited greatly from thoughtful stakeholder feedback
- The proposed changes offer many benefits, including:
 - Ensures that all resources that sell capacity are commercial, thereby addressing the ‘phantom entry’ concern
 - Improves the accuracy of information used to determine auction inputs, parameters, and costs, leading to more efficient outcomes
 - Simplifies many auction participation and administration elements
 - Helps facilitate the move to seasonal markets with accreditation reforms
- These benefits are expected to facilitate the region’s transition to the future grid

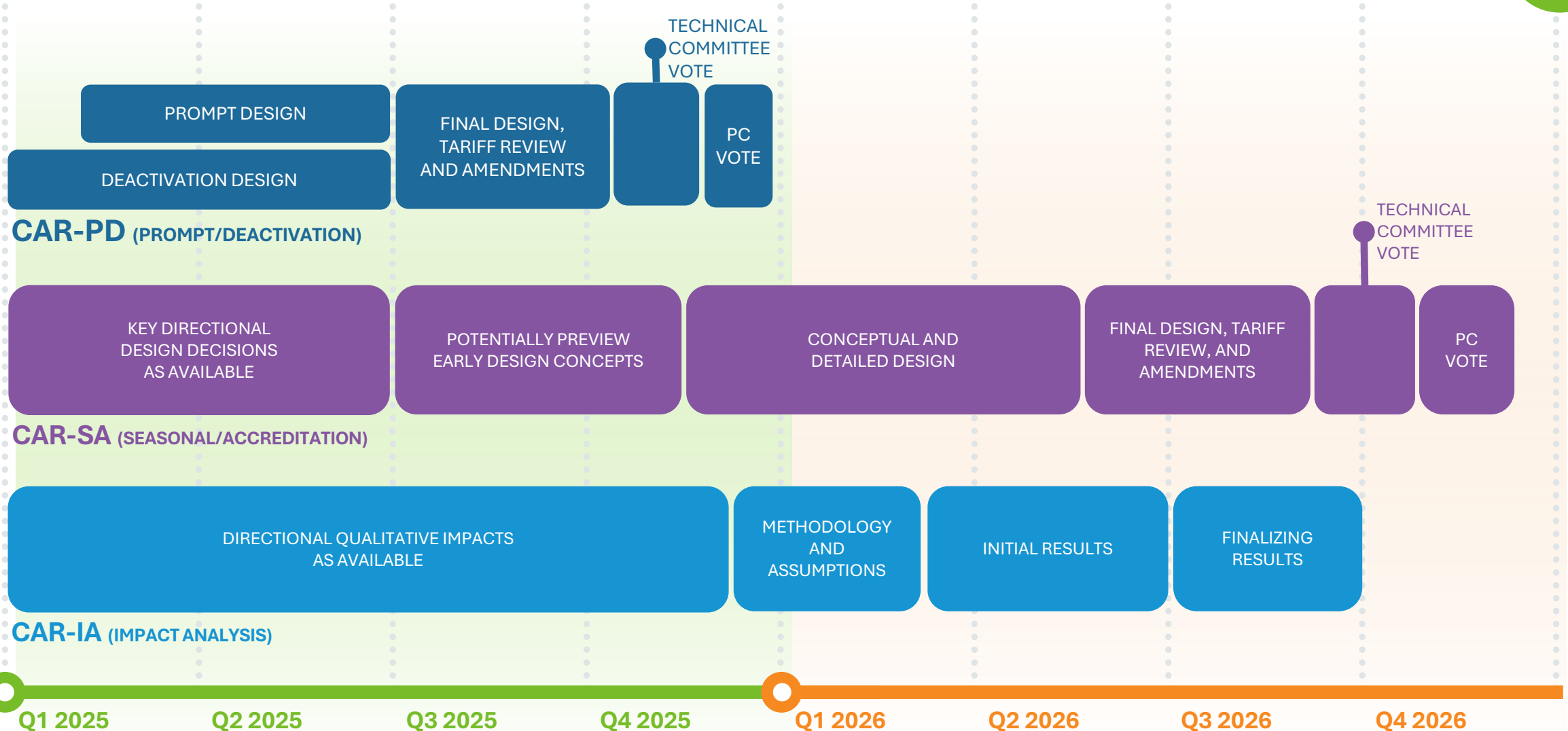


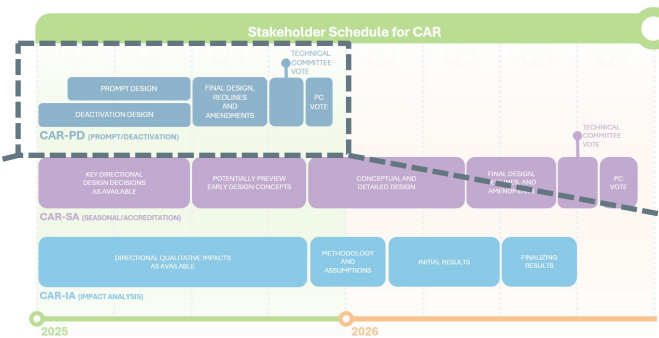
STAKEHOLDER SCHEDULE



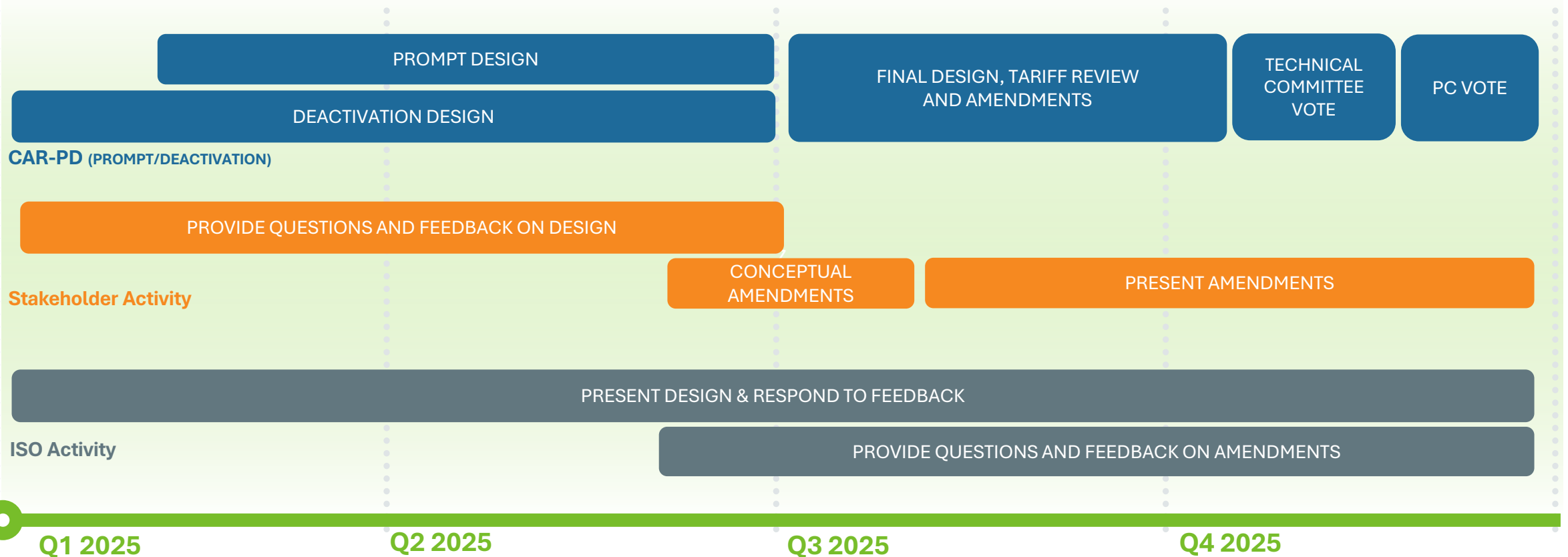
Stakeholder Schedule for CAR

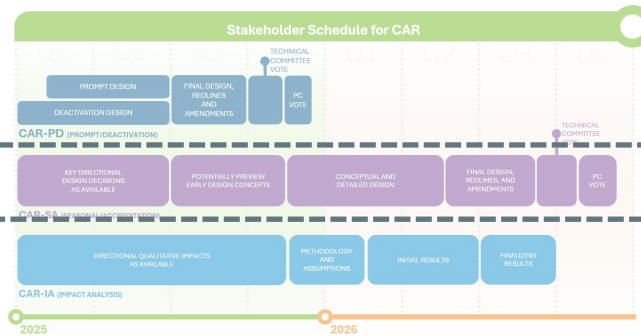
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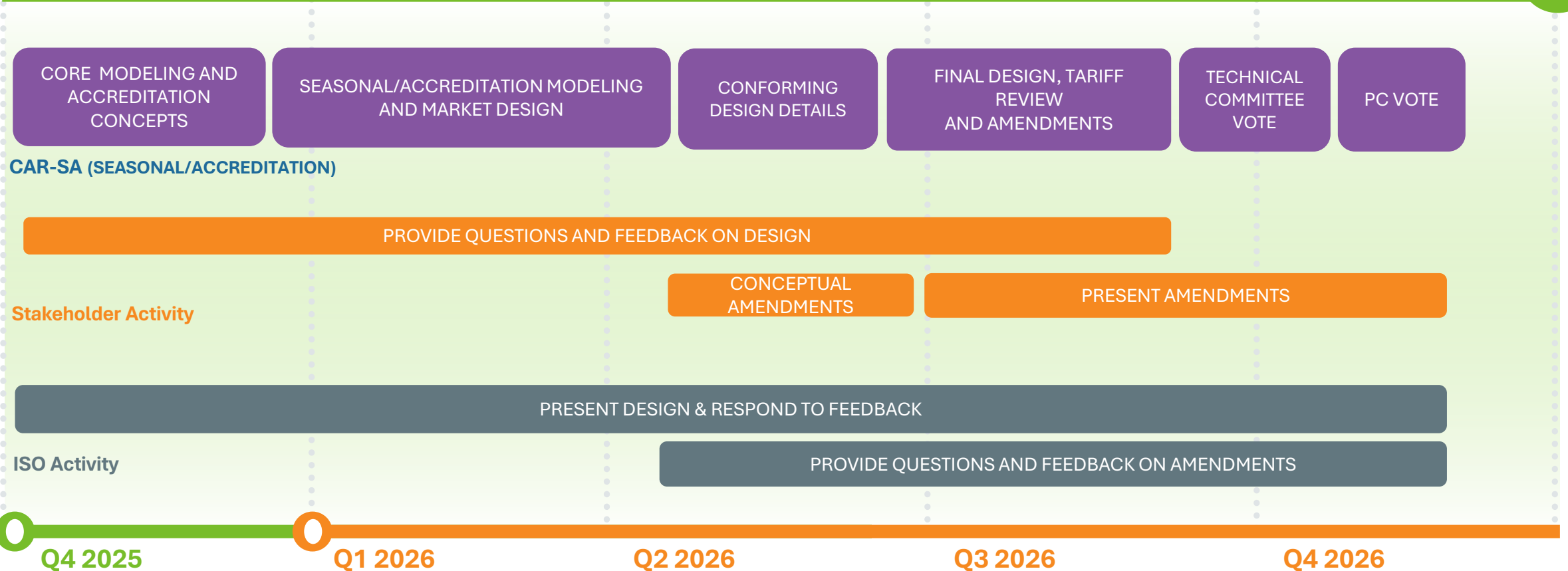


Stakeholder Schedule for CAR-PD





Stakeholder Schedule for CAR-SA



CAR-SA Schedule Projection

- **November**

- Gas Design Conceptual Introduction (MC timeframe)
- Gas Availability Study Methodology (Analysis Group) (MC timeframe)
- Energy Limited Resource Modeling and Accreditation (MC timeframe)
- Demand Response Modeling and Accreditation (RC timeframe)
- Seasonal Tie Benefits Modeling (RC timeframe)

- **December**

- Seasonal Market Design Concepts and Risk Split (MC timeframe)
- Gas Availability Study Follow-up with Analysis Group (MC timeframe)
- Gas Market Constraint Conceptual Introduction (MC timeframe)
- Overview of Impact Analysis Plan (MC timeframe)
- Energy Storage Resource Modeling and Accreditation (Includes Pumped Hydro) (RC timeframe)
- Q4 Follow-up Medley (MC timeframe)

All NEPOOL members are invited to attend meetings where CAR topics are discussed

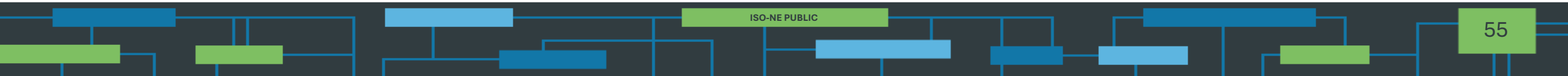
CAR-SA Preliminary Topic Schedule November and Beyond

(Continued)

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- The list below provides a projection of when core accreditation committee discussions will begin:

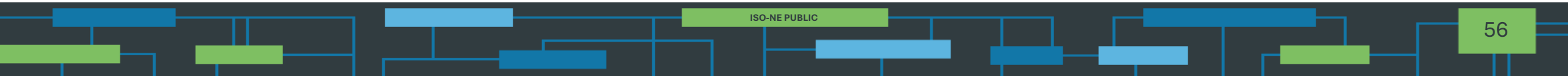
Topics	Projected Committee Discussions
Gas-only Resource Modeling and Accreditation	January – February
Development of Gas Market Constraint	January – March
Intermittent Power Resource Modeling and Accreditation (includes run-of-river hydro)	January – February



CAR-SA Preliminary Topic Schedule November and Beyond (Continued)

- The list below provides a projection of when core accreditation committee discussions will begin:

Topics	Projected Committee Discussions
Energy Limited Resource Modeling and Accreditation, Continued (Dual Fuel)	January-February
Import Resource Modeling and Accreditation	February
Modeling Deliverability: Summary of All Resource Types	February
Hybrid Resource Modeling and Accreditation	February – March

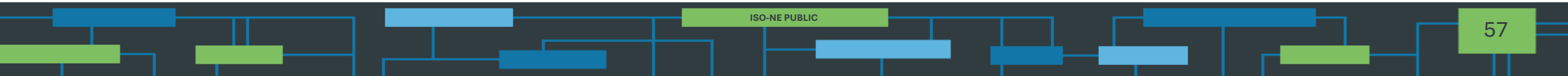


CAR-SA Preliminary Topic Schedule November and Beyond

(Continued)

- The list below provides a projection of when core accreditation committee discussions will begin:

Topics	Projected Committee Discussions
ICR and Seasonal Demand Curve Estimation	February – March
Impact Analysis Initial Results	March – June
Q1 Follow-up Medley	March
Gas-only Resource Contract Requirements	April – May



To: Participants Committee

From: Jasleen Singh, Secretary, Markets Committee

Date: November 13, 2025

Subject: Actions of the Markets Committee

This memo is notification to the Participants Committee of the following actions taken by the Markets Committee (MC) at the November 2025 MC meeting. A quorum was established.

Agenda Item No. 1.A – Approval of Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee approves the minutes for the October 15-16, 2025 Markets Committee meeting, October 15-16, 2025 Joint meeting of the Markets and Reliability Committees, October 15-16, 2025 Joint meeting of the Markets and Transmission Committees, and October 22, 2025 Joint meeting of the Reliability and Markets Committees, as circulated for the November 12-13, 2025 NEPOOL Markets Committee meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a voice vote, was approved with none opposed and one abstention (End User).

Agenda Item No. 3.1.e – Capacity Auction Reforms – Prompt/Deactivation (CAR-PD)

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends the Participants Committee support ISO-NE's proposed Capacity Auction Reforms – Prompt/Deactivation package and related revisions to: Section I.2.2, Market Rule 1, including the new Section III.15, of the Transmission, Markets, and Services Tariff, as well as, Sections II.51-54 of the Open Access Transmission Tariff (OATT), as circulated for its November 12-13th meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

Before the main motion could be voted, the following three motions were moved and seconded by the Markets Committee to amend the main motion as follows:

(Vote 1 – Failed) Agenda Item 3.1.e.i – Jericho Power Amendment – Fixed COPT price for 2028-2029 at \$4.984/kWm

RESOLVED, that the main motion be amended to reflect changes to Section III.A.22.2.1 of Market Rule 1 as contained in the materials provided by Jericho Power to rely on a fixed COPT at \$4.984/kWm for the Capacity Auction associated with Capacity Commitment Period (CCP) 2028-2029; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to amend was voted and, based on a roll call vote, failed to pass with a vote of 56.67% in favor. The individual Sector votes were Generation (16.67% in favor, 0.00% opposed, 0 abstentions), Transmission (0.00% in favor, 16.67% opposed, 1 abstention), Supplier (16.67% in favor, 0.00% opposed, 10 abstentions), Publicly Owned Entity (0.00% in favor, 16.67% opposed, 0 abstentions), Alternative Resources (16.67% in favor, 0.00% opposed, 1 abstention), and End User (6.67% in favor, 10.00% opposed, 4 abstentions).

