David T. Doot
Secretary

December 29, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

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

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the January meeting of the Participants Committee will be held **in person on *Thursday*, January 6, 2022, at the Seaport Boston Hotel, 1 Seaport Lane, Boston, MA in the Seaport Ballroom** for the purposes set forth on the attached agenda that has also been posted with the meeting materials at nepool.com/meetings/.

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

We have included with this notice the safety protocols that will be in effect for in-person attendance at the January 6 Participants Committee meeting. In summary, only those who are fully vaccinated, and have provided in advance of the meeting verification of full vaccination, will be permitted to attend in person. Pursuant to the City of Boston's mask mandate, all attendees must wear masks or face coverings at all times during an indoor meeting except when actively eating or drinking. Additional safety measures are outlined in the protocols. An e-mail with instructions for meeting registration will be sent under separate cover.

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

There are a limited number of rooms available at the Seaport Boston Hotel for the evening before the January 6 meeting at the rate of $149.00 per night, on a first-come, first-served basis through **Friday, December 31, 2021**. Please make your reservation here or contact the hotel directly (1-877-732-7678) and reference the "**New England Power Pool**" block of rooms.

Happy Holidays to each of you.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the December 2, 2021 Participants Committee Annual Meeting. The draft preliminary minutes of that meeting, marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

2A. To consider, and take action, as appropriate, on proposed Billing Policy changes to require Requested Billing Adjustments (RBAs) to be submitted to Participant Support and Solutions at the ISO via its support system (currently AskISO). Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

2B To consider and take action, as appropriate, on the following revisions to (i) convert some credits and charges in the Forward Capacity Market (FCM) settlement to a daily settlement; and (ii) correct inconsistencies and remove outdated language:

   i. Revisions to Tariff § 1.2.2, Market Rule 1 §§ 3.8 and 13, Appendix I to Market Rule 1 (Form of Cost of Service Agreement), and Manual M-28 (Market Rule 1 Accounting), as recommended by the Markets Committee at its November 9-10, 2021 meeting; and

   ii. Revisions to the Billing and Financial Assurance Policies, as considered by the Budget & Finance Subcommittee at its October 12, 2021 meeting.

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

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

4. To receive a report from the ISO Chief Operating Officer. The January COO report will be circulated and posted in advance of the meeting.

[continued on next page]

5. To consider and take action, as appropriate, on the following Tariff revisions in response to the FERC's Final Rule on the participation of distributed energy resource aggregations in ISO/RTO markets (Order 2222):

   a. Revisions to Tariff § 1.2.2 and Market Rule 1, as recommended by the Markets Committee at its December 7-9, 2021 meeting;

   b. Revisions to Tariff § 1.2.2 and § II, as recommended by the Transmission Committee at its December 13, 2021 meeting; and

   c. Revisions to Tariff §§ I.2.2, III.1.5, III.1.7.13, and III.12, as recommended by the Reliability Committee at its December 14, 2021 meeting.

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

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

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

8. Administrative matters.

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

NEPOOL
NEW ENGLAND POWER POOL

Protocols for In-Person Attendance at NEPOOL Meetings
During the Covid-19 Pandemic

These protocols for return to in-person NEPOOL meetings are effective as of the date above and may be modified from time to time as guidelines from the U.S. Centers for Disease Control ("CDC"), applicable state or local requirements, or circumstances change.

Background

The Protocols provided herein outline recommended and preventative measures to reduce the COVID-related risks associated with attendance in person at NEPOOL meetings.[1] Measures include safety precautions individuals must take while at in-person meetings. In-person attendance will follow and adhere to the latest CDC guidelines (as well as any additional, applicable state or local requirements that may be in place). As with any in-person meeting, there will be COVID-related risks associated with in-person attendance. **Each in-person attendee should perform their own risk/benefit calculus in deciding whether to participate in-person or remotely.**

Safety Precautions

Proof of Full Vaccination Required. To attend a NEPOOL meeting in person, each attendee must be fully vaccinated.[2] Proof of vaccination (e.g., a copy of a completed COVID-19 Vaccination Record/Card) must be provided to NEPOOL counsel (pmgerity@daypitney.com) in advance of the meeting.[3] An attendee who is unable to provide a copy of a completed COVID-19 Vaccination Record may sign and provide a COVID-19 Vaccination Status Attestation as an alternate form of proof. All such records will be maintained by NEPOOL Counsel in a confidential file. Those who are not vaccinated, or who have not timely provided proof of vaccination, will not be permitted in the meeting room and will be encouraged to participate by teleconference/WebEx. An individual's ability to attend a meeting in person will be restored following proof of vaccination.

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[1] NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting.

[2] A person is considered fully vaccinated: (i) 2 weeks after their second dose in a 2-dose series, such as the Pfizer or Moderna vaccines, or (ii) 2 weeks after a single-dose vaccine, such as Johnson & Johnson's Janssen vaccine. If you don't meet either of these criteria, regardless of age, you are NOT fully vaccinated.

[3] Proof of vaccination of ISO employees or representatives, as a condition of their in-person attendance, will be confidentially (i) collected and maintained by the ISO and (ii) verified by an ISO committee officer with NEPOOL counsel in advance of attendance at a meeting.

Registration Required; Contact Tracing. Registration for in-person attendance will be required and the Committee Secretary will keep a separate record of all individuals in attendance in person for the purpose of later contact tracing. Specific contact tracing information is confidential and NEPOOL will not use this information for any other reason. Contact tracing information will be kept for 28 days and destroyed thereafter.

Attendance In-Person Not Permitted if Experiencing Covid-19 Indicative Symptoms. Individuals should not attend an in-person meeting if they are experiencing new or worsening symptoms of any of the following in the last 14 days:

- Fever of 100.4 ^{0}F (38.0 ^{0}C) or higher
- Chills
- Cough
- Shortness of breath or difficulty breathing
- Fatigue
- Muscle or body aches
- Headache
- New Loss of Taste or Smell
- Sore Throat
- Congestion or runny nose
- Nausea or vomiting
- Diarrhea

Attendance In-Person Not Permitted if Recent Exposure to Covid-19-Positive Individual. Individuals should not attend in-person meetings if they have had a likely exposure to a COVID-19 positive individual in the last 14 days.

Physical Distancing. The opportunity for physical distancing at meeting tables will be provided where and as possible, but will not be enforced. Attendees are encouraged, whenever otherwise possible, to separate themselves by 6 feet of distance. Seating at round tables should be limited to six or fewer.

Masks. If and as required by CDC guidelines or by the requirements of the state or locale in which the meeting is taking place, face coverings ("masks") shall be worn. Where physical distancing cannot be maintained, it is recommended that attendees wear masks whenever they are not seated, including while in transit to or from their seat and while standing in lines or in the room.

Sanitizing. Hand sanitizer and wipes will be made available at each meeting. Additional arrangements will be implemented to facilitate sanitation measures. (e.g. All microphones will be positioned and sanitized prior to arrival. Microphones will also be sanitized at lunch and at the end of the day. Alcohol sanitizing wipes will be available for attendees to utilize during the meeting to sanitize the microphones between users.)

Reporting and Communicating a Positive COVID-19 Result

In the event of a COVID-19-positive test result, an individual that attended an in-person meeting within 14 days of that result should immediately contact NEPOOL Counsel (pmgerity@daypitney.com) to report their COVID-19 status. NEPOOL Counsel will maintain the individual's privacy while notifying those that attended the meeting in person of the positive test result. Please be advised that all health information is private and strictly confidential and will only be shared on a need-to-know basis to confirm and trace any contact with the positive tester at a NEPOOL in-person meeting and contact those who may have been exposed. Any notice of a COVID-19-positive test result will be kept for 28 days and destroyed thereafter.

Remote Participation

For those individuals who are otherwise authorized to attend a NEPOOL meeting, but choose not to, or because of safety measures are unable to, attend meetings in person, remote participation (i.e. by teleconference and/or by WebEx) will continue to be made available.

PRELIMINARY

Pursuant to notice duly given, the annual meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, December 2, 2021, at the Colonnade Hotel, Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting.

Mr. David Cavanaugh, Chair, presided, and Mr. David Doot, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and guests who were present, including ISO Board Members Cheryl LaFleur, Caren Anders and Brook Colangelo, and numerous guests from the FERC and New England state officials.

REMARKS BY ISO BOARD CHAIR CHERYL LAFLEUR

The Chair recognized ISO Board Chair Cheryl LaFleur for some introductory remarks. Board Chair LaFleur began by recognizing the attendance of FERC Commissioner Allison Clements. She introduced Ms. Caren Anders, one of the new ISO Board members, highlighting Ms. Anders' leadership experience in transmission operations and planning. Ms. LaFleur also recognized Mr. Brook Colangelo in the audience and noted that he would chair the Joint Nominating Committee efforts to identify and recommend a slate of candidates for election to the Board in 2022. She then briefly described her expectations and her outlook with respect to the various issues facing the region in 2022. She concluded her remarks with comments about the upcoming winter, noting that ISO management was working diligently to prepare for the colder temperatures utilizing all tools available and necessary. She noted plans for a regional press conference planned for the following week, which would address winter preparations, expectations and concerns, as had also been discussed at the November Participants Committee meeting.

APPROVAL OF NOVEMBER 3, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the November 3, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

REMARKS BY FERC COMMISSIONER ALLISON CLEMENTS

Mr. Cavanaugh welcomed ~~FERC~~ Commissioner ~~Allison~~ Clements and introduced her to the Committee.

Commissioner Clements expressed appreciation for the chance to meet and speak in person with New England stakeholders. She introduced her Technical Advisors who had joined her at the meeting: Mr. Kris Fitzpatrick, Ms. Vivian Chum, and legal intern Patrick Montgomery.

Commissioner Clements began by noting that the energy sector was facing an overall system challenge largely due to ongoing cyber threats and climate change-induced weather conditions. She acknowledged the need to address this new energy future, noting that New England was at the forefront of the need for change given its climate and the tight interrelationship between local commodity prices and electricity prices. She reflected that system problems require system solutions and those solutions need to protect customers and ensure reliability. She noted the importance of collaboration and coordination across jurisdictional lines in the collective efforts ahead, as market issues and transmission priorities greatly impact reliability and resilience.

Commissioner Clements then discussed two key topics – wholesale power markets and transmission planning. With respect to wholesale power markets, she said that the industry needed to move beyond reliance on a minimum offer price rule (MOPR) and acknowledged New England's efforts in that regard. She commented favorably on the fact that the region was considering more closely the contribution to reliability of each type of resource (which she referred to as ELCC (Effective Load Carrying Capability)) and expressed the view that market reforms need to provide certainty and facilitate a changing resource mix. She urged innovative thinking and a nondiscriminatory approach to using wholesale market competition to help achieve system reliability. She noted New England's historic leadership on energy efficiency, and the ability of the New England States to expand on the set of resources available. She further commented favorably on the Future Grid efforts in the region.

Addressing transmission planning, Commissioner Clements referred to the FERC's Advanced Notice of Proposed Rulemaking on building for the future through regional transmission planning and cost allocation and generator interconnection (Transmission ANOPR), and noted the broad consensus for reform and the need for significant new transmission investment. Referring to the extensive comments that had been received in response to the Transmission ANOPR, she acknowledged that there was not consensus on the details and those would need to be worked out. She expressed the need for long-term planning that goes beyond 10 years. She opined that the magnitude of the potential investment suggested the need for an oversight mechanism to ensure costs are reasonable. She then noted that transmission for offshore wind, a topic unique to the east coast and one that the FERC was currently addressing, was important to future transmission planning, cost allocation and interconnection.

Commissioner Clements concluded her prepared remarks and invited feedback and questions. In response to questions about potential improvements to facilitate renewable project development, she reminded the Committee that the FERC's role is to ensure just, reasonable and not unduly non-discriminatory rates for customers. Acknowledging that her comments reflected her personal views and perhaps not the views of the Commission, she opined that the FERC could help ensure that outcome through facilitating transmission planning that carefully balances investments based on their cost/benefit ratio and not necessarily based on what silo they might fit into in the markets. She agreed that the pace of transition was taking a lot of time and would ideally be accelerated to reduce investment uncertainty. For that to happen, Commissioner Clements encouraged stakeholders to focus more on moving forward together towards common goals that account for a full suite of future needs.

She acknowledged the challenges for the FERC to prioritize next steps with respect to potential transmission planning reforms. She noted that everything was on the table and being reviewed by the FERC and that prioritization would follow the FERC's consideration of the multiple comments received. She was asked to consider the fact that necessary and appropriate market reform may well be different in each region of the country. In response, Commissioner Clements acknowledged that she understood the importance of regional differences and would take that request back to her colleagues. Commenting in response to a question on the proposal in the Transmission ANOPR for an- independent transmission monitor, she explained that the proposal was one of a number of ideas being considered in order to provide assurance that future transmission investments are prudent. In response to concerns about- the increasingly blurred line between FERC and state jurisdiction, she noted recent Supreme Court guidance and the current efforts underway to improve communications and cooperation between the FERC and the states.

On behalf of the Committee, Mr. Cavanaugh thanked the Commissioner for her time, her travel to New England, and her thoughtful comments.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved as circulated, with an abstention by Mr. Kuser's alternate noted.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), offered his well-wishes for happy holidays and then referred the Committee to the summary of ISO New England Board and Committee Meetings that was circulated and posted in advance of the meeting. There were no questions or comments on the summary.

Additionally, Mr. van Welie talked about the ISO's planned press conference with regional media on December 6th to share details on the upcoming winter outlook and related reliability concerns. He noted that the materials, which would be distributed during the press conference, would also be posted on the ISO website.

ISO COO REPORT

~~***Operations Highlights***~~

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his ~~November~~December report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through November 22, 2021, unless otherwise noted. The report highlighted: (i) Energy Market value for November 2021 was $375 million, down $185 million from the updated October 2021 value of $560 million and up $130 million from November 2020; (ii) November 2021 average natural gas prices were 6.1% higher than October average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for November ($52.22/MWh) were 6.6% lower than October averages; (iv) average November 2021 natural gas prices and Real-Time Hub LMPs over the period were up 154% and 112%, respectively, from November 2020 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 98.6% during November (down from 99% in October), with the minimum value for the month (93.9%) on November 22; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for November totaled $2.5 million, which was down $1.0 million from October 2021 and down $0.6 million from November 2020. November NCPC payments, which were 0.7% of total Energy Market value, were comprised of: (a) $2.2 million in first contingency payments (down $0.7 million from October), (b) $177,000 in second contingency payments, and (c) $210,000 in voltage and distribution payments.

Addressing transmission outages, Dr. Chadalavada reported that the outage previously scheduled for the replacement of structures on line 312/393 from Northfield to Alps had been postponed and that line would be back in service later that day, restoring transfers to/from New York to 1,600 MW. He indicated in response to a question that the outage had not yet been rescheduled. He also noted an outage on the Buxton-Scobee line in Maine, line 391, planned for December 13 through December 18, which would limit transfers from the rest of New England into Maine and had the potential to require reliability commitments in Maine should there not be sufficient generation cleared in the market during the outage. In response to a question about the line 391 outage and a request for further analysis, Dr. Chadalavada noted that outage windows were scheduled and planned at times most ideal for generators and the ISO.

He was questioned about uplift in November resulting from generator auditing. He described the auditing results at a composite level from all generators and confirmed that the ISO typically audited certain generation prior to the winter. He indicated that the ISO would investigate providing more details concerning aggregate results to the extent possible without violating its confidentiality obligations.

Dr. Chadalavada reported that NERC GridEx VI, which included power systems, cyber security, and weather events, was conducted on November 16 and 17. Highlights from that exercise, including commentary from the local transmission owners, would be compiled and shared at a future meeting, which he thought would likely be in February.

Turning to the upcoming winter, he indicated that the latest 90-day weather outlook from the National Oceanic and Atmospheric Administration (NOAA) still indicated a 40-50% probability of above-normal temperatures for all of New England and an equal chance for above-average or below-average precipitation for the winter months of December, January and February. He reported that prices for January delivery of liquefied natural gas (LNG), as of November 19, were $29/~~MMBTU~~MMBtu for deliveries to Europe, $35/~~MMBTU~~MMBtu for deliveries to Asia, and $19/~~MMBTU~~MMBtu for deliveries to Algonquin/New England. He then noted that oil inventories for New England generators had increased slightly to 53% from 51% capacity, with limited new quantities expected. In response to a question, he confirmed that the oil inventory charts were intended to be updated on a weekly basis at this time.

2021 NEPOOL ANNUAL REPORT

Mr. Cavanaugh referred the Committee to the 2021 NEPOOL Annual Report, “Transitions: Preparing for Tomorrow’s Grid Today”, distributed at the meeting and posted on the NEPOOL website. Mr. Cavanaugh thanked the Day Pitney team for their efforts to assemble and complete that Annual Report. He encouraged Participant feedback on the format and substance of the Annual Report.

TRANSMISSION PLANNING REVISIONS

Ms. Emily Laine, Transmission Committee Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposal to revise ISO Tariff Sections I (Definitions) and II (Open Access Transmission Tariff (OATT), Attachment K) to authorize the ISO to conduct transmission planning studies in response to requests from NESCOE for such studies (Transmission Planning Revisions). She explained that the proposal was part of a larger process to “implement a state-led, proactive scenario-based planning process for longer term analysis of state mandates and policies as a routine planning practice”. She reported that the Transmission Committee unanimously supported a motion to recommend Participants Committee support for the Transmission Planning Revisions, with three abstentions in the Supplier Sector.

A Supplier Sector representative expressed his Participants’ support for the proposal after gaining additional information and fully understanding the intent. A NESCOE representative remarked that the proposal was a welcome way to cap off what had been another year of active engagement among NESCOE, ~~ISO-NE~~the ISO, and NEPOOL. He said that the Revisions put in place a key vision that the States set forth the year before in identifying the need for fundamental changes in connection with the regional electric system. The States supported the establishment of a state-led, scenario-based analysis as a permanent feature of ~~ISO-NE's~~the ISO's planning process, providing visibility to the region on future policy-driven transmission needs. He also noted that the Transmission Planning Revisions were directionally consistent with the kind of flexible planning tool that the FERC focused on in its Transmission ANOPR, when it identified concerns that existing planning processes failed to adequately account for anticipated future generation. On behalf of NESCOE, he then thanked the ISO for prioritizing this work and expressed his gratitude for the efforts of Brent Oberlin, Monica Gonzalez, and other ISO staff for translating a vision into Tariff language.

The following motion was duly made, seconded and unanimously approved, with an abstention by Mr. Kuser's alternate noted:

> RESOLVED, that the Participants Committee supports the Transmission Planning Revisions to Sections I and II of the ~~ISO-NE~~ISO Tariff as recommended by the Transmission Committee and as distributed to the Participants Committee for its December 2, 2021 meeting, together with any non-substantive changes agreed to by the Chair and Vice-Chair of the Transmission Committee after the meeting.

ELECTION OF 2022 PARTICIPANTS COMMITTEE OFFICERS

Mr. Cavanaugh referred the Committee to the proposed slate of 2022 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting.

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

> WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and
>
> WHEREAS, pursuant to those procedures the individuals identified in the following resolution were nominated and elected for 2022 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 2022 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	David A. Cavanaugh
Vice-Chair	Christina H. Belew
Vice-Chair	Sarah Bresolin
Vice-Chair	Francis J. Ettori, Jr.
Vice-Chair	Michelle C. Gardner
Vice-Chair	Aleksander Mitreski
Secretary	David T. Doot
Assistant Secretary	Sebastian M. Lombardi

ESTIMATED BUDGET FOR 2022 NEPOOL EXPENSES

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated and posted in advance of the meeting concerning the estimated budget for 2022 Participant Expenses (a copy of which is included as Attachment 2 to these minutes). He reported that, consistent with past practice, the Subcommittee worked with NEPOOL Counsel, the GIS Administrator, the ISO and NEPOOL's Independent Financial Advisor to develop the 2022 Budget. There were no concerns or objections identified by Subcommittee members.

Without further discussion, the following motion was duly made, seconded and approved unanimously, with abstentions noted by Cross-Sound Cable and Mr. Kuser's alternate:

> RESOLVED, that the Participants Committee adopts the estimated budget for NEPOOL expenses for 2022 as presented at this meeting.

LITIGATION REPORT

Mr. Doot referred the Committee to the December 1 Litigation Report that had been circulated and posted prior to the meeting. He highlighted the following:

(i) *Killingly Energy Center Capacity Supply Obligation (CSO) Termination Filing*. Comments on the ISO's filing were expected to be filed before the end of the following week;

(ii) *FCA16-related filings*. Information regarding qualification and auction parameters had been filed, with requests for waivers and protests of qualification requirements and determinations and comments on the parameters filed;

(iii) *Mystic ROE*. The FERC had modified its discussion and set aside in part its order on the return on equity (ROE) provided for in the Mystic cost of service agreement. This matter was already before the U.S. Court of Appeals for the DC Circuit;

(iv) *BTM Generation Proposal*. FERC staff~~-~~ had issued a second deficiency letter in the proceeding to consider the effect of behind-the-meter generation on the calculation of Regional Network Load. He explained that FERC would be required to act on that filing within the 60 days after the response to the second deficiency letter (due December 13) ~~has been~~was filed;

(v) *Transmission ANOPR*. A technical conference took place on November 15th and comments had been filed and were in the record; and

(vi) *Commissioner Willie Phillips Congressional Confirmation*. Commissioner Phillips had been confirmed by Congress and, once sworn in, would restore the Commission to its full complement of five members.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting would be held virtually on December 7, 8 and 9 and would include a discussion on MOPR and votes on Tariff changes in response to Order 2222.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the regularly-scheduled RC meeting would be held on December 14 and would include a presentation of stakeholder concerns with the ISO's assumptions in modeling batteries.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the scheduled December 13 TC meeting would include a vote on interconnection-related Tariff changes as part of the response to the requirements of Order 2222.

Budget & Finance Subcommittee. Mr. Cavanaugh reported that the next B&F meeting ~~will~~would be held January 26, 2022.

Membership Subcommittee. Ms. Bresolin noted that the next Membership Subcommittee virtual meeting was scheduled for Friday, December 10 at 10:00 a.m.

ADMINISTRATIVE MATTERS

Mr. Doot indicated that the January 2022 Participants Committee meeting was scheduled for Thursday, January 6, at the Seaport Boston Hotel and would include consideration of Tariff changes in response to Order 2222. Looking ahead, Mr. Cavanaugh indicated that the next Future Pathways working session would take place virtually on Monday, December 6~~th~~.

There being no other business, the meeting adjourned at 11:32 a.m.

Respectfully submitted,

David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE DECEMBER 2, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard (tel)		
American Petroleum Institute	Associate Non-Voting	Paul Powers (tel)		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission			Zach Teti (tel)
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein (tel)
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Dave Thompson (tel)	
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Mike Purdie	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission	James Daly	Dave Burnham (tel)	
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier		Bob Stein (tel)	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE DECEMBER 2, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hampshire Power Corporation	Supplier	Todd Ford		
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz (tel)	
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar (tel)	
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate’s Office	End User	Drew Landry (tel)		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley (tel)
Marble River, LLC	Supplier	Seth Kaplan		
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew (tel)		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York (tel)	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski (tel)		Brian Forshaw (tel); Dave Cavanaugh; Brian Thomson
New England Power Generators Association (NEPGA)	Associate Non-Voting	Bruce Anderson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Supplier	Neal Fitch (tel)		
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE DECEMBER 2, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
Small RG Group Member	AR-RG	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User		Mary Smith (tel)	
Vermont Electric Power Company (VELCO)	Transmission			James Daly (tel)
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley (tel)	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission		Dave Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Vitol Inc.	Supplier	Joe Wadsworth (tel)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
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		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

ESTIMATED 2022 NEPOOL BUDGET COMPARED TO
2021 NEPOOL BUDGET AND 2021 PROJECTED ACTUAL EXPENSES

Line Items	2021 Approved Budget	2022 Proposed Budget	2021 Current Forecast
NEPOOL Counsel Fees (1)	$4,100,000	$4,200,000	$4,100,000
NEPOOL Counsel Disbursements (1)	$ 20,000	$ 30,000	$ 35,000
Independent Financial Advisor Fees and Disbursements (2)	$ 45,000	$ 45,000	$ 45,000
Committee Meeting Expenses (3)(4)	$ 510,000	$ 725,000	$ 75,000
Generation Information System (5)	$ 1,070,600	$ 950,000	$ 1,070,600
Credit Insurance Premium (3)	$ 475,000	$ 637,000	$ 649,000
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (6)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$6,220,600	$6,587,000	$5,974,600
Revenue			
NEPOOL Membership Fees (3) (7)	($2,110,000)	($2,140,000)	($2,110,000)
Generation Information System (5) (8)	($1,070,600)	($ 950,000)	($1,070,600)
Credit Insurance Premium (3) (9)	($ 475,000)	($ 637,000)	($ 649,000)
TOTAL REVENUE	($3,655,600)	($3,727,000)	($3,829,600)
TOTAL NEPOOL EXPENSES	**$2,565,000**	**$2,860,000**	**$2,145,000**

Notes

(1) 2022 proposed estimate provided by Day Pitney LLP, NEPOOL counsel.

(2) 2022 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2022 proposed estimate provided by ISO New England Inc. (ISO).

(4) 2022 proposed estimate is based on 2019 actuals assuming resumption of in person meeting on a forward going basis in 2022.

(5) Based on fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the fixed fee for 2022 is projected to be $950,000. Estimate assumes NEPOOL will not exceed 500 development hours for changes to GIS, and any additional development hours would impose additional charges on NEPOOL.

(6) If NEPOOL determines that an audit should be performed in 2022, funding for that audit will be addressed separately.

(7) The 2022 proposed estimate is based on the 2021 actual receipts through September 2021, plus a forecast for new members for the remainder of the year. The breakdown for the proposed budget is approximately: 400 members at $5,000 each, 25 members at $1,000 each, 17 members at $500 each, 30 members at $1,500 each, and 29 members of large end users and MPEU's. This estimate takes into account the terminations throughout the year.

(8) GIS costs, other than those associated with accessing the GIS through the application programming interface (API) are paid by "GIS Participants" under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2002. GIS costs associated with accessing the GIS through the API are paid by the GIS account holders using that API.

(9) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy. The 2022 premium is based on 2021 annual policy sales, with projected escalation factors for 2022.

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's December 14, 2021 meeting, dated December 14, 2021.[1]

1. PP-10 Revisions (Clean-Up, Conforming Changes)

Support revisions to ISO New England Planning Procedure No. 10 (PP-10) (Planning Procedure to Support the Forward Capacity Market), which include conforming changes, clarifications, changes for consistency with Transmission Planning, and other clean-up related revisions, as recommended by the RC at its December 14, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

2. Appendix K to OP-16 Revisions (Biennial Review, Clarifying Updates)

Support biennial review revisions to Appendix K (Submission of Short Circuit Data) to ISO New England Operating Procedure (OP) No. 16 (Transmission System Data) (OP-16), including minor updates to the process flow diagram, changes to the description of ISO provided data sheets and general editorial edits, as recommended by the RC at its December 14, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

3. OP-3 Revisions (Biennial Review Changes)

Support revisions to OP-3 (Transmission Outage Scheduling), including the global replacement of "Generator" with "Resource", reference updates, inclusion of RAS (Remedial Action Scheme) to align with the NPCC definition, and other non-substantive changes and corrections, as recommended by the RC at its December 14, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

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

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: December 29, 2021

RE: Changes to ISO-NE Billing Policy – RBA Submission and Acknowledgement Procedures

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At its January 6, 2022 meeting, the Participants Committee will be asked to consider limited changes to the ISO New England Billing Policy ("Billing Policy"). The changes will require submission of Requested Billing Adjustments ("RBAs") to Participant Support and Solutions at the ISO via AskISO (which will assign a case number) and the transmission by the ISO to the submitting Participant of an acknowledgement and/or case number assignment. The proposed changes are included in Attachment 1 to this memorandum, and this memorandum summarizes those changes.

Currently, the Billing Policy requires that RBAs be submitted to the ISO's Chief Financial Officer and does not specify a delivery method for RBAs or require ISO acknowledgement to the submitting Participant. The ISO reported that RBAs are generally submitted via e-mail, but that increasingly tighter ISO cybersecurity controls have in some cases hampered receipt. Accordingly, to allow for consistency and structure around RBA submission, to add a receipt acknowledgement requirement, and to reduce cyber security risk and conflict with cybersecurity controls, the ISO has proposed that RBAs be submitted to the ISO via AskISO, the current support system managed by the ISO's Participant Support and Solutions group.

The ISO discussed these proposed changes with the Budget & Finance Subcommittee (the "Subcommittee") at its November 29 teleconference. No one participating in the Subcommittee teleconference objected to the Billing Policy changes. The ISO indicated that, if supported, the proposed Billing Policy changes would be filed with the FERC in conjunction with the FCM Accelerated Billing changes to be considered at the January 6 meeting under Agenda Item 2B.

The following form of resolution may be used for Participants Committee action on the Billing Policy changes:

> RESOLVED, that the Participants Committee supports the changes to the procedures for RBA submission and acknowledgement under the ISO New England Billing Policy, as proposed by the ISO and as circulated to this Committee with the supplemental notice 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 ID
ISO NEW ENGLAND BILLING POLICY

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must not involve Disputed Amounts paid on an Invoice for Non-Hourly Charges pursuant to the ISO New England Financial Assurance Policy, provided, however, that this provision shall not preclude a Disputing Party from submitting a Requested Billing Adjustment for a Disputed Amount on a fully paid monthly Invoice for Non-Hourly Charges which has been paid pursuant to an Invoice for Non-Hourly Charges in that month.

Section 6.2 -Effect of the ISO New England Billing Policy on Rights of Market Participant, PTO, or Non-Market Participant Transmission Customer with Respect to a Disputed Amount. Except as otherwise set forth in this Section 6.2, nothing in this Section 6 shall in any way abridge the right of any Covered Entity to seek legal or equitable relief under the Federal Power Act and/or any other applicable laws with respect to any Disputed Amount. Prior to commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction to resolve the dispute which is the subject of the Requested Billing Adjustment, the Disputing Party must first submit the Requested Billing Adjustment to the ISO for review pursuant to Section 6.3 of the ISO New England Billing Policy.

Section 6.3 -ISO Review of Requested Billing Adjustment.

Section 6.3.1 -Submission of Requested Billing Adjustment to the ISO; Required Contents of Requested Billing Adjustment. A Disputing Party shall submit a Requested Billing Adjustment in writing to the ~~Chief Financial Officer of the ISO~~Participant Support and Solutions at the ISO via its support system. A Requested Billing Adjustment will be deemed received once an acknowledgement and/or a case number has been assigned and transmitted to the Disputing Party. In its Requested Billing Adjustment, the Disputing Party must specify: (a) the Disputed Amount at issue, (b) the instance of alleged error at issue, including a statement detailing the specific provisions of all applicable governing documents that support the Requested Billing Adjustment, and (c) the specific person or persons to whom all communications to the Disputing Party regarding the Requested Billing Adjustment are to be addressed. A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

Section 6.3.2 -Notice of ISO Review of Requested Billing Adjustment. Within three Business Days of the receipt ~~by the ISO's Chief Financial Officer~~ ISO Participant Support and Solutions of a Requested Billing Adjustment, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Requested Billing Adjustment ("Notice of RBA"), including, subject to the protection of Confidential Information, the specifics of the Requested Billing Adjustment. The Notice of RBA shall identify a specific representative of the ISO to whom all communications regarding the Requested Billing Adjustment are to be sent.

Section 6.3.3 -ISO Review of Requested Billing Adjustments. The ISO shall complete its review of a Requested Billing Adjustment received pursuant to Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA. To the extent that either party makes such a request and both parties agree to such request, the ISO and Disputing Party may meet or otherwise confer during this period in an effort to resolve the Requested Billing Adjustment.

Section 6.3.4 -Comment Period. Any Covered Entity which desires to do so, or NEPOOL if it desires to do so, may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the Notice of RBA, written comments to the ISO with respect to the Requested Billing Adjustment. Any such comments are to be transmitted simultaneously to the Disputing Party. The Disputing Party may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the Notice of RBA. In determining the action it will take with respect to the Requested Billing Adjustment, the ISO shall consider the written response filed by the Disputing Party. The ISO may but is not required to consider any written comments that are filed by any other interested party.

Section 6.3.5 -ISO Action on Requested Billing Adjustment. The ISO shall provide to the Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee a written decision (the "RBA Decision") accepting or denying a Requested Billing Adjustment received pursuant to this Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO. The ISO shall provide written notice and a copy of each RBA Decision to each Covered Entity either eligible for reimbursement, denied reimbursement of a Disputed Amount or required to provide reimbursement of a Disputed Amount because of an RBA Decision (hereafter referred to as an "Affected Party" or the "Affected Parties") within five (5) Business Days of the date the RBA

Section 6.4.1 -Right to Further Review. An Affected Party may seek review of an RBA Decision by an independent third party neutral by submitting, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, a request for arbitration of the Requested Billing Adjustment with the American Arbitration Association ("AAA"). At the same time that it submits its request to the AAA, the Affected Party commencing any such review of an RBA Decision shall transmit its request for arbitration: (i) to the ISO's designated representative for that particular RBA Decision; and (ii) to each of the Affected Parties; and (iii) to the Chair of the NEPOOL Budget and Finance Subcommittee. The ISO and any Affected Party shall be joined as parties to the arbitration. NEPOOL and other Covered Entities shall be permitted to intervene in the arbitration if they desire to do so.

Section 6.4.2 -Finality of the AAA Neutral's Decision. Except as otherwise provided in this Section 6.4.2, the written, final decision of the AAA neutral shall become final and binding on the Affected Parties, including the ISO, and shall not be appealable in any forum on the twenty-first (21st) Business Day after the date on which the final decision of the AAA neutral was issued. The final decision of the AAA neutral shall not become final or binding if on or before the twentieth (20th) Business Day after the date on which the final decision of the AAA neutral was issued, an Affected Party or Parties or the ISO has appealed the final decision of the AAA neutral by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute. If any such appeal is filed, the final decision of the AAA neutral shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process.

Section 6.5 -Access to Confidential Information. Information that is deemed confidential pursuant to the ISO New England Information Policy in the possession, custody or control of the ISO concerning the dollar amount in Invoices or Remittance Advices issued by the ISO ("Confidential Information") shall be made available under these billing dispute procedures only to "Dispute Representatives" who have executed a confidentiality agreement in accordance both with this Section 6.5 and the ISO New England Information Policy in the form of Attachment 1 hereto ("Confidentiality Agreement"). A copy of the executed Confidentiality Agreement for a Dispute Representative shall be provided to the ISO prior to the disclosure of any Confidential Information to said Dispute Representative. Confidential Information shall not be disclosed to anyone other than in accordance with this Section 6.5, and shall be used only in connection with the billing dispute procedures provided under this Section 6.

a) *Potential Disputing Parties' Right of Access to Confidential Information.* A Market Participant, PTO or Non-Market Participant Transmission Customer that is a potential Disputing Party is entitled to obtain access to Confidential Information for its Dispute Representative, if and only if, it can demonstrate to the ISO that such access is required to determine if it has a substantive basis for filing a Requested Billing Adjustment with the ISO. Such demonstration by a potential Disputing Party, at a minimum, shall include: the information submitted to ISO Participant Support and Solutions ~~the Chief Financial Officer of the ISO~~ required in Section 6.3.1; and, why lack of access to Confidential Information prevents the potential Disputing Party from determining if it has a substantive basis for filing such a Requested Billing Adjustment. A potential Disputing Party shall submit a request for access to Confidential Information in writing to the ISO (an "Information Request"). The ISO shall evaluate and respond to such an Information Request within ten (10) days of the receipt of the Information Request, and where the need for access to Confidential Information is demonstrated in accordance with the above, shall provide access to such Confidential Information within fifteen (15) days of the receipt of the Information Request.

b) *Affected Parties Right of Access to Confidential Information*. If the RBA Decision is submitted to the AAA for resolution pursuant to Section 6.4, then for purposes of that AAA proceeding a Market Participant or Non-Market Participant Transmission Customer that is an Affected Party is entitled to obtain access to Confidential Information for its Dispute Representative if, and only if, it can demonstrate to the AAA Neutral that such access is required to protect its financial interests with respect to review of an RBA Decision pending before the Neutral. An Affected Party shall submit a request for access to Confidential Information concerning an RBA Decision within the timeframes established by the Neutral. The Neutral shall have the authority to enter such orders as may be necessary to protect the Confidential Information, in accordance with applicable

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Rosendo Garza, NEPOOL Counsel

DATE: December 29, 2021

RE: ISO-NE's Proposal to Accelerate FCM Settlement & Billing Processes

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At the January 6, 2022 Participants Committee[1] meeting, you will be asked to vote on proposed revisions to convert certain credits and charges associated with the Forward Capacity Market (FCM) from a monthly settlement to a daily settlement (the FCM Settlement/Billing Proposal). A copy of the following proposed revisions are included with this memorandum: (1) changes to Market Rule 1 and Manual M-28 (Market Rule 1 Accounting) (*see* Attachment A); and (2) modifications to the ISO-NE Financial Assurance Policy (FAP) and the ISO-NE Billing Policy (Billing Policy) (*see* Attachment B). ISO-NE Counsel has advised us that ISO-NE will request, with one limited exception, an effective date of June 1, 2022 for the FCM Settlement/Billing Proposal.[2] These revisions were all broadly supported at the Markets Committee and Budget and Finance Subcommittee (B&F Subcommittee) but must be voted outside the Consent Agenda because the B&F Subcommittee is a non-voting subcommittee.

I. Market Rule 1 & Manual M-28 Changes

Under the current Tariff rules, FCM credits and charges are included in the non-hourly bill that is issued on the first Monday (or Tuesday if the Monday is a holiday) after the ninth day of the following month (with remittances due within two Business Days and credits within four Business Days after bill is issued). The related FCM Financial Assurance (FA) is based on any outstanding charges but, due to the timing of this current non-hourly billing process, the required FCM FA ends up being based on up to two months of outstanding charges. As a result, Load Serving Entities must post FA for an average of one and one-half months of obligation charges,

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[1] Capitalized terms used but not defined in this memorandum are intended to have the same meaning 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-NE) Transmission, Markets and Services Tariff (Tariff).

[2] The one exception with respect to a June 1, 2022 requested effective date concerns the changes to Market Rule 1 § III.3.8(b) (Notice of Meter Data Error (MDE) Correction). The changes to the Notice of MDE Correction provision, which were effectively conforming changes proposed for the same reasons described in the memo and materials for Agenda Item 2A (the RBA submission and acknowledgement changes, and together with the Notice of MDE Correction provision, the RBA Changes), were reviewed and recommended by the Markets Committee as part of the FCM Settlement/Billing Proposal. The RBA Changes will be filed as part of the FCM Settlement/Billing Proposal filing (the Filing). However, ISO-NE has advised us that, for the RBA Changes, an (March) effective date that is 60 days from the date of the Filing will be requested.

and capacity resources must wait 14 to 23 days after the obligation month for payment. With the stated goal of "improv[ing] the overall financial position of the control area, reduc[ing] the Financial Assurance for Load Serving Entities, and accelerat[ing] Resource payments," ISO-NE is proposing to convert a majority of monthly FCM settlement credits and charges to a daily settlement, as the following table indicates.

FCM Credits/Charges Converting to Daily Settlement	**FCM-related Credits/Charges Remaining Monthly**
• Forward Capacity Auction • Annual Reconfiguration Auction • Monthly Reconfiguration Auction • Intermittent Power Resource Adjustment • Multi-year Adjustment • Capacity Transfer Rights (CTR) Pool-Planned Unit • CTR Transmission Upgrade • Self-Supply • HQICC	• Pay for Performance • Failure to cover • Retained for reliability • Forfeited FA • Excess revenue • Export capacity

As part of its FCM Settlement/Billing Proposal, ISO-NE also proposes conforming revisions to the current Capacity Load Obligation Bilateral deadline to accommodate daily settlement, as well as corrections, clarifications, and clean-up revisions to Market Rule 1 and Manual M-28 to remove outdated language and correct inconsistencies, e.g., removal of the expired Peak Energy Rent (PER) adjustment from Market Rule 1.[3, 4]

At its November 10, 2021 meeting, the Markets Committee considered the Market Rule 1 and Manual M-28 revisions to implement ISO-NE's Proposal. Based on a voice vote, the Markets Committee unanimously recommended that the Participants Committee support those changes. A copy of the revisions, which require a 60% Vote to be supported by the Participants Committee, are included as Attachment A.[5]

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[3] In 2015, the Commission accepted revisions to remove the PER adjustments from the Tariff effective June 1, 2019. *See ISO New England Inc.*, 151 FERC ¶ 61,096 at P 1 (May 5, 2015)(order accepting PER Mechanism Changes). Thus, ISO-NE is using this filing as an opportunity to remove outdated Market Rule language related to PERs.

[4] Additional clarifying/clean-up changes include revisions to correct the Tariff's failure to cover adjustment and the Intermittent Power Resource capacity adjustment, and clarify how the Capacity Transmission Rights pool-planned unit charge is allocated system-wide.

[5] Please note that Attachment A also includes a non-substantive change to Section III.13.7.5.1.1 of the Tariff, which, pursuant to their authority under the resolution recommending Participants Committee approval, the Markets Committee's Chair and Vice-Chair approved. Notice of that non-substantive change was also provided to the Markets Committee on Dec. 21, 2021.

II. Financial Assurance Policy & Billing Policy Changes

At its October 12, 2021 meeting, the B&F Subcommittee reviewed changes to the FAP and the Billing Policy to reflect the implementation of the FCM Settlement/Billing Proposal. Specifically, the FAP revisions include, among other things, conforming changes to the Hourly Requirements to exclude Daily FCM Charges from Hourly Charges in the calculation and adding a new component—"Daily FCM Requirements"—to the Participant's Financial Assurance Obligations to collateralize a Participant's Daily FCM Charges. The Billing Policy changes add the FCM settlement credits and charges as Daily FCM Charges. No one participating in the October 12 B&F Subcommittee meeting objected to the proposed changes to the FAP or to the Billing Policy. A copy of the FAP and Billing Policy changes, which require a 66.67% Vote to be supported by the Participants Committee, are included as Attachment B.

III. Participants Committee Review

Given what appears to be unanimous support for the FCM Settlement/Billing Proposal, the Participants Committee may consider the package of changes together in a single resolution, absent objection by any voting member. The following form of combined resolutions may be used in a single vote for Participants Committee action absent objection, or individually in separate resolutions:

> RESOLVED, that the Participants Committee supports the Tariff and Manual M-28 revisions related to converting certain credits and charges associated with the Forward Capacity Market from a monthly settlement to a daily settlement, as recommended by the Markets Committee at its November 9–10 meeting and circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.
>
> RESOLVED, that the Participants Committee supports revisions to Sections III.A, VII.A, VII.C, and VII.F(1)(a) of the ISO New England Financial Assurance Policy and Sections 1.3 and 2.4(e) of the ISO New England Billing Policy to implement the changes to convert certain credits and charges associated with the Forward Capacity Market from a monthly settlement to a daily settlement, as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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

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

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

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.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand 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 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 Resource's or Seasonal Peak Demand 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.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 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 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 of Market Rule 1 and the ISO New England Manuals.

~~**Average Monthly PER** is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.~~

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.

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

~~**Hourly PER** is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.~~

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 offered 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.

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 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 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

~~**Monthly PER** is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.~~

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 Regional Network Load is defined in Section II.21.2 of the OATT.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

~~**Peak Energy Rent (PER)** is described in Section III.13.7.1.2 of Market Rule 1.~~

~~**PER Proxy Unit** is described in Section III.13.7.1.2.1 of Market Rule 1.~~

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand 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.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) -Within three Business Days of the receipt ~~by the ISO's Chief Financial Officer~~ of an RBA form for a Meter Data Error as defined in Section 6.3.1 of the ISO New England Billing Policy, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) -In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error

RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits~~, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values~~. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

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, 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.

Special Retirement De-List Bid, Permanent De-List Bid and Substitution Auction Demand Bid Modification and Withdrawal Provisions for the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025). For the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025), on or before June 3, 2021, the Internal Market Monitor will modify any submitted Permanent De-List Bids, Retirement De-List Bids and substitution auction test prices (whether or not associated with a Retirement De-List Bid) submitted for the sixteenth Forward Capacity Auction to reflect the impact of updated CONE, Net CONE and Capacity Performance Payment Rate values accepted by the Commission in Docket No. ER21-787.

The Internal Market Monitor will provide Lead Market Participants with updated Permanent De-List Bids, Retirement De-List Bids and substitution auction test prices in the retirement determination notifications that it issues on June 3, 2021. Within 5 Business Days of the issuance of the retirement determination notifications, a Lead Market Participant may withdraw its Retirement De-List Bid, Permanent De-List Bid, or substitution auction demand bid, and the attendant substitution auction test price, by written notification to the Internal Market Monitor. The election to withdraw a Retirement De-List Bid will also withdraw the associated substitution auction demand bid.

Special Dynamic De-List Threshold and Certain Information Publications for the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025). For the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025), on or before June 3, 2021, the ISO will recalculate and re-post the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.1.A to reflect the impact of updated CONE and purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $11.978/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $7.114/kW-month.

CONE and Net CONE shall be recalculated no less often than once every three 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 Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section

III.A.21.1.2(e)(5) shall not apply). ~~Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.~~

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

Capacity Supply Obligation Bilaterals are available for monthly periods. The qualification of resources subject to a Capacity Supply Obligation Bilateral is determined in the same manner as the qualification of resources is determined for reconfiguration auctions as specified in Section III.13.4.2.

A resource having a Capacity Supply Obligation seeking to shed that obligation (Capacity Transferring Resource) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (Capacity Supply Obligation Bilateral), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (Capacity Acquiring Resource), subject to the following limitations.

(a) A Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) 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 Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation) of the Capacity Acquiring Resource during the month covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource’s unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

III.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.

III.13.5.2.1.1. Timing.

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 Forward 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 pm on the ~~second~~ first Business Day ~~after the end~~ 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.13.5.2.1.2. Application.

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.13.5.2.1.3. 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 II.13.5.2 are not met.

III.13.5.2.1.4. 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 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.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Capacity Performance Bilateral, and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met.

III.13.5.3.3. Effect of Capacity Performance Bilateral.

A Capacity Performance Bilateral does not affect in any way 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 Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2.

III.13.5.4 Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are available for annual reconfiguration auctions for Capacity Commitment Periods beginning on or after June 1, 2020, except that Annual Reconfiguration Transactions are not available for the first annual reconfiguration auction for the Capacity Commitment Period beginning on June 1, 2020.

III.13.5.4.1 Timing of Submission.

The Lead Market Participant or Project Sponsor for either a Capacity Transferring Resource or a Capacity Acquiring Resource may submit an Annual Reconfiguration Transaction to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Annual Reconfiguration Transactions as soon as practicable after the issuance of Forward Capacity Auction results. An Annual Reconfiguration Transaction must be confirmed by the party other than the party submitting the Annual Reconfiguration Transaction to the ISO no later than the end of the relevant submittal window.

III.13.5.4.2 Components of an Annual Reconfiguration Transaction.

The submission of an Annual Reconfiguration Transaction must include the following:

1. the resource identification number of the Capacity Transferring Resource;
2. the applicable Capacity Commitment Period;

(3) the resource identification number of the Capacity Acquiring Resource, and;

3. a price ($/kW-month), quantity (MW) and Capacity Zone, to be used in settling the Annual Reconfiguration Transaction.

The maximum quantity of an Annual Reconfiguration Transaction is the higher of:

(1) the Capacity Transferring Resource's maximum demand bid quantity determined pursuant to Section III.13.4.2.2(b), less the quantity of any previously confirmed Annual Reconfiguration Transactions, and;

(2) the Capacity Acquiring Resource's maximum supply offer quantity determined pursuant to Section III.13.4.2.1.1, less the quantity of any previously confirmed Annual Reconfiguration Transactions.

An Annual Reconfiguration Transaction may not be submitted unless the maximum demand bid quantity and maximum supply offer quantity are each greater than zero.

Each Annual Reconfiguration Transaction is limited to a single Capacity Acquiring Resource and a single Capacity Transferring Resource.

If any demand bid of a Capacity Transferring Resource or supply offer of a Capacity Acquiring Resource that is associated with an Annual Reconfiguration Transaction is rejected for reliability reasons pursuant to Section III.13.2.2(c) or Section III.13.4.2.1.5, respectively, the Annual Reconfiguration Transaction is cancelled.

III.13.5.4.3 Settlement of Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are settled on a ~~monthly~~ daily basis during the applicable Capacity Commitment Period. The ~~monthly~~ total of the daily payment amounts for the month is equal to the transaction quantity multiplied by the difference between the annual reconfiguration auction clearing price and the transaction price. If the payment amount is positive, payment is made to the Lead Market Participant with the Capacity Transferring Resource and charged to the Lead Market Participant with the Capacity Acquiring Resource. If the payment amount is negative, payment is made to the Lead Market Participant with the Capacity Acquiring Resource and charged to the Lead Market Participant with the Capacity Transferring Resource.

III.13.6.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource or a Generating 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 Section III.13 of this Tariff 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.13.6.4.1. -Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

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.13 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.13.7.1. 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.13.7.1.1~~, as adjusted to account for peak energy rents as described in Section III.13.7.1.2~~.

III.13.7.1.1. ~~**Monthly**~~ **Payments and Charges Reflecting Capacity Supply Obligations.**

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA 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~~ based on the following amounts:~~. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward 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 has 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 clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or 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 price associated with the Capacity Supply Obligation Bilateral.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

~~**III.13.7.1.2 Peak Energy Rents.**~~

~~For Capacity Commitment Periods beginning prior to June 1, 2019, Capacity Base Payments to resources with Capacity Supply Obligations, except for (1) On-Peak Demand Resources, (2) Seasonal Peak Demand Resources, and (3) New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve FCM Commercial Operation, shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.~~

~~**III.13.7.1.2.1 Hourly PER Calculations**.~~

~~(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with one of the following formulas, which include scaling adjustments for system load and availability:~~

~~For hours within the period beginning September 30, 2016 through May 31, 2018:~~

~~Hourly PER($/kW) = [(LMP - Adjusted Hourly PER Strike Price) * [Scaling Factor] * [Availability Factor]~~
~~Where:~~

~~Adjusted Hourly PER Strike Price = Strike Price + Hourly PER Adjustment~~

~~Hourly PER Adjustment = average of Five-Minute PER Strike Price Adjustment values~~

~~Five-Minute PER Strike Price Adjustment = MAX (Thirty-Minute Operating Reserve clearing price - $500/MWh, 0)+ MAX (Ten-Minute Non-Spinning Reserve clearing price – Thirty-Minute Operating Reserve clearing price - $850/MWh, 0).~~

~~Strike Price = as defined below~~

~~Scaling Factor = as defined below~~

~~Availability Factor = as defined below~~

~~For all other hours:~~

~~Hourly PER($/kW) = [LMP - Strike Price] * [Scaling Factor] * [Availability Factor]~~
~~Where:~~

~~Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.~~

~~Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy~~

~~Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Capacity Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.~~

~~Availability Factor = 0.95.~~

~~(b) PER Proxy Unit characteristics shall be as follows:~~

~~(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of the following, as determined on a daily basis: ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation; or day-ahead gas measured at the AGT-CG (Non-G) hub;~~

~~(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;~~

~~(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.~~

~~III.13.7.1.2.2. Monthly PER Application.~~

~~The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource's Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource's PER deduction for an Obligation Month be less than zero or~~

~~greater than the product of the resource's Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.~~

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward 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~~ (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments)~~.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

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.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 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.

described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 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.13.7.4(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.13.7.3 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.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), ~~less PER adjustments for resources in the zone as defined in Section III.13.7.1.2,~~ and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. ~~A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.~~ A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, 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 ~~as of the end~~on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward 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.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

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.

IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(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.13.7.5.1.1.6. 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 FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity ~~Load~~ Obligation in all Capacity Zones.

III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.

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.13.7.5.1.1.8 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.13.7.5.4.4 (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.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in ~~the~~ all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, 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.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by ~~Zonal~~ Total Capacity Load Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.2. 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 Forward Capacity Auction pursuant to Section III.13.2.3.4. 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.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) 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 two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

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; 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 ~~annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period~~ daily Coincident Peak Contributions, to the sum of all load serving entities' ~~annual coincident contributions to the system-wide annual peak load~~daily Coincident Peak Contributions in that Capacity Zone~~ from the calendar year prior to the start of the Capacity Commitment Period~~.

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 FCA 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 or Demand Response Resource.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward 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.13.7.5.3. Excess Revenues.

(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) 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 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.13.7.5.4. Capacity Transfer Rights.

III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone~~, as adjusted for PER~~.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

III.13.7.5.4.2. Allocation of Capacity Transfer Rights.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated.

Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.4.4. 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.13.7.5.4.2.

(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.13.7.5.4.2.

(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 to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price 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.13.7.5.4.5. 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 an initial allocation of CTRs equal to the ~~most recent~~ seasonal claimed capability of the ownership entitlements in such unit at the time of qualification, adjusted for any designated self-supply quantities as described in Section III.13.1.6.2. Municipal utility entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward 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 ("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) The value of CTRs specifically allocated pursuant to this Section 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 MW quantity of the specifically allocated CTRs. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.5. Forward Capacity Market Net Charge Amount.

The Forward 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; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

APPENDIX I

SCHEDULE 3

SUPPLEMENTAL CAPACITY PAYMENT

For each Obligation Month during the Term, a Supplemental Capacity Payment shall be calculated for the Resource[s] as set forth below. The Supplemental Capacity Payment shall be charged to Regional Network Load in the affected Reliability Region.

Section III.13 references are to Market Rule 1, Section III.13 – Forward Capacity Market.

The Annual Fixed Revenue Requirement (AFRR) for the [generating station / Resource] is $___________.

The Annual Fixed O&M Expenses for the [generating station / Resource] is $___________.

The AFRR is the cost-of-service for the [generating station / Resource], including fixed operation and maintenance expenses, depreciation, amortization, taxes and return, as accepted by the Commission. The Annual Fixed O&M Expenses is the fixed operating & maintenance expense component of the AFRR. Where the AFRR and the Annual Fixed O&M Requirement have been determined for a generating station that is composed of two or more Resources, each shall be allocated to the Resources pro-rata according to their Capacity Supply Obligations as of the Effective Date. [list the allocated amounts below.]

(Part 1)

Supplemental Capacity Payment =

Plus: Maximum Monthly Fixed Cost Payment

Less: Total COS Availability Penalties for the Obligation Month

Less: Revenue Credit for the Obligation Month

Providing that for any given Capacity Commitment Period the monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments plus Revenue Credits plus Availability Credits (as defined in Section III.13.7.2.7.1.4) shall not exceed the AFRR (subject to the additional provisions of Part 5 if applicable).

In the event that the Supplemental Capacity Payment would otherwise be less than zero in any Obligation Month, the Supplemental Capacity Payment for that Obligation Month shall be zero and any unapplied

COS Availability Penalty or Revenue Credit shall roll-forward for crediting in a future Obligation Month. For the last Obligation Month of the Term, the ISO shall charge the Owner for any unapplied roll-forward amount and shall refund that amount to Regional Network Load (subject to the additional provisions of Part 5 below if applicable).

(Part 2)

Maximum Monthly Fixed Cost Payment = AFFR / 12

COS Price = Maximum Monthly Fixed Cost Payment / Capacity Supply Obligation

The Total COS Availability Penalty for the Obligation Month equals the sum of the COS Availability Penalties for each Shortage Event that has been defined and recognized in accordance with Sections III.13.7.1.1.1 through III.13.7.1.1.4. The COS Availability Penalty for each Shortage Event shall be determined in accordance with the provisions of Section III.13.7.2.7.1.2, except that it shall be based on the COS Price instead of the Capacity Clearing Price and the Annual Fixed Revenue Requirement instead of the Resource's Annualized FCA Payment. The per day and per month COS availability penalties assessed shall be subject to the caps set forth in Section III.13.7.2.7.1.3, except that the caps shall be based on the Annual Fixed Revenue Requirement rather than the Resource's Annualized FCA Payment. The sum of Total COS Availability Penalties for each Capacity Commitment Period shall not exceed the Annual Fixed Revenue Requirement.

(Part 4)

The purpose of the Revenue Credit is to recognize that the Resource has earned revenues from sources other than this Supplemental Capacity Payment. The Supplemental Capacity Payment is reduced accordingly so that the Resource receives a total payment for its capacity during the Commitment Period equal to its Annual Fixed Revenue Requirement reduced for any COS Availability Penalties.

Revenue Credit for the Obligation Month =

Plus: FCA Payment for the Obligation Month
~~Less: PER Adjustment for the Obligation Month~~
Less: Availability Penalty for the Obligation Month
Plus: All other revenues related to the Resource (i.e. all revenues except for revenues from the New England Forward Capacity Market) that are in excess of Stipulated Offer Costs.

Provided, however, any Availability Credits earned according to the provisions of Section III.13.7.2.7.1.4 shall be ignored for calculating this Revenue Credit and shall inure to the benefit of the Owner subject to the provisions of Part 1.

Where the FCA Payment~~, PER Adjustment~~ and Availability Penalty for the Obligation Month are the amounts calculated in the normal monthly settlement based on the Capacity Clearing Price for the Capacity Zone and the provisions of Section III.13.7.

(Part 5)

If this Agreement terminates other than at the end of a Capacity Commitment Period:

5.1 The ISO shall credit the Resource for Availability Penalties and COS Availability Penalties during that Capacity Commitment Period that are in excess of the pro-rated Annualized FCA Payment and AFRR respectively. The ISO shall charge the appropriate Market Participants defined in Section III.13.7.3 and Regional Network Load in the Reliability Region according to which entities had received the benefit of these excess Availability Penalties and COS Availability Penalties.

5.2 The monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments plus Revenue Credits plus Availability Credits (as defined in Section III.13.7.2.7.1.4) shall not exceed the prorated AFRR.

(Part 6)

While the roll-forward provisions of Part 1 provide that the Supplemental Capacity Payment cannot result in a monthly charge to the Resource because of a Supplemental Capacity Payment that calculates to a negative amount, nothing in this Agreement provides that the sum of all charges and credits for the Resource cannot result in a net amount owed to the ISO for any Obligation/Operating Month.

SECTION III

MARKET RULE 1

APPENDIX I

FORM OF COST-OF-SERVICE AGREEMENT

APPENDIX I

FORM OF COST-OF-SERVICE AGREEMENT

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SCHEDULE 1	Information on Marginal Cost
SCHEDULE 2	Resource Characteristics
SCHEDULE 3	Supplemental Capacity Payment

ARTICLE 11
MISCELLANEOUS PROVISIONS

11.1. Assignment.

11.1.1. None of the Parties shall assign its rights or delegate its duties under this Agreement without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Upon any assignment made in compliance with this Article 11.1, this Agreement shall inure to and be binding upon the successors and assigns for the assigning Parties.

11.1.2. Notwithstanding Section 11.1.1, each Party may, without the need for consent from the other Party (and without relieving itself from liability hereunder), transfer or assign this Agreement: (i) to an Affiliate, or (ii) where such transfer is incident to a merger or consolidation with, or transfer of all, or substantially all, of the assets of the transferor to another person, business entity, or political subdivision or public corporation created under the Laws governing the creation and existence of the transferor which shall as a part of such succession assume all of the obligations of the assignor or transferor under this Agreement. Provided, however, that any Party who transfers or assigns this Agreement as provided in subsections “i” or “ii” of this Section 11.1.2 shall provide timely notice to the other Party or Parties of such change, including the effective date and changes, if any, to the nominations under Section 11.2 and Exhibits A or B, as appropriate. Any Party may collaterally assign its rights in this Agreement to its lenders without the need for consent from the other Party. To the extent that any Party seeks to transfer its rights and obligations to a successor entity, such Party shall seek to assign this Agreement to such successor entity, pursuant to this Section 11.1.2.

11.1.3. Upon 60 days notice from Owner or Lead Participant, the Lead Market Participant’s role under this Agreement may terminate and then this function must be assigned by Owner to another entity fully capable of fulfilling this role consistent with the ISO New England Filed Documents and the ISO New England System Rules. The Owner, the current Lead Participant, and the successor Lead Participant must comply with all ISO requirements for Customer Asset registration. Owner is not obligated to assign the Lead Market Participant role to another entity and may assume this role, if it is qualified to do so, by notifying the ISO.

11.1.4. The Owner may designate a new Registered Owner by providing 30 days notice under the Agreement and a written copy of any agreement between the Owner and the new registered Owner. The Owner, the Registered Owner and the Lead Participant must comply with all ISO requirements for Customer and Asset registration.

11.2. Notices.

Except as otherwise expressly provided in this Agreement or required by Law, all notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by personal delivery, certified mail, return receipt requested, facsimile transmission, or by recognized overnight courier service, to the intended Party at such Party's address set forth below. All such notices shall be deemed to have been duly given and to have become effective: (a) upon receipt if delivered in person or by facsimile; (b) two days after having been delivered to an air courier for overnight delivery; or (c) seven days after having been deposited in the United States mail as certified or registered mail, return receipt requested, all fees pre-paid, addressed to the applicable addresses set forth below. Each Party's address for notices shall be as follows (subject to change by notice in accordance with the provisions of this Section 11.2):

OWNER AND LEAD PARTICIPANT:
NOTICES & CORRESPONDENCE
[TO COME]

ISO:
NOTICES & CORRESPONDENCE
~~Mark H. Freise, Reliability Contracts Manager~~
[Name], [Title]
ISO New England Inc.
One Sullivan Road, Holyoke, MA 01040
Tel: [to be provided] ~~(413) 540-4429~~ Fax: ~~(413) 535-4156~~[to be provided]

with a copy to:
[Name], [Title]
~~Theodore Paradise Senior Counsel~~ ISO New England Inc.
One Sullivan Road Holyoke, MA 01040
Tel: [to be provided] Fax: [to be provided]
~~Tel: (413) 540-4585 Fax: (413) 535-4379~~

The foregoing notice provisions may be modified by providing written notice, in accordance with ISO Protocols established from time-to-time.

11.3. Parties' Representatives.

All Parties to this Agreement shall ensure that throughout the term of this Agreement, duly appointed representatives are available for communications between the Parties. The representatives shall have full authority to deal with all day-to-day matters arising under this Agreement. Acts and omissions of representatives shall be deemed to be acts and omissions of the Party. Owner and ISO shall be entitled to assume that the representatives of the other Party are at all times acting within the limits of the authority given by the representatives' Party. Owner's and Lead Participants representatives shall be identified on Exhibit A. ISO's representatives shall be identified on Exhibit B. The Parties may at any time replace their representatives by sending the other Party a revision to its respective Exhibit.

11.4. Effect of Invalidation, Modification, or Condition.

Each covenant, condition, restriction, and other term of this Agreement is intended to be, and shall be construed as, independent and severable from each other covenant, condition, restriction, and other term. If any covenant, condition, restriction, or other term of this Agreement is held to be invalid or otherwise modified or conditioned by any Governmental Authority, the invalidity, modification, or condition of such covenant, condition, restriction, or other term shall not affect the validity of the remaining covenants, conditions, restrictions, or other terms hereof. If an invalidity, modification, or condition has a material impact on the rights and obligations of the Parties, the Parties shall make a good faith effort to renegotiate and restore the benefits and burdens of this Agreement as they existed prior to the determination of the invalidity, modification, or condition. If the Parties fail to reach agreement, then the Party whose rights and obligations have been adversely affected may, in its sole discretion, terminate this Agreement or refer the dispute for resolution under the Alternative Dispute Resolution provisions in Appendix D of Market Rule 1.

11.5. Amendments.

Any amendments or modifications of this Agreement shall be made only in writing and duly executed by all Parties to this Agreement. Such amendments or modifications shall become effective only after the Parties have received any authorizations required from the Commission. The Parties agree to negotiate in good faith any amendments to this Agreement that are needed to reflect the intent of the Parties as

EXHIBIT B

ISO'S REPRESENTATIVES

~~Kevin Kirby~~[Name]

~~Vice President, Market Operations~~[Title]

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040

SCHEDULE 3
SUPPLEMENTAL CAPACITY PAYMENT

For each Obligation Month during the Term, a Supplemental Capacity Payment shall be calculated for the Resource[s] as set forth below. The Supplemental Capacity Payment shall be charged to Regional Network Load in the affected Reliability Region.

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(Part 1)

Supplemental Capacity Payment =

Plus: Maximum Monthly Fixed Cost Payment

Less: Total COS Availability Penalties for the Obligation Month

Less: Revenue Credit for the Obligation Month

Providing that for any given Capacity Commitment Period the monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments plus Revenue Credits plus Availability Credits (as defined in Section III.13.7.2.7.1.4) shall not exceed the AFRR (subject to the additional provisions of Part 5 if applicable).

In the event that the Supplemental Capacity Payment would otherwise be less than zero in any Obligation Month, the Supplemental Capacity Payment for that Obligation Month shall be zero and any unapplied COS Availability Penalty or Revenue Credit shall roll-forward for crediting in a future Obligation Month.

For the last Obligation Month of the Term, the ISO shall charge the Owner for any unapplied roll-forward amount and shall refund that amount to Regional Network Load (subject to the additional provisions of Part 5 below if applicable).

(Part 2)

Maximum Monthly Fixed Cost Payment = AFFR / 12

COS Price = Maximum Monthly Fixed Cost Payment / Capacity Supply Obligation

The Total COS Availability Penalty for the Obligation Month equals the sum of the COS Availability Penalties for each Shortage Event that has been defined and recognized in accordance with Sections III.13.7.1.1.1 through III.13.7.1.1.4. The COS Availability Penalty for each Shortage Event shall be determined in accordance with the provisions of Section III.13.7.2.7.1.2, except that it shall be based on the COS Price instead of the Capacity Clearing Price and the Annual Fixed Revenue Requirement instead of the Resource's Annualized FCA Payment. The per day and per month COS availability penalties assessed shall be subject to the caps set forth in Section III.13.7.2.7.1.3, except that the caps shall be based on the Annual Fixed Revenue Requirement rather than the Resource's Annualized FCA Payment. The sum of Total COS Availability Penalties for each Capacity Commitment Period shall not exceed the Annual Fixed Revenue Requirement.

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Plus: FCA Payment for the Obligation Month

~~Less: PER Adjustment for the Obligation Month~~

Less: Availability Penalty for the Obligation Month

Plus: All other revenues related to the Resource (i.e. all revenues except for revenues from the New England Forward Capacity Market) that are in excess of Stipulated Offer Costs. Provided, however, any Availability Credits earned according to the provisions of

Section III.13.7.2.7.1.4 shall be ignored for calculating this Revenue Credit and shall inure to the benefit of the Owner subject to the provisions of Part 1.

Where the FCA Payment~~, PER Adjustment~~ and Availability Penalty for the Obligation Month are the amounts calculated in the normal monthly settlement based on the Capacity Clearing Price for the Capacity Zone and the provisions of Section III.13.7.

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If this Agreement terminates other than at the end of a Capacity Commitment Period:

5.1 The ISO shall credit the Resource for Availability Penalties and COS Availability Penalties during that Capacity Commitment Period that are in excess of the pro-rated Annualized FCA Payment and AFRR respectively. The ISO shall charge the appropriate Market Participants defined in Section III.13.7.3 and Regional Network Load in the Reliability Region according to which entities had received the benefit of these excess Availability Penalties and COS Availability Penalties.

5.2 The monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments plus Revenue Credits plus Availability Credits (as defined in Section III.13.7.2.7.1.4) shall not exceed the prorated AFRR.

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While the roll-forward provisions of Part 1 provide that the Supplemental Capacity Payment cannot result in a monthly charge to the Resource because of a Supplemental Capacity Payment that calculates to a negative amount, nothing in this Agreement provides that the sum of all charges and credits for the Resource cannot result in a net amount owed to the ISO for any Obligation/Operating Month.

ISO New England Manual for

Market Rule 1 Accounting

Manual M-28

Revision: 62
Effective Date: August 6, 2020

Prepared by
ISO New England Inc.

ISO New England Manual for

Market Rule 1 Accounting

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Section 6: Resettlement Process: Data Reconciliation and Requested Billing Adjustment for Meter Data Errors

Section 7: Settlement Power System Model and Unmetered Load Calculations

Section 1: Market Accounting Overview

1.1 Market Accounting Overview

The ISO performs the accounting for the New England wholesale market and determines the charges and credits that are allocated among the Governance Participants in conformance with Market Rule 1. This process is also referred to as market settlement. Market settlement is designed to operate on a balanced basis. That is, the total amount of the charges equals the total amount of the credits; there are no residual funds. The exceptions to this balanced result are the settlement of transmission congestion and losses, where unequal charges and credits can occur as an expected result.

The ISO performs an initial settlement of the markets; bills are issued twice a week for hourly markets and services, and daily Forward Capacity Market settlements. Bills are issued once a month for monthly markets and services, including monthly Forward Capacity Market settlements. The ISO then performs the Data Reconciliation Process (DRP), where all markets and services are resettled using updated meter readings and other data revisions as authorized in Market Rule 1 Section III.3.6. Any monetary difference between the initial and resettled results are included in a bill issued five months after the operating month. See the *Understanding the Bill* and *Billing Process Summary* on the ISO website for more detail.

Section 5: Initial Settlement Process

5.1 Overview

This section defines the responsibilities of the meter data reporting entities and the timing within which such data must be received by the ISO.

5.3 Timing

(1) The Assigned Meter Reader, Host Participant and ISO provide the following data within the timelines described below for use in the daily settlement processes:

(a) By 0800 of the next Business Day following the Operating Day, the ISO provides loss data for which it is the Assigned Meter Reader to the appropriate Market Participants. If the ISO fails to provide this data by the time frame indicated, the deadline for Host Participant daily settlement data submission will be delayed by one hour for each hour that the data is delayed but in no case will the deadline for Host Participant daily settlement data submission be extended beyond the beginning of hour 1700 three Business Days after the Operating Day.

(b) If the Assigned Meter Reader is not the Host Participant, for Real-Time Energy Market settlement purposes:

i. For DC coupled facilities participating in the market as separate Assets, prior to determining each Directly Metered Asset's data, the Assigned Meter Reader must arrange for access from the Host Participant to the meter data for the AC Point of Interconnection for the facility. The Host Participant must provide the Assigned Meter Reader access to the meter data.

ii. The Assigned Meter Reader provides a copy of the Directly Metered Asset data, that will be supplied to the ISO, to the Host Participant by 0800 of the next Business Day following the Operating Day or at a later time as mutually agreed.

(c) Prior to submitting data to the ISO which is different than what the Assigned Meter Reader shared with the Host Participant, the Assigned Meter Reader must ensure that the Host Participant is in agreement with the revision within the 37-hour reporting period.

(d) The Assigned Meter Reader provides to the ISO all meter data required to carry out the settlement process for each settlement interval of an Operating Day including daily Coincident Peak Contributions. The Assigned Meter Reader provides the ISO with interval meter data for all Generator Assets, Load Assets, and Tie-Line Assets for which it is the Assigned Meter Reader (including both Directly Metered Asset data and Profiled Load Asset data). Such data is provided by 1300 on the second Business Day after the Operating Day. For each Demand Response Asset, the Assigned Meter Reader shall provide the ISO with interval meter data by 1300 on the second Business Day after the Operating Day. Market Participants may obtain a list of their Generator Asset, Load Asset and Tie-Line Asset data by Node, Metering Domain and Load Zones, as applicable, through a request to ~~Customer~~ Participant Support and Solutions.

(e) If an Assigned Meter Reader fails to provide the required metering data in the time frame indicated, the settlement processes will be delayed one Business Day for each day of delay in the data submittal. To facilitate completion of the settlement process, the ISO, at its discretion, may insert a temporary estimated meter reading for those meter readings not received.

(2) The Assigned Meter Reader must provide the following data within the timelines to support initial monthly settlement process as described below:

(a) By 1300 on the third Business Day after last Operating Day of the settlement month all data required for Demand Assets associated with Seasonal Demand Resources and On-Peak Demand Resources.

(3) The Market Participant must provide the following data within the timelines to support the initial ~~monthly~~ settlement process as described below:

(a) By 1200 on the second Business Day after last Operating Day of the settlement month, Capacity Performance Bilaterals must be submitted.

(b) By 1200 on the ~~second~~ first Business Day ~~after last Operating Day~~ of the settlement month, Capacity Load Obligation Bilateral Transactions must be submitted.

Section 6: Resettlement Process: Data Reconciliation and Requested Billing Adjustment for Meter Data Errors

6.1 Data Reconciliation Process

Meter reconciliation and data corrections that are discovered by Governance Participants after the Customer Bill has been issued for a particular month or that are discovered prior to the issuance of the Customer Bill for the relevant month but not included in that Customer Bill or in the other Customer Bills for that month are reconciled by the ISO. The Data Reconciliation Process is based on data submitted to the ISO by the Host Participant or Assigned Meter Reader that is applicable to the month for which the revision applies.

Meter data changes are submitted to the ISO by the Host Participant or Assigned Meter Reader prior to the Correction Limit. In addition, Market Participants may submit new or revised Internal Bilateral for Market for Energy, Internal Bilateral for Load, Capacity Load Obligation Bilateral Transactions, and Capacity Performance Bilaterals prior to the Correction Limit.

6.1.1 Data Reconciliation Process Timeline

The Assigned Meter Reader or Host Participant provides the ISO all meter data required to carry out the Data Reconciliation Process to account for actual meter readings. Meter data are submitted for every hour of a day, unless the Market Participant is authorized to provide subhourly interval data to the ISO for a specific Generator Asset or Load Asset. Meter data for these assets are submitted for every subhourly interval of the day. Market Participants provide the ISO all Internal Bilateral for Market for Energy (Real-Time only), Internal Bilateral for Load, Capacity Load Obligation Bilateral, and Capacity Performance Bilateral data required to carry out the Data Reconciliation Process to account for actual transactions. The Assigned Meter Readers, Host Participants, and Market Participants provide the ISO with such data in accordance with the timelines and process defined below. For the purpose of describing the Data Reconciliation Process deadlines, the days referenced begin on the first calendar day following the settlement month:

(1) On or before 1700 on the 29th day, the Assigned Meter Reader must send Directly Metered Asset data to lead asset owners for Tie-Line Assets and wholesale Load Assets, and Lead Market Participant and/or facility owners for Generator Assets.

(2) On or before 1700 on the 34th day, lead asset owners, Lead Market Participants and/or generation facility owners must review the Directly Metered Asset data submitted in Section 6.1.1 (1) above and advise the Assigned Meter Reader if they do not agree with the Directly Metered Asset values.

(3) On or before 1700 on the 39th day, lead asset owners, Lead Market Participants and/or generation facility owners, and Assigned Meter Readers must reach agreement on Directly Metered Asset values submitted in Section 6.1.1(1) above.

(4) On or before 1700 on the 45th day, Assigned Meter Readers must submit interval meter data for all Directly Metered Assets. When resubmitting interval data, all intervals of the day must be submitted to the ISO. The ISO will not accept partial-day data for re-settlement. After the 45th day, the ISO will not accept revisions to Directly Metered Asset data from any Assigned Meter Reader that is not a Host Participant.

(5) On the 46th day, the ISO will provide a report[1] to the Host Participant for all Metering Domains for which the Host Participant is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to day 46.

(6) On the 46th day, the ISO will provide a report to the Directly Metered Asset owners reflecting the latest Directly Metered Asset data, by Asset identification, submitted to the ISO prior to day 46.

(7) During days 46 through 52, the Directly Metered Asset owners must review the Directly Metered Asset data provided by the ISO to the asset owner. If an error is discovered with the Directly Metered Asset data, the asset owner and the Host Participant and the Assigned Meter Reader will work together to determine the correct interval data.

If the Directly Metered Asset owner's issue cannot be resolved prior to 1700 on the 65th day, the Host Participant will provide written notification to ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~) on or before 1700 on the 65th day that a potential Requested Billing Adjustment for a Meter Data Error may result after the review of the error is complete. The notice must include the following information for those Directly Metered Assets that are initiating the investigation:

(a) Asset identification number(s);
(b) Asset Name(s);
(c) Assigned Meter Reader's Participant identification number(s); and
(d) Month and year for which the Directly Metered Asset data are under review.

(8) On or before 1700 on the 65th day, final Directly Metered Asset data will be submitted by the Host Participants. Final meter data shall be supplied to the ISO using the following procedure:

(a) The Host Participant ~~forwards the e-mail containing~~submits the agreed upon data to ISO ~~Customer Support~~ Participant Support and Solutions (~~custserv@iso-ne.com~~through~~copies~~ the Ask ISO participant support system) and sends the same

[1] The ISO issues several other reports to Market Participants during the Data Reconciliation Process that are described in a calendar posted on the ISO website.

information to the Assigned Meter Reader, the lead asset owner, Lead Market Participant, and/or generation facility owner as appropriate.

(b) In order for the ISO to accept revisions to Tie-Line Assets that affect one or more Host Participants, the affected Host Participants must agree to the revisions. The Host Participant who is the Assigned Meter Reader for the Tie-Line Asset will initiate an e-mail to the other Host Participants that use the Tie-Line Asset values asking that they accept the change to the asset value(s). The affected Host Participants will then ~~respond with a confirming e-mail indicating~~confirm their consent in writing to submit the revised Tie-Line Asset values to the ISO. The Host Participant who is the Assigned Meter Reader will ~~forward~~ submit confirmation ~~the confirming e-mails to the ISO with~~ including the revised Tie-Line Asset values to ISO Participant Support and Solutions (through the Ask ISO participant support system). In the event that the affected Tie-Line Asset is to the PTF, rather than another Metering Domain, the Host Participant should ~~direct the e-mail requesting~~request consent ~~to~~ from ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~). The ISO will then respond ~~with a confirming e-mail~~ indicating their consent.

(9) On or before 1700 on the 65th day, the Host Participant may submit preliminary settlement data for Profiled Load Asset data.

(10) After the 65th day, the ISO will not accept any revisions to the Directly Metered Asset data for use in the meter reconciliation re-settlement process.

(11) On the 66th day, the ISO will provide a report[1] to the Host Participant for all Metering Domains for which the Host Participant is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to the 66th day.

(12) On the 66th day, the ISO will provide a report[1] to the Directly Metered Asset owners reflecting the latest Directly Metered Asset data, by Asset identification, submitted to the ISO prior to the 66th day.

(13) Prior to 1700 on the 70th day, the Lead Market Participant or its DDE must submit meter data or demand reduction values for all Demand Assets associated with On-Peak Demand Resources or Seasonal Peak Demand Resources, and Demand Response Assets.

(14) Prior to 1700 on the 85th day, the Host Participant must submit meter data for all Profiled Load Assets and Coincident Peak Contribution values for all Load Assets.

(15) On the 86th day, the ISO will provide a report[1] to the Profiled Load Asset owners reflecting the latest Profiled Load Asset data, by Asset identification, submitted to the ISO prior to the 86th day.

(16) On the 86th day, the ISO will provide a report[1] to the Host Participant for all Metering Domains for which the Host Participant is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to 86th day.

(17) On or before 1700 on the 90th day, the Profiled Load Asset Owners must review the Profiled Load Asset data and notify the Host Participant, for the applicable Profiled Load Asset, of any issues that they identify with the Profiled Load Asset data. Any issues identified and submitted to the Host Participant with the Profiled Load Asset data that are discovered after 1700 on the 90th day but prior to the 99th day remain eligible for a Meter Data RBA, however, the Host Participant is under no obligation to investigate any such issues during the Data Reconciliation Process.

(18) By the 99th day, the Host Participant must investigate any issue associated with a Profiled Load Asset that was identified by a Profiled Load Asset owner and submitted on or before 1700 on the 90th day. If the issue can be resolved, the Host Participant will submit revised Profiled Load Asset data on or before 1700 on 99th day. Also by 1700 on the 99th day, the Host Participant will provide the ISO with the any revised Coincident Peak Contribution values related to the meter data error correction. These data submissions will be submitted ~~via e-mail~~ to ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~). Data will not be accepted by the ISO from the Host Participant after the 99th day.

If the Profiled Load Asset owner's issue cannot be resolved prior to the 99th day, the Host Participant will provide written notification to ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~) by 1700 on the 99th day that a potential Meter Data RBA may result after the review of the error is complete. The notice must include the following information for those Profiled Load Assets that are initiating the investigation:

(a) Asset identification number(s);
(b) Asset name(s);
(c) Assigned Meter Reader Participant identification number(s); and
(d) Month and year for which the Profiled Load Asset data are under review.

(19) On the 100th day, the ISO will provide a report to the Profiled Load Asset owners reflecting the latest Profiled Load Asset data, by Load Asset identification, submitted to the ISO prior to the 100th day.

(20) On the 100th day, the ISO will provide a report to the Host Participant for all Metering Domains for which the Host Participant is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to the 100th day.

(21) By 1700 on the 101st day, Market Participants may submit new or revised Internal Bilaterals for Market for Energy, Internal Bilaterals for Load, Capacity Load Obligation Bilaterals, and Capacity Performance Bilaterals.

6.2 Meter Data Error RBA Process

Meter Data Errors discovered by a Market Participant that satisfy the eligibility conditions specified in Market Rule 1 Section III.3.8 for a Requested Billing Adjustment may be resettled by the ISO. The Meter Data Error RBA Process is based on data submitted to the ISO by the Host Participant that is applicable to the month for which the revision applies.

In addition, Market Participants may submit new or revised Internal Bilateral Transactions associated with the Real-Time Energy Market and new or revised Capacity Load Obligation Bilateral Transactions and Capacity Performance Bilaterals as part of the resettlement.

6.2.1 Meter Data Error RBA Process Timeline

On or before 1700 on the day of the Meter Data Error RBA Submission Limit, the Host Participant, Assigned Meter Reader, or Asset Owner must submit a completed RBA Form for Meter Data Error, as posted on the ISO website, to ~~the ISO's Chief Financial Officer~~ISO Participant Support and Solutions (through the Ask ISO participant support system). (See also Section 6 of the ISO New England Billing Policy.) The ISO will assign an identifying RBA number and provide it to the submitter and to the Host Participant (if different from the submitter) as identified on the RBA form for Meter Data Error.

For the purpose of describing the deadlines for the Meter Data Error RBA Process, the days referenced in the following timeline start on the first calendar day following the Meter Data Error RBA Submission Limit. All data submissions under this timeline, which may include meter data, Coincident Peak Contributions, and Internal Bilateral Transactions, are ~~performed via e-mail~~ submitted to ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~). This timeline defines the deadlines for all possible categories of data submittals, although the requirements for a specific Meter Data Error RBA may be limited to a subset of these submittals. Specifically, the process for a Meter Data Error RBA involving corrections to interval meter data values may include submittals of meter data for Directly Metered Assets, Profiled Load Assets, Coincident Peak Contributions, Internal Bilateral for Market for Energy, Internal Bilateral for Load, Capacity Load Obligation Bilateral, and Capacity Performance Bilaterals.

(1) The Host Participant must send any corrected Directly Metered Asset data to the ISO by day 40.

(2) Corrected meter data must be supplied to the ISO using the following procedure:

   (a) The Host Participant must ~~forward the e-mail, containing~~submit the agreed upon data~~,~~ to ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~) and must send a copy to the Assigned Meter Reader, the lead Asset owner, Lead Market Participant, and/or generation facility owner as appropriate. ~~The e-mail~~All communications shall reference the Meter Data Error RBA number assigned by the ISO.

(b) In order for the ISO to accept revisions to Tie-Line Assets that affect one or more Host Participants, the affected Host Participants must agree to the revisions. The Host Participant that is the Assigned Meter Reader for the Tie-Line Asset must initiate an e-mail to the other Host Participants that use the Tie-Line Asset values requesting that they accept the change to the asset value(s). The affected Host Participants must then ~~respond with a confirming e-mail~~ confirm ~~indicating~~ their consent in writing to submit the revised Tie-Line Asset values to the ISO. The Host Participant that is the Assigned Meter Reader must ~~forward~~ submit confirmation ~~the confirming e-mails to the ISO with~~ including the revised Tie-Line Asset values to ISO Participant Support and Solutions (through the Ask ISO participant support system). In the event that the affected Tie-Line Asset is to the PTF, rather than another Metering Domain, the Host Participant should ~~direct the e-mail requesting consent to~~contact ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~). The ISO will then respond ~~with a confirming e-mail~~ indicating their consent.

(3) On the 41st day, the ISO will provide a report to the Directly Metered Asset owners reflecting the latest Directly Metered Asset data, by Asset identification, submitted to the ISO prior to the 41st day.

(4) The Directly Metered Asset Owners will have one Business Day, following the 41st day, to review the report. If the Directly Metered Asset owner does not agree with the revised values, the Directly Metered Asset owner must contact the Host Participant by 1700 on the first Business Day following the 41st day. The Host Participant will review the revised data and determine the values that need to be submitted to the ISO.

(5~~)~~) On or before 1700 on the 45th day, the Host Participant must provide final Directly Metered Asset data. The ISO will not accept changes to Directly Metered Asset data after this deadline. Changes to Directly Metered Asset data that are submitted must meet at least one of the following eligibility criteria:

(a) Directly Metered Asset changes for assets specified in the Requested Billing Adjustment for a Meter Data Error that meets the MWh threshold.
(b) Directly Metered Asset changes for assets specified in the Requested Billing Adjustment for a Meter Data Error that was identified during the Data Reconciliation Process and could not be resolved by 36 days prior to the Correction Limit (day 65).
(c) Directly Metered Asset changes that result from changes to other Directly Metered Asset that met either criterion in (a) or (b) above.

The submittal process for the data is as follows:

(i) The Host Participant must ~~forward the e-mail, containing~~submit the agreed upon data~~,~~ to ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@isone.com~~) and must send a copy the

Assigned Meter Reader, the lead Asset owner, Lead Market Participant and/or generation facility owner as appropriate. ~~The e-mail~~All communications shall reference the Meter Data Error RBA number assigned by the ISO.

(ii) In order for the ISO to accept revisions to Tie-Line Assets that affect one or more Host Participants, the affected Host Participants must agree to the revisions. The Host Participant that is the Assigned Meter Reader for the Tie-Line Asset must initiate an e-mail to the other Host Participants that use the Tie-Line Asset values requesting that they accept the change to the asset value(s). The affected Host Participants must then ~~respond with a confirming e-mail~~confirm their consent in writing ~~indicating their consent~~ to submit the revised Tie-Line Asset values to the ISO. The Host Participant that is the Assigned Meter Reader must submit confirmation ~~forward the confirming e-mail to the ISO with~~ including the revised Tie-Line Asset values to ISO Participant Support and Solutions (through the Ask ISO participant support system). In the event that the affected Tie-Line Asset is to the PTF, rather than another Metering Domain, the Host Participant should ~~direct the e-mail requesting~~request consent ~~to~~ from ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~). The ISO will then respond ~~with a confirming e-mail~~ indicating their consent.

(6) On the 46th day, the ISO will provide a report to the Host Participant for all Metering Domains for which the Host Participant is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to the 46th day.

(7) On the 46th day, the ISO will provide a report to the Directly Metered Asset owners reflecting the final Directly Metered Asset data, by Load Asset ID, submitted to the ISO prior to the 46th day.

(8) By 1700 on the 60th day, the Host Participant must provide any revised Profiled Load Asset data. Changes to Profiled Load Asset data that are submitted to the ISO must meet at least one of the following eligibility criteria:

(a) Profiled Load Asset changes for assets specified in the Requested Billing Adjustment for a Meter Data Error that meets the MWh threshold.

(b) Profiled Load Asset changes for assets specified in the Requested Billing Adjustment for a Meter Data Error that were identified during the Data Reconciliation Process and could not be resolved prior to the Correction Limit.

