NEW ENGLAND POWER POOL

David T. Doot
Secretary

May 28, 2020

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of June 4, 2020 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the next meeting of the Participants Committee will be held **via teleconference on *Thursday*, June 4, 2020, beginning at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2020.php. **Please note, as indicated on the Final Agenda, that the meeting will end with a confidential executive session *for members and alternate members or their delegates only*.**

For your information, the June 4 meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

The dial-in number for the general session, to be used only by those members, alternates and welcomed guests who otherwise attend NEPOOL meetings, is **866-803-2146; Passcode: 7169224**. The dial-in number for the executive session, to be used only by members, alternates, or their delegates, will be circulated to members and alternate members with the confidential materials.

We trust all of you have marked your calendars for virtual summer meeting sessions to be held on the mornings of Tuesday, June 23 and Wednesday, June 24, 2020. As noted earlier, the June 23 meeting will begin at 9:00 a.m. and will include a presentation by Dr. David Patton, President of Potomac Economics, ISO New England's External Market Monitor of the EMM's 2019 Annual Report on the New England Markets and an opportunity for questions to Dr. Patton. The June 24 meeting is scheduled to be from 8:30 to 12:30, with the promised educational session associated with future grid discussions. There will be virtual Sector meetings with the ISO Board panels on Thursday, June 25 and Friday June 26. We are also working to set up opportunities for Sector discussions with state regulators and officials for those who are interested. We will provide further details as plans are finalized.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meeting held on May 7, 2020, which have been marked to show changes since the draft circulated with the initial notice.

2. To adopt and approve all actions recommended by the Technical Committees that are identified on the Consent Agenda included with this supplemental notice and posted with the meeting materials.

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To receive a report on the ISO's preliminary 2021 Operating and Capital Budgets by its Chief Financial & Compliance Officer, Robert Ludlow. Background materials are included and posted with this supplemental notice.

6. To consider and take action, as appropriate, on proposed revisions to the Financial Assurance Policy (a/k/a the "Know Your Customer Changes"). These revisions were reviewed and discussed by the Budget & Finance Subcommittee. Background materials and a draft resolution are included and posted with this supplemental notice.

7. To consider and take action, as appropriate, on proposed changes to the Tariff in response to the requirements of the FERC's March 19, 2020 Order 845 Compliance Filing Order. Background materials and a draft resolution are included and posted with this supplemental notice.

8. To consider and take action, as appropriate, on proposed changes to ISO New England Planning Procedure No. 10 (Planning Procedure to Support the Forward Capacity Market), as recommended by the Reliability Committee, which provide the implementation details for the alignment of reliability reviews of de-list bids with the competitive solicitation process for new transmission and better describe how responses in the competitive solicitation process will be accounted for in those reviews. Background materials (including materials from Exelon relating to concerns with these changes) and a draft resolution are included and posted with this notice.

9. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. The litigation report will be posted in advance of the meeting.

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

    - Markets Committee
    - Reliability Committee
    - Transmission Committee
    - Budget & Finance Subcommittee
    - GIS Agreement Working Group
    - Joint Nominating Committee
    - Others

11. Administrative matters.

[continued on next page]

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

Discussion on Items 13-14 will be held in executive session, during which participation will be limited exclusively to voting Members and Alternates, or their designates. A separate call in number for this portion of the meeting is being circulated with confidential supporting materials.

13. To consider and take action, as appropriate, on revisions to the ISO-NE Tariff to reflect a settlement among certain settling parties in the formula rate proceeding in FERC Docket No. EL16-19. A background memorandum and a draft resolution is included and posted with this supplemental notice. Because the settlement has not yet been finalized and remains subject to privileged and confidential treatment, pursuant to Rule 606 of the FERC's Rules of Practice and Procedure, the additional materials for this item are confidential and are being circulated under separate confidential cover only to members and alternates.

14. To consider and take action, as appropriate, on requirements recommended by the ISO as additional conditions to the requested membership of Invenia Technical Computing Corp. A background memorandum and a draft resolution are included and posted with this supplemental notice. Additional confidential materials are being circulated under separate confidential cover only to members and alternates.

Electronic Participation Guidelines
June 4, 2020 Participants Committee Teleconference

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, 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.

BEFORE THE MEETING

- **Download meeting materials** from the NEPOOL or ISO-NE websites**.** Will minimize disruptions WebEx or internet service interruptions.

PROXIES

- If unable to participate for any portion of the meeting, members and alternates are encouraged to designate a temporary alternate or proxy by e-mail to pmgerity@daypitney.com.

JOIN THE TELECONFERENCE

866-803-2146; 7169224#

- 866-803-2146; access code 7169224#.
- Slowly state your name and the Participant you are representing, followed by the # key.
- Audio by phone only. No computer-based audio available.

JOIN THE WEBEX

Join Meeting

WebEx Link

- Click <Classic View> on right side of menu. Do not use <Modern View>.
- Enter first name, last name and e-mail address.
- Enter meeting password: **nepool.**
- Click <Join>.

DURING THE MEETING

*6

- **MUTE YOUR PHONE** (*6) when not speaking.
- **DO NOT PLACE THE CALL ON HOLD** – if taking another call, hang-up and rejoin when ready.
- **USE A HANDSET** when speaking. Use of headsets/speaker phones strongly discouraged.
- **ASK AND WAIT** to be recognized by the Chair.
- **IDENTIFY** yourself/your Participant once recognized and before continuing.

VOTING

- Voice Votes. Oppositions and Abstentions will be noted for the record.
- Roll Call Votes. Will be taken if and as (i) necessary or (ii) requested by any member.

SERVICE INTERRUPTIONS

- Report dropped calls by e-mail to the Chair or Secretary.
- If teleconference system has failed, stand by on e-mail for updates via NPC distribution list.
- PATIENCE. We thank you for your patience during these unprecedented times of remote workforce deployment and strain on teleconference and WebEx services.

Stay Safe and Healthy

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, May 7, 2020. 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 teleconference meeting.

Ms. Nancy Chafetz, Chair, presided and Mr. David Doot, Secretary, recorded. Ms. Chafetz began by confirming that, as previously announced, the 2020 Summer Meeting would not be held in person. She said virtual sessions were being planned for June 23, minimally to hear from the External Market Monitor (EMM) about his 2019 Annual Report on the New England Markets, and for June 24 to have the promised educational session relating to the future grid discussions. She said that the annual report by the Internal Market Monitor (IMM) would be presented at the June Markets Committee meeting, and encouraged all interested members to participate. Efforts were underway to identify times for virtual sector meetings with the ISO Board panels for late June or July, with specific timing and format to be determined and circulated when finalized.

Ms. Chafetz also provided an update on the future grid efforts. In addition to the June 24 educational session just noted, a joint meeting of the Markets and Reliability Committees had been scheduled for May 27 to discuss the planned study.

APPROVAL OF APRIL 2, 2020 MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the April 2, 2020 meeting, as circulated and posted in advance of the meeting. Following motion duly made and

seconded, the preliminary minutes of the April 2, 2020 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser noted.

CONSENT AGENDA

Ms. Chafetz referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved without comment, with an abstention by Mr. Michael Kuser noted.

OATT SCHEDULE 24 REVISIONS

Ms. Chafetz referred the Committee to revisions to Schedule 24 of the ISO-NE Open Access Transmission Tariff (OATT) to incorporate updated Business Practice Standards from the North American Electric Standard Board (NAESB) for the Wholesale Electric Quadrant (Schedule 24 Revisions). She explained that the Schedule 24 Revisions were proposed in response to FERC Order 671-I. She said that this matter would have been on the Consent Agenda but for the timing of the Transmission Committee's consideration and vote.

The following motion was duly made, seconded, and unanimously approved without comment, with an abstention noted by Mr. Kuser:

> RESOLVED, that the Participants Committee supports the Schedule 24 Revisions as recommended by the Transmission Committee and reflected in the materials posted for the May 7, 2020 Participants Committee teleconference meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), began his report by describing the ISO's plans for a phased re-entry into ISO facilities of ISO personnel, most of

whom had been working remotely since the COVID-19 outbreak. He indicated that, subject to state and federal requirements which continued to evolve, the ISO was planning to initiate re-entry June 1, at the earliest. The ISO would implement changes to ensure appropriate social distancing and require the use of personal protective equipment as appropriate. He said that information technology personnel would be among the first to return, with additional groups of employees following through the rest of the summer months. The ISO planned in re-entry to use both its main headquarters and the facilities at the back-up control center. ~~They~~The ISO expected that many of its employees would continue to work from home during and following the re-entry period.

Then, Mr. van Welie noted and commented on the May 1 Presidential Executive Order on Securing the United States Bulk-Power System (BPS). He reported that the Order would prohibit the future acquisition or installation of BPS electric equipment designed, developed, manufactured, or supplied, by persons owned by, controlled by, or subject to the jurisdiction or direction of a foreign adversary. He said the language of the Order was very broad and the US Department of Energy (DOE) was tasked to provide guidance. ~~They~~The ISO's initial assessment was that it did not have equipment or applications that would require replacement as a result of the Executive Order. ~~He~~Mr. van Welie committed to keep Participants apprised of any issues that arise, at least initially through information in the monthly Chief Operating Officer (COO~~-~~) reports. He acknowledged that the Executive Order created confusion and uncertainty that needed to be addressed through future DOE guidance. He assured Participants that, through the ISO/RTO Council (IRC), the ISO would have input into the DOE efforts to develop that guidance and would share appropriate information as that guidance was developed.

Mr. van Welie completed his remarks, referring the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the April 2, 2020 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO COO, reviewed highlights from the May COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites.

COVID-19 Summary Update

He began his report by providing an update on ISO operations during the continuing COVID-19 pandemic. Roughly 95 percent of the ISO workforce continued to work remotely. Restrictions on ISO travel and visitor access to ISO facilities would continue through at least Labor Day. Protective measures were in place for control room operators and on-site staff, and there was and would continue to be continuous monitoring of their health and safety. He described the ISO's operational outreach to Participants, to local control centers and reliability coordinators, and to industry groups. He reported on coordination with asset owners, many of whom had deferred non-essential maintenance or had cancelled outages completely. He expressed confidence in the ISO's ability to manage maintenance deferred to the fall.

Dr. Chadalavada then summarized ISO plans for a measured re-entry of its personnel into ISO facilities, which he said was targeted to begin June 1 and to be phased in over at least three months. The re-entry plan would be flexible, subject to national, state and local criteria being met, and would be adjusted according to changing conditions and daily metrics. Re-entry would be based on business needs and priorities, and would provide for re-deployment of work-at-home operations if a second wave of coronavirus occurred later in the fall or winter. He said the ISO

would remain vigilant and flexible, and would continue to work to ensure reliable operation of the bulk power system.

He then talked about the continuing impact of COVID-19 on system loads. He said system-wide demand continued to be down by about three to five percent. He reported that the ISO had built a backcast model to calculate what load would have been without the pandemic. He referred the Committee to slides that compared average hourly load deviations and loads to those produced by the backcast model (which were not weather-normalized), making the following observations: (i) overnight loads, on average, were lower than would be expected; (ii) morning ramps were slower, likely due to staggering schedules that conform more closely to individual tendencies than a set schedule; (iii) morning peaks were lower and an hour later; (iv) mid-day loads were lower; (v) loads tended to drop off after lunchtime, more so on days with favorable weather, when people appeared to shut down early; (vi) evening peaks were lower; and (vii) the transition to night loads was less steep (with fewer loads to shut down). Comparing 2020 loads to 2019 (though not on a weather-adjusted basis), there was an approximately six percent reduction in average load. He opined that COVID-19 contributed between three to five percent of the reduction in loads from historic figures; energy efficiency and photovoltaic (PV) installations made up a majority of the remaining difference. He acknowledged that the figures were not weather adjusted and he was not able to predict at that time how recorded loads might trend in the future based on growth in energy efficiency and PV resources.

Dr. Chadalavada then summarized the challenges in accurately forecasting loads during this period. Even with data spanning more than six weeks, the ISO still needed more actual data to establish consistent patterns. Until that ~~happens~~happened, load forecast would continue to be choppy, with mean absolute percentage error increasing on average closer to 3 percent (and

sometimes much higher) rather than around the ISO's normal target of 1.8 percent. The forecasts models still underestimated the full breadth of PV output.

He agreed in response to questions and comments, that loads would be impacted by the recession once businesses returned to work, but noted how the complexities involved made developing those forecasts/projections quite a challenge. He also acknowledged that the Capacity, Energy, Loads, and Transmission (CELT) reports needed to incorporate expeditiously updated load forecast and resource data reflecting the "new normal" and other economic impacts. He indicated that the ISO would take a cautious approach with respect to reflecting the impact of economic downturn on load forecasts. The ISO recognized it had discretion in making its load projections, but with the current load uncertainty it ~~will~~would continue in the long-term to look to the best available data and not discretionary observations. ~~Many~~He said that many factors ~~are~~were impacting loads and may in the future, both increasing loads at times and decreasing loads at other times. Projecting loads ~~is~~was and would be particularly challenging as the economy seeks to restart and the work force is dispersed but gradually starting to go back to their places of employment. He said the ISO ~~will~~would work diligently with others in the industry to ensure its load projections ~~are~~would be based on reliable and current data sets. He reaffirmed the commitment to keep the Committee appraised of corresponding changes in load forecasts as a result of developments during and after the business shutdowns for COVID-19. He also announced that, in response to Participant requests, the ISO would begin producing a weekly report on system load impacts, similar in scope to the report being posted by the New York ISO.

He reported that the region set a record low load on Saturday, April 25, 2020, during hour ending 15 (8,199 MW). He said that record low was broken one week later on Saturday, May 2,

with a minimum load of 8,003 MW. He indicated in response to questions that he expected in the future that mid-day loads on off peak days would frequently be lower than overnight loads, with behind-the-meter PV load continuing to grow.

Responding to further questions, Dr. Chadalavada noted that there were not many hours of negative pricing, outside of prices in Maine on April 10, when there was a snow storm and limited export capability. He noted that unit commitments were still on the low end of the supply curve and market performance had not been materially impacted. He acknowledged in response to a question that very low loads experienced and the available generation to serve load might encourage future electrification of the transportation sector to help achieve regional decarbonization goals. He also indicated in response to a question that the ISO would continue to assess whether it had sufficient ramping capabilities from the market on the system and, if needed, to make future market changes to encourage additional ramping capabilities on the system. That ISO commitment was reflected in its work plan and in future discussions post-ESI implementation.

Operations Report

Dr. Chadalavada then continued with his regular operations report. He noted that: (i) Energy Market value was $154 million, down $18 million from March 2020 and down $99 million from April 2020; (ii) average natural gas prices over the period were 3.9 percent higher than March average values; (iii) average Real-Time Hub LMPs ($18.13/MWh) were 7.8 percent lower than March averages; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 97.6 percent in April, down from 98.7 percent in March (with a minimum value on April 2 of 93.8%); and (v) daily Net Commitment Period Compensation (NCPC) for April totaled $1.3 million, down $400,000 from March 2020 and

down $700,000 from April 2019. April 2020 NCPC, which was 0.9 percent of total Energy Market value, was comprised of (a) $1.3 million in first contingency payments, down $200,000 from March, and (b) $45,000 in second contingency payments (there was no NCPC for distribution payments).

Dr. Chadalavada reported that the review process for the Boston 2028 RFP was ahead of schedule and expected the ISO to be able to report in July if not sooner on the Phase I proposals that would move to Phase II. In response to a question on FCA-15, he confirmed for that auction that, although he was unaware of whether final studies had been completed, the ISO expected that Maine would be an export-constrained zone nested inside Northern New England and that Southeast New England and Connecticut would both import-constrained zones.

BILLING POLICY ENHANCEMENTS AND CLEAN-UP CHANGES

~~Mr~~Ms. Michelle Gardner, Budget & Finance (B&F) Subcommittee (Subcommittee) Chair, referred the Committee to the materials posted in advance of the meeting concerning enhancements and cleanup changes to the ISO Billing Policy. She reported that these Billing Policy changes were identified by the ISO in conjunction with other enhancements to the Financial Assurance and Billing Policies that were still under Subcommittee review. She said that that Billing Policy changes were discussed by the Subcommittee and no Subcommittee members objected to the changes. She reported that the ISO had expressed its plan to file the changes later in May. Without further discussion, the following motion was moved, seconded, voted, and passed unanimously, with an abstention by Mr. Kuser noted:

> RESOLVED, that the Participants Committee supports revisions to the ISO New England Billing Policy to make certain enhancements and clean-up changes, as proposed by the ISO and as circulated to this Committee with the April 30, 2020 supplemental notice, together with such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

LITIGATION REPORT

Mr. Doot referred the Committee to the May 2 Litigation Report that had been circulated and posted in advance of the meeting. He then highlighted the following items:

- *Energy Security Improvements (ESI) Alternatives Filing* - Comments on the ISO and NEPOOL alternatives were due May 15, 2020. NEPOOL submitted its support for the NEPOOL-approved alternative on April 24;
- *Hybrid Resources Technical Conference* – The FERC had scheduled for July 23, 2020 a technical conference to discuss technical and market issues prompted by growing interest in projects comprised of more than one resource type at the same plant location (hybrid resources). Individuals interested in participating as panelists had until May 15, 2020 to submit self-nomination forms;
- *NERA Petition* – On April 14, 2020, the New England Ratepayers Association (NERA) asked the FERC to assert jurisdiction and price the power per applicable requirements whenever energy from a behind-the-meter facility is greater than the energy being consumed at that time behind the meter. The gist of the argument in the petition was that those energy transfers onto the grid were sales of power for resale and therefore FERC jurisdictional, and must be priced under federal rules and requirements, not at state retail rates. He reported also that the FERC extended the comment date 30 days, to June 15, 2020, in response to numerous requests for a 90-day extension;
- *Request for Technical Conference/Workshop on Carbon Pricing in RTO/ISO Markets* - Comments on a request for a technical conference or workshop to discuss

integrating state, regional, and national carbon pricing in FERC-jurisdictional organized regional wholesale electric energy markets were due May 21; and

- *ISO's Inventoried Energy Program (IEP or Chapter 2B) Proposal* – The IEP, which became effective by operation of law because of a lack of a FERC quorum and was subsequently challenged in appeals to the DC Circuit Court of Appeals, was remanded back to FERC at the request of the FERC, with the concurrence of the parties to the proceeding. He noted that the FERC committed to deadlines for issuing its order on remand and an order on any requests for rehearing from that order on remand.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Bill Fowler, the MC Vice-Chair, reported that the next MC meeting would be May 12, 2020, with plans to consider a modification to the submission deadline for offers and bids in the Day-Ahead Energy Market, to receive highlights from the IMM's 2020 Winter quarterly markets report, and to begin discussion on updates to Cost of New Entry (CONE), Net CONE, and Offer Review Trigger Prices.

Budget & Finance Subcommittee. Ms. Michelle Gardner, B&F Chair, reported that B&F was scheduled to meet on May 14, 2020, and would continue discussion of potential "know your customer" enhancements to the Financial Assurance Policy's minimum eligibility requirements for new and existing Participants. All those interested were encouraged to participate and to review the proposed changes.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting would be May 19, 2020, at which the RC would consider changes to Planning Procedure (PP) No. 10 (Planning Procedure to Support the Forward

Capacity Market) to incorporate the competitive transmission solution process in De-List reliability reviews. He indicated those changes were expected to be presented to the Participants Committee for vote in early June, and would take effect immediately thereafter, since PPs are not filed with the FERC.

Generation Information System (GIS) Agreement Working Group. Mr. Dave Cavanaugh, Working Group Chair, said that the Working Group would hold its seventh teleconference the following day to continue discussions of options in light of the December 2020 expiration of the GIS Administration Agreement between NEPOOL and APX, Inc. He encouraged all interested, particularly those with hands-on experience with GIS and other Renewable Energy Credit tracking and trading systems, to participate. He confirmed that the Working Group would present its recommendations for final action to the Participants Committee. He said call-in information for the teleconference was available on the NEPOOL and ISO calendars.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the TC was scheduled to meet on May 27, 2020 (just ahead of the joint MC/RC future grid meeting). The key items planned for discussion were (i) the ISO's compliance with the FERC's March 19, 2020 Order 845 (interconnection reforms) compliance filing order; and (ii) a new settlement in the on-going proceeding related to the transparency of the Regional Network Service/Local Network Service formula transmission rates and rate protocols.

OTHER BUSINESS

Mr. Doot reported that the next Participants Committee meeting would be held by teleconference on June 4, 2020, with a number of voting items to be addressed and a presentation by the ISO's Chief Financial Officer of the ISO's 2021 preliminary Operating and Capital Budgets.

There being no further business, the meeting adjourned at 11:30 a.m.

Respectfully submitted,

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David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MAY 7, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Able Grid Infrastructure Holdings, LLC	Provisional Group		Sam Lines	
American Petroleum Institute	Fuels Industry Part.			Andrew Ten Eyck
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley	Brad Swalwell	
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend		
American PowerNet Management	Supplier			Mary Smith, Michael Macrae
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			~~R.~~Roger Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Avangrid Renewables	Transmission	Kevin Kilgallen		
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		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
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	
Competitive Energy Services, LLC	Supplier		Glenn Poole	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Conservation Law Foundation (CLF)	End User	Jerry Elmer		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Direct Energy Business, LLC	Supplier	Nancy Chafetz		
Dominion Energy Generation Marketing, Inc.	Generation		Jim Davis	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Energy Services	Supplier		Bill Fowler	
Enel X North America, Inc.	AR-LR		Herb Healy	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Cal Bowie	Dave Burnham, Vandan Divatia
Excelerate Energy LP	Fuels Industry Part.			Gary Ritter
Exelon Generation Company	Supplier		Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		Nancy Chafetz
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation			Ron Coutu; Bob Stein
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.	Supplier	Louis Guibault	Bob Stein	
Harvard Dedicated Energy Limited	End User	Mary Smith	Michael Macrae	
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	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MAY 7, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Interstate Gas Supply, Inc.	Supplier		Scott Hendricks	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		
KCE CT 1, LLC	Provisional Group	Rachel Goldwasser		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity	Craig Kieny		
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marble River, LLC	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew	Ben Griffiths	
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	Michael Kuser		
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		~~B~~Brian. Forshaw; ~~D~~Dave. Cavanaugh; Brian Thomson~~B. Thomson~~
New Hampshire Office of Consumer Advocate	End User		Erin Camp	
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	Generation		Pete Fuller	
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	
PowerOptions, Inc.	End User			Erin Camp
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
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	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
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	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	Michael Macrae
Vermont Electric Coop.	Publicly Owned	Craig Kieny		
Vermont Electric Power Co. (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MAY 7, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
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	

CONSENT AGENDA

Markets Committee

From the previously-circulated notice of actions of the Markets Committee's May 12, 2020 meeting, dated May 13, 2020:[1]

1. **Information Policy §2.3 Revisions (Enhancements/Clarifications)**

   Support revisions to Section 2.3 of the Information Policy (Attachment D to the Tariff), designed to (i) improve communications with stakeholders regarding the status of defaulting participants emerging from bankruptcy, (ii) remove confidentiality restrictions applicable to defaulting participants to enable ISO-NE to act more quickly and efficiently when emergency judicial or regulatory relief is needed, and (iii) clarify the timing of removal from the weekly info policy notice, all as recommended by the Markets Committee at its May 12, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was unanimously approved with one abstention in the End User Sector noted.

2. **Market Rule 1 and Manual M-11 Changes (Day-Ahead Energy Market Offer Window Modification and Offer Cap Clean-Up Changes)**

   Support revisions to Market Rule 1 and Manual M-11 (Market Operations) (i) to modify the submission deadline for offers and bids in the Day-Ahead Energy Market from 10:00 a.m. to 10:30 a.m. and (ii) to reflect clean-up revisions conforming the Tariff to the offer cap filing revisions that were approved by the FERC in ER17-1565, as recommended by the Markets Committee at its May 12, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was unanimously approved with one abstention in the End User Sector noted.

Reliability Committee

From the previously-circulated notice of actions of the Reliability Committee's May 19, 2020 meeting, dated May 19, 2020:[2]

3. **OP-12 Revisions (Clarify Source of Data Updated in OP-12, Appendix B (OP-12B))**

   Support revisions to ISO Operating Procedure (OP) No. 12 (Voltage and Reactive Control), which reflect the source of the data in OP-12B (Voltage and Reactive Schedules), explain the different categories of voltage control for generators, clarify the use of "On Peak Period" and "Off Peak Period", adds that OP-12B would be updated "as needed", and specify that ISO-NE may request AVR status for a "LD-Node" modeled unit that has operational impact, all as recommended by the Reliability Committee at its May 19, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

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

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

Summary of ISO New England Board and Committee Meetings

June 4, 2020 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Markets Committee, the Nominating and Governance Committee, the System Planning and Reliability Committee, and the Board of Directors each met on May 19 by teleconference.

The Nominating and Governance Committee discussed assignments to Board committees and issues related to succession planning for board leadership positions. The Committee also discussed the format for upcoming meetings in light of telephonic participation versus in-person meetings.

The Audit and Finance Committee reviewed the Company's financial performance against the 2020 budget, and approved the first quarter's unaudited financial statements after management confirmed that all relevant disclosures were included in the financial statements. Next, the Committee discussed the preliminary 2021 operating and capital budgets. The Committee then undertook its annual risk assessment and reviewed the key risks within the scope of the Committee's oversight of Company operations. The Committee also reviewed the structure of the Company's compliance and risk management programs, including the Company's physical security and business continuity plans. Next, the Committee discussed the annual vendor report, which showed the top fifteen vendors and a comparison to the previous period. Finally, the Committee reviewed a draft of the Company's 2019 tax return on Form 990 and discussed the process for appointing an external audit firm.

The Markets Committee reflected on the market design initiatives encompassed in the Company's strategic planning update recently provided to the Board. The Committee then reviewed highlights of the External Market Monitor's draft annual markets report for 2019, and discussed the recommendations that will be contained in the report. The Committee was also provided with a market monitoring review of winter 2019-2020. Finally, the Committee received an update on the sunset of the Forward Reserve Market for Capacity Commitment Period 16, and the review of delist bids for FCA 15.

The System Planning and Reliability Committee was provided with an overview of the Company's workforce re-entry plan which includes a measured approach to returning the workforce in phased transitions in light of the COVID-19 pandemic. The Committee considered staffing postures, plan activation, and re-entry protocols. The Committee also received an update on the review of delist bids for FCA 15.

The Board of Directors received reports from the standing committees, including an update on the Company's workforce re-entry plan from the System Planning and Reliability Committee. The Board discussed the Company's corporate goals, including a preliminary assessment of the COVID-19 pandemic on the 2020 work plan and budget. The Board also continued its discussion regarding strategic planning and core values and themes included within the plan. Finally, the Board considered possible issues for discussion at the upcoming virtual sector meetings with NEPOOL in June.

NEPOOL Participants Committee Report

June 2020

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

ISO Operations During COVID-19 Outbreak

- Effective March 14, ~95% of ISO workforce is working remotely
- All reliability, market and planning functions are being operated in accordance with all applicable standards
- ISO remote deployment posture extended until June 15, when it expects to start its re-entry plan
- The ISO re-entry plan conforms to national, state, and local guidelines, is phased over four months, and based on business needs and priorities
- The ISO will continue to monitor the situation and take all necessary steps to reliably operate the bulk power system

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - April 2020 Energy market value totaled $159M, the lowest total monthly result since 2003 Standard Market Design implementation
  - May 2020 Energy market value was $120M over the period, down $39M from April and down $107M from May 2019
    - May 2020 natural gas prices over the period were 16% lower than April average values
    - Average RT Hub Locational Marginal Prices ($16.39/MWh) over the period were 9.4% lower than April averages
      - DA Hub: $16/MWh
    - Average May 2020 natural gas prices and RT Hub LMPs over the period were down 41% and 28%, respectively, from May 2019 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 97.9% during May
    - The minimum value for the month was 92% on Wednesday, May 13th

DATA THROUGH May 27, EXCEPT WHERE NOTED.

Underlying natural gas data furnished by:

ICE Global markets in clear view

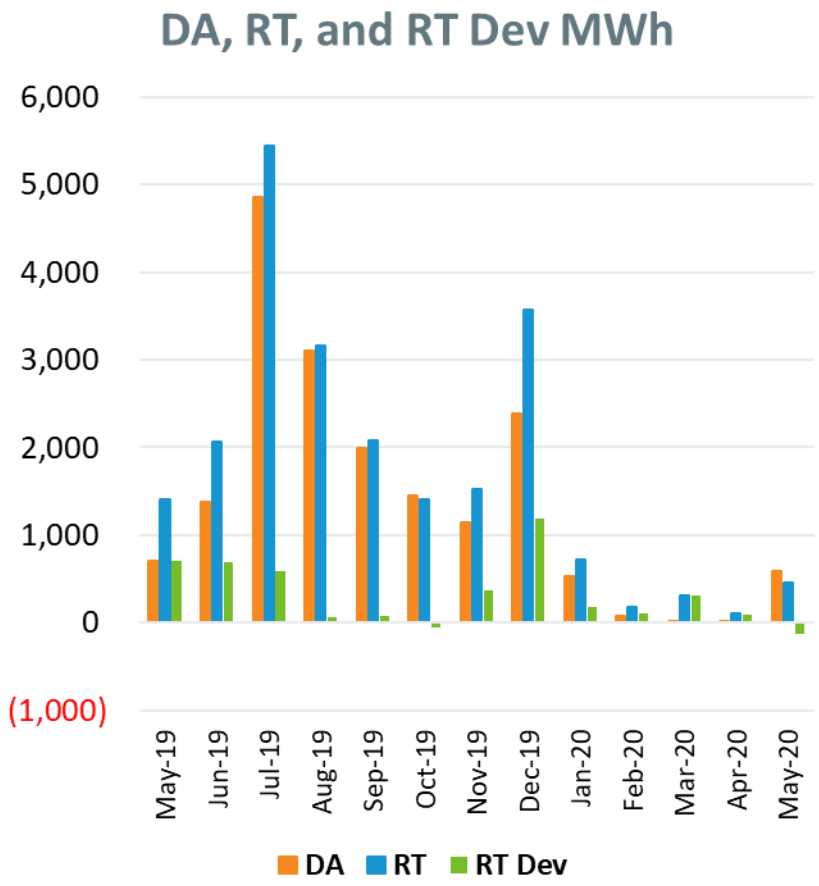
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

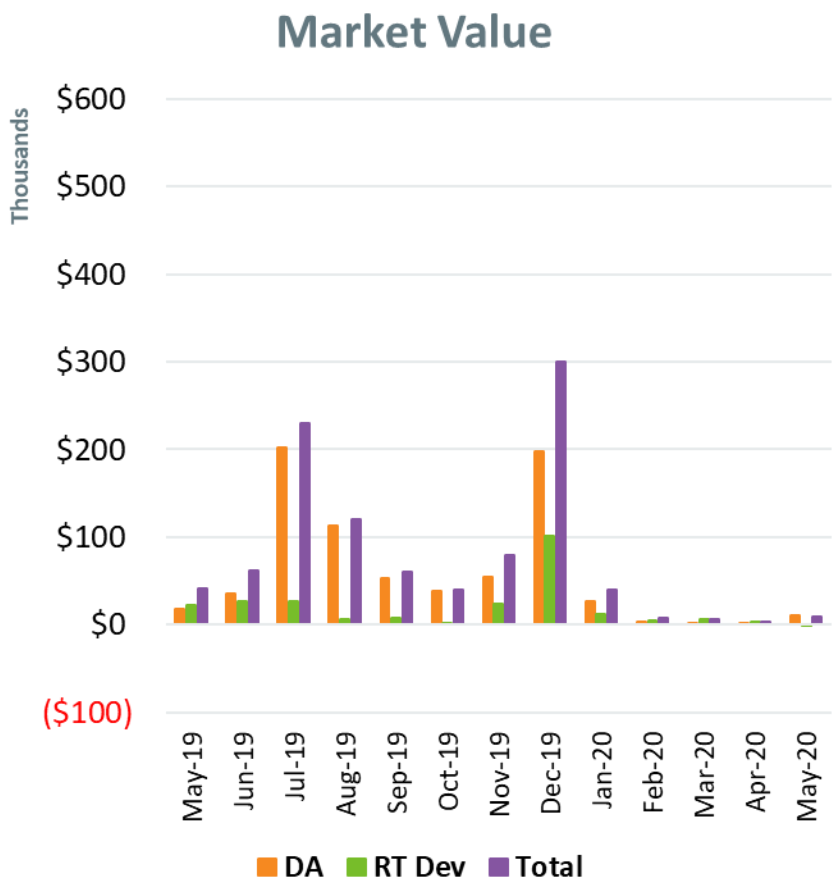
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - May 2020 NCPC payments totaled $1.7M over the period, up $0.2M from April 2020 and down $0.4M from May 2019
  - First Contingency* payments totaled $1.7M, up $0.3M from April
    - $1.4M paid to internal resources, up $0.1M from April 2020
      - » $424K charged to DALO, $547K to RT Deviations, $399K to RTLO
    - $282K paid to resources at external locations, up $165K from April
      - » Charged to RT Deviations
    - Second Contingency payments were negligible ($11K), down $33K from April
  - NCPC payments over the period as percent of Energy Market value were 1.4%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $167K; Rapid Response Pricing (RRP) Opportunity Cost - $146K; Posturing - $0K; Generator Performance Auditing (GPA) - $85K**

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

- In response to the Boston 2028 RFP, 36 Phase One Proposals were received from 8 QTPSs
  - The ISO will discuss the draft list of qualifying Phase One Proposals at the June PAC meeting
- It was confirmed at the May 28 PSPC meeting that FCA 15 will model the same zones as FCA 14
- Final 2019 Northeast Coordinated System Plan was posted on May 4
- Final 2018 Electric Generator Air Emissions Report was posted on May 14
- 2020 Public Policy Transmission Upgrade Process will be discussed at the June PAC meeting
- EE Reconstitution Project is underway, and tariff redlines will be presented to the RC in June
- 2019 Economic Studies are nearing completion
  - NESCOE report is on target for July 1
- 2020 Economic Study work has commenced

Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - Third and final annual reconfiguration auction (ARA3) was held March 2-4 and results were posted on April 1
- CCP 12 (2021-2022)
  - Second reconfiguration auction (ARA2) will be August 3-5 and results to be posted by September 2

CCP – Capacity Commitment Period

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - First reconfiguration auction (ARA1) was held June 1-3, and results to be posted by July 1
- CCP 14 (2023-2024)
  - Auction results were filed with FERC on February 18 and FERC accepted the filing on April 10

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - It was confirmed at the May 28 PSPC meeting that FCA 15 will model the same zones as FCA 14
    - Export-constrained zones: Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England
  - Existing capacity values were posted on March 6
  - Summary of retirement and permanent delist bids was posted on March 18 and summary of substitution auction demand bids was posted on May 1
  - Show of Interest window closed on April 24
  - ICR and related values development are underway, with assumption discussions held at the May 28 PSPC meeting

FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- EE Reconstitution project is underway
  - RC was introduced to the issue at their April 22 meeting, and discussions with NEPOOL will continue into early summer
  - Changes will impact the 2021 forecast used for FCA 16 Installed Capacity Requirement development

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
- The Public Policy Process was initiated on 1/14/2020
  - Stakeholder input on federal, state, and local Public Policy Requirements (PPRs) was required to be submitted by 2/28/2020
  - Two PPR submittals were received
  - NESCOE submitted a communication to the ISO regarding PPRs on 5/1/2020
  - No stakeholder input was received on NESCOE's communication regarding federal Public Policy Requirements
  - The ISO will provide an update at the 6/17/20 PAC meeting

Boston 2028 Request for Proposal (RFP)

- The ISO issued the Boston 2028 RFP on 12/20/2019, which is its first RFP for a competitively-selected transmission solution
  - Phase One Proposals were required to be submitted by 11:00 p.m. on 3/4/2020
  - 36 Phase One Proposals were received from 8 QTPSs
    - Installed cost estimates ranged from $49M to $745M
    - In-service dates range from March 2023 to December 2026
  - The ISO will discuss the draft list of qualifying Phase One Proposals at the June PAC meeting

Highlights

- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning June 6, 2020

JUNE 4, 2020

ISO new england

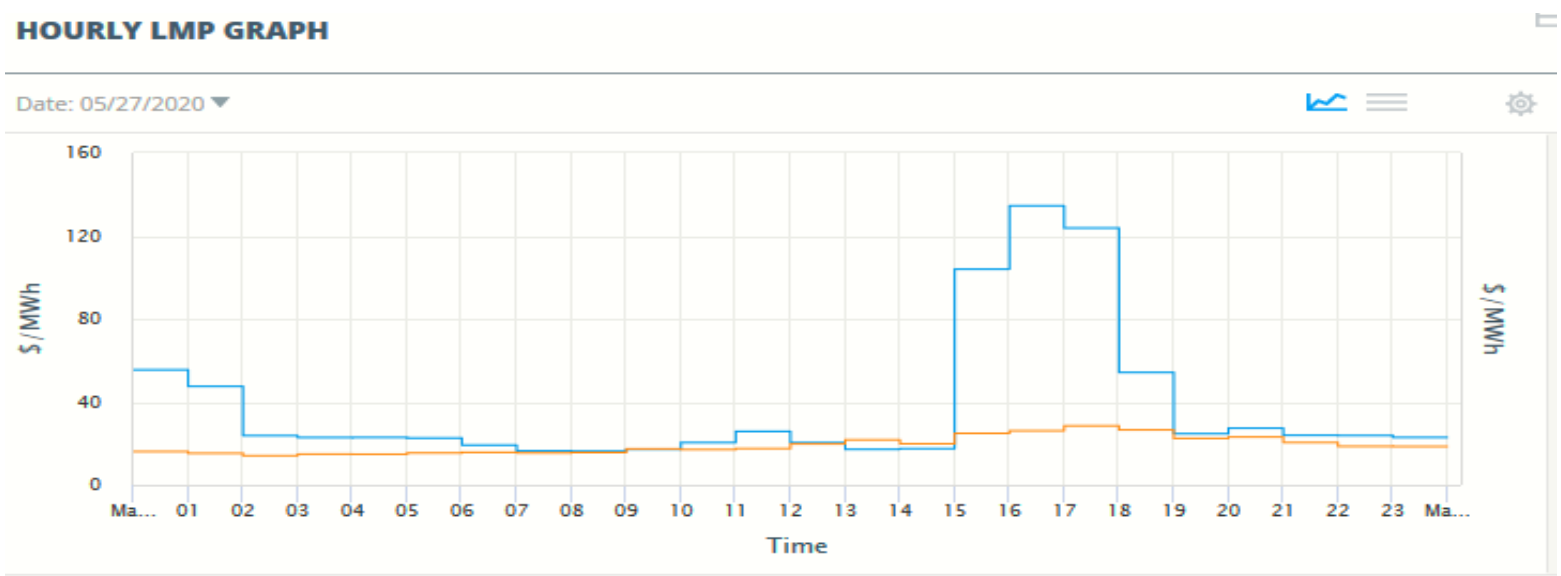
System Events on 5/27 and 5/29

May Operational Events

- There were two operational events that occurred in May
- 5/27 Event
  - Loss of a Phase II at 14:48 on 5/27 due to a lightning strike
  - At the time of the disturbance, Phase II was operating at approximately 1,980 MW
- 5/29 Event
  - Loss of a major generation facility at 14:04 on 5/29 resulted in the loss of 1,250 MW
  - Loss of one pole of Phase II at 20:23 on 5/29 and the second pole at 20:34 due to equipment failure resulted in the loss of 1,340 MW

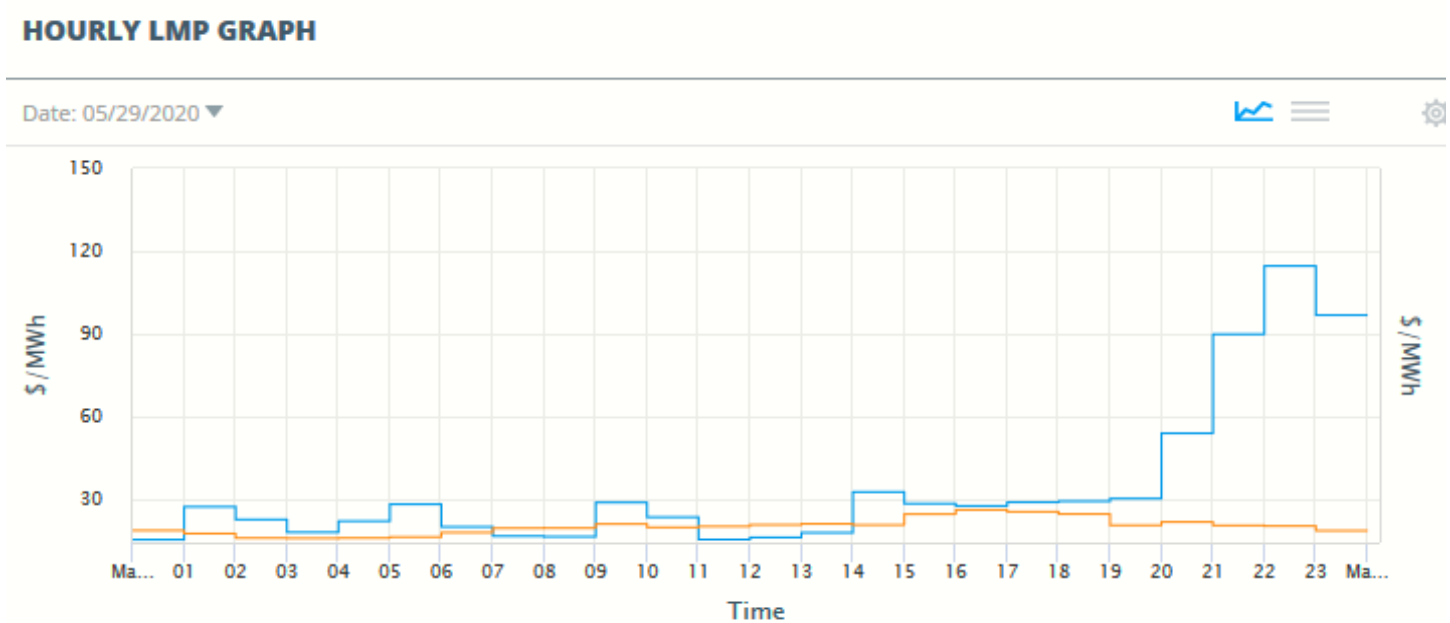
5/27 Loss of a major transmission intertie facility (Phase II)

- On 5/27 at 14:48 the system experienced the loss of Phase II due to a lightning strike which resulted in the loss of 1,980 MW
- All transmission and disturbance control standard criteria were met and maintained during and after the event
  - Recovery times for the Disturbance Control Standard were met within approximately 10 minutes
  - All reserve criteria were met during and following the event
  - The following chart displays Real-Time vs Day-Ahead prices for the day
  - Phase II was returned to commercial service after inspection and testing at 18:00 on 5/27



5/29 Loss of a major Generator

- On 5/29 at 14:04 the system experienced the loss of a major generation facility resulting in the loss of approximately 1,250 MW
- All transmission and disturbance control standard criteria were met and maintained during and after the event
  - Recovery times for the Disturbance Control Standard were met within criteria in approximately 8 minutes
  - All reserve criteria were met during and following the event
  - The following chart displays Real-Time vs Day-Ahead prices for the day (this also reflects the loss of the major transmission facility later in the day)



5/29 Loss of a major transmission intertie facility (Phase II)

- On 5/29 at 20:23, one pole of Phase II tripped and at 20:34, the second pole was tripped
- The cause was due to equipment failure and resulted in the loss of 1,340 MW
- All transmission and disturbance control standard criteria were met and maintained during and after the event
  - Recovery times for the Disturbance Control Standard were met within criteria in approximately 6 minutes each for the two separate events
  - All reserve criteria were met during and following the event
  - Half of the facility was returned to service on 5/30 after repairs, inspection and testing and the other half remains out of service for repairs

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (1.2°F) Max: 83°F, Min: 34°F Precipitation: 2.21" – Below Normal Normal: 3.49"	Hartford	Temperature: Below Normal (1.1°F) Max: 83°F, Min: 31°F Precipitation: 1.62" - Below Normal Normal: 4.35"

Peak Load:	16,294 MW	May, 29, 2020	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for May, 2020			

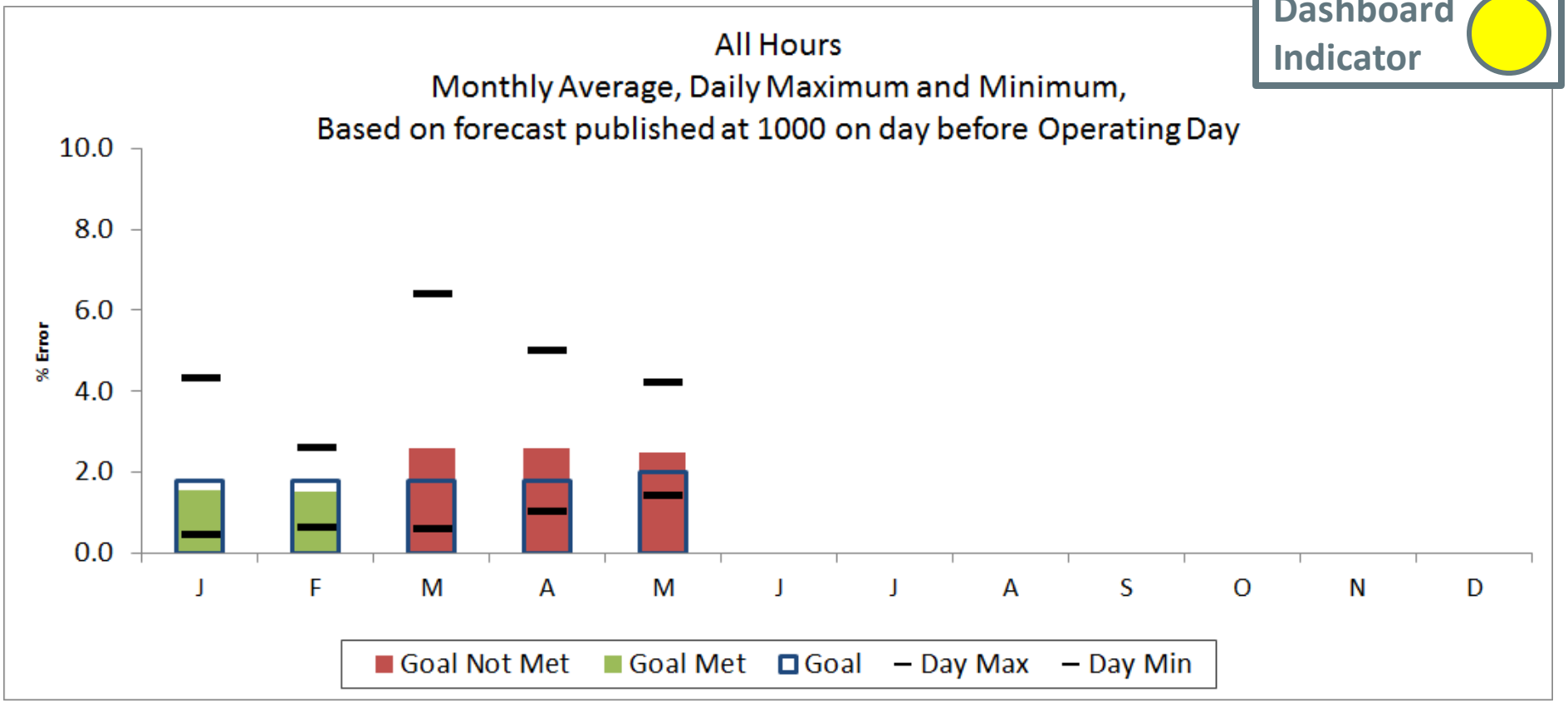
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
5/3	NYISO	580
5/8	IESO	850
5/27	ISO-NE	1980
5/29	ISO-NE	1250
5/29	ISO-NE	670
5/29	ISO-NE	670

2020 System Operations - Load Forecast Accuracy

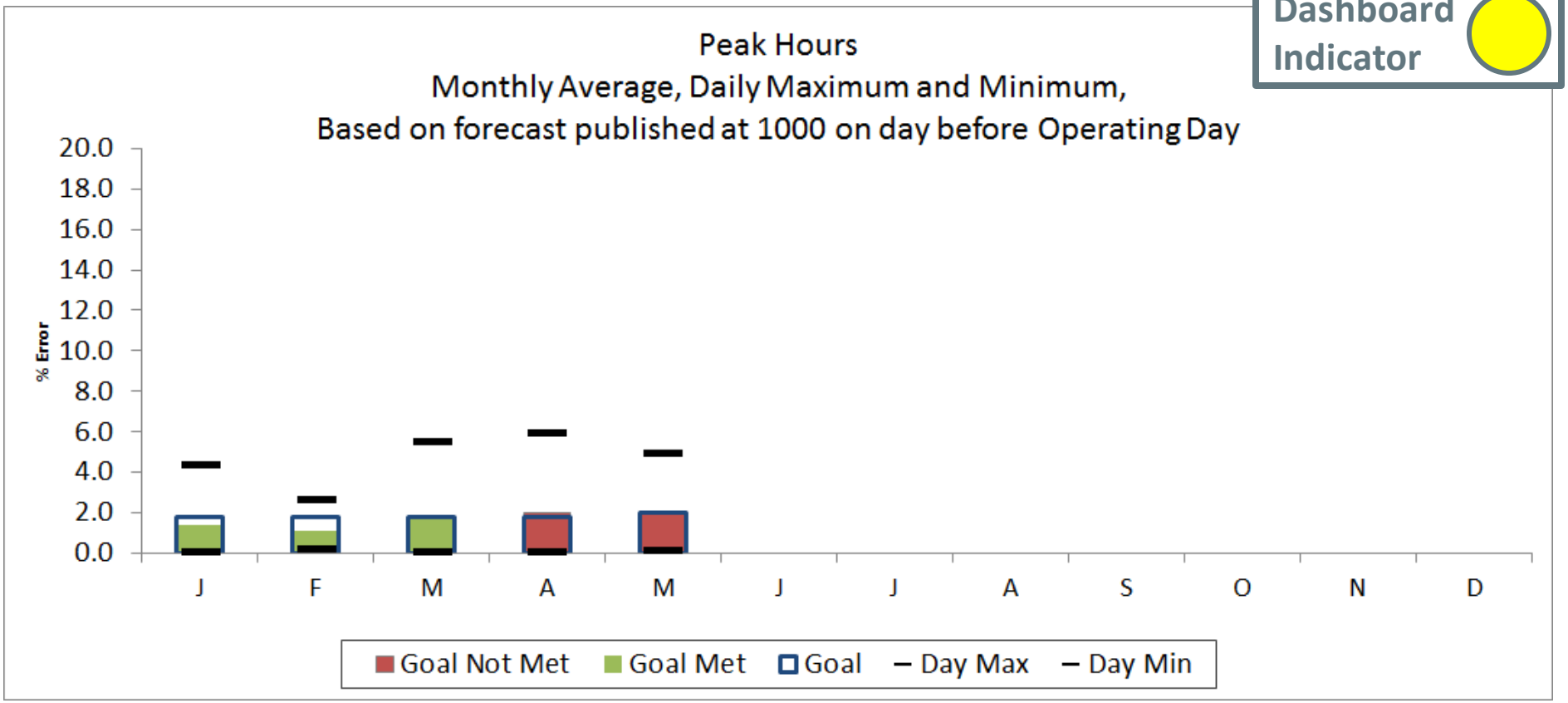
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	2.59	6.40	5.00	4.22								6.40
Day Min	0.46	0.61	0.58	1.03	1.42								0.46
MAPE	1.57	1.54	2.60	2.58	2.49								2.16
Goal	1.80	1.80	1.80	1.80	2.00								

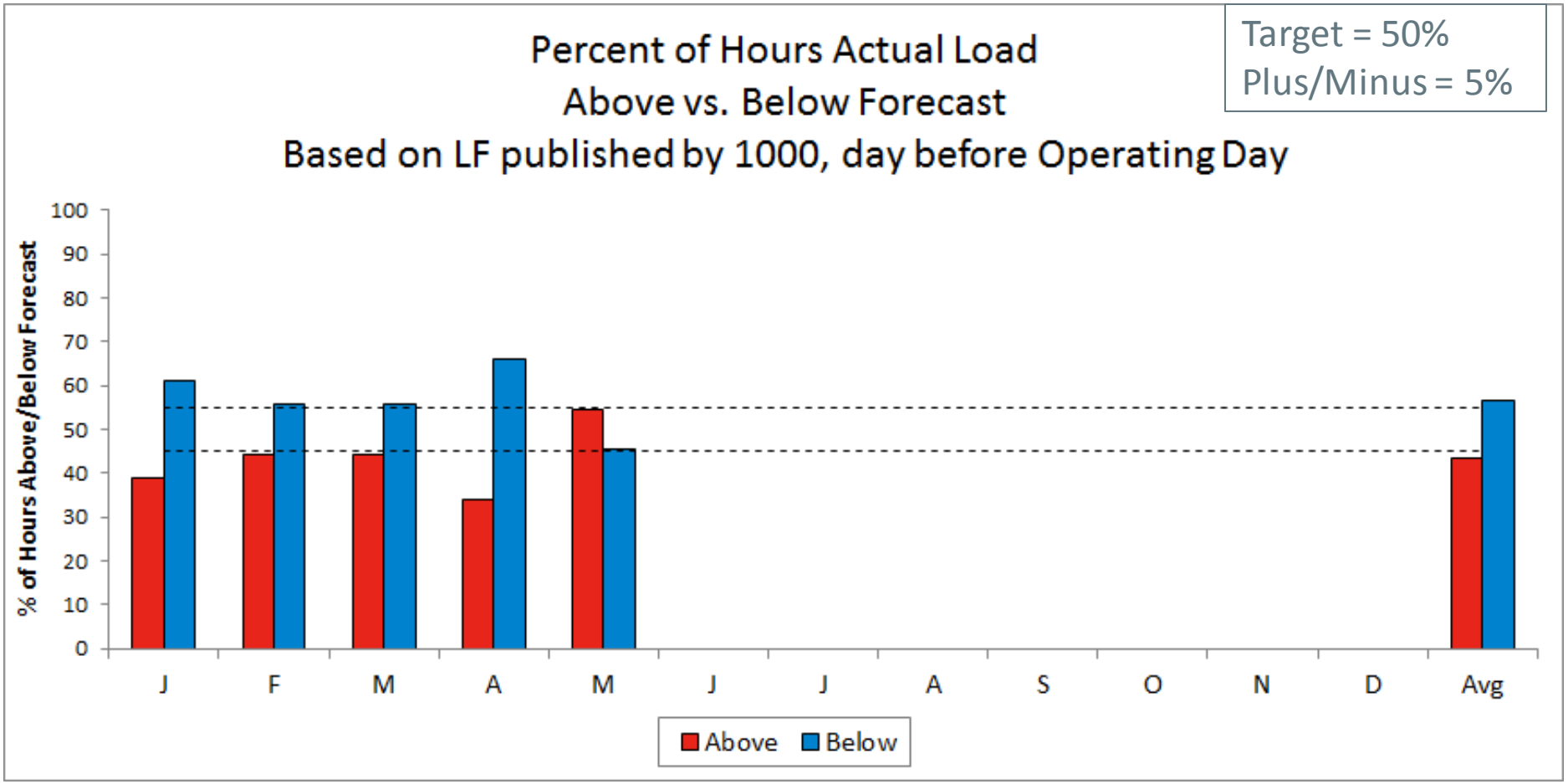
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



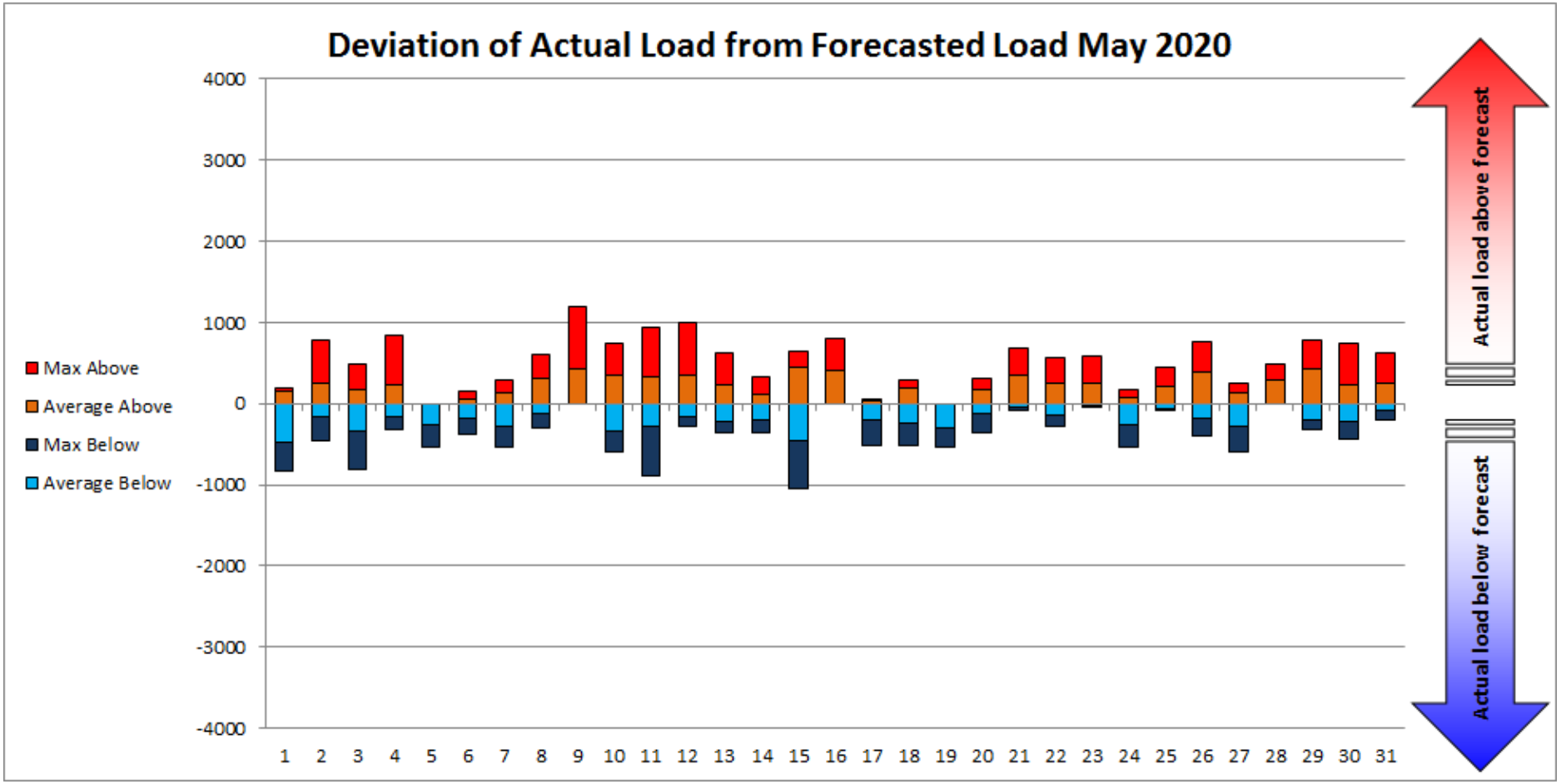
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59	5.48	5.93	4.94								5.93
Day Min	0.07	0.19	0.01	0.00	0.13								0.00
MAPE	1.41	1.12	1.72	1.97	2.11								1.67
Goal	1.80	1.80	1.80	1.80	2.00								

2020 System Operations - Load Forecast Accuracy cont.

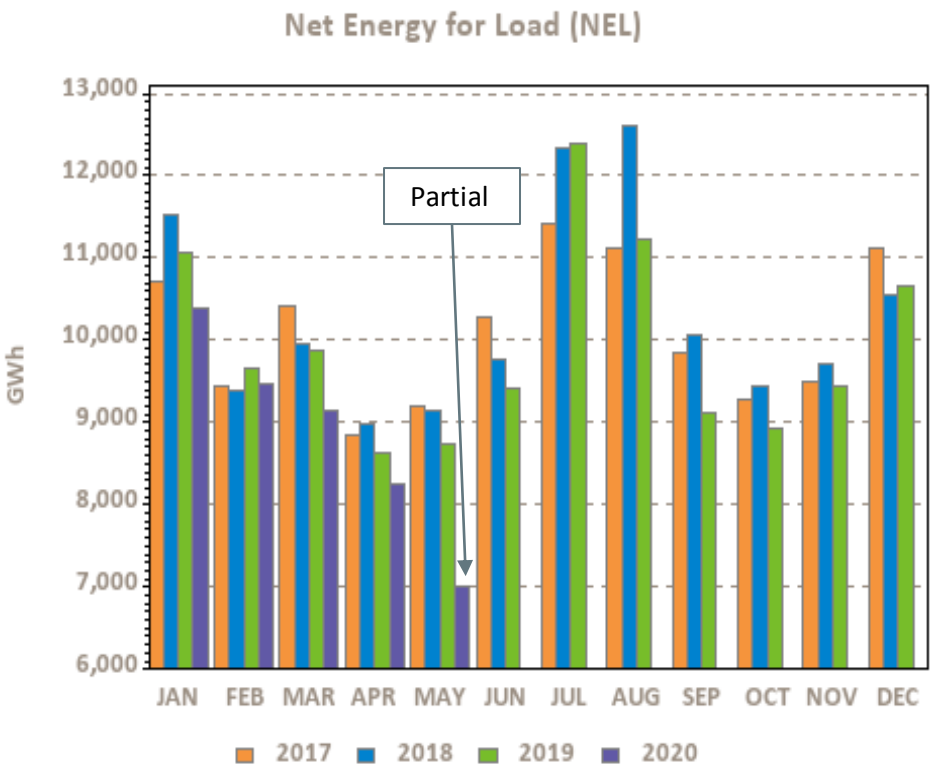


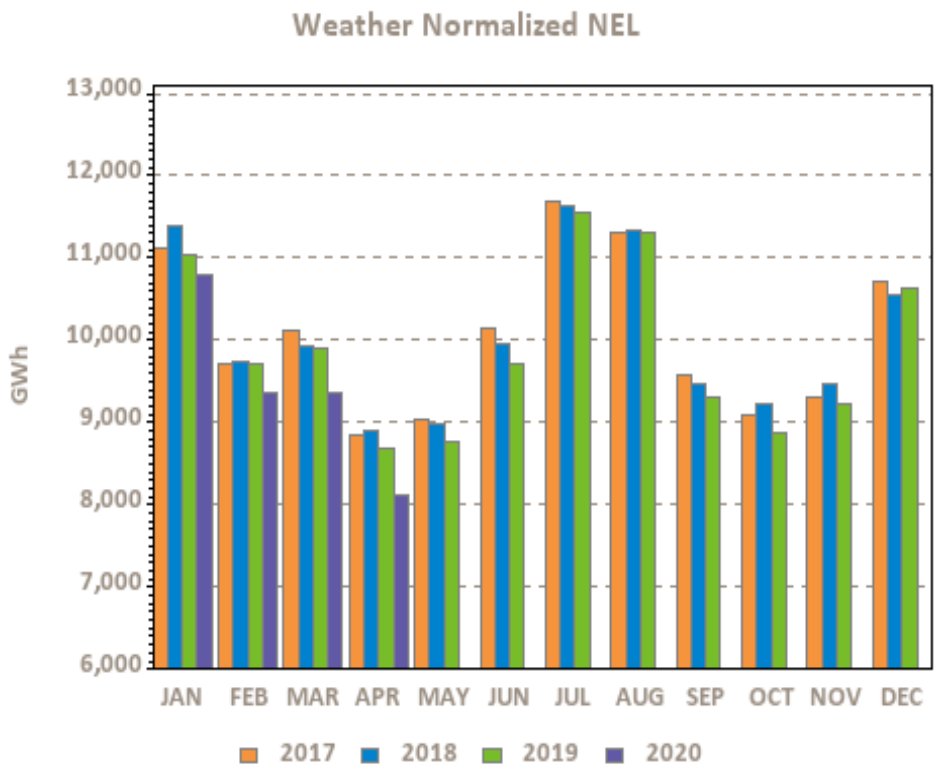
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3	44.4	33.9	54.4								43
Below %	61	55.7	55.6	66.1	45.6								57
Avg Above	136.2	169.9	207	178.9	231.9								232
Avg Below	-192.4	-157.6	-263.9	-265.3	-196.3								-265
Avg All	-65	-13	-56	-106	38								-40

2020 System Operations - Load Forecast Accuracy cont.



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



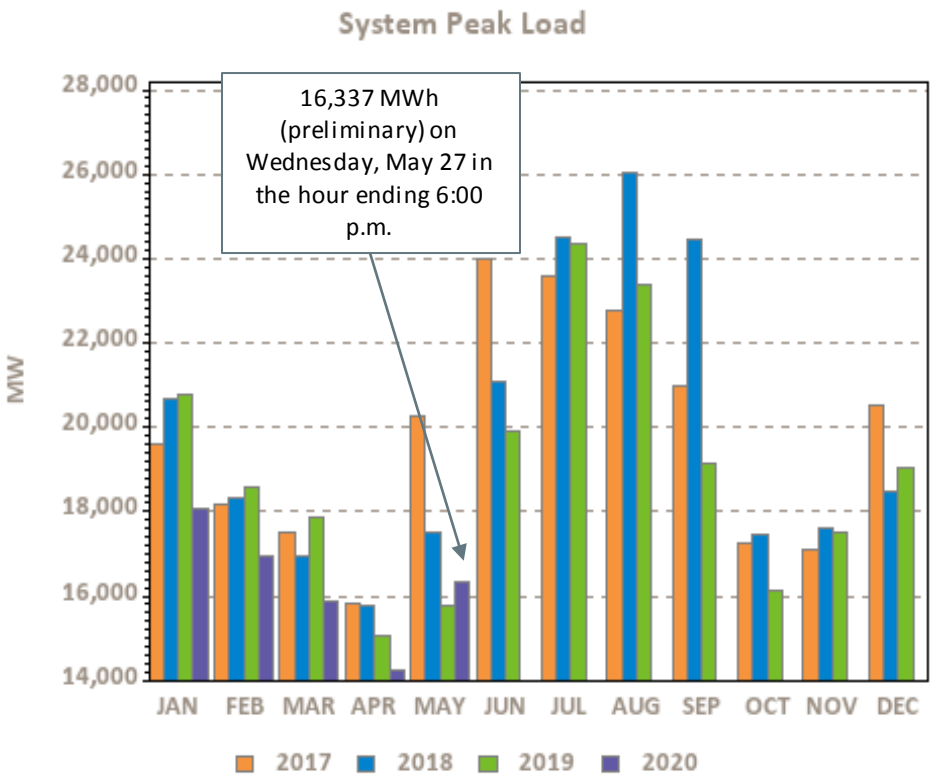


	2017	2018	2019	2020
Ann Tot (TWh):	121.2	123.5	119.2	44.3

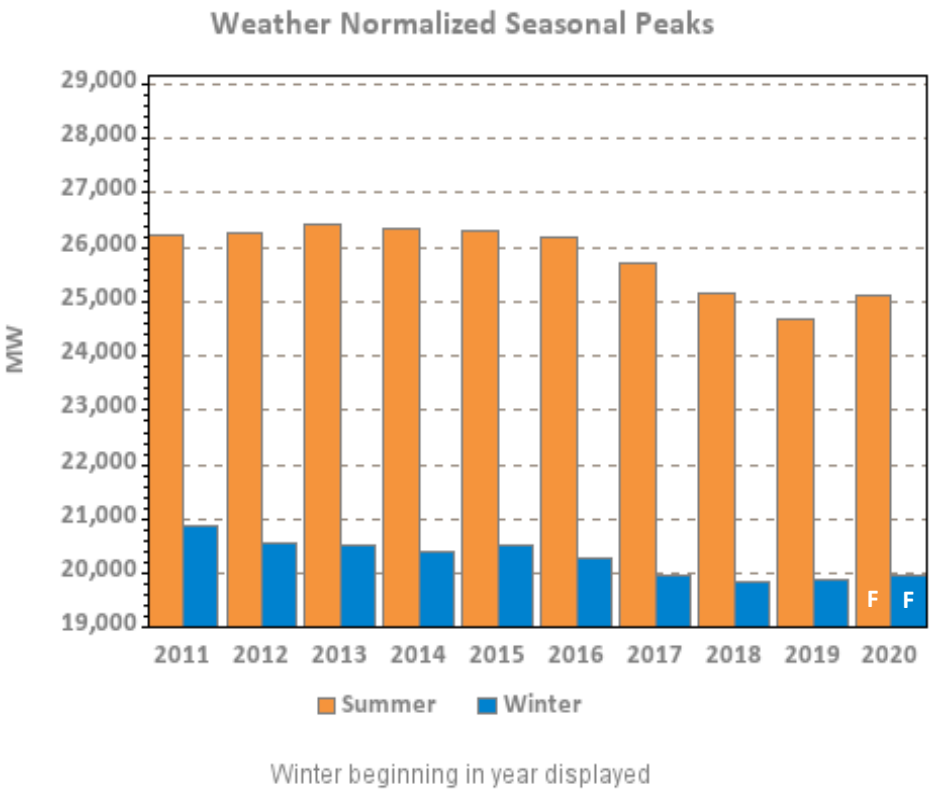
	2017	2018	2019	2020
Ann Tot (TWh):	120.7	120.6	118.7	37.7

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 may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