(Vote 2 – Failed) Agenda Item 3.1.e.ii – Calpine Energy Services Amendment – Median of expected scarcity hours, at Net ICR, as basis for COPT Calculation

RESOLVED, that the main motion be amended to reflect changes to Section III.A.22.2.1 of Market Rule 1 as contained in the materials provided by Calpine Energy Services, to calculate the COPT in accordance with Calpine's derived formula as the product of the following components: (1) median (50th percentile) of expected capacity scarcity hours at Net Installed Capacity Requirement (ICR) in the corresponding study period, (2) expected balancing ratio equal to 1.0, and (3) the expected performance payment rate; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to amend was voted and, based on a roll call vote, failed to pass with a vote of 53.82% in favor. The individual Sector votes were Generation (16.67% in favor, 0.00% opposed, 0 abstentions), Transmission (0.00% in favor, 16.67% opposed, 0 abstentions), Supplier (16.67% in favor, 0.00% opposed, 9 abstentions), Publicly Owned Entity (0.00% in favor, 16.67% opposed, 0 abstentions), Alternative Resources (14.93% in favor, 1.74% opposed, 1 abstention), and End User (5.56% in favor, 11.11% opposed, 3 abstentions).

(Vote 3 – Passed) Agenda Item 3.1.e.iii – NEPGA Amendment – Retain Ambient Air De-Lists

RESOLVED, that the main motion be amended to reflect changes to Sections III.15.2 and III.A.22.2.2 of Market Rule 1 as contained in the material provided by the New England Power Generators Association, to carry forward the treatment of ambient temperature deratings in capacity auction offers; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to amend was then voted and, based on a roll call vote, passed with a vote of 83.33% in favor. The individual Sector votes were Generation (16.67% in favor, 0.00% opposed, 0 abstentions), Transmission (16.67% in favor, 0.00% opposed, 0 abstentions), Supplier (16.67%

in favor, 0.00% opposed, 8 abstentions), Publicly Owned Entity (0.00% in favor, 16.67% opposed, 0 abstentions), Alternative Resources (16.67% in favor, 0.00% opposed, 0 abstentions), and End User (16.67% in favor, 0.00% opposed, 2 abstentions).

(Vote 4 – Passed) Agenda Item 3.1.e – Once-Amended Main Motion

ACTION: RECOMMEND SUPPORT

The amended main motion was then voted and, based on a roll call vote, passed with a vote of 97.92% in favor. The individual Sector votes were Generation (16.67% in favor, 0.00% opposed, 3 abstentions), Transmission (16.67% in favor, 0.00% opposed, 0 abstentions), Supplier (14.58% in favor, 2.08% opposed, 7 abstentions), Publicly Owned Entity (16.67% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (16.67% in favor, 0.00% opposed, 0 abstentions), and End User (16.67% in favor, 0.00% opposed, 1 abstention).

11

Proposed NEPOOL Policy Statement: GIS Waiver Requests



66.67%

To consider, and take action, as appropriate, on a proposed NEPOOL Policy Statement regarding GIS Waiver Requests.

RESOLVED, that the Participants Committee hereby adopts the NEPOOL Policy Statement regarding GIS Waiver Requests 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 Participants Committee

Dec 4, 2025
Meeting

**NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING**

December 4, 2025

**FORM OF RESOLUTION
NEPOOL POLICY STATEMENT RE GIS WAIVER REQUESTS**

RESOLVED, that the Participants Committee hereby adopts the NEPOOL Policy Statement regarding GIS Waiver Requests 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 Participants Committee.

NEPOOL Policy Statement re GIS Waiver Requests

1. Purpose and Guiding Principles

The NEPOOL Generation Information System (“GIS”) issues and tracks certificates for all MWh of generation and load produced in the New England control area and for imported MWh from adjacent areas (“Certificates”). The GIS was established to provide the New England States with a reliable platform to support compliance with state renewable portfolio standard (“RPS”) and related programs, e.g., GIS issues and tracks Renewable Energy Certificates or RECs.

This Policy Statement ensures that waiver requests of the GIS Operating Rules and GIS Administration Agreement are handled in a manner that preserves market predictability and fairness while deferring to the authority of state regulatory agencies, which remain the ultimate arbiters of compliance with their respective programs.

2. NEPOOL GIS Governing Framework

The NEPOOL GIS is operated under the GIS Operating Rules (“Rules”) and the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. (“APX”) and NEPOOL, as amended and extended (the “GIS Agreement”). Under the GIS Agreement, APX serves as the NEPOOL GIS Administrator.¹

- GIS Operating Rule 1.4 and Section 4.2 of the GIS Agreement require APX to administer and operate the GIS in accordance with the GIS Operating Rules. Under these provisions, APX, as the GIS Administrator, has “the sole responsibility for the compilation, indexing, reasonable interpretation and implementation of the GIS Operating Rules.”
- Rule 2.8(a) provides that any request for an adjustment of the number of Certificates of different types or classes needs to be submitted at least five days prior to the Creation Date for those Certificates. The submission deadline is firm.

The information on Certificates can be corrected without a waiver only if they were issued erroneously because of a software error in the GIS or in the ISO-NE settlement system or because of a data entry error by APX or ISO-NE (Rule 3.8).

¹ NEPOOL’s GIS Operating Rules Working Group is responsible for discussing, exploring and recommending proposed changes to the GIS Operating Rules. In addition, NEPOOL has a GIS Usability Group that provides a forum to discuss and vet future potential improvements to the usability of the GIS.

3. Seeking Waiver of the GIS Operating Rules & GIS Agreement

Neither the GIS Rules nor the GIS Agreement between APX and NEPOOL provides APX the contractual authority to change or alter Certificates after they have been issued. As such, absent a software-related error or data entry error as described above, APX does not have the authority to correct the monthly generation data on the Certificates without both APX and NEPOOL waiving Section 4.2 of the GIS Agreement and Rule 1.4, which again requires APX to administer and operate the GIS in accordance with the Rules.

For purposes of this Policy Statement, a “GIS Waiver Request” means the request by any GIS Account Holder to waive one or more provisions of the GIS Operating Rules to permit a change to be made to any of the information on Certificates that would not otherwise be permitted under the GIS Operating Rules.

To provide relief for a GIS Waiver Request, NEPOOL would specifically need to waive applicable provisions of both the GIS Operating Rules and the GIS Agreement. As Section 13.5 of the GIS Agreement requires that any modifications to that Agreement be in writing signed by both NEPOOL and the GIS Administrator, APX would also need to agree to any waiver.

To date, no provisions of the GIS Rules or the GIS Agreement have been waived.

4. State Jurisdictional Authority

Because the NEPOOL GIS was originally created as a service to the New England states to help demonstrate compliance with their RPS requirements, it is up to each state to make determinations on whether to accept Certificates to establish compliance with their state programs.

Historically, the New England States, through their relevant regulatory authority of jurisdiction have been willing to address certain errors or omissions in Certificates, with state regulators periodically resolving GIS Certificate related issues on a case-by-case basis. In doing so, NEPOOL rarely, if ever, has been presented with a request for waiver of the GIS Rules. This process has worked in the past, and NEPOOL encourages New England state regulators to continue to resolve these issues, as appropriate, outside of the NEPOOL process.

More recently though, with one New England state regulatory body no longer willing, in the normal course, to address such issues pursuant to its jurisdictional authority, there has been a steady increase in affected GIS Account Holders seeking NEPOOL’s (and APX’s) approval of requested waivers to the GIS Rules and GIS Agreement.²

² NEPOOL does not take a position on how state regulatory authorities respond to GIS Account Holder requests or waivers. NEPOOL recognizes the burdens such requests may place on regulators. However, NEPOOL is supportive of relevant state regulatory authorities addressing Certificate-related issues/requests, as appropriate, on a case-by-case basis.

5. NEPOOL Policy Protocol(s)

As a matter of general policy and procedure, and all without prejudice as to the merits, NEPOOL will not formally consider or take action on a GIS Waiver Request.

For the avoidance of doubt, this policy protocol does not preclude the requesting party and a relevant state regulatory authority from addressing and resolving a Certificate-related issue outside of the NEPOOL process.

Effective Date: This Policy Statement is effective immediately upon adoption by the NEPOOL Participants Committee and may be updated or amended as needed.

NEPOOL Policy Statement re GIS Waiver Requests

1. Purpose and Guiding Principles

The NEPOOL Generation Information System (“GIS”) issues and tracks certificates for all MWh of generation and load produced in the New England control area and for imported MWh from adjacent areas (“Certificates”). The GIS was established to provide the New England States with a reliable platform to support compliance with state renewable portfolio standard (“RPS”) and related programs, e.g., GIS issues and tracks Renewable Energy Certificates or RECs.

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Historically, the New England States, through their relevant regulatory authority of jurisdiction have been willing to address certain errors or omissions in Certificates, with state regulators periodically resolving GIS Certificate related issues on a case-by-case basis. In doing so, NEPOOL rarely, if ever, has been presented with a request for waiver of the GIS Rules. This process has worked in the past, and NEPOOL encourages New England state regulators to continue to resolve these issues, as appropriate, outside of the NEPOOL process.

More recently though, with one New England state regulatory body no longer willing, in the normal course, to address such issues pursuant to its jurisdictional authority, there has been a steady increase in affected GIS Account Holders seeking NEPOOL’s (and APX’s) approval of requested waivers to the GIS Rules and GIS Agreement.²

² NEPOOL does not take a position on how state regulatory authorities respond to GIS Account Holder requests or waivers. NEPOOL recognizes the burdens such requests may place on regulators. However, NEPOOL is supportive of relevant state regulatory authorities addressing Certificate-related issues/requests, as appropriate, on a case-by-case basis.

5. NEPOOL Policy Protocol(s)

As a matter of general policy and procedure, and all without prejudice as to the merits, NEPOOL will not ~~consider a GIS Waiver Request until the requesting party first seeks relief and receives a determination from the relevant regulatory body with appropriate jurisdiction over its state compliance program(s) for which the GIS Waiver Request is made. Furthermore, when such determination is made by the state regulator(s), NEPOOL will not~~ formally consider ~~nor~~or take action on a GIS Waiver Request ~~unless and until the regulator has expressly indicated support for NEPOOL's review and consideration. Put simply, NEPOOL will not consider a request for waiver of the GIS Rules and/or GIS Agreement without explicit state support from a relevant state regulatory authority with jurisdiction over the applicable compliance program for its state.~~

~~This~~For the avoidance of doubt, this policy protocol does not preclude the requesting party and a relevant state regulatory authority ~~to address~~from addressing and resolving a Certificate-related issue outside of the NEPOOL process.

Effective Date: This Policy Statement is effective immediately upon adoption by the NEPOOL Participants Committee and may be updated or amended as needed.

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Litigation Report



Dec 4, 2025
Meeting

EXECUTIVE SUMMARY

Status Report of Current Regulatory and Legal Proceedings as of December 3, 2025

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated November 5, 2025 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

Executive Orders

*	1	Launching the Genesis Mission (EO 14363)	Nov 24	DOE directed to create an AI experimentation platform to transform scientific research and discovery

I. Complaints/Section 206 Proceedings

*	5	PSNH X-178 Powerline Rebuild Asset Condition Project Complaint (EL26-27)	Nov 17	Individual Complainants (Kristina Pastoriza and Ruth Ward) request that the FERC conduct an objective expert third-party investigation of the Eversource X-178 project; comment deadline Dec 8, 2025
	5	BP Phantom Load Complaint (EL26-5)	Nov 10	BP submits Answer and does not oppose Eversource's request for extension of time to Dec 12, 2025 to answer Complaint
			Nov 12	FERC grants request for extension to Dec 12, 2025 for the filing of answers, interventions, comments, and protests to the Complaint
	6	Local Transmission Planning Complaint (EL25-44)	Nov 11	Industrial Energy Consumers of America submitted comments to rebut utilities' opposition to transmission development

II. Rate, ICR, FCA, Cost Recovery Filings

*	12	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER26-578)	Nov 21	ISO-NE and NEPOOL jointly file ICR-Related Values and HQICCs for 2026/27 ARA3 and 2027/28 ARA2; comment deadline Dec 12, 2025
			Dec 1	National Grid intervenes
*	12	CIP-IROL Rate Schedule Filing: FPL Wyman IV (ER26-577)	Nov 21	FPL Wyman files Rate Schedule; comment deadline Dec 12, 2025
*	12	CIP-IROL Cost Recovery Filing: Canal (ER26-517)	Nov 14	Canal requests recovery of \$1,075,392 in CIP-IROL Costs incurred between Apr 1, 2024 and Mar 31, 2025
			Nov 26	Canal files corrected Rate Schedule; comment deadline Dec 17, 2025
			Dec 1	National Grid intervenes
	14	PBOP Collections Report (Eversource) (ER26-58)	Nov 25	FERC accepts collections report, eff. Dec 8, 2025

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

	15	Order 2222 Conforming Changes (ER26-105)	Nov 18	ISO-NE files an errata to correct the Order 2222 Conforming Changes effective date from Dec 31, 2025 to Nov 1, 2026

IV. OATT Amendments / TOAs / Coordination Agreements

*	16	Order 898 Compliance Revisions (ER26-439)	Nov 6	PTO AC submits proposed revisions to the formula rate in response to the requirements of Order 898

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes & Agreements

17	Schedule 21-RIE: Block Island Wind Farm Facilities Reclassification (ER26-397)	Nov 18	RI Division intervenes

VII. NEPOOL Agreement/Participants Agreement Amendments*No Activity to Report***VIII. Regional Reports**

18	Capital Projects Report – 2025 Q3 (ER26-152)	Nov 18	FERC accepts 2025 Q3 Report, eff. <i>Oct 1, 2025</i>
* 18	IMM Quarterly Markets Reports: Summer 2025 (ZZ25-4)	Nov 12	IMM files Summer 2025 Report
* 18	ISO-NE 2025 Q3 FERC Form Q3 (not docketed)	Nov 20	ISO-NE submits its 2025 Q3 FERC Form Q3

IX. Membership Filings

* 19	Dec 2025 Membership Filing (ER26-617)	Nov 26	New Member: The Energy Authority; Name Changes: Long Island Power Authority (f/k/a Long Island Lighting Company d/b/a LIPA) and Lighthouse Naugatuck, LLC (f/k/a Naugatuck Avenue Storage LLC); comment deadline Dec 17, 2025
19	Oct 2025 Membership Filing (ER25-3571)	Nov 28	FERC accepts (i) the memberships AE-ESS Holyoke, LLC; American Power & Gas of RI, LLC; and Burgess BioPower; and (ii) the termination of the Participant status of Hudson Energy Services
* 19	Suspension Notice – Phillips 66 Energy Trading (not docketed)	Nov 19	ISO-NE files notice of <i>Nov 17, 2025</i> suspension of Phillips 66 Energy Trading from the New England Markets

X. Misc. - ERO Rules, Filings; Reliability Standards

* 20	Revised Reliability Standard: MOD-026-2 (RD26-3)	Nov 4	NERC files proposed Reliability Standard MOD-26-2; comment deadline Dec 8, 2025
		Nov 18	Calpine intervenes
* 20	Revised Reliability Standard: MOD-033-3 (RD26-2)	Nov 4	NERC files proposed Reliability Standard MOD-033-3; comment deadline Dec 8, 2025
		Nov 18	Calpine intervenes
21	NOPR: Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization) (RM24-8)	Nov 21-24	BPA, EEI, GE Vernova, MISO, NERC, Portland General Electric file comments

XI. Misc. - of Regional Interest

23	203 Application: CPower/NRG (EC25-102)	Nov 14	FERC authorizes NRG's indirect acquisition of the membership interests in Enerwise Global Technologies, LLC d/b/a CPower
23	203 Application: Constellation/ Calpine (EC25-43)	Nov 21	PA OCA petitions DC Circuit for review of <i>Merger Order</i> and <i>Constellation Merger Order Allegheny Notice</i>
24	PURPA Enforcement Petition – Allco Finance Ltd (EL25-117)	Nov 21	FERC issues a notice of its intent not to initiate an enforcement action in response to Allco's Complaint regarding CT DEEP's implementation of PURPA section 210