(c) The Profiled Load Asset changes result from changes to Directly Metered Assets submitted to the ISO as part of the Requested Billing Adjustment for a Meter Data Error.

(d) The Profiled Load Asset changes are a result of changes to another Profiled Load Asset changes that met either criterion in (a) or (b) above.

The submittal process for the data is as follows:

(i) The Host Participant must ~~forward the e-mail, containing~~submit the data~~,~~ to ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@isone.com~~)~~. The e-mail~~ and shall reference the Meter Data Error RBA number assigned by the ISO.

(9) On the 61st day, the ISO will provide a report to the Profiled Load Asset owners reflecting the latest Profiled Load Asset data, by Load Asset identification, submitted to the ISO prior to the 61st day.

(10) On or before 1700 on the 73rd day, the Load Asset owners must review the Profiled Load Asset data and notify the Host Participant, for the applicable Load Asset, of any potential issues identified with the Profiled Load Asset data.

(11) By the 86th day, the Host Participant must investigate and resolve any issue identified by the Load Asset owner. Final interval values must be submitted to the ISO by the Host Participant for Profiled Load Asset data by 1700 on the 86th day. Any revisions to Coincident Peak Contribution values must also be submitted to the ISO by 1700 Changes to Coincident Peak Contribution data that are submitted to the ISO must meet at least one of the following eligibility criteria:

(a) Coincident Peak Contributions that change as a result of any meter data revisions that were submitted as described in steps (1) through (11) above.

(b) Coincident Peak Contributions revised as the result of a Meter Data Error RBA which meets the eligibility criterion for the average error in daily Coincident Peak Contribution for an affected Load Asset, in which case this is the first deadline for a data submittal for the Meter Data Error RBA. The data submittal will reflect the revision for the affected Load Asset, and any other Load Assets that change as a result of the revision for the affected Load Asset.

The submittal process for the data is as follows:

(i) The Host Participant must ~~forward the e-mail, containing~~submit the data~~,~~ to ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@isone.com~~)~~. The e-mail~~ and shall reference the Meter Data Error RBA number assigned by the ISO.

(12) On the 87th day, the ISO will provide a report to the Profiled Load Asset owners reflecting the latest Profiled Load Asset data, by Load Asset ID, submitted to the ISO prior to day 87.

(13) By 1700 on the 90th day, Market Participants may submit new or revised Internal Bilateral Transactions applicable to the Real-Time Energy Market or new or revised Capacity Load Obligation Bilateral Transactions or Capacity Performance Bilaterals. If the Meter Data Error RBA was submitted under the eligibility criterion involving only the error in the Coincident Peak Contributions, then only Capacity Load Obligation

Bilateral Transactions are eligible for submittal. The counter-party for the transaction must also ~~submit an e-mail to~~contact ISO ~~Customer~~ Participant Support and Solutions (through the Ask ISO participant support system~~custserv@iso-ne.com~~) confirming the transaction by the 1700 deadline. ~~The e-mail~~All Communications shall reference the Meter Data Error RBA number assigned by the ISO.

6.2.2 Meter Data Error RBA Rescission

In the event the submitting party elects to rescind a previously submitted Meter Data Error RBA, the submitting party must notify ISO ~~Customer~~ Participant Support and Solutions ~~via e-mail~~ (through the Ask ISO participant support system~~custserv@iso-ne.com~~) of its intent. The ~~e-mail~~notification must contain the applicable RBA number, month, year, and affected Generator Asset, Load Asset, or Tie-Line Asset ID. The ISO will acknowledge ~~the~~ receipt of the notice ~~of the e-mail~~, and will send a notification to the Participants that the RBA has been rescinded. All settlement activities related to the Meter Data Error RBA will cease after the receipt of the rescission ~~e-mail~~notification and there will be no resettlement or billing associated with a rescinded request.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

F. Credit Limits for FTR-Only Customers

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

G. Total Credit Limit

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} \text{HC}_i \times \text{LMP ratio} \times 1.15$$

Where:

t =	The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;
n =	The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;
HC =	The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and
LMP ratio =	The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

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(ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily Charges Estimator = MAX(FCM_Daily_Credit_CM x NDAY_CM + FCM_Daily_Credit_PM x NDAY_PM + FCM_Charge_LD x NDAY_P2 x FCA_Price_Ratio, 0)

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Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

FCA_Price_Ratio = (((Clearing Price_CCP_n x NDAY_P2_CCP_n) + (Clearing Price_CCP_{n+1} x NDAY_P2_CCP_{n+1}))/NDAY_P2)/(Clearing Price_CCP_n)

Where:

Clearing Price_CCP_n is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

Clearing Price_CCP_{n+1} is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following CCP_n;

NDAY_P2_CCP_n is number of days in the CCP_n within NDAY_P2; and

NDAY_P2_CCP_{n+1} is number of days in the CCP_{n+1} within NDAY_P2.

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~~(ii)~~(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for ~~capacity transactions~~the Forward Capacity Market, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(~~iii~~iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;~~.~~

(~~iv~~v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus
~~a.~~b. such Market Participant's Daily FCM Requirements; plus
~~b.~~c. such Market Participant's Virtual Requirements; plus
~~c.~~d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus
~~d.~~e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
~~e.~~f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus
~~f.~~g. the amount of any Disputed Amounts received by such Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) any financial assurance that remains after the allocation described in subsection (d) (ii) shall be allocated so as to ensure that the Market Participant's Transmission Credit Test Percentage is no greater than 100%;

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

A Designated FCM Participant must include 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:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF x DF] – MCC

Where:

MCC (monthly capacity charge) equals monthly capacity payments ~~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.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1 and, during February through May and September through November, excluding the Capacity Supply Obligation associated with any Energy Efficiency measures. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1 and, during February through May and September through November, excluding the Capacity Supply Obligation associated with any Energy Efficiency measures. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the instant Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all three years reflect actual data.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1 and, during February through May and September through November, excluding the Capacity Supply Obligation associated with any Energy Efficiency measures, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all three years reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant’s Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. ~~FCM Capacity Charge Requirements~~[Reserved for Future Use]

~~The FCM Capacity Charge Requirements shall be calculated for the current month and all previously unbilled months. The FCM Capacity Charge Requirements shall be the product of the Estimated Capacity Load Obligation times the FCM Charge Rate for the applicable Capacity Zone. For purposes of this calculation, the FCM Charge Rate for Capacity Commitment Periods beginning prior to June 1, 2022 for a Capacity Zone will be calculated using the same methodology described in Section III.13.7.5 of Market Rule 1 for deriving the Net Regional Clearing Price, with the exception that the FCM Charge Rate will include the balance of the CTR fund after the value of specifically allocated CTRs has been paid, as described in Section III.13.7.5.3.1 of Market Rule 1. For purposes of this calculation, the FCM Charge Rate for Capacity Commitment Periods beginning on or after to June 1, 2022 for a Capacity Zone will be calculated as the sum of the charge and adjustment rates specified in Section III.13.7.5.1.1 of Market Rule 1.~~

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the “Non-Commercial Capacity Cure Period”), then, in

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

F. Transfer of Capacity Supply Obligations

1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)) and the current month FCM charges are prorated to the proportion of remaining days in the month. The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

a) The term "Charge" refers to 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.

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 -General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, ~~and~~ Net Commitment Period Compensation~~,~~, and daily Forward Capacity Market charges and payments ("Daily FCM Charges") (all such ~~hourly~~ charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the monthly Forward Capacity Market (exclusive of settlements included in the Hourly Charges) and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 -Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 -Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 -TIMING AND CONTENT OF STATEMENTS.

Section 2.1 - Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly, some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 -Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 - Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 -Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *~~Capacity~~ Monthly Forward Capacity Market Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of ~~capacity charges, penalties~~ Capacity Performance Payments and other transactions in the Forward Capacity Market that are not included in the Daily FCM Charges.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) *Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 - Monthly Statements for Transmission Charges. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a "Transmission Statement"). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).Section 2.6 –Certain Subsequent Adjustments to Previously Issued Statements.

a) *Adjustments Requested by Covered Entities*. Covered Entities supplying Regional Network Load and other input data to the ISO for use by the ISO in

Summary of ISO New England Board and Committee Meetings

January 6, 2022 Participants Committee Meeting

Since the last update, the Markets Committee met on December 3, the Board of Directors met on December 10, and the Information Technology and Cyber Security Committee met on December 16. All of the meetings were held virtually.

The Markets Committee met to provide new directors and the External Market Monitor with an opportunity to review and discuss the structure of External Market Monitor reports. During executive session, the Committee received an update on the markets-related personnel needs of the ISO, including plans to return to the office in January, 2022.

The Board of Directors received an update on management's plans for the workforce to return to the office in January, 2022, including an update on the current vaccination status of employees.

The Information Technology and Cyber Security Committee was provided with an update on the Company's three-year cyber security plan, and discussed the plan's major areas of emphasis. The Committee reviewed the Company's business continuity and disaster recovery plans, and discussed the current initiatives underway to update business processes, further develop and refine disaster recovery plans, and to perform periodic testing. The Committee discussed the annual review of critical vendors. The review includes an evaluation of the critical vendors to determine the risk of service interruption and to identify a mitigation plan in the event of a disruption in service for any of these vendors. The Committee also conducted its annual review of the IT-related portions of the Internal Audit Department's work plan. The Committee then reviewed its calendar for the upcoming year, and held an executive session to discuss the achievement of corporate goals for 2021, and the proposed corporate goals for 2022.

NEPOOL Participants Committee Report

January 2022

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

Highlights

All data through December 27th

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: November 2021 Energy Market value totaled $570M
  - December 2021 Energy market value was $656M, up $86M from November 2021 and up $206M from December 2020
    - December 2021 natural gas prices over the period were 60% higher than November average values
    - Average RT Hub Locational Marginal Prices ($62.35/MWh) over the period were 6% higher than November averages
      - DA Hub: $67.80/MWh
    - Average December 2021 natural gas prices and RT Hub LMPs over the period were up 112% and 50%, respectively, from December 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 97.6% during December, down from 98.2% during November*
    - The minimum value for the month was 92.1% on Monday, December 6th

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

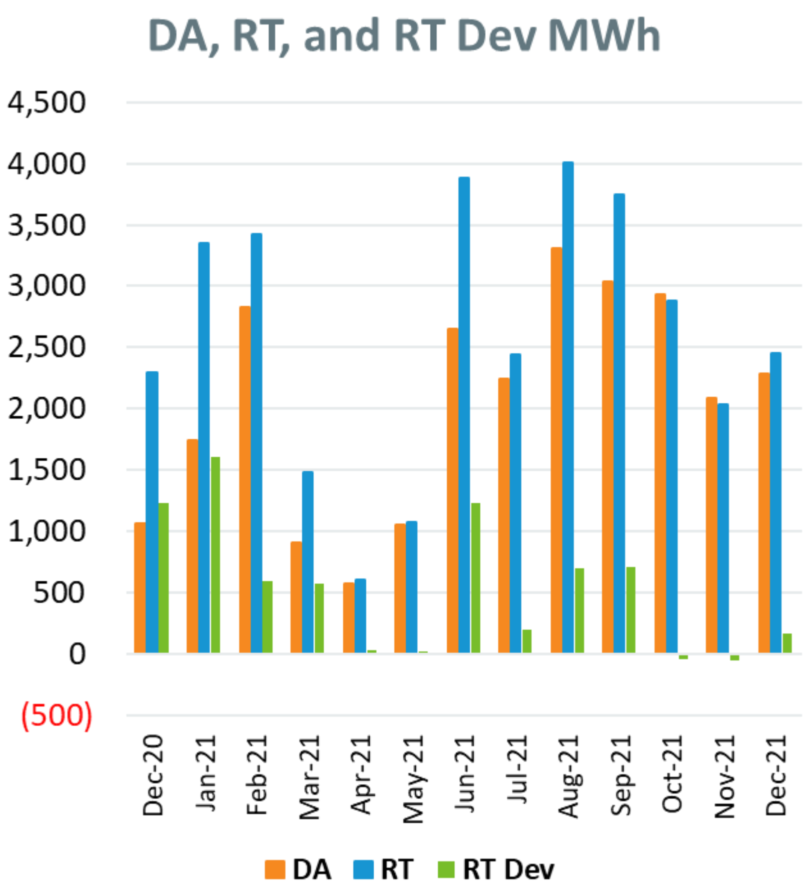
Underlying natural gas data furnished by: ICE Global markets in clear view

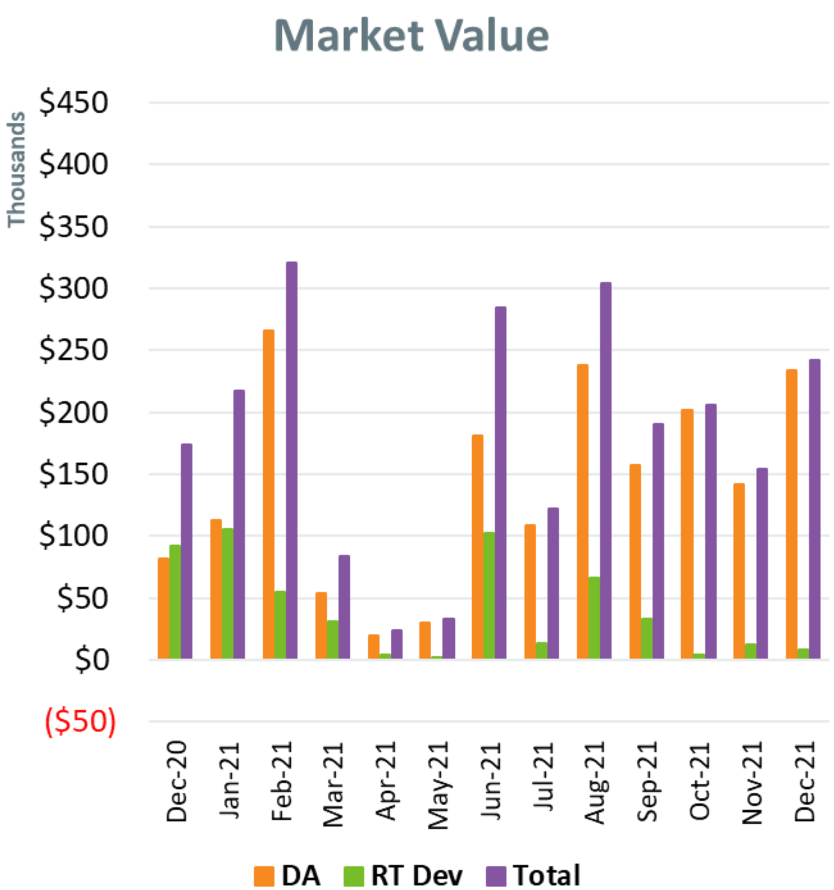
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - December 2021 NCPC payments totaled $5.3M over the period, up $2M from November 2021 and up $1.7M from December 2020
    - First Contingency payments totaled $2.9M, up $0.1M from November
      - $2.8M paid to internal resources, down $0.1M from November
        - » $1.2MK charged to DALO, $868K to RT Deviations, $704K to RTLO*
      - $176K paid to resources at external locations, up $172K from
        - » $126K charged to DALO at external locations, $50K to RT Deviations
    - Second Contingency payments totaled $2.3M, up $2.1M from November
    - Voltage payments totaled $19K, down $191K from November
  - NCPC payments over the period as percent of Energy Market value were 0.8%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $298K; Rapid Response Pricing (RRP) Opportunity Cost - $279K; Posturing - $22K; Generator Performance Auditing (GPA) - $104K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Highlights

- Preparations are ongoing for FCA 16, which will commence on February 7
- The draft Transmission Planning for the Clean Energy Transition (TPCET) Pilot Study Report was posted to the PAC website on December 22, 2021
  - Comments are due to PACmatters@iso-ne.com by January 10
- ISO finalized the 2050 Transmission Study scope on December 22, 2021
- Additional high-level transmission, ancillary services, and probabilistic resource adequacy results for the 2021 Economic Study (Future Grid Reliability Study) were discussed at the December 15, 2021 PAC meeting

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - Third and final annual reconfiguration auction (ARA3) will be held on March 1-3, and results will be posted no later than March 31
  - ICR and Related Values were filed with FERC on November 30, 2021
- CCP 14 (2023-2024)
  - Second annual reconfiguration auction (ARA2) will be held on August 1-3, and results will be posted no later than August 31
  - ICR and Related Values were filed with FERC on November 30, 2021
- CCP 15 (2024-2025)
  - First annual reconfiguration auction (ARA1) will be held on June 1-3, and results will be posted no later than July 5
  - ICR and Related Values were filed with FERC on November 30, 2021

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - FCA 16 will model the same zones as FCA 15
    - Export-constrained zones: Northern New England, and Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England
  - Both the ICR and Informational (qualification) FERC filings were made on November 9, 2021
  - Preparations are ongoing for the auction that will commence on February 7

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 2, 2021
    - TOs to identify in-service dates for new transmission projects and revisions to previously certified projects
    - Approved projects to be shared with the RC at their January meeting
  - Capacity zone development discussions began at the November 17, 2021 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - ISO to calculate and post the FCA 17 dynamic delist bid threshold price no later than early March

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- Efforts to expand/improve the transportation electrification forecast for CELT 2022 are complete
- Upcoming Meetings
  - Load Forecast Committee Meeting will be held on February 18
  - Both the Energy-Efficiency Forecast Working Group (EEFWG) and Distributed Generation Forecast Working Group (DGFWG) will meet on February 14

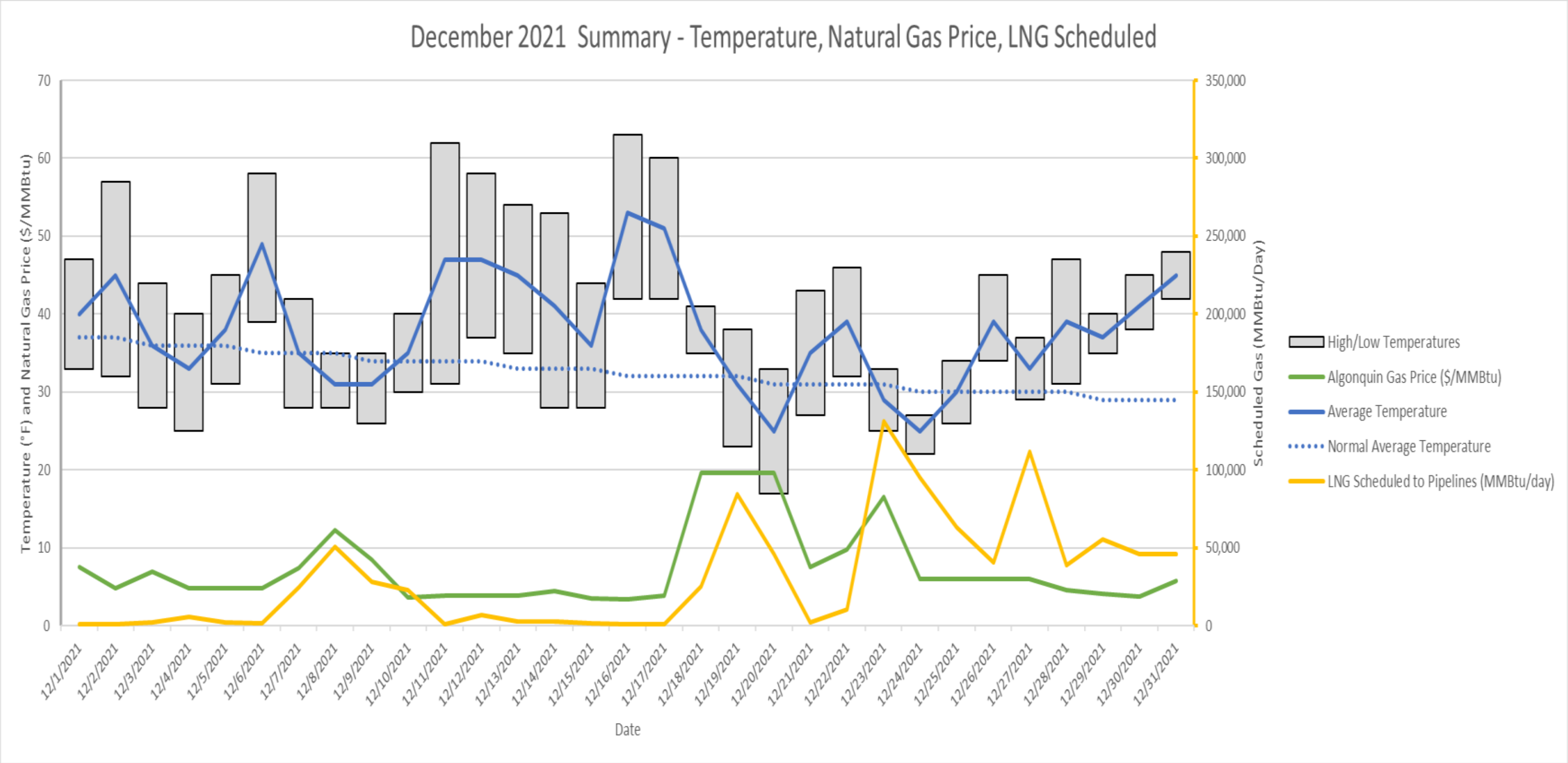
Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 8, 2022.

New England Winter Outlook

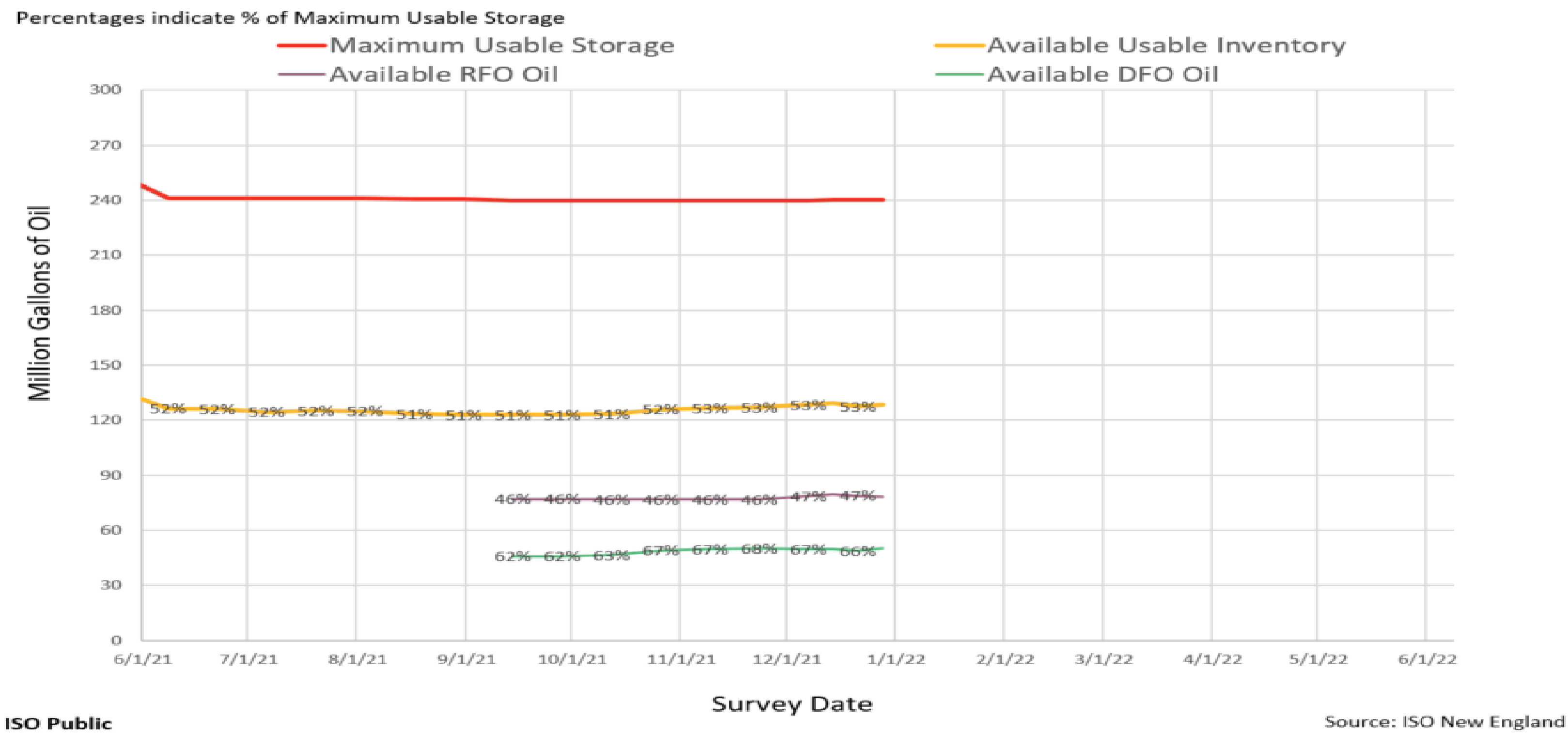
December 2021 Weather

- Average temperature was warmer than normal by approximately 5°F, resulting in lower than normal demand
- On a few days in the second half of December, lower-than-normal temperatures coincided with high natural gas prices and the utilization of fuel oil for power generation



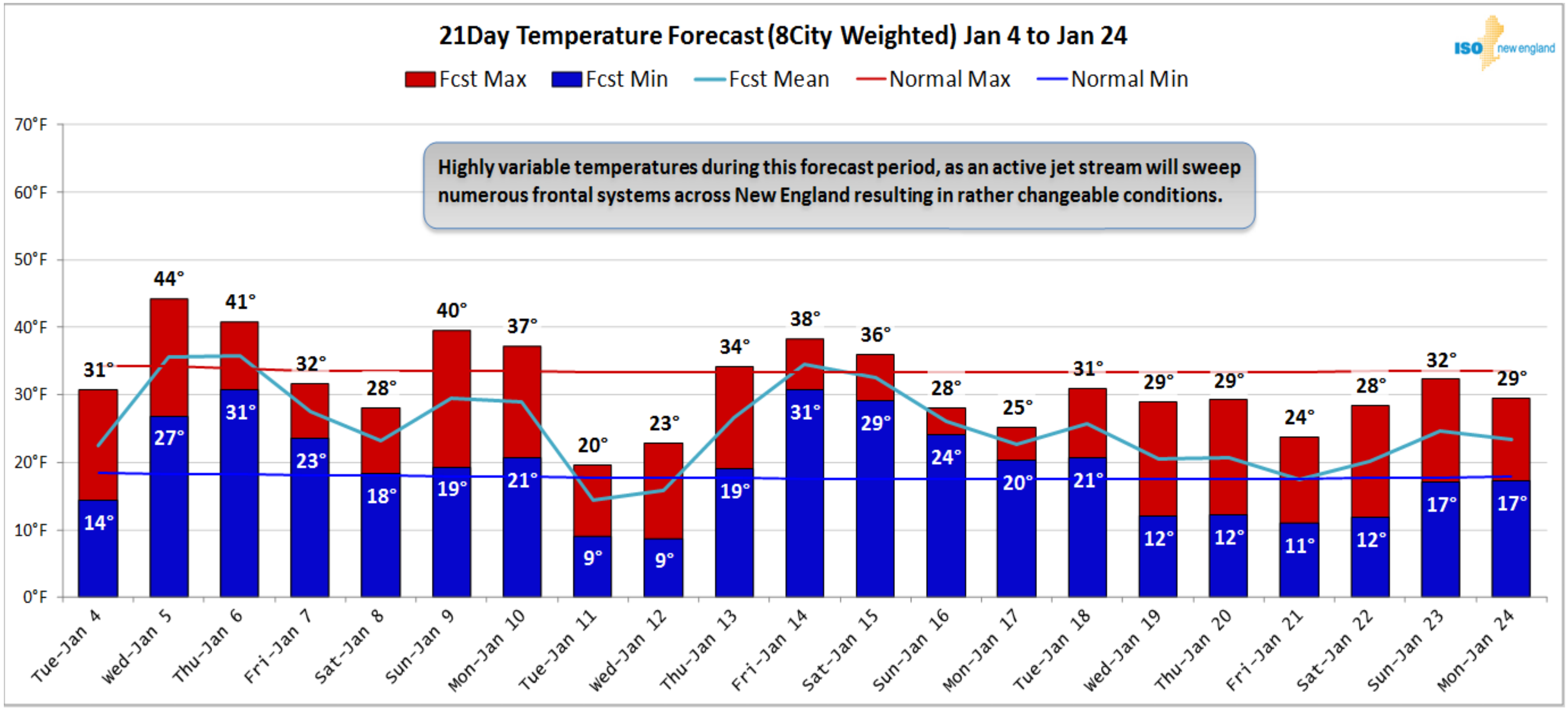
Fuel Oil Replenishment

- Coincident with higher natural gas prices, oil units were in merit on some days in December
- In aggregate, fuel oil inventories have been relatively stable since the beginning of winter



21 Day Forecast

- Gas Prices for February Delivery as of 1/4/2022 are:
  - European Gas/LNG $26.648
  - Asian Gas/LNG $30.505
  - Algonquin/New England $17.07
- Latest 21 day ISO Forecast



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.3°F) Max: 64°F, Min: 20°F Precipitation: 2.45" – Below Normal Normal: 4.18" Snow: 8.6"	Hartford	Temperature: Above Normal (5.0°F) Max: 63°F, Min: 17°F Precipitation: 2.92" – Below Normal Normal: 3.96" Snow: 4.2"

Peak Load:	17,827 MW	Dec 20, 2021	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for December			

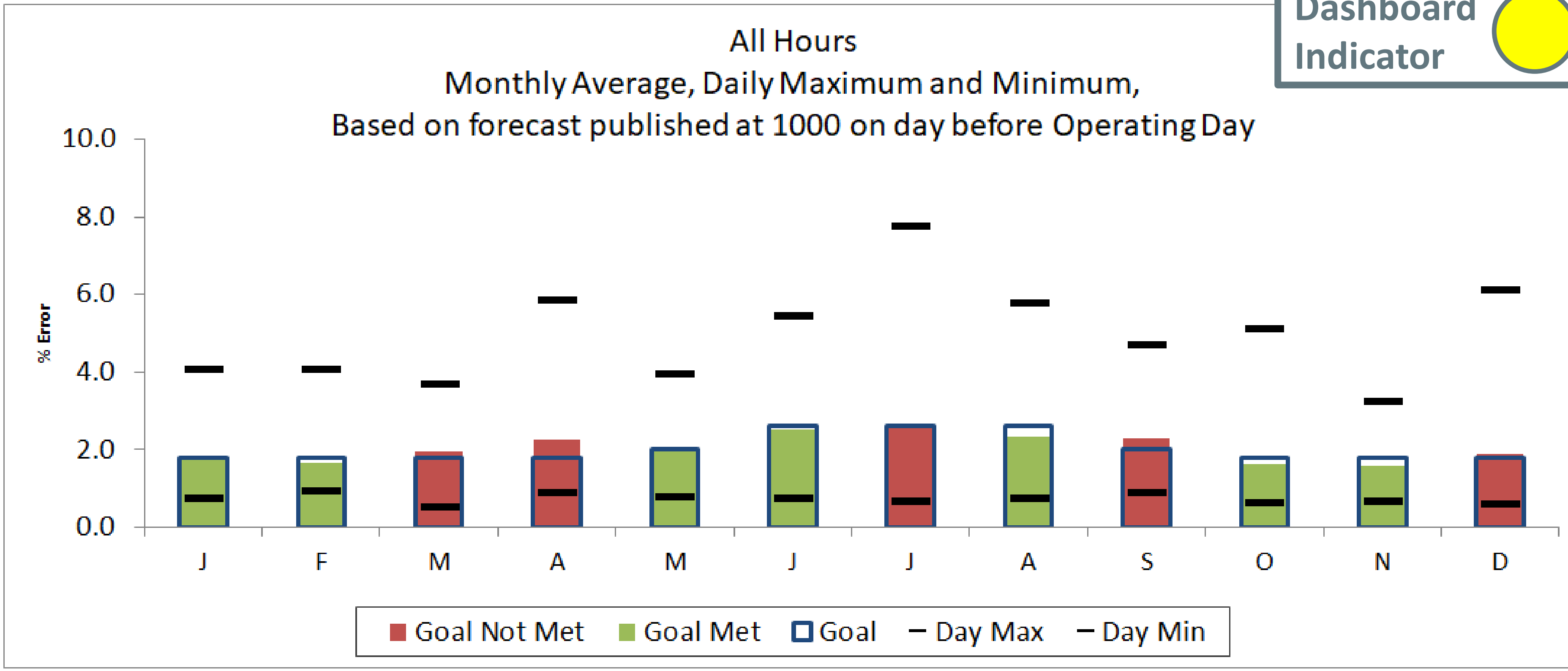
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
12/8	NBPSO	300
12/17	NYISO	1286
12/23	IESO	600

2021 System Operations - Load Forecast Accuracy

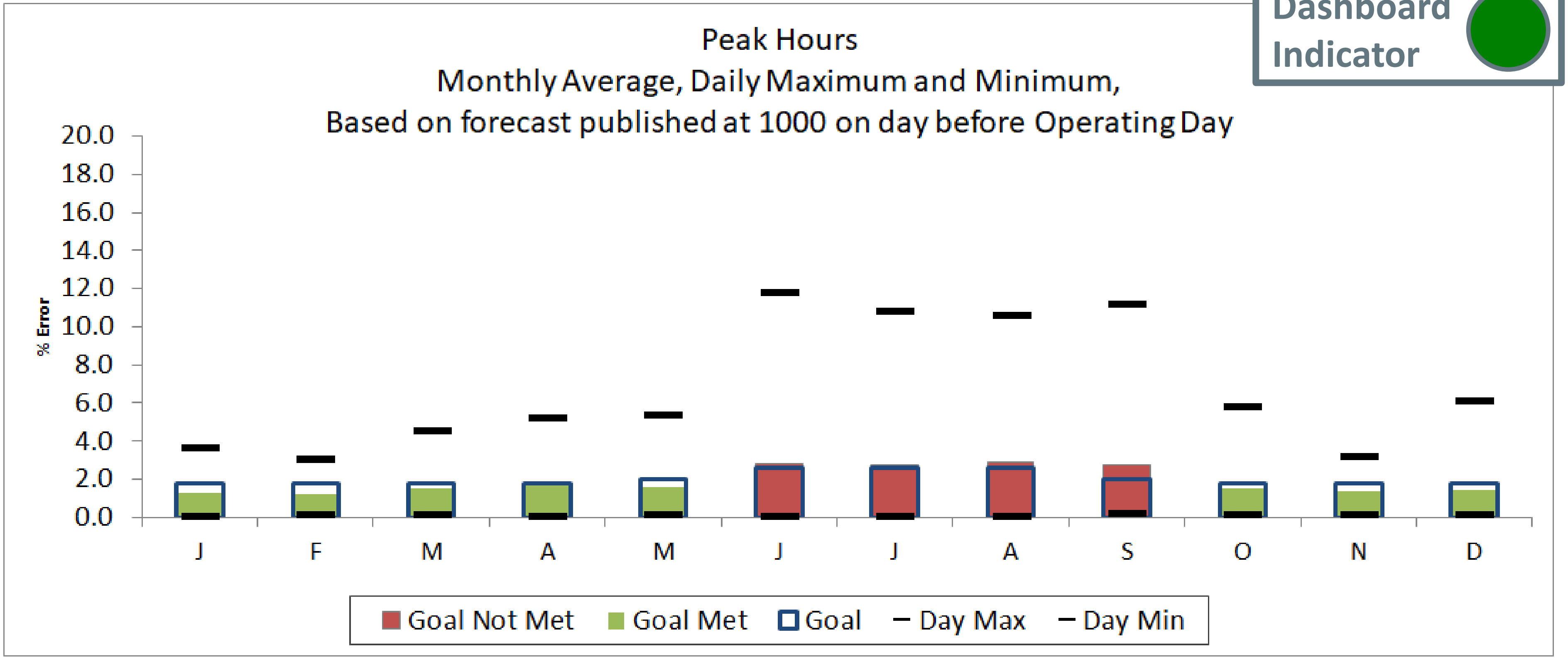
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03	3.67	5.85	3.92	5.41	7.75	5.77	4.68	5.08	3.21	6.10	7.75
Day Min	0.70	0.92	0.49	0.88	0.77	0.73	0.63	0.71	0.86	0.60	0.64	0.58	0.49
MAPE	1.72	1.66	1.97	2.24	1.95	2.50	2.61	2.33	2.30	1.62	1.59	1.88	2.03
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

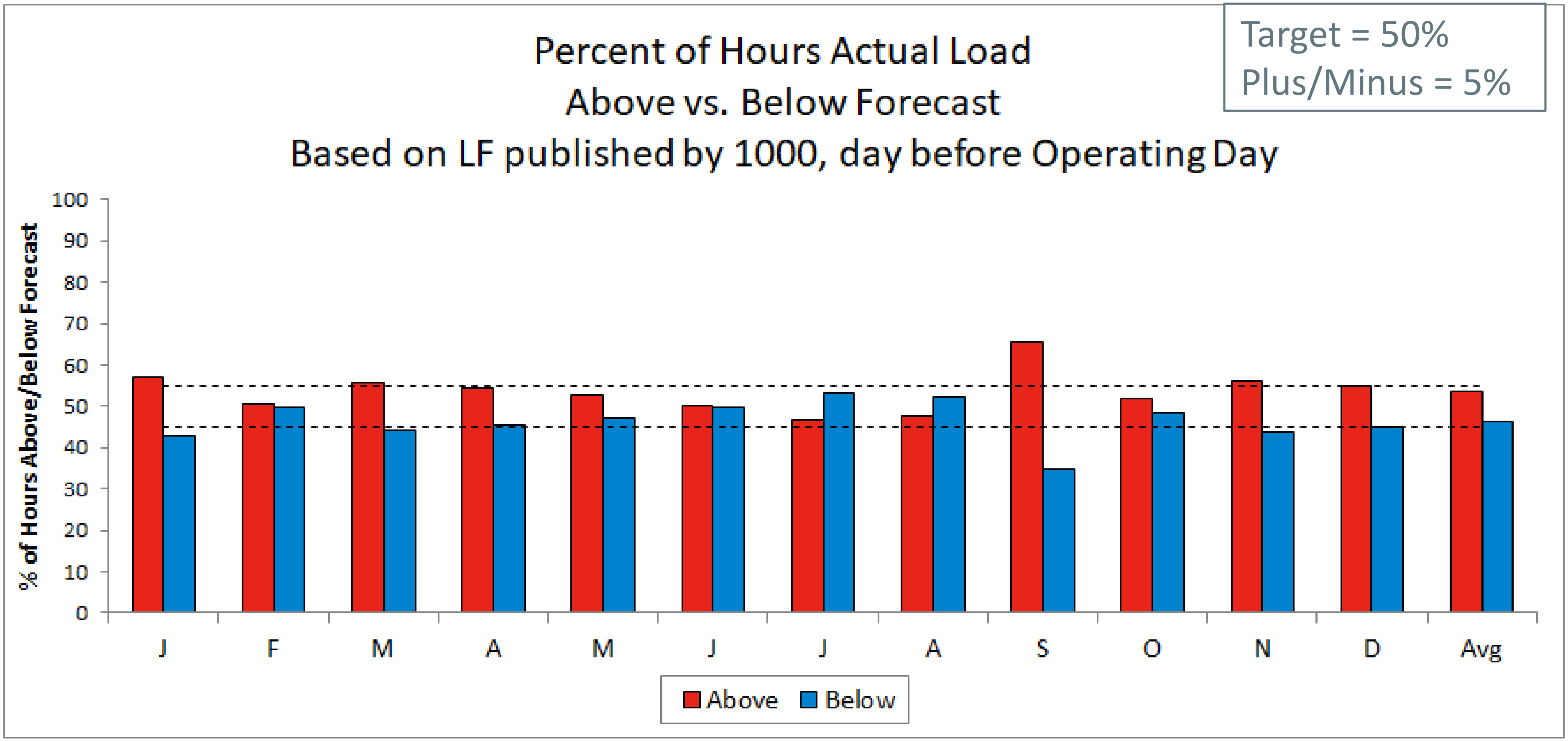
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



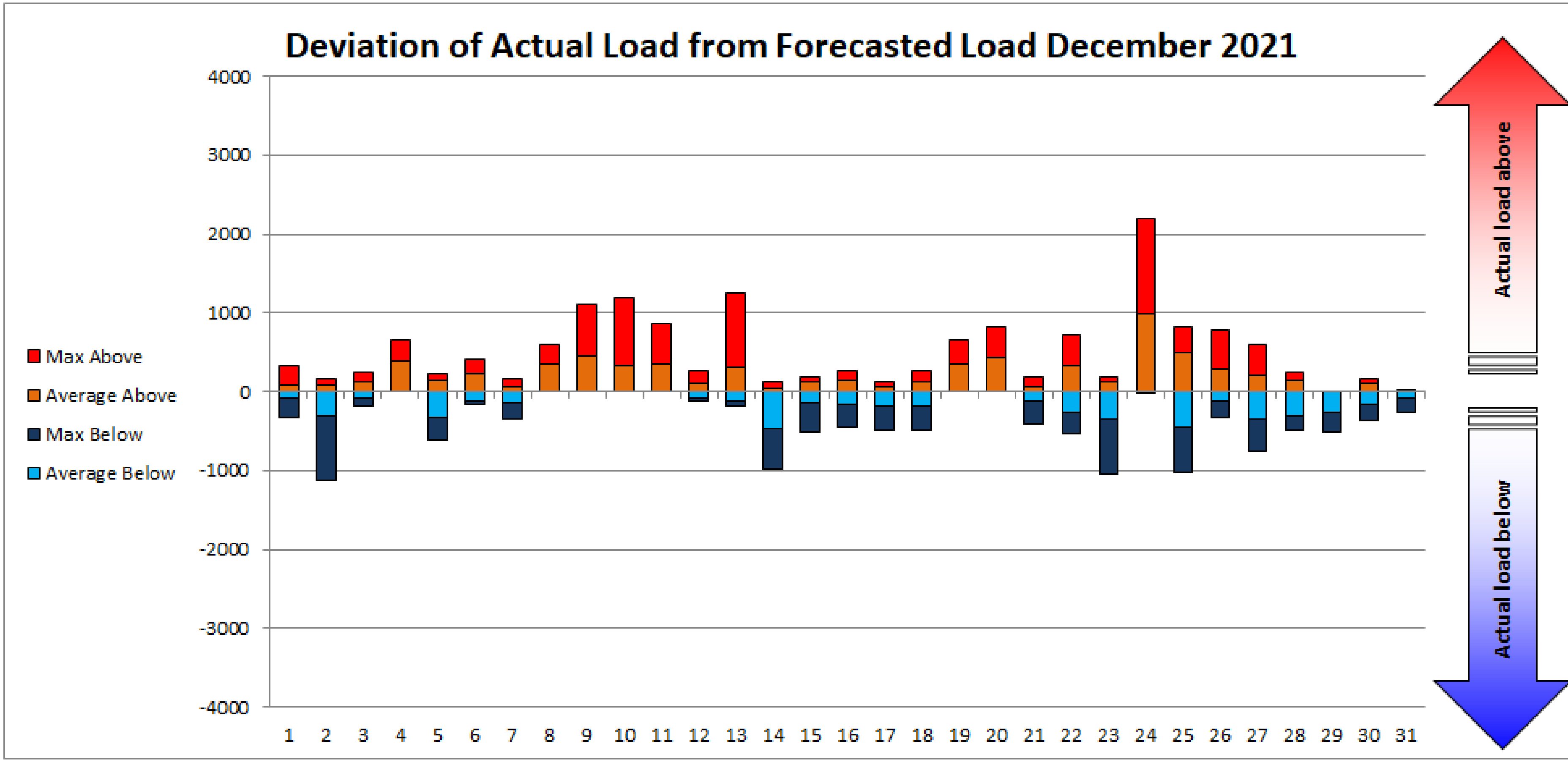
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03	4.47	5.19	5.31	11.76	10.75	10.54	11.13	5.79	3.17	6.07	11.76
Day Min	0.02	0.06	0.08	0.03	0.11	0.04	0.05	0.01	0.17	0.09	0.12	0.10	0.01
MAPE	1.26	1.18	1.48	1.66	1.60	2.79	2.78	2.86	2.76	1.51	1.39	1.45	1.90
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

2021 System Operations - Load Forecast Accuracy cont.

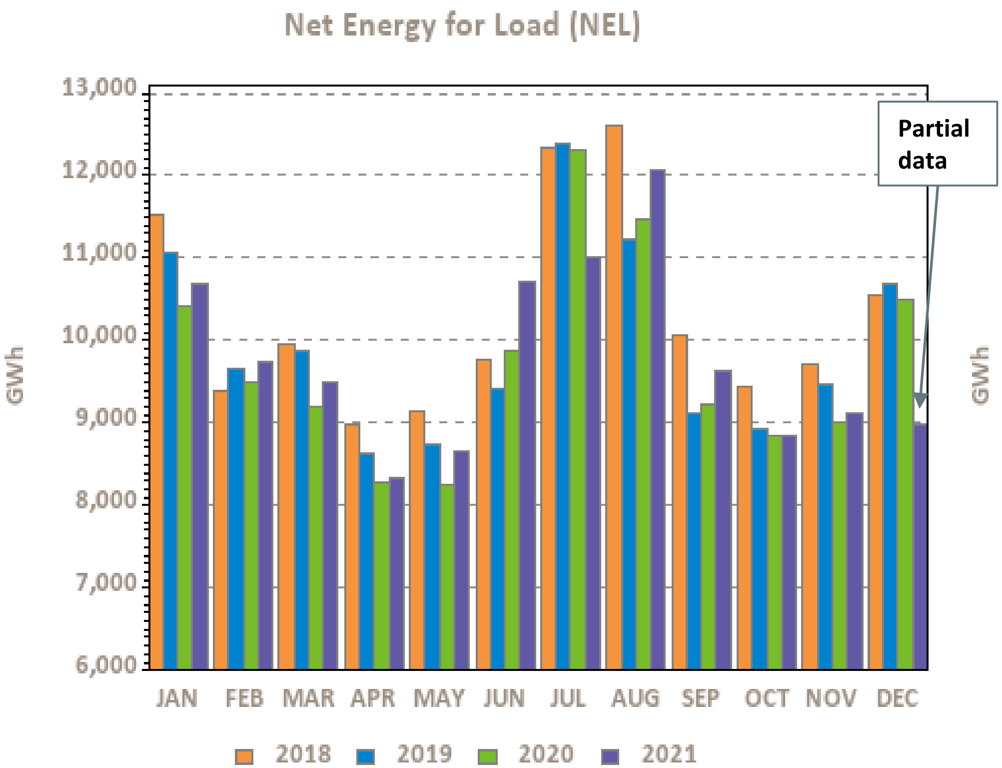


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4	55.6	54.4	52.8	50.3	46.9	47.8	65.4	51.7	56.3	55	54
Below %	42.9	49.6	44.4	45.6	47.2	49.7	53.1	52.2	34.6	48.3	43.7	45	46
Avg Above	209.5	166.7	185.4	206.1	227.4	233.1	214.5	227	263.1	115.6	178.4	225.8	263
Avg Below	-147.6	-216.4	-188.0	-167.9	-146.8	-309.1	-348.1	-307.5	-196.2	-173.4	-188.4	-156.0	-348
Avg All	60	-25	30	40	61	-48	-122	-79	102	-31	17	62	6

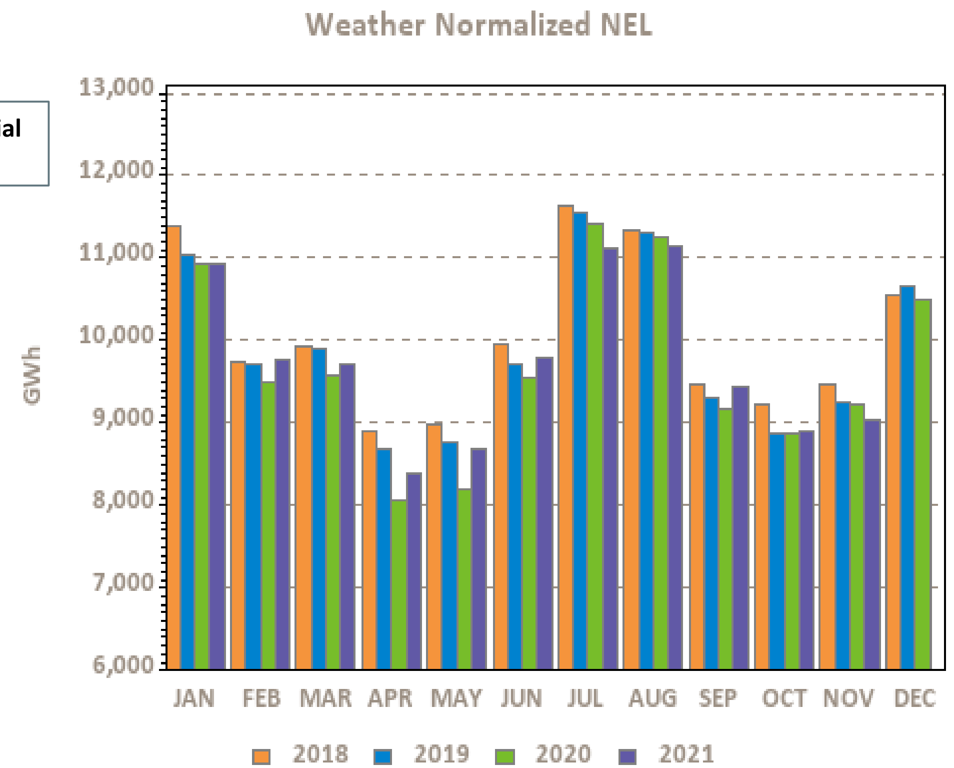
2021 System Operations - Load Forecast Accuracy cont.



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



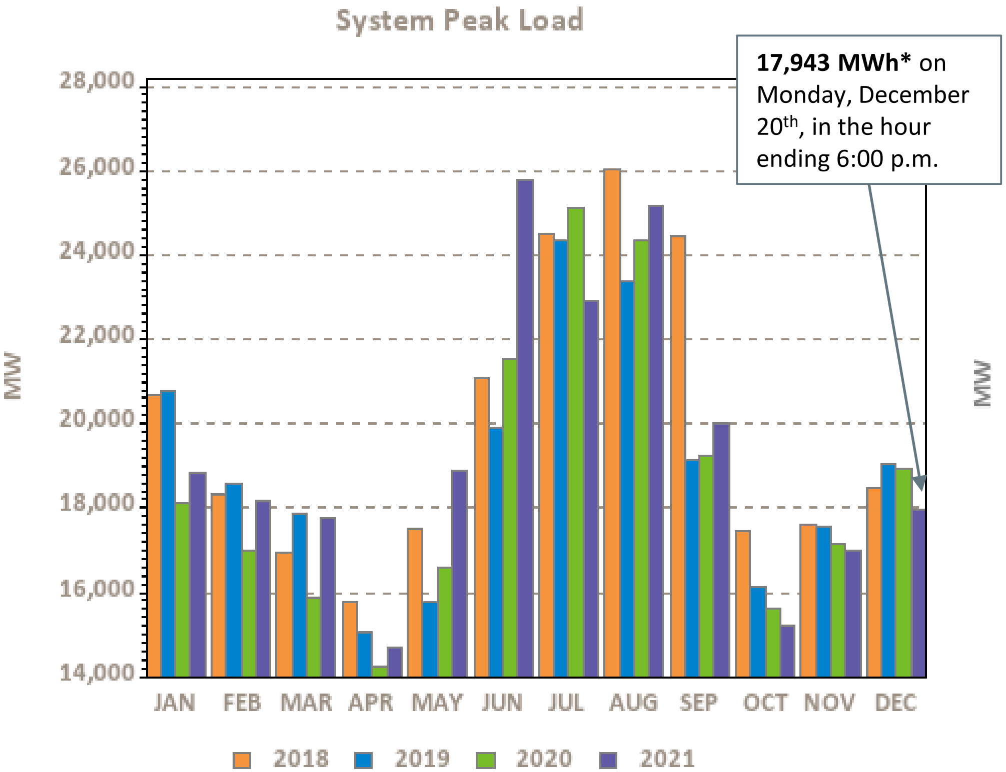
Ann Tot (TWh): 123.5 119.2 116.9 117.3



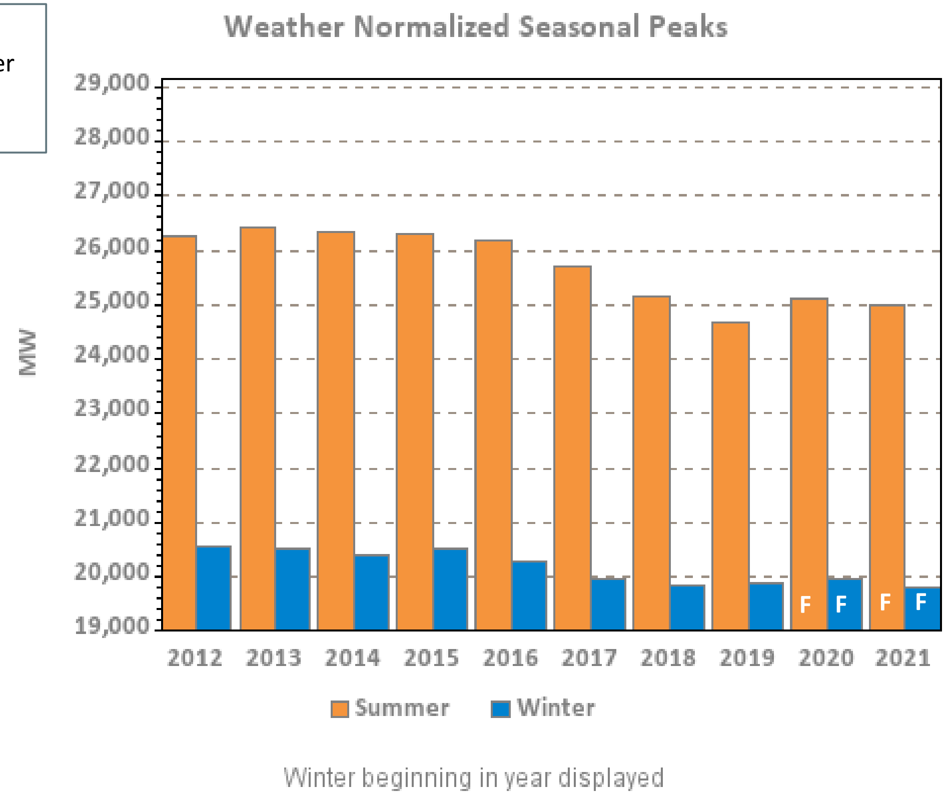
Ann Tot (TWh): 120.6 118.8 116.3 106.9

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 – 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.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



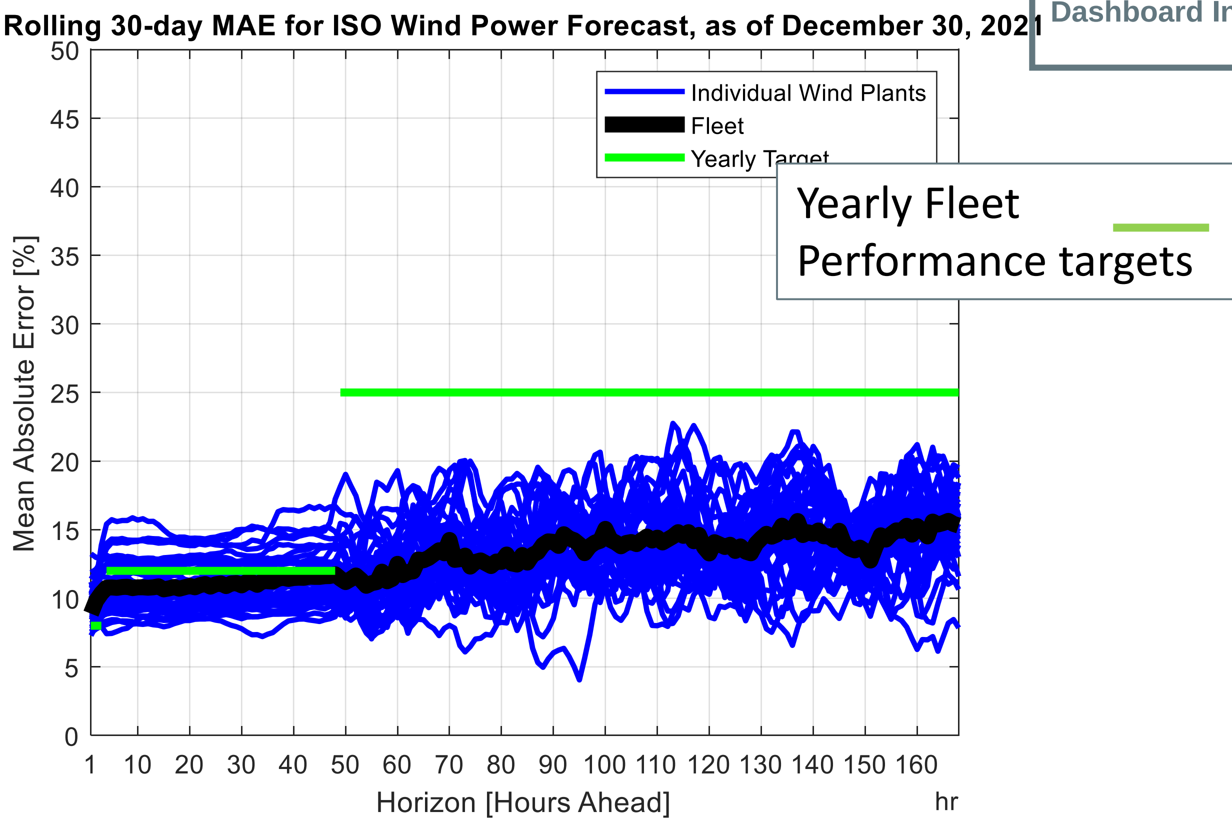
*Revenue quality metered value



F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE

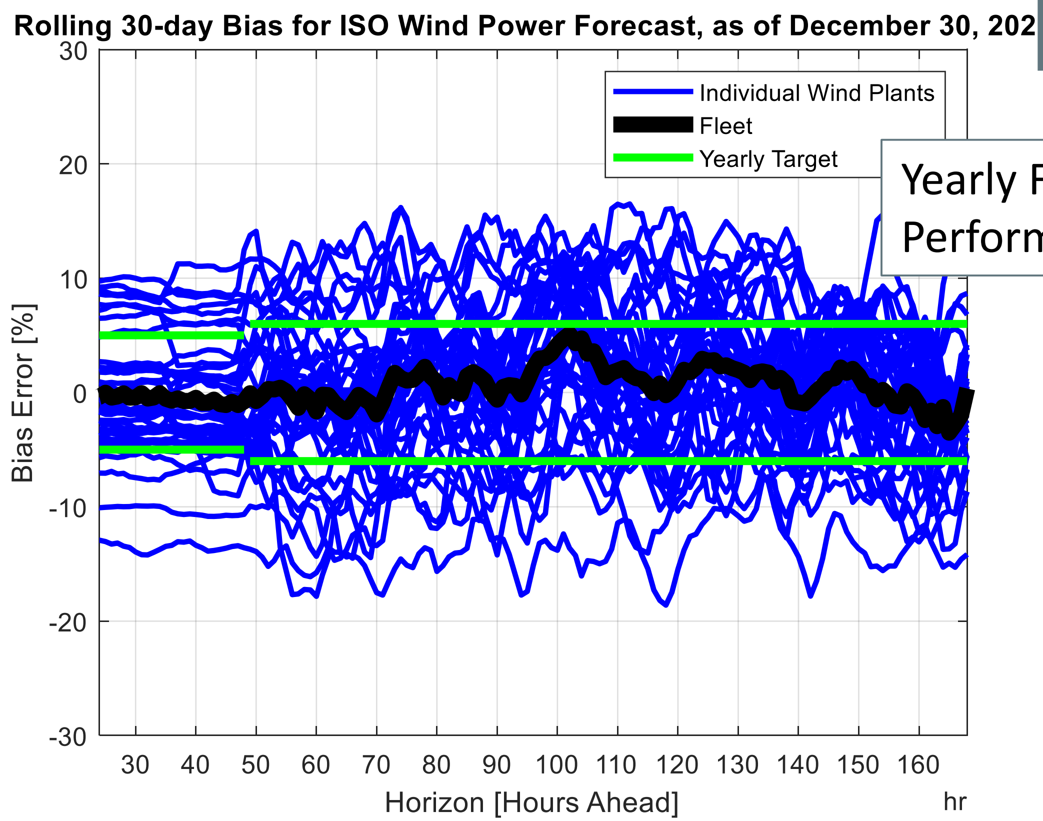
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, and monthly MAE (with the exception of the first hour of look ahead) is within the yearly performance targets.

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias

Dashboard Indicator

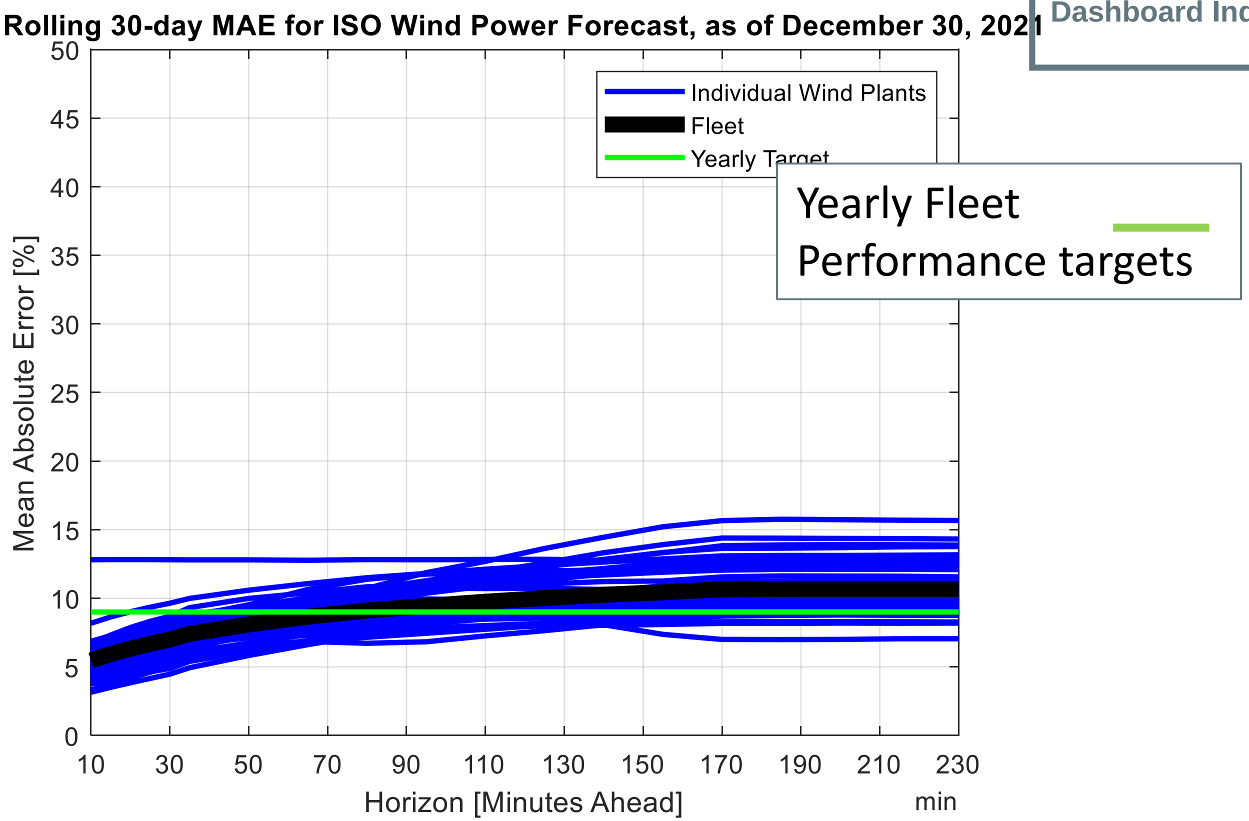


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

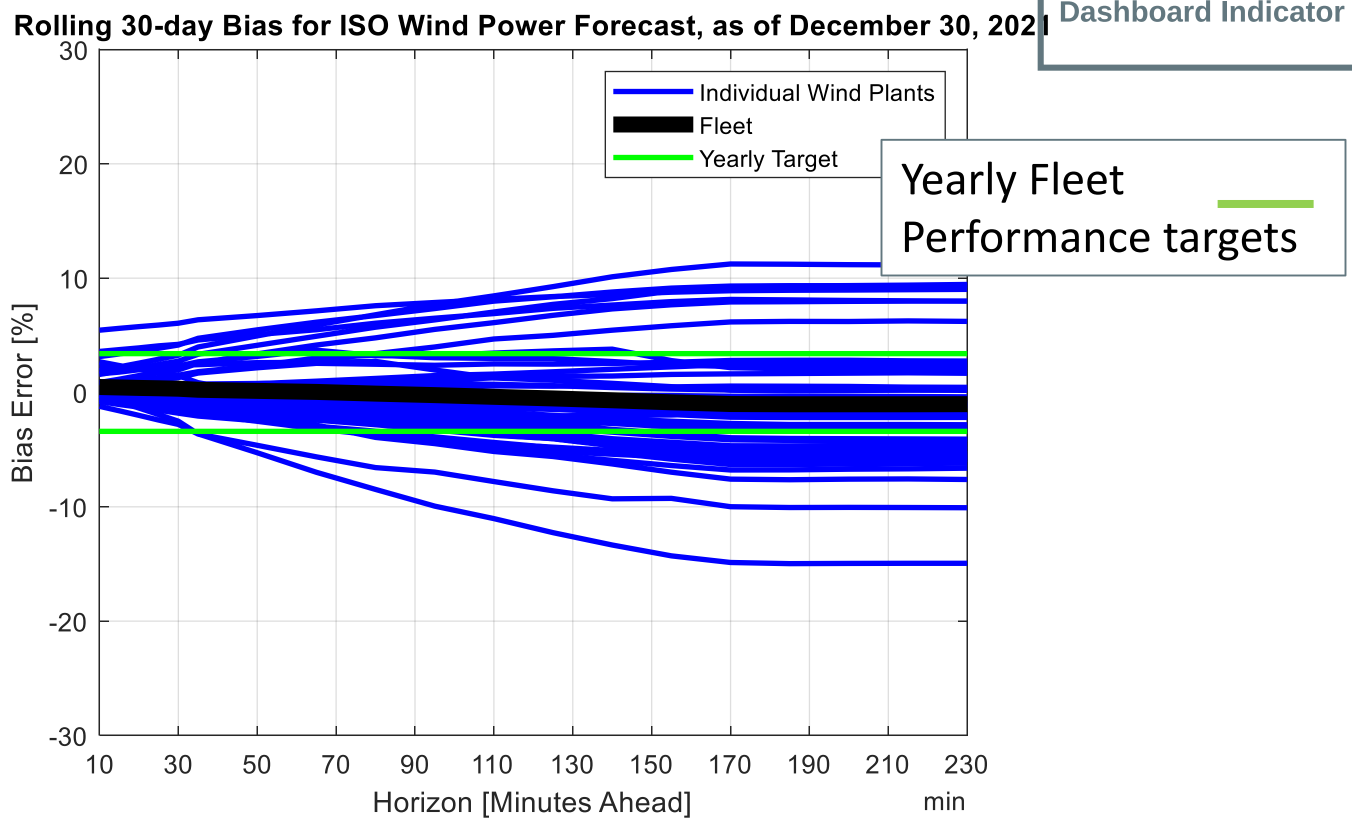
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, and up to 90 minutes look-ahead monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

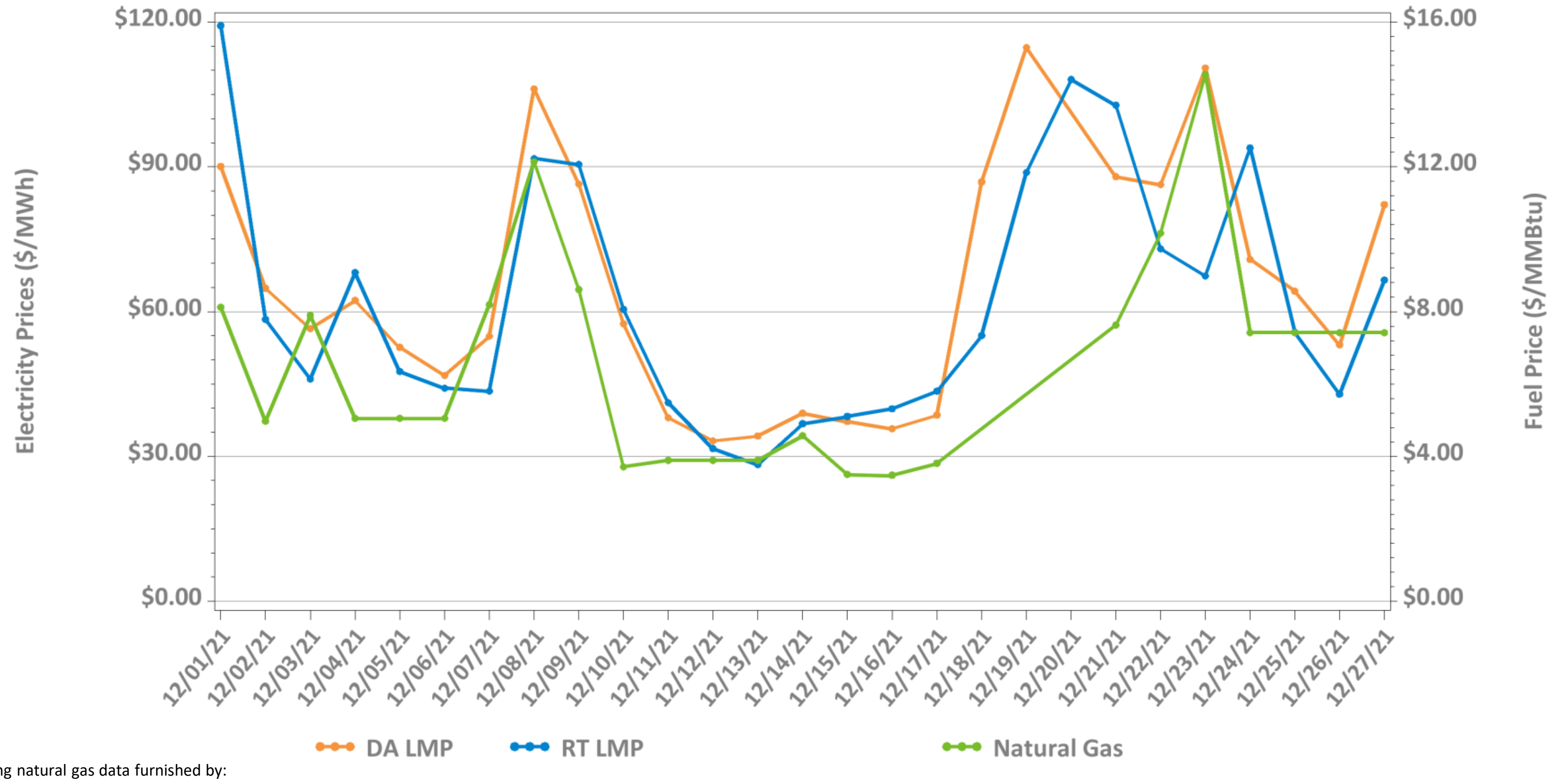
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and monthly Bias is within yearly performance.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: December 1-27, 2021

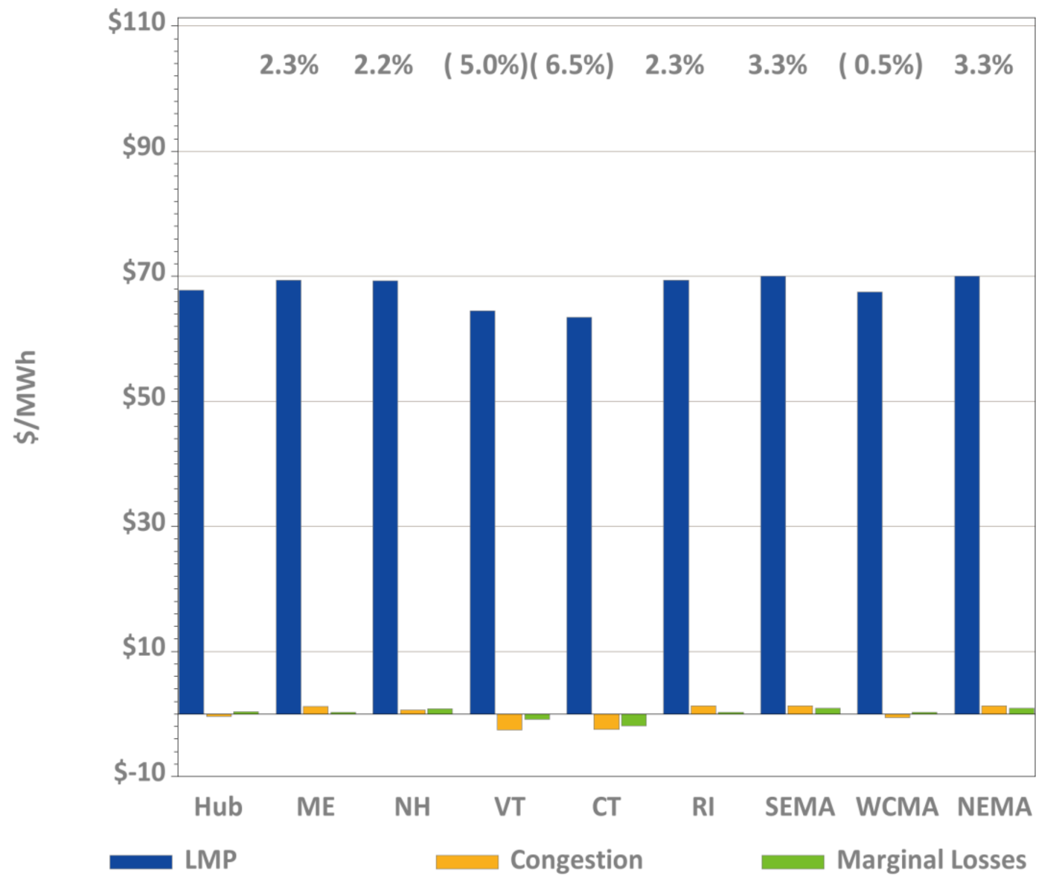


Underlying natural gas data furnished by:

ice Global markets in clear view

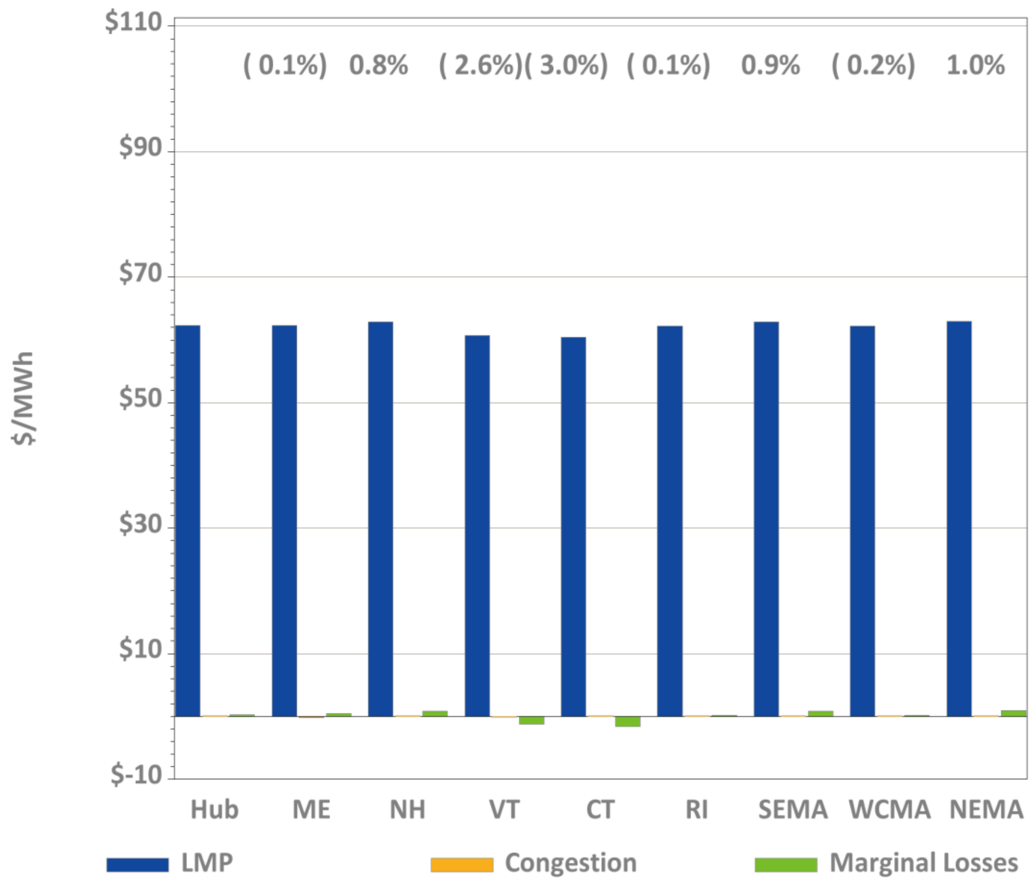
Average price difference over this period (DA-RT): $5.45
Average price difference over this period ABS(DA-RT): $12.36
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 20%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, December 2021



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

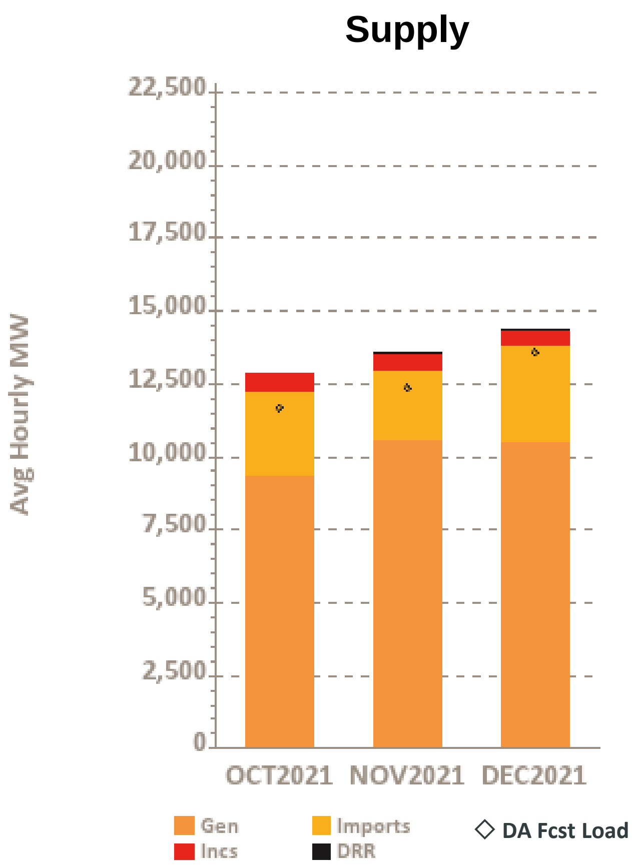
RT LMPs Average by Zone & Hub, December 2021

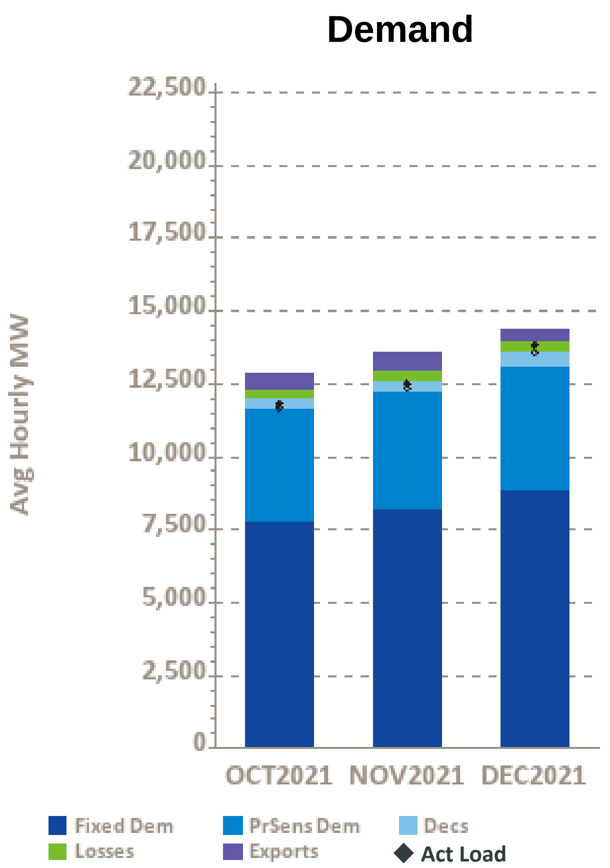


Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand – Last Three Months

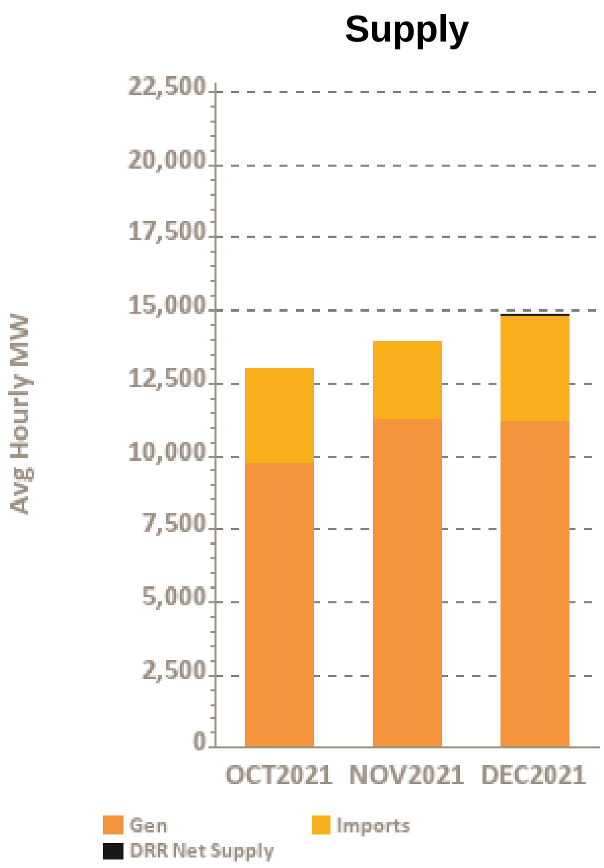


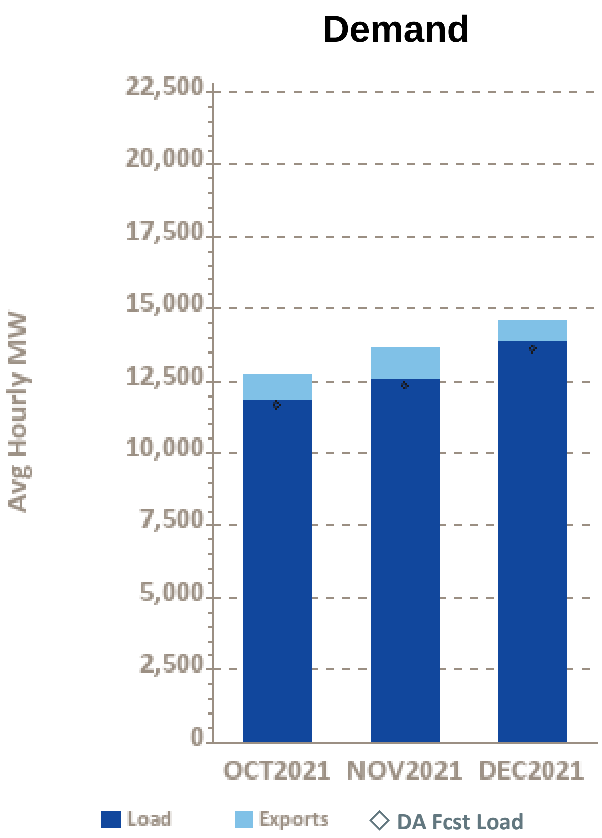


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

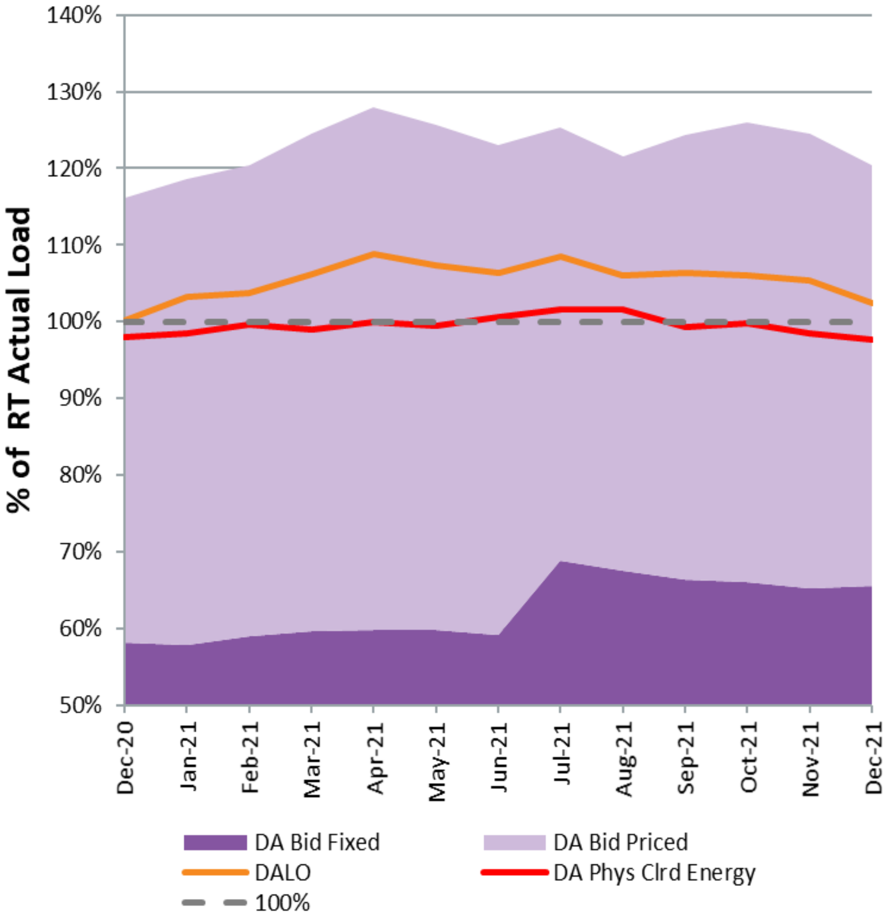
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