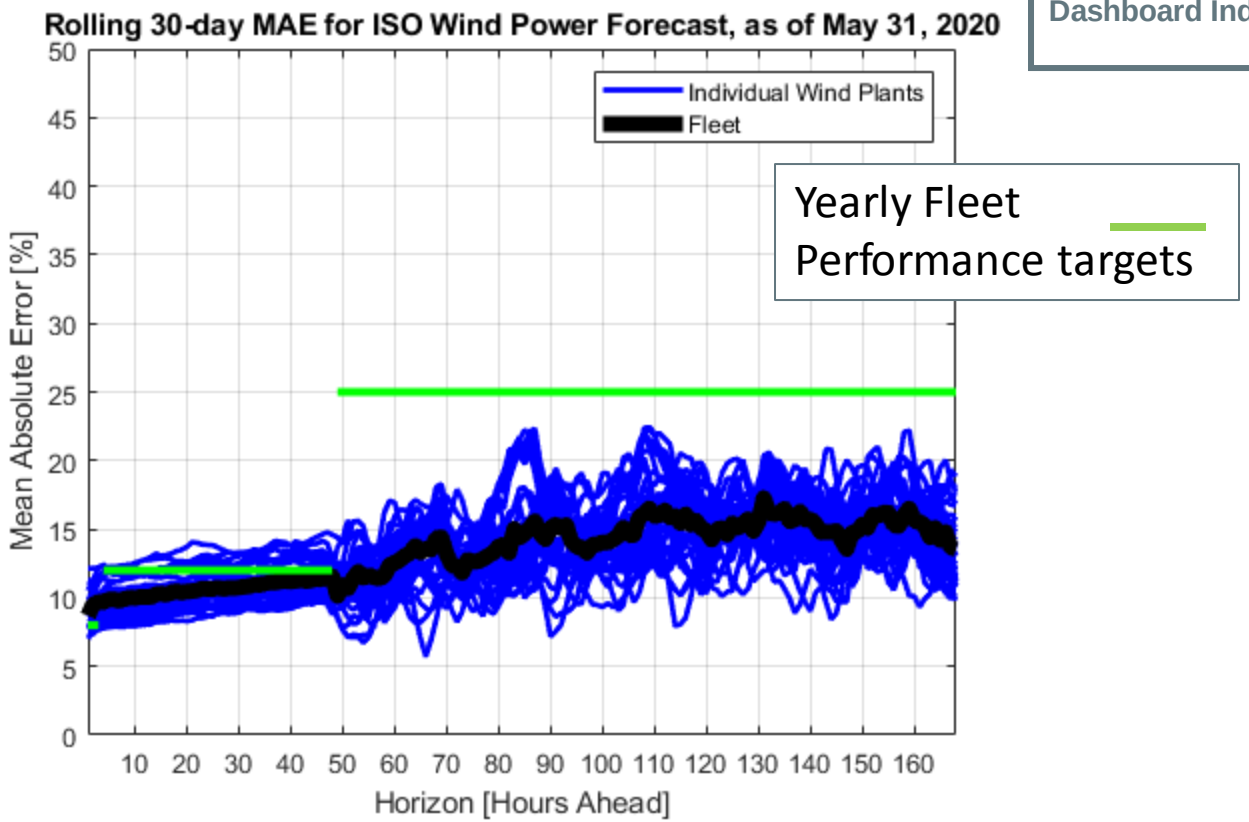
Revenue quality metered value



F – designates forecasted values, which are 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

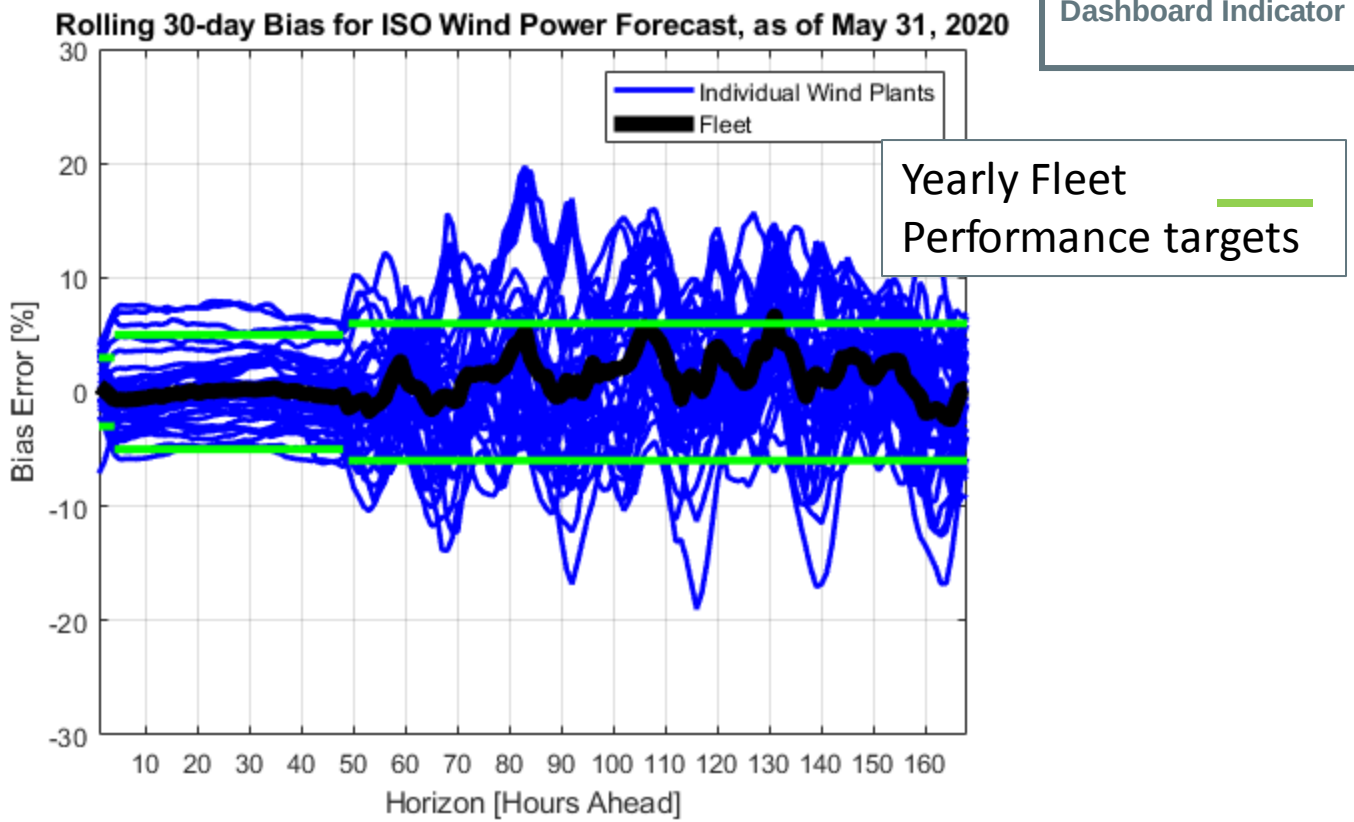
Dashboard Indicator



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-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

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

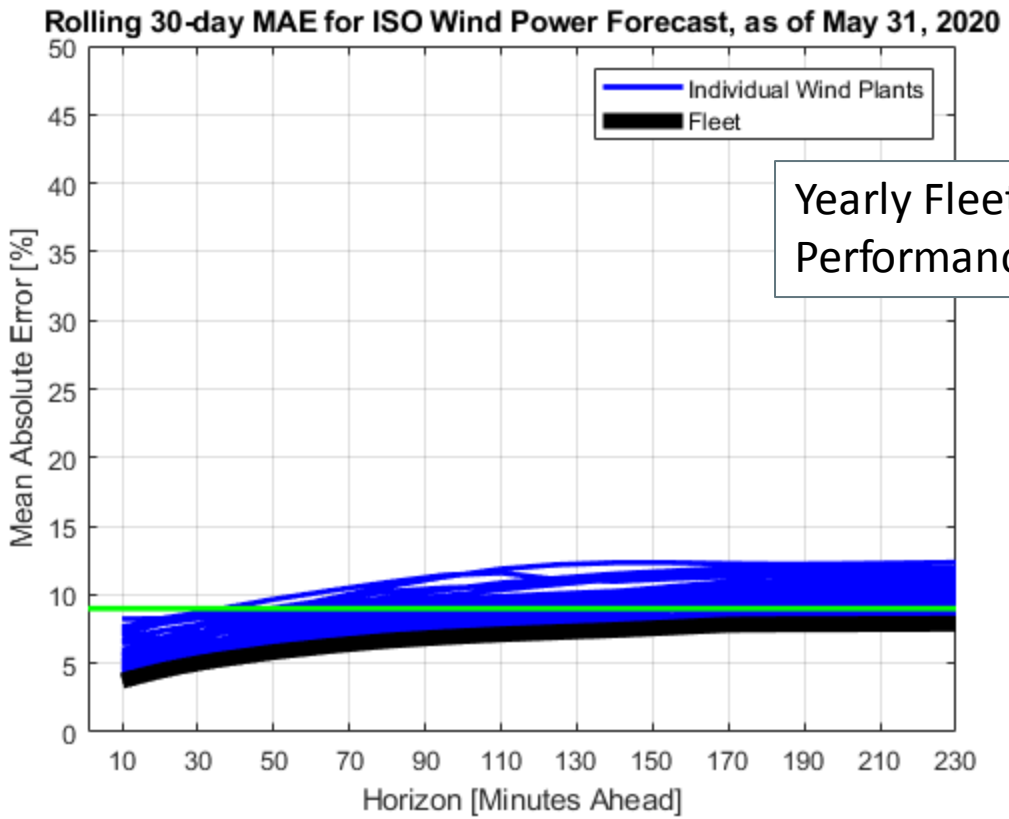
Dashboard Indicator



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-GL forecast compares well with industry standards, and monthly Bias is mostly within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator

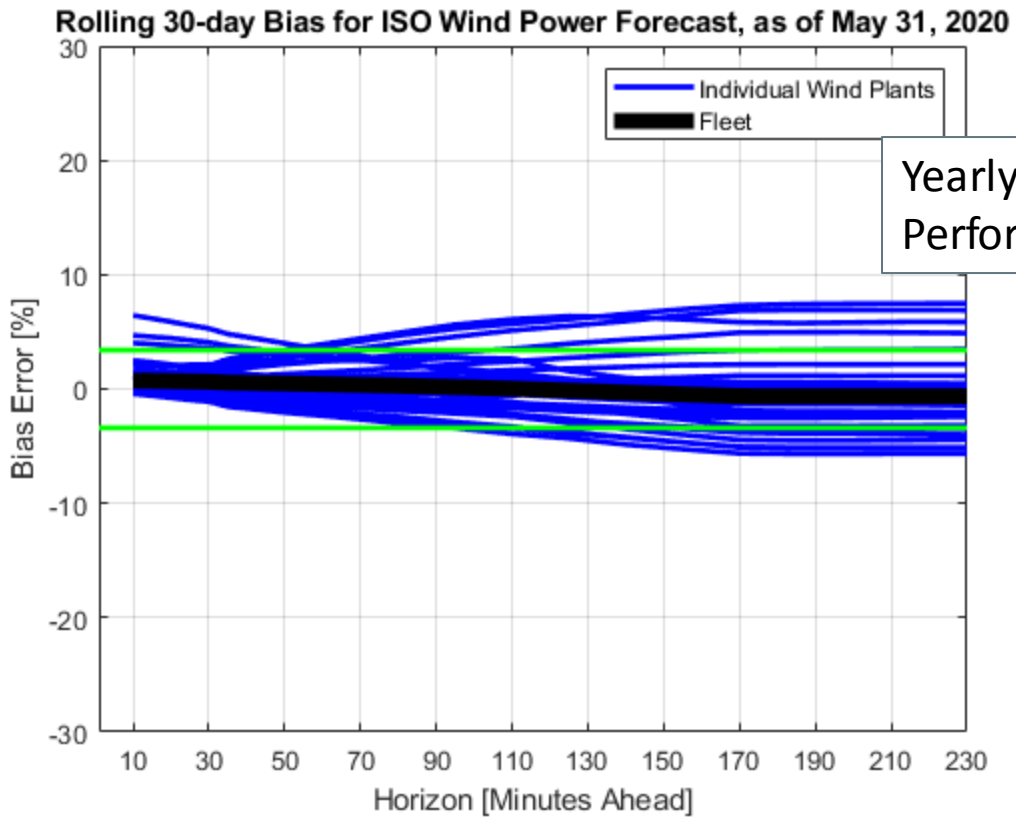


Yearly Fleet Performance targets

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-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

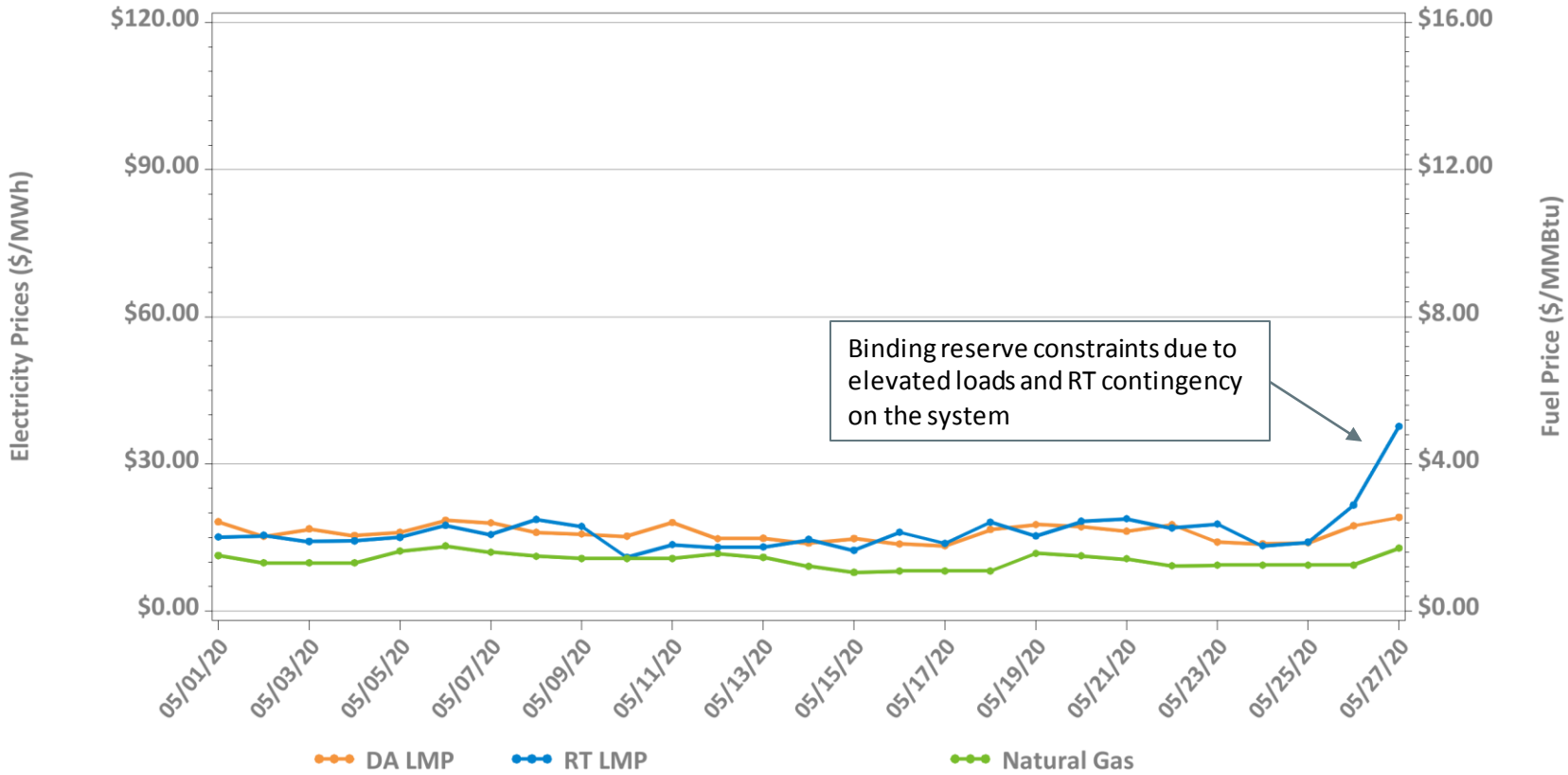


Yearly Fleet Performance targets

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-GL 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: May 1-27, 2020

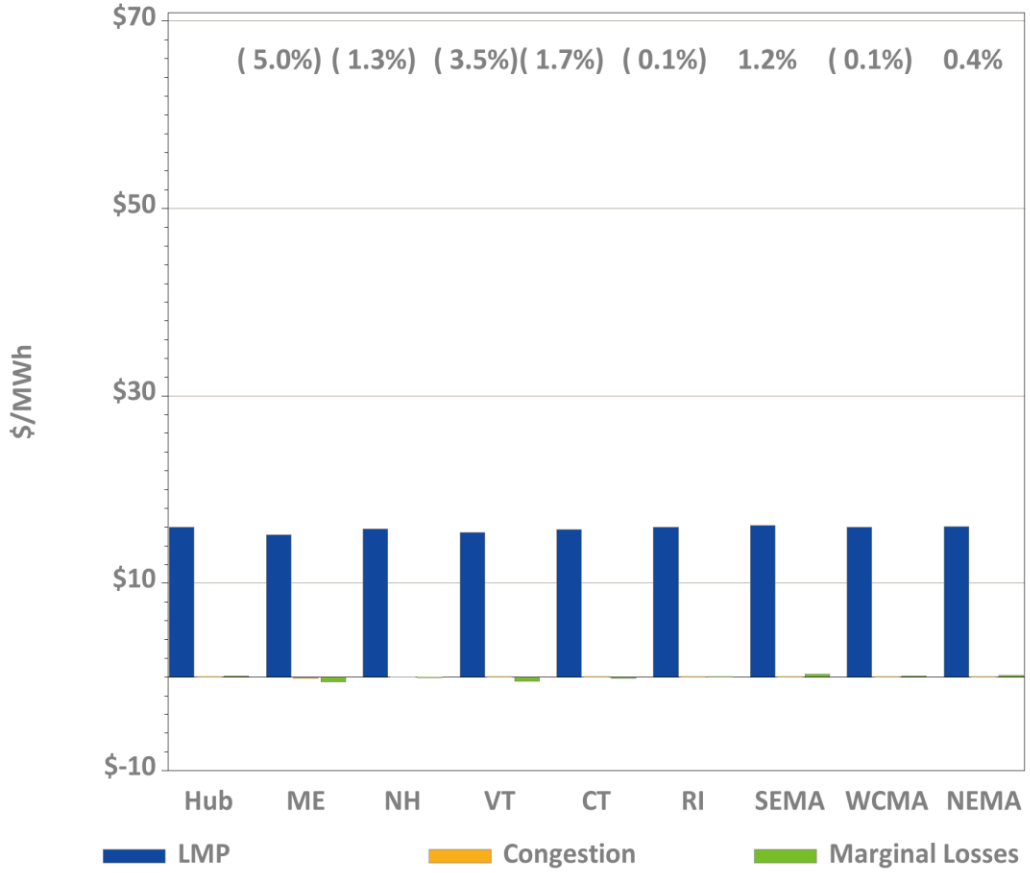


Underlying natural gas data furnished by:

ICE Global markets in clear view

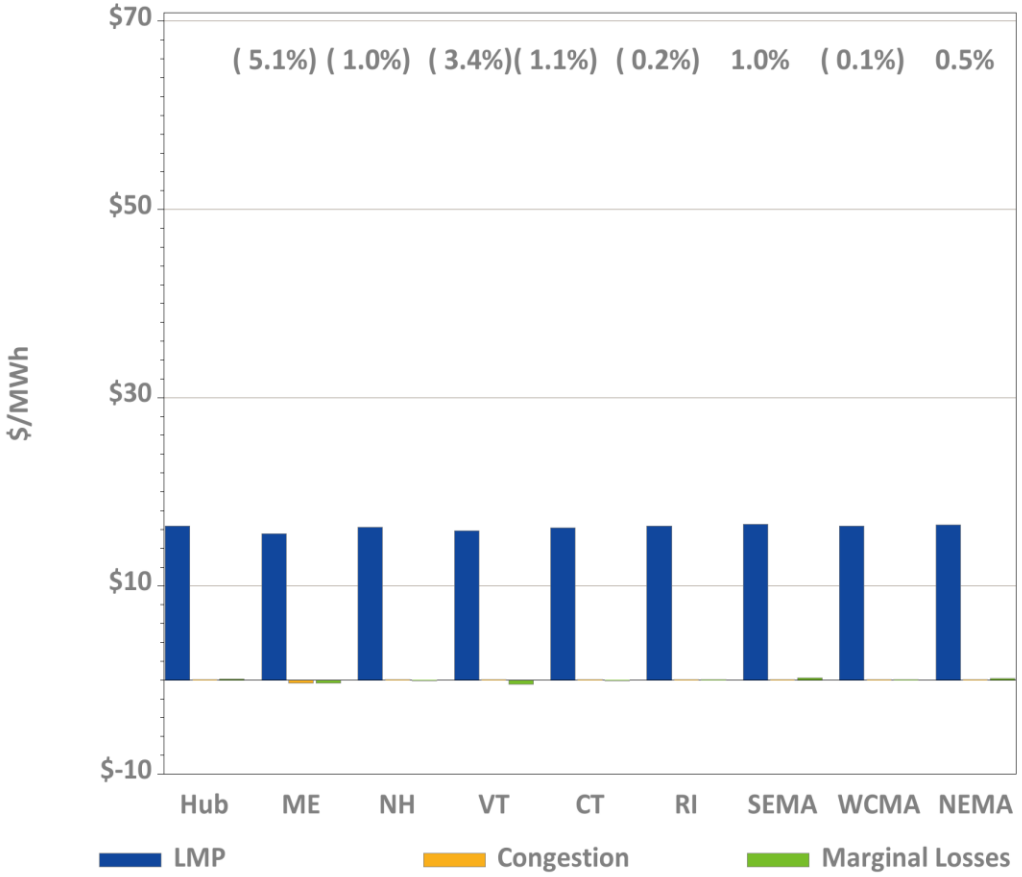
Average price difference over this period (DA-RT): $-0.39
Average price difference over this period ABS(DA-RT): $2.56
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 16%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, May 2020



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

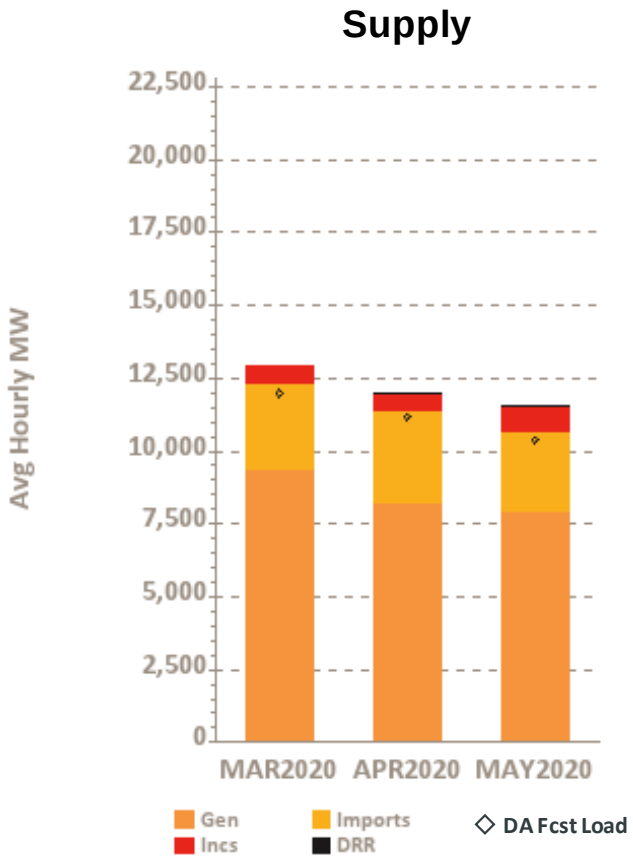
RT LMPs Average by Zone & Hub, May 2020

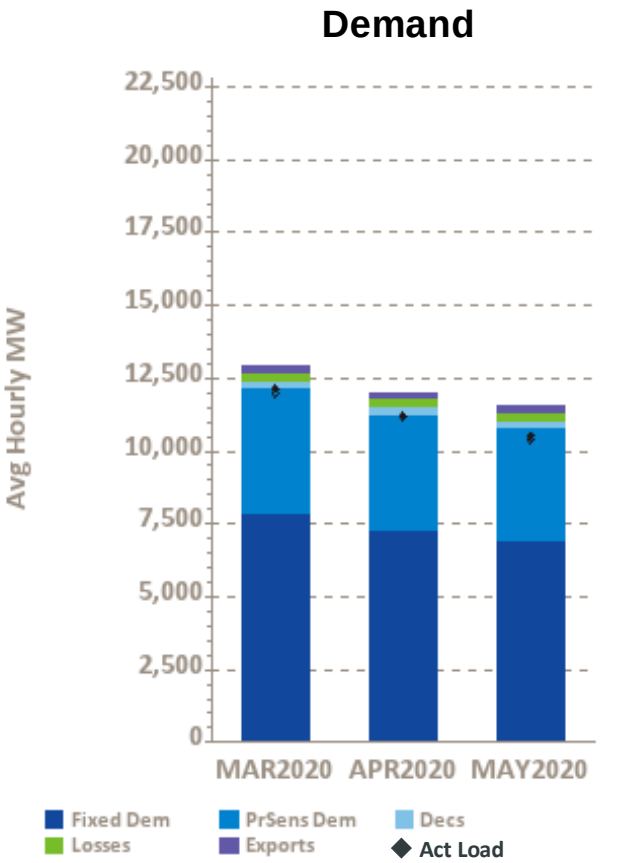


Definitions

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

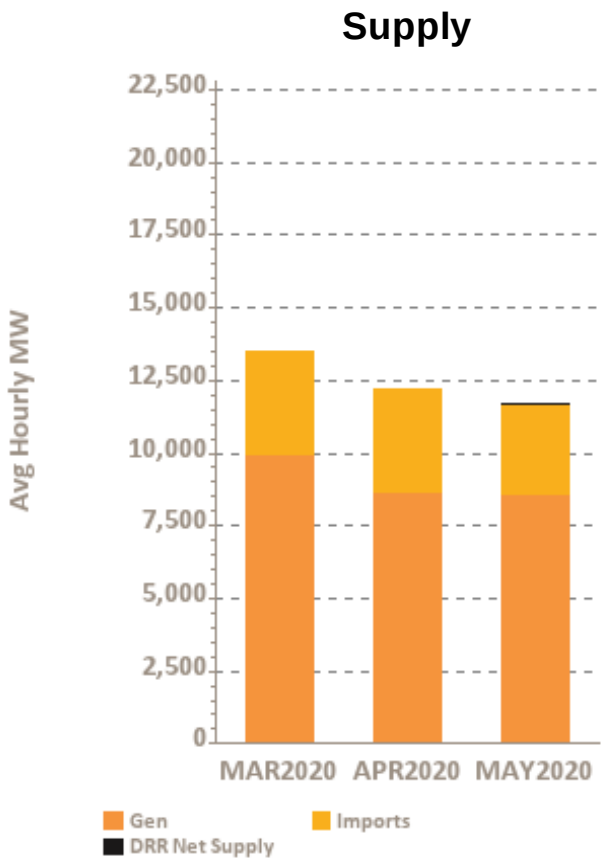


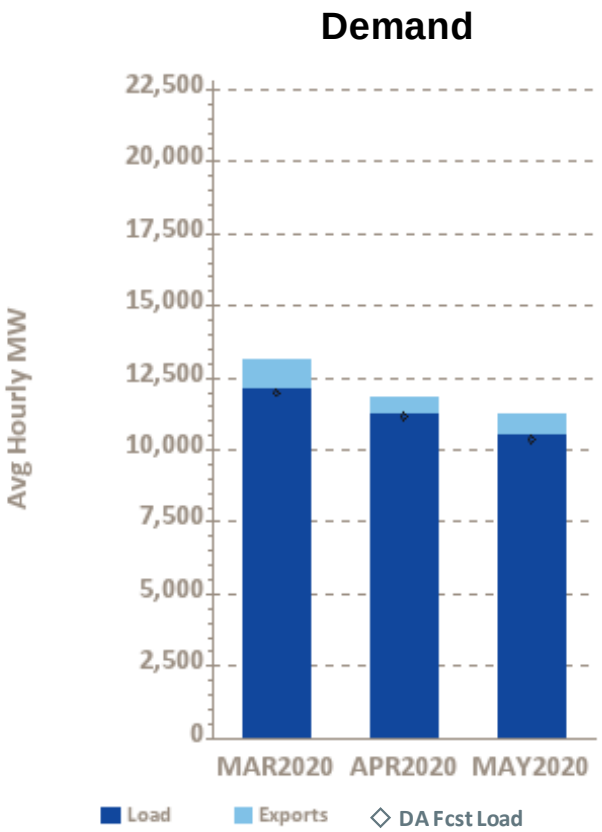


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

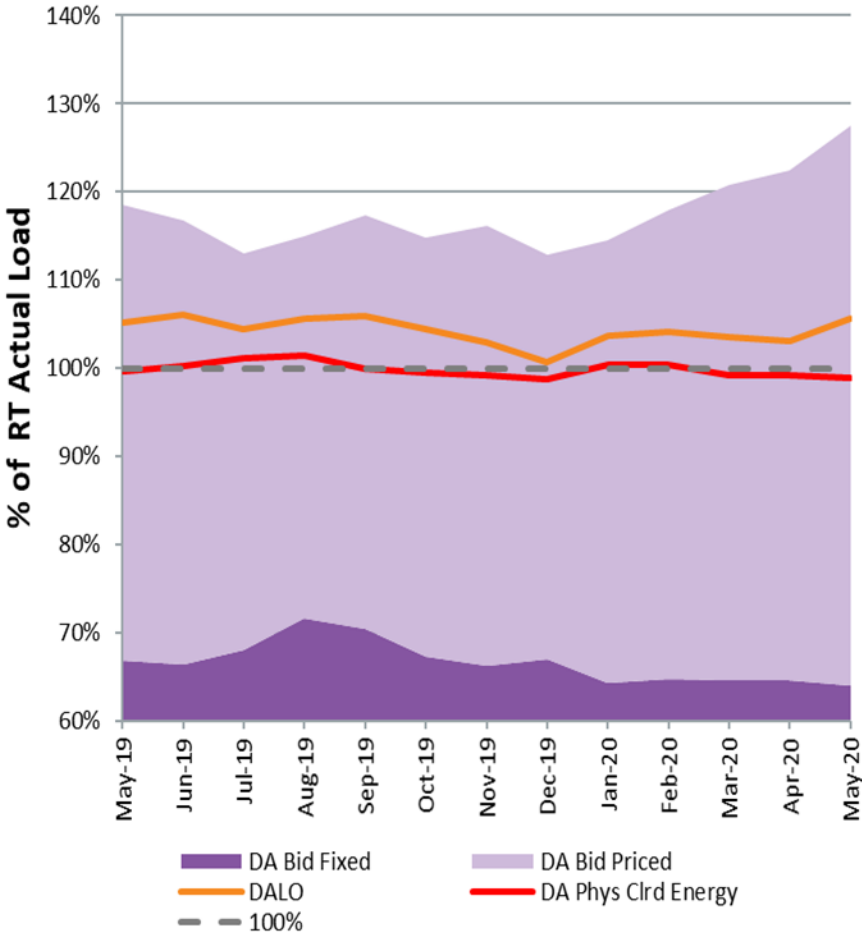
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

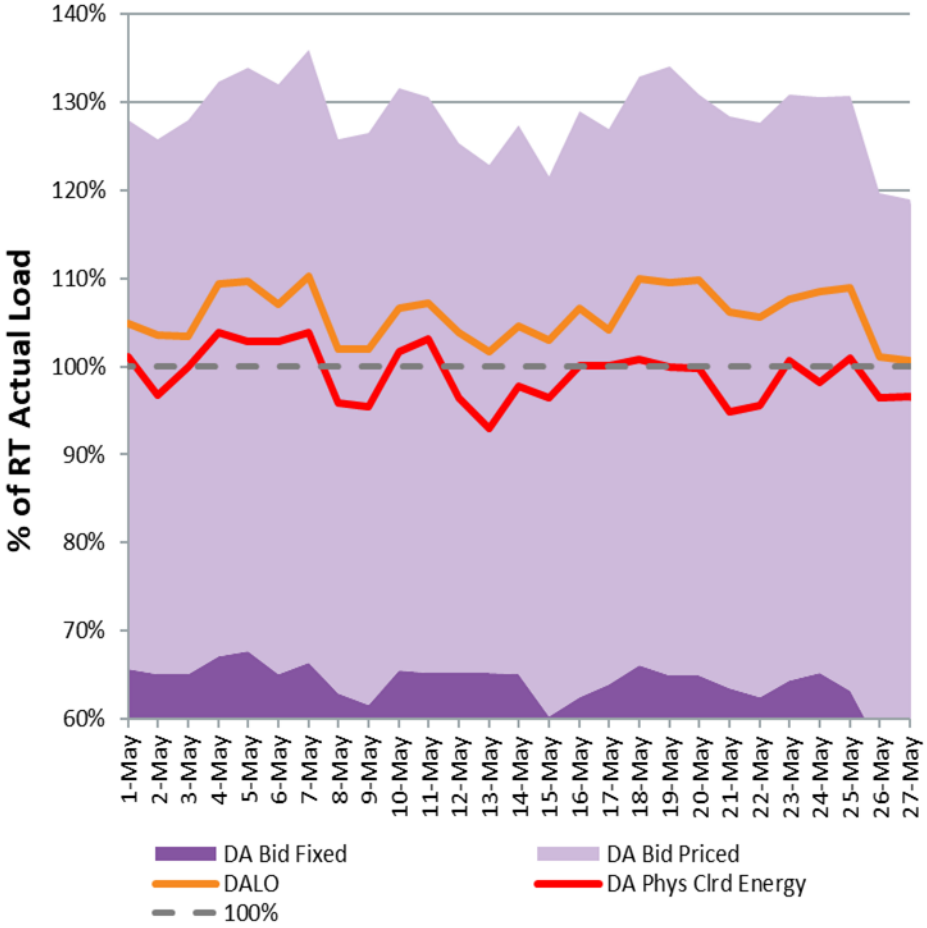
Components of RT Supply and Demand – Last Three Months





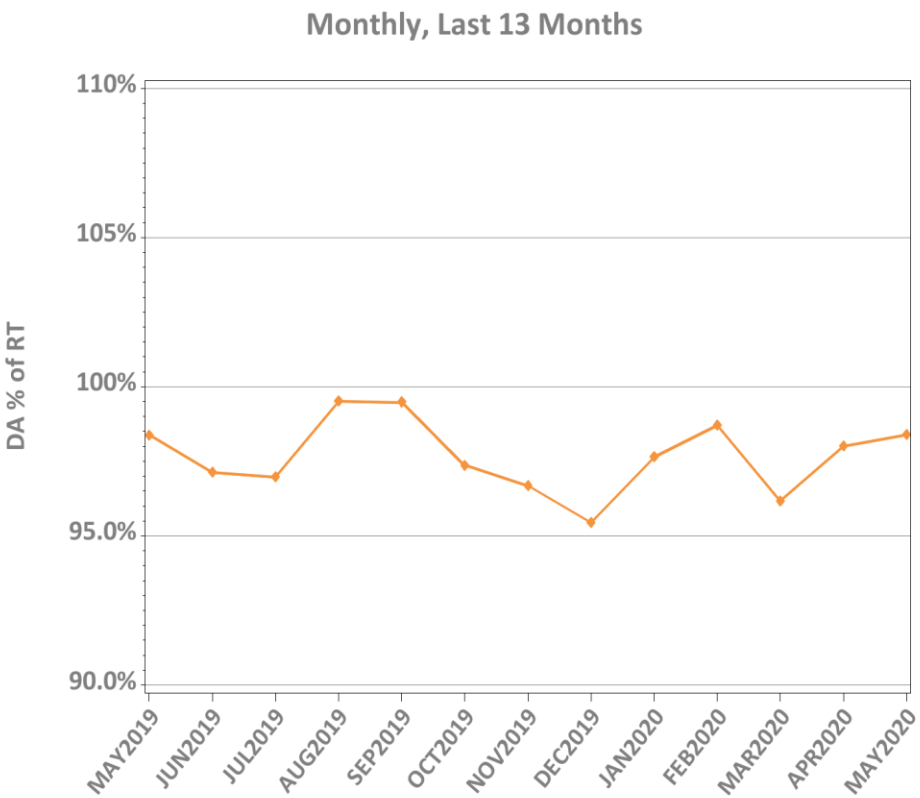
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

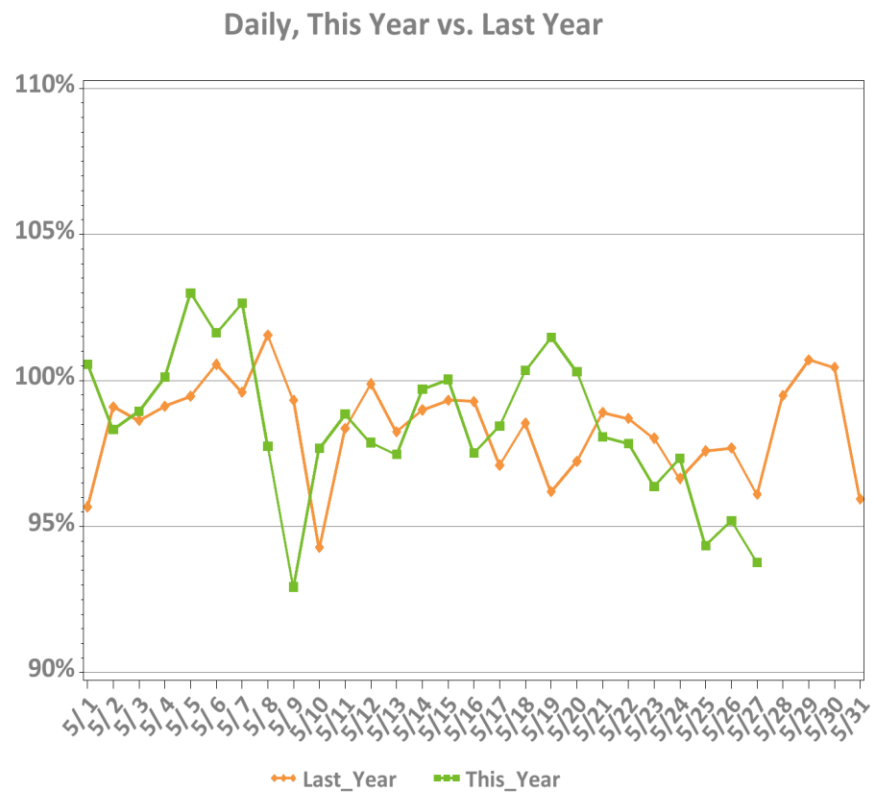




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

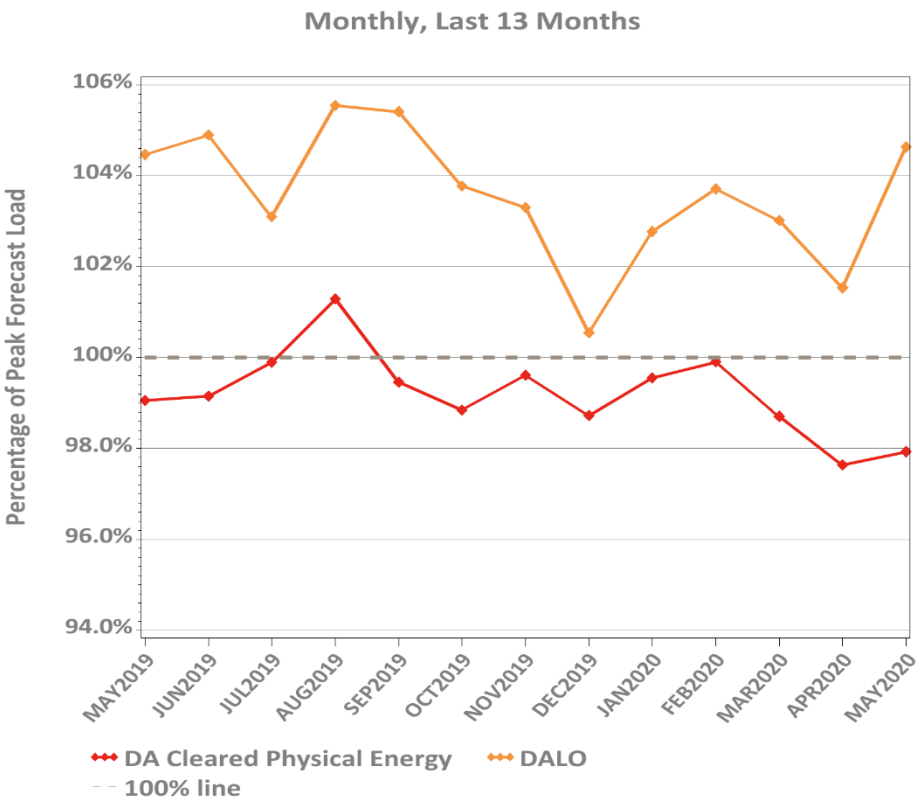
DA vs. RT Load Obligation: May, This Year vs. Last Year

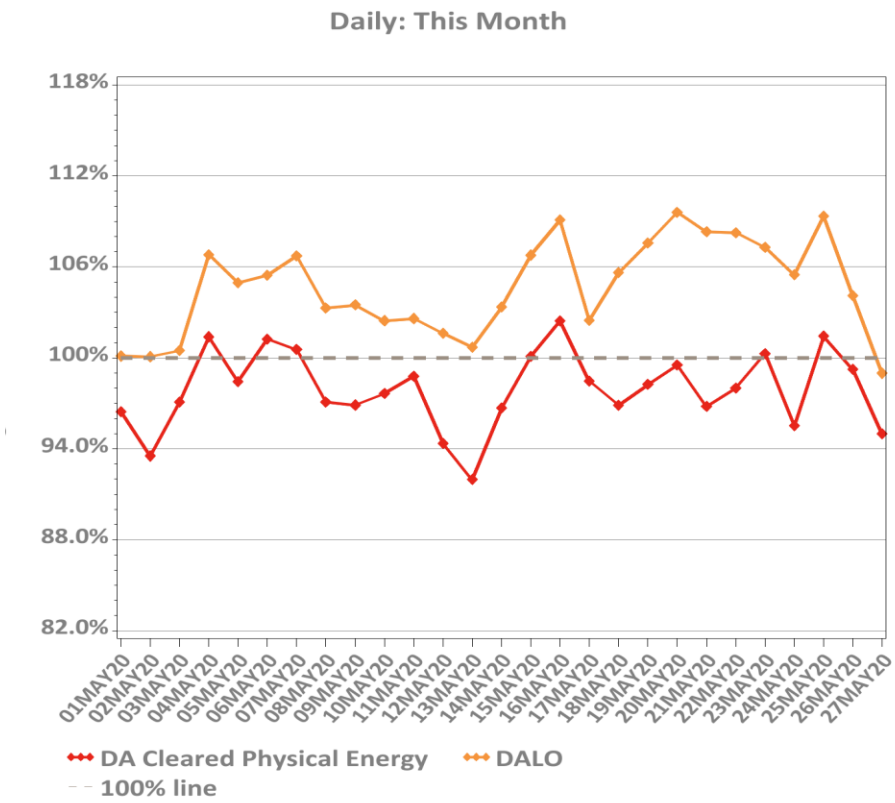




*Hourly average values

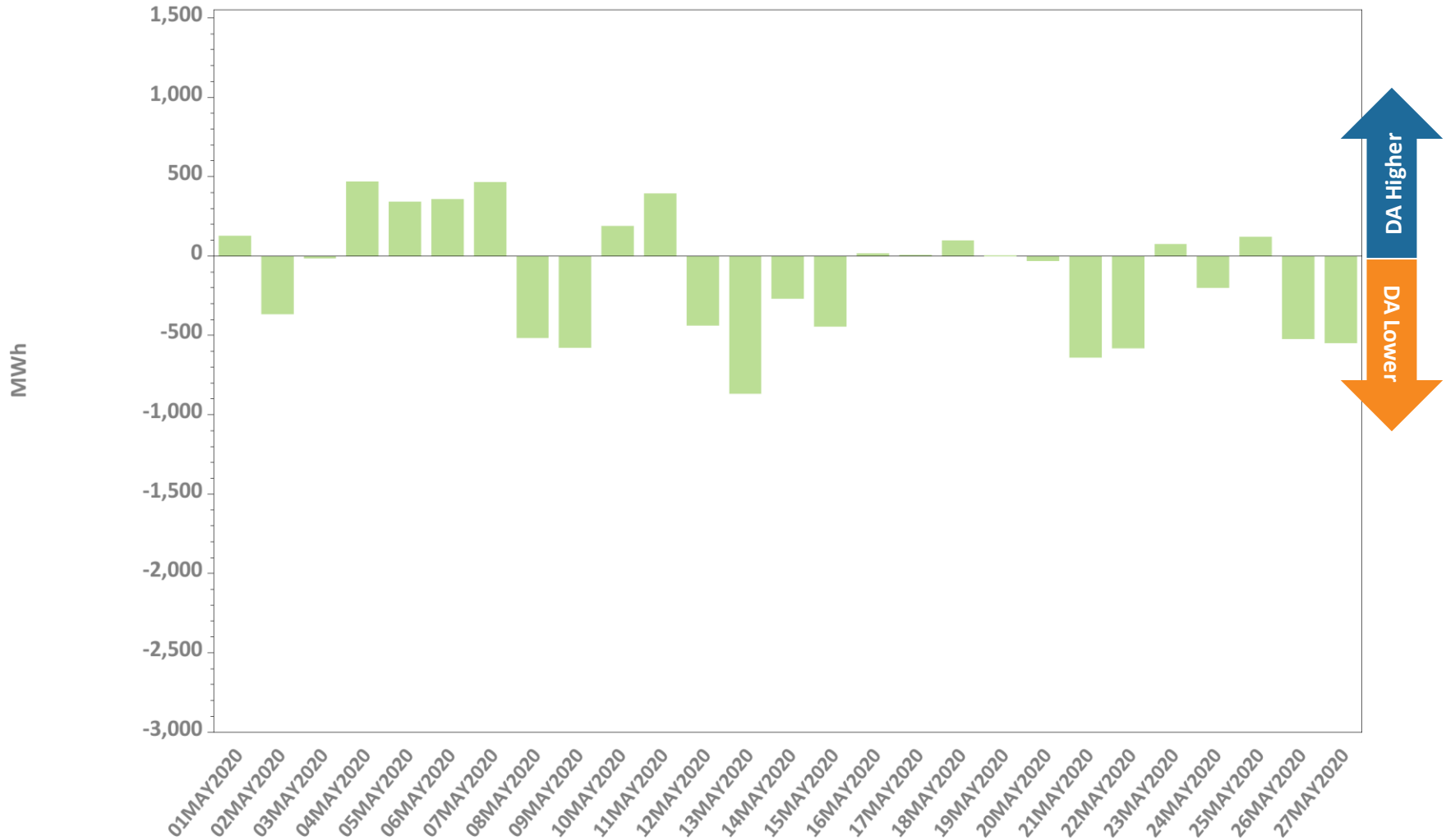
DA Volumes as % of Forecast in Peak Hour





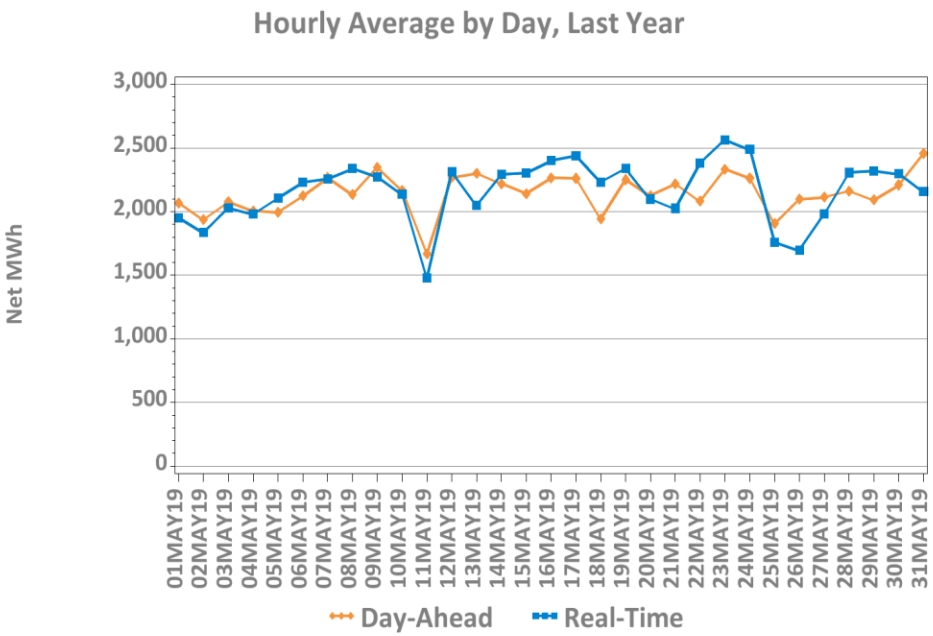
* There were *no* system-level supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during May.

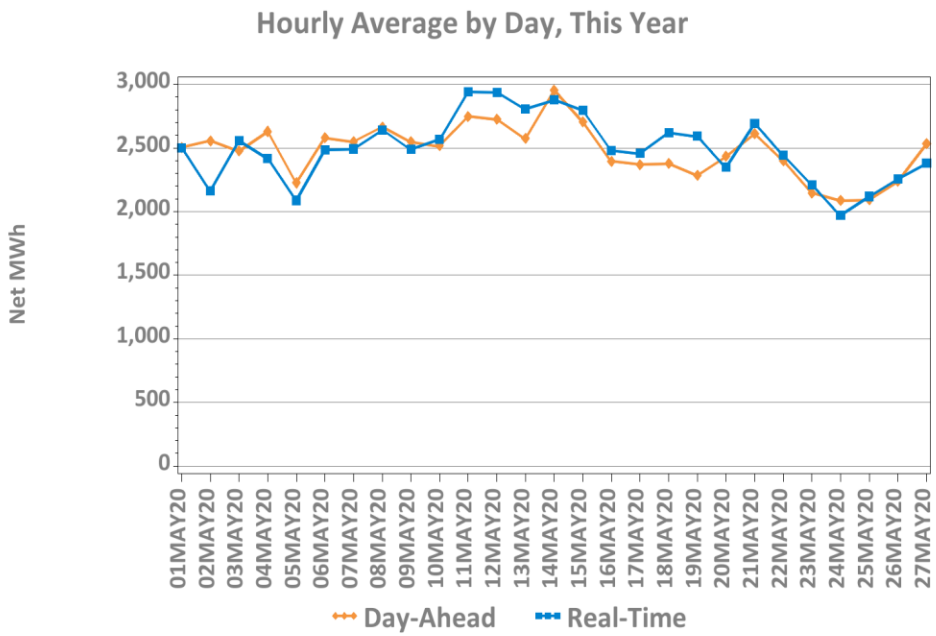
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

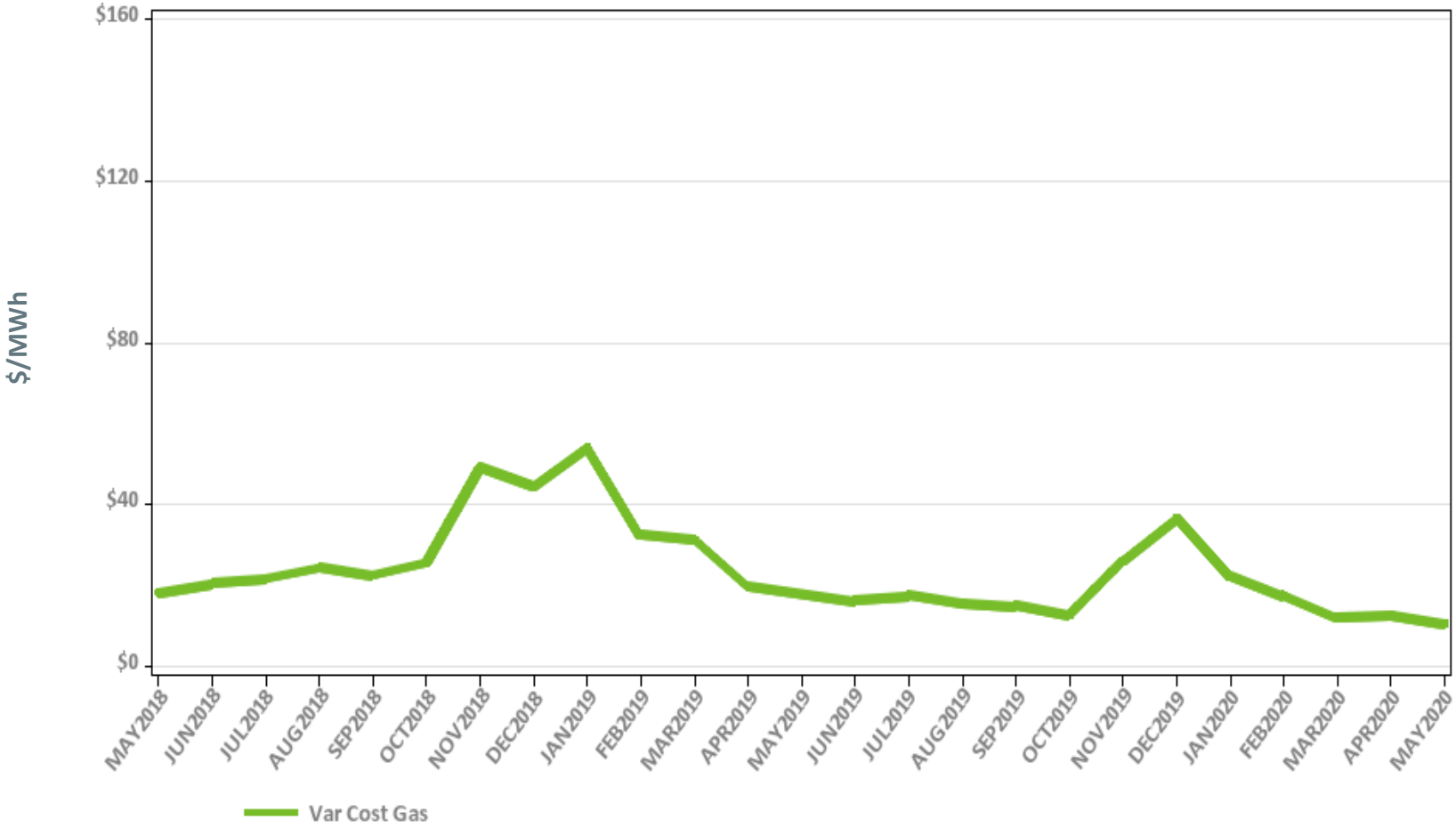
DA vs. RT Net Interchange May 2019 vs. May 2020





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

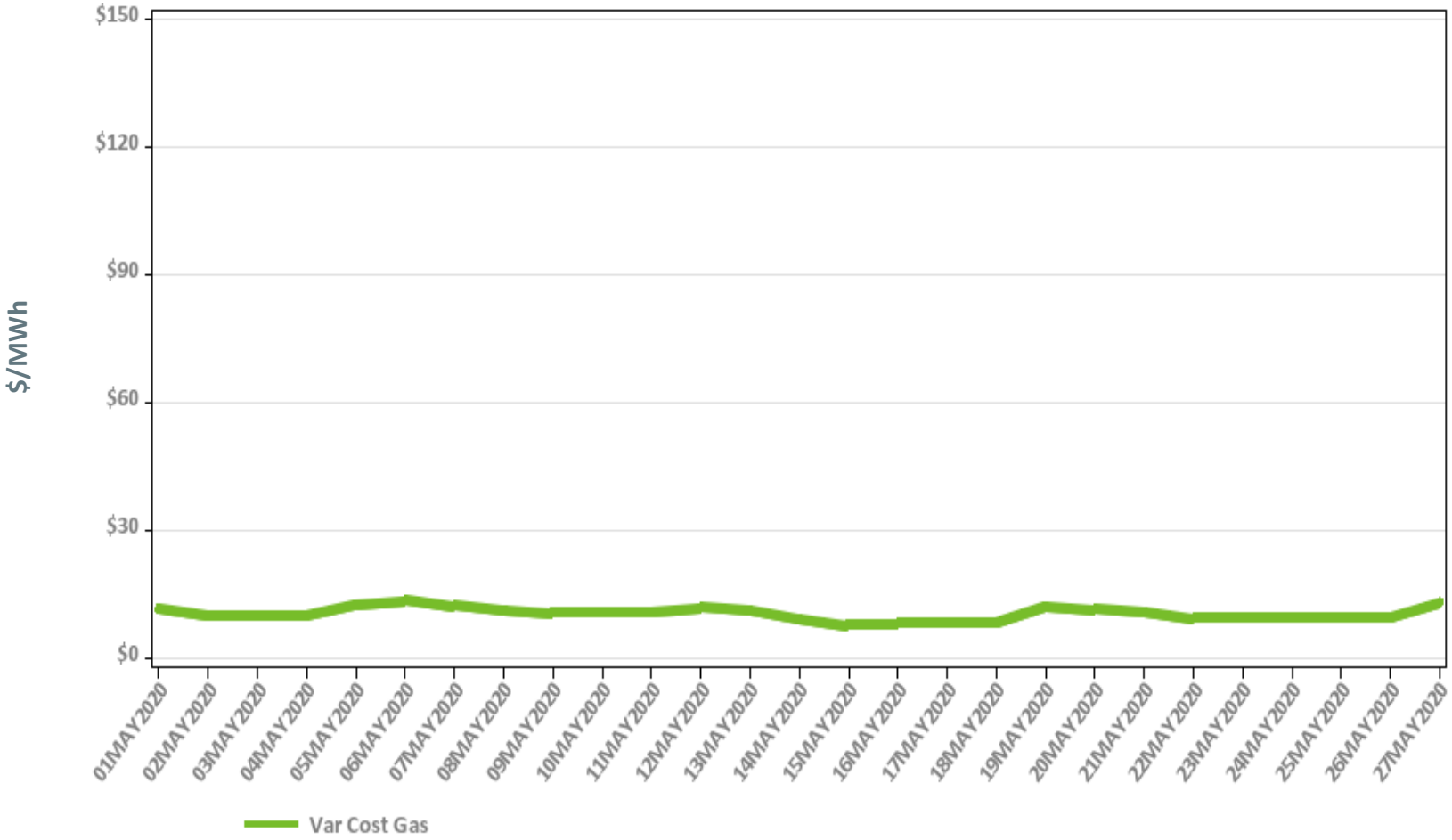


Underlying natural gas data furnished by:

ice Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

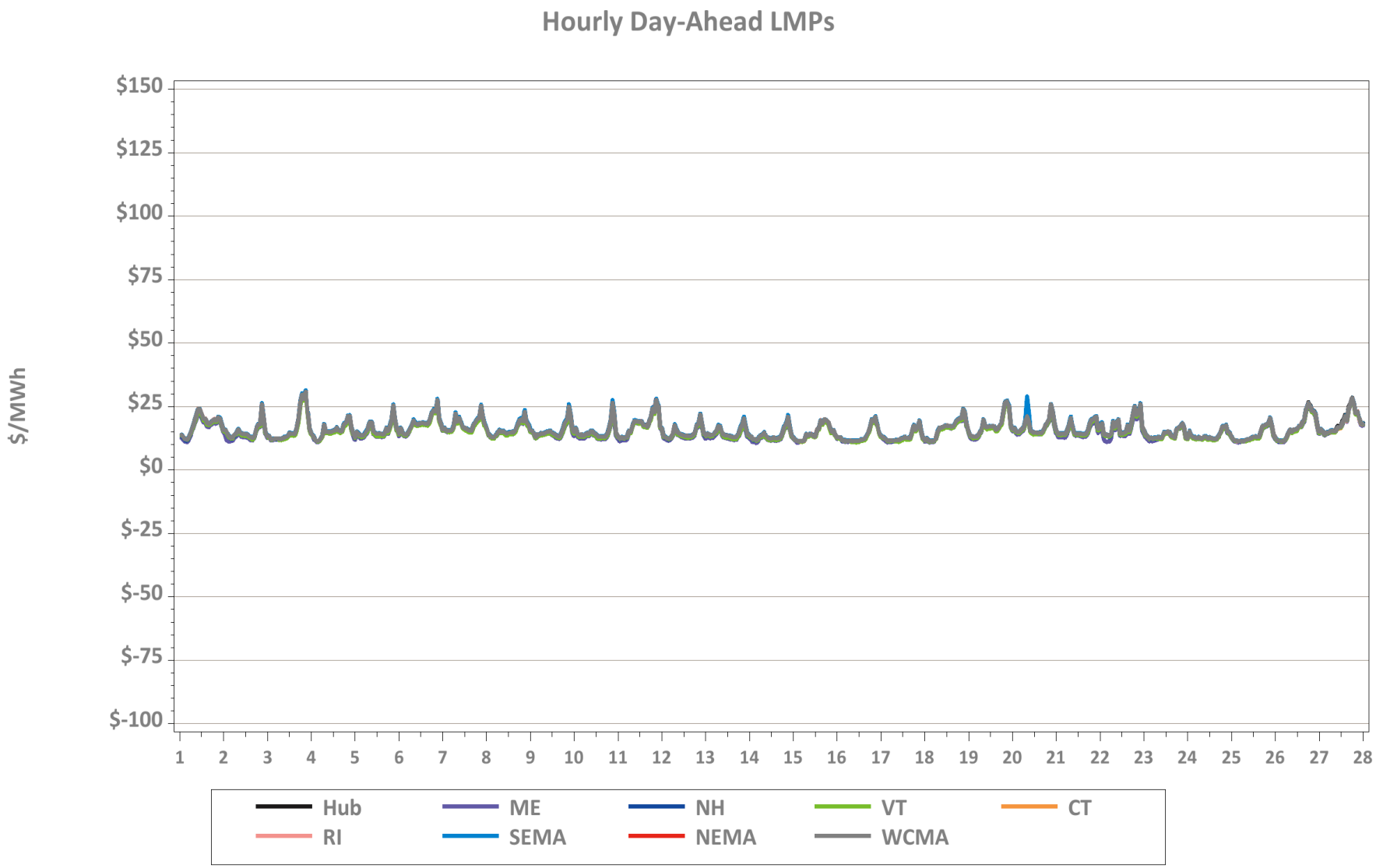


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

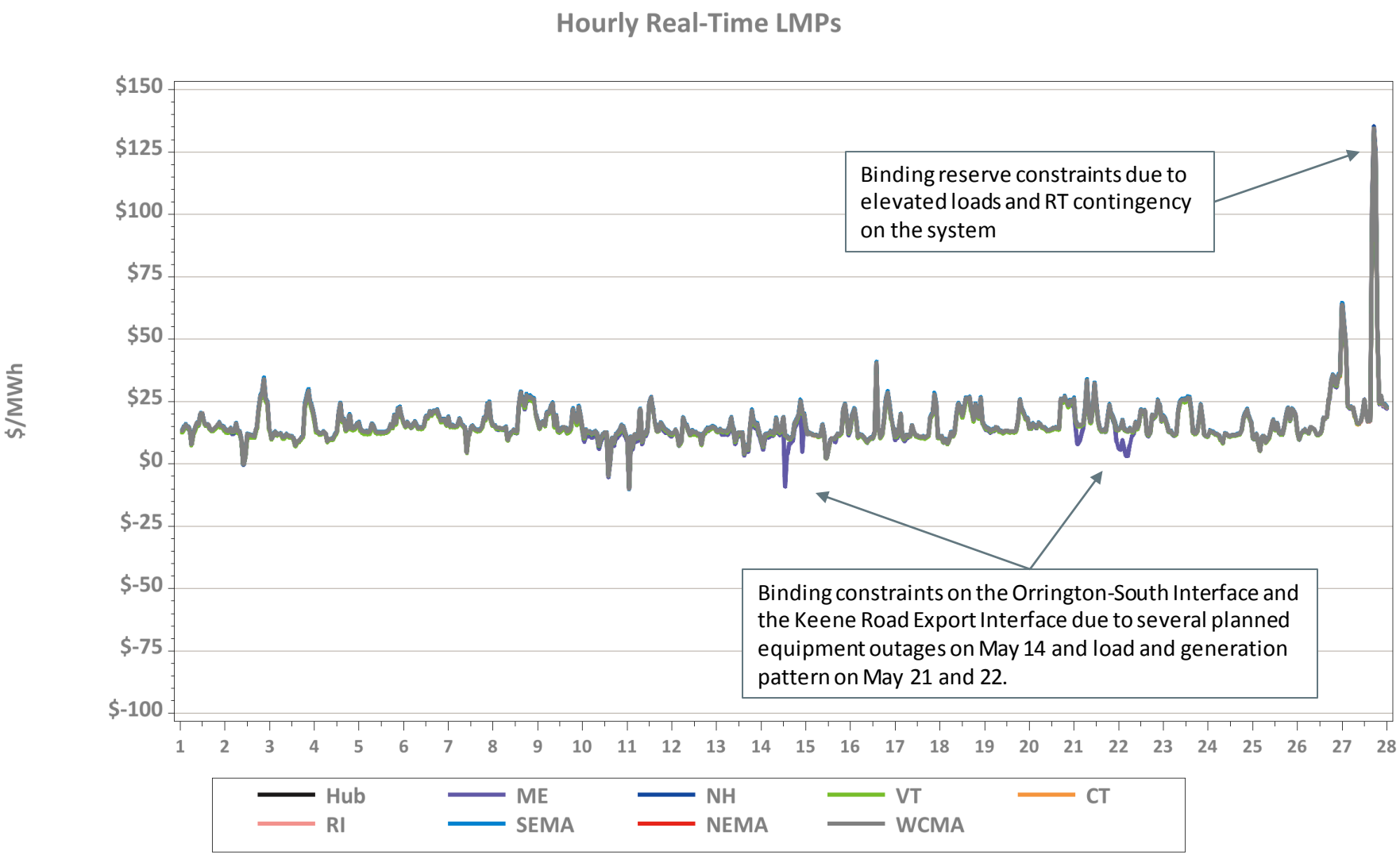
Underlying natural gas data furnished by:

ICE Global markets in clear view

Hourly DA LMPs, May 1-27, 2020

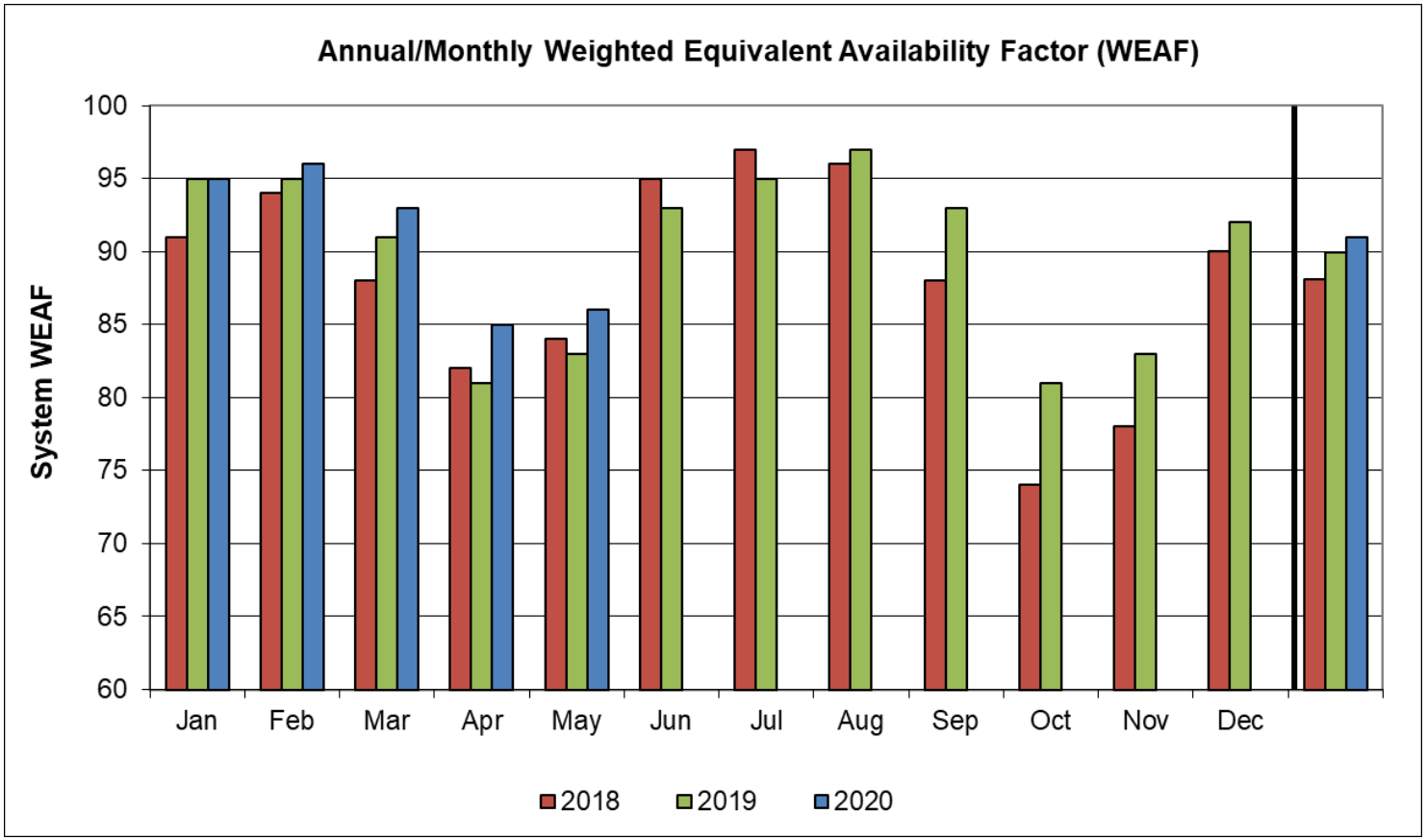


Hourly RT LMPs, May 1-27, 2020



- No Minimum Generation Emergencies were declared during May.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95	96	93	85	86								91
2019	95	95	91	81	83	93	95	97	93	81	83	92	90
2018	91	94	88	82	84	95	97	96	88	74	78	90	88

Data as of 5/26/2020

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for June 2020

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	59.4	184.1	0.0	243.5
NH	31.8	147.3	0.0	179.1
VT	22.9	100.6	0.0	123.5
CT	93.2	154.2	549.2	796.7
RI	34.4	268.2	0.0	302.6
SEMA	38.0	443.0	0.0	481.0
WCMA	67.0	463.6	45.3	575.9
NEMA	48.9	811.3	0.0	860.2
Total	**395.6**	**2,572.3**	**594.5**	**3,562.4**