* 24	Wholesale Distribution Tariff – Versant (II) (ER26-528)	Nov 17	Versant files a revised WDT, responding to FERC concerns expressed in the FERC order rejecting an earlier proposed WDT; comment deadline Dec 8, 2025
24	Facilities (Distrigas) Support Agreement Cancellation - NSTAR/National Grid (ER25-3550)	Nov 24	FERC accepts cancellation, eff. <i>Sep 30, 2025</i>

XII. Misc. - Administrative & Rulemaking Proceedings

25	Tech Conf: Wildfire Risk Mitigation (AD25-16)	Nov 20-24 Dec 1	Post-tech conf comments filed by several organizations and entities Tech conf transcript posted in eLibrary
26	Annual Reliability Tech Conf (AD25-8)	Nov 24 Dec 1	Constellation submits post-tech conf comments Tech conf transcript posted in eLibrary
26	Joint Federal-State Current Issues Collaborative (AD24-7)	Nov 5	FERC postpones meeting of the Collaborative (previously set for Nov 12, 2025 in Seattle) to Feb 26, 2026 in Washington, DC
27	2025-2026 Winter Energy Market and Electric Reliability Assessment Staff Report (AD06-3)	Nov 25	FERC Staff issues 2025-26 Winter Energy Market Report
27	Proposed Policy Statement: Waiver of Tariff Requirements (PL20-7)	Nov 20	FERC withdraws Proposed Policy Statement; terminates proceeding
28	ANOPR: Interconnection of Large Loads to the Interstate Transmission System (RM26-4)	Nov 4 Nov 13 Nov 21	NESCOE supports Org. of MISO states (OMS) request of a 2-week extension of time, until Nov 28, to submit initial comments U.S. Senators file comments Comments filed by ISO-NE, NESCOE, and many others
28	Order 914: Implementation of EO 14270 (RM25-14)	Nov 17-20	Comments filed by several organizations/individuals
29	NOPR: Duty of Candor (RM22-20)	Nov 20	FERC withdraws <i>Duty of Candor NOPR</i> ; terminates proceeding

XIII. FERC Enforcement Proceedings

* 30	2025 OE Staff Enforcement Report (AD07-13-009)	Nov 20	FERC Staff issues 2025 Enforcement Report
Electric-Related Enforcement Actions			
30	American Efficient Show Cause Order (IN24-2)	Nov 24	FERC's OERA Litigation Staff replies to American Efficient's Nov 3 motion

XIV. Natural Gas Proceedings

32	Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)	Nov 13 Nov 20	FERC issues data request Algonquin submits response to Nov 13 data request
32	Order 915: Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing (RM25-9)	Nov 6	NRDC requests rehearing of <i>Order 915</i>

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts



34	<i>Order 904: Compensation for Reactive Power Within the Standard Power Factor Range (5th Circuit – 25-60055 et al.) (consolidated)</i>	Nov 18	Briefing schedule established following the filing of a certified list in lieu of the administrative record
36	<i>Avangrid v. NextEra (NECEC Civil Suit) (D.MA 24-30141)</i>		A hearing on NextEra’s motion to dismiss the State Law Claims set for Dec 18, 2025
36	Allco PURPA Enforcement Petition (D.CT 3:25CV01321)	Nov 24	Defendants and CT Commissioners file a motion to dismiss the Complaint and stay discovery; Responses due on or before Dec 15, 2025

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: December 3, 2025

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 December 3, 2025. 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

Questions concerning any of the Executive Orders (“EO”) or Agency Directives summarized below can be directed to Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Joan Bosma (617-345-4651; jbosma@daypitney.com).

- **Executive Order: Launching the Genesis Mission (EO 14363)**

On November 24, 2025, President Trump issued an Executive Order (“EO”) launching the “Genesis Mission.” The EO directs the Department of Energy (“DOE”) to create an integrated Artificial Intelligence (“AI”) and high-performance computing platform to accelerate scientific discovery and advance national, economic, and energy security. The DOE Secretary must establish and operate the American Science and Security Platform, leveraging DOE supercomputers, secure cloud AI environments, and Federal scientific datasets to train scientific foundation models and deploy AI agents for automated experimentation. On or before **January 23, 2026**, DOE must identify and submit at least 20 national science and technology challenges spanning priority domains such as advanced manufacturing, biotechnology, critical materials, nuclear fission and fusion energy, quantum information science, and semiconductors and microelectronics. On or before **February 22, 2026**, the DOE Secretary must inventory Federal and industry computing, storage, and networking resources available to support the Genesis Mission. On or before **March 24, 2026**, the DOE must identify initial data and model assets and develop a cybersecurity-informed plan to incorporate datasets from other agencies, federally funded research, academia, and approved private partners. On or before **July 22, 2026**, the DOE must review robotic and AI-directed experimentation capabilities across the national labs. And, on or before **August 21, 2026**, the DOE must demonstrate an initial operating capability of the Platform for at least one of the identified national challenges. The EO also requires the DOE Secretary to report on the Platform’s operational status to the President within one year and annually thereafter.

- **Revolution Wind Stop-Work Order**

On August 22, 2025, the Department of the Interior’s Bureau of Ocean Energy Management (“BOEM”) issued a [Director’s Order](#) (“Stop-Work Order”) to Revolution Wind, LLC to halt all ongoing activities related to the Revolution Wind Project to allow BOEM to “address concerns that have arisen during the review that the

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”).

Department is undertaking pursuant to the President's Memorandum of January 20, 2025".² In response, the Rhode Island and Connecticut Attorney Generals filed suit against the Trump Administration requesting an injunction on the basis that the federal government arbitrarily reversed course. On September 22, 2025, a DC District Court judge granted a preliminary injunction, allowing construction to resume while the lawsuit against the government proceeds. The project is about 80% built and remains targeted for commercial operation in 2026.³

- **Executive Order: Accelerating Federal Permitting of Data Center Infrastructure (EO 14318)**

On July 23, 2025, President Trump issued an EO to facilitate "the rapid and efficient buildout" of AI data centers and associated infrastructure. The EO directs the Secretary of Commerce to launch an initiative to provide financial support for "Qualifying Projects," which are defined as data centers and related infrastructure that require over 100 MW of incremental electric load, a commitment of \$500 million or more in capital expenditures, or are otherwise designated as such. All relevant agencies were directed to identify existing National Environmental Policy Act ("NEPA") categorical exclusions that could facilitate the construction of Qualifying Projects to the Council on Environmental Quality within 10 days; the EO also establishes a presumption that federal financial assistance that is less than half of the total project cost does not constitute a "major Federal action" under NEPA. The Environmental Protection Agency ("EPA") is tasked with reviewing and revising permitting regulations under the Clean Air Act, Clean Water Act ("CWA"), and other laws to streamline approval processes, and must issue guidance to support the reuse of Superfund and Brownfield sites for data centers by **January 19, 2026**. And, the Army must assess whether a new nationwide permit is necessary under the CWA or Rivers and Harbors Appropriation Act to facilitate the efficient permitting of Qualifying Projects. Additionally, the EO instructs the Departments of the Interior, Energy, and Defense to identify and authorize federal and military lands for qualifying development, including streamlined consultations under the Endangered Species Act for construction of Qualifying Projects over the next 10 years and competitively leasing sites for data centers. The EO also mandates FAST-41 transparency project designation and permitting dashboard integration by August 22, 2025.

- **Executive Order: Ending Market Distorting Subsidies for Unreliable, Foreign Controlled Energy Sources (EO 14315)**

On July 7, 2025, following the recent signing of the One Big Beautiful Bill Act ("OBBA"), President Trump issued an EO directing the Secretary of the Treasury to implement provisions of the OBBA 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 OBBA's termination of Sections 45Y and 48E tax credits, including restricting safe harbor provisions and "beginning of construction" standards. The Treasury is also directed to implement the OBBA's enhanced Foreign Entity of Concern ("FEOC") restrictions.

- **Executive Order: Empowering Commonsense Wildfire Prevention and Response (EO 14308)**

On June 12, 2025, President Trump issued an EO to consolidate wildfire programs, develop a technology roadmap, and revise rules to enable more effective wildfire prevention and response through the use of prescribed burns, improved power system practices, and modernized response metrics and satellite data. As it relates to the FERC, the EO directed the FERC to consider by September 15, 2025 rulemakings to establish best practices to reduce wildfire ignition risk from the bulk-power system ("BPS") without increasing end-user costs. As summarized in Section XII below (AD25-16), the FERC issued on September 10, 2025 a notice of an October 21, 2025 Staff-led technical conference on wildfire mitigation, including cost-effective best practices to reduce the risk of wildfire ignition from the BPS.

² 90 Fed. Reg. 8,363 (Jan. 29, 2025).

³ The current timeline for completion of the Revolution Wind project is available at: <https://revolution-wind.com/construction-updates#3>.

- **Executive Order: Reinvigorating the Nuclear Industrial Base (EO 14302)**

On May 23, 2025, President Trump issued an EO directing the U.S. Department of Energy (“DOE”) to accelerate the growth of the U.S. nuclear sector. EO 14302 specifically directs the DOE to facilitate 5 GW of power uprates to existing reactors and the start of construction on ten new large reactors **by 2030**. The DOE Loan Programs Office is directed to prioritize projects including restarts, uprates, new construction, and fuel supply chain improvements. The DOE and the Department of Defense (“DoD”) are to assess the use of closed nuclear sites for military energy hubs. EO 14302 also requests a report and sets timelines for action on nuclear fuel recycling, enrichment, and cooperative procurement, including near-term use of Defense Production Act authorities.

- **Executive Order: Reforming Nuclear Reactor Testing at the Department of Energy (EO 14301)**

Also on May 23, 2025, President Trump issued EO 14301 mandating the DOE revise NEPA regulations by June 30, 2025 to streamline environmental reviews for reactor testing through new or existing categorical exclusions. EO 14301 also directs the DOE to issue guidance on “qualified test reactors” and establish a pilot program for at least three test reactors outside the National Laboratories by **July 4, 2026**.

- **Executive Order: Ordering the Reform of the Nuclear Regulatory Commission (EO 14300)**

Also on May 23, 2025, President Trump issued EO 14300 directing the Nuclear Regulatory Commission (“NRC”) to overhaul its licensing and fee structures to expedite approvals. EO 14300 specifically mandates final decisions on applications for new reactors within 18 months, and for continued operation of existing reactors within one year, with caps on hourly fee recovery. EO 14300 also directs the NRC to streamline approval of reactor designs already tested and demonstrated by the DOE or DoD, so to focus reviews only on new application-specific risks.

- **Executive Order: Deploying Advanced Nuclear Reactor Technologies for National Security (EO 14299)**

President Trump issued yet another Executive Order on May 23, 2025 directing the DOE, DOD, and the Secretary of State to accelerate the deployment and export of advanced nuclear reactor technologies to meet national security objectives and support rapid growth of advanced nuclear technologies. EO 14299 requires the DOE to designate AI data centers at DOE sites as critical defense infrastructure and to select sites within 90 days for deployment of advanced nuclear reactors to support AI and other national security missions, with the first reactor to be operational within 30 months. The DoD must also commence operation of a nuclear reactor at a domestic military installation by no later than **September 30, 2028**. EO 14299 also directs the Secretary of State to pursue at least 20 new section 123 of the Atomic Energy Act of 1954 Agreements for Peaceful Nuclear Cooperation by the close of the 120th Congress and requires the DOE to review and act on export authorization requests within 30 days of completion.

- **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 Federal Power Act (“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. (see Section XII below).

- **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 FERC is not directly tasked under EO 14262, implementation of its provisions may influence FERC-jurisdictional processes.

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.⁴ Overall highlights of 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, Clean Energy Organizations,⁵ 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.”⁶ Clean Energy Organizations request that DOE “withdraw the Resource Adequacy Protocol or otherwise address the errors contained in it.”

- **Executive Order: Reinvigorating America's Beautiful Clean Coal Industry and Amending EO 14241 (EO 14261)**

Also on April 8, 2025, President Trump issued an EO that (i) reclassifies Coal as a Strategic National Asset (granting coal eligibility for federal support programs, including those under the Defense Production Act and DOE’s loan authorities, and directing a review of policies that may discourage coal production, with agencies tasked to revise or rescind such policies within 60 days); (ii) accelerates coal access on federal lands (directing federal agencies to identify coal-rich areas on federal lands, address barriers to mining on federal lands and propose actions to maximize coal mining on federal lands, and prioritize coal leasing and encourage the use of emergency authorities to expedite permitting and environmental reviews, including a push for broader use of categorical

⁴ 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.

⁵ “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”).

⁶ 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.

exclusions under NEPA. The assessment requires an analysis of the impact the use of coal resources could have on electricity costs and grid reliability); and (iii) aligns coal with emerging industrial needs (positioning coal as a critical resource for emerging industries, directing agencies to assess its potential for powering AI data centers and supporting steelmaking, and calling for accelerated development of coal technologies and commercial applications in advanced manufacturing).

- **Executive Order: Protecting American Energy From State Overreach (EO 14260)**

On April 8, 2025, President Trump issued an EO directing the U.S. Attorney General to identify and challenge state and local laws, regulations, and policies that may act as “illegitimate impediments” to the development, siting, production, investment in, or use of domestic energy resources, and further instructs the Attorney General to stop the enforcement of these state climate-related policies. While the EO does not directly implicate FERC, it may affect regional efforts such as the Regional Greenhouse Gas Initiative (“RGGI”) and other state-led programs. A report detailing the Attorney General’s actions and recommended executive or legislative responses was due to the President within 60 days.

I. Complaints/Section 206 Proceedings

- **PSNH X-178 Powerline Rebuild Asset Condition Project Complaint (EL26-27)**

On November 14, 2025, individual complainants, Kristina Pastoriza and Ruth Ward,⁷ filed a complaint requesting that the FERC open an investigation into the Public Service Company of New Hampshire’s (Eversource) \$400 million proposed rebuild of the X-178 115 kV transmission line from Beebe River to Whitefield, NH (approximately 49 miles, including a 12.4-mile segment in the White Mountain National Forest). The Complaint requests that the FERC direct an objective expert third-party investigation into (i) the need for the project (Physical Condition, Current Demand, Projected Load, Reliability and Safety), (ii) the prudence of sunk and projected costs, and (iii) the accounting basis of the formula rate charges, and (iv) if the resulting rates are just and reasonable and not unduly discriminatory. The Complaint asserts that ISO-NE treated the project as an “asset condition” rebuild outside the ISO-NE *Order 890/1000* planning process, and it notes related pending approvals before the New Hampshire Site Evaluation Committee and the U.S. Department of Agriculture Forest Service. Comments are due on or before **December 8, 2025**. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@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. On November 10, 2025, BP filed an answer in which it did not oppose a November 4, 2025 Eversource request for a 29-day extension of time to respond to the Complaint. On November 12, 2025, the FERC granted an extension of time, to on or before **December 12, 2025**, to file answers, intervention comments, or protests to the Complaint. Thus far, Calpine, National Grid, the Retail Energy Supply Association (“RESA”), Public Citizen, and NRG have intervened doc-lessly. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **NEPGA Balancing Ratio and Stop Loss Allocation Methodology Complaint (EL25-106)**

As previously reported, on July 25, 2025, NEPGA filed a complaint in response to the impacts of the events of June 24, 2025, seeking (i) a Balancing Ratio cap at 1.0; and (ii) a revised allocation of the “bonus pool” that gets collected to pay over-performers. In the Complaint, NEPGA proposed, pointing to precedent established in PJM, that the FERC (a) cap the Balancing Ratio at 1.0 and (b) adopt the PJM charge and bonus allocation (instead of charging resources with a Capacity Supply Obligation to make up any bonus revenue shortfall, simply split the

⁷ Kristina Pastoriza is an owner of the property and lives on the property, and Ruth Ward is an owner of the property and is an Eversource retail electricity customer.

bonus pool that gets collected to pay over-performers). NEPGA asked that the FERC set an immediate refund effective date and requested fast track processing of the Complaint.

On August 21, 2025, ISO-NE filed its answer, requesting (i) with respect to the PFP stop-loss mechanism cost allocation, the FERC deny the Complaint on the merits; (ii) with respect to the Balancing Ratio, the FERC “take account of ISO-NE’s arguments and narrow concession”, and (iii) provide at least 180 days to file any replacement rate deemed necessary as a result of the Complaint. NEPOOL filed limited comments to provide additional context but taking no substantive position on the Complaint. Comments supporting the Complaint were filed by MMWEC, FirstLight Power, RENEW, LS Power Development, Electric Power Supply Association (“EPSA”), and jointly by Braintree and Taunton. Comments on the Complaint were also filed by NESCOE and the New England Consumer Advocates (“CANE”).⁸ Vitol filed a protest requesting the FERC deny the Complaint. Interventions only were filed by the IMM, AEU, Avangrid (out-of-time), Brookfield, Calpine, CPV Towantic, Dominion, Energy New England (“ENE”), Enel, Eversource, LS Power, ME OPA, National Grid, NextEra, RI Energy, Shell, Vistra, MA DPU, the National Hydropower Association (“NHA”), and Public Citizen.