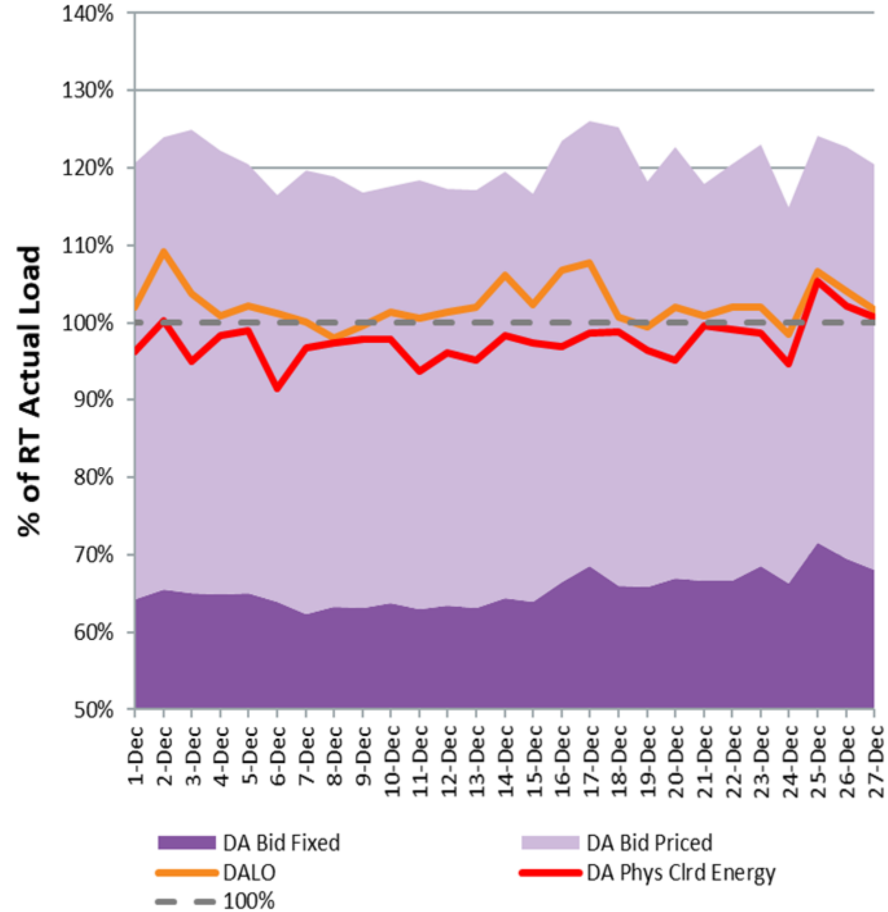
Components of RT Supply and Demand – Last Three Months





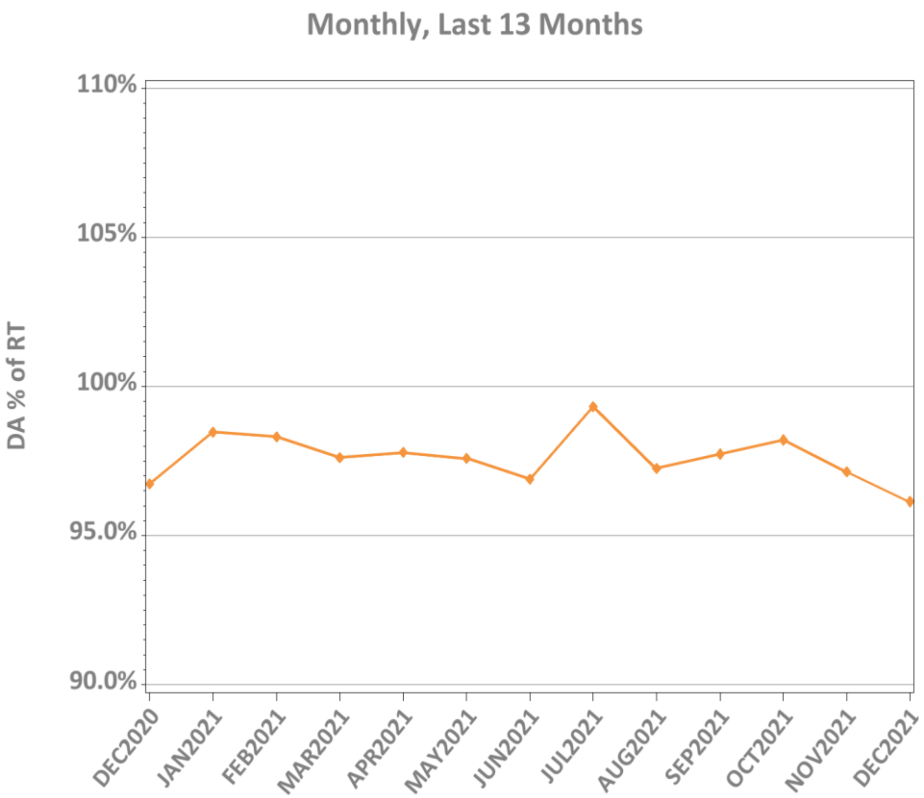
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

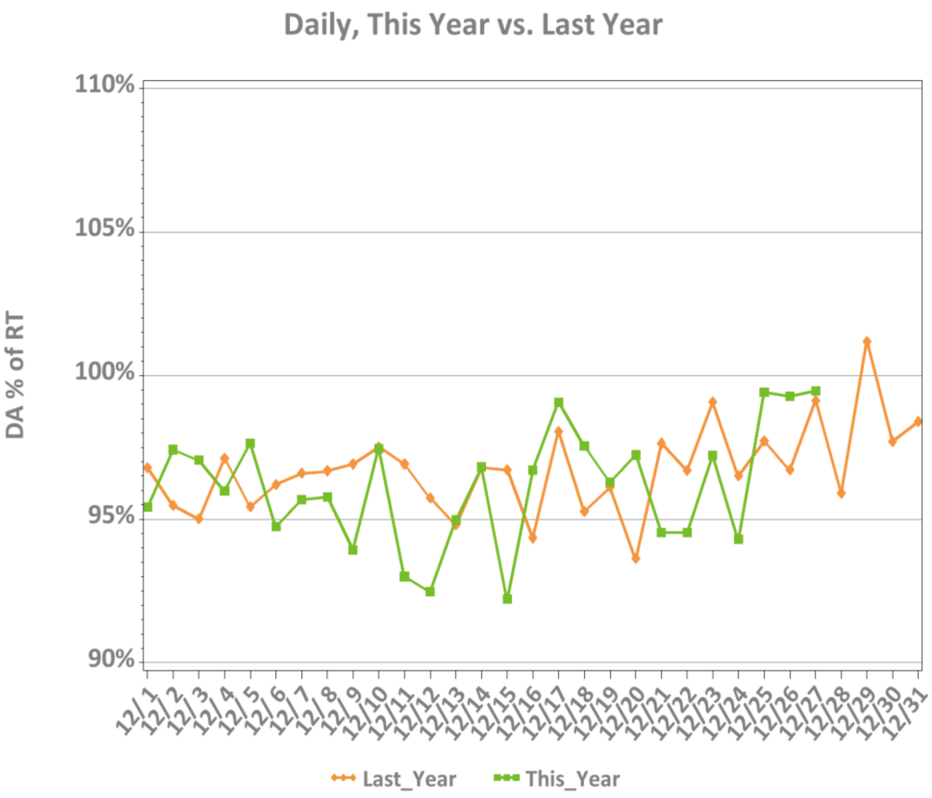




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

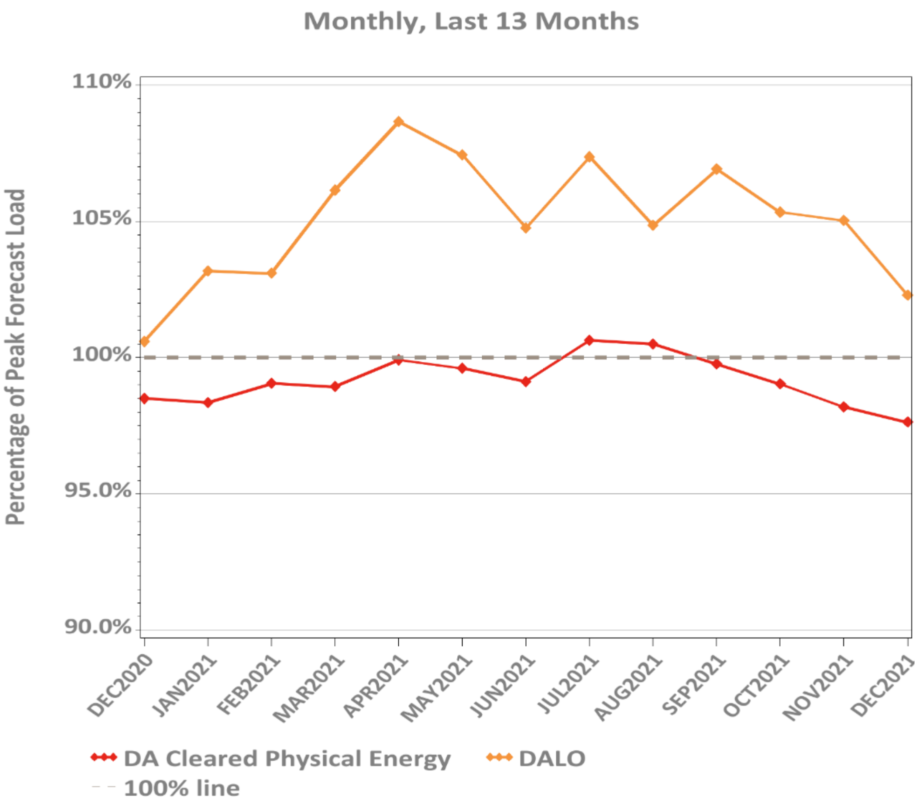
DA vs. RT Load Obligation: December, This Year vs. Last Year

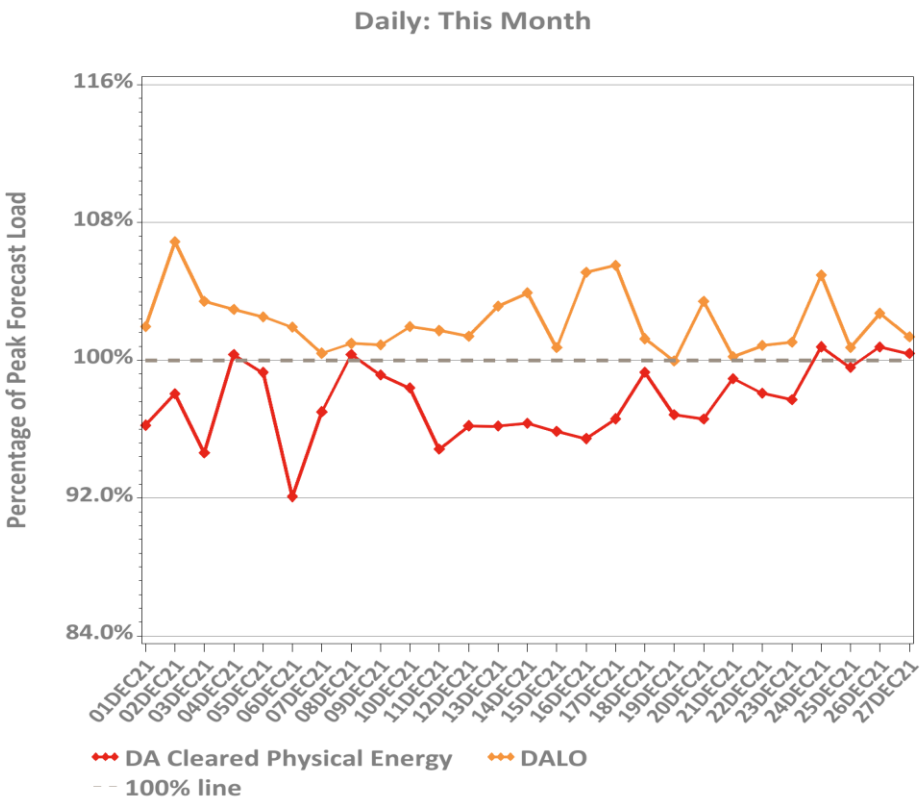




*Hourly average values

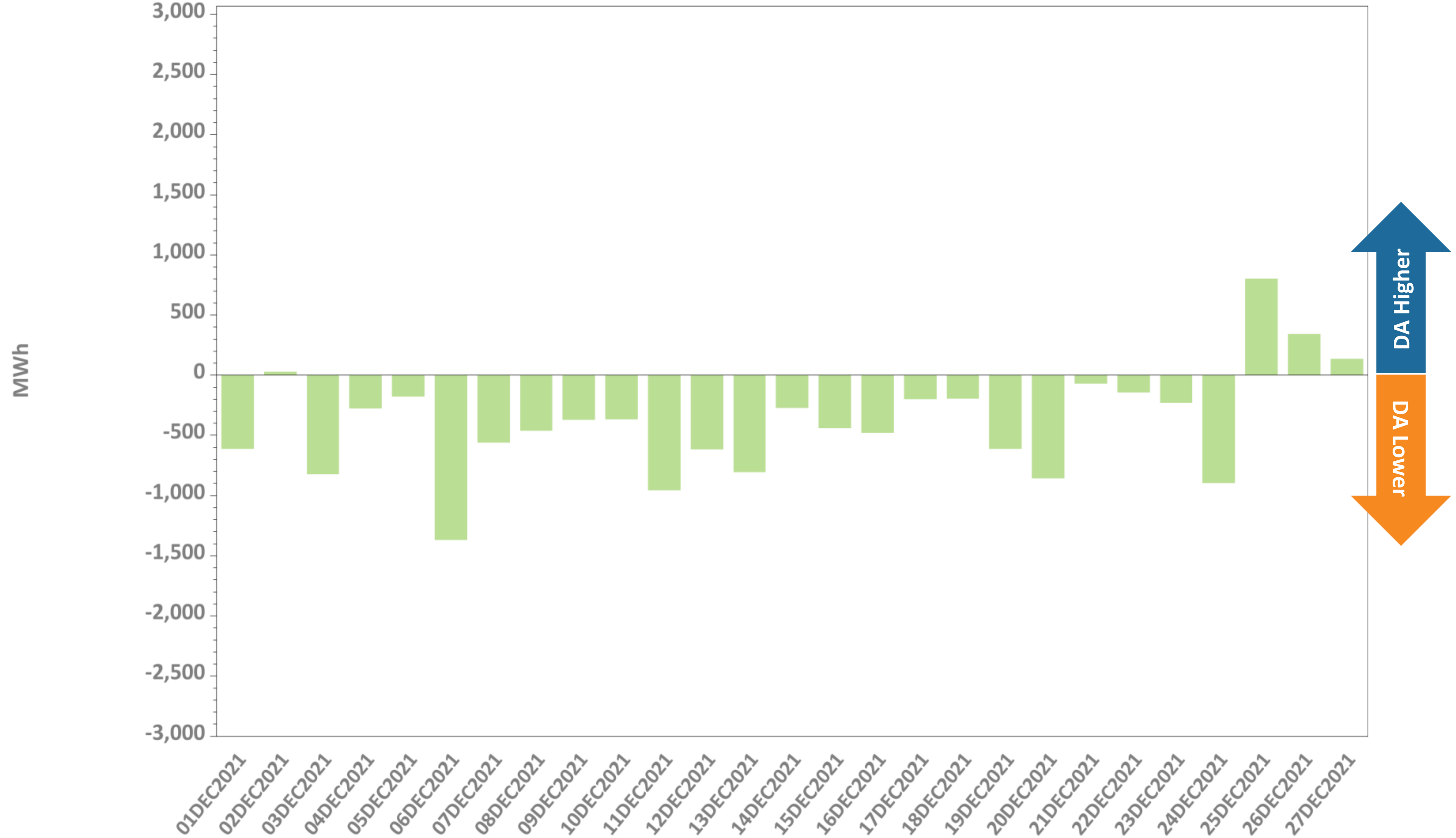
DA Volumes as % of Forecast in Peak Hour





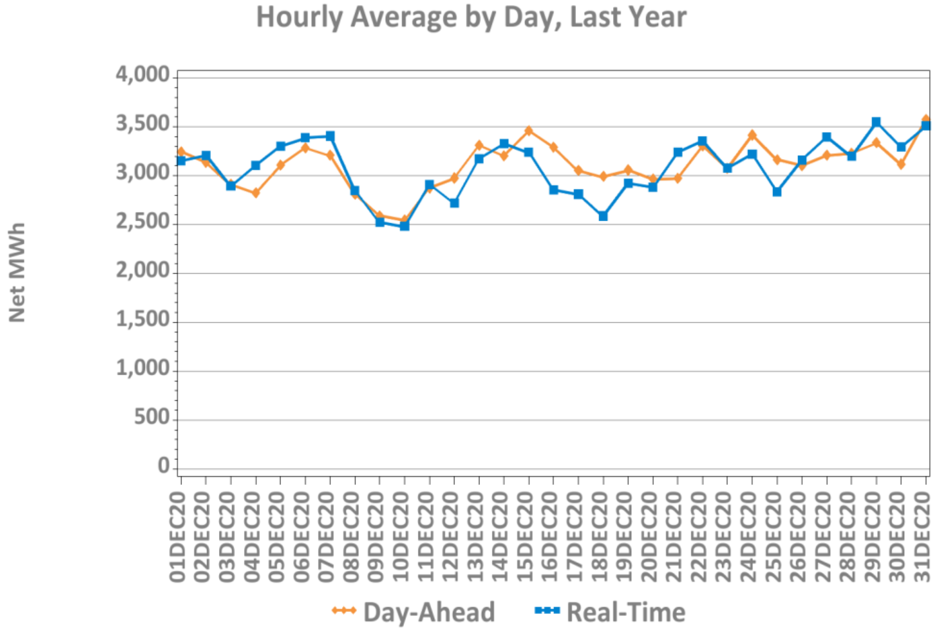
Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during the month.

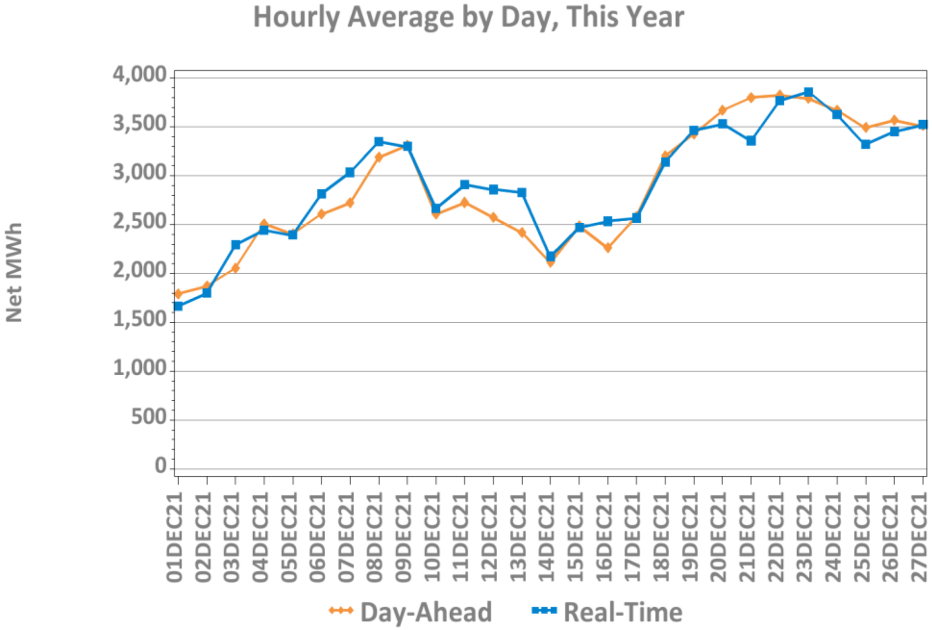
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



***Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.**

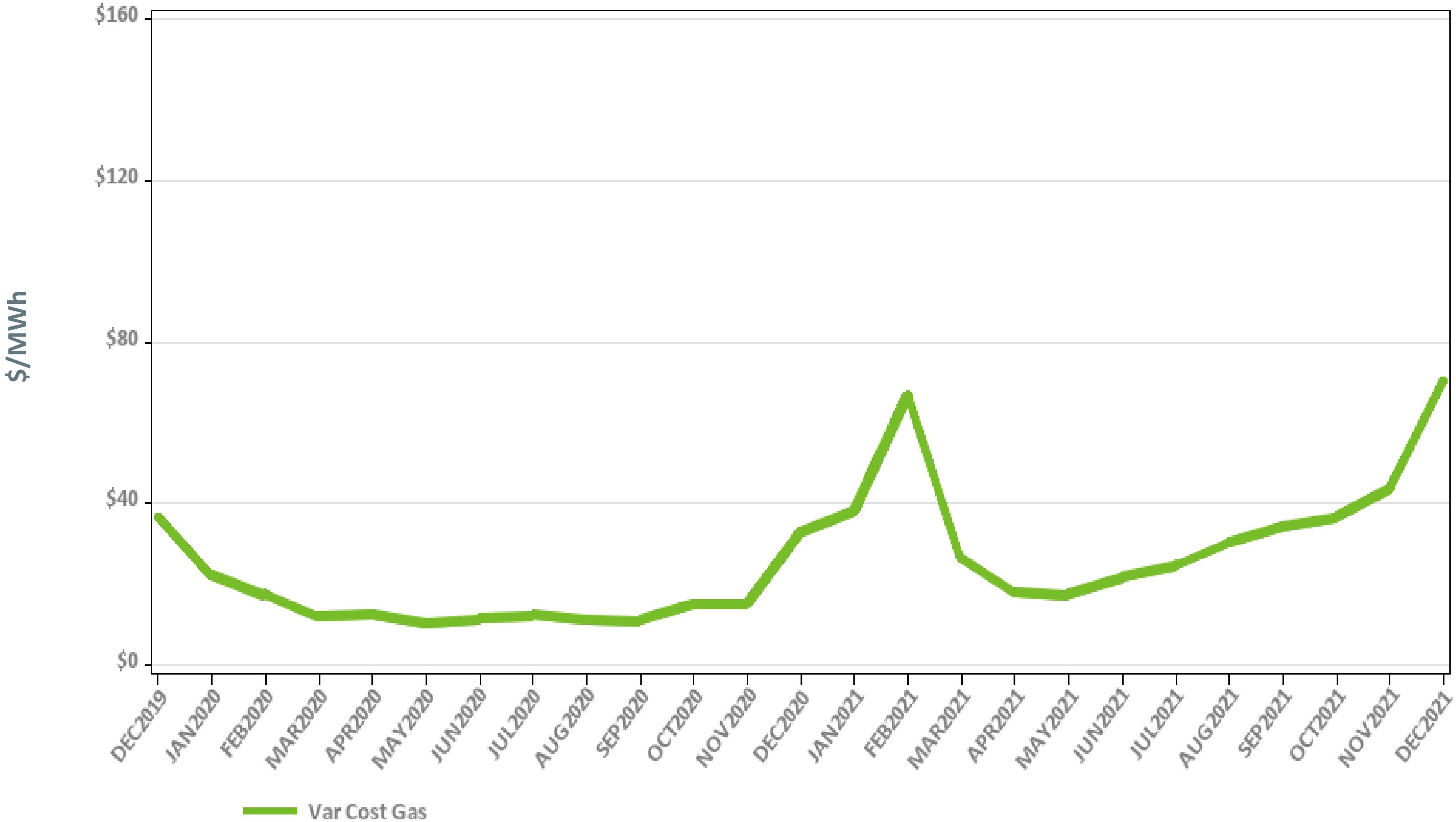
DA vs. RT Net Interchange December 2020 vs. December 2021





Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

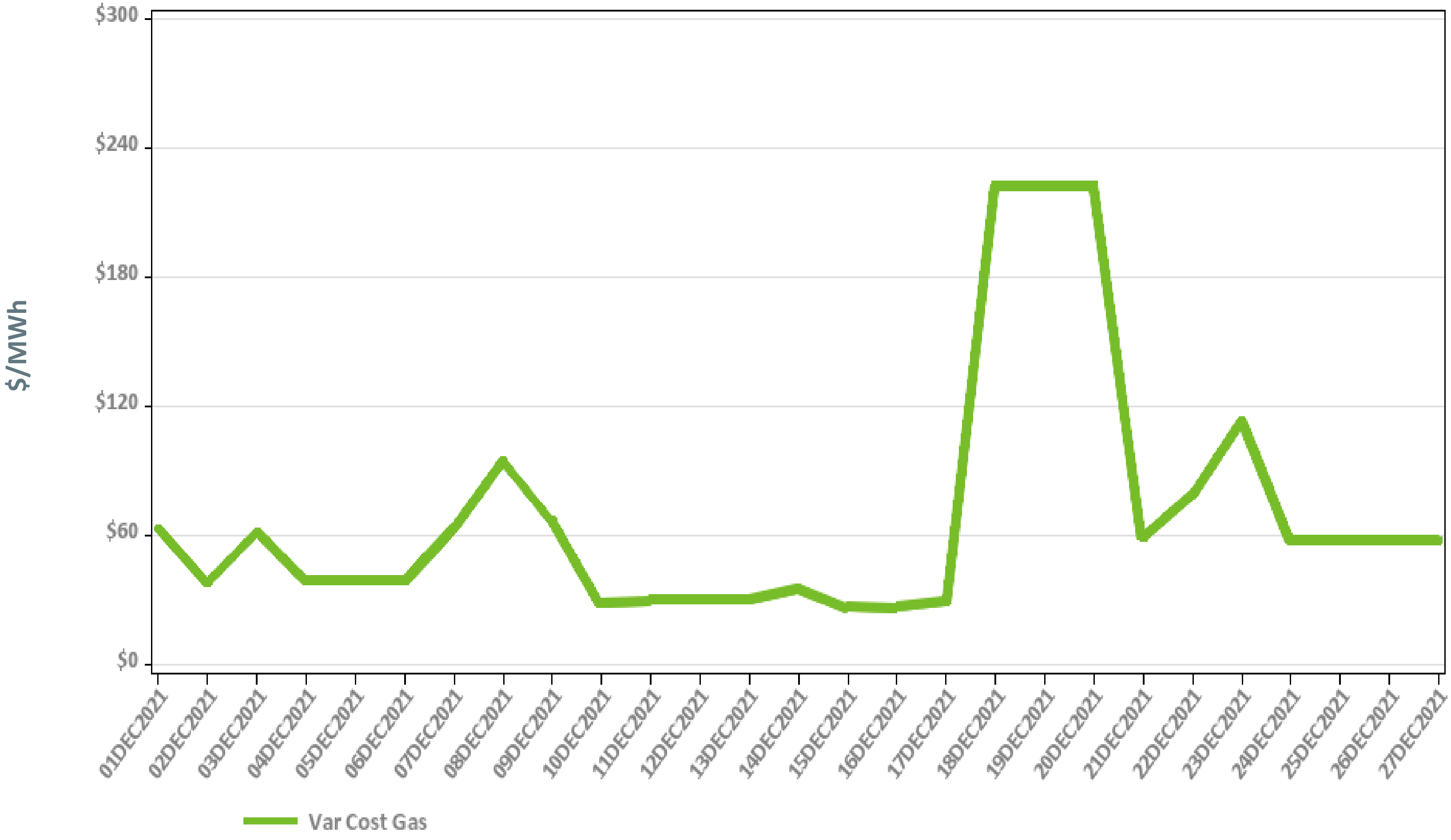
Variable Production Cost of Natural Gas: Monthly



Underlying natural gas data furnished by:

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

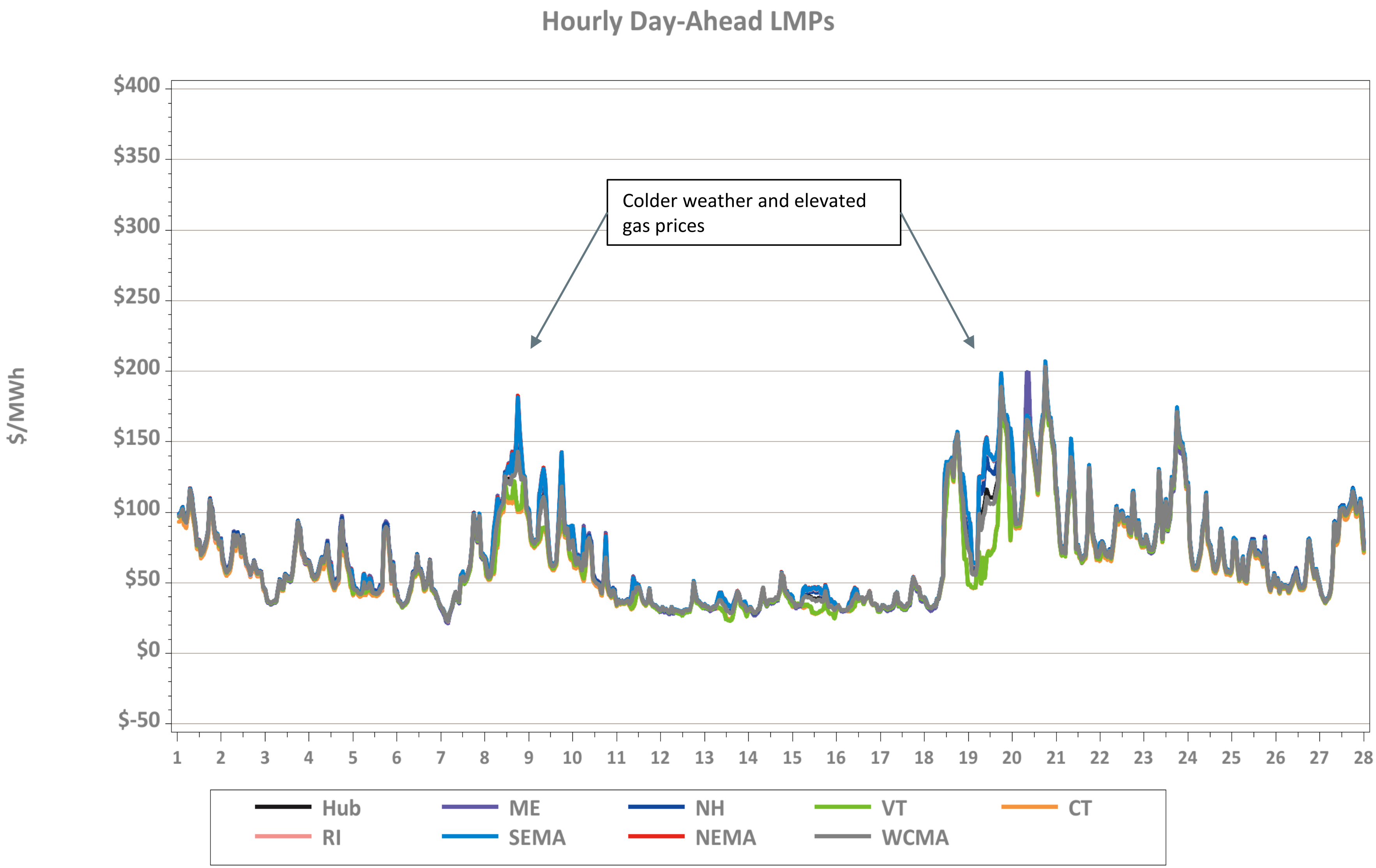
Variable Production Cost of Natural Gas: Daily



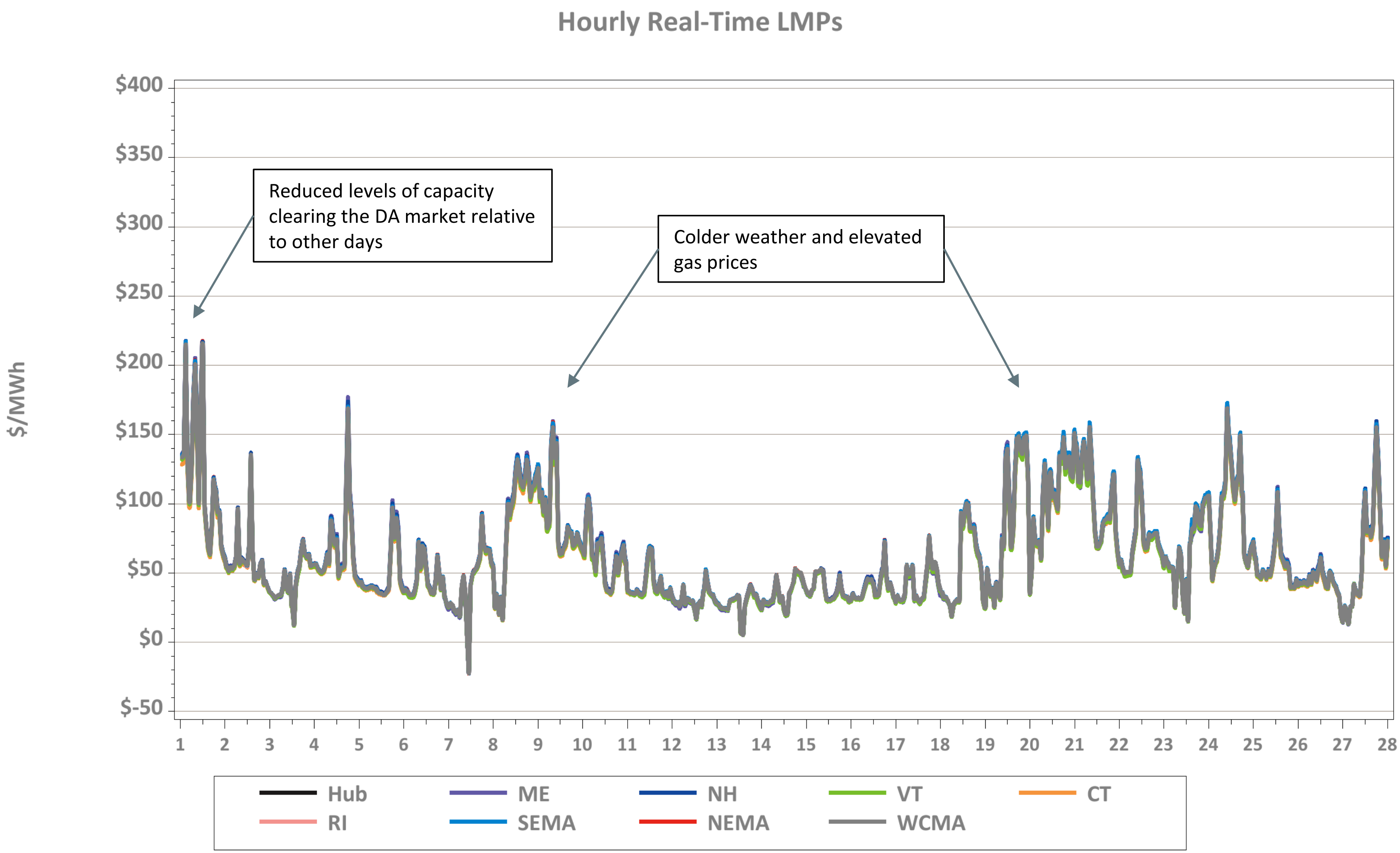
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

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

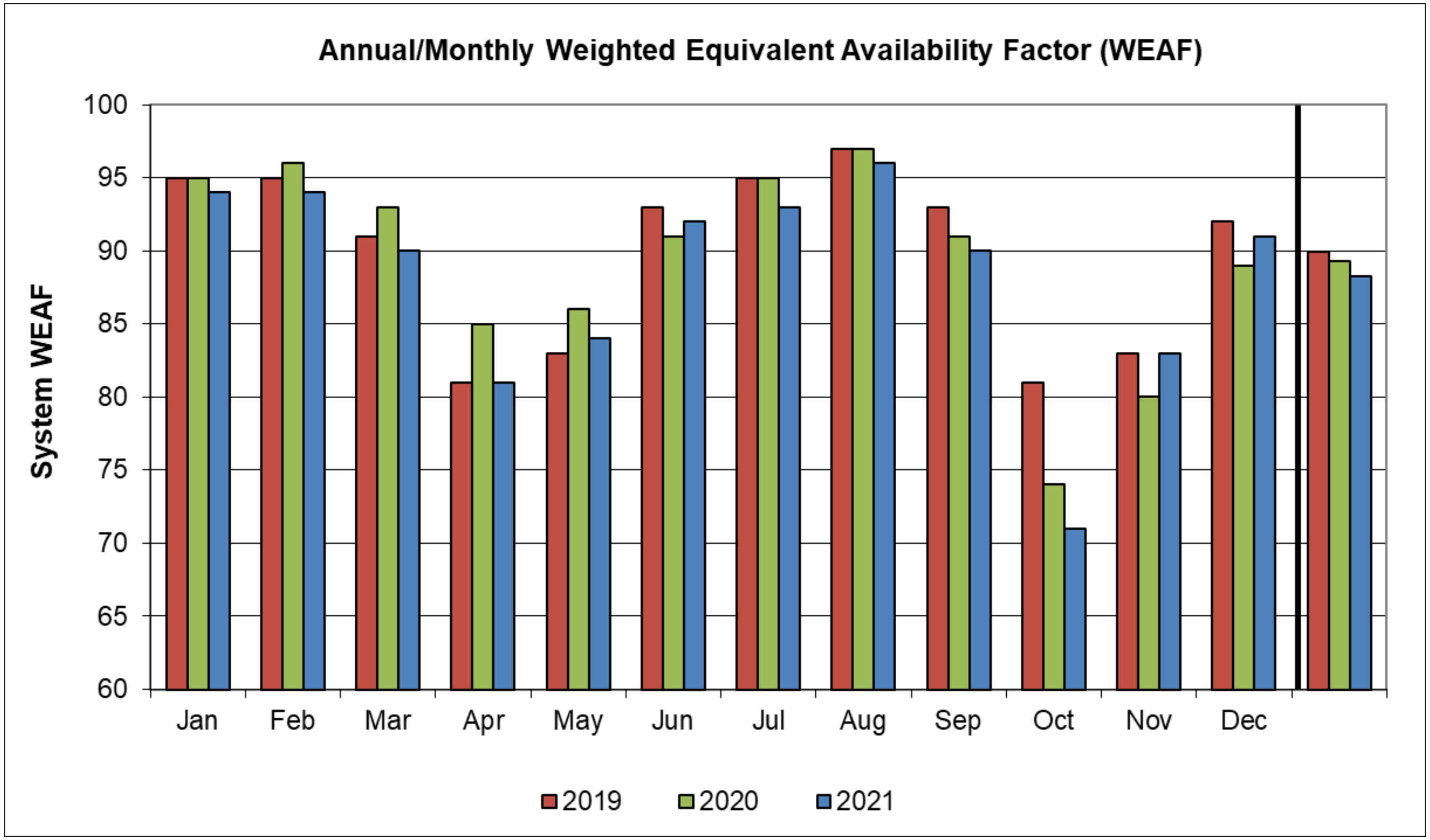
Hourly DA LMPs, December 1-27, 2021



Hourly RT LMPs, December 1-27, 2021



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2021	94	94	90	81	84	92	93	96	90	71	83	91	88
2020	95	96	93	85	86	91	95	97	91	74	80	89	89
2019	95	95	91	81	83	93	95	97	93	81	83	92	90

Data as of 12/17/2021

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for January 2022

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	96.1	157.5	0.0	253.6
NH	42.3	148.9	0.0	191.2
VT	47.2	161.9	0.0	209.1
CT	126.0	113.6	630.9	870.5
RI	34.0	319.7	0.0	353.7
SEMA	43.5	509.2	0.0	552.7
WCMA	81.2	559.0	18.0	658.2
NEMA	59.3	866.2	0.0	925.5
Total	**529.5**	**2,836.0**	**648.9**	**4,014.4**

*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

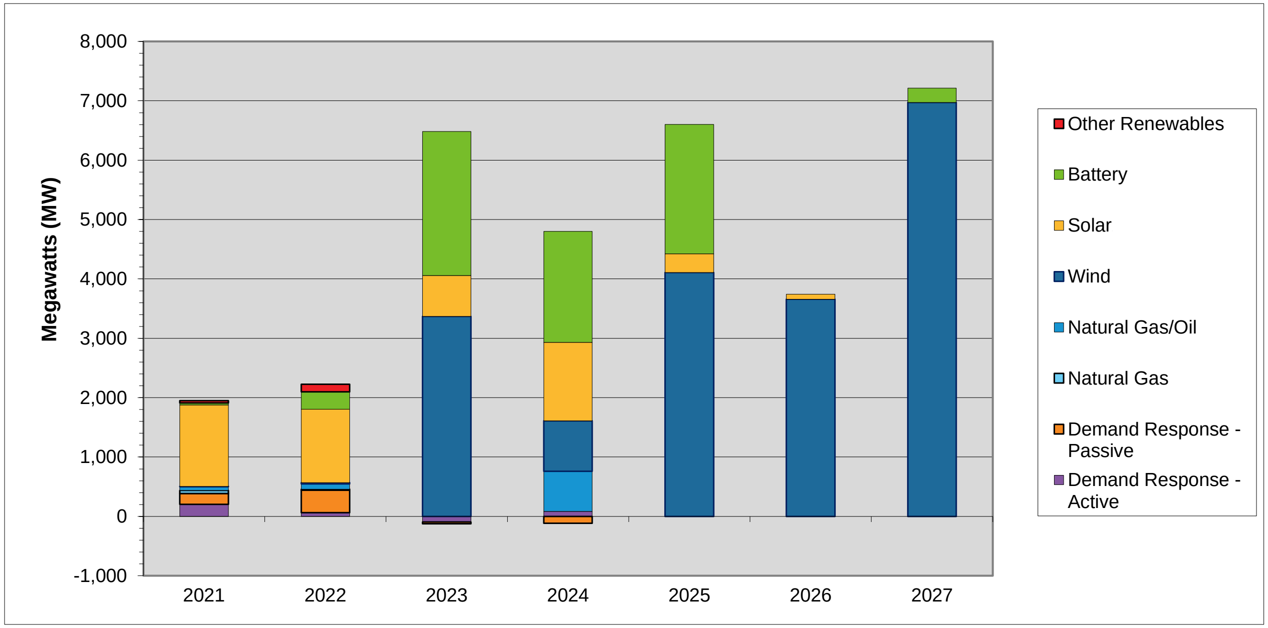
NEW GENERATION

New Generation Update
Based on Queue as of 12/31/21

- Ten projects totaling 512 MW were added to the interconnection queue since the last update
  - They consist of three battery projects and seven solar project, with in-service dates of 2021 through 2027
- Two projects were withdrawn and five projects went commercial
- In total, 303 generation projects are currently being tracked by the ISO, totaling approximately 32,101 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



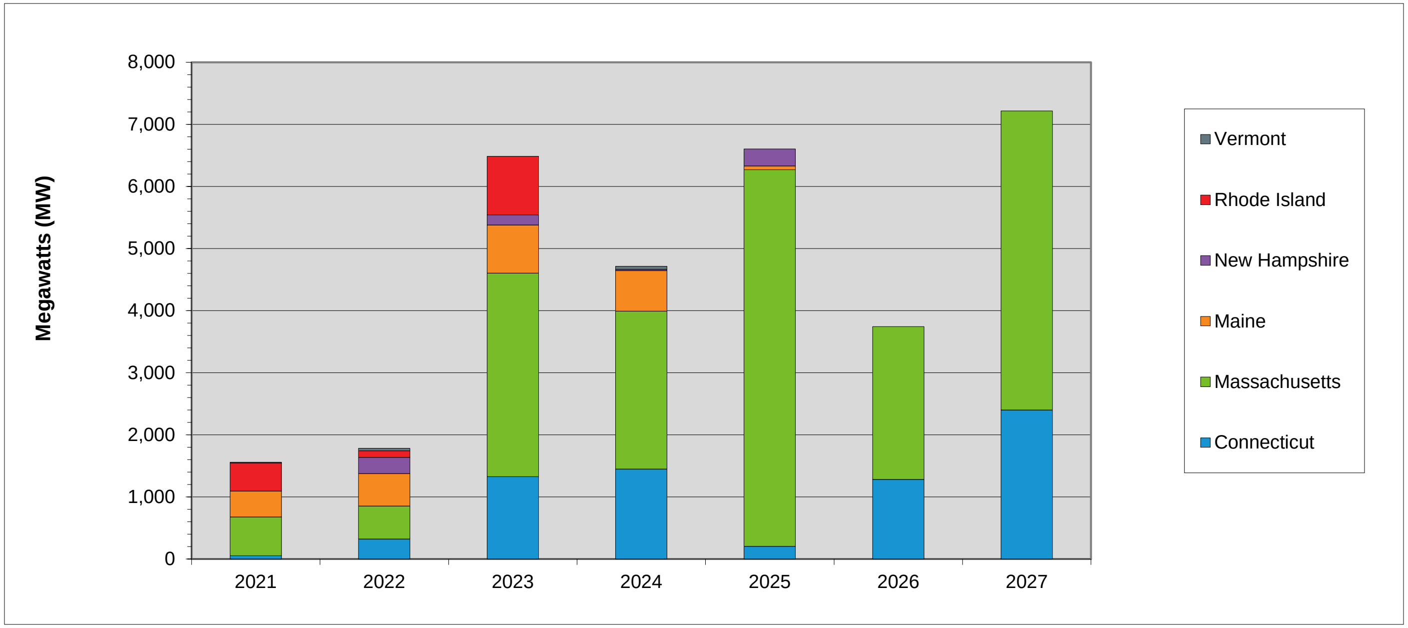
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	38	128	0	0	0	0	0	166	0.5
Battery	34	293	2,427	1,869	2,180	0	242	7,045	21.5
Solar[2]	1,373	1,236	691	1,321	316	83	0	5,020	15.3
Wind	4	20	3,367	852	4,107	3,658	6,972	18,980	57.9
Natural Gas/Oil[3]	62	89	0	672	0	0	0	823	2.5
Natural Gas	49	18	0	0	0	0	0	67	0.2
Demand Response - Passive	184	380	-28	-114	0	0	0	422	1.3
Demand Response - Active	204	62	-94	86	0	0	0	258	0.8
Totals	**1,948**	**2,226**	**6,363**	**4,686**	**6,603**	**3,741**	**7,214**	**32,781**	**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

- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.3
Rhode Island	450	106	944	0	0	0	0	1,500	4.7
New Hampshire	0	261	164	20	272	0	0	717	2.2
Maine	418	525	774	654	64	0	0	2,435	7.6
Massachusetts	626	531	3,278	2,541	6,062	2,458	4,814	20,310	63.3
Connecticut	51	321	1,325	1,449	205	1,283	2,400	7,034	21.9
Totals	**1,560**	**1,784**	**6,485**	**4,714**	**6,603**	**3,741**	**7,214**	**32,101**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	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	43	7,045	0	0	43	7,045
Fuel Cell	2	30	0	0	2	30
Hydro	3	99	2	71	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	0	0	5	823
Nuclear	1	37	0	0	1	37
Solar	213	5,020	16	183	197	4,837
Wind	29	18,980	0	0	29	18,980
Total	303	32,101	18	254	285	31,847

- 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
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	107	1	5	5	102
Intermediate	7	804	0	0	7	804
Peaker	261	12,210	17	249	244	11,961
Wind Turbine	29	18,980	0	0	29	18,980
Total	303	32,101	18	254	285	31,847

- Green denotes projects with a high probability of going into service
- 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	43	7,045	0	0	0	0	43	7,045	0	0
Fuel Cell	2	30	2	30	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	213	5,020	0	0	0	0	213	5,020	0	0
Wind	29	18,980	0	0	0	0	0	0	29	18,980
Total	303	32,101	6	107	7	804	261	12,210	29	18,980

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation (CSO) FCA 12

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*	624.445	659.137	34.692	603.776	-55.361	587.270	-16.506
	Passive Demand	2,975.36	3,045.073	69.713	3,123.232	78.159	3,322.722	199.490
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**3,727.008**	**22.798**	**3,909.992**	**182.984**
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159	28,941.276	321.031
	Intermittent	880.317	806.609	-73.708	660.932	-145.677	663.179	2.247
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**	**29,604.455**	**323.278**
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**	**1207.78**	**-99.807**
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**	**34,722.227**	**406.455**
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,230**	**-1,320**	**32,925**	**695**

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

ARA – Annual Reconfiguration Auction
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

Capacity Supply Obligation FCA 13

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*	685.554	683.116	-2.438	658.659	-24.457		
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392		
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**		
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07		
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387		
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**		
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**		
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**		
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**		

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 14

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*	592.043	688.07	96.027				
Demand	*Passive Demand*	3,327.071	3,327.932	0.861				
Demand Total		**3,919.114**	**4,016.002**	**96.888**				
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241				
Generator	*Intermittent*	1,160.916	1,128.446	-32.47				
Generator Total		**28,977.818**	**29,403.589**	**425.771**				
Import Total		**1,058.72**	**1,058.72**	**0**				
Grand Total*		**33,955.652**	**34,478.311**	**522.661**				
Net ICR (NICR)		**32,490**	**32,980**	**490**				

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

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						
	Passive Demand	3,212.865						
Demand Total		**3,890.538**						
Generator	*Non-Intermittent*	28,154.203						
	Intermittent	1,089.265						
Generator Total		**29,243.468**						
Import Total		**1,487.059**						
Grand Total*		**34,621.065**						
Net ICR (NICR)		**33,270**						

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly 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
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	**2375.422**	**370.734**	**2746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2571.361**	**639.586**	**3210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3085.734**	**514.072**	**3599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3386.703**	**653.541**	**4040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3596.056**	**323.058**	**3919.114**
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**

RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

What are Daily NCPC Payments?

- Payments made to resources whose commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output during the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

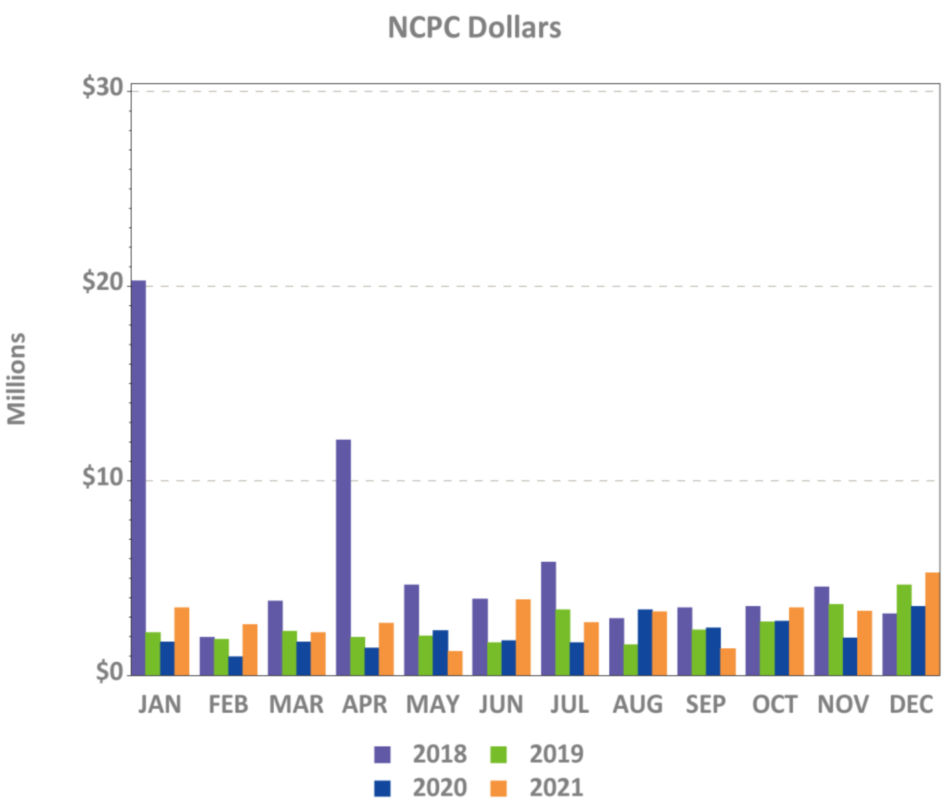
Definitions

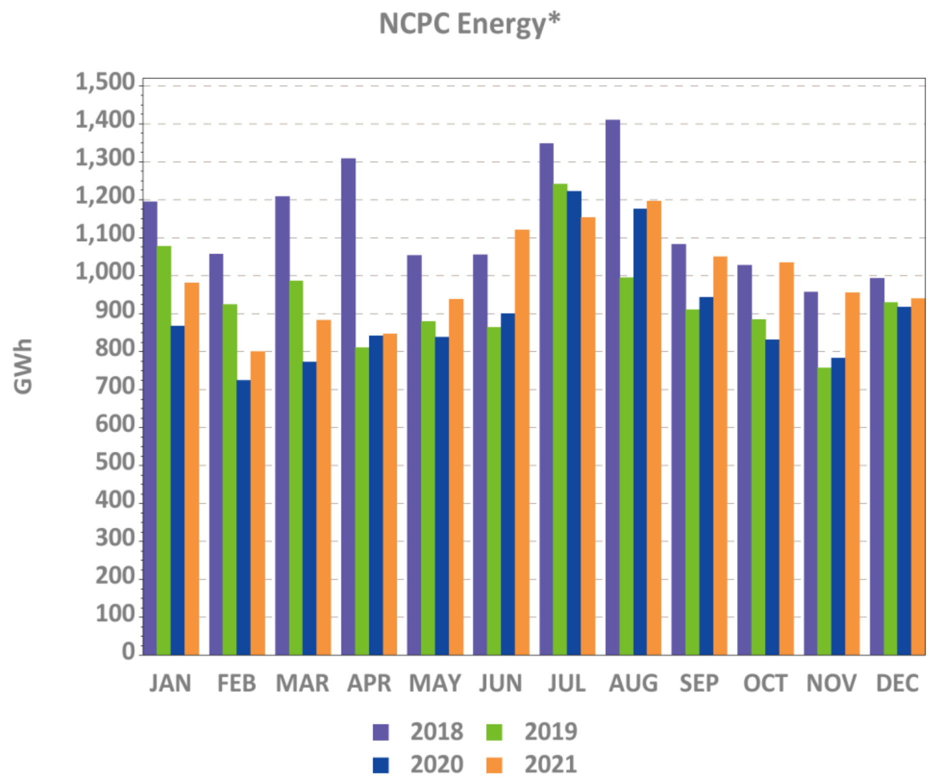
1^{st} Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2^{nd} Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2^{nd} Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
OATT	Open Access Transmission Tariff

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Economic Generator/DARD Posturing, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost NCPC (allocated to RTLO); and Min Generation Emergency NCPC (allocated to RTGO).

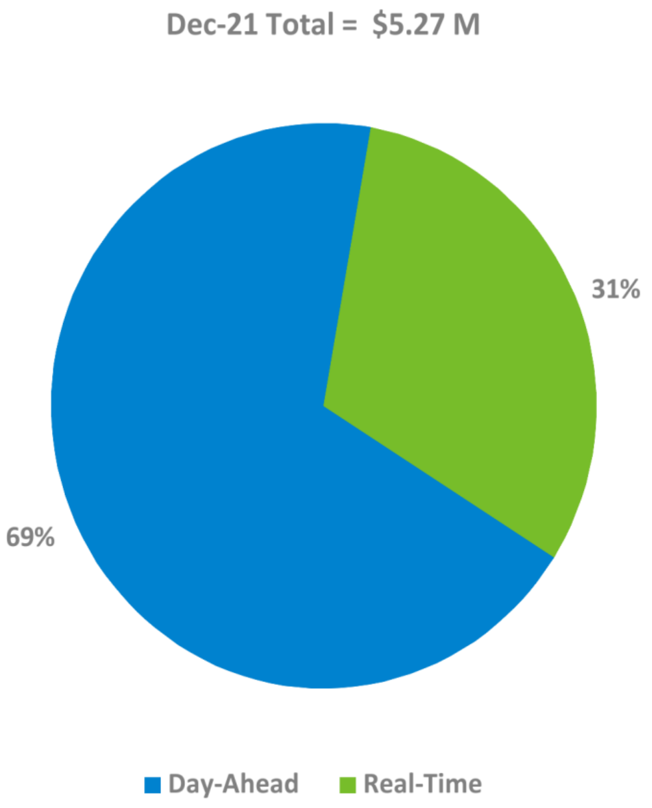
Year-Over-Year Total NCPC Dollars and Energy

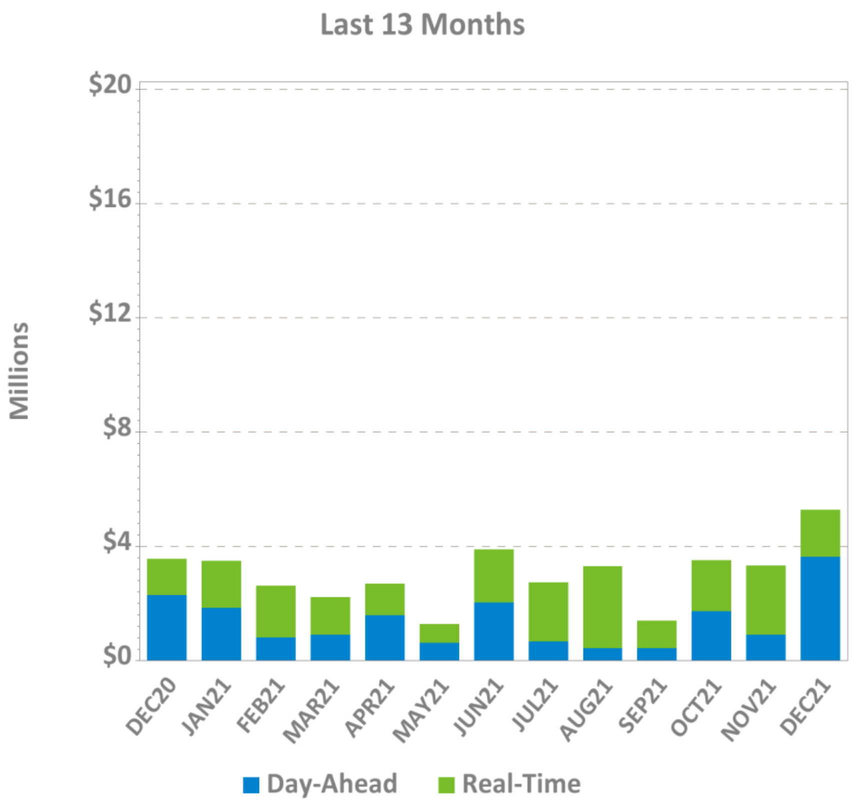




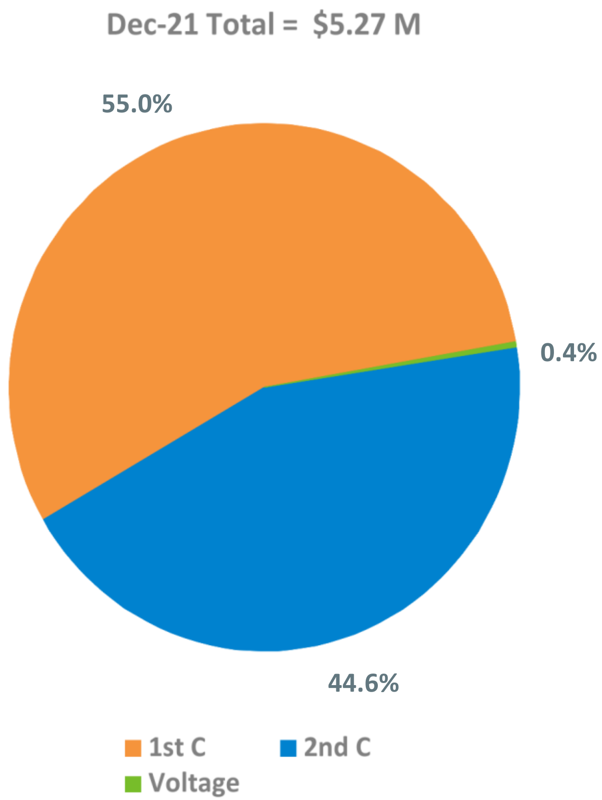
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.**

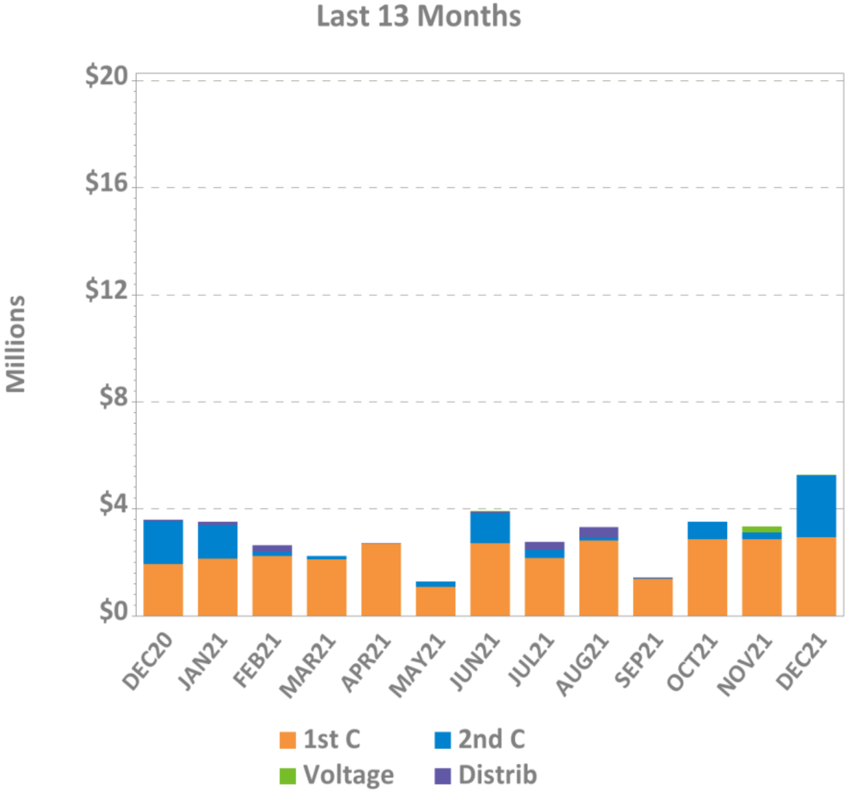
DA and RT NCPC Charges





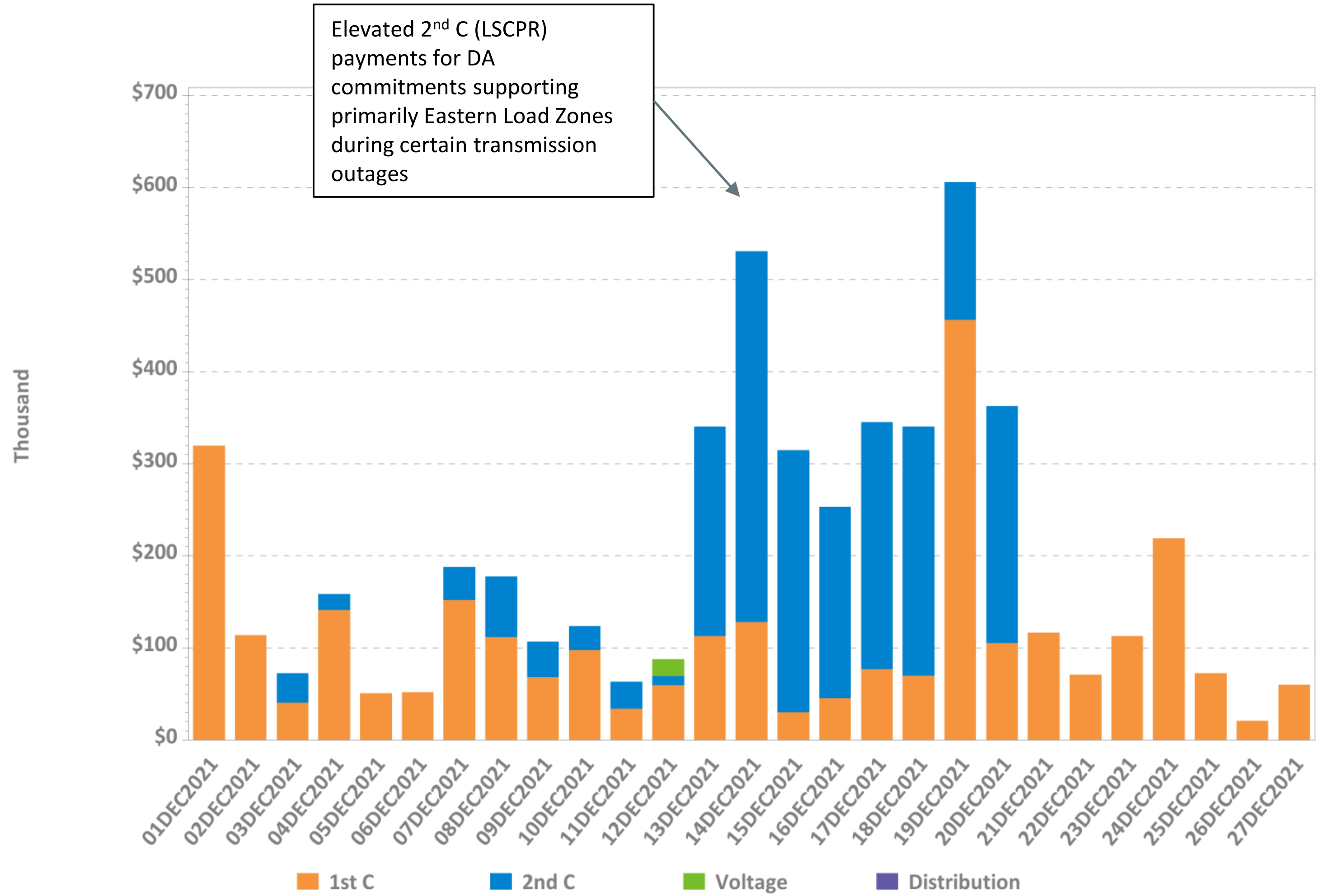
NCPC Charges by Type



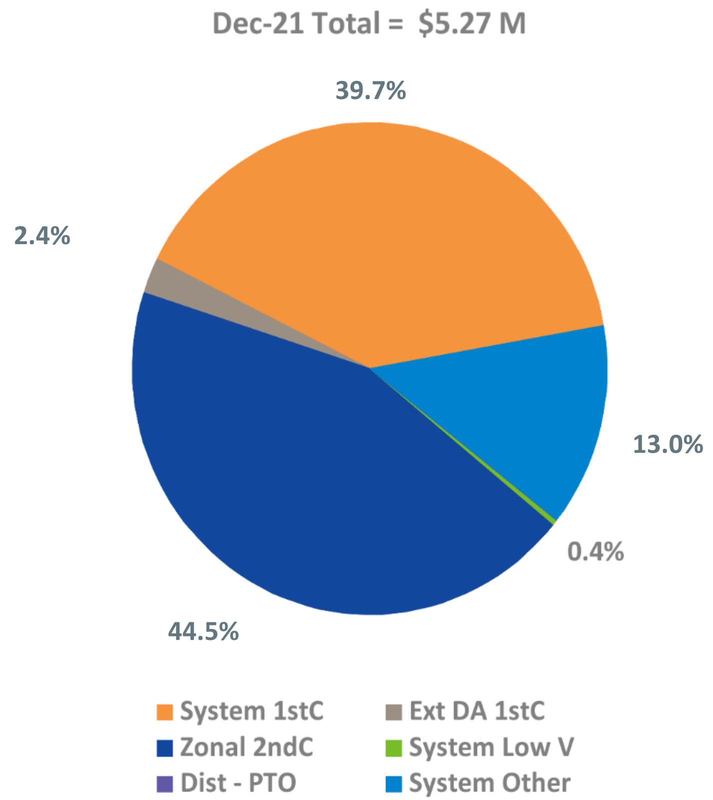


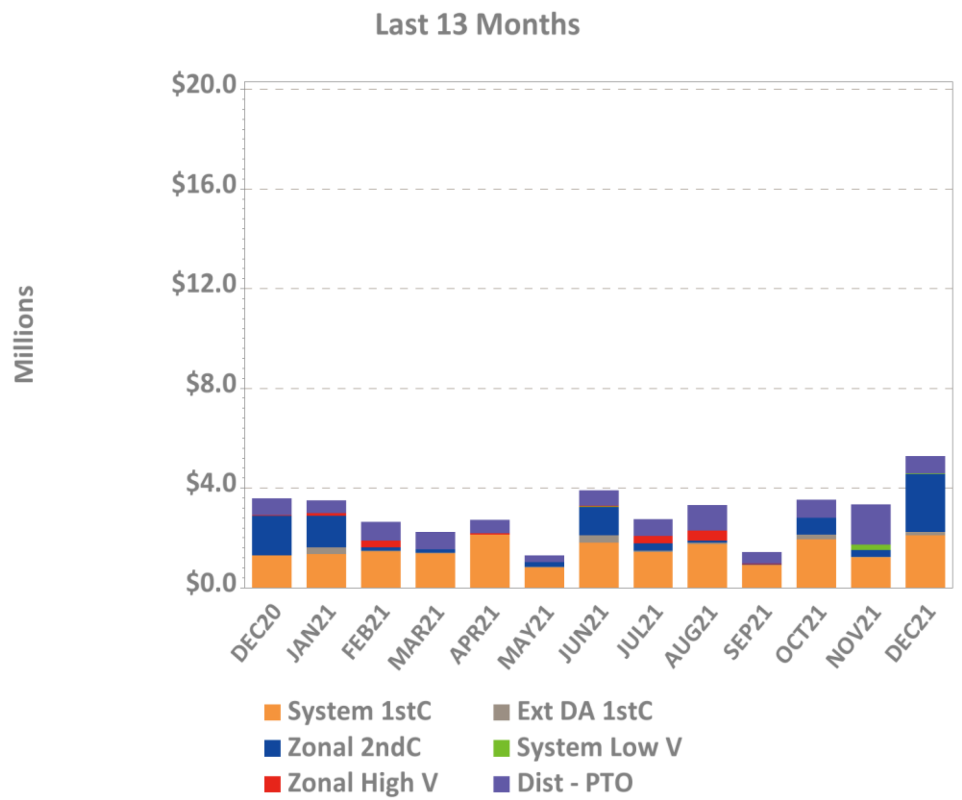
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



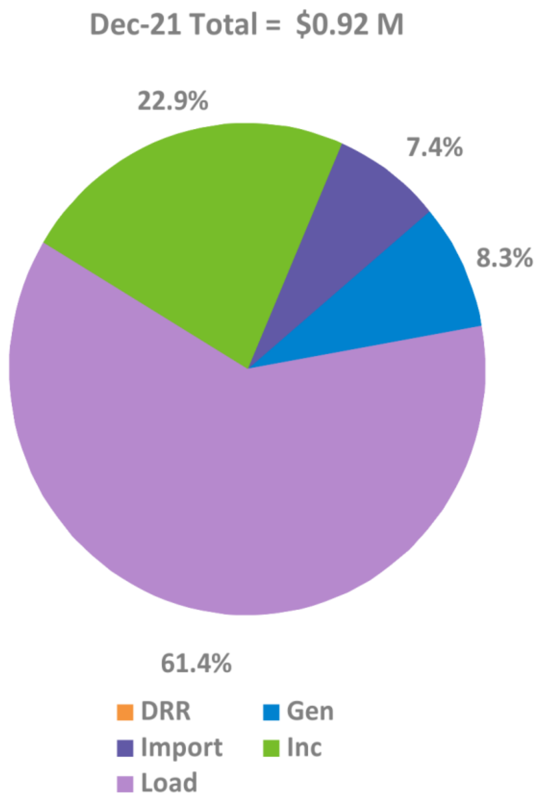
NCPC Charges by Allocation

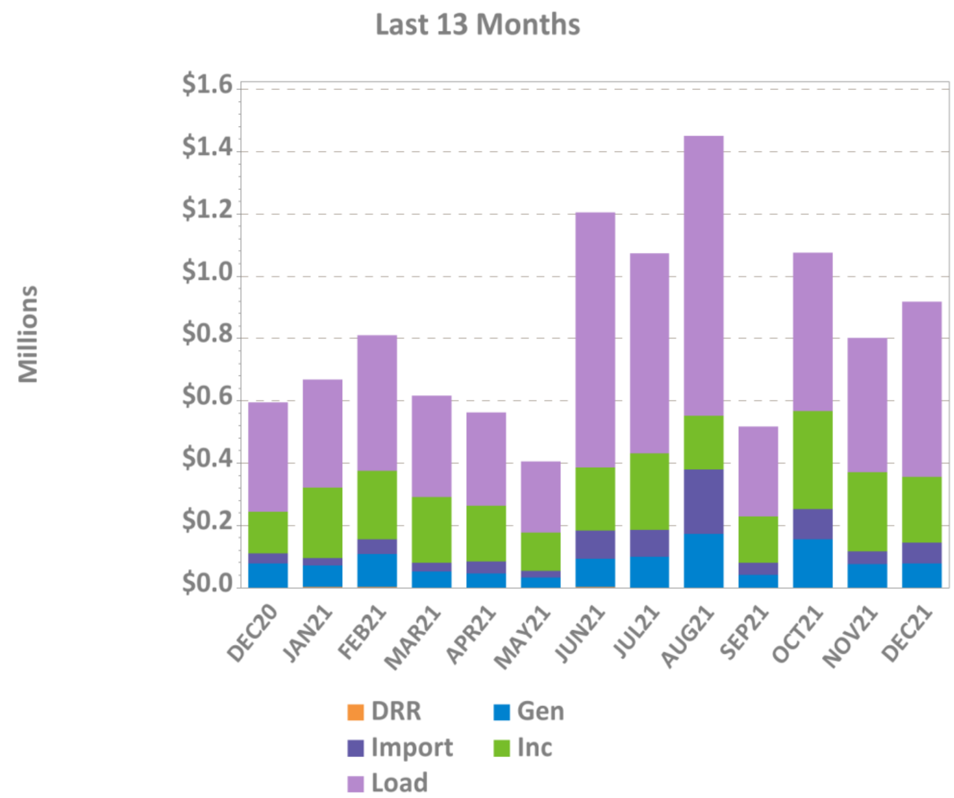




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

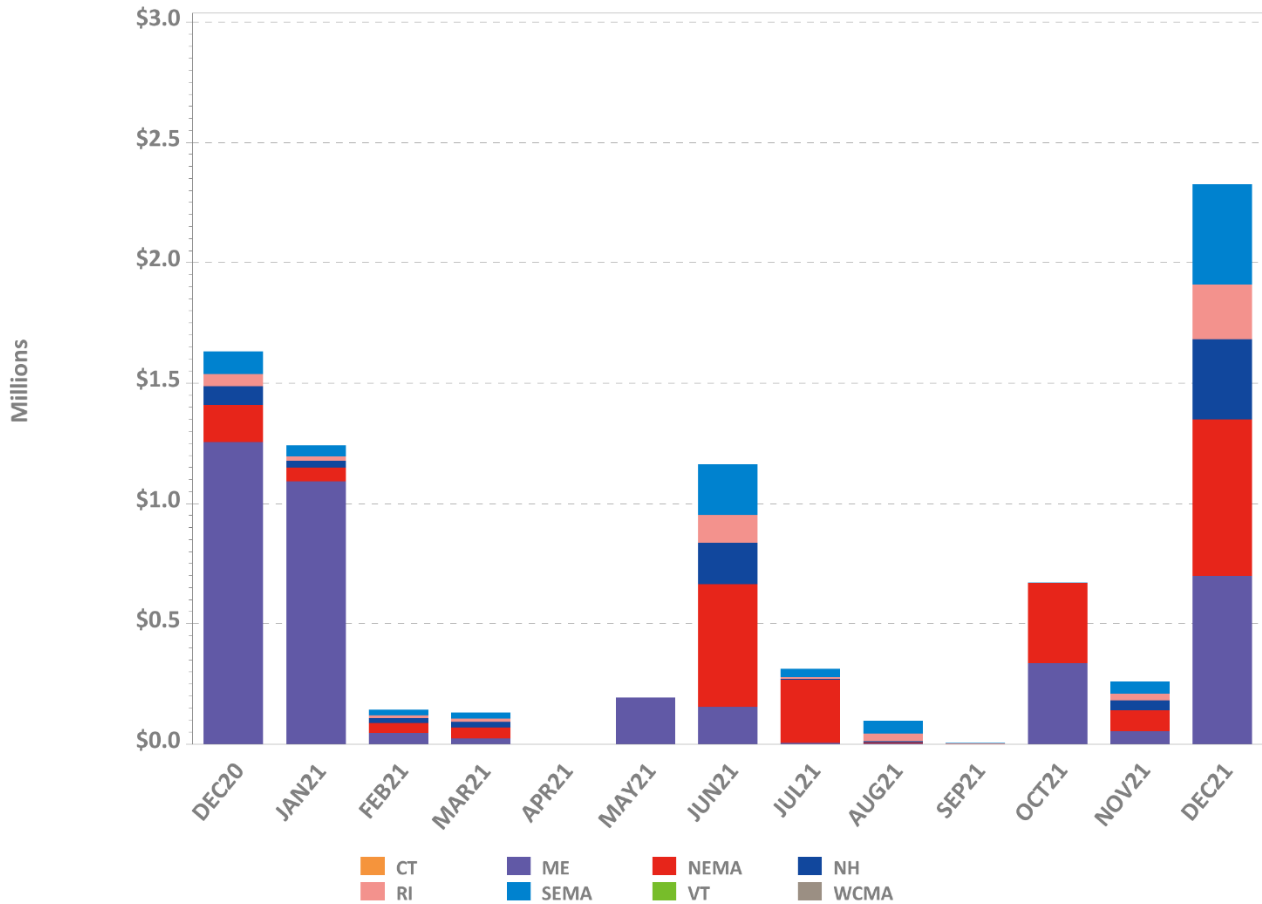
RT First Contingency Charges by Deviation Type





DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

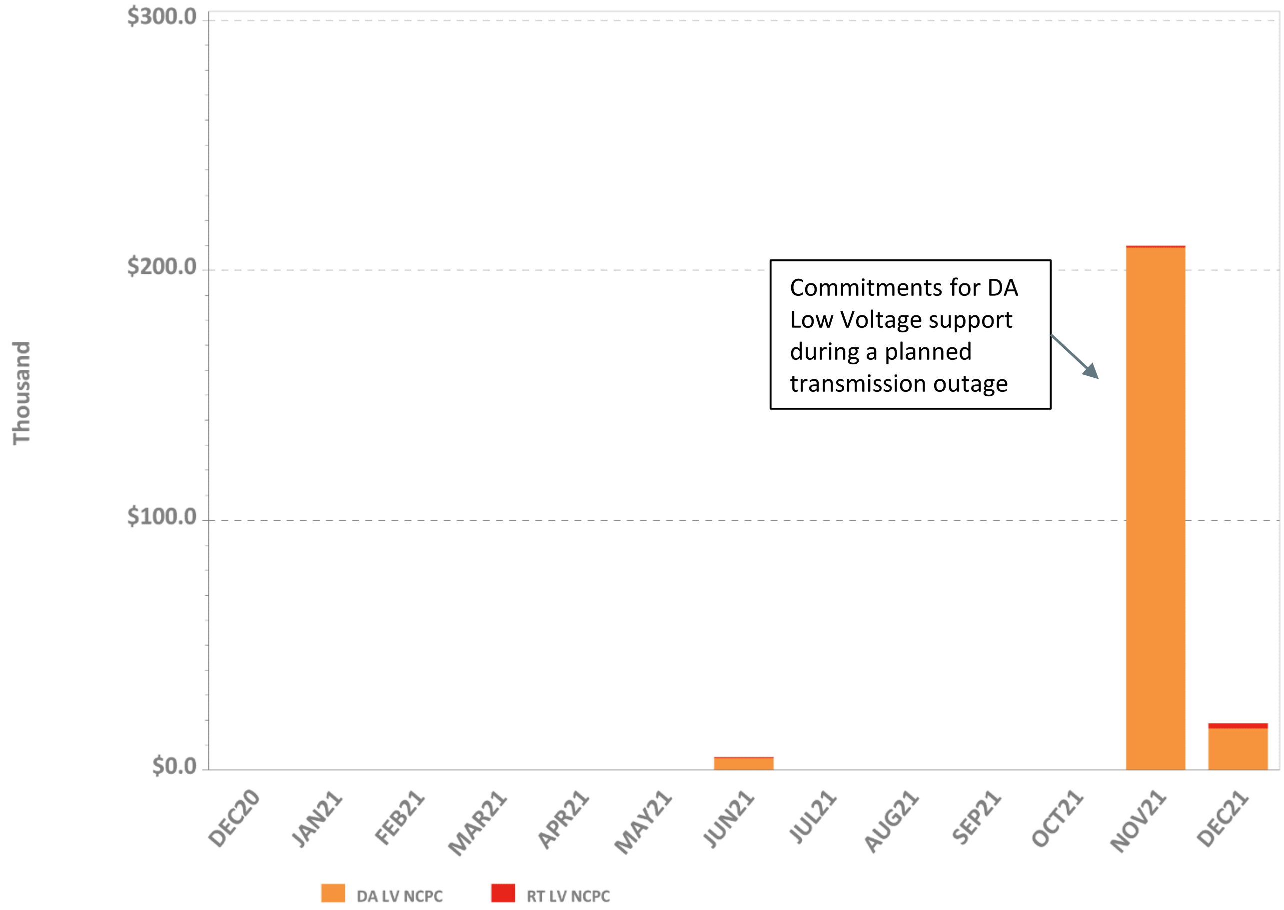
LSCPR Charges by Reliability Region



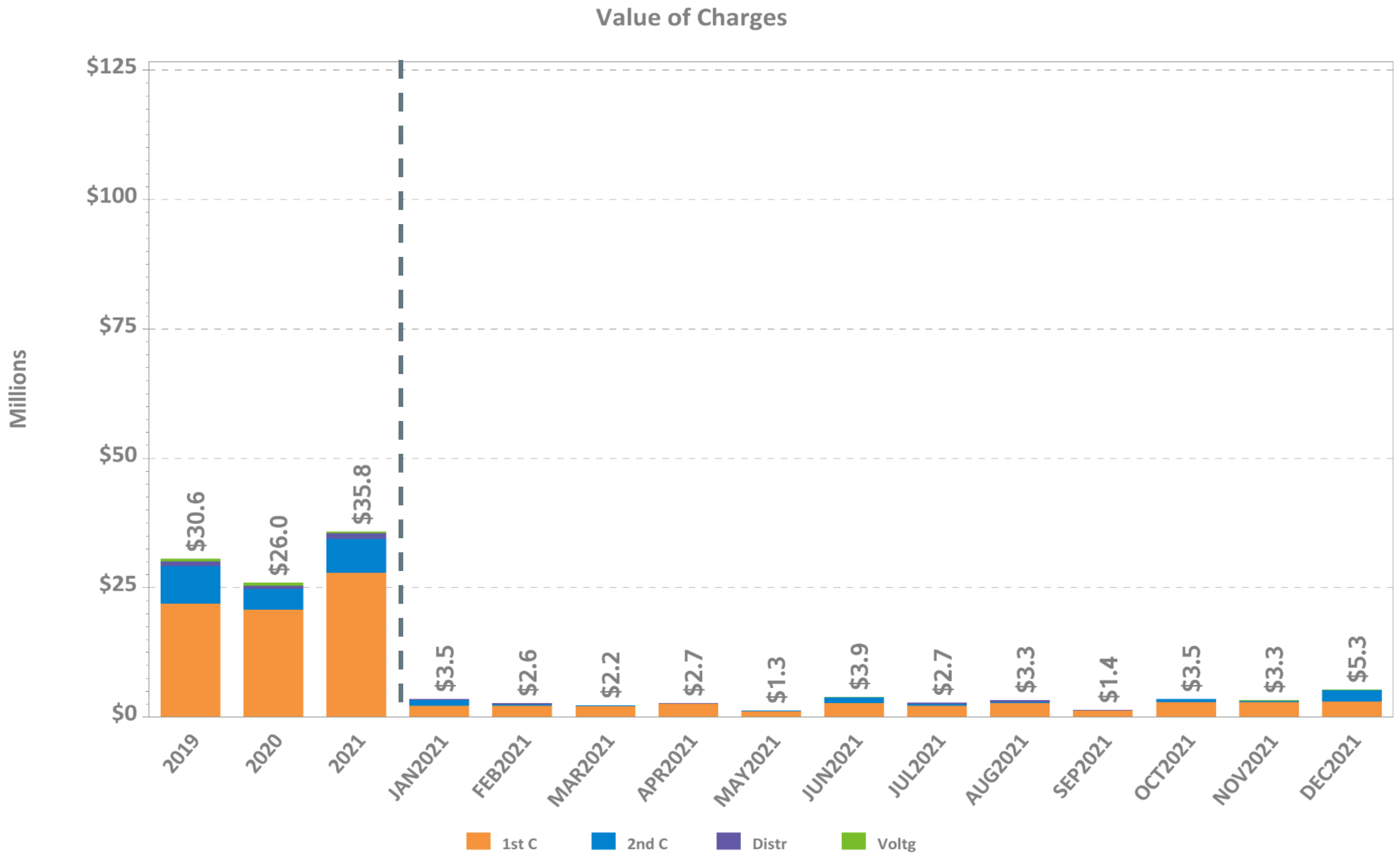
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

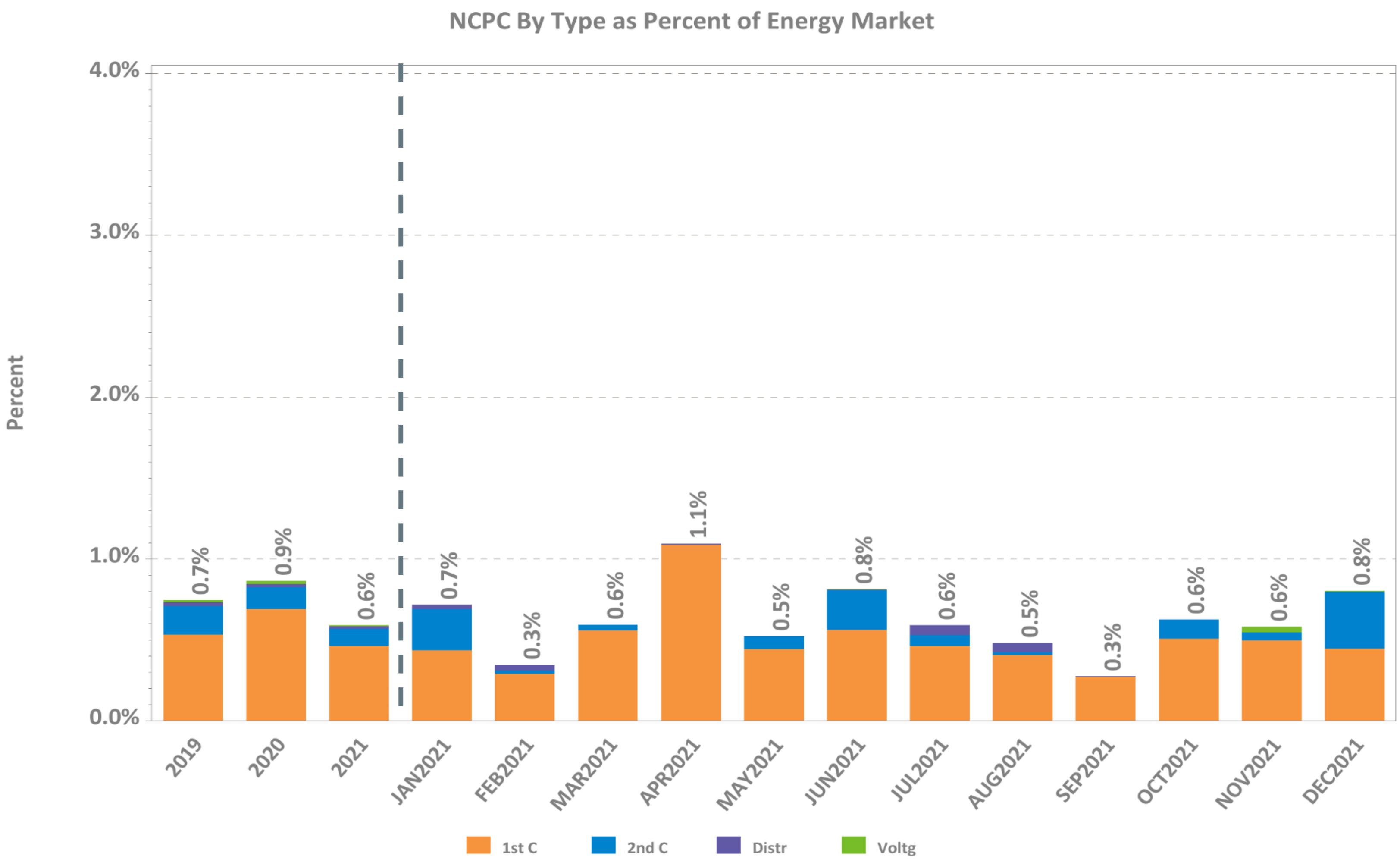
NCPC Charges for Voltage Support and High Voltage Control