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

NEW GENERATION

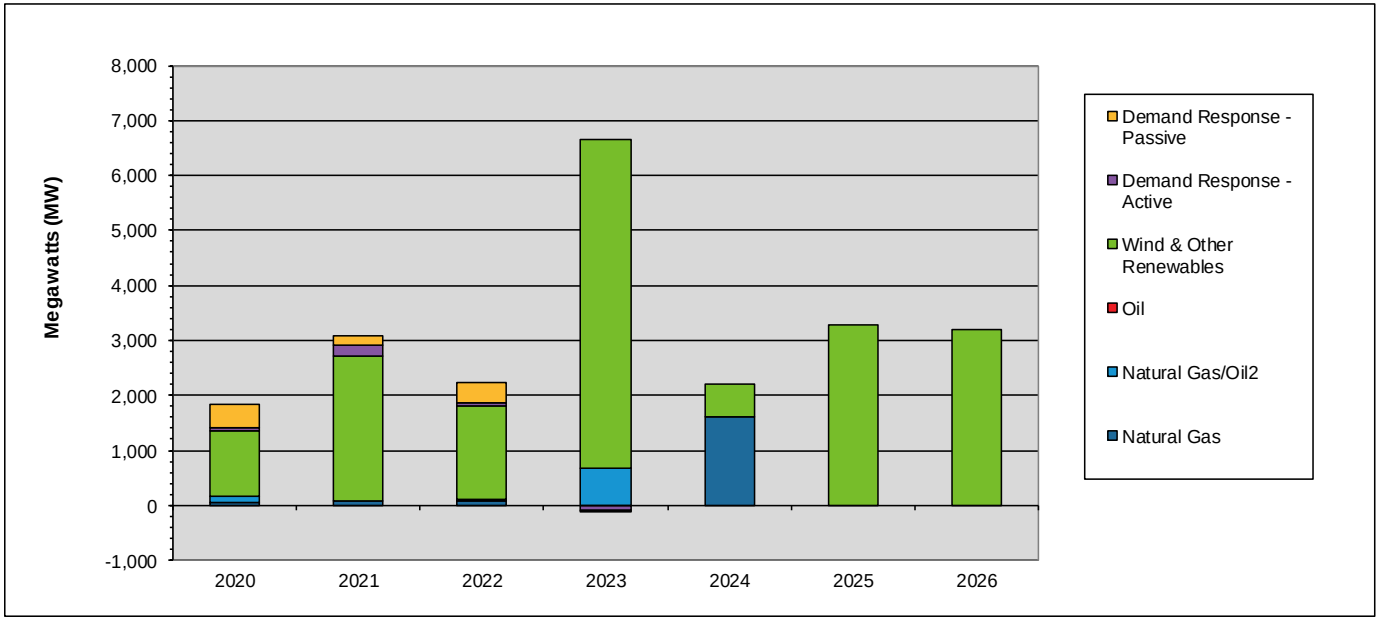
New Generation Update

Based on Queue as of 5/29/20

- Four projects totaling 273 MW applied for interconnection study since the last update
- No projects went commercial or withdrew, resulting in a net increase in new generation projects of 273 MW
- In total, 236 generation projects are currently being tracked by the ISO, totaling approximately 21,146 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



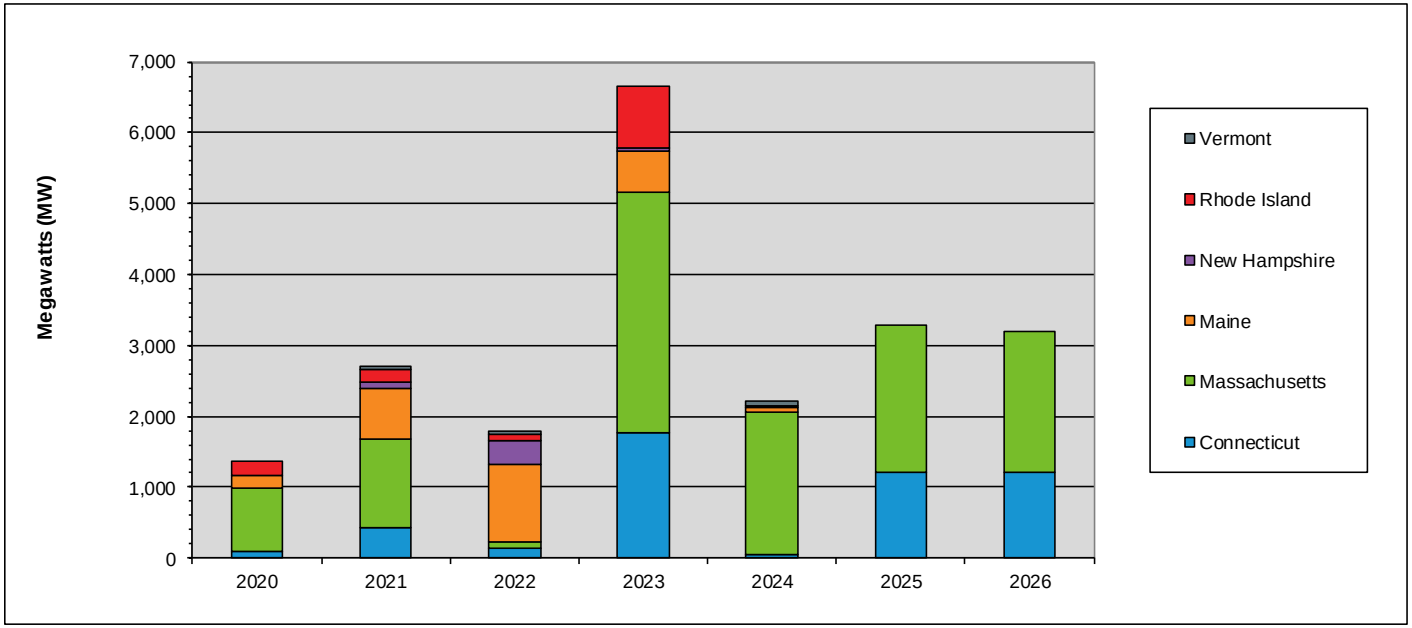
	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Demand Response - Passive	422	184	380	-28	0	0	0	958	4.3
Demand Response - Active	42	204	62	-94	0	0	0	214	1.0
Wind & Other Renewables	1,201	2,627	1,685	5,990	607	3,276	3,200	18,586	83.0
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	121	0	39	672	0	0	0	832	3.7
Natural Gas	43	76	73	0	1,600	0	0	1,792	8.0
Totals	**1,830**	**3,091**	**2,239**	**6,540**	**2,207**	**3,276**	**3,200**	**22,383**	**100.0**

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

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

- 2020 values include the 64 MW of generation that has gone commercial in 2020
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions
By State



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Vermont	0	35	60	0	50	0	0	145	0.7
Rhode Island	206	196	73	880	0	0	0	1,355	6.4
New Hampshire	0	83	352	50	20	0	0	505	2.4
Maine	161	717	1,090	571	81	0	0	2,620	12.4
Massachusetts	896	1,232	87	3,384	2,016	2,076	2,000	11,691	55.1
Connecticut	102	440	135	1,777	40	1,200	1,200	4,894	23.1
Totals	**1,365**	**2,703**	**1,797**	**6,662**	**2,207**	**3,276**	**3,200**	**21,210**	**100.0**

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

- 2020 values include the 64 MW of generation that has gone commercial in 2020

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	0	0	1	8
Battery Storage	15	2,079	0	0	15	2,079
Hydro	3	99	1	66	2	33
Landfill Gas	0	0	0	0	0	0
Natural Gas	13	1,792	0	0	13	1,792
Natural Gas/Oil	6	787	1	14	5	773
Nuclear	1	37	0	0	1	37
Oil	0	0	0	0	0	0
Solar	175	3,860	7	171	168	3,689
Wind	22	12,484	0	0	22	12,484
Total	236	21,146	9	251	227	20,895

- 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

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	133	0	0	8	133
Intermediate	12	2,433	1	14	11	2,419
Peaker	194	6,037	8	237	186	5,800
Wind Turbine	22	12,543	0	0	22	12,543
Total	236	21,146	9	251	227	20,895

- 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

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	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	1	8	1	8	0	0	0	0	0	0
Battery Storage	15	2,079	0	0	0	0	15	2,079	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	13	1,792	4	55	8	1,731	1	6	0	0
Natural Gas/Oil	6	787	0	0	4	702	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	175	3,860	0	0	0	0	174	3,740	1	120
Wind	22	12,484	0	0	0	0	1	61	21	12,423
Total	236	21,146	8	133	12	2,433	194	6,037	22	12,543

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 11

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*	419.928	441.221	21.293	594.551	153.33	584.35	-10.201
	Passive Demand	2,791.02	2,835.354	44.334	2,883.767	48.413	2,964.695	80.928
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**	**3,549.045**	70.727
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661	2,9678.995	-480.896
	Intermittent	894.217	823.796	-70.421	809.571	-14.225	689.524	-120.047
Generator Total		**31,389.02**	**30,888.027**	**-500.993**	**30,969.462**	**81.435**	**30,368.519**	**-600.943**
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**	**1,124.6**	**-485.244**
****Grand Total**		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**	**35,042.164**	**-1015.46**
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**	**32,205**	**-1,315**

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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 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				
	Passive Demand	2,975.36	3,045.073	69.713				
Demand Total		**3,599.81**	**3,704.21**	**104.4**				
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654				
	Intermittent	880.317	806.609	-73.708				
Generator Total		**30,011.07**	**30,051.013**	**39.943**				
Import Total		**1,217**	**1,305.487**	**88.487**				
****Grand Total**		**34,827.88**	**35,060.710**	**232.83**				
Net ICR (NICR)		**33,725**	**33,550**	**-175**				

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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 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						
	Passive Demand	3,354.69						
Demand Total		**4,040.244**						
Generator	*Non-Intermittent*	28,586.498						
	Intermittent	1,024.792						
Generator Total		**2,9611.29**						
Import Total		**1,187.69**						
**Grand Total		**34,839.224**						
Net ICR (NICR)		**33,750**						

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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						
	Passive Demand	3,327.071						
Demand Total		3,919.114						
Generator	*Non-Intermittent*	27,816.902						
	Intermittent	1,160.916						
Generator Total		28,977.818						
Import Total		1,058.72						
**Grand Total		33,955.652						
Net ICR (NICR)		32,490						

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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	2,375.422	370.734	2,746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2,571.361	639.586	3,210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3,085.734	514.072	3,599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3,386.703	653.541	4,040.244
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	3,596.056	323.058	3,919.114

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

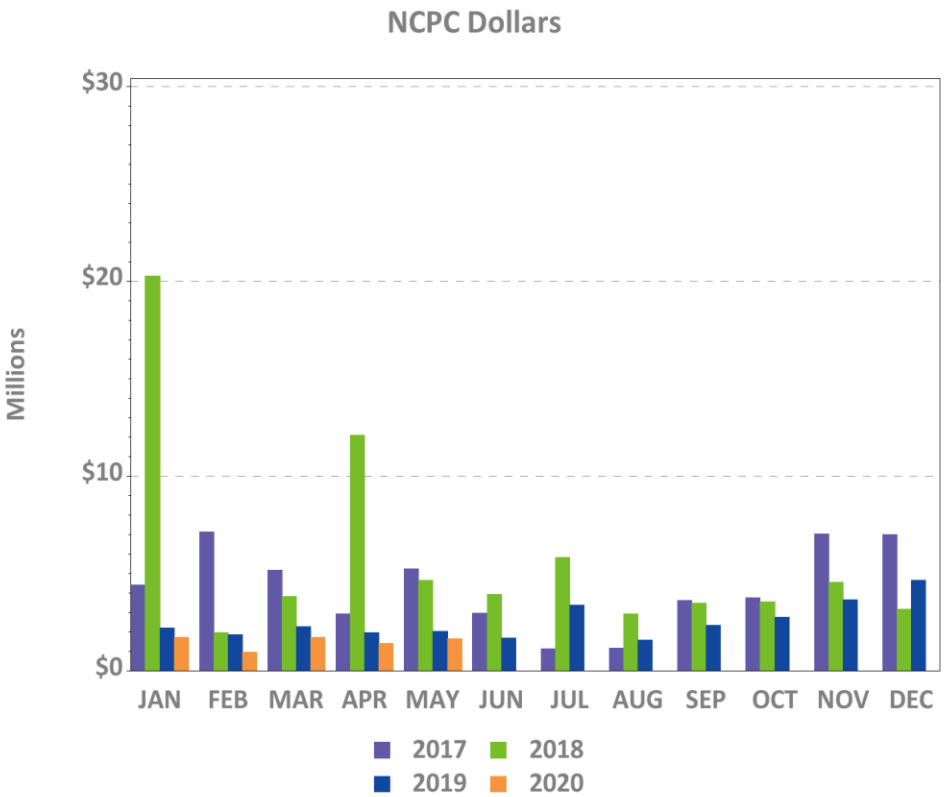
Definitions

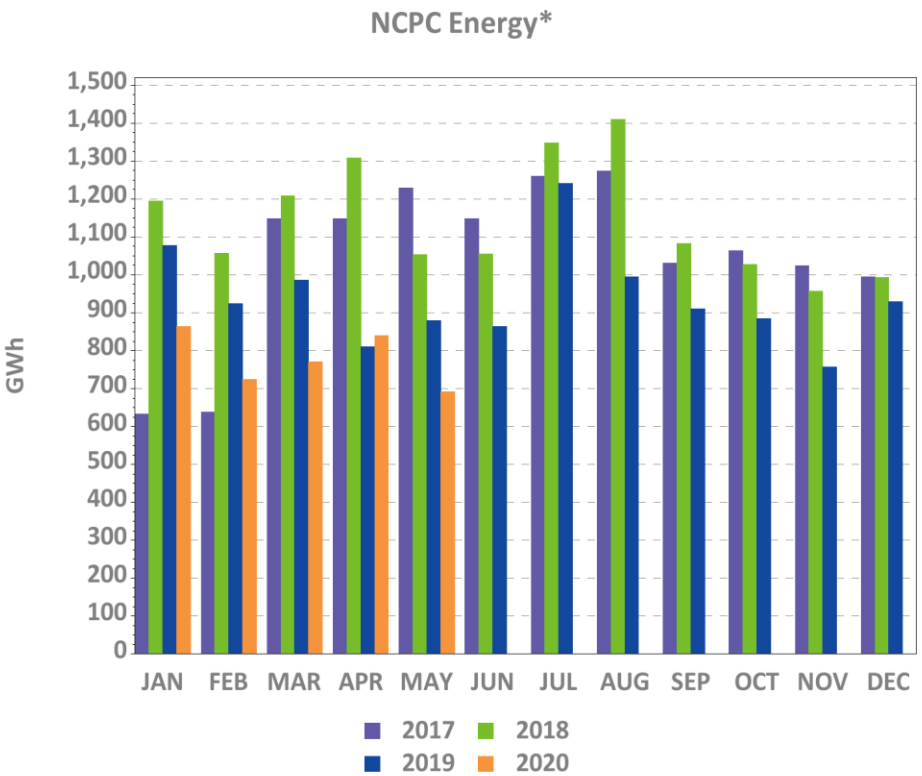
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd 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).

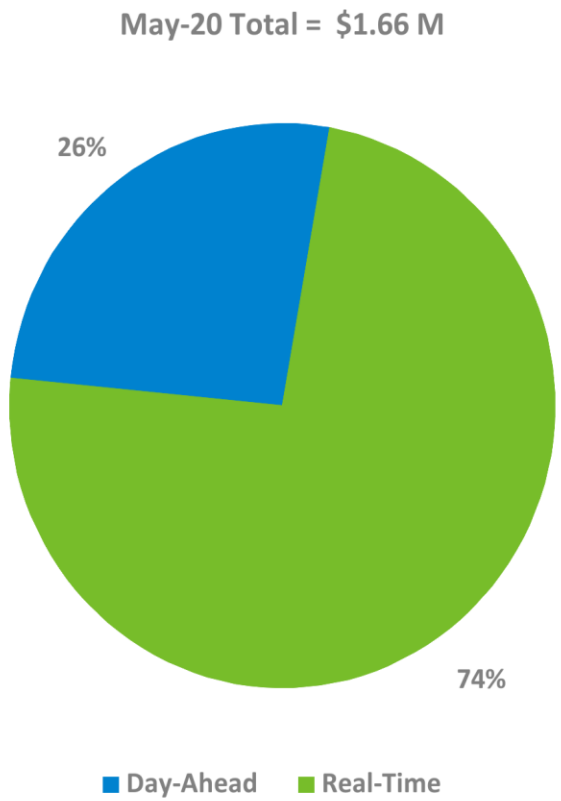
Year-Over-Year Total NCPC Dollars and Energy

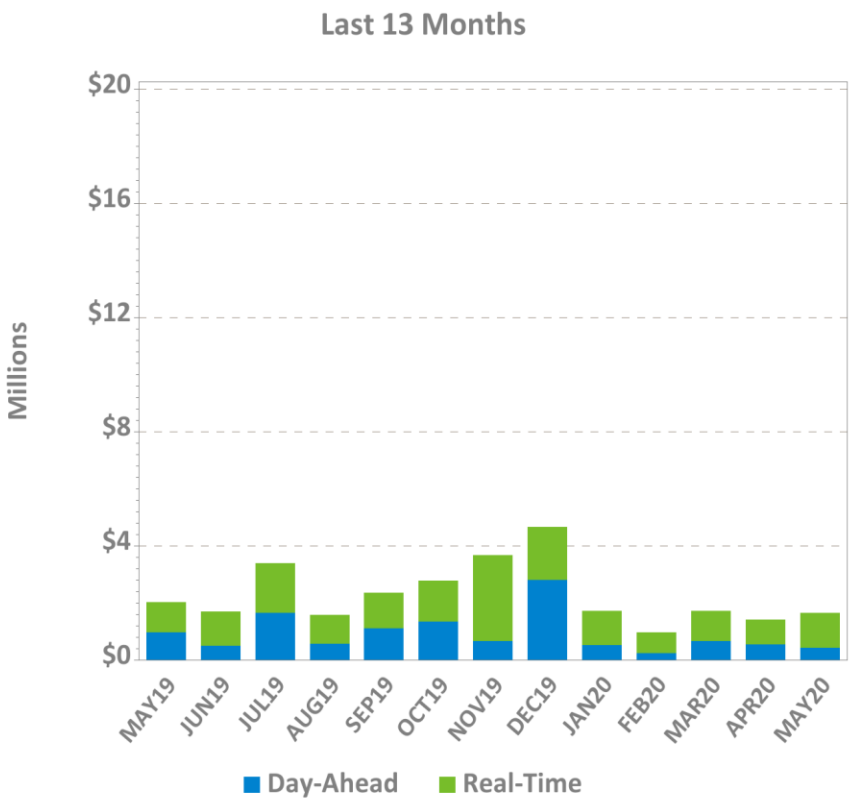




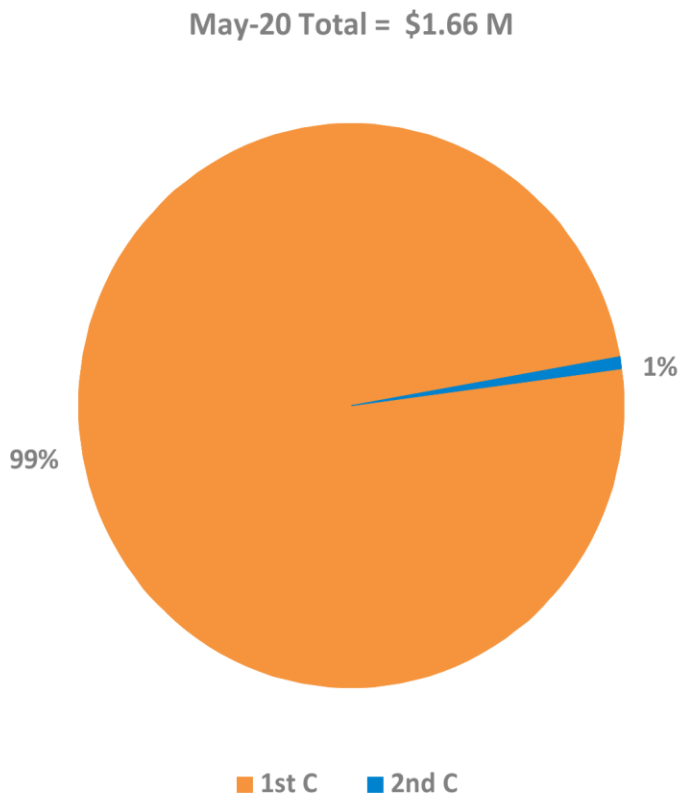
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

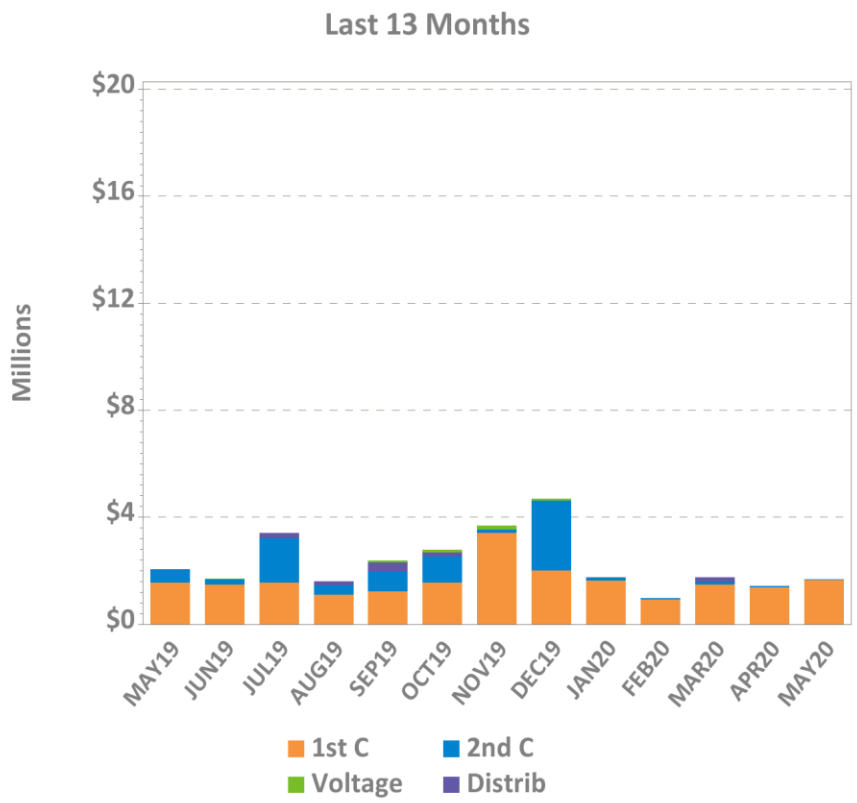
DA and RT NCPC Charges





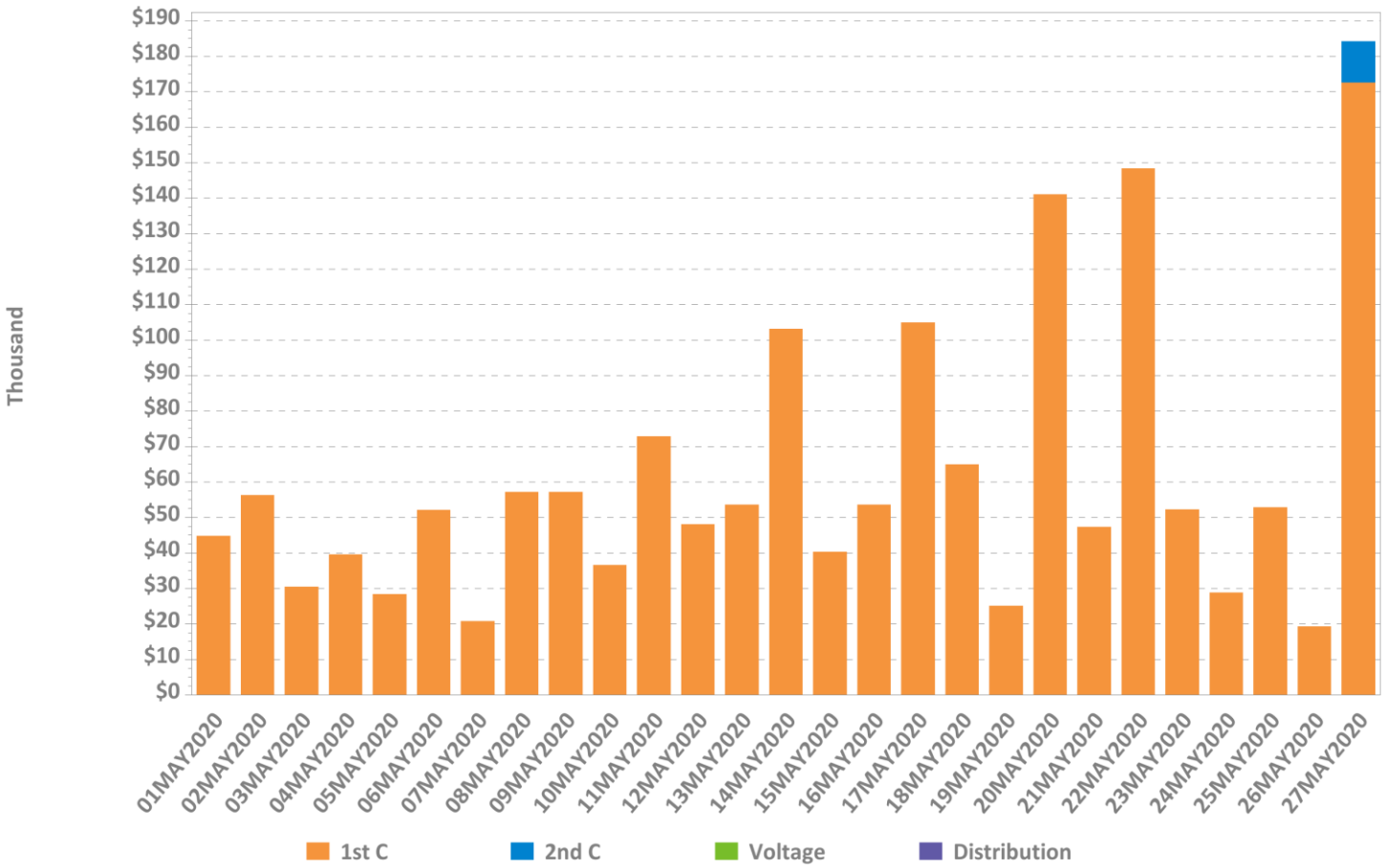
NCPC Charges by Type



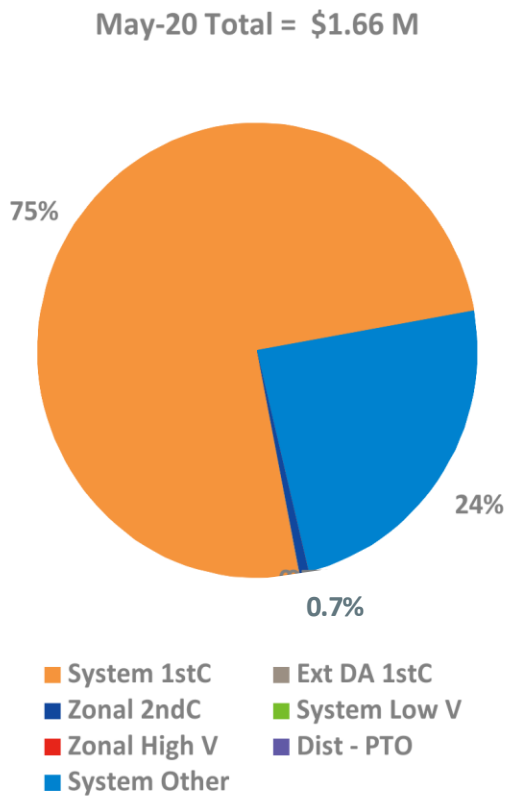


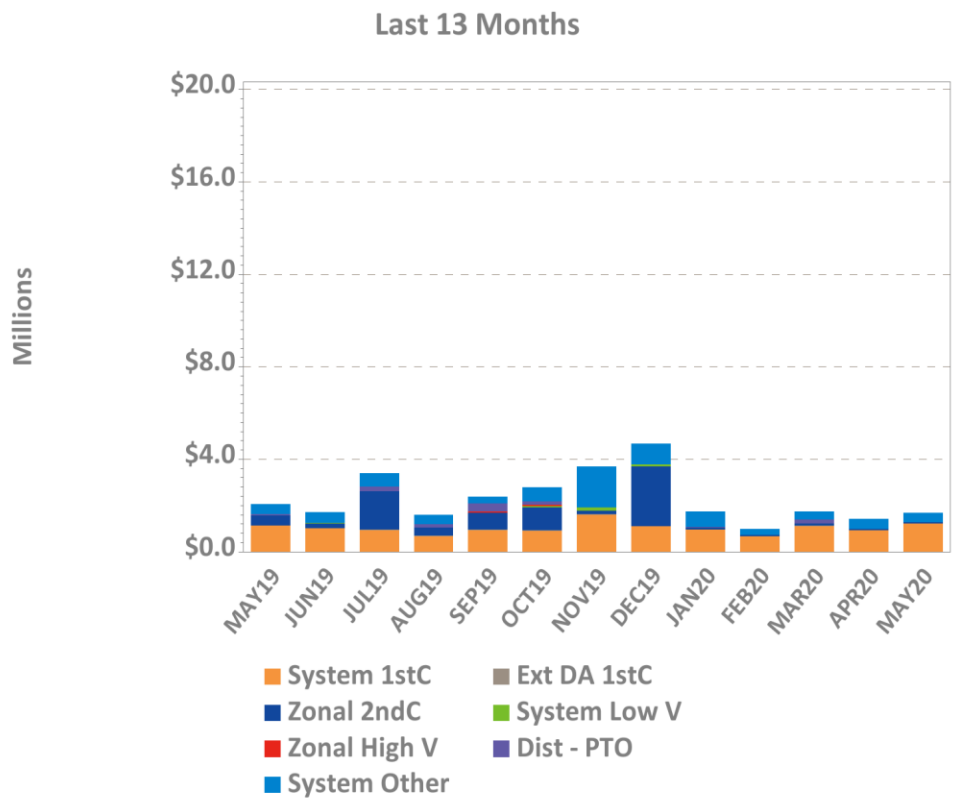
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



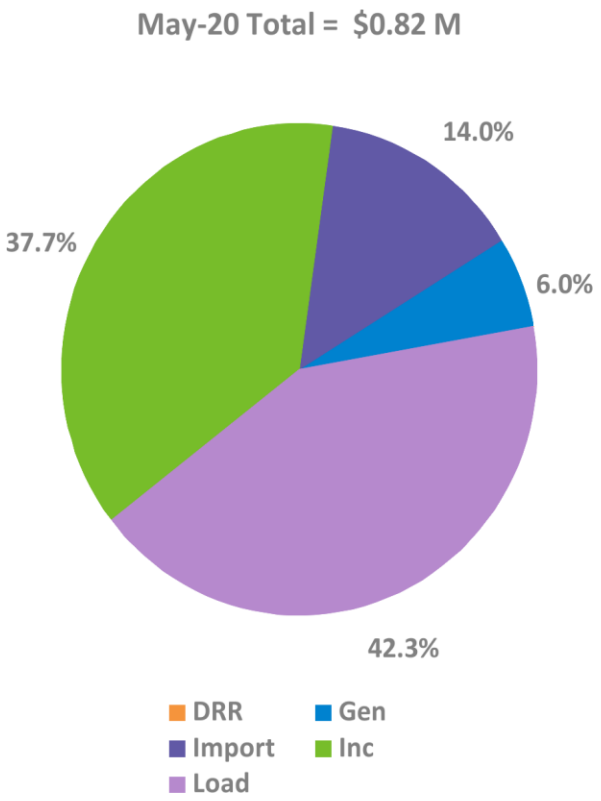
NCPC Charges by Allocation

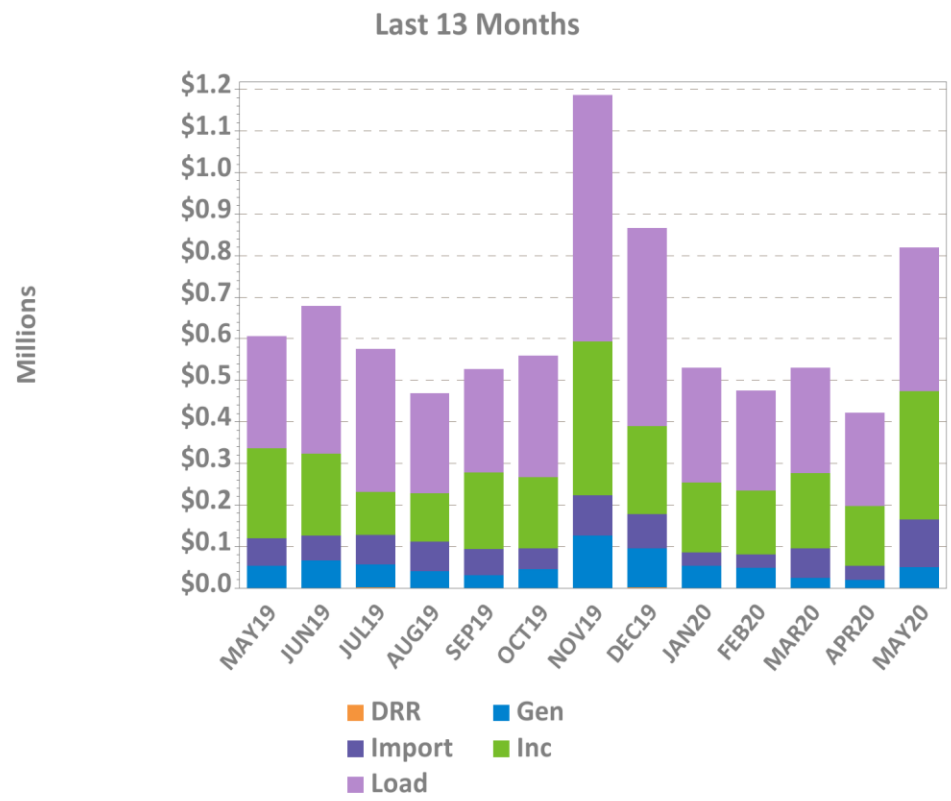




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

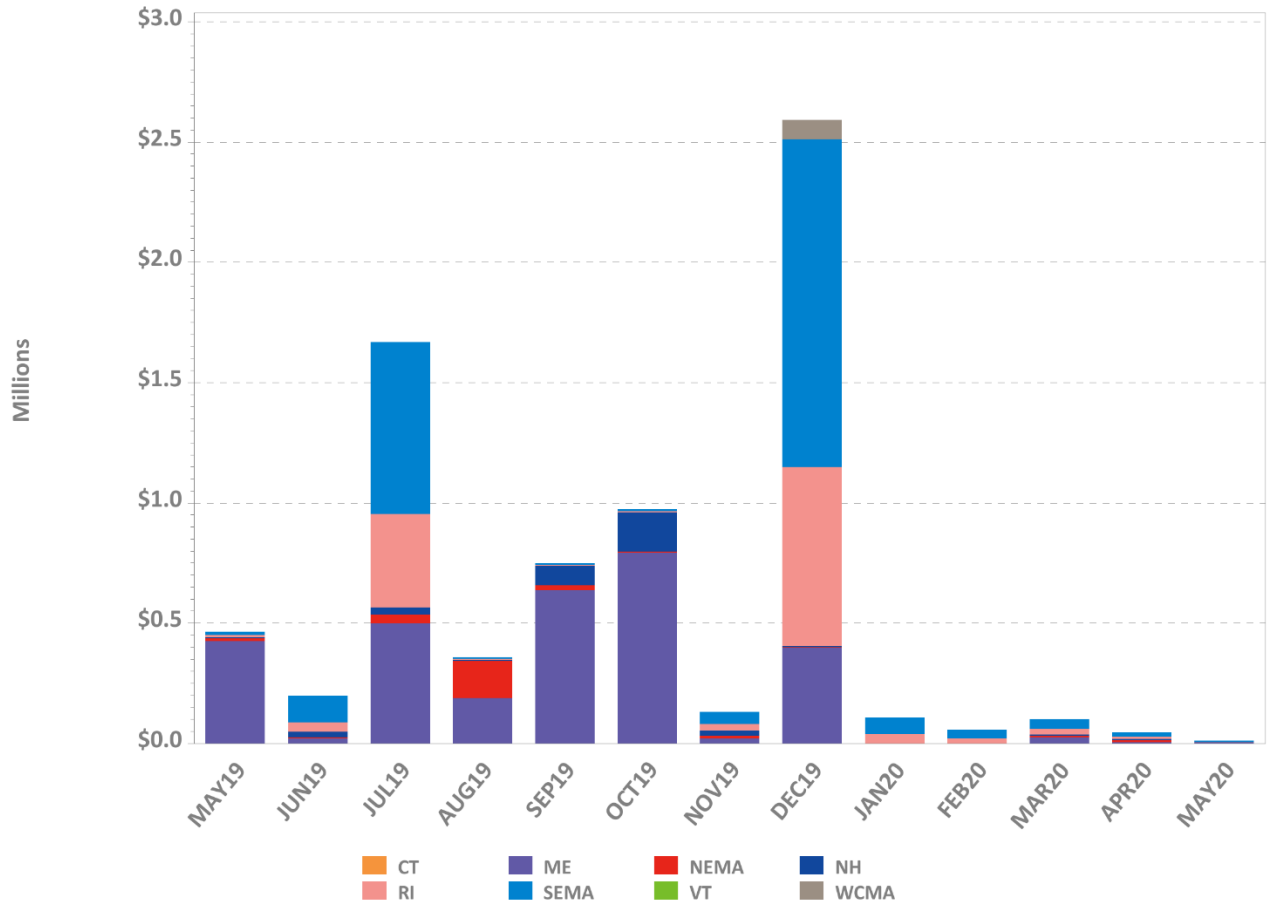
RT First Contingency Charges by Deviation Type





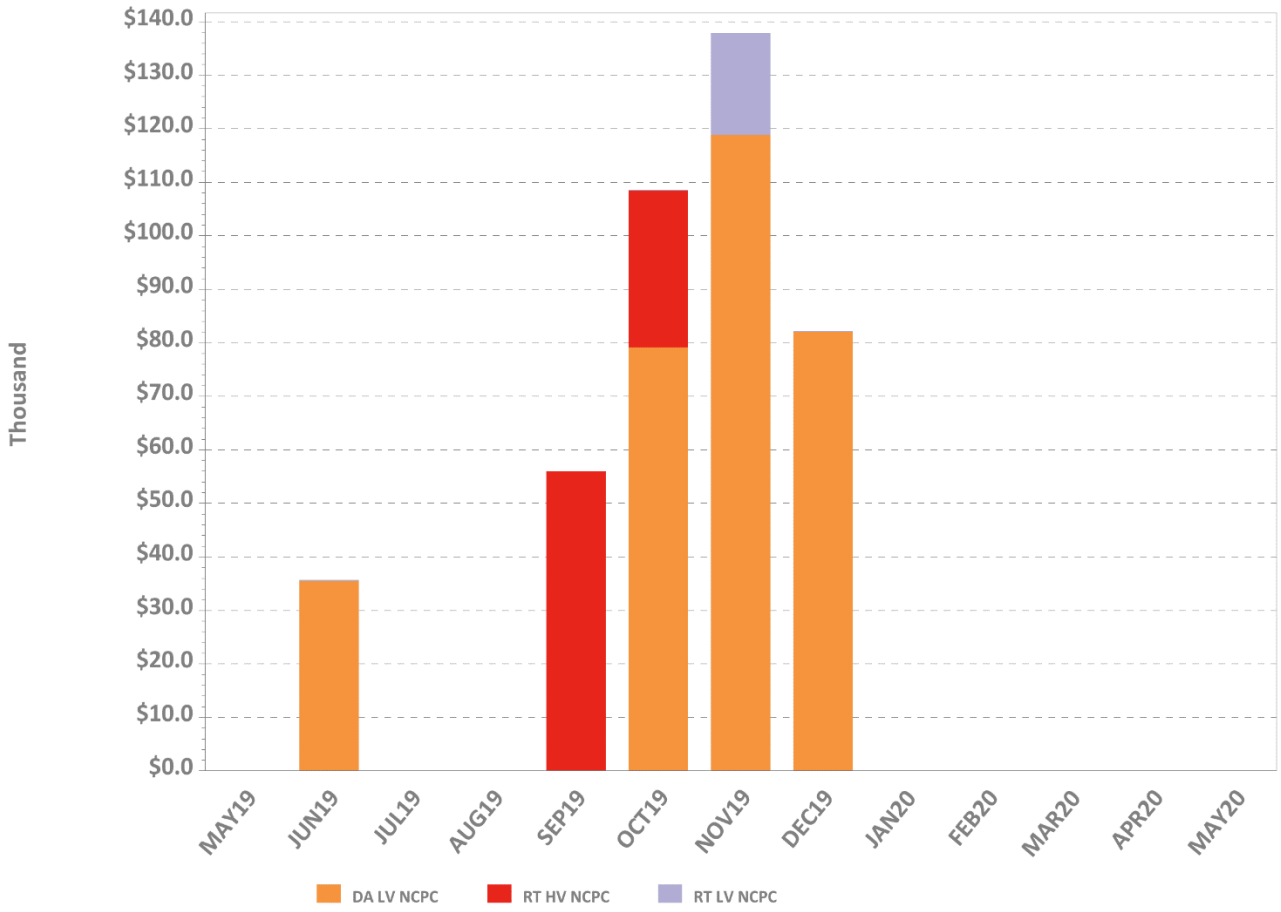
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

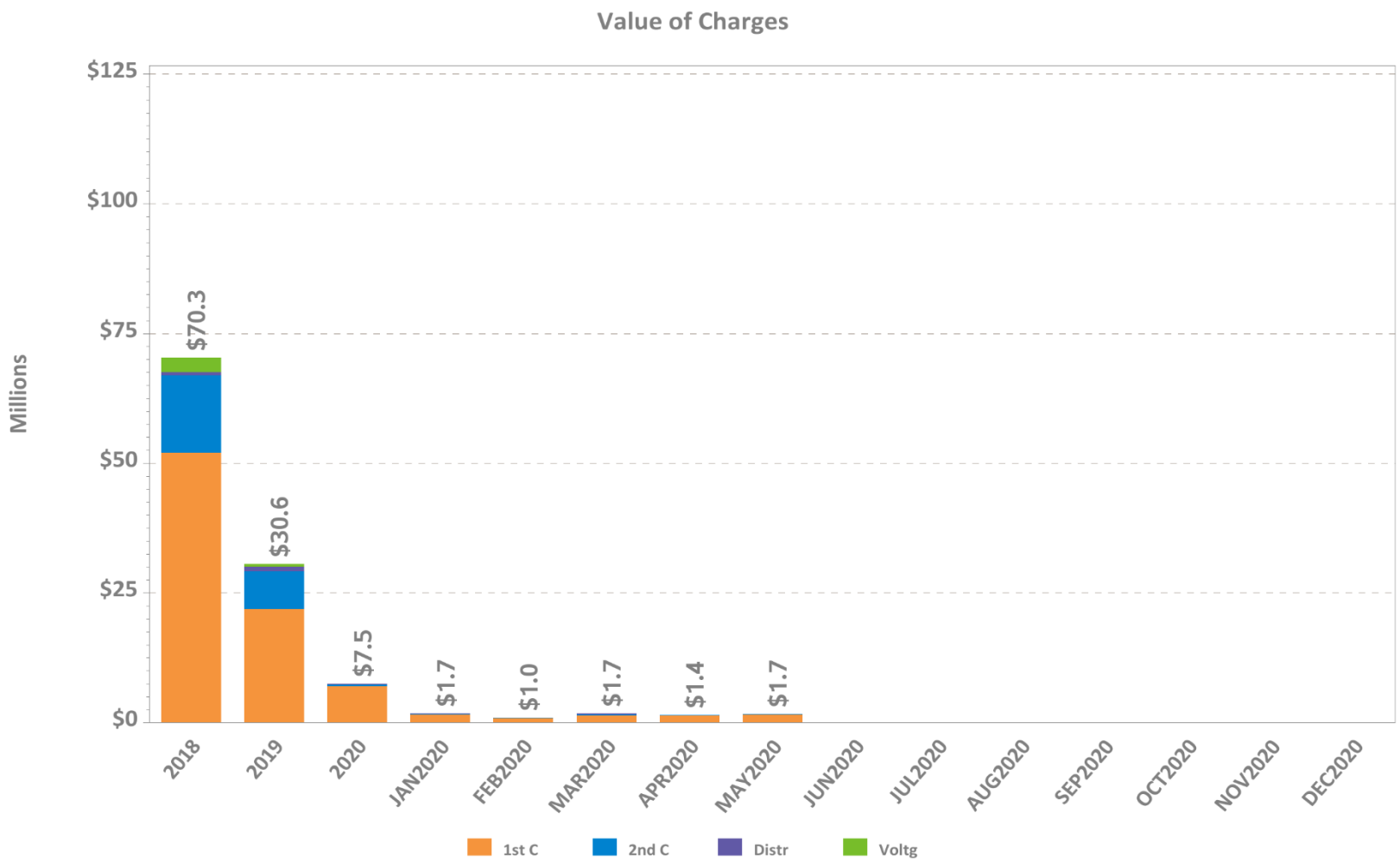


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

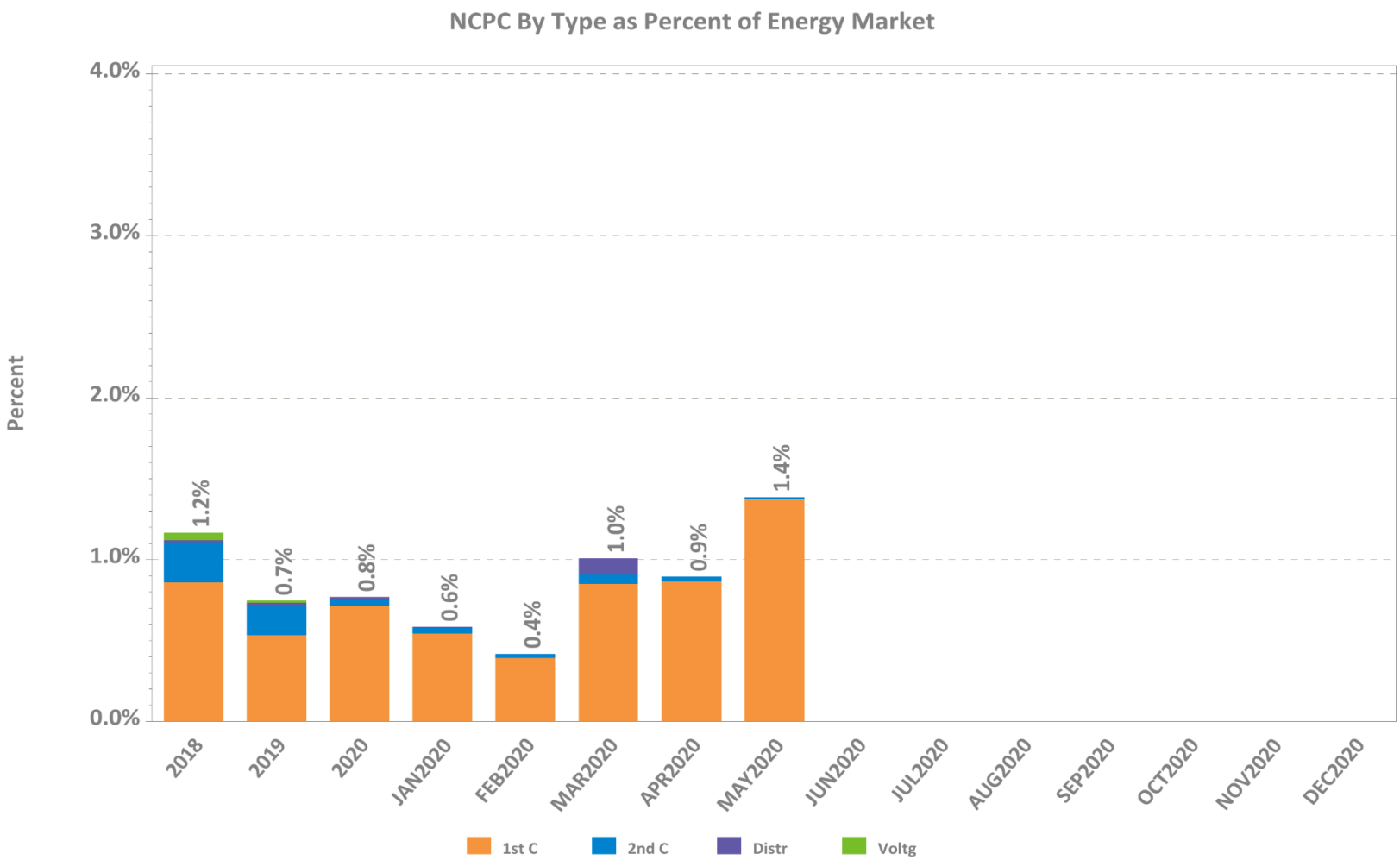
NCPC Charges for Voltage Support and High Voltage Control



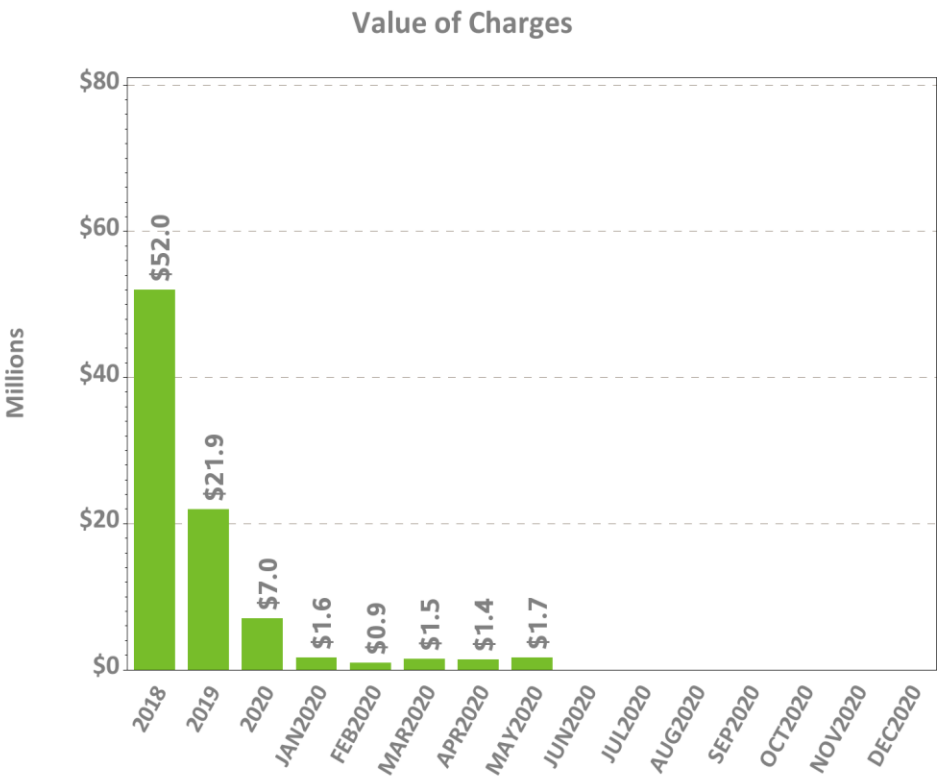
NCPC Charges by Type

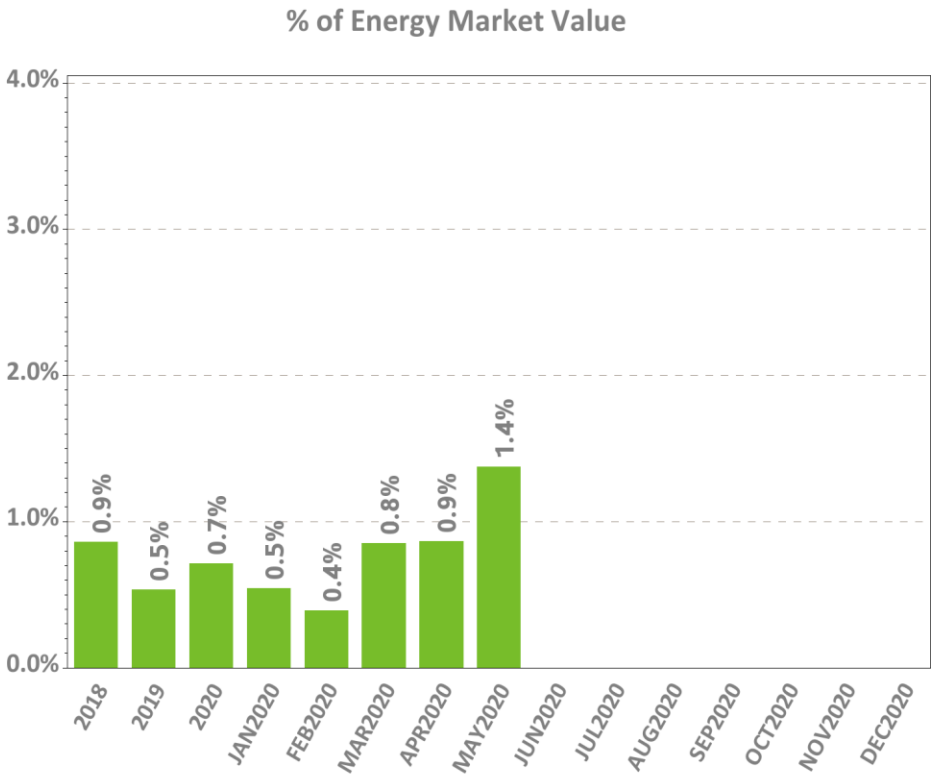


NCPC Charges as Percent of Energy Market



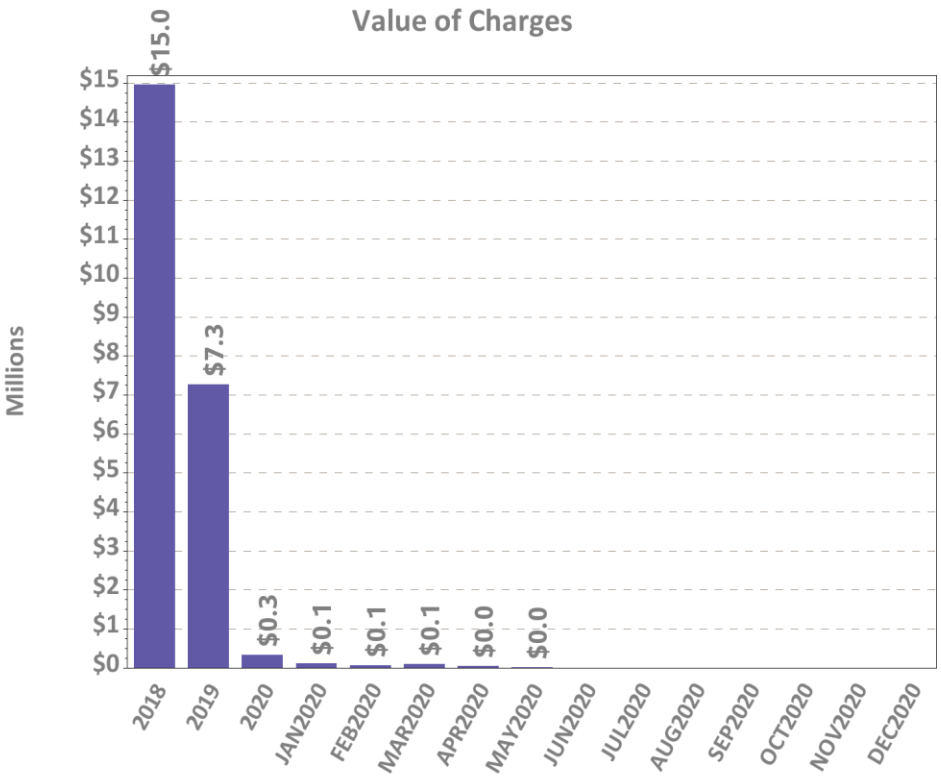
First Contingency NCPC Charges

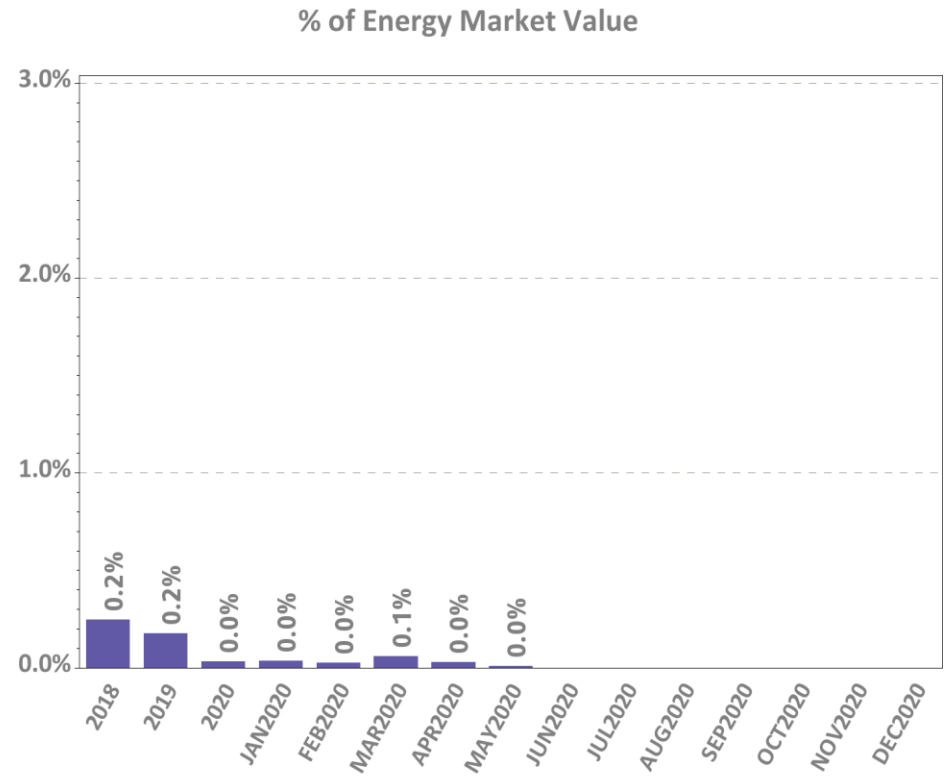




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

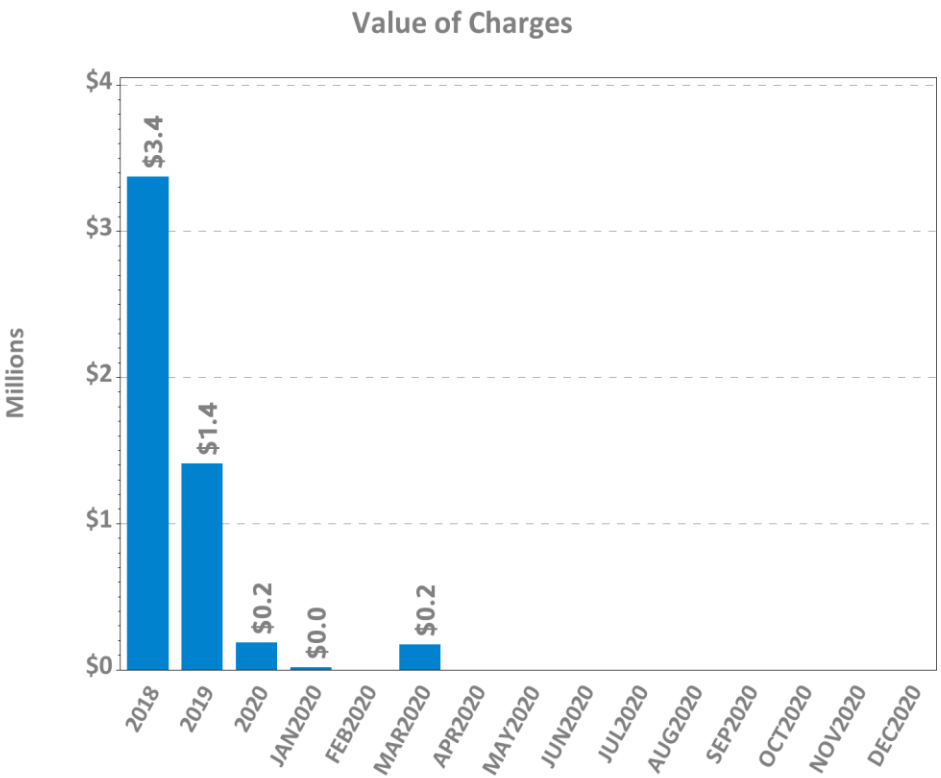
Second Contingency NCPC Charges

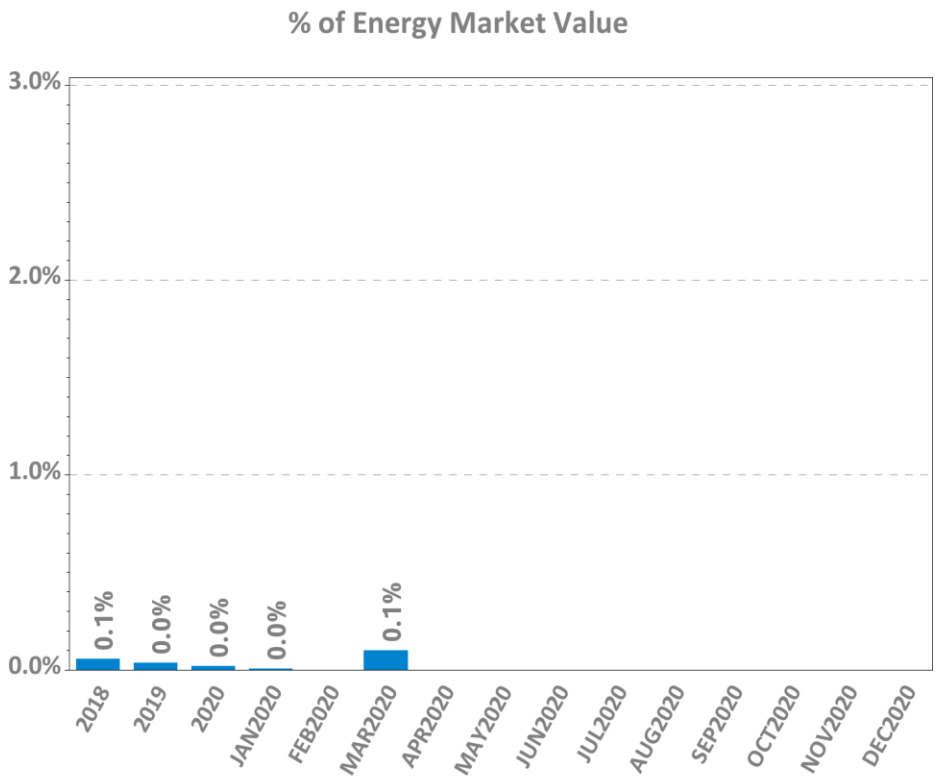




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

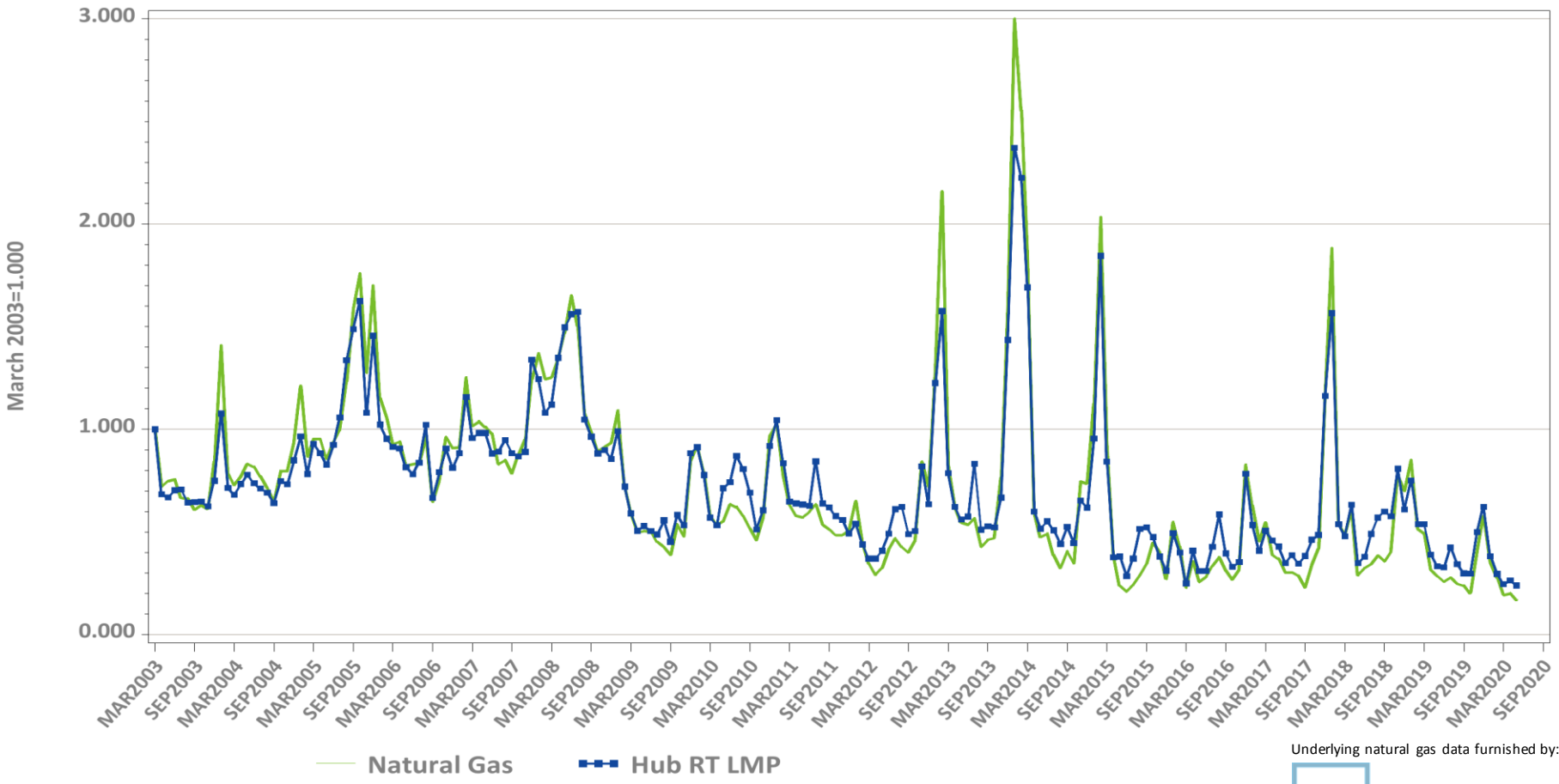
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2018	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$44.45	$43.60	$42.63	$44.04	$43.71	$44.11	$44.62	$44.19	$44.13
Real-Time	$43.87	$43.13	$41.03	$43.17	$42.83	$43.37	$43.68	$43.58	$43.54
RT Delta %	-1.3%	-1.1%	-3.8%	-2.0%	-2.0%	-1.7%	-2.1%	-1.4%	-1.3%
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%

May-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$24.43	$23.92	$23.83	$24.23	$23.65	$24.18	$24.77	$24.27	$24.21
Real-Time	$23.09	$22.76	$22.67	$22.90	$22.25	$22.75	$22.89	$22.93	$22.89
RT Delta %	-5.5%	-4.9%	-4.9%	-5.5%	-5.9%	-5.9%	-7.6%	-5.5%	-5.5%
May-20	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$16.06	$15.73	$15.20	$15.79	$15.43	$15.99	$16.19	$15.97	$16.00
Real-Time	$16.47	$16.20	$15.54	$16.23	$15.83	$16.35	$16.55	$16.36	$16.39
RT Delta %	2.5%	3.0%	2.3%	2.8%	2.6%	2.3%	2.2%	2.4%	2.4%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-34.3%	-34.2%	-36.2%	-34.9%	-34.8%	-33.9%	-34.6%	-34.2%	-33.9%
Yr over Yr RT	-28.7%	-28.8%	-31.4%	-29.1%	-28.9%	-28.1%	-27.7%	-28.6%	-28.4%

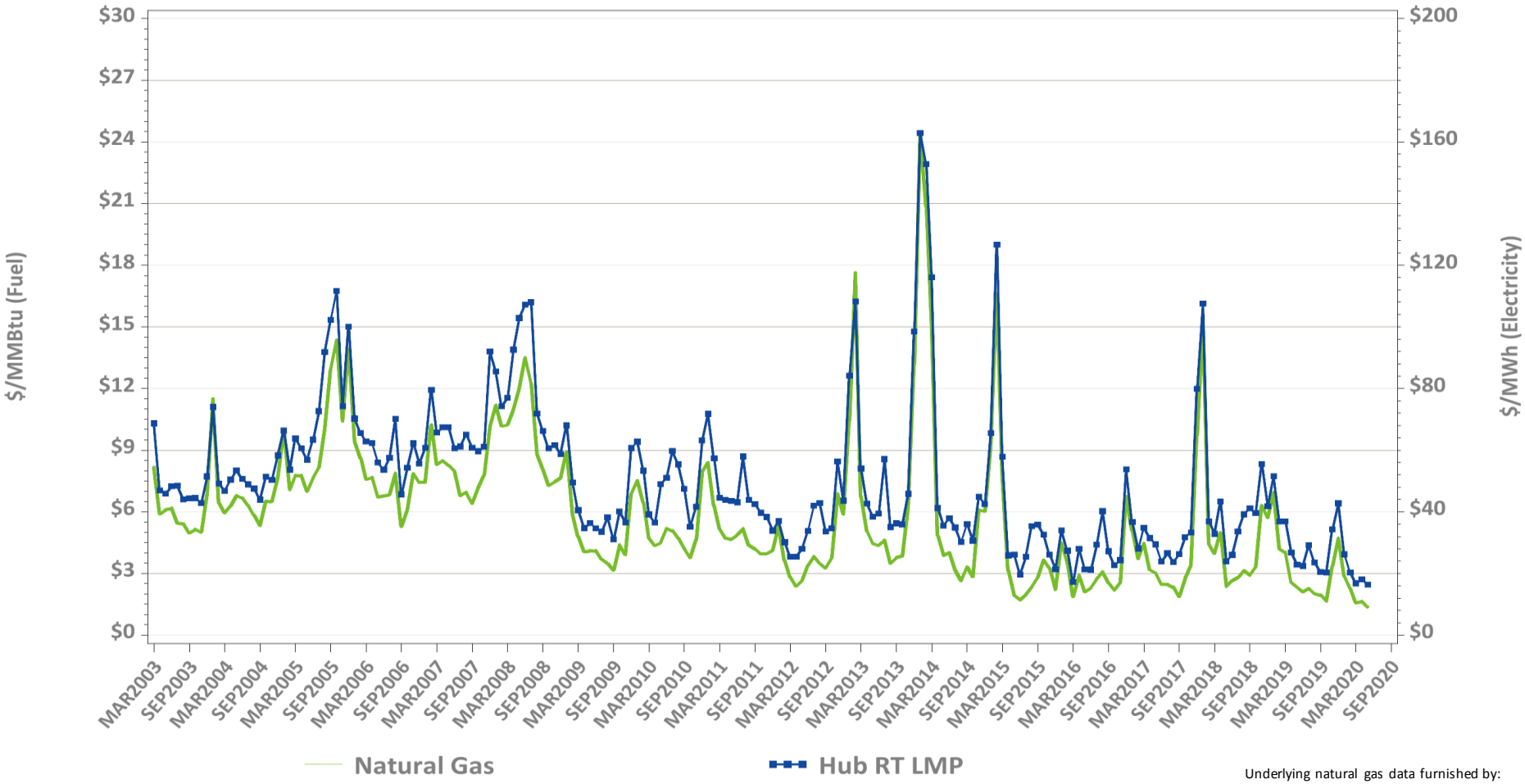
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