The following parties filed answers: **ISO-NE** ((i) answering NEPGA’s second answer, reiterating that, while it would not oppose a FERC order capping the Balancing Ratio at 1.0, it continued to oppose NEPGA’s position that the current stop-loss cost allocation approach is unjust and unreasonable and opposes adopting PJM’s general stop loss approach; and (ii) and asserting that FirstLight’s alternative requests for relief are outside the scope of this proceeding); **NEPGA** (emphasizing broad support for the Complaint, reiterating its argument that holding capacity resources to obligations beyond their committed capability is unjust and unreasonable, and urging the FERC to adopt PJM’s allocation methodology as the replacement rate); **the IMM** (expressing sympathy with NEPGA’s complaint, supporting a 1.0 cap on the Balancing Ratio, and requesting clarification as to how related payments would be allocated); **RENEW** (supporting NEPGA’s proposed reforms to ISO-NE’s PFP cost allocation rules); and **Vitol** (opposing NEPGA’s second answer and requesting that the FERC deny the Complaint, stating that the reforms should be addressed through the stakeholder process).

The Complaint remains pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Local Transmission Planning Complaint (EL25-44)**

As previously reported, a group of “Consumer Complainants”⁹ filed a complaint almost one year ago, on December 19, 2024, against all FERC-jurisdictional public utility transmission providers with local planning tariffs (including ISO-NE and the remaining ISO/RTOs) asserting that their 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

⁸ The New England Consumer Advocates or “CANE” consist of the: Massachusetts Attorney General’s Office (“MA AG”), Connecticut Office of Consumer Counsel (“CT OCC”), Maine Office of the Public Advocate (“ME OPA”), New Hampshire Office of the Consumer Advocate (“NH OCA”), and Rhode Island Division of Public Utilities and Carriers (“RI Division”).

⁹ “Consumer Complainants” are Industrial Energy Consumers of America, 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.

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”),¹⁰ [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](#),¹¹ 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”¹² and on July 25, 2025 [ATC](#) answered Complainants April 24, 2025 answer. Since the last Report, the [Industrial Energy Consumers of America](#) submitted comments rebutting utilities’ opposition to competitive transmission development. 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 was no activity in this proceeding since the last Report. As noted, 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).

¹⁰ 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 Power (“Versant”).

¹¹ “Public Interest Organizations” or “PIOs” are Earthjustice, Natural Resources Defense Council (“NRDC”), Sustainable FERC Project, and the Southern Environmental Law Center.

¹² 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 Company and Kentucky Utilities Company (together, “LG&E/KU”), Tampa Electric Company (“TEC”), Florida Power and Light (“FPL”), and Alabama Power Company, Georgia Power Company, and Mississippi Power Company.

- **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).¹³ 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.¹⁴ 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.¹⁵ 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.¹⁶ The refund effective date for this proceeding is June 24, 2024.¹⁷ A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and was reviewed with, the Transmission Committee.

Interventions were due on or before July 5, 2024 and were filed by the following New England-related parties:¹⁸ 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*¹⁹ 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”)²⁰ 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](#)

¹³ *ISO New England Inc. et al.*, 187 FERC ¶ 61,170 (June 13, 2024) (“*TO Initial Funding Show Cause Order*”).

¹⁴ *Id.* at P 1.

¹⁵ *Id.*

¹⁶ *Id.* at P 2.

¹⁷ Notice of this 206 proceeding was published in the *Fed. Reg.* on June 24, 2024 (Vol. 89, No. 121) pp. 52,454-52,455.

¹⁸ 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).

¹⁹ 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.

²⁰ The NETOs, for purposes of this proceeding, are: Eversource; Central Maine Power Company (“CMP”); The United Illuminating Company (“UI”); New England Power Company (“National Grid”); The Narragansett Electric Company (“RI Energy”); Fitchburg Gas and Electric Light Co. (“Unitil”); and Versant Power (“Versant”).

[Organizations](#), [Public Systems](#), [Clean Energy Associations](#), [EEL](#), [WIRES](#), and the [Harvard Law Initiative](#). Since the last Report, the 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 parties²¹ 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)**

There are four proceedings, long pending before the FERC, in which the TOs' return on equity ("Base ROE") for regional transmission service has been challenged.

- **Base ROE Complaint I (EL11-66).** In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,²² set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).²³ However, the FERC's orders were challenged, and in *Emera Maine*,²⁴ the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.
- **Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated).** The second (EL13-33)²⁵ and third (EL14-86)²⁶ ROE complaint proceedings were consolidated for purposes of hearing and

²¹ 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. Svc. Co. LLC, Xcel Energy Services Inc., Northern States Power Co., a MN Corp., Northern States Power Co., a WI Corp., and Southwestern Pub. Svc. Co. ("8th Circuit Parties").

²² The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarif.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*").

²³ *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

²⁴ *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

²⁵ The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% ROE, and seeks a reduction of the Base ROE to 8.7%.

²⁶ The 2014 Base ROE Complaint, filed July 31, 2014 by the MA AG, together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.²⁷ The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- **Base ROE Complaint IV (EL16-64).** The fourth and final ROE proceeding²⁸ also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.²⁹ The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was **not** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.³⁰ Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine*, proposed a new methodology for determining whether an existing ROE remains just and reasonable.³¹ The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see, however, Opinion 569-A*³² (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.³³

At highest level, the new methodology will determine whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA Section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA Section 206. In determining whether an existing ROE is unjust and under the first prong of Section 206, the FERC stated that it will determine a "composite" zone of reasonableness based

²⁷ *Environment Northeast v. Bangor Hydro-Elec. Co. and Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 154 FERC ¶ 63,024 (Mar. 22, 2016) ("2012/14 ROE Initial Decision").

²⁸ The 4th ROE Complaint asked the FERC to reduce the TOS' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("Base ROE Complaint IV Order"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "Base ROE Complaint IV Orders"). The *Base ROE Complaint IV Orders*, as described in Section XVI below, have been appealed to, and are pending before, the DC Circuit.

²⁹ *Belmont Mun. Light Dept. v. Central Maine Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("Base ROE Complaint IV Initial Decision").

³⁰ *Id.* at P 2.; Finding of Fact (B).

³¹ *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("Order Directing Briefs" or "Coakley").

³² *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("Opinion 569-A"). The refinements to the FERC's ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

³³ *Id.* at P 19.

on the results of three models: the Discounted Cash Flow (“DCF”), Capital Asset Pricing Model (“CAPM”), and Expected Earnings models. Within that composite zone, a smaller, “presumptively reasonable” zone will be established. Absent additional evidence to the contrary, if the utility's existing ROE falls within the presumptively reasonable zone, it is not unjust and unreasonable. Changes in capital market conditions since the existing ROE was established may be considered in assessing whether the ROE is unjust and unreasonable.

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.³⁴ The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers³⁵ for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute (“EEI”), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs’ January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*³⁶ and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and Complainant-Aligned Parties (“CAPs”) opposed the TOs’ request and brief. No action was ever taken in response to this activity.

Nov 2023 Supplemental Brief. As reported at the December 5, 2024 Annual Meeting, the TOs filed, on November 13, 2024, a [“Motion to File Supplemental Brief Addressing the Inability of the \[FERC\]’s MISO Methodology to Satisfy the Mandate of the *Emera Maine* Court in these Cases, the Requirements of Section 206, and the Need to Promote Transmission Investment in New England”](#). On December 13, 2024, WIRES/EEI

³⁴ *Id.* at P 59.

³⁵ For purposes of the motion seeking clarification, “Customers” are CT PURA, MA AG and EMCOS.

³⁶ *Ass’n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (Nov. 21, 2019) (“*MISO ROE Order*”), *order on reh’g*, Opinion No. 569-A, 171 FERC ¶ 61,154 (May 21, 2020).

supported the TOs Motion,³⁷ and CAPs³⁸ replied in opposition to the Motion. On December 20, 2024, the TOs filed an answer to the CAPs' statements concerning the FERC's authority to order refunds for the period from when the FERC issues its order on remand back to October 16, 2014.

These matters remain pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER26-578)**

On November 21, 2025, ISO-NE and NEPOOL jointly filed the Installed Capacity Requirements ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and Marginal Reliability Impact ("MRI") Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2026-27 Capability Year and the second ARA for the 2027-28 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 6, 2025 meeting (Consent Agenda Items 3 and 4). An effective date of January 21, 2026 was requested. Comments are due on or before **December 12, 2025**. Thus far, National Grid has intervened. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **CIP-IROL Rate Schedule Filing: FPL Wyman (ER26-577)**

On November 21, 2025, FPL Energy Wyman IV LLC ("FPL Wyman") requested that the FERC accept its proposed rate schedule to allow recovery of eligible Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff, effective November 22, 2025. FPL Wyman stated that the rate schedule will provide interested parties notice of its intent to recover eligible incremental capital, operations and maintenance, and related administrative and regulatory CIP-IROL Costs for its 600MW generating facility designated as an IROL-Critical Facility, and that an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the Schedule 17 pre-filing process and a subsequent FPA section 205 filing identifying the specific costs to be recovered. Comments on this filing are due on or before **December 12, 2025**. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **CIP-IROL Cost Recovery Filing: Canal (ER26-517)**

On November 14, 2025, as corrected on November 26, 2025, Canal Marketing LLC ("Canal") requested FERC acceptance of its revised rate schedule to allow recovery of eligible CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff, effective January 13, 2026. Canal seeks to recover **\$1,075,392** of CIP-IROL Costs incurred between April 1, 2024 and March 31, 2025. Comments on Canal's request are due on or before **December 17, 2025**. Thus far, National Grid intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

³⁷ Agreeing with the TOs, the WIRES/EEI comments asserted: (i) that the FERC lacks the statutory authority to order refunds outside the 15-month refund period; (ii) the FERC's claim of remedial authority to correct legal error does not justify retroactive ROE refunds; and (iii) the FERC should accept and give consideration to the NETOs' supplemental brief and supporting affidavits.

³⁸ "CAPs" are: the Conn. Pub. Utils. Regulatory Authority ("CT PURA"); the Conn. Office of Consumer Counsel ("CT OCC"); Mass. Mun. Wholesale Elec. Co. ("MMWEC"); NH Elec. Coop. ("NHEC"); the RI Div. of Pub. Utils. and Carriers ("RI Div"); and Eastern Mass. Consumer-Owned Systems ("EMCOS"), who consist of the Belmont Mun. Light Dept. ("Belmont"); Braintree Elec. Light Dept. ("Braintree"); Concord Mun. Light Plant ("Concord"); Georgetown Mun. Light Dept. ("Georgetown"); Groveland Elec. Light Dept. ("Groveland"); Hingham Mun. Lighting Plant ("Hingham"); Littleton Elec. Light & Water Dept. ("Littleton"); Merrimac Mun. Light Dept. ("Merrimac"); Middleton Elec. Light Dept. ("Middleton"); Reading Mun. Light Dept. ("Reading"); Rowley Mun. Lighting Plant ("Rowley"); Taunton Mun. Lighting Plant ("Taunton"); and Wellesley Mun. Light Plant ("Wellesley").

- **PBOP Collections Report (RI Energy) (ER26-387)**

On October 31, 2025, 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.³⁹ No changes to the filed rate were sought. The report shows an over-recovery, after interest, of **\$938,616**. If accepted, the PBOP figures will be used in RIE’s 2026 Annual Update. Comments on this filing were due on or before November 21, 2025; 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).

- **PBOP Collections Report (National Grid) (ER26-172)**

On October 17, 2025, National Grid (New England Power) filed a report identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions 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 **\$2,954,638**. If accepted, the PBOP figures will be used in National Grid’s 2025 Annual Update. Comments on this filing were due on or before November 7, 2025; 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).

- **2026 NESCOE Budget (ER26-145)**

On October 15, 2025, ISO-NE, joined by NESCOE, filed Tariff changes for the funding of NESCOE’s 2026 operations. The 2026 Operating Expense Budget for NESCOE is \$2,731,108. The amount to be recovered reflects true-ups from 2024 (over-collections of \$933,127). Accordingly, if accepted, the NESCOE budget will result in a charge of \$0.00806 per kilowatt (“kW”) of Monthly Network Load (a \$0.00090/kW increase from 2025). The 2026 NESCOE budget was supported by the Participants Committee at its October 9, 2025 meeting (Agenda Item #5b). Comments and any interventions are on or before November 5, 2025. On November 3, 2025, NEPOOL submitted comments supporting NESCOE’s 2026 Budget. National Grid and the MA DPU intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2026 ISO-NE Administrative Costs and Capital Budgets (ER26-144)**

On October 15, 2025, ISO-NE filed for recovery of its 2026 administrative costs (the “2026 Revenue Requirement”) and submitted its capital budget for calendar year 2026 (“2026 Capital Budget”, and together with the 2026 Revenue Requirement, the “2026 ISO Budgets”). The 2026 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, 2025 filing, ISO-NE reported that the 2026 Revenue Requirement is \$330.0 million (a \$23.6 million or 7.7% increase over 2025), which decreases to \$314.4 million after the overcollection for 2024 is subtracted. Of that total, ISO-NE’s administrative costs (i.e., the 2026 Core Operating Budget) comprise \$281.8 million; depreciation and amortization of regulatory assets total \$48.2 million; and a \$15.6 million true-up decrease for 2022 over-collections. An effective date of January 1, 2026 was requested.

ISO-NE further reported that the 2026 Capital Budget is \$42.5 million, consistent with 2025, and is comprised of the following (with 2026 projected costs and target completion dates, if available, in parentheses):

³⁹ 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).

nGEM Real-Time Market Clearing Engine Implementation (May 2026)	(\$3.2 million)	Oracle Platform Replacement (Nov 2026)	(\$2.2 million)
Single Interval MCE Improvements (2028)	(\$5 million)	Managing Transmission Line Ratings; Order 881 (Dec 2026)	(\$1 million)
Order 2222 Integration (Nov 2026)	(\$2.6 million)	Adoption of NERC CIP Compliance of Synchrophasor Systems (Aug 2026)	(\$1 million)
EMS Short-Term Load Forecast (Jan 2026)	(\$1.2 million)		

Comments were due on or before November 5, 2025. On October 20, 2025, NEPOOL filed comments in support of the 2026 ISO Budgets, noting that the Participants Committee unanimously supported the Operating and Capital Budgets at its October 9, 2025 meeting (with abstentions). National Grid and MA DPU filed doc-less interventions only. This matter is pending before FERC. If there are any questions on this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Kleen Energy CIP-IROL (Schedule 17) Rate Schedule Filing (ER26-132)**

On October 14, 2025, Kleen Energy Systems, LLC (“Kleen Energy”) requested the FERC accept its proposed rate schedule to allow Kleen Energy to begin the recovery period for certain CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff. Kleen Energy stated that the rate schedule will provide interested parties notice of Kleen Energy’s intent to recover CIP-IROL Costs for its facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process contemplated by Schedule 17 and a subsequent Section 205 filing identifying the specific costs to be recovered. An October 14, 2025 effective date was requested. Comments were due on or before November 4, 2025; none were filed. National Grid intervened doc-lessly. 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).

- **PBOP Collections Report (Eversource) (ER26-58)**

On November 25, 2025, the FERC accepted Eversource’s report, effective *December 8, 2025*, identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions under Appendix A to Attachment F to the ISO-NE OATT.⁴⁰ The report was required to be filed with the FERC because the absolute value of the over-recovery exceeded the threshold identified in OATT Attachment F. As previously reported, the report showed an over-recovery, after interest, of **\$368,462** for CL&P, **\$759,568** for NSTAR East, and **\$179,779** for PSNH. The PBOP figures will be used in Eversource’s 2025 Annual Updates. Unless the November 25 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Transmission Rate Annual (2023-24) Update/Info Filing (MOPA Formal Challenge (ER20-2054-000)**

As summarized in the last Report, on September 18, 2025, the FERC accepted in part and denied in part⁴¹ the Maine Office of the Public Advocate’s (“MOPA”) formal challenge (“MOPA Formal Challenge”)⁴² to the TO’s

⁴⁰ ISO New England Inc., Docket No. ER26-58-000 (Nov. 25, 2025) (unpublished letter order).