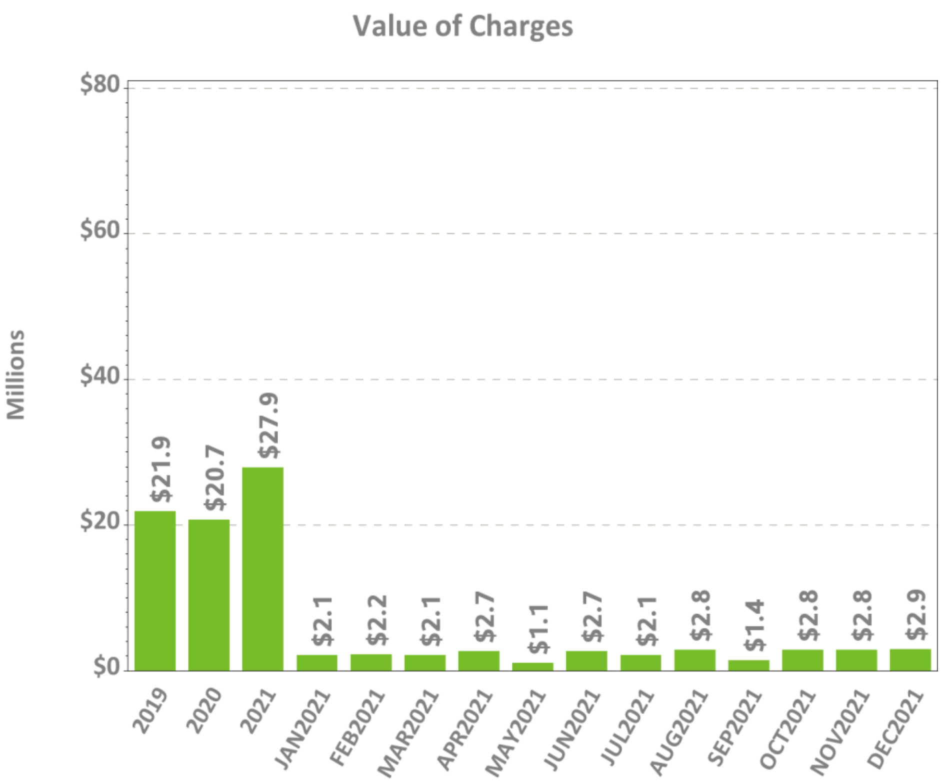
NCPC Charges by Type

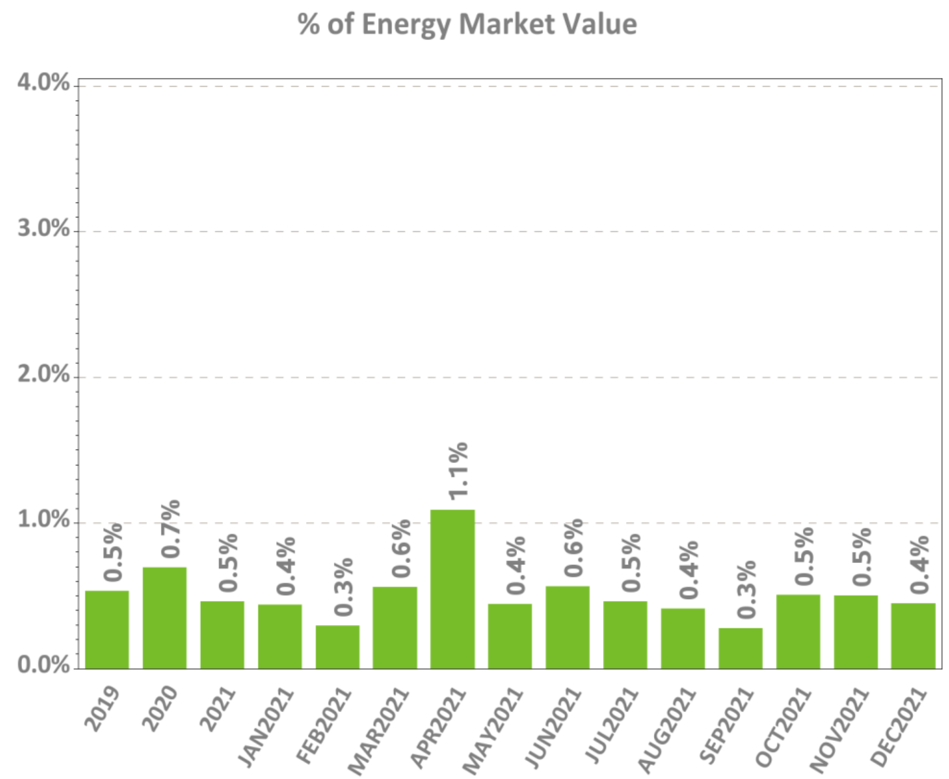


NCPC Charges as Percent of Energy Market



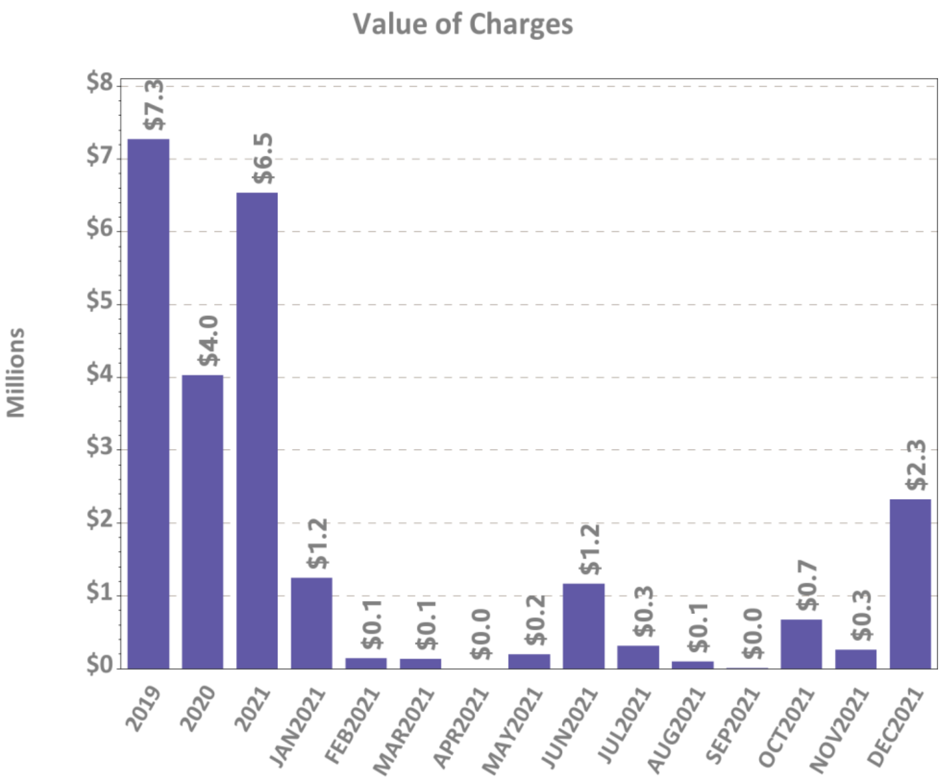
First Contingency NCPC Charges

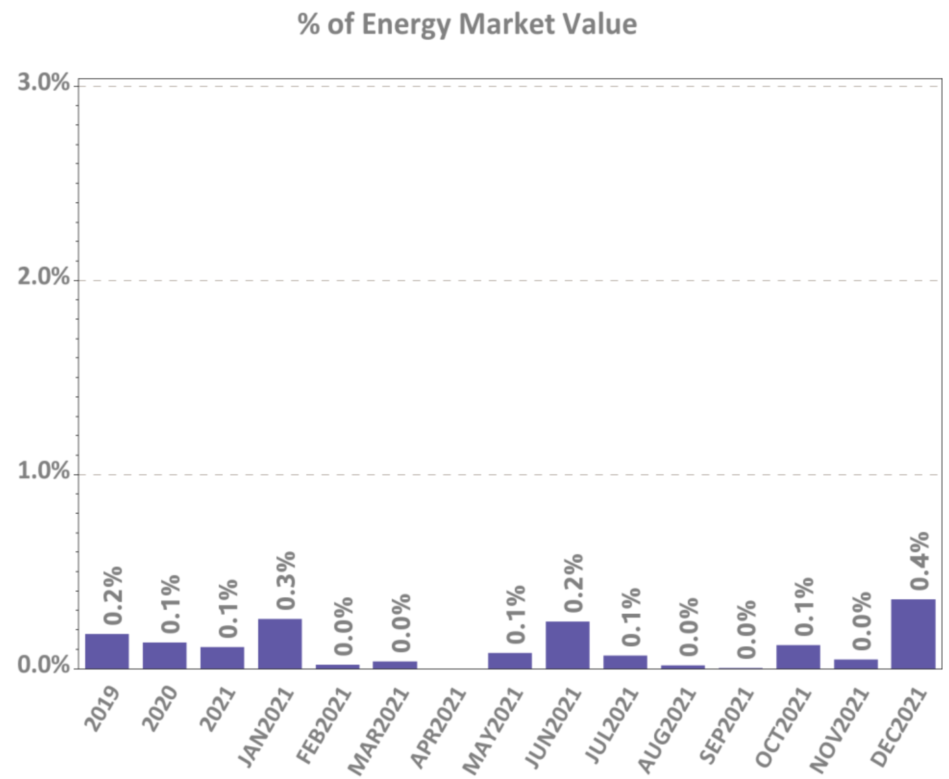




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

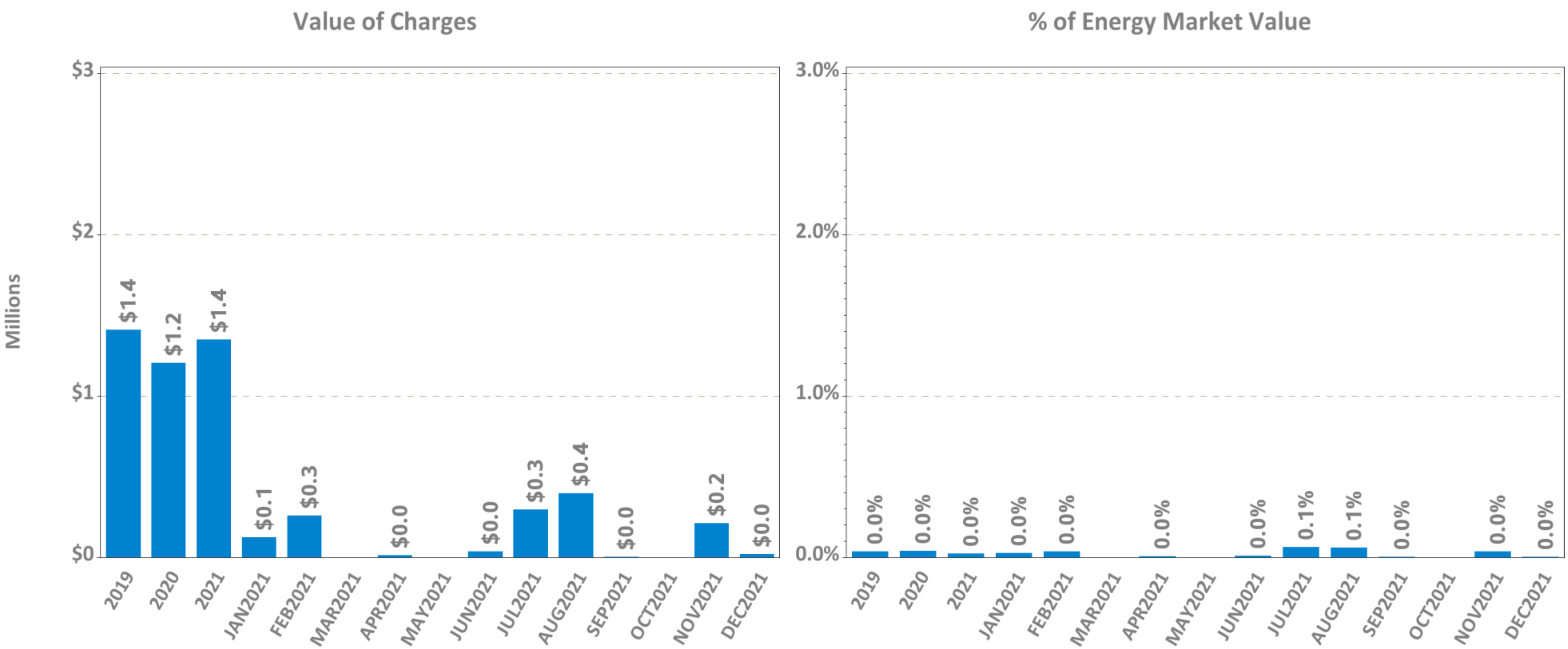
Second Contingency NCPC Charges





Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

DA vs. RT Pricing

The following slides outline:

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

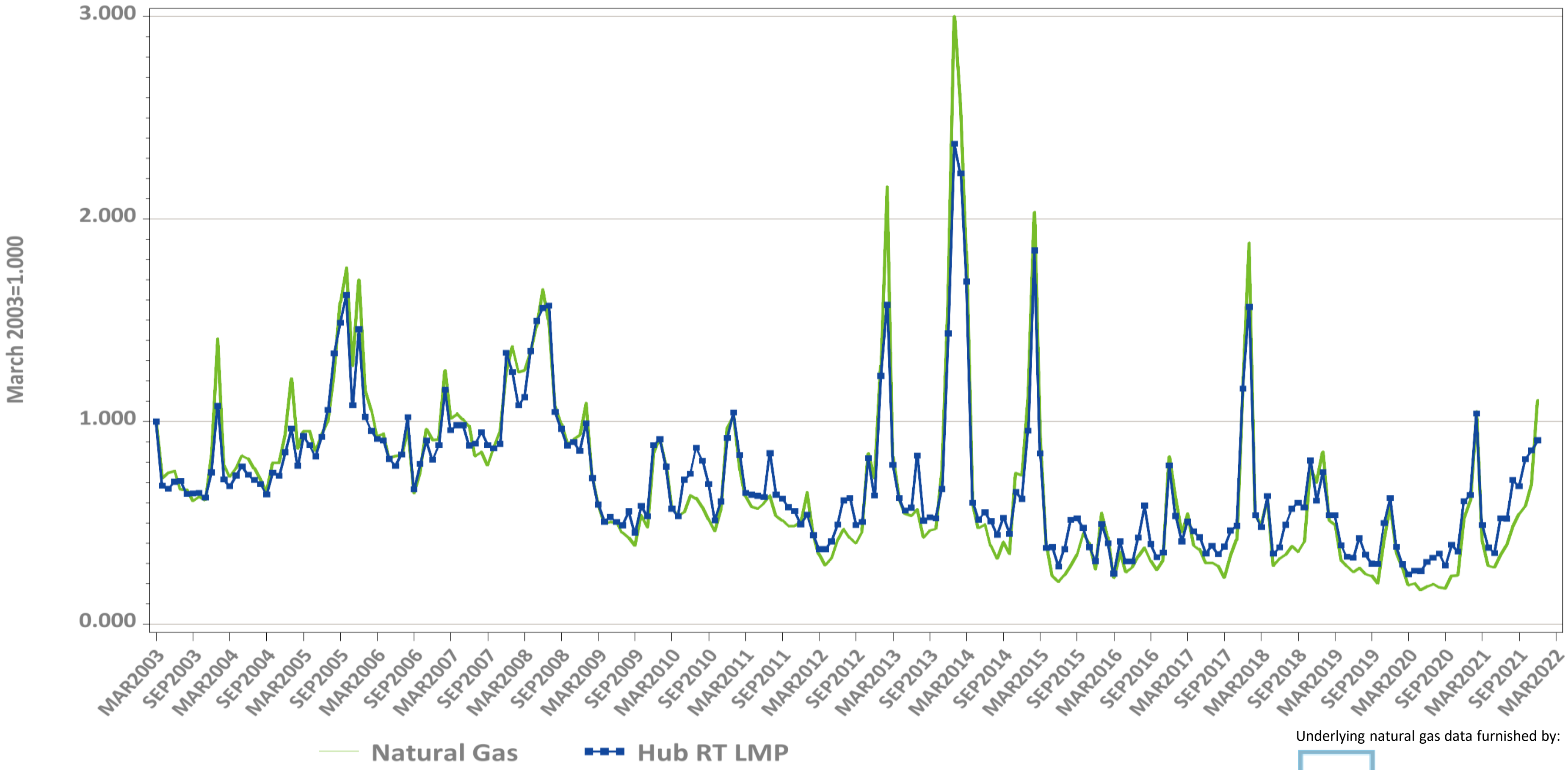
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2019	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%
Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%

December-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$40.74	$38.38	$39.90	$40.46	$38.92	$40.45	$40.80	$40.05	$40.15
Real-Time	$42.00	$40.64	$40.64	$41.73	$40.78	$41.77	$42.07	$41.62	$41.70
RT Delta %	3.1%	5.9%	1.9%	3.2%	4.8%	3.3%	3.1%	3.9%	3.9%
December-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$70.07	$63.40	$69.33	$69.32	$64.44	$69.35	$70.04	$67.47	$67.80
Real-Time	$62.95	$60.46	$62.31	$62.83	$60.69	$62.26	$62.92	$62.19	$62.35
RT Delta %	-10.2%	-4.6%	-10.1%	-9.4%	-5.8%	-10.2%	-10.2%	-7.8%	-8.0%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	72.0%	65.2%	73.8%	71.3%	65.6%	71.4%	71.7%	68.5%	68.9%
Yr over Yr RT	49.9%	48.8%	53.3%	50.6%	48.8%	49.1%	49.6%	49.4%	49.5%

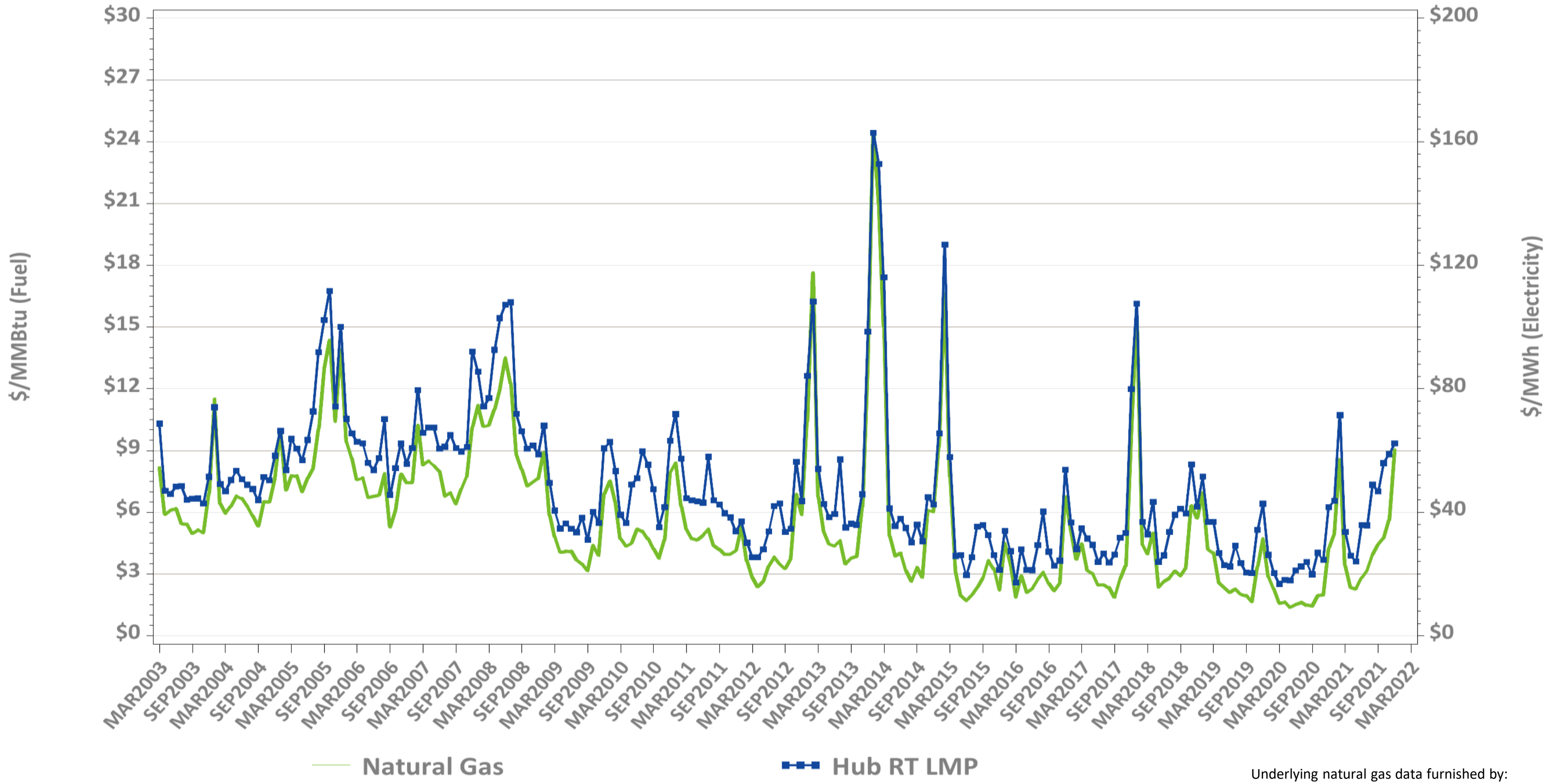
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

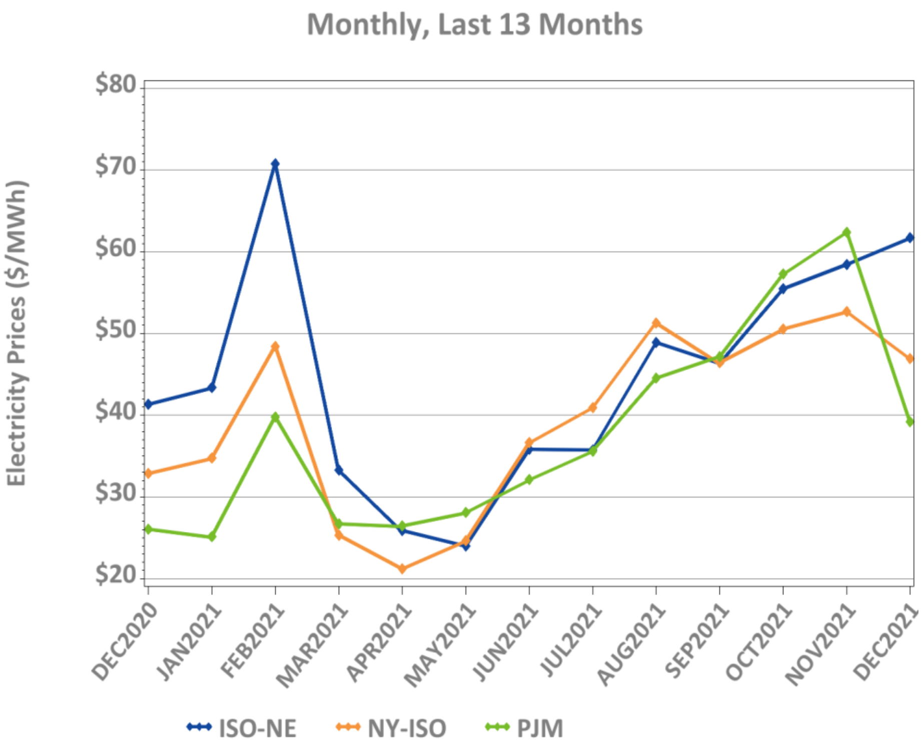
Monthly Average Fuel Price and RT Hub LMP



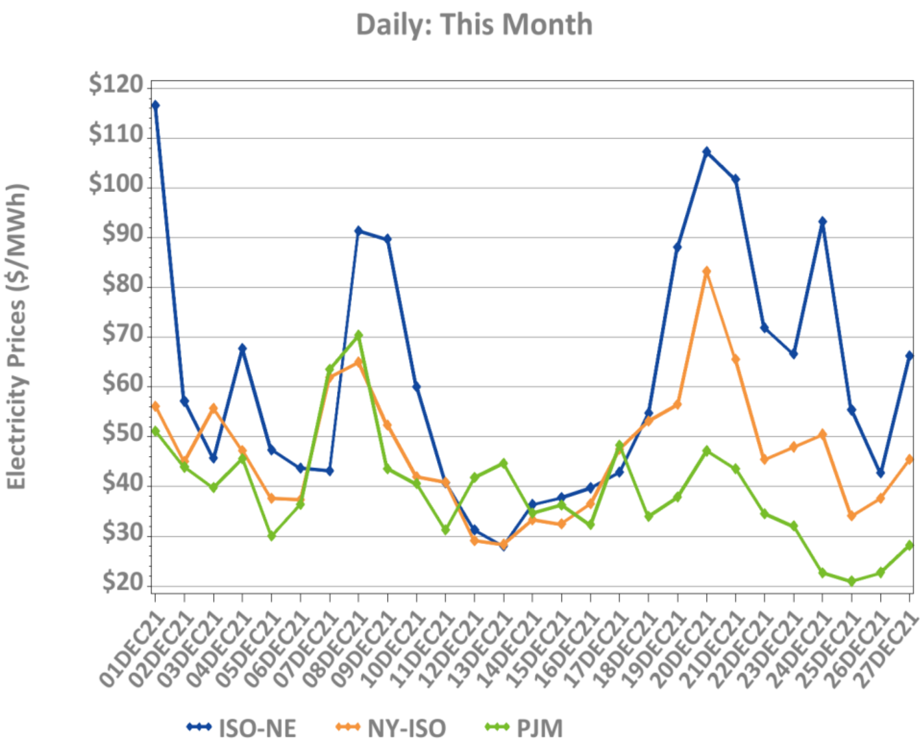
Underlying natural gas data furnished by:

ice Global markets in clear view

New England, NY, and PJM Hourly Average Real Time Prices by Month

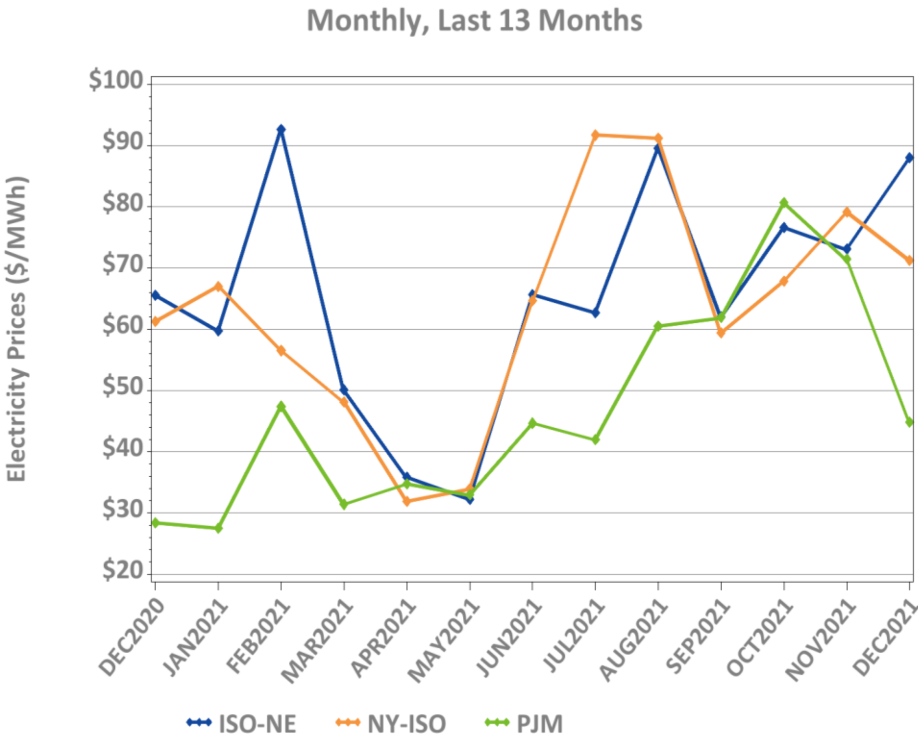


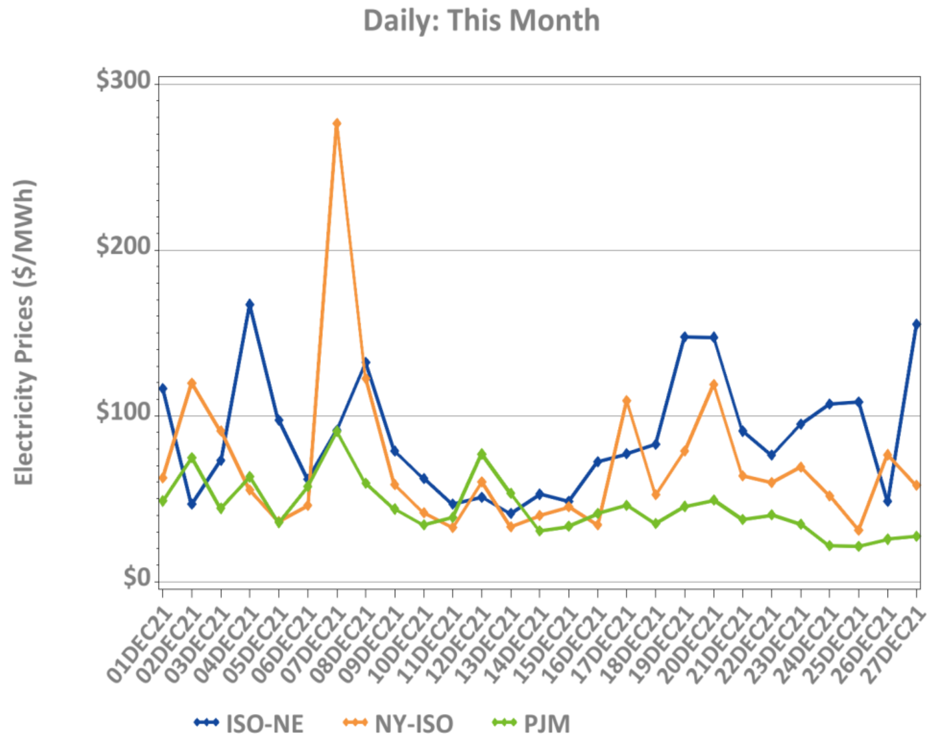
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Average Peak Hour Real Time Prices





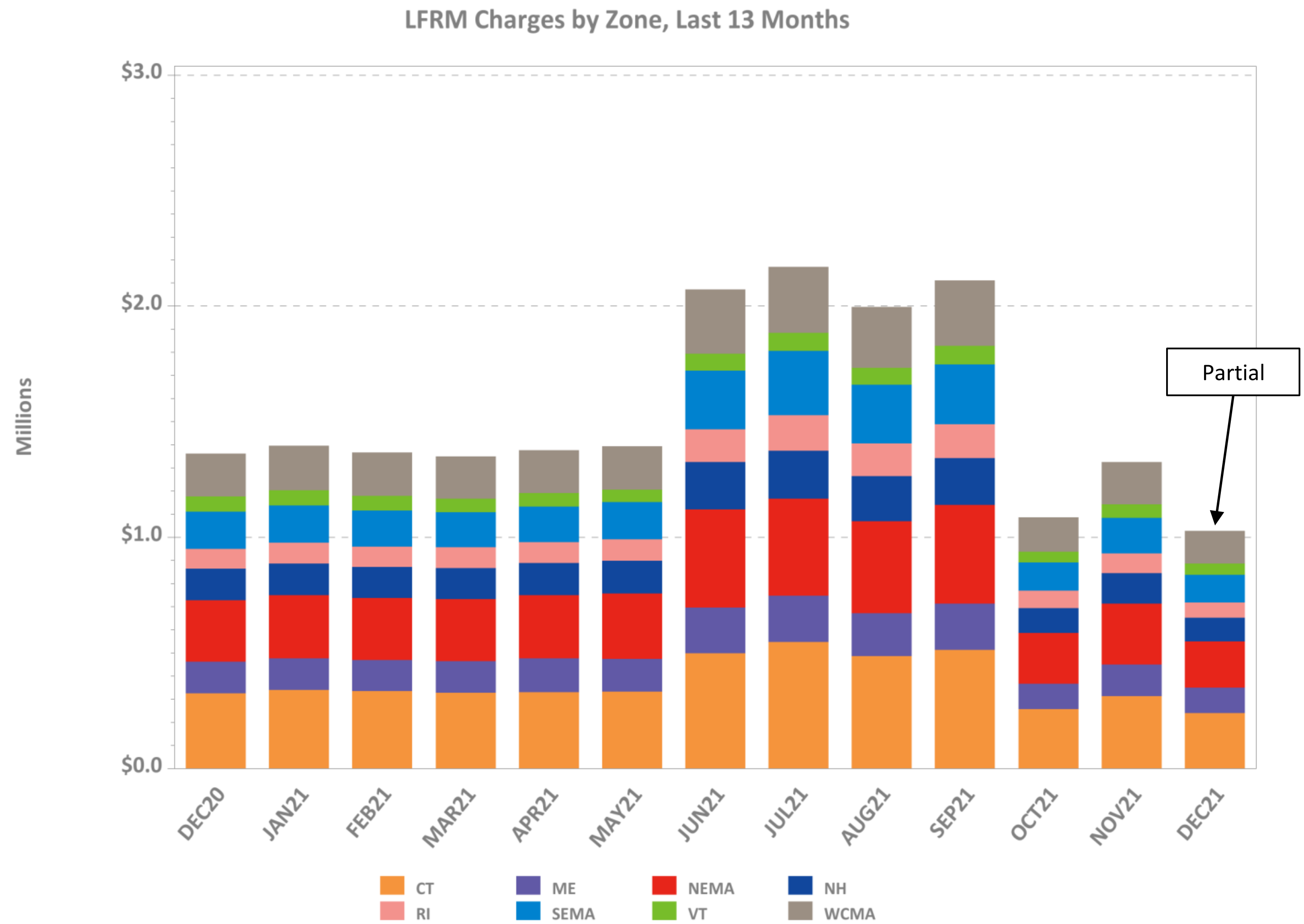
***Forecasted New England daily peak hours reflected**

Reserve Market Results – December 2021

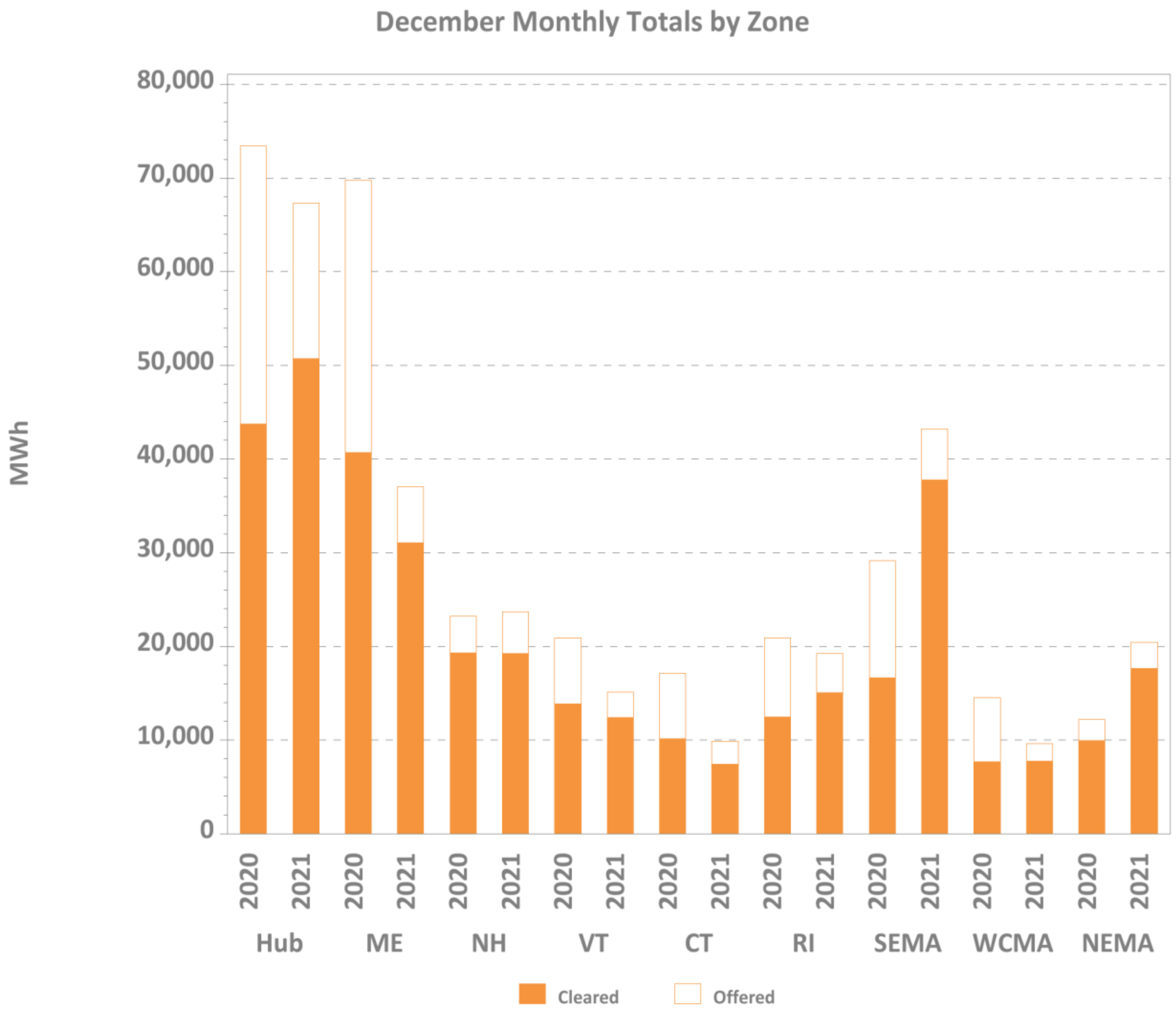
- Maximum potential Forward Reserve Market payments of $1.2M were reduced by credit reductions of $54K, failure-to-reserve penalties of $81K and no failure-to-activate penalties, resulting in a net payout of $1M or 88% of maximum
  - Rest of System: $0.73M/0.85M (86%)
  - Southwest Connecticut: $0.03M/0.03M (94%)
  - Connecticut: $0.27M/0.28M (96%)
  - NEMA: $2.8K/4.1K (68%)
- $427K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $427K in Real-Time Reserve payments
  - Rest of System: 130 hours, $297K
  - Southwest Connecticut: 130 hours, $61K
  - Connecticut: 130 hours, $40K
  - NEMA: 130 hours, $29K

Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

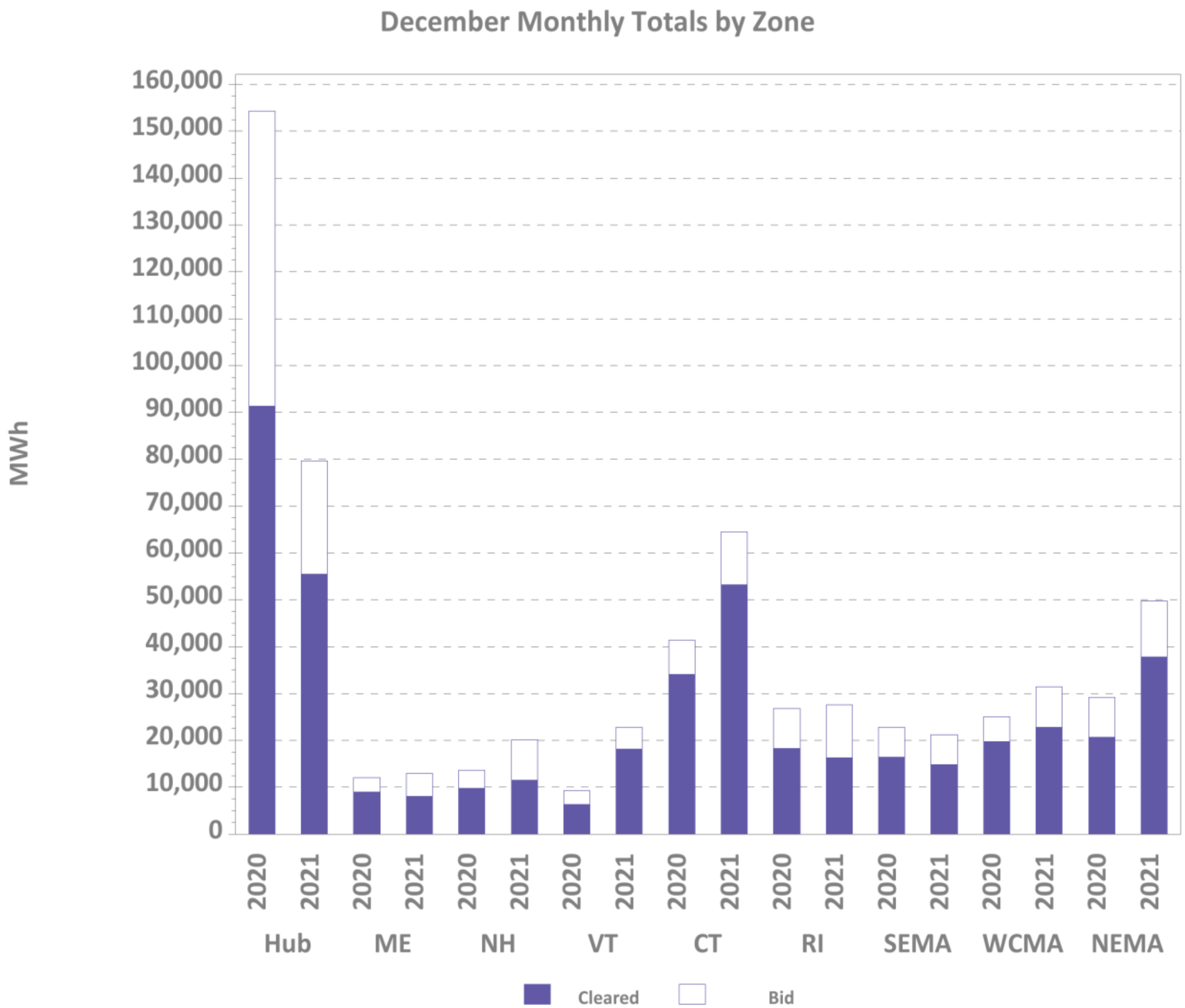
LFRM Charges to Load by Load Zone ($)



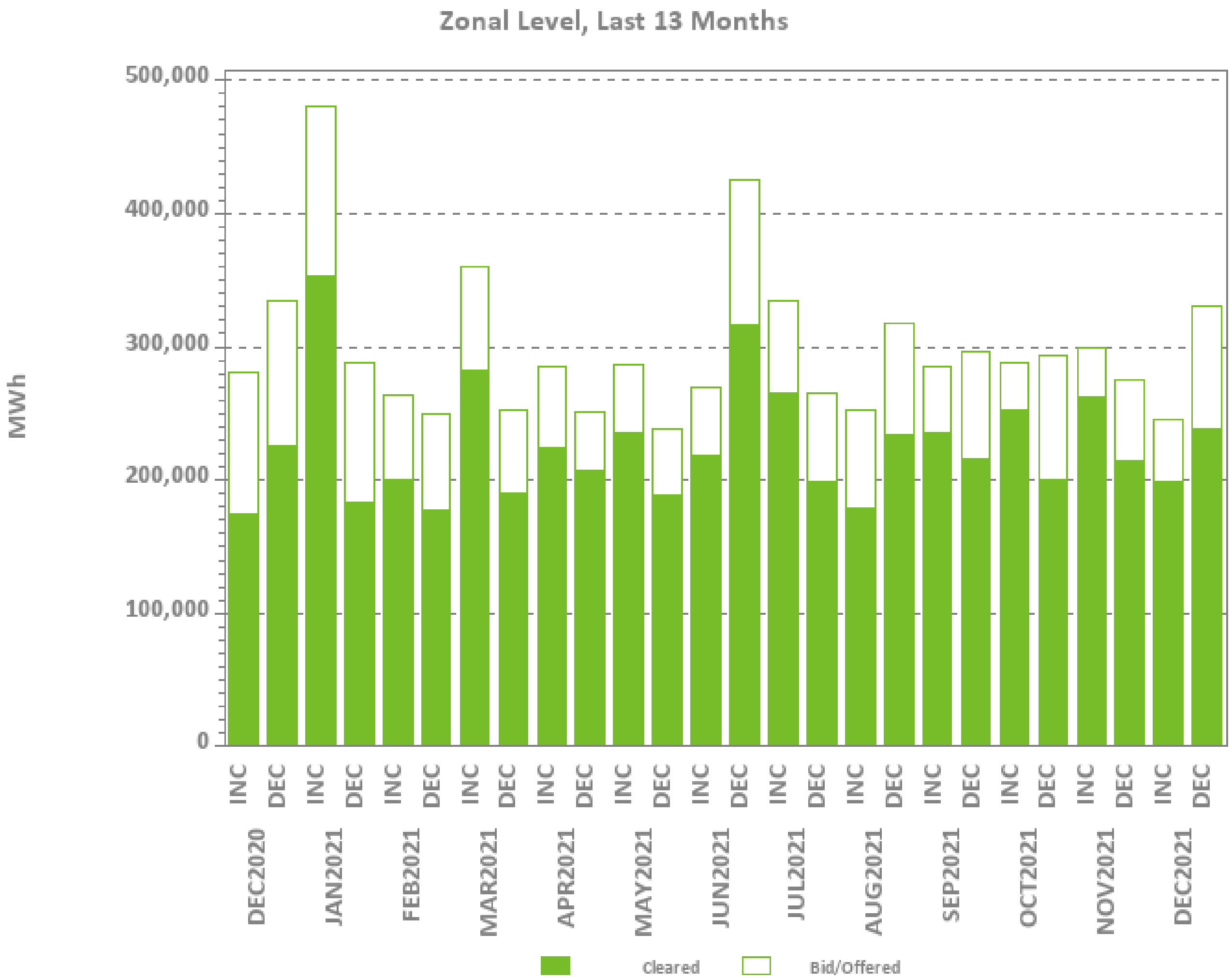
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

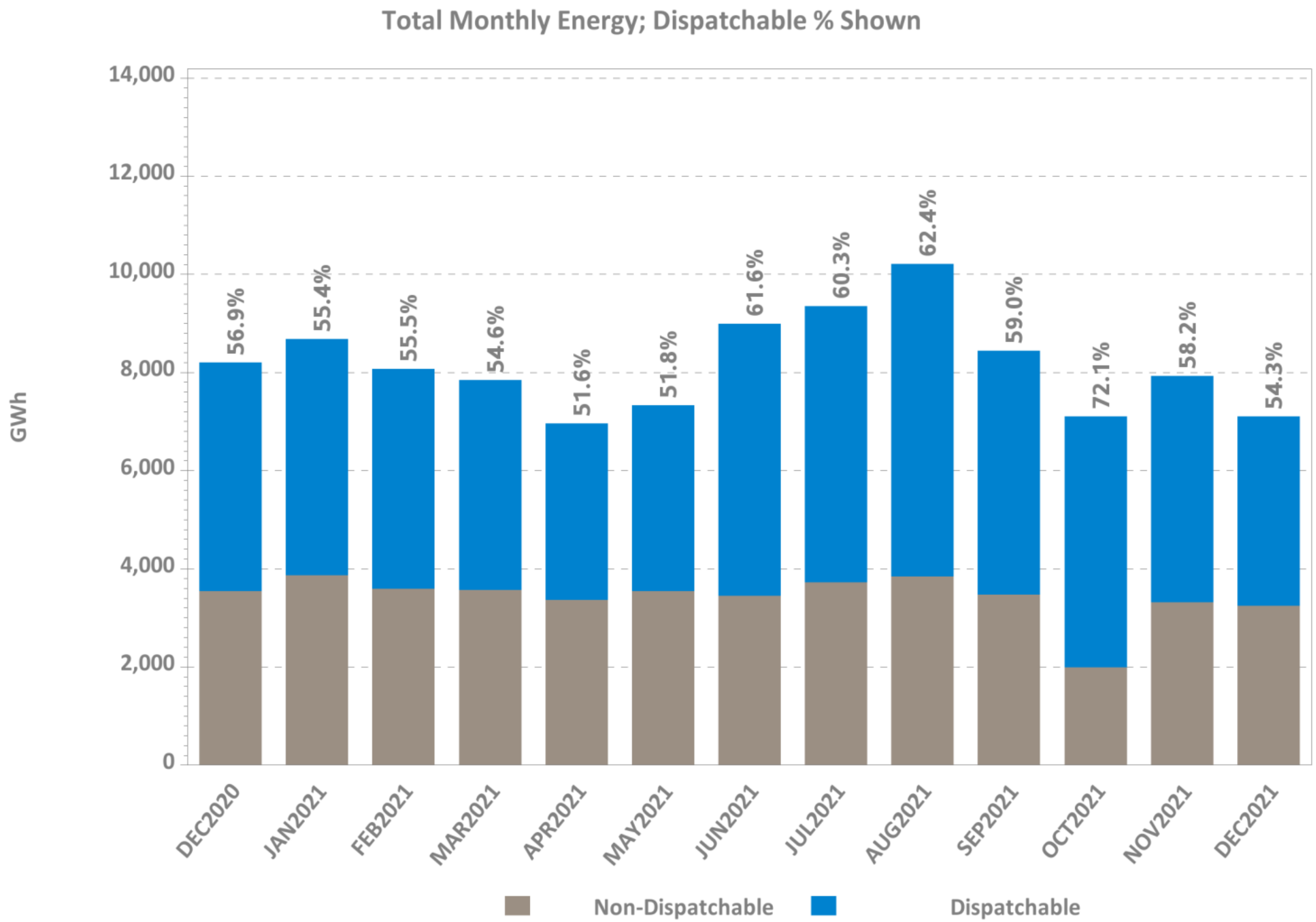


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



*** Dispatchable MWh here are defined to be all generation output that is not self-committed ('must run') by the customer.**

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- January 20 PAC Meeting Agenda Topics*
  - 2021 Economic Study: Future Grid Reliability Study
    - Preliminary Ancillary Services Analysis - Part 4
    - Preliminary Production Cost Results - Part 4
    - Resource Adequacy Screen & Probabilistic Resource Availability Analysis - Preliminary Observations and Recommendations - Part 2
  - Asset Condition Projects
    - K42 Transmission Line Replacement Project (VELCO)
    - P145 Line Rebuild - Asset Condition and Optical Ground Wire (OPGW) Project (Eversource)
  - Moody's Analytics Update
  - Environmental Update
  - Interregional Planning Update

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

Transmission Planning for the Clean Energy Transition (TPCET)

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to transmission planning study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published final revisions to the Transmission Planning Technical Guide reflecting these changes on 9/30/21
- CEII supplement to the PAC presentations was released on 10/5/21
- The draft TPCET Pilot Study Report was posted to the PAC website on 12/22/21
  - Comments are due to PACmatters@iso-ne.com by 1/10/22
- Future testing will focus on transient stability modeling and performance criteria

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21

Economic Studies

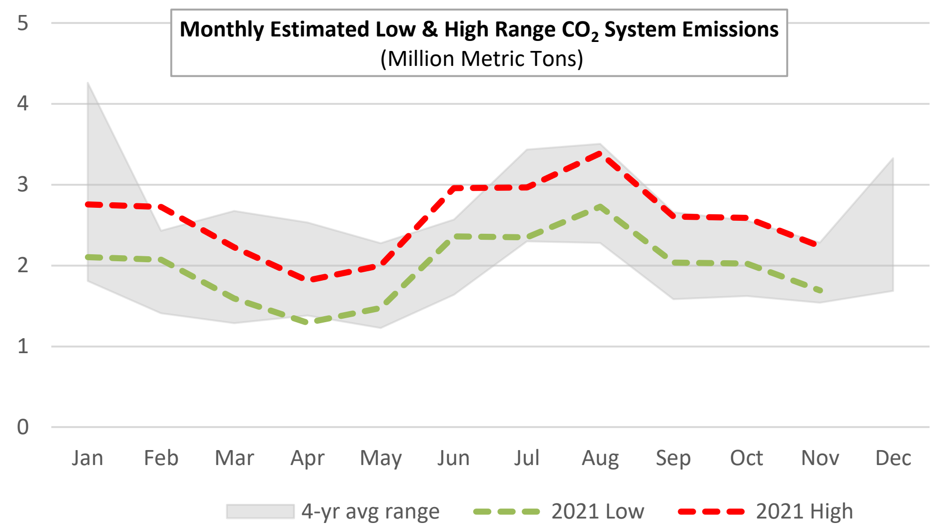
- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Draft report expected in early 2022
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Additional ancillary services, high-level transmission, and probabilistic resource adequacy screen results were discussed at the December 15, 2021 PAC meeting

Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - Phase 1 work was submitted as the only 2021 economic study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined

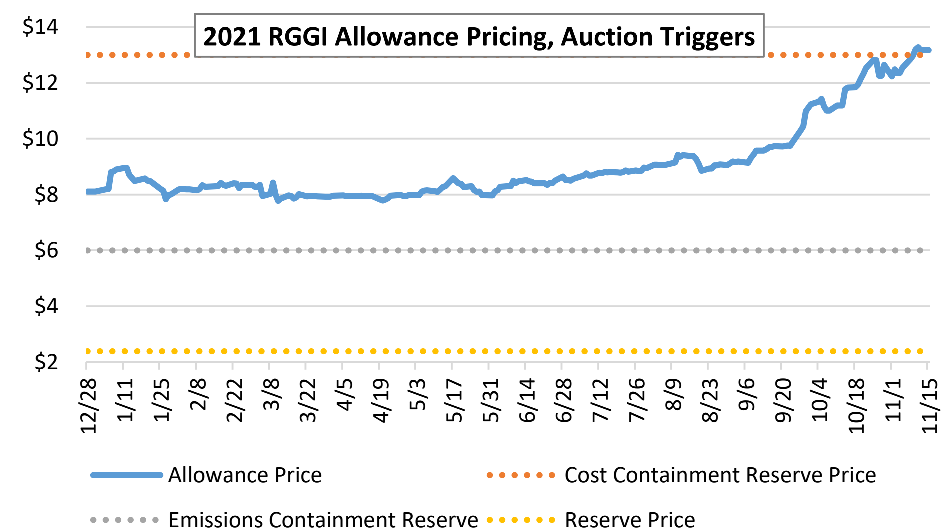
Environmental Matters – System CO_2 Emissions Up, Compliance Cost Trends Higher

- New England January - November 2021 estimated system CO_2 emissions range between **21** and **27** million metric tons (MMT)
  - January - October four-year average (2017-2020) CO_2 emissions range between **18** and **29** MMT
- RGGI compliance costs increasing for affected generators
  - Average allowance prices up 44% between 2020 and 2021 YTD
  - Spot prices up from $**8.11** (12/28/20) to $**13.85** (as of 12/15/21)
  - At $13, compliance costs increase 68% year-to-year for a natural-gas-fired generator, from $**2.88**/MWh (2020) to $**4.85**/MWh (2021)



RGGI Annual Compliance Costs by Fuel Type ($/MWh)

	2019	2020	2021
Natural Gas	$2.51	$2.88	$4.85
No. 2 Oil	$5.19	$5.95	$12.24
No. 6 Oil	$5.03	$5.77	$11.88
Coal	$5.67	$6.50	$13.39
RGGI average price ($/short ton)	$5.51	$6.31	$9.07



RGGI – Regional Greenhouse Gas Initiative

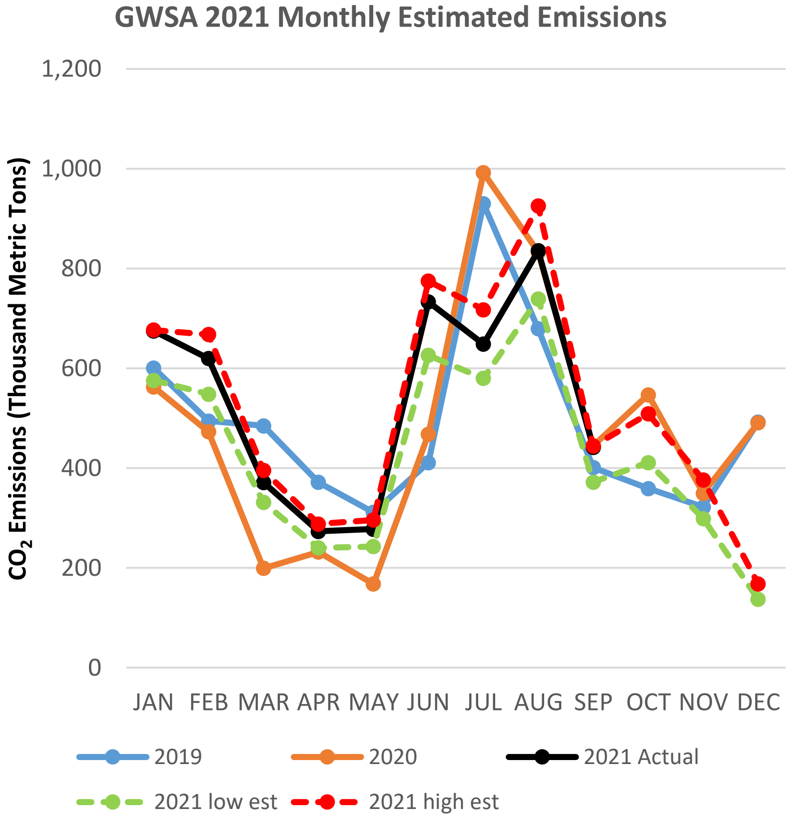
Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 Emissions, Allowance Prices Trending Higher vs. 2020

- As of 12/13/21, estimated GWSA CO_2 emissions range between **5.1** to **6.2** MMT (62% to 75%) of 2021 cap (8.28 MMT)
- Last 2021 GWSA auction cleared at $10 per metric ton. Using latest clearing price, IMM estimated compliance costs by fuel type (based average GWSA emission/heat rates):
  - No. 2 fuel oil - $8.54/MWh
  - No. 6 fuel oil - $8.29/MWh
  - Natural gas - $2.39/MWh
- Affected generators have access to banked allowances in excess of expected 2021 emissions

GWSA - Global Warming Solutions Act

2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



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.

Greater Boston Projects

Status as of 12/16/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-23	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

* Substation portion of the project is a Present Stage status 4

Greater Boston Projects, cont.

Status as of 12/16/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 12/16/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Mar-21	4

Greater Boston Projects, cont.

Status as of 12/16/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-22	3
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 12/16/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1520	Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
1643	Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
1341, 1645	Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
1646	Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
1647	Install a 115 kV breaker in series with the 5 breaker at Framingham	Mar-17	4
1554	Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

SEMA/RI Reliability Projects

Status as of 12/16/2021

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 12/16/2021

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	3
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	May-25	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	Dec-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-23	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 12/16/2021

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	Dec-23	1
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	Dec-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 12/16/2021

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	3
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	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 12/16/2021

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	Jun-22	2
1724	Replace the Kent County 345/115 kV transformer	Mar-22	2
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 12/16/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
1851	Upgrade Card 115 kV to BPS standards	Mar-23	2
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	1

Eastern CT Reliability Projects, cont.

Status as of 12/16/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	1
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	1
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	1
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Mar-22	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	1
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Mar-22	2

Eastern CT Reliability Projects, cont.

Status as of 12/16/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	June-22	2
1862	Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	1
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	1
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	1

Boston Area Optimized Solution Projects

Status as of 12/16/2021

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Jun-22	3
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Jan-23	2
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	2

New Hampshire Solution Projects

Status as of 12/16/2021

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +50/-25 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Aug-23	2
1879	Install a +50/-25 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Aug-23	2
1880	Install a +100/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec-23	2
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Nov-23	1

Upper Maine Solution Projects

Status as of 12/16/2021

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	Dec-27	1
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-27	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-27	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-27	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	Dec-25	1

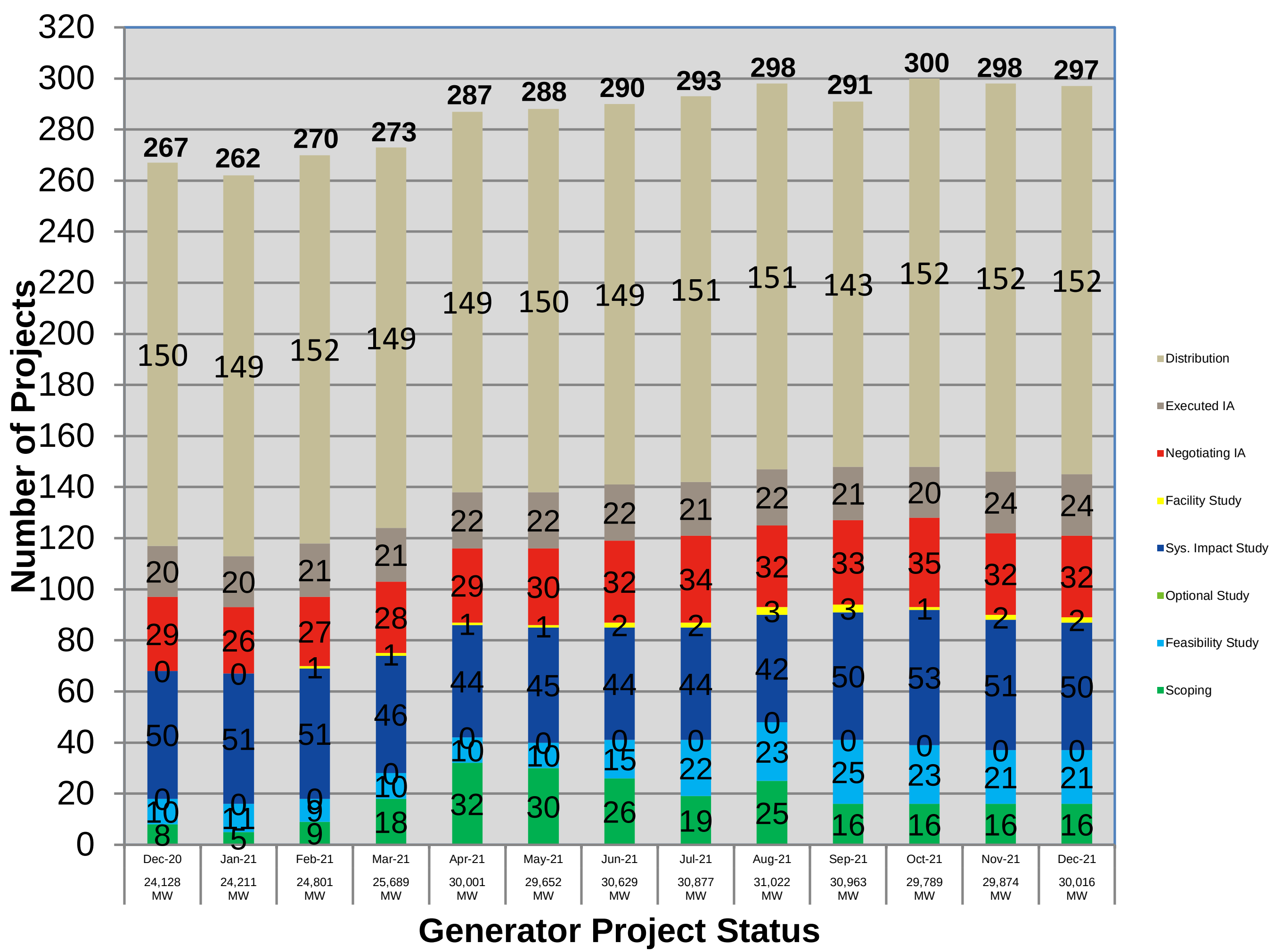
Upper Maine Solution Projects, cont.

Status as of 12/16/2021

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	Dec-25	1
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Dec-23	1
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	1

Status of Tariff Studies



Note: December 2021 is based on partial data.

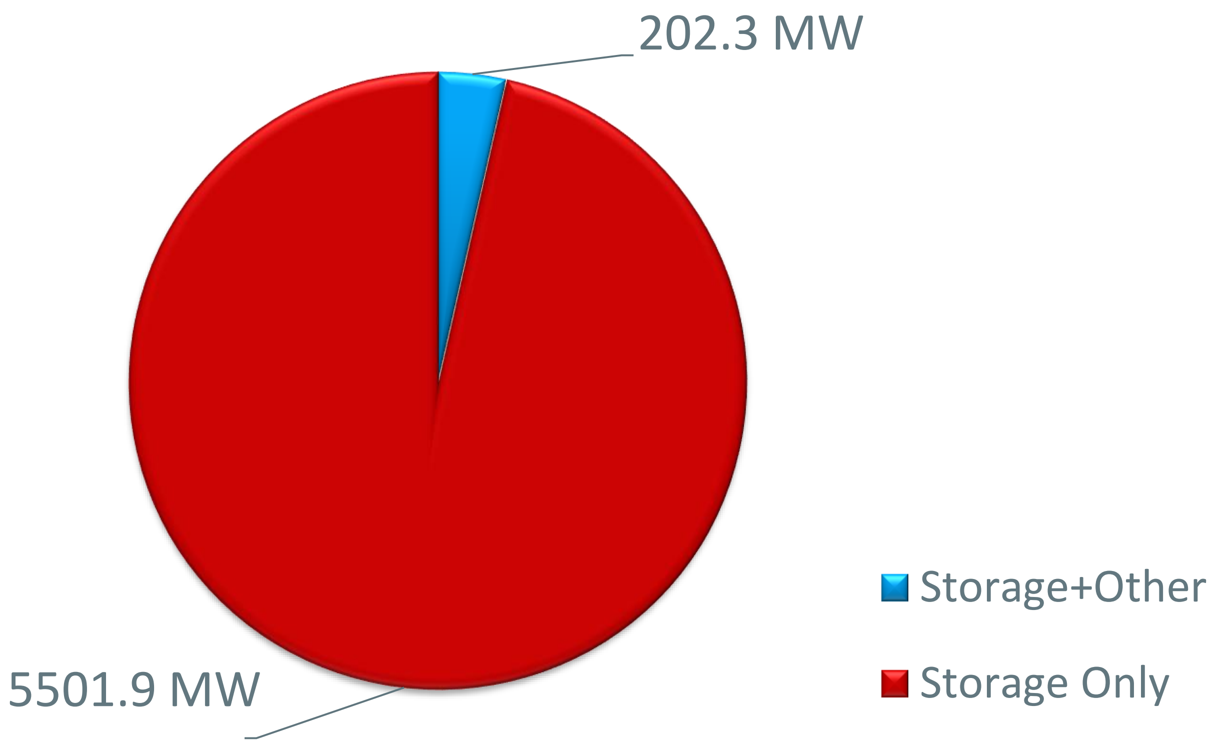
As of December 2021: 1 ETU in Scoping, 2 in FS, 1 in SIS, 0 in OIS, 1 in FAC, 1 Negotiating IA, and 2 with Executed IA

Transmission Service Requests needing study: 1 in Scoping

https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of December 16, 2021)

Storage Projects are proposed as stand-alone storage or as co-located with wind or solar projects



OPERABLE CAPACITY ANALYSIS

Winter 2022 Analysis

Winter 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,711	32,112
Active Demand Capacity Resource (+) [5]	490	410
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,077	1,077
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	91	564
Gas Generator Outages MW (-)	3	43
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,732	4,244
Net Capacity (NET OPCAP SUPPLY MW)	24,684	25,980
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,710	19,710
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,015	22,015
Operable Capacity Margin	2,669	3,965

[1]Operable Capacity is based on data as of **December 27, 2021** 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 **December 27, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 8, 2022.**

[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 2022 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,711	32,112
Active Demand Capacity Resource (+) [5]	490	410
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,077	1,077
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	91	564
Gas Generator Outages MW (-)	3	43
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,543	5,174
Net Capacity (NET OPCAP SUPPLY MW)	23,873	25,050
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,349	20,349
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,654	22,654
Operable Capacity Margin	1,219	2,396

[1]Operable Capacity is based on data as of **December 27, 2021** 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 **December 27, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 8, 2022.**

[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 2022 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

December 27, 2021 - 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 during June, July, August, and Mid September.

Report created: 12/27/2021

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
1/8/2022	**29711**	**490**	**1077**	**32**	**91**	**3**	**2800**	**3732**	**24684**	**19710**	**2305**	**22015**	**2669**	**Y**	**Winter 2021/2022**
1/15/2022	29711	490	1077	32	65	0	2800	3590	24855	19710	2305	22015	2840	N	Winter 2021/2022
1/22/2022	29711	490	1077	32	39	0	2800	3141	25330	19710	2305	22015	3315	N	Winter 2021/2022
1/29/2022	29779	541	1143	37	30	0	3100	2842	25528	19488	2305	21793	3735	N	Winter 2021/2022
2/5/2022	29779	541	1143	37	65	0	3100	2543	25792	19222	2305	21527	4265	N	Winter 2021/2022
2/12/2022	29779	541	1143	37	37	0	3100	2244	26119	19193	2305	21498	4621	N	Winter 2021/2022
2/19/2022	29779	541	1143	37	32	0	3100	1795	26573	18931	2305	21236	5337	N	Winter 2021/2022
2/26/2022	29779	541	1143	37	87	0	3100	1496	26817	17944	2305	20249	6568	N	Winter 2021/2022
3/5/2022	29787	541	1135	37	438	270	2200	927	27665	17596	2305	19901	7764	N	Winter 2021/2022
3/12/2022	29787	541	1135	37	738	718	2200	0	27844	17400	2305	19705	8139	N	Winter 2021/2022
3/19/2022	29787	541	1135	37	1266	963	2200	0	27071	17036	2305	19341	7730	N	Winter 2021/2022
3/26/2022	29763	540	1135	37	1727	757	2700	0	26291	16472	2305	18777	7514	N	Winter 2021/2022

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2022 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

December 27, 2021 - 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 during December, January, February, March and April.

Report created: 12/27/2021

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
1/8/2022	**29711**	**490**	**1077**	**32**	**91**	**3**	**2800**	**4543**	**23873**	**20349**	**2305**	**22654**	**1219**	**Y**	Winter 2021/2022
1/15/2022	29711	490	1077	32	65	0	2800	4338	24107	20349	2305	22654	1453	N	Winter 2021/2022
1/22/2022	29711	490	1077	32	39	0	2800	4039	24432	20349	2305	22654	1778	N	Winter 2021/2022
1/29/2022	29779	541	1143	37	30	0	3100	4039	24331	20121	2305	22426	1905	N	Winter 2021/2022
2/5/2022	29779	541	1143	37	65	0	3100	3590	24745	19847	2305	22152	2593	N	Winter 2021/2022
2/12/2022	29779	541	1143	37	37	0	3100	3291	25072	19817	2305	22122	2950	N	Winter 2021/2022
2/19/2022	29779	541	1143	37	32	0	3100	2693	25675	19547	2305	21852	3823	N	Winter 2021/2022
2/26/2022	29779	541	1143	37	87	0	3100	2244	26069	18533	2305	20838	5231	N	Winter 2021/2022
3/5/2022	29787	541	1135	37	438	270	2200	1824	26768	18174	2305	20479	6289	N	Winter 2021/2022
3/12/2022	29787	541	1135	37	738	718	2200	778	27066	17973	2305	20278	6788	N	Winter 2021/2022
3/19/2022	29787	541	1135	37	1266	963	2200	84	26987	17598	2305	19903	7084	N	Winter 2021/2022
3/26/2022	29763	540	1135	37	1727	757	2700	0	26291	17017	2305	19322	6969	N	Winter 2021/2022

Column Definitions

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

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

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

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

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

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

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

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

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

10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.

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

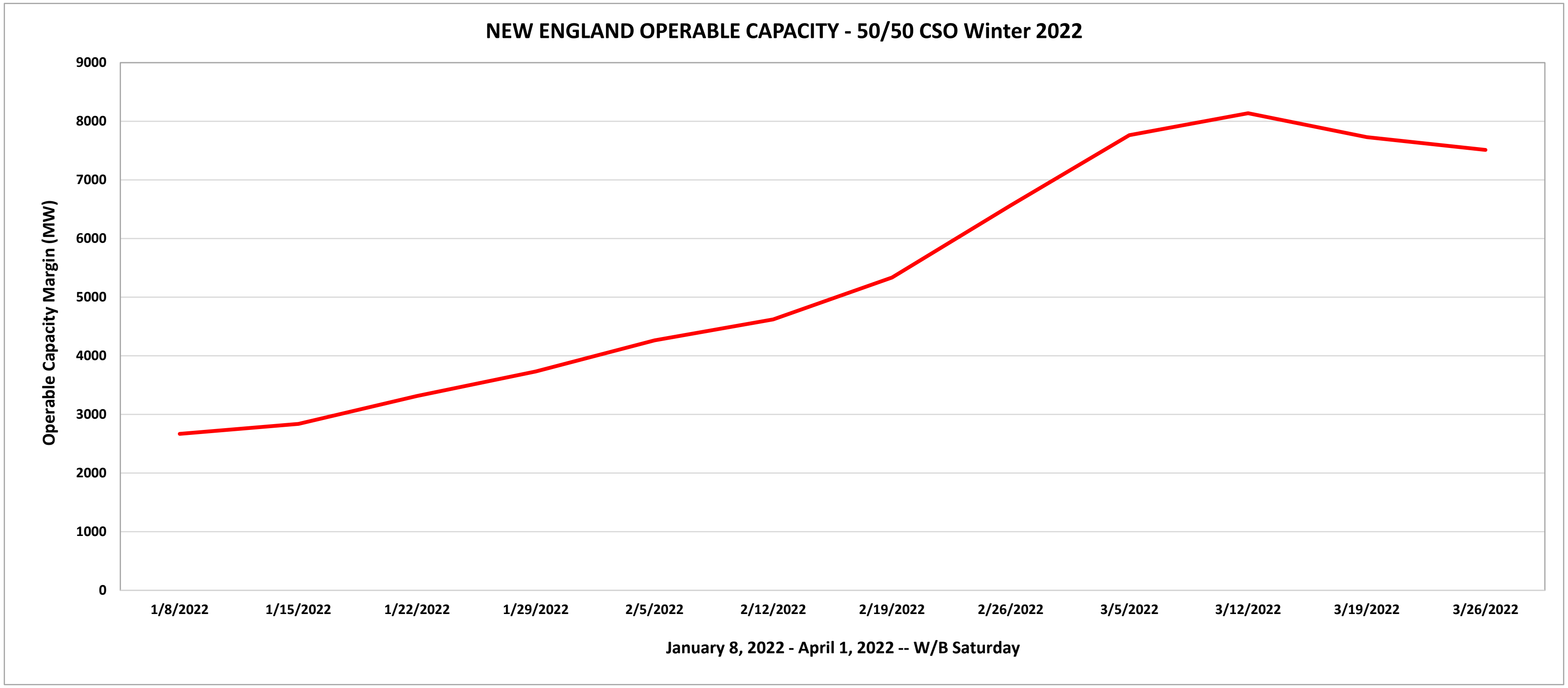
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

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

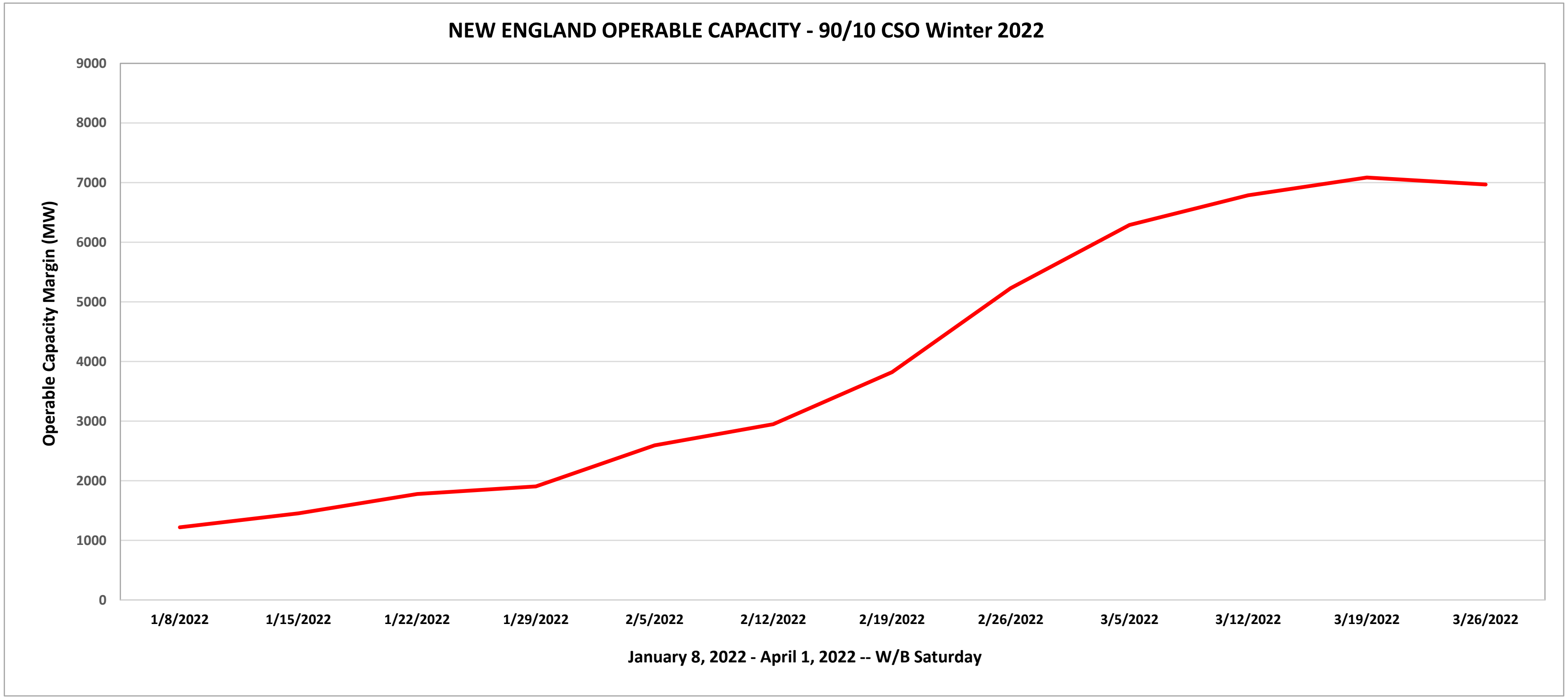
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Winter 2022 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2022 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

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

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: December 29, 2021

RE: Order No. 2222 Compliance Proposal (Participation of Distributed Energy Resource Aggregations in RTO/ISO Markets)

At its January 6, 2022 meeting, the Participants Committee[1] (PC) will be asked to consider supporting a package of Tariff revisions proposed by ISO-NE to address the compliance requirements contained in the Federal Energy Regulatory Commission's Final Rule regarding the participation of distributed energy resource aggregations (DERAs) in RTO/ISO markets (the *Order 2222* Changes).

This memorandum provides a high-level summary of the ISO's compliance proposal and the stakeholder process that vetted the proposal. Included with the memorandum are the following Attachments:

- Attachments A1–A3: ISO-NE's Tariff redlines as presented at the Markets Committee (A1), the Transmission Committee (A2), and the Reliability Committee (A3).
- Attachment B: ISO-NE's voting memorandum to the Technical Committees.
- Attachment C1–C3: The Notices of Actions for each Technical Committee.
- Attachment D: Advanced Energy Economy's (AEE) presentation, as presented at the MC, on its proposed amendments to the ISO's Order No. 2222 compliance proposal.
- Attachment E: ISO-NE's response to AEE's Revised Amendment 1A

BACKGROUND & OVERVIEW OF *ORDER 2222* COMPLIANCE PROPOSAL

In September 2020, the Commission issued Order No. 2222 directing RTOs/ISOs to adopt "reforms to remove barriers to the participation of distributed energy resource aggregation" in the wholesale markets. The Commission enumerated 11 directives in its *Order 2222*.[2] ISO-NE's responsive filing is due February 2, 2022.[3]

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[1] Capitalized terms used but not defined in this memorandum are intended to have the same meaning 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-NE) Transmission, Markets and Services Tariff (Tariff).

[2] The 11 compliance directives are as follows: (1) allow DERAs to participate directly in RTO/ISO markets and establish distributed energy resource aggregators as a type of market participant; (2) allow DER aggregators to register DERAs under one or more participation models that accommodate the physical and operational characteristics of the DERAs; (3) establish a minimum size requirement for

In response to *Order 2222*, ISO-NE proposes a package of market reforms that seek to accommodate the physical and operational characteristics of DERAs. Through seven participation models, ISO-NE proposes to allow DERAs to participate in the wholesale markets and provide five wholesale services[4] in the Energy and Ancillary Services Markets. The following table provides a high-level summary of each participation model.

Participation Model	High-Level Summary
Demand Response DERA (DRDERA)	• New model that accommodates demand reduction, energy injection, and energy withdrawal • Obligates DRDERAs to follow ISO-NE's Desired Dispatch Point, except when the distribution utility overrides the dispatch due to safety or reliability issues • Uses Demand Response Resource (DRR) baseline methodology for each distributed energy resource (DER)
Settlement Only DERA (SODERA)	• New model that accommodates energy injection and energy withdrawal • Non-dispatchable • No must offer requirements for SODERAs with Capacity Supply Obligations (CSOs)
Generator Asset	• Existing model expanded to accommodate energy injection
Binary Storage Facility	• Existing models expanded to accommodate energy injection, energy withdrawal, and regulation
Continuous Storage Facility	
DRR	• Existing model that is unchanged and accommodates energy injection
Alternative Technology Regulation Resource	• Existing model modified to meet Order No. 2222's size and locational requirements, which accommodates regulation

DERAs that does not exceed 100 kW; (4) address locational requirements for DERAs; (5) address distribution factors and bidding parameters for DERAs; (6) address information and data requirements for DERAs; (7) address metering and telemetry requirements for DERAs; (8) develop rules on coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities; (9) address modifications to the list of resources in a DERA; (10) address market participation agreements for DER aggregators; and (11) implement opt-in provision for distribution companies with less than or equal to 4 million MWhs in annual sales in the previous fiscal year.

[3] On May 24, 2021, the Commission accepted ISO-NE's motion for extension of time to February 2, 2022 to submit its compliance filing. *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 175 FERC ¶ 61,156 at P 5 (May 24, 2021).

[4] *See* Proposed § III.6.1(b).

Other proposed changes in the *Order 2222* compliance package that are intended to accommodate the physical and operational characteristics of DERAs and satisfy the Commission's directives include but are not limited to the following: an opt-in provision for distribution companies with less than or equal to 4 million MWh in annual sales; a four stage registration process to allow a distribution utility (DU) to confirm necessary capabilities to participate in a DERA; a minimum size of 100 kW for DERAs in all participation models; specification of locational requirements for each participation model; proposed conforming changes to existing metering and telemetry rules; and operational coordination rules intended to delineate the responsibilities related to the coordination of a DERA between a DER aggregator, the ISO, and the Host Utility.

In addition, ISO-NE proposes various revisions to the Forward Capacity Market (FCM) rules, including a new type of capacity resource—Distributed Energy Capacity Resource (DECR)—which is defined as an aggregation of one or more DERAs for participation in the FCM (as well in the Forward Reserve Market (FRM)).[5] These new rules include a package of revisions concerning the qualification and participation of DERAs in the FCM, including associated obligations (depending on the facility type).[6]

ISO-NE plans to request two effective dates for its package of *Order 2222* Changes. For the proposed rules impacting the FCM, the ISO plans to request an effective date during the fourth quarter of 2022, which will be in advance of the qualification process for the eighteenth Forward Capacity Auction.[7] For the remainder of the Tariff revisions that impact the Energy and Ancillary Services Markets, ISO-NE plans to request an effective date during the fourth quarter of 2026.[8]

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[5] *See, e.g.*, Proposed § III.13.1.4A (permitting qualified DECRs to participate in the Forward Capacity Auction). To review changes related to the FRM, see revisions throughout Section III.9. Additionally, the ISO proposes conforming Tariff revisions to ensure DECRs are considered in modeling the Installed Capacity Requirements. *See* Proposed §§ III.12.7.2, III.12.7.3, III.12.9.2.4.

[6] *See* Proposed § III.13.1.4A. Relatedly, the ISO's *Order 2222* Changes consists of conforming changes to the post-FCA rules, such as Critical Path Schedule monitoring, Proposed §§ III.13.1.4A.1.1.2.3, III.13.1.4A.1.1.2.4; III.13.3.1.2, III.13.3.2.2(a), (c) (showing conforming revisions), covering CSOs, Proposed § III.13.3.4, must offer requirements (except for DECRs with SODERAs), Proposed § III.13.6.1.7.1(a) (requiring DECRs with CSOs to offer into the energy markets); § III.13.6.1.7.1(b) (excluding DECRs comprising of SODERAs from the must offer requirement)), among others. Moreover, DECRs without CSOs must comply with the certain additional requirements. *See* Proposed § III.13.6.2.2.4. Also, the ISO's proposal includes conforming changes to the audit rules to establish the claimed capability values for generation and demand capacity resources. *See* §§ III.1.5.1.1–III.5.1.3, III.1.5.1.4; Proposed §§ III.1.5.1.3.2, III.1.5.2(d), III.1.7.13.

[7] Attachment B at 1.

[8] *Id.* at 1–2.

More detailed information on the *Order 2222* Changes is provided in ISO-NE's supporting materials included with this memorandum.[9]

STAKEHOLDER PROCESS TO DATE

Various aspects of the complete package of *Order 2222* Changes were considered separately by NEPOOL's three standing Technical Committees, as detailed below.

A. Markets Committee (MC) Review

Beginning in December 2020, the MC began discussing ISO-NE's approach to meeting the Commission's *Order 2222* directives. Throughout multiple meetings, the MC vetted ISO-NE's compliance proposal, as that proposal evolved over time to reflect input received in the stakeholder process, with a focus on the market reforms (i.e., Tariff revisions for the Energy and Ancillary Services Markets and the FCM), metering and telemetry requirements, the DER/DERA registration process, and operational coordination.

Ultimately, at its December 7–9, 2021 meeting, the MC considered ISO-NE's final, recommended proposal to comply with the Commission's *Order 2222* directives. Before voting on that proposal, the MC also considered seven amendments,[10] all of which failed to garner sufficient support to pass. All amendments considered were sponsored by AEE and are described in materials previously circulated to the MC. In addition to Attachment D, AEE's presentation to the MC can be accessed here. Following consideration of and voting on the AEE amendments, the MC then considered and recommended that the Participants Committee support ISO-NE's un-amended *Order 2222* compliance proposal, with a 71.11% Vote in favor.[11] The MC votes are reflected in Attachment C1.[12]

Consistent with past practice, Participants are reminded that procedural objections will not be raised by NEPOOL or ISO-NE at the FERC should any amendments that were already considered, but not supported at the MC, be advocated to the FERC notwithstanding that such amendments were not presented for a vote by the Participants Committee. With this understanding, we have been informed that AEE does ***not*** plan to seek a Participants Committee vote on any of the seven amendments it offered at the MC. We've also included at ISO-NE's

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[9] In addition, ISO-NE's presentation materials can be accessed via hyperlinks included in the voting memorandum included as Attachment B.

[10] The ISO did not support these amendments, as explained in its memorandum that can be accessed here. AEE's response to the ISO's memorandum can be reviewed here.

[11] The individual Sector votes at the MC on the ISO's *Order 2222* proposal were as follows: Generation – 16.7% in favor, 0% opposed, 1 abstention; Transmission – 16.7% in favor, 0% opposed, 0 abstentions; Supplier – 14.31% in favor, 2.39% opposed, 5 abstentions; Publicly Owned Entity – 16.7% in favor, 0% opposed, 0 abstentions; Alternative Resources – 6.7% in favor, 9.8% opposed, 2 abstentions; and End User – 0% in favor, 16.7% opposed, 1 abstention. Id. at 4–5.