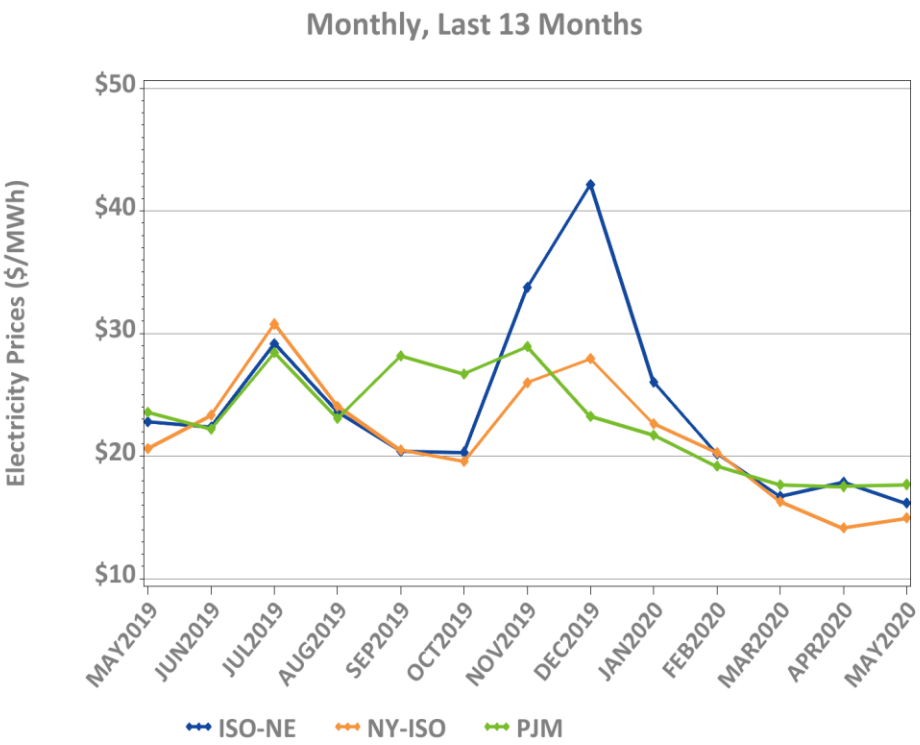
Monthly Average Fuel Price and RT Hub LMP



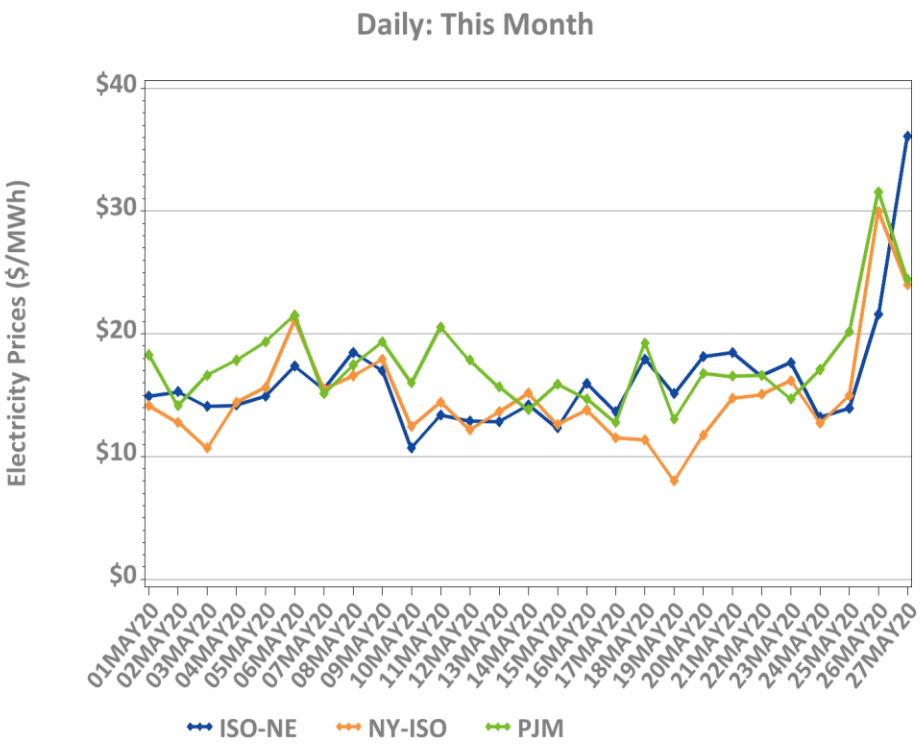
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

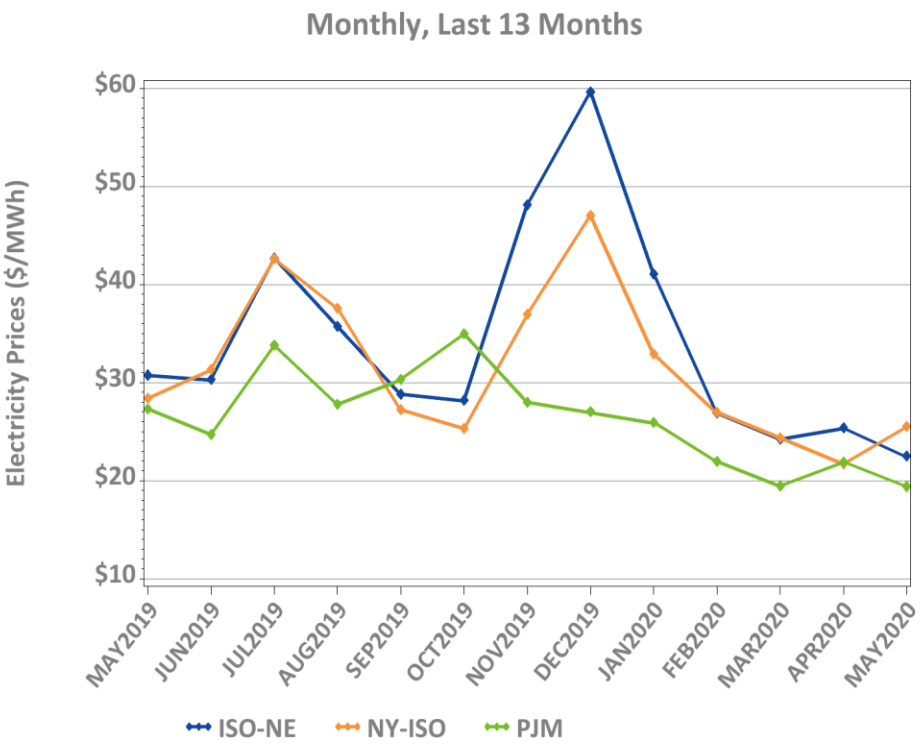


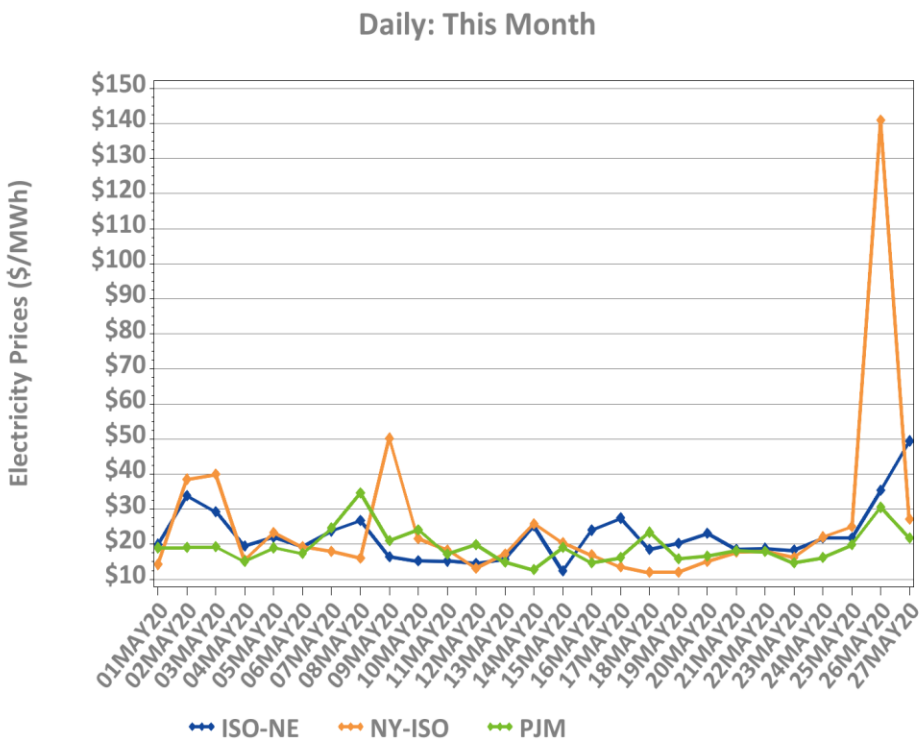
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





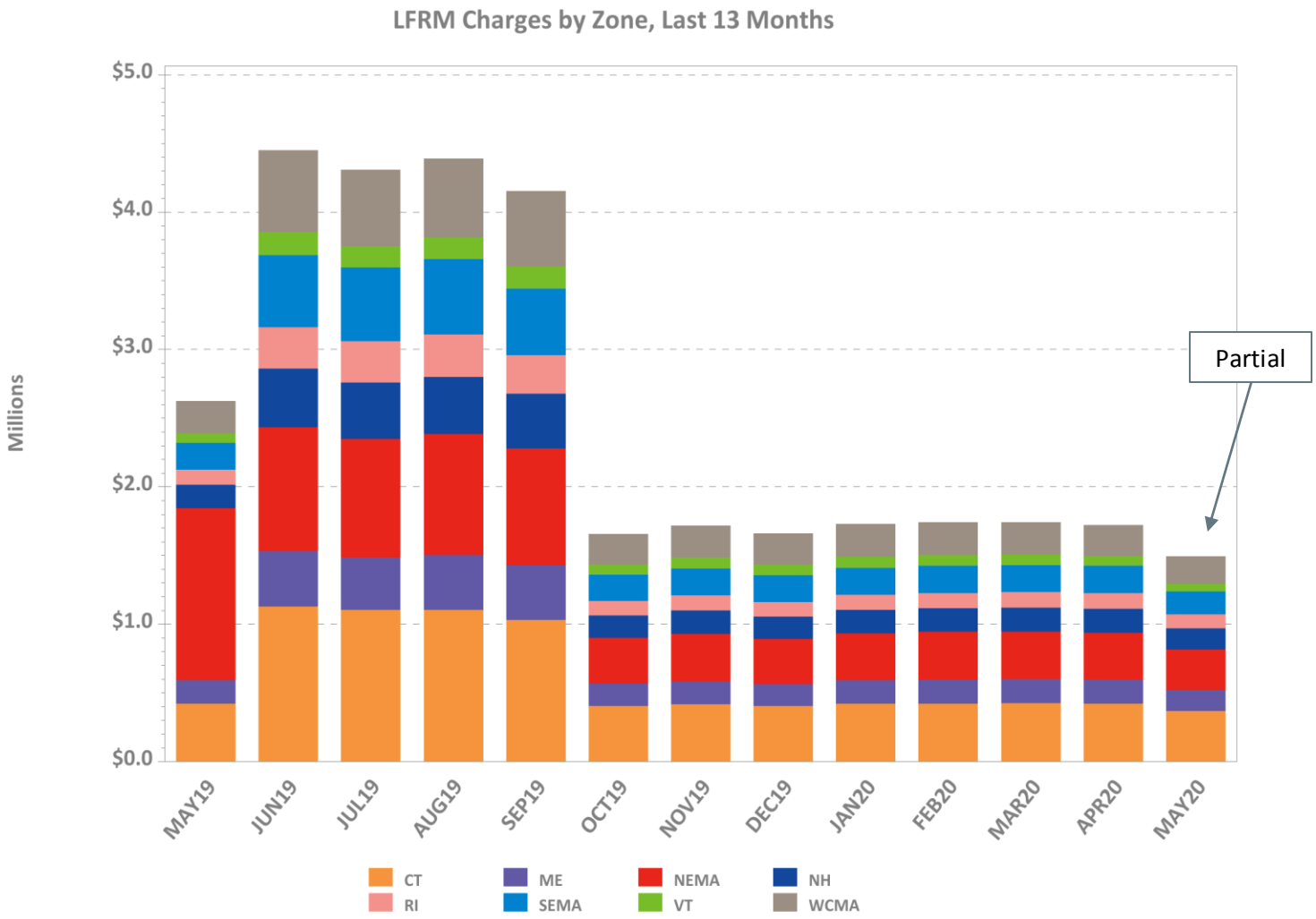
***Forecasted New England daily peak hours reflected**

Reserve Market Results – May 2020

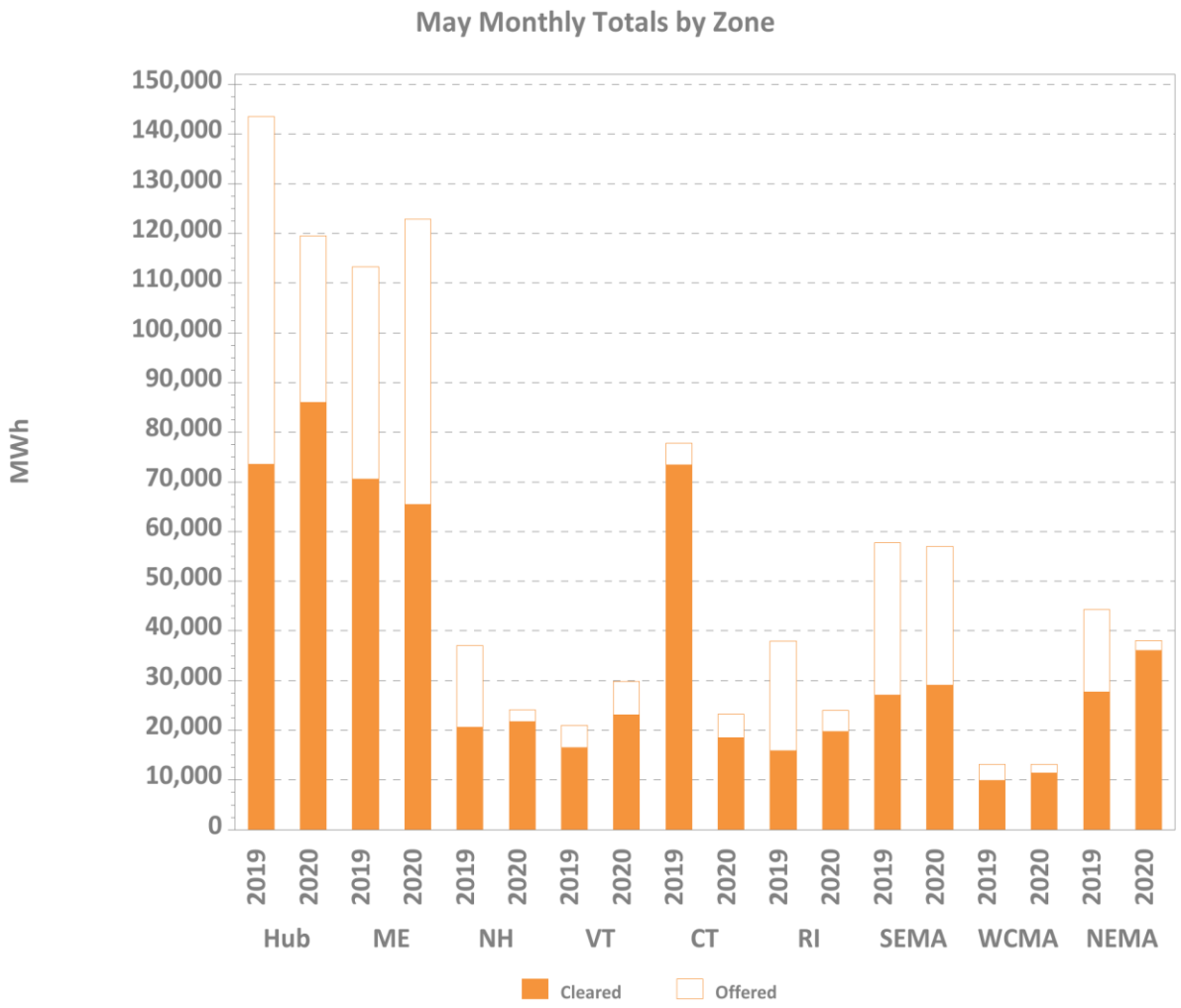
- Maximum potential Forward Reserve Market payments of $1.6M were reduced by credit reductions of $16K, failure-to-reserve penalties of $46K and failure-to-activate penalties of $20K, resulting in a net payout of $1.5M or 95% of maximum
  - Rest of System: $1.14M/1.2M (95%)
  - Southwest Connecticut: $0.05M/0.05M (92%)
  - Connecticut: $0.31M/0.33M (96%)
- $939K total Real-Time credits were reduced by $115K in Forward Reserve Energy Obligation Charges for a net of $824K in Real-Time Reserve payments
  - Rest of System: 313 hours, $516K
  - Southwest Connecticut: 313 hours, $190K
  - Connecticut: 313 hours, $89K
  - NEMA: 313 hours, $28K

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.

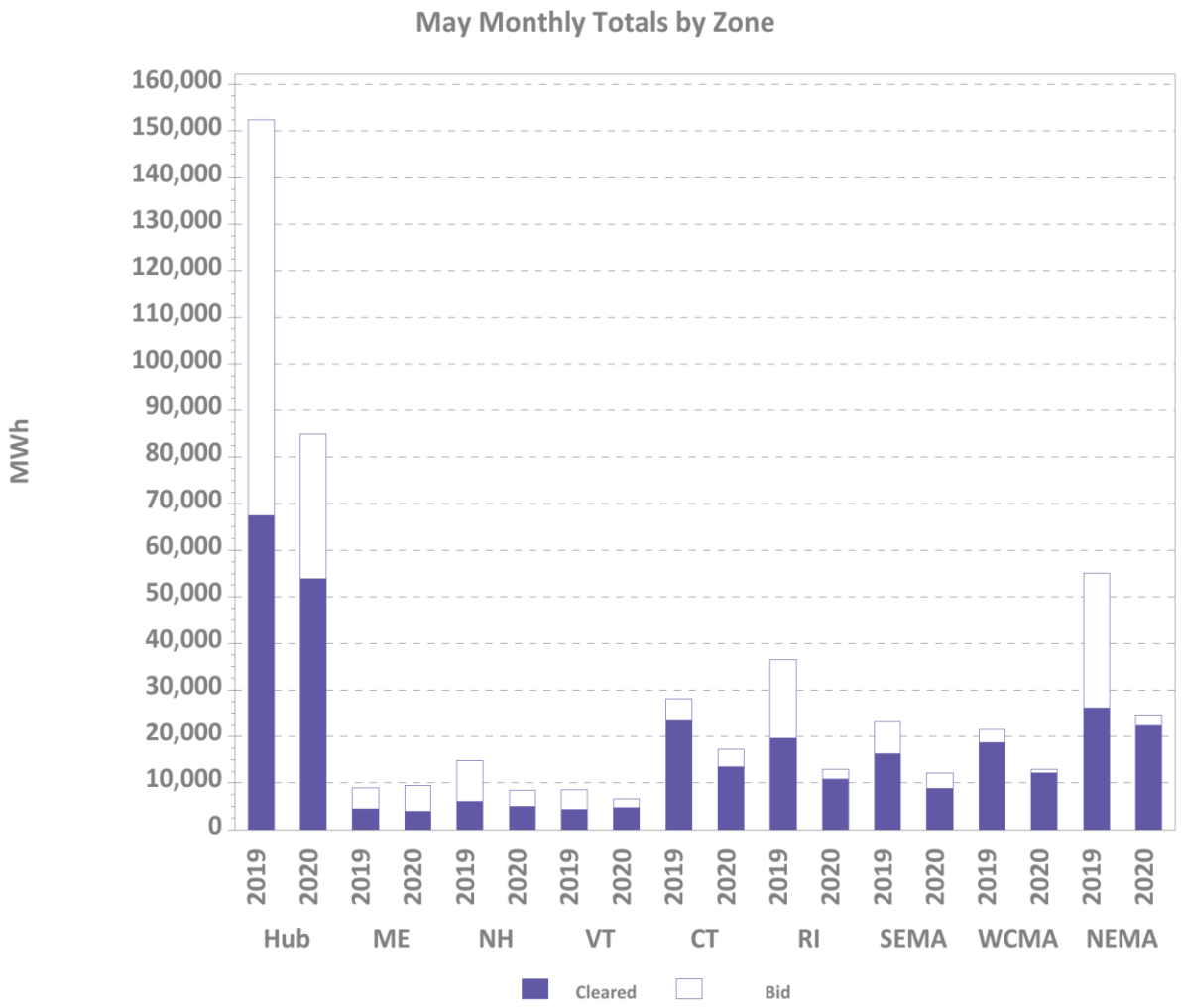
LFRM Charges to Load by Load Zone ($)



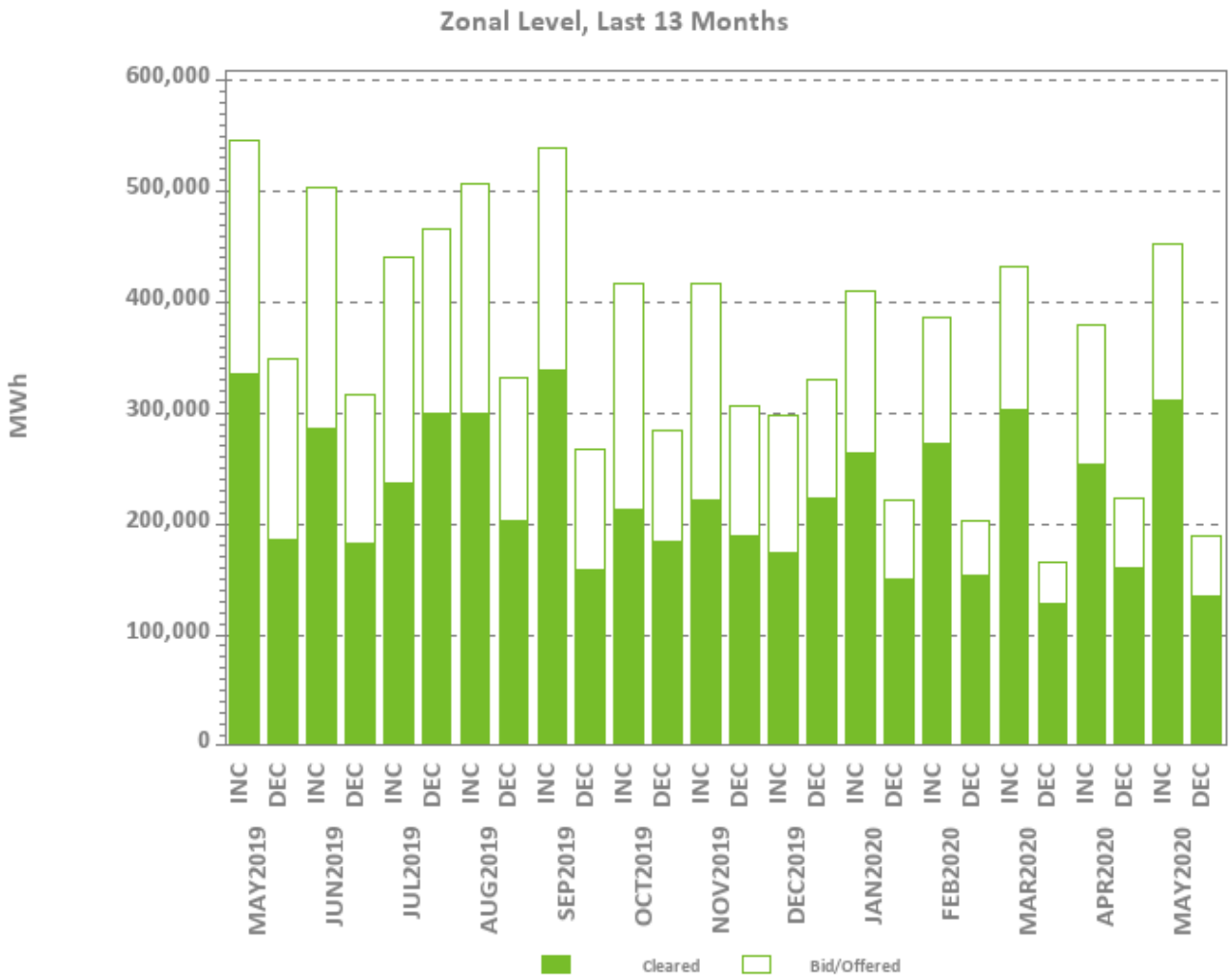
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

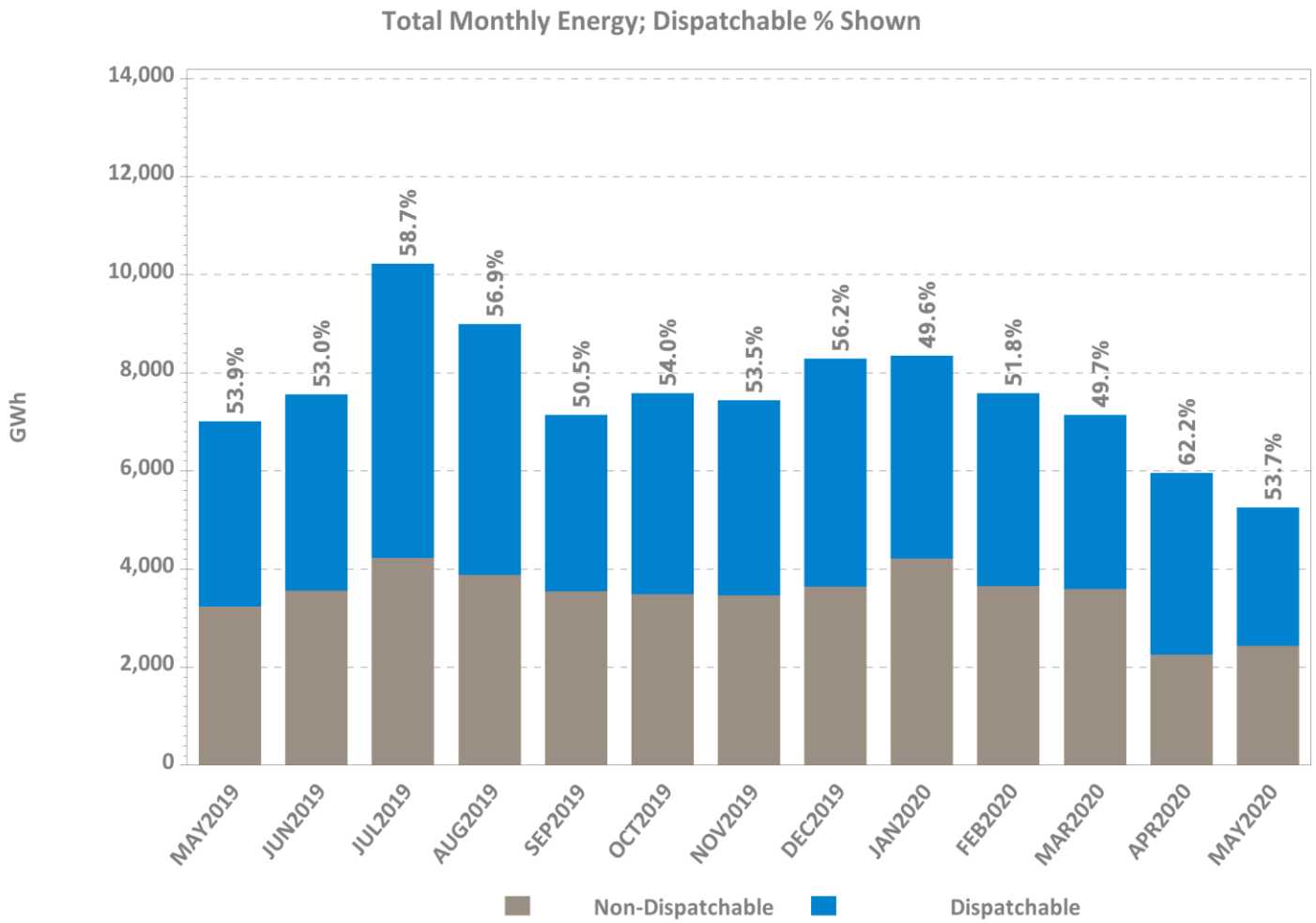


Total Increment Offers and Decrement Bids



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)

- June 17 PAC Meeting Agenda Topics*
  - Regional System Plan Transmission Projects and Asset Condition June 2020 Update
  - Representative Future Locational Reserve Needs for Current Reserve Zones
  - New Hampshire Solutions Study Alternatives
  - 2020 Public Policy Transmission Upgrade Process
  - 2020 Economic Study Update
  - 2019 Economic Study Offshore Wind Transmission Interconnection Analysis
  - Boston 2028 RFP – Review of Phase One Proposals

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

Interregional Planning

- Final 2019 Northeastern Coordinated System Plan (NCSP19) was posted on May 4
- Inter-Area Planning Stakeholder Advisory Committee (IPSAC) meeting was held on May 15 and included discussions of:
  - Regional Planning Needs and Solutions for PJM, ISO-NE, and NYISO
  - Interconnection Coordination - Interconnection Queue and Long-Term Firm Transmission Requests for NYISO, ISO-NE, and PJM
  - Review of Final NCSP19
  - Stakeholder Input and Outline Next Steps

Economic Studies

- Three 2019 study requests were received (NESCOE, Anbaric, and RENEW)
  - RENEW scenarios modeled varying degrees of increases in Orrington-South transfer limit
  - NESCOE and Anbaric scenarios modeled different transmission and resource expansion options
- Anbaric and RENEW studies are complete and efforts are now focused on report writing to be completed in July
- NESCOE ancillary services and transmission interconnection results were presented to PAC on May 20
  - In addition, as a late request, a marginal emissions analysis was also performed
  - A concise report has been requested by NESCOE, and the final report is targeted to be completed by July
- NGRID submitted a 2020 economic study request
  - Assumptions are under development and presentation was made to PAC in May, with additional presentation scheduled for June
  - Goal is to complete study work by Q4 2020 and publish the report in Q1 2021

2018 Generator Emissions Report

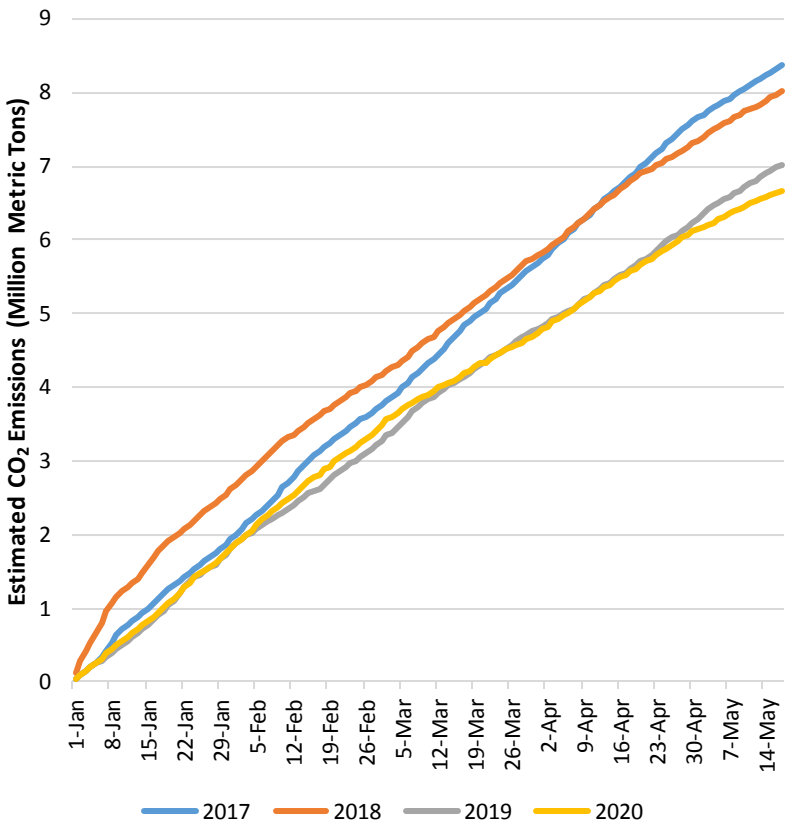
- Final 2018 ISO New England Electric Generator Air Emissions Report was posted on May 14
- At the April EAG meeting, stakeholders discussed obstacles to reporting emissions from imports, and what actions could be taken to overcome the lack of publically available information
  - Comments on the options presented by the ISO will be addressed at the next EAG meeting in June

Environmental Matters – Carbon Dioxide (CO_2) Emissions from Native Generation (1/1 - 5/17)

Air Emissions Lower, Reflect Mix of Milder Weather, COVID-19

- Estimated 2020 year-to-date CO_2 system emissions declined 5% compared to same period in 2019 (1/1 - 5/17):
  - Native emitting generation declined -4% in 2020 YTD (17,511 GWh) compared to 2019 YTD (18,159 GWh)
  - Natural gas generation increased 28%; coal (-78%) and oil (-27%) declined
- EPA issued various guidances responding to COVID-19 pandemic, temporarily waiving compliance and reporting requirements for regulated entities, including power plants for air emissions and water discharges but:
  - Limited in scope, conditional, discretionary for EPA, not binding on states, tribes, or localities, and temporary

Cumulative CO_2 System Emissions (Million Metric Tons)

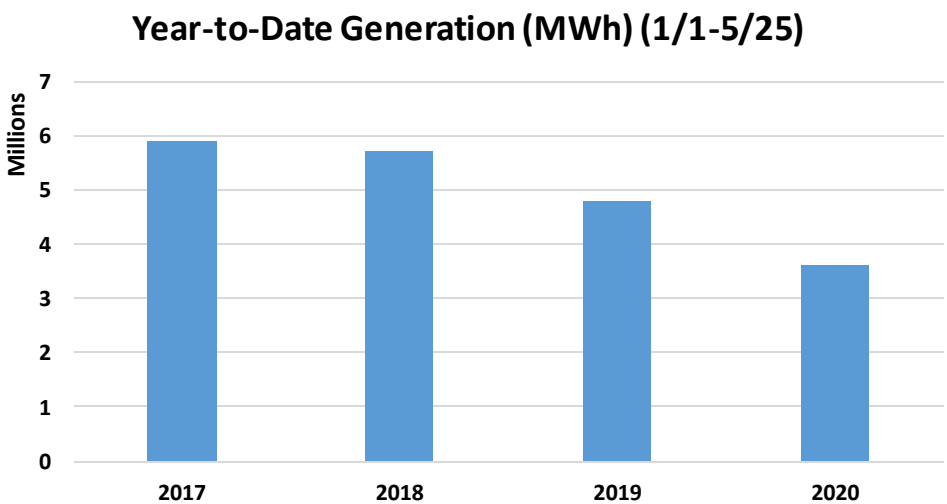


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2020 YTD Emissions Declined 25%, Generation Declined 29% vs. 2019

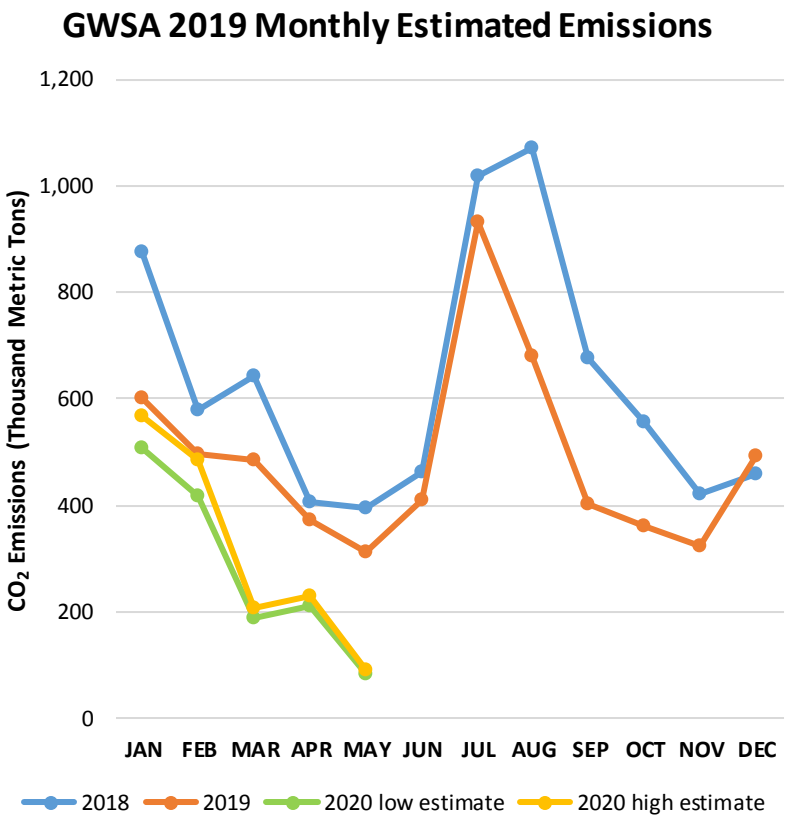
2020 CO_2 Estimated Emissions Below 2019 Trend lines

- Year-to-date generation from affected generators declined 25%, while estimated emissions declined 29% compared to same period in 2019



GWSA - Global Warming Solutions Act

2020 Estimated, Past 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.

New Hampshire/Vermont 10-Year Upgrades

Status as of 5/22/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	May-20	3
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 5/22/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Aug-16	4
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Dec-14	4
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 5/22/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Dec-14	4
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Apr-17	4
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Feb-17	4
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Jun-18	4
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Mar-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Nov-20	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Mar-20	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	4
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Nov-20	3
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	4
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-18	4
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	4
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Jun-18	4
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Mar-16	4
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Oct-18	4
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Sep-17	4
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jul-18	4
Loop the 1570 line in and out the Pootatuck substation	Jul-18	4
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-20	3
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-16	4
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-19	4
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	4

Southwest Connecticut Projects, cont.

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4
Upgrade the 115 kV bus at the Baird substation	Mar-18	4
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	4
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Jun-21	3

Southwest Connecticut Projects, cont.

Status as of 5/22/20

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Remove the Sackett phase shifter	Mar-17	4
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-16	4
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-16	4
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	4
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Nov-16	4
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 5/22/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
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*	Dec-21	3*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
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 5/22/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Oct-20	3
Install third 115 kV line from West Walpole to Holbrook	Oct-20	3
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
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
Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 5/22/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-21	3
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	Dec-20	3

Greater Boston Projects, cont.

Status as of 5/22/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-21	3
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
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 5/22/20

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

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

Pittsfield/Greenfield Projects

Status as of 5/22/20

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Mar-17	4
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Nov-17	4
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Jun-17	4
Build a new 115 kV three-breaker switching station (Erving) ring bus	Mar-17	4
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Jun-17	4
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 5/22/20

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	4
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Mar-17	4
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 5/22/20

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Jun-20	3

SEMA/RI Reliability Projects

Status as of 5/22/20

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

Project 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	Sep-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	3
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	3
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 5/22/20

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-20	3
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Dec-20	2*
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	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-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Sep-21	2*

* The ISO is reevaluating this project with updated data and assumptions.

SEMA/RI Reliability Projects, cont.

Status as of 5/22/20

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

Project 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	1
1727	Retire the Barnstable SPS	Dec-21	1
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-21	1

* The ISO is reevaluating this project with updated data and assumptions.

SEMA/RI Reliability Projects, cont.

Status as of 5/22/20

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	1
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	1
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Dec-21	1**
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	Dec-20	3

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

** The ISO is reevaluating this project with updated data and assumptions.

SEMA/RI Reliability Projects, cont.

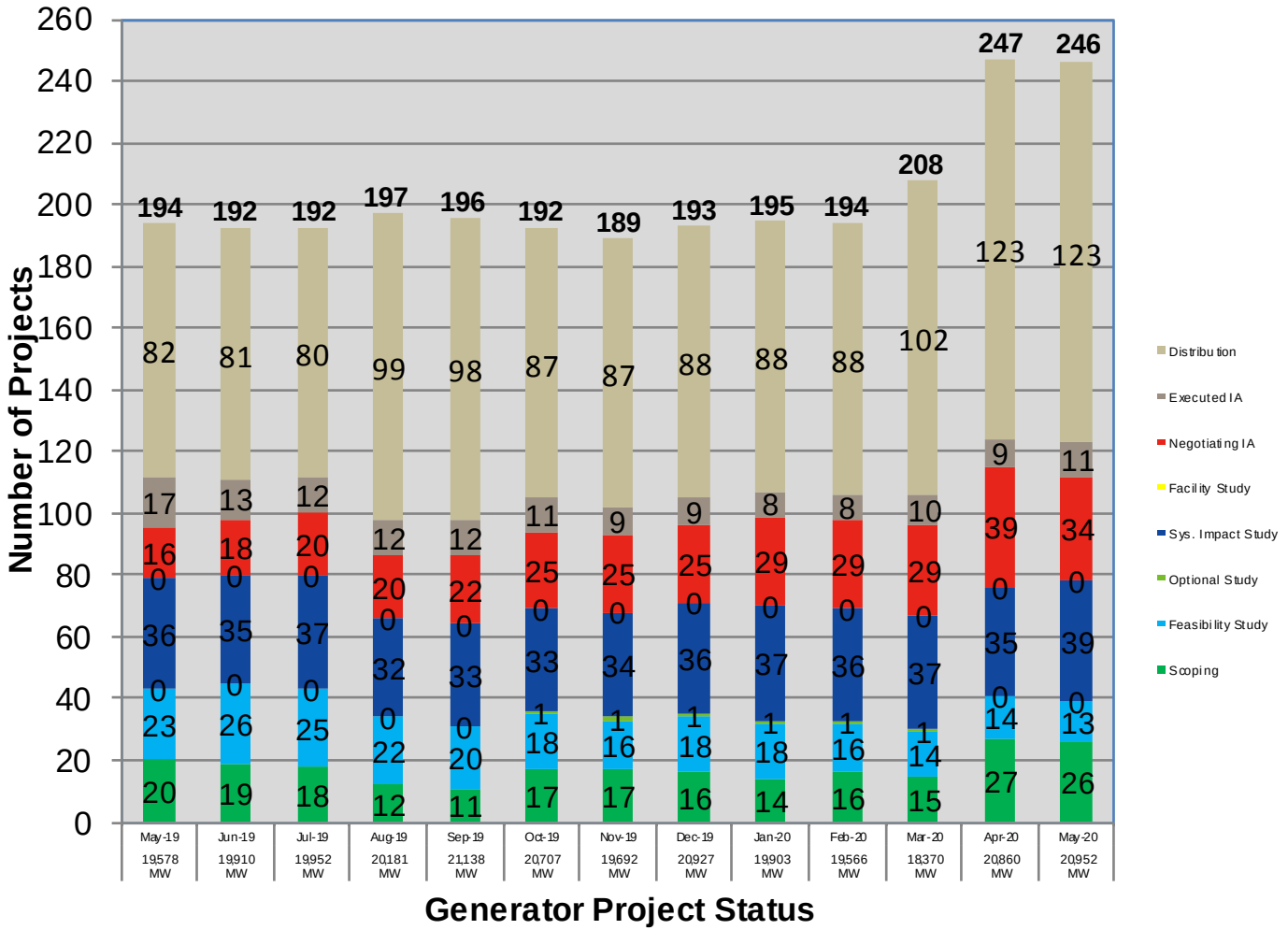
Status as of 5/22/20

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

Project 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	Dec-21	2*
1724	Replace the Kent County 345/115 kV transformer	Feb-21	2*
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	3
1790	Medway 115 kV circuit breaker replacements	Dec-21	3

* The ISO is reevaluating this project with updated data and assumptions.

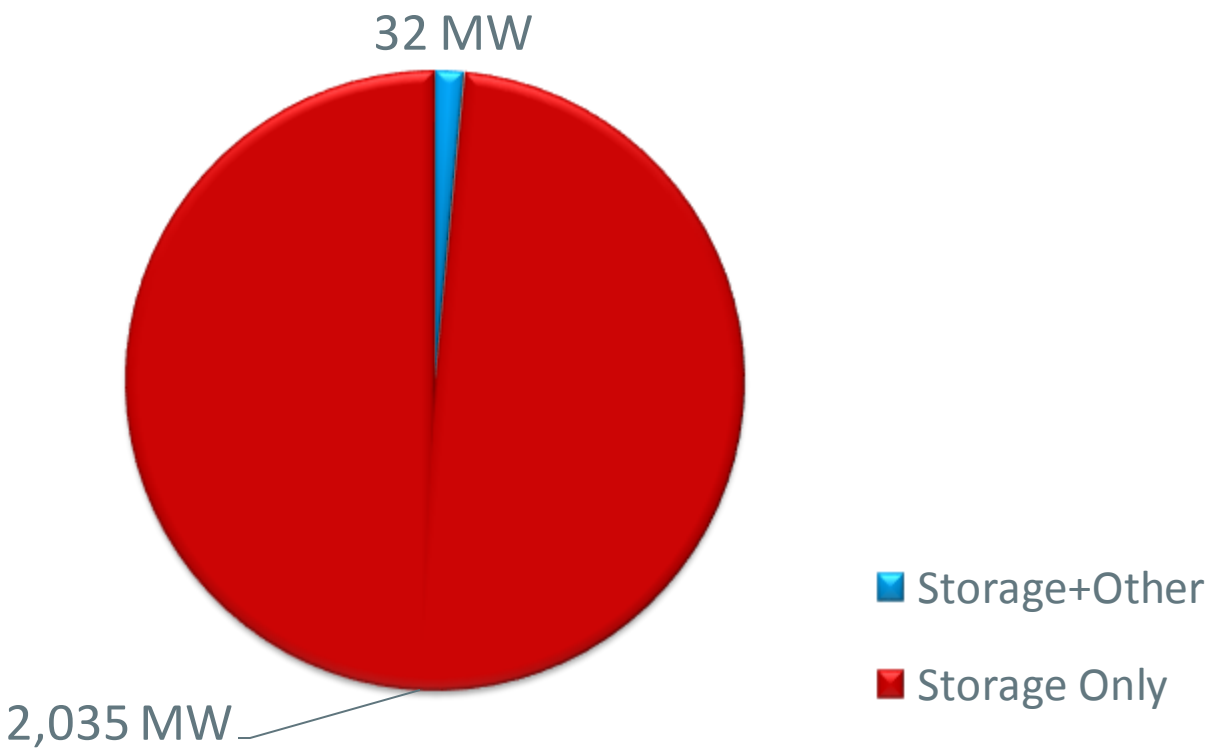
Status of Tariff Studies



Note: May 2020 is based on partial data.
As of May 2020, there are 4 ETU's in Scoping, 4 in FS, 4 in SIS, 0 in FAC, 0 Negotiating IA, and 1 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of May 27, 2020)

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



OPERABLE CAPACITY ANALYSIS

Summer 2020 Analysis

Summer 2020 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2020[2] CSO (MW)	June - 2020[2] SCC (MW)
Operable Capacity MW [1]	29,897	31,079
Active Demand Capacity Resource (+) [5]	366	452
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,101	1,101
Non Commercial Capacity (+)	5	5
Non Gas-fired Planned Outage MW (-)	1,196	1,234
Gas Generator Outages MW (-)	719	723
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,654	27,880
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,125	25,125
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,430	27,430
Operable Capacity Margin	-776	450

[1] Operable Capacity is based on data as of **May 25, 2020** 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 **May 25, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 6, 2020.**

[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.

Summer 2020 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	June - 2020[2] CSO (MW)	June - 2020[2] SCC (MW)
Operable Capacity MW [1]	29,897	31,079
Active Demand Capacity Resource (+) [5]	366	452
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,101	1,101
Non Commercial Capacity (+)	5	5
Non Gas-fired Planned Outage MW (-)	1,196	1,234
Gas Generator Outages MW (-)	719	723
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,654	27,880
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	27,084	27,084
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,389	29,389
Operable Capacity Margin	-2,735	-1,509

[1] Operable Capacity is based on data as of **May 25, 2020** 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 **May 25, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 6, 2020.**

[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.

Summer 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

May 29, 2020 - 50-50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
6/6/2020	**29897**	**366**	**1101**	**5**	**1196**	**719**	**2800**	**0**	**26654**	**25125**	**2305**	**27430**	**-776**
6/13/2020	29897	366	1101	5	738	479	2800	0	27352	25125	2305	27430	-78
6/20/2020	29897	366	1101	5	93	0	2800	0	28476	25125	2305	27430	1046
6/27/2020	29897	366	1101	5	40	0	2800	0	28529	25125	2305	27430	1099
7/4/2020	30156	537	1025	7	652	0	2100	0	28973	25125	2305	27430	1543
7/11/2020	30156	537	1025	7	445	0	2100	0	29180	25125	2305	27430	1750
7/18/2020	30156	537	1025	7	274	0	2100	0	29351	25125	2305	27430	1921
7/25/2020	30156	537	1025	7	310	0	2100	0	29315	25125	2305	27430	1885
8/1/2020	30156	537	1025	7	354	0	2100	0	29271	25125	2305	27430	1841
8/8/2020	30156	537	1025	7	899	0	2100	0	28726	25125	2305	27430	1296
8/15/2020	30156	537	1025	7	912	0	2100	0	28713	25125	2305	27430	1283
8/22/2020	30156	537	1025	7	357	0	2100	0	29268	25125	2305	27430	1838
8/29/2020	30156	537	1025	7	461	0	2100	0	29164	25125	2305	27430	1734
9/5/2020	30156	537	1025	7	1049	0	2100	0	28576	25125	2305	27430	1146
9/12/2020	30156	537	584	7	2438	66	2100	0	26680	25125	2305	27430	-750

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Summer 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

May 29, 2020 - 90-10 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
6/6/2020	**29897**	**366**	**1101**	**5**	**1196**	**719**	**2800**	**0**	**26654**	**27084**	**2305**	**29389**	**-2735**
6/13/2020	29897	366	1101	5	738	479	2800	0	27352	27084	2305	29389	-2037
6/20/2020	29897	366	1101	5	93	0	2800	0	28476	27084	2305	29389	-913
6/27/2020	29897	366	1101	5	40	0	2800	0	28529	27084	2305	29389	-860
7/4/2020	30156	537	1025	7	652	0	2100	0	28973	27084	2305	29389	-416
7/11/2020	30156	537	1025	7	445	0	2100	0	29180	27084	2305	29389	-209
7/18/2020	30156	537	1025	7	274	0	2100	0	29351	27084	2305	29389	-38
7/25/2020	30156	537	1025	7	310	0	2100	0	29315	27084	2305	29389	-74
8/1/2020	30156	537	1025	7	354	0	2100	0	29271	27084	2305	29389	-118
8/8/2020	30156	537	1025	7	899	0	2100	0	28726	27084	2305	29389	-663
8/15/2020	30156	537	1025	7	912	0	2100	0	28713	27084	2305	29389	-676
8/22/2020	30156	537	1025	7	357	0	2100	0	29268	27084	2305	29389	-121
8/29/2020	30156	537	1025	7	461	0	2100	0	29164	27084	2305	29389	-225
9/5/2020	30156	537	1025	7	1049	0	2100	0	28576	27084	2305	29389	-813
9/12/2020	30156	537	584	7	2438	66	2100	0	26680	27084	2305	29389	-2709

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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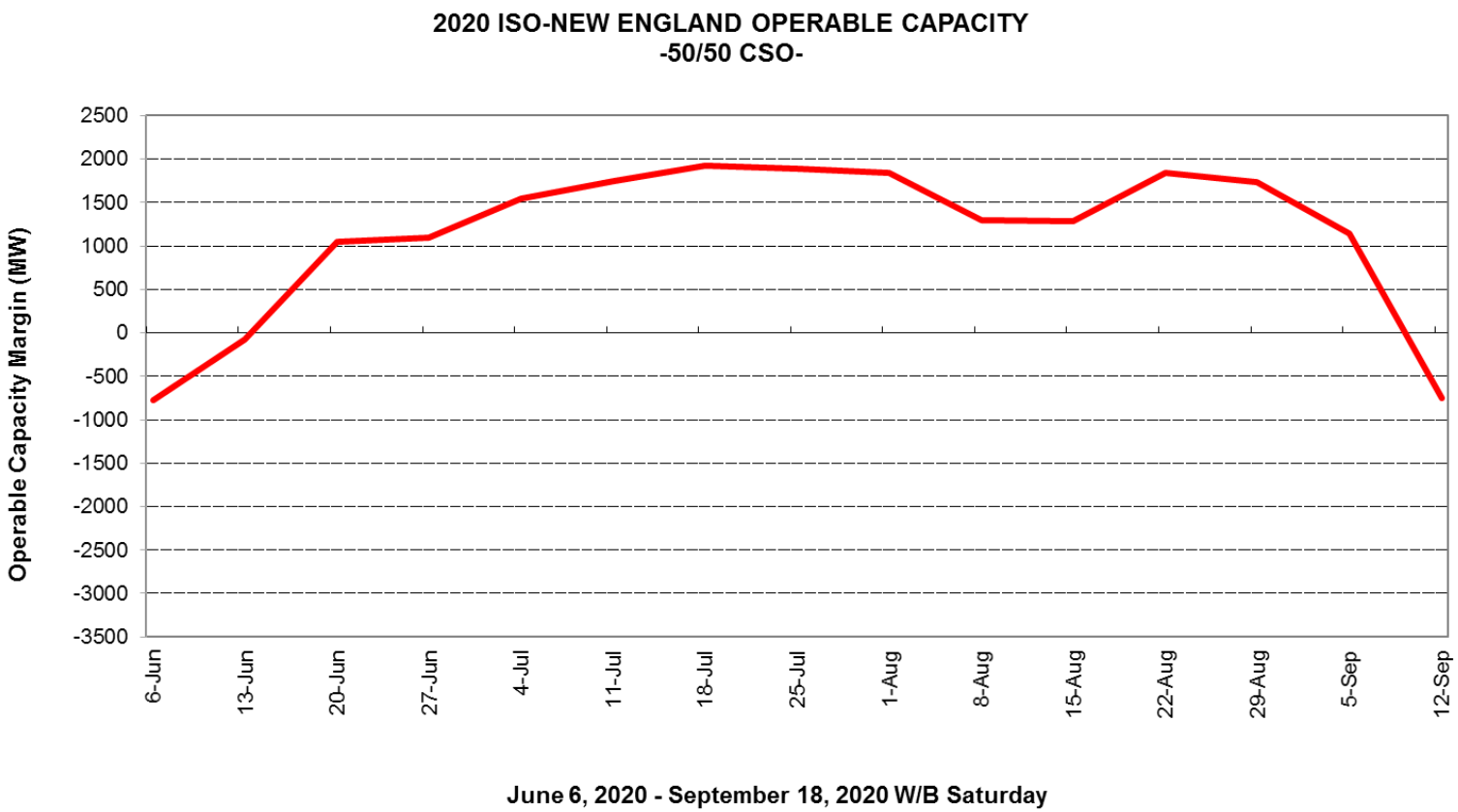
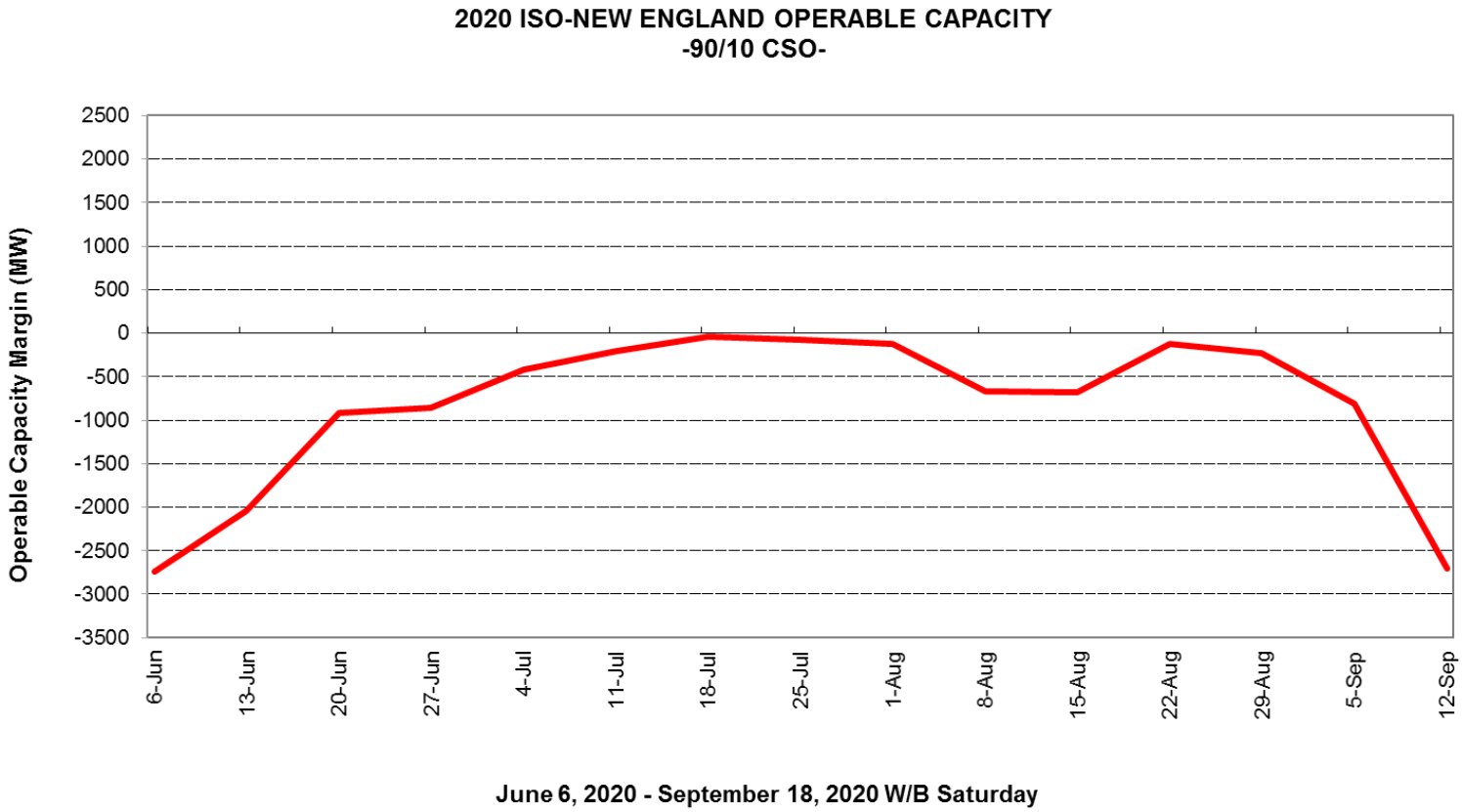
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

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

Summer 2020 Operable Capacity Analysis
50/50 Forecast (Reference)



Summer 2020 Operable Capacity Analysis
90/10 Forecast (Extreme)



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

JUNE 4, 2020

ISO New England 2021 and 2022 Preliminary Operating and Capital Budgets

NEPOOL Participants Committee Meeting

Robert Ludlow

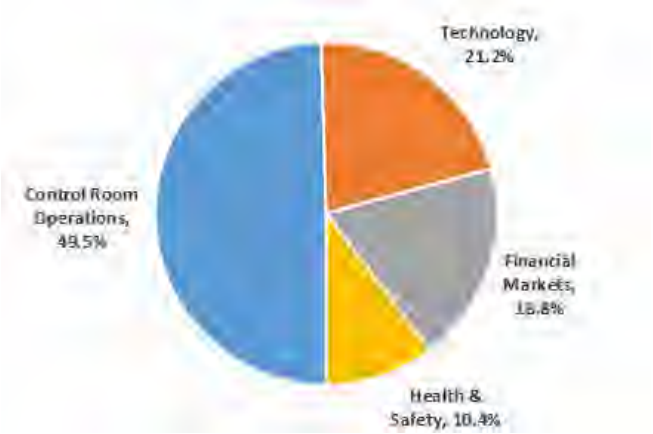
VP, CHIEF FINANCIAL & COMPLIANCE OFFICER

Contents of Presentation

OVERVIEW OF ECONOMIC IMPACT ON 2020 OPERATING BUDGET AND 2021 PRELIMINARY OPERATING BUDGET

Economic Environment - Update on COVID-19 Impact on 2020 Operating Budget

- In January 2020, ISO updated and activated its Pandemic Response Plan
- ISO has continued to monitor the progression of COVID-19 through the various state, local and federal channels, while working with them and responding accordingly
- The financial impact of COVID-19 to the 2020 budget is forecast to be a net effect of a savings; committed COVID-19 spending totals $730k with current projected possible risks of an additional $300k
- The financial risks are broken down into in four major categories:
  - Sustaining control room operations
  - Technology – to support remote work
  - Financial Markets – impact on interest rates
  - Overall health, safety and environmental costs



Economic Environment - Update on COVID-19 Impact on 2020 Operating Budget, *(cont.)*

- Offsetting the increased costs related to COVID-19, are planned costs that will not be incurred in 2020, estimated to be $800k
  - These savings are primarily derived from suspended travel and training and the limited hiring of interns in 2020
- ISO Tariff collections for the period of January 2020 through April 2020 were lower by 5.7% or $3.6M, reflecting the decreased load in the region, which is estimated to be 3-5% lower due to COVID-19
- Partially offsetting the lower load collections, is projected lower spending as a result of other factors (not directly related to COVID -19), including in the areas of: salaries and benefits, network operations and computer services
- The ISO's working capital line is expected to be sufficient to cover the net under funding created by the projected undercollection of ISO Tariff revenues
- The ISO will continue to update stakeholders through the regular stakeholder meetings

Economic Environment - Impact on 2021 Operating Budget

- The country and world economies are facing huge uncertainties related to COVID-19
- The budget ultimately filed by the ISO will be responsive to the resulting economic environment, which is quite uncertain at this point
- The projection included in this presentation reflects best estimates of costs and activities at this time and the ISO is continuing to perform analyses on the various costs/work/studies that are currently contemplated in the 2021 Operating Budget
- The ISO's approach to the preliminary 2021 Operating Budget is to be mindful of what many other industries and states will be facing in 2021 and we anticipate a slow economic recovery; the ISO will continue to monitor the environment and review our current and proposed budgets for savings opportunities

Economic Environment - Impact on 2021 Operating Budget *(cont.)*

- In advance of the detailed proposed budgets being presented in August for stakeholder review, and keeping in mind the economic damage experienced in the country as a result of the shut-down, the following examples are areas being considered for reductions:
  - Salaries and benefits will be adjusted as the financial situation continues to unfold; merit and promotional (M&P) increases will be based on survey data for 2021 which should reflect the impact of the economic downturn; numbers for merit and promotional increases used in this presentation are **placeholders**; the preliminary budget currently includes an amount of 3.5% combined M&P, which we believe is at the high end of the range; we anticipate reducing this number, but need to wait for the survey data which will only be available in the Fall; as a reference, every 1% reduction in the budgeted amount would translate to a savings of a little under $1 Million
  - Insurance levels/programs are being re-evaluated to ensure proper coverage at reasonable rates
  - Although we will do our best to maintain momentum on the various activities that are underway, we recognize that budget reductions may also be made by deferring 2021 work plan activities, where possible, and particularly those that require expenditures in the areas of professional fees
- In sum, all sections of the budget will be analyzed and a revised proposed 2021 Operating Budget with associated deferred work or reductions will be presented in August

2021 AND 2022 PRELIMINARY BUDGET OVERVIEW

2021 and 2022 Preliminary Budget Overview

- The following presentation provides high-level information regarding ISO-NE's projected 2021 and 2022 Operating Budgets
- In addition to compensation and other inflationary costs, the primary activities driving year-over-year changes for 2021 are:
  - Energy Security Initiative (ESI)
  - Renewable Resources/Emerging Technologies (wind, photovoltaic, energy storage) impacting Market Monitoring and System Planning
  - We anticipate that the "Future of the Grid/Market" discussions will continue in 2021 and we are assuming we can support this activity with internal resources
  - Increases in Computer Services; and Cyber Security and NERC CIP Compliance, including additional consultant resources, costs for new and enhanced products, and for data archiving
  - Insurance costs as a result of market rate increases
  - Efficiencies and Reductions (e.g., one-time studies, non-recurring costs)

2021 and 2022 Preliminary Budget Overview, *(cont.)*

- Competitive transmission solution (FERC Order 1000) and the Operating budgets:
  - Allocated funding to FERC Order 1000 will only be used for this purpose with any underutilization of funds being returned in a subsequent budget
  - Status of FERC Order 1000 projected spending for 2020 and 2021:
    - In 2020, the ISO budgeted $1.3M for Order 1000 activities; projected spending against this budget is $800K, leaving a $500K underrun
    - For 2021, projected spending is $700K less 2020 underrun leaving $200K to be recovered in rates; similarly any underrun will be returned in a subsequent budget

2021 and 2022 Preliminary Budget Overview, *(cont.)*

2022 Budget Highlights

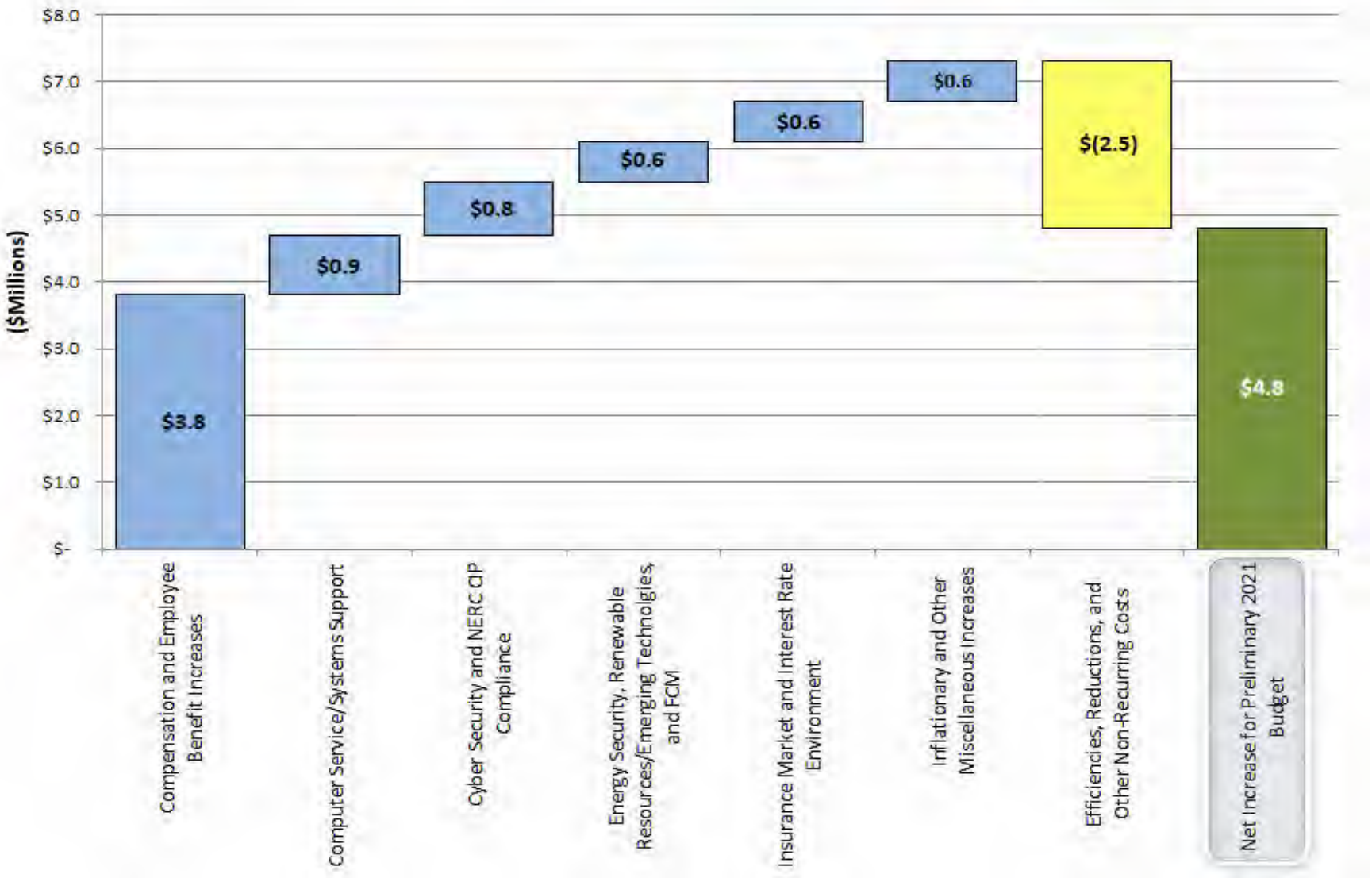
- The current economic environment is in an unprecedented state of uncertainty and slow-down but at this time, ISO-NE does not envision any step changes to the organizational functions in 2022
- The 2022 Operating Budget contemplates standard inflationary increases in the areas of:
  - Compensation, medical, and defined contribution pension plan increases (Compensation increase is a placeholder at the moment; this will be updated based on industry survey data and will be reviewed/approved by the Board C&HR Committee)
  - Computer Services & Network Operations
  - On-going support/inflationary increases
  - Efficiencies and reductions

2021 and 2022 Preliminary Budget Overview, *(cont.)*

- In summary, the 2021 and 2022 budgets' year-over-year increases before depreciation are projected to be $4,757,800 or 2.7% and $6,330,600 or 3.5%, respectively
  - 2021 changes with and without Order 1000 implementation are as follows:
    - Excluding FERC Order 1000, and before depreciation, the budget is $5.9M or 3.4% above 2020
    - Including FERC Order 1000, and before depreciation, the budget is $4.8M or 2.7% above 2020 (due to reduction in FERC Order 1000 costs)
  - The 2021 Depreciation expense has been assumed flat in the preliminary budget
  - The proposed budget, presented in August, will include updated depreciation expense based on a detailed review of project budgets and estimated go live dates
- The 2021 Capital Budget is also presented in summary form
  - Portfolio budget of $28.0 million with a list of projects that are in planning/conceptual design (See slides 28 - 30)
  - Detailed project descriptions will be presented in August once the final resource requirements are determined

Note: Throughout the presentation some schedules may appear inconsistent due to rounding

2021 Preliminary Budget Change (net increase of 2.7% over 2020)



2021 Operating Budget Risks

- Additional funding may be required to support the impact of increasing penetration of variable resources and emerging technologies
- Information Technology software licensing and maintenance costs may require additional funding
- Insurance policy renewals may be higher than increases estimated in the 2021 budget
- Interest Rates may impact ISO-NE floating rates on tax-exempt debt, pension plan liability costs, and interest income on settlement float balance
- Subsequent waves of COVID-19 cases may require sequestration
- Legal costs from material litigation that may arise during the course of the year would pose a risk to ISO-NE's ability to operate within the approved budget
- Federal and state policy directives due to new or changing policies could result in additional cost associated with new requirements
- The "Future of the Grid/Markets" activity may require additional and/or external resources

Next Steps

- Review 2021 proposed Operating and Capital Budgets at the August 10th NEPOOL Budget & Finance Subcommittee meeting
- Review 2021 proposed Operating and Capital Budgets at the meeting with State Agencies on August 10th
- Review 2021 proposed Operating and Capital Budgets at the August 20th Audit & Finance Committee meeting
- Review 2021 proposed Operating and Capital Budgets at the September 16th Board Meeting with submitted State Agencies comments
- NPC vote on the ISO-NE 2021 proposed Budgets at the October 1st meeting
- ISO New England Board of Directors vote on the 2021 proposed Budgets subsequent to the NPC vote in October
- ISO New England filing of the 2021 Budgets with FERC on October 16th (estimated date)

2021 Budget Components and Key Assumption Details

2021 Preliminary Budget Details

Item	Description	Amount ($ in millions)
Compensation and Employee Benefit Increases	Annual compensation merit increase of 3.0% and promotional increases of 0.5% (placeholder data, will be replaced with survey data in the Fall); changes in employee benefit plan costs with budgeted increases for medical costs (7.0%) and dental (3.0%); based on early indications; an increase in Post-Retirement Medical Plan funding due largely to earning projections; an increase in funding for the defined contribution pension plan as additional employees become eligible (employees hired on or after January 1, 2014); the increase in medical trend (7.0% noted above) was completely mitigated by higher employee cost sharing.	$ 3.8
Computer Service/Systems Support	Computer Service increases include those for Infrastructure, Energy Management, new products, and inflationary increases. Infrastructure increases include 2 consultant resources for system administration, and licensing for archiving demands. Energy Management System (EMS) increases relate to a number of recent market enhancements made as well as the introduction of an updated Energy Market platform and the development of the next generation of the EMS (nGEM). Support for new products include compliance and Information Technology training software.	$ 0.9
Cyber Security and NERC CIP Compliance	Funding for 2 FTE consulting resources to support Cyber Security team for work related to a 2021 CIP audit; funding for threat detection software; increased maintenance for replacement security event and log monitoring software (above previous product); and funding for a social engineering data and training subscription.	$ 0.8

2021 Preliminary Budget Details *(cont.)*

Item	Description	Amount ($ in millions)
Energy Security, Renewable Resources/Emerging Technologies, and FCM	Funding for Energy Security Initiative (ESI) implementation, funding related to the continuing evolution and penetration of variable resources and emerging technologies (wind, photovoltaic, demand resources, energy storage) in energy markets, and funding allocated to the Forward Capacity Market (FCM). Additions include consulting resources and data subscriptions in Market Monitoring for ESI; funding for FCM and energy storage; and increases in System Planning related to FCM, energy storage, and wind activities.	$ 0.6
Insurance Market and Interest Environment	Majority of the increase include a significant rise in property and liability insurance policies, by an estimated 25%, with insurers passing along market impacts seen over the past several years and a much lesser net increase due to a drop in rates, creating lower interest income, mostly offset by lower interest expense.	$ 0.6
Inflationary and Other Miscellaneous Increases	Includes increases for Board of Director and Committee chair retainer fees implemented in 2019 subsequent to development of the 2020 budget; consultant pay rates; cyclical building maintenance and janitorial and building security services; communication maintenance contracts and phone rates; and subscription increases for legal and credit monitoring.	$ 0.6

2021 Preliminary Budget Details *(cont.)*

Item	Description	Amount ($ in millions)
Efficiencies, Reductions, and Other Non-Recurring Costs	Includes reduction or removal of funding for various studies, including: for Energy Security Improvements; the reevaluation and updating of Cost of New Entry (CONE), Net CONE, and Offer Review Trigger Price in the Forward Capacity Market; System Planning reductions for Order 1000 project management, non-repetitive studies and work that will be absorbed by internal staff; a contract Enterprise Learning position that was replaced by reallocating an existing ISO-NE employee; reductions in various other items including leased equipment, and removal of unrelated business income tax due to a tax law change.	$ (2.5)
Total	*(this represents a 2.7% increase over 2020)*	**$ 4.8**

APPENDIX 1: 5 YEAR BUDGET COMPARISON

2021 Preliminary Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2021	% Change	2020	% Change	2019	% Change	2018	% Change	2017
Operating Budget Before Depreciation	$180.0	3.3%	$174.2	3.1%	$168.9	2.9%	$164.2	3.3%	$158.9
FERC Order 1000	$0.2	(84.0)%	$1.3		-		-		-
Capital Budget	28.0	0.0%	28.0	0.0%	28.0	0.0%	28.0	0.0%	28.0
Total Cash Budget	**$208.2**	**2.3%**	**$203.4**	**3.3%**	**$196.9**	**2.5%**	**$192.2**	**2.8%**	**$186.9**
Operating Budget Before Depreciation	$180.0	3.3%	$174.2	3.1%	$168.9	2.9%	$164.2	3.3%	$158.9
FERC Order 1000	$0.2	(84.0)%	$1.3	-	-		-		-
Depreciation **(1)**	26.3	0.0%	26.3	(9.6)%	29.1	(6.2)%	31.0	(8.1)%	33.7
Revenue Requirement Before True-up	206.5	2.4%	201.7	1.9%	198.0	1.5%	195.2	1.3%	192.7
True up	0.2		(2.9)		(9.3)		0.4		(0.4)
Revenue Requirement (excl. FERC Order 1000)	**$206.4**	**4.5%**	**$197.5**	**4.7%**	**$188.7**	**(3.5)%**	**$195.5**	**1.7%**	**$192.3**
Revenue Requirement (incl. FERC Order 1000)	**$206.6**	**4.0%**	**$198.8**	**5.4%**	**$188.7**	**(3.5)%**	**$195.5**	**1.7%**	**$192.3**
Forecast – TWhs (2)	**147.4**	**1.0%**	**145.9**	**0.2%**	**145.6**	**2.5%**	**142.1**	**1.2%**	**140.3**
$/KWh Rate	**$0.00140**	**2.9%**	**$0.00136**	**5.1%**	**$0.00130**	**(5.8%)**	**$0.00138**	**0.4%**	**$0.00137**
Average Monthly Consumer Cost (3)	**$1.05**		**$1.02**		**$0.97**		**$1.03**		**$1.03**

(1) The 2021 *preliminary* depreciation budget is a placeholder. The 2021 *proposed* budget will result in a detailed review of project budgets and estimated go-live dates for the impact on depreciation expenses.