⁴¹ ISO New England Inc., 192 FERC ¶ 61,234 (Sep. 18, 2025) (“MOPA 2023-24 Annual Rate Update Challenge Order”).

⁴² In the MOPA Formal Challenge, MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in 2022, “Identified TOs” (Eversource (CL&P, NSTAR East, NSTAR West, and PSNH); National Grid; MEPCO; Narragansett; and VELCO/VTransco) have refused to answer questions regarding investment policies and practices related to prudence of these investments and (ii) that the Identified TOs’ decision not to respond to these questions violates their obligation under the OATT’s Protocols.

2023-24 Annual Update.⁴³ Specifically, the FERC directed Eversource, National Grid, and MEPCO to respond to Maine OPA's Information Request Questions 1(b)(1) and 1(c)(2), and directed all of the Identified NETOs (Eversource; National Grid; MEPCO; Narragansett ; and VELCO/VTransco) to respond to Question 4,⁴⁴ on or before October 19, 2025. In addition, the FERC granted MOPA's request to permit it to supplement the MOPA Formal Challenge, as requested, with regard to the prudence of Identified NETOs' asset condition project costs reflected in the 2023 Annual Update, with such supplement to be filed on or before **December 18, 2025**. Of note, Commissioner Chang's concurrence emphasized stakeholders' fundamental right to transmission planning and investment information through existing formula rate protocols and encouraged transmission owners/planners to proactively share information on transmission projects and planning.

Of the 4 Identified TOs, only one (VELCO/VTransco on October 17, 2025) filed its response to Question 4 publicly. Subject to any further information exchange and any MOPA supplement to its Formal Challenge due **December 18, 2025** as described above, the MOPA Formal Challenge remains 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: Return of CSO Payments (Brookfield) (ER26-143)**

On October 15, 2025, Brookfield Renewable Trading and Marketing LP ("Brookfield") requested a limited waiver of the Tariff to allow it to refund to ISO-NE, with interest, improperly received CSO payments for its Lièvre Power portfolio. The payments were received for the months of October, November, and December 2024 and January 2025 (because Brookfield failed to shed a portion of its full-year CSO through the respective monthly reconfiguration auctions) and would be returned to Participants with Capacity Load Obligations during the corresponding months. While Brookfield would like to refund these payments ("BRTM Refund"), with interest, to ISO-NE, the Tariff does not have a provision that allows ISO-NE to accept the BRTM Refund or specifies how refunds should in turn be made. Brookfield asked the FERC for an order allowing ISO-NE to accept the BRTM Refund and directing ISO-NE to return the BRTM Refund to the FCM's Capacity Load Obligation for the months of October, November, and December 2024 and January 2025 ("FCM Refund"). Brookfield reported that ISO-NE authorized it to state that ISO-NE does not oppose the Waiver Request and can, if the Waiver Request is granted, implement the FCM Refund as described. Comments on this Waiver Request were due on or before November 5, 2025; none were filed. National Grid 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).

- **Order 2222 Conforming Changes (ER26-105)**

On October 10, 2025, ISO-NE and NEPOOL filed conforming changes to the ISO-NE Tariff to (i) clarify participation rules for Demand Response Distributed Energy Resource Aggregations ("DR DERAs") in the Energy and Ancillary Services Markets, (ii) reduce the minimum size for Generator Assets participating in the Regulation

⁴³ On July 31, 2023, 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 2024 (the "2023-24 Annual Update"). The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2022 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2023 and 2024, as well as the Annual True-up including associated interest. The PTO-AC stated that the annual updates result in a Pool "postage stamp" RNS Rate of \$154.35/kW-year effective Jan. 1, 2024, an increase of \$12.71 /kW-year from the charges that went into effect on Jan. 1, 2023. In addition, the filing included 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 \$1.95 kW-year (effective June 1, 2023 through May 31, 2024), a \$0.20/kW-year increase from the Schedule 1 charge that last went into effect on June 1, 2023.

⁴⁴ Question 1(b)(1) requested copies of any written policies that describe the procedures and processes employed to evaluate the need for a particular asset condition project; Question 1(c)(2) requested copies of any documents (or a narrative description if no documents exist) identifying the reasons why those participating in the decision-making process recommended against proceeding with a particular asset condition project; Question 4 related to the existence and employment of safeguards against the placement of asset condition projects into service before they are needed.

Market consistent with *Order 2222*-compliant resources, and (iii) make other clarifying and conforming Tariff edits to facilitate participation by DERAs. An effective date of November 1, 2026 was requested. Comments were due on or before October 31, 2025; none were submitted. Calpine, MA DPU, NRG Business Marketing and National Grid intervened doc-lessly. Since the last Report, on November 18, 2025, ISO-NE filed an errata to correct the requested effective date for the *Order 2022 Conforming Changes* from December 31, 2025 to November 1, 2026. 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).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Order 898 Compliance Revisions (ER26-439)**

On November 6, 2025, the Participating Transmission Owners Administrative Committee (“PTO AC”)⁴⁵ filed changes to Appendix A (Transmission Formula Rate Template) and Appendix D (Depreciation/Amortization Rates) to OATT Attachment F (Annual Transmission Revenue Requirements) in response to the requirements of Order 898 (“Accounting and Reporting Treatment of Certain Renewable Energy Assets”) (conforming references in the formula rate to *Order 898*’s revisions to the electric Uniform System of Accounts and associated FERC Forms 1 and 3Q). The Participants Committee voted unanimously in favor of the revisions to Appendix A at its November 6, 2025 meeting. An effective date of December 21, 2025 was requested. Comments on the *Order 898* Compliance Revisions were due on or before November 28, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **RI Energy Revision to Fixed PBOP Expense Amount (ER26-390)**

On October 31, 2025, RI Energy filed to revise its PBOP expense amount under Appendix A to Attachment F of the OATT to limit potential over-recoveries of PBOP expenses. An effective date of January 1, 2026 was requested. Comments on this filing were due on or before November 21, 2025; none were filed. 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).

- **Order 676-K Compliance Filings (ER25-2654; ER25-2657)**

On June 27, 2025, in accordance with *Order 676-K*,⁴⁶ the following *Order 676-K* compliance filings to incorporate, or seek waiver of, the WEQ Version 004 Standards were submitted:

- ♦ *Order 676-K* Compliance Filing (ISO-NE, NEPOOL, CSC: Tariff Schedule 24 and Schedule 18-Attachment Z) (ER25-2654); and
- ♦ *Order 676-K* Compliance Filing (ISO-NE, PTO AC, Schedule 20-A Service Providers: Schedules 20A-Common and 21-Common) (ER23-2657).

Comments on the compliance filings were due on or before July 17, 2025; none were filed. Calpine intervened in each proceeding. The *Order 676-K* compliance filings remain pending before the FERC. If there are questions on any of these compliance filings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

⁴⁵ PTO AC filed on behalf of the New England PTOs: Central Main Power Company; Eversource on behalf of CL&P, NSTAR, and PSNH; FG&E; Green Mountain Power Corporation (“GMP”); Maine Electric Power Company (“MEPCO”); Rhode Island Energy (“RIE”); National Grid; New Hampshire Transmission, LLC (“NHT”); The United Illuminating Company (“UI”); Vermont Transco, LLC (“VTransco”); and Versant Power.

⁴⁶ *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-K, 190 FERC ¶ 61,116 (Feb. 19, 2025) (“*Order 676-K*”).

- **Order 904 Compliance Filing – Reactive Power Compensation Revisions (ER25-1703)**

On September 16, 2025, the FERC accepted the revisions to Schedule 2 of the ISO-NE OATT filed in compliance with *Order 904* (“Reactive Power Compensation Changes”).⁴⁷ As previously reported, the Reactive Power Compensation Changes eliminate compensation for reactive power capability within the standard power factor range of 0.95 leading to 0.95 lagging, while continuing to allow compensation for capability outside that range. The proposed revisions to Schedule 2 of the OATT will become effective 6-12 months from the date of the September 16 order, with an actual date to be submitted one month in advance. Unless the September 16 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) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes & Agreements⁴⁸

- **Schedule 21-RIE: Block Island Wind Farm Facilities Reclassification (ER26-397)**

On October 31, 2025, RI Energy submitted adjustments to the Block Island Transmission System (“BITS”) Surcharge set forth in 2 service agreements with Block Island Power Company (“BIPCO”) to reflect a change in the classification of the electric facilities associated with the Block Island Wind Farm from distribution to transmission. The proposed adjustments are expected to increase the BITS Surcharge, but the overall impact on customers is expected to be minimal. A January 1, 2026 effective date was requested. Comments on this filing are due on or before November 21, 2025; none were filed. The RI Division intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP: BTM Gen & SSCDC Cost Revisions (ER26-386)**

On October 31, 2025, Green Mountain Power (“GMP”) filed revisions to Schedule 21-GMP intended to provide more commercially and operationally reasonable terms for generators to take local non-firm point-to-point service on GMP’s system. The revisions clarify that behind-the-meter (“BTM”) generation is excluded from Local Network Load, which is consistent with how Regional Network Load is calculated under the ISO-NE OATT; and revise the billing methodology for Scheduling, System Control and Dispatch Costs (“SSCDC”) to replace the rolling 12-month average billing methodology in Schedule 1. A December 31, 2025 effective date was requested. Comments on this filing were due on or before November 21, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-ES: Eversource Removal of Duplicative True Up of S&D Costs (ER26-321)**

On October 30, 2025, Eversource, on behalf of CL&P, NSTAR (East/West), and PSNH, filed changes to Schedule 21-ES to eliminate a duplicative true up of scheduling and dispatch costs (“S&D”), which added to the ISO-NE OATT (“Formula Rate Template”) and eliminates the need for the Schedule 21-ES S&D calculation. On November 4, 2025, Eversource amended the filing to request a January 1, 2026 effective date. Comments on the amended filing were due on or before November 25, 2025; none were filed. This matter is pending

⁴⁷ *ISO New England Inc.*, Docket No. ER25-1703-000 (Oct. 16, 2025).

⁴⁸ 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).

before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 2022 Annual Update Settlement Agreement (ER20-2054-003)**

Still pending is Versant's August 29, 2023 Joint Offer of Settlement ("Versant 2022 Annual Update Settlement Agreement") between itself and the MPUC.⁴⁹ Versant stated that, if approved, the 2022 Annual Update Settlement Agreement would resolve all issues raised by the MPUC with respect to the 2022 Annual Update. Although no adverse comments on the Versant 2022 Annual Update Settlement Agreement were filed, this matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports⁵⁰

- **Capital Projects Report – 2025 Q3 (ER26-152)**

On November 18, 2025, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule for the third quarter ("Q3") of calendar year 2025 (the "Report").⁵¹ As previously reported, Report highlights included the following new projects: (i) Oracle Platform Replacement (\$2,795,600); (ii) CIP Electronic Security Perimeter Redesign Phase III (\$1,180,000); (iii) IMM Datamart Infrastructure Deployment (\$750,000); (iv) Capital Projects Issue Resolution Phase II (\$713,700); and (v) VAR Capability Testing Application (\$420,000). Projects placed in service this quarter included: CAMS Application Software Technology Upgrade; FCM Delivery Financial Assurance; and Replace Employee Expense Management System. And projects reported to have significant changes in funds included: Enterprise Core Network Refresh (reduced by \$350,000); Identity Access Management Automation Improvements (reduced by \$152,800); ARD Circuit Continuity Improvements (reduced by \$150,000); SMS Application Technology Upgrade (reduced by \$144,200); and the NECEC Transmission Line (increased by \$100,100). The Report was accepted effective as of *October 1, 2025*. Unless the November 18 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **IMM Quarterly Markets Reports: Summer 2025 (ZZ25-4)**

On November 12, 2025, the IMM filed with the FERC its Summer 2025 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 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Summer 2025 Report will be discussed with the Markets Committee at the Markets Committee's December 9-10 meeting. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ISO-NE 2025 Q3 FERC Form 3Q (not docketed)**

On November 20, 2025, ISO-NE submitted its 2025/Q3 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which

⁴⁹ Joint Offer of Settlement Regarding Versant Power, Bangor Hydro District Charges.

⁵⁰ 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.

⁵¹ *ISO New England Inc.*, Docket No. ER26-152-000 (Nov. 18, 2025) (unpublished letter order).

supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for public comment.

IX. Membership Filings

Questions concerning any of the Membership Filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

• Dec 2025 Membership Filing (ER26-617)

On November 26, 2025, NEPOOL requested that the FERC accept: (i) the membership in NEPOOL of The Energy Authority, Inc. (“TEA”) (Supplier Sector); and (ii) the name changes of Long Island Power Authority (f/k/a Long Island Lighting Company d/b/a LIPA) and Lighthouse Naugatuck, LLC (f/k/a Naugatuck Avenue Storage LLC). Comments on this filing, if any, are due on or before **December 17, 2025**.

• Nov 2025 Membership Filing (ER26-363)

On October 31, 2025, NEPOOL requested that the FERC accept the membership in NEPOOL of the Mid-Coast Region Redevelopment Authority (“MRR”) (Publicly Owned Entity Sector). Comments on this filing, if any, were due on or before November 21, 2025; none were filed. This matter is pending before the FERC.

• Oct 2025 Membership Filing (ER25-3571)

On November 28, 2025, the FERC accepted: (i) the following Applicants’ membership in NEPOOL: AE-ESS Holyoke, LLC [Related Person to Agilitas Companies (AR Sector, DG Sub-Sector)]; American Power & Gas of RI, LLC [Related Person to American Power & Gas of MA, LLC (Supplier Sector)]; and Burgess BioPower [Related Person to Berlin Station (Generation Sector Group Member)]; and (ii) the termination of the Participant status of Hudson Energy Services.⁵² Unless the November 28 order is challenged, this proceeding will be concluded.

• Suspension Notice (not docketed)

Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC noting that the following Market Participant was suspended from the New England Markets on the date indicated (at 8:30 a.m.):

<i>Date of Suspension/ FERC Notice</i>	<i>Participant Name</i>	<i>Default Type</i>
Nov 17, 2025	Phillips 66 Energy Trading LLC	Financial Assurance

Suspension notices are for the FERC’s information only and are not docketed or noticed for public comment

X. Misc. - ERO Rules, Filings; Reliability Standards⁵³

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).

⁵² *New England Power Pool Participants Comm.*, Docket No. ER25-3571-000 (Nov. 28, 2025) (unpublished letter order).

⁵³ 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.*).

- **NERC FFT/CE Programs Annual Report (RC11-6-021)**

On September 23, 2025, NERC filed its annual report on the Find, Fix, and Track (“FFT”) and Compliance Exception (“CE”) programs, in accordance with prior orders.⁵⁴ Building upon NERC and FERC Staff’s annual coordinated review of FFTs and CEs summarized in the last Report, NERC reported that the FFT and CE Programs continue to meet expectations. NERC added that the results of the annual joint review show continued overall improvement in program implementation and significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. Comments on the Annual Report were due on or before October 8, 2025; none were filed.

- **Revised Reliability Standard: MOD-026-2 (RD26-3)**

On November 4, 2025, NERC requested FERC approval of proposed Reliability Standard MOD-026-2 (Verification and Validation of Dynamic Models and Data, and the proposed definitions of Model Validation and Model Verification). MOD-026-2 was developed in response to *Order 901*’s Milestone 3 directives on Inverter-Based Resources (“IBRs”) and would replace and combine the currently effective standards MOD-026-1 and MOD-027-1 and include new requirements addressing validation of models across modeling domains including electromagnetic transient (“EMT”) models of Inverter-Based Resources (“IBR”), high-voltage direct current (“HVDC”) systems, flexible alternating current transmission system (“FACTS”) devices, and dynamic reactive resources. MOD-026-2 is intended to advance the reliability of the Bulk-Power System by (“BPS”) improving the accuracy and dependability of models used in planning and interconnection analyses through requiring Generator Owners and Transmission Owners, particularly of IBRs, to perform Model Validation and Model Verification of positive sequence dynamic and EMT models that are provided to their Transmission Planner. Under the proposed Implementation Plan, MOD-026-2 would become effective on the first day of the first calendar quarter after the effective date of the FERC order approving the standard; MOD-026-1 and MOD-027-1 would be retired immediately prior to the effective date of the revised successor standard. Comments on the MOD-026-2 are due on or before **December 8, 2025**. Thus far, Calpine intervened doc-lessly.