[12] *See* Attachment C1 at 2–4.

request as Attachment E ISO-NE's response to AEE's Revised Amendment 1A (an Add-Back Baseline Methodology).

B. Transmission Committee (TC) Review

During multiple meetings in 2021, the TC considered *Order 2222*-related proposals and Tariff revisions. At its December 13, 2021, the TC reviewed proposed Tariff revisions to definitions in Section I of the Tariff and changes to the Small Generator Interconnection Procedures in Section II of the Tariff to exempt certain DERs from those procedures.[13] The TC unanimously supported the proposed revisions under its review, with three abstentions noted.[14] These revisions were subject to the 66.67% voting threshold, and this item would have been on the Consent Agenda but for its inclusion in the comprehensive compliance package.

C. Reliability Committee (RC) Review

During multiple meetings in 2021, the RC considered *Order 2222*-related proposals and Tariff revisions. At its December 14, 2021 meeting, the RC reviewed proposed Tariff revisions that included the following: (i) new and revised definitions in Section I of the Tariff; (ii) inclusion of DERAs in the auditing rules contained in Section III of the Tariff; and (iii) inclusion of DECR in the rules related to calculation of the Installed Capacity Requirement in Section III of the Tariff. The RC unanimously supported the proposed revisions under its review, with 10 abstentions.[15] This item would have been on the Consent Agenda but for its inclusion in the comprehensive compliance package.

PC CONSIDERATION OF *ORDER 2222* COMPLIANCE PROPOSAL

To be approved by the PC, the *Order 2222* Tariff revisions recommended by the MC and the RC require a 60% Vote and the proposed Tariff revisions recommended by the TC require a 66.67% Vote. The following forms of resolutions may be used for PC action on this matter, voted together or in any combination if desired by the PC and there are no objections, or voted individually if the PC elects to do so or one or more participants object to voting them together:

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[13] *See* Schedule 23, § 1.1.1.

[14] One abstention was recorded in the Alternative Resources Sector, the End User Sector, and the Supplier Sector. *See* Attachment C2 at 2.

[15] The abstentions were recorded in the following Sectors: 2 in the Generation Sector; 1 in the Transmission Sector; 5 in the Supplier; 2 in the AR Sector. *See* Attachment C3 at 6. Note, Attachment C3 indicates incorrectly that the RC voted to recommend revisions to Section III.9.5.3. The RC, however, did not vote those revisions. Rather, the MC reviewed and voted to recommend changes to Section III.9.5.3.

a. RESOLVED, that the Participants Committee supports revisions to Tariff § I.2.2 and Market Rule 1, as recommended by the Markets Committee and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

b. RESOLVED, that the Participants Committee supports revisions to Tariff § I.2.2 and § II, as recommended by the Transmission Committee and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

c. RESOLVED, that the Participants Committee supports revisions to Tariff §§ I.2.2, III.1.5, III.1.7.13, and III.12, as recommended by the Reliability Committee and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.

As noted above, we have been advised that AEE does not intend to ask the PC to vote any of AEE's amendments that were not supported by the MC. If anyone else wishes to offer any amendment(s) for PC consideration, please provide those amendments to NEPOOL Counsel (slombardi@daypitney.com or rgarza@daypitney.com) as soon as possible so that we can circulate them in time for member review and consideration before the January 6 meeting.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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

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

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 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 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 Resource or Seasonal Peak Demand Resource, a Distributed Energy Resource participating as part of 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.

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.

Baseline Deviation Offer is an offer by a Market Participant with a Demand Response Distributed Energy Resource Aggregation to reduce demand and/or inject additional energy.

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 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);~~ and~~ (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~~ each hour~~day~~); and (8) with respect to Baseline Deviation Offers administered by the ISO, a quantity of reduced demand or additional energy injection with a related price (Baseline Deviaiton Offers may contain multiple sets of quantity and price pairs 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.

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, ~~or~~ 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 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.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 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

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 or a Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation, 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 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.

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.

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 Distributed Energy Resource Aggregation Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Distributed Energy Resource Aggregation starts reducing demand and/or injecting energy.

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 Distributed Energy Resource Aggregation Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Distributed Energy Resource Aggregation can reduce demand and/or inject additional energy.

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.

Demand Response Distributed Energy Resource Aggregation Start-Up Time is the period of time between the time a Demand Response Distributed Energy Resource Aggregation starts reducing demand and/or injecting energy at the conclusion of the Demand Response Distributed Energy Resource Aggregation Notification Time and the time the resource can reach its Minimum Deviation 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, or Demand Response Distributed Energy Resource Aggregation dispatched by the ISO in accordance with the asset's Offer Data.

Deviation Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Distributed Energy Resource Aggregation is scheduled or dispatched in the New England Markets to reduce demand and/or provide additional energy injection.

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 or Demand Response Distributed Energy Resource Aggregations, 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 or Baseline Deviation 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, Demand Response Distirbuted Energy Resource Aggregation, 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 or Baseline Deviation 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.

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, and Existing Demand 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, Baseline Deviation 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 is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, Baseline Deviation Offer, or Demand Bid 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.

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.

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.

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 Demand Response Distributed Energy Resource Aggregation is a Distributed Energy Resource Aggregation that meets the following criteria: (i) Minimum Deviation Time does not exceed one hour; (ii) Minimum Time Between Deviations does not exceed one hour; (iii) Demand Response Distributed Energy Resource Aggregation Start-Up Time plus Demand Response Distributed Energy Resource Aggregation 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 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 Feasibility Study Agreement 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 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.

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

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.

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, is the entity authorized to submit Supply Offers, Demand Bids ~~or~~ ,Demand Reduction Offers or Baseline Deviaiton 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.

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.

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 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 Deviation is the maximum available baseline deviation, in MW, of a Demand Response Distributed Energy Resource Aggregation that a Market Participant offers to reduce demand and/or provide energy injection in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer

Maximum Deviation Capability is an estimate of the maximum demand reduction and/or energy injection that a Distributed Energy Resource comprising a Demand Response Distributed Energy Resource Aggregation can deliver, as measured at the Retail Delivery Point and/or Point-of-Interconnection

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 or that a Demand Response Distributed Energy Resource Aggregation 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.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand 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 Resources or Seasonal Peak Demand 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 or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand 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 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

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 Deviation is the minimum available baseline deviation, in MW, of a Demand Response Distributed Energy Resource Aggregation that a Market Participant offers to reduce demand and/or provide additional energy injection in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer.

Minimum Deviation Time is the minimum number of hours of baseline deviation at or above the Minimum Deviation for which the ISO must dispatch a Demand Response Distributed Energy Resource Aggregation to reduce demand and/or provide additional energy injection.

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 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 Time Between Deviations is the number of hours that must elapse after a Demand Response Distributed Energy Resource Aggregation has received a Dispatch Instruction to stop reducing demand and/or injecting additional energy before the Demand Response Distirbuted Energy Resource

Aggregation can achieve its Minimum Deviation after receiving a Dispatch Instruction to start reducing demand and/or injecting additional energy.

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 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

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 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 tenth 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.

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, ~~or~~ 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 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 during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand 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 described in Section III.13.1.4.1.1.1 of Market Rule 1.

New Distributed Energy Capacity Resource is a type of Demand 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 Demand Capacity Resource.

New Distributed Energy Capacity Resource Show of Interest Form is 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 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.

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, and Demand Response Distributed Energy Resource Aggregation operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, ~~and~~ Demand Response Resources and Demand Response Distributed Energy Resource Aggregations 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.

Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer or a Baseline Deviation 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 or a Fast Start Demand Response Distributed ~~Enenrgy~~Energy Resource Aggregation that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer or a Baseline Deviation 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 or a Fast Start Demand Response Distributed ~~Enenrgy~~Energy Resource Aggregation that has not been dispatched.

On-Peak Demand 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, Settlement Only Distributed Energy Resource Aggregation, the energy injection and/or energy withdrawal portion of a Demand Response Distributed Energy Resource Aggregation, 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.

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. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Distributed Energy Resource Aggregation for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Deviation Time does not exceed one hour; and (ii) Demand Response Distributed Energy Resource Aggregation Notification Time plus Demand Response Distributed Energy Resource Aggregation 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 n offer or bid may not be rationed in the Forward 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

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 or, revised Baseline Deviation Offers associated with Demand Response Distributed Energy Resource Aggregation.

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.

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, ~~or~~ a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

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 to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand 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.

Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources and Demand Response Distributed Energy Resource Aggregations are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 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.

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 Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, Demand Response Distributed Energy Resource Aggregation, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to potential referral under Section III.A.19.

III.1.7.19 Real-Time Reserve Designation.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

III.1.7.19.1 Eligibility.

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

III.1.7.19.2.3 Demand Response Resources and Demand Response Distributed Energy Resource Aggregations.

For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2. The Demand Response Distributed Energy Resource Aggregation Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Distributed Energy Resource Aggregation Ramp Rate and its audited Demand Response Distributed Energy Resource Aggregation Ramp Rate as described in Section III.1.5.2.

III.1.7.19.2.3.1 Dispatched.

(a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational~~demand reduction~~ level, within ten minutes given Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation). For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand

Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational ~~demand reduction~~ level, within ten minutes given its Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation).

(c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational ~~demand reduction~~ level, within thirty minutes given Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is not being dispatched that is not a Fast Start Demand Response Resource or Fast Start Demand Response Distributed Energy Resource Aggregation, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource or a Fast Start Demand Response Distributed Energy Resource Aggregation that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource or a Fast Start Demand Response Distributed Energy Resource Aggregation that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response

Resource's or Demand Response Distributed Energy Resource Aggregation's Offered CLAIM10, its CLAIM10, and its Maximum Reduction or Maximum Deviation.

(c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's or Demand Response Distributed Energy Resource Aggregation Offered CLAIM30, its CLAIM30, and its Maximum Reduction or Maximum Deviation, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource or Demand Response Distributed Energy Resource Aggregation pursuant to subsection (b) above.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, ~~or~~ , demand reduction levels or baseline deviation levels of Generator Assets, DARDs, ~~or~~ Demand Response Resources, or Demand Response Distributed Energy Resource Aggregations; change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers, ~~and Demand Response Resources~~ Demand Reduction Offers, and Baseline Deviation Offers above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers, Baseline Deviation Offers, and Demand Reduction Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each Generator Asset as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and

No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets, ~~or~~ Demand Response Resources, or Demand Response Distributed Energy Resource Aggregations with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers ~~or~~, Demand Reduction Offers or Baseline Deviation Offers.

III.1.10.1A Energy Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead Energy Market until 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead

Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} X — \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, Baseline Deviation Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, Baseline Deviation Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Baseline Deviation Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Baseline Deviation Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions, Minimum Deviations and Maximum Deviations are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer or Baseline Deviation Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions, Minimum Deviations and Maximum Deviations.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

(l) **Demand Response Distributed Energy Resource Aggregation Baseline Deviation Offers –** Market Participants selling into the New England Markets from Demand Response Distributed Energy Resource Aggregations may submit Baseline Deviation Offers for the supply of energy for the following Operating Day. A Baseline Deviation Offer shall constitute an offer to submit the Demand Response Distributed Energy Resource Aggregation to the ISO for commitment and dispatch in accordance with the terms of the Baseline Deviation Offer. Baseline Deviation Offers:

(i) Shall specify the Demand Response Distributed Energy Resource Aggregation and Blocks (price and baseline deviation quantity pairs) for each hour of the Operating Day. The prices and baseline deviation quantities may vary on an hourly basis.

(ii) Shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(viii) ——Shall not include average avoided peak transmission or distribution losses in the baseline deviation quantity.

(ix) May specify a Deviation Cost for each hour of the Operating Day, which may vary on an hourly basis.

(x) Shall specify a Minimum Deviation Time to be used for scheduling purposes that does not exceed 24 hours.

(xi) Shall specify a Maximum Deviation amount no greater than the sum of the Maximum Deviation Capabilities of the Demand Response Distributed Energy Resource Aggregation's operational Distributed Energy Resources.

(xii) Shall specify changes to the Maximum Deviation and Minimum Deviation from those submitted as part of the Demand Response Distributed Energy Resource Aggregation's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Distributed Energy Resource Aggregation.

(m) **Settlement Only Distributed Energy Resource Aggregation Supply Offers and/or Demand Bids –** Market Participants selling into the New England Markets from Settlement Only Distributed Energy Resource Aggregations and/or purchasing from the New England Markets for Settlement Only Distributed Energy Resource Aggregations may submit Supply Offers and /or Demand Bids, which will apply only to the Day-Ahead Energy Market. Such offers and/or bids must specify the Resource and

Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered and/or bid by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, Baseline Deviation Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs, ~~or~~ Demand Response Resources, or Demand Response Distributed Energy Resource Aggregations committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost, Deviation Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers ~~and~~, Demand Reduction Offers and Baseline Deviation Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation shall not be Self-Scheduled.

III.1.10.4 External Resources.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

(i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;

(ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, revisions to Baseline Deviation Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer- parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions. Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Baseline Deviation Offer parameters: price and baseline deviation quantity pairs, Deviation Cost, Demand Response Distributed Energy Resource Aggregation Start-Up Time, Demand Response Distributed Energy Resource Aggregation Notification Time, Minimum Deviation Time, and Minimum Time Between Deviations.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.10.10 Local Second Contingency Protection Resources

III.1.10.10.1 [Reserved.]

III.1.10.10.2 Day-Ahead and Real-Time Energy Market.

When establishing operating schedules, the ISO will select and identify Local Second Contingency Protection Resources on a not unduly discriminatory basis in accordance with the procedures defined in the ISO New England Manuals. Appendix A will determine which, if any, Supply Offers will be adjusted. The ISO will also record, in an auditable log, the reason the Resource was selected.

III.1.10.10.2.1 Special Constraint Resources.

When establishing operating schedules, at the request of a Transmission Owner or distribution company in order to maintain area reliability, the ISO will commit and dispatch Generator Assets to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or the ISO's operating procedures in accordance with the procedures defined in the ISO New England Manuals. The ISO will also record, in an auditable log, the designation of such a Generator Asset as a Special Constraint Resource and the name of the requesting Transmission Owner or distribution company. Any NCPC Charge associated with the Real-Time operation of the Special Constraint Resource is charged in accordance with the provisions of Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.1.10.10.3 [Reserved.]

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, Baseline Deviation Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Settlement Only Distributed Energy Resource Aggregations, and Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and solar Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a

Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) ~~Settlement Only Resources (including and Settlement Only Distributed Energy Resource Aggregations) are not eligible to be DNE Dispatchable Generators.~~

~~Wind and hydro Intermittent Power Resources, including Distributed Energy Resource Aggregations participating as a Generator Asset consisting entirely of any combination of wind and/or hydro Intermittent Power Resources, that are not Settlement Only Resources or Settlement Only Distributed Energy Resource Aggregations are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:~~

~~(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.~~

~~(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.~~

~~(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.~~

All wind and hydro Intermittent Power Resources are required to be DNE Dispatchable Generators, with the exception of wind and hydro Intermittent Power Resources with an injection capability of less than 5 MW that are connected through transmission facilities rated at less than 115 kV. A Distributed Energy Resource Aggregation is required to be a DNE Dispatchable Generator if it 1) consists entirely of wind or hydro Intermittent Power Resources or a combination of wind and hydro Intermittent Power Resources, and 2) participates as a Generator Asset.

(i) A Market Participant may elect to have a wind or hydro Intermittent Power Resource with an injection capability less than 5 MW that is connected through transmission facilities rated at less than 115 kV be a DNE Dispatchable Generator.

(ii) A Market Participant may elect to have a hydro Intermittent Power Resource or a Distributed Energy Resource Aggregation consisting entirely of hydro Intermittent Power Resources and participating as a Generator Asset be a DDP Dispatchable Resource if it is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range.

(f) The ISO may request that dual-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding electric output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of resources supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, ~~or~~ Interruption Cost, or Deviation Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time ~~or~~, Minimum Reduction Time or Minimum Deviation Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time ~~or~~, Minimum Reduction Time or Minimum Deviation Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed $2,000/MWh.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

(f) If the Rapid Response Pricing Asset is a Fast Start Demand Response Distributed Energy Resource Aggregation that has not satisfied its Minimum Deviation Time, its energy offer shall be increased by the Deviation Cost divided by the product of the Maximum Deviation and the Minimum Deviation Time.

(g) If the Rapid Response Pricing Asset is a Fast Start Demand Response Distributed Energy Resource Aggregation that has satisfied its Minimum Deviation Time, its energy offer shall not be increased.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, Demand Response Distributed Energy Resource Aggregations, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.7A(c); and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of Nodal Day-Ahead Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers, Baseline Deviation Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and supply. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available supply at the Generator Asset's Economic Maximum Limit, ~~and~~ demand reduction at the Demand Response Resource's Maximum Reduction, and baseline deviation at the Demand Response Distributed Energy Resource Aggregation's Maximum Deviation, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the External Transaction Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction Offer, Baseline Deviation Offers, or Increment Offer price cleared).

Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line Generator Assets, dispatched Demand Response Resources, dispatched Demand Response Distributed Energy Resource Aggregations, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line Generator Assets (excluding Settlement Only Resources), dispatched Demand Response Resources, dispatched Demand Response Distributed Energy Resource Aggregations, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide supply (including fixed External Transaction purchases) with all possible Generator Assets off line and with all remaining Generator Assets at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed Generator Assets down proportionately by ratio of Economic Minimum Limits, but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line Generator Assets (excluding Settlement Only Resources); and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all Generator Assets generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factors:

Real-Time Requirement	**Reserve Constraint Penalty Factor**
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	$1500/MWh
Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	$50/MWh

The Reserve Constraint Penalty Factors shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed for every five-minute interval, using the ISO’s Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website.

III.3 Accounting And Billing

III.3.1 Introduction.

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

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

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

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

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

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

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

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

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

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

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

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

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

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

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

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

(vi) **Real-Time Demand Reduction Obligation for Demand Response Distributed Energy Resource Aggregations** – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by a Demand Response Distributed Energy Resource Aggregation at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction provided by a Demand Response Distributed Energy Resource Aggregation are equal to the sum of the demand reductions produced by its Distributed Energy Resources, which is each Distributed Energy Resource's -performance as calculated pursuant to Section III.6.5(d), except such performance will not include any incremental energy injections for each- Distributed Energy Resource. Demand reductions are increased by average avoided peak distribution losses.

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

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

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **Real-Time Energy Market Deviations For Demand Response Resources and Demand Response Distributed Energy Resource Aggregations**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(b) and (c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(f) **Day-Ahead Energy Market Charge/Credit** – For each Market Participant for each settlement interval, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(g) **Real-Time Energy Market Charge/Credit Excluding Demand Response Resources and Demand Response Distributed Energy Resource Aggregations** **–** For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources and Demand Response Distributed Energy Resource Aggregations). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time

Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

~~(h)~~ **Real-Time Energy Market Charge/Credit For Demand Response Resources** – For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. ~~–~~The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

~~(i)~~(h)

(i~~j~~) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

(~~j~~j~~k~~) **Day-Ahead Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(k~~lk~~) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(~~l~~lm~~m~~) **Real-Time Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(o) and Emergency transactions as described under Section III.4.3(a).

(~~m~~mn~~n~~) **Real-Time Loss Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(l)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(~~n~~no~~o~~) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(~~o~~op~~p~~) **Inadvertent Energy Revenue** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p)

Inadvertent Energy Revenue Charges or Credits – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(o)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(q) **Real-Time Energy Market Charge/Credit For Demand Response Distributed Energy Resource Aggregations –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from, or sales to the Real-Time Energy Market associated with Demand Response Distributed Energy Resource Aggregations. The charge or credit shall be equal to the sum of (1) the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs; and (2) the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

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

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

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

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

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

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

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

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

(e) For a Demand Response Distributed Energy Resource Aggregation, the Metered Quantity For Settlement equals the sum of the demand reductions of each Distributed Energy Resource produced in response to a non-zero Dispatch Instruction, with the demand reduction for each Distributed Energy Resource calculated pursuant to Section III.6.5(d) except such performance will not include any incremental energy injections, and the hourly revenue quality meter data value apportioned over the five minute intervals in the hour in accordance with sub-section (f) below. If the Demand Response Distributed Energy Resource Aggregation provides five minute interval data, such data will be used in the Metered Quantity for Settlement calculation.

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

III.3.2.2 Metering and Communication.

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

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

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

(c) Additional Metering and Telemetry Requirements for Demand Response Assets and Distributed Energy Resources Associated with a Demand Response Distributed Energy Resource Aggregation

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource and for each Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation. Individual Distributed Energy Resources with a Maximum

Deviation Capability less than 10 kW and constituting a homogeneous population, as determined by the ISO, must aggregate their demand reduction and energy injection capability to achieve a Maximum Deviation Capability of at least 10 kW to report telemetry. The telemetry values shall measure: the real-time demand of Demand Response Assets as measured at their Retail Delivery Points; or the real-time demand and output of Distributed Energy Resources associated with a Demand Response Distributed Energy Resource Aggregation as measured at their Retail Delivery Points and/or points of interconnection and shall be reported to the ISO as an average value every five minutes. For a Demand Response Resource and a Demand Response Distributed Energy Resource Aggregation to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute~~. Telemetry values reported by Market Participants to the ISO~~, which shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

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

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets or Distributed Energy Resources be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset or Distributed Energy Resource shall be excluded from the Demand Response Resource or Demand Response Distributed Energy Resource Aggregation with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset or a Distributed Energy

Resource. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset or a Distributed Energy Resource available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled

Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets, ~~and~~ Demand Response Resources, and Demand Response Distributed Energy Resource Aggregations shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets, ~~and~~ Demand Response Resources, and Demand Response Distributed Energy Resource Aggregations shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and

III.6 Distributed Energy Resource Aggregations

A Distributed Energy Resource Aggregation may participate in the New England Markets as described below. A Distributed Energy Resource Aggregation must comply with all applicable registration, metering, and accounting rules in this section.

III.6.1 Participation Requirements

An aggregation of Distributed Energy Resources that satisfies the requirements of Section III.6 may participate in the New England Markets as a Distributed Energy Resource Aggregation. A Distributed Energy Resource Aggregation shall:

(a) comprise one or multiple facilities at one or more points of interconnection or Retail Delivery Points;

(b) have regulation capability, energy injection capability, or combined demand reduction capability and energy injection capability of at least 0.1 MW;

(c) be metered in accordance with Section III.6.4;

(d) be registered pursuant to Section III.6.7;

(e) participate in the wholesale markets as, and subject to all requirements applicable to a Generator Asset, Alternative Technology Regulation Resource, Continuous Storage Facility, Binary Storage Facility, Demand Response Resource, Settlement Only Distributed Energy Resource Aggregation, or Demand Response Distributed Energy Resource Aggregation;

   i. A Distributed Energy Resource Aggregation may participate as a Continuous Storage Facility or Binary Storage Facility to the extent the Distributed Energy Resource Aggregation as a whole is able to comply with all the requirements of a Continuous Storage Facility or Binary Storage Facility as stated in Sections III.1.10.6(b) and (c) respectively, regardless of whether any or all of the individual Distributed Energy Resources comprising the Distributed Energy Resource Aggregation meet the definition of Energy Storage Facility as defined in Section III.1.10.6.

(f) not be located in the metering domain of a Host Utility that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such Host Utility to host Distributed Energy Resource Aggregations; and

(g) meet the locational rules specified Section III.6.2.

III.6.2 Locational Requirements

A Distributed Energy Resource Aggregation must meet the following locational requirements.

(a) For a Distributed Energy Resource Aggregation participating as an Alternative Technology Regulation Resource or a Demand Response Resource, all associated Distributed Energy Resources shall be located in a single DRR Aggregation Zone.

(b) For a Distributed Energy Resource Aggregation participating as a Generator Asset, Binary Storage Facility, Continuous Storage Facility, Settlement Only Distributed Energy Resource Aggregation, or Demand Response Distributed Energy Resource Aggregation, all associated Distributed Energy Resources shall be located within both a single DRR Aggregation Zone and a single Host Utility metering domain.

(c) A Distributed Energy Resource Aggregation shall be settled at the DRR Aggregation Zone Node price, except where a single Distributed Energy Resource or a group of Distributed Energy Resources can inject greater than or equal to 5 MW at a single transmission Node, in which case, they are prohibited from aggregating with facilities at other Nodes, and will be settled at the single transmission Node price, not at the DRR Aggregation Zone Node price.

(d) The ISO shall determine that all of the Distributed Energy Resources in a Distributed Energy Resource Aggregation are located in the same DRR Aggregation Zone. For Distributed Energy Resources in a Distributed Energy Resource Aggregation with energy injection capability or demand reduction capability of 1 MW or greater, the ISO's determination shall be based on the Host Utility's evaluation of the transmission node that will serve the Distributed Energy Resource.

III.6.3 Distributed Energy Resource Size Requirements

Individual Distributed Energy Resources participating in a Distributed Energy Resource Aggregation must meet the following size requirements.

(a) A Distributed Energy Resource with overall injection capability of 5 MW or greater that participates in the New England Markets through a Distributed Energy Resource Aggregation must participate as a single facility Distributed Energy Resource Aggregation and be modeled and priced at a single transmission Node.

(b) If a group of Distributed Energy Resources can inject greater than or equal to 5 MW at a single transmission Node, this group of Distributed Energy Resources cannot aggregate with facilities at other Nodes. This group of Distributed Energy Resources may participate as a Distributed Energy Resource Aggregation that is modeled and priced at the single transmission Node.

(c) For a Distributed Energy Resource Aggregation with multiple Distributed Energy Resources participating as a Generator Asset, Binary Storage Facility, or Continuous Storage Facility, each participating Distributed Energy Resource in the aggregation must have injection capability of less than 5 MW.

(d) For a Distributed Energy Resource Aggregation participating as a Demand Response Resource, the size requirements in Section III.8 shall apply.

(e) For a Distributed Energy Resource Aggregation participating as a Demand Response Distributed Energy Resource Aggregation, the size requirements in III.6.5(b) shall apply.

(f) For a Distributed Energy Resource Aggregation participating as a Settlement Only Distributed Energy Resource Aggregation, the size requirements in III.6.6 shall apply.

(g) For a Distributed Energy Resource Aggregation participating as an ATRR, the size requirements in Section III.14 shall apply.

III.6.4 Metering and Telemetry Requirements

Distributed Energy Resource Aggregations must meet the following metering and telemetry requirements.

(a) Distributed Energy Resource Aggregations participating as a Generator Asset, Binary Storage Facility, or Continuous Storage Facility, must comply with the metering and telemetry requirements in Sections III.3.2.1 and III.3.2.2.

(b) Distributed Energy Resource Aggregations participating as an Alternative Technology Regulation Resource must comply with the metering and telemetry requirements in Section III.14.2.

(c) Distributed Energy Resource Aggregations participating as Demand Response Resources or Demand Response Distributed Energy Resource Aggregations must comply with the metering and telemetry requirements in Section III.3.2.2. The metering and communication equipment associated with each participating Distributed Energy Resource must meet the requirements in Section III.3.2.2 and ISO New England Operating Procedure No. 18, Metering and Telemetering.

(d) Metering for each Distributed Energy Resource participating in a Distributed Energy Resource Aggregation shall meet all applicable state and Host Utility requirements and be located at, a Retail Delivery Point, or point of interconnection as applicable. A Distributed Energy Resource's point of interconnection may be located behind a Retail Delivery Point to the extent that the pertinent Host Participant Assigned Meter Reader can accommodate such a configuration.

(e) If a Distributed Energy Resource's point of interconnection is located behind a Retail Delivery Point it shall be reported such that its output or load does not impact the load reported for the Retail Delivery Point. A Distributed Energy Resource Aggregator may only propose a metering location behind a Retail Delivery Point if the Host Utility confirms in writing to the Distributed Energy Resource Aggregator that the appropriate metering and associated system upgrades are in place to support load and generation reporting and any necessary reconstitution. Proof of such written confirmation from the Host Utility should be provided as part of the attestation as referenced in Section III.6.7(c)(i)2.

(f) The Distributed Energy Resource Aggregator shall retain metering data for each participating Distributed Energy Resource for a period of six years for purposes of auditing.

III.6.5 Additional Requirements For Demand Response Distributed Energy Resource Aggregations

In addition to the rules applicable to all Distributed Energy Resource Aggregations, the following rules apply to Demand Response Distributed Energy Resource Aggregations. A Demand Response Distributed Energy Resource Aggregation allows Distributed Energy Resources with demand reduction capability, Distributed Energy Resources with energy injection capability and Distributed Energy Resources with energy withdrawal capability to participate in the wholesale markets as a single resource.

(a) A Demand Response Distributed Energy Resource Aggregation must include Distributed Energy Resources with both demand reduction capability and energy injection capability and may include Distributed Energy Resources with energy withdrawal capability.

(b) Size Requirements. Individual Distributed Energy Resources participating in a Demand Response Distributed Energy Resource Aggregation must meet the following size requirements:

(i) An individual Distributed Energy Resource with a Maximum Deviation Capability or ability to inject greater than or equal to 5 MW may not be registered as a component of a Demand Response Distributed Energy Resource Aggregation if its maximum energy injection capability is greater than its Maximum Facility Load. Such a Distributed Energy Resource must be the only facility associated with a Demand Response Distributed Energy Resource Aggregation and shall be modeled and priced at the transmission Node.

(ii) An individual Distributed Energy Resource with a Maximum Deviation Capability and maximum energy injection capability less than 5 MW may participate in a Demand Response Distributed Energy Resource Aggregation with other facilities located within the same DRR Aggregation Zone and metering domain. Such a Demand Response Distributed Energy Resource Aggregation shall be modeled and priced at the DRR Aggregation Zone Node.

(iii) If a group of Distributed Energy Resources has a Maximum Deviation Capability of, or can inject greater than or equal to 5 MW at a single transmission Node, this group of Distributed Energy Resources cannot aggregate with facilities at another Node. This group of Distributed Energy Resources may participate as a Demand Response

Distributed Energy Resource Aggregation that is modeled and priced at the single transmission Node.

(c) Baseline, Offer Requirements and Related Threshold Requirements. For each Demand Response Distributed Energy Resource Aggregation:

(i) The ISO shall establish a baseline for each Distributed Energy Resource in the same manner as prescribed for a Demand Response Asset in Section III.8.2.

(ii) The Distributed Energy Resource Aggregator shall submit a Baseline Deviation Offer pursuant to Section III.1.10.1A(l) that reflects the aggregation's ability to deviate from its normal operational level.

(iii) Its Baseline Deviation Offer shall be subject to the Demand Reduction Threshold calculated pursuant to Section III.1.10.1A(f)

(iv) It may inject energy outside of dispatch intervals, which will be settled consistent with the rules for Settlement Only Resources.

(v) It may withdraw energy outside of dispatch intervals, which will be settled consistent with the rules for Load Assets.

(d) Performance Calculation. The ISO shall calculate a Demand Response Distributed Energy Resource Aggregation's performance when it is dispatched. Such performance shall be the sum of the performance of each constituent Distributed Energy Resource. The ISO shall calculate the performance of each Distributed Energy Resource in the same manner as prescribed for a Demand Response Asset in Section III.8.4.

III.6.6 Additional Requirements For Settlement Only Distributed Energy Resource Aggregations

A Settlement Only Distributed Energy Resource Aggregation is a Distributed Energy Resource Aggregation that may include Distributed Energy Resources with non-dispatchable energy injection capability and/or non-dispatchable energy withdrawal capability. A Settlement Only Distributed Energy Resource Aggregation shall comply with all Market Rules applicable to Settlement Only Resources and the following additional rules.

(a) A Settlement Only Distributed Energy Resource Aggregation may submit a Supply Offer and/or Demand Bid in the Day-Ahead Energy Market in accordance with the requirements in Section III.1.10.1A(m).

(b) There is no maximum size limit for a Settlement Only Distributed Energy Resource Aggregation, provided each constituent Distributed Energy Resource would otherwise be eligible to register as a Settlement Only Resource pursuant to OP-14.

III.6.7 Coordination of Registration and Modification

The process of coordinating the registration and activation for participation in the New England Markets between the ISO, the Distributed Energy Resource Aggregator and the Host Utility, regardless of the participation model chosen, includes four stages: 1) Initial Notification of Intent to Register a Distributed Energy Resource Aggregation; 2) Eligibility Confirmation; 3) Registration and Activation; and 4) Updates to an Existing Distributed Energy Resource Aggregation Registration. Completion of the Distributed Energy Resource Aggregation registration process requires that the Distributed Energy Resource Aggregator, Host Utility (or its agent) and ISO meet the following requirements for each stage.

(a) Initial Notification

(i) Distributed Energy Resource Aggregator shall make an initial notification to both the ISO and the Host Utility (or the Host Utility's Agent) of its intent to register a Distributed Energy Resource Aggregation. Such notification shall include the information required by applicable ISO New England Manuals, including, but not limited to: the retail billing account(s) of the individual Distributed Energy Resource(s) participating in the aggregation, information regarding the location, anticipated size, technologies to be included, ~~and~~ markets in which participation is planned, information required by the Host Utility Tariff and Terms and Conditions, and the participation model that the Distributed Energy Resource Aggregation intends to use for the Distributed Energy Resource Aggregation; interconnection agreement(s) for each participating Distributed Energy Resource, if required under state law; and an anticipated date to begin energy and/or ancillary service market participation.

(b) Eligibility Confirmation. The Host Utility (or its agent) shall review each Distributed Energy Resource's eligibility to participate in a Distributed Energy Resource Aggregation and confirm the Aggregator's eligibility to register the proposed Distributed Energy Resource Aggregation in the manner established in this subsection. The time period for such review shall begin when the Host Utility or its agent receives the initial notification from the Distributed Energy Resource Aggregator and shall not exceed 60 calendar days. The Host Utility (or its agent) shall provide written notice to the ISO and the Distributed Energy Resource Aggregator of the eligibility confirmation, in accordance with the eligibility criteria described in this subsection. The eligibility confirmation shall be provided by the Host Utility or its agent to the appropriate relevant electric retail regulatory authority upon request. If the ISO does not receive timely notification from the Host Utility or its agent, then the ISO will assume that the operation of the

Distributed Energy Resource will not have a material reliability and/or safety impact on the applicable distribution system and shall be eligible to register with the proposed Distributed Energy Resource Aggregation.

(c)

(i) In order to verify eligibility, the Host Utility or its agent shall, to the extent practicable based on the representations made by the Distributed Energy Resource Aggregator in the initial notification or through information otherwise in the Host Utility's (or its agent's) possession:

1. confirm that each Distributed Energy Resource's metered net consumption or injection of energy will not be included in another Load Asset (if the Distributed Energy Resource Aggregation includes load) or Generator Asset.

2. confirm, based on the representations made by the Distributed Energy Resource Aggregator that no individual ~~no~~ Distributed Energy Resource (as identified by any retail billing account record of the Host Utility) is participating in a retail program that prohibits it from providing the requested service in New England Markets.

3. confirm based on the representations made by the Distributed Energy Resource Aggregator that the proposed operation of each Distributed Energy Resource as part of the proposed Distributed Energy Resource Aggregation has appropriate interconnection and/or operating agreements in place with the Host Utility applicable to its technology and size.

4. determine whether the Distributed Energy Resource Aggregation ~~will~~ may pose significant risks, or may require further study to evaluate the potential significance of the risks, to the safe and reliable operation of the distribution system based on analysis of relevant risk factors, such as overloads, voltage, stability, short circuit interrupting capability, flicker, equipment operation frequency coordination, and contingency analysis.

5. consider whether the proposed operation of any Distributed Energy Resource participating in a proposed Distributed Energy Resource Aggregation, or the Distributed Energy Resource Aggregation as a whole, imposes a need for distribution system upgrades to avoid safety and reliability impacts and, if so, confirm that the Distributed Energy Resource Aggregator has self-certified that such upgrades have been completed or will be completed before the Distributed Energy Resource desired activation date.

6. confirm that all the Distributed Energy Resources are within the Host Utility's metering domain~~,~~.

7. confirm that the net injection and consumption capability of the Distributed Energy Resources participating in the Distributed Energy Resource Aggregation do not exceed the capabilities as authorized by any associated interconnection agreements.

(ii) For a Distributed Energy Resource Aggregation connecting to a Host Utility that served less than or equal to 4 million MWh of load in the previous fiscal year, the Host Utility (or its agent) shall confirm that the Host Utility has opted to allow Distributed Energy Resource Aggregations to participate in wholesale markets.

(iii) If the Host Utility (or its agent) confirms that the Distributed Energy Resource Aggregation is eligible in full or in part, the Distributed Energy Resource Aggregator shall provide a finalized list to the ISO and the Host Utility (or its agent) of the Distributed Energy Resources that have been found to be eligible for participation in the Distributed Energy Resource Aggregation, the participation model that the Distributed Energy Resource Aggregation intends to use, and the New England Markets in which the Distributed Energy Resource Aggregation plans to participate.

(iv) If the Host Utility (or its agent) confirms that the Distributed Energy Resource Aggregation is not eligible in full or in part, the Host Utility (or its agent) shall provide a written notice to the ISO and the Distributed Energy Resource Aggregator describing the eligibility criteria that were not met for any Distributed Energy Resource.

(v) In the event the Host Utility (or its agent) confirms that a Distributed Energy Resource Aggregation has not fulfilled the requirements of this subsection to be activated for participation in the New England Markets, and the Distributed Energy Resource Aggregator disputes this confirmation, the Distributed Energy Resource Aggregation may seek dispute resolution in a process established by the relevant electric retail regulatory authority, if available, or if not available, in accordance with Section I.6 of the Tariff. Any disputes regarding whether the Distributed Energy Resource Aggregator has appropriate contractual rights to offer a Distributed Energy Resource as part of a Distributed Energy Resource Aggregation in the New England Markets shall be resolved in the manner established in such contract, or otherwise by a court of competent jurisdiction as applicable.

(vi) In the event the ISO determines that a Distributed Energy Resource Aggregation is ineligible to participate in the New England Markets for reasons that are not related to the

Host Utility (or its agent's) review, the Distributed Energy Resource Aggregator may seek resolution in accordance with Section I.6 of the Tariff.

(d) Registration/Activation

(i) In order to complete the registration and activation of a DERA the DER Aggregator shall:

1. Provide both the ISO and the Host Utility (or its agent) with a desired activation date, once eligibility has been confirmed.
2. Provide the information required by applicable ISO New England Manuals, as well as 1) an attestation, in a form prescribed by the ISO, stating that all participating Distributed Energy Resources are fully compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any relevant electric retail regulatory authority, including the terms of any state interconnection agreements, and that the Distributed Energy Resource Aggregator retains the rights to offer the individual Distributed Energy Resource in New England Markets; and 2) confirmation in writing to the ISO and Host Utility (or its agent) that all Distributed Energy Resources in the Distributed Energy Resource Aggregation have been deemed eligible under subsection (b) of this section; and that the required metering and telemetry is in place, to meet the ISO requirements for participation in the planned markets.

(ii) Prior to activation, the ISO must receive confirmation from the Host Utility (or its agent) that the Distributed Energy Resource Aggregator has met all applicable requirements with respect to metering and telemetry to enable the Host Utility or Assigned Meter Reader to include the Distributed Energy Resource Aggregation's metering in the appropriate Load Asset and metering domain.

(iii) Distributed Energy Resources participating in a Distributed Energy Resource Aggregation may provide both retail and wholesale services to the extent such dual participation is allowed under state law or regulation, the Distributed Energy Resource Aggregator retains the rights to such services from the owner of the Distributed Energy Resource, and so long as the Distributed Energy Resource Aggregation is able to comply with all requirements under the ISO Tariff.

(e) Updates/Modifications to Existing Distributed Energy Resource Aggregation

(i) When a Distributed Energy Resource is added to or removed from an existing Distributed Energy Resource Aggregation, the Distributed Energy Resource Aggregator shall update the Distributed Energy Resource Aggregation's registration information. Such updates shall include: the information required by applicable ISO New England Manuals, sufficient to confirm that any newly added Distributed Energy Resources are eligible for participation; notification to the ISO and the Host Utility (or its agent) -by the Distributed Energy Resource Aggregator of any Distributed Energy Resource being removed from the aggregation; verification that any required metering is in place for the reconfigured Distributed Energy Resource Aggregation; and an updated list of participating Distributed Energy Resources and the updated performance capabilities of the aggregation to be reflected in the aggregation's registration information.

(ii) The Host Utility (or its agent) shall have up to 60 days to confirm eligibility and review any impacts associated with Distributed Energy Resources that the Distributed Energy Resource Aggregator is proposing to add to or remove from an existing Distributed Energy Resource Aggregation.

(iii) Changes to the Distributed Energy Resources participating in a Distributed Energy Resource Aggregation shall become effective in the manner stated in Manual M-RPA.

III.6.8 Operational Coordination

The responsibilities related to the coordination of operations of a Distributed Energy Resource Aggregation between the Distributed Energy Resource Aggregator, the ISO, and the Host Utility are as follows:

(a) The Distributed Energy Resource Aggregator shall: operate Distributed Energy Resources in a manner consistent with the limitations and operating orders established by the Host Utility; confer with the applicable Host Utility on a periodic basis to ensure available distribution service exists to operate its Distributed Energy Resources consistent with its New England Market obligations; submit outage requests for each Distributed Energy Resource Aggregation as necessary and to the extent required by ISO Operating Documents, in order to reflect known distribution system constraints or limitations that reduce the overall capability of the Distributed Energy Resource Aggregation; as required, account for any known limitations of the distribution system to which the Distributed Energy Resources are connected in its Offer Data for the Distributed Energy Resource Aggregation including restrictions that have been placed directly on the Distributed Energy Resource Aggregation by the Host Utility in the form of an override of an ISO Dispatch Instruction; determine a

Distributed Energy Resource-level operating plan to be provided to the Host Utility for analysis, subject to the requirements of each Host Utility.

(b) The Distributed Energy Resource Aggregator shall have a Designated Entity or Demand Designated Entity, as applicable, for each of its Distributed Energy Resource Aggregations in accordance with the provisions set forth in ISO Operating Procedures. Designated Entities and Demand Designated Entities for Distributed Energy Resource Aggregations shall comply with the requirements of each Host Utility and/or relevant electric retail regulatory authority as applicable.

(c) In the event that the Host Utility identifies conditions on the distribution system that result in actual or anticipated limitations on the operation of individual Distributed Energy Resources or Distributed Energy Resource Aggregations, the Host Utility shall notify the relevant Distributed Energy Resource Aggregator as soon as practicable.

(d) The Host Utility may temporarily override the ISO's dispatch of a Distributed Energy Resource Aggregation. Such override shall only occur in circumstances where needed to maintain the reliable and safe operation of the distribution system.

(e) Failure of a Distributed Energy Resource Aggregation to follow an ISO Dispatch Instruction due to a Host Utility override does not excuse the Distributed Energy Resource Aggregator from any applicable charges (including any penalties) to which the Distributed Energy Resource Aggregator is subject under the terms of the Tariff.

(f) The ISO shall coordinate with the applicable Host Utility to avoid conflicting operational directives, which may include but is not limited to sharing Day-Ahead Energy Market results and Real-Time Dispatch Instructions.

~~III.6 Local Second Contingency Protection Resources~~

~~III.6.1 [Reserved.]~~

~~III.6.2 Day-Ahead and Real-Time Energy Market.~~

~~When establishing operating schedules, the ISO will select and identify Local Second Contingency Protection Resources on a not unduly discriminatory basis in accordance with the procedures defined in the ISO New England Manuals. Appendix A will determine which, if any, Supply Offers will be adjusted. The ISO will also record, in an auditable log, the reason the Resource was selected.~~

~~III.6.2.1 Special Constraint Resources~~~~.~~

~~When establishing operating schedules, at the request of a Transmission Owner or distribution company in order to maintain area reliability, the ISO will commit and dispatch Generator Assets to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or the ISO's operating procedures in accordance with the procedures defined in the ISO New England Manuals. The ISO will also record, in an auditable log, the designation of such a Generator Asset as a Special Constraint Resource and the name of the requesting Transmission Owner or distribution company. Any NCPC Charge associated with the Real-Time operation of the Special Constraint Resource is charged in accordance with the provisions of Schedule 19 of Section II of the Transmission, Markets and Services Tariff.~~

~~III.6.3 [Reserved.]~~

there is insufficient data to calculate the Demand Response Baseline; and in any interval in which the Market Participant fails to comply with the Demand Response Asset metering and communication requirements in Section III.3.2.2 or ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(b) Notwithstanding the foregoing, a Demand Response Asset's demand reduction for purposes of determining Actual Capacity Provided during a Capacity Scarcity Condition shall be calculated pursuant to Section III.13.7.2.2.

III.9 Forward Reserve Market

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

III.9.1 Forward Reserve Market Timing.

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

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

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

III.9.2 Forward Reserve Requirements.

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

III.9.2.1 System Forward Reserve Requirements.

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

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

(ii) The minimum forward ten-minute reserve requirement described in subsection (i) will be increased if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The increase shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

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

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

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

III.9.2.2 Zonal Forward Reserve Requirements.

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

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

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

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

(a) Change in Configuration of the Transmission System

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

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

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

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

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

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

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted.

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

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

for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the Forward Reserve Clearing Prices and Forward Reserve Obligations and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations, or: (2) in the event that the ISO is unable to calculate and post final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance which will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

(a) Prior to the close of the Re-Offer Period for each Operating Day of the Forward Reserve Procurement Period, Market Participants must convert their Forward Reserve Obligations into Resource-specific obligations by assigning Forward Reserve MWs to specific eligible Forward Reserve Resources, in accordance with procedures set forth in the ISO New England Manuals. The assignment of Forward Reserve MWs to a Forward Reserve Resource must be performed by the Lead Market Participant for the Resource.

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a Generator Asset or a Dispatchable Asset Related Demand, or be the Lead Market Participant of a Forward Reserve Resource that is a Demand Response Resource, and Demand Response Distributed Energy Resource Aggregations in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

(a) Forward Reserve Resources are Resources that have been assigned by Market Participants to meet their Forward Reserve Obligations. To be eligible as a Forward Reserve Resource, a Resource must satisfy the following criteria:

(i) If the Generator Asset is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation -which has not been dispatched, it must be a Fast Start Demand Response Resource or a Fast Start Demand Response Distributed Energy Resource Aggregation and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(iii) If the Generator Asset or Dispatchable Asset Related Demand is expected to be on-line, or, for a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

(iv) Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;

(v) The Resource must be capable of receiving and responding to electronic Dispatch Instructions;

(vi) The Resource must follow Dispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Operating Reserve as specified in ISO New England Operating Procedure No. 14;

(vii) The portion of the Resource that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.1.7.19;

(viii) The portion of the Resource to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.

(b) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Resource CLAIM10 and CLAIM30.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30.

1. The CLAIM10 or CLAIM30 of a Resource shall equal:
    (a) the maximum output or demand-reduction level reached, including the level reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current Forward Reserve Procurement Period or the preceding like-season Forward Reserve Procurement Period, subject to the conditions in Section III.9.5.3.1.2 below;

    (b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.

2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:
    (a) The value shall not include any dispatch in which the Resource becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;

    (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.

3. A Resource's CLAIM10 shall be no greater than the Resource's CLAIM30.

4. The CLAIM10 or CLAIM30 of a Resource shall be calculated and distributed to the Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.

5. The values described in Sections III.9.5.3.1(1)(a) and (b) shall not include any dispatch where:

a) The Resource is dispatched at the request of the Market Participant or Designated Entity and the dispatch was not related to an Establish Claimed Capability Audit request made pursuant to Section III.1.5.1.2, a Seasonal DR Audit request made pursuant to Section III.1.5.1.3.1, or a CLAIM10 or CLAIM30 audit request made pursuant to Section III.9.5.3.2;

b) The prices associated with the Blocks to Economic Min for the Real-Time dispatch of the Resource are less than or equal to zero;

c) For Generator Assets, the ratio of (i) the sum of the applicable Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min used in the Real-Time dispatch of the Resource in the Operating Day to (ii) the maximum total hourly Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min submitted for the Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold value determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to (i) differences in cost between Gas Days, or (ii) a reduction in the cost of gas within the Operating Day reflected in the offers submitted for the Resource during the remainder of the Operating Day, then the Market Participant may request that the ISO evaluate whether the dispatch may be included; or

d) For Demand Response Resources, the ratio of (i) the sum of the applicable Interruption Cost and the demand reduction cost to Minimum Reduction used in the Real-Time dispatch of the Demand Response Resource in the Operating Day to (ii) the maximum total hourly Interruption Cost and demand reduction cost to Minimum Reduction submitted for the Demand Response Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.

e) For Demand Response Distributed Energy Resource Aggregations, the ratio of (i) the sum of the applicable Deviation Cost and the baseline deviation cost to Minimum Deviation used in the Real-Time dispatch of the Demand Response Distributed Energy Resource Aggregation in the Operating Day to (ii) the maximum total hourly Deviation Cost and baseline deviation cost to Minimum Deviation submitted for the Demand Response Distributed Energy Resource

Aggregation for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.

6. A Demand Response Resource's CLAIM10 and CLAIM30 on June 1, 2018 and October 1, 2018 shall be as follows:
   a) On June 1, 2018 and October 1, 2018, the CLAIM10 of a Demand Response Resource shall equal zero.
   b) On June 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource" (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Summer Capability Period beginning June 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) July 2, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before June 27, 2018, its CLAIM30 shall be set to zero on July 2, 2018.
   c) On October 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource" (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Winter Capability Period beginning October 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) October 29, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before October 24, 2018, its CLAIM30 shall be set to zero on October 29, 2018.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A Market Participant may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO's annual maintenance scheduling process or during a scheduled curtailment pursuant to Section III.8.3, a Market Participant may submit a restoration plan to the ISO to restore the Resource's CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource's inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the increase of the Resource's CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the Market Participant shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources that are Generator Assets or Dispatchable Asset Related Demand for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day, even if the Supply Offers do not clear the Day-Ahead Energy Market, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are Demand Response Resources or Demand Response Distributed Energy Resource Aggregations for an hour by offering the capability into the Real-Time Energy Market by submitting -Demand Reduction Offers or Baseline Deviation Offers no later than the close of the Re-Offer Period at or above the Forward Reserve Threshold Price for the Operating Day.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

The formula for determining the Forward Reserve Threshold Prices shall be fixed for the duration of the Forward Reserve Procurement Period. The ISO will reevaluate the Forward Reserve Threshold Price level for successive Forward Reserve Auctions on the basis of experience, expected operating conditions and other relevant information.

Forward Reserve Threshold Price: is calculated as the Forward Reserve Heat Rate multiplied by the daily Forward Reserve Fuel Index.

Forward Reserve Heat Rate: shall be fixed for the duration of the Forward Reserve Procurement Period and announced in the announcement for the Forward Reserve Auction. New Forward Reserve Heat Rates shall be specified for successive auctions, and shall be calculated as follows:

(a) For each of the five most recently completed Summer Capability Periods or Winter Capability Periods (as applicable to the Forward Reserve Procurement Period), for each on-peak hour, the ISO shall calculate an implied heat rate, expressed in Btu/kWh, by dividing the hour's Hub Price by the lower of the applicable natural gas or heating oil price index.

(b) All resulting hourly implied heat rates above 45,000 Btu/kWh shall be excluded, and the remaining values shall be listed in order from high to low.

(c) The Forward Reserve Heat Rate for the Forward Reserve Procurement Period shall be the lesser of: (i) the heat rate that occurs at the 97.5th percentile of the list described in subsection (b) above; or (ii) 21,999 Btu/kWh.

Forward Reserve Fuel Index: is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.13.4, 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 Participant in accordance with Section III.A.3. 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.

III.9.6.4 Forward Reserve Qualifying Megawatts.

(a) Generator Assets and Dispatchable Asset Related Demands – Qualifying megawatts for Generator Assets and Dispatchable Asset Related Demands are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

Off-line qualifying megawatts. Off-line qualifying megawatts are the amount of a Generator Asset's capability equal to or below the Economic Maximum Limit for an off-line Forward Reserve Resource offered at or above the Forward Reserve Threshold Price. The Generator Asset must satisfy this requirement in the Real-Time Energy Market. In the case of off-line Forward Reserve Resources, the calculation for Forward Reserve Qualifying Megawatts shall include both the energy Supply Offer and a pro-rated amount of Start-Up Fees and No-Load Fees as defined below. The off-line qualifying megawatts of a Dispatchable Asset Related Demand are zero.

An off-line Forward Reserve Resource must offer its capability so that the following holds:

$$\frac{StartUp}{EcoMax \times 1\ hour} + \frac{NoLoad}{EcoMax} + Energy\ Offer_i \geq ForwardReserveThresholdPrice$$

where:

StartUp	= cold Start-Up Fee.
NoLoad	= No-Load Fee.
$EnergyOffer_i$	= the Energy offer price for
Energy offer block $_i$.	
EcoMax	= Economic Maximum Limit.

<u>On-line qualifying megawatts</u>: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line Generator Asset or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the applicable Forward Reserve Threshold Price for a Dispatchable Asset Related Demand. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line Generator Asset that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

(b) **<u>Demand Response Resources and Demand Response Distributed Energy Resource Aggregations</u>** – Qualifying megawatts for Demand Response Resources or Demand Response Distributed Energy Resource Aggregations supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have not been dispatched and Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

<u>Qualifying megawatts for a Demand Response Distributed Energy Resource Aggregation that has not been dispatched</u>: is the amount of capability equal to or below the Maximum Deviation for the Demand Response Distributed Energy Resource Aggregation offered at or above the Forward Reserve Threshold Price. The Demand Response Distributed Energy Resource Aggregation must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Distributed Energy Resource Aggregations that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Baseline Deviation Offer price and a pro-rated amount of the Deviation Cost as defined below.

A Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation that has not been dispatched must offer its capability so that the following holds:

$$\frac{Interruption\ Cost\ or\ Deviation\ Cost}{MaxRed\ or\ MaxDev} + Energy\ Offer_i \geq Forward\ Reserve\ Threshold\ Price$$

where:

Interruption Cost = Interruption Cost.
Deviation Cost =Deviation Cost
EnergyOffer$_i$ = Demand Reduction Offer or Baseline Deviation price for Energy offer block $_i$.
Max-Red = Maximum Reduction x 1 hour.
MaxDev = Maximum Deviation x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

Qualifying megawatts for a Demand Response Distributed Energy Resource Aggregation which has been dispatched: is the capability that is less than or equal to the Maximum Deviation and greater than the Minimum Deviation that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Distributed Energy Resource Aggregation. The Demand Response Distributed Energy Resource Aggregation must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Distributed Energy Resource Aggregation which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

(a) Forward Reserve Delivered Megawatts for an off-line Generator Asset are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount, in MW, of Forward Reserve that the off-line Generator Asset can provide, based upon CLAIM10 and CLAIM30 provided in the Generator Asset's Real-Time Supply Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(b) Forward Reserve Delivered Megawatts for an on-line Generator Asset are calculated in megawatts for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the on-line Generator Asset, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(c) Forward Reserve Delivered Megawatts for an on-line Dispatchable Asset Related Demand are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2),

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(d) A Forward Reserve Resource's hourly Forward Reserve Delivered Megawatts for each Reserve Zone is calculated as the sum of the Market Participant's Resource specific hourly Forward Reserve Delivered Megawatts for each Reserve Zone.

(e) Resource specific Forward Reserve Delivered Megawatts for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in that Reserve Zone. Any surplus Forward Reserve Delivered Megawatts for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in that Reserve Zone. Forward Reserve Delivered Megawatts remaining within that Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone have been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided that the Forward Reserve Delivered Megawatts can be delivered to the other Reserve Zones.

(f) Forward Reserve Delivered Megawatts for a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 provided in the Demand Response Resource's Demand Reduction Offer or in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate of that Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses, limited as described below.

(i) The ISO will assume that Demand Response Resources first reduce their net load from the electricity system before providing additional Net Supply.

(ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Resource can reduce from the electric system based on the net load of its constituent Demand Response Assets.

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the remaining Net Supply Capability of the Demand Response Resource.

(i) In determining Forward Reserve Delivered Megawatts for a Demand Response Distributed Energy Resource Aggregation the portion of the Forward Reserve Delivered Megawatts not associated with energy injection shall be increased by average avoided peak distribution losses, limited as described below.

(i) The ISO will assume that Demand Response Distributed Energy Resource Aggregations first reduce their net load from the electricity system before providing additional energy injection.

(ii) The portion of the Forward Reserve Delivered Megawatts not associated with energy injection shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Distributed Energy Resource Aggregation can reduce from the electric system based on the net load of its constituent Distributed Energy Resources.

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with energy injection will be capped at the remaining energy injection capability of the Demand Response Distributed Energy Resource Aggregation.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

A Real-Time Forward Reserve Failure-to-Reserve 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.

(a) Forward Reserve Failure-to-Reserve Megawatts:

(i) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(1) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and

(2) Zero.

(ii) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(1) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and

(2) Zero.

(b) <u>Forward Reserve Failure-to-Reserve Penalties</u>: A Market Participant's Forward Reserve Failure-to-Reserve Penalty for a Reserve Zone in an hour is defined as:

(i) Forward Reserve Failure-to-Reserve Penalty for TMNSR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Reserve Penalty for TMOR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;
- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) **Forward Reserve Failure-to-Activate Megawatts**:

(i) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(1) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

(2) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period or the Resource's Economic Minimum Limit ~~or~~, Minimum Reduction or Minimum Deviation, whichever is greater, (ii) the Resource's CLAIM10, and (iii) the Resource's Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
4. For Demand Response Resources and Demand Response Distributed Energy Resource Aggregations, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate times 10 minutes, (ii) the Resource's Maximum Reduction or Maximum Deviation minus the Resource's initial demand reduction or baseline deviation at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial demand reduction or baseline deviation at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

(ii) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(1) Maximum of Forward Reserve Delivered Megawatts for TMOR plus Forward Reserve Delivered Megawatts for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

(2) Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that are not dispatched is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit ~~or~~, Minimum Reduction or Minimum Deviation, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial

consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.

4. For Demand Response Resources or Demand Response Distributed Energy Resource Aggregations, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate times 30 minutes, (ii) the Resource's Maximum Reduction or Maximum Deviation minus the Resource's initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

(iii) In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses. The portion of the Target Activation Megawatts not associated with Net Supply shall be calculated as the greater of: (1) the Target Activation Megawatts minus the amount of Net Supply that the Demand Response Resource produced during activation or (2) zero.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start, or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

A Market Participant's Forward Reserve Failure-to-Activate Penalty for a Resource in an hour is defined as:

(i) Forward Reserve Failure-to-Activate Penalty for TMNSR = The sum of the Forward Reserve Payment Rate for TMNSR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Activate Penalty for TMOR = The sum of the Forward Reserve Payment Rate for TMOR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Activate Penalty Rate = Maximum of 2.25 multiplied by the Forward Reserve Payment Rate, or the applicable nodal LMP.

III.9.7.3 Known Performance Limitations.

The ISO may have reason to believe that a particular Forward Reserve Resource is frequently receiving, or may frequently receive, Forward Reserve payments for a portion or all of its capability that is not capable of activating the Forward Reserve Assigned Megawatts for TMNSR or the Forward Reserve Assigned Megawatts for TMOR. When the ISO believes there is such a limited Forward Reserve Resource, the ISO shall contact and confer with the affected Market Participant before taking any action.

(a) The ISO will, whenever practicable, contact the affected Market Participant of the Forward Reserve Resource to request an explanation of the relevant resource Offer Data;

(b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned Forward Reserve payments are consistent with Forward Reserve Resource capabilities, no further action will be taken; and

(c) If no agreement is reached, or an acceptable explanation is not provided, the Market Participant may request a Resource performance audit. If the Forward Reserve Resource fails the performance audit or the Market Participant refuses to request a Resource performance audit, the ISO may take remedial action. Remedial actions may include, but are not limited to: (i) redeclaration, by the ISO, of any relevant operational Offer Data parameter, or (ii) removing the Resource or the relevant portion of the Resource’s capability to provide Forward Reserve on a going-forward basis.

III.10 Settlement for Real-Time Reserves

For purposes of this Section III.10, unless otherwise expressly stated, the settlement interval is five minutes. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.10.1 Reserve Quantity For Settlement

Each Resource receiving a Real-Time Reserve Designation pursuant to Section III.1.7.19 shall receive, for each settlement interval, a Reserve Quantity For Settlement. The Reserve Quantity For Settlement shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve. The Reserve Quantity For Settlement values will equal the corresponding Real-Time Reserve Designation values, adjusted downward after the fact to account for actual reserve capability based on Metered Quantity For Settlement.

III.10.2 Real-Time Reserve Credits

For each Market Participant for each hour, the ISO will determine a credit for provision of Operating Reserve in Real-Time. Demand Response Resource credits will be limited as described in Section III.9.6.5(h).

(a) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMSR for an hour shall be equal to the sum of the Real-Time Reserve Credit for TMSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMSR for an interval is calculated by multiplying the Market Participant's Resource specific Reserve Quantity For Settlement for TMSR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with -energy injection, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMSR for the interval. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMNSR shall be equal to the sum of the Real-Time Reserve Credit for TMNSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMNSR for an interval is calculated by multiplying the Market

Participant's Resource specific Reserve Quantity For Settlement for TMNSR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with energy injection , is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMNSR for the interval. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMOR shall be equal to the sum of the Real-Time Reserve Credit for TMOR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMOR for an interval is calculated by multiplying the Market Participant's Resource specific Reserve Quantity For Settlement for TMOR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with energy injection, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMOR for the interval. The Real-Time Reserve Credit for TMOR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMOR in that Load Zone.

III.10.3 Real-Time Reserve Charges.

(a) For each hour, the ISO will allocate the sum of the Real-Time Reserve Credits and Forward Reserve Obligation Charges for each Load Zone, calculated separately for TMSR, TMNSR and TMOR, to each Market Participant as follows:

Real-Time Reserve $\text{Charge}_{k,i}$ = [Reserve Charge Allocation $\text{MW}_{k,i}$] x [RT_CHRG_RT_i]

Where:

Real-Time Reserve $\text{Charge}_{k,i}$, is Market Participant *k's* Real-Time Reserve Charge for Load Zone *i* for all Real-Time reserve services and Forward Reserve Obligation Charges;

Reserve Charge Allocation MW = Market Participant *k's* Real Time Load Obligation in Load Zone *i* adjusted for the Reserve Quantity For Settlement MWs of Market Participant *k's* Dispatchable Asset Related Demand MWs in Load Zone *i*.

For purposes of the calculations in this Section III.10.4: (1) when a Market Participant assigns a Forward Reserve Resource in one Reserve Zone to meet a Forward Reserve Obligation in another Reserve Zone, any Forward Reserve Obligation Charge megawatts associated with that Resource are allocated to the Reserve Zone in which the Market Participant holds the Forward Reserve Obligation; and (2) if a Market Participant satisfies a Forward Reserve Obligation for TMOR with Forward Reserve Delivered MW of TMNSR, the Forward Reserve Obligation Charge megawatts are allocated to the Market Participant's Forward Reserve Obligation for TMOR.

III.10.4.1 Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Forward Reserve Resource are equal to the lesser of the Forward Reserve Delivered MW or Reserve Quantity For Settlement (where any portion of Reserve Quantity For Settlement provided by a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses).

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Market Participant is equal to the lesser of the sum of Forward Reserve Obligation Charge megawatts for all the Reserve Resources assigned by the Market Participant, or the Final Forward Reserve Obligation

III.10.4.3 Forward Reserve Obligation Charge.

The Forward Reserve Obligation Charge will be calculated as follows:

(a) A Market Participant's Forward Reserve Obligation Charge for TMNSR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMNSR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMNSR in that Reserve Zone.

(b) A Market Participant's Forward Reserve Obligation Charge for TMOR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMOR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMOR in that Reserve Zone.

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, 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.

Special Retirement De-List Bid, Permanent De-List Bid and Substitution Auction Demand Bid Modification and Withdrawal Provisions for the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025). For the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025), on or before June 3, 2021, the Internal Market Monitor will modify any submitted Permanent De-List Bids, Retirement De-List Bids and substitution auction test prices (whether or not associated with a Retirement De-List Bid) submitted for the sixteenth Forward Capacity Auction to reflect the impact of updated CONE, Net CONE and Capacity Performance Payment Rate values accepted by the Commission in Docket No. ER21-787.

The Internal Market Monitor will provide Lead Market Participants with updated Permanent De-List Bids, Retirement De-List Bids and substitution auction test prices in the retirement determination notifications that it issues on June 3, 2021. Within 5 Business Days of the issuance of the retirement determination notifications, a Lead Market Participant may withdraw its Retirement De-List Bid, Permanent De-List Bid, or substitution auction demand bid, and the attendant substitution auction test price, by written notification to the Internal Market Monitor. The election to withdraw a Retirement De-List Bid will also withdraw the associated substitution auction demand bid.

Special Dynamic De-List Threshold and Certain Information Publications for the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025). For the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025), on or before June 3, 2021, the ISO will recalculate and re-post the Dynamic

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), ~~or~~ a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4) or a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (Section III.13.1.4A). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, Existing Distributed Energy Capacity Resource, New Generating Capacity Resource, New Import Capacity Resource, ~~and~~ New Demand Capacity Resource, and New Distributed Energy Capacity Resource.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the FCM Deposit. The Lead Market Participant for a resource participating in a Forward Capacity Auction may not change in the 15 Business Days prior to, or during, that Forward Capacity Auction.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), ~~or~~ a New Demand Capacity Resource or Existing Demand Capacity Resource (as ~~discussed~~ defined in Section III.13.1.4), or a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (as defined in Section III.13.1.4A) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New ~~Capacity~~ Generating Capacity Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate 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) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A Market Participant that elects to have a resource that has previously been counted as a capacity resource participate in the Forward Capacity Auction as a New Generating Capacity Resource, must notify the ISO when the existing resource ceases to operate and the New Generating Capacity Resource commences operation. If a Market Participant with a resource that has previously been counted as a capacity resource elects, pursuant to Section III.13.3.4(a)(iii), to have the resource that has previously been counted as a capacity resource cover the Capacity Supply Obligation of a New Generating Capacity Resource and the resource that has previously been counted as a capacity resource must take an outage in

Technology Resources that are New Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

(e) The cap for each Capacity Commitment Period beginning on June 1, 2022 or June 1, 2023 or June 1, 2024 is 514 MW minus the cumulative amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources in the first or second run of the primary auction-clearing process pursuant to Section III.13.2 for each Capacity Commitment Period that begins on or after June 1, 2021.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), ~~or~~ as a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4), or as a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (Section III.13.1.4A) shall be an Existing Generating Capacity Resource.

III.13.1.2.1.1. Attributes of Existing Generating Capacity Resources.

For purposes of Forward Capacity Auction qualification, a Market Participant may not change any Existing Generating Capacity Resource attribute (including but not limited to the resource's status as an Intermittent Power Resource) in the period beginning 20 Business Days prior to the Existing Capacity Retirement Deadline and ending with the conclusion of the Forward Capacity Auction. Outside of this period, any such change must be accompanied by documentation justifying the change.

III.13.1.2.1.2 Rationing Minimum Limit.

No later than 120 days before the Forward Capacity Auction Market Participants may specify a Rationing Minimum Limit for an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource.

(a) With regard to any Forward Capacity Auction qualification process, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's net output in the Winter Intermittent Reliability Hours. If there are less than five full winter periods since the Intermittent Power Resource achieved FCM Commercial Operation, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved FCM Commercial Operation.

(b) The Intermittent Power Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) 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 if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource is associated with a New Generating Capacity Resource or New Distributed Energy Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource or New Distributed Energy Capacity Resource achieves FCM Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings or Existing Distributed Energy Capacity Resource's positive summer Seasonal DECR Audit Values from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1 or Section III.13.1.4A.2.A] plus [the amount of the New Generating Capacity Resource or New Distributed Energy Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource or New Distributed Energy Capacity Resource achieves FCM Commercial Operation, the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1 or Section III.13.1.4A.2.A.1.1, except that no data from the time period prior to the New Generating Capacity Resource or New Distributed Energy Capacity Resource's FCM Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource.

(b) Where an Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource is associated with a New Generating Capacity Resource or New Distributed Energy Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource or New Distributed Energy Capacity Resource achieves FCM Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings or Existing Distributed Energy Capacity Resource's positive winter Seasonal DECR Audit Values from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2 or Section III.13.1.4A.2.A.1.2] plus [the amount of the New Generating Capacity Resource or New Distributed Energy Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource or New Distributed Energy Capacity Resource achieves FCM Commercial Operation, the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2 or Section III.13.1.4A.2.A.1.2, except that no data from the time period prior to the New Generating Capacity Resource or New Distributed Energy Capacity Resource's FCM Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline.

Where the most recent summer Seasonal Claimed Capability or most recent summer Seasonal DECR Audit Value, as of the fifth Business Day in October, of an Existing Generating Capacity Resource (other than a Settlement Only Resource or an Intermittent Power Resource) and Existing Distributed Energy Capacity Resource (other than one comprised of Settlement Only Resources or an Intermittent Power Resource) is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, and Section III.13.1.4A.2.A.1.1, respectively by:

(1) for Capacity Commitment Periods beginning prior to June 1, 2023, more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW;

(2) for Capacity Commitment Periods beginning on or after June 1, 2023, more than the lesser of:

(i) the greater of 10 percent of that summer Qualified Capacity or two MW, or;

(ii) 10 MW;

then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Retirement Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability or summer Seasonal DECR Audit Value as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, Section III.13.1.4A.1.1.2.3, or Section III.13.1.4A.1.1.2.4, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource or Existing 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.13.1.2.2.1.1 or Section III.13.1.4A.2.A.1.1 by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 or Section III.13.1.4A.2.A.1.1

for the Forward Capacity Auction. For an Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource (other than a Settlement Only Resource) meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than the close of the New Capacity Show of Interest Submission Window. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction meets the requirements of this Section, but the incremental amount of capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental amount of capacity with excess Qualified Capacity at that same resource, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Capacity Resource, Existing Distributed Energy Capacity Resource, or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Capacity Resource, or Existing Import 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.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

Where an Existing 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.13.1.4A.2.A, then that resource must have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

(a) For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Retirement Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located.

(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 an Existing Generating Capacity Resource as described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than five Business Days before the Existing Capacity Retirement Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, a Permanent De-List Bid, or a Retirement De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Retirement Package and Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and Administrative Export De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline.

submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Project Sponsors 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 Resources and Seasonal Peak Demand Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Project Sponsor 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 value and measures installed by Load Zone and meter domain. Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor or 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.13.1.4A. Distributed Energy Capacity Resources.

To participate in a Forward Capacity Auction as a Distributed Energy Capacity Resource, a resource must meet the requirements of this Section III.13.1.4A. Each Distributed Energy Capacity Resource shall be a minimum of 100 kW. A facility connected at a point of interconnection that is 5 MW or greater cannot be 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 On-Peak Demand Resource or Seasonal Peak Demand 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 import or export bids or Administrative Export De-List Bids.

III.13.1.4A.1. Definition of New Distributed Energy Capacity Resource.
A New Distributed Energy Capacity Resource is a Distributed Energy Capacity Resource that has not cleared in a previous Forward Capacity Auction.

III.13.1.4A.1.1. Qualification Process for New Distributed Energy Capacity Resources.
For Forward Capacity Auctions a New Distributed Energy Capacity Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's estimated net injection capability and, as applicable, the resource's estimated demand reduction value as submitted and reviewed pursuant to this Section III.13.1.4A. The FCA Qualified Capacity for a New Distributed Energy Capacity Resource (other than an Intermittent Power Resource) shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity.

For a resource to qualify as a New Distributed Energy Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit estimated net energy injection values and, as applicable, estimated demand reduction values and supporting information in the New Distributed Energy Capacity Resource Show of Interest Form as described in Section III.13.1.4A.1.1.1. Second, the Project Sponsor must submit a New Distributed Energy Capacity Resource Qualification Package as described in Section III.13.1.4A.1.1.2.

III.13.1.4A.1.1.1. New Distributed Energy Capacity Resource Show of Interest Form.
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must submit to the ISO a New Distributed Energy Capacity Resource Show of Interest Form as described in this Section III.13.1.4A.1.1.1 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project.

(a) General Requirements. A completed New Distributed Energy Capacity Resource Show of Interest Form shall include, but is not limited to, the following information: project name; the DRR Aggregation Zone, Load Zone and Dispatch Zone within which the resource will be located; a description of the project and its expected configuration, including the types of generation and demand response comprising the project; a description of the customer classes and end-uses served by the project; the resource's expected Commercial Operation date; estimated summer and winter net injection capability values (MW) per facility; the installation date of facilities that are part of the project and already constructed, installed, or in commercial operation; ISO Market Participant status and ISO customer identification (if applicable); Project Sponsor's contact information and the ISO Customer Status; expected nameplate capacity by technology type per facility; indication of whether the project elects Intermittent Power Resource treatment (available if the project is a homogenous aggregation of intermittent technology); and the project's applicable technical and financial contacts.

For purposes of this Section III.13.1.4A:
(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. If the resource includes Demand Response Resources, the completed New Distributed Energy Capacity Resource Show of Interest Form shall include the following additional information: the estimated summer and winter demand reductions 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 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 New Distributed Energy Capacity Resource Show of Interest Form 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 or Equal to 1 MW and less than 5 MW. If the 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 New Distributed Energy Capacity Resource Show of Interest Form 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.13.1.4A.1.1.2. New Distributed Energy Capacity Resource Qualification Package.
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must submit a New Distributed Energy Capacity Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Distributed Energy Capacity Resource Qualification Package shall conform to the requirements of this Section III.13.1.4A.1.1.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4A.1.1.2.1. Source of Funding.
The Project Sponsor must provide in the New Distributed Energy Capacity Resource Qualification Package the source of funding, which includes, but is not limited to, the following: the source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; and a completed ISO credit application.

III.13.1.4A.1.1.2.2. Customer Acquisition Plan.

(a) A Project Sponsor with more than a single customer must include in the New Distributed Energy Capacity Resource Qualification Package a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

(b) A Project Sponsor for a New Distributed Energy Capacity Resource that includes one or more end-use customer facilities with behind-the-meter generation must include in the New Demand Capacity Resource Qualification Package information demonstrating that each facility's net injection capability will be less than 5 MW or less than or equal to the facility's Maximum Facility Load.

(c) The requirements of this Section III.13.1.4A1.1.2.2 shall not apply for facilities with a net injection capability equal to or greater than 1 MW and less than 5 MW at a point of interconnection.

III.13.1.4A.1.1.2.3. Critical Path Schedule for a Distributed Energy Capacity Resource Having a Facility with a Demand Reduction Value or Net Injection Capability of at Least 5 MW at a Single Retail Delivery Point.

The Project Sponsor of a Distributed Energy Capacity Resource with a customer facility having a demand reduction value of at least 5 MW at a single Retail Delivery Point or having behind-the-meter generation with net injection capability greater than 5 MW at a single Retail Delivery Point, shall provide in the New Distributed Energy Capacity Resource Qualification Package a critical path schedule as set forth in Section III.13.1.1.2.2.2.

III.13.1.4A.1.1.2.4. Critical Path Schedule for a Distributed Energy Capacity Resource with All Facilities ~~Retail Delivery Points~~ Having a Demand Reduction Value or Net Injection Capability of Less Than 5 MW at a Single Retail Delivery Point or ~~All~~ Points of Interconnection.

The Project Sponsor of a Distributed Energy Capacity Resource with all facilities having a demand reduction value or net injection capability of less than 5 MW at a single Retail Delivery Point or point of interconnection shall provide in the New Distributed Energy Capacity Resource Qualification Package a critical path schedule comprised of a delivery schedule of the share of total offered demand reduction value and net injection capability achieved as of target dates, as follows: (i) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; (ii) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; and (iii) target date 3 which is the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Distributed Energy Capacity Resource described in the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package has achieved its full demand reduction value and net injection capability, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total demand reduction value and net injection capability must be complete.

III.13.1.4A.1.1.2.5. Additional Requirements for Distributed Energy Capacity Resources that are Intermittent Power Resources

In addition to the information described elsewhere in this Section III.13.1.4A.1.1.2, for each Intermittent Power Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III. 13.1.4A.1.1.2 (b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource.

III.13.1.4A.1.1.2.6. Offer Information From New Distributed Energy Capacity Resources.

The Project Sponsor for a New Distributed Energy Capacity Resource must indicate in the New Distributed Energy Capacity Resource Qualification Package if an offer from the New Distributed Energy Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4A.1.1.3. Initial Analysis for Distributed Energy Capacity Resources.

For each New Distributed Energy Capacity Resource, the ISO shall perform an analysis based on the information provided in the New Distributed Energy Capacity Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Distributed Energy Capacity Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Distributed Energy Capacity Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4A.1.1.4. Consistency of the New Distributed Energy Capacity Resource Qualification Package and New Distributed Energy Capacity Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package for consistency with its New Distributed Energy Capacity Resource Show of Interest Form. The New Distributed Energy Capacity Resource Qualification Package may not contain material changes relative to the New Distributed Energy Capacity Resource Show of Interest Form. If a material change exists between the New Distributed Energy Capacity Resource Qualification Package and the New Distributed Energy Capacity Resource Show of Interest Form, the New Distributed Energy Capacity Resource Show of Interest Form will be withdrawn by the ISO. A material change includes, but is not limited to the following: (i) a misrepresentation or change of the interconnection status of a facility within the New Distributed Energy Capacity Resource; (ii) the addition of facilities at a point of interconnection with net injection capability greater than 1 MW; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in DRR Aggregation Zone within which the project is located; (iv) for any component of the New Distributed Energy Capacity Resource that is a Demand Response Resource, an aggregate change in the total summer or winter demand reduction values of all such Demand Response Resources by more than 30 percent; (v) for any component of the New Distributed Energy Capacity Resource with net injection capability less than 5 MW, a change in the total summer or winter net injection capability of the resource by more than 30 percent; (vi) for non-demand response components of a New Distributed Energy Capacity Resource, the introduction of a new technology type for the New Distributed Energy Capacity Resource; (vii) for demand response components of a the New Distributed Energy Capacity Resource, a change to the technology type providing demand reduction for the New Distributed Energy Capacity Resource; (viii) for a facility that interconnects at a point of interconnection, any increase in size of the facility; (ix) for any non-demand response components of any New Distributed Energy Capacity Resource that interconnects at a point of interconnection, a decrease in size greater than 60 percent for any facility with greater than 1 MW connected at the same point of interconnection.

III.13.1.4A.1.1.5. Evaluation of New Distributed Energy Capacity Resource Qualification Materials.

The ISO shall review the information submitted by New Distributed Energy Capacity Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4A and whether, based on the information provided, the Distributed Energy Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by New Distributed Energy Capacity Resources is accurate and contains all of the elements required by this Section III.13.1.4A;

(b) whether the critical path schedule submitted by New Distributed Energy Capacity Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Distributed Energy Capacity Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Distributed Energy Capacity Resource are satisfied; and

(e) whether the customer acquisition plan and source of funding plan are sufficiently detailed and reasonably achievable.

III.13.1.4A.1.1.6. New Distributed Energy Capacity Resources that are Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Distributed Energy Capacity Resource that is an Intermittent Power Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.4A.2.A.1, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity.

III.13.1.4A.1.1.7. Qualification Determination Notification for New Distributed Energy Capacity Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Distributed Energy Capacity Resource indicating whether the New Distributed Energy Capacity Resource has been accepted for participation in the Forward Capacity Auction.

(a) For a New Distributed Energy Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Distributed Energy Capacity Resource's summer and winter Qualified Capacity, which shall be, which shall be the ISO-determined summer and winter net injection capability and demand reduction value, which in the latter case shall be increased by average avoided peak transmission and distribution losses (that is, eight percent).

(b) For a New Distributed Energy Capacity Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4A.2. Definition of Existing Distributed Energy Capacity Resources.

Existing Distributed Energy Capacity Resources shall include Distributed Energy Capacity Resources that have cleared in a previous Forward Capacity Auction. Except as specified in this Section III.13.1.4A, Existing Distributed Energy Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Distributed Energy Capacity Resources shall be subject to Section III.13.1.2.2.5.2. Any Distributed Energy Resource Aggregation that is part of an Existing Capacity Resource shall count only as existing Qualified Capacity, and shall not count toward the Qualified Capacity of a New Distributed Energy Capacity Resource. Any Existing Generating Capacity Resource or Existing Demand Capacity Resource that could qualify as an Existing Distrbuted Energy Capacity Resource may convert to an Existing Distributed Energy Capacity Resource.

III.13.1.4A.2.A Qualified Capacity for Existing Distributed Energy Capacity Resources.

III.13.1.4A.2.A.1 Existing Distributed Energy Capacity Resources Other Than Intermittent Power Resources

III.13.1.4A.2.A.1.1. Summer Qualified Capacity

The summer Qualified Capacity of an Existing Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer Seasonal Audit Value from the five most recent years, as of the fifth Business Day in October of each year, with only positive summer value included in the median calculation. Where an Existing Distributed Energy Capacity Resource has fewer than five summer Seasonal Audit Values, then the summer Qualified Capacity for that Existing Distributed Energy Capacity Resource shall be equal to the median of all of that resource's previous summer Seasonal Audit Values, as of the fifth Business Day in October of each year, with only positive summer values included in the median calculation. If for an Existing Distributed Energy Capacity Resource there are no previous Seasonal Audit Values because the resource had not yet achieved FCM Commercial Operation, then the Existing Distributed Energy Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Distributed Energy Capacity Resource in previous Forward Capacity Auctions.

III.13.1.4A.2.A.1.2 Winter Qualified Capacity

The winter Qualified Capacity of an Existing Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's winter Seasonal Audit Value from the five most recent years, as of the fifth Business Day in June of each year, with only positive winter value included in the median calculation. Where an Existing Distributed Energy Capacity Resource has fewer than five winter Seasonal Audit Values, then the winter Qualified Capacity for that Existing Distributed Energy Capacity Resource shall be equal to the median of all of that resource's previous winter Seasonal Audit Values, as of the fifth Business Day in June of each year, with only positive winter values included in the median calculation. If for an Existing Distributed Energy Capacity Resource there are no previous Seasonal Audit Values because the resource had not yet achieved FCM Commercial Operation, then the Existing Distributed Energy Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Distributed Energy Capacity Resource in previous Forward Capacity Auctions.

III.13.1.4A.2.A.2 Existing Distributed Energy Capacity Resources That Are Intermittent Power Resources

Existing Distributed Energy Capacity Resources that are Intermittent Power Resources shall follow the same rules for Existing Generating Capacity Resources that are Intermittent Power Resources in section III.13.1.2.2.2. The Existing Qualified Capacity may not be greater than the amount of summer (or winter, as applicable) capacity that cleared in a Forward Capacity Auction as a New Distributed Energy Capacity Resource.

III.13.1.4A.2.A.3 Qualified Capacity Adjustment for Partially New and Partially Existing Resources

Rules related to a Distributed Energy Capacity Resource's Qualified Capacity Adjustment for Partially New and Partially Existing Resources can be found in Section III.13.1.2.2.3.

III.13.1.4A.2.A.4 Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline.

Rules related to a Distributed Energy Capacity Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline can be found in Section III.13.1.2.2.4.

III.13.1.4A.2.1. Qualified Capacity Notification for Existing Distributed Energy Capacity Resources.

(a) For each Existing Distributed Energy Capacity Resource, no later than 15 Business Days before the Existing Capacity Retirement Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the DRR Aggregation Zone in which the Existing Distributed Energy Capacity Resource is located.

(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 an Existing Distributed Energy Capacity Resource, then the Lead Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than five Business Days before the Existing Capacity Retirement Deadline. If an Existing Distributed Energy Capacity Resource does not submit a Static De-List Bid, a Permanent De-List Bid, or a Retirement De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.4A.2.2. Existing Distributed Energy Capacity Resource De-List Bids.

An Existing Distributed Energy Capacity Resource may submit a Permanent De-List Bid or Retirement De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5 no later than the Existing Capacity Retirement Deadline or a Static De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.1 no later than the Existing Capacity Qualification Deadline, provided, however, that no de-list bid shall be used as a mechanism to inappropriately qualify Distributed Energy Resource Aggregations associated with Existing Distributed Energy Capacity Resources as New Distributed Energy Capacity Resources.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.4.1.1.6. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Capacity Resource, April through November where the summer resource is a Demand Capacity Resource) 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 (October through May where the summer resource is not a Demand Capacity Resource, December through March where the summer resource is a Demand Capacity Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered 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 an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Capacity Resource.

No later than five Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Capacity Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource, ~~or~~ an Existing Generating Capacity Resource, a New Distributed Energy Capacity Resource, or an Existing Distributed Energy Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the FCM Deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. A New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA 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.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource, ~~or~~ Existing Import Capacity Resource, , New Distributed Energy Capacity Resource, or Existing Distributed Energy Capacity Resource and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources 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 FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Capacity Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list, retire or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which 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.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

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.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, ~~and~~ New Demand Capacity Resources, and New Distributed Energy Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, 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, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, ~~or~~ New Demand Capacity Resource, or New Distributed Energy Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, 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, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, ~~or~~ New Demand Capacity Resource, or New Distributed Energy Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (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 automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (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) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic De-List Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, ~~and~~ Existing Demand Capacity Resources, and Existing Distributed Energy Capacity Resources as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, ~~and~~ Existing Demand Capacity Resource, and Existing Distributed Energy Capacity Resources without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, ~~or~~ Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's

Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.
The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section III.A.21.1.2(e)(5) shall not apply). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, ~~and~~ New Demand Capacity Resources, and New Distributed Energy Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, ~~and~~ Existing Demand Capacity Resources, and Existing Distributed Energy Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource, ~~or~~ Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), 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 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, 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 III.13.2.5.2.5.1(b), 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.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1)

III.13.3. Critical Path Schedule Monitoring.

III.13.3.1. Resources Subject to Critical Path Schedule Monitoring.

III.13.3.1.1. New Resources Electing Critical Path Schedule Monitoring.

A Project Sponsor that submits a critical path schedule for a New Capacity Resource in the qualification process may request that the ISO monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3. The ISO will monitor the New Capacity Resource's compliance from the time the ISO approves the request until the resource achieves FCM Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4A, or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

In addition, a Lead Market Participant with a New Import Capacity Resource backed by one or more existing External Resources seeking to qualify for Capacity Commitment Period(s) prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which it is qualifying must request monitoring under this Section III.13.3.1.1.

A request under this Section III.13.3.1.1 must be made in writing no later than five Business Days after the deadline for submission of the FCM Deposit pursuant to Section III.13.1.9.1.

III.13.3.1.2. New Resources Clearing in the Forward Capacity Auction.

For each new resource required to submit a critical path schedule in the qualification process, including but not limited to a New Generating Capacity Resource (pursuant to Section III.13.1.1.2.2), a New Import Capacity Resource backed by a new External Resource (pursuant to Section III.13.1.3.5), ~~or~~ a New Demand Capacity Resource (pursuant to Section III.13.1.4), or Distributed Energy Capacity Resource (pursuant to Section III.131.4A), if capacity from that resource clears in the Forward Capacity Auction, then the ISO shall monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3 (regardless of whether the Project Sponsor requested monitoring pursuant to Section III.13.3.1.1) from the time that the Forward Capacity Auction is conducted until the resource achieves FCM Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4A, or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

III.13.3.2.2. 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 (discussed in Section III.13.3.2.2(b)) and Distributed Energy Capacity Resources with all Retail Delivery Points and facilities at the point of interconnection having in the aggregate a demand reduction value and net injection capability of less than 5 MW (discussed in Section III.13.3.2.2(c)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 Project Sponsor 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.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor 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**. If during the qualification process it was determined that transmission upgrades (including any upgrades identified in a re-study pursuant to Section 3.2.1.3 of Schedule 22, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) are needed for the new resource to complete its interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades 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 Project Sponsor 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 Project Sponsor shall provide documentation showing the total offered demand reduction value achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value must be complete.