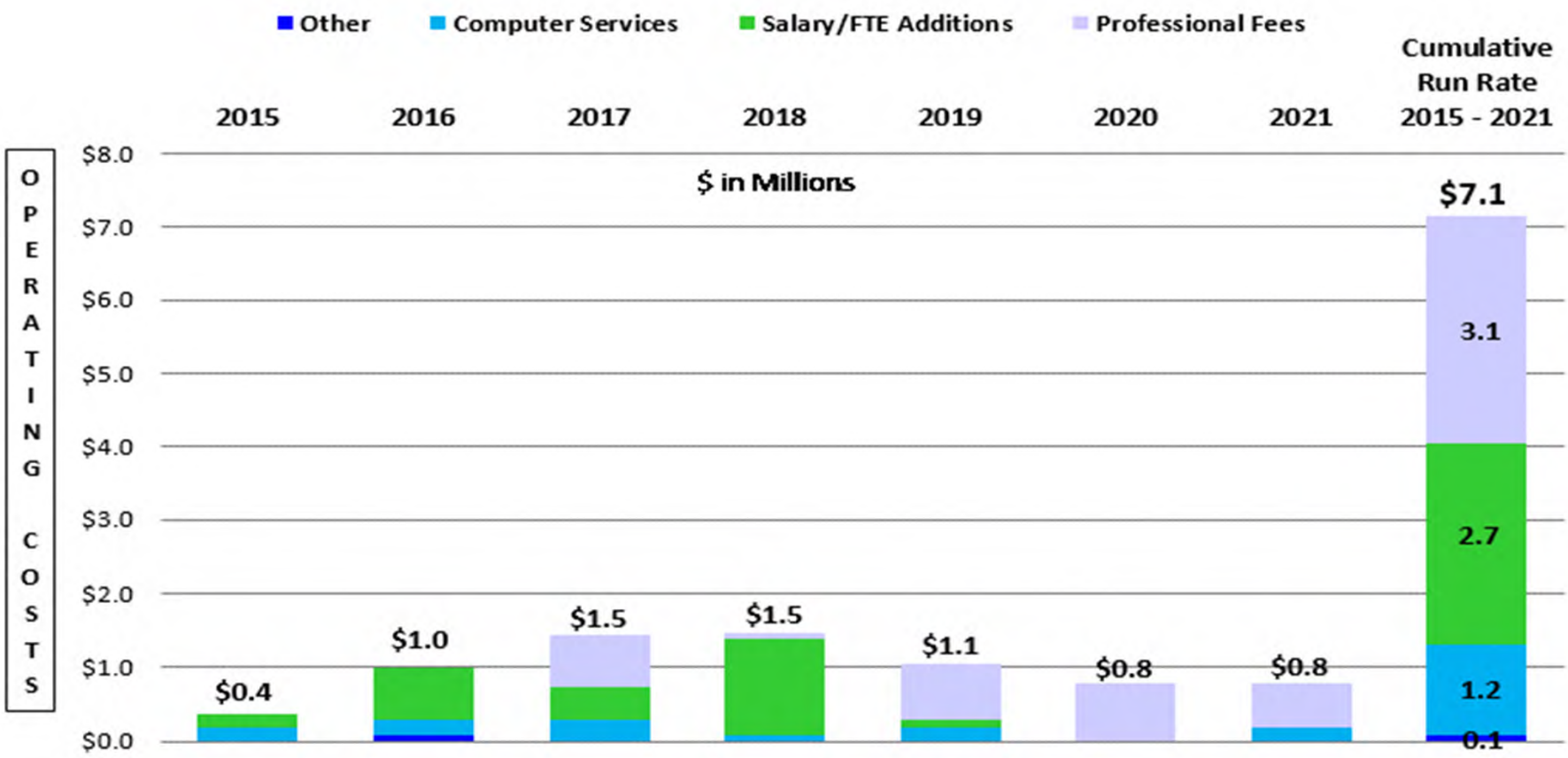
(2) 2020 and 2021 Forecasts based on May 2020 CELT Report (Schedule 1.5.2 - Net Annual Energy - Gross (without reductions)). All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.

(3) Based on average consumption of 750 kWh per month.

Note: Throughout the presentation some schedules may be inconsistent due to rounding.

APPENDIX 2: CYBER SECURITY ANNUAL COSTS 2015-2021

Cyber Security Annual Capital and Incremental Operating Costs 2015-2021



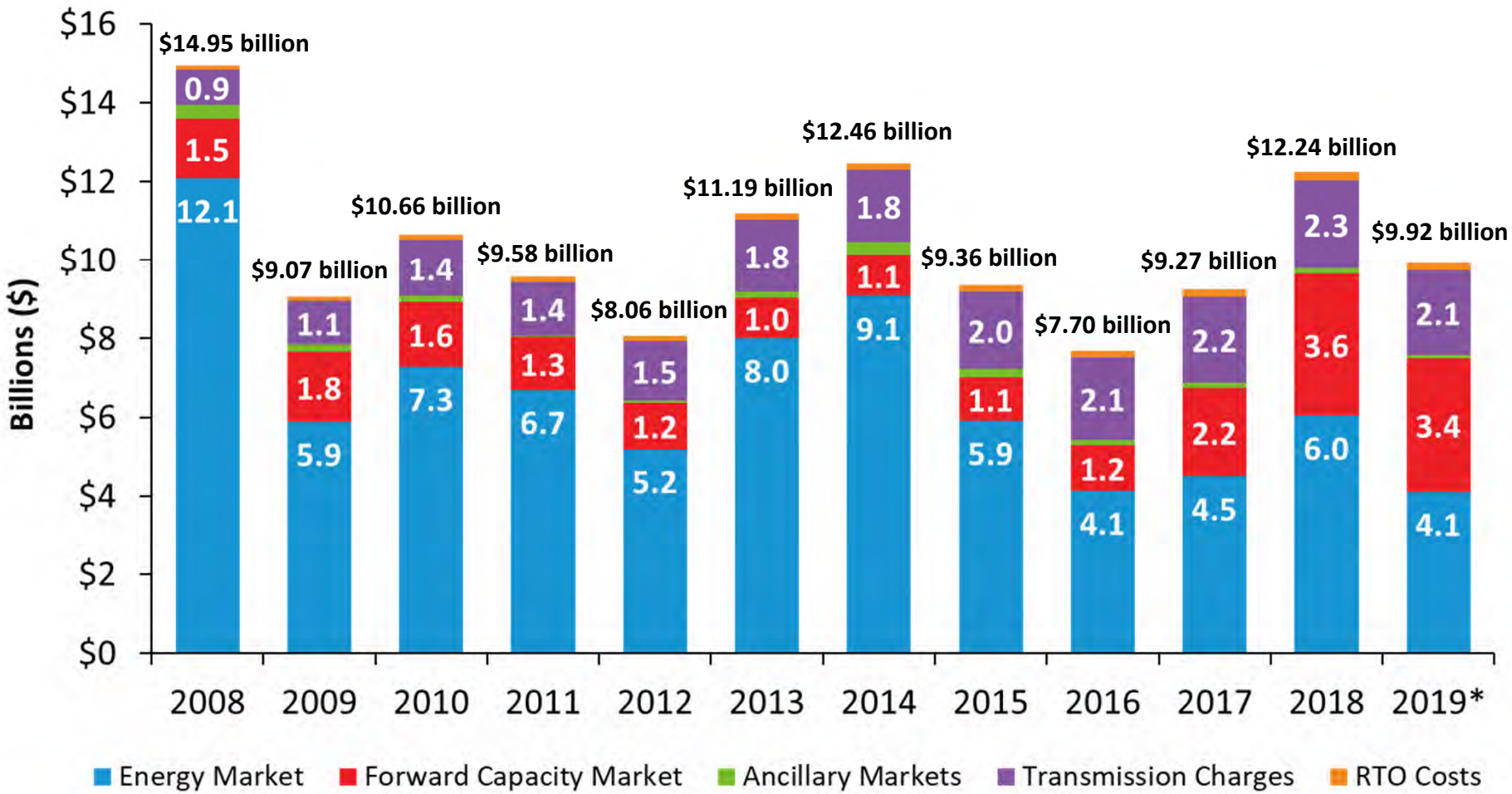
Capital Costs	$2.3	$1.3	$1.2	$1.5	$3.0	$3.2	$3.0	$15.5

Above amounts represent cumulative annual costs for cyber security that have been added in the 2015 through 2021 budgets and are on-going and included in the 2021 preliminary budget. An additional $1.1 million of incremental non-recurring cyber security costs were incurred from 2015 through 2020 that are not included above.

APPENDIX 3: HISTORICAL NEW ENGLAND WHOLESALE AND RETAIL ENERGY COSTS

New England Wholesale Electricity Costs

Annual wholesale electricity costs have ranged from $7.7 billion to $15 billion



Source: *2019 Report of the Consumer Liaison Group*; * 2019 data is preliminary and subject to resettlement

Note: Forward Capacity Market values shown are based on auctions held roughly three years prior to each calendar year.

New England Wholesale Electricity Costs[a]

	2015		2016		2017		2018		2019*	
	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh
Wholesale Market Costs										
Energy (LMPs)[b]	$5,910	4.5	$4,130	3.2	$4,498	3.5	$6,041	4.7	$4,105	3.3
Ancillaries[c]	$210	0.2	$146	0.1	$132	0.1	$147	0.1	$81	0.1
Capacity[d]	$1,110	0.8	$1,160	0.9	$2,245	1.8	$3,606	2.8	$3,401	2.7
Subtotal	*$7,229*	5.5	*$5,437*	*4.2*	*$6,875*	*5.4*	*$9,794*	*7.6*	*$7,586*	*6.0*
Transmission charges[e]	$1,964	1.5	$2,081	1.6	$2,199	1.7	$2,250	1.7	$2,146	1.7
RTO costs[f]	$165	0.1	$180	0.1	$193	0.2	$196	0.2	$184	0.1
Total	**$9,358**	**7.1**	**$7,698**	**5.9**	**$9,267**	**7.3**	**$12,240**	**9.4**	**$9,915**	**7.9**

(a) Average annual costs are based on the 12 months beginning January 1 and ending December 31. Costs in millions = the dollar value of the costs to New England wholesale market load servers for ISO-administered services. Cents/kWh = the value derived by dividing the dollar value (indicated above) by the real-time load obligation. These values are presented for illustrative purposes only and do not reflect actual charge methodologies. *** The wholesale values for 2019 are preliminary and subject to resettlement.**

(b) Energy values are derived from wholesale market pricing and represent the results of the Day-Ahead Energy Market plus deviations from the Day-Ahead Energy Market reflected in the Real-Time Energy Market.

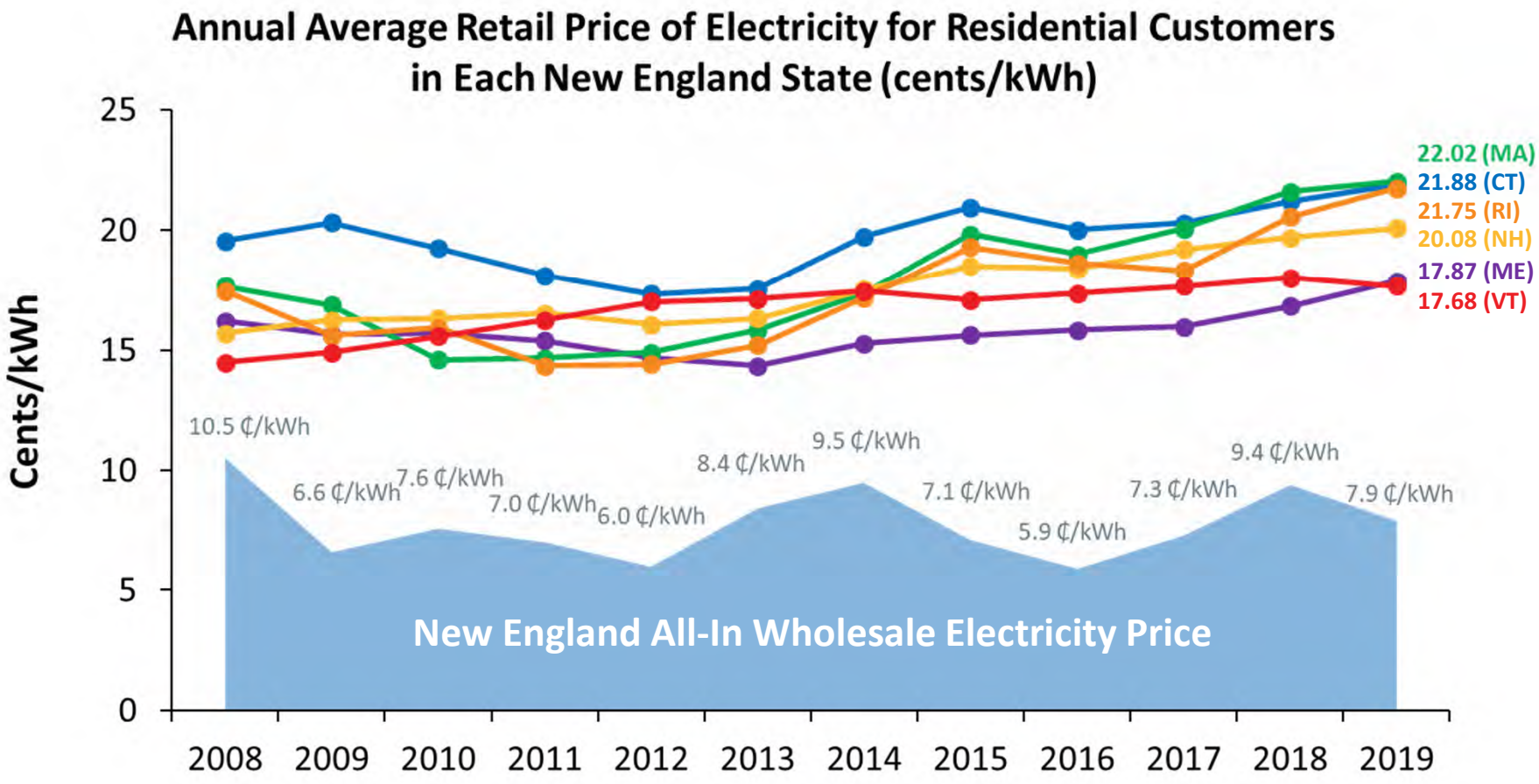
(c) Ancillaries include first- and second-contingency Net Commitment-Period Compensation (NCPC), forward reserves, real-time reserves, regulation service, and a reduction for the Marginal Loss Revenue Fund.

(d) Capacity charges are those associated with the Forward Capacity Market (FCM).

(e) Transmission charges reflect the collection of transmission owners' revenue requirements and tariff-based reliability services, including black-start capability, voltage support, and FCM reliability. In 2019, the cost of payments made to these generators for reliability services under the ISO's tariff was $42.2 million. Transmission charge totals reflect the refund of Schedule 1 TOUT charges to regional network load.

(f) RTO costs are the costs to run and operate ISO New England and are based on actual collections, as determined under Section IV of the *ISO New England Inc. Transmission, Markets, and Services Tariff*.

Retail Electricity Prices Follow Wholesale Prices, But Are Also Influenced by Individual State Policies



Source: U.S. Energy Information Administration, *Electric Power Monthly*, Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State; *2019 Report of the Consumer Liaison Group*, the New England all-in wholesale electricity price is derived by dividing total wholesale electricity costs by real-time load obligation (presented for illustrative purposes; does not reflect actual charge methodologies)

APPENDIX 4: 2021 Preliminary Capital Budget

Capital Budget
2021 Expenditures

Projects In Planning/Conceptual Design		
	nGEM Day-Ahead Market Clearing Engine Implementation	$5.0M
	Energy Security	$3.0M
	nGEM Software Development Part II	$2.0M
	2021 Issue Resolution Projects	$1.5M
	Enhanced Market Simulator	$1.5M
	CIP Network Perimeter Security	$1.0M
	2021 Cyber Security Improvements	$1.0M
	2021 Forward Capacity Market Improvements	$1.0M
	Internal Market Monitoring Data Analysis Phase III	$0.5M
	Wireless Infrastructure Upgrade	$0.5M
	PI Historian for Short-Term PMU Data Repository	$0.5M
	Security Information and Event Management Log Monitoring Replacement	$0.5M
	Identity and Access Management Phase III	$0.5M
	Enterprise Application Integration 3.0	$0.5M
	TranSMART Technical Architecture Update	$0.5M
	Continued Next Page	

The 2021 Capital Budget is a preliminary estimate and still being defined.

Capital Budget

2021 Expenditures *(cont.)*

In Planning/Conceptual Design (Continued):		
	Governance, Risk Management & Compliance Software Phase II	$0.5M
	FERC Forms 1, 3-Q, 714	$0.5M
	Sub-accounts for Financial Transmission Rights Market	$0.5M
	Human Resources Workflow & Document Management	$0.5M
	Governance, Risk Management & Compliance Software Phase I	$0.4M
	External Website Migration to Cloud	$0.1M
	Non-Project Capital Expenditures	$3.5M
	Other Emerging Work	$2.0M
	Capital Interest	$0.5M
Total 2021 Capital Budget		**$28.0M**

The 2021 Capital Budget is a preliminary estimate and still being defined.

APPENDIX 5: CAPITAL STRUCTURE

Capital Structure

- The ISO has a $20M working capital line which expires on July 1, 2021
- Capital project costs are largely funded by $50M in Private Placement Notes; the ISO has funded its capital needs with $11M in Private Placement Notes entered into in 2013, and refinanced its $39M tranche of Private Placement Notes in 2014; both series of notes expire in November 2024
- Tax-Exempt Debt
  - In 2005, the ISO entered into tax-exempt financing in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds for $45.5M to fund the construction of the Main Control Center in Holyoke, MA
  - In 2012, the ISO entered into a new tax-exempt financing in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds for $36M to fund a new Backup Control Center
  - The tax-exempt bonds are auctioned weekly and amortize quarterly for 25 years
- In November 2013, the ISO entered into an Interest Rate Cap (to mitigate the interest rate risks associated with the tax-exempt debt) for the notional value of $32,215,000, which will expire in 2024 and amortizes as principal payments are made on the tax-exempt debt
- For the three months ended March 31, 2020, the ISO's total weighted average cost of capital was 2.93%, excluding fees charged on the various debt financing; fees range from .075% to .38%

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: May 28, 2020

RE: **"**Know Your Customer" and Clean-Up Changes to ISO-NE Financial Assurance Policy

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At its June 4, 2020 meeting, the Participants Committee will be asked to consider changes to the ISO New England Financial Assurance Policy ("FAP") related to applications by new Market Participants and annual compliance submissions to the ISO by existing Market Participants (the so-called "Know Your Customer" changes) and other clean-up changes. The changes to the FAP were discussed by the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") at its March 26, 2020, April 21, 2020 and May 14, 2020 teleconferences. No Subcommittee members objected to the changes, although some asked that their concerns be noted, as described below. This memorandum describes the proposed changes to FAP, and those changes are included in Attachment 1 to this memorandum.

Know Your Customer Changes

Like many of the other regional transmission organizations ("RTOs"), the ISO has been reviewing the disclosures it requires from Markets Participants and applicants to participate in the New England Markets. As a result of that review, the ISO proposed changes to the FAP, including the introduction of a new information disclosure form as an attachment to the FAP that includes and expands on the existing disclosure requirements in the FAP (prior to these proposed changes, the required disclosures were detailed in the FAP itself). At a high level, the Know Your Customer changes include the following:

- Several of the required disclosures were expanded from only the Market Participant or applicant and Principals to include predecessors, and certain personnel with decision-making responsibility in the New England Markets and to ask about their previous activities in the relevant markets;
- Questions about market activity were expanded from the United States to include all North American energy markets;
- The disclosure period was expanded from five to ten years for most items (and some items with previously indefinite lookback periods were limited to five years);
- Questions were added regarding revocation of participation in another RTO, and for new applicants, plans for funding activities in the New England Markets;
- Language was added giving the ISO the ability to request additional information about risk management functions, specifically, segregation of duties (including organizational charts or equivalent information); and

- A provision was added requiring that an applicant cure any previous uncured payment defaults before being allowed to rejoin the New England Markets, including those of any predecessor entity.

Over the course of the three Subcommittee meetings on this topic, the ISO's proposed FAP changes were adjusted in response to the Subcommittee's comments, including (1) revising the question about market activity from other international markets to all North American markets, (2) changing the requirement that all applicants provide an organization chart to a requirement that supporting documentation be provided showing separation of the trading and risk management functions only if requested, (3) adding language stating that a Market Participant or applicant is not required to provide information if that disclosure is prohibited by law; (4) adding specificity regarding personnel and former personnel to limit the scope; and (5) limiting disclosure of prior suspensions in other markets to uncured suspensions.

While no Subcommittee members objected to the Know Your Customer changes moving forward, several wanted comments noted in the memorandum. One member stated that the FAP language is vague regarding which personnel with decision-making authority are covered and whether disclosing sanctions or governmental investigations would waive privilege. Another member stated that the request for information on how an applicant will fund its activity in the New England Markets could raise concerns that the same information is not sought from existing Market Participants and could require the disclosure of confidential information. A third member wanted to require Market Participants and applicants to be required to disclose a failure to comply with a New England state renewable portfolio standard requirement.

Clean-up Changes

While the ISO was revising the FAP for the Know Your Customer changes, it updated some other items in the FAP, as follows:

- Section III – The period that a terminated Market Participant's financial assurance is retained was increased from 120 days to 150 days to allow for the full application of the Data Reconciliation Process;
- Section VII.C – References to Peak Energy Rent were removed from the calculation of FCM Charge Requirements, as they are no longer applicable;
- Section IX – Several changes were made to the credit insurance provisions, including clean-up changes and:
    - Language was added providing for a pro rata reduction in credit insurance for each Credit Qualifying Rated Market Participant if the full amount of the credit insurance cannot be obtained;
    - The credit insurance coverage multiplier was reduced from 3.5 to 2.5 to match the financial assurance requirement multiplier;
    - A materiality threshold was added for adjusting the amount each Credit Qualifying Rated Market Participant is covered for; and
    - FTR transactions were excluded from the credit coverage calculation and a $50 million cap was added to conform the FAP to the credit insurance policy requirements; and

- Section X – The letter of credit provisions were changed as follows:
    - The form of letter of credit was updated to be consistent with industry best practices, and language was added requiring existing letters of credit to be replaced by the new form not later than December 31, 2021 (or earlier if a Market Participant is amending its letter of credit);
    - A reference to NYMEX was removed from the issuing bank rating requirement because NYMEX has been merged into the Chicago Mercantile Exchange; and
    - The language regarding a bank that fails to honor the terms of a letter of credit twice in 730 days has been clarified.

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

> RESOLVED, that the Participants Committee supports revisions to the ISO New England Financial Assurance Policy to make certain "Know Your Customer" and clean-up changes, as proposed by the ISO and as circulated to this Committee with the May 28, 2020 supplemental notice, 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.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy~~: (i) a list of Principals; (ii) a list of any material criminal or civil litigation involving the customer or applicant or any of the Principals of the customer or applicant arising out of participation in any U.S. wholesale or retail energy market in the past five years; (iii) a list of sanctions involving the customer or applicant or any of the Principals of the customer or applicant imposed by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets where such sanctions were either imposed in the past five years or, if~~

~~imposed prior to that, are still in effect; (iv) a written summary of any bankruptcy, dissolution, merger or acquisition of the customer or applicant in the preceding five years; and (v) a list of current retail and wholesale electricity markets-related operations in the United States, other than in the New England Markets.~~. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities and Exchange Commission or other similar regulatory agencies that include substantially similar information to that required above, provided, however, that the customer or applicant must clearly indicate where the specific information is located in those filings. An applicant that fails to provide this information will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this information by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the information to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) The ISO will review the information provided pursuant to subsection (a) above, and will also review whether the customer or applicant or any of the Principals of the customer or applicant are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. If, after review of the information provided pursuant to subsection (a) above or any other information disclosed pursuant to this Section II, the ISO in its sole discretion requires additional information to make its analysis under this subsetion (b), the ISO may require additional information from the customer or applicant. If, based on these reviews, the ISO determines that the commencement or continued participation of such customer or applicant in the New England Markets may present an unreasonable risk to those markets or its Market Participants, the Chief Financial Officer of the ISO shall promptly forward to the Participants Committee or its delegate, for its input, such concerns,

together with such background materials deemed by the ISO to be necessary for the Participants Committee or its delegate to develop an informed opinion with respect to the identified concerns, including any measures that the ISO may recommend imposing as a condition to the commencement or continued participation in the markets by such customer or applicant (including suspension) or the ISO's recommendation to prohibit or terminate participation by the customer or applicant in the New England Markets. The ISO shall consider the input of the Participants Committee or its delegate before taking any action to address the identified concerns. If the ISO chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

2. Risk Management

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. ~~The customer or applicant shall also attach to each Attachment 3, an organizational chart that demonstrates the segregation of duties within the risk policies, procedures, and controls of the Certifying Entity referenced in the foregoing, or, if applicable, in the case of a customer provide a statement that there have been no changes to the previously submitted organizational chart.~~ The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant and must be notarized. An applicant that fails to provide this certificate will be prohibited from participating in the New England

Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls (and any supporting documentation, if applicable) or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable); or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls, including supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

The applicant's or customer's written policies, procedures, and controls and any supporting documentation received by the ISO or its designee pursuant to this subsection (b) shall be treated as Confidential Information.

(c) Where an applicant or customer submits risk management policies, procedures, and controls or supporting documentation to the ISO or its designee pursuant to any provision of subsection (b) above, the ISO or its designee shall assess that those policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v)

placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Where, as a result of the assessment described above in this subsection (c), the ISO or its designee believes that the applicant's or customer's written policies, procedures, and controls do not conform to prudent risk management practices, then the ISO or its designee shall provide notice to the applicant or customer explaining the deficiencies. The applicant or customer shall revise its policies, procedures, and controls to address the deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of

eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the applicant by a Senior Officer of the applicant and must be notarized.

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section II.A.5. If at any time the ISO becomes aware that a customer no longer satisfies the requirements of this Section II.A.5, the customer shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

6. Prior Uncured Defaults

In addition to, and not in limitation of Section IV of the ISO New England Financial Assurance Policy, an applicant who has a previous uncured payment default must cure such payment default by payment to the ISO of all outstanding and unpaid obligations, as well as meet all requirements for participation in the New England Markets contained in the ISO New England Financial Assurance Policy. For purposes of this Section II.A.6 and the ISO's evaluation of information disclosed pursuant to Section II of the ISO New England Financial Assurance Policy, the ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England Markets under a different name, affiliation, or organization, should be treated as the same customer or applicant that experienced the previous payment default. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry. Notwithstanding the foregoing, an applicant shall not be required to cure a payment default that has lawfully been discharged pursuant to the U.S. Bankruptcy Code.

B. Proof of Financial Viability for Applicants

Each Applicant must, with its membership application and at its own expense, submit proof of financial viability, as described below, satisfying the ISO requirements to demonstrate the Applicant's ability to meet its obligations. Each Applicant that intends

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) 15~~2~~0 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 for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly Charges for such Market Participant that have been settled but not invoiced, plus (z) the Hourly 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:

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

Where:

t = The last day that such Market Participant's Hourly 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 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;

(ii) 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, (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) 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) 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);

(v) 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
b. such Market Participant's Virtual Requirements; plus
c. such Market Participant's Non-Hourly Requirements times 2.5~~-~~0 (subject to Section X.D with respect to Provisional Members); plus
d. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
e. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus
f. the amount of any Disputed Amounts received by such Market Participant; and

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

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~~s~~ that the FCM Charge Rate~~: will not subtract PER adjustments as described in such section; and~~ 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~~, but without the adjustments for PER described in such section~~. 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 addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity

subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

VIII. [Reserved]

IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage ~~, a performance or surety bond, or a combination thereof~~ ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion at least in an amount covering collectively the Credit Qualifying Rated Market Participants based on the formula below. Notwithstanding the foregoing, if the entity providing such Credit Coverage cannot provide the amount required by this Section IX, the ISO will reduce the

required coverage for all Credit Qualifying Rated Market Participants on a pro rata basis. ~~The amount of the Credit Coverage shall be adjusted monthly~~ The total amount of the Credit Coverage shall be at least the aggregate of the following formula; provided, however, if the entity providing the Credit Coverage denies coverage (in whole or in part) for any Credit Qualifying Rated Market Participant based on its rights under the insurance policy, the ISO will use reasonable efforts to obtain documentation regarding the denial and will make reasonable efforts to appeal such denial. For each Credit Qualifying Rated Market Participant, the portion of the Credit Coverage ~~and~~ shall be ~~equal to~~the -lesser of: (A) ~~at least~~ the sum of (x) ~~3~~2.5 times the average Hourly Charges for ~~all~~ such Credit Qualifying Rated Market Participant~~s~~ within the previous fifty-two calendar weeks plus (y) ~~3~~2.5 times the sum of the average Non-Hourly Charges (excluding charges or credits related to FTR transactions) and the average Transmission Charges for ~~all~~ such Credit Qualifying Rated Market Participant~~s~~ within the previous twelve calendar months; or (B) $50 million. For any Credit Qualifying Rated Market Participant, the applicable amount of the Credit Coverage shall be adjusted monthly if the above formula produces a change that is either (A) 10% or greater, or (B) greater than $100,000. ~~.~~ The Credit Coverage shall be provided by an insurance company rated "A-" or better by A.M. Best & Co. or "A" or better by S&P. The cost of the Credit Coverage obtained for each calendar year shall be allocated to all Credit Qualifying Rated Market Participants pro rata based, for each Credit Qualifying Rated Market Participant, on the average amount of the Invoices issued to that Credit Qualifying Rated Market Participant under the ISO New England Billing Policy in the preceding calendar year. Each Credit Qualifying Rated Market Participant shall provide the ISO with such information as may be reasonably necessary for the ISO to obtain the Credit Coverage at the lowest possible cost.

X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity"). Any Posting Entity requesting a change to one of the model forms attached to the ISO New England Financial Assurance Policy which would be specific to such Posting Entity (as opposed to a generic improvement to such form) shall, at the time of making that request, pay a $1,000 change fee, which fee shall be deposited into the Late Payment Account maintained under the ISO New England Billing Policy.

Notwithstanding the foregoing, an investment in shares of a registered fund in a shareholder account shall not be an acceptable form of financial assurance for a Posting Entity that is not a U.S. Person, as defined in Regulation S under the Securities Act of 1933, as amended, unless the financial institution selected by the ISO allows such Posting Entity to invest in the investment options listed at the time on the ISO's website or the Posting Entity is invested in the investment options listed on the ISO's website as of March 19, 2015.

B. Letter of Credit

An irrevocable standby letter of credit provides an acceptable form of financial assurance to the ISO. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the end of the Business Day that is 30 days prior to the termination of such letter of credit. If the letter of credit amount is below the required level, the Posting Entity shall immediately replenish or increase the letter of credit amount or obtain a substitute letter of credit. The account party on a letter of credit must be either the Posting Entity whose obligations are secured by that letter of credit or an Affiliate of that Posting Entity.

1. Requirements for Banks

Each bank issuing a letter of credit that serves as additional financial assurance must meet the requirements of this Section X.B.1. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers." The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly. To be included on the List of Eligible Letter of Credit Issuers, the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank and either: (i) be recognized by ~~the New York Mercantile Exchange ("NYMEX") or~~ the Chicago Mercantile Exchange ("CME") as an approved letter of credit bank; or (ii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's or "A-" by Fitch so long as its letter of credit is confirmed by a bank that is recognized by ~~NYMEX or~~ CME as an approved letter of credit issuer as described in clause (i) above; or (iii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of

"A-" by S&P, or "A3" by Moody's, or "A-" by Fitch and be approved by the ISO in its sole discretion (the ISO will promptly advise the NEPOOL Budget and Finance Subcommittee of any additional bank approved by it under this provision). Because the ratings described in clauses (ii) and (iii) are minimum ratings, a bank will not be considered to have satisfied the requirement of those clauses if any applicable rating from the Rating Agencies falls below the levels listed in those clauses. In addition, no Posting Entity may provide a letter of credit that has been issued or confirmed by a bank that is an Affiliate of that Market Participant. If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy any of the criteria set forth above, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure to replace the letter of credit with a letter of credit from a bank satisfying those criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. In the case of a bank that is removed from ~~the NYMEX or~~ CME list of approved letter of credit banks, the ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. No letter of credit bank may issue or confirm letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued or confirmed by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue or confirm letters of credit in favor of the ISO, (C) ~~and~~ any letters of credit issued or confirmed by such bank in favor of the ISO will not be renewed, and (D) any letters of credit issued or confirmed by such bank in favor of the

ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.1.

Any letter of credit provided for a new Posting Entity for the purpose of covering the Initial Market Participant Financial Assurance Requirement must have a minimum term of 120 days.

2. Form of Letter of Credit

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a Letter of Credit in the Form of Attachment 2, or (b) December 31, 2021. Any letter of credit provided for a new Posting Entity must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

C. Special Provisions for Provisional Members

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing a cash deposit in accordance with Section X.A. Provisional Members will not have any other

ATTACHMENT 2

SAMPLE STANDBY LETTER OF CREDIT

[DATE PROVIDED]

IRREVOCABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE] ~~AT OUR COUNTERS~~

WE DO HEREBY ISSUE ~~AN~~ THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF ~~ON BEHALF OF~~ [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] ("ACCOUNT PARTY") IN FAVOR OF ISO NEW ENGLAND INC. ("ISO" OR "BENEFICIARY") ("STANDBY LETTER OF CREDIT")

THIS STANDBY LETTER OF CREDIT IS IRREVOCABLE AND IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS AND BONA FIDE HOLDERS OF THIS STANDBY LETTER OF CREDIT THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT WILL BE HONORED ON PRESENTATION OF THIS STANDBY LETTER OF CREDIT.

THIS STANDBY LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS AND MAY BE DRAWN HEREUNDER FOR THE ACCOUNT OF THE ACCOUNT PARTY UP TO ~~IN~~ AN AMOUNT NOT EXCEEDING US$ _____.00 (UNITED STATES DOLLARS _____ AND 00/100).

THIS STANDBY LETTER OF CREDIT IS DRAWN AGAINST BY PRESENTATION TO US AT OUR OFFICE LOCATED AT THE FOLLOWING ADDRESS:

_____

_____

_____

~~OF~~ A DRAWING CERTIFICATE SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF PRESENTATION CONTAINING THE FOLLOWING STATEMENT:

> "THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] ("~~BANK~~ISSUER"), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] ISSUED BY ~~[BANK]~~ISSUER IN FAVOR OF ISO NEW ENGLAND INC. ("ISO"), THAT [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____."

IF PRESENTATION OF ANY DRAWING CERTIFICATE IS MADE ON A BUSINESS DAY AND SUCH PRESENTATION IS MADE AT OUR COUNTERS ON OR BEFORE 10:00 A.M. _____ TIME, WE SHALL SATISFY SUCH DRAWING REQUEST ON THE SAME BUSINESS DAY. IF THE DRAWING CERTIFICATE IS RECEIVED AT OUR COUNTERS AFTER 10:00 A.M. _____ TIME, WE WILL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. FOR THE PURPOSES OF THIS SECTION, A BUSINESS DAY MEANS A DAY, OTHER THAN A SATURDAY OR SUNDAY, ON WHICH THE FEDERAL RESERVE BANK OF NEW YORK IS NOT AUTHORIZED OR REQUIRED TO BE CLOSED. DISBURSEMENTS SHALL BE IN ACCORDANCE WITH THE INSTRUCTIONS OF THE ISO.

THE FOLLOWING TERMS AND CONDITIONS APPLY:

> THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].
>
> THE AMOUNT WHICH MAY BE DRAWN BY YOU UNDER THIS STANDBY LETTER OF CREDIT SHALL BE AUTOMATICALLY REDUCED BY THE AMOUNT OF ANY DRAWINGS HEREUNDER AT OUR COUNTERS. ANY NUMBER OF PARTIAL DRAWINGS ARE PERMITTED FROM TIME TO TIME HEREUNDER.
>
> ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY.

THIS STANDBY LETTER OF CREDIT IS NOT TRANSFERABLE OR ASSIGNABLE. THIS STANDBY LETTER OF CREDIT DOES NOT INCORPORATE AND SHALL NOT BE DEEMED MODIFIED, AMENDED OR AMPLIFIED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE ~~UCP~~ISP, AS DEFINED BELOW) OR (B) IN WHICH THIS STANDBY LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS STANDBY LETTER OF CREDIT RELATES.

THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNATIONAL STANDBY PRACTICES ("ISP98") OF -THE ~~UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS, 2007 REVISION,~~ INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. ~~600~~ 590, INCLUDING ANY AMENDMENTS, MODIFICATIONS, OR REVISIONS THEREOF (THE "~~UCP~~ISP"), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ~~UCP~~ISP, ~~INCLUDING BUT NOT LIMITED TO ARTICLES 14(b) AND 36 OF THE UCP,~~ IN WHICH CASE THE TERMS OF ~~THE~~ THIS STANDBY LETTER OF CREDIT SHALL GOVERN. THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY THE INTERNAL LAWS OF THE COMMONWEALTH OF MASSACHUSETTS TO THE EXTENT THAT THE TERMS ARE NOT GOVERNED BY THE ISP.

THIS STANDBY LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE ISO AND ~~US~~ISSUER.

WE HEREBY ENGAGE WITH YOU THAT DOCUMENTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL BE DULY HONORED UPON PRESENTATION AS SPECIFIED AND WE REPRESENT THAT THE ACCOUNT PARTY IS NOT AN AFFILIATE OF THE ~~BANK~~ISSUER.

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, ~~TELEGRAM,~~ OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW;

PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE WHEN ACTUALLY RECEIVED BY THE INTENDED RECIPIENT PARTY.

IF TO THE BENEFICIARY OF THIS STANDBY LETTER OF CREDIT:

ISO NEW ENGLAND INC.
ATTENTION: CREDIT DEPARTMENT
1 SULLIVAN RD. HOLYOKE, MA 01040
FAX: 413-540-4569
EMAIL: CREDITDEPARTMENT@ISO-NE.COM

IF TO THE ACCOUNT PARTY:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

IF TO ~~US~~ISSUER:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

_____ _____

[signature] [signature]

ATTACHMENT 3

ISO NEW ENGLAND MINIMUM CRITERIA FOR MARKET PARTICIPATION OFFICER CERTIFICATION FORM

Certifying Entity:	

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the minimum criteria for market participation requirements set forth in Sections II.A.2 and II.A.3 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Transmission, Markets and Services Tariff), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity has established or contracted for written policies, procedures, and controls applicable to participation in the New England Markets, approved by Certifying Entity's independent risk management function[1], which provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Certifying Entity is exposed, including, but not limited to, credit risk, liquidity risk, concentration risk, default risk, operation risk, and market risk.

~~2. Certifying Entity has attached to this Certification Form, an organizational chart that demonstrates the segregation of duties within the risk policies, procedures, and controls of the Certifying Entity referenced in Question 1 above or Certifying Entity certifies that there have been no changes to the previously submitted organizational chart.~~

3. Certifying Entity has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets.

4. Certifying Entity has appropriate operating procedures and technical abilities to promptly and effectively respond to all ISO New England communications and directions.

Date: _____ _____
(Signature)

Print Name:_____

[1] As used in this certification, a Certifying Entity's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Certifying Entity's trading functions, such as a risk management committee, a risk officer, a Certifying Entity's board or board committee, or a board or committee of the Certifying Entity's parent company.

ATTACHMENT 5

ISO NEW ENGLAND CERTIFICATE REGARDING CHANGES TO SUBMITTED RISK MANAGEMENT POLICIES FOR FTR PARTICIPATION

Certifying Entity:	

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the annual certification requirement for FTR market participation regarding its risk management policies, procedures, and controls set forth in Section II.A.2(b) of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows (check applicable box):

1. ☐ There have been no changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market.

   OR

2. ☐ There have been changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market and such changes are clearly identified and attached hereto.*

_____
(Signature)

Print Name:_____

Title: _____

Date: _____

Subscribed and sworn before me_____, a notary public of the State of _____, in and for the County of _____, this _____ day of _____, 20_____.

_____

(Notary Public Signature)

My commission expires: _____/_____/_____

_____

* As used in this certificate, "clearly identified" changes may include a redline comparing the current written risk management policies, procedures, and controls and the previously submitted written risk management policies, procedures, and controls; or resubmission of the written risk management policies, procedures, and controls with a bulleted list of all changes, including section and/or page numbers.

ATTACHMENT 6

MINIMUM CRITERIA FOR MARKET PARTICIPATION INFORMATION DISCLOSURE FORM

[to be inserted]

(Mod)

ATTACHMENT 6~~Appendix 1 Original Form~~

MINIMUM CRITERIA FOR MARKET PARTICIPATION

INFORMATION DISCLOSURE FORM

Date: _____

Prepared by: _____

~~Participant~~Customer/Applicant:[1] _____ ~~("Participant")~~

~~Pursuant to Section II.A.1.(a) of the ISO New England Inc. ("ISO") Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"), Participant submits the following:~~

I, _____ a duly authorized Senior Officer of _____ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals[~~1~~2]. Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

2. List all material litigation (criminal or civil) ~~litigation~~ involving ~~Participant or any of Participant's Principals~~) involving Certifying Entity or any of the Certifying Entity's Principals, Personnel (current and/or former),[3] Predecessors,[4] or an entity that a Principal of the Certifying Entity was a Principal of, arising out of participation in

---

[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

[~~1~~2] Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission ("FERC"), the Securities and Exchange Commission ("SEC"), the Commodity Futures Trading Commission ("CFTC"), any exchange monitored by the National Futures Association ("NFA"), or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

[3] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

any ~~U.S.~~ wholesale or retail energy market (domestic or international) or trading exchanges in the past ~~five~~ten (~~5~~10) years:
(Enter ~~n~~N/~~a~~A if not applicable)

3. List ~~of~~all sanctions involving ~~Participant or any of Participant's~~Certifying Entity's Principals~~-~~, Personnel (current and/or former), Predecessors, or an entity that a principal of the Certifying Entity was a Principal of, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any state entity responsible for regulating activity in ~~energy markets~~any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ~~five~~ten (~~5~~10) years or, if imposed prior to that, are still in effect~~:~~. List all known material ongoing investigations involving Certifying Entity's Principals, Personnel (current and/or former), Predecessors, or an entity that a principal of the Certifying Entity was a Principal of, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any state entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
(Enter ~~n~~N/~~a~~A if not applicable)

4. ~~A~~Provide a summary of any bankruptcy, dissolution, merger, or acquisition of ~~Participant~~Certifying Entity in the ~~preceding five~~past ten (~~5~~10) years (include date, jurisdiction, and other relevant details):
(Enter ~~n~~N/~~a~~A if not applicable)

5. List ~~of retail and~~all wholesale ~~electricity markets related~~or retail energy market-related operations in ~~the United States~~North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (~~i.~~e.g., PJM - FTRs):
(Enter ~~n~~N/~~a~~A if not applicable)

6. Describe if any of Certifying Entity's Principals, Personnel (current and/or former), or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each in the in the past five (5) years. If so, please explain:
(Enter N/A if not applicable)

If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's (a) ability to comply with the time frames to post financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: _____

By: _____
(Signature)

Print Name: _____

Title: _____

Date: _____

** To satisfy the disclosure requirements above, a ~~Participant~~Certifying Entity may attach additional materials and may provide ~~SEC~~the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that ~~Participant~~Certifying Entity clearly indicates where the specific information is located in those filings.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: May 28, 2020

RE: Vote on Further Compliance with Order No. 845 and March 19 Compliance Order

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At the June 4, 2020 Participants Committee meeting you will be asked to vote on a set of revisions to Schedule 22 to the ISO-NE Open Access Transmission Tariff ("Order No. 845 Revisions"). The Transmission Committee has recommended Participants Committee support for the Order No. 845 Revisions.

The Order No. 845 Revisions respond to the FERC's March 19, 2020 order on ISO-NE's Order No. 845 compliance filing in Docket No. ER19-1951 (the "March 19 Order").[1] The March 19 Order accepted much of the compliance filing but rejected certain portions and required a further compliance filing consistent with the order. NEPOOL counsel summarized the March 19 Order and the further compliance requirements in a March 20 memo to the Transmission Committee, which has been included with the materials for this agenda item.[2] ISO-NE has provided two presentations to the Transmission Committee describing the further compliance revisions that have been included with the materials for this agenda item.[3]

At its May 27 meeting, the Transmission Committee voted unanimously to support the Order No. 845 Revisions. This item would have been on the Consent Agenda but for the timing of the votes.

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[1] ISO-NE made its original Order No. 845 compliance filing on May 22, 2019. NEPOOL supported an alternative to the ISO's compliance proposal and filed a protest of a part of that filing pertaining to Surplus Interconnection Service. NEPOOL argued against certain restrictions to the availability and use of Surplus Interconnection Service that the ISO had proposed. The March 19 Order decided these issues in favor of NEPOOL, as described further in the NEPOOL counsel memo available through n. 2 below.

[2] The NEPOOL counsel memo is available here: https://www.iso-ne.com/static-assets/documents/2020/03/a00_tc_2020_03_25_nepool_counsel_memo_order_845.DOCX

[3] The April 28 ISO-NE presentation is available here: https://www.iso-ne.com/static-assets/documents/2020/04/a04_2020_04_28_order_845_further_compliance.pptx. The May 27 ISO-NE presentation is available here: https://www.iso-ne.com/static-assets/documents/2020/05/a03_tc_2020_05_27_845_presentation.pptx

The following form of resolution can be used for Participants Committee action on the Order No. 845 Revisions[4]:

> RESOLVED, that the Participants Committee supports the Order No. 845 Revisions, as recommended by the Transmission Committee, and as reflected in the materials posted for the June 4, 2020 Participants Committee 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 Transmission Committee.

[4] This vote has a minimum two-thirds voting threshold.

SCHEDULE 22

LARGE GENERATOR INTERCONNECTION PROCEDURES

SECTION I. DEFINITIONS

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

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

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

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

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

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

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

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

interconnection is sought; or (e) that the Interconnection Customer has filed applications for required permits to site on federal or state property.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, and Interconnecting Transmission Owner must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If the System Operator, Interconnecting Transmission Owner, and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the System Operator must provide the Interconnection Customer a written technical explanation outlining why the System Operator does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 ~~Business D~~ days of its determination.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in this Schedule 22 to the Tariff.

Standard Large Generator Interconnection Procedures ("LGIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in this Schedule 22 to the Tariff.

Study Case shall have the meaning specified in Sections 6.2 and 7.3 of this LGIP.

Surplus Interconnection Service shall mean a form of Interconnection Service that allows an Interconnection Customer to use any Unused Capability of Interconnection Service established in an Interconnection Agreement for an existing Generating Facility that has achieved Commercial Operation, such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the same Point of Interconnection would remain the same.

System Protection Facilities shall mean the equipment, including necessary signal protection communications equipment, required to protect (1) the New England Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the New England Transmission System or on other delivery systems or other generating systems to which the New England Transmission System is directly connected.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Unused Capability shall mean: (i) in the case of NR Interconnection Service at an existing, commercial Generating Facility,~~, for Summer, the Summer NR Capability minus the latest Seasonal Claimed Capability for Summer as corrected to 50 degrees F, and, for Winter, the Winter NR Capability minus the latest Seasonal Claimed Capability for Winter as corrected to 0 degrees F~~ the MW quantity as determined by the Original Interconnection Customer (as defined in Section 3.3 of the LGIP), not to exceed the existing, commercial Generating Facility's NR Interconnection Service; and (ii) in the case of CNR Interconnection Service at an existing, commercial Generating Facility, for Summer, the Summer CNR Capability minus the latest Summer Qualified Capacity, and for Winter, the Winter CNR Capability minus the latest Winter Qualified Capacity.

SECTION 2. SCOPE, APPLICATION AND TIME REQUIREMENTS.

2.1 Application of Standard Large Generator Interconnection Procedures.

The LGIP and LGIA shall apply to Interconnection Requests pertaining to Large Generating Facilities. Except as expressly provided in the LGIP and LGIA, nothing in the LGIP or LGIA shall be construed to limit the authority or obligations that the Interconnecting Transmission Owner or System Operator, as applicable, has with regard to ISO New England Operating Documents.

2.2. Comparability.

The System Operator shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. The System Operator and Interconnecting Transmission Owner will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection

Nothing in this LGIP shall constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

2.5 Time Requirements.

Parties that must perform a specific obligation under a provision of the Standard Large Generator Interconnection Procedure or Standard Large Generator Interconnection Agreement within a specified time period shall use Reasonable Efforts to complete such obligation within the applicable time period. A Party may, in the exercise of reasonable discretion and within the time period set forth by the applicable procedure or agreement, request that the relevant Party consent to a mutually agreeable alternative time schedule, such consent not to be unreasonably withheld.

SECTION 3. INTERCONNECTION REQUESTS.

3.1 General.

To initiate an Interconnection Request, an Interconnection Customer must comply with all of the requirements set forth in Section 3.4.1. The Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. The Interconnection Customer must comply with the requirements specified in Section 3.4.1 for each Interconnection Request even when more than one request is submitted for a single site.

Within three (3) Business Days after its receipt of a valid Interconnection Request, System Operator shall submit a copy of the Interconnection Request to Interconnecting Transmission Owner.

At Interconnection Customer's option, System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement, or the Interconnection System Impact

Study Agreement if the Interconnection Customer elects not to pursue the Interconnection Feasibility Study.

System Operator shall consider requests for Interconnection Service below the Large Generating Facility capability. An Interconnection Customer that submits an Interconnection Request for Interconnection Service below the Large Generating Facility capability shall include in the Interconnection Request the proposed control technologies to restrict the Large Generating Facility's output to the requested Interconnection Service levels. These requests for Interconnection Service shall be studied at the level of Interconnection Service requested for purposes of determining necessary Interconnection Facilities ~~and~~ Network Upgrades, and associated costs the requests shall be studied at the full Generating Facility capability to ensure the acceptability of the proposed control technology to restrict the facility's output and the safety and reliability of the system, with the study costs borne by the Interconnection Customer. Interconnection Customers may be subject to additional control technologies as well as testing and validation of those technologies consistent with Article 6 of the LGIA. The necessary control technologies and protection systems shall be established in Appendix C of the executed, or requested to be filed unexecuted, LGIA.

All deposits that must be submitted to the System Operator under this LGIP must be delivered to the System Operator's bank account by electronic transfer within the period specified in the respective provision. A deposit will not be considered received until it is in the System Operator's bank account.

3.2 Type of Interconnection Services and Long Lead Time Facility Treatment

At the time the Interconnection Request is submitted, the Interconnection Customer must request either CNR Interconnection Service or NR Interconnection Service, as described in Sections 3.2.1 and 3.2.2 below. An Interconnection Customer that meets the requirements to obtain CNR Interconnection Service shall obtain NR Interconnection Service up to the NR Capability upon completion of all requirements for NR Interconnection Service, including all necessary upgrades. Upon completion of all requirements for the CNR Interconnection Service, the Interconnection Customer shall also receive CNR Interconnection Service for CNR Capability. An Interconnection Customer that meets the requirements to obtain NR Interconnection Service shall receive NR Interconnection Service for the Interconnection Customer's NR Capability. At the time the Interconnection Request is submitted, the Interconnection Customer may also request Long Lead Facility treatment in accordance with Section 3.2.3.

deemed withdrawn under Section 3.7 if the Interconnection Customer fails to comply with the requirements for Long Lead Facility treatment, including the milestones specified in Section 3.2.1.4. In this circumstance, the conditions specified in an Interconnection Agreement for a Generating Facility seeking CNR Interconnection Service or External ETU seeking CNI Interconnection Service that had an Interconnection Request of a Queue Position lower than the Long Lead Facility, but cleared (in the case of the Elective Transmission Upgrade, the Import Capacity Resource) in a Forward Capacity Auction prior to the Long Lead Facility, shall be removed.

3.2.3.6 Participation in Earlier Forward Capacity Auctions.

An Interconnection Customer with a Long Lead Facility may, without loss of Queue Position, elect to participate in an earlier Forward Capacity Auction than originally anticipated, but only if the election to accelerate is made to the System Operator in writing within thirty (30) Calendar Days of the Scoping Meeting or within thirty (30) Calendar Days of the completion of the System Impact Study (but before the Long Lead Facility and the results of the associated System Impact Study are incorporated into the Base Cases). Otherwise, such an election shall be considered a Material Modification.

3.3 Utilization of Surplus Interconnection Service.

Surplus Interconnection Service allows an existing Interconnection Customer whose Generating Facility is already interconnected to the Administered Transmission System and is in Commercial Operation to utilize or transfer Surplus Interconnection Service at the existing Generating Facility's existing Point of Interconnection. For purposes of Surplus Interconnection Service, the existing Interconnection Customer is referred to as the "Original Interconnection Customer," and the entity requesting Surplus Interconnection Service is referred to as the "Surplus Interconnection Customer." The Original Interconnection Customer or, with written consent of the Original Interconnection Customer, one of its affiliates shall have priority to utilize Surplus Interconnection Service. If the Original Interconnection Customer or one of its affiliates does not exercise this priority, then the Surplus Interconnection Service may be utilized by a third party of the Original Interconnection Customer's choosing and with the Original Interconnection Customer's written consent.

Surplus Interconnection Service may be available for any Unused Capability of Interconnection Service established in the Interconnection Agreement for the Original Interconnection Customer's

Generating Facility. If the Interconnection Agreement for the Original Interconnection Customer's Generating Facility is for CNR Interconnection Service, any Surplus Interconnection Service may be for CNR Interconnection Service or NR Interconnection Service. If the Interconnection Agreement for the Original Interconnection Customer's Generating Facility is for NR Interconnection Service, any Surplus Interconnection Service shall be for NR Interconnection Service. Surplus Interconnection Service is not applicable when a new Interconnection Request for Interconnection Service or Network Upgrades would be required to implement the proposed change to the Original Interconnection Customer's Generating Facility. Surplus Interconnection Service is also not available for a retirement or repowering of the Original Interconnection Customer's Generating Facility.

The Original Interconnection Customer shall specify the amount of Unused Capability that is available for use by the Surplus Interconnection Customer's Generating Facility. The total output of the Original Interconnection Customer's Generating Facility plus the Surplus Interconnection Customer's Generating Facility behind the same Point of Interconnection shall be limited to the maximum total amount of Interconnection Service granted to the Original Interconnection Customer as established in the Interconnection Agreement for the Original Interconnection Customer's Generating Facility. ~~The Original Interconnection Customer must stipulate the amount of Unused Capability that is available for use by the Surplus Interconnection Customer's Generating Facility.~~ Control technology to restrict the total output of the Original Interconnection Customer's and Surplus Interconnection Customer's Generating Facilities shall be required in the case where the sum of the maximum output of the Original Interconnection Customer's Generating Facility plus the maximum output of the Surplus Interconnection Customer's Generating Facility exceeds the total amount of Interconnection Service established in the Original Interconnection Customer's Interconnection Agreement. Surplus Interconnection Service shall only be available at the existing Point of Interconnection of the Original Interconnection Customer's Generating Facility.

3.3.1 Surplus Interconnection Service Request

An Original Interconnection Customer or, with the consent of the Original Interconnection Customer, its affiliate or a third party of the Original Interconnection Customer's choosing may request Surplus Interconnection Service by submitting to the System Operator a completed

Surplus Interconnection Service Request Application in the form contained in Attachment C to Appendix 1 of the LGIP. The Surplus Interconnection Service Request Application shall be accompanied by the Original Interconnection Customer's written consent for the Surplus Interconnection Customer's use of Unused Capability for Surplus Interconnection Service, and the technical data called for in the form.

Studies for Surplus Interconnection Service may consist of reactive power, short circuit/fault duty, stability analyses, and/or other appropriate studies. Steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required reliability conditions are studied. The study shall consider the full Generating Facility capability to ensure the acceptability of the proposed control technology to restrict the total output of the Original Interconnection Customer's and Surplus Interconnection Customer's Generating Facilities. If the Surplus Interconnection Service was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original Interconnection System Impact Study is not available for ~~the Original Interconnection Customer's Generating Facility, limited analysis may need to be performed~~ Surplus Interconnection Service, both off-peak and peak analysis may need to be performed for the existing Generating Facility associated with the request for Surplus Interconnection Service. The reactive power, short circuit/fault duty, stability, and steady-state analyses for Surplus Interconnection Service will identify any additional Interconnection Facilities and/or Network Upgrades necessary. ~~which may include, but not be limited to, both off-peak and peak analyses, and/or reactive power, short circuit/fault duty, stability, and steady-state analyses, to confirm the Surplus Interconnection Service request can be accommodated without the need for additional upgrades and a new Interconnection Request.~~ Any analyses shall be performed at the Surplus Interconnection Customer's expense.

The Interconnection Agreement for the Original Interconnection Customer's Generating Facility shall be replaced by a new agreement among the System Operator, Interconnecting Transmission Owner, Original Interconnection Customer, and Surplus Interconnection Customer. The agreement shall be in the form of the most currently effective LGIA, modified to reflect the Surplus Interconnection Customer's Generating Facility and the amount of, and the terms for the use of, ~~and~~ the ~~associated~~ Surplus Interconnection Service. The agreement shall be developed

3.5.1

The System Operator will maintain on its OASIS a list of all Interconnection Requests in its Control Area. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected Initial Synchronization Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the type of Interconnection Service being requested (i.e., CNR Interconnection Service or NR Interconnection Service); and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Except in the case of an Affiliate, the list will not disclose the identity of the Interconnection Customer until the Interconnection Customer executes an LGIA or requests that the System Operator and Interconnecting Transmission Owner jointly file an unexecuted LGIA with the Commission. Before participating in a Scoping Meeting with an Interconnection Customer that is also an Affiliate, the Interconnecting Transmission Owner shall post on OASIS an advance notice of its intent to do so. The System Operator shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to the System Operator's OASIS site subsequent to the meeting between the System Operator, Interconnecting Transmission Owner, and Interconnection Customer to discuss the applicable study results. The System Operator shall also post any known deviations in the Large Generating Facility's Initial Synchronization Date.

3.5.2 Requirements to Post Interconnection Study Metrics

The System Operator will maintain on its website summary statistics related to processing Interconnection Studies pursuant to Interconnection Requests, updated quarterly. If the System Operator posts this information on its website, a link to the information must be provided on the System Operator's OASIS site. For each calendar quarter, the System Operator must calculate and post the information detailed in Sections 3.5.2.1 through 3.5.2.4.

3.5.2.1 Interconnection Feasibility Studies Processing Time.

(A) Number of Interconnection Requests that had Interconnection Feasibility Studies completed

for the System Operator's Administered Transmission System during the reporting quarter,

(B) Number of Interconnection Requests that had Interconnection Feasibility Studies completed for the System Operator's Administered Transmission System during the reporting quarter that were completed more than ninety (90) ~~forty-five (45)~~ Calendar Days after receipt by System Operator of the Interconnection Customer's executed Interconnection Feasibility Study Agreement,

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with ongoing incomplete Interconnection Feasibility Studies where such Interconnection Requests had executed Interconnection Feasibility Study Agreements received by System Operator more than ninety (90) ~~forty-five (45)~~ Calendar Days before the reporting quarter end,

(D) Mean time (in days), Interconnection Feasibility Studies completed for the System Operator's Administered Transmission System during the reporting quarter, from the date when System Operator received the executed Interconnection Feasibility Study Agreement to the date when System Operator provided the completed Interconnection Feasibility Study to the Interconnection Customer,

(E) Percentage of Interconnection Feasibility Studies exceeding ninety (90) ~~forty-five (45)~~ Calendar Days to complete this reporting quarter, calculated as the sum of 3.5.2.1(B) plus 3.5.2.1(C) divided by the sum of 3.5.2.1(A) plus 3.5.2.1(C).

3.5.2.2 Interconnection System Impact Studies Processing Time.

(A) Number of Interconnection Requests that had Interconnection System Impact Studies completed for the System Operator's Administered Transmission System during the reporting quarter,

(B) Number of Interconnection Requests that had Interconnection System Impact Studies completed for the System Operator's Administered Transmission System during the reporting quarter that were completed more than two hundred and seventy (270) ~~ninety (90)~~ Calendar Days

after receipt by System Operator of the Interconnection Customer's executed Interconnection System Impact Study Agreement,

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with ongoing incomplete System Impact Studies where such Interconnection Requests had executed Interconnection System Impact Study Agreements received by System Operator more than two hundred and seventy (270) ~~ninety (90)~~ Calendar Days before the reporting quarter end,

(D) Mean time (in days), Interconnection System Impact Studies completed for the System Operator's Administered Transmission System during the reporting quarter, from the date when System Operator received the executed Interconnection System Impact Study Agreement to the date when System Operator provided the completed Interconnection System Impact Study to the Interconnection Customer,

(E) Percentage of Interconnection System Impact Studies exceeding two hundred and seventy (270) ~~ninety (90)~~ Calendar Days to complete this reporting quarter, calculated as the sum of 3.5.2.2(B) plus 3.5.2.2(C) divided by the sum of 3.5.2.2(A) plus 3.5.2.2(C).

3.5.2.3 Interconnection Facilities Studies Processing Time.

(A) Number of Interconnection Requests that had Interconnection Facilities Studies that are completed for the System Operator's Administered Transmission System during the reporting quarter,

(B) Number of Interconnection Requests that had Interconnection Facilities Studies that are completed for the System Operator's Administered Transmission System during the reporting quarter that were completed more than ninety (90) Calendar Days for no more than +/- 20 percent cost estimate or one hundred eighty (180) Calendar Days for +/- 10 percent cost estimate after receipt by System Operator of the Interconnection Customer's executed Interconnection Facilities Study Agreement,

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with

information or actions that cure the deficiency or to notify the System Operator of its intent to pursue Dispute Resolution, and System Operator shall notify Interconnecting Transmission Owner and any Affected Parties of the same.