- **Revised Reliability Standard: MOD-033-3 (RD26-2)**

Also on November 4, 2025, NERC requested FERC approval of proposed Reliability Standard MOD-033-3 (Steady-State and Dynamic System Model Validation). MOD-033-3 was developed in response to *Order 901*’s Milestone 3 directives on Inverter-Based Resources (“IBRs”) and would replace existing Reliability Standard MOD-033-2. MOD-033-3 is intended to establish a comprehensive process for system model validation and to advance Bulk-Power System (“BPS”) reliability by enhancing existing system-level model validation requirements so that planning System models must include BPS-connected IBRs and aggregated Distributed Energy Resources (“DERs”) present on the System and be validated against actual system behavior. The proposed Reliability Standard applies to Planning Coordinators, Reliability Coordinators, and Transmission Operators. Under the proposed Implementation Plan, MOD-033-3 would become effective on the first day of the first calendar quarter that is the later of (i) the first day of the calendar quarter that is three months after FERC approval of MOD-033-3 and the associated NERC Glossary definitions of “Model Validation” and “Distributed Energy Resources,” or (ii) January 1, 2030; MOD-033-2 would be retired immediately prior to the MOD-033-3 effective date. Comments on the MOD-033-3 filing are due on or before **December 8, 2025**. Thus far, Calpine intervened doc-lessly.

- **Wildfire Prevention, Detection, and Mitigation Best Practices (RD25-9)**

On September 10, 2025, the FERC directed NERC to submit in an informational filing a report on best practices to reduce the risk of wildfire ignition from the BPS on or before **May 1, 2026**.⁵⁵ The report must assess methods such as “vegetation management, the removal of forest-hazardous fuels along transmission lines,

⁵⁴ See *N. Am. Elec. Rel. Corp.*, 138 FERC ¶ 61,193 (2012); *N. Am. Elec. Rel. Corp.*, 143 FERC ¶ 61,253 (2013); *N. Am. Elec. Rel. Corp.*, 148 FERC ¶ 61,214 (2014); and *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-004 (Nov. 13, 2015) (unpublished letter order).

⁵⁵ *N. Am. Elec. Rel. Corp.*, 192 FERC ¶ 61,212 (Sep. 10, 2025).

improved engineering approaches, and safer operational practices.⁵⁶ The report must also include an assessment of known and emerging technologies that can be deployed to detect and mitigate wildfire in the context of protecting the BPS and its use to provide reliable service to customers. The FERC noted its concurrently issued notice of technical conference on wildfire mitigation (see AD25-16 in Section XII below) and said NERC should consider the testimony from that conference as an input for its informational filing, including in its consideration of the need for new or revised Reliability Standards or alternative further action.

- **Revised Reliability Standard: EOP-012-3 (RD25-7)**

On September 18, 2025, the FERC approved Reliability Standard EOP-012-3 (Extreme Cold Weather Preparedness and Operations)⁵⁷ and directed NERC, for a period of time,⁵⁸ to collect and submit certain information to the FERC.⁵⁹ As previously reported, EOP-012-3 is intended to improve the efficiency and effectiveness of the BPS in future cold weather seasons by providing clarity regarding the criteria for declaring Generator Cold Weather Constraints, shortening timelines for implementing corrective action plans following cold weather reliability events, and requiring more frequent review of validated constraints to reflect evolving technologies and operating conditions. Revised EOP-012-3 also includes new requirements for BES generating units entering commercial operation on or after October 1, 2027 to have cold weather capability upon entry, unless a validated constraint applies. EOP-012-3 went into effect on *October 1, 2025*. Requests for clarification of the *EOP-012-3 Order* were filed by each of NERC and Joint Trade Associations.⁶⁰ The FERC did not take action in response to those requests within the required 30-day statutory timeframe and, accordingly, the requests can be deemed denied by operation of law.

- **NOPR: Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization⁶¹) (RM24-8)**

On September 18, 2025, the FERC issued a notice of proposed rulemaking (“NOPR”)⁶² proposing to approve 11 modified CIP Reliability Standards,⁶³ and 4 new and 18 modified definitions in the NERC Glossary of

⁵⁶ See Exec. Order No. 14308 (Empowering Commonsense Wildfire Prevention and Response), 90 Fed. Reg. 26175 (June 12, 2025), <https://www.whitehouse.gov/presidential-actions/2025/06/empowering-commonsense-wildfire-prevention-and-response/> (Executive Order 14308).

⁵⁷ *N. Am. Elec. Rel. Corp.*, 192 FERC ¶ 61,229 (Sep. 18, 2025) (“EOP-012-3 Order”).

⁵⁸ Starting no later than **Oct. 2026** and ending in **Oct. 2034** (EOP-012-3 Order at P 37).

⁵⁹ The FERC directed NERC to submit: (i) for each Regional Entity, anonymized **data on**: (a) the number of submitted Generator Cold Weather Constraint declarations, (b) the number of approved declarations, (c) the aggregate MVA of approved declarations, and (d) a summary of the rationale(s) provided for approved declarations. (EOP-012-3 Order at P 34); (ii) a **narrative analysis addressing** the following issues: (a) whether reliability coordinators, transmission operators, and balancing authorities (or other relevant entities) are timely notified of Generator Cold Weather Constraint declarations and corrective action plan extensions; (b) the reliability impact, if any, of allowing generators 36 months, rather than a shorter time period, such as 24 months, to correct known freeze related issues; and (c) whether the Generator Cold Weather Constraint declarations approval process is consistently interpreted and applied by the CEAs in a timely manner to address the reliability risks presented by extreme cold weather; whether the Generator Cold Weather Constraint declaration criteria in Attachment 1 is adequately defined and clear so that applicable entities understand what is required of them; and the reliability impact on the BPS due to Generator Cold Weather Constraint declarations from each criterion in Attachment 1, in addition to the reliability impact from approved corrective action plan extensions.

⁶⁰ “Joint Trade Associations” are the American Public Power Association (“APPA”), Electric Power Supply Association (“EPSA”), Large Public Power Council (“LPPC”), National Rural Electric Cooperative Association (“NRECA”), and Transmission Access Policy Study Group (“TAPS”).

⁶¹ Virtualization is “the process of creating virtual, as opposed to physical, versions of computer hardware to minimize the amount of physical hardware resources required to perform various functions.”

⁶² *Virtualization Reliability Standards*, 192 FERC ¶ 61,228 (Sep. 18, 2025) (“Virtualization NOPR”).

⁶³ The revised Cyber Security Standards are: CIP-002-7 (BES Cyber System Categorization); CIP-003-10 (Security Management Controls); CIP-004-8 (Personnel & Training); CIP-005-8 (Electronic Security Perimeter(s)); CIP-006-7 (Physical Security of BES Cyber Systems); • CIP-007-7 (Systems Security Management); CIP-008-7 (Incident Reporting and Response Planning); CIP-009-7 (Recovery Plans for BES Cyber Systems); CIP-010-5 (Configuration Change Management and Vulnerability Assessments); CIP-011-4 (Information Protection); and CIP-013-3 (Supply Chain Risk Management).

Terms,⁶⁴ to facilitate the full implementation of virtualization and to address the risks associated with virtualized environments.⁶⁵ As previously reported, the proposed CIP Reliability Standards would permit Responsible Entities with more “traditional” architecture to continue with their current configurations. In the NOPR, the FERC seek comments specifically on the proposed replacement of the phrase “where technically feasible” with the phrase “per system capability”, including alternative approaches, which the FERC said would assist it in formulating a possible directive in a final rule.⁶⁶ Comments on the *Visualization NOPR* were due on or before November 24, 2025⁶⁷ and were filed by BPA, EEI, GE Vernova, MISO, NERC, and Portland General Electric. This matter is pending before the FERC.

- **Order 912: Supply Chain Risk Management (“SCRM”) Reliability Standards (RM24-4)**

On September 18, 2025, almost a year to the day the FERC issued its *SCRM Standards NOPR*, the FERC issued its final rule (*Order 912*)⁶⁸ largely adopting the NOPR’s proposals, directing NERC to develop (i) new or modified Reliability Standards that address the sufficiency of responsible entities’ SCRM plans related to the identification of and response to supply chain risks and (ii) modifications related to supply chain protections for protected cyber assets. Although the FERC declined to direct NERC to require responsible entities to validate data received from vendors, it nonetheless encouraged entities to voluntarily implement this security practice as appropriate.⁶⁹ *Order 912* became effective *November 24, 2025*.⁷⁰ In response to comments, the FERC directed NERC to submit the new or revised Reliability Standards within 18 months of the effective date.

- **ITCS: Strengthening Reliability Through the Energy Transformation (AD25-4)**

On November 19, 2024, NERC submitted for FERC consideration the Interregional Transfer Capability Study (“ITCS”) directed by the U.S. Congress in the Fiscal Responsibility Act of 2023 (“Fiscal Responsibility Act”). NERC stated that the ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. The ITCS focuses on transfer capability in accordance with the congressional directive, while acknowledging that other processes and pending projects may help support a reliable future grid. The ITCS was not designed to be a transmission plan or blueprint. NERC stated that the ITCS demonstrates that sufficient transfer capability and resources exist at present to maintain energy adequacy under most scenarios, but when calculating current transfer capability and projected future conditions, the ITCS identifies potential energy inadequacy across several transmission planning regions in the event of extreme weather. The ITCS recommends an increase of 35 GW of transfer capability across different regions as technically prudent additions to demonstrably strengthen reliability. The ITCS also recommends region-specific enhancements to transfer capability, “because a one-size-fits all approach across the U.S. may be inefficient and ineffective.”

Comments on NERC’s ITCS were filed by, among others: [AEU](#), [ENGIE](#), [Eversource](#), [Grid United](#), [Invenergy](#), [National Grid](#), [NRG](#), [ACPA/SEIA](#), [ACORE](#), [APPA](#), [EEI](#), [EIPC](#), [EPSA](#), [Public Interest Organizations](#), [Northeast States](#),

⁶⁴ The new and/or revised Glossary Terms are: BES Cyber Asset (“BCA”), BES Cyber System (“BCS”), BES Cyber System Information (“BCSI”), CIP Senior Manager, Cyber Assets, Cyber Security Incident, Cyber System, Electronic Access Point (“EAP”); External Routable Connectivity (“ERC”), Electronic Security Perimeter (“ESP”), Interactive Remote Access (“IRA”), Intermediate System, Management Interface, Physical Access Control Systems (“PACS”), Physical Security Perimeter (“PSP”), Protected Cyber Asset (“PCA”), Removable Media, Reportable Cyber Security Incident, Shared Cyber Infrastructure (“SCI”), Transient Cyber Asset (“TCA”), and Virtual Cyber Asset (“VCA”).

⁶⁵ The FERC also proposed to approve the associated violation risk factors, violation severity levels, implementation plans, and effective dates for the proposed Reliability Standards, as well as to approve the retirement of the currently effective version of each proposed Reliability Standard.

⁶⁶ *Virtualization NOPR* at P 3.

⁶⁷ The *Visualization NOPR* was published in the *Fed. Reg.* on Sep. 23, 2025 (Vol. 90, No. 182) pp. 45,679-45,685.

⁶⁸ *Supply Chain Risk Mgmt. Reliability Standards Revisions*, Order No. 912, 192 FERC ¶ 61,230 (Sep. 18, 2025) (“*Order 912*”).

⁶⁹ *Id.* at P 2.

⁷⁰ *Order 912* was published in the *Fed. Reg.* on Sep. 23, 2025, 2025 (Vol. 90, No. 182) pp. 45,661-45,671.

[NRECA](#), [NASUCA](#), [R Street](#), and [WIRES](#). On March 25, 2025, NERC submitted a reply to clarify certain of the matters raised in those comments on the ITCS.

XI. Misc. - of Regional Interest

- **203 Application: Cricket Valley Energy Center (EC25-116)**

On September 19, 2025, the FERC authorized a transaction pursuant to which certain parties⁷¹ will indirectly acquire voting interest of 10% or more in Cricket Valley Energy Center (“CVEC”) and the right to appoint one or more non-independent directors or managers to the board of one of CVEC or its upstream owners.⁷² When consummated, CVEC will become a Related Person to Bridgewater Power and Burgess BioPower (each in the Generation Group Seat). Pursuant to the September 19 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: CPower/NRG (EC25-102)**

On November 14, 2025, the FERC authorized a proposed transaction pursuant to which, as specifically relevant to New England, NRG⁷³ will indirectly acquire the membership interests in Enerwise Global Technologies, LLC d/b/a CPower (“CPower”), making NRG and CPower Related Persons.⁷⁴ Pursuant to the *NRG/CPower Order*, NRG 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: Burgess BioPower/White Mountain Power (EC25-99)**

On August 13, 2025, the FERC authorized a transaction by which White Mountain Power (an affiliate of, among others, Bridgewater Power and David Energy Supply) will acquire from Burgess BioPower all of the indirect ownership interests of Berlin Station in connection with a plan of reorganization under Chapter 11 of the US Bankruptcy Code.⁷⁵ Pursuant to the August 13 order, White Mountain Power 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: Constellation/Calpine (EC25-43)**

On July 23, 2025, the FERC conditionally authorized⁷⁶ Constellation’s acquisition of Calpine, subject to Applicants’ commitments to divest certain generation facilities (“Mitigation Plan”), to extend certain pre-existing commitments that apply to the Constellation Applicants and their public utility subsidiaries in PJM market to all Applicants in the PJM market, to abide by the terms of an agreement reached between Constellation and the PJM IMM, and to implement interim mitigation (“Interim Behavioral Mitigation”) until the Mitigation Plan is completed. Pursuant to the July 23 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. When consummated, Constellation and Calpine will become Related Persons.

⁷¹ Kiwoom US, PE-US Jiminy OFLEX Blocker, LLC and PE-US Jiminy Aggregator, L.P., Cricket Valley Funding, and Cricket Valley Energy Holdings II LLC (“Applicants”).

⁷² *Cricket Valley Energy Center, LLC*, 192 FERC ¶ 62,181 (Sep. 19, 2025).

⁷³ For purposes of the Report, “NRG” is NRG East Generation Holdings LLC (“NRG East Holdings”), NRG Demand Response Holdings LLC (“NRG DR Holdings”), and Lightning Power, LLC (“Lightning Power”).

⁷⁴ *NRG East Generation Holdings, LLC et al.*, 193 FERC ¶ 61,124 (Nov. 14, 2025) (“*NRG/CPower Order*”).

⁷⁵ *Burgess BioPower, LLC and White Mountain Power, LLC*, 192 FERC ¶ 62,085 (Aug. 13, 2025).

⁷⁶ *Constellation Energy Corp. et al.*, 192 FERC ¶ 61,074 (July 23, 2025) (“*Merger Order*”).

On August 22, 2025, two requests for rehearing of the *Merger Order* were filed, one by the Pennsylvania Office of Consumer Advocate (“PA OCA”); the other by the Public Citizen Petitioners.⁷⁷ The Constellation Applicants filed an answer on September 8, 2025, requesting the FERC deny the requests for rehearing. On September 22, 2025, the FERC issued an *Allegheny Notice*,⁷⁸ noting that the requests for rehearing may be deemed denied by operation of law, but noting that the requests will be addressed in a future order.⁷⁹ On November 21, 2025, the PA OCA petitioned the DC Circuit Court for review of the *Merger Order* and the *Constellation Merger Order Allegheny Notice*. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PURPA Enforcement Petition – Allco Finance Ltd/CT DEEP (EL25-117)**

On November 21, 2025, the FERC issued a notice⁸⁰ that it has decided not to act on the PURPA Complaint filed by Allco Finance Limited (“Allco”) related to the Connecticut Department of Energy and Environmental Protection’s (“CT DEEP”) improper implementation of section 210 of PURPA.⁸¹ The FERC’s decision not to act means that Allco may itself bring an enforcement action against Connecticut in the appropriate federal district court.⁸² If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Wholesale Distribution Tariff (II) – Versant Power (ER26-528)**

On November 17, 2025, Versant Power filed a revised Wholesale Distribution Tariff (“WDT”) for Electric Energy Delivery to Energy Storage Systems (“ESS”) for its Bangor Hydro District responding to concerns identified by the FERC in its order rejecting Versant’s earlier proposed WDT in Docket No. ER25-2500.⁸³ The revised WDT eliminates transmission service charges and is intended to clarify the terms for ESS taking wholesale distribution service over Versant’s facilities and to address the FERC’s directives regarding consistency with ISO-NE’s Tariff and Order 841. An effective date of January 17, 2026 was requested. Comments are due on or before **December 8, 2025**. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Facilities (Distrigas) Support Agreement Cancellation - NSTAR/National Grid (ER25-3550)**

On November 24, 2025, the FERC accepted a notice of cancellation filed by NSTAR of a Facilities Support Agreement between itself and National Grid (Service Agreement No. DSA-NSTAR-002), effective *September 30, 2025*.⁸⁴ As previously reported, the Agreement provided NEP access to certain NSTAR distribution facilities as a back-up supply to serve National Grid’s retail customer, Distrigas of Massachusetts. NSTAR reported that the

⁷⁷ “Public Citizen Petitioners” are: Public Citizen, PennFuture, Clean Air Council, and Citizens Utility Board.