(ii) **Additional Requirements**. For each customer and each prospective customer the Project Sponsor 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 Project Sponsor shall also provide the Asset identification number.

(c) For Distributed Energy Capacity Resources with all Retail Delivery Points and facilities at the point of interconnection having in the aggregate a demand reduction value and net injection capability of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor 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 Project Sponsor shall provide documentation showing the total offered demand reduction value and net injection capability achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Distributed Energy Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Distributed Energy Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Distributed Energy Capacity Resource described in the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package has achieved its full demand reduction value and net injection capability, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value and net injection capability must be complete.

(ii) Additional Requirements. For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Distributed Energy Resource Aggregation has been registered with the ISO, then the Project Sponsor shall also provide the Distributed Energy Resource Aggregation identification number.

III.13.3.2.3. Additional Relevant Information.

The Project Sponsor 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 or the feasibility that the project will achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period.

III.13.3.2.4. Additional Information for Resources Previously Counted As Capacity.

For each resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, a ~~or~~ New Demand Capacity Resource pursuant to Section III.13.1.4.1, or a New Distributed Energy Capacity Resource pursuant to Section III.13.1.4A and clearing in that auction, the Project Sponsor must provide information in the critical path schedule report demonstrating: (a) the shedding of the resource's Capacity Supply Obligation in accordance with the provisions of Section III.13.1.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.1.2, III.13.1.1.1.3, and III.13.1.1.1.4) is being met.

III.13.3.3. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Project Sponsor proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.13.3.2.1), then the ISO shall consult with the Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 Project Sponsor. If the Project Sponsor 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.13.3.4A. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.13.3.2.

III.13.3.4. Covering Capacity Supply Obligations.

(a) If a capacity supplier determines that a resource may not be able to demonstrate its ability to deliver the full amount of its Capacity Supply Obligation, the capacity supplier may take actions to cover all or part of the Capacity Supply Obligation for any portion of the Capacity Commitment Period, as follows:

(i) A capacity supplier may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4.

(ii) A capacity supplier may cover its Capacity Supply Obligation through one or more Capacity Supply Obligation Bilaterals, subject to the satisfaction of the requirements in Section III.13.5.

(iii) A capacity supplier that has qualified a resource pursuant to Section III.13.1.1.1.2 may cover its Capacity Supply Obligation by electing, no later than ten Business Days prior to the offer and bid deadline for the third annual reconfiguration auction prior to the start of the applicable Capacity Commitment Period, to have the resource that was previously counted as a capacity resource cover the Capacity Supply Obligation of the New Generating Capacity Resource for up to two Capacity Commitment Periods. If an election is made to have the resource that was previously counted as a capacity resource cover the Capacity Supply Obligation of the New Generating Capacity Resource, the capacity supplier with the resource that was previously counted as a capacity resource shall be required to comply with the requirements set forth in Section III.13.6.1 so long as it continues to cover for the New Generating Capacity Resource.

(b) During a Capacity Commitment Period, a failure to cover charge will apply to any capacity resource that has not demonstrated the ability to deliver the full amount of its Capacity Supply Obligation by the end of an Obligation Month. The failure to cover charge is the difference between a resource's monthly Capacity Supply Obligation and its Maximum Demonstrated Output, multiplied by the Failure to Cover Charge Rate, where:

Maximum Demonstrated Output Period

Maximum Demonstrated Output Period is the period beginning six years prior to the start of the applicable Capacity Commitment Period and ending with the most recently completed calendar month in the Capacity Commitment Period, including all prior months in the Capacity Commitment Period.

Provided that, for a resource that has previously been counted as a capacity resource and for which an election has been made to participate as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2, and for which a cover election has been made pursuant to Section III.13.3.4(a)(iii), then: (1) the Maximum Demonstrated Output Period will be the Maximum Demonstrated Output Period of the resource that has been previously counted as capacity, and; (2) the Maximum Demonstrated Output Period of the New Generating Capacity Resource will begin on the earlier of: (i) the date that the resource that has previously been counted as a capacity resource began any outage as provided in Section III.13.1.1.1.2, and; (ii) the date that the New Generating Capacity Resource commenced Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff).

Failure to Cover Charge Rate

For Capacity Commitment Periods beginning prior to June 1, 2022, the Failure to Cover Charge Rate for a Capacity Zone is the higher of the Capacity Clearing Price and the clearing price in any annual reconfiguration auction for that Capacity Commitment Period.

For Capacity Commitment Periods beginning on or after June 1, 2022, the Failure to Cover Charge Rate for a Capacity Zone is the price determined by a second clearing of the third annual reconfiguration auction prior to the start of the Capacity Commitment Period in which the aggregated zonal quantities of undemonstrated Capacity Supply Obligation, as of the completion of the third annual reconfiguration auction, and as determined pursuant to Section III.13.3.4 (b), are included as demand bids at the Forward Capacity Auction Starting Price for each applicable Capacity Zone.

Provided that, if an existing resource is covering for a New Generating Capacity Resource pursuant to Section III.13.3.4(a)(iii), then the undemonstrated Capacity Supply Obligation for the New Generating Capacity Resource is the difference between the existing resource's Maximum Demonstrated Output and the new resource's Capacity Supply Obligation.

Maximum Demonstrated Output

The Maximum Demonstrated Output is the sum of the highest output levels achieved by each Generator Asset associated with a Generating Capacity Resource, each Demand Response Asset associated with an Active Demand Capacity Resources, ~~and~~ assets associated with a Seasonal Peak Demand Resource or On-Peak Demand Resource, and each Distributed Energy Resource Aggregation associated with a Distributed Energy Capacity Resources during the Maximum Demonstrated Output Period as specified below. The minimum Maximum Demonstrated Output for all assets is zero.

Provided that, if a resource that was previously counted as capacity is covering for a New Generating Capacity Resource pursuant to Section III.13.3.4(a)(iii), then the Maximum Demonstrated Output is the sum of the highest aggregate output level achieved by each asset associated with the resource that has previously been counted as capacity during the Maximum Demonstrated Output Period.

At the asset level, Maximum Demonstrated Output is calculated as follows:

Demand Response Assets associated with an Active Demand Capacity Resource: The Maximum Demonstrated Output for dates occurring prior to June 1, 2018 is the highest audit value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses. The Maximum Demonstrated Output for dates occurring on or after to June 1, 2018 will be equal to the highest demand reduction calculated, pursuant to Section III.8.4, in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses for non-Net Supply.

Distributed Generation associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest hourly metered output in the Maximum Demonstrated Output Period after the resource has completed testing and has achieved commercial operation, increased by average avoided peak transmission and distribution losses for non-Net Supply.

Load Management associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest hourly demand reduction value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses for non-Net Supply.

Energy Efficiency associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest reported monthly performance value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses.

Generator Assets: The Maximum Demonstrated Output for dates occurring prior to March 1, 2017 is the highest hourly Revenue Quality Metering in the Maximum Demonstrated Output Period beginning on or after Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff). The Maximum Demonstrated Output for dates occurring on or after March 1, 2017 is the highest Metered Quantity for Settlement in the Maximum Demonstrated Output Period beginning on or after Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff).

If a single Generator Asset is split into two or more new Generator Assets, the Maximum Demonstrated Output associated with the single Generation Asset will be prorated among the new assets based on their summer maximum net output. If multiple Generator Assets are consolidated to fewer assets, the Maximum Demonstrated Output of the Generator Assets that are being consolidated will be allocated to the consolidated assets based on the summer maximum net output.

Import Capacity Resources: For an Import Capacity Resource that is backed by external generation that has not achieved commercial operation at the time of qualification, in part or entirely, the Maximum Demonstrated Output is the highest revenue quality metered output for a five-minute or greater interval after the resource has completed testing and has achieved commercial operation. Provided that, the Maximum Demonstrated Output of an Import Capacity Resource associated with an Elective Transmission Upgrade may be limited by the highest demonstrated capability of the Elective Transmission Upgrade after the Elective Transmission Upgrade has completed testing and has achieved commercial operation.

Distributed Energy Resource Aggregations associated with a Distributed Energy Capacity Resource: The Maximum Demonstrated Output is the sum of the highest output levels achieved by each asset associated with the Distributed Energy Capacity Resource during the Maximum Demonstrated Output Period, pursuant to Section III.13.3.4.

III.13.3.4A Termination of Capacity Supply Obligations.

If a Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if a Project Sponsor covers a Capacity Supply Obligation for two Capacity Commitment Periods, 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 Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource's Capacity Supply Obligation for any future Capacity Commitment Periods and the resource's right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource's qualified capacity for participation in the Forward Capacity Market; provided that, where a Project Sponsor voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.13.3.6, no filing with the Commission shall be necessary to terminate the resource's Capacity Supply Obligation. Upon Commission ruling, the Project Sponsor shall forfeit any additional amount of financial assurance as described in Section VII.B.2.c of the ISO New England Financial Assurance Policy.

Notwithstanding any other provision of this Section III.13, if any of the resource's Capacity Supply Obligation in the deferral period was shed in a reconfiguration auction or Capacity Supply Obligation Bilateral prior to Commission approval of the deferral request, then the resource's settlements shall be adjusted by the ISO to ensure that the resource does not receive any payments associated with that transaction in excess of the charges associated with that transaction; the resource will be responsible for any charges in excess of payments.

III.13.3.8. FCM Commercial Operation.

A resource (or portion thereof) achieves FCM Commercial Operation when (1) the ISO has determined that the resource (or portion thereof) has achieved all its critical path schedule milestones, including completion of any transmission upgrades necessary for the resource to obtain the requisite interconnection service; and (2) the ISO verifies the resource's (or a portion of the resource's) summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating).

(a) For a Generating Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation as soon as practicable following the ISO's verification of the resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating), which may take place in any month of the year. The ISO shall verify the summer capacity rating of a Generating Capacity Resource that is an Intermittent Power Resource following no fewer than 30 consecutive calendar days of operation (for periods from October 1 through May 31, a Market Participant must request such verification).

(b) For a Demand Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon verifying that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, subject to the requirements of Section III.13.6.1.5.3(b).

(c) For an Import Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon demonstration that the Import Capacity Resource described in the New Capacity Qualification Package has achieved its full Qualified Capacity.

(d) For a Distributed Energy Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon verifying that the Distributed Energy Capacity Resource described in the New Distributed Energy Capacity Resource Qualification Package has achieved its full demand deviation value and net injection capability, subject to the requirements of Section III.13.6.1.7.3 and below.

(i) For facilities connected at a point of interconnection with net injection capability greater than or equal to 1 MW and less than 5 MW or facilities having a demand reduction value and net injection capability greater than 5 MW at a single Retail Delivery Point, these facilities shall map exactly to how the Distributed Energy Capacity Resource was qualified.

(ii) For facilities connected at a point of interconnection with net injection capability greater than or equal to 1 MW and less than 5 MW or facilities having a demand reduction value, to become fully commercial, the nameplate of each technology within the Distributed Energy Resource Aggregations mapped to the Distributed Energy Capacity Resource must be at least 70% of the expected nameplate of each technology used to support the Distributed Energy Capacity Resource Qualified Capacity.

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) 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.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.9.2 of ***Appendix A*** of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource's Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. 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. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will 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 expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.1.5. Distributed Energy Capacity Resources.

III.13.4.2.1.2.1.5.1. Summer ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.5.2. Winter ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

(i) The sum of the most recently-determined winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the winter period of the relevant Capacity Commitment Period and increased by average avoided peak transmission and distribution losses) and any winter capacity that has cleared in a Forward Capacity Auction and not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of winter capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) provided that the resource is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.2.5. Distributed Energy Capacity Resources.

III.13.4.2.1.2.2.5.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the lesser of: (i) its most recently-determined summer Qualified Capacity and (ii) its summer Seasonal DECR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.5.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the lesser of: (i) its most recently-determined winter Qualified Capacity and (ii) its winter Seasonal DECR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved FCM Commercial Operation, the ISO shall subtract the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values (for Capacity Commitment Periods beginning on or before June 1, 2019) or the least of these 12 values (for Capacity Commitment Periods beginning on or after June 1, 2020), if the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by:

(1) for Capacity Commitment Periods beginning on or before June 1, 2019, more than the lesser of:
  - (i) 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or;
  - (ii) 40 MW;

(2) for Capacity Commitment Periods beginning on June 1, 2020, June 1, 2021 and June 1, 2022, more than the lesser of:
  - (i) the greater of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or two MW, or;
  - (ii) 40 MW;

(ii) the resource's Capacity Supply Obligation minus Qualified Capacity minus 10 MW.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource may not submit a supply offer for a monthly reconfiguration auction unless it is expected to achieve FCM Commercial Operation prior to the end of the relevant Obligation Month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. A resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month. 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 the values determined pursuant to subsections (a) and (b) below:

(a) The resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity as adjusted pursuant to Section III.13.4.2, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period or, where the resource did not qualify for the third annual reconfiguration auction for the relevant Capacity Commitment Period, the quantity of MW either being monitored by the ISO in accordance with Section III.13.3 (provided that all applicable Financial Assurance requirements have been met and the resource is expected to achieve all its critical path schedule milestones prior to the end of the relevant Obligation Month in accordance with posted schedules) or the amount of capacity that achieved all its critical path schedule milestones after the third annual reconfiguration qualification deadline; provided that the value determined pursuant to this subsection (a) shall be limited by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f) or, for a Demand Capacity Resource, the amount of Qualified Capacity for the relevant Capacity Commitment Period.

(b) The amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

III.13.4.2.1.5. ISO Review of Supply Offers.

Supply offers in reconfiguration auctions shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO's reliability reviews will assess such offers, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation outage information, and will include transmission security studies. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.

Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

(a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.

(b) Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource's capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.

(c) All demand bids in reconfiguration auctions shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's reviews will consider the location and operating and rating limitations of resources associated with demand bids that would otherwise clear to ensure reliability standards will remain satisfied if the committed capacity is withdrawn. The ISO shall reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO

New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO's reliability reviews will assess such bids, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation outage information, and will include transmission security studies. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.3. [Reserved.]

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.

All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.4.5. Annual Reconfiguration Auctions.

Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period. For each annual reconfiguration auction, the capacity demand curves, New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period. For purposes of the annual reconfiguration auctions, the Forward Capacity Auction Starting Price used to define the System-Wide Capacity Demand Curve shall be the Forward Capacity

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

Capacity Supply Obligation Bilaterals are available for monthly periods. The qualification of resources subject to a Capacity Supply Obligation Bilateral is determined in the same manner as the qualification of resources is determined for reconfiguration auctions as specified in Section III.13.4.2.

A resource having a Capacity Supply Obligation seeking to shed that obligation (Capacity Transferring Resource) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (Capacity Supply Obligation Bilateral), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (Capacity Acquiring Resource), subject to the following limitations.

(a) A Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) 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 Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation) of the Capacity Acquiring Resource during the month covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource’s unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

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, 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.13.5.1.1.3. 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 provisions of this Section III.13.5.1 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 relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation outage information, and will include transmission security studies. The ISO will review all confirmed Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. The ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource.

The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting 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.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.13.5.2. Capacity Load Obligations Bilaterals.

A Market Participant having a Capacity Load Obligation seeking to shed that obligation (“Capacity Load Obligation Transferring Participant”) may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone (“Capacity Load Obligation Bilateral”) to any Market Participant seeking to acquire a Capacity Load Obligation (“Capacity Load Obligation Acquiring Participant”). 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.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources with Capacity Supply Obligations.

III.13.6.1.1.1. 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.13.6.1.1.1(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

(b) Level 2 Audit: the ISO will 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.13.6.1.6. DNE Dispatchable Generator.

III.13.6.1.6.1. Energy Market Offer Requirements.
Beginning on June 1, 2019, Market Participants with 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.13.6.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.

III.13.6.1.7.1. 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.13.6.1.7.1; 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 will 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; or

(b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource aAggregations, 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.13.6.1.7.2. 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 known capability of the resource.

III.13.6.1.7.3. 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 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.13.6.2. 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.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.1.1. 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.13.6.2.1.1.1. 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.13.6.2.1.1.2. 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.13.6.2.1.2. 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 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.13.6.2.2. Distributed Energy Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.2.1. 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.13.6.2.2.2. 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.13.6.2.2.3. 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.13.6.2.2.4. 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.13.6.1.7.3.

~~**III.13.6.2.2. [Reserved.]**~~

III.13.6.2.3. Intermittent Power Resources without a Capacity Supply Obligation.

III.13.6.2.3.1. 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.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources 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.

(a) complying with Section III.13.6.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.13.6.1.5.5 and the ISO New England Manuals; and

(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 outlined in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no 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.13.6.3. 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.13.6.3 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.

III.13.6.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource, ~~or~~ 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 Section III.13 of this Tariff 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.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.13.7.1.3. Export Capacity.
If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward 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 (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

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.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 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.13.7.2.2 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.13.7.2.2, 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 Resource or Seasonal Peak Demand 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, if the Capacity Scarcity Condition occurs during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be equal to the applicable reported monthly performance value; if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then 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.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(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 a 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.

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Zonal Capacity Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.2. 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 Forward Capacity Auction pursuant to Section III.13.2.3.4. 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.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) 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 two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

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 month and 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 annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to 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 prior to the start of the Capacity Commitment Period.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each month and Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA 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, ~~or~~ Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.
Dispatchable Asset Related Demand resources will not receive Forward 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.

III.14 Regulation Market.

For purposes of this Section III.14, the settlement interval is every five minutes. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.14.1 Regulation Market System Requirements.

The Regulation Capacity Requirement and Regulation Service Requirement are determined based on historical control performance and compliance with NERC and NPCC control standards. The Regulation Capacity Requirement and Regulation Service Requirement will be published on the ISO's website.

During abnormal system conditions, the ISO may deviate from the Regulation Capacity Requirement or Regulation Service Requirement to maintain system reliability.

III.14.2 Regulation Market Eligibility.

A Regulation Resource must satisfy the following conditions:

(a) Physical Parameters.

(i) Automatic Response Rate.

1. The minimum Automatic Response Rate is 1 MW/minute.

(ii) Regulation Capacity.

1. The minimum Regulation Capacity of a Generator Asset that is not part of an Electric Storage Facility will be determined based on the Generator Asset's size and operating characteristics and must be greater than or equal to: (a) 5 MW, and; (b) two times the Generator Asset's AGC SetPoint Deadband plus 1 MW.

2. The minimum Regulation Capacity of an Alternative Technology Regulation Resource, ~~a Continuous Storage ATRR,~~ a Binary Storage DARD, and a Generator Asset associated with a Binary Storage Facility is 0.1 MW.

3. ~~The minimum Regulation Capacity of a Resource that does not provide Regulation pursuant to subsections (ii)(1) or (ii)(2) of this Section III.14.2(a) is 1 MW after aggregation.~~

(b) Regulation Registration and Technical Requirements.

A facility capable of providing Regulation:

(i) shall be located within the New England Control Area;

(ii) shall meet the requirements specified in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18;

(iii) shall not be registered as both an ATRR and a dispatchable Generator Asset, nor as both an ATRR and a DARD, unless it is a Continuous Storage Facility (however, an ATRR may be located at the same facility as either or both a Generator Asset and a DARD if the Generator Asset and DARD are separately metered and reported);

(iv) may provide Regulation only as an ATRR, and not as another Resource type, if registered as an ATRR;

(v) shall be capable of receiving and following AGC SetPoints sent electronically at four-second intervals;

(vi) shall have a demonstrated capability to reliably follow Dispatch Instructions, consistent with normal operating characteristics and physical offer parameters, including Regulation Capacity and Automatic Response Rate. Resources without an operational history of providing Regulation must establish and demonstrate this capability as follows:

1. Any Resource with less than one-hour sustainability must participate in the Regulation test environment specified in Section III.14.9. (For a storage facility, sustainability is measured based on full rate of charge/discharge starting from a half-full status.)
2. All Resources must satisfy a minimum responsiveness test that demonstrates that a Resource can follow AGC SetPoints.

(c) Aggregation.

(i) An ATRR that is not part of a Continuous Storage Facility may be composed of an aggregation of facilities of less than 1 MW in size.~~,~~ All facilities in an ATRR must be located in the same DRR Aggregation Zone~~which may be geographically dispersed~~. Each of the facilities that form the aggregated ATRR must meet the Regulation Market eligibility requirements specified in this Section III.14.2 other than MW size.

(ii) A single AGC SetPoint will be sent every AGC cycle to the aggregated ATRR. A Market Participant with an aggregated ATRR is responsible for management and control of the component facilities to ensure an accurate aggregate response to the AGC SetPoint.

(iii) The component facilities must be metered and recorded in a manner that allows real-time performance to be measured against Dispatch Instructions and provides for the retention of the recorded information for purposes of verification, accounting for any performance offsets from other loads, generation or devices under the direct or indirect control of the aggregator as specified in ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

III.14.3 Regulation Market Offers.

(a) A Market Participant with a Regulation Resource must submit a Regulation Market Supply Offer to provide Regulation. The Regulation Market Supply Offer may specify offer parameters that vary on an hourly basis and shall remain effective until cancelled or replaced by the Market Participant. A Market Participant may modify Regulation Market Supply Offer parameters for a given hour up to five minutes before the start of the hour. Regulation Resource availability must be updated throughout the Operating Day to reflect the actual operating capability of the resource. The Regulation Market Supply Offer of a Regulation Resource must specify the following offer parameters:

(i) Regulation Resource status (available/unavailable)

(ii) Regulation High Limit

For a Generator Asset, the Regulation High Limit must be less than or equal to the Generator Asset's Economic Maximum Limit. For Dispatchable Asset Related Demand, the Regulation High Limit must be greater than or equal to a Dispatchable Asset Related Demand's Minimum Consumption Limit. For a Continuous Storage ATRR, the Regulation High Limit must be positive and equal to the Regulation Low Limit multiplied by negative one, with an allowance for round-trip efficiency loss.

(iii) Regulation Low Limit

For a Generator Asset, the Regulation Low Limit must be greater than or equal to the Generator Asset's Economic Minimum Limit. For Dispatchable Asset Related Demand, the Regulation Low Limit must be less than or equal to a Dispatchable Asset Related Demand's Maximum Consumption Limit. For a Continuous Storage ATRR, the Regulation Low Limit must be negative and equal to the Regulation High Limit multiplied by negative one, with an allowance for round-trip efficiency loss.

(iv) Automatic Response Rate (MW/minute)

(v) Regulation Capacity Offer ($/MW)

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:

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Distributed Energy Resource participating as part of 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.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids ~~or~~ , Demand Reduction Offers or Baseline Deviation 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.

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, Settlement Only Distributed Energy Resource Aggregation, the energy injection and/or energy withdrawal portion of a Demand Response Distributed Energy Resource Aggregation, or a Load Asset, where such facility is interconnected to the New England Transmission System.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, ~~or~~ a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

SECTION 1. APPLICATION

1.1 Applicability

1.1.1 The Small Generator Interconnection Procedures ("SGIP") and Small Generator Interconnection Agreement ("SGIA") shall apply to Interconnection Requests, as defined in Attachment 1, pertaining to Small Generating Facilities, except that the SGIP and SGIA shall not apply to: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; ~~or~~ (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility; or (iv) a Distributed Energy Resource that will be participating in the wholesale market exclusively through a Distributed Energy Resource Aggregation. In the event the SGIP and SGIA do not apply, the Interconnection Customer shall follow the applicable state tariff, rules or procedures regarding generator interconnections.

A Distributed Energy Resource reviewed as part of a Distributed Energy Capacity Resource that qualifies in any Forward Capacity Auction that takes place prior to the effective date of Section III.6 (Distributed Energy Resource Aggregations), shall not be subject to the SGIP, provided that: i) the Distributed Energy Resource meets the requirements of, and is included in the Distributed Energy Capacity Resource as a single-resource Distributed Energy Resource Aggregation, ii) the Distributed Energy Capacity Resource was qualified as a resource composed of one or more Distributed Energy Resource Aggregations that are each single-resource aggregations; iii) each underlying Distributed Energy Resource has a valid state interconnection agreement, and iv) each of the underlying Distributed Energy Resources has received approval from the ISO for a Proposed Plan Application pursuant to Section I.3.9 of the Tariff, if applicable. Each Distributed Energy Resource Aggregation in such a Distributed Energy Capacity Resource shall comply with all requirements of Section III.6 of the Tariff (Distributed Energy Resource Aggregations) following its effective date.

A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) to the Interconnecting Transmission Owner's Distribution System that is part of the Administered Transmission System shall be evaluated under the section 2 Fast Track Process if the eligibility requirements of section 2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) (solely as a Network Resource) shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility no larger than 20 megawatts (MW) that does not meet the eligibility requirements of section 2.1, or does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 3 Study Process.

I.2.2. Definitions:

Baseline Deviation Offer is an offer by a Market Participant with a Demand Response Distributed Energy Resource Aggregation to reduce demand and/or inject additional energy.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset, ~~or~~ 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.

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 Distributed Energy Resource Aggregation Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Distributed Energy Resource Aggregation starts reducing demand and/or injecting energy.

Demand Response Distributed Energy Resource Aggregation Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Distributed Energy Resource Aggregation can reduce demand and/or inject additional energy.

Demand Response Distributed Energy Resource Aggregation Start-Up Time is the period of time between the time a Demand Response Distributed Energy Resource Aggregation starts reducing demand and/or injecting energy at the conclusion of the Demand Response Distributed Energy Resource Aggregation Notification Time and the time the resource can reach its Minimum Deviation and be ready for further dispatch by the ISO.

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, or Demand Response Distributed Energy Resource Aggregation dispatched by the ISO in accordance with the asset's Offer Data.

Deviation Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Distributed Energy Resource Aggregation is scheduled or dispatched in the New England Markets to reduce demand and/or provide additional energy injection.

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 or Demand Response Distributed Energy Resource Aggregations, 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 or Baseline Deviation 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.

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.

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.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids ~~or~~ , Demand Reduction Offers or Baseline Deviaiton 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.

Maximum Deviation is the maximum available baseline deviation, in MW, of a Demand Response Distributed Energy Resource Aggregation that a Market Participant offers to reduce demand and/or provide energy injection in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer

Minimum Deviation is the minimum available baseline deviation, in MW, of a Demand Response Distributed Energy Resource Aggregation that a Market Participant offers to reduce demand and/or provide additional energy injection in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer or a Baseline Deviation 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 or a Fast Start Demand Response Distributed ~~Enenrgy~~Energy Resource Aggregation that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer or a Baseline Deviation 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 or a Fast Start Demand Response Distributed ~~Enenrgy~~Energy Resource Aggregation that has not been dispatched.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, ~~or~~ a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

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.

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 Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority’s Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority’s Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: “Pre-scheduling” as specified in Section III.1.9, “Scheduling” as specified in III.1.10, and “Dispatch” as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's or Settlement Only Distributed Energy Resource Aggregation's ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset's or Settlement Only Distributed Energy Resource Aggregation's capability to perform under specified summer and winter conditions for a specified duration.

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) A Seasonal DRDERA Audit value determines the ability of a Demand Response Distributed Energy Resource Aggregation to perform during specified months for a specified duration.

~~(iii)~~(v) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's Establish Claimed Capability Audit value, ~~or~~ the Demand Response Resource's Seasonal DR Audit value or the Demand Response Distributed Energy Resource Aggregation's Seasonal DRDERA Audit value.

(b) The Claimed Capability Audit value of a Generator Asset or Settlement Only Distributed Energy Resource Aggregation shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.

(b) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(c) For a newly commercial Generator Asset or Settlement Only Distributed Energy Resource Aggregation:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and

3. Intermittent Generator Assets or intermittent Settlement Only Distributed Energy Resource Aggregations

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation.

(d) For Generator Assets or Settlement Only Distributed Energy Resource Aggregations with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.

(ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset or the sum of the maximum energy injection capabilities of the Settlement Only Distributed Energy Resource Aggregation's constituent Distributed Energy Resources.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

(g) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit or the Settlement Only Distributed Energy Resource Aggregation's net output to increase from the current operating level to its maximum energy injection capability.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

(i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset -of a type not listed in Section III.1.5.1.2 (h) or a Settlement Only Distributed Energy Resource Aggregation consisting of a single technology type not listed in Section III.1.5.1.2(h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.

(b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets and Settlement Only Distributed Energy Resource Aggregation except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's or Settlement Only Distributed Energy Resource Aggregation's Seasonal Claimed Capability Audit obligation.

(d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(e) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset or Settlement Only Distributed Energy Resource Aggregation which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset or Settlement Only Distributed Energy Resource Aggregation for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2
Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1

Hydraulic Turbine-Reversible (Electric Storage) Hydraulic Turbine-Other	2
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

(k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(l) A Generator Asset or Settlement Only Distributed Energy Resource Aggregation that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset or Settlement Only Distributed Energy Resource Aggregation to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset or Settlement Only Distributed Energy Resource Aggregation during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.3.2 Seasonal DRDERA Audits.

(a) A Seasonal DRDERA Audit may be performed only for a Demand Response Distributed Energy Resource Aggregation.

(b) A Seasonal DRDERA Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DRDERA Audit must be conducted by all Demand Response Distributed Energy Resource Aggregations:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DRDERA Audit must be conducted by all Demand Response Distributed Energy Resource Aggregations:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DRDERA Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DRDERA Audit:

(i) The ISO shall perform the Seasonal DRDERA Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DRDERA Audit by issuing a Dispatch Instruction ordering the Demand Response Distributed Energy Resource Aggregation to its Maximum Deviation.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Baseline Deviation Offer parameters, to its Maximum Deviation.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DRDERA Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.2 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DRDERA Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DRDERA Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Distributed Energy Resource Aggregation Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DRDERA Audit as provided in this Section III.1.5.1.3.2 may be used to fulfill the Seasonal DRDERA Audit obligation of a Demand Response Distributed Energy Resource Aggregation.

(h) An ISO-Initiated Claimed Capability Audit fulfills the Seasonal DRDERA Audit obligation of a Demand Response Distributed Energy Resource Aggregation.

(i) Each Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation is evaluated during the Seasonal DRDERA Audit of the Demand Response Distributed Energy Resource Aggregation.

(j) Any Distributed Energy Resource on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DRDERA Audit value (summer or winter) of a Demand Response Distributed Energy Resource Aggregation resulting from the Seasonal DRDERA Audit shall be the sum of the load reductions demonstrated during the audit by each of the Demand Response Distributed Energy Resource Aggregation's constituent Distributed Energy Resources plus the energy injected by the Demand Response Distributed Energy Resource Aggregation during the audit period.

(l) If a Distributed Energy Resource is added to or removed from a Demand Response Distributed Energy Resource Aggregation between audits, the Demand Response Distributed Energy Resource Aggregation's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Distributed Energy Resource, such that at any point in time the summer or winter Seasonal DRDERA Audit value of a Demand Response Distributed Energy Resource Aggregation shall equal the sum of the most recent valid like-season audit values of its constituent Distributed Energy Resources.

(m) The Seasonal DRDERA Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Distributed Energy Resource shall be set to zero at the end of the Capability Demonstration Year if the Distributed Energy Resource did not perform a Seasonal DRDERA Audit for that season as part of a Demand Response Distributed Energy Resource Aggregation during that Capability Demonstration Year.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource, shall replace either the summer or winter Seasonal DRDERA Audit value for a Demand Response Distributed Energy Resource Aggregation ,and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability or equivalent interconnection agreements for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation location.

(c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit, Settlement Only Distributed Energy Resource Aggregation to its maximum energy injection capability ~~or~~ the Demand Response Resource to its Maximum Reduction, or the Demand Response Distributed Energy Resource Aggregation to its Maximum Deviation.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

~~(iii)~~ For Settlement Only Distributed Energy Resource Aggregations, begin the audit with the first full clock hour after sufficient time has been allowed for the net output of the Settlement Only Distributed Energy Resource Aggregation to increase from the current operating level to its maximum energy injection capability.

(iv)

(v) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

~~(iv)~~(vi) For Demand Response Distributed Energy Resource Aggregations, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Baseline Deviation Offer parameters, to its Maximum Deviation.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2

Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource or Demand Response Distributed Energy Resource Aggregations	1
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer, Baseline Deviation Offer or other operating parameter that impacts the ability of a Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation to provide real-time energy or reserves.

(b) Generator Asset audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) Demand Response Distributed Energy Resource Aggregation audits shall be performed using the following methods:

(i) **Maximum Deviation**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to achieve the current offered Maximum Deviation value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Distributed Energy Resource Aggregation Ramp Rate**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Distributed Energy Resource Aggregation Ramp Rate.

(iii) **Demand Response Distributed Energy Resource Aggregation Start-Up Time**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to achieve its Minimum Deviation within the offered Demand Response Distributed Energy Resource Aggregation Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Distributed Energy Resource Aggregation Notification Time.

(iv) **Demand Response Distributed Energy Resource Aggregation Notification Time**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to start deviating demand within its offered Demand Response Distributed Energy Resource Aggregation Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Distributed Energy Resource Aggregation was not previously deviating demand.

(v) **CLAIM10**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

~~(d)~~(e) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation performance in response to Dispatch Instructions.

~~(e)~~(f) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation for the parameters being audited.

~~(f)~~(g) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

~~(g)~~(h) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer, Baseline Deviation Offer, or other operating parameter values that are not representative of the actual capability of the Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation, the values for the Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation shall be restricted to those values that are supported by the audit.

~~(h)~~(i) In the event that a Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

(i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

~~III.1.7.13~~ III.1.7.13 Seasonal DECR Audit Value.

(a) A Seasonal DECR Audit Value must be established and maintained for all Distributed Energy Capacity Resources. A summer Seasonal DECR Audit Value is established for use from June 1 through September 30 and a winter Seasonal DECR Audit Value is established for use from October 1 through May 31.

(b) The Seasonal DECR Audit Value of Distributed Energy Capacity Resources is the sum of: the Seasonal Claimed Capabilities of Distributed Energy Resource Aggregations participating as a Generator Asset or a Settlement Only Distributed Energy Resource Aggregation; the Seasonal DR Audit value of a Distributed Energy Resource Aggregation participating as a Demand Response Resource; and the Seasonal DRDERA Audit values of the Demand Response Distributed Energy Resource Aggregations comprising the Distributed Energy Capacity Resource.

(c) The Seasonal Claimed Capability of a Settlement Only Distributed Energy Resource is:

a. Based upon review of historical data for non-intermittent daily cycle hydro.

b. The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities as reflected in hourly revenue metering data.

c. For all other Settlement Only Distributed Energy Resources, the minimum of: (1) the Settlement Only Distributed Energy Resource's current Establish Claimed Capability Audit value and (2) the Settlement Only Distributed Energy Resource's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

~~(a)~~(d) The Seasonal DRDERA Audit value for Distributed Energy Resource Aggregations participating as Demand Response Distributed Energy Resource Aggregations is the value of the audit for the aggregation performed pursuant to Section III.1.5.1.3.2.~~**[Reserved.]**~~

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each 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 Forward Capacity Auction 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 include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each 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.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

(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 Projects Selected Through the Competitive Transmission Process.

For a transmission project selected through the competitive transmission process pursuant to Sections 4.3 and 4Aof Attachment K, such transmission project, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement. The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement to determine whether to include the transmission project, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission project 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.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

(a) all Existing Generating Capacity Resources,

(b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) 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

(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:

(~~f~~e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period, (g~~f~~) 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

(h~~g~~) 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.

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:

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.]

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.

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

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction 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.

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 Resources and Seasonal Peak Demand 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 Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

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;
4. Qualified Existing Distributed Energy Capacity Resources reflecting their existing Qualified Capacity for the Capacity Commitment Period;
54. 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

memo

To: NEPOOL Markets, Reliability, and Transmission Committees

From: Henry Yoshimura, Director, Demand Resource Strategy

Date: December 1, 2021

Subject: Order No. 2222: Participation of Distributed Energy Resource Aggregations in Wholesale Markets

The ISO is requesting votes on its proposed Tariff revisions to comply with the Commission's Order No. 2222 regarding the participation of distributed energy resource aggregations in wholesale markets. By way of background, Order No. 2222 requires revisions to the Tariff to allow distributed energy resources to provide all wholesale services that they are technically capable of providing through an aggregation of resources as described in eleven key compliance directives. The Commission allows Independent System Operators and Regional Transmission Organizations to comply with Order No. 2222 by revising their tariffs to be consistent with the specific requirements of the Order, or by demonstrating how current tariff provisions satisfy the intent and objectives of the Order.

The ISO has put together a package of Tariff changes that will allow Distributed Energy Resources (DERs) to provide all wholesale services that they are technically capable of providing through an aggregation of DERs (known as Distributed Energy Resource Aggregations or "DERAs") that collectively address the eleven key compliance directives. The ISO has presented to and collaborated with stakeholders on this compliance project since December, 2020 through the various NEPOOL technical committees.

With regards to the compliance requirements of Order No. 2222, the Markets Committee has focused on the market design (for the energy and ancillary services markets, and the Forward Capacity Market), metering and telemetry requirements, the DER/DERA registration process, and operational coordination. The Reliability Committee has focused on matters related to auditing and Installed Capacity Requirements. The Transmission Committee has focused on matters related to the interconnection procedures. All committees have reviewed the changes to defined terms that are used in their respective Tariff areas.

The ISO is proposing two effective dates for these proposed compliance revisions. The proposed effective date for the Forward Capacity Market changes will be during the fourth quarter of 2022 so that the ISO could implement needed changes on time for the FCA 18 qualification process, which commences in the spring of 2023. Assuming that the Commission accepts the ISO's proposal by the fourth quarter of 2022, Distributed Energy Capacity Resources will be able to participate in FCA 18, which will be conducted in February, 2024 for the Capacity Commitment Period beginning June 1, 2027. The proposed effective date for the changes to the energy and ancillary services markets will be during the fourth quarter of 2026,

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Holyoke, MA 01040-2841

such that resources can be commercial and integrated ahead of the Capacity Commitment Period beginning June 1, 2027.

The ISO's proposal incorporates a number of stakeholder-suggested revisions and is the product of extensive discussion with stakeholders. The proposal for the committees' consideration at its December meetings have been presented on the meeting dates outlined below:

Markets Committee

- December 8, 2020, agenda item #8
- January 12, 2021, agenda item #3
- February 9-10, 2021, agenda item #7
- March 9, 2021, agenda item #4
- April 6, 2021, agenda item #6
- May 11, 2021, agenda item #4
- June 8-9, 2021, agenda item #4
- July 7-8, 2021, agenda item #5
- August 10-12, 2021, agenda item #2
- September 13-14, 2021, agenda item #4
- October 13-14, 2021, agenda item #10
- November 9-10, 2021, agenda item #8

Transmission Committee

- February 23, 2021, agenda item #3
- March 23, 2021, agenda item #3
- May 27, 2021, agenda item #3
- June 10, 2021, agenda item #3
- July 14, 2021, agenda item #4
- September 28, 2021, agenda item #5
- October 26, 2021, agenda item #4
- November 19, 2021, agenda item #4

Reliability Committee

- July 13, 2021, agenda item #7
- August 17, 2021, agenda item #8
- September 21, 2021, agenda item #8
- October 19, 2021, agenda item #7

memo

To: Participants Committee

From: Jay Dwyer, Acting Secretary, Markets Committee

Date: December 10, 2021

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 its December 7-9, 2021 meeting. All sectors had a quorum.

Agenda Item No. 1A - Meeting Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee approves the minutes of the October 13-14, 2021 NEPOOL Markets Committee meeting and the minutes of the October 21, 2021 NEPOOL Markets Committee meeting, as circulated on December 1, 2021 for the December 7-9, 2021 NEPOOL Markets Committee meeting, with those changes recommended by this Committee at the meeting and 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 unanimously.

Agenda Item No. 1B - MC Vice Chair Election

ACTION: APPROVED

The following motion was adopted by the Markets Committee by unanimous consent:

RESOLVED, that the Markets Committee hereby elects William Fowler for 2022 to the office of Vice-Chair to serve until his successor is elected and qualified.

Agenda Item No. 3(a) - Order No. 2222 - Participation of Distributed Energy Resource Aggregations in Markets Operated By RTOs/ISOs

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

ISO New England Inc.
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413-535-4135
jdwyer@iso-ne.com

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Section I.2.2 of the Tariff and Market Rule 1 to allow distributed energy resources (DERs) to provide all wholesale services that they are technically capable of providing through an aggregation, as proposed by ISO New England's Order No. 2222 compliance proposal (Docket No. RM18-9-000), and as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

(Vote 1 – Failed - Agenda Item No. 3(a)(i) - Advanced Energy Economy Amendment 1B: Expand Baseline Calculation Optionality for DRRs and DRDERAs by Allowing Generation to Count as Load Reduction)

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to Section III.8.2A of Market Rule 1, as contained in the materials provided by Advanced Energy Economy, to expand the baseline calculation optionality for DRRs and DRDERAs by allowing generation to count as load reduction, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a roll call vote, the motion failed to pass with a vote of 32.98% in favor. The individual Sector votes were Generation (4.18% in favor, 12.53% opposed, 0 abstentions), Transmission (0.00% in favor, 16.70% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 9 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 1 abstention), Alternative Resources (12.10% in favor, 4.40% opposed, 3 abstentions), and End User (16.70% in favor, 0.00% opposed, 6 abstentions).

(Vote 2 – Failed - Agenda Item No. 3(a)(ii) - Advanced Energy Economy Amendment 2 - Allow Submetered Load to Participate as Demand Response)

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to Section I.2.2 of the Tariff and Sections III.3.2.2(c)(i), III.6.1, III.6.4, III.6.5.b and III.8.1.1 of Market Rule 1, as contained in the materials provided by Advanced Energy Economy, to allow submetered load to participate as demand response, ascirculated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a roll call vote, the motion failed to pass with a vote of 36.02% in favor. The individual Sector votes were Generation (5.57% in favor, 11.13% opposed, 1 abstention), Transmission (0.00% in favor, 16.70% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 11 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 1 abstention), Alternative Resources (13.75% in favor, 2.75% opposed, 4 abstentions), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

(Vote 3 – Failed - Agenda Item No. 3(a)(iii)- Advanced Energy Economy Amendment 3: Allow Third Parties to Perform Sub-Metering)

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to Section I.2.2 of the Tariff and Section III.6.4(g) of Market Rule 1, as contained in the materials provided by Advanced Energy Economy, to allow third parties to perform sub-metering, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a roll call vote, the motion failed to pass with a vote of 40.70% in favor. The individual Sector votes were Generation (8.35% in favor, 8.35% opposed, 3 abstentions), Transmission (0.00% in favor, 16.70% opposed, 0 abstentions), Supplier (5.57% in favor, 11.13% opposed, 12 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 0 abstentions), Alternative Resources (10.08% in favor, 6.42% opposed, 5 abstentions), and End User (16.70% in favor, 0.00% opposed, 4 abstentions).

(Vote 4 – Failed - Agenda Item No. 3(a)(iv) - Advanced Energy Economy Amendment 4A: Remove Barriers for DERs That Can Provide Ancillary Services by Removing the Requirement to Clear in the Energy Market if Providing Spinning Reserves)

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to Section III.1.7.19.2.3 of Market Rule 1, as contained in the materials provided by Advanced Energy Economy, to remove barriers for DERs that can provide ancillary services by removing the requirement to clear in the energy market if providing spinning reserves, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a roll call vote, the motion failed to pass with a vote of 35.90% in favor. The individual Sector votes were Generation (4.18% in favor, 12.53% opposed, 0 abstentions), Transmission (0.00% in favor, 16.70% opposed, 0 abstentions), Supplier (3.34% in favor, 13.36% opposed, 9 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 0 abstentions), Alternative Resources (11.69% in favor, 4.81% opposed, 3 abstentions), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

(Vote 5 – Failed - Agenda Item No. 3(a)(v) - Advanced Energy Economy Amendment 4B: Remove Barriers for DERs That Can Provide Ancillary Services by Allowing Sub-metering for Resources Providing Regulation)

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to Sections III.6.4, III.14.2 of Market Rule 1, as contained in the materials provided by Advanced Energy Economy, to remove barriers for DERs that can provide ancillary services by allowing sub-metering for resources providing regulation, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a roll call vote, the motion failed to pass with a vote of 32.56% in favor. The individual Sector votes were Generation (4.18% in favor, 12.53% opposed, 0 abstentions), Transmission (0.00% in favor, 16.70% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 11 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 0 abstentions), Alternative Resources (11.69% in favor, 4.81% opposed, 3 abstentions), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

(Vote 6 – Failed - Agenda Item No. 3(a)(vii) - Advanced Energy Economy Amendment 1A: Expand Baseline Calculation Optionality for Demand Response Resources (DRRs) and Demand Response Distributed Energy Resource Aggregations (DRDERAs) with an Add-Back Baseline Methodology)

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to Section I.2.2 of the Tariff and Sections III.1.5.1.3.1, III.1.10.1A(e)(ii), III.1.10.1A(e)(ii)(a), III.3.2.1, III.6.5, III.8.2, III.8.3.1, III.8.3.2, III.8.3.3, III.8.3.4, III.8.4, III.8.4.1, III.8.4.2, III.8.4.3, III.8.4.4, III.8.5, III.8.6, and III.9.5.3.4 of Market Rule 1, as contained in the materials provided by Advanced Energy Economy, to expand baseline calculation optionality for DRRs and DRDERAs with an add-back baseline methodology, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a roll call vote, the motion failed to pass with a vote of 26.78% in favor. The individual Sector votes were Generation (0.00% in favor, 16.70% opposed, 1 abstention), Transmission (0.00% in favor, 16.70% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 11 abstentions), Publicly Owned Entity (0.00% in favor, 0.00% opposed, 49 abstentions) [1], Alternative Resources (10.08% in favor, 6.42% opposed, 3 abstentions), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

(Vote 7 – Passed - Agenda Item No. 3(a) – Main Motion)

The main motion was then voted and, based on a roll call vote, the motion passed with a vote of 71.11% in favor. The individual Sector votes were Generation (16.70% in favor, 0.00% opposed, 1 abstention), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (14.31% in favor, 2.39% opposed, 5 abstentions), Publicly Owned Entity (16.70% in favor, 0.00% opposed, 0 abstentions), Alternative

[1] For this vote, with a Sector Quorum and all Sector members abstaining, no portion of the Adjusted Sector Voting Share was (i) reallocated to the other Sectors or (ii) included in either the totals in favor or opposed to the motion.

Resources (6.70% in favor, 9.80% opposed, 2 abstentions), and End User (0.00% in favor, 16.70% opposed, 1 abstention).

memo

To: NEPOOL Participants Committee

From: Jay Dwyer, Secretary, NEPOOL Transmission Committee

Date: December 13, 2021

Subject: Actions of the Transmission Committee

This memo is notification to the Participants Committee of the following actions taken by the Transmission Committee at its December 13, 2021 meeting. A quorum was present for all votes.

Agenda Item No. 2. November 19, 2021 Meeting Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Transmission Committee:

> *Resolved*, that the Transmission Committee approves the minutes of the November 19, 2021 meeting as reflected in the materials distributed for its December 13, 2021 meeting, with any changes agreed to at the meeting and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. The motion passed based on a voice vote, with no opposition and no abstentions recorded.

Agenda Item No. 3: reconfirmation of the Election of the Committee Vice Chair:

ACTION: APPROVED

The following motion was moved and seconded by the Transmission Committee:

> *Resolved,* that, in keeping with its prior practice, the Transmission Committee reconfirms its election of Jose Rotger for the new term commencing January 1, 2022.

The motion was then voted. The motion passed on voice vote with no opposition and no abstentions recorded.

Agenda Item No. 4: Order No. 2222 Participation of Distributed Energy Resource Aggregations in Wholesale Markets – ISO Compliance Filing

ACTION: Recommend Support

The following motion was moved and seconded by the Transmission Committee:

> *Resolved*, that the Transmission Committee recommends Participant Committee support for ISO New England's proposed revisions to Sections I.2.2. and II of the Transmission, Markets, and Services Tariff in compliance with the FERC's Order 2222, with such changes as are accepted by the ISO at the meeting and such further non-substantive changes as the Chair and Vice Chair of the Transmission Committee approve.

The motion was then voted. The motion passed on voice vote with no opposition and three abstentions recorded (one each in the Alternative Resources, End User, and Supplier Sectors).

ISO new england

memo

To: Participants Committee

From: Marc Lyons, Secretary, Reliability Committee

Date: December 14, 2021

Subject: Actions of the December 14, 2021 Reliability Committee Meeting – **Revision 1**

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its December 14, 2021 meeting of the Reliability Committee. All Sectors had a quorum with the exception of End User.

(Agenda Item 2.0) (66.67% Vote) RC Vice Chair Confirmation

ACTION: APPROVED

Resolved, that the Reliability Committee hereby re-elects Robert Stein for 2022 to the office of Vice-Chair to serve until his successor is elected and qualified.

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

(Agenda Item 3.0) (66.67% Vote) Meeting Minutes

ACTION: APPROVED

Resolved, the Reliability Committee recommends that ISO New England Inc. approve the minutes of the following RC meetings as distributed to the committee for the December 14, 2021 meeting together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee:

- November 16, 2021

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-540-4517
mlyons@iso-ne.com

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

(Agenda Item 5.1) (66.67% Vote) Bay State Wind Generation and Transmission Project (QP 846) - Proposed Plan Applications (PPAs) ES-18-G63-Rev. 1, ES-18-T26-Rev. 1, ES-18-27-Rev. 1, ES-18-28-Rev. 1, ES-18-29-Rev. 1, & ES-18-T30-Rev. 1

ACTION: APPROVED

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the Bay State Wind Generation and Transmission Project (QP 846) - Proposed Plan Applications (PPAs) ES-18-G63-Rev. 1, ES-18-T26-Rev. 1, ES-18-27-Rev. 1, ES-18-28-Rev. 1, ES-18-29-Rev. 1, & ES-18-T30-Rev. 1 from Eversource Energy (ES), as detailed in their December 6, 2021 transmittal to ISO New England and distributed to the committee for the December 14, 2021 meeting, together with a recommendation letter from ISO New England, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

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

(Agenda Item 5.2) (66.67% Vote) Milford Grid Battery Energy Storage Generation and Transmission Project (QP 1017) - Proposed Plan Applications (PPAs) AGIH-21-G03, AGIH-21-T03, ES-21-T96, & UI-21-T02

ACTION: APPROVED

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the Milford Grid Battery Energy Storage Generation and Transmission Project (QP 1017) - Proposed Plan Applications (PPAs) AGIH-21-G03, AGIH-21-T03, ES-21-T96, & UI-21-T02 from Able Grid Infrastructure Holdings (AGIH), Eversource Energy (ES), and United Illuminating (UI) as detailed in their December 5, 2021, November 30, 2021, & December 3, 2021 transmittals to ISO New England and distributed to the committee for the December 14, 2021 meeting, together with a recommendation letter from ISO New England, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and three abstentions (1 Generation Sector, 1 Supplier Sector, 1 Alternative Resource Sector)

(Agenda Item 5.3) (66.67% Vote) Leeds Solar Generation Project (QP 923) - Proposed Plan Application (PPA) CMP-21-G32

ACTION: APPROVED

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of Leeds Solar Generation Project (QP 923) described in Proposed Plan Application (PPA) CMP-21-G32 from Central Maine Power (CMP) as detailed in their November 30, 2021 transmittal to ISO New England and distributed to the committee for the December 14, 2021 meeting, together with a recommendation letter from ISO New England, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

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

(Agenda Item 5.4) (66.67% Vote) Glenvale River Road Putnam Solar Project - Proposed Plan Application (PPA) ES-21-G103

ACTION: APPROVED

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of Glenvale River Road Putnam Solar Project described in Proposed Plan Application (PPA) ES-21-G103 from Eversource Energy (ES) as detailed in their November 30, 2021 transmittal to ISO New England and distributed to the committee for the December 14, 2021 meeting, together with a recommendation letter from ISO New England, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

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

(Agenda Item 5.5) (66.67% Vote) Winslow and Lakewood Distributed Energy Resource (DER) Group Study Project - Proposed Plan Applications (PPAs) CMP-21-G34 through CMP-21-G53

ACTION: APPROVED

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of Winslow and Lakewood Distributed Energy Resource (DER) Group Study Project - Proposed Plan Applications (PPAs) CMP-21-G34 through CMP-21-G53 from Central Maine Power Company (CMP) as detailed in their November 30, 2021 transmittal to ISO New England and distributed to the committee for the December 14, 2021 meeting, together with a recommendation letter from ISO New England, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and two abstentions (1 Generation Sector, 1 Alternative Resource Sector).

(Agenda Item 6.1) (66.67% Vote) PTF Cost Allocation - TCA Application ES-21-TCA-36, ES-21-TCA-37, ES-21-TCA-38, ES-21-TCA-43, & ES-21-TCA-48

ACTION: APPROVED

Resolved, the Reliability Committee has reviewed the requested $64.658M (2021 Estimated Costs) of aggregated Transmission Upgrade costs for work associated with the 115 kV and 230 kV wood structure replacement projects located in Massachusetts, Connecticut and New Hampshire as described in TCA Applications: ES-21-TCA-36 ($5.672M), ES-21-TCA-37 ($11.636M), ES-21-TCA-38 ($5.451M), ES-21-TCA-43 ($13.105M), and ES-21-TCA-48 ($28.794M) which were submitted to ISO-NE between August 2, 2021 and October 7, 2021 by Eversource Energy; and the Reliability Committee recommends that ISO New England approve, as consistent with the criteria set forth in Section 12C of the ISO New England Open Access Transmission Tariff for receiving regional support and inclusion in Pool-Supported PTF Rates, the requested $64.658M as eligible for Pool-Supported PTF cost recovery and with none of the costs associated with such upgrades being considered Localized Costs.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and **no abstentions.**

(Agenda Item 6.2) (66.67% Vote) PTF Cost Allocation - TCA Application ES-21-TCA-42, ES-21-TCA-35, ES-21-TCA-27, ES-21-TCA-29, ES-21-TCA-46, ES-21-TCA-24, ES-21-TCA-25, ES-21-TCA-30, ES-21-TCA-26, ES-21-TCA-40, & ES-21-TCA-01

ACTION: APPROVED

Resolved, the Reliability Committee has reviewed the requested $186.287M (2021 Estimated Costs) of aggregated Transmission Upgrade costs for work associated with the 345 kV structure replacement projects located in Massachusetts, Connecticut and New Hampshire as described in TCA Applications: ES-21-TCA-01 ($9.351M), ES-21-TCA-24 ($14.535M), ES-21-TCA-25 ($14.900M), ES-21-TCA-26 ($7.838M), ES-21-TCA-27 ($9.860M), ES-21-TCA-29 ($16.778M), ES-21-TCA-30 ($21.160M), ES-21-TCA-35 ($8.039M), ES-21-TCA-40 ($9.7040M), ES-21-TCA-42 ($61.333M), and ES-21-TCA-46 ($12.781) which were submitted to ISO-NE between January 22, 2021 and August 24, 2021 by Eversource Energy; and the Reliability Committee recommends that ISO New England approve, as consistent with the criteria set forth in Section 12C of the ISO New England Open Access Transmission Tariff for receiving regional support and inclusion in Pool-Supported PTF Rates, the requested $186.2878M as eligible for Pool-Supported PTF cost recovery and with none of the costs associated with such upgrades being considered Localized Costs.

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

(Agenda Item 6.3) (66.67% Vote) PTF Cost Allocation - TCA Application ES-19-TCA-48 Rev. 1

ACTION: APPROVED

Resolved, the Reliability Committee has reviewed the requested $23.854 million (2021 Actual Costs) of Transmission Upgrade costs for work associated with replacement of wood structures on the 1261/1598 115 kV line, as described in TCA Application ES-19-TCA-48 Rev. 1 submitted to ISO New England on October 7, 2021 by Eversource Energy; and the Reliability Committee recommends that ISO New England approve, as consistent with the criteria set forth in Section 12C of the ISO New England Open Access Transmission Tariff for receiving regional support and inclusion in Pool-Supported PTF Rates, the requested $23.854 million as eligible for Pool-Supported PTF cost recovery and with none of the costs associated with such upgrades being considered Localized Costs.

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

(Agenda Item 8.1) (66.67% Vote) ISO New England Planning Procedure 10

ACTION: APPROVED

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Planning Procedure 10 – Planning Procedure to Support the Forward Capacity Market as distributed to the committee for the December 14, 2021 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

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

(Agenda Item 9.0) (60.0% Vote) Order 2222 – Participation of DER Aggregation in the Wholesale Markets

ACTION: APPROVED

Resolved, that the Reliability Committee recommends Participant Committee support for ISO New England's proposed revisions related to compliance with Order 2222, to Sections: I.2.2., III.1.5, III.1.7.13, III.9.5.3, and III.12 of the Transmission, Markets, and Services Tariff as distributed for the December 14, 2021 Reliability Committee meeting, with such changes as are accepted by the ISO at the meeting and such further non-substantive changes as the Chair and Vice Chair of the Reliability Committee approve.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and ten abstentions (2 Generation Sector, 1 Transmission Sector, 5 Supplier Sector, 2 Alternative Resource Sector).

(Agenda Item 12.1) (66.67% Vote) ISO New England Operating Procedure No. 16K

ACTION: APPROVED

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 16K – Transmission System Data – Submission of Short Circuit Data, as distributed to the committee for the December 14, 2021 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

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

(Agenda Item 12.2) (66.67% Vote) ISO New England Operating Procedure No. 3

ACTION: APPROVED

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 3 – Transmission Outage Scheduling, as distributed to the committee for the December 14, 2021 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

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

Proposed Amendments to ISO-NE's Order No. 2222 Compliance Proposal

Advanced Energy Economy

December 7-9, 2021

Markets Committee

About Advanced Energy Economy (AEE)

- National association of businesses that are making the energy we use secure, clean, and affordable.

- We are the only industry association in the United States that represents the full range of advanced energy technologies and services, both grid-scale and distributed. Advanced energy includes energy efficiency, demand response, energy storage, wind, solar, hydro, nuclear, electric vehicles, and more.

- AEE's members include:
  - Leading developers of distributed energy resources like rooftop solar PV, energy storage, electric vehicles, demand response, and energy efficiency resources;
  - Aggregators providing energy management services to industrial, commercial, and residential customers;
  - EV supply equipment and electrified fleet developers and owners, including passenger vehicles, buses and transit, and delivery vehicles; and
  - Large customers with distributed energy resources.

Outline

- Benefits to expanding market participation for DERs
- Outstanding barriers within ISO-NE proposal
- Proposed amendments and tariff revisions

Benefits to DER Participation in ISO-NE

Order No. 2222 is not just a Compliance Obligation, but an Opportunity to Realize Many Benefits for our Region

- Viable participation models that enable DERs to fairly compete by participating in wholesale markets to their full potential will:*
  - Make the ISO's jobs of maintaining **reliability** easier by increasing **visibility** and **dispatchability** of resource mix, especially during system peaks
  - **Reduce customer costs** by avoiding reliance (and payment) to other resources to supply system needs that DERs can provide more cost-effectively
  - **Reduce emissions** and usage of less-efficient resources, which will promote state clean energy policies
  - Substantially augment **load flexibility**, which will help to manage an increasingly variable resource mix

- Without viable participation models for DERs, these resources do not have a reliable funding steam, and our region is foregoing all the benefits listed above.

**Source: American Council for an Energy Efficient Economy*

DER potential in New England is Significant

- There are already 7-8 GW of DERs in New England, and this number is growing rapidly.

- State commitments are a clear indicator of the growing DER market:
  - **CT**: 580 MW customer-sited storage by 2030; 150,000 EVs by 2025 / 500,000 EVs by 2030.
  - **MA**: 300,000 EVs by 2025; 1,000 MWh of storage by 2025.
  - **ME**: 400 MW storage by 2030; 41,000 EVs by 2025 / 219,000 EVs by 2030.
  - **RI**: 43,000 EVs by 2025
  - **VT**: 50,000 EVs by 2025
  - Not listed above include growing numbers of smart water heaters, smart thermostats, electric fleets, etc.

Modifying the DRR model is within the scope of Order 2222

- In July, ISO-NE stated that it was not considering modifications to the existing DRR model because this was "not within the scope of Order No. 2222 compliance" due to FERC's statement that the "final rule does not affect existing demand response rules" (ISO-NE July MC presentation, slide 21)

- **While FERC did not want Order 2222 to disrupt existing DR participation**, we disagree with ISO-NE's conclusion. In Order No. 2222, FERC identified the shortcomings of existing DRR models as an example of the market participation barriers that it found were unjust and unreasonable and that must be remedied by RTOs/ISOs:
  - "In order to participate in RTO/ISO markets, distributed energy resources tend to participate in RTO/ISO demand response programs. While these demand response programs have helped reduce barriers to load curtailment resources, **they often limit the operations of some types of distributed energy resources, such as electric storage or distributed generation, as well as the services that they are eligible to provide.**" *P28 (emphasis added)*

- FERC also specified that this could be accomplished by creating new participation models, modifying existing participation models, or some combination thereof:
  - "…to meet the goals of the final rule, each RTO/ISO can comply with the requirement to allow distributed energy resource aggregators to participate in its markets **by modifying its existing participation models to facilitate the participation of distributed energy resource aggregations,** by establishing one or more new participation models for distributed energy resource aggregations, or by adopting a combination of those two approaches." *P102-103, emphasis added*

Proposed Amendments

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
- **Amendment 2**: Allow submetered load to participate as demand response
- **Amendment 3**: Allow third parties to perform submetering
- **Amendment 4:** Remove barriers for DERs that can provide ancillary services
  - 4a: Remove the requirement to clear in energy market if providing spinning reserves
  - 4b: Allow submetering for DERs providing regulation service
- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
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- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

Amendment 1 Background

- **Background:** What is a baseline?
  - Baselines were created 10+ years ago as a way to approximate "normal load" absent a load reduction; DR's load reduction is equal to the difference between the baseline and metered load
  - Given the evolution in DERs, **certain ISOs offer multiple baseline calculation options** or have evolved their baselines (e.g., NYISO, PJM, CAISO)
  - In ISO-NE, baseline is based on average of metered load for the same interval from recent weekdays (if calculating for a weekday) or from recent weekends/holidays (if calculating for a weekend/holiday); there is also a day-of adjustment to reflect that day's operations.

- **Proposal**: Add two new baseline calculation *options* for DRRs and DRDERAs:
  a) "Add-back" methodology for frequently utilized DERs (NYISO)
  b) Generation as reduced load (PJM)

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
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  - 4b: Allow submetering for DERs providing regulation service
- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

Amendment 1a: Changes to further ensure a facility is unable to receive payments if they take no action to reduce their consumption from the grid

- As indicated in the December 3rd Memo posted by AEE, we are proposing two additional modifications to Amendment 1A:
  - Any DER Aggregator that chooses this baseline option will be required to submit both meter data and device-level data that demonstrates that there was a change in net consumption at the customer facility during the ISO dispatch. (slide 17)
  - Any DER Aggregator that choses this baseline option would completely forgo positive energy payments outside of Pay for Performance ("PfP") events. (slide 15)

Amendment 1a: Add-back baseline methodology (based on FERC approved NYISO tariff)

Overview of intent for proposed Tariff redlines

1. Current DR price offer model does not change, DR still subject to the Demand Reduction Threshold Price requirements
2. Resources using the Distributed Energy Resource Add-Back Baseline option may offer and clear below Demand Reduction Threshold Price, but receive no energy market compensation
3. Resources may elect to apply either the existing DR Baseline or the Distributed Energy Resource Add-Back Baseline
4. Distributed Energy Resource Add-Back Baselines follow identical tariff language as Demand Response Baselines
5. Weekday, Saturday, and Sunday & Holiday Distributed Energy Resource Addback Baseline adapted from current tariff baseline language to include any demand reduction along with metered load
6. Distributed Energy Resource Addback Baseline Adjustment adapted from current tariff baseline language to include any demand reduction along with metered load

See appendix for overview of add-back concept and how it addresses a baseline erosion barrier for frequently utilized DERs.

Current DR price offer model does not change, DR still subject to the Demand Reduction Threshold Price requirements

III.1.10.1A (e) (ii)

Demand Response Resources and Distributed Energy Resources associated with a Demand Response Distributed Energy Resource Aggregation using the Demand Response Baseline methodology shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day unless they meet the exception in Section III.1.10.1A (e) (ii) (a). For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day with the exception of prices submitted by resources described in Section III.1.10.1A (e) (ii) (a).

Resources using the Distributed Energy Resource Add-Back Baseline option may offer and clear below Demand Reduction Threshold Price, but receive no energy market compensation

Tariff Language Revised During December 7-9 MC Meeting

III.1.10.1A(e) (ii) (a)

(a) Demand Response Resources and Distributed Energy Resources associated with a Demand Response Distributed Energy Resource Aggregation using the Demand Response Add-Back Baseline methodology pursuant to III.8.4 may specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any resource associated with a Demand Response Distributed Energy Resource Aggregation using the Demand Response Add-Back Baseline shall receive no positive settlement payments for either the Day-Ahead or Real-Time Energy Market.

Resources may elect to apply either the existing DR Baseline or the Distributed Energy Resource Add-Back Baseline

I.2.2

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.8.3.

Distributed Energy Resource Add-Back 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.8.4.

***

III.8.2

Electing to Apply the Demand Response Baselines or the Distributed Energy Resource Add-Back Baselines

Demand Response Resources and Distributed Energy Resources associated with a Demand Response Distributed Energy Resource Aggregation may elect to apply the Demand Response Baseline methodology according to Section III.8.3 or the Distributed Energy Resource Add-Back Baseline methodology according to Section III.8.4.

Distributed Energy Resource Add-Back Baselines follow identical tariff language as Demand Response Baselines

III.8.4 Distributed Energy Resource Add-Back Baselines

(a) A **Distributed Energy Resource Add-Back** Baseline is calculated for each Demand Response Asset for the following three day types:

(i) weekdays (excluding Demand Response Holidays);

(ii) Saturdays; and

(iii) Sundays and Demand Response Holidays.

(b) A Market Participant shall not take any action to create or maintain a Distributed Energy Resource Add-Back Baseline that exceeds the typical electricity consumption levels of its end-use metered customers expected in the normal course of business. Any DER Aggregator that chooses the Distributed Energy Resource Add-Back Baseline option will be required to submit both meter data and device-level data that demonstrates that there was a change in net consumption at the customer facility during the ISO dispatch.

(c) If a Demand Response Asset produces Net Supply in an interval, that Net Supply will be used in the Demand Response Baseline calculations for that interval.

Weekday Distributed Energy Resource Addback Baseline adapted from current tariff baseline language to include any demand reduction along with metered load

III.8.4.1 Determining the Weekday Non-Holiday Distributed Energy Resource Addback Baseline.

A Distributed Energy Resource Asset's weekday (non-Demand Response Holiday) Distributed Energy Resource Addback Baseline in each five-minute interval is equal to the sum of the average of the asset's meter data and any demand reduction for the same five-minute interval from 10 prior non-Demand Response Holiday weekdays, as follows:

(a) For a Distributed Energy Resource Asset without a weekday Distributed Energy Resource Baseline, the initial weekday Distributed Energy Resource Baseline will be created using meter data from the first 10 consecutive non-Distributed Energy Resource Holiday weekdays with a complete set of five-minute interval meter data.

(b) For a Distributed Energy Resource Asset that has established a weekday Distributed Energy Resource Baseline, the baseline will be updated using the sum of the asset's meter data and any demand reduction from the 10 most recent non-Demand Response Holiday weekdays in which the Distributed Energy Resource Asset was not on a forced or scheduled curtailment as described in Section III.8.5.

Saturday Distributed Energy Resource Addback Baseline adapted from current tariff baseline language to include any demand reduction along with metered load

III.8.4.2 Determining the Saturday Distributed Energy Resource Add-Back Baseline

A Distributed Energy Resource Asset's Saturday Distributed Energy Resource Addback Baseline in each five-minute interval is equal to the sum of the average of the asset's meter data and any demand reduction for the same five-minute interval from five prior Saturdays as follows:

(a) For a Distributed Energy Resource Asset without a Saturday Distributed Energy Resource Baseline, the Saturday Distributed Energy Resource Baseline will be created using meter data from the first five consecutive Saturdays with a complete set of five-minute interval meter data.

(b) For a Distributed Energy Resource Asset that has established a Saturday Distributed Energy Resource Baseline, the baseline will be updated using the sum of the asset's meter data and any demand reduction from the five most recent Saturdays, excluding Saturdays during which the asset was on a forced or scheduled curtailment as described in Section III.8.5.

Sunday & Holiday Distributed Energy Resource Addback Baseline adapted from current tariff baseline language to include any demand reduction along with metered load

III.8.4.3 Determining the Sunday and Demand Response Holiday Distributed Energy Resource Add-Back Baseline

A Distributed Energy Resource Asset's Sunday and Demand Response Holiday Distributed Energy Resource Addback Baseline in each five-minute interval is equal to the sum of the average of the asset's meter data and any demand reduction for the same five-minute interval from five prior Sundays or Demand Response Holidays as follows:

(a) For a Distributed Energy Resource Asset without a Sunday and Demand Response Holiday Distributed Energy Resource Baseline, the Sunday and Demand Response Holiday Distributed Energy Resource Baseline will be created using meter data from the first five consecutive Sundays and Demand Response Holidays with a complete set of five-minute interval meter data.

(b) For a Distributed Energy Resource Asset that has established a Sunday and Demand Response Holiday Distributed Energy Resource Baseline, the baseline will be updated using the sum of the asset's meter data and any demand reduction from the five most recent Sundays or Demand Response Holidays excluding Sundays or Demand Response Holidays during which the asset was on a forced or scheduled curtailment as described in Section III.8.3. Distributed Energy Resource Distributed Energy Resource

Distributed Energy Resource Addback Baseline Adjustment adapted from current tariff baseline language to include any demand reduction along with metered load

III.8.4.4 Adjusted Distributed Energy Resource Add-Back Baselines

(a) The ISO will also calculate an adjusted Distributed Energy Resource Add-Back Baseline for each Demand Response Asset in each interval in which its associated Demand Response Resource receives a non-zero Dispatch Instruction.

(b) The adjusted Distributed Energy Resource Add-Back Baseline shall equal the Distributed Energy Resource Add-Back Baseline plus an adjustment (which may be positive or negative) equal to the average megawatt difference between the Demand Response Asset's metered demand (which may reflect Net Supply) and its Distributed Energy Resource Add-Back Baseline during the three most recently completed five-minute intervals prior to the issuance of the start-up instruction; provided that, if there was a non-zero Dispatch Instruction during any of those three five-minute intervals, the adjustment during the current dispatch will equal the adjustment during the prior dispatch.

(c) For Demand Response Assets that cannot produce Net Supply, the adjusted Distributed Energy Resource Add-Back Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

(d) For Demand Response Assets that can produce Net Supply, the adjusted Distributed Energy Resource Add-Back Baseline shall not be less than (that is, shall not result in expected output at the Retail Delivery Point that exceeds) the asset's Net Supply Capability and shall not exceed the asset's Maximum Load.

Distributed Energy Resource Addback Baseline Energy Market Performance calculations mirror the Demand Response Baseline Energy Market Performance Calculations

III.8.6 Demand Response Asset Energy Market Performance Calculations

(b) The demand reduction contribution by a Demand Response Asset to its Demand Response Resource or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation using the Distributed Energy Resource Add-Back Baseline methodology shall equal to the MW value cleared in the Day-Ahead and Real-Time Energy Markets, except as follows:

(i) On the first day of a forced curtailment, a Demand Response Asset's demand reduction shall equal the difference between the Distributed Energy Resource Add-Back Baseline of the Demand Response Asset and the metered demand of the Demand Response Asset; and

(ii) A Demand Response Asset shall be assessed a zero demand reduction on any day of a forced curtailment other than the first day; on any day of a scheduled curtailment; in any interval in which there is insufficient data to calculate the Distributed Energy Resource Add-Back Baseline; and in any interval in which the Market Participant fails to comply with the Demand Response Asset metering and communication requirements in Section III.3.2.2 or ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
- **Amendment 2**: Allow submetered load to participate as demand response
- **Amendment 3**: Allow third parties to perform submetering
- **Amendment 4:** Remove barriers for DERs that can provide ancillary services
  - 4a: Remove the requirement to clear in energy market if providing spinning reserves
  - 4b: Allow submetering for DERs providing regulation service
- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

Amendment 1b: Allow generator output to be used to quantify load reduction

- **Proposal:** For DR that uses generation to curtail load, the load reduction will equal generator output, provided that this generation would not have been deployed but for the dispatch instruction from ISO-NE

- **Barriers addressed:**
  - Addresses Barrier #2 by expanding baseline measurement options for additional DER use cases—those that generate electricity (e.g., solar + storage, standalone storage, EVs)

- **Regulatory precedent:**
  - FERC-approved in PJM: “The hourly integrated output from a generator used to provide Guaranteed Load Drop. This method may only be utilized if the generation would not have otherwise been deployed on the emergency or pre-emergency event or test day and must comply with the provisions contained in the PJM Manuals”

Amendment 1b Tariff Revisions

Revised Language

III.8.2A Calculating the Demand Reduction Using the Generator Output Baseline Methodology

The Generator Output Baseline Methodology is available only to a Demand Response ~~Resource~~ Asset whose generation output is used to curtail load and such generation would not have otherwise been deployed but for a Dispatch Instruction. Pursuant to Section III.8.2A, the demand reduction is equal to the metered generation output. The asset owner shall ~~attest~~ provide documentation at registration that the generation output and the energy consumption at the Retail Delivery Point are not interdependent and attest that the energy consumption at the Retail Delivery Point will not be purposely changed based on the generation output.

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
- **Amendment 2**: Allow submetered load to participate as demand response
- **Amendment 3**: Allow third parties to perform submetering
- **Amendment 4:** Remove barriers for DERs that can provide ancillary services
  - 4a: Remove the requirement to clear in energy market if providing spinning reserves
  - 4b: Allow submetering for DERs providing regulation service
- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

Amendment 2: Allow submetered load to participate as DR

- **Proposal**: Allow *load reductions* from a DER to be measured *against a baseline* at a submeter behind a customer meter.
  - Apply this to both the existing DRR model and the proposed DRDERA models

- **Barriers addressed:**
  - Allows customers who cannot participate at the customer meter (due to the cost of metering and/or widely variable load) to participate with a dispatchable device behind the meter

- **Regulatory precedent**:
  - CAISO uses a FERC-approved DR model that allows submetered EV charging equipment to participate as DR under Order 745 (ER20-2443 – see more information in the Appendix)

Amendment 2 Tariff Revisions

I.2.2 Definitions

Alternative Point of Load Reduction is a load meter behind the Retail Delivery Point at which the participant provides load reductions as part of a Demand Response Asset or a Distributed Energy Resource that is associated with a Demand Response Distributed Energy Resource Aggregation.

III.8.1.1 Demand Response Asset Registration and Aggregation

(a) A Demand Response Asset must have a Maximum Interruptible Capacity of at least 10 kW.

(b) A Demand Response Asset must have a single Retail Delivery Point or Alternative Point of Load Reduction and be registered at a single Node, unless it meets the conditions for aggregation in Section III.8.1.1(f).

Amendment 2 Tariff Revisions

New Language

III.6.4 Metering and Telemetry Requirements

(e) If a Distributed Energy Resource's point of interconnection is located behind a Retail Delivery Point it shall be reported such that its output or load does not impact the load reported for the Retail Delivery Point. A Distributed Energy Resource Aggregator may only propose a metering location behind a Retail Delivery Point if the Host Utility confirms in writing to the Distributed Energy Resource Aggregator that the appropriate metering and associated system upgrades are in place to support load and generation reporting and any necessary reconstitution. Proof of such written confirmation from the Host Utility should be provided as part of the attestation as referenced in Section III.6.7(c)(i)2. The requirement for the Host Utility to provide written confirmation as required in Section III.6.4(e) does not apply if the meter behind a Retail Delivery Point is an Alternative Point of Load Reduction.

Amendment 2 Tariff Revisions

New Language

III.8.1.1 Demand Response Asset Registration and Aggregation

(c) A Demand Response Asset may participate at an Alternative Point of Load Reduction if the Market Participant submits: 1) documentation at registration that demonstrates that there are no interdependencies between devices or loads behind the Retail Delivery Point that would cause energy consumption at the Retail Delivery Point or at another device behind the Retail Delivery Point to increase when energy consumption at the Alternative Point of Load Reduction is decreased and, 2) an attestation at registration that the energy consumption at the Retail Delivery Point or another device behind the Retail Delivery Point will not be purposely increased when energy consumption at the Alternative Point of Load Reduction is decreased.

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
- **Amendment 2**: Allow submetered load to participate as demand response
- **Amendment 3**: Allow third parties to perform submetering
- **Amendment 4:** Remove barriers for DERs that can provide ancillary services
  - 4a: Remove the requirement to clear in energy market if providing spinning reserves
  - 4b: Allow submetering for DERs providing regulation service
- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

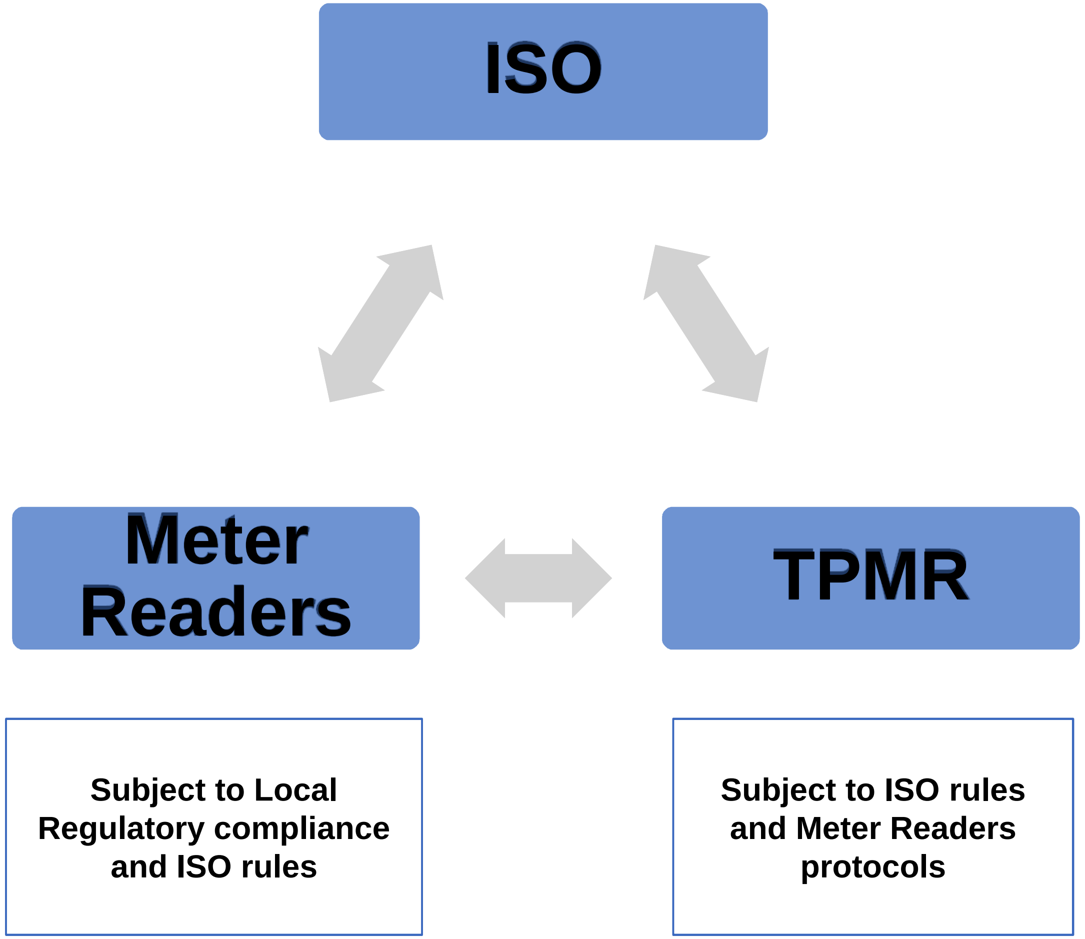
Amendment 3: Allow 3rd party metering

- **Proposal**: Allow Aggregators or their authorized agents to meter the injection, withdrawal and the load reduction of all DERs within each DER Aggregation and report meter quantities to Host Participants/Assigned Meter Readers for the applicable Meter Domain
  - New definition in Section I.2.2: Third Party Meter Reader (TPMR)
  - New Section III.6.4 (g) to enable TPMR to perform metering and meter data service to DERAs

- **Benefits:**
  - Will facilitate DERA deployment sooner and in the areas with no AMI/AMF
  - Allows viable submetering option enabling many DER use cases
  - Unburden Meter Readers from reconstitution when required
  - 3rd parties will bear costs of additional equipment

- **Example**:
  - How it works in NYISO (the concept is not new and has been proven and tested by time)

Amendment 3: General Principles



- New Third Party Meter Reader (TPMR) construct
  - authorizes ISO to approve qualified entities to provide meter services to DER Aggregations
- New Third Party Meter Reader rules will define:
  - Roles and responsibilities
  - Eligibility and requirements
  - Data standards and communication
- New TPMR rules will not impact existing metering constructs used by Meter Readers

Amendment 3: Structure

- **The amendment itself consists of a definition of TPMR, including the capabilities the TPMR must demonstrate to be approved by ISO**
  - Financial eligibility and insurance coverage
  - State authorization to do business
  - Service territories and services to be provided
  - Agreement to comply with ISO New England rules
  - Certification of employee and company qualifications to provide services
  - Demonstration of meter testing and lab facilities and capabilities
  - Meter data validation, editing, estimating and management plans
  - Physical and cyber security plans
  - Record-keeping plans
  - Protocols for timely and accurate reporting to Host Participant/Assigned Meter Readers
  - Other information as required by ISO
- **And a provision that allows DERAs to use TPMRs to meet ISO Tariff metering requirements**
- **Manuals, Operating Procedures and any other necessary documentation will be developed prior to the full implementation of Order 2222 Compliance**

Amendment 3: Roles and Responsibilities

- **TPMR**:
  - Demonstrate data collection, validation, retention, security, and communication protocols compliant with the ISO and Meter Reader rules and requirements
  - Collect, verify, aggregate, and report real-time telemetry and revenue grade meter data to the ISO and Meter Reader(s) in accordance with existing data quality and timeliness standards
- **ISO**:
  - Authorization of TPMR
  - Auditing of TPMR
  - Perform settlements in accordance with billing and settlement rules
  - Resolve disputes

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
- **Amendment 2**: Allow submetered load to participate as demand response
- **Amendment 3**: Allow third parties to perform submetering
- **Amendment 4:** Remove barriers for DERs that can provide ancillary services
  - 4a: Remove the requirement to clear in energy market if providing spinning reserves
  - 4b: Allow submetering for DERs providing regulation service
- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

Amendment 4a: Allow DR & DRDERA to provide spinning reserves

- **Proposal**: Allow both DRRs and DRDERAs to provide spinning reserves by removing the requirement to clear in the energy market

- **Barriers addressed:**
  - Will increase use cases for DERs in ISO-NE (e.g., storage, solar + storage)

- **Regulatory precedent:**
  - Every other organized wholesale market in North America
  - No other ISO requires load to already be dispatched for energy in order to provide spinning reserves

Amendment 4a: Allow DRR & DRDERA to provide spinning reserves

Tariff Section	Description of Change	Reason for Change
III.1.7.19.2.3	Eliminate the barrier created by using dispatched into energy market as a proxy for synchronized to the grid	Order 2222: “The Commission will evaluate each proposal submitted on compliance to determine whether it meets the goals of this final rule **to allow distributed energy resources to provide all services that they are technically capable of providing through aggregation**.” (pg. 103, para. 130)

Amendment 4a Proposed Tariff Language

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is not being dispatched that is not a Fast Start Demand Response Resource or Fast Start Demand Response Distributed Energy Resource Aggregation, all components of the Real-Time Reserve Designation shall be zero.

(a) Ten-Minute Spinning Reserve. For a Fast Start Demand Response Resource or a Fast Start Demand Response Distributed Energy Resource Aggregation that is not being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For all other Fast Start Demand Response Resource or Fast Start Demand Response Distributed Energy Resource Aggregation that is not being dispatched Ten-Minute Spinning Reserve shall be zero.

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
- **Amendment 2**: Allow submetered load to participate as demand response
- **Amendment 3**: Allow third parties to perform submetering
- **Amendment 4:** Remove barriers for DERs that can provide ancillary services
  - 4a: Remove the requirement to clear in energy market if providing spinning reserves
  - 4b: Allow submetering for DERs providing regulation service
- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

Amendment 4b: Allow submetered DERs to provide regulation service without current restrictions

- **Current rules:** Allow telemetry at the submeter for regulation purposes provided there is interval metering at the customer meter; the ATRR consists of a single device (aggregation of one), and certain other requirements are met.

- **Proposal**: Allow submetering of DERs if the submetered resource is exclusively providing regulation service.
  - The ATRR DERA would earn only regulation revenues
  - Interval metering at customer meter not required
  - Reconsider requirement for submetered ATRRs to be aggregations of one

- **Barriers addressed:**
  - Addresses Barrier #1 without the need for reconstitution or parallel metering.

- **Regulatory Precedent:**
  - PJM allows submetering for regulation (Manual 11)

Amendment 4b Tariff Revisions

Revised Language

III.14.2A Regulation Provided at a Point of Interconnection Located Behind a Retail Delivery Point.

A resource will be permitted to provide Regulation at a point of interconnection behind a Retail Delivery Point provided that the participant provides documentation during its registration ~~attests~~ that the regulating device or system at the facility operates independently from all other end-use loads or generators behind the same Retail Delivery Point. The metering requirements of the ISO New England Operating Procedure No. 18, Metering and Telemetry Criteria will apply to such a resource only at the point of interconnection.

Proposed Amendments

- **Amendment 1**: Expand baseline calculation optionality for DRRs & DRDERAs
  - 1a: Add-back baseline methodology (NYISO)
  - 1b: Allow generation to count as load reduction (PJM)
- **Amendment 2**: Allow submetered load to participate as demand response
- **Amendment 3**: Allow third parties to perform submetering
- **Amendment 4:** Remove barriers for DERs that can provide ancillary services
  - 4a: Remove the requirement to clear in energy market if providing spinning reserves
  - 4b: Allow submetering for DERs providing regulation service
- **Amendment 5**: Periodic review requirement (WITHDRAWN)

- *Note: These amendments are proposed individually/independently, not as a package.

Amendment 5: Periodic Review Requirement (WITHDRAWN)

- **Proposal:** Periodically review the success of the DERA models.

- **Barriers addressed:**
  - DER technologies and metering capabilities are changing rapidly
  - Increased availability of interval metering will open new opportunities to measure and evaluate DER performance, especially at residential facilities
  - New types of DER use cases in the future may be constrained by models designed today
  - To avoid getting stuck with a model that is not viable or that could be updated to work better, the region should periodically evaluate the extent to which the new DERA models are being used, and whether there are any barriers that can be resolved

- **Regulatory precedent:** Coordinated Transaction Scheduling (requirement to evaluate at the 2- and 3-year marks after implementation and make refinements as needed). FERC accepted this in 2012.