Withdrawal shall result in the loss of the Interconnection Customer's Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, the System Operator may eliminate the Interconnection Customer's Interconnection Request from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to System Operator, Interconnecting Transmission Owner, and any Affected Parties all costs prudently incurred with respect to that Interconnection Request prior to System Operator's receipt of notice described above. The Interconnection Customer must pay all monies due before it is allowed to obtain any Interconnection Study data or results.

The System Operator shall update the OASIS Queue Position posting. Except as otherwise provided elsewhere in this LGIP, the System Operator and the Interconnecting Transmission Owner shall arrange to refund to the Interconnection Customer any portion of the Interconnection Customer's deposit or study payments that exceeds the costs incurred, including interest calculated in accordance with section 35.19a(a)(2) of the Commission's regulations, or arrange to charge to the Interconnection Customer any amount of such costs incurred that exceed the Interconnection Customer's deposit or study payments, including interest calculated in accordance with section 35.19a(a)(2) of the Commission's regulations. In the event of such withdrawal, System Operator, subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information, shall provide, at Interconnection Customer's request, all information developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

3.8 Identification of Contingent Facilities.

System Operator shall identify Contingent Facilities before the execution of the LGIA by reviewing the Interconnection Facilities and Network Upgrades associated with an Interconnection Request with a higher Queue Position or the list of transmission projects planned or proposed for the New England

Transmission System to identify those upgrades that are not yet in service but upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing. Planned or proposed upgrades will be identified as Contingent Facilities for an Interconnection Request if the absence of those upgrades would cause additional Adverse System Impacts to be identified in the System Impact Study, using the same conditions as those used in the System Impact Study. The thresholds for identification of Adverse System Impact for the purpose of identifying Contingent Facilities will be as follows: (i) an increase in the flow in an element by at least two percent of the element's rating and that causes that flow to exceed that element's appropriate thermal rating by more than two percent where the appropriate thermal rating is the normal rating with all lines in service and the long time emergency or short time emergency rating after a contingency; (ii) a change of at least one percent in a voltage that causes a voltage level that is higher or lower than the appropriate high or low rating by more than one percent; (iii) an increase of at least a one percent change in the short circuit current experienced by an element and that causes a short circuit stress that is higher than an element's interrupting or withstand capability; or (iv) the introduction of a violation of stability criteria. Contingent Facilities that are identified during the evaluation of the Interconnection Request shall be documented in the Interconnection System Impact Study report or the LGIA for the Large Generating Facility. System Operator shall also provide, upon request of the Interconnection Customer, the estimated Interconnection Facility and/or Network Upgrade costs and estimated in-service completion time for each identified Contingent Facilities when this information is readily available and not commercially sensitive.

SECTION 4. QUEUE POSITION.

4.1 General.

System Operator shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form in Appendix 1 to this LGIP, and Interconnection Customer provides such information in accordance with Section 3.4.3, then System Operator shall assign Interconnection Customer a Queue Position based on the date the application form was originally submitted.

8.2 Scope of Interconnection Facilities Study.

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Administered Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. The Interconnection Facilities Study shall also identify any potential control technology for the Large Generating Facility if the Interconnection Customer has requested Interconnection Service at a level that is lower than the nameplate capability of the facility. The scope and cost of the Interconnection Facilities Study shall include completion of any engineering work limited to what is reasonably required to (i) estimate such aforementioned cost to the accuracy specified by the Interconnection Customer pursuant to Section 8.3, (ii) identify, configurations of required facilities and (iii) identify time requirements for construction and installation of required facilities.

8.3 Interconnection Facilities Study Procedures.

The System Operator shall coordinate the Interconnection Facilities Study with Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, pursuant to Section 3.6 above. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the study and the System Operator shall issue a draft Interconnection Facilities Study report to the Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, within the following number of days after receipt of an executed Interconnection Facilities Study Agreement: ninety (90) Calendar Days, with no more than a +/- 20 percent good faith cost estimate contained in the report; or one hundred eighty (180) Calendar Days, if the Interconnection Customer requests a +/- 10 percent good faith cost estimate. Such cost estimates either individually or in the aggregate will be provided in the final study report. If the System Operator uses Clustering, the System Operator and the

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

RECITALS

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

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

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

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

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

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

ARTICLE 1. DEFINITIONS

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

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

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

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

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

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

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

Site Control shall mean documentation reasonably demonstrating: (a) that the Interconnection Customer is the owner in fee simple of the real property or holds an easement for which new interconnection is sought; (b) that the Interconnection Customer holds a valid written leasehold or other contractual interest in the real property for which new interconnection is sought; (c) that the Interconnection Customer holds a valid written option to purchase or a leasehold interest in the real property for which new interconnection is sought; (d) that the Interconnection Customer holds a duly executed written contract to purchase, acquire an easement, a license or a leasehold interest in the real property for which new interconnection is sought; or (e) that the Interconnection Customer has filed applications for required permits to site on federal or state property.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, and Interconnecting Transmission Owner must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If the System Operator, Interconnecting Transmission Owner, and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the System Operator must provide the Interconnection Customer a written technical explanation outlining why the System Operator does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 ~~Business D~~ days of its determination.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in this Schedule 22 to the Tariff.

Standard Large Generator Interconnection Procedures ("LGIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in this Schedule 22 to the Tariff.

Surplus Interconnection Service shall mean a form of Interconnection Service that allows an Interconnection Customer to use any Unused Capability of Interconnection Service established in an Interconnection Agreement for an existing Generating Facility that has achieved Commercial Operation,

such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the same Point of Interconnection would remain the same.

Study Case shall have the meaning specified in Sections 6.2 and 7.3 of this LGIP.

System Protection Facilities shall mean the equipment, including necessary signal protection communications equipment, required to protect (1) the New England Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the New England Transmission System or on other delivery systems or other generating systems to which the New England Transmission System is directly connected.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Unused Capability shall mean, **Unused Capability** shall mean: (i) in the case of NR Interconnection Service at an existing, commercial Generating Facility, ~~for Summer, the Summer NR Capability minus the latest Seasonal Claimed Capability for Summer as corrected to 50 degrees F, and, for Winter, the Winter NR Capability minus the latest Seasonal Claimed Capability for Winter as corrected to 0 degrees F~~ the MW quantity as determined by the Original Interconnection Customer (as defined in Section 3.3 of the LGIP), not to exceed the existing, commercial Generating Facility's NR Interconnection Service; and (ii) in the case of CNR Interconnection Service at an existing, commercial Generating Facility, for Summer, the Summer CNR Capability minus the latest Summer Qualified Capacity, and for Winter, the Winter CNR Capability minus the latest Winter Qualified Capacity.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 **Effective Date**. This LGIA shall become effective upon execution by the Parties subject to acceptance by the Commission (if applicable), or if filed unexecuted, upon the date specified by the Commission. System Operator and Interconnecting Transmission Owner shall promptly and jointly file this LGIA with the Commission upon execution in accordance with Section 11.3 of the LGIP and Article 3.1, if required.

promptly provide written notice to the Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 **Alternate Option**. If the dates designated by Interconnection Customer are acceptable to Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities by the designated dates.
If Interconnecting Transmission Owner subsequently fails to complete Interconnecting Transmission Owner's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B (Milestones); Interconnecting Transmission Owner shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable System Operator refuses to grant clearances to install equipment.

5.1.3 **Option to Build**. Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of new Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. ~~If the dates designated by Interconnection Customer are not acceptable to Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall so notify the Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2; provided that the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades do not involve the moving or outage of existing transmission~~

~~equipment (except for the outage necessary to tie-in the completed Interconnecting Transmission Owner's Interconnection Facility and Stand Alone Network Upgrade to the existing system), in which case the Option to Build is not available~~. The System Operator, Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by System Operator in accordance with applicable codes of conduct and confidentiality requirements must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A to the LGIA. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If the dates designated by Interconnection Customer are not acceptable to Interconnecting Transmission Owner, the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives, or the procurement and construction of all facilities other than the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.3). If the Parties are unable to reach agreement on such terms and conditions, then, pursuant to Article 5.1.1 (Standard Option), Interconnecting Transmission Owner shall assume responsibility for the design, procurement and construction of all facilities other than the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build.

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

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

(c) construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

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

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

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

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

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

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

remedy deficiencies in that portion of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

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

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

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

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

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

(13) ~~If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.3, Interconnection Customer shall pay Interconnecting Transmission Owner the actual costs for Interconnecting Transmission Owner to execute the responsibilities enumerated to Interconnecting Transmission Owner under Article 5.2.~~ Interconnection Customer shall pay Interconnecting Transmission Owner the agreed upon amount of [$ PLACEHOLDER] for

Interconnecting Transmission Owner to execute responsibilities enumerated to Interconnecting Transmission Owner under this Article 5.2. Interconnecting Transmission Owner shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

5.3 **Liquidated Damages**. The actual damages to the Interconnection Customer, in the event the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not completed by the dates designated by the Interconnection Customer and accepted by the Interconnecting Transmission Owner pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by the Interconnecting Transmission Owner to the Interconnection Customer in the event that Interconnecting Transmission Owner does not complete any portion of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, in the aggregate, for which Interconnecting Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades for which the Interconnecting Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by the Interconnecting Transmission Owner to the Interconnection Customer as just compensation for the damages caused to the Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Interconnecting Transmission Owner's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of the Interconnecting Transmission Owner's

which the Large Generating Facility and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. System Operator and Interconnecting Transmission Owner shall permit Interconnection Customer to operate the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.9.2 Provisional Interconnection Service. ~~Prior to the commencement of the Interconnection System Impact Study associated with a Large Generating Facility, an Interconnection Customer may request Provisional Interconnection Service.~~ Upon the request of Interconnection Customer, and prior to completion of requisite Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities, System Operator and the Interconnecting Transmission Owner may execute a Provisional Large Generator Interconnection Agreement or Interconnection Customer may request the filing of an unexecuted Provisional Large Generator Interconnection Agreement with the Interconnection Customer for Provisional Interconnection Service at the discretion of System Operator and Interconnecting Transmission Owner based upon an evaluation that will consider the results of available studies. System Operator and Interconnecting Transmission Owner shall determine, through available studies or additional studies as necessary, whether stability, short circuit, thermal, and/or voltage issues would arise if Interconnection Customer interconnects without modifications to the Large Generating Facility or the New England Transmission System. System Operator and Interconnecting Transmission Owner shall determine whether any Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities that are necessary to meet the requirements of NERC, or any applicable Regional Entity for the interconnection of a new, modified and/or expanded Large Generating Facility are in place prior to the commencement of Interconnection Service from the Large Generating Facility. Where available studies indicate that such Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities that are required for the interconnection of a new, modified and/or expanded Large Generating Facility are not currently in place, System Operator will perform a study, at the Interconnection

MAY 27, 2020 | WEBEX

FERC Order No. 845 Further Compliance

Reform of Generator Interconnection Procedures and Agreements

Al McBride

DIRECTOR, TRANSMISSION STRATEGY & SERVICES

FERC Order No. 845 Further Compliance

Proposed Effective Date: Further changes will be effective March 19, 2020 once accepted by FERC (Compliance Filing is required by July *17, 2020*)

- On April 19, 2018, the Federal Energy Regulatory Commission ("Commission") issued Order No. 845, its Final Rule on Reform of Generator Interconnection Procedures and Agreements
- The ISO held discussions at the NEPOOL Transmission Committee from May to September 2018 and March and April 2019 on its approach to comply with Order No. 845
- ISO-NE and the PTO-AC filed proposed changes to Schedule 22 on May 22, 2019
- On March 19, 2020, the Commission issued an Order on Compliance in Docket No. ER19-1951 partially accepting the May 22, 2019 Compliance Filing
- The ISO presented its initial Tariff redlines on April 28, 2020
- This presentation provides additional changes in response to stakeholder discussions, a complete proposed redline can be found in the posted *pro forma*

OPTION TO BUILD

Proposed Further Compliance Tariff Language

Updates to the language presented at the April RC in green text

LGIA Article 5.2(13)

- Original PTO sponsored variation to be replaced with *pro forma* language.

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

SURPLUS INTERCONNECTION SERVICE

Proposed Further Compliance Tariff Language

Updates to the language presented at the April RC in green text

Update to the ISO's Proposal for Surplus Service in the case of NR Interconnection Service

- The ISO received feedback at the April TC meeting regarding the application of Surplus Interconnection Service in the case of Network Resource Interconnection Service
  - Committee members described how arrangements could be made, for example to identify when the surplus customer would not operate when the original customer needed to operate
- The ISO has also had time to continue to evolve the understanding of how co-located resources may operate in the energy and capacity markets
  - Including the case where a limiting device is used to limit the overall output of a co-located facility
- The ISO is proposing that the original customer would identify and eventually memorialize in the Interconnection Agreement such terms of use of the Surplus Interconnection Service
  - When necessary, a limiting device would be used to limit the overall output of a co-located facility
- Finally, FERC responded to ISO's Request for Clarification on May 19, 2020
  - The ISO is now proposing to adopt the Order No. 845/845A pro forma language regarding the scope of study for Surplus Interconnection Service requests

LGIA/LGIP Definitions

Unused Capability shall mean (i) in the case of NR Interconnection Service at an existing, commercial Generating Facility, the MW quantity as determined by the Original Interconnection Customer (as defined in Section 3.3 of the LGIP)~~;~~ ~~a continuous, or periodic, MW quantity as determined by the existing commercial Generating Facility and specified in an Interconnection Agreement~~, not to exceed the existing, commercial Generating Facility's NR Interconnection Service; and (ii) in the case of CNR Interconnection Service at an existing, commercial Generating Facility, for Summer, the Summer CNR Capability minus the latest Summer Qualified Capacity, and for Winter, the Winter CNR Capability minus the latest Winter Qualified Capacity

LGIP Section 3.3

Utilization of Surplus Interconnection Service.

The Original Interconnection Customer shall specify the amount of Unused Capability that is available for use by the Surplus Interconnection Customer's Generating Facility. The total output of the Original Interconnection Customer's Generating Facility plus the Surplus Interconnection Customer's Generating Facility behind the same Point of Interconnection shall be limited to the maximum total amount of Interconnection Service granted to the Original Interconnection Customer as established in the Interconnection Agreement for the Original Interconnection Customer's Generating Facility. Control technology to restrict the total output of the Original Interconnection Customer's and Surplus Interconnection Customer's Generating Facilities shall be required in the case ~~the facility's output is required in the case~~ where the sum of the maximum output of the Original Interconnection Customer's Generating Facility plus the maximum output of the Surplus Interconnection Customer's Generating Facility exceeds the total amount of associated Interconnection Service granted to the Original Interconnection Customer. ~~The Original Interconnection Customer must stipulate the amount of Unused Capability that is available for use by the Surplus Interconnection Customer's Generating Facility.~~ Surplus Interconnection Service shall only be available at the existing Point of Interconnection of the Original Interconnection Customer's Generating Facility

LGIP Section 3.3.1

Studies for Surplus Interconnection Service may consist of reactive power, short circuit/fault duty, stability analyses, and/or other appropriate studies. Steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required reliability conditions are studied. The study shall consider the full Generating Facility capability to ensure the acceptability of the proposed control technology to restrict the total output of the Original Interconnection Customer's and Surplus Interconnection Customer's Generating Facilities. If the Surplus Interconnection Service was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original Interconnection System Impact Study is not available for ~~the Original Interconnection Customer's Generating Facility, limited analysis may need to be performed~~ Surplus Interconnection Service, both off-peak and peak analysis may need to be performed for the existing Generating Facility associated with the request for Surplus Interconnection Service. The reactive power, short circuit/fault duty, stability, and steady-state analyses for Surplus Interconnection Service will identify any additional Interconnection Facilities and/or Network Upgrades necessary. ~~which may include, but not be limited to, both off-peak and peak analyses, and/or reactive power, short circuit/fault duty, stability, and steady-state analyses, to confirm the Surplus Interconnection Service request can be accommodated without the need for additional upgrades and a new Interconnection Request.~~ Any analyses shall be performed at the Surplus Interconnection Customer's expense.

LGIP Section 3.3.1 (Continued)

~~System Operator shall continue such studies until it determines whether any additional Interconnection Facilities and/or Network Upgrades are necessary to accommodate the Surplus Interconnection Customer's Generating Facility. If additional Network Upgrades are required to accommodate the Surplus Interconnection Customer's Generating Facility, Surplus Interconnection Service is not applicable and the Surplus Interconnection Customer may pursue its Generating Facility's interconnection by submitting a new Interconnection Request.~~

The Interconnection Agreement for the Original Interconnection Customer's Generating Facility shall be replaced by a new agreement among the System Operator, Interconnecting Transmission Owner, Original Interconnection Customer, and Surplus Interconnection Customer. The agreement shall be in the form of the most currently effective LGIA, modified to reflect the Surplus Interconnection Customer's Generating Facility and the amount of, and the terms for the use of, ~~and~~ the ~~associated~~ Surplus Interconnection Service. The agreement shall be developed and negotiated in accordance with Section 11 of the LGIP, at the Surplus Interconnection Customer's expense.

ADDITIONAL CONFORMING CHANGES

Newly included since the April TC meeting

Sections 3.5.2.1-2 Study Timelines

- Conforming changes related to the Commission accepted study timeline modifications in Docket No. ER19-1952
- Change timelines from 45 to 90 days for processing Interconnection Feasibility Studies in Section 3.4.2.1
- Change timelines from 90 to 270 days for processing Interconnection System Impact Studies in Section 3.4.2.2

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Transmission Committee April 28, 2020	First review of proposed Tariff language
Transmission Committee **May 27, 2020**	Second review of proposed Tariff language and Vote
Participants Committee **June 4, 2020**	Vote

Questions

memo

To: Participants Committee

From: Jay Dwyer, Secretary, NEPOOL Transmission Committee

Date: May 27, 2020

Subject: Actions of the Transmission Committee

This memo is notification to the Participants Committee of the following actions taken by the Transmission Committee (TC) at its May 27, 2020 meeting. All sectors had a quorum.

1. **Agenda Item No. 2: April 28, 2020 MEETING MINUTES**
   ACTION: APPROVED

   The Transmission Committee approved the minutes of the April 28, 2020 Transmission Committee meeting by a voice vote with no opposition and no abstentions recorded.

2. **Agenda Item No. 3: Order 845 Further Compliance**
   ACTION: APPROVED

   The following motion was made and seconded by the Transmission Committee:
   Resolved, that the Transmission Committee recommends Participant Committee support for the ISO-NE further compliance filing in FERC Docket No. ER-19-1951 as distributed to the Transmission Committee for its meeting on May 27, 2020 with any changes agreed to by the ISO.

   The motion was voted on a voice vote and passed with no opposition and no abstentions recorded.

3. **Agenda Item No. 4: Revisions to the ISO-NE Tariff to Carry Out the Settlement in FERC Docket No. EL16-19-000-002**
   ACTION: APPROVED

   The following motions were made and seconded by the Transmission Committee:

   a. Motion to enter Executive Session:

   A motion was made and seconded to enter an executive session open only to NEPOOL Members and Alternates and parties to the Settlement Agreement for purposes of discussing confidential settlement information distributed by NEPOOL Counsel for the meeting.

   The motion was voted on a voice vote and passed with no opposition and no abstentions

   b. Motion to recommend Participant Committee Support for the proposed Tariff revisions:

   The following motion was made and seconded by the Committee

Resolved, that the Transmission Committee recommends Participants Committee support for the revisions to the ISO-NE Tariff (the "Formula Rate Revisions") to carry out the settlement agreed to by the parties to the formula rate proceeding in FERC Docket No. EL16-19-000, -002, as distributed to the Transmission Committee for its meeting on May 27, 2020, subject to any non-substantive changes agreed to by the Chair and Vice Chair of the Transmission Committee after the meeting.

The motion was voted on a voice vote and passed with no opposition and 11 abstentions noted (2 in the AR Sector, 2 in the End User Sector, 2 in the Generation Sector, 1 in the Publicly Owned Sector, and 4 in the Supplier Sector).

c. Motion to leave Executive Session:

A motion was made and seconded to leave executive session.

The motion was voted on a voice vote and passed with no opposition and no abstentions noted.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-535-4135
jdwyer@iso-ne.com

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: May 28, 2020

RE: **Vote on Planning Procedure 10 Revisions**

At the June 4, 2020 Participants Committee meeting you will be asked to vote on revisions to Planning Procedure 10 ("PP-10"). The proposed revisions to Section 7.5 of PP-10 (the "PP-10 Revisions") provide the implementation details for the alignment of reliability reviews of de-list bids with the competitive transmission solution process under Section 4 of Attachment K of the ISO-NE Open Access Transmission Tariff.[1] The Reliability Committee recommended the PP-10 Revisions, with one opposition, at its May 19, 2020 meeting.[2] The sole opponent of the PP-10 Revisions has requested that they be included as an item on the discussion agenda for the June 4 Participants Committee meeting.

The following form of resolution can be used for Participants Committee action on the PP-10 Revisions[3]:

> RESOLVED, that the Participants Committee supports the PP-10 Revisions as recommended by the Reliability Committee, and as reflected in the materials distributed for the June 4, 2020 Participants Committee meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

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[1] An ISO-NE presentation on the PP-10 Revisions is available here: https://www.iso-ne.com/static-assets/documents/2020/05/a06.2_rc_2020_05_19_pp10_incorp_compet_trans.zip.

[2] The motion passed with a roll-call vote of 98.80% in favor. The individual Sector votes were Generation (16.77% in favor, 0.00% opposed, 0 abstentions), Transmission (16.77% in favor, 0.00% opposed, 0 abstentions), Supplier (15.58% in favor, 1.20% opposed, 0 abstentions), Publicly Owned Entity (16.77% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (16.04% in favor, 0.00% opposed, 0 abstentions), and End User (16.77% in favor, 0.00% opposed, 0 abstentions). In addition, the votes from Provisional Members were (0.09% in favor, 0.00% opposed, 0 abstentions).

[3] To pass, this matter requires at least two-thirds vote in support.

ISO NEW ENGLAND PLANNING PROCEDURE NO. 10

PLANNING PROCEDURE TO SUPPORT THE FORWARD CAPACITY MARKET

REFERENCES: ISO New England Transmission, Markets and Services Tariff (the "Tariff")

NERC TPL-001, Transmission System Planning Performance Requirements (NERC TPL-001)

NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System (NPCC Directory 1)

ISO New England Planning Procedure No. 3 (PP3): Reliability Standards for the New England Area Pool Transmission Facilities

ISO New England Planning Procedure No. 5-6 (PP5-6): Interconnection Planning Procedure for Generation and Elective Transmission Upgrades

ISO New England Operating Procedure No. 4 (OP4): Action During a Capacity Deficiency

ISO New England Operating Procedure No. 19 (OP19): Transmission Operations

Master/Local Control Center Procedure No. 1 – Nuclear Plant Transmission Operations (M/LCC1)

Master/Local Control Center Procedure No. 15 – System Operating Limits Methodology (M/LCC15)

Transmission Planning Technical Guide

Contents

- One critical resource in the electrical vicinity of the resource associated with the de-list bid under review will be assumed out of service.

Appendix A of this procedure illustrates a detailed list of assumptions supporting the above conditions.

7.3 Minimum MW Quantity Threshold

No analysis is required to assess the individual impact of a de-list bid or demand bid with a MW quantity smaller than 5 MW. However, analyses may be conducted to assess the cumulative impact of such de-list bids and demand bids, in conjunction with other de-list bids or demand bids.

For a full de-list or demand bid, the quantity analyzed is the resource's Qualified Capacity, Capacity Supply Obligation or the lesser of the two depending on the type of de-list or demand bid and the timeframe of review, as shown in Appendix A.

For a partial de-list or demand bid, the quantity analyzed is the MW reduction of the de-list or demand bid and applied to the resource's Qualified Capacity, Capacity Supply Obligation or the lesser of the two depending on the type of de-list or demand bid and the timeframe of review, as shown in Appendix A.

7.4 Order of Review

7.4.1 De-list Bids for a Forward Capacity Auction

For a Forward Capacity Auction, de-list bids and demand bids will be reviewed in the order prescribed by Section III.13.2.5.2.5(a) of Market Rule 1.

7.4.2 Demand Bids for an Annual Reconfiguration Auction

For an Annual Reconfiguration Auction, demand bids will be reviewed in the order prescribed by Section III.13.4.2.2(c) of Market Rule 1.

7.5 De-list Bids Rejected for Reliability

Pursuant to Section III.13.2.5.2.5(a) of Market Rule 1, de-list bids shall only be rejected for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the de-list bid may result in the procurement of less capacity than the net Installed Capacity Requirement or the Local Sourcing Requirement for a Capacity Zone.

For thermal analyses, the capacity associated with the de-list bid or demand bid under review will be maintained to address local loadings beyond the applicable thermal rating of the Element when the removal of the capacity results in either an increase to the loading beyond the applicable thermal rating of the Element greater than 10 MVA or an increase to the loading beyond the applicable thermal rating of the Element that is greater than or equal to 2% of the Element's applicable thermal rating.

De-list bids that retained their Capacity Supply Obligation as a result of a reliability review rejection will be modeled as Existing Capacity in all subsequent reliability reviews performed for the Capacity Commitment Period under consideration until the reliability need has been met.

Following each Annual Reconfiguration Auction, pursuant to Section III.13.2.5.2.5(e) of Market Rule 1, the ISO will re-evaluate any and all de-list bids rejected for reliability reasons to determine if the reliability need which caused the ISO to reject the de-list bid has been met as the result of a new transmission project, formerly de-listed resources, New Capacity Resource(s) having obtained a Capacity Supply Obligation or updates to all relevant assumptions. Rejected de-list bids will be re-evaluated in the order that was used in the initial review and described in Section III.13.2.5.2.5(a) of Market Rule 1.

Where a request for proposal (RFP) under Section 4 of Attachment K has been issued in response to a de-list bid rejected for reliability reasons, the ISO's re-evaluation of the rejected de-list bid may consider:

1. Whether there are responses to the RFP with in-service dates prior to the relevant Capacity Commitment Period for the rejected de-list bid and the ISO determines that some of those responses, including the Backstop Transmission Solution, are reasonably likely to be in-service prior to the relevant Capacity Commitment Period for the rejected de-list bid; and
2. Whether some of such responses are expected to address the reliability need(s) set forth in the RFP.

In such cases, responses to the RFP may be determined to be timely and sufficient to meet the reliability need caused by the rejected de-list bid.

Pursuant to Section III.13.2.5.2.5(f) of Market Rule 1, should the local reliability issue that caused the ISO to reject the de-list bid be satisfied prior to or during the Capacity Commitment Period, then the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

7.6 Stakeholder Review

In accordance with Section III.13.1.8.(e) of Market Rule 1, the ISO shall post on its website no later than three Business Days after the Existing Capacity Retirement Deadline information (aggregated by Load Zone) concerning Permanent De-List Bids and Retirement De-List Bids, including Permanent De-List Bids and Retirement De-List Bids entered from the prior FCA. The ISO will

10.0 Document History

Rev. 0 App: RC – 02/13/07; NPC – 03/02/07; ISO-NE – 03/07/07

Rev. 1: Inserted Appendix F and Updated Appendix D – 05/30/07

Rev. 2 App: RC – 08/08/07; NPC – 09/07/07; ISO-NE – 09/10/07

Rev. 3 App: RC – 12/19/07; NPC – 01/04/08; ISO-NE – 01/07/08

Rev. 4 App: RC – 04/15/08; NPC – 05/09/08; ISO-NE – 05/14/08

Rev. 5 App: RC – 11/04/08; NPC – 11/20/08; ISO-NE – 11/24/08

Rev. 6 App: RC – 06/16/09; NPC – 06/22/09; ISO-NE – 07/07/09

Rev. 7 App: RC – 01/28/10; NPC – 02/05/10; ISO-NE – 02/05/10

Rev. 8 App: RC – 06/14/10; NPC – 06/21/10; ISO-NE – 07/19/10

Rev. 9 App: RC – 02/15/11; NPC – 03/04/11; ISO-NE – 04/20/11

Rev. 10 App: RC – 09/17/12; NPC – 10/03/12; ISO-NE – 10/04/12

Rev. 11 App: RC – 02/14/13; NPC – 03/01/13; ISO-NE – 04/22/13

Rev. 12 App: RC – 03/19/13; NPC – 04/05/13; ISO-NE – 04/22/13

Rev. 13 App: RC – 06/18/13; NPC – 08/02/13; ISO-NE – 09/20/13

Rev. 14 App: RC – 06/18/14; NPC – 08/01/14; ISO-NE – 08/07/14

Rev. 15 App: RC – 08/12/14; NPC – 09/12/14; ISO-NE – 09/15/14

Rev. 16 App: RC – 12/17/14; NPC – 01/09/15; ISO-NE – 01/13/15

Rev. 17 App: RC – 05/20/15; NPC – 06/05/15; ISO-NE – 06/18/15

Rev. 18 App: RC – 07/12/16; NPC – 08/05/16; ISO-NE – 08/17/16

Rev. 19 App: RC – 10/17/17; NPC – 11/03/17; ISO-NE – 11/15/17

Rev. 20 App: RC – 03/14/18; NPC – 04/06/18; ISO-NE – 06/01/18

Rev. 21 App: RC – 08/22/18; NPC – 08/24/18; ISO-NE – 12/03/18

Rev. 22 App: RC – ; NPC – ; ISO-NE – 02/01/19

Rev. 23 App: RC – 04/24/19; NPC – 05/03/19; ISO-NE – 05/31/19

Rev. 24 App: RC – 12/18/19; NPC – 02/06/20; ISO-NE – 02/06/20

Rev. 25 App: RC – 09/25/19; NPC – 10/04/19; ISO-NE – 02/10/20

Rev. 26 App: RC - ; NPC - ; ISO-NE

MAY 19, 2020 | WEBEX

Incorporating the Competitive Transmission Solution Process in De-List Reliability Reviews: Planning Procedure 10 (PP10)

Reliability Committee

Al McBride

DIRECTOR, TRANSMISSION SERVICES AND RESOURCE QUALIFICATION

Proposed Revisions to Planning Procedure 10

Proposed Effective Date: June 4, 2020

- Proposed changes to Section 7.5 of PP10 provide the implementation details for the alignment of reliability reviews of de-list bids with the competitive solution process under Section 4 of Attachment K
- Proposed changes better describe how responses in the competitive solicitation process that meet certain conditions may be accounted for in the review of rejected de-list bids under Section 7.5 of PP10
- The ISO presented and discussed the proposed PP10 changes at the April 22, 2020 Reliability Committee meeting
  - In this presentation, the ISO summarizes the responses to questions regarding the proposal

Proposal

- The proposed changes identify how transmission solution responses from the competitive solution process that meet certain conditions, can be taken into account in the PP10 review of rejected de-list bids for subsequent commitment periods
- The proposal better aligns the timing of consideration of transmission solutions from the competitive process with the timeframes experienced with Solution Studies under Section 4.2* of Attachment K
  - A significant amount of information is provided about transmission projects early in the competitive solicitation process
  - Based on the information submitted in the competitive solicitation process, it may be reasonably likely that responses to the solicitation that address the reliability need will be in-service prior to the relevant Capacity Commitment Period

*Section 4.2 of Attachment K describes Regulated Transmission Solutions in Solutions Studies, where the Competitive Solution Process is not used

Proposed Changes to PP10

Section	Change	Reason for Change
PP10, Section 7.5	Where a request for proposal (RFP) under Section 4 of Attachment K has been issued in response to a de-list bid rejected for reliability reasons, the ISO's re-evaluation of the rejected de-list bid may consider: 1. Whether there are responses to the RFP with in-service dates prior to the relevant Capacity Commitment Period for the rejected de-list bid and the ISO determines that some of those responses, including the Backstop Transmission Solution, are reasonably likely to be in-service prior to the relevant Capacity Commitment Period for the rejected de-list bid; and 2. Whether some of such responses are expected to address the reliability need(s) set forth in the RFP. In such cases, responses to the RFP may be determined to be timely and sufficient to meet the reliability need caused by the rejected de-list bid.	Update Section 7.5 to provide detail regarding how RFP responses that meet certain conditions will be accounted for

Why does the proposal not require that a transmission solution be certified pursuant to ISO Tariff III.12.6 when considering competitive solutions in the review of a previously rejected De-list bid?

- The Attachment K process identifies transmission solutions necessary to meet reliability needs
  - In some cases, these reliability needs will be specifically associated with the retirement of a resource

ISO Tariff Section II, Attachment K, Section 4.1 (a) Triggers for Needs Assessments

Address system performance in consideration of de-list bids and cleared demand bids consistent with sections 4.1(c) and 4.1(f) of Attachment K

ISO Tariff Section II, Attachment K, Section 4.1 (c) Conduct of a Needs Assessment for Rejected De-List Bids

(i) In the case of a rejected Static De-List Bid or Dynamic De-List Bid, the ISO may as warranted, with advisory input from the Reliability Committee, examine the unavailability of the resource(s) with the rejected bid as a sensitivity in a Needs Assessment, or examine the unavailability of the resource(s) in the base representation in a Needs Assessment. The ISO may as warranted, with advisory input from the Reliability Committee, initiate a Needs Assessment for the purpose of modeling rejected Static De-List Bids or Dynamic De-List Bids where the ISO believes that the initiation of such a study is warranted

ISO Tariff Section II, Attachment K, Section 4.1 (f) Treatment of Market Responses in Needs Assessments

The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction

Why does the proposal not require that a transmission solution be certified pursuant to ISO Tariff III.12.6 when considering competitive solutions in the review of a previously rejected De-list bid? (Continued)

- The ISO provides annual status updates to the Reliability Committee on the evaluations associated with De-List Bids in the Regional System Planning Process
  - Example: Link to December 2019 Reliability Committee Presentation
  - These updates summarize all of the activity taking place to develop transmission solutions that meet the reliability needs of a system without the resource that that has requested to retire
- Once it becomes clear that the reliability need will be met, in this case by means of the competitive transmission solution process, the resource will be allowed to retire
  - For this specific purpose, the Section III.12.6 certification step is not necessary

Will the proposal affect the outcomes of the selection processes that take place under Order 1000?

- No
- No changes are proposed to the evaluation process described in Attachment K for competitive transmission proposals
  - Among other things, Section 4.3 of Attachment K describes the information requirements for competitive transmission proposals, the review conducted by the ISO and the process for sharing information with the Planning Advisory Committee
    - None of these activities will be affected by the proposed changed to PP10

Will the proposal have any effect on how new resources participate in the Forward Capacity Market?

- No
- No changes are proposed to the methodologies for conducting the initial interconnection analyses and overlapping impact analyses for new resources seeking to qualify for the FCA
  - Note that the existing procedures already provided for a process where approved retirements can be removed from the evaluation (and those provisions are not changed by this proposal)
- As is the process today, resources that qualify for the FCA and obtain a Capacity Supply Obligation would not incur additional transmission upgrade responsibilities because of a later (after clearing in the FCA) addition to the network model described in ISO Tariff Section III.12.6
  - It also remains the case that a new resource could be relieved of an originally-identified upgrade responsibility in the case where a similar upgrade is identified in the regional planning process before the resource's Interconnection Agreement is finalized

Does the proposal introduce new inconsistencies between the annual reconfiguration auctions (ARAs) and the FCA?

- No
- The network model is updated each year in accordance with Section III.12.6
  - The model is used for various activities for both the FCA and ARA
- It is the case, under the current rules, that a change in the in-service date of a previously-certified project or the introduction of a new certified project with an early in-service date can result in differences in conditions between the FCA and the associated ARAs for the same Capacity Commitment Period
  - Such differences are part of the normal preparation and conduct of the auctions
  - No changes to these provisions are proposed

Summary

- Proposed changes to Section 7.5 of PP10 provide the implementation details for the alignment of reliability reviews of rejected de-list bids with the competitive solution process under Attachment K
- Proposed changes describe how responses in the competitive solicitation process that meet certain conditions may be accounted for in the reliability review of rejected de-list bids under Section 7.5 of PP10
- The proposed changes would prevent unnecessarily retaining a resource for reliability if transmission responses in the competitive solicitation process address the reliability need and meet certain conditions

Stakeholder Schedule for Revisions to PP10

Proposed Effective Date – June 4, 2020

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee **April 22, 2020**	Introduction to proposed revisions to PP10
Reliability Committee **May 19, 2020**	Vote on the proposed revisions to PP10
Participants Committee **June 4, 2020**	Vote on the proposed revisions to PP10

Questions

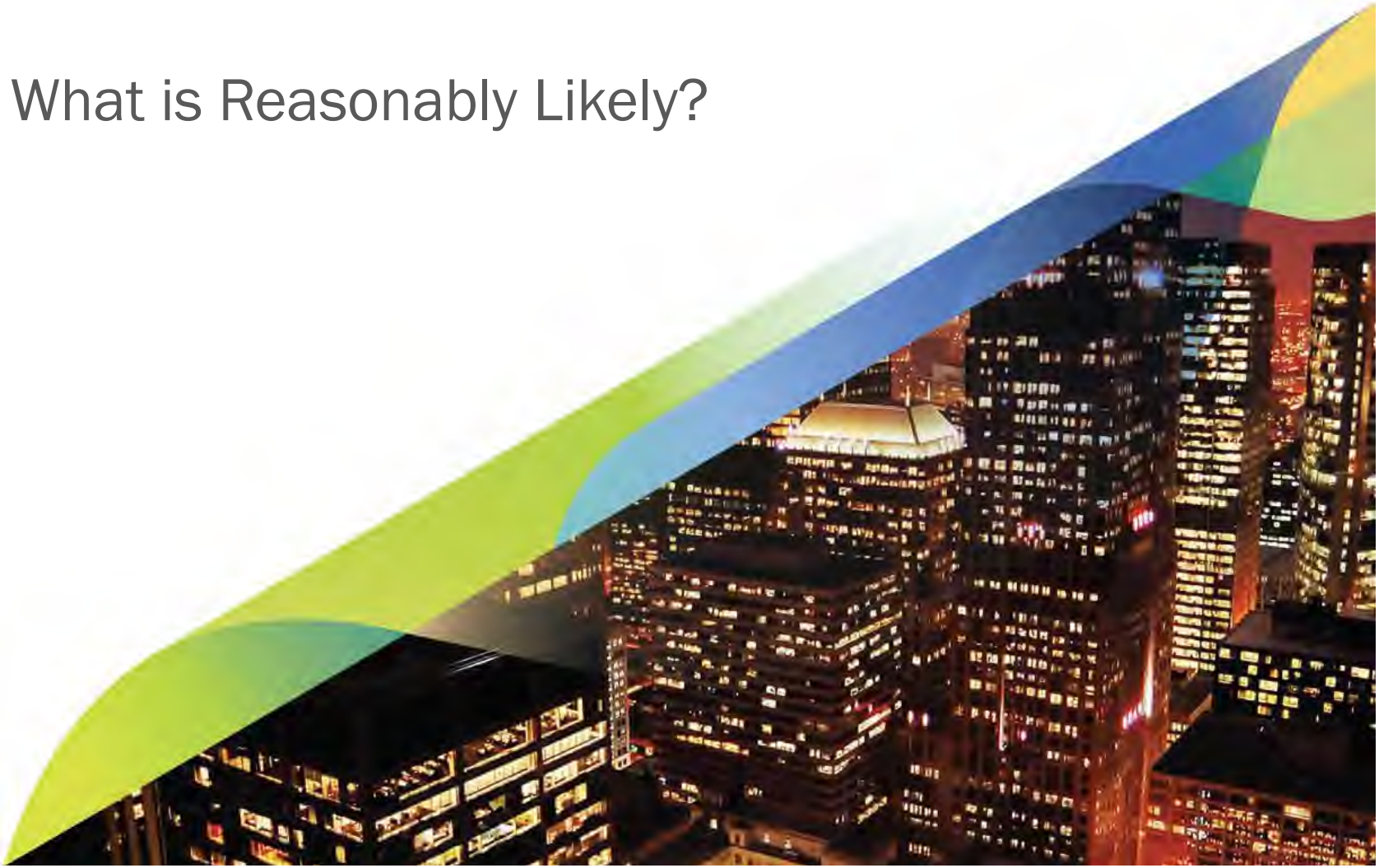
Al McBride

(413) 540-4223

Exelon

Planning Procedure 10

What is Reasonably Likely?



PP 10 Section 7.5 Proposed Change

"Whether there are responses to the RFP with in-service dates prior to the relevant Capacity Commitment Period for the rejected de-list bid and the ISO determines that some of those responses, including the Backstop Transmission Solution, are ***reasonably likely*** *to be in-service prior to the relevant Capacity Commitment Period for the rejected de-list bid; and . . ."*

Flaws in this approach include but are not limited to:

1. ISO's proposed changes unnecessarily jeopardize reliability
   - History overwhelmingly demonstrates that a transmission solution which appears "reasonably likely" to be in-service as of a certain date is frequently <u>not</u> constructed on-time (or on budget, for that matter), particularly so in the Greater Boston area
2. This change would provide ISO excessive discretion in transmission security analyses that will extend beyond FCA 15 and the Mystic situation.
3. The change will not be included in any other modeling or study processes for FCA 15, skewing market outcomes and potentially prejudicing the outcome of the Order 1000 evaluation.

The proposed amendment to Planning Procedure 10 appears to be a result-driven attempt to preclude the potential retention of Mystic 8 and 9 for transmission security; the amendment and its attendant consequences, however, will live long after Mystic 8 & 9 have retired.

Exelon.

Non-Order 1000 Process for Network Model Changes

- The process employed by ISO until now requires projects: (1) to be considerably further along in development, (2) to be accompanied by officer certification, and (3) to include evidence of corporate commitment to build.
- Despite this robust process and relatively advanced stage of development, transmission projects are frequently delayed (see slide 5)

Non-Order 1000 Process

- ISO Identifies a need
- TOs Propose solutions with proposed costs and in-service date(s)
- TOs and ISO work together and through the PAC to select a "Preferred Alternative"
- TOs and ISO conduct in-depth engineering to finalize the solution.
- For a proposal to be considered in-service and included in Network Models, that solution must be explicitly identified, and sufficient engineering and permitting work completed so that the TO can develop a detailed critical path schedule.
  - The CPS schedule must show all key milestones that lead up to the proposed completion date.
  - An Officer from the TO must certify that the CPS schedule is achievable, and that the company intends to build the facility in accordance with that schedule.
  - Tariff cites in in MR1 Section 12.6.2 (Appendix)

ISO's Proposed Approach: "Reasonably Likely" Standard

- ISO proposes to ignore the Network Model for the sole purposes of determining whether Mystic is needed for reliability based on an assumed solution to the transmission need prior to the completion of or at the end of stage 1, despite the fact that the Order 1000 projects have had considerably less stakeholder and ISO review, officer commitment to a particular schedule is not required, and there is no corporate commitment to build.
- More fundamentally, it is unclear the criteria by which the assumed winner is selected and how that choice will affect the actual winner of the RFP and how the inconsistent transmission assumptions will affect capacity market outcomes.

• Order 1000 Process

- ISO issued RFP based on identified need (December 2019)
- Respondents provide solution set (note: many respondents provided multiple solution sets)
- ISO narrows down the solution set at the end of stage 1 and begin stage 2 with the narrowed down solution set (Summer 2020)
- In stage 2 (summer 2020), the ISO brings forward a narrowed group of proposals and begins an extensive engineering process and reviews the proposal(s) to ensure they meet the needs identified in the Order 1000.
- At the conclusion of stage 2 (summer 2021), the ISO and project sponsor finalize the engineering requirements and critical path schedule and execute an agreement. At such time the solution set is "certified" to be in service based on the critical path schedule.

The "Reasonably Likely" Standard Raises Many Questions

Some of the additional questions raised by the ISO's proposal:

1. How will ISO determine which of the 36 proposals will be in-service in time?
2. How can ISO assure, at this stage in the process and given the RFP's anticipated selection of the preferred solution no earlier than summer 2021 that the project ultimately selected will be timely completed?
   - There will be, at most, three years before the start of the FCA 15 Capacity Commitment Period for financing, permitting, obtaining land rights, development, and construction in Boston.
3. Will ISO automatically reject proposals with in-service dates after the FCA 15 Capacity Commitment Period?
   - RFP selection criteria did not require responses to have an in-service date prior to FCA 15.
4. How can ISO ensure that predicting the winner now for reliability review purposes will not prejudice the Order 1000 selection process, potentially to the detriment of ratepayers?

ISO's proposal allows it broad discretion to make assumptions that will have implications for ratepayers and <u>all</u> market participants, including the Order 1000 RFP respondents.

Exelon.

Is the "Reasonably Likely" Standard Reasonable in Light of History?

- There have been dozens of transmission projects in New England and even more components (individual lines) that have missed their original in-service/certified dates.
- Risk of delay is compounded by the fact that this is the first Order 1000 competitive process in New England - other RTOs have experienced extensive litigation and other delays with the Order 1000 process itself

Greater Boston Upgrades - Currently there are at least six projects that have missed their certified in service dates. Many of these projects have been re-certified multiple times as on-line dates are repeatedly moved forward. (See next slide)

October 2019 Regional System Plan Transmission Projects Conditions Presentation (Slide 3)

- Major Cost Estimate Changes that occurred between June 2019 and October 2019 (four months) Project List
  - MA Boston Upgrades – increase of $157 million for 8 projects due to actual construction bids coming in higher than estimated costs, lengthy and extensive permitting and restrictive permitting conditions.

March 2020 Regional System Plan Transmission Projects Conditions Presentation (Slide 3)

- Major Cost Estimate changes that occurred between the October 2019 and March 2020 Project List (six months))
  - (MA) Greater Boston – cost increase of $52.3 Million for 3 projects due to Massachusetts *Energy Facility Siting Board approved underground solution, siting delays, and construction obstructions*
  - (MA) Southeast Massachusetts/Rhode Island Reliability Project (SEMARI) – cost increase of $61.2 Million for 6 projects *due to higher engineering and siting/permitting costs, increased material and contract costs, and lengthy multiyear system outage schedule and restrictions*.

Delayed Greater Boston Projects

Project	PPA Appr Date	Est In service date in PPA	Original FCA Certification	1st Modified Certification	Latest Modified Certification	Latest Cert Date	Latest COD Est 4/2/20 COO report
W Walpole-Holbrook new 115 kV	6/9/2016	Dec -2018	Jan.2013 list of Certification projects Dec 2016	On Jan 2016 revised cert date until July 2017	Jan 2017 revised cert from July 2017 to Sept 2019	Sept 2019	May 20
New Sharon Sub	6/9/2016	Dec 2018		January 2017 revised Cert date From Dec 2017 to June 2019	Jan 2017 revised cert from June 2017 to Sept 2019	Sept 2019	May 20
New Mystic Chelsea 115 KV	6/9/2016	Dec 2018	Jan.2013 list of Certification projects Dec 2016	In Jan 2016 added to list of Dec 2018 COD	Jan 2019 revised cert from Dec June to Dec 2019	Dec 2019	July 20
Split 110-552 and 240-510 DCT	6/9/2016	Dec 2018		January 2016 Added to list Dec COD 2018	Jan 2019 revised cert date from Dec 2018 to Dec 2019	Dec 2019	Dec 20
New Wakefield – Woburn 345 KV and Substation	6/9/2016	Dec 2018		January 2016 Added to list Dec 2018 COD	Jan 2019 revised cert from Dec 2019 to May 2021	May 2021	May 21
New Mystic Woburn 115 KV	6/9/2016	Dec 2018		January 2016 added to list Dec 208 COD	Jan 2019 revised cert 2018 to Dec 2020	Dec 2020	Dec 21

True cost of reliability?

- Concern has been voiced about the possibility of paying for two transmission solutions in FCA 15, however this concern can be easily addressed:
  - If the best and cheapest Order 1000 project happens to have a proposed in-service date prior to June 1, 2024, it can easily be pushed June 1, 2025 (FCA 16).
  - Even if the project has a proposed in-service date of June 1, 2024, in all likelihood it will be delayed. This is especially true in light of the short time for construction between the execution of a final agreement and FCA 15.

- A Gap RFP should be a fallback, not the primary plan to ensure reliability in Boston.
  - In light of the overwhelming likelihood of transmission construction delays, if the ISO lets Mystic retire, a Gap RFP will be inevitable, with no guarantee of adequate solutions.
  - This approach ignores a known and operational asset to preserve reliability (Mystic) in favor of an RFP for speculative solutions to meet needs of New England's largest city.
  - Ratepayers would pay for the extra capacity purchased through the Gap RFP, but the capacity would not be factored into the FCA in any way, thus posing the same risk of double payment as voiced with respect to transmission (above).

Exelon.

Final Thoughts, Questions

- Reliability is at stake if the Order 1000 Project is late. Based on recent history of transmission projects in Boston it is likely that the project will be late. Note, at this time, there are no penalties if the project is late and no "stick" to prevent a solution proponent to be optimistic in their proposed solution set.
- If the PP 10 rule change is approved and ISO determines that Mystic is not needed for reliability with the identification of a transmission solution to be in place for FCA 15, then all proposals with in-service dates beyond FCA 15 should be rejected before stage 2 even if the solutions with proposed in service dates beyond the start of FCA 15 are cheaper, potentially less complex and otherwise superior.

Questions

1) What specific criteria (permitting, siting, engineering) will the ISO use to determine whether a project is "reasonably likely" to be in service by June 1, 2024? Why is a lower standard, which presents a greater risk of delay, appropriate for a transmission security review of a retiring resource?
2) If ISO determines that at least one proposed solution is "reasonably likely" to be in service by June 1, 2024 and permits Mystic to retire, will the ISO automatically reject cheaper and superior solutions that have an in-service dates beyond June 1, 2024? Is ISO now modifying the RFP?

Exelon.

Appendix
Non-Order 1000 Network Model Changes - Tariff Cites

III.12.6.2. Initial Threshold to be Considered In-Service. The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period.

b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner or Elective Transmission Upgrade Interconnection Customer has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner or Elective Transmission Upgrade Interconnection Customer concurs that the schedule is achievable, and it is the intent of the Transmission Owner or Elective Transmission Upgrade Interconnection Customer to build the proposed transmission project in accordance with that schedule.

ISO new england

memo

To: Participants Committee

From: Jay Dwyer, Acting Secretary, Reliability Committee

Date: May 19, 2020

Subject: Actions of the Reliability Committee from the April 22, 2020 Meeting

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its May 19, 2020 meeting. All Sectors had a quorum.

(Agenda Item 1.1) (66.67% Vote) Meeting Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Reliability Committee:

Resolved, the Reliability Committee approves the minutes of the following RC meetings as distributed to the committee for the May 19, 2020 meeting:

April 22, 2020

The motion was voted and passed, based on a voice vote with none opposed and no abstentions.

(Agenda Item 3.1) (66.67% Vote) NEP Western Massachusetts Cluster Group 2
ACTION: APPROVED

The following motion was moved and seconded by the Reliability Committee:

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that the implementation of the Western Massachusetts Cluster Group 2 projects described in Proposed Plan Application ("PPA") NEP-20-G03 and associated transmission PPAs NEP-14-T07 Rev2, NEP-20-T09 - NEP-20-T24, NEP-20-T26, and NEP-20-T27 from National Grid as detailed in their May 11, 2020 transmittal to ISO New England and distributed to the committee for the May 19, 2020 meeting 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 voted and passed, based on a voice vote with none opposed and no abstentions.

($20.9), ES-19-TCA-67 ($7.077), ES-19-TCA-92 ($6.021), ES-19-TCA-87 ($26.175), ES-19-TCA-85 ($41.3), ES-19-TCA-103 ($11.131), ES-19-TCA-100 ($6.59), ES-19-TCA-98 ($10.995), ES-19-TCA-101 ($14.408), ES-19-TCA-102 ($17.313), ES-19-TCA-99 ($11.589), ES-19-TCA-97 ($13.631), and ES-20-TCA-16($8.200) which were submitted to ISO-NE between August 30, 2019 and April16, 2020 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 $375.368M 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 voted and passed, based on a voice vote with none opposed and no abstentions.

(Agenda Item 5.0) (66.67% Vote) QRR Request –NextEra Coolidge Solar
ACTION:
APPROVED

The following motion was moved and seconded by the Reliability Committee:

Resolved, the Reliability Committee recommends that ISO New England approve the following dynamic reactive resource meeting the CCCP eligibility requirements defined in the ISO-NE Tariff Schedule 2 and the Schedule 2 Business Procedure be designated as CCCP, with eligibility for Schedule 2 Capacity Cost Compensation associated with the QRR designation to be effective April 1, 2020 for, NextEra Coolidge Solar, Asset ID #:50815.

The motion was voted and passed, based on a voice vote with none opposed and one abstention in the AR Sector.

(Agenda Item 6.2) (66.67% Vote) Planning Procedure 10
ACTION: APPROVED

The following motion was moved and seconded by the Reliability Committee:

Resolved, that the Reliability Committee recommends Participants Committee support for revision of ISO New England Planning Procedure No. 10 as distributed to the committee for the May 19, 2020 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 passed with a vote of 98.80% in favor. The individual Sector votes were Generation (16.77% in favor, 0.00% opposed, 0 abstentions), Transmission (16.77% in favor, 0.00% opposed, 0 abstentions), Supplier (15.58% in favor, 1.20% opposed, 0 abstentions), Publicly Owned Entity (16.77% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (16.04% in favor, 0.00% opposed, 0 abstentions), and End User (16.77% in favor, 0.00% opposed, 0 abstentions). In addition, the votes from Provisional Members were (0.09% in favor, 0.00% opposed, 0 abstentions).

(Agenda Item 7.1) (66.67% Vote) OP-12
ACTION: APPROVED

The following motion was moved and seconded by the Reliability Committee:

Resolved, that the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 12 as distributed to the committee for the May 19, 2020 meeting, together with such other changes as

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings as of June 2, 2020

The following activity, as more fully described in the attached litigation report, has occurred since the report dated May 4, 2020 ("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	Technical Conference on the Impacts of COVID-19 on the Energy Industry (AD20-17)	May 20	FERC issues notice of Jul 8-9 technical conference to explore the potential longer-term impacts of the emergency conditions caused by COVID-19 on FERC-jurisdictional entities
	1	Extension of Filing Deadlines (AD20-11)	May 8	FERC issues a supplemental notice waiving through Sep 1, 2020 its regulations that require filings with the FERC be notarized or supported by sworn declarations

I. Complaints/Section 206 Proceedings

	2	NERA Petition: FERC Jurisdiction Over Customer-Side-of-the-Retail-Meter Energy Sales (EL20-42)	May 5-Jun 2	Over 50 Entities intervene; more than 70 sets of comments submitted comment date ***Jun 15, 2020***
	4	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19-002)	May 18	TOs submit status report; a next status report will be filed, if and as necessary, on or before Jun 8, 2020

II. Rate, ICR, FCA, Cost Recovery Filings

	9	MPD OATT 2020 Annual Informational Filing (ER15-1429-000)	May 18	Versant Power (f/k/a Emera Maine) submits revisions to 2020 MPD Annual Update (reflecting the loss of the load of Houlton Water Company, which, on May 15, 2020, interconnected with NB Power

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

*	10	EE CSOs During Scarcity Conditions (ER20-1967)	Jun 2	ISO-NE and NEPOOL jointly file changes to address an implementation issue regarding the treatment of Energy Efficiency resources during Capacity Shortage Conditions; comment date Jun 23, 2020
	11	Extension of Implementation Date: SOG Dispatchability Changes (ER20-1582)	May 8	FERC accepts ISO-NE deferral request; previously-accepted revisions to Tariff § I.2 that require SOGs above 5 MW to register as dispatchable generators and meet offer telemetry reqs. to become eff. Jan 1, 2021
	11	ESI Alternatives (ER20-1567)	May 14-18	Avangrid, API, Calpine/Vistra, Cogentrix, Dominion, Excelerate, Exelon, FirstLight, IECG, MA AG/NH OCA, MMWEC, NECOES/ENE, NESCOE, Repsol, NEPGA, NRG, PIOs, ISO-NE IMM, Potomac Economics, CT DEEP, MPUC, VT PUC, AEE, EPSA, National Hydropower Assoc., NGSA file comments and protests
			May 6-15	CLF, NRDC/Sustainable FERC Project, Acadia Center, Environmental Defense Fund, NextEra, Repsol, Shell, UCS, Vistra, Sierra Club, CT AG, APPA, Vote Solar intervene
			Jun 1	NEPOOL, NESCOE submit answers
	12	eTariff § III.13.6 Conforming Changes (ER20-1497)	Jun 1	FERC accepts changes, eff. Jun 1, 2020

	14	Economic Life Determination Compliance and Prospective Revisions (ER18-1770)	May 27	FERC accepts Revisions, eff. Aug 10, 2018, with Revisions to apply beginning with FCA16
	17	2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)	Jun 1	FERC issues tolling order affording it additional time to consider TransCanada's request for rehearing of the *2013/14 Winter Reliability Program Order on Compliance and Remand*

IV. OATT Amendments / TOAs / Coordination Agreements

	18	CIP IROL Cost Recovery Rules (ER20-739)	May 26	FERC accepts Schedule 17, eff. Mar 6, 2020, finding that Schedule 17 permits recovery only of CIP costs incurred on or after the effective date of an IROL-Critical Facility Owner's section 205 filing to recover such costs
	18	ISO-NE *Order 845* Compliance Filing (ER19-1951)	May 19	FERC rejects ISO-NE's Apr 20 motion

V. Financial Assurance/Billing Policy Amendments

*	20	Billing Policy Enhancements and Clean-Up Changes (ER20-1862)	May 20	ISO-NE and NEPOOL file enhancements and changes; comment date Jun 10
			May 26	Calpine intervenes
			May 27	Plant-E protests limitation on use of pre-payments

VI. Schedule 20/21/22/23 Changes

	21	Sched. 21-NEP NGrid/ Winchendon Hydro SGIA (ER20-1413)	May 15	FERC accepts SGIA, eff. Feb 26, 2020
*	22	Schedule 21-GMP: Annual True Up Calculation Informational Filing (ER12-2304)	Jun 1	GMP submits annual info filing containing true-up calculation of its actual costs for the Jan 1, 2019 through Dec 31, 2019 period
	22	Schedule 21-VEC and 20-VEC: Annual Informational Filing (ER10-1181)	May 12	VEC submits an errata to its annual update, correcting an error in the calculation of Transmission System Peak Load, and thereby reducing per unit charges
*	22	Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)	Jun 1	NSTAR submits an informational filing containing the true-up of billings under Schedule 21-NSTAR for the Jan1, 2019 through Dec 31, 2019 period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	23	Capital Projects Report - 2020 Q1 (ER20-1824)	May 14	ISO-NE files Q1 Report; comment date Jun 4
			Jun 2	Eversource, National Grid intervene
*	23	IMM 2019 Annual Markets Report (ZZ20-4)	May 26	IMM files annual report covering calendar year 2019; to be reviewed at Jun 10 Markets Committee meeting
*	24	ISO-NE FERC Form 3Q (2020/Q1) (not docketed)	May 28	ISO-NE submits its 2020 Q1 FERC Form 3Q
*	24	ISO-NE 2019 FERC Form 714 (not docketed)	Jun 1	ISO-NE submits 2019 FERC Form 714

IX. Membership Filings

*	24	June 2020 Membership Filing (ER20-1943)	May 31	***Memberships***: Actual Energy; Borrego Solar Systems; Paper Birch Energy; Priogen Power; and Standard Normal Energy; ***Terminations***: Royal Bank of Canada; Wallingford Energy II; and Agera Energy; comment date Jun 22, 2020
	25	April 2020 Membership Filing (ER20-1454)	May 21	FERC accepts (i) the memberships of Axon Energy; Energy Harbor; and Nexus Energy; and (ii) the termination of the Participant status of ADG Group; Beacon Falls Energy Park; Clear River Energy; Entergy Nuclear Power Marketing; and Rinar Power
*	25	Suspension Notice – Energy Federation Inc. (not docketed)	May 13	ISO-NE files notice of May 11 suspension of Energy Federation Inc. from the New England Markets
*	25	Suspension Notice – Great American Power (not docketed)	May 13	ISO-NE files notice of May 11 suspension of Great American Power from the New England Markets
*	25	Suspension Notice – EPIS, Inc. (FTR-Only Customer) (not docketed)	May 13	ISO-NE files notice of May 11 suspension of EPIS, Inc. from the New England Markets

X. Misc. - ERO Rules, Filings; Reliability Standards

	27	NOPR - Retirement of Reliability Standard Reqs. (Standards Efficiency Review) (RM19-17; -16)	May 14	NERC submits notice of withdrawal of VAR-001-6 (the Standard that the FERC proposed to remand, rather than approve, in the NOPR)
*	28	Report of Comparisons of 2018 Budgeted to Actual Costs for NERC and its Reg. Entities (RR20-3)	May 29	FERC files report; comment date Jun 19

XI. Misc. - of Regional Interest

	28	PJM MOPR-Related Proceedings (EL18-178; EL16-49)	May 8-Jun 1	Energy Harbor, Exelon, NRECA, Ohio Public Utilities Commission, Old Dominion Electric Cooperative appeal *April 2020 PJM MOPR Rehearing Order* to DC Circuit Court of Appeals
			May 15-18	PJM IMM, Energy Harbor, Exelon, N. VA Elec. Coop., NRECA, PA Pub. Utils. Comm., Vistra request rehearing and/or clarification of *April 2020 PJM MOPR Rehearing Order*
*	31	*Opinion 569-A*: FERC's Base ROE Methodology (EL14-12; EL15-45)	May 21	FERC issues *Opinion 569-A*, refining its methodology for setting the ROE that electric utilities earn on electric transmission investments
*	32	NITSA Termination: Versant Power/ Houlton Water Co. (ER20-1914)	May 28	Versant files notice of termination of Network Integration Transmission Service Agreement between itself and Houlton, which expired by its terms on May 15, 2020, the date Houlton directly interconnected its electric system with that of New Brunswick Power
*	32	NSTAR Transmission Service Agreement Cancellations (ER20-1896)	May 26	NSTAR files notice of cancellation of various transmission service agreements no longer active but not yet previously cancelled; comment date Jun 16
*	32	D&E Agreement: CL&P-Gravel Pit Solar (ER20-1871)	May 21	CL&P files preliminary Engineering and Design Agreement with Gravel Pit Solar LLC; comment date Jun 11, 2020
*	33	VTransco VTA Waiver Request (ER20-1823)	May 14	VTransco asks for waiver of the Vermont Transmission Agreement (VTA) to allow it to amortize over a 24-month period (rather than bill monthly) a portion of the shortfall resulting from lower RNS revenues
			May 22	FERC grants waiver

*	33	System Upgrade Reimbursement Agreement Cancellation: NEP/ Deerfield Wind (ER20-1820)	May 13	New England Power submits a notice of cancellation of Agreement with Deerfield Wind; comment date Jun 3, 2020
	34	Emera Maine/Houlton Water Company NITSA (ER20-1445)	May 28	FERC accepts NITSA, eff. Apr 1, 2020
	34	IA Amendment: CMP/Sappi (ER20-1434)	May 28	FERC accepts IA, eff. Feb 29, 2020
	34	IA Cancellations: NGrid/GRS, NGrid/Mini-Watt (ER20-1405/1406/1407)	May 13, 22	FERC accepts notices of cancellation of superseded Mini-Watt Unit Nos. 2 and 3 (ER20-1407) and GRS (ER20-1405) SGIAs, each eff. May 27, 2020
	34	D&E Agreement Cancellation: CL&P/CPV Towantic (ER20-1221)	May 7	FERC accepts notice of cancellation, eff. Feb 26, 2020

XII. Misc. - Administrative & Rulemaking Proceedings

	35	Carbon Pricing in RTO/ISO Markets (AD20-14)	May 5-22	Over 25 sets of comments supporting the request for a tech. conf. or workshop filed, including comments by ISO-NE, Exelon, National Grid, NEPGA, NESCOE, PSEG, Potomac Economics, Public Interest Organizations, Shell, and a group of US Senators that included Sheldon Whitehouse (RI) and Angus King (ME)
	38	NOPR – Electric Transmission Incentives Policy (RM20-10)	May 8 May 15	State Entities request extension of time to submit comments FERC denies requested extensions of time; comments remain due July 1, 2020
	42	*Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)	May 6 May 13 May 20	EEI requests 4-month extension of implementation deadline EPSA supports EEI request FERC extends effective date and implementation deadlines by ***six*** months; *Order 860* effective date extended to Apr 1, 2021; deadline for baseline submissions extended to and including Aug 2, 2021
*	43	Waiver of Tariff Requirements (PL20-7)	May 21	FERC issues *Proposed Policy Statement* that would both clarify and modify its waiver standards, and in some instances, make it harder to obtain waivers; comment date Jun 18, 2020; reply comments due Jul 2, 2020
	45	FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4)	May 21	FERC issues Policy Statement that applies to natural gas and oil pipelines, with certain exceptions, the FERC's ROE methodology adopted in *Opinion 569-A*, eff. May 27, 2020

XIII. Natural Gas Proceedings

No Activity to Report

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

No Activity to Report

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: June 3, 2020

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 June 2, 2020. If you have questions, please contact us.

COVID-19

- **Technical Conference on the Impacts of COVID-19 on the Energy Industry (AD20-17)**

On May 20, 2020, the FERC issued a notice that it will convene a Commissioner-led technical conference on July 8-9, 2020 to explore the potential longer-term impacts of the emergency conditions caused by COVID-19 on FERC-jurisdictional entities "in order to ensure the continued efficient functioning of energy markets, transmission of electricity, transportation of natural gas and oil, and reliable operation of energy infrastructure today and in the future, while also protecting consumers". The conference will include consideration of: (i) the energy industry's ongoing and potential future operational and planning challenges due to COVID-19 and as the situation evolves moving forward; (ii) the potential impacts of changes in electric demand on operations, planning, and infrastructure development; (iii) the potential impacts of changes in natural gas and oil demand on operations, planning, and infrastructure development; and (iv) issues related to access to capital, including credit, liquidity, and return on equity. The conference will be open for the public to attend remotely, with no fee for attendance. Those planning to attend are encouraged to pre-register online at: http://www.ferc.gov/whats-new/registration/07-07-20-form.asp.

- **Remote ALJ Hearings (AD20-12)**

On April 23, 2020, Chief Judge Cintron issued a notice that all hearings before Administrative Law Judges will be held remotely through video conference software until further notice. 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.

- **Extension of Filing Deadlines (AD20-11)**

In a March 19 notice, the FERC indicated that entities may 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. The FERC committed to take action on any such motions as expeditiously as possible.

[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").

Since the last Report, On May 8, 2010, the FERC issued a supplemental notice waiving through September 1, 2020 the FERC's regulations that require that filings with the FERC be notarized or supported by sworn declarations.

- **Blanket Waiver of ISO/RTO Tariff In-Person Meeting and Notarization Requirements (EL20-37)**

On April 2, 2020, the FERC, pursuant to Section 206 of the Federal Power Act ("FPA"), provided a blanket waiver, effective April 2, 2020 and through September 1, 2020, of all jurisdictional agreement[2] requirements for (i) document notarization and (ii) *in-person* meetings (such meetings must still be held, but should be conducted by other means). The FERC, noting alternatives like electronic signatures and telephonic and web-based meeting capabilities, indicated that it was taking the action given the President's proclamation of a National Emergency, the unprecedented risk to health and safety currently presented by personal contact, and consistent with guidance from public health officials on social distancing. The blanket waiver made moot requests separately filed earlier by ISO-NE (ER20-1484) and NYISO (ER20-1419), among others.

I. Complaints/Section 206 Proceedings

- **NERA Petition: FERC Jurisdiction Over Customer-Side-of-the-Retail-Meter Energy Sales (EL20-42)**

As previously reported, the New England Ratepayers Association ("NERA") has asked the FERC, through an April 14, 2020 petition for declaratory order, to assert jurisdiction over energy sales from facilities located on the customer side of the retail meter (rooftop solar and other DG) (i) whenever the DG output exceeds customer demand or (ii) where the energy from the DG is designed to bypass the customer's load and therefore is not used to serve demand behind the customer's meter, and ensure the output is priced accordingly. Comments on NERA's Petition are due on or before June 15, 2020.[3]

The Petition has engendered both regional and national attention. More than 130 Entities, including NEPOOL, have thus far intervened. In addition, nearly 80 sets of comments have been submitted. Those comments have thus far largely been from individuals and officials from New Hampshire (who have not intervened as parties), and are nearly uniform in their opposition to NERA's request. But with the June 15 comment date still ahead, and most of the intervenors yet to submit comments, we have yet to see the full breadth of positions on this matter. A summary of the comments submitted will be provided, minimally, in the next Report.

- **Liberty Complaint – Eversource/ISO-NE Failure to Correct Nov 2018 Meter Data Error/Load Assignment (EL20-27)**

As previously reported, Liberty Power Holdings, LLC ("Liberty") filed a complaint on February 28, 2020 against Eversource Energy Company ("Eversource") and ISO-NE related to a November 2018 Meter Data Error ("Nov 2018 Error") for a load in Metering Domain #685 ("Nov 2018 Load"). Liberty asserted (i) that Eversource

[2] This waiver applies to any tariff, rate schedule, service agreement, or contract subject to the FERC's jurisdiction under the FPA, the Natural Gas Act, or the Interstate Commerce Act.