⁷⁸ The FERC issues an “Allegheny Notice” when it does not act within 30 days after receiving a challenge (a request for clarification and/or rehearing) to a FERC order. An Allegheny Notice confirms that the request is deemed denied by operation of law (see *Allegheny Def. Project v. FERC*, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020) (*en banc*)) and the FERC order is final and ripe for appeal. The FERC has the right, up to the point when the record in a proceeding is filed with a Federal Court of appeals, to modify or set aside, in whole or in part, any finding or order made or issued by it. The FERC’s intention to avail itself of its right and to issue a further order addressing the issues raised in the request (a “merits order”) is signaled by the phrase “and providing for Further Consideration”; the absence of that phrase signals that the FERC does not intend to issue a merits order in response to the rehearing request.

⁷⁹ *Constellation Energy Corp. et al.*, 192 FERC ¶ 61,183 (Sep. 22, 2025) (“*Constellation Merger Order Allegheny Notice*”).

⁸⁰ *Allco Finance Limited*, 193 FERC ¶ 61,149 (Nov. 21, 2025).

⁸¹ Specifically, Allco asked the FERC to remedy violations that (i) permit Eversource to charge a QF for interconnection costs than are higher than the interconnection costs permitted under 18 C.F.R. §292.101(b)(7) and PURPA, and (ii) permit Eversource to allow generators that applied for interconnection after Allco to jump ahead of Allco’s interconnections.

⁸² 16 U.S.C. § 824a-3(h)(2)(B).

⁸³ *Versant Power*, 193 FERC ¶ 61,044 (October 17, 2025) (taking issue with proposed rate schedule because it may result in transmission service charges being assessed at times on energy storage facilities).

⁸⁴ *NSTAR Electric Co.*, Docket No. ER25-3550-000 (Nov. 24, 2025) (unpublished letter order).

Agreement is no longer required because all work under the Agreement has been completed and invoices have been paid. Unless the November 24 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Joan Bosma (617-345-4651; jbosma@daypitney.com).

- **Order 676-K Compliance Changes Versant Power (ER25-2566)**

On June 23, 2025, Versant filed revisions to Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the “MPD OATT”), which incorporate by reference certain of the revisions required by *Order No. 676-K*. Versant also requested waiver of certain of the standards that Maine Public District (“MPD”) is unable to meet. Versant requested effective dates of February 27, 2026 and August 27, 2026. Comments on Versant’s *Order 676-K* changes were due on or before July 14, 2025; none were filed. Versant’s *Order 676-K* Compliance Changes remain pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Order 904 Compliance Filing: Versant MPD OATT (ER25-1393)**

On February 25, 2025, Versant submitted a compliance filing in response to *Order 904*,⁸⁵ proposing revisions to its MPD OATT, effective June 1, 2025. Versant’s filing: (i) revises Schedule 2 to exclude charges for reactive power within the standard power range; (ii) removes related payment provisions from the *pro forma* LGIA and SGIA; and (iii) removes Note 1 from Exhibit 1a in Attachment J. Comments on Versant’s compliance filing were due on or before March 18, 2025; none were filed. On October 31, 2025, Versant amended its filing to request that the proposed compliance changes be made effective May 26, 2025 (rather than June 1, 2025 as originally requested). Comments on the October 31 amendments were due on or before November 21, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **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,⁸⁶ effective August 4, 2025.⁸⁷ 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; 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 Proceedings⁸⁸

- **Technical Conf: Wildfire Risk Mitigation (AD25-16)**

On October 21, 2025, the FERC convened a Staff-led technical conference (right after the tech conf in AD25-8 discussed below) to discuss cost-effective best practices to reduce the risk of wildfire ignition from the Bulk Power System (“BPS”) in response to Executive Order 14308. There were two panel discussions – (i) interagency coordination challenges and grid-focused best practices for wildfires (Panel 1); and (ii) leveraging

⁸⁵ *Compensation for Reactive Power Within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024) (“*Order 904*”).

⁸⁶ 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”)).

⁸⁷ *Central Maine Power Co.*, 192 FERC ¶ 61,110 (Aug. 4, 2025) (“*CMP ESF Rate Settlement Order*”).

⁸⁸ Reporting on the following administrative and rulemaking proceedings has been suspended and will be continued if and when there is new activity to report: Large Loads Co-Located at Generating Facilities (AD24-11); Annual Reliability Tech. Conf. (AD24-10); Innovations and Efficiencies in Generator Interconnection (AD24-9); and the EQR Filing Process and Data Collection NOPR (RM23-9).

technology to monitor, evaluate, and mitigate wildfire risks (Panel 2). Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. On October 23, 2025, the FERC invited post-technical conference comments to address issues raised during the technical conference or identified in the October 15, 2025 Second Supplemental Notice. Those comments were due on or before November 24, 2025; National Rural Electric Cooperative Association ("NRECA"), Working for Advanced Transmission Technologies Coalition ("WATT Coalition"), and several others provided comments to inform the FERC's wildfire risk mitigation efforts. On December 1, 2025, the technical conference's transcript was posted in the FERC's eLibrary.

- **Annual Reliability Technical Conference (AD25-8)**

The FERC also convened on October 21, 2025 its annual Commissioner-led Reliability Technical Conference to discuss policy issues related to the reliability and security of the BPS. The following two topics were discussed: (i) leadership perspectives on the state of the BPS and priorities (Panel 1); and ensuring reliability with large loads (Panel 2). Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. Post-technical conference comments addressing issues raised during the technical conference or identified in the October 15, 2025 Third Supplemental Notice for this technical conference were due on or before November 24, 2025 and were filed by Constellation and by Digital Power Network.

- **Tech Conf: Meeting the Challenge of Resource Adequacy in ISO/RTOs (AD25-7)**

On June 4-5, 2025, the FERC convened a Commissioner-led technical conference to discuss generic issues related to resource adequacy constructs, including the roles of capacity markets in ISO/RTO regions that utilize them and alternative constructs in regions without capacity markets. The conference explored current and impending risks to resource adequacy, including increasing load forecasts and potential resource shortfalls; the effectiveness of capacity markets in ensuring resource adequacy at just and reasonable rates; comparisons between capacity markets and alternative constructs; and the roles and interests of states and other entities with legal authority over resource adequacy. A June 5 panel that addressed Resource Adequacy Challenges in the Northeast RTOs/ISOs included Emilie Nelson (NYISO, Executive Vice President and Chief Operating Officer), Stephen George (ISO-NE, Vice President of System Operations and Market Administration), Adam Evans (NY DPS, Chief of Wholesale and Clean Energy Markets), MPUC Chairman Phil Bartlett, CT DEEP Commissioner Katie Dykes, Michelle Gardner (NextEra Energy Resources, Executive Director Northeast Region), Pallas Lee VanShaick (Potomac Economics), and Sarah Bresolin (NEPOOL Chair).

Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. On June 5, 2025, the FERC invited post-technical conference comments to be filed on or before July 7, 2025. Post-technical conference comments were filed by over 60 parties, including the following: [Acadia Center](#), [Dominion](#), [LS Power](#), [National Grid](#), [NEPGA](#), [NESCOE](#), [Shell](#), [ACPA](#), [AMP](#), [APPA](#), [Concentric](#), [EEI](#), [EPSA](#), [FRS](#), [LPPC](#), [NRECA](#), [TAPS](#), [UCS](#), and [Public Citizen](#).

- **Joint Federal-State Current Issues Collaborative⁸⁹ (AD24-7)**

Next Meeting Feb 2026. The next meeting of the Collaborative (previously scheduled for November 12 in Seattle, Washington) has been moved to **February 2026** during NARUC's Winter Policy Summit in Washington, DC.

⁸⁹ *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.

Notice of 2025/26 State Commission Representatives. In accordance with the *Appointment Procedure Order*,⁹⁰ the FERC gave notice on September 22, 2025 of NARUC's appointment of the state commission representatives to the Collaborative for the August 28, 2025 through August 27, 2026 term. The NECPUC representatives will again be MPUC Chairman Phil Bartlett and NH PUC Commissioner Pradip Chattopadhyay.⁹¹

- **2025-2026 Winter Energy Market and Electric Reliability Assessment Staff Report (AD06-3)**

On November 25, 2025, the FERC's Office of Technical Reporting and Economics and the Office of Electric Reliability issued its 2025-2026 Winter Energy Market and Electric Reliability Assessment ("Winter Report") summarizing the FERC's outlook for December 2025-February 2026 winter conditions, predicting slightly warmer temperatures nationally, adequate operating reserves in all NERC assessment areas under normal winter conditions with possible reliability challenges under extreme conditions, 26% higher natural gas prices despite increased production, continued growth in LNG exports, and a net increase in U.S. winter generating capacity and transmission line-miles. The Winter Report also notes new cold-weather planning standards for generators and transmission, ISO-NE's expanded 21-day energy and winter readiness assessments, greater use of probabilistic tools to gauge energy shortfall risk, and the possibility of higher uplift costs when RTOs/ISOs commit resources in advance of forecasts of extreme cold. These filings are not noticed for public comment.

- **Proposed Policy Statement: Waiver of Tariff Requirements (PL20-7)**

On November 20, 2025, the FERC withdrew its Proposed Policy Statement on Waiver of Tariff Requirements⁹² and terminated this proceeding.⁹³ The Proposed Policy Statement set forth an approach that the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive ratemaking. In withdrawing the Proposed Policy Statement and terminating the proceeding, the FERC found that (i) the record did not support adopting the Proposed Policy Statement and (ii) the issues discussed in the Proposed Policy Statement are, "in general, better considered on a case-by-case basis."⁹⁴ There is no change to the FERC's policy on waiver of its prior notice requirements.⁹⁵

Importantly, however, the FERC "encourage[d] regulated entities to adopt tariff revisions that: (1) allow the entities to cure good-faith errors themselves within a discrete period of time without the need for a [FERC] waiver, and also tariff revisions that (2) provide advanced notice in the tariff that specific provisions may be waived" by a FERC order. Both avenues, the FERC suggested, "may help to avoid conflicts with the filed rate doctrine and rule against retroactive ratemaking, which in the past have prevented the [FERC] from granting some waiver requests that may have yielded more equitable outcomes."⁹⁶

⁹⁰ *Federal and State Current Issues Collaborative*, 192 FERC ¶ 61,056, at P 3 (July 17, 2025) ("*Appointment Procedure Order*") (explaining that NARUC will fill state commissioner vacancies on the Collaborative without formal FERC appointment and that the FERC will issue periodic notices listing new members).

⁹¹ The remaining representatives are: from the Mid-Atlantic Conf. of Regulatory Utils. Comm'rs ("MACRUC") Comm'r Kelsey Bagot, VA State Corp. Comm'n and Comm'r Kathryn Zerfuss, PA PUC; from the Mid-America Regulatory Conf. Chair Sarah Martz, IA Utils. Comm'n and Comm'r Stacey Paradis, IL Commerce Comm'n; from the Southeastern Assoc. of Regulatory Util. Comm'rs Comm'r Karen Kemerait, NC Utils. Comm'n and Comm'r Gabriella Passidomo Smith, FL Pub. Svc. Comm'n; and from the Western Conf. of Pub. Svc. Comm'rs Vice Chair Nick Myers, AZ Corp. Comm'n and Chair Brian Rybarik, WA Utilities and Transportation Comm'n.

⁹² *Waiver of Tariff Requirements*, 171 FERC ¶ 61,156 (2020) ("Proposed Policy Statement").

⁹³ *Waiver of Tariff Requirements*, 193 FERC ¶ 61,135 (Nov. 20, 2025) (Withdrawing Proposed Policy Statement).

⁹⁴ *Id.* at P 21.

⁹⁵ *Id.* at P 24.

⁹⁶ *Id.* at P 23.

- **ANOPR: Interconnection of Large Loads to the Interstate Transmission System (RM26-4)**

On October 27, 2025, the FERC issued a Notice inviting comments on a Department of Energy (“DOE”) proposed Advance Notice of Proposed Rulemaking (“ANOPR”)⁹⁷ concerning standardized procedures for the timely and orderly interconnection of large loads to the interstate transmission system.⁹⁸ The ANOPR requests FERC take expeditious action and propose a framework under which “large loads” (defined as >20 MW) interconnecting directly to transmission (including AI data centers) would be studied and processed using LGIP/LGIA-style deposits, readiness requirements, and withdrawal penalties. Comments were due on or before November 14, 2025 and reply comments were due on or before November 28, 2025. U.S. Senator Edward J. Markey together with several other senators filed comments requesting FERC proactively investigate RTOs’ treatment of AI data centers and prioritize protection of residential ratepayers. The MA AG, MOPA, NH OCA, Brookfield, LS Power Development, Enel North America, Enerwise Global, Vitol, and Voltus intervened doc-lessly. The FERC granted the November 4 request for a 2-week extension of time, to November 28, 2025, to file initial comments filed by Organization of MISO States (“OMS”) and supported by the Organization of PJM States (“OPSI”) on November 5, 2025. On November 21, comments were filed by over 100 parties including by ISO-NE, New England Public Systems,⁹⁹ the New England Consumer-Owned Systems (“NECOS”)¹⁰⁰ jointly with Energy New England, LLC (“ENE”), Advanced Energy United (“AEU”), Maine Office of the Public Advocate (“MOPA”), MA AG with RI DPUC and CT DEEP, NESCOE, NEPGA, American Public Power Association (“APPA”), American Clean Power Association (“ACPA”), Union of Concerned Scientists, Eversource, Constellation, National Grid, Vistra, Energy New England, ENGIE, Shell, NRG, LS Power Development, Invenergy, Voltus, Google, Microsoft, Meta Platforms, Amazon Energy, PSEG Companies,¹⁰¹ and the PPL Companies.¹⁰²

- **Order 914: Implementation of EO 14270 (RM25-14)**

On October 1, 2025, the FERC issued a direct final rule (*Order 914*)¹⁰³ and a related NOPR, in response to Executive Order 14270 (“Zero-Based Regulatory Budgeting to Unleash American Energy”) (see Executive Orders Section above),¹⁰⁴ to sunset 53 regulations identified as outdated or unnecessary. *Order 914* establishes a one-year sunset from its *December 5, 2025* effective date,¹⁰⁵ after which the regulations will be removed from the Code of Federal Regulations and the FERC will no longer treat them as effective, unless adverse comments are received by November 20, 2025. If “significant adverse comments”¹⁰⁶ are filed, the FERC will publish a document

⁹⁷ *Ensuring the Timely and Orderly Interconnection of Large Loads*, Advance Notice of Proposed Rulemaking (Oct. 23, 2025). The FERC Notice and DOE letter accompanying the ANOPR noted that the ANOPR was issued pursuant to the Secretary of Energy’s authority in section 403 of the Department of Energy Organization Act.

⁹⁸ The full text of the October 23, 2025 ANOPR is available here: <https://www.energy.gov/sites/default/files/2025-10/403%20Large%20Loads%20Letter.pdf>.

⁹⁹ New England Public Systems consists of: Connecticut Municipal Electric Energy Cooperative (“CMEEC”), the Massachusetts Municipal Wholesale Electric Company (“MMWEC”), and the Vermont Public Power Supply Authority (“VPPSA”).

¹⁰⁰ NECOS are: Belmont Mun. Light Dept, Block Island Utility District, Braintree Elec. Light Dept, Concord Mun. Light Plant, Danvers Elec. Division, Georgetown Mun. Light Dept, Groveland Elec. Light Dept, Hingham Mun. Lighting Plant, Hudson Light & Power Dept, Littleton Elec. Light & Water Dept, Merrimac Mun. Light Dept, Middleborough Gas & Elec. Dept, Middleton Elec. Light Dept, North Attleborough Elec. Dept, Norwood Mun. Light Dept, Clear River Elec. & Water District, Rowley Mun. Lighting Plant, Stowe Elec. Dept, Taunton Mun. Lighting Plant, Town of Wallingford, CT Dept of Public Utilities Elec. Division, Westfield Gas and Elec. Light Dept, and Mid-Coast Regional Redevelopment Authority.