Contact Info

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Appendix

Amendment 1a: Adopt NYISO's FERC approved baseline option for frequently utilized DERs

- **Proposal**:
  - Allow DRRs and DRDERAs to use an "Add-back" baseline calculation methodology
  - Allow resources that choose this option to offer below the Net Benefits Threshold; the resource would still be participating in the energy/ancillary services market and be credited with providing energy/ancillary services for audit and PfP purposes, but would receive no energy compensation if market clears below the NBT

- **Barriers addressed:**
  - Improves existing DRR construct for frequently utilized behind-the-meter DERs (e.g. storage, electrified school bus fleets, etc.).
  - Overcomes baseline erosion problem by reestablishing a baseline from which DER performance can be evaluated; addresses compensation questions by providing the option to offer below the NBT and forego energy revenues
  - Submetering the DER is unnecessary and there are no changes to Meter Reader workflow for facilities with interval meters

- **Regulatory precedent:**
  - In NYISO, FERC has approved this "add-back" baseline methodology shown on the following slides as well as the option to offer below the NBT and forego energy market compensation (https://www.ferc.gov/sites/default/files/2020-05/E-18_35.pdf)

Amendment 1a: Add-back for frequently utilized DERs

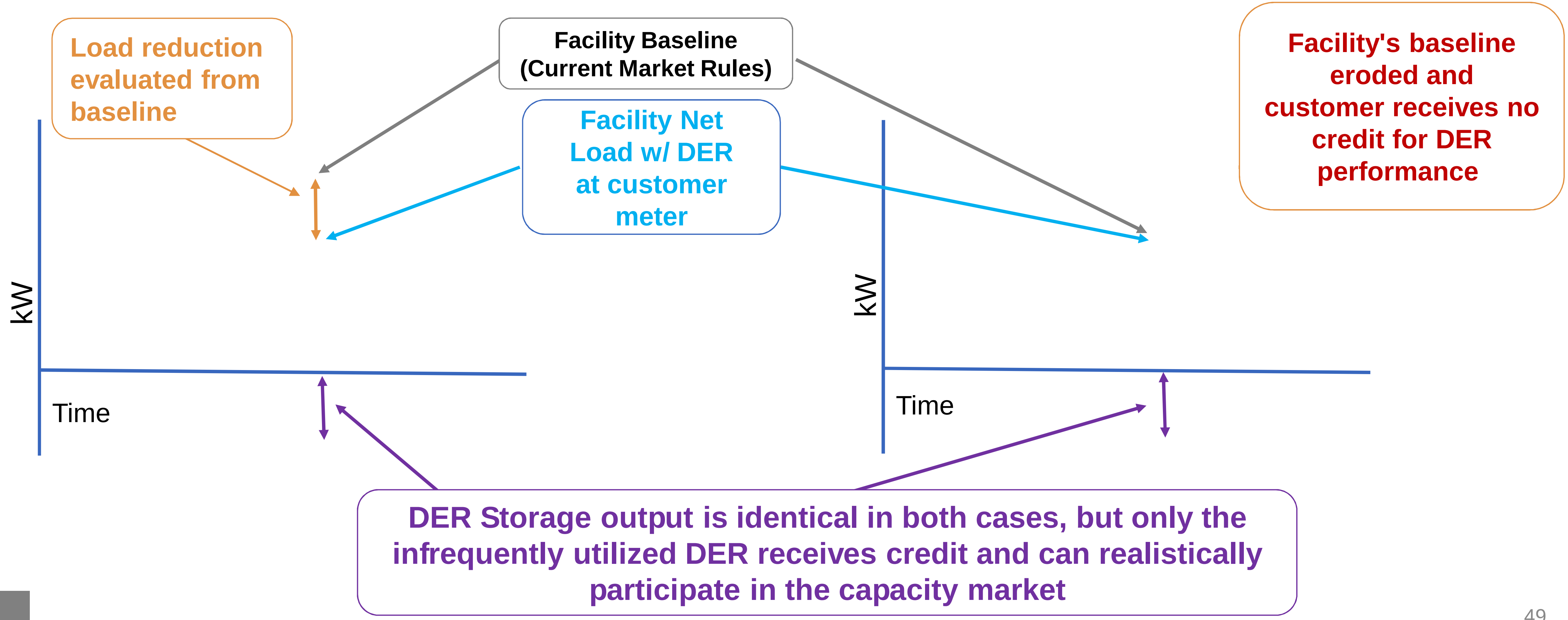
- Why is this change necessary?
  - Currently, frequently dispatched DERs have no viable participation option in the capacity market as they receive no credit for performance even when they are dispatching (Slide 15); this exposes such DERs to untenable PfP risk

- Why is the status quo problematic?
  - **Reliability**: DERs that could be visible and available to the ISO control room during system emergencies or during peak periods will not participate in the wholesale market
  - **Competition and Market Optimization**: DERs that could increase market competition and reduce prices will not participate in the wholesale market; also creates price formation issues
  - **Emissions**: If the ISO does not have visibility into a DER, it will be forced to depend on other resources, which during peak periods is likely an inefficient fossil unit

NEPOOL PARTICIPANTS COMMITTEE
JAN 6, 2022 MEETING, AGENDA ITEM #5
Attachment D - AEE Presentation

Amendment 1a: What is baseline erosion?

Customer A: Infrequently Utilized DER | **Customer B: Frequently Utilized DER**



Amendment 1a: Add-back provides a means to evaluate frequently utilized DERs

- How the "**Add-Back**" methodology works:
  - Baseline includes last 10 days, *regardless of whether there is dispatch.* (column a)
  - The ISO performs "**Add-back**" for any event performance if the DER clears the energy market. (column b)
  - Baseline for the next day at the same interval is the **median** of the last 10 days' load, including add-backs. (column d)

Illustrative Comparison of Baseline Calculation

Date	Load at Meter (MW)	DER that cleared in energy market (MW)	Gross Load (MW)	ISO-NE Baseline (MW)	NYISO Baseline (MW)
	a	*b*	*a+b*	*c*	*d*
1-Mar	2.9	0.5	3.4	2.9	3.4
28-Feb	2.9	0.5	3.4	2.9	3.4
27-Feb	2.9	0.5	3.4	2.9	3.4
26-Feb	3.0	0.5	3.5	3.0	3.5
23-Feb	2.9	0.5	3.4	2.9	3.4
22-Feb	2.8	0.5	3.3	2.8	3.3
21-Feb	2.8	0.5	3.3	2.8	3.3
20-Feb	2.8	0.5	3.3	2.8	3.3
19-Feb	2.9	0.5	3.4	2.9	3.4
16-Feb	2.8	0.5	3.3	2.8	3.3
Baseline outcome for same interval next day:				**2.9**	**3.4**
				*Average of 10	*Median of 10

Amendment 1a: Eliminating baseline erosion allows DER performance to be measured, unlocking system benefits

Table shows that under current ISO market rules, DER performance receives no compensation.

	Current Rules	Proposed
Unadjusted Baseline outcome for this interval:	2.9	3.4
Adjusted Baseline outcome for this interval (MW):*	2.8	3.3
Facility load meter value for this interval (MW):	2.8	2.8
Actual DER performance for this interval (MW):	-0.5	-0.5
DER MW settled for this interval (MW):	0.0	-0.5

Key Proposal Outcomes:

1. Overcomes baseline erosion by providing a baseline from which DER performance can be evaluated.

2. Incentivizes DERs to participate in the capacity market and bid and schedule their output into the energy and ancillary service markets, providing ISO-NE increased visibility into DER performance, thereby improving scheduling, dispatch, etc. of the system

FERC Order on CAISO EV Option for DR

- Sept 30, 2020 FERC Order (ER20-2443) found CAISO's proposal to treat EV as a separate load reduction measure, with the baseline measured at the EV charging station submeter.
- Some commenters raised concerns about gaming; they worried that a customer might switch the charging of a device from the submeter to the master meter in order to show a load reduction at the submeter (but ultimately providing no benefit to the grid since the load at the master meter would increase by the amount of the load reduction at the submeter).
- FERC found that this type of market manipulation is unlikely and notes that CAISO works with its Market Monitor to monitor demand response providers and therefore no formal monitoring and reporting requirement is necessary. (p 20)

DER Use Cases: Opportunities Under *Existing* ISO-NE Participation Models

Current market rules	Technology/Use Case	Participation Model
Viable Participation Model	1 - C&I Load Curtailment/Infrequently Dispatched DG	Existing Active DRR Program
Current models do not allow resources to offer all services	2 - Residential behind-the-meter resources, such as customer-sited solar plus storage	Some participation today via passive DR Options; this falls short of enabling these resources to offer all services they are technically capable of providing
Good foundation but challenges remain	3 - Front-of-the-meter distribution-connected resources, such as community solar and solar+storage	Existing four options presented in April 2020 webinar properly integrate these DERs, with exception of reserves accounting for collocated resources; interconnection remains a challenge, as does the inability to aggregate.
Signifiant barriers to ISO-NE participation	4 - DERs that can be frequently dispatched, such as electric school buses and other electric vehicles	Active DR Baseline rules and prohibition on real-time energy market participation for DR challenge the ability of these resources to participate; we expect these use cases to proliferate in New England.
Signifiant barriers to ISO-NE participation	5 - Residential demand response devices, such as smart thermostats and water heaters	Current ISO-NE metering and telemetry requirements coupled with lack of Advanced Metering Infrastructure (AMI) renders participation nearly impossible.

Use Case 2: Residential behind-the-meter resources, such as customer-sited solar plus storage

Participation Model	Viable?	Gaps / Barriers
Demand Response DERA	No	Interval metering at RDP is cost-prohibitive, baseline method not workable with something that is frequently dispatched
Settlement Only DERA	No	Interval metering at RDP is cost-prohibitive, submetering not viable
Continuous Storage Facility	No	Participating at RDP mingles storage with facility load but load may not be fully dispatchable, Interval metering at RDP is cost-prohibitive, submetering not viable
Generator Asset	No	Interval metering at RDP is cost-prohibitive, submetering not viable
Binary Storage Facility	No	N/A
Demand Response Resource	No	Interval metering at RDP is cost-prohibitive, baseline method not workable with something that is frequently dispatched
Alternative Technology Regulation Resource	No	Interval metering at RDP is cost-prohibitive, submetering not viable

Use Case 4: DERs that can be frequently dispatched, e.g., electric school busses and other EV fleets

Participation Model	Viable?	Gaps / Barriers
Demand Response DERA	No	Baseline methodology doesn’t work with frequent dispatch
Settlement Only DERA	No	Can only monetize injection
Continuous Storage Facility	No	Not viable without submetering for BTM assets
Generator Asset	No	Can only monetize injection
Binary Storage Facility	No	N/A
Demand Response Resource	No	Baseline methodology doesn’t work with frequent dispatch
Alternative Technology Regulation Resource	Maybe?	Could be viable for some use cases

Note: These DERs are expected to participate as BTM resources (without parallel metering) to take full advantage of DER value stacking (e.g., to facilitate demand-charge management in addition to wholesale market participation). FTM resources or resources that install parallel metering will have more opportunities to participate.

Use Case 5: Residential demand response devices, such as smart thermostats and water heaters

Participation Model	Viable?	Gaps / Barriers
Demand Response DERA	No	Interval metering at RDP not practical, baseline method not workable
Settlement Only DERA	No	Can only monetize injection
Continuous Storage Facility	No	N/A
Generator Asset	No	N/A
Binary Storage Facility	No	N/A
Demand Response Resource	No	Interval metering at RDP not practical, baseline method not workable
Alternative Technology Regulation Resource	No	Metering at RDP not feasible, submetering not feasible

Amendment 1a: Adopt FERC-approved NYISO baseline method to integrate frequently dispatched DERs

Injection & Demand Reduction Response-Only Demand Reduction

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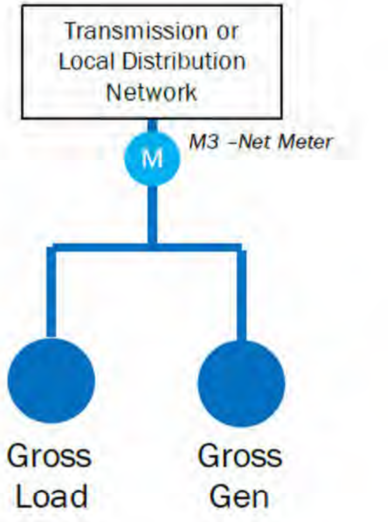
- DER has host load 2 MW based on M3 meter data for a specific 5-minute interval, also has a dispatchable 4 MW generator, and is the only DER in the Aggregation
- At the start of that 5-minute interval:
  - The Aggregation is dispatched for 2 MW by the NYISO
  - The facility baseline load is 2 MW
  - The generator outputs 2 MW
- Injection component:
  - At the point of interconnection (i.e. M3) there is 0 MW of Injection
  - Injection Response = max(0, Net Meter Value)
  - Injection Response = max(0, 0)
  - Injection Response = 0, Therefore the Injection response of the DER is 0 MW
- Demand Reduction component:
  - The baseline of the facility is 2 MW
  - At the point of interconnection the M3 meter reads 0 MW
  - Demand Reduction Response = max(0, Baseline + min(0, Net Meter Value))
  - Demand Reduction Response = max(0, 2 + min(0,0))
  - Demand Reduction Response = 2, Therefore, Demand Reduction response of the DER is 2 MW



Total Response= Injection + Demand Reduction
Total Response = 2 MW

NEW YORK INDEPENDENT SYSTEM OPERATOR

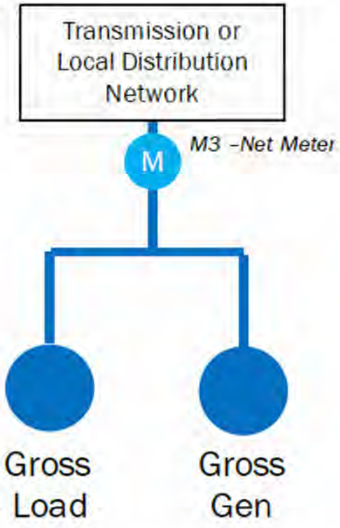
DRAFT – FOR DISCUSSION PURPOSES ONLY

Amendment 1a: Adopt FERC-approved NYISO baseline method to integrate frequently dispatched DERs

Injection and Demand Reduction-No Dispatch

6/19 MIWG

- DER has host load 2 MW based on M3 meter data for a specific 5-minute interval, also has a dispatchable 4 MW generator, and is the only DER in the Aggregation
- At the start of that 5-minute interval:
  - The Aggregation is not dispatched by the NYISO
  - The facility baseline load is 2 MW
  - The generator outputs 0 MW
- Injection component:
  - At the point of interconnection (i.e. M3) there is 2 MW of Load
  - Injection Response = max(0, Net Meter Value)
  - Injection Response = max(0, -2)
  - Injection Response = 0, Therefore the <u>Injection</u> response of the DER is 0 MW
- Demand Reduction component:
  - The baseline of the facility is 2 MW
  - At the point of interconnection the M3 meter reads -2 MW
  - Demand Reduction Response = max(0, Baseline + min(0, Net Meter Value))
  - Demand Reduction Response = max(0, 2 + min(0,-2))
  - Demand Reduction Response = 0, Therefore, <u>Demand Reduction</u> response of the DER is 0 MW



Total Response=
Injection + Demand Reduction
Total Response = 0 MW

NEW YORK INDEPENDENT SYSTEM OPERATOR

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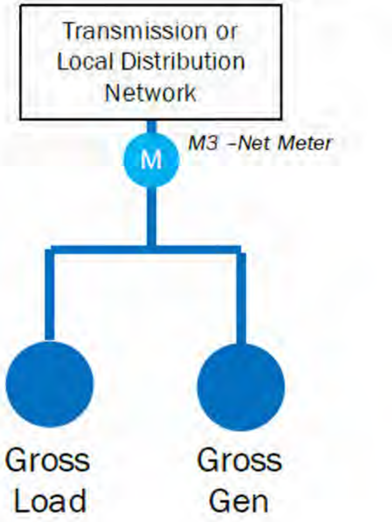
Amendment 1a: Adopt FERC-approved NYISO baseline method to integrate frequently dispatched DERs

Injection and Demand Reduction Response-Injection and Demand Reduction – Example 1

6/19 MIWG

- DER has host load 2 MW based on M3 meter data for a specific 5-minute interval, also has a dispatchable 4 MW generator, and is the only DER in the Aggregation
- At the start of that 5-minute interval:
  - The Aggregation is dispatched for 4 MW by the NYISO
  - The facility baseline load is 2 MW
  - The generator outputs 4 MW
- Injection component:
  - At the point of interconnection (i.e. M3) there is 2 MW of Injection
  - Injection Response = max(0, Net Meter Value)
  - Injection Response = max(0, 2)
  - Injection Response = 2, Therefore the Injection response of the DER is 2 MW
- Demand Reduction component:
  - The baseline of the facility is 2 MW
  - At the point of interconnection the M3 meter reads 2 MW, a net injection
  - Demand Reduction Response = max(0, Baseline + min(0, Net Meter Value))
  - Demand Reduction Response = max(0, 2 + min(0,2))
  - Demand Reduction Response = 2, Therefore, Demand Reduction response of the DER is 2 MW



Total Response= Injection + Demand Reduction

Total Response = 4 MW

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

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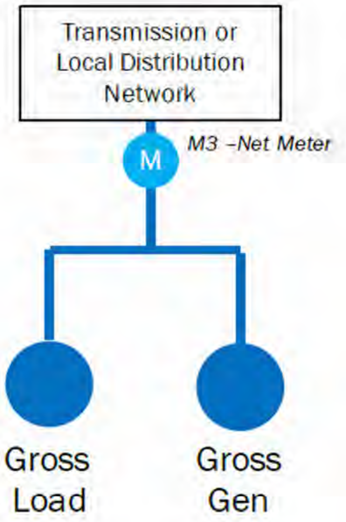
Amendment 1a: Adopt FERC-approved NYISO baseline method to integrate frequently dispatched DERs

Injection and Demand Reduction Response-Injection and Demand Reduction – Example 2

6/19 MIWG

- DER has host load 2 MW based on M3 meter data for a specific 5-minute interval, also has a dispatchable 4 MW generator, and is the only DER in the Aggregation
- At the start of that 5-minute interval:
  - The Aggregation is dispatched for 4 MW by the NYISO
  - The facility baseline load is 2 MW
  - The facility load curtails 2 MW, the generator outputs 2 MW
- Injection component:
  - At the point of interconnection (i.e. M3) there is 2 MW of Injection
  - Injection Response = max(0, Net Meter Value)
  - Injection Response = max(0, 2)
  - Injection Response = 2, Therefore the Injection response of the DER is 2 MW
- Demand Reduction component:
  - The baseline of the facility is 2 MW
  - At the point of interconnection the M3 meter reads 2 MW, a net injection
  - Demand Reduction Response = max(0, Baseline + min(0, Net Meter Value))
  - Demand Reduction Response = max(0, 2 + min(0,2))
  - Demand Reduction Response = 2, Therefore, Demand Reduction response of the DER is 2 MW



Total Response= Injection + Demand Reduction
Total Response = 4 MW

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Amendment 1a: Adopt FERC-approved NYISO baseline method to integrate frequently dispatched DERs

DER Response, con't

- **Telemetry and revenue/settlement data submittals for an Aggregation shall be provided by the aggregator, using the following calculation:**
  - (1) For net-injection component of individual DER response:
    - Injection Response = max(0, Net Meter Value)
  - (2) For net-withdrawal component of individual DER response of directly metered Withdrawal-Eligible Generator:
    - Withdrawal Response = min(0, Net Meter Value)
  - (3) For net-demand reduction component of individual DER response:
    - Demand Reduction Response = max(0, Baseline + min(0, Net Meter Value))
  - Total Response= (1) + (2) + (3)
    - Coincident injection and reduction response for the same resource shall be measured separately, telemetered separately and submitted in the separate and applicable meter files for settlements
- **Sign convention used for DER response calculation:**
  - 'Baseline' is always non-negative
  - 'Net Meter Value' is negative when DER is net-withdrawing from the grid, and positive when DER is net-injecting into the grid as measured at the net facility meter

NEW YORK INDEPENDENT SYSTEM OPERATOR

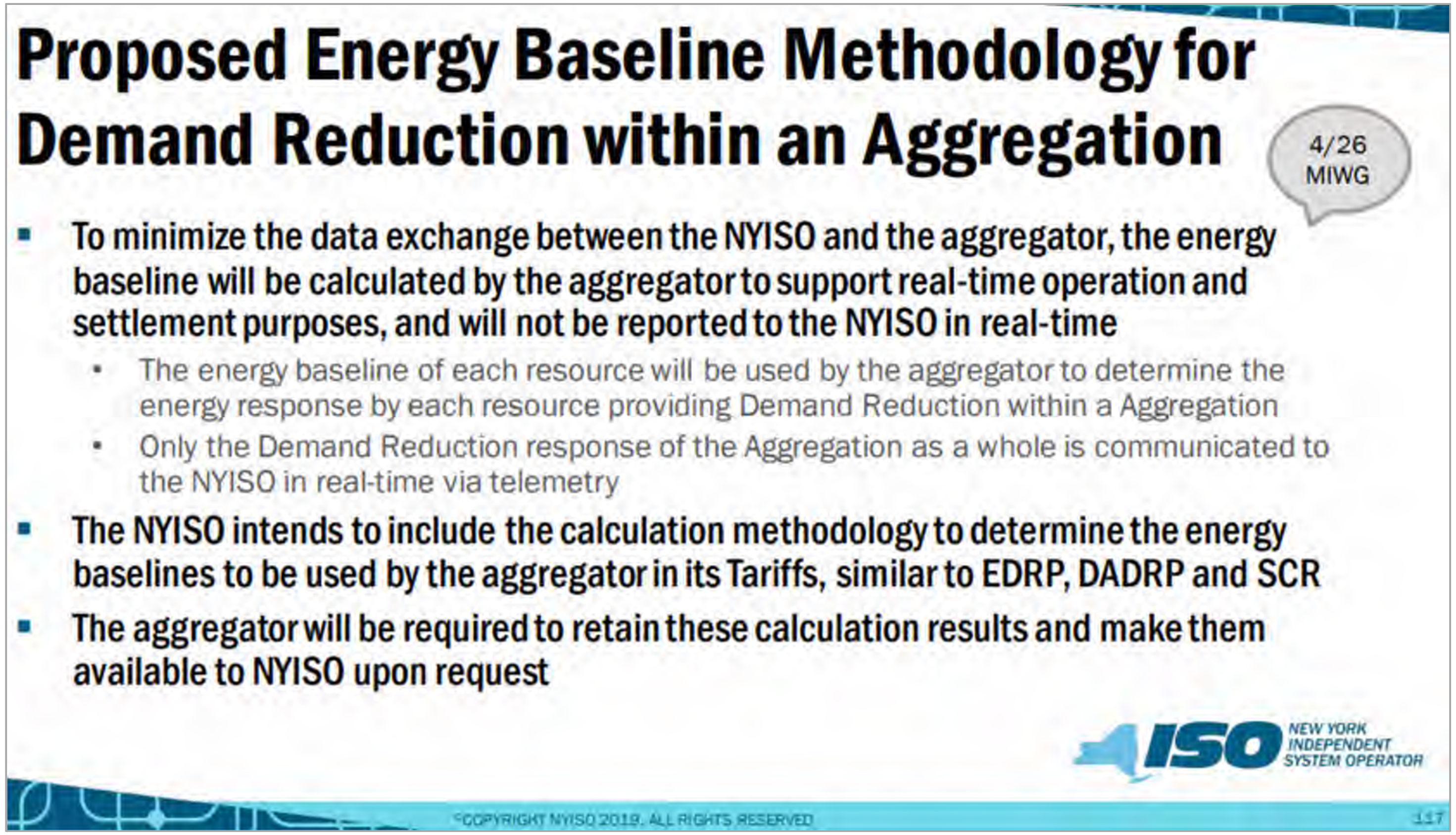
DRAFT – FOR DISCUSSION PURPOSES ONLY

Amendment 1a: Adopt FERC-approved NYISO baseline method to integrate frequently dispatched DERs

- Only the Demand Reduction response of the Aggregation as a whole is communicated to the NYISO in real-time via telemetry to minimize data exchange requirements.

- The aggregator uses an adjusted 5-minute ECBL for calculating the Demand Reduction of a resource when the Aggregation is providing energy.

- Dispatchable DER are intended to be dispatched in real-time for energy and ancillary services, making a 5-minute granular baseline more applicable when capturing load variability and resource capability.



https://www.nyiso.com/documents/20142/6006612/BIC%20DER%20Market%20Design%20Presentation.pdf/9cdc8700-ab90-d741-c28d-0c29b3468807

Amendment 5 Proposed Tariff Revisions (WITHDRAWN)

III.A.17.2.5. Additional Report on the Performance of Order No. 2222 Tariff Revisions

Within one [or two or three] years of the effective date of operation of Order No. 2222 Tariff revisions filed on February 2, 2022, or as soon as adequate data becomes available, and in furtherance of its functions under Section III.A.2 of this Appendix A, including without limitation Sections III.A.2.3 (e) and (k) therein, the Internal Market Monitor shall perform an independent evaluation and prepare a report on the ISO-NE Tariff's success in removing barriers to the participation of DERAs in the capacity, energy, and ancillary service markets administered by ISO-NE. Although the Internal Market Monitor may solicit and/or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in the report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO's website a final version of the report. Thereafter, the Internal Market Monitor shall continue to report on the Tariff's effectiveness to remove barriers to the participation of DERAs in the capacity, energy, and ancillary service markets in its quarterly and/or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

Key Barriers in ISO-NE Proposal

ISO-NE's Proposal Has 2 Key Barriers to DER Participation

- ISO-NE's proposal does not meet FERC's directive to enable DERs to offer wholesale market services they are technically capable of providing through aggregation

- Two key barriers within ISO-NE's DERA models:
  1. Lack of a viable submetering option restricts many DER use cases
  2. DRR/DRDERA models do not accommodate many DER use cases

- Without viable participation models for many DERs, the region will forego the option to also pursue cost savings, market efficiencies and reliability benefits of DERs in wholesale markets

Barrier 1: Lack of Viable Submetering Option

- Submetering uses device-level metering behind the customer meter (i.e., Retail Delivery Point (RDP)) to separate out DER performance from the rest of the facility load.
  - As presented at Dec. 2020 and June 2021 MC, submetering is critical for many current and future DER use cases (e.g., EVs, hot water heaters, smart HVAC, etc.)

- **ISO-NE's proposal does not provide a viable means for submetering because it is dependent upon the capabilities of non-FERC jurisdictional distribution utilities who have stated they do not have these capabilities.**

Barrier 2: Existing DR Model Does Not Accommodate Many DER Use Cases

- The existing DR model works reasonably well for certain DR use cases, but not all, including:
  - Frequently utilized DERs (e.g., storage, solar + storage, electrified transit fleets like school buses) are unable to demonstrate performance due to baseline erosion (see slide 16).
  - DERs for which participation at the customer meter is infeasible/impractical, because:
    - Interval metering is cost prohibitive or
    - The customer's load is widely variable and therefore the DER behavior is indistinguishable

- Many of these pre-existing challenges from the DR model are still present in ISO-NE's compliance proposal for Order No. 2222 (see next slide)

Barrier 2: DR Model Does Not Accommodate Many DER Use Cases

#	Technology/Use Case	Improvements under ISO-NE 2222 proposal?	Remaining Challenges
1	**C&I Load Curtailment/ Infrequently utilized DR**	**Already had a viable participation model**	None. Existing Active DRR Program.
2	**Residential behind-the-meter resources**, such as customer-sited solar plus storage, EVs	**No new viable participation models**	These resources are precluded from participating in all of the proposed DERA models due to lack of interval metering, infeasibility of submetering, and/or incompatible baseline methodologies.
3	**Front-of-the-meter distribution-connected resources**, such as community solar and solar + storage	**New DERA models resolve some barriers, but others remain**	These assets will be able to aggregate or participate as a single DERA, which resolves current barriers to aggregation and should improve interconnection process. Reserves accounting for collocated resources remains unresolved.
4	**DERs that can be frequently utilized**, such as electric school buses and other electric vehicles	**No new viable participation models**	These resources will be precluded from participating in most of the proposed DERA models due to infeasibility of submetering and/or baseline methodologies that are not compatible with frequently utilized DERs. Some, but not all, use cases may be able to participate as ATRR.
5	**Residential demand response devices**, such as smart thermostats and water heaters	**No new viable participation models**	These assets will be precluded from participating in all of the proposed DERA models due to lack of interval metering, infeasibility of submetering, and/or baseline methodologies that are not compatible with frequently utilized DERs

memo

To: NEPOOL Participants Committee

From: ISO New England

Date: December 29, 2021

Subject: ISO New England's Response to Advanced Energy Economy's Revised Amendment 1A Regarding an Add-Back Baseline Methodology

On December 8, 2021, the NEPOOL Markets Committee voted to support the ISO's proposed Tariff changes designed to comply with FERC Order No. 2222, which concerns the participation of distributed energy resource aggregations in wholesale markets. Several amendments to the ISO's proposal were offered by Advanced Energy Economy ("AEE"), none of which were supported by the Markets Committee. However, AEE's Amendment 1A regarding the incorporation of an add-back baseline methodology, which was presented at the December Markets Committee meeting, included modifications to address concerns previously expressed by the ISO.[1] The purpose of this memo is to provide the ISO's further analysis and position on revised Amendment 1A as presented to the Markets Committee in December.[2]

The specific change presented by AEE at the December Markets Committee meeting is highlighted below in yellow:

> **Section III.1.10.1A(e) (ii) (a)**
>
> Demand Response Resources and Distributed Energy Resources associated with a Demand Response Distributed Energy Resource Aggregation using the Demand Response Add-Back Baseline methodology pursuant to III.8.4 may specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any resource associated with a Demand Response Distributed Energy Resource Aggregation using the Demand Response Add-Back Baseline shall receive no positive[3] settlement payments for either the Day-Ahead or Real-Time Energy Market.

Following the December Markets Committee meeting, ISO staff met with members of the AEE coalition to better understand the proposed amendment as it relates to the ISO's Order No. 2222 compliance effort. In our understanding, Amendment 1A was designed to enable Demand Response Resources ("DRRs") to

[1] AEE Amendment 1A was first described at the October Markets Committee meeting. Specific Tariff language was provided at the November Markets Committee meeting, which was subsequently modified and presented at the December Markets Committee meeting.

[2] The ISO's positions on the remaining AEE Amendments are summarized in a memo provided to the Markets Committee at its November 2021 meeting.

[3] AEE added the word "positive" to its Tariff change proposal during the December Markets Committee meeting.

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participate in both retail demand response programs[4] and ISO-administered wholesale markets simultaneously. AEE explained that the specific revision highlighted above was intended to eliminate the incentive for a participant to inflate the DRR's baseline by eliminating Energy Market payments of the DRRs using the AEE-proposed Demand Response Add-Back Baseline methodology ("Add-Back Baseline") – a concern that was previously raised by the ISO. It was reasoned by AEE that, absent Energy Market compensation, a Market Participant would have no reason to inflate a DRR's baseline, which is used to determine the Real-Time Energy Market performance of a DRR.

The ISO believes that it is reasonable and appropriate for a DRR to participate in both retail demand response programs and in wholesale markets simultaneously so long as wholesale services are not double counted in the process. However, while the ISO appreciates AEE's effort to address the ISO's concerns regarding baseline integrity, the ISO still does not support the revised Amendment 1A for several reasons, as further explained below.

First, Amendment 1A still provides incentives for a participant to inflate the DRR's baseline despite the revision. Eliminating positive settlement payments in the Energy Market may reduce the financial incentive *in that market* for a participant to inflate the baseline of a DRR. However, it is our understanding that DRRs using the Add-Back Baseline will be participating in the Forward Capacity Market ("FCM"). Under revised Amendment 1A, there remains a financial incentive for a participant to inflate the baseline of a DRR for FCM settlement purposes. This is because, all other things equal, a DRR with a higher baseline can meet a higher Capacity Supply Obligation – and thus earn the participant higher monthly capacity payments – than one with a lower baseline. Further, the performance of a DRR in response to Capacity Scarcity Conditions is exaggerated if its baseline is inflated. While we agree that eliminating positive Energy Market settlement payments helps mitigate the incentive to inflate the baseline to some degree, it does not wholly eliminate the incentive to inflate a DRR's baseline.

Second, revised Amendment 1A could result in the submission of Demand Reduction Offers into the Energy Market that do not reflect the cost associated with the dispatch of DRRs. The current Energy Market design motivates resource owners to submit accurate, cost-based offers into the Energy Market by allowing resource owners to financially benefit (assuming no market power issues) from making such offers. A resource owner that submits an above-cost offer could end up not being dispatched when LMPs are higher than actual costs, whereby the resource owner misses out on earning profits. Conversely, a resource owner that submits below-cost offers could end up being dispatched when LMPs are lower than actual costs, whereby the resource owner sees an erosion of profits. Under revised Amendment 1A, the financial motivation of a DRR owner to submit a cost-based offer like other Energy Market resources is disrupted since the DRR owner would not earn any positive revenues, and thus earns no profits, through the Energy Market. Rather, a DRR owner's Demand Reduction Offer under Amendment 1A would likely be motivated by other factors, such as submitting offers so as to maintain a higher baseline for use in capacity markets.

Third, the Add-Back Baseline may result in the double counting of wholesale capacity market services. For example, the Massachusetts Clean Peak Energy Portfolio Standard, cited above, is designed to reduce monthly and annual system peak demand. The ISO understands that this program puts a high premium (i.e., the program grants substantially more clean peak certificates) on reducing load at the time of the Actual

[4] For example, one of these programs includes the Massachusetts Clean Peak Energy Portfolio Standard. *See* 225 CMR 21.00 *et seq.*

Monthly System Peak,[5] which is defined as "[t]he highest net demand for electricity in a calendar month ***in ISO-NE Control Area***" (emphasis added).[6] By reducing annual and monthly peak loads, the participants can reduce their allocation of capacity costs. But if retail program participants also participate as a capacity supply resource in the FCM, the Add-Back Baseline would facilitate the double counting of wholesale capacity services provided by these resources (i.e., by granting both load and supply credits for the same resource/service).

When participants in retail demand response programs reduce their load during peak load hours, they receive compensation through the retail program and they, or load serving entities, also receive savings through a lower capacity cost allocation. The Add-Back Baseline would then add the calculated load reduction (for which they have already received a financial benefit) back to the participant's actual metered load to create a higher baseline for FCM participation purposes. This higher baseline then allows the very same load reduction produced in response to the retail demand response program to be counted and remunerated as a supply resource in the FCM. This results in double-counting the capacity provided by these participants – once as a load reduction and once again as a supply resource – which is a result the Federal Energy Regulatory Commission ordered the ISO to avoid in Order No. 2222.[7] In contrast, the ISO's Order No. 2222 compliance proposal is narrowly designed to avoid counting more than once the services provided by DRRs in wholesale markets by using a baseline methodology that permits only load reductions supplied *in addition* to those produced in response to retail demand response programs to be counted as a wholesale market resource.

Other consequences of the aforementioned double counting in the capacity market that result from Amendment 1A include potential reliability issues, or unnecessarily higher customer costs. By consistently reducing annual and monthly peak loads, the participants in retail demand response programs help lower the ISO's Installed Capacity Requirement ("ICR") by reducing forecasted load. However, if these same participants are allowed to obtain a Capacity Supply Obligation for the same load reductions, the double-counting issue identified above could result in an under procurement of capacity. For example, assume an ICR equal to expected system load – e.g., 10 MW – and the Forward Capacity Auction ("FCA") procures 3 MW of DRRs and 7 MW of generation to satisfy the ICR. However, if the expected system load upon which the ICR is based already includes the 3 MW load reduction from DRRs participating in retail demand response programs, the actual load the ISO would see in real time will be 10 MW when the DRRs perform. And with only 7 MW of generation capacity acquired through the FCA, the system is deficient in serving real-time energy requirements by 3 MW. That is, by counting the 3 MW DRR as both a reduction in the ICR and as a capacity supply resource, the ISO would end up under-procuring the ICR by 3 MW as 7 MW of generation cannot supply 10 MW of load. The resulting under-procurement of capacity could be addressed by increasing the ICR by 3 MW so that the DRRs can acquire Capacity Supply Obligations without displacing the acquisition of needed capacity. However, increasing the ICR in this manner does not produce any incremental reliability benefit because the reliability benefit of the DRRs was already captured through the

[5] *See* 225 CMR 21.05(6)(b).

[6] *See* 225 CMR 21.02.

[7] *See* Order No. 2222 at PP 160-161. The ISO further notes that double counting is generally problematic as it could distort price offers into wholesale markets that affect price formation and increase total system costs, result in cost-shifting from participating to non-participating customers, and potentially contribute to reliability issues.

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reduced load produced in response to retail demand response programs. Thus, increasing the ICR in this manner would only serve to increase customer costs without increasing reliability benefits.

For these reasons, the ISO cannot support revised Amendment 1A as presented to the NEPOOL Participants Committee.

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of January 4, 2022

The following activity, as more fully described in the attached litigation report, has occurred since the report dated December 1, 2021 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

1	Extension of Filing Deadlines (AD20-11)	Dec 8	FERC further extends through ***Mar 31, 2022*** FERC regulations that require filings be notarized or supported by sworn declarations
2	Blanket Waiver of ISO/RTO Tariff In-Person Meeting and Notarization Requirements (EL20-37)	Dec 8	FERC further extends through ***Mar 31, 2022*** blanket waivers of ISO/RTO Tariff in-person meeting and notarization requirements

I. Complaints/Section 206 Proceedings

No Activity to Report

II. Rate, ICR, FCA, Cost Recovery Filings

8	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER22-556)	Dec 8-9	Calpine, NESCOE intervene
8	FCA16 Qualification Informational Filing (ER22-391)	Dec 9 Dec 17	ISO-NE IMM and EMM respond to Anbaric/MMWEC protest Anbaric/MMWEC answer ISO-NE IMM and EMM answers
9	ICR-Related Values and HQICCs – FCA16 (2025-26) Capacity Commitment Period (ER22-378)	Dec 21	FERC accepts ICR-Related Values for the 2025-26 Capacity Commitment Period
8	2022 NESCOE Budget (ER22-117)	Dec 21	FERC accepts changes for recovery of 2022 NESCOE Budget, eff. Jan 1, 2022
9	2022 ISO-NE Administrative Costs and Capital Budgets (ER22-113)	Dec 21	FERC accepts ISO-NE Budgets, eff. Jan 1, 2022
11	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Dec 2, 6 Dec 17 Dec 20	ENECOS, NESCOE reply to Mystic's Nov 17, 2021 reply Mystic requests rehearing of the *Mystic ROE Allegheny Order* Mystic submits sixth compliance filing in response to requirements of the *Mystic ROE Allegheny Order*; comment deadline ***Jan 10, 2022***

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

12	CSO Termination: Killingly Energy Center (ER22-355)	Dec 2, 13 Dec 3 Dec 20 Dec 28 Jan 3	Mitsubishi Power Americas, CT OCC intervene FERC grants NTE Connecticut's request for a one-week extension of the comment deadline; NTE CT protests termination of Killing Energy Center CSO ISO-NE answers NTE CT protest NTE CT answers ISO-NE Dec 20 answer FERC accepts termination filing, eff. Jan 4, 2022

IV. OATT Amendments / TOAs / Coordination Agreements

*	13	Tariff Changes Associated with *Order 1000* Lessons Learned (ER22-733)	Dec 28 Jan 3-4	ISO-NE and NEPOOL file changes; comment deadline ***Jan 18, 2022*** NESCOE, MA DPU, RENEW intervene doc-lessly
*	13	Attachment K Planning Changes (ER22-727)	Dec 27 Dec 29-Jan 4	ISO-NE and NEPOOL file changes; comment deadline ***Jan 18, 2022*** Champlain VT, NESCOE, NRDC, RENEW intervene
	14	Attachment K Resource Assumption Changes (ER22-400)	Dec 2 Jan 4	Eversource intervenes FERC accepts changes, eff. Jan 11, 2022
	14	BTM Generation Proposal (ER21-2337)	Dec 13	PTO AC and ISO-NE submit responses to Nov 12, 2021 deficiency letter

V. Financial Assurance/Billing Policy Amendments

	15	Removal of FAP Notarization Requirements (ER22-213)	Dec 6	FERC authorizes removal of notarization requirements, eff. Jan 1. 2022

VI. Schedule 20/21/22/23 Changes

*	16	Schedule 23: NSTAR/Berkshire Wind/ISO-NE SGIA (ER22-720)	Dec 23	ISO-NE and NSTAR file 3-party SGIA with Berkshire Wind; comment deadline ***Jan 12, 2022***
*	16	Schedule 21-NEP: 2nd Revised Narragansett LSA (ER22-707)	Dec 22 Dec 28	National Grid files 2nd Revised LSA with Narragansett and ISO-NE Green Development intervenes and requests an add'l week, to Jan 19, to comment on the LSA filing FERC extends comment deadline to ***Jan 19, 2022***
	16	Schedule 21-NEP: Sterling Municipal LSA (ER22-97)	Dec 9	FERC accepts LSA, eff. Dec 13, 2021

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	18	Capital Projects Report - 2021 Q3 (ER22-125)	Dec 17	FERC accepts Q3 Report, eff. Oct 1, 2021
*	19	FCA15 Fuel Security Reliability Review Info Filing (ER18-2364)	Dec 2	ISO-NE files report assessing the study triggers, assumptions and scenarios used by ISO-NE in its FCA15 fuel security reliability review in comparison to actual conditions experienced during Winter 2020-21
*	19	*Order 2222* Stakeholder Process Status Update; Voltus Tech Conf Request (RM18-9)	Dec 20 Dec 22	ISO-NE submits update on the status of its stakeholder process and schedule Voltus requests FERC convene a tech conf on Order 2222-related issues
*	19	ISO-NE FERC Form 3Q (2021/Q3) (not docketed)	Dec 3	ISO-NE submits its 2021 Q3 FERC Form 3Q

IX. Membership Filings

*	19	January 2022 Membership Filing (ER22-747)	Dec 30	NEPOOL requests the FERC accept (i) the memberships of EnPowered USA and Sheldon Energy; and (ii) the termination of the Participant status of ENGIE Power & Gas; comment deadline ***Jan 20, 2022***

X. Misc. - ERO Rules, Filings; Reliability Standards

	20	Revised Reliability Standards: CIP-004-7, CIP-011-3 (RD21-6)	Dec 7	FERC approves revised Standards, eff. Jan 1, 2024
	20	CIP Standards Development: Info Filings on Virtualization and Cloud Computing Services Projects (RD20-2)	Dec 15	NERC submits quarterly informational filing, advising of a modified schedule for the revised Standards included in Project 2016-02 (FERC filing scheduled for Jun 2022)
	21	NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)	Dec 17	NERC submits Dec 2021 Informational Filing pursuant to directives in Dec 2020 *Order Directing Info. Filing*
	23	Report of Comparisons of 2020 Budgeted to Actual Costs for NERC and the Regional Entities (RR21-5)	Dec 2 Dec 23	FERC accepts NERC's Jun 1, 2021 Report; directs filing of info. report NERC files informational report

XI. Misc. - of Regional Interest

	24	203 Application: Howard Wind / Greenbacker Wind (EC22-13)	Dec 28	Greenbacker Wind supplements it application; comment deadline on supplement ***Jan 7, 2022***
	24	203 Application: Castleton Commodities/Atlas Power (GSP companies) (EC22-7)	Dec 6	FERC authorizes Atlas acquisition of the remaining interests in the upstream owner of the Granite Shore Power companies from an affiliate of Castleton Commodities Inc.
	24	203 Application: Hull Street/CMEEC (EC22-3)	Dec 2	FERC authorizes MPH (Hull Street Related Person) acquisition of CMEEC's 84 MW Wallingford electric generating facility
	25	203 Application: PSEG/Generation Bridge II (ArcLight) (EC21-125)	Dec 6 Dec 17	FERC issues deficiency letter Applicants respond to deficiency letter; comment deadline ***Jan 7, 2022***
	25	203 Application: Valcour Wind Energy/AES (EC21-114)	Dec 2	Applicants submit notice of consummation of transaction; Valcour Wind Energy becomes Related Person to AES Renewable Holdings
	25	203 Application: Covanta/EQT (EC21-113)	Dec 10	Applicants submit notice of Nov 30 consummation of transaction; Covanta and Cypress Creek Renewables become Related Persons
	26	203 Application: NRG/Generation Bridge (ArcLight) (EC21-74)	Dec 3	Applicants submit notice of Dec 1 consummation of transaction; NRG Project Companies become Generation Bridge Related Persons
*	26	Related Facilities Agreement: CL&P / Revolution Wind (ER22-1151)	Dec 21	CL&P files RFA; comment deadline ***Jan 11, 2022***
*	26	Cost Reimbursement Agreement Cancellation: Narragansett / CV South Street Landing (ER22-612)	Dec 10	Narragansett files notice of cancellation of Cost Reimbursement Agreement
*	26	D&E Agreement Cancellation: CL&P/NRG Middletown (ER22-599)	Dec 9	CL&P submits notice of cancellation of D&E Agreement
	27	D&E Agreement Cancellation: NSTAR/Cranberry Storage (ER22-214)	Dec 15	FERC accepts notice of cancellation, eff. Oct 27, 2021
	27	Cost Reimbursement Agreement Cancellation: National Grid/GRS (ER22-129)	Dec 15	FERC accepts notice of cancellation, eff. Dec 18, 2021

27	IA Termination: CL&P/Sterling Property (ER21-2860)	Dec 8	CL&P and Brookfield request rehearing and/or clarification of *Sterling IA Order*; FERC action required on or before ***Jan 7, 2022***
		Dec 20	Sterling Property answers CL&P and Brookfield Dec 8 answers
28	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Dec 3	*ER21-1709 (VTransco).* VTransco submits additional information and certain revisions to Schedule 21-VTransco
		Dec 3	*ER21-1694 (GMP).* GMP submits revisions and addition information to its *Order 864* compliance filing
		Dec 3	*ER20-2594-001 (VTransco)*. VTransco submits additional information and certain revisions to the VTA ADIT Worksheet
		Dec 7	*ER21-1241 (NEP)*. NEP files revisions to Sched. 21-NEP related to ADIT requirements from Jan 1, 2020 through Dec 31, 2021
		Dec 7	*ER21-1154 (FG&E)*. FG&E submits revisions to Schedule 21-FG&E related to ADIT requirements from Jan 1, 2020 through Dec 31, 2021
		Dec 8	*ER21-1654 (CL&P).* CL&P submits revisions and additional information to its *Order 864* compliance filing
		Dec 8	*ER21-1650 (NSTAR). NSTAR* submits revisions and additional information to its *Order 864* compliance filing
		Dec 22	*(ISO-NE and TOs).* FERC conditionally accepts the ISO-NE/TOs' Regional Network Service ("RNS") compliance filing effective Jan 27, 2020 and Jan 1, 2022; directs further compliance filing
		Dec 30	*various (New England Transmission Owners).* FERC accepts Transmission Owners' proposed Local Network Service ("LNS") compliance filings effective Jan 27, 2020 and Jan 1, 2022; directs CMP to submit a further compliance filing

XII. Misc. - Administrative & Rulemaking Proceedings

	31	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Dec 22-28	Comments on the issues raised at the first public Task Force meeting filed by: AEP, LA PSC, PJM, Public Citizen
			Dec 14	FERC notices second public Task Force meeting, scheduled for ***Feb 16, 2022*** in Washington, DC
			Jan 4	Institute for Policy Integrity suggests agenda item topic (need for a national perspective)
	33	Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)	Dec 6	FERC invites post-tech conf comments on topics discussed during the Sep 14 and Oct 12 tech conf; initial comments deadline ***Feb 4, 2022***; reply comments deadline, ***Mar 7, 2022***
	34	Office of Public Participation (AD21-9)	Dec 2	One individual ratepayer files comments
*	35	NOI: Industry Assoc'n Dues & Expenses Rate Recovery, Reporting, and Acc'ting Treatment (RM22-5)	Dec 16	FERC seeks comments on (i) the rate recovery, reporting, and accounting treatment of industry assoc. dues and certain expenses; (ii) the ratemaking implications of potential changes; (iii) whether additional transparency or guidance is needed; and (iv) a framework for any such guidance; Initial comments deadline, ***Feb 22, 2022***; reply comments, ***March 23, 2022***
	36	*Order 881*: Managing Transmission Line Ratings (RM20-16)	Dec 16	FERC issues *Order 881*, eff. [60 days from the later of the date Congress receives the FERC notice or the date *Order 881* is published in the *Federal Register*]
	37	NOPR: Electric Transmission Incentives Policy (RM20-10)		Post-Oct 18 Workshop comment deadline ***Jan 14, 2022***
		FERC Composition	Dec 3	Willie Phillips, Jr. sworn in as a member of the FERC for a term expiring Jun 30, 2026

XIII. FERC Enforcement Proceedings

	41	Rover/ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)	Dec 16	FERC issues show cause order directing Rover and ETP to show why they should not be found to have violated the NGA, FERC regulations, and their CPCN in connection with the Rover Project's drilling operations and why they should not be assessed civil penalties in the amount of ***$40 million***
			Dec 20	Rover/ETP request extension of time to respond
			Dec 22	FERC grants Respondents extension of time to respond to ***Mar 21, 2022***

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

*	48	CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (21-1275)	Dec 30	CSC petitions DC Circuit for review of FERC's orders denying CSC recovery under Schedule 17 of all CIP-IROL Costs prudently incurred between Jan 1, 2016 and May 31, 2021
			Jan 3	Court issues order requiring appearances, docketing statements and statement of issues by ***Feb 2, 2022***; dispositive motions, if any, and a Certified Index to the Record, by ***Feb 17, 2022***
	48	Mystic ROE (21-1198) (consol.)	Dec 2	Court grants MA AG motion to intervene
			Dec 3	Court grants FERC motion to extend deadline for filing certified index to the record to ***Jan 28, 2022***
			Dec 13-15	CT Parties, ENECOS, MA AG file docketing statements and statements of issues
			Jan 5	CT Parties appeal *Mystic ROE Allegheny Order*
	48	ISO-NE Implementation of *Order 1000* Exemptions for Immediate Need Reliability Projects (20-1422)		Oral argument before Judges Rogers, Pillard, Randolph scheduled for ***Jan 27, 2022***
	49	Mystic 8/9 Cost of Service Agreement (20-1343)(consol.)	Dec 6	FERC files Respondent's Brief
			Dec 20	Intervenors for Respondents' (ISO-NE and ENECOS) file briefs
	50	*Opinion 531-A* Compliance Filing Undo (20-1329)	Dec 15	FERC submits status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance
	51	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)	Dec 28	Court ***denies*** TransCanada's Petition for Review

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: January 5, 2022

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 January 4, 2022. If you have questions, please contact us.

COVID-19

- **Remote ALJ Hearings (AD20-12)**

All hearings before Administrative Law Judges ("ALJs") are being held remotely through video conference software (WebEx and SharePoint) until further notice.[2] The Presiding Judge in each remote hearing will ensure that the participants have access to an "IT Day" prior to the hearing to allow all participants, witnesses, and the public who will attend the hearing to learn more about the remote hearing software and to get their technical questions answered by the appropriate FERC staff. Uniform Hearing Rules for all Office of the ALJ hearings were adopted effective September 15, 2020.[3] The "Remote Hearing Guidance for Participants" was revised on May 18, 2021 to make two additional changes.[4] The Uniform Hearing Rules and Remote Hearing Guidance for Participants are publicly available in this proceeding in eLibrary and on the FERC's Administrative Litigation webpage.

- **Extension of Filing Deadlines (AD20-11)**

On December 8, 2021, the wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations was ***extended for an additional three months, through March 31, 2022***.[5] The December 8 notice extended the waiver first noticed in May, 2020[6] for a fourth time. As previously reported, Entities may also seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of regulations that govern the form of filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus.[7] The FERC does not anticipate issuing any

[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (June 17, 2020).

[3] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 1, 2020).

[4] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (May 18, 2021) (requiring that only attorneys may access Live Litigation (§VI(a)(vii)) and encouraging that privileged sessions be limited and revising guidance on privileged versus public session management (§VI(k)).

[5] *See Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Dec. 8, 2021) ("Fourth Extension").

[6] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (May 8, 2020)("First Extension"); *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Jan. 25, 2021) ("Second Extension"); *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (July 26, 2021) ("Third Extension").

[7] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Apr. 2, 2020).

further blanket extensions after March 31, 2022, but is closely monitoring developments and will make that decision in light of conditions near the end of the Fourth Extension period.

- **Blanket Waiver of ISO/RTO Tariff In-Person Meeting and Notarization Requirements (EL20-37)**

In light of the continuing nature of the COVID-19 National Emergency, the FERC extended on December 8, 2021, ***for an additional 3 months, through March 31, 2022***, the blanket waivers of ISO/RTO Tariff *in-person*[8] meeting and notarization requirements.[9] The July 26 order extended for a fourth time the blanket waivers first granted in the FERC's April 2, 2020 order and extended in orders issued August 20, 2020, January 25, 2021, and July 26, 2021.[10] The FERC does not anticipate issuing any further blanket extensions after March 31, 2022, but is closely monitoring developments and will make that decision in light of conditions near the end of this fourth extension.

I. Complaints/Section 206 Proceedings

- **206 Investigation: ISO-NE Tariff Schedule 25 and Section I.3.10 (EL21-94)**

As previously reported, the FERC instituted on September 7, 2021 a proceeding under FPA Section 206 to consider whether Schedule 25 and Tariff section I.3.10 may be unjust and unreasonable.[11] This proceeding arises out of issues raised in the NECEC/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the [FERC]'s open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[12]

Accordingly, the FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff section I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff section I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. On September 8, 2021, the FERC issued a notice of the proceeding and of the refund effective date, which will be October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021.[13] NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, Pixelle Androscoggin (out-of-time), Vistra (out-of-time), American Clean Power Association ("ACPA"), EPSA, RENEW Northeast, and Public Citizen intervened.

[8] The waiver only applies to a specific requirement that meetings be held *in person*. Other than the in-person requirement, such meetings must still be held consistent with the tariff, but should be conducted by other means (e.g. telephonically).

[9] *Temporary Action to Facilitate Social Distancing*, 177 FERC ¶ 61,174 (Dec. 8, 2021).

[10] *Temporary Action to Facilitate Social Distancing*, 171 FERC ¶ 61,004 (Apr. 2, 2020) (waiving notarization requirements through Sep. 1, 2020, contained in any tariff, rate schedule, service agreement, or contract subject to the FERC's jurisdiction under the Federal Power Act ("FPA"), the Natural Gas Act ("NGA"), or the Interstate Commerce Act); 172 FERC ¶ 61,151 (Aug. 20, 2020) (extending the waivers through Jan. 29, 2021); 174 FERC ¶ 61,047 (Jan. 25, 2021) (extending the waivers through July 31, 2021); 176 FERC ¶ 61,044 (July 26, 2021) (extending the waivers through Jan. 1, 2022).

[11] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021) ("*Sep 7 Order*").

[12] *Id.* at P 20.

[13] The *Notice* was published in the *Fed. Reg.* on Sep. 14, 2021 (Vol. 86, No. 175) p. 51,140.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff section I.3.10 remain just and reasonable. ISO-NE called for the FERC to "assist Affected Parties and Interconnection Customers in resolving any disputes pertaining to upgrades on Affected Systems—such as the dispute between NECEC Transmission and NextEra Energy Seabrook, LLC in Docket No. EL21-6—as quickly as possible." Interested parties have until January 7, 2022 to address whether ISO-NE's existing Tariff remains just and reasonable and if not, what changes to ISO-NE's Tariff should be implemented as a replacement rate.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Green Development DAF Charges Complaint Against National Grid (EL21-47)**

As previously reported, on September 23, 2021, the FERC denied in part, but granted in part, the complaint ("Complaint")[14] by Green Development, LLC ("Green Development") against New England Power Company ("NEP") and Narragansett Electric Company (together with NEP, "National Grid" or "Grid").[15] The *Complaint Order* partially denied the Complaint, finding that Green Development did not meet its burden of proof that the assignment of Direct Assignment Facility ("DAF") charges violated the first part of the ISO-NE Tariff definition of Direct Assignment Facilities (requiring that the facilities be constructed for the sole use/benefit of a particular Transmission Customer requesting service under the ISO-NE Tariff).[16] However, the *Complaint Order* found that Green Development demonstrated a failure by National Grid to comply with the requirement that the facilities be "specified in a separate agreement among ISO-NE, the Interconnection Customer and the Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified."[17] As a result, National Grid is not permitted, unless and until it complies with that part of the definition, to assess DAF charges to Narragansett in association with the upgrades necessary for the Projects.[18]

Request for Partial Rehearing Denied by Operation of Law. On November 26, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[19] The Notice confirmed that the 60-day period during which a petition for review of the *Green Development Complaint Order* can be filed with an appropriate federal court was triggered when the FERC did not act on Green Development's request for partial rehearing of the *Complaint Order*.[20] The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

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[14] The Complaint requested a finding that Grid's assessment of Direct Assignment Facility ("DAF") charges for Green Development's projects is unauthorized under the ISO-NE Tariff (the "Complaint").

[15] Green Development, LLC v. New England Power Co. and Narragansett Elec. Co., 176 FERC ¶ 61,193 (Sep. 23, 2021) ("*Green Development Complaint Order*" or "*Complaint Order*")).

[16] *Id.* at PP 54-55, 59-60.

[17] *Id.* at PP 54, 61-62.

[18] *Id.* at P 62.

[19] *Green Development, LLC v. New England Power Co. and Narragansett Elec. Co.*, 177 FERC ¶ 62,099 (Nov. 26, 2021) ("*Green Development Complaint Allegheny Order*").

[20] On October 25, 2021, Green Development requested partial rehearing of the *Green Development Complaint Order*, asking the FERC to reverse its finding that Green Development did not meet its burden of proof that the assignment of DAF charges violated the first part of the ISO-NE Tariff definition of DAF (requiring that the facilities be constructed for the sole use/benefit of a particular Transmission Customer requesting service under the ISO-NE Tariff), and grant its Complaint in full.

If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)**

As previously reported, NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") filed a complaint (the "Complaint") on October 13, 2020 requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the NECEC Project and seeking, among other things, an initial, expedited order that would grant certain relief[21] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage. NextEra submitted an answer to the October 13 Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's November 17 answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid also answered the supplemental answer.

Avangrid amended the Complaint on March 26, 2021 to reflect that aspects of the relief originally requested in the Complaint are no longer feasible within the timeline previously sought. Avangrid continues to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021 (which did not occur). On April 15, 2021, NextEra answered the amended Complaint. On April 20, 2021, Avangrid answered NextEra's April 15 answer. On May 6, 2021, ISO-NE submitted a letter to express importance of prompt resolution of these matters. On May 17, Avangrid submitted a letter supporting ISO-NE's May 6, 2021 letter.

Additional Briefing. On September 7, 2021, the FERC issued an order establishing additional briefing in this proceeding and instituted a broader Section 206 proceeding (*see* EL21-94 above).[22] Initial briefs[23] were due on or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs were due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. Since the last Report, Avangrid answered NextEra's November 4 answer, NextEra moved to lodge a letter from a Branch Chief of the Nuclear Regulatory Commission ("NRC"), including an Inspection Report for Seabrook Station for the time period from July 1, 2021 through September 30, 2021 (together, the "NRC Seabrook Report"), to directly refute a central claim of Avangrid (that Seabrook should have already replaced the Generation Breaker at issue in this proceeding), and Avangrid opposed that motion to lodge (asserting that the NRC Seabrook Report is outside the scope of these

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[21] Directing NextEra to comply with the ISO-NE OATT, to comply with open access requirements, and to cease and desist unlawful interference with the NECEC Project; and to have the FERC temporarily revoke NextEra's blanket waiver under Part 358 of the FERC's regulations and to initiate an investigation and require NextEra to preserve and provide documents related to the interconnection of the NECEC Project.

[22] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021).

[23] The FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues: (i) whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility; (ii) if Seabrook's breaker is part of Seabrook's generating facility, under what authority, if any, Seabrook may be subject to the upgrade obligations imposed on Affected Parties under the ISO-NE Tariff; (iii) if Seabrook's breaker is part of Seabrook's generating facility, what obligations, if any, Seabrook has under its LGIA with respect to replacement of the breaker and whether or not ISO New England Operating Documents and Applicable Reliability Standards impose an obligation to replace the breaker. If Seabrook's breaker is appropriately classified as a system protection facility, what obligations Seabrook has to replace the breaker. If the Seabrook LGIA obligates Seabrook to act, a description of the scope of Seabrook's obligation under the LGIA; (iv) whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker; and (v) If replacement of Seabrook's breaker is necessary for the interconnection of the NECEC Project, whether there exists any interim solution for the interconnection of the NECEC Project that would allow energization of the NECEC Project prior to the replacement of Seabrook's breaker.

proceedings and will not assist the FERC in its decision making). With briefing complete, this matter is again before the FERC, which is expected to issue an order in late January, 2022.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)**

In a related matter, initiated a week earlier than the Avangrid Complaint, NextEra Energy Seabrook, LLC ("Seabrook") filed a Petition for a Declaratory Order ("Petition") "by which it seeks to understand the scope of its FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC". Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on Seabrook's Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order Petition. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. Since the last Report, NextEra moved to lodge the NRC Seabrook Report. 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).

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

There are four proceedings pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

- ***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,[24] 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*).[25] However, the FERC's orders were challenged, and in *Emera Maine,*[26] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its

[24] 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*")).

[25] *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*").

[26] *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).

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)[27] and third (EL14-86)[28] ROE complaint proceedings were consolidated for purposes of hearing and 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.[29] 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 proceeding[30] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[31] 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.[32] 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.[33] 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*[34] (EL14-12; EL15-45) in

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[27] 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%.

[28] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General, 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.

[29] *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*").

[30] 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.

[31] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("*Base ROE Complaint IV Initial Decision*").

[32] *Id.* at P 2.; Finding of Fact (B).

[33] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("*Order Directing Briefs"* or "*Coakley*").

[34] *Ass'n of Buss. 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

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[35]

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 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%.[36] 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 Customers[37] 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, 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

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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*.

[35] *Id.* at P 19.

[36] *Id.* at P 59.

[37] For purposes of the motion seeking clarification, "Customers" are CT PURA, MA AG and EMCOS.

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*[38] 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 CAPs opposed the TOs' request and brief.

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 (ER22-556)**

On November 30, 2021, ISO-NE and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2022-23 Capability Year, the second ARA for the 2023-24 Capability Year, and the first ARA for the 2024-25 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 3, 2021 meeting (Consent Agenda Items 3 and 4). A January 29, 2022 effective date was requested. Comments on this filing were due December 21, 2021; none were filed. Calpine, Eversource and NESCOE filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning these matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA16 Qualification Informational Filing (ER22-391)**

On November 9, 2021, ISO-NE submitted its informational filing (the "FCA16 Informational Filing") for qualification in FCA16. ISO-NE is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by ISO-NE for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA16 is scheduled to begin February 7, 2022. The Informational Filing contained ISO-NE's determinations that four Capacity Zones will be modelled for FCA15 -- Southeastern New England ("SENE"), Northern New England ("NNE"), the Maine Capacity Zone ("Maine"), and Rest of Pool. SENE will again be modeled as import-constrained; NNE will be modeled as export-constrained. The Maine Load Zone will be modeled as a separate nested export-constrained Capacity Zone within NNE. The Informational Filing reported that there will be 33,356 MW of existing capacity in FCA16 competing with 5,246 MW of new capacity under a Net ICR of 31,645 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 503 MW of Static De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 15 demand bids, totaling 994 MW, and 193 supply offers, totaling 779 MW, to participate in the substitution auction.

Comments on the FCA16 Informational Filing were due November 24, 2021. Protests were filed by Borrego Solar Systems ("Borrego") and jointly by Anbaric Development Partners, LLC ("Anbaric") and Massachusetts Municipal Wholesale Electric Company ("MMWEC"). Each protested the basis for the IMM's mitigation of a storage resource – for ***Borrego***, the mitigation to zero of an assumed 26.2% percent value for a storage Investment Tax Credit ("ITC") included in the "Build Back Better Act" that had not yet, but has since, been passed; for ***Anbaric/MMWEC***, the IMM's rejection of project-specific offer components that rely on

[38] *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).

either documented competitive advantages enjoyed by each of Anbaric/MMWEC or on FERC-approved storage ORTP offer components. Doc-less interventions only were filed by NEPOOL, Calpine, Dominion, ENE (out-of-time), Eversource, National Grid, NESCOE, NRG, and the Massachusetts Department of Public Utilities ("MA DPU").

On December 9, 2021, the ISO-NE IMM and EMM each responded to the Anbaric/MMWEC protest. Anbaric and MMWEC responded to those answers on December 17. This matter is 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).

- **ICR-Related Values and HQICCs – FCA16 (2025-26) Capacity Commitment Period (ER22-378)**

On December 21, 2021, the FERC accepted the ICR, LSR for SENE, MCL for the Maine and NNE Capacity Zones, HQICCs, and Marginal Reliability Impact ("MRI") Demand Curves (collectively, the "2025-26 ICR-Related Values") for the 2025-26 Capacity Commitment Period ("CCP") filed by ISO-NE and NEPOOL.[39] As previously reported, the 2025-26 ICR will be 32,568 MW (reflecting tie benefits of 1,830 MW) and HQICCs of 923 MW/mo., the net amount of capacity to be purchased in FCA16 to meet the ICR will be 31,645 MW. The LSR for the SENE Capacity Zone is 9,450 MW. The MCL for the Maine Capacity Zone is 4,095 MW. The MCL for the NNE Capacity Zone is 8,555 MW. The 2025-26 ICR-Related Values were accepted effective as of January 8, 2022. Unless the December 21 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 Sophia Browning (202-218-3904; sbrowning@daypitney.com).

- **2021 NESCOE Budget (2022 NESCOE Budget (ER22-117)**

This proceeding was initiated by ISO-NE's October 15, 2021 filing of the budget for funding NESCOE's 2022 operations. The 2022 Operating Expense Budget for NESCOE is $2,485,156. The amount to be recovered reflects true-ups from 2021 (over-collections of $781,482). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00736 per kilowatt ("kW") of Monthly Network Load (a $0.00110/kW increase over 2021). The 2022 NESCOE budget was supported by the Participants Committee at its October 7, 2021 meeting. Comments and any interventions were due on or before November 5. NEPOOL filed comments supporting the 2022 NESCOE Budget. Doc-less interventions only were filed by NESCOE, Eversource, MA DPU, and National Grid. This matter is pending before the FERC. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2022 ISO-NE Administrative Costs and Capital Budgets (ER22-113)**

Also on December 21, 2021, the FERC accepted ISO-NE's filing for recovery of its 2022 administrative costs (the "2022 Revenue Requirement") and its calendar year 2022 capital budget and supporting materials ("2022 Capital Budget", and together with the 2022 Revenue Requirement, the "2022 ISO Budgets").[40] As previously reported, the 2022 Revenue Requirement is $215.1 million (a $10.1 million or 4.9% increase over 2021), which increases to $216.1 million after the under-collection for 2020 is added. Of that total, ISO-NE's administrative costs (i.e., the 2022 Core Operating Budget) comprise $189.1 million; depreciation and amortization of regulatory assets, $26 million; and a $1.1 million true-up for 2020 under-collections.

The accepted 2022 Capital Budget is $32 million, a $4 million increase over 2021, and is comprised of the following (with 2022 projected costs and target completion dates, if available, in parentheses):

- nGem Market Clearing Engine Implementation (Mar 2023) ($4.4 million)
- nGem Software Development Part II (Dec 2022) ($2.8 million)

[39] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER22-378 (Dec. 21, 2021) (unpublished letter order) (order accepting FCA16 ICR-Related Values and HQICCs).

[40] *ISO New England Inc.*, Docket No. ER22-113 (Dec. 21, 2021) (unpublished letter order) (order accepting 2022 ISO-NE Budgets).

- nGem Hardware Phase II (Dec 2022) ($3 million)
- Cyber Security Improvements (Dec 2022) ($2 million)
- MOPR (Dec 2023) ($1.5 million)
- CIP Electronic Security Perimeter Redesign Phase II ($1 million)
- IMM Data Analysis Phase III (Dec 2022) ($900,000)
- Solar Do Not Exceed Dispatch (Sep 2022) ($500,000)
- Integrated Market Simulator Phase I (Jun 2022) ($400,000)
- Identity and Access Management – Phase III (Dec 2022) ($400,000)
- Windows Server 2019 R2 Deployment (Jun 2023) ($400,000)
- Forward Capacity Market Cost Allocation & Accelerated Billing (May 2022) ($300,000)
- TTC Calculator Redesign (May 2022) ($300,000)
- TranSMART Technical Architecture Update (Jun 2022) ($300,000)
- Forecast Enhancements (Jun 2020) ($200,000)
- LMP Monitor Replacement (Apr 2022) ($100,000)
- Forward Capacity Tracking System Infrastructure Conversation Part III (Dec 2022) ($2.9 million)
- 2022 Issue Resolution Projects (June 2022 and Dec 2022) ($1.5 million)
- Amazon Web Services Cloud Foundation (Apr 2022) ($1 million)
- IMM Data Analysis Phase III (Dec 2022) ($900,000)
- Linear State Estimator (Oct 2022) ($500,000)
- Enterprise Application Integration Phase III (Nov 2022) ($500,000)
- External Website Migration to Cloud (Oct 2022) ($400,000)
- Integrated Market Simulator Phase I (Jun 2022) ($400,000)
- Security Information and Event Management Log Monitoring Replacement (Jul 2022) ($300,000)
- Security Information and Event Management Log Monitoring Replacement (Jul 2022) ($300,000)
- TranSMART Technical Architecture Update (Jun 2022) ($300,000)
- E-mail List Server Technology Refresh (Jan 2023) ($300,000)
- Capitalized Interest ($500,000)
- Non-Project Capital Expenditures ($3 million)
- Other Emerging Work ($2.4 million)

The 2022 ISO-NE Budgets were accepted effective as of January 1, 2022. Unless the December 21 order is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (ER21-2334)**

On August 31, 2021, the FERC denied the request by Cross-Sound Cable Company LLC ("CSC") for authorization to establish a regulatory asset that would include all CIP-IROL Costs[41] that CSC prudently incurred between January 1, 2016 and May 31, 2021 ($1.324 million) and recover those costs under Schedule 17 (from all ISO-NE transmission customers) over a five-year period (beginning on the date the FERC makes

[41] Interconnection Reliability Operating Limits ("IROL") Critical Infrastructure Protection ("CIP") costs under Schedule 17 of the ISO-NE Tariff.

this rate treatment and related cost recovery effective).[42] Relying on its *Schedule 17 Orders*,[43] which found that Schedule 17 permits recovery only of CIP-IROL costs incurred on or after the effective date of a FPA section 205 filing made by an IROL-Critical Facility owner to recover such costs, and recovery of CIP-IROL costs incurred prior to the effective date of any relevant, individual FPA section 205 filing would violate the rule against retroactive ratemaking, the FERC found that permitting the recovery here proposed by CSC would violate the filed rate doctrine.[44] The FERC rejected the alternative bases for FERC approval proposed by CSC.[45]

CSC Request for Rehearing Denied by Operation of Law. On November 1, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[46] The Notice confirmed that the 60-day period during which a petition for review of the *August 31 Order* can be filed with an appropriate federal court was triggered when the FERC did not act on CSC's request for rehearing of the *August 31 Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." CSC has appealed the FERC's orders in this proceeding to the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") (*see* Section XVI below, where reporting on this matter will continue). If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Mystic 8/9 Cost of Service Agreement (ER18-1639)**

Each of the *July 17 Orders*[47] and the *Mystic ROE Order,*[48] which addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[49] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen"), have been appealed to the DC Circuit (*see* Section XVI below).

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[42] *Cross-Sound Cable Co., LLC*, 176 FERC ¶ 61,073 (Aug. 31, 2021) ("*August 31 Order*").

[43] *ISO New England Inc.,* 171 FERC ¶ 61,160 ("*Schedule 17 Order*"), *order on reh'g*, 172 FERC ¶ 61,251 (2020) ("*Schedule 17 Rehearing Order*") (collectively, "*Schedule 17 Orders*"), *appeal pending sub nom.*, *Cogentrix Energy Power Mgmt., LLC v. FERC*, D.C. Cir. No. 20-1389 (filed Oct. 14, 2020) (*see* Section XVI).

[44] *August 31 Order* at P 33.

[45] *Id.* at PP 33-37. As previously reported, CSC proposed three alternative bases upon which the FERC could grant its request to use a regulatory asset for CIP IROL cost recovery and rate treatment: (i) FPA section 219 and Order 679 (incentive rate framework); FPA section 205 (in furtherance of the FERC's expressed policy of ensuring reliability of the BES in response to cybersecurity threats); or (iii) FPA section 309 (FERC's remedial authority). In the *August 31 Order*, the FERC rejected each of these in turn.

[46] *Cross-Sound Cable Co., LLC*, 177 FERC ¶ 62,064 (Nov. 1, 2021) (Notice of Denial By Operation of Law of Rehearings of *August 31 Order*).

[47] The "*July 17 Orders*" are the *July 2018 Rehearing Order, Dec 2018* Rehearing *Order* and the *July 17 Compliance Order. Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020) ("*July 2018 Rehearing Order*"); *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020) ("*Dec 2018* Rehearing *Order*"); *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

[48] *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*") (setting the base ROE for the Mystic COS Agreement at 9.33%).

[49] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility.

Mystic ROE Allegheny Order. On November 18, 2021, the FERC issued an "Allegheny Order"[50] modifying the discussion in the *Mystic ROE Order* and setting aside that *Order*, in part.[51] In particular, agreeing with Connecticut Parties that "Otter Tail is properly excluded [as an outlier] from the [Discounted Cash Flow model ("DCF")] under the natural break analysis", the FERC found that the resulting average of the medians of the DCF, Capital Asset Pricing, and Risk Premium models (which sets the ROE) is 9.19%.[52] According the FERC directed Mystic to submit a compliance filing revising the Mystic Agreement to reflect a 9.19% (rather than a 9.33%) base ROE. The FERC also clarified that Avangrid's exclusion from the proxy group was based on its controlled status (ownership stakes by a single entity greater than 50%) and not on the particulars of Iberdrola's ownership or operations.[53] The FERC either disagreed with or dismissed as repetitive the remainder of the parties' arguments on rehearing.

Revised ROE (Sixth) Compliance Filing (-014). On December 20, 2021, in response to the requirements of the *Mystic ROE Allegheny Order*, and subject to the outcome of the pending Federal Court appeals (*see* Section XVI), Mystic filed yet another revised COS Agreement. The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing are due on or before January 10, 2022.

First CapEx Info. Filing. On September 15, 2021, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols"), its informational filing to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between June 1, 2022 to December 31, 2022 ("First CapEx Projects Info. Filing"). Formal challenges to the September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Comments on the formal challenges were due on or before November 17, 2021, and Mystic responded on November 17 asserting that that the challenges should be rejected without further procedures. ENECOS and NESCOE replied to Mystic's November 17, 2021 reply on December 2 and December 6, respectively. The formal challenges are pending before the FERC.

If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **CSO Termination: Killingly Energy Center (ER22-355)**

On January 3, 2022, the FERC accepted ISO-NE's November 21, 2021 filing[54] to involuntarily terminate the CSO held by NTE Connecticut LLC ("NTE CT") as Project Sponsor for Resource No. 38633, the Killingly Energy

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50 An "Allegheny Order" is a merits rehearing order issued on or after the 31st day after receipt of a rehearing request, reflecting the FERC's authority to "modify or set aside, in whole or in part," its order until it files the record on appeal with a reviewing federal court. An Allegheny Order will use "modifying the discussion" if the FERC is providing a further explanation, but is not changing the outcome, of the underlying order; or "set aside" if the FERC is changing the outcome of the underlying order. Aggrieved parties have 60 days after a deemed denial to file a review petition, even if FERC has announced its intention to issue a further merits order.

51 *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE Allegheny Order*") (re-setting Mystic's ROE to 9.19%).

52 *Id.* at P 15.

53 *Id.* at P 21.

54 Comments on this filing were due Dec. 3, 2021, following a request by NTE CT for a one-week extension of time to respond to ISO-NE's filing (which the FERC granted on Dec. 3). NTE CT protested ISO-NE's filing on Dec. 3, 2021. ISO-NE answered NTE CT's protest on Dec. 20, 2021 and NTE CT answered ISO-NE's answer on Dec. 28, 2021. Doc-less interventions were filed by Calpine, Connecticut Light & Power ("CL&P"), Emera Energy Services, NEPGA, NESCOE, National Grid, CT AG, CT DEEP, EPSA, Gemma Power Systems, North Atlantic States Regional Council of Carpenters, Public Citizen, Sierra Club, Yankee Gas, CT OCC, and Mitsubishi Power Americas, Inc.

Center.[55] In accepting the filing, the FERC found that the relevant condition for termination set forth in Tariff section III.13.3.4A was met,[56] and ISO-NE had fulfilled the requirement to consult with NTE CT before termination.[57] The CSO termination was accepted effective January 4, 2022. ISO-NE will draw down the amount of financial assurance provided by NTE CT with respect to the Killingly CSO and Killingly will be ineligible to participate in FCA16. Unless the Killingly CSO Termination Order is challenged, with any challenges due on or before February 3, 2022, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Waiver Request: FCA16 Qualification (Andro Hydro) (ER22-174)**

On October 20, 2021, as later supplemented on October 26, Andro Hydro LLC ("Andro Hydro") requested a one-time waiver of the FCM qualification rules to allow Andro Hydro's Riley-Jay-Otis-Livermore hydroelectric generating resource to participate in the sixteenth Forward Capacity Auction ("FCA16") at a reduced qualification level (8 MW rather than 12.884 MW). Andro Hydro states that ISO-NE informed it of its determination just one day ahead of the Tariff deadline to reduce the capacity amount for which FCA16 qualification sought, insufficient time for it to understand and address ISO-NE's determination.[58] Andro Hydro seeks all necessary waivers to allow it to lower the FCA16 MWs for its resource (avoiding any concerns regarding required upgrades), and thereby make it possible for its resource to participate in FCA16. Comments on Andro Hydro's waiver request were due on or before November 10, 2021. Oppositions to Andro Hydro's request were filed by ISO-NE and Pixelle Androscoggin, LLC. NEPOOL filed a doc-less motion to intervene. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Tariff Changes Associated with *Order 1000* Lessons Learned (ER22-733)**

On December 28, 2021, ISO-NE and NEPOOL filed proposed Tariff revisions, developed after a "lessons learned" process with stakeholders conducted shortly after the conclusion of the Boston RFP, intended to improve New England's competitive transmission planning process ("Transmission Planning Improvements"). An effective date of February 28, 2022 was requested for the Transmission Planning Improvements. The Participants Committee unanimously supported the Transmission Planning Improvements at its November 3, 2021 meeting (Consent Agenda Items # 3 & 4). Comments on this filing are due on or before January 18, 2022. Thus far NESCOE, the MA DPU and RENEW Northeast have filed doc-less interventions. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Attachment K Planning Changes (ER22-727)**

On December 27, 2021, ISO-NE and NEPOOL filed proposed Tariff revisions Tariff revisions to incorporate a supplementary transmission planning mechanism for ISO-NE to perform state-requested, scenario-based transmission analysis as a permanent feature of the Attachment K Regional System Planning Process ("RSP") (the "Attachment K Planning Changes") The Attachment K Planning Changes provide an additional option for the New England states to further their energy policy goals. The Participants Committee unanimously supported the Attachment K Planning Changes at its December 2, 2021 meeting (Agenda Item # 6A). Comments on this filing are also due on or before January 18, 2022. Thus far Champlain VT, NESCOE, Natural Resources Defense Council and

[55] *ISO New England Inc.*, 178 FERC ¶ 61,001 (Jan. 3, 2022) ("*Killingly CSO Termination Order*").

[56] *Id.* at P 25.

[57] *Id.* at P 27.

[58] ISO-NE determined that Andro Hydro's resource did not qualify to participate in FCA16 because a portion of the administered transmission system owned by CMP would require upgrades (not expected to be upgraded before the 2025-2026 Capacity Commitment Period ("CCP")) to allow the Resource to supply capacity.

the Sustainable FERC Project (together, "NRDC"), and RENEW Northeast have filed doc-less interventions. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Attachment K Resource Assumption Changes (ER22-400)**

On January 4, 2022, the FERC accepted jointly filed Tariff revisions (i) to expand the resources that may be relied upon in certain transmission planning studies and (ii) to clarify language in Attachment K (collectively, the "Attachment K Resource Assumption Changes").[59] With the Attachment K Resource Assumption Changes, ISO-NE will include all existing resources, with the exception of imports, in Needs Assessments and Public Policy Transmission Studies. The changes were accepted effective as of January 11, 2022, as requested. Unless the January 4 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).

- **BTM Generation Proposal (ER21-2337)**

On July 1, 2021, ISO-NE and the Participating Transmission Owners Administrative Committee ("PTO AC") jointly filed revisions to Tariff sections I and II to clarify that the calculation of Monthly Regional Network Load excludes load served by behind-the-meter ("BTM") generation, which does not participate in the New England wholesale markets as a Generator Asset, as well as the portions of a Generator Asset utilized to net load at the same retail meter ("BTM Generation Proposal"). The Participants Committee supported the BTM Generation Proposal at its June 3, 2021 meeting (Consent Agenda Items #3 and 4). Comments on this filing were due on or before July 22, 2021. Comments and protests were filed by NEPOOL, the ISO-NE IMM, AEE, IECG, NECOS/ENE, NEPGA, Public Systems, MPUC/CT PURA/MA DPU, and the VT PUC. Doc-less interventions were filed by Calpine, EMI, IECG, National Grid, NESCOE, and NRG. The PTO AC answered the NEPGA protest on August 6, 2021. Answers to the PTO AC Answer were filed by NEPGA and the IMM on August 13 and August 16, respectively. IECG filed an answer to the NEPGA and IMM answers.

Deficiency Letter I. On August 20, 2021, the FERC issued a deficiency letter, directing ISO-NE to provide within 30 days additional information and clarifications. The responses to the Deficiency Letter were due and were filed by ISO-NE on September 20, 2021. Comments on ISO-NE's deficiency letter responses were due on or before October 12, 2021, and NEPGA filed an amended protest and comments on that day. On October 27, the PTO AC answered NEPGA's amended protest and comments.

Deficiency Letter II. On November 12, 2021, the FERC issued a second deficiency letter, directing ISO-NE to provide within 30 days further additional information.[60] The responses to the Deficiency Letter were due and were filed on December 13, 2021. The responses to the second deficiency letter re-set the 60-day deadline for FERC action on this matter to February 11, 2022. Comments on the responses to Deficiency Letter II were due on or before January 3, 2022; none were filed.

This matter is pending before the FERC, with FERC action required on or before February 11, 2022. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **TOs *Order 676-I* Compliance Filing (ER21-2529)**

On July 27, 2021, the PTO AC, ISO-NE, Schedule 20A Service Providers, GMP, and VTransco filed revisions to ISO-NE Tariff Schedule 21-Common and Schedule 20A-Common in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by the Wholesale

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[59] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER22-400 (Jan. 4, 2022) (unpublished letter order).

[60] Specifically, ISO-NE must (i) provide additional support or information regarding the current practices of TOs in calculating Monthly RNL and an illustrative example and a narrative explanation of how transmission costs would be reallocated among Network Customers as a result of the proposal; and (ii) an explanation as to how Filing Parties' proposal is consistent with transmission planning practices with respect to the treatment of BTM generation.

Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB") and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 19, 2021; none were filed. National Grid filed a doc-less intervention on August 13, 2021.

Amended Revisions (ER21-2529-001). On October 22, 2021, the PTO AC submitted amendments to the July 27 compliance filing to include in Schedules 20A-Common and 21-Common revised and new WEQ standards identified in the FERC's March 3, 2020 errata notice to *Order 676-I* ("*Order 676-I Errata Notice*") but not included in the July 27, 2021 filing. Any comments on the errata filing were due on or before November 12, 2021; none were filed.

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).

- **CSC Schedule 18 *Order 676-I* Compliance Filing (ER21-2509)**

On July 26, 2021, CSC and ISO-NE filed revisions to ISO-NE Tariff Schedule 18-Attachment Z in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by NAESB's Wholesale Electric Quadrant and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 16, 2021; none were filed. National Grid and CSC filed doc-less interventions on August 13, 2021 and August 16, 2021, respectively.

Amended Revisions (ER21-2509-001). On October 27, 2021, ISO-NE and CSC submitted amendments to the July 26 compliance filing to include in Schedule 18 revised and new WEQ standards identified in the FERC's *Order 676-I Errata Notice* but not included in the July 26, 2021 filing. Any comments on the errata filing were due on or before November 17, 2021; none were filed.

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).

- **ISO-NE/NEPOOL *Order 676-I* Compliance Filing (ER21-941)**

On January 26, 2021, ISO-NE and NEPOOL, in response to *Order 676-I*, jointly filed changes to incorporate by reference in Schedule 24 of the OATT the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The Participants Committee unanimously supported the *Order 676-I* revisions at its May 7, 2020 meeting. Comments on this filing were due on or before February 16, 2021; none were filed.

Amended Revisions (ER21-941-001). On October 22, 2021, ISO-NE and NEPOOL submitted amendments to the January 26 compliance filing to include in Schedule 24 revised and new WEQ standards identified in the *Order 676-I Errata Notice* to but not included in the July 26, 2021 filing. Any comments on the errata filing were due on or before November 12, 2021; none were filed.

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).

V. Financial Assurance/Billing Policy Amendments

- **Removal of FAP Notarization Requirements (ER22-213)**

On December 6, 2021, the FERC accepted changes jointly filed by ISO-NE and NEPOOL to the ISO-NE Financial Assurance Policy ("FAP") to remove the notarization requirement from the FAP officer certification forms and to add a statement of acknowledgment of the Senior Officer executing the officer certification forms ("FAP

Revisions").[61] The FAP Revisions were accepted effective as of January 1, 2022, as requested. Unless the December 6 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

VI. Schedule 20/21/22/23 Changes

- **Schedule 23: NSTAR/Berkshire Wind/ISO-NE SGIA (ER22-720)**

On December 23, 2021, ISO-NE and NSTAR filed a non-conforming Small Generation Interconnection Agreement ("SGIA") with Berkshire Wind Power Cooperative Corporation ("Berkshire Wind") to cover the continued interconnection of Berkshire Wind's 19.6 MW Small Generating Facility at Brodie Mountain in Lanesborough and Hancock, MA. The SGIA, which replaces a 2014 SGIA, was filed as a result of a requested increase in Capacity Network Resource Interconnection Service ("CNRIS"), as well to update facility descriptions and certain milestones in Appendix B associated with two wind turbine additions, the merger into NSTAR of WMECO and update contact information, and incorporate other ministerial clean-up changes. The CNRIS increase required the filing of a new three-party SGIA, and the 2021 SGIA carries forward certain non-conforming provisions from the 2014 SGIA related to indemnification provisions. A notice of cancellation of the 2014 SGIA was also submitted. A November 23, 2021 effective date for the 2021 SGIA and cancellation of the 2014 SGIA was requested. Comments on this filing are due on or before January 13, 2022. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: 2nd Revised Narragansett LSA (ER22-707)**

On December 22, 2021, ISO-NE and National Grid filed a Local Service Agreement ("LSA") among New England Power, The Narragansett Electric Company ("Narragansett") and ISO-NE to reflect the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island. A January 1, 2022 effective was requested. Following a request by Green Development for an extra week to respond to this filing, subsequently granted by the FERC on January 3, 2022, comments on this filing are now due on or before January 19, 2022. Thus far, Green Development is the only party that has intervened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: Sterling Municipal LSA (ER22-97)**

On December 9, 2021, the FERC accepted a non-conforming LSA between New England Power and Sterling Municipal Light Department ("Sterling Municipal").[62] As previously reported, this LSA extends the term of service to Sterling Municipal and includes other new provisions, particularly those related to the DAF Charge that Sterling Municipal is required to pay pursuant to the LSA. Since the LSA covers an existing, interconnected facility, a new three-party interconnection agreement (that would have included ISO-NE) was not required. The LSA was accepted effective as of December 13, 2021, as requested. Unless the December 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[61] *ISO New England Inc.*, Docket No. ER22-213 (Dec. 6, 2021) (unpublished letter order).