[3] The comment date was initially noticed as May 14, 2020. A number of state-affiliated organizations, including NARUC, NRECA/APPA, "State Entities" (Mass. Attorney General Maura Healey ("MA AG"), the state attorneys general of Conn., the District of Columbia, Iowa, Maryland, Michigan, Minnesota, New Jersey, North Carolina, Rhode Island ("RI AG"), the Maine Office of the Public Advocate ("MOPA") , and the Pub. Util. Comm. of Oregon), the Organization of MISO States, and the National Association of State Energy Officials, requested a 90-day extension of time. Several parties, including NESCOE, Joint Parties (the Conn. Pub. Utils. Regulatory Authority ("CT PURA"), the New Jersey Board of Pub. Utils. ("NJ BPU"), the Conn. Dept. of Energy and Environ. Protection ("CT DEEP"), the Conn. Office of Consumer Counsel ("CT OCC") and the New Jersey Division of Rate Counsel), PIOs (the Center for Biological Diversity, Climate + Energy Project, Conservation Law Foundation ("CLF"), Environmental Law & Policy Center, Natural Resources Defense Council ("NRDC"), Public Citizen, Idaho Conservation League, RENEW Wisconsin, Sierra Club, Solar United Neighbors, Sustainable FERC Project, and Vote Solar), Advanced Energy Economy ("AEE"), Solar Energy Industries Association ("SEIA"), and the Kansas Corp. Comm., supported the request for a 90-day extension of time. NERA opposed the requests for 90 days, suggesting instead an extension of between 30 and 60 days. On May 4, the FERC granted a 30-day extension of time to intervene/comment in this proceeding.

incorrectly assigned the Nov 2018 Load to Liberty (as it did with a December 2018 load, which was subsequently corrected via Meter Data Error ("MDE") request #12/18/02MD); and (ii) ISO-NE refused to correct the error for the Nov 2018 Load at Liberty's Request Billing Adjustment ("RBA") because the RBA was not received within three months of the date that the Invoice containing the Disputed Amount was issued. Liberty further asserted that the Tariff, in light of the facts and circumstances Liberty describes in the Complaint, provides a basis for the correction beyond the three-month period for RBA submissions.[4] The amount in dispute is $191,440 plus interest ("Disputed Amount"). Liberty seeks an order directing Eversource to refund the Disputed Amount to ISO-NE and directing ISO-NE to refund the Disputed Amount to Liberty.

ISO-NE and Eversource responded to Liberty's Complaint on March 19 and 18, 2020, respectively. In its response, ***ISO-NE*** asserted that "Liberty's Complaint has no basis under the Tariff, law, or equity, and should be rejected" because Liberty "failed to take timely or appropriate action to detect the [Nov 2018 E]rror and request that it be corrected" pursuant to ISO Tariff procedures. ISO-NE reported that, "in the three months leading up to the applicable deadline, Liberty was given information on five separate occasions that should have alerted it … to the Nov[] 2018 [E]rror." ISO-NE stated that the "tolling provision that Liberty claims gives safe harbor where a party only discovers an error after the deadline has passed is taken from a set of billing procedures that explicitly do not apply in this case." ISO-NE added that the Liberty Complaint "also ignores the importance of settlement finality that underlies the correction procedures in the Tariff." ***Eversource*** argued for summary dismissal in its response by highlighting the opportunities Liberty had to timely identify the Nov 2018 Error, by explaining why denying the Complaint is consistent with and supportive of the filed-rate doctrine, as well as distinguishable from other instances in which the FERC has allowed the correction of billing errors. Eversource also explained that any correction would have been (or would need to be) paid by different retail supplier (not Eversource). NEPOOL submitted a doc-less motion to intervene.

There was no activity in this proceeding since the last Report and 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).

- **206 Investigation: ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (EL19-90)**

As previously reported, the FERC instituted a proceeding under FPA Section 206 on October 17, 2019 to consider whether ISO-NE may be implementing exemptions for immediate need reliability projects in a manner that is inconsistent with what the FERC directed pursuant to *Order 1000*, and therefore may be unjust and unreasonable, unduly preferential and discriminatory.[5] The FERC noted that, "based on its review of the annual informational filings and materials provided in stakeholder processes as posted on the Responding RTOs' websites, we are concerned that the Responding RTOs may be implementing the exemption in a manner that is inconsistent with or more expansive than what the Commission directed."[6] The FERC directed ISO-NE to respond to questions in the *October 17 Order* to: (1) demonstrate how it is complying with the immediate need reliability project criteria; (2) demonstrate that the provisions in the Tariff, as implemented, containing certain exemptions to the requirements of *Order 1000* for immediate need reliability projects remain just and reasonable; and (3) consider additional conditions or restrictions on the use of the exemption for immediate need reliability projects to appropriately balance the need to promote competition for transmission development and avoid delays that could endanger reliability. ISO-NE's response was due and was filed on December 27, 2019. The FERC noted its expectation that it would issue a final order within six

[4] *See* § 6.3.1 of the Tariff: 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.

[5] *ISO New England Inc. et al.*, 169 FERC ¶ 61,054 (Oct. 17, 2019) ("*October 17 Order*").

[6] *Id.* at P 7.

months of ISO-NE's response.[7] On October 18, the FERC issued a notice of the proceeding and of the refund effective date, which will be October 28, 2019 (the date the *October 17 Order* was published in the *Federal Register*).

Those interested in participating in this proceeding were required to intervene on or before November 27, 2019.[8] Interventions were filed by: NEPOOL, ISO-NE, Anbaric, Avangrid, Calpine, CT AG, CT, OCC, CT PURA, ENE, Eversource, IECG, LSPower, MA AG, MA DPU, MMWEC, MS PSC, NESCOE, NHEC, NextEra, NRDC, NRG, PSEG, AK PSC, ATC, Developers Advocating Transmission Advancements, East TX Cooperative, EEI, IECA, LA PSC, MD PSC, Mid-Kansas Electric Co., NJ PBU, NY TOs, NY Transco, Northeast TX Electric Cooperative, PA PUC, Public Citizen, Sunflower Electric Cooperative, and Xcel Energy Services. As noted above, ISO-NE submitted its responses on December 27, 2019.

Comments on ISO-NE's response are due on or before January 27, 2020 and were filed by: NEPOOL, Avangrid, Eversource, LSP Transmission, MMEWC, National Grid, NESCOE, CT PURA, State Agencies,[9] Developers Advocating Transmission Advancements, and EEI. Reply comments were submitted by ISO-NE, Eversource and Avangrid and National Grid. On February 21, State Agencies answered National Grid's reply comments. On March 3, LSP Transmission replied to the replies submitted by ISO-NE, Eversource/Avangrid and National Grid. There has been no activity in this proceeding since the last Report.

As noted above, a FERC order in this proceeding is expected by the end of June 2020. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19-002)**

As described below, the procedural schedule in this proceeding is now suspended until June 8, 2020 "with aim to finalize settlement." Tariff changes supporting a new, uncontested Settlement Agreement were unanimously approved by the Transmission Committee on May 27, 2020 and will be considered by the Participants Committee in executive session at its June 4 meeting (Agenda Item #13).

2018 Settlement (Rejected). The FERC rejected a first, contested settlement in this proceeding, concluding that the contested 2018 Joint Offer of Settlement (the "Settlement"),[10] filed to resolve all issues in the Section 206 proceeding instituted by the FERC on December 28, 2015,[11] lacked sufficient detailed information to enable it to apply any of the approaches available to it to approve a contested settlement.[12] (As reported

[7] *Id.* at P 23.

[8] The *October 17 Order* was published in the *Fed. Reg.* on Oct. 29, 2019 (Vol. 84, No. 208) pp. 57,726-57,727.

[9] "State Agencies" are: the CT and MA Attorneys General, CT DEEP, CT OCC, and MOPA.

[10] As previously reported, the Settling Parties filed the Settlement on Aug. 17, 2018, in ER18-2235. The Settlement proposed changes to Section II.25, Schedules 8 and 9, Attachment F (including the addition of Interim Formula Rate Protocols ("Interim Protocols")), and the Schedule 21s to the ISO-NE OATT. Had they been approved, the changes to Attachment F would have become effective mid-June, 2019, with the remaining changes to be effective January 1, 2020. The Interim Protocols, as well as the changes to Section II.25 and Schedules 8 and 9, were supported by the Participants Committee at its July 24, 2018 meeting.

[11] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied,* 154 FERC ¶ 61,230 (Mar. 22, 2016) ("*RNS/LNS Rates and Rate Protocols Order*"). The *RNS/LNS Rates and Rate Protocols Order* found the ISO-NE Tariff unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS"). The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates". The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced. The FERC-established refund date is January 4, 2016.

[12] The FERC outlined in a seminal case the following four alternative approaches for approving contested settlements: (1) where the FERC can render a binding merits decision on each contested issue, (2) where the FERC can approve the settlement based on a finding that the overall settlement *as a package* is just and reasonable, (3) where the FERC can determine that the benefits of the settlement

previously in prior Reports, the first Settlement was supported by ***NESCOE*** but opposed by Municipal PTF Owners[13] and FERC Trial Staff.) Accordingly, the FERC remanded this proceeding (EL16-19) to Chief Judge Cintron to resume hearing procedures.[14]

Hearings (Currently Suspended). On May 23, 2019, Chief Judge Cintron designated Judge David H. Coffman as the Presiding Judge for the purpose of hearings and issuance of an initial decision within Track III procedural time standards.[15] A prehearing conference was held on June 6, 2019. Following that conference, orders establishing a procedural schedule and adopting rules of conduct for the hearing were issued. That schedule has since been extended three times by a total of 85 days and is currently suspended (*see* immediately below).

Procedural Schedule (Further Suspended Until June 8, 2020) / NPC June 4, 2020 Consideration. On April 21, 2020, the TOs requested a further 47-day suspension of the procedural schedule. Chief Judge Cintron issued an order on April 22, 2020 granting that request, with the proceedings to be held in further abeyance until June 8, 2020. On May 18, 2020, the TOs filed a status report with the Chief Judge and Presiding Judge, reporting that the "NETOs and other active participants have continued to make progress towards finalizing settlement documents" and committed to "submit additional filings as appropriate by June 8, 2020." As noted, Tariff changes supporting the new Settlement will be considered by the Participants Committee at its June 4 meeting.

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,[16] 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*).[17] However, the FERC's orders were challenged, and in *Emera Maine,*[18] the DC Circuit Court vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the

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outweigh the nature of the objections and the interests of the contesting party are too attenuated, and (4) where the FERC can approve the settlement as uncontested for the consenting parties, and can sever the contesting parties to allow them to litigate the issues raised. *See Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345, at 62,342-44 (1998).

[13] "Municipal PTF Owners" are: Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford.

[14] *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement Order*").

[15] Track III time standards require a hearing be convened within 42 weeks and an initial decision issued within 63 weeks.

[16] 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 clarific.*, 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*")).

[17] *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*").

[18] *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).

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)[19] and third (EL14-86)[20] 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.[21] 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[22] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[23] 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.[24] 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.[25] 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* (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[26]

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[19] 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%.

[20] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General ("MA AG"), together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

[21] *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*").

[22] 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 XV below, have been appealed to, and are pending before, the DC Circuit.

[23] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("*Base ROE Complaint IV Initial Decision*").

[24] *Id.* at P 2.; Finding of Fact (B).

[25] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("*Order Directing Briefs"* or "*Coakley*").

[26] *Id.* at 19.

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%.[27] 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[28] 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. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, 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*[29] 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, EMCOS and CAPs opposed the TOs' request and brief.

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[27] *Id.* at P 59.

[28] For purposes of the motion seeking clarification, "Customers" are CT PURA, MA AG and EMCOS.

[29] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*MISO ROE Order*"), *order on reh'g*, Opinion No. 569-A, 171 FERC ¶ 61,154 (May 21, 2020).

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

- **Mystic 8/9 Cost of Service Agreement (ER18-1639)**

Final actions by the FERC in this proceeding remain pending. As previously reported, the FERC conditionally accepted the Cost-of-Service Agreement ("COS Agreement")[30] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE.[31] The COS Agreement will provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. The *Mystic Order* directed Mystic to submit a compliance filing (intended to modify aspects of the COS Agreement that FERC rejected or directed be changed) on or before February 18, 2019, and established a paper hearing to ascertain whether and how the ROE methodology that FERC proposed in *Coakley* should apply in the case. Requests for clarification and/or rehearing of the *Mystic Order* were filed by Constellation Mystic Power, CT Parties, EDF, ENECOS, MA AG, NESCOE, NextEra, and Repsol. CT Parties answered Constellation's request for rehearing. Constellation answered the other parties' requests for rehearing. NESCOE answered Constellation's answer. On February 15, 2019, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending.

Mystic's Compliance Filing. On March 1, 2019, Mystic submitted its required compliance filing. The compliance filing included the following modifications:

- Modification to Section 2.2 (Termination) which provides ISO-NE will be required to seek FERC authorization to extend the term of the COS Agreement beyond May 31, 2024; deletion of Section 2.2.1 in its entirety;
- Inclusion of a clawback provision;
- Modification to Section 4.4 related to settlement of over- and underperformance credits;
- A clarification that fuel opportunity costs will not be included as part of the Stipulated Variable Costs used to calculate the revenue credits;
- Modifications to information access provisions (§ 6.2) both to allow ISO-NE full access to information and to support verification of third-party sales;
- Modifications to Schedule 3 supporting multiple compensation-related directives (e.g. cost of capital/cost of service, fuel supply charge, settlement of over- and under-performance credits);
- Schedule 3A modifications related to Mystic's true-up process; and
- Non-substantive conforming changes.

In addition, Mystic's compliance filing included for informational purposes changes to the Fuel Supply and Terminal Services Agreements. Comments on Mystic's compliance filing were due on or before March 22, 2019. Protests and comments were filed by CT Parties, ENECOS, MA AG, National Grid, Public Systems (MMWEC/NHEC), and NESCOE. Mystic answered the March 22 protests on April 8. Also, on March 22, Concord, Reading and Wellesley moved for the release from Protective Order a documentary response regarding the net book value of

[30] 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, and on the continued provision of surplus LNG from Distrigas to third parties.

[31] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Mystic Order*").

Mystic 8 and 9 from the 2006 Mystic 8/9 RMR proceeding (ER06-427). Mystic's compliance filing and the pleadings related thereto remain pending before the FERC.

ROE Paper Hearing. The *Mystic Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, Mystic, Connecticut Parties, ENECOS, MA AG, and FERC Trial Staff filed initial briefs. On July 18, 2019, Constellation Mystic Power, CT Parties, ENECOS, MA AG, National Grid, FERC Trial Staff filed reply briefs. The ROE Paper Hearing is now pending before the FERC.

July Mystic COS Agreement Order. Rehearing remains pending of the FERC's July order. As previously reported, the FERC issued an initial order regarding the COS Agreement, accepting the COS Agreement but suspending its effectiveness and setting it for accelerated hearings and settlement discussions.[32] The *Mystic COS Agreement Order* was approved by a 3-2 vote, with dissents by Commissioners Powelson and Glick. Challenges to the *July Mystic COS Agreement Order* were filed by NESCOE, ENECOS, MA AG, and the NH PUC. Constellation answered the NESCOE request for reconsideration on August 21. On September 10, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com); or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **MPD OATT 2020 Annual Informational Filing (ER15-1429-000)**

On May 1, 2020, Emera Maine (now known as Versant Power) submitted its annual informational filing setting forth, for the June 1, 2020 to May 31, 2021 rate year, the charges for transmission service under the Maine Public District ("MPD") OATT ("MPD Charges") and an updated transmission real power loss factor. Since the last Report, Versant Power revised its filing of the 2020-2021 MPD Charges to reflect the loss of the load of Houlton Water Company, which on May 15, 2020 interconnected its electric system with that of NB Power. While neither filing will be noticed for public comment, they will be subject to the process established in the "Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas" and may result in further proceedings (*see, e.g.*, 2019 and 2018 filings below below). If there are questions on the 2020 MPD OATT Informational Filing, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **MPD OATT 2019 Annual Informational Filing (ER15-1429-000)**

The motion by Maine Customer Group ("MCG") to strike a portion of Emera Maine's 2019 MPD OATT Informational Filing remains pending. As previously reported, MCG moved to strike the trueup to actuals portion of Emera's 2019 Annual Update filing to the extent that true-up proposes a change in the formula rate from a direct assignment of MPD's post- retirement benefits other than pensions ("PBOPs") to an allocation of company-wide PBOPs (which MCG argued would be a retroactive change to Emera Maine's formula rate, otherwise required to effect only prospectively). On June 26, 2019, Emera Maine answered MCG's motion to strike. This matter remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **MPD OATT 2018 Annual Informational Filing Settlement Agreement (ER15-1429-012)**

Emera Maine's uncontested Joint Offer of Settlement between itself, MPUC and the MCG to resolve all the issues set for hearing by the FERC in its *2018 Challenge Order,*[33] filed March 12, 2020, remains pending

[32] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July Mystic COS Agreement Order*"), *reh'g requested*.

[33] *Emera Maine*, 167 FERC ¶ 61,090 (Apr. 30, 2019) ("*2018 Challenge Order*") (granting, in part, the formal challenge filed on Dec. 31, 2018 by the MCG (the "2018 Challenge") to Emera Maine's May 15, 2018 annual informational filing and setting the remaining issues for hearing and settlement judge procedures). The 2018 Challenge sought certain cost reductions/ exclusions to be effective June 1, 2018 following unsuccessful efforts to obtain the relief sought directly from Emera Maine MPD through informal resolution procedures in

before the FERC.[34] As previously reported, Emera Maine was authorized by Chief Judge Cintron to implement the settlement rates as of February 1, 2020, subject to refund or surcharge, with interest, pending the outcome of the FERC's consideration of the Settlement Agreement.[35] The Settlement Agreement is uncontested, was certified to the FERC (and recommended for approval) by Settlement Judge Dring on April 14, 2020,[36] and is pending before the FERC.

- **TOs' *Opinion 531-A* Compliance Filing Undo (ER15-414)**

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[37] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[38] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[39] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be just and reasonable in its order on remand" so as to "put the parties in the position that they would have been in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[40] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*, which remains pending. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **EE CSOs During Scarcity Conditions (ER20-1967)**

On June 2, 2020, ISO-NE and NEPOOL jointly filed changes to address an implementation issue regarding the treatment of energy efficiency resources ("EE") during Capacity Scarcity Conditions ("EE Changes"). Specifically, EE Capacity Supply Obligations ("CSOs") will be removed from the denominator of the balancing ratio outside of measure hours, so that EE will be absent from both the numerator and the denominator of the ratio in those hours. The EE Changes will eliminate the undercollection problem and associated mutual insurance pool charges,43 and will more appropriately allocate Pay For Performance proceeds, all while more fully honoring the Commission's directive in the 2014 PFP Order to calculate performance payments for energy efficiency resources only when scarcity conditions occur during measure hours. The EE Changes were supported by the Participants

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accordance with the Protocols. In granting in part the 2018 Challenge, the FERC found that Emera Maine's formula rate should be corrected for the current rate year and directed Emera Maine to submit a compliance filing revising its 2018-2019 formula rate charges to correct certain acknowledged errors, exclusion of certain costs for land associated with a project not in service, the exclusion of certain costs for distribution equipment from transmission rates, and the flowback of excess accumulated deferred income tax ("ADIT"). As to the remaining issues, addressing Administrative and General ("A&G") expenses, merger-related prior losses, exclusion of costs attributed to Line 6901, and exclusion of land rights cost, the FERC found that the 2018 Annual Update raised issues of material fact that could not be resolved based on the record and set those issues for hearing and settlement judge procedures, resolved in this Settlement.

[34] Initial comments and reply comments were due on April 1, 2020 and April 13, 2020, respectively. On April 1, FERC Trial Staff filed comments supporting the Settlement; no other comments were filed.

[35] *Emera Maine*, 170 FERC ¶ 63,028 (Mar. 18, 2020) ("*Settlement Rates Order*").

[36] *Emera Maine*, 171 FERC ¶ 63,008 (Apr. 14, 2020) ("*MPD OATT 2018 Annual Info Filing Settlement Agreement Certification*").

[37] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*"), *reh'g requested*.

[38] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

[39] *Order Rejecting Filing* at P 1.

[40] *Id.* at P 36.

Committee at its April 2, 2020 meeting (Consent Agenda Item #4). ISO-NE requested an effective date of August 1, 2020 for the EE Changes. Comments on the EE Changes are due on or before June 23, 2020. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: Settlement Only Resources Definition -- GMP's Searsburg facility (ER20-1755)**

On May 4, Green Mountain Power ("GMP") requested a limited waiver from the revised definition of Settlement Only Resources[41] as applied to GMP's Searsburg wind power facility[42] because the vintage and unique physical characteristics of the Searsburg facility's wind turbines will make compliance with the revised definition of a Settlement Only Resource infeasible.[43] Comments on GMP's waiver request are due on or before May 22, 2020. Thus far, NEPOOL filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Extension of Implementation Date: SOG Dispatchability Changes (ER20-1582)**

On May 8, the FERC accepted the deferral requested by ISO-NE[44] of the effective date of previously-accepted revisions to Tariff § I.2[45] that require Settlement Only Resources (SOGs) above 5 MW to register as dispatchable generators and meet offer telemetry requirements, from Jun 1, 2020 to Jan 1, 2021. ISO-NE reported that a total of 23 generators (with an aggregate capacity of approximately 90 MW) are required to either convert from SOG status to dispatchable status under the Tariff change or otherwise demonstrate that their maximum net output is not 5 MW or greater, and those that plan to convert were finding their ability to complete the necessary equipment upgrades or reconfiguration significantly impeded or made impossible in light of COVID-19 and COVID-19-related governmental restrictions. The SOG Dispatchability changes will now become effective January 1, 2021. Unless the May 8 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ESI Alternatives (ER20-1567)**

This proceeding was initiated by ISO-NE's April 15, 2020 filing of Tariff revisions to incorporate comprehensive, long-term market enhancements to address the fuel security challenges facing the New England region ("Energy Security Improvements" or "ESI").[46] The revisions included NEPOOL-supported alternatives to certain aspects of the enhancements proposed by ISO-NE, which ISO-NE and NEPOOL agreed would be considered on equal legal footing with ISO-NE's favored alternative. ISO-NE asked that the FERC issue an order and accept the changes effective no later than November 1, 2020, conditioned on ISO-NE's filing of an appropriate market power mitigation proposal supported by a Market Power Assessment by the fourth quarter of 2021. The ESI Proposals

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[41] *See* ER20-1582 below.

[42] The Searsburg facility is comprised of eleven Zond Z-40 turbines, each of which is rated at 550 kW; the overall project has a nameplate rating of 6MW. However, due to the age and physical characteristics of the turbines (the facility went online in July 1997, and reached its projected design lifetime of 20 years in July 2017), the Searsburg facility has a 20-25 percent capacity factor and produces on average 1.2 to 1.5 MW annually.

[43] Searsburg's SCADA system does not have the ability to set an active power limit for the wind facility, and the GMP control room does not have any turbine-level control capability. In addition, because the facility's Zond Z-40 turbines are among the last turbines of this model still in operation in the country, updated or modified control systems or spare parts for Searsburg's legacy Zond turbines are not available, and GMP states that it is unable to acquire turbine software capable of allowing Searsburg to set up an active power limit. The power output of the facility can only be limited by manually taking individual turbines offline, if a technician is available, or alternatively, shutting down the entire plant remotely by tripping the substation breaker, potentially damaging the wind turbines. Over the coming years, as each of Searsburg's turbines becomes inoperable, GMP will decommission the turbine.

[44] *ISO New England Inc.*, Docket No. ER20-1582 (May 8, 2020) (unpublished letter order).

[45] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER20-1094 (Apr. 20, 2020).

[46] This filing was submitted in response to the requirements of the *Mystic Waiver Order,* which directed ISO-NE, in part, to submit permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns. *See ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

were considered at the April 2 Participants Committee meeting. ISO-NE's ESI proposal with three amendments proposed by NESCOE was approved by NEPOOL and is the NEPOOL Alternative. ISO-NE's ESI proposal without the amendments (the "ISO-NE Proposal") was not supported. Comments on this filing are due on or before May 15, 2020. On April 24, NEPOOL submitted comments to provide NEPOOL's support for the NEPOOL Alternative.

Comments and protests were filed by Avangrid, API, Calpine/Vistra, Cogentrix, Dominion, Excelerate, Exelon, FirstLight, IECG, MA AG/NH OCA, MMWEC, NECOES/ENE, NESCOE, Repsol, NEPGA, NRG, PIOs, ISO-NE IMM, Potomac Economics, CT DEEP, MPUC, VT PUC, AEE, EPSA, National Hydropower Assoc., and the National Gas Supply Association ("NGSA"). On June 1 NEPOOL and NESCOE filed answers to some of the pleadings submitted. Doc-less interventions were filed by Acadia Center, Brookfield RTM, CT OCC, CT AG, CLF, ENE, Environmental Defense Fund, Eversource, National Grid, NextEra, NRDC/Sustainable FERC Project, PSEG, Repsol, Shell, UCS, Vistra, AWEA, APPA, EPSA, Helix Maine, Public Citizen, Sierra Club, and Vote Solar.

This matter is now pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **eTariff § III.13.6 Conforming Changes (ER20-1497)**

On June 1, 2020, the FERC accepted updates to ISO-NE's eTariff filed April 3, 2020[47] to ensure that Section III.13.6 consolidates, as of June 1, 2020, previously-accepted changes made with the October 18, 2019 PRD Revisions,[48] April 2, 2018 FCM Revisions,[49] and October 12, 2016 Resource Dispatchability Changes.[50] The changes were accepted effective June 1, 2020, as requested. Unless the June 1, order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)**

Still pending FERC action is Vineyard Wind's December 14, 2018 petition for a waiver of the ISO-NE Tariff provisions necessary to allow Vineyard Wind to participate in FCA13 as an RTR. As previously reported, Vineyard Wind's request for RTR designation was earlier rejected by ISO-NE on the basis that the resource is to be located in federal waters. Under the CASPR Conforming Changes, Vineyard Wind would not have been precluded from utilizing the RTR exemption. Consistent with the discussion in the CASPR Conforming Changes filing, Vineyard Wind asked that the proration requirement that would be triggered by Vineyard Wind's participation in FCA13 as an RTR be limited for FCA13 to it and any other similarly-situated entities (i.e. new offshore wind resources located in federal waters seeking RTR treatment); Vineyard Wind claimed that there would have been no impact on resources qualified to use the RTR exemption in FCA13. ISO-NE filed comments not opposing the Waiver Request, but requested FERC action by January 29, 2019 if the waiver was to be effective for FCA13. NEPGA protested the Waiver Request. Answers to NEPGA's protest were filed by Vineyard Wind and NESCOE. On January 15, the Massachusetts Department of Energy Resources ("MA DOER") intervened out-of-time and submitted comments supporting the Waiver Request. Doc-less interventions were filed by NEPOOL, Avangrid, Dominion, ENE, National Grid, and NextEra. Despite several

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[47] *ISO New England Inc.*, Docket No. ER20-1497 (June 1, 2020) (unpublished letter order).

[48] *See* Price Responsive Demand Clean-Up Changes, *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER20-140 (filed Oct. 18, 2019) ("PRD Revisions"); accepted in *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER20-140 (Dec. 10, 2019) (unpublished letter order).

[49] *See* Forward Capacity Market Revisions, *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER18- 1287-000 (filed Apr. 2, 2018) ("FCM Revisions"). Accepted in *ISO New England Inc. and New England Power Pool Participants Comm.,* Docket No. ER18-1287 (May 8, 2018) (unpublished letter order).

[50] *See* Revisions to Increase Resource Dispatchability , *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER17-68 (filed Oct. 12, 2016) ("Resource Dispatchability Changes"). Accepted in *ISO New England Inc. and New England Power Pool Participants Comm.*, 157 FERC ¶ 61,189 (Dec. 9, 2016).

last minute requests to do so, including a Vineyard Wind emergency motion for immediate stay of FCA13 or, in the alternative, a requirement that FCA13 be re-run following FERC action, the FERC took no action ahead of FCA13 and FCA13 was run without Vineyard Wind receiving RTR treatment. As noted, this matter remains pending before the FERC, with no activity since the last Report. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)**

As previously reported, the FERC conditionally accepted on November 22, 2019, subject to an additional compliance filing, New England's *Order 841*[51] compliance filing.[52] For the majority of the revisions, the effective date was December 3, 2019; the effective date for the revisions to Section II.21, Schedule 9 (Regional Network Service), and Schedule 21 (Local Service) of the OATT was December 1, 2019; the effective date for the remainder of the changes will be January 1, 2024.[53]

Order 841 Compliance Filing II (ER19-470-004). On February 10, 2020, ISO-NE and NEPOOL jointly filed Tariff revisions in response to the *Order 841 Initial Compliance Filing Order*. The revisions included: (i) a provision that addresses the state of charge and duration characteristics of an energy storage facility in the Day-Ahead Energy Market;[54] (ii) metering and accounting practices for electric storage resources, including direct metering requirements and certainty that electric storage resources will not pay twice for the same charging energy; and (ii) a provision which provides that an electric storage facility will "not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and [FCM] obligations". The filing explained why no additional Tariff language was needed to apply transmission charges to an electric storage resource when it is charging for later resale in the wholesale markets and not providing a service. The Tariff Revisions were unanimously supported by the Participants Committee at its February 6 meeting (Agenda Item #5). Comments on this filing were due on or before March 2, 2020; none were filed. This filing is now pending before the FERC.

If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[51] *See Elec. Storage Participation in Mkts. Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*").

[52] *ISO New England Inc.*, 169 FEC ¶ 61,140 (Nov. 22, 2019) ("*Order 841 Initial Compliance Filing Order*").

[53] The Order 841 revisions that became effective on Dec. 3, 2019 were filed in ER19-470-000; the revisions to § II.21, Schedule 9 and Schedule 21 became effective on Dec. 1, 2019 as requested in ER19-470-002; the remainder of the changes will become effective on Jan. 1, 2024 as requested in ER19-470-001.

[54] *See* proposed § III.1.10.6(d) -- "In clearing the Day-Ahead Energy Market, the ISO will account for maximum run time, maximum charge time, state of charge, maximum state of charge, and minimum state of charge through bidding parameters or other means, as required by the Commission in Order No. 841." This language reflects ISO-NE's pending challenge to the *Order 841 Initial Compliance Filing Order* on this point and will be subject to additional revision following disposition of that challenge.

- **Fuel Security Retention Proposal (ER18-2364)**

Requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[55] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[56] in all respects, despite the various protests and alternative proposals filed. There was a concurring decision from Commissioner Glick, and a partial dissent from Chairman Chatterjee on the FCA price treatment issue. Challenges to the *Fuel Security Retention Proposal Order* were filed by NEPGA, NRG, Verso, Vistra/Dynegy Marketing & Trade, MPUC, and PIOs.[57] On February 1, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Economic Life Determination Compliance Revisions (ER18-1770-003)**

On May 27, 2020, the FERC accepted Tariff changes, jointly filed by ISO-NE and NEPOOL on April 9, 2020, that reflect the FERC's rejection on rehearing[58] of the previously-accepted[59] Economic Life Revisions to Section III.13.1.2.3.2.1.2.C of the Tariff, and the prospective implementation of the Economic Life Revisions beginning with FCA16.[60] Specifically, the Section was revised in relevant part to read: "The economic life is the maximum evaluation period in which a resource's net present value is non-negative. However, effective April 9, 2020, beginning with the sixteenth Forward Capacity Auction, the economic life is the evaluation period in which a resource's net present value is maximized." Unless the May 27 order is challenged, this proceeding will be

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[55] *ISO New England Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018), *reh'g requested* ("*Fuel Security Retention Proposal Order*"). In accepting the ISO-NE Proposal, the FERC, among other things: (i) found ISO-NE's trigger and assumptions for the fuel security reliability review for retention of resources be reasonable, but required ISO-NE at the end of each winter to "to submit an informational filing comparing the study assumptions and triggers from the modeling analysis to actual conditions experienced in the winter of 2018/19; (ii) found cost allocation on a regional basis to Real-Time Load Obligation just and reasonable and consistent with precedent regarding the past Winter Reliability Programs; (iii) found that entering retained resources into the FCAs as price takers would be just and reasonable to ensure that they clear and are counted towards resource adequacy so that customers do not pay twice for the resource; and (Iv) found that it was appropriate to include FCAs 13, 14 and 15 in the term. The FERC agreed that it is necessary to implement a longer-term market solution as soon as possible, and required ISO-NE to file its longer-term market solution no later than June 1, 2019. The FERC declined to provide guidance on what the long-term solution(s) should be.

[56] As previously reported, ISO-NE filed, in response to the *Mystic Waiver Order*, "interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns". ISO-NE proposed three sets of provisions to expand its authority on a short-term basis to enter into out-of-market arrangements in order to provide greater assurance of fuel security during winter months in New England (collectively, the "Fuel Security Retention Proposal"). ISO-NE stated that the interim provisions would sunset after FCA15, with a longer-term market solution to be filed by July 1, 2019, as directed in the *Mystic Waiver Order*. In addition, the ISO-NE transmittal letter described (i) the generally-applicable fuel security reliability review standard that will be used to determine whether a retiring generating resource is needed for fuel security reliability reasons; (ii) the proposed cost allocation methodology (Real-Time Load Obligation, though ISO-NE indicated an ability to implement NEPOOL's alternative allocation methodology if determined appropriate by the FERC); and (iii) the proposed treatment in the FCA of a retiring generator needed for fuel security reasons that elects to remain in service. The ISO-NE Fuel Security Changes were considered but not supported by the Participants Committee at its August 24, 2018 meeting. There was, however, super-majority support for (1) the Appendix L Proposal with some important adjustments to make that proposal more responsive to the FERC's guidance in the Mystic Waiver Order and other FERC precedent, and (2) the PP-10 Revisions, also with important adjustments (together, the "NEPOOL Alternative").

[57] "PIOs" for purposes of this proceeding are Sierra Club, NRDC, Sustainable FERC Project, and Acadia Center.

[58] *ISO New England Inc. and New England Power Pool Participants Comm.*, 170 FERC ¶ 61,187 (Mar. 10, 2020) ("*Economic Life Revisions Rehearing Order*") (rejecting the Economic Life Revisions, effective Aug. 10, 2018, without prejudice to ISO-NE filing proposed Tariff revisions similar to the Economic Life Revisions, to be effective prospectively. Notwithstanding the fact that the Economic Life Revisions were rejected with an effective date prior to FCA13 and FCA14, the FERC did not require ISO-NE to re-run FCA13 or FCA14 without applying the Economic Life Revisions).

[59] *ISO New England Inc. and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,088 (Nov. 9, 2018) ("*Economic Life Determination Revisions Order*"), *reh'g granted*, 170 FERC ¶ 61,187 (Mar. 10, 2020).

[60] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER18-1770-003 (May 27, 2020) (unpublished letter order).

concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)**

On July 2, 2018, the FERC issued an order[61] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement (COS Agreement) to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[62] Even if it were inclined to apply its waiver criteria, the FERC stated that it would still have denied the waiver request as "not sufficiently limited in scope."[63]

Although it denied the waiver request, the FERC was persuaded that the record supported "the conclusion that, due largely to fuel security concerns, the retirement of Mystic 8 and 9 may cause ISO-NE to violate NERC reliability criteria." Finding ISO-NE's methodology and assumptions in the Operational Fuel-Security Analysis ("OFSA") and Mystic Retirement Studies reasonable, the FERC directed the filing of both interim and permanent Tariff revisions to address fuel security concerns (or a filing showing why such revisions are not necessary).[64] The FERC directed ISO-NE to consider the possibility that a resource owner may need to decide, prior to receiving approval of a COS Agreement, whether to unconditionally retire, and provided examples of how to address that possibility.[65] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that addresses how cost-of-service-retained resources would be treated in the FCM[66] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[67]

Requests for Rehearing and/or Clarification. The following requests for rehearing and or clarification of the *Mystic Waiver Order* remain pending before the FERC:

- ***NEPGA*** (requesting that the FERC grant clarification that it directed, or on rehearing direct, ISO-NE to adopt a mechanism that prohibits the re-pricing of Fuel Security Resources in the FCA at $0/kW-mo. or at any other uncompetitive offer price);

[61] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[62] *Id.* at P 47.

[63] *Id.* at P 48.

[64] *Id.* at P 55.

[65] *Id.* at PP 56-57.

[66] *Id.* at P 57.

[67] *Id.* at P 58.

- ***Connecticut Parties***[68] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);
- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[69] (requesting clarification that (i) the central purpose of ISO-NE's July 1, 2019 filing is to assure that New England adds needed new infrastructure to address the fuel supply shortfalls and associated threats to electric reliability that ISO-NE identified in its OFSA and (ii) that, in developing the July 1, 2019 filing, ISO-NE is to evaluate Tariff revisions (such as those the EDCs described in their request), through which ISO-NE customers would pay for the costs of natural gas pipeline capacity additions via rates under the ISO-NE Tariff);
- ***PIOs***[70] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and
- ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding

[68] "Connecticut Parties" are CT PURA and CT DEEP.

[69] The "EDCs" are the National Grid companies (Mass. Elec. Co., Nantucket Elec. Co., and Narragansett Elec. Co.) and Eversource Energy Service Co. (on behalf of its electric distribution companies – CL&P, NSTAR and PSNH).

[70] "PIOs" are the Sierra Club, Natural Resources Defense Council ("NRDC"), and Sustainable FERC Project.

that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

On August 13, 2018, CT Parties opposed the NEPGA motion for clarification. On August 14, NEPOOL filed a limited response to Indicated New England EDCs, requesting that the FERC "reject the relief sought in [their motion] to the extent that relief would bypass or predetermine the outcome of the stakeholder process, without prejudice to [them] refiling their proposal, if appropriate, following its full consideration in the stakeholder process." Answers to the Indicated New England EDCs were also filed by the MA AG, NEPGA, NextEra, and CLF/NRDC/Sierra Club/Sustainable FERC Project. On August 29, the Indicated New England EDCs answered the August 14/16 answers. On August 27, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Rehearing of the FERC's order accepting ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions,[71] summarized in more detail in prior Reports, remains pending. Those requests were filed by (i) ***NextEra/NRG*** *(which* challenged the RTR Exemption Phase Out); (ii) ***ENECOS***[72] (challenging the FERC's findings with respect to the definition of Sponsored Policy Resource and the allocation of CASPR side payment costs to municipal utilities); (iii) ***Clean Energy Advocates***[73] (which challenged the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (which also challenged the CASPR construct in its entirety and the *CASPR Order*'s failure to define "investor confidence"). On April 24, ISO-NE answered Clean Energy Advocates' answer. On May 7, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)**

On April 1, 2020, the FERC issued its long-awaited order on compliance and remand, accepting ISO-NE's January 23, 2017 compliance filing and finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable.[74] The FERC also provided the further reasoning requested by the DC Circuit for this finding.[75] As has been reported for some time, the FERC directed ISO-NE in its August 8, 2016 remand order[76] to request from Program participants the basis for their bids, including the process used to

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[71] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*"), *reh'g requested*.

[72] The Eastern New England Consumer-Owned Systems ("ENECOS") are: Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Littleton Electric Light & Water Department, Middleton Electric Light Department, Middleborough Gas & Electric Department, Norwood Light & Broadband Department, Pascoag (Rhode Island) Utility District, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wallingford (Connecticut) Department of Public Utilities. Wellesley Municipal Light Plant, which intervened in this proceeding as one of the ENECOS, did not join in the ENECOS' request for rehearing.

[73] For purposes of this proceeding, "Clean Energy Advocates" are, collectively, the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

[74] *ISO New England Inc.*, 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*"), *reh'g requested*.

[75] *See Id.* at PP 54-96.

[76] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*"). As previously reported, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable), and directing the FERC to either

formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and ISO-NE's recommendation as to the reasonableness of the bids, so that the FERC could further consider the question of whether the Bid Results were just and reasonable.[77] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." Both TransCanada and the MA AG protested ISO-NE's conclusion and recommendation that modification of the program was unwarranted, but the FERC did not find convincing either challenge.

Request for Rehearing (ER13-2266-005). On May 1, TransCanada requested rehearing of the *2013/14 Winter Reliability Program Order on Compliance and Remand*. In its request for rehearing, TransCanada argued that the Order (i) erred when it found the bid results just and reasonable; (ii) violated FPA Section 205, the rule against retroactive ratemaking and the filed rate doctrine by approving the bid results under a market-based rate paradigm; and (iii) was arbitrary and capricious, not based on reasoned decision-making and contrary to, and without foundation in, substantial evidence in the record. On June 1, 2020, the FERC issued a tolling order affording it additional time to consider TransCanada's request for rehearing, which remains pending.

If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV.OATT Amendments / TOAs / Coordination Agreements

- **CIP IROL Cost Recovery Rules (ER20-739)**

On May 26, 2020, the FERC accepted revisions that incorporate into the Tariff as a new Schedule 17 a mechanism to facilitate the recovery of critical infrastructure protection ("CIP") costs by facilities that ISO-NE identifies as critical to the derivation of Interconnection Reliability Operating Limits ("IROL") (the "CIP IROL Cost Recovery Rules").[78] In accepting Schedule 17, the FERC found that "Schedule 17 permits recovery only of CIP costs incurred on or after the effective date of a section 205 filing made by an IROL-Critical Facility Owner to recover such costs".[79] The FERC accepted the CIP IROL Cost Recovery Rules effective as of March 6, 2020. Unless the *CIP IROL Cost Recovery Order* is challenged, with any challenges due on or before June 25, 2020, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO-NE *Order 845* Compliance Filing (ER19-1951)**

On March 19, 2020, the FERC conditionally accepted, subject to further compliance filings, the proposed revisions to the Large Generator Interconnection Procedures ("LGIP") and Agreement ("LGIA") in

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offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable. *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

[77] *2013/14 Winter Reliability Program Remand Order* at P 17.

[78] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*").

[79] *Id.* at PP 1, 27. "Section 2.2(A) of proposed Schedule 17 would permit IROL-Critical Facility Owners to make FPA section 205 filings to recover costs incurred by the IROL Critical Facility Owner *during the period in which the subject facility is designated as an IROL-Critical Facility*. While the parties dispute the meaning of the italicized language, that language is appropriately read in conjunction with the requirement that IROL-Critical Facility Owners submit individual FPA section 205 filings to recover such costs … Thus, we find that, read in context with the remainder of section 2.2(A), the italicized language would allow IROL-Critical Facility Owners to recover only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing."

Schedule 22 of the ISO-NE OATT jointly filed on May 22, 2019 by ISO-NE and the PTO AC ("Filing Parties") in response to the requirements of *Order 845* ("*Order 845* Compliance Filing").[80] While the Order largely accepted the *Order 845* Compliance Filing, the FERC identified a number of ways in which the *Order 845* Compliance Filing only partially complied or did not comply with *Order 845*, directing changes to the following (Paragraph citations to the *Order 845 Compliance Filing Order* in brackets):

- ***Stand-Alone Network Upgrades definition***. Finding that the Filing Parties did not sufficiently justify their proposal to revise the definition of "Stand Alone Network Upgrades" to specify that the 15-day period for the system operator to provide a written explanation for why an upgrade is not considered a stand-alone network upgrade is 15 business days instead of 15 calendar days, the FERC directed the Filing Parties either to provide sufficient justification or to submit proposed Tariff revisions that make no modification to the 15 calendar day period. [P 32]
- ***Interconnection Customer's ability to exercise the option to build***. Finding the Filing Parties independent entity variation justification insufficient, the FERC directed the Filing Parties to "submit a further compliance filing within [120][81] days of the date of this order with proposed Tariff revisions that remove this variation from ISO-NE *pro forma* LGIA article 5.1.3." [P 35]
- ***Option to Build Cost Recovery***. The FERC rejected the PTO-sponsored proposed variation for transmission owners to recover the actual costs for their oversight responsibilities pursuant to ISO-NE *pro* forma LGIA article 5.2 as "not consistent with or superior to the oversight cost requirements in the [FERC's] pro forma LGIA". [P 36]
- ***Determination of Contingent Facilities***. Finding the proposed Tariff revisions "lack the requisite transparency required by *Orders 845* and *845-A* because the proposed Tariff revisions do not detail the specific technical screens or analyses and the specific thresholds or criteria that ISO-NE will use as part of its method to identify contingent facilities," the FERC directed the Filing Parties to add "in section 3.8 of the ISO-NE LGIP (1) the method ISO-NE will use to determine contingent facilities, including technical screens or analyses Filing Parties propose to use to identify these facilities and (2) the specific thresholds or criteria ISO-NE will use in its technical screens or analysis to achieve the level of transparency required by *Order 845*." [PP 45-46]
- ***Requesting interconnection service below generating facility capacity***. Filing Parties were directed to incorporate required language into LGIP sections 3.1 and 8.2. [PP 78, 76]
- ***Provisional Interconnection Service***. Rejecting the proposal to require interconnection customers to request provisional interconnection service before the system impact study, the FERC directed the Filing Parties to remove the following sentence from *pro forma* ISO-NE LGIA article 5.9.2: "Prior to the commencement of the Interconnection System Impact Study associated with a Large Generating Facility, an Interconnection Customer may request Provisional Interconnection Service." [PP 85-86]
- ***Surplus Interconnection Service – Definition***. Agreeing with NEPOOL's and other parties' protests, the FERC directed the Filing Parties "to provide sufficient justification for their independent entity variation that limits the availability of surplus interconnection service for customers with NRIS, or to propose Tariff revisions that adopt the *pro forma* definition of 'Surplus Interconnection Service' for NRIS customers." [PP 111-112]
- ***Surplus Interconnection Service – Process***. Again agreeing with NEPOOL's and other parties' protests, the FERC directed the Filing Parties to revise revises section 3.3.1 of the LGIP to make clear that ISO-NE will not limit studies for surplus interconnection service to 10 business days, and will continue to study a surplus interconnection service request, without requiring a new interconnection request,

[80] *ISO New England Inc. and Participating Transmission Owners Admin. Comm.*, 170 FERC ¶ 61,209 (Mar. 19, 2020) ("*Order 845 Compliance Filing Order*").

[81] The FERC issued an errata notice on Apr. 22, 2020 correcting the deadline from "60 days to the intended 120 days".

until it determines whether any additional interconnection facilities and/or network upgrades necessary for surplus interconnection service. [PP 128-129]

A memo describing the in more detail the *Order 845 Compliance Order* was posted with the materials for, and discussed at, the March 25, 2020 Transmission Committee meeting. The *Order 845* Compliance Filing changes were conditionally accepted effective May 19, 2020. A compliance filing with the directed changes is due on or before July 17, 2020. Changes in response to the *Order 845 Compliance Filing Order* will be considered by the Participants Committee at its June 4 meeting (Agenda Item #7).

ISO-NE April 20 Filing Rejected. On May 19, the FERC rejected[82] ISO-NE's April 20, 2020 request for expedited clarification of the *Order 845 Compliance Filing Order*.[83] The FERC found that, "while ISO-NE's pleading nominally styles itself as a "Motion for Clarification," in substance, it is a request for rehearing" and did "not meet the Commission's requirements for submission of a request for rehearing of a Commission order." Accordingly, the FERC rejected the April 20 filing.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V.Financial Assurance/Billing Policy Amendments

- **Billing Policy Enhancements and Clean-Up Changes (ER20-1862)**

On May 20, 2020, ISO-NE and the NEPOOL jointly filed enhancements and clean-up changes to the Billing Policy. Among other things, the filing: (i) updates the definition of Non-Hourly Charges (to include any pass-through charges where ISO-NE acts as agent (including communications related charges, OASIS- related charges, and fees related to the Shortfall Funding Arrangement); (ii) changes the timing of Statements for Non-Hourly Charges (from the first Monday after the tenth of each calendar month to the first Monday after the ninth of each calendar month); (iii) reflects the issuance (rather than the sending) of Invoices and Remittance Advices; (iv) changes the timing for payment instructions; (v) limits distributions from late payment accounts (to only those Market Participants not in a Payment Default at the time of a distribution); and (vi) limits the frequency for the use of pre-payments (to five in any rolling 365-day period), limiting the risk that prepayment provisions are being used to deflate financial assurance obligations. A July 27, 2020 effective date was requested. The changes were unanimously supported by the Participants Committee at its May 7 meeting (Agenda Item #6). Comments on this filing will be due on or before June 10, 2020. Thus far, Plant-E Corp. submitted comments protesting the change that would limit for all the frequency for the use of pre-payments (Plant-E suggests, alternatively, that the limitation not be imposed on Market Participants, like it, that are unable because of their formation in a non-US jurisdiction to use a BlackRock account as part of its additional financial assurance arrangements). A doc-less intervention was submitted by Calpine. If you have any questions concerning this matter, please contact Paul Belval (pnbelval@daypitney.com; 860-275-0381).

[82] ISO-NE sought clarification that, (1) with respect to its obligation to remove the variation related to an Interconnection Customer's ability to exercise the option to build from ISO-NE pro forma LGIA article 5.1.3, it may submit the proposed changes with the rest of its compliance changes due July 17 (rather than May 18). The FERC issued an errata notice on April 22, 2020 correcting the deadline for the submission of this change "to the intended 120 days." (*see* n. 81 *infra*); and (2) related to the availability of Surplus Interconnection Service for Network Resource Interconnection Service ("NR Interconnection Service" or "NRIS") customers, (i) that surplus interconnection service is limited to the same service available to the Original Interconnection Customer and (ii) that ISO-NE is only required to identify whether upgrades are required and that, if the ISO's analysis confirms that upgrades are required to accommodate a request for surplus interconnection service, then its analysis under the expedited process ceases (or additional guidance if the FERC did in fact intend to require ISO-NE to identify the specific upgrades that would be required to accommodate the proposed surplus interconnection request).

[83] *ISO New England Inc. and Participating Trans. Owners Admin. Comm.*, 171 FERC ¶ 61,122 (May 19, 2020) ("*Notice Rejecting April 20 Filing*").

VI.Schedule 20/21/22/23 Changes

- **Schedule 21-NEP: NSTAR LSA (ER20-1692)**

On April 29, 2020, National Grid filed a Local Service Agreement ("LSA") between NEP and NSTAR that provides for the provision of Local Network Service and Firm Local Point-To-Point Service over NEP's Local Service transmission facilities to NSTAR Electric after the existing Service Agreement for Network Integration Transmission Service Agreement expired on March 30, 2020. National Grid states that the LSA sets forth the same provisions as the *pro forma* LSA contained in Attachment A to Schedule 21-Common, but was filed as a non-conforming agreement because, as a two-party agreement, it omits references to ISO-NE as a party. Comments on this filing were due on or before May 20; none were filed. Eversource, on behalf of NSTAR, intervened doc-lessly. 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).

- **Schedule 20A-NEP: NEP-Brookfield RTM Phase I/II HVDC-TF Service Agreement (ER20-1626)**

On April 21, 2020, New England Power Company ("NEP") submitted a new Phase I/II HVDC-TF Service Agreement between NEP and Brookfield Renewable Trading and Marketing LP ("Brookfield RTM"). The Service Agreement will allow the continuation without interruption of firm point-to-point transmission service that is currently being provided under Schedule 20A. NEP stated that the Agreement conforms generally to the *pro forma* Schedule 20A service agreement, but contains provisions related to NEP's contractual rights allowing it to sell service over the Phase I/II HVDC transmission facilities ("Phase I/II HVDC-TF") through October 31, 2020, and that permit Brookfield to exercise its transmission customer rollover service rights through August 31, 2025 as specified in the NEP-Brookfield Service Agreement. NEP requested a September 1, 2020 effective date for the changes. Comments on this filing were due on or before May 12. On April 29, 2020, Brookfield RTM submitted comments urging the FERC to accept the Agreement and clarifying that, by executing the Agreement, Brookfield RTM has not waived its rights to continue taking service from another IRH or IRHs in the event that NEP does not renew its Use Rights by extending participation as an IRH under the Phase I/II agreements. No other comments were filed. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-NEP National Grid/Winchendon Hydro SGIA (ER20-1413)**

On May 15, 2020, the FERC accepted a non-conforming Small Generation Interconnection Agreement ("SGIA") between National Grid and Winchendon Hydroelectric LLC ("Winchendon Hydro").[84] As previously reported, the SGIA covers the continued interconnection of Winchendon Hydro's 100 kW run-of-river hydro facility located in Winchendon, Massachusetts. The SGIA replaced an existing interconnection agreement. Since the SGIA covers an existing, interconnected facility, a new three-party interconnection agreement (that would include ISO-NE) was not required. The SGIA was accepted effective as of February 26, 2020, as requested. Unless the May 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).

- **Schedule 21-EM: 2019 Annual Update Settlement Agreement (ER15-1434-004)**

On March 19, 2020, Emera Maine submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Emera Maine's 2019 annual charges update filed, as previously reported, on June 10, 2019 (the "Emera 2019 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM, "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 2019 Annual Update, all of which are resolved by the Emera 2019 Annual Update Settlement Agreement. Comments on the Emera 2019 Annual Update Settlement Agreement were due on or before April

[84] *Mass. Elec. Co.*, Docket No. ER20-1413 (May 15, 2020) (unpublished letter order).

9, 2020; 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-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

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,*[85]and certified by Settlement Judge Dring[86] to the Commission,[87] remains pending before the FERC. As previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P-EM of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP Annual True Up Calculation Informational Filing (ER12-2304)**

On June 1, 2020, pursuant to Section 4 of Schedule 21-GMP, GMP submitted its annual informational filing containing the true-up calculation of its actual (rather than estimated) costs for the January 1, 2019 through December 31, 2019 time period. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VEC and 20-VEC Annual Informational Filing (ER10-1181)**

On April 30, 2020, VEC submitted its 17th annual update to the formula rates contained in Schedules 21-VEC and 20-VEC covering the July 1, 2020 – June 30, 2021 period. VEC indicated that it was not proposing any changes to the underlying formulas. In addition, VEC noted that, as a not-for-profit entity, it does not have ADIT, and no change would be necessary to address ADIT if VEC were a public utility subject to an Order 864 compliance obligation. On May 12, 2020, VEC made a errata filing correcting an error in the calculation of the Transmission System Peak Load, which reduces the per unit charges. The FERC will not notice these filings for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)**

On June 1, 2020, NSTAR submitted an informational filing containing the true-up of billings under Schedule 21-NSTAR for the period January 1, 2019 through December 31, 2019. NSTAR stated that the filing complies with the requirements of Section 4 and Attachment D of Schedule 21-NSTAR, as well as the Settlement Agreement approved previously by the FERC.[88] The FERC will not notice this filing for public comment, and absent further

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[85] *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.

[86] 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.

[87] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

[88] *See NSTAR Elec. Co.*, 123 FERC ¶ 61,270 at P 5 (2008).

activity, no further FERC action is expected. If there are questions on this matter, 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)**

FG&E's 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).

- ***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*[89] *and 531-B*[90] 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 - 2020 Q1 (ER20-1824)**

On May 14, 2020, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the first quarter ("Q1") of calendar year 2020 (the "Report"). ISO-NE is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) FCM Nested Zones ($825,000); (ii) nGEM value added development ($792,000); (iii) Generation Survey System ($439,600); (iv) inter-control center communications protocol network buildout over shared telecommunications network ($310,000); (v) forward reserve market infrastructure conversion ($205,000); and (vi) information technology policy compliance software update ($80,000). Projects with a significant changes were (i) 2020 issue resolution phase I ($255,000 budget increase); and (ii) 2020 issue resolution phase II ($280,000 budget decrease). Comments on this filing are June 4. Thus far, Eversource and National Grid filed doc-less interventions only. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **IMM 2019 Annual Markets Report (ZZ20-4)**

On May 26, the IMM filed its 2019 Annual Markets Report, which covers the 2019 calendar year period.[91] The report addresses the development, operation, and performance of the New England Markets and presents an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 17.2.4 of Appendix A to Market Rule 1. On the basis of its review of market outcomes and related information, the IMM concluded, as it has for many years in a

[89] *Martha Coakley, Mass. Att'y Gen.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[90] *Martha Coakley, Mass. Att'y Gen.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

[91] Please note that Annual Markets Reports filings are not noticed for public comment by the FERC.

row, that the New England Market operated competitively in 2019. In contrast to 2018, there were no periods in the Real-Time Energy Market when a relative shortage of energy and reserves resulted in scarcity pricing (due to a combination of surplus supply capacity, mild summer weather and the lack of sustained cold temperatures during the winter). There was a further improvement in the structural competitiveness of the Real-Time Energy Market, with fewer hours with pivotal suppliers in Real-Time compared with the prior four years. The number of energy market supply offers mitigated for market power remained very low, totaling just 0.02% of all supply offers. For the sixth consecutive year, the forward capacity auction procured surplus capacity, and clearing prices were the result of a competitive auction." Other highlights included:

- 2019 Total wholesale costs ($9.8 billion) were $2.3 billion lower than 2018, with 85% of the overall decrease driven by lower energy costs.
- 2018 Energy costs totaled $4.1 billion, down $1.9 billion or 32% from 2018, with the decrease driven by lower natural gas prices, which averaged $3.26/MMBtu, down 34% from 2018 prices.
- Electricity demand in the third quarter of the year decreased by 6%, or by 1,011 MW per hour, and drove a 4% year-over-year decrease in demand. On a weather-normalized basis, demand was again down slightly, continuing a longer-term downward trend due to the increase in utility-backed energy efficiency programs and behind-the-meter photovoltaic generation.

In light of its review, the IMM made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2020. These recommendations will be discussed in more detail at the Markets Committee's June 10 Meeting.

- **ISO-NE FERC Form 3Q (2020/Q1) (not docketed)**

On May 28, 2020, ISO-NE submitted its 2020/Q1 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

- **ISO-NE 2019 FERC Form 714 (not docketed)**

On June 1, 2020, ISO-NE submitted its Annual Electric Balancing Authority Area and Planning Area Report for calendar year 2019. Through its Form 714 filing, ISO-NE reports, among other things, generation in the New England Control Area, actual and scheduled inter-balancing authority area power transfers, and net energy for load, summer-winter generation peaks and system lambda. The FERC uses the data to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled inter-balancing authority area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-balancing authority area bulk power trade information. Planning area data will be used to monitor forecasted demands by electric utility entities with fundamental demand responsibility, and to develop hourly demand characteristics. These filings are not noticed for comment.

IX.Membership Filings

- **June 2020 Membership Filing (ER20-1943)**

On May 31, 2020 NEPOOL requested that the FERC accept (i) the memberships of: Actual Energy (Supplier Sector); Borrego Solar Systems, Inc. (AR Sector, DG Sub-Sector); Paper Birch Energy, LLC [Related Person to CS Berlin Ops/Berlin Station (Generation Sector Group Seat)]; Priogen Power LLC (Supplier Sector); and Standard Normal Energy LLC (Supplier Sector); (ii) the termination of the Participant status of: Royal Bank of Canada (Supplier Sector) (May 1, 2020); Wallingford Energy II, LLC [Related Person to Jericho Power (AR Sector; RG Sub-Sector)] (May 1, 2020); Agera Energy LLC (Supplier Sector) (June 1, 2020); and (iii) the name changes of: Versant Power (f/k/a Emera Maine) and IPKeys Power Partners, Inc. (f/k/a IPKeys Power Partners LLC). The membership of Borrego Solar System fully activates the AR Sector's DG Sub-Sector. Accordingly, the AR Sector Voting Share, as

well as each of the other five Sector's Coting Share, will be 16.67%. Comments on this filing are due on or before June 22, 2020.

- **May 2020 Membership Filing (ER20-1694)**

On April 30, 2020 NEPOOL requested that the FERC accept the membership of RPA Energy Inc. d/b/a/ Green Choice Energy (Supplier Sector) and termination of the Participant status of Empire Generating Co, LLC [Related Person of Kleen Energy Systems (Generation Sector)]. Comments on this filing were due on or before May 21, 2020; none were filed. This matter is pending before the FERC.

- **April 2020 Membership Filing (ER20-1454)**

On May 21, 2020, the FERC accepted (i) the memberships of Axon Energy, LLC (Supplier Sector); Energy Harbor LLC (Supplier Sector); and Nexus Energy Inc. (Supplier Sector); and (ii) the termination of the Participant status of ADG Group Inc. (Supplier Sector); Beacon Falls Energy Park, LLC (Related Person of Kleen Energy Systems (Generation Sector)); Clear River Energy (Related Person of Invenergy Energy Management (Generation Sector); Entergy Nuclear Power Marketing (Supplier Sector); and Rinar Power (Data-Only Participant). Unless the May 21 order s challenged, this proceeding will be concluded.

- **Suspension Notices (not docketed)**

Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC noting that the following Participants were suspended from the New England Markets on the date indicated (at 8:30 a.m.) due to a Payment or Financial Assurance Default:

Date of Suspension/ FERC Notice	***Participant Name***	***Date Reinstated***
May 11/13	Energy Federation Inc.	--
May 11/13	EPIS Inc. (FTR-Only Customer)	--
May 11/13	Great American Power	--

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

X. Misc. - ERO Rules, Filings; Reliability Standards

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).

- **Joint Staff White Paper on Notices of Penalty for Violations of CIP Standards (AD19-18)**

Still pending is the FERC's White Paper, prepared jointly with NERC staff and issued on August 27, 2019, that sets out a proposed new format for NERC Notices of Penalty ("NOP") involving violations of CIP Reliability Standards. The FERC explained that the revised format is intended to improve the balance between security and transparency in the filing of NOPs. Specifically, NERC CIP NOP submissions would consist of a proposed public cover letter that discloses the name of the violator, the Reliability Standard(s) violated (but not the Requirement), and the penalty amount. NERC would submit the remainder of the CIP NOP filing containing details on the nature of the violation, mitigation activity, and potential vulnerabilities to cyber systems as a nonpublic attachment, along with a request for the designation of such information as CEII.

Public comment on the proposal was sought with respect to the following: (i) the potential security benefits from the new proposed format; (ii) potential security concerns that could arise from the new format; (iii) any other implementation difficulties or concerns that should be considered; and (iv) whether the proposed format provides sufficient transparency to the public. Other suggested approaches to CIP NOP submissions were

welcomed. No changes to the CIP NOP filing format will be made prior to consideration of public comment on the White Paper. Comments were filed by over 80 parties. This matter is pending before the FERC.

- **Complaint re: CIP-014-2 (Physical Security) (EL20-21)**

On January 30, 2020, Michael Mabee, a private citizen ("Complainant"), filed a formal complaint alleging that Critical Infrastructure Protection ("CIP") Reliability Standard (CIP-014-2) (Physical Security) is inadequate and asked the FERC to issue an order directing NERC to correct the deficiencies. Specifically, Complainant alleges that (1) CIP-014-2 is inadequate in that there is no requirement that an entity's risk assessment or physical security plan be reviewed by anyone with any physical security expertise and no regulator determination as to the effectiveness of any entity's physical security plan and (2) enforcement of CIP-014-2 seems nonexistent (asserting that in the past seven years, there's only been four citations (for administrative violations) for violations of CIP-014-2. Complainant supplement his complaint on February 19 with further background and detail on the allegations and further recommendations. Responses and comments to this complaint, as supplemented, were due on or before March 10, 2020, and were filed by NERC (requesting that the FERC dismiss the Complaint), APPA/LPPC/TAPS, EEI/NRECA, the Foundation for Resilient Societies, Task Force on National and Homeland Security, and by individuals supporting the Complaint, including R. James Woolsey, an honorary co-chairman of the Secure the Grid Coalition (a project of the Center for Security Policy) (encouraging the FERC to "deeply analyze the effectiveness and the enforcement of the physical security standard you previously approved against the current threat environment and the reality that our modern civilization depends entirely upon the bulk power system"). AEP, Georgia System Operations Corp., LA PSC, Public Citizen and Dayton Power & Light intervened doc-lessly. This matter is pending before the FERC.

- **Revised Reliability Standard: PRC-024-3 (RD20-7)**

On March 20, 2020, NERC filed for approval proposed changes to Reliability Standards PRC-024-3 (Frequency and Voltage Protection Settings for Generating Resources) ("Revised PRC-024"). The changes clarify voltage and frequency protection settings requirements. Specifically, the changes clarify the types of protection subject to the requirements and incorporates language used by inverter manufacturers and solar development owners in order to ensure inverter-based resources respond to grid disturbances in a manner that contributes to the reliable operation of the Bulk-Power System. 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. Comments on Revised PRC-024 were due on or before April 20, 2020 and were filed by CAISO (supporting approval of Revised PRC-024). This matter is pending before the FERC.

- **Revised Reliability Standards: FAC-002-3; IRO-010-3; MOD-031-3; MOD-033-2; NUC-001-4; PRC-006-4; TOP-003-4 (RD20-4)**

Still pending before the FERC are the proposed changes to the following Reliability Standards filed on February 21, 2020: FAC-002-3 (Facility Interconnection Studies); IRO-010-3 (Reliability Coordinator Data Specification and Collection); MOD-031-3 (Demand and Energy Data); MOD-033-2 (Steady-State and Dynamic System Model Validation); NUC-001-4 (Nuclear Plant Interface Coordination); PRC-006-4 (Automatic Underfrequency Load Shedding); and TOP-003-4 (Operational Reliability Data) ("Revised Standards"). The changes remove references to Load Serving Entity (which is no longer an applicable entity), add Underfrequency Load Shedding ("UFLS")-Only Distribution Provider to PRC-006-3 as an applicable entity, and make consistent across the Standards the use of the term "Planning Coordinator". 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 three months following FERC approval. Comments on the Revised Standards were due on or before March 23, 2020; none were filed. American Municipal Power ("AMP") submitted a doc-less intervention. This matter remains pending before the FERC.

- **CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects (RD20-2)**

On February 20, 2020, the FERC directed NERC to submit, on or before March 23, 2020, an informational filing describing the activity of two NERC CIP standard drafting projects pertaining to virtualization and cloud computing services.[92] Specifically, NERC was directed to submit a schedule for Project 2016-02 (Modifications to CIP Standards) and Project 2019-02 (BES Cyber System Information Access Management) (collectively, the "NERC Projects"), that would include the current status of the project, interim target dates, and the anticipated filing date for new or modified Reliability Standards. NERC submitted that filing on March 19, 2020. Comments were submitted by a private citizen (Barry Jones) and VMware, Inc. on April 21 and 27, respectively. In addition, the FERC directed NERC to file on an information basis quarterly status updates, until such time as new or modified Reliability Standards are filed with the FERC.

- **NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)**

On February 20, 2020, the FERC issued a notice of inquiry 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 ("NOI").[93] On March 25, 2020, Joint Associations[94] 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. Thus far, comments have been filed by the Bureau of Reclamation, Barry Jones, Siemens Energy Management, VMware, Inc., American Association for Laboratory Accreditation ("A2LA"), and Waterfall Security Solutions. As noted, further reply comments are due on or before July 31, 2020.

- **NOPR - Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On January 23, 2020, the FERC issued a NOPR[95] proposing to approve the retirement of 74 of the 77 Reliability Standard requirements requested to be retired by NERC in these two dockets[96] in connection with the first phase of work under NERC's Standards Efficiency Review[97] ("*Retirements NOPR*"). The FERC explained in the *Retirements NOPR* that the requirements to be retired "(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."[98] The FERC also proposes to approve the associated VRFs, VSLs, implementation plan, and

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[92] *N. Am. Elec. Rel. Corp.*, 170 FERC ¶ 61,109 (Feb. 20, 2020).

[93] *Virtualization and Cloud Computing Services*, 170 FERC ¶ 61,110 (Feb. 20, 2020).

[94] "Joint Associations" are for purposes of this proceeding: EEI, APPA, NRECA, and LPPC.

[95] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020).

[96] As previously reported, NERC filed in ***RM19-17*** for approval (i) the retirement of individual requirements in the following four Reliability Standards: FAC-008-4 (Facility Ratings); INT-006-5 (Evaluation of Interchange Transactions); INT-009-3 (Implementation of Interchange); and PRC-004-6 (Protection System Misoperation Identification and Correction); and (ii) the retirement, in their entirety, of the following 10 Reliability Standards: 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-001-1a (Available Transmission System Capability); MOD-004-1 (Capacity Benefit Margin); MOD-008-1 (Transmission Readability Margin Calculation Methodology); MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators); MOD-028-2 (Area Interchange Methodology); MOD-029-2a (Rated System Path Methodology); and MOD-030-3 (Flowgate Methodology). NERC filed in ***RM19-16*** for approval of the retirement of individual requirements in the following three Reliability Standards: IRO-002-7 (Reliability Coordination – Monitoring and Analysis); TOP-001-5 (Transmission Operations); and VAR-001-6 (Voltage and Reactive Control).

[97] The Standards Efficiency Review initiative, which began in 2017, 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.

[98] *Id.* at P 1.

effective dates proposed by NERC. With respect to the remaining three requirements that NERC seeks to retire, the FERC seeks more information on two -- the retirement of FCA-008-3, Requirements R7 and R8 (with the FERC's final determination to be based on the comments received) – and proposes to remand one – VAR-001-6 – in order to retain R2, which it found neither redundant nor unnecessary for reliability. Comments on the *Retirements NOPR* were due on or before April 6, 2020.[99] Comments were filed by J. Applebaum, Bonneville Power Administration ("BPA"), NERC, and the Western Area Power Administration ("WAPA").

NERC Notice of Withdrawal of VAR-001-6. Since the last Report, on May 14, 2020, NERC submitted a notice of, and requested the FERC permit, withdrawal of VAR-001-6, either by order or expiration of the 15-day period in Rule 216 of the Commission's Rules of Practice and Procedure.

- **Report of Comparisons of Budgeted to Actual Costs for 2019 for NERC and the Regional Entities (RR20-3)**

On May 29, 2020, NERC filed comparisons of actual to budgeted costs for 2019 for NERC and the seven Regional Entities operating in 2019, 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 2019 budgets and actual results. Comments on this filing are due on or before June 19, 2020.

XI. Misc. - of Regional Interest

- **203 Application: CMP/NECEC (EC20-24)**

On March 13, 2020, the FERC authorized CMP to transfer to NECEC Transmission LLC 7 TSAs, executed on June 13, 2018, that provide the rates, terms, and conditions under which transmission service will be provided over the New England Clean Energy Connect ("NECEC") Transmission Line to the participants that are funding construction of the Line.[100] Pursuant to the March 13 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.

- **PJM MOPR-Related Proceedings (EL18-178; EL16-49)**

As previously reported, the FERC, on April 16, 2020, issued an order granting, in part, and denying, in part, the requests for rehearing and clarification of the *Dec 2019 PJM MOPR Order*, and directed PJM to submit a further compliance filing within 45 days.[101] Since the last Report, requests for rehearing and/or clarification of the *April 2020 PJM MOPR Rehearing Order* were filed by the PJM IMM, Energy Harbor, Exelon, Northern Virginia Electric Cooperative, NRECA, Pennsylvania Public Utility Commission, and Vistra and are pending before the FERC. Several petitions for federal court review of the FERC's April *2020 PJM MOPR Rehearing Order* have been filed, including appeals by APPA/AMP, Energy Harbor, Exelon, Illinois Commerce Commission, New Jersey Division of Rate Counsel/Office of the People's Counsel for the District of Columbia/Maryland Office of People's Counsel/Delaware Division of the Public Advocate, Ohio Public Utilities Commission, Old Dominion Electric Cooperative, the North Carolina Electric Membership Corporation, and NRECA. Those appeals are pending before the US Court of Appeals for the DC Circuit ("DC Circuit").