¹⁰¹ PSEG Companies are: Public Service and Gas Company (“PSE&G”), PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

¹⁰² PPL Companies are: PPL Electric Utilities Corp. (“PPL Electric”), Louisville Gas & Electric Co. (“LG&E”) and Kentucky Utilities (“KU”) (collectively, “LG&E/KU”), and The Narragansett Electric Company d/b/a Rhode Island Energy (“RIE”).

¹⁰³ *Implementation of the Executive Order Entitled “Zero-Based Budgeting to Unleash American Energy”*, Order No. 914, 193 FERC ¶ 61,002 (Oct. 1, 2025) (“*Order 914*”); Errata Notice correcting regulatory text section, Oct. 21, 2025.

¹⁰⁴ EO 14270, Zero-Based Regulatory Budgeting to Unleash American Energy (Apr. 9, 2025).

¹⁰⁵ *Order 914* was published in the *Fed. Reg.* on Oct. 21, 2025 (Vol. 90, No. 201) pp. 48,397-48,408.

¹⁰⁶ See *Order 914* at P 3 for the definition of “significant adverse comment.”

that withdraws any such part of this action and will address the comments received in a subsequent final rule as a response to the companion NOPR (RM25-14) or take other action as it may deem appropriate. Comments were filed by the [American Conservative Union Foundation's](#) Center for Regulatory Freedom (d/b/a Conservative Political Action Coalition Foundation), [Our Children's Trust](#), [Joint Comments of the American Gas Association and the American Public Gas Association](#), and two individuals.¹⁰⁷

- **ANOPR: Implementation of Dynamic Line Ratings (RM24-6)**

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")¹⁰⁸ seeking comments on both the need for a dynamic line ratings ("DLRs")¹⁰⁹ requirement and proposed framework of DLR reforms to improve the accuracy of transmission line ratings. Proposed reforms would require transmission providers to implement, on all transmission lines, DLRs that reflect solar heating, based on the sun's position and forecastable cloud cover, and on certain transmission lines, DLRs that reflect forecasts of wind speed and wind direction. The FERC seeks comments about whether to reflect hourly solar conditions and wind conditions in all transmission line ratings, how transmission congestion levels and environmental factors could identify locations of transmission lines that would most benefit from DLR, and what other technical details of transmission line ratings reflect wind conditions. A more detailed summary of the ANOPR was provided to and reviewed with the Transmission Committee. Comments in response to the ANOPR were due October 15, 2024¹¹⁰ and were filed by nearly 70 parties, including by the following New England parties: [ISO-NE](#), [AEU](#), [Avangrid](#), [Dominion](#), [Eversource](#), [MA AG](#), [National Grid](#), [NESCOE](#), [NextEra](#) (on October 22), [EEI](#), [EPSA](#), [NASUCA](#), [NERC](#), [PIOs](#), [Public Power](#),¹¹¹ [TAPS](#), and [R Street Institute](#). Nine sets of reply comments were filed, including from: [ISO-NE](#), [DC Energy](#), and the [US DOE](#).

- **NOPR: Duty of Candor (RM22-20)**

On November 20, 2025, the FERC also withdrew its *Duty of Candor NOPR*¹¹² which proposed to add a regulation requiring that any entity communicating with the FERC or other specified organizations related to a matter subject to FERC jurisdiction submit accurate and factual information and not submit false or misleading information or omit material information.¹¹³ Based on the feedback received, the FERC exercised its discretion to withdraw the NOPR and terminate this proceeding. The FERC stressed that "there are numerous existing regulations that prohibit untruthful, inaccurate, or incomplete communications to the [FERC] and other organizations upon which [the FERC] relies," regulations which the FERC "will continue to diligently enforce".¹¹⁴

¹⁰⁷ These individuals are "[Jvd Veen](#)" and "[Charlotte Lorthioir](#)."

¹⁰⁸ *Implementation of Dynamic Line Ratings*, 187 FERC ¶ 61,201 (Jun. 27, 2024) ("*DLR ANOPR*"). The ANOPR reflects public comments in response to the FERC's February 17, 2022, Notice of Inquiry ("NOI") on DLRs. The NOI, in turn, found its roots in *Order 881*, which required transmission line ratings to reflect ambient air temperatures to improve efficiency in operating transmission lines.

¹⁰⁹ DLRs, are transmission line ratings that reflect up-to-date forecasts of weather conditions, such as ambient air temperature, wind, cloud cover, solar heating, and precipitation, in addition to transmission line conditions such as tension or sag.

¹¹⁰ The ANOPR was published in the *Fed. Reg.* on July 15, 2024 (Vol. 89, No. 135) pp. 57,690-57,716.

¹¹¹ "Public Power" is: The National Rural Elec. Coop. Assoc. ("NRECA"), the American Public Power Assoc. ("APPA"), and the Large Public Power Council ("LPPC").

¹¹² *Duty of Candor*, 193 FERC ¶ 61,129 (Nov. 20, 2025) (Withdrawing Duty of Candor NOPR).

¹¹³ *Duty of Candor*, 87 FR 49784 (Aug. 12, 2022), 180 FERC ¶ 61,052 (2022) ("*Duty of Candor NOPR*").

¹¹⁴ *Id.* at P 2.

XIII. FERC Enforcement Proceedings

- **2025 Office of Enforcement Staff Report (AD07-13-019)**

On November 20, 2025, the FERC's Office of Enforcement and Regulatory Accounting¹¹⁵ issued its 2025 Report on Enforcement summarizing FY2025 activities and priorities. Highlights include: Enforcement's focus on fraud/market manipulation, serious Reliability Standard violations, anticompetitive conduct, threats to energy infrastructure, and conduct undermining market transparency; 13 FERC-approved settlements totaling approximately \$22.84 million in civil penalties and \$18.73 million in disgorgement; 24 investigations opened (17 were closed with no action) involving tariff violations, market manipulation and duty-of-candor issues; and 304 Hotline inquiries, 297 of which were resolved within the fiscal year. The Report also notes a joint gas-electric reliability review of the January 2025 winter storms presented at the April 17, 2025 open meeting, continued Order No. 898 implementation work within the Division of Audits and Accounting, and Division of Analytics and Surveillance's ongoing market surveillance with EQR administration to transfer to DAS in FY2026. These reports are not noticed for public comment.

Electric-Related Enforcement Actions

- **American Efficient Show Cause Order (IN24-2)**

As previously reported, the FERC issued on December 16, 2024 a show cause order¹¹⁶ in which it directed American Efficient, LLC, its various subsidiary companies,¹¹⁷ and its corporate parents¹¹⁸ (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;¹¹⁹ 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").¹²⁰ 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 may seek a modification of these amounts consistent with FPA § 31(d)(4).¹²¹

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

¹¹⁵ In August 2025, the Office of Enforcement was renamed the Office of Enforcement and Regulatory Accounting.

¹¹⁶ *American Efficient, LLC et al.*, 189 FERC ¶ 61,196 (Dec. 16, 2024) ("*American Efficient Show Cause Order*").

¹¹⁷ Affirmed Energy LLC, Wylan Energy L.L.C., Midcontinent Energy LLC, and Maple Energy LLC.

¹¹⁸ Modern Energy Group LLC and MIH LLC.

¹¹⁹ 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."

¹²⁰ 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.

¹²¹ 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."

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 updates on some related federal court developments, each of which it asserted weigh against rushing if not issuing a penalty order. Since the last Report, 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.

This matter remains pending before the Commission. 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)**

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas ("Northern District") issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,¹²² suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

On June 14, 2023, the FERC issued an Order on Presiding Officer Reassignment,¹²³ which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

- **Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)**

On December 16, 2021, the FERC issued a show cause order¹²⁴ in which it directed Rover and ETP (together, "Respondents") to show cause why they should not be found to have 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 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;

¹²² See *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*"). The hearings will be to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "Respondents") violated section 157.5 of the FERC's regulations and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.

¹²³ *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 183 FERC ¶ 61,190 (June 14, 2023) ("*June 14 Order*").

¹²⁴ *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 177 FERC ¶ 61,182 (Dec. 16, 2021) ("*Rover/ETP Tuscarawas River HDD Show Cause Order*").

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*").

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.

and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed **\$40 million** in civil penalties.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, 2022, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.¹²⁷ This matter is pending before the FERC.

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

- **Order 915: Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing (RM25-9)**

On October 7, 2025, the FERC issued its final rule removing from its regulations a rule that precludes the issuance of authorizations to proceed with construction activities with respect to natural gas facilities approved pursuant to section 3 or section 7 of the NGA for a limited time while certain requests for rehearing are pending before the FERC.¹²⁸ On November 6, 2025, NRDC requested rehearing of *Order 915*. That request is pending, with FERC action required by **December 8, 2025** or the request will be deemed denied by operation of law.

New England Pipeline Proceedings

The following New England pipeline projects are currently under construction or before the FERC:

- **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.
 - Algonquin submits supplemental information to its Application on October 30, 2025.
 - Interventions filed by NSTAR Electric, NSTAR Gas, National Grid Gas Delivery Companies, and New York State Gas & Electric and Maine Natural Gas Co. Comments filed by a number of Chambers of Commerce on the Cape.
 - FERC issues data request on November 13, 2025 and Algonquin submits response on November 20, 2025

¹²⁷ *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 179 FERC ¶ 61,090 (May 11, 2022) ("*Designation Notice Rehearing Order*"). The "Designation Notice" provided updated notice of designation of the staff of the FERC's Office of Enforcement ("OE") as non-decisional in deliberations by the FERC in this docket, with the exception of certain staff named in that notice.

¹²⁸ *Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing*, Order No. 915, 193 FERC ¶ 61,014 (Oct. 7, 2025) ("*Order 915*").

- **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).
- ▶ Three-year construction project; service now requested for **March 25, 2027**.
- ▶ On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.¹²⁹ The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within **three years** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
- ▶ On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- ▶ On June 17, 2022, in accordance with the *Iroquois Certificate Order*, Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- ▶ On October 28, 2024, Iroquois requested an extension of time, until **March 25, 2027**, to construct and place into service its Enhancement by Compression Project (Project) located in Greene and Dutchess Counties, New York and Fairfield and New Haven Counties, Connecticut as authorized in the *Iroquois Certificate Order*. (The *Iroquois Certificate Order* required Iroquois to complete construction of the Project and make it available for service within three years of the date of the Order or by March 25, 2025.) Iroquois stated that construction of the Project has been delayed due to pending state permit approvals, specifically air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois asserts that it has been working in good faith with these agencies and expects to receive approvals for the Project in the near future.
- ▶ Comments on Iroquois' request were due on or before November 15, 2024. Protests and comments were filed by the Sierra Club of Connecticut, Save the Sound, and nearly 20 individual citizens. A number of others requested an extension of time to comment, but those requests have not been (nor should be expected to be) acted on by the FERC.¹³⁰
- ▶ On February 19, 2025, the FERC granted the requested two-year extension of time, to March 25, 2027, to construct the project and place it into service.¹³¹ The FERC found that Iroquois has worked and continues to work toward obtaining the state permits necessary to enable construction to commence, no bad faith or delay on Iroquois's behalf, and therefore good cause to grant the two-year extension of time to complete construction of the project.¹³²

¹²⁹ *Iroquois Gas Transmission Sys., L.P.*, 178 FERC ¶ 61,200 (2022) ("*Iroquois Certificate Order*").

¹³⁰ The FERC will aim to issue an order acting on the request within 45 days. The FERC will address all arguments relating to whether the applicant has demonstrated there is good cause to grant the extension. The FERC will not consider arguments that re-litigate the issuance of the certificate order, including whether the Commission properly found the project to be in the public convenience and necessity and whether the Commission's environmental analysis for the certificate complied with NEPA.

¹³¹ *Iroquois Gas Transmission System, L.P.*, 190 FERC ¶ 61,112 (Feb. 19, 2025).

¹³² *Id.* at P 15.

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).

- **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: RM22-22¹³³

Status: Briefing underway

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 (January 17, 2026); FERC’s Brief (April 17, 2026); Response Brief Intervenors in Support of FERC (May 1, 2026); Petitioners’ Reply Briefs (June 1, 2026); Deferred Joint Appendix (June 8, 2026); and Final Briefs (June 15, 2026)).

- **Order 1920: Transmission Planning Reforms (4th Circuit – 24-1650)**

Case Title: *Appalachian Voices v. FERC*

Underlying FERC Proceeding: RM21-17¹³⁴

Status: Briefing Underway

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*.¹³⁵ 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 Response Brief is due January 5, 2026. Since the Last Report, Organization of PJM States (OPSI) filed and was granted its motion to file an amicus curiae brief, due February 4, 2026. Petitioners reply briefs will be due February 25, 2026; the Joint Appendix must be filed by March 4, 2026; and final briefs by March 11, 2026.

¹³³ *Compensation for Reactive Power Within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (Oct. 17, 2024).

¹³⁴ *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*”).

¹³⁵ Petitioners for review of *Order 1920* have also been filed in the 1st, 4th, 5th, and 9th Circuits.

- **Orders 2023 and 2023-A (23-1282 et al.) (consolidated)**

Case Title: *Advanced Energy United, et al. v. FERC*

Underlying FERC Proceeding: RM22-14¹³⁶

Status: Oral Argument Held September 26, 2025; Decision Pending

Several Petitioners have challenged *Orders 2023 and 2023-A*. Those challenges were consolidated, with the AEU docket (23-1282) as the lead docket. Briefing is now complete. Oral argument was held **September 26, 2025** before a merits panel comprised of Judges Millett, Walker, and Childs. This matter remains pending before the Court.

- **CASPR (20-1333, 21-1031) (consolidated)****

Case Title: *Sierra Club, et al. v. FERC*

Underlying FERC Proceeding: ER18-619¹³⁷

Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF

Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due 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 four times. In the most recent request (filed March 1, 2024) (fourth abeyance request), Petitioners asked the Court to hold this matter in abeyance until March 1, 2026 "in light of the continued delay of the revisions to its capacity market that ISO New England previously asserted were a predicate to eliminating the market impediment that is the subject of the underlying claims before the Court". The Court granted the request on May 12, 2024, ordering the parties to file motions to govern future proceedings by **March 2, 2026**.

- **Opinion 531-A Compliance Filing Undo (20-1329)**

Case Title: *Central Maine Power Company, et al. v. FERC*

Underlying FERC Proceeding: ER15-414¹³⁸

Petitioners: TOs (CMP et al.)

Status: Being Held in Abeyance

On August 28, 2020, the TOs¹³⁹ 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*¹⁴⁰ decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future

¹³⁶ *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*"); 184 FERC ¶ 62,163 (Sep. 28, 2023) (Notice of Denial of Rehearing by Operation of Law).

¹³⁷ *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

¹³⁸ *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

¹³⁹ 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.

¹⁴⁰ *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged *Order Rejecting Compliance Filing*, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status reports at 120-day intervals. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the FERC remain ongoing and that this appeal should continue to remain in abeyance, was filed on November 13, 2025.

- **Avangrid/NextEra NECEC Civil Suit (D.MA) (Civil Action No. 24-30141-MGM)**

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 has been set for **December 18, 2025**.

- **Allco PURPA Enforcement Petition (D.CT) (Case No. 3:25CV01321)**

Case Title: *Allco Finance Limited Inc. v. Dykes et al.*

Status: **Responses to Motions to Dismiss Due Dec 15, 2025**

Following a FERC notice¹⁴¹ that it had decided not to act on Allco's PURPA Complaint related to Connecticut's¹⁴² implementation under section 210 of PURPA of its Shared Clean Energy Facility ("SCEF")

¹⁴¹ *Allco Finance Limited*, 192 FERC ¶ 61,116 (Aug. 4, 2025).

¹⁴² 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").

Program,¹⁴³ Allco brought an enforcement action against Connecticut in federal district court in Connecticut.¹⁴⁴ *Allco Finance Limited Inc. v. Dykes et al.* (case no. 3:25CV01321). On November 24, 2025, Defendants¹⁴⁵ filed a motion to dismiss the Complaint and stay discovery. DEEP Commissioner, Katie S. Dykes, PURA Commissioners, David Arconti, Michael Caron, and Marissa Gillett,¹⁴⁶ and DOAG Commissioner, Bryan P. Hurlburt, also filed a joint motion to dismiss the Complaint. Responses are due on or before **December 15, 2025**.

¹⁴³ 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.

¹⁴⁴ 16 U.S.C. § 824a-3(h)(2)(B).

¹⁴⁵ Defendants are UI, Avangrid Networks, Inc., Avangrid, Iberdrola, S.A., Charlotte Ancel, and Pedro Azagra Blázquez.

¹⁴⁶ Marissa Gillett resigned her position as chair of PURA, effective Oct. 10, 2025.

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Admin
Matters

Dec 4, 2025
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