[62] *New England Power Co.*, Docket No. ER22-97-000 (Dec. 9, 2021) (unpublished letter order).

- **Schedule 21-VP: 2020 Annual Update Settlement Agreement (ER15-1434-005)**

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement were due on or before December 9, 2021; reply comments, December 19, 2021; 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-VP: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

Still pending before the FERC is the MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[63] and certified by Settlement Judge Dring[64] to the Commission.[65] As previously reported, under this Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P of the BHD OATT and $260,000 under the MPD OATT. 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 Reports

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

Fitchburg Gas & Electric's ("FG&E") June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[63] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*MPS Merger-Related Costs Order*"). In the *MPS Merger-Related Costs Order*, the FERC accepted, but established hearing and settlement judge procedures for, filings by Emera Maine seeking authorization to recover certain merger-related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). The Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following an audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders. The *MPS Merger-Related Costs Order* set resolution of the issues of material fact for hearing and settlement judge procedures, consolidating the separate compliance filing dockets.

[64] ALJ John Dring was the settlement judge for these proceedings. There were five settlement conferences -- three in 2016 and two in 2017. With the Settlement pending before the FERC, settlement judge procedures, for now, have not been terminated.

[65] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

- **Opinions *531-A/531-B* Regional Refund Reports (EL11-66)**

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[66] *and 531-B*[67] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

- Central Maine Power
- Emera Maine
- Eversource
- National Grid
- NHT
- NSTAR
- United Illuminating
- VTransco

If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Capital Projects Report - 2021 Q3 (ER22-125)**

On December 17, 2021, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2021 (the "Report").[68] As previously reported, Report highlights included the following new projects: (i) E-Mail List Server Technology Refresh ($769,000); and (ii) Total Transfer Capability ("TTC") Calculator Redesign ($492,400). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) Secure Lightweight Directory Access Protocol ("LDAP") Channel Binding Adaption ($100,000); and (ii) 2021 Issue Resolution Project ($100,000). Unless the December 17, 2021 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q3 2021 (ER19-1951)**

On November 12, 2021, ISO-NE filed, as required,[69] public and confidential[70] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the third quarter of 2021 ("2021 Q3"). ISO-NE reported that:

- ***Interconnection Feasibility Study ("IFS") Reports.*** 8 of the 14 2021 Q3 IFS Reports delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[71] In addition, three IFS Reports that are not yet completed have exceeded the 90 day completion expectation. The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS Report to the Interconnection Customer was 124 days (approximately 30 days more than 2021 Q2).
- ***System Impact Study ("SIS") Reports.*** Four SIS Reports were delivered to Interconnection Customers, with three delivered later than the best efforts completion timeline of 270 days. The average mean time

[66] *Martha Coakley, Mass. Att'y Gen.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[67] *Martha Coakley, Mass. Att'y Gen.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

[68] *ISO New England Inc.*, Docket No. ER22-125 (Dec. 17, 2021) (unpublished letter order).

[69] Under section 3.5.4 of ISO-NE's Large Generator Interconnection Procedures ("LGIP"), ISO-NE must submit an informational report to the FERC describing each study that exceeds its Interconnection Study deadline, the basis for the delay, and any steps taken to remedy the issue and prevent such delays in the future. The Exceedance Report must be filed within 45 days of the end of the calendar quarter, and ISO-NE must continue to report the information until it reports four consecutive quarters where the delayed amounts do not exceed 25 percent of all the studies conducted for any study type in two consecutive quarters.

[70] ISO-NE requested that the information contained in Section 3 of the un-redacted version of the Exceedance Report, which contains detailed information regarding ongoing Interconnection Studies and if released could harm or prejudice the competitive position of the Interconnection Customer, be treated as confidential under FERC regulations.

[71] 90 days from the Interconnection Customer's execution of the study agreement.

from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS Report to the Interconnection Customer was 422.5 days (53 days less than 2021 Q2).

- ***Facility Study Reports.*** One Facility Study Report was delivered to an Interconnection Customer and it was delivered later than the best efforts completion timeline of 90 days to refine the costs to the 20% range. In addition, no Facility Studies that are in process have exceeded the 90-day/180-day completion expectation. The time from executed Facility Study Agreement receipt to delivery of the completed Facility Study report to the Interconnection Customer was 147 days.

Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

- **FCA15 Fuel Security Reliability Review Info Filing (ER18-2364)**

Pursuant to the *Fuel Security Retention Proposal Order*,[72] ISO-NE filed on December 2, 2021 its third and final informational filing assessing the study triggers, assumptions and scenarios that it used in performing its fuel security reliability review for FCA15 in comparison to the actual conditions experienced during Winter 2020-2021. This filing is for informational purposes only and will not be noticed for public comment or subject to a FERC order.

- ***Order 2222* Stakeholder Process Status Update; Tech Conf Request (RM18-9)**

Pursuant to the FERC's order granting an extension of time for the filing of the region's *Order 2222* compliance filing,[73] ISO-NE filed on December 20, 2021 an update on the status of the stakeholder process and its schedule for making the required compliance filing (due February 2, 2022). The Participants Committee will consider the proposed compliance filing changes at its January 6, 2022 meeting (Agenda Item #5). This filing is for informational purposes only and will not be noticed for public comment or subject to a FERC order.

Voltus Petition for a FERC Technical Conference on Order 2222. On December 22, 2022, Voltus, Inc. ("Voltus") requested that the FERC convene a technical conference regarding *Order 2222*-related issues sometime in the months of February or March, 2022. Specifically, Voltus requested the technical conference to allow for a collective discussion of key issues arising from the ISO/RTO *Order 2222* compliance proposals, including certain regional variability, roles of industry participants, narrowing perceived knowledge gaps, and subsequent FERC guidance, all of which Voltus asserts supports the request for a technical conference. The Voltus request is pending before the FERC.

- **ISO-NE FERC Form 3Q (2021/Q3) (not docketed)**

On December 3, 2021, ISO-NE submitted its 2021/Q3 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is required to be filed quarterly, and supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **January 2022 Membership Filing (ER22-747)**

On December 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of EnPowered USA Inc. (Supplier Sector); and Sheldon Energy LLC [Related Person to Invenergy Energy Management (Supplier

[72] *ISO New England Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018) ("*Fuel Security Retention Proposal Order*"), *order addressing arguments on reh'g,* 173 FERC ¶ 61,204 (Dec. 3, 2020).

[73] *Participation of Distributed Energy Resource Aggregations in Mkts. Operated by RTOs and ISOs*, 175 FERC ¶ 61,156 at P 5 (May 24, 2021) ("*May 24 Order*").

Sector)]; and (ii) the termination of the Participant status of ENGIE Power & Gas [Related Person to ENGIE Energy Marketing NA (AR Sector, RG Sub-Sector)]. Comments on this filing are due on or before January 20, 2022.

- **December 2021 Membership Filing (ER22-502)**

On November 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of BP Retail Energy LLC [Related Person to BP Energy Co. (Supplier Sector)]; and PSEG Power Connecticut LLC [Related Person to PSEG Energy Resources & Trade and PSEG New Haven (Supplier Sector)]; (ii) the termination of the Participant status of CHI Power Marketing, Inc. (Supplier Sector); J. F. Gray & Associates, LLC (End User Sector); Liberty Power Delaware LLC (Supplier Sector); South Jersey Energy Company and South Jersey Energy ISO3 (together "South Jersey") (Supplier Sector); and (iii) the name change of AES Renewable Holdings, LLC (f/k/a AES Distributed Energy, Inc.). Comments on this filing were due on or before December 21, 2021; none were filed. This filing is pending before the FERC.

X. Misc. - ERO Rules, Filings; Reliability Standards[74]

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Revised Reliability Standards: CIP-004-7, CIP-011-3 (RD21-6)**

On December 7, 2021, the FERC approved changes to Reliability Standards CIP-004-7 (Cyber Security – Personnel & Training) and CIP-011-3 (Cyber Security – Information Protection).[75] As previously reported, the changes clarify the protections required for the use of third-party solutions (e.g. cloud services, which depend less on the actual storage location of the information and more on file-level rights and permissions) for BES Cyber System Information ("BCSI"). The changes will become effective (and the currently effective versions be retired) on January 1, 2024. Unless the December 7 order is challenged, this proceeding will be concluded.

- **CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects (RD20-2)**

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. On December 15, 2021, NERC submitted an informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02")).[76] Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. A revised schedule for Project 2016-02 calls for final balloting of revised standards in March 2022, NERC Board of Trustees Adoption in May 2022 and filing of the revised standards with the FERC in June 2022.

- **Revised Reliability Standards (SOL Changes): FAC-003-5, 011-4, 014-3; IRO-008-3; PRC 002-3, 023-5, -026-2; and TOP-001-6 (RM21-19)**

On June 28, 2021, NERC filed for approval proposed changes to the following Reliability Standards related to establishing and communicating System Operating Limits ("SOLs", and together the "SOL Changes"):

- ♦ FAC-011-4 (System Operating Limits Methodology for the Operations Horizon)
- ♦ FAC-014-3 (Establish and Communicate System Operating Limits)

[74] Reporting on the following proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: NOI: Enhancements to CIP Standards (RM20-12).

[75] *N. Am. Elec. Rel. Corp.*, Docket No. RD21-6 (Dec. 7, 2021).

[76] The other project which had been addressed in prior updates, Project 2019-02, has concluded, and the FERC approved (in RD21-6 just above) the Reliability Standards revised as part of that project (CIP-004-7 and CIP-011-3) on Dec. 7, 2021.

- FAC-003-5 (Transmission Vegetation Management)
- IRO-008-3 (Reliability Coordinator Operational Analyses and Real-time Assessments)
- PRC-002-3 (Disturbance Monitoring and Reporting Requirements)
- PRC-023-5 (Transmission Relay Loadability)
- PRC-026-2 (Relay Performance During Stable Power Swings)
- TOP-001-6 (Transmission Operations)

NERC also requested the retirement of Reliability Standard FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) and modifications to NERC's Glossary of Terms to revise the definition for System Operating Limit and to include "System Voltage Limit". The SOL Changes (NERC Project 2015-09) were developed in response to recommendations from a periodic review of the FAC-010, FAC-011, and FAC-014 Reliability Standards. NERC asked that revised Reliability Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 24 months following FERC approval. The SOL Changes have not yet been noticed for public comment.

- **NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)**

On February 20, 2020, the FERC issued a NOI seeking comments on (i) the potential benefits and risks associated with the use of virtualization and cloud computing services in association with bulk electric system ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization or cloud computing services.[77] On March 25, 2020, Joint Associations[78] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft.

Dec 2021 Informational Filing. In part in response to the comments filed, the FERC, in a December 17, 2020 order,[79] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards. NERC submitted that informational filing on December 17, 2021. In that filing, NERC addressed the status of NERC's formal process to assess the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, evaluated potential modifications to the CIP Standards to facilitate expanded use of the cloud, and considered topic areas raised in comments to the NOI. NERC requested that the FERC accept the informational filing as consistent with the *Order Directing Info. Filing*. NERC committed to continue to consider ways to support industry in securely adopting evolving technologies as necessary, including conducting BES reliability operating services in the cloud. NERC reported that there is no Standard Authorization Request ("SAR") to initiate standards development or a field test, nor had it identified a reliability gap that would necessitate standards development to facilitate BES reliability operating services in the cloud.

[77] *Virtualization and Cloud Computing Services*, 170 FERC ¶ 61,110 (Feb. 20, 2020).

[78] "Joint Associations" are for purposes of this proceeding: EEI, APPA, NRECA, and LPPC.

[79] *Virtualization and Cloud Computing Services*, 173 FERC ¶ 61,243 (Dec. 17, 2020) ("*Order Directing Info. Filing*").

- ***Order 873*** **- Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[80] concluding that the 18 requirements "(1) provide little or no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[81] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4 requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[82]

The FERC left for another day its final action on the remaining 56 requirements for which the FERC proposed to approve retirement in the *Retirements NOPR*[83] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices, which were accepted in *Order 676-J*.[84]

- **Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)**

On September 29, 2021, NERC filed for approval changes to sections 400 (Compliance Monitoring and Enforcement) and 1500 (Confidential Information), Appendix 2 (Definitions) and Appendix 4C (Compliance Monitoring and Enforcement Program) of the NERC Rules of Procedure ("ROP"). The changes were proposed to further enhance the risk-based approach to the Compliance Monitoring and Enforcement Program ("CMEP") whereby registered entities and the ERO Enterprise focus on the greatest risks to the reliability and security of the Bulk Power System ("BPS"). Comments on this filing were due on or before October 20, 2021. Comments were filed by Public Utility District No. 1 of Chelan County and jointly by APPA/LPPC/TAPS. This matter remains pending before the FERC.

- **Rules of Procedure Changes (Reliability Standards Development Revisions) (RR21-8)**

On August 18, 2021, NERC filed for approval revisions to sections 300 (Reliability Standards Development), Appendix 3B (Procedure for Election of Members of the Standards Committee) and Appendix 3D (Development of Registered Ballot Body Criteria) of the NERC Rules of Procedure ("ROP"), which are designed to update language,

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[80] *Elec. Rel. Org. Proposal to Retire Reqs. in Rel. Standards Under the NERC Standards Efficiency Review*, Order No. 873, 172 FERC ¶ 61,225 (Sep. 17, 2020) ("*Order 873*"). The four Reliability Standards being eliminated in their entirety are FAC-013-2 (Assessment of Transfer Capability for the Near-term Transmission Planning Horizon), INT-004-3.1 (Dynamic Transfers), INT-010-2.1 (Interchange Initiation and Modification for Reliability), MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operations and Reliability Coordinators). The five modified Reliability Standards are INT-006-5 (Evaluation of Interchange Transactions), INT-009-3 (Implementation of Interchange) and PRC-004-6 (Protection System Misoperation Identification and Correction), IRO-002-7 (Reliability Coordination—Monitoring and Analysis), TOP-001-5 (Transmission Operations).

[81] *Order 873* at P 2.

[82] *Order 873* at P 5. Pursuant to FPA section 215(d)(4), if the FERC disapproves a modification to a Reliability Standard in whole or in part, it must remand the entire Reliability Standard to NERC for further consideration. Accordingly, although it was satisfied here with the justification for the retirement of R7, the FERC was required to remand both R7 and R8 so that its concerns with the retirement of Requirement R8 could be addressed.

[83] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020) ("*Retirements NOPR*") (proposing to approve the retirement of 74 of 77 Reliability Standard requirements requested to be retired by NERC in these two dockets in connection with the first phase of work under NERC's Standards Efficiency Review, an initiative begun in 2017 that reviewed the body of NERC Reliability Standards to identify those Reliability Standards and requirements that were administrative in nature, duplicative to other standards, or provided no benefit to reliability). As previously reported, NERC withdrew its proposed changes to VAR-001-6 on May 14, 2020, reducing to 76 the number of requirements proposed to be retired.

[84] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*").

staff titles, and processes; remove unnecessary or duplicative obligations; and clarify roles and responsibilities related to the development of Reliability Standards (the "Reliability Standards Development ROP Revisions"). Comments on this filing were due on or before September 8, 2021; none were filed. This matter remains pending before the FERC.

- **Report of Comparisons of 2020 Budgeted to Actual Costs for NERC and the Regional Entities (RR21-5)**

On June 1, 2021, NERC filed comparisons of actual to budgeted costs for 2020 for NERC and the six Regional Entities operating in 2020, including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2020 budgets and actual results. Comments on this filing were due on or before June 22, 2021; none were filed. On December 2, 2021, the FERC accepted the filing,[85] provided guidance to NERC on its future handling of certain financial decisions,[86] and directed NERC to make an informational filing.[87] NERC submitted that informational filing on December 23, 2021, and was not noticed for public comment. The December 2 order was not challenged and is final and unappealable.

- **SolarWinds and Related Supply Chain Compromise White Paper (not docketed)**

On July 7, 2021, FERC staff and E-ISAC released a joint white paper emphasizing the need for continued vigilance by the electricity industry related to supply chain compromises and incidents and recommending specific cybersecurity mitigation actions to better ensure the security of the bulk-power system ("BPS"). View the Report here.

- **FERC/NERC Joint Report on Real Time Assessments (not docketed)**

On July 8, 2021, FERC staff, together with staff from NERC and its regional entities issued a report outlining recommendations for real-time assessments of grid operating conditions.[88] The report concluded that system operators are prepared to manage limited impairments of their primary assessment tools or data through system redundancy and redundant data sources. However, infrequent events involving significant real-time data loss or the failure of primary analysis tools lasting more than two hours require the development of alternative data sources, tools, and analyses work to mitigate the potential loss of visibility and control resulting from the impairment of their primary tools. The report addressed the following seven technical areas related to Real-Time assessments, including observations, conclusions, and recommendations for each: (i) Real-Time Assessment Tools Under Normal Operating Conditions; (ii) Real-Time Data and Data Quality; (iii) Real-Time Data Loss Management; (iv) Alternative Real-Time Assessment and Study Tools; (v) Model Management; (vi) Control Center Hardware Configuration; and (vii) Major System Upgrades/Vendor Changes. View the Report here.

[85] *N. Amer. Elec. Rel. Corp*., 177 FERC ¶ 61,163 (Dec. 2, 2021).

[86] *Id.* at P 14. The FERC directed NERC to submit for FERC approval a "paragraph 7(b)(ii) filing" when there is to be any redirections of previously budgeted funds and/or expenditure of operating reserves as required by its Working Capital and Operating Reserve Policy and the 2013 Settlement Agreement that requires NERC to file for FERC review and approval proposals to expend $500,000 or more from its operating reserves for unforeseen contingencies. *See N. Amer. Elec. Rel. Corp.*, 142 FERC ¶ 61,042, at P 7 (2013) ("2013 Settlement Agreement").

[87] *Id.* at P 13. NERC was directed to explain expenditures and amounts from the Cyber Risk Information Sharing Program (CRISP) Special Projects Reserve to fund the Operational Technology (OT) pilot program, and to explain if and how NERC plans on using $243,549 remaining in the reserve at the end of 2021 in 2022.

[88] Real-time assessments evaluate system conditions using real-time data to measure existing and potential operating conditions to ensure continued reliable operation of the bulk electric system. The joint staff review focuses on strategies and techniques used by reliability coordinators and transmission operators to perform these assessments following a loss or degradation of data or tools used to maintain situational awareness. The review included on-site discussions with representatives of nine participating reliability coordinators and transmission operators.

- **FERC/NERC Joint Report on Review of Protection System Commissioning Programs (not docketed)**

On November 4, 2021, FERC staff, together with staff from NERC and its regional entities issued a report summarizing their review of, and outlining recommendations for, Protection System Commissioning ("PSC") Programs. The review was initiated in 2019 after Misoperation Information Data Analysis System ("MIDAS") data indicated that between 18 and 36 percent of misoperations in MIDAS could be attributed to issues that should have been detected through PSC. The goal of the review was to reduce misoperations attributable to PSC by identifying opportunities for improvement and developing recommendations and best practices for registered transmission and generator owners' PSC programs. View the Report here.

- **FERC/NERC Joint Report on the February 2021 Cold Weather Outages in Texas and the South Central United States (not docketed)**

On November 16, 2021, FERC staff, together with staff from NERC and its regional entities issued a report describing the severe cold weather event occurring between February 8 and 20, 2021 and how it impacted the reliability of the bulk electric system in Texas and the South Central United States. To prevent recurrence of just such an event, the report identifies 28 key recommendations, together with proposed timeframes for implementation, focused on revisions to the Reliability Standards, actions to prevent electric generating unit and natural gas infrastructure freezing issues, grid operations and gas-electric coordination measures for cold weather preparedness. View the Report here.

XI. Misc. - of Regional Interest

- **203 Application: Howard Wind / Greenbacker Wind (EC22-13)**

On November 3, 2021, Greenbacker Wind, LLC requested authorization to acquire from Everpower Wind Holdings, Inc. ("Everpower"), 100% of the equity interests in Howard Wind LLC. No comments on the initial application were filed. On December 28, 2021, Howard Wind supplemented its application by clarifying that the QFs in New York with which it is affiliated are all behind-the-meter. Comments on the supplemental filing are due on or before January 7, 2022. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Castleton Commodities/Atlas Power (GSP companies) (EC22-7)**

On December 6, 2021, the FERC authorized the acquisition by ACR II Granite Shore Power Holdings LLC, an Atlas Capital Resources affiliate (together, "Atlas"), and 50% of owner of Granite Shore Power Holdings LLC ("GSP Holdings"), of the remaining 50% of GSP Holdings from CCI PAH II, an indirect subsidiary of Castleton Commodities International LLC ("CCI").[89] Following consummation of the transaction, Atlas will wholly own GSP Holdings, the indirect owner of NEPOOL members GSP Lost Nation LLC, GSP Merrimack LLC, GSP Newington LLC, GSP Schiller LLC, and GSP White Lake LLC. Pursuant to the December 6 order, Atlas 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: Hull Street/CMEEC (EC22-3)**

On December 2, 2021, the FERC authorized the acquisition by MPH AL Pierce, LLC ("MPH"), indirectly owned by affiliates of Hull Street Energy, of 100 % of the interests in CMEEC's 84 MW Wallingford electric generating facility.[90] Pursuant to the December 2 order, MPH 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).

[89] *ACR II Granite Shore Power Holdings LLC*, 177 FERC ¶ 62,129 (Dec. 6, 2021).

[90] *MPH AL Pierce, LLC*, 177 FERC ¶ 62,115 (Dec. 2, 2021).

- **203 Application: PSEG/Generation Bridge II (ArcLight) (EC21-125)**

On September 2, 2021, PSEG Project Companies[91] and Generation Bridge II, LLC ("Purchaser") requested authorization for a transaction pursuant to which 100% of the membership interests in the PSEG Project Companies will be sold to Generation Bridge II, a wholly-owned, indirect subsidiary of ArcLight Fund VII, which is itself affiliated with Great River Hydro. On September 28, 2021, applicants submitted revised pages of an affidavit included in the original filing to correct statements regarding the ownership of certain assets. Applicants stated that the correction did not affect the analysis or conclusions presented in the original filing. Comments on the correction were due on or before November 2, 2021; none were filed.

Deficiency Letter. On December 6, 2021, the FERC issued a deficiency letter directing the applicants to provide within 30 days additional information and clarifications. Responses to the Deficiency Letter were due and were filed on December 17, 2021. Comments on the deficiency letter responses are due on or before January 7, 2022. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Valcour Wind Energy/AES (EC21-114)**

On December 2, 2021, AES notified the FERC that it consummated its previously-authorized acquisition[92] on November 29, 2021. As a result of the transaction, Valcour Wind Energy, LLC ("Valcour") became a Related Person of AES Corporation (and thereby joins AES Renewable Holdings in the AR Sector). Reporting on this proceeding is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Covanta/EQT (EC21-113)**

On December 10, 2021, Covanta submitted the required notice that transaction authorized by the FERC was consummated on November 30, 2021.[93] Consummation of this and the Cypress Creek Holdings transaction summarized in earlier Reports (EC21-108) make Covanta and Cypress Creek Renewables Related Persons (these companies together vote as members of the AR Sector's Renewable Generation Sub-Sector). This concludes reporting on this matter. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: PPL/Narragansett (EC21-87)**

On September 23, 2021, the FERC authorized a transaction pursuant to which a wholly-owned subsidiary of PPL Corporation will acquire 100% of the outstanding shares of common stock of The Narragansett Electric Company ("Narragansett").[94] This transaction is now expected to close in the first quarter of 2022. Pursuant to the September 23 order, notice must be filed 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).

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[91] The "PSEG Project Companies" are: PSEG New Haven LLC ("PSEG New Haven"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC ("PSEG Power NY").

[92] *The AES Corp.*, 177 FERC ¶ 62,026 (Oct. 15, 2021).

[93] *Covanta Holding Corp*., 177 FERC ¶ 62,031 (Oct. 18, 2021) (authorizing transaction pursuant to which Covanta Holding Corporation and its public utility subsidiaries, including NEPOOL member Covanta Energy Marketing, LLC (together, "Covanta"), will become wholly-owned subsidiaries of Covert Intermediate, Inc., itself an indirectly, wholly-owned affiliate of EQT AB ("EQT")).

[94] *PPL Corp. and The Narragansett Elec. Co.*, 176 FERC ¶ 61,175 (Sep. 23, 2021).

- **203 Application: NRG/Generation Bridge (ArcLight) (EC21-74)**

On December 3, 2021, certain NRG Project Companies[95] and Generation Bridge Acquisition, LLC ("Purchaser" or "Generation Bridge"), a wholly-owned, indirect subsidiary of ArcLight Fund VI, which is itself affiliated with Great River Hydro, notified the FERC that the previously-authorized transaction,[96] pursuant to which 100% of the membership interests in the NRG Project Companies was sold to Generation Bridge, was consummated on December 1, 2021. The NRG Project Companies has also requested termination of their status as Participants. This concludes reporting on this matter. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Exelon Generation (EC21-57)**

On August 24, 2021, the FERC authorized a "spin" transaction in which, after completion of an internal reorganization, the ownership of the public utility subsidiaries ("ExGen Utility Subsidiaries") of Exelon Generation Company, LLC ("ExGen") intermediate holding company owner, HoldCo, will be distributed to the shareholders of Applicants' current ultimate upstream owner, Exelon Corporation (the "Transaction").[97] Following the Transaction, Exelon Corporation and its remaining subsidiaries will retain no interest in, or affiliation with, ExGen or the ExGen Utility Subsidiaries; Exelon Corporation and HoldCo will be separate publicly-traded companies. Notice must be filed 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).

- **Related Facilities Agreement: CL&P / Revolution Wind (ER22-697)**

On December 21, 2021, The Connecticut Light & Power Company ("CL&P") filed a Related Facilities Agreement ("RFA") between CL&P and Revolution Wind LLC. The RFA provides the terms and conditions governing CL&P's activities, and Revolution Wind's cost responsibility for, completing the Related Facilities required to interconnect Revolution Wind's facility to National Grid's 115 kV Davisville Substation in Washington County, Rhode Island. A December 21, 2021 effective date was requested. Comments on this filing are due on or before January 11, 2022. Thus far, doc-less interventions were submitted by New England Power and Narragansett and Revolution Wind. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Reimbursement Agreement Cancellation: Narragansett / CV South Street Landing (ER22-612)**

On December 10, 2021, Narragansett filed a notice of cancellation of its Cost Reimbursement Agreement with CV South Street Landing, LLC ("South Street"). Performance under the Agreement, which related to work by National Grid to underground a 115 kV transmission line,[98] has been completed and all amounts due and owing have been paid in full. A February 9, 2022 effective date was requested. Comments on this filing were due on or before January 3, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: CL&P/ NRG Middletown (ER22-599)**

On December 9, 2021, NSTAR filed a notice of cancellation of the Preliminary Engineering & Design Agreement ("D&E Agreement") with NRG Middletown Repowering LLC ("NRG Middletown"). The D&E Agreement set forth the terms and conditions under which CL&P was to undertake certain preliminary design and engineering activities on the Interconnection Facilities for NRG Middletown's proposed Large Generation Facility prior to the

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[95] The New England "NRG Project Companies" are Connecticut Jet Power LLC ("Connecticut Jet"), Devon Power LLC ("Devon"), Middletown Power LLC ("Middletown"), and Montville Power LLC ("Montville").

[96] *Arthur Kill Power LLC et al.*, 176 FERC ¶ 62,086 (Aug. 18, 2021).

[97] *Exelon Generation Co., LLC*, 176 FERC ¶ 61,121 (Aug. 24, 2021).

[98] *See* Filing of Cost Reimbursement Agreement with CV South Street Landing LLC, *The Narragansett Elec. Co.*, Docket No. ER16-986 (filed Feb. 22, 2016); accepted in *The Narragansett Elec. Co.*, Docket No. ER16-986 (Mar. 21, 2016).

execution of an LGIA. On December 1, 2021, NRG Middletown provided written notice to CL&P that it was terminating the Agreement effective December 31, 2021. CL&P has finalized all billing and invoices and no further work is being done under the Agreement. A December 31, 2021 effective date was requested. Comments on this filing were due on or before December 30, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Cranberry Storage (ER22-214)**

On December 15, 2021, the FERC accepted NSTAR's notice of cancellation of its Engineering, Design, and Procurement Agreement ("D&E Agreement") with Cranberry Point Energy Storage, LLC ("Cranberry Storage").[99] As previously reported, the D&E Agreement set forth the terms and conditions under which Cranberry Storage reimbursed NSTAR for costs associated with advancing certain design and engineering activities for upgrades that were identified in the applicable ISO-NE studies, prior to execution of an LGIA. The D&E Agreement terminated by its terms when an LGIA was executed on October 8, 2021. The notice of cancellation was accepted effective as of October 27, 2021, as requested. Unless the December 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Reimbursement Agreement Cancellation: National Grid/GRS (ER22-129)**

On December 15, 2022, the FERC accepted National Grid's notice of cancellation of its Cost Reimbursement Agreement with Gas Recovery Systems ("GRS").[100] As previously reported, performance under the Agreement has been completed, all amounts due and owing have been paid in full, and a new interconnection agreement between National Grid and GRS has been accepted and is currently in effect. The Agreement was accepted effective as of December 18, 2021 , as requested. Unless the December 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Termination: CL&P / Sterling Property (ER21-2860)**

On November 8, 2021, the FERC rejected the notice of termination filed by CL&P of a 2002 Interconnection Agreement ("IA") governing interconnection service to what CL&P characterized as a since-decommissioned 26 MW waste-tire fueled generator located in Sterling, Connecticut (the "Facility").[101] In rejecting the notice, the FERC found that CL&P had "not provided adequate justification demonstrating that the Facility has been decommissioned in order to terminate the Interconnection Agreement."[102] However, the FERC noted that its determination did not indicate that Sterling retains any interconnection rights under the IA, stating that there had been no interconnection rights associated with the facility since ISO-NE deemed the Facility retired in 2017.

Requests for Rehearing and/or Clarification. On December 8, 2021, CL&P and Brookfield each requested rehearing and/or clarification of the *Sterling IA Order.* Sterling Property answered the CL&P and Brookfield requests on December 20, 2021. The requests for rehearing are pending, with FERC action required on or before January 7, 2022, or the requests will be deemed denied by operation of law. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Power MPD OATT *Order 676-I* Compliance Filing (ER21-2498)**

On July 23, 2021, Versant Power filed proposed revisions to Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the "MPD OATT") to incorporate by reference certain of

[99] *NSTAR Elec. Co.,* Docket No. ER22-214 (Dec. 15, 2021) (unpublished letter order).

[100] *Mass. Elec. Co.*, Docket No. ER22-129 (Dec. 15, 2021) (unpublished letter order).

[101] *The Connecticut Light and Power Co.*, 177 FERC ¶ 61,083 (Nov. 8, 2021) ("*Sterling IA Order*").

[102] *Id*. at P 23.

the revisions required by *Order 676-I* and requested waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT. Comments on this filing were due on or before August 13, 2021; none were filed. Subsequently, on November 1, 2021, Versant submitted amendments to its July 23 compliance filing to include revised and new WEQ standards identified in the Order *676-I* Errata Notice but not included in the July 23, 2021 filing. Comments on the amendment filing were due on or before December 1, 2021; none were filed. This matter is again pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Orders 864/864-A*** **(Public Util. Trans. ADIT Rate Changes):** ***New England Compliance Filings*** **(various)**

In accordance with *Order 864*[103] and *Order 864-A,*[104] and extensions of time granted, New England's transmission-owning public utilities have submitted their *Order 864* compliance filings, with the specific dockets and filing dates identified in the following table. The FERC has begun to address the compliance filings as noted below:

[103] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess Accumulated Deferred Income Taxes ('ADIT") from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information ("ADIT Worksheet"). The ***ADIT Worksheet*** must contain the following five specific categories of information: (i) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein ("***Category 1 Information***"); (ii) is the accounting for any excess or deficient amounts in Accounts 254 (Other Regulatory Liabilities) and 182.3 (Other Regulatory Assets) ("***Category 2 Information***"); (iii) whether the excess or deficient ADIT is protected (and thus subject to the Tax Cuts and Jobs Act's normalization requirements) or unprotected ("***Category 3 Information***"); (iv) the accounts to which the excess or deficient ADIT are amortized ("***Category 4 Information***"); and (v) the amortization period of the excess or deficient ADIT being returned or recovered through the rates ("***Category 5 Information***"). In addition, the FERC stated that it expects public utilities to identify each specific source of the excess and deficient ADIT, classify the excess or deficient ADIT as protected or unprotected, and list the proposed amortization period associated with each classification or source.

[104] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 171 FERC ¶ 61,033, Order No. 864-A (Apr. 16, 2020) ("*Order 864-A*").

Docket(s)	Transmission Provider	Date Filed	Date Accepted
ER20-2572 ER21-1130	New England TOs (RNS)	Jul 30, 2020	Conditionally, Dec 22, 2021
ER20-2429	Central Maine Power ("CMP") (LNS)	Jul 15, 2020 Jul 6, 2021 Nov 8, 2021	Conditionally, Dec 22, 2021
ER21-1702	CMP (Schedule 1 Appendix A Implem. Rule)	Dec 20, 2021 Apr 16, 2021	Conditionally, Dec 30, 2021
ER21-1654	CL&P (LNS)	Dec 8, 2021 Apr 9, 2021	Dec 30, 2021
ER20-2610	CL&P (Phase II BECO AC Support Agreement; Millstone TSA)	Aug 26, 2021 Aug 5, 2020	pending
ER21-1295	Eversource (CL&P, PSNH, NSTAR) (LNS; Schedule 21-ES)	Dec 1, 2021 Mar 8, 2021	Dec 30, 2021
ER21-1154	FG&E (LNS)	Dec 7, 2021 Feb 16, 2021	Dec 30, 2021
ER21-1694	Green Mountain Power	Dec 3, 2021 Apr 16, 2021	Dec 30, 2021
ER21-311	Green Mountain Power	Oct 30, 2020	Dec 30, 2021
ER20-1089	New England Elec. Trans. Corp.	Dec 11, 2020 Feb 26, 2020	pending
ER20-1087	New England Hydro Trans. Corp.	Dec 11, 2020 Feb 26, 2020	pending
ER20-1088	New England Hydro Trans. Elec. Co.	Dec 11, 2020 Feb 26, 2020	pending
ER21-1241	NEP (LNS)	Dec 7, 2021 Mar 1, 2021	Dec 30, 2021
ER20-2551	NEP (Schedule 21-NEP and TSA-NEP-22 Compliance Revisions)	Jul 30, 2020	pending
ER20-2219	NEP (Tariff No. 1)	Jun 29, 2020	pending
ER20-2614	NEP (AC Support Agreement)	Aug 5, 2020	pending
ER20-2607	NEP (Seabrook Transmission Support Agreement)	Aug 4, 2020	pending
ER20-2553	NEP (MECO/Nantucket LSA)	Jul 30, 2020	pending
ER21-1325	NHT (LNS)	Mar 11, 2021	Dec 30, 2021
ER20-2609	NSTAR (Phase II BECO AC Support Agreement)	Aug 4, 2020	pending
ER21-1650	NSTAR (Schedule 1 Appendix A Implem. Rule)	Dec 8, 2021 Apr 9, 2021	Dec 30, 2021
ER21-1293	NSTAR (LNS)	Nov 24, 2021 Mar 8, 2021	Dec 30, 2021
ER20-2608	PSNH (Seabrook TSA)	Aug 5, 2020	pending
ER21-1709	VTransco (LNS)	Dec 3, 2021 Jul 31, 2020	Dec 30, 2021
ER20-2594	VTransco (1991 VTA)	Dec 3, 2021 Jul 31, 2020	Dec 30, 2021
ER20-1839	VETCO	Jan 22, 2021 Jan 7, 2021 May 18, 2020	pending
ER20-2133 -001, -002	Versant Power	Nov 22, 2021 Mar 12, 2021 Jun 23, 2020	pending

Compliance Filings Accepted. Since the last Report, the FERC accepted the following RNS and LNS-related *Order 864* compliance filings (with those accepted conditionally, subject to 60-day compliance filings, followed by an asterisk):

♦ ***ER20-2572; ER21-1130 (New England Transmission Owners ("TOs") - RNS)***.* The FERC conditionally accepted the *Order 864*-related changes to Tariff Attachment F and the Settlement Agreement attached thereto as Appendix A, subject to a further, 60-day compliance filing.[105] Areas the TOs must address in their compliance filing include: (i) changes to the Rate Base Adjustment and Income Tax Allowance Adjustment Mechanisms (TOs must adjust the Settled Formula Rate with respect to each mechanism to meet *Order 864* transparency requirements by specifying the source of the data used in those mechanisms); (ii) ADIT Worksheet Category 3 Information (TOs must clearly identify if excess and deficient ADIT is protected or unprotected); Category 4 Information (TOs must revise the Revised ADIT Worksheet to show amortized excess ADIT amounts included in Account 411.1 and amortized deficient ADIT amounts included in Account 410.1); Category 5 Information (TOs must correct discrepancies in the Revised ADIT Worksheet and the amortization periods; Versant Power must clarify which amortization method it will use; and UI, MEPCO, CMP, and VTransco must provide further justification for their proposed unprotected non-plant amortization periods). Also, the TOs were directed to file the Revised ADIT Worksheet in eTariff format. The Interim Period Formula Rate was accepted effective as of January 27, 2020; the Settled Formula Rate, January 1, 2022. The TOs filing in response to the requirements of the *TOs First Order 864 Compliance Filings Order* is due on or before February 22, 2022.

♦ ***Various Dockets (TOs LNS Compliance Filings).*** On December 30, 2021, the FERC accepted, with the exception of CMP's filing in ER21-1702, which it conditionally accepted, subject to a further 60-day compliance filing, the TOs' revisions to each of their currently effective local transmission formula rate templates under Schedule 21 of the ISO-NE Tariff.[106] The FERC also accepted revisions to certain TOs' currently effective formula rate templates for scheduling, system control, and dispatch service for various transmission services under the respective Schedule 1 of the ISO-NE Tariff, and VTransco's revisions to its formula rate under its grandfathered 1991 Vermont Transmission Agreement ("VTA").

♦ ***ER20-2429 (CMP - LNS)***.* The FERC conditionally accepted CMP's proposed Tariff revisions, effective January 27, 2020,[107] subject to a further, 60-day compliance filing.[108] CMP must address in that compliance filing, due on or before February 22, 2022, the following aspects of its ADIT Worksheet: (i) Category 1 (provide sufficiently detailed information in the re-measurement portion of the ADIT Worksheets to permit interested parties to tie the amounts provided to the rest of the ADIT Worksheets); (ii) Category 4 (revise the ADIT Worksheets to show amortized excess ADIT amounts recorded to Account 411.1, and deficient ADIT amounts recorded to Account 410.1); and (iii) Category 5 (revise its proposal such that the amortization period for unprotected non-plant, deficient ADIT balances is the same amortization period as unprotected non-plant, excess ADIT balances or demonstrate how its deviation from this requirement is consistent with or superior to this requirement of *Order 864*; and revise note (g) of its ADIT Worksheet to make clear that it will amortize unprotected excess ADIT over a five-year period and unprotected deficient ADIT over a 10-year period).

Other Order 864-related activity since the last Report included:

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[105] *ISO New England Inc. et al.*, 177 FERC ¶ 61,219 (Dec. 22, 2021) ("*TOs First Order 864 Compliance Filings Order*").

[106] *ISO New England Inc. et al.*, 177 FERC ¶ 61,239 (Dec. 30, 2021) ("*TO's Order 864 LNS Compliance Order*"). *Order 864* LNS compliance filings accepted were those by: FG&E (ER21-1154-001); NEP (ER21-1241-001); NSTAR (ER21-1293-001 and ER21-1650-001); Eversource (ER21-1295-001); NHT (ER21-1325-001); CL&P (ER21-1654-001); GMP (ER21-311-000; ER21-1694-001); CMP (ER21-1702-001); and VTransco (ER21-1709-001; ER20-2594-001.

[107] The FERC denied CMP's request for a Jan. 1, 2018 effective date, which was earlier than the FERC is authorized under section 206 of the FPA to prescribe a rate 'to be thereafter observed'. Rather, the FERC accepted this filing on the earliest possible date, or Jan. 20, 2020, the date the FERC in *Order 864* required parties to make changes to their tariffs.

[108] ISO New England Inc. and Central Maine Power Co., 177 FERC ¶ 61,218 (Dec. 22, 2021) ("CMP *First Order 864 Compliance Filings Order*").

♦ ***ER21-1709-001 (VTransco)***. On December 3, 2021, VTransco filed additional information and certain revisions to Schedule 21-VTransco. Comments were due on or before Dec 13, 2021; none were filed.

♦ ***ER21-1702-001 (CMP)***. On December 20, 2021, CMP filed revisions and clarifications to its ADIT worksheet and additional support for its proposed amortization periods for excess or deficient ADIT. Comments were due on or before December 27, 2021; none were filed.

♦ ***ER21-1694-001 (GMP)***. On December 3, 2021, GMP filed revisions and addition information to its *Order 864* compliance filing. Comments were due on or before December 13, 2021; none were filed.

♦ ***ER21-1654-001 (CL&P)***. On December 8, 2021, CL&P proposed limited revisions to its *Order 864* compliance filing, including: (i) a revised Permanent ADIT Worksheet and Re-measurement Support Worksheet; (ii); minor revisions to Schedule 21-CL&P; (iii) additional support for CL&P's proposed amortization periods for excess or deficient ADIT; and (iv) a delay in the amortization of excess ADIT until after the FERC has approved both regional and local *Order 864* compliance filings. Comments were due on or before December 20, 2021; none were filed.

♦ ***ER21-1650-001 (NSTAR)***. Also on December 8, 2021, NSTAR proposed limited revisions to its *Order 864* compliance filing, including: (i) a revised Permanent ADIT Worksheet and Re-measurement Support Worksheet; (ii); minor revisions to Schedule 21-NSTAR; (iii) additional support for NSTAR's proposed amortization periods for excess or deficient ADIT; and (iv) a delay in the amortization of excess ADIT until after the FERC has approved both regional and local *Order 864* compliance filings. Comments were due on or before December 20, 2021; none were filed.

♦ ***ER21-1241-001 (NEP)***. On December 7, 2021, New England Power amended its Order 864 compliance filings with revisions and clarifications to Schedule 21-NEP related to ADIT requirements during the January 1, 2020 through December 31, 2021 period ("Interim Period"). Comments were due on or before December 17, 2021; none were filed.

♦ ***ER21-1154-001 (FG&E)***. Also on December 7, 2021, FG&E amended its compliance filing with revisions to Schedule 21-FG&E to comply with ADIT requirements during the Interim Period until supplanted by the Settled Formula Rate beginning on January 1, 2022. Comments were due on or before December 17, 2021; none were filed.

♦ ***ER20-2594-001 (VTransco)***. On December 3, 2021, VTransco submits additional information and certain revisions to the 1991 Vermont Transmission Agreement ("VTA") ADIT Worksheet. Comments were due on or before December 13, 2021; none were filed.

XII. Misc. - Administrative & Rulemaking Proceedings[109]

- **Joint Federal-State Task Force on Electric Transmission (AD21-15)**

On June 17, 2021,the FERC established a Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force").[110] The Transmission Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective."[111] On July 19, 2021, NARUC

[109] Reporting on the following proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: Electrification and the Grid of the Future (AD21-12); ISO/RTO Credit Principles and Practices (AD21-6); Offshore Wind Integration in RTOs/ISOs (AD20-18); Waiver of Tariff Requirements (PL20-7); FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4); and NOI: Certification of New Interstate Natural Gas Facilities (PL18-1).

[110] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021).

[111] Topics that the Task Force may consider include: (i) identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers; (ii) exploring potential

nominated the 10 state commissioners to the Transmission Task Force, including New England Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU).

On August 30, 2021, the FERC issued an order listing the 10 state commissioner members (confirming the nominations of Commissioner Allen and Chairman Nelson), announcing the first public meeting of the Task Force (November 10, 2021) in Louisville, Kentucky, in conjunction with the NARUC meeting scheduled to be held there), and inviting agenda topics (all interested persons, including all state commissions, were invited to file on or before September 10, 2021 comments in this docket on agenda topics for the first public meeting).[112] Comments on the agenda were filed by AEP, APPA, the Environmental Law and Policy Center and National Audubon Society, ITC, NYU's Institute for Policy Integrity, Shell, Southern Company Services, and Wires.

Public Meetings.

♦ The first Joint Federal-State Task Force meeting, which focused on incorporating state perspectives into regional transmission planning, was convened on November 10, 2021. Comments on those issues were on or before December 22, 2021, and were filed by: AEP, LA PSC, MI PSC, PJM, and Public Citizen.

♦ A second meeting is scheduled for February 16, 2022 in Washington, DC (Renaissance Downtown Hotel). Task Force members will consider suggested agenda topics, which were due on or before January 4, 2022, in developing the agenda for the second meeting. The one set of comments suggesting topics for the second meeting was filed by the Institute for Policy Integrity at the New York University School of Law ("Institute for Policy Integrity"), which encouraged the FERC and Task Force to explore how a *national perspective* could inform and improve the transmission development process, including by establishing a baseline set of nationally uniform informational inputs and parameters for scenario planning and modeling, as well as specifications of benefits and costs to inform project selection in all transmission planning regions The public may attend the second meeting in person or via Webcast.

- **Climate Change, Extreme Weather, and Electric Sys. Reliability: Jun 1-2 Technical Conference (AD21-13)**

On June 1-2, 2021, FERC staff convened a technical conference to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events. This technical conference addressed (i) concerns that, because extreme weather events are increasing in frequency, intensity, geographic expanse, and duration, the number and severity of weather-induced events in the electric power industry may also increase; and (ii) specific challenges posed to electric system reliability by climate change and extreme weather, which may vary by region. The FERC seeks to understand the near, medium and long-term challenges facing the regions of the country; how decision makers in the regions are evaluating and addressing those challenges; and whether further FERC action is needed to help achieve an electric system that can withstand, respond to, and recover from extreme weather events. Pre-technical conference comments were due on or before April 15, 2021 and were filed by, among others, ISO-NE, AEE, Dominion, EDF, Eversource, Exelon, LS Power, National Grid, PSEG, Vistra, APPA, Capital Power, EEI, NARUC, NEI, NERC, NRECA, and the R Street Institute. Speaker materials were posted in eLibrary on June 3, 2021; transcripts of the June 1-2 days, July 22, 2021.

On August 11, 2021, the FERC issued a notice inviting post-technical conference comments. Comments could address the questions raised in the notice, as well as any other issues raised during the technical conference

bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals; (iii) exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions; (iv) reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms; (v) examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and (vi) discussing mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

[112] *Joint Federal-State Task Force on Electric Transmission*, 176 FERC ¶ 61,131 (Aug. 30, 2021).

or identified in the Supplemental Notices of Technical Conference issued March 15 and May 21, 2021. Comments were due on or before September 27, 2021 and were filed by: CAISO; MISO; NYISO; PJM; AEP; City of New Orleans; City of New York; Columbia Law School's Sabin Center for Climate Change Law; EDF and Sabin Center for Climate Change Law; EEI; EPSA; Eversource; Exelon, Jupiter Intelligence; Louisville Gas and Electric Company and Kentucky Utilities Company; MI PSC; NRDC, Sierra Club, Sustainable FERC Project, and UCS; Old Dominion Electric Cooperative ("ODEC"); NERC; and C. Wright. On October 14, Entergy answered the comments submitted by City of New Orleans. This matter is pending before the FERC.

- **Reliability Technical Conference (Sep 30) (AD21-11)**

On September 30, 2021, the FERC convened its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the Bulk-Power System ("BPS"). Panel discussions addressed: (1) BPS reliability and security (current state, challenges and initiatives); (2) extreme weather, risks and challenges); (3) managing cyber risks in the electric power sector; and (4) maintaining electric reliability with changing resource mix. A detailed final agenda, identifying the presenters and panelists, is available here. Speaker materials have been posted to eLibrary. A transcript of the September 30 technical conference was posted in eLibrary on November 16, 2021.

- **Modernizing Electricity Market Design - Resource Adequacy (AD21-10)**

March 23 Tech Conf (PJM). The FERC convened a Commissioner-led technical conference on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. Speaker materials from the March 23 technical conference have been posted to eLibrary. On March 29, Ohio PUC Commission Dan Conway submitted written comments. On April 5, the FERC issued a notice inviting post-technical conference comments on specific PJM-specific questions. Initial comments were due on or before April 26, 2021; reply comments must be submitted on or before May 10, 2021. More than 45 sets of comments were filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA, some of which addressed issues to be discussed in the May 25 New England technical conference (identified immediately below). On May 10, 2021, reply comments were filed by the American Clean Power Association ("ACPA"), AEP, EPSA, Exelon, Joint Consumer Advocates, LS Power, Old Dominion Electric Cooperative ("ODEC"), PJM Power Providers ("P3"), Public Interest Organizations ("PIOs"), and the Retail Electric Supply Association ("RESA").

May 25 Tech Conf (New England). On May 25, 2021, the FERC held a Commissioner-led technical conference regarding the wholesale markets administered by ISO New England Inc. Supplemental notices of the technical conference were issued on May 3 and May 17. The May 17 supplemental notice identified panelists and topics/questions for discussion for the technical conference. Panel discussions included: (1) a Commissioner-led discussion of the relationship between state policies and the New England Markets; (2) a Staff-led discussion of short-term options and complementary potential market changes to accommodate state policies in New England; and (3) a Staff-led discussion of long-term options and centralized procurement of clean energy.

Post (New England) Tech Conf Comments. On June 4, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the May 17, 2021 supplemental notice. Post-technical conference comments were due on or before ***July 19, 2021*** and were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

- **Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)**

Tech Conferences. As previously reported, the FERC held in the Fall of 2021 two staff-led technical conferences addressing ISO/RTO energy and ancillary services markets (including potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time).[113] The first technical conference was held September 14, 2021; the second, October 12, 2021. Transcripts of both technical conferences are posted in eLibrary.

Post-Technical Conference Comments. On December 6, 2021, the FERC invited all interested persons to file initial and reply comments on the topics discussed during each of the two technical conferences. Initial comments must be submitted on or before ***February 4, 2022***; reply comments, ***March 7, 2022***.

- **Office of Public Participation (AD21-9)**

On June 24, 2021, the FERC issued a report in which it detailed the forthcoming creation of the Office of Public Participation ("OPP"), which it intends to grow over the course of a four-year period before OPP reaches its full operating status by the close of Fiscal Year ("FY") 2024. By the end of FY2021, the FERC plans to hire the OPP Director (which it has done – *see* below), as well as the Deputy Director and an administrative staff member. The FERC plans to assess OPP's workload and reevaluate needed resources for additional growth into and beyond FY2024 to ensure meaningful and consistent compliance with FPA section 319. A report, prepared by M.J. Bradley & Associates for NRDC's Sustainable FERC Project, summarizing stakeholder feedback provided to the FERC through listening sessions and written comments, was posted to the FERC's eLibrary on August 3, 2021.

The FERC held, on October 7, 2021 a virtual workshop to discuss technical assistance in electric proceedings, solicit public input on their technical assistance needs, and explore ways OPP could work with external entities to facilitate technical assistance to interested parties. Further details on the agenda, including registration information, can be found on the U.S. Department of Energy's ("DOE") Pacific Northwest National Laboratory ("PNNL") website. Information on this technical workshop was also posted on the Calendar of Events on the FERC's website, www.ferc.gov.

On October 12, 2021, FERC Chairman Glick announced that Elin Katz, the former head of the Connecticut Office of Consumer Counsel ("CT OCC") and president of the National Association of State Utility Consumer Advocates ("NASUCA"), will lead OPP. Ms. Katz assumed her role as the Director of OPP in late November.

Since the last Report, one set of comments was filed by an individual New England (New Hampshire) ratepayer requesting that the FERC "place pressure on ISO to change their algorithm to incentivize clean, sustainable, renewable energy … and support public participation by requiring ISO New England make their plan for grid transition transparent to the community".

- **Hybrid Resources (AD20-9)**

As previously reported, the FERC convened a July 23, 2020 technical conference to discuss technical and market issues prompted by growing interest in projects that are comprised of more than one resource type at the same plant location ("hybrid resources"). The focus was on generation resources and electric storage resources paired together as hybrid resources. Speaker materials and a transcript of the technical conference have been posted to the FERC's eLibrary. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO, PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street Institute, Savion, and SEIA.

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the "Issues"); (b) an update on the status of any ongoing efforts to develop reforms related to each of the Issues; and (c) responses to the specific requests for information contained in the

[113] In advance of the technical conferences, in an effort to frame discussions at those technical conferences, FERC staff issued on Sept. 7, 2021, a White Paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs" summarizing recent energy and ancillary services markets reforms as well as reforms then under consideration.

order. The ISO/RTO Reports, including ISO-NE's, were filed on July 19, 2021. Public comments in response to the ISO/RTO reports were filed in September 20, 2021.[114]

Hybrid Resources White Paper. On May 26, 2021, the FERC issued a white paper that discusses the hybrid resources technical conference, as well as information learned in post-technical conference comments. Interested persons were invited to submit comments on the white paper and encouraged to jointly respond to both the white paper and RTO/ISO informational reports where applicable to avoid duplicate comments. Comments on the white paper will also be due on September 20, 2021.

Comments. Comments on the RTO filing and on the FERC's Hybrid Resources White Paper were submitted by the American Council on Renewable Energy ("ACRE"), Clean Grid Alliance, EEI, the City of New York, Hybrid Resource Coalition, NRECA, Pine Gate Renewables, PJM IMM, and UCS. On October 20, 2021, NYISO submitted comments in response to issues raised by those comments. These matters remain pending before the FERC.

- **NOI: Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses (RM22-5)**

On December 16, 2021, the FERC issued a notice of inquiry ("NOI")[115] seeking comments on (i) the rate recovery, reporting, and accounting treatment of industry association dues and certain civic, political, and related expenses; (ii) the ratemaking implications of potential accounting and reporting changes; (iii) whether additional transparency or guidance is needed with respect to defining donations for charitable, social, or community welfare purposes; and (iv) a framework for guidance should the FERC determine action is necessary to further define the recoverability of industry association dues charged to utilities and/or utilities' expenses from civic, political, and related activities. Initial comments are due February 22, 2022; reply comments, March 23, 2022.

- **ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)**

On July 15, 2021, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[116] to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained. Specifically, the ANOPR discusses proposals or concepts for changes to existing processes in several broad categories: regional transmission planning, regional cost allocation, generator interconnection funding, generator interconnection queueing processes and consumer protection, and in several instances the ANOPR also offers a potential rationale or argument for potential proposals. The FERC seeks comments from the public on these proposals and welcomes commenters to offer additional or alternative proposals for consideration.

Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEE, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute.

November 15, 2021 Tech Conf. On November 15, 2021, the FERC convened a technical conference to examine in detail issues and potential reforms related to regional transmission planning as described in the July

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114 Public comments were initially due Aug. 18, 2021. However, in response to a request by the Energy Storage Association ("ESA"), the American Clean Power Association ("ACP"), and Solar Energy Industry Association ("SEIA"), the FERC granted a 30-day extension of time, to Sep. 20, 2021, to file comments in response to the ISO/RTO reports.

115 *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses*, 177 FERC ¶ 61,180 (Dec. 16, 2021) ("*Dues & Expenses NOI*").

116 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("*Transmission Planning & Allocation/Generation Interconnection ANOPR*").

15, 2021 ANOPR. Specifically, the technical conference examined issues related to incorporating sufficiently long-term and comprehensive forecasts of future transmission needs during regional transmission planning processes, including considering the needs of anticipated future generation in identifying needed transmission facilities. Speaker materials were posted to eLibrary on November 16, 2021.

Reply and Post-Tech Conf Comments. ANOPR Reply Comments and Post-November 15 technical conference comments were due on or before ***November 30, 2021*** and were filed by over 100 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEE, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. This matter is pending before the FERC.

- **NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14)**

On March 18, 2021, the FERC issued a NOI[117] seeking comments on whether to revise its Demand Response ("DR") Opt-Out regulations established in *Orders 719 and 719-A.* Those regulations require an ISO/RTO not to accept bids from an aggregator of retail customers ("ARC") that aggregates DR of the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' DR to be bid into ISO/RTO markets by an ARC. The FERC now seek information to help it examine the potential costs/burdens and benefits, both quantitative and qualitative, of removing the DR Opt-Out, as well as other changes relating to DR since the FERC issued *Orders 719 and 719-A*. The FERC is not seeking comment on the Small Utility Opt-In. Comments on the NOI, following an extension, were due on or before July 23, 2021 and were filed by nearly 30 parties, including by AEE, Voltus, AEMA, APPA/NRECA, EEI, and NARUC. Reply comments were due on or before August 23, 2021, and were filed by AEP, Armada Power, Entergy, Southern Pioneer Electric, Voltus, State Commissions from LA/MS, MI, MO, NC, APPA/NRECA, Assoc. of Bus. Advocating Tariff Equity ("ABATE"), and PIOs. This matter is pending before the FERC.

- **NOPR: Cybersecurity Incentives (RM21-3)**

On December 17, 2020, the FERC issued a NOPR[118] proposing to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the BPS.

Comments on the *Cyber security Incentives NOPR* were due on or before April 6, 2021. Comments were filed by: NECPUC, APPA, EEI, EPSA, LPPC, NERC, NRECA, TAPS, Accenture, aDolus Inc. et al.,[119] Alliant, Anterix, Bureau of Reclamation, CA Dept of Water Resources State Water Project/CPUC, George Cotter, FRS, Hitachi ABB Power Grids, IECA, ITC, Joint Consumer Advocates, MI PUC, Org of MISO States, MISO TOs, PJM TOs, and Public Citizen. Reply comments were due May 6, 2021[120] and were filed by APPA/TAPS, EEI, SEIA, California Public Utilities Commission and California Department of Water Resources ("CA PUC/DWR"), and the Office of the Ohio Federal Energy Advocate ("Ohio FEA"). This matter remains pending before the FERC.

- ***Order 881*: Managing Transmission Line Ratings (RM20-16)**

On December 16, 2021, the FERC issued its final rule, *Order 881*, on Managing Transmission Line Ratings.[121] In *Order 881*, the FERC reforms both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, *Order 881* requires:

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117 *Participation of Aggregators of Retail Demand Response Customers in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,198 (March 18, 2021) ("*DR Aggregator NOI*").

118 *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Cybersecurity Incentives NOPR*").

119 These joint comments were filed by aDolus Inc., Fortress Information Security, GMO GlobalSign Inc., Ion Channel, ReFirm Labs and Reliable Energy Analytics LLC.

120 The *Cybersecurity Incentives NOPR* was published in the *Fed. Reg.* on Feb. 5, 2021 (Vol. 86, No. 23) pp. 8,309-8,325.

121 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (Dec. 16, 2021) ("*Order 881*").

(i) transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service;

(ii) ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly;

(iii) transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s); and

(iv) transmission providers to maintain a database of transmission owners' transmission line ratings and transmission line rating methodologies on the transmission provider's Open Access Same-Time Information System ("OASIS") site or other password-protected website.

Order 881 will become effective [60 days from the later of the date Congress receives the FERC notice or the date *Order 881* is published in the *Federal Register*].

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

Supplemental NOPR. In light of comments already received in this proceeding,[122] the FERC issued on April 15, 2021 a *Supplemental NOPR*[123] to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The Incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC seeks comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[124]

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[122] Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES.

[123] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (Apr. 15, 2021) ("*Supplemental NOPR*").

[124] As previously reported, the *March NOPR* proposed revisions to the FERCs existing transmission incentives policy and corresponding regulations, including the following:

- ♦ A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ♦ ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period and an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ♦ ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ♦ ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ♦ ***Eliminate Transco Incentives***.
- ♦ ***Transmission Organization Incentive***. A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ♦ ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ♦ ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ♦ ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups.[125] Since the last Report, reply comments were posted from New England State Parties,[126] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the American Clean Power Association.

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[127] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

Notice Inviting Post-Workshop Comments. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning incentives and shared savings. Comments must be submitted on or before ***January 14, 2022***.

If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order* 860/*860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

As previously reported, *Order 860,*[128] issued three years after the FERC's *Data Collection NOPR,*[129] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will *not* adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC has posted on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. As recently extended (*see* below), *Order 860* became effective July 1, 2021, and submitters have until close of business on November 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain FERC-generated IDs for reportable entities that do

[125] "Public Interest Groups" are NRDC, Sierra Club, Sustainable FERC Project, and Western Grid Group.

[126] "New England State Parties" are CT PURA, CT DEEP and the MA AG.

[127] Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

[128] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 168 FERC ¶ 61,039 (July 18, 2019) ("*Order 860*"), *order on reh'g and clarif.*, 170 FERC ¶ 61,129 (Feb. 20, 2020).

[129] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (July 21, 2016) ("*Data Collection NOPR*").

not have CIDs or LEIs, as well as Asset IDs for reportable generation assets without an EIA code so that every ultimate upstream affiliate or other reportable entity has a FERC-assigned company identifiers ("CID"), Legal Entity Identifier,[130] or FERC-generated ID and that all reportable generation assets have an code from the Energy Information Agency ("EIA") Form EIA-860 database or a FERC-assigned Asset ID. Requests for rehearing and/or clarification of *Order 860* were denied,[131] other than TAPS' request that the FERC clarify that the public will be able to access the relational database. On that point, the FERC clarified "that we will make available services through which the public will be able to access organizational charts, asset appendices, and other reports, as well as have access to the same historical data as Sellers, including all market-based rate information submitted into the database. We also clarify that the database will retain information submitted by Sellers and that historical data can be accessed by the public."

MBR Database. On January 10, 2020, the FERC issued a notice that updated versions of the XML, XSD, and MBR Data Dictionary are available on the FERC's website and that the test environment for the MBR Database is now available and can be accessed on the MBR Database webpage.

March 18 Notice. On March 18, 2021, the FERC issued a notice seeking comments on proposed changes to the MBR Data Dictionary to reflect the affiliations, or lack of affiliation, among Sellers for which their ultimate upstream affiliate is an institutional investor who acquired their securities pursuant to a section 203(a)(2) blanket authorization.[132] Specifically, the FERC proposes to update the MBR Data Dictionary and add the following three new attributes to the Entities table: the blanket authorization docket number, and the utility ID types and the utility IDs of the utilities whose securities were purchased under the corresponding blanket authorization docket number. Appropriate Sellers would be required to submit the docket number of the proceeding in which the FERC granted the section 203(a)(2) blanket authorization and the upstream affiliate whose securities were acquired pursuant to the section 203(a)(2) blanket authorization. Comments on the Notice were due on or before June 7, 2021,[133] and were filed by EEI, the Global LEI Foundation, TAPS, and XBRL US. In light of the proposed changes, the FERC deferred by three months the effective date of *Order 860* and its associated deadlines.

Effective Date: July 1, 2021; Baseline Submissions March 3, 2022; First change in Status Filings, April 29, 2022. On October 22, 2021, the FERC issued a second notice extending the effective and associated implementation dates of *Order 860* by an additional *three* months. The deadline for baseline submissions will be February 1, 2022. First change in status filings under these new timelines will be due March 3, 2022; second change in status filings, April 29, 2022.

Order Adopting Changes to MBR Database. On August 19, 2021, the FERC issued an order revising the MBR Data Dictionary as proposed in the March 18 Notice.[134] Specifically, Sellers whose ultimate upstream affiliate(s) own their voting securities pursuant to a section 203(a)(2) blanket authorization must provide, in the MBR Database, three additional data fields: (1) the docket number of the section 203(a)(2) blanket authorization, (2) the Utility_ID_Type_CD of the utility whose securities were acquired under the corresponding section 203(a)(2) blanket authorization docket number, and (3) the Utility ID of that utility.

[130] An LEI is a unique 20-digit alpha-numeric code assigned to a single entity. They are issued by the Local Operating Units of the Global LEI System.

[131] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, Order No. 860-A, 170 FERC ¶ 61,129 (Feb. 20, 2020) ("*Order 860-A*").

[132] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 174 FERC ¶ 61,214 (Mar. 18, 2021).

[133] The Notice was published *Fed. Reg.* on Apr. 6, 2021 (Vol. 86, No. 64) pp. 17,823-17,828.

[134] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 176 FERC ¶ 61,109 (Aug. 19, 2021).

- ***Order 676-J*: Incorporation of NAESB WEQ Standards v. 003.3 into FERC Regs (RM05-5-029, -030)**

On May 20, 2021, the FERC issued Order 676-J,[135] which revises FERC regulations to incorporate by reference the latest version (Version 003.3) of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). The WEQ Version 003.3 Standards include, in their entirety, the WEQ-023 Modeling Business Practice Standards contained in the WEQ Version 003.1 Standards, which address the technical issues affecting Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC") calculation for wholesale electric transmission services, with the addition of certain revisions and corrections. The FERC also revised its regulations to provide that transmission providers must avoid unduly discriminatory and preferential treatment in the calculation of ATC. *Order 676-J* became effective August 2, 2021.[136] Public utilities must make a compliance filing to comply with the requirements of this final rule through eTariff 12 months after implementation of the WEQ Version 003.2 Standards. Compliance filings for cybersecurity and Parallel Flow Visualization standards are due March 2, 2022.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[137] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement filed its reply on September 14, 2021. Should the FERC choose to pursue a civil penalty against PacifiCorp for the alleged violations, PacifiCorp has already exercised its right to adjudicate these allegations in federal district court. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **GreenHat (IN18-9)**

On November 5, 2021, the FERC issued its order assessing civil penalties against GreenHat Energy, LLC ("GreenHat"), John Bartholomew, Kevin Ziegenhorn, and [Luan Troxel as the Executor for] the Estate of

[135] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*").

[136] *Order 676-J* was published *Fed. Reg.* on June 2, 2021 (Vol. 86, No. 104) pp. 29,491-29,503.

[137] *PacifiCorp,* 175 FERC ¶ 61,039 (Apr. 15, 2021) ("*PacifiCorp Show Cause Order*").

Andrew Kittell ("Kittell Estate") (collectively, "Respondents").[138] The FERC found that Respondents violated FPA section 222, along with section 1c.2 of the FERC's regulations, PJM Tariff Attachment Q, Section B and section 15.1.3 of PJM's Operating Agreement, by engaging in a manipulative scheme in PJM's Financial Transmission Rights ("FTR") market which generated more than $13 million in unjust profits for Respondents and imposed approximately $179 million in losses on PJM Members. The FERC assessed civil penalties of ***$179 million***, ***$25 million***, and ***$25 million*** against GreenHat, Bartholomew, and Ziegenhorn, respectively. The FERC ordered Respondents, including the Kittell Estate, to disgorge unjust profits of just ***over $13 million***, plus interest. Each of Respondents is jointly and severally liable for payment of that disgorgement amount.[139] As previously reported, Respondents have already exercised their right to adjudicate these allegations in federal district court,[140] and the *GreenHat Penalties Order* will not be subject to rehearing. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

- **Rover Pipeline, LLC and Energy Transfer Partners, L.P. (CPCN Show Cause Order) (IN19-4)**

On March 18, 2021, the FERC issued a show cause order[141] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity ("CPCN") under NGA section 7(c).[142] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show CPCN Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15. This matter is pending before the FERC.

- **Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)**

On December 16, 2021, the FERC issued a show cause order[143] 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

[138] *GreenHat Energy, LLC et al.*, 177 FERC ¶ 61,073 (Nov. 5, 2021) ("*GreenHat Penalties Order*").

[139] *Id.* at P1.

[140] If the penalty is unpaid within 60 days, the FERC will institute a proceeding in the appropriate district court seeking an order affirming the assessment of a civil penalty. The district court will have the authority to review *de novo* the law and facts involved and the jurisdiction to enforce, modify, or set aside, in whole or in part, the penalty assessment, subject to review by the appropriate U.S. Court of Appeals.

[141] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP CPCN Show Cause Order*").

[142] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

[143] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 177 FERC ¶ 61,182 (Dec. 16, 2021) ("*Rover/ETP Tuscarawas River HDD Show Cause Order*").

Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[144] 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;[145] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***. Following a request from Respondents, the answer period was extended to and including March 21, 2022.

- ***BP (*IN13-*15)***

On December 17, 2020, the FERC issued *Opinion 549-A*,[146] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[147] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[148] Opinion 549-A revised Ordering Paragraph (C) to direct the disgorged profits to non-profits that disburse the Low Income Home Energy Assistance Program of Texas funds, rather than to the Texas Department of Housing.[149]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

- ***Total Gas & Power North America, Inc. et al. (IN12-17)***

On April 28, 2016, the FERC issued a show cause order[150] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[151]

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[144] *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").

[145] 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.

[146] *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*")

[147] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

[148] *BP Penalties Allegheny Order* at P 1.

[149] *Id*. at P 319.

[150] *Total Gas & Power North America, Inc.,* 155 FERC ¶ 61,105 (Apr. 28, 2016) ("*TGPNA Show Cause Order*").

[151] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated NGA section 4A and the

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[152] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[153] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference. Judge Krolikowski issued an order confirming her rulings from the August 26 prehearing conference and establishing a procedural schedule that calls for, among other dates, pre-hearing briefs by July 25, 2022, hearings (estimated to take 2-3 weeks) to begin on August 15, 2022, and an initial decision on January 9, 2023. In light of the settlement judge procedures described just below, Respondents and OE Staff moved to temporarily suspend the procedural schedule for about six weeks to "allow the Participants to direct all of their resources towards fully participating in settlement discussions." Chief Judge Cintron granted the motion, extending the hearing commencement and initial decision deadlines to September 26, 2022, and February 20, 2023, respectively.

Settlement Judge Procedures. On September 21, 2021, Chief Judge Cintron concurrently designated Judge Joel deJesus as Settlement Judge to explore the possibility of settlement. Three settlement conferences were held (October 15, 25 and November 1, 2021). On November 9, 2021, Judge deJesus declared an impasse and recommended that settlement judge procedures be terminated. On November 16, 2021, Chief Judge Cintron issued an order terminating settlement judge procedures. The procedural schedule for the hearing will continue to remain in effect.

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

New England Pipeline Proceedings
The following New England pipeline projects are currently under construction or before the FERC:

- **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).

Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

152 *Total Gas & Power North America, Inc. et al.,* 176 FERC ¶ 61,026 (July 15, 2021).

153 The hearing in this proceeding will be convened within 55 weeks (Aug. 15, 2022) and the initial decision issued within 76 weeks (January 9, 2023) of the issuance of the Chief Judge's order.

- Three-year construction project; service request by November 1, 2023.
- February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on January 26, 2021 that the FERC act promptly and issue the certificate; National Grid and ConEd submit comments supporting Iroquois' application and request for action.
- On May 27, 2021, FERC staff issued a notice that it will prepare an environmental impact statement ("EIS") for this Project, which will respond to comments filed on the Environmental Assessment, and plans to release that EIS on September 3, 3021.
- On June 11, 2021, FERC staff issued a notice that it has prepared a draft EIS for this Project, which responds to comments on the September 30, 2020 Environmental Assessment, and with the exception of greenhouse gas ("GHG") emissions, concludes that approval of the proposed Project, with the mitigation measures recommended in the EIS, would not result in significant environmental impacts. FERC staff did not come to a determination of significance with regards to GHG emissions. Comments on the draft EIS were due on or before August 9, 2021. Since the last Report, 93 sets of individual comments were filed, bring to nearly 300 the number of individual comments have been filed. Algonquin responded to those comments on August 24, 2021.
- On September 2, 2021, FERC staff modified the issuance date of its final EIS for the Project, due to the "complexity of comments received on the draft EIS". Issuance of a final EIS is now expected on November 12, 2021; the 90-day Federal Authorization Decision Deadline, February 9, 2022.
- On September 3, 2021, FERC staff issued environmental information request #4, to which Iroquois responded on September 13, 2021.
- On October 15, 2021, Iroquois submitted a supplemental Life Cycle Greenhouse Gas Analysis Report.
- On November 12, 2021, FERC staff issued the final EIS for the Project, which responds to comments that were received on the September 30, 2020 Environmental Assessment and June 11, 2021 draft EIS and discloses downstream GHG emissions for the Project. "With the exception of climate change impacts, FERC staff concluded that approval of the proposed Project, with the mitigation measures recommended in this EIS, would not result in significant environmental impacts."

- ***Atlantic* Bridge *Project (CP16-9)***
  - On February 24, 2020, the FERC authorized Algonquin Gas Transmission, LLC ("Algonquin") and Maritimes & Northeast Pipeline, LLC ("Maritimes") to place facilities associated with the Atlantic Bridge Project into service.[154] Rehearing of the *Authorization Order* was timely requested, but denied by operation of law.
  - *Briefing Order*. In a fairly unprecedented order issued February 18, 2021,[155] the FERC, expressing concerns regarding operation of the project, established briefing on the following matters:
    - In light of the concerns expressed regarding public safety, is it consistent with the FERC's responsibilities under the NGA to allow the Weymouth Compressor Station to enter and remain in service?
    - Should the Commission reconsider the current operation of the Weymouth Compressor Station in light of any changed circumstances since the project was authorized? For example, are there changes in the Weymouth Compressor Station's projected air emissions impacts or public safety impacts the Commission should consider? We encourage parties to address how any such changes affect the surrounding communities, including environmental justice communities.

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[154] *Algonquin Gas Transmission, LLC*, Docket No. CP16-9 at 1 (Sep. 24, 2020) (delegated order) ("*Authorization Order*").

[155] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 174 FERC ¶ 61,126 (Feb. 18, 2021) ("*Briefing Order*").

  - Are there any additional mitigation measures the Commission should impose in response to air emissions or public safety concerns?
  - What would the consequences be if the Commission were to stay or reverse the *Authorization Order*?
- Requests for rehearing of the *Briefing Order* were filed by Algonquin, NGSA and Center for Liquefied Natural Gas, and by America and Energy Infrastructure Council. Cheniere Energy submitted comments in support of the requests for rehearing. On April 19, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[156] The Notice confirmed that the 60-day period during which a petition for review of its *Briefing Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Briefing Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." On May 19, the FERC issued that order,[157] dismissing the requests for rehearing of the *Briefing Order*, noting, over the objection of Commissioner Danly, that the *Briefing Order* was an exercise of the FERC's continuing oversight of the Project (meaning the claimed harms would be speculative and premature) and Algonquin and Trade Associations will have an opportunity to submit, if they choose, in requests for rehearing of any final decision by the Commission in this proceeding. Algonquin petitioned the DC Circuit for review of the *Briefing Order* and the notice of denial by operation of law on May 3, 2021 (*see* Section XVI below).
- Requests for rehearing of the *May 19 Order* were filed by Algonquin and INGAA. On July 16, 2021, the FERC issued a Notice of Denial of Rehearings by Operation of Law of the requests for rehearing of the *May 19 Order*.
- Algonquin also petitioned the DC Circuit for review of the *Briefing Order*, *April 19 Notice of Denial of Rehearings by Operation of Law*, and the *May 19 Order*.[158]
- This matter is before the DC Circuit (*see* Section XVI below).

Non-New England Pipeline Proceedings

The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

- **Northern Access Project (CP15-115)**
  - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[159] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).
  - As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[160] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which

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[156] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 62,022 (Apr. 19, 2021) ("*April 19 Notice of Denial of Rehearings by Operation of Law*").

[157] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 61,150 (May 19, 2021) ("*May 19 Order*").

[158] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 176 FERC ¶ 62,029 (July 16, 2021) ("*July 16 Notice of Denial of Rehearings by Operation of Law*").

[159] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[160] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*"), *reh'g denied*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[161] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.

- The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3, 2017.[162] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[163] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[164] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[165]
- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [166] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting

[161] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[162] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), *reh'g denied*, 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

[163] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[164] Summary Order, *Nat'l Fuel Gas Supply Corp. v. N.Y. State Dep't of Envtl. Conservation*, Case 17-1164 (2d. Cir., issued Feb. 5, 2019).

[165] *See Sierra Club v. FERC*, No. 19-01618 (2d Cir. filed May 30, 2019); *NYSDEC v. FERC*, No. 19-1610 (2d. Cir., filed May 28, 2019) (consolidated).

[166] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[167]

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

In October 2020, the six New England states released their "Vision Statement", outlining their vision for "a clean, affordable, and reliable 21st century regional electric grid" and committing to engage in a collaborative and open process, supported by NESCOE, intended to advance the principles discussed in the Vision Statement. As part of that effort, the following series of online technical forums to discuss the issues presented in the Vision Statement were held:

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions were, following an extension, due by May 13, 2021. Comments submitted are posted on **NewEnglandEnergyVision.com**. Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are also available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

Report to the Governors. On June 29, 2021, the NESCOE Managers published their Progress Report to the New England Governors Regarding "Advancing the New England Energy Vision". The Report was further discussed at the August 5, 2021 Participants Committee meeting. View Report here.

ISO-NE Board Response. On September 23, 2021, the ISO-NE Board responded to the New England States' Vision Statement and Advancing the Vision Report. A copy of that response was included with the materials for the October 7, 2021 Participants Committee meeting and is posted on the ISO-NE website here.

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).

[167] *Id.* at P 10.

- **CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (21-1275)**
  Underlying FERC Proceeding: ER21-2334[168]
  Petitioner: CSC
  Status: Filing of Initial Submissions Underway

On December 30, 2021, CSC petitioned the DC Circuit Court of Appeals for review of the FERC's orders denying it authorization to establish a regulatory asset that would include all CIP-IROL Costs prudently incurred between January 1, 2016 and May 31, 2021 and to recover those costs under Schedule 17 over a five-year period. Appearances are due February 2, 2022. CSC must file a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decision from which the appeal arises by February 2, 2022. Dispositive motions, if any, and a Certified Index to the Record must be filed by February 17, 2022.

- **Mystic ROE (21-1198; 21-1222, 21-1223, 21-1224) (consolidated)**
  Underlying FERC Proceeding: EL18-1639-010, -011[169]
  Petitioners: Mystic, CT Parties,[170] **MA AG, ENECOS**
  Status: Filing of Initial Submissions Underway

As previously reported, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. On October 14, 2021, the Court ordered Mystic to file, and Mystic filed on October 29, a Docketing Statement Form, a Statement of Intent to Utilize Deferred Joint Appendix, a Statement of Issues to be Raised, and the Underlying Decision from which the appeal arises. Since the last Report, the Court granted the MA AG's motion to intervene and the FERC's motion to extend the deadline for filing certified index to the record to January 28, 2022 (allowing for inclusion of all activity following the *Mystic ROE Allegheny Order*). Statements of Issues and Docketing Statements were filed by CT Parties, ENECOS and the MA AG in mid-December.

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[171]
  Petitioner: LS Power
  Status: Briefing Complete; Oral Argument Scheduled for Jan 27, 2022

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for immediate need reliability projects. Since the last Report, MMWEC filed on July 8 a notice that it would not submit a Reply Brief. On July 9, 2021, LSP Transmission filed Petitioner's Reply Brief. LSP Transmission filed a Joint Appendix on July 16. On July 28, 2021, MMWEC filed an Intervenor for Petitioner Final Brief. Final Briefs were filed on July 30, 2021. Briefing is now complete. On November 13, 2021, the Court scheduled oral argument for Thursday, January 27, 2022. The argument panel will be composed of Judges Rogers, Pillard and Randolph.

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[168] *Cross-Sound Cable Co., LLC*, 176 FERC ¶ 61,073 (Aug. 31, 2021) ("*August 31 Order*"); *Cross-Sound Cable Co., LLC*, 177 FERC ¶ 62,064 (Nov. 1, 2021) (Notice of Denial By Operation of Law of Rehearings of *August 31 Order*).

[169] *Constellation Mystic Power, LLC, 176 FERC ¶ 61,019 (July 15, 2021) ("Mystic ROE Order"); Constellation Mystic Power, LLC, 176 FERC ¶ 62,127 (Sep. 13, 2021) ("September 13 Notice") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Order).*

[170] In this appeal, "CT Parties" are the Connecticut Public Utilities Regulatory Authority ("CT PURA"), Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the Connecticut Office of Consumer Counsel ("CT OCC").

[171] *ISO New England Inc., 171 FERC ¶ 61,211 (June 18, 2020) ("Order Terminating Proceeding")* (finding (i) "insufficient evidence in the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential; (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed"; and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption); and *ISO New England Inc.,* 172 FERC ¶ 61,293 (Sep. 29, 2020) *("Order 1000 Exemptions Allegheny Order")* (addressing arguments raised by request for rehearing denied by operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[172]
  Petitioner: Cogentrix, Vistra
  Status: Briefing Complete; Oral Argument Held Nov 12; Awaiting Decision

On September 25, 2020, Cogentrix and Vistra petitioned the DC Circuit Court of Appeals for review of the FERC's orders allowing for recovery of expenditures to comply with the IROL-CIP requirements, but only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing, including undepreciated costs of any such past capital expenditures to comply with the IROL-CIP requirements. Following the completion of briefing, oral argument before Judges Srinivasan, Katsas and Randolph was held on November 12, 2021. This matter is pending before the Court.

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[173]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Briefing Underway

Mystic, NESCOE, MA AG, and CT Parties have separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, ExGen and ISO-NE.[174] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. On April 16, 2021, the Court ordered the parties to file, and the parties did file, by May 17, 2021, proposed formats for the briefing of these cases.

On June 23, 2021, the Court established a briefing schedule. Thus far, FERC filed a Certified Index to the Record (on July 12, 2021); Mystic and State Petitioners filed Opening Briefs (September 7, 2021); and Intervenor for State Petitioners filed their Brief (September 21, 2021). Since the last Report, Respondent's (FERC's) Brief was filed on December 6, 2021; and Intervenors for Respondents' (ISO-NE and ENECOS) Briefs were filed December 20, 2021). Next up are Reply Briefs (February 3, 2022); Joint Appendix (February 17, 2022); and Final Briefs (February 24, 2022). The date for oral argument and the composition of the merits panel will be identified at a later time.

- ***CASPR* (20-1333, 20-1331) (consolidated)****
  Underlying FERC Proceeding: ER18-619[175]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until June 1, 2022)

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On

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[172] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*") and *ISO New England Inc.*, 172 FERC ¶ 61,251 (Sep. 17, 2020) ("*CIP IROL Allegheny Order*", and together with the CIP IROL Cost Recover Order, the "*CIP IROL Orders*").

[173] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[174] The COS Agreement is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

[175] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

October 29, Petitioners opposed the FERC's motion. On November 5, 2020, the FERC filed a reply, indicated that an order on rehearing would be issued imminently and suggested that, if the Court declines to dismiss the petition, it should be held in abeyance until the Commission issues an order on rehearing. As noted above, the FERC issued the *CASPR Allegheny Order* on November 19, modifying the discussion in the *CASPR Order*, but reaching the same the result. The Sierra Club, NRDC and CLF also requested rehearing of the November 19 order.

On January 12, 2021, the Court dismissed as moot the FERC's October 19 motion to hold this proceeding in abeyance and ordered that the motion to dismiss be referred to the merits panel (Judges Pillard, Katsas and Walker) and addressed by the parties in their briefs. On January 25 and 26, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these cases. On March 24, 2021, the Court granted NEPOOL's intervention and established a briefing schedule that, as explained just below, has since been superseded.

On April 7, 2021, the Court granted Petitioners' motion to hold this matter in abeyance, pending further order of the Court. The parties were directed to file motions to govern future proceedings in these cases on or before October 22, 2021. On October 22, 2021, Petitioners Sierra Club, NRDC, Renew Northeast, Inc., and CLF moved the Court to hold this matter in abeyance until June 1, 2022. On October 25, 2021, the Court granted Petitioners' second motion to hold this matter in abeyance. The parties were directed to file motions to govern future proceedings in these cases on or before June 1, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[176]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[177] 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*[178] 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 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 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 report by September 1, 2021 and at 120-day intervals thereafter. The parties

[176] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

[177] 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.

[178] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. On December 15, 2021, the FERC submitted a status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[179]
  Petitioner: TransCanada
  Status: Petition for Review DENIED on Dec 28, 2021

On December 28, 2021, the Court (Judges Srinivasan, Henderson and Edwards) denied TransCanada Power Marketing's petition for review of the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[180] In denying TransCanada's appeal, the Court found that: (i) the FERC reasonably chose to analyze the rates associated with the 2013/14 Winter Reliability Program under a market-based paradigm (since the bid auction employed by the Program was a market mechanism); (ii) the supply curve and 25% adder reflected reasonable estimates of participant costs and reasonably accounted for indeterminate factors such as participants' lack of information and the unique nature of the Program; and (iii) TransCanada forfeited its remaining arguments by failing first to adequately raise them before the FERC. Reporting on this matter is now concluded.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[181]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Briefing Complete; Oral Argument Held Oct 21; Awaiting Decision

As previously reported, at the unopposed request of the FERC, the Court issued an order suspending the previous briefing schedule and remanding the record back to the FERC. Subsequently, the FERC issued its *IEP Remand Order* (June 18, 2020) and its Notice of Denial by Operation of Law of the requests for rehearing of its *IEP Remand Order* (August 20, 2020). As previously reported, each of the Petitioners filed amended petitions for review in the consolidated proceeding in order to bring the FERC's *IEP Remand Order* and the post-remand FERC record before the DC Circuit. Following completion of briefing, oral argument was held October 21, 2021 before Judges Wilkins, Katsas and Jackson. This matter is pending before the Court

Other Federal Court Activity of Interest

- ***Order 872*** **(20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[182]
  Petitioners: SEIA et al.
  Status: Briefing Complete; Oral Argument Scheduled for March 8, 2022

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[183] Briefing is now complete and oral argument has been scheduled for March 8, 2022, though the Court stated that

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179 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*") (accepting ISO-NE's January 23, 2017 compliance filing, finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable, and providing for this finding the further reasoning requested by the DC Circuit in *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (DC Cir. 2015) ("*TransCanada*").)

180 The Court determined that the issues, fully considered, do not warrant a published opinion.

181 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

182 *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

183 *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

panel to be assigned could decide to submit the case on the briefs instead. The composition of the argument panel will be identified roughly 30 days prior to oral argument.

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[184]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel
  Status: Being Held in Abeyance

The Supreme Court proceedings up on which abeyance in this proceeding had been based ended on August 2, 2021. The parties filed a motion to govern future proceedings on September 1, 2021, suggesting that supplemental briefing was in order. On September 13, 2021, the Court ordered that Petitioners and Respondents file supplemental briefs on November 12, 2021. However, on October 29, the FERC and Petitioners NJ DEP, DE and Raritan Canal Commission, NJ Conservation Foundation and The Watershed Institute, NJ Division of Rate Counsel, Township of Hopewell, NJ and ConEd (collectively, "Movants") requested that the Court suspend the supplemental briefing schedule entered on September 13, 2021 and hold this consolidated case in abeyance. The Court granted that motion on November 12, 2021 and directed the parties to file motions to govern future proceedings by February 18, 2022.

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513) (consol.)**
  Underlying FERC Proceeding: EL14-12; EL15-45[185]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Oral Argument Held Nov 18; Awaiting Decision

The MISO TOs, Transource and "Dec 23 Petitioners",[186] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Following completion of briefing, oral argument was held on November 18, 2021 before Judges Srinivasan, Katsas and Walker. This matter is pending before the Court.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.);**
  Underlying FERC Proceeding: CP16-9-012[187]
  Petitioners: LS Power, Algonquin, INGA
  Status: Case Being Held in Abeyance

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022.

[184] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[185] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[186] "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperative Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Public Service Comm.; MO Joint Municipal Electric Utility Comm.; Organization of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

[187] *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law.*

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