As previously reported, on December 19, 2019, in a long-awaited order (approved 2-1),[102] the FERC ***found*** that "any resource, new *or existing*, that receives, or is entitled to receive, a State Subsidy, and does not

[99] The *Retirements NOPR* was published in the *Fed. Reg.* on Feb. 6, 2020 (Vol. 85, No. 25) pp. 6,831-6,838.

[100] *Central Maine Power Co.*, 170 FERC 62,145 (Mar. 13, 2020).

[101] *PJM Interconnection, L.L.C.* and *Calpine Corp. et al. v. PJM*, 171 FERC ¶ 61,035 (Apr. 16, 2020) ("*April 2020 PJM MOPR Rehearing Order*").

[102] *PJM Interconnection, L.L.C.* and *Calpine Corp. et al.*, 169 FERC ¶ 61,239 (Dec. 19, 2019) ("*Dec 2019 PJM MOPR Order*"), *reh'g and clarification granted, in part, and denied, in part*, 171 FERC ¶ 61,035 (Apr. 16, 2020).

qualify for [an exemption], should be subject to the [Minimum Offer Price Rule ("MOPR")]"[103] and ***directed*** PJM to submit a replacement rate that "extends the MOPR to include both new and existing resources, internal and external, that receive, or are entitled to receive, certain out-of-market payments, with certain exemptions."[104] The FERC directed PJM to include five exemptions: (1) a Self-Supply Exemption [PP 12; 202-204]; (2) a Demand Response, Energy Efficiency, and Capacity Storage Resources Exemption [PP 13; 208-209]; (3) a RPS Exemption [PP 14; 173-174]; (4) a Competitive Exemption [PP 15; 161]; and (5) a Unit-Specific Exemption [PP 16; 214-216].[105] The FERC established the replacement rate under section 206 of the FPA, but declined to order refunds (which it otherwise had the discretion to do).[106] The FERC directed PJM to submit a compliance filing consistent with its guidance on or before March 18, 2020 (90 days from the date of the *Dec 2019 PJM MOPR Order*). In the compliance filing, PJM was directed to also provide revised dates and timelines for the 2019 Base Residual Auction ("BRA") and related incremental auctions, along with revised dates and timelines for the May 2020 BRA and related incremental auctions.[107]

The *Dec 2019 PJM MOPR Order* was the latest milestone in the FERC's consideration of out-of-market support affecting the PJM capacity market.[108] The FERC found in a *June 2018 PJM MOPR Order*[109] that "the integrity and effectiveness of the capacity market administered by [PJM] have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources," determined that the PJM Tariff was unjust and unreasonable, rejected the PJM MOPR Filing, granted in part Calpine's Complaint, and *sua sponte* initiated a new FPA section 206 proceeding (EL18-178) in which it conducted a paper hearing to resolve proposed

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[103] *Id.* at P 9 (emphasis added).

[104] *Id.* at P 2 ("[g]oing forward, the default offer price floor for applicable new resources will be the Net Cost of New Entry ("Net CONE") for their resource class; the default offer price floor for applicable existing resources will be the Net Avoidable Cost Rate ("Net ACR") for their resource class").

[105] *Id.* ("The replacement rate will include three categorical exemptions to reflect reliance on prior Commission decisions: (1) existing self-supply resources, (2) existing demand response, energy efficiency, and storage resources, and (3) existing renewable resources participating in RPS programs. The replacement rate will also include a fourth exemption, the Competitive Exemption, for new and existing resources that are not subsidized and thus do not generally require review to protect 'the integrity and effectiveness of the capacity market.' To preserve flexibility, PJM will also permit new and existing suppliers that do not qualify for a categorical exemption to justify a competitive offer below the applicable default offer price floor through a Unit-Specific Exemption.")

[106] *Id.* at P 3. The FERC had previously established a refund effective date of March 21, 2016, the date of the original Calpine Complaint in EL16-49.

[107] *Id.* at P 4. As previously reported, the FERC directed PJM not to run the BRA in August 2019 as it had proposed to do (*see Calpine et al. v. PJM*, 168 FERC ¶ 61,051 (July 25, 2019)).

[108] The *PJM 2019 MOPR Order* addressed a paper hearing that arose from two separate, but related proceedings. The first, EL16-49, was initiated by a complaint originally filed by Calpine, joined by additional generation entities ("Calpine Complaint") on March 21, 2016, and later amended on January 9, 2017. The Calpine Complaint argued that PJM's MOPR was unjust and unreasonable because it did not address the impact of existing resources receiving out-of-market payments on the capacity market, and proposed interim tariff revisions that would extend the MOPR to a limited set of existing resources. The Calpine Complaint also requested the FERC to direct PJM to conduct a stakeholder process to develop and submit a long-term solution. The second proceeding was PJM's filing of its proposed revisions to its Tariff, pursuant to section 205 of the FPA in ER18-1314 ("PJM MOPR Filing"). The PJM MOPR Filing consisted of two alternate proposals designed to address the price impacts of state out-of-market support for certain resources. The first approach, preferred by PJM but not supported by its stakeholders, consisted of a two-stage annual auction, with capacity commitments first determined in stage one of the auction and the clearing price set separately in stage two ("Capacity Repricing"). The second alternative approach, proposed in the event that the FERC determined that Capacity Repricing was unjust and unreasonable, would have revised PJM's MOPR to mitigate capacity offers from both new and existing resources, subject to certain proposed exemptions ("MOPR-Ex"). A summary of the development and FERC consideration of PJM's capacity market is set out in the Order.

[109] *Calpine Corp. et al.*, 163 FERC ¶ 61,236 (June 29, 2018) ("*June 2018 PJM MOPR Order*"), *clarif. and/or reh'g dismissed,* 171 FERC ¶ 61,036 (Apr. 21, 2020).

alternatives, whether put forth in the *June 2018 PJM MOPR Order* or otherwise,[110] addressing "price-suppressive" effects of out-of-market support for certain resources.

The *Dec 2019 PJM MOPR Order* affirmed the FERC's prior finding that "[a]n expanded MOPR with few or no exceptions, should protect PJM's capacity market from the price-suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[111] The expanded MOPR[112] only applies to "State-Subsidized Resources" (Resources that receive, or are entitled to receive, State Subsidies).[113] The FERC considers a "State Subsidy" to be:

> a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction.[114]

The FERC declined to adopt a materiality threshold for the level of State Subsidies or the size of State-Subsidized Resources. State-Subsidized Resources "that intend to offer below the default offer price floor for a given resource type, and do not qualify for [one of the four] categorical exemption[s], must support their offers through a Unit-Specific Exemption."[115] While the FERC acknowledged that the extension of the MOPR may prevent certain existing resources that states have recently chosen to subsidize from clearing PJM's capacity auctions, it noted that states may continue to support their preferred resource types in pursuit of state policy goals and make decisions about preferred generation resources, with "resources that states choose to support, and whose offers may fail to clear the capacity market under the revised MOPR directed in this order, … still … permitted to sell energy and ancillary services in the relevant PJM markets."[116] The *Order*,

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[110] The proposed alternative approach would have (i) modified PJM's MOPR such that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type, but would include few to no exemptions; and (ii) in order to accommodate state policy decisions and allow resources that receive out-of-market support to remain online, established an option in PJM's Tariff that would allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. That option, which is similar in concept to the Fixed Resource Requirement ("FRR") that currently exists in PJM's Tariff, is referred to as the "FRR Alternative." Unlike the existing FRR construct, the FRR Alternative would apply only to resources receiving out-of-market support.

[111] *Dec 2019 PJM MOPR Order* at P 5.

[112] The FERC adopted an expanded MOPR rather than PJM's Resource Carve-Out ("RCO") and Extended RCO proposals. The FERC determined that those proposals would unacceptably distort the markets, inhibiting incentives for competitive investment in the PJM market over the long term. PJM's longstanding FRR Alternative remains unchanged in the PJM tariff. *See Id.* at P 6.

[113] Resources with federal subsidies will not be subject to the MOPR. *See Id.* at P 10.

[114] *Id.* at P 9. Renewable Energy Credits ("RECs") procured as part of a state-mandated or state-sponsored procurement process are State Subsidies. *Id.* at P 176. Demand response, energy efficiency, and capacity storage resources that participate in the PJM capacity market are considered to be capacity resources for purposes of this definition. *Id.* at P 9.

[115] *Id.* ("A threshold based on resource size will not prevent a collection of smaller resources from having a significant cumulative impact on competitive outcomes. In addition, if a State Subsidy is small enough for a capacity resource to perform economically without it, then the State-Subsidized Resource should be able to secure a Unit-Specific Exemption.")

[116] *Id.* at P 7.

the FERC highlighted, "addresses the growing impact of State-Subsidized Resources because those subsidies reject the premise of the capacity market and circumvent competitive outcomes."[117]

The *Dec 2019 PJM MOPR Order* was accompanied by a 28-page dissent of Commissioner Glick ("Glick Dissent"), who explained why he believes the Order to be "illegal, illogical, and truly bad public policy."[118] Commissioner Glick further suggested that it "may well be that a mandatory capacity market is no longer a sensible approach to resource adequacy at a time when states are increasingly exercising their authority under the FPA to shape the generation mix. Indeed, the conclusion that I draw from the record in front of us is not that there is an urgent need to mitigate the effects of state public policies, but rather that we should be taking a hard look at whether a mandatory capacity market remains a just and reasonable resource adequacy construct in today's rapidly evolving electricity sector."[119]

Requests for Rehearing and Clarification Denied, In Part, and Granted In Part. As reported above, on April 16, 2020, the FERC issued an order granting, in part, and denying, in part, the requests for rehearing and clarification[120] of the *Dec 2019 PJM MOPR Order*, and directed PJM to submit a further compliance filing within 45 days.

Also, as previously reported, the New Jersey Division of Rate Counsel ("NJ Rate Counsel") and NRECA, each out of an abundance of caution, have appealed the *Dec 2019 PJM MOPR Order*. They each explained that they seek judicial review now in case the DC Circuit's action in *Allegheny Defense Project v. FERC*[121] should work to advance the time period for those wishing to seek judicial review of the *Dec 2019 PJM MOPR Order.* Until a decision on *Allegheny Defense Project v. FERC* is issued and its import known, each asked the DC Circuit to hold its appeal in abeyance. For further information on these proceedings, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- ***Opinion 569-A*: FERC's Base ROE Methodology (EL14-12; EL15-45)**

In an Opinion which could impact the resolution of New England return on equity ("ROE") cases, the FERC refined, in ruling on a MISO ROE proceeding, its methodology for setting the ROE that electric utilities earn on electric transmission investments.[122] The refinements to the FERC's methodology include:

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[117] *Id.* at P 17.

[118] Glick Dissent at P 1.

[119] Id. at P 62.

[120] Requests for rehearing and/or clarification ("Requests") of the Dec 2019 PJM MOPR Order were filed by over 50 parties, including: PJM IMM, AEP/Duke, AES, Buckeye Power, Calpine, Clean Energy Advocates, CPower, Dominion, EDF Renewables, Exelon, FirstEnergy Utility Companies, First Energy Solutions, Hershey Co., J-POWER, Longroad Development, PSEG, Vistra, Allegheny Electric Coop., East Kentucky Power Coop. ("EKPC"), IL Municipal Electric Agency, North Carolina Electric Membership Corp., Old Dominion Elec. Coop., the S. MD Elec. Coop, the Organization of PJM States ("OPSI"), DC PSC, IL ICC, MD PSC, NJ BPU, OH PUC, PA PUC, VA State Corporation Commission, WV PSC, DE Public Advocate, DC AG, IL AG, MD AG, NJ Div. of Rate Counsel/People's Counsel for DC/MD People's Counsel, OH Consumers' Counsel, PJM Consumer Representatives, Advanced Energy Buyers Group, Advanced Energy Economy ("AEE"), APPA/AMP/Public Power Assoc. of NJ, AWEA, ELCON, EPSA and the PJM Power Providers Group, NEI, NRECA/EKPC, and Public Citizen. An answer to PJM IMM's request for clarification was filed by the Talen PJM Companies. Answers were also filed by the PJM IMM, Longroad Development and Old Dominion Electric Cooperative. EEI filed a motion for reconsideration. On February 18, 2020, the PJM IMM filed a second request for clarification and The National Association of State Energy Officials filed a letter to the Commissioners. On February 25, Old Dominion answered EEI's request for reconsideration. On February 28, the MD PSC answered the IMM's second request for clarification.

[121] *Allegheny Def. Project v. FERC*, Case No. 17-1098 (D.C. Cir. Dec. 5, 2019).

[122] *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 use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206. The FERC stated that "the defects of the Risk Premium model do not outweigh the benefits of model diversity and reduced volatility resulting from the averaging of more models."

- Adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model.

- 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*. By raising the threshold to 200%, the FERC believes it will reduce the risk that rational results are inappropriately excluded. Continued application of the natural break analysis will allow the exclusion of ROEs that are truly irrational or anomalously high.

- Calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*. The FERC found that the quartile approach, which excluded the bottom eighth and top eighth of the overall zone of reasonableness, was inappropriate because it ignores some "potentially lawful ROEs" when determining which ranges of ROEs should be considered presumptively just and reasonable.

A more detail summary and background of Opinion 569-A prepared by NEPOOL counsel was posted with the materials for and discussed at the May 19, 2020 Transmission Committee meeting. Please note that *Opinion 569-A* is still subject to requests for rehearing, and may ultimately be subject to judicial review, so this issue is not yet settled.

- **NITSA Termination Versant Power/Houlton Water Company (ER20-1914)**

On May 28, 2020, Versant Power filed a notice of termination of the Network Integration Transmission Service Agreement ("NITSA") between itself and Houlton Water Company ("Houlton") (accepted in ER20-1445), which expired by its terms on May 15, 2020, the date Houlton directly interconnected its electric system with that of New Brunswick Power. A May 15, 2020 effective date was requested for the termination notice. Comments, if any, on the notice are due on or before June 18, 2020 If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NSTAR Transmission Service Agreement Cancellations (ER20-1896)**

On May 26, 2020, NSTAR filed notice of cancellation of various transmission service agreements no longer active but not yet previously cancelled. A July 25, 2020 effective date was requested for the cancellation notices. Comments, if any, on the notice are due on or before June 16, 2020. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: CL&P-Gravel Pit Solar (ER20-1871)**

On May 21, CL&P filed an Agreement for Design, Engineering and Construction services (the "D&E Agreement") between itself and Gravel Pit Solar LLC ("Gravel Pit Solar"). The D&E Agreement sets forth the terms and conditions under which CL&P will undertake preliminary design and engineering activities (related to line work and switching station that is required to interconnect the project to the transmission system.) related to a large generating facility that is being developed by Gravel Pit Solar (ISO-NE Queue Position 892) and will be subject to an LGIA that is being completed. CL&P requested that the D&E Agreement be accepted for filing as of the date of filing, or May 21, 2020. Comments on this filing are due on or before June 11, 2020.

If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VTransco VTA Waiver Request (ER20-1823)**

On May 23, 2020, the FERC accepted the May 14 request by Vermont Transco LLC ("VTransco") for waiver of Article IV of its FERC Rate Schedule 1, 1991 Transmission Agreement ("VTA") to enable it to amortize $10 million of the difference between the budgeted and actual Regional Network Service ("RNS") revenues over a 24-month period, beginning in 2021.[123] VTransco asserted that the waiver will permit it to mitigate the rate impact to Vermont distribution utilities, and in turn to Vermont ratepayers, resulting from the COVID-19 pandemic. Unless the May 23 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).

- **System Upgrade Reimbursement Agreement Cancellation: NEP/ Deerfield Wind (ER20-1820)**

On May 13, 2020, New England Power ("NEP") filed a notice of cancellation of its System Upgrade Reimbursement Agreement with Deerfield Wind, LLC ("Deerfield"). The Reimbursement Agreement was superseded by a Related Facilities Agreement ("RFA") accepted by the FERC in late December, 2019.[124] Comments on this filing are due on or before June 3, 2020. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VTransco/VEC ShPA and O&M Agreements (ER20-1679)**

On April 29, Vermont Transco LLC ("VTransco") submitted a Shared Structure Participation Agreement ("ShPA") and an Operating and Maintenance Agreement ("O&M Agreement") between VTransco and Vermont Electric Cooperative, Inc. ("VEC"). VTransco reported that the ShPA and O&M Agreement are part of a transaction between VTransco and VEC that involves the cancellation of a Bill-Back Agreement and an Operating and Maintenance Agreement,[125] and the entering into of a Purchase and Sale Agreement ("PSA"), dated as of April 30, 2020. The ShPA establishes the allocation of costs associated with the design, construction, repair, replacement, general maintenance, operation, and preventative maintenance of facilities on VTransco' s structures shared with VEC, where those facilities are used either exclusively by VEC or in common with VTransco. The purpose of the ShPA is to calculate and allocate those costs that are not recovered through a regional transmission tariff on file with the FERC. The O&M Agreement establishes VTransco's and VEC's operational control of the facilities on the shared structures. Comments on the Agreements were due on or before May 20, 2020; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Phase II VT DMNRC Support Agreement Order 864-Related Filing (ER20-1480)**

On April 1, Vermont Electric Power Company ("VELCO"), as an agent of the Joint Owners, submitted a filing (following consultation with FERC staff) that described why no changes were required to the Phase II Vermont Dedicated Metallic Neutral Return Conductor ("DMNRC") Support Agreement[126] as a result of *Order 864*. Comments on this filing were due April 22 and were filed by GMP, which supported the filing and agreed with VELCO that no *Order 864* compliance filing is necessary. The IRH Management Committee, Eversource

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[123] *Vermont Transco LLC*, Docket No. ER20-1823 (May 22, 2020) (unpublished letter order).

[124] *New England Power Co.*, Docket No. ER20-214 (Dec. 5, 2019) (unpublished letter order).

[125] Both the Bill-Back Agreement and the original Operating and Maintenance Agreement were entered into between VTransco's predecessor, VELCO, and VEC's predecessor, Citizens Communication Company. VTransco submitted a separate Notice of Cancellation of the Bill-Back Agreement and the original Operating and Maintenance Agreement, effective April 30, 2020, in ER20-1685.

[126] The DMNRC was installed on VETCO's Phase I facilities to provide a neutral return for Phase I and Phase II at a total construction cost of approximately $2.6 million. Pursuant to the Agreement, the Joint Owners recover their total cost of service by making the DMNRC available to NHH who in turn makes the DMNRC available to the Participants pursuant to, and for the term of, the Phase II New Hampshire Transmission Facilities Support Agreement.

and National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Emera Maine/Houlton Water Company NITSA (ER20-1445)**

On May 28, 2020, the FERC accepted the March 31, 2020 filing by Emera Maine of a non-conforming Network Integration Transmission Service Agreement with Houlton Water Company.[127] The NITSA provided for continued provision of network integration transmission service by Emera Maine to Houlton until Houlton's electric system is successfully interconnected with New Brunswick Power (which, as noted above, happened May 15, 2020). The NITSA was accepted effective as of April 1, 2020, as requested. Unless the May 28 order is challenged, this proceeding will be concluded. As summarized in ER20-1914 just above, Versant Power filed a notice of termination of the NITSA. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Amendment: CMP/Sappi (ER20-1434)**

Also on May 28, 2020, the FERC accepted a first amendment to the interconnection agreement ("IA") between Central Maine Power ("CMP") and Sappi North America, Inc. ("Sappi").[128] As previously reported, the Amendment extends the term of the Agreement, which expired by its own terms on February 29, 2020, for an additional 20 years, to February 29, 2040. The IA was accepted effective as of February 29, 2020, as requested. Unless the May 28 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 Cancellations: NGrid/GRS and NGrid/Mini-Watt (ER20-1405/1406/1407)**

The FERC has now accepted each of the notices of cancellation filed by Massachusetts Electric Company ("NGrid") of three Interconnection Agreements[129] superseded by previously-accepted Small Generator Interconnection Agreements. ("SGIA") -- one with Gas Recovery Systems ("GRS") for its Fall River facility (ER20-1405),[130] and two with Mini-Watt Hydroelectric, LCC ("Mini-Watt") covering Mini-Watt Unit No 1. (ER20-1406) and Units 2 and 3 (ER20-1407).[131] If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: CL&P/CPV Towantic (ER20-1221)**

On May 7, 2020, the FERC accepted the notice of cancellation of CL&P's Design and Engineering Agreement ("D&E Agreement") with CPV Towantic (designated as service agreement IA-ESCLP-005).[132] The D&E Agreement set forth the terms and conditions under which CL&P undertook preliminary engineering and design activities on the mitigation of violations (including reconductoring a 115kV 1029-2 line from Bunker Hill to Baldwin Tap) identified in ISO-NE studies, prior to execution of an LGIA. The D&E Agreement terminated by its terms when an LGIA was executed on February 26, 2020. The notice of cancellation was accepted effective as of February 26, 2020, as requested. Unless the May 7 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).

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[127] *Emera Maine*, Docket No. ER20-1445 (May 28, 2020) (unpublished letter order).

[128] *Central Maine Power Co.*, Docket No. ER20-1434 (May 28, 2020) (unpublished letter order).

[129] *Mass. Elec. Co.*, Docket No. ER20-1405 (May 22, 2020) (GRS); *Mass. Elec. Co.*, Docket No. ER20-1407 (May 13, 2020) (Mini-Watt Unit Nos. 2, 3); and *Mass. Elec. Co.*, Docket No. ER20-1405 (Apr 28, 2020) (Mini-Watt Unit No. 1).;

[130] The currently effective SGIA with GRS was accepted in *Mass. Elec. Co.*, Docket No. ER19-2352 (Aug. 13, 2019) (unpublished letter order).

[131] The currently effective SGIAs with Mini-Watt were accepted in *Mass. Elec. Co.*, Docket No. ER19-2464 (Sep. 16, 2019) (unpublished letter order) (Unit No. 1) and *Mass. Elec. Co.*, Docket No. ER19-2465 (Sep. 16, 2019) (unpublished letter order) (Unit Nos. 2-3).

[132] *The Connecticut Light and Power Co.*, Docket No. ER20-1221 (May 7, 2020) (unpublished letter order).

- **FERC Enforcement Action: Order Assessing Civil Penalties – Vitol & F. Corteggiano (IN14-4)**

On October 25, 2019, the FERC issued an order[133] finding Vitol Inc. ("Vitol") and its co-head of FTR trading operations, Frederico Corteggiano, violated from October 28-November 1, 2013, the FERC's Anti-Manipulation Rule by selling physical power at a loss in CAISO's market in order to eliminate congestion that they expected to cause losses on Vitol's congestion revenue rights ("CRRs").[134] The FERC assessed civil penalties of $1,515,738 against Vitol and $1 million against Corteggiano. In addition, the FERC directed Vitol to disgorge unjust profits, plus applicable interest of $1,227,143.

Because Respondents' previously elected the FPA's *de novo* review procedures, which permits a reviewing federal court "to review *de novo* the law and the facts involved" and "jurisdiction to enter a judgment . . . modifying . . . or setting aside [the assessment] in whole or in Part", the *Vitol Penalties Order* was not subject to rehearing. On January 6, 2020, the FERC instituted an action in federal district court (Eastern District of California) for an order affirming the penalties assessed against Respondents and ordering Vitol to disgorge its unjust profits, plus interest.[135] Reporting on this case will be continued in future Reports, when and as appropriate, in Section XV.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Carbon Pricing in RTO/ISO Markets (AD20-14)**

On April 14, 2020, Interest Parties[136] requested that the FERC convene a technical conference or workshop to discuss integrating state, regional, and national carbon pricing in FERC-jurisdictional organized regional wholesale electric energy markets. They suggested that the scope of the conference/workshop could include examination of a variety of mechanisms through which carbon could be priced on a state, regional, or national level and how wholesale market pricing and dispatch could (or already do) account for the costs arising from compliance with such programs. A technical conference or workshop, they believe, "would be helpful to the Commission and stakeholders in the electric energy industry in deciding how best to move forward at the state and regional levels on these issues and in the relevant organized markets. This dialogue would complement state, regional, and national discussions currently taking place." Comments on the request were due on or before May 21, 2020. More than 30 sets of comments supporting the request were filed, including comments by Over 25 sets of comments supporting the request for a tech. conf. or workshop filed, including comments by ISO-NE, Exelon, MA AG, National Grid, NEPGA, NESCOE, PSEG, Potomac Economics, Public Interest Organizations, Shell, and a

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[133] *Vitol Inc. and Federico Corteggiano*, 169 FERC ¶ 61,070 (Oct. 25, 2019) ("*Vitol Penalties Order*").

[134] Enforcement Staff alleges that Vitol and Corteggiano ("Respondents") sold physical power at a loss at the Cragview node in CAISO's day-ahead market from Oct. 28 through Nov. 1, 2013, in order to eliminate congestion costs that they expected would negatively affect Vitol's CRRs. On Vitol's behalf, Corteggiano purchased CRRs sourcing at Cragview in CAISO's annual CRR auction for 2013. In mid-October 2013, CAISO derated the Cascade intertie to "0" in only the export direction, while still allowing imports. During the derate, an unusually high LMP appeared at Cragview due to congestion costs. The congestion costs caused Respondents' CRRs to lose money. CAISO announced that identical derates would occur during the week of October 28 through November 1 and on additional dates later in November and in December. Respondents were able to protect against losses on their CRR positions for November and December by buying counter-flow CRRs in the CRR auctions for those months (i.e., "flattening" the CRR position). However, because the monthly CRR auction for October had closed, it was too late for Respondents to flatten their CRR position for the last week of October. Facing over $1.2 million in potential losses on their CRRs during that week's scheduled partial derate, Respondents imported physical power in the day-ahead market at an offering price of $1/MWh, which prevented a recurrence of the congestion costs that Respondents had observed during the October 18-19 derate. Staff alleges Respondents undertook the import transactions in disregard of market fundamentals and were indifferent to whether they made a profit on them. In fact, Respondents lost money on the imports, but avoided a far larger loss on their CRRs. *Id.* at P 3.

[135] FERC v. Vitol Inc. and Federico Corteggiano, Case No. 2:20-cv-00040-KJM-AC (E. D. CA) (filed Jan. 6, 2020).

[136] "Interested Parties" are AEE, the American Council on Renewable Energy, the American Wind Energy Association, Brookfield Renewable, Calpine, CPV, EPSA, the Independent Power Producers of New York ("IPPNY"), LS Power Associates ("LS Power"), the Natural Gas Supply Association ("NGSA"), NextEra, PJM Power Providers Group, R Street Institute, and Vistra Energy Corp.

group of US Senators that included Sheldon Whitehouse (RI) and Angus King (ME). The request is now pending before the FERC.

- **Hybrid Resources Technical Conference (AD20-9)**

On April 7, 2020, the FERC issued a notice that staff will convene a technical conference on July 23, 2020 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"). For purposes of this inquiry, the focus will be on a generation resource and an electric storage resource paired together as a hybrid resource. Commissioners may participate in the technical conference. A supplemental notice will be issued prior to the technical conference with further details regarding the agenda and organization, whether it will be held in-person or via teleconference, and if there are changes to the date or time of the technical conference.

- **Credit Reforms in Organized Wholesale Markets (AD20-6)**

Energy Trading Institute's[137] December 16, 2019 request that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[138] and Section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by RTO/ISOs remains pending. As previously reported, ETI, citing a recent filing by NYISO (which it protested),[139] and stating that several expedited initiatives related to RTO/ISO credit policies are underway, suggested that it would be helpful for the FERC to consolidate any "filings with this proceeding and hold the technical conference ETI is requesting by March 30, 2020 so the ISOs, RTOs and their stakeholders consider those discussions in any initiatives they have underway." ETI suggested in its request that RTO/ISO credit support requirements be standardized, and that the requested technical conference and rulemaking explore various ways to identify and mitigate counterparty risk (including know-you-customer ("KYC") tools and participant suspensions or bans) and enhance risk management infrastructure/processes within the organized markets. Doc-less interventions have been filed by, among others, PJM, the PJM IMM, SPP, CAISO, Tenaska, Avangrid, and Roscommon Analytics. On January 24, the ISO/RTO Council ("IRC"), including ISO-NE, submitted comments and proposed, as an alternative approach to the one suggested by ETI, that the FERC not commence a rulemaking or schedule a technical conference at this time and instead allow individual RTO/ISOs to address their respective credit and risk management issues, permit sufficient time for experience with the evolving rules to be gained, and then consider the best path forward to facilitate a dialogue on best practices and potential points of alignment among the RTO/ISO. ETI responded to those comments on February 10, 2020.

The FERC issued a notice of ETI's request for technical conference and petition for rulemaking on February 11, 2020, setting March 12, 2020 as the deadline for comments thereon. Comments were submitted by a number

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[137] In its request, The Energy Trading Institute ("ETI") describes itself generally as "represent[ing] a diverse group of energy market participants, all with substantial interests in wholesale electricity transactions in Commission-jurisdictional markets. ETI members provide important services to a wide variety of wholesale energy market participants. They act as intermediaries between producers and consumers of electric energy that have mismatched quantity, timing, and contract type needs. In addition, they provide liquidity by engaging in energy related commercial transactions with a variety of market entities including, but not limited to, generation owners, project developers, load-serving entities, and investors. ETI members advocate for markets that are open, transparent, competitive and fair - all necessary attributes for markets ultimately to benefit electricity consumers."

[138] *Credit Reforms in Organized Wholesale Elec. Mkts.*, 75 Fed. Reg. 65942 (2010), FERC Stats. & Regs. ¶ 31,317 (2010) ("*Order 741*"); *order on reh'g*, 76 Fed. Reg. 10492 (2011), FERC Stats. & Regs. ¶ 31,320 (2011) ("*Order 741-A*"); *order on reh'g*, 135 FERC ¶ 61,242 (2011) ("*Order 741-B*"); 18 C.F.R. § 35.47.

[139] *See* Proposed Tariff Amendments to Enhance Credit Reporting Requirements and Remedies, *New York Indep. Sys. Operator*, Inc., Docket No. ER20-483 (filed Nov. 26, 2019).

of parties, including APPA, CAISO, the Committee of Chief Risk Officers ("CCRO"), DC Energy, EEI, EPSA, Indicated PJM Transmission Owners,[140] and an independent consultant.[141] This matter remains pending before the FERC.

- **Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)**

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[142] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[143] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7, Foundation for Resilient Societies ("FRS") requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). AD18-7 was initiated to evaluate the resilience of the bulk power system in RTO/ISO regions. The FERC directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[144] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into three parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the

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[140] "Indicated PJM Transmission Owners" are Exelon Corp. ("Exelon"), American Electric Power Service Corp. ("AEP"), Dominion Energy Services, Inc. ("Dominion"), PPL Electric Utilities Corp. ("PPL"), the FirstEnergy Utility Companies. ("FirstEnergy"), East Kentucky Power Coop. ("EKPC"), Duke Energy Corp. ("Duke"), Duquesne Light Co. ("Duquesne"), and the PSEG Companies ("PSEG").

[141] W. Scott Miller, III, Whitehall Bay Energy Services, LLC.

[142] *Grid Rel. and Resilience Pricing*, 162 FERC ¶ 61,012 (Jan. 8, 2018), *reh'g requested*.

[143] As previously reported, the FERC opened the DOE NOPR proceeding in response to a September 28, 2017 proposal by Energy Secretary Rick Perry, issued under a rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, that would have required RTO/ISOs to develop and implement market rules for the full recovery of costs and a fair rate of return for "eligible units" that (i) are able to provide essential energy and ancillary reliability services, (ii) have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters, (iii) are compliant with all applicable environmental regulations, and (iv) are not subject to cost-of-service rate regulation by any State or local authority. More than 450 comments were submitted in response to the DOE NOPR, raising and discussing an exceptionally broad spectrum of process, legal, and substantive arguments. A summary of those initial comments was circulated under separate cover and can be found with the posted materials for the November 3, 2017 Participants Committee meeting. Reply comments and answers to those comments were filed by over 100 parties.

[144] ISO-NE defined fuel security as "the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."

NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and AMP and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[145] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that 2018 request is pending.

- **Increasing Market and Planning Efficiency Through Improved Software (AD10-12)**

The FERC will hold a technical conference by WebEx addressing increasing Real-Time and Day-Ahead market efficiency through improved software June 23-25, 2020. This is the eleventh consecutive year that the FERC has held a summer conference on this topic. FERC Staff will be facilitating a discussion to explore research and operational advances with respect to market modeling that appear to have significant promise for potential efficiency improvements. A supplemental notice of the technical conference was posted on April 7. Those planning to participate in the WebEx must register through the FERC's website by June 12, 2020. WebEx connections may not be available to those who do not register. Staff anticipates facilitating participant questions and discussions of materials presented through WebEx. Details will be released prior to the conference on how such discussions will take place. The FERC will accept comments following the conference, with a deadline of July 31, 2020.

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

On March 20, 2020, the FERC issued a NOPR[146] proposing to revise its existing transmission incentives policy and corresponding regulations.[147] The proposed revisions include 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.

[145] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

[146] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (Mar. 20, 2020) ("*Electric Transmission Incentives NOPR*").

[147] 18 CFR 35.35 (2020).

- ***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***.
- ***RTO-Participation Inventive*.** A 100-basis-point increase for transmitting utilities that turn over their wholesale facilities to an RTO, ISO, or Transmission Organization, and available regardless of whether participation 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 its March 25, 2020 meeting. Comments on the proposed revisions are due on or before July 1, 2020.[148] Thus far, one set of comments has been submitted (by Schulte Associates). On April 29, American Manufacturers[149] requested a 90-day extension of time to comment. Their request was supported by APPA/TAPS, but opposed by WIRES and EEI (each advocating for no more than a few weeks' extension). On May 8, 2020 State Entities[150] requested an extension, to September 29, 2020, to submit comments to the NOPR. On May 15, the FERC denied the requested extensions of time. Comments in this proceeding remain due on July 1, 2020. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NOPR: QF Rates and Requirements; Implementation Issues under PURPA (RM19-15)**

In an action that could have significant impacts on the development and financing of renewable resources, the FERC, on September 19, 2019, proposed rules to reform its long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[151] Those regulations address the obligation of electric utilities to purchase power produced by "qualifying facilities" or "QFs" at rates that must be

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[148] The *Electric Transmission* Incentives NOPR was published in the *Fed. Reg.* on Apr. 2, 2020 (Vol. 85, No. 64) pp. 18,784-18,810.

[149] "American Manufacturers" are: the Indus. Energy Consumers of America ("IECA"), Aluminum Assoc., American Chemistry Council, American Forest & Paper Assoc. ("AF&PA"), American Foundry Society, American Fuel & Petrochemical Manufacturers, American Iron and Steel Institute, Associated Industries of Arkansas, Assoc. of Businesses Advocating Tariff Equity ("ABATE"), California Large Energy Consumers Assoc., California Manufacturers & Technology Assoc., CalPortland Co., Carolina Indus. Group for Fair Utility Rates I, II & III, Carolina Utility Customers Assoc., Carpenter Technology Corp., Chemistry Council of New Jersey, Clearwater Paper Corp., Coalition of MISO Transmission Customers, Conn. Indus. Energy Consumers, Domtar Corp., ELCON, Ellwood Quality Steels, Evonik Corp., Fertilizer Institute, Flex-N-Gate, Florida Indus. Power Users Group, Ford Motor Co., Gerdau, Glass Packaging Institute, Illinois Indus. Energy Consumers, Indiana Indus. Energy Consumers, Indus. Energy Consumers of Penn., Indus. Energy Users-Ohio, Indus. Minerals Assoc. – North America, Ingevity Corp., Iowa Indus. Energy Group, Kimberly-Clark, Kentucky Indus. Utility Customers, Lafarge-Holcim, Louisiana Chemical Assoc., Maine Indus. Energy Consumer Group ("IECG"), Messer Americas, Michigan Chemistry Council, Michigan Indus. Energy Assoc., Midwest Food Products Assoc., National Council of Textile Orgs., National Stone, Sand & Gravel Assoc., Ohio Energy Group (OEG), Ohio Manufacturers' Assoc. Energy Group, Oklahoma Indus. Energy Consumers, Olin Corp., Penn. Energy Consumers Assoc., PJM Indus. Customer Coalition, Portland Cement Assoc., South Carolina Energy Users Comm., Steel Manufacturers Assoc., TimkenSteel Corp., Tyson Foods, US Silica Co., Utah Assoc. of Energy Users, WestRock Co., West Virginia Energy Users Group, Western Kansas Indus. Energy Consumers, and Wisc. Indus. Energy Group.

[150] For purposes of this proceeding, "State Entities" are: the attorneys general of Conn., the District of Columbia, Illinois, Maryland, Mass., Michigan, and New Jersey, the CA Pub. Utils. Comm., the Conn. Dept. of Energy and Environ. Protection, and the Maine Office of the Public Advocate.

[151] 16 U.S.C. § 2601 et seq. (2018). PURPA was enacted to help lessen the dependence on fossil fuels and promote the development of power generation from non-utility power producers.

"just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against" those QFs.[152]

The *QF NOPR* seeks public comment on draft rule changes "to rebalance the benefits and obligations of the [FERC's] PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated."[153] The *QF NOPR* proposes the following changes that would revise how and when prices for QF power may be established and would reduce the circumstances under which a utility's mandatory purchase obligation would be triggered:

- Provide states the flexibility to establish QF energy rates at the purchasing utility's avoided costs at the time of energy *delivery*, rather than allowing the QFs to elect to *fix* the energy rate for an extended term at the time the utility becomes compelled to purchase the QF's energy.
- Specify that an avoided cost rate for QF energy can be based on *market factors* (including locational market prices, indices, trading hubs, or competitive solicitation processes) or, at the state's discretion, can continue to be set as they are under current PURPA Regulations.
- Reduce in states with a retail choice program an electric utility's obligation to purchase from QFs to the extent that the utility's provider of last resort ("POLR") supply obligation has been reduced by the state's program. If POLR supplies are obtained through solicitations having a specific contract term, the term of any PURPA purchase contract should match the term of the POLR supply contract.
- Decrease from 20 MW to 1 MW the maximum size of QFs that would be entitled to require utilities located in areas with demonstrably competitive markets (RTO/ISOs) to purchase their power. If QF facilities qualify as cogeneration, the 20 MW cap would not change.
- Replace the "one-mile rule" for determining whether generation facilities under common ownership should be considered to be part of a single facility (to be eligible for favorable QF treatment, a small power production facility must be 80 MW or less). Some have argued that the current one-mile rule has been gamed to permit QF certification of projects that if combined would otherwise exceed the 80 MW cap. The impact of this change, if made, would primarily affect projects in non-RTO/ISO markets (e.g., the bilateral markets of the southern and western United States).
- Clarify that a utility's mandatory purchase obligation under PURPA does not arise until the QF can demonstrate commercial viability and financial commitment pursuant to objective and reasonable state-defined criteria.
- Allow for interested stakeholders to protest the self-certification of a QF.

Comments on the proposed rule changes were due on or before December 3, 2019.[154] More than 130 sets of comments were submitted, including comments from Bloom Energy, Borrego Solar, ConEd, Covanta, CT PURA, MA AG, MA DPU, and AEE. Since the last Report, several Congressman have sent comments supporting comments submitted by others. Chairman Chatterjee acknowledged each of the comments received from Congressmen. Late filed comments were submitted by the American Dams, California PUC, TerraForm and the Arizona Corporation Commission. Since the last Report, US Representative Sean Casten (D-IL) submitted comments opposing FERC action. SEIA submitted supplemental comments. This matter remains pending before the FERC.

[152] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a)-(b).

[153] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Notice of Proposed Rulemaking, 168 FERC ¶ 61,184 (2019) ("*QF NOPR*").

[154] The *QF NOPR* was published in the *Fed. Reg.* on Oct. 4, 2019 (Vol. 84, No. 193) pp. 53,246-53,275.

- ***Orders 864/864-A*: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 21, 2019, the FERC issued its final rule a NOPR ("*Order 864*")[155] requiring 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 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. The FERC did not adopt its proposals in the ADIT NOPR[156] that were applicable to public utilities with stated rates. *Order 864* will become effective January 27, 2020. Requests for rehearing were filed by APPA and Exelon.

Order 864-A. On April 16, the FERC denied the requests for rehearing and granted APP's request for clarification in part.[157] Specifically, the FERC clarified that public utilities with transmission stated rates that have a FERC-approved ratemaking method for addressing excess and deficient ADIT return the appropriate amount of excess ADIT resulting from the Tax Cuts and Jobs Act to customers through their transmission stated rates. For public utilities with transmission stated rates that lack a FERC-approved ratemaking method, the ratemaking method used to make provision for excess and deficient ADIT will be subject to case-by-case determination in a later rate proceeding.[158]

New England TO Compliance Filings - Extensions of Time to File. VTransco (Feb 3), National Grid (Feb 10), Eversource (Feb 18), UI (Feb 20), VT Electric Transmission Co. ("VETCO") (Feb 25), and New Hampshire Transmission ("NHT") (Feb 26) each requested that their deadline for submitting a compliance filing be extended until July 31, 2020—the date of the TOs' next annual informational filing for regional formula rates. Each of those requests has been granted.

New England Compliance Filings - New England Electric Transmission Corporation (ER20-1089), New England Hydro Transmission Electric Company (ER20-1088), and New England Hydro Transmission Corporation (ER20-1087) each submitted their compliance filings on February 26, 2020, with comments, if any, on those filings due on or before March 18, 2020; none were filed. VELCO, the IRH Management Committee, and GMP (just in ER20-1089) each intervened. These compliance filings are pending before the FERC.

- **DER Participation in RTO/ISOs (RM18-9)**

In *Order 841*[159] (*see* RM16-23 below), the FERC initiated a new proceeding in order to continue to explore the proposed distributed energy resource ("DER") aggregation reforms it was considering in the *Storage NOPR*.[160] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the April 10-11 technical conference in AD18-10,[161] were also to be filed in RM18-9. On June

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[155] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 869, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020).

[156] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018) ("*ADIT NOPR*").

[157] *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*").

[158] *Order 864-A* at PP 18-19

[159] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), reh'g and/or *clarif. requested* ("*Order 841*").

[160] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[161] On April 10-11, 2018, the FERC held a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on

26, 2018, over 50 parties submitted post-technical conference comments in this proceeding, including comments from ISO-NE, Calpine, Direct, Eversource, Icetec, NRG, Utility Services, EEI, EPRI, EPSA, NARUC, NRECA, and SEI. On February 11, 2019, a group of 18 US Senators submitted a letter urging the FERC to adopt a final rule that enable all DERs the opportunity to participate in the RTO/ISO markets and requesting an update no later than March 1, 2019. Reply comments and answers were submitted by the Arkansas PUC, AEE, AEMA, and the Missouri PUC. APPA/NRECA submitted supplemental comments.

On September 5, the FERC requested that each of the RTO/ISOs provide responses to data requests seeking information on their policies and procedures that affect DER interconnections. The RTO/ISO responses were due and were filed on October 7, 2019. Comments on the responses were filed by 8 parties, including comments addressing ISO-NE's responses by MA DPU, MA DOER and MA AG (collectively, "Massachusetts"), MMWEC, AEE, EEI and NRECA. This matter is pending before the FERC.

- ***Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

As previously reported, *Order 860,*[162] issued three years after the FERC's *Data Collection NOPR,*[163] (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 will post 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* will become effective April 1, 2021, and submitters will have until close of business on August 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain in Spring 2021 FERC-generated IDs for reportable entities that do 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,[164] 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,[165] 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."

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the bulk power system. Technical conference materials are posted on the FERC's eLibrary. Interested persons were invited to file post-technical conference comments on the topics concerning the Commission's DER aggregation proposal discussed during the technical conference, including on follow-up questions from FERC Staff related to the panels. Comments related to DER aggregation were to be filed in RM18-9; comments on the potential effects of DERs on the bulk power system, in AD18-10.

[162] *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).

[163] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (July 21, 2016) ("*Data Collection NOPR*").

[164] 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.

[165] *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*").

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.

Effective Date Extended by 6 Months. On May 6, 2020, EEI requested a four-month extension of implementation of *Order 860*. EPSA supported that request on May 13, 2020. On May 20, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by *six* months. The new *Order 860* effective date will be April 1, 2021, and the deadline for baseline submissions to and including August 2, 2021. First change in status filings under these new timelines will be due August 31, 2021.

- ***Order 676-I*: NAESB WEQ Standards v. 003.2 - Incorporation by Reference into FERC Regs (RM05-5-027)**

On February 4, 2020, the FERC issued Order *676-I*,[166] which incorporates by reference into its regulations, with certain enumerated exceptions, the latest version (Version 003.2) of certain 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").[167] The Version 003.2 Standards included NAESB's Version 003.1 revisions, which were the subject of an earlier NOPR.[168] The FERC declined to adopt the proposal to remove the incorporation by reference of the WEQ-006 Manual Time Error Correction Business Practice Standards as adopted by NAESB. *Order 676-I* will become effective April 27, 2020.[169] Requests for clarification and/or rehearing of *Order 676-I* were filed by EEI and Southern Companies. On April 6, the FERC issued a tolling order affording it additional time to consider those requests, which remain pending before the FERC.

Compliance dates: Public utilities must make a compliance filing to comply with the requirements of *Order 676-I* through eTariff no later than July 27, 2020. The FERC will set an effective date for the proposed tariff changes in the order(s) on the compliance filings, but no earlier than October 27, 2020.

- **Waiver of Tariff Requirements (PL20-7)**

On May 21, 2020, the FERC issued a Proposed Policy Statement that would clarify its policy regarding requests for waiver of tariff provisions.[170] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

Specifically, the FERC proposed the following guidance on filing procedures to implement its new approach for granting waivers of tariff provisions and to no longer grant retroactive waivers except as consistent with the *Proposed Policy Statement*:

1. *Style Requests as Requests for Remedial Relief*. Filings seeking relief in connection with actions or omissions that have already occurred prior to the date relief is sought from the FERC would be characterized as a request for remedial relief (rather than as a request for a waiver). In response to such a request, the FERC will focus on what remedy, if any, is required

[166] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-I, 170 FERC ¶ 61,062 (Feb. 4, 2020) ("*Order 676-I*"), *reh'g and/or clarif. pending*.

[167] *Standards for Business Practices and Communication Protocols for Public Utilities*, 167 FERC ¶ 61,127 (May 16, 2019) ("*NAESB WEQ v. 003.2 Standards NOPR*").

[168] *Standards for Business Practices and Communication Protocols for Public Utilities*, 156 FERC ¶ 61,055 (July 21, 2016), ("*WEQ v. 003.1 NOPR*").

[169] *Order 676-I* was published *Fed. Reg.* on Feb. 25, 2020 (Vol. 85, No. 37) pp. 10,571-10,586.

[170] *Waiver of Tariff Requirements*, 171 FERC ¶ 61,156 (May 21, 2020) ("*Proposed Policy Statement*").

to cure acknowledged or alleged deviations from a filed tariff. "Waiver" is to be limited to (a) requests for prospective relief when a requested future deviation from the filed tariff has not yet occurred at the time a request is filed; or (b) petitions for remedial relief when a tariff expressly authorizes regulated entities to seek a remedial waiver from the FERC for past non-compliance with the filed tariff.

2. *Form of Filing*. When the entity requesting remedial relief is the entity that acted (or believes it may have acted) in a manner inconsistent with the tariff, such requests should be filed as petitions for declaratory order under Rule 207 of the FERC's Rules of Practice and Procedure. When the filing entity alleges a different entity has acted in a manner inconsistent with the tariff, such requests should be filed as complaints under Rule 206. Given the filing fees associated with petitions for declaratory order, the industry was encouraged to directly address this aspect of the proposal.

3. *Expressly Request FERC Action pursuant to FPA section 309 or NGA section 16.4*. These provisions have been found to afford the FERC the latitude to remedy past non-compliance "provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act."

The FERC acknowledged that this Policy would represent a change from its past approach, particularly in situations where inadvertent failures to comply with ministerial tariff requirements have not been protested. The FERC suggested a few ways tariffs may be modified to avoid what may appear by comparison to be harsh outcomes, including expressly stating in the tariff that a failure to comply with a certain deadline may be waived by order of the FERC or by allowing various kinds of errors to be cured within a reasonable period of time after a default has occurred or an error has been discovered, but is difficult to imagine how feasible or how well these options might work in practice.

The FERC proposed to incorporate its current four-part analysis[171] in considering both requests for prospective waiver and petitions for remedial relief, but cautioned that it would apply that analysis only in those limited circumstances where the request for remedial relief would not violate the filed rate doctrine or the rule against retroactive ratemaking due to adequate prior notice, or the requested relief is within the FERC's authority to grant under FPA section 309 or NGA section 16.

Finally, the FERC proposed requiring a stronger showing when a petitioner is seeking remedial relief for its own failure to comply with a tariff – petitions will be more compelling when the failure to comply was due to something more than inadvertent error or administrative oversight. Petitions for remedial relief will generally be denied when a protestor credibly contends, or the FERC independently determines, that the requested remedial relief will result in undesirable consequences (e.g. harm to third parties).

With respect to prospective requests to waive the 60-day prior notice requirement under FPA section 205(d) (or the 30-day prior notice requirement under NGA section 4(d)), which the FERC has discretion to waive "for good cause shown," the FERC proposes to leave in effect its policy of generally granting such waivers,[172] to the extent that entities seek an effective date no earlier than the day *after* the date a rate change is submitted to the FERC.

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[171] Under current practice, the FERC grants tariff provision waivers where: (1) the underlying error was made in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties.

[172] *See Cent. Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106, *order on reh'g*, 61 FERC ¶ 61,089 (1992) ("*Central Hudson*"). Factors that will generally support a waiver of prior notice include: (1) uncontested filings that do not change rates; (2) filings that reduce rates and charges; and (3) filings that increase rates as prescribed by a previously accepted contract or settlement on file with the FERC.

Comments on the Proposed Policy Statement are now due on or before June 18, 2020; reply comment, July 2, 2020.

- **FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4)**

On May 21, 2020, the FERC issued a Policy Statement that applies to natural gas and oil pipelines, with certain exceptions to account for the statutory, operational, organizational and competitive differences among the electric, natural gas and oil pipeline industries, the FERC's ROE methodology adopted in *Opinion No. 569-A*.[173] Specifically, the FFERC revised its policy and will determine natural gas and oil pipeline ROEs by averaging the results of the DCF and CAPM, but will not use the risk premium model discussed in *Opinion 569/569-A* ("Risk Premium"). In addition, the FERC clarified its policies governing the formation of proxy groups and the treatment of outliers in proceedings addressing natural gas and oil pipeline ROEs. Finally, the FERC encouraged oil pipelines to file revised FERC Form No. 6, page 700s for 2019 reflecting the revised ROE policy. This Policy Statement became effective May 27, 2020.[174]

As previously reported, the FERC issued a notice of inquiry on March 21, 2019 seeking information and views to help the FERC explore whether, and if so how, it should modify its policies concerning the determination of the return on equity ("ROE") to be used in designing jurisdictional rates charged by public utilities.[175] The Commission also sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI followed *Emera Maine*, which reversed *Opinion 531*, and seeks to engage interests beyond those represented in the *Emera Maine* proceeding (see EL11-66 *et al.* in Section I above).

- **NOI: Electric Transmission Incentives Policy (PL19-3)**

As reported above, the FERC issued its *Electric Transmission Incentives NOPR* on March 20, 2020, based in part on the record developed earlier in this proceeding. Reporting on developments with respect to the FERC's Electric Transmission Incentives Policy will be addressed in future Reports in RM20-10.

- **NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)**

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[176] seeks comments from interested parties on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[177] comments were due on or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before the FERC.

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[173] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (May 21, 2020) ("*Natural Gas and Oil Pipeline ROE Policy Statement*").

[174] The *Natural Gas and Oil Pipeline ROE Policy Statement* was published *Fed. Reg.* on May 27, 2020 (Vol. 85, No. 102) pp. 31,760-31,773.

[175] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (Mar. 21, 2019) ("*ROE Policy NOI*").

[176] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

[177] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

XIII.Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[178] affirming Judge Cintron's August 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 Commission's regulations ("Anti-Manipulation Rule") and NGA Section 4A.[179] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[180] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[181] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 BP requested rehearing of the *BP Penalties Order*. On September 8, 2018, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, 2016, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, 2016, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[182]

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January

[178] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

[179] *BP America Inc.,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

[180] *BP Penalties Order* at P 3.

[181] *BP America Inc.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

[182] *BP America Inc.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*").

25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter remains pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[183] 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.[184]

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. This matter remains pending before the FERC.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Harold proceeding (CP1*-***)
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- **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.[185] 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*.[186]

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[183] *Total Gas & Power North America, Inc.,* 155 FERC ¶ 61,105 (Apr. 28, 2016) ("*TGPNA Show Cause Order*").

[184] 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 section 4A of the Natural Gas Act and the 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.

[185] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[186] *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).

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 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,[187] 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.[188] 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.[189] 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,[190] provided a "more clearly articulate[d] basis for denial."
- On August 27, 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.[191]

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[187] 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).

[188] *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*").

[189] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[190] 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).

[191] *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).

XIV.State Proceedings & Federal Legislative Proceedings

- **Executive Order on Securing the United States Bulk-Power System**

On May 1, 2020, President Trump signed an Executive Order that authorizes U.S. Secretary of Energy Dan Brouillette to work with the Cabinet and energy industry to secure America's Bulk-Power System ("BPS"). The Executive Order prohibits Federal agencies and U.S. persons from "acquiring, transferring, or installing BPS equipment in which any foreign country or foreign national has any interest and the transaction poses an unacceptable risk to national security or the security and safety of American citizens. Evolving threats facing our critical infrastructure have only served to highlight the supply chain risks faced by all sectors, including energy, and the need to ensure the availability of secure components from American companies and other trusted sources." The Secretary of Energy is accordingly authorized to (i) establish and publish criteria for recognizing particular equipment and vendors as "pre-qualified" (pre-qualified vendor list); (ii) identify any now-prohibited equipment already in use, allowing the government to develop strategies and work with asset owners to identify, isolate, monitor, and replace this equipment as appropriate; and (iii) work closely with the Departments of Commerce, Defense, Homeland Security, Interior; the Director of National Intelligence; and other appropriate Federal agencies to carry out the authorities and responsibilities outlined in the Executive Order. A Task Force led by Secretary Brouillette will develop energy infrastructure procurement policies to ensure national security considerations are fully integrated into government energy security and cybersecurity policymaking. The Task Force will consult with the energy industry through the Electricity and Oil and Natural Gas Subsector Coordinating Councils to further its efforts on securing the BPS. A copy of the Executive Order may be accessed here.

XV.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). 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).

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated)**
  Underlying FERC Proceeding: ER19-1428[192]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); SIERRA CLUB/UCS (19-1253)

On October 24, 2019, ENECOS[193] petitioned the DC Circuit Court of Appeals for review of the FERC's August 6, 2019 Chapter 2B Notice that ISO-NE's Chapter 2B Proposal took effect by operation of law. MA AG (November 25), the NH PUC and NH OCA (December 3) (together, the "State Petitioners"), and RENEW Northeast, Sierra Club and UCS (December 3) ("Nonprofit Petitioners")[194] similarly filed separate appeals. All of the cases were ultimately consolidated on December 30, 2019 (with 19-1224 to serve as the lead docket). Petitioners' initial submissions, procedural and dispositive motions were filed on January 6, 2020. On January 6, 2020, the FERC submitted a motion asking for 60 days between the filing of Petitioners' opening brief and the FERC's brief in response, and filed the Certified Index to the Record. On January 21, the Court granted the motions to intervene

[192] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[193] "ENECOS" are Belmont; Block Island Utility District; Braintree; Energy New England ("ENE"); Georgetown Municipal Light Department; Groveland; Hingham; Littleton; Merrimac; Middleborough; Middleton; North Attleborough; Norwood; Pascoag; Reading; Rowley; Stowe; Taunton; and Wellesley.

[194] RENEW has since moved, and the court granted that motion, to withdraw its appeal.

of NEPOOL, ISO-NE, NEPGA, Calpine, and the MPUC. On March 5, 2020 Petitioners proposed a briefing format and schedule for this case, which included separate briefing for Petitioners (three opening and reply briefs, one each for ENECOS, State Petitioners and Nonprofit Petitioners), and the extra time requested by the FERC.

At the unopposed request of the FERC, the Court issued an order suspending the briefing schedule and remanded the record back to the FERC. In the request to suspend the briefing schedule and remand the record, the FERC stated that it "now has a quorum of Commissioners who can participate in the review of the ISO New England tariff filing," that remand "could obviate the need for a subsequent appeal by Petitioners", and it "anticipates issuing an order on remand within 90 days of this Court's order remanding the agency record and an order addressing the merits of any subsequent requests for rehearing within 180 days of the close of the 30-day period for applying for rehearing". The Court directed the FERC to file status reports at 90-day intervals beginning July 20, 2022 and the parties to file motions to govern further proceedings in these consolidated cases within 30 days of the completion of the remand proceedings.

- ***Order 841* (19-1142, 19-1147) (consol.)**
  Underlying FERC Proceeding: RM16-23; AD16-[195]
  Petitioners: NARUC, APPA et al.

NARUC and APPA et al.[196] petitioned the DC Circuit Court of Appeals for review of *Orders 841* and *841-A* (Electric Storage Participation in RTO/ISO Markets). The cases were consolidated, with 19-1142 as the lead docket. Since the last Report, briefing was completed.[197] On March 11, oral argument was set for May 5, 2020. In light of the Court's March 17 order suspending all in-person onsite oral arguments (in response to the COVID-19 (coronavirus) pandemic), the Court-assigned panel (Judges Rodgers, Garland and Wilkins) proceeded by teleconference and augments by counsel for NARUC, APPA and FERC were heard. This matter is now pending before the panel.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[198] **EL15-23**[199]
  Petitioners: NEPGA, Exelon

On February 2, 2018, DC Circuit granted NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23).[200] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded the case to the FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course. The remand is now pending before the FERC.

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[195] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[196] "APPA et al." are APPA, NRECA, EEI, and AMP.

[197] Final Briefs were filed by: Respondent (FERC) (Mar 13); Petitioner (NARUC) (Mar 13); Petitioner (APPA/NRECA/EEI/AMP) (Mar 12); Joint Intervenor for Respondent (AEE/ESA/SEIA) (Mar 16); Joint Intervenor for Respondent (EDF/NRDC/Vote Solar) (Mar 16); Intervenor for Petitioner (TAPS); and Amicus for Respondent (Sunrun/Tesla/Vivint Solar/Engie Storage Services) (Mar 11).

[198] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[199] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[200] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018).

Other Federal Court Activity of Interest

- **PG&E Bankruptcy (19-71615) (9th Cir.)**
  Underlying FERC Proceeding: EL19-35, EL19-36[201]
  Petitioner: PG&E

On June 26, PG&E appealed the FERC's orders finding that it has concurrent jurisdiction with the bankruptcy courts to review and address the disposition of wholesale power contracts sought to be rejected through its bankruptcy. On July 11, PG&E moved to suspend the briefing schedule pending the Court's decision on whether to authorize direct appeal of a decision by the Bankruptcy Court in the Northern District of California. In a declaratory judgment, the Bankruptcy Court came to a completely different conclusion than the FERC and held that it has "original and exclusive jurisdiction over . . . [PG&E's] rights to assume or reject executory contracts under 11 U.S.C. § 365" and that the FERC "does not have concurrent jurisdiction, or any jurisdiction, over the determination of whether any rejections of power purchase contracts by [PG&E] should be authorized."[202] Because of the opposite conclusions, PG&E suggested that, should the Ninth Circuit allow the direct appeal of the Bankruptcy Court decision, the two appeals should proceed together. The PG&E motion was granted on August 1. On February 24, 2020, PG&E submitted a motion to further expedite oral argument in this case so that the case can be resolved by June 30, 2020, if possible. In response to that motion, the Court issued an order directing the case be calendared on a priority basis and assigned to the next available panel, but not by June 30, 2020. The Court issued an order that this "case will be calendared on August 12 or 14, 2020 in Pasadena. The Court is planning on in person oral arguments, but is monitoring the ongoing health emergency and CDC guidelines and will update the parties closer to the argument date if the panel intends on holding arguments remotely."

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[203]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Pending before the DC Circuit is an appeal of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[204] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). All briefing is complete and oral argument was scheduled for October 4, 2019. However, on October 1, the court removed the cases from the oral argument calendar and will hold the cases in abeyance "pending final disposition of any post-dispositional proceedings in the Third Circuit or proceedings before the United States Supreme Court resulting from the Third Circuit's decision in No. 19-1191 (In re: PennEast Pipeline Company, LLC (3rd Cir. Sep. 10, 2019)), or other action that resolves the obstacle PennEast poses". That decision held that the Eleventh Amendment barred condemnation cases brought by PennEast in federal district court in New Jersey to gain access to property owned by the State or its agencies, thus calling into question the viability of PennEast's proposed project route, and the certificates issued in the underlying case. Until the Third Circuit case is resolved, the DC Circuit will not take up this case. As reported in the May 4, 2020 Report, the parties filed status reports indicating that the Third Circuit case remains unresolved, with some requesting that the Court continue to hold this case in abeyance, and with Delaware Riverkeeper Network and the Delaware Riverkeeper ("DRN") reiterating its request that the PennEast Certificate Order also be stayed.

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[201] *NextEra Energy, Inc. v. PG&E*, 166 FERC ¶ 61,049 (Jan. 25, 2019); *Exelon Corp. v. PG&E*, 166 FERC ¶ 61,053 (Jan. 28, 2019); *Order Denying Rehearing*, 167 FERC ¶ 61,096 (May 1, 2019).

[202] Declaratory Judgment at 1-2, *PG&E v. FERC*, (Bankr. N.D. Cal. June 7, 2019).

[203] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[204] PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.

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M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: May 28, 2020

RE: **Vote on Formula Rate Revisions to Implement Settlement in EL16-19-000, -002**

At the June 4, 2020 Participants Committee meeting you will be asked to discuss in executive session and vote on a set of recommended revisions to the ISO-NE Tariff to implement the settlement in the formula rate proceeding in FERC Docket Nos. EL16-19-000, -002 (the "Formula Rate Revisions"). At its May 27 meeting, The Transmission Committee recommended Participants Committee support for the Formula Rate Revisions.[1] This item would have been on the Consent Agenda but for the timing of the votes.

Given that this is an active settlement proceeding, it is subject to the FERC's confidentiality rules governing such proceedings. Therefore, the substantive materials, including a descriptive memo from NEPOOL counsel and the marked Tariff revisions, have been provided separately only to NEPOOL Participants Committee members and alternates, will not be publicly available, and should not be distributed further.

The following form of resolution can be used for Participants Committee action on the Formula Rate Revisions:[2]

> RESOLVED, that the Participants Committee supports the Formula Rate Revisions as recommended by the Transmission Committee, and as reflected in the materials distributed for the June 4, 2020 Participants Committee meeting, together with any such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

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[1] The vote to recommend support had no opposition and nine abstentions.

[2] To pass, this matter requires at least two-thirds vote in support.

Overview of Settlement FERC Docket No. EL16-19

NETOs' Presentation to

NEPOOL Transmission Committee

April 28, 2020

Background

- Proceeding initiated by FERC in December 2015
- FERC determined that New England PTO transmission formula rates appear to be unjust and unreasonable
  - Formula rates are insufficiently specific with respect to calculation of some components
  - RNS formula rate (Attachment F) may not be synchronized with LNS formula rates of individual PTOs, potentially leading to over-recovery of costs
- Original Settlement filed on August 17, 2018 (Opposed by FERC Trial Staff and contested by Indicated Municipal PTF Owners [IMPTFOs])
- FERC rejected Settlement on May 22, 2019
- Reached agreements in principle in October 2019 with FERC Trial Staff and IMPTFOs; these agreements retain core of prior Settlement, with targeted modifications
- All parties are in the process of reviewing settlement documents and red-line tariff changes
- Target date for filing the Settlement = late May/early June

Core of Formula Rate Settlement

- All Regional and Local revenue requirements will be determined through a single formula rate in Attachment F.
  - Individual PTO revenue requirement calculations in Schedule 21 are eliminated.
- Prior Attachment F formula replaced by Excel templates that are similar to formula rate templates used around the country.
- Costs allocated between regional service (PTF),local service and Schedule 12C costs pursuant to gross plant allocator.
- Moved regional rates to a calendar-year billing and average rate base rather than prior June-May billing and year-end rate base.
- Retains feature of using projected costs that are trued up to actual costs after Form 1s are filed.
- Added additional Attachments into the Excel formula rate template as requested by Trial Staff and IMPTFOs.

Protocols

- Settling parties have agreed on procedures for reviewing annual updates that are based on FERC-approved protocols elsewhere.
- Initiated by PTO submittal of DRAFT annual informational filing posted on ISO-NE's website on June 15th with updated revenue requirements calculation.
- Customers and interested regulators may ask discovery on the revenue requirement calculations.
- If any formula rate inputs are challenged and cannot be resolved through negotiation, customers and regulators may bring a challenge at FERC.
- This process is not available to change the Attachment F formula itself, which must be done under Sections 205 or 206.

Change to ISO-NE Planning Procedure

- The settlement includes changes to ISO-NE Planning Procedure 4 to provide more timely information about new transmission projects before they are included in regional revenue requirements.
- TCA applications will be submitted to the ISO prior to the start of Major Construction (a defined term added to PP4).
- If Applicant determines TCA application cannot be submitted before Major Construction commences, Applicant will provide to RC a project and preliminary cost update within 6 months, and at least annually thereafter.
  - TCA application to be submitted before start of Major Construction for the final element of the Project.
- Force Majeure or Emergency events may result in submittal of TCA Application after Project placed in service, but no more than one year later.

Moratorium

- Most elements of the settlement are subject to a moratorium, which means they are not subject to change by filing under Sections 205 or 206 during the moratorium period.
- There is an agreed upon list of moratorium exceptions for items such as ROE and transmission incentives, certain changes in depreciation rates, and tax law changes.

Regulatory Review

- Settlement represents an overall compromise of issues.
- Settlement is only effective if approved in its entirety without modification or condition.
- If FERC approves the settlement with conditions or modifications any settling party may terminate the settlement or seek re-negotiation to restore balance of consideration.
- If settling parties are unable to reach agreement on changes that are consistent with FERC order, any settling party has the right to terminate the settlement in its entirety.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity
Counsel, Membership Subcommittee

DATE: May 28, 2020

RE: Invenia Technical Computing Corp ("Invenia"): Proposed Additional Condition to Membership

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You will be asked at the June 4 meeting to approve the application for membership in NEPOOL of Invenia Technical Computing Corp ("Invenia") subject to an additional condition to membership identified in the form of resolution included below ("Additional Condition"). Participants Committee ("NPC") action is required because the Membership Subcommittee's ("Subcommittee") delegated authority over membership applications is limited to approving applications subject solely to the standard conditions, waivers and reminders ("SCWRs") previously approved by the NPC. The Subcommittee recommended the approval of Invenia's membership (and supports Invenia's participation in the New England Markets) subject to the Additional Condition. Given the commercial sensitivity of this topic, discussion of this matter will take place in Executive Session. We have summarized and provided additional information concerning the Additional Condition in materials that are being circulated confidentially only to Participants Committee members and alternates.

The following form of resolution can be used for NPC action on Invenia's membership and the Additional Condition:

> RESOLVED, that the Participants Committee approves the membership of Invenia Technical Computing Corp (Invenia) and supports its participation in the New England Markets, subject to the following conditions: (1) that NEPOOL Counsel and the ISO find Invenia's application complete; (2) that Invenia execute an Indemnification Agreement; and (3) that Invenia sign and return a letter accepting the Standard Membership Conditions, Waivers and Reminders in addition to the following additional condition: that, until the later of one year after the effectiveness of Invenia's membership or the ISO's receipt of Invenia's 2020 audited financial statements, Invenia provide additional collateral (in addition to the applicable financial assurance required under the Financial Assurance Policy) in an amount satisfactory to the ISO's Chief Financial Officer.

NEW ENGLAND POWER POOL

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Membership Subcommittee

DATE: May 26, 2020

SUBJECT: **ACTION OF THE NEPOOL MEMBERSHIP SUBCOMMITTEE**

This memorandum is notification that the NEPOOL Membership Subcommittee took the following action at its special meeting earlier today:

1. **Recommended Participants Committee Approval of Invenia's Membership Application Subject to an Additional Condition Proposed by ISO-NE.** The Subcommittee recommended that the Participants Committee approve the application for membership in NEPOOL of Invenia Technical Computing Corp ("Invenia") subject to the following *additional* condition to membership proposed by ISO-NE under § II.A.1(b) of the Financial Assurance Policy:

   > That, until the later of one year after the effectiveness of Invenia's membership or the ISO's receipt of Invenia's 2020 audited financial statements, Invenia provide additional collateral (in addition to the applicable financial assurance required under the Financial Assurance Policy) in an amount satisfactory to the ISO's Chief Financial Officer

   in addition to the following usual routine conditions: (i) that Invenia sign and return the Standard Membership Conditions, Waivers and Reminders acceptance letter (also reflecting the additional membership condition); (ii) that the ISO and NEPOOL Counsel find the application complete; and (iii) that Invenia execute an Indemnification Agreement should it request an effective date that is sooner than 60 days from completion of its application.

   This recommendation is scheduled for Participants Committee consideration at the June 4, 2020 meeting (Agenda Item #14). Additional information will be provided with the supplemental notice for that meeting.

Next ***regularly***-scheduled Subcommittee meeting: ***Mon***, ***Jun 15, 2020 10:00 a.m***.

Subcommittee Activity since Jan 1, 2020

Number of Meetings	New Member Applications	Terminations	Other Actions
7	18	16	0

2020 NEPOOL Membership Totals (as of May 1, 2020)

New Members	Terminations				Gen	TO	Supplier	POE	AR	End User	Other
11	14	Total Members	504		60	20	213	62	82	46	21
		Voting Members	272		11	5	127	59	19	39	12