NEW ENGLAND POWER POOL

David T. Doot
Secretary

November 24, 2020

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of December 3, 2020 NEPOOL Participants Committee Annual Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the December meeting of the Participants Committee will be held **via teleconference on *Thursday, December 3, 2020, beginning at 9:30 a.m. in executive session, for members and alternate members or their delegates only, with the general session expected to begin at 10:00 a.m. (or five minutes following the end of executive session, whichever is later)***. The December meeting is held for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2020.php. The dial-in number for the executives session will be circulated under separate cover. The dial-in number for the general session, to be used only by those who otherwise attend NEPOOL meetings, is **866-803-2146; Passcode: 7169224.**

For your information, except for the discussions in executive session, the December 3 annual 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.

By way of reminder, the December meeting is the Participants Committee's annual meeting and any member wishing to change its Sector for next year ***must provide us with written notice of that request prior to the December 3 meeting***. Under Section 6.3 of the current NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective at the first annual meeting following that request.

We will hold a New Member Orientation on Friday, December 4 from 10:00 a.m. to 12:00 p.m. for anyone wishing to learn more about the NEPOOL stakeholder process. There are 26 entities that became NEPOOL members in 2020. Representatives of these new members and anyone else new to the process or otherwise wanting to learn more about the NEPOOL stakeholder process are welcome and encouraged to participate. Please let Kathryn Dube know if you plan to participate. She can be reached at kdube@daypitney.com / (860) 275-0196.

We wish you all a very Happy Thanksgiving and our hope that you are staying safe and healthy.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

Discussion on Item 1 will be held in executive session, beginning at 9:30 a.m., during which participation will be limited exclusively to voting members and alternates, or their designates.

1. To receive in executive session any confidential feedback on the incumbent ISO Board Director eligible for reelection in 2021. No formal action required. Confidential background materials will be circulated to members and alternates under separate cover in advance of the meeting.

The remainder of the meeting will be in general session, which is expected to begin at 10:00 a.m.:

2. **Deferred**. ~~To approve the draft minutes of the November 5, 2020 Participants Committee meeting.~~

3. To adopt and approve the actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials.

3A. To consider and take action, as appropriate, on the following actions recommended by the Reliability Committee that, but for timing of the RC's action, would have been on the Consent Agenda:

   a. Revisions to Appendix K to OP-23 (edits resulting from periodic review that includes incorporating Tariff approved terms, grammatical updates, and clarifying language).

   b. Revisions to OP-24 (edits resulting from the periodic review that include technical terminology changes, editorial corrections, and corresponding edits to the Appendices).

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

4. To receive an ISO Chief Executive Officer report.

5. To receive an ISO Chief Operating Officer report.

6. To receive the 2020 NEPOOL Annual Report, which will be circulated under separate cover in advance of the meeting.

7. To elect NEPOOL Participants Committee Officers for 2021. A draft resolution reflecting the outcome of earlier balloting for the Participants Committee Chair and candidates for Secretary and Assistant Secretary is included and posted with this supplemental notice.

8. To adopt a NEPOOL Budget for 2021. Background materials and a draft resolution are included and posted with this supplemental notice.

9. To consider and take action, as appropriate, on revisions to the Tariff to update the Cost of New Entry (CONE), Net CONE, and Performance Payment Rate values, and to recalculate existing and establish new Offer Review Trigger Prices using updated data for FCA16, as recommended by the Markets Committee at its November 9-10, 2020 meeting. Background materials with draft resolutions are included and posted with this supplemental notice.

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

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

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

12. Pathways to the Future Grid. The following presentations and discussions are planned:

    Michael Borgatti, VP, Gabel Associates, presentation and discussion of an additional potential market framework for New England, "*Capacity as a Commodity*". Mr. Borgatti's presentation materials will be circulated and posted in advance of the meeting.

    Dr. Frank Felder, continuation of discussion on various questions and tradeoffs associated with potential future pathways explored to date (i.e., the pros and cons of each pathway). Dr. Felder's presentation will be circulated and posted in advance of the meeting.

13. Administrative matters.

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

Electronic Participation Guidelines
General Session Part I – December 3, 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 Materials** from the NEPOOL or ISO-NE websites. Will minimize disruptions from WebEx or internet service interruptions

PROXIES

- If unable to participate for any portion of the general session, 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 Meeting

JOIN THE WEBEX 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>. Video will be disabled.

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DURING GENERAL SESSION

- **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

Electronic Participation Guidelines
General Session Part II – December 3, 2020 Participants Committee (WebEx Event)

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

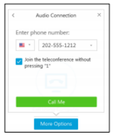
JOIN THE WEBEX EVENT

Join Event

[WebEx Link]

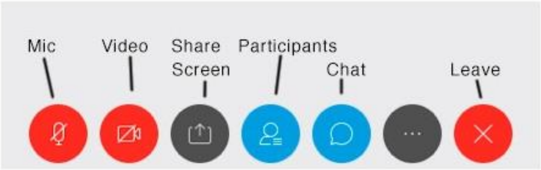
- Click <Classic View> on right side of menu. Do not use <Modern View>. Use **WebEx Events** Tab.
- Enter first name, last name and e-mail address.
- Enter event password: **nepool.**
- Click <Join>.

CONNECT TO WEBEX AUDIO



- **Call Me** - Enter a phone number, select **Call Me** (encouraged) and WebEx calls you.
- **Call Using Computer** – choose this option to connect to audio using VoIP. Use of headset when using VoIP strongly encouraged.
- **Call In** – If you prefer to use your phone for audio, dial the phone number shown on your screen. When prompted, use your phone keypad to enter the access code, and the Attendee ID shown on your screen. Choose this option if your Internet connection is slow. **Turn off sound from your computer to avoid feedback**.

DURING THE MEETING



- **TURN OFF YOUR VIDEO** – Choose Active Speaker View. Only Presenters should be seen on video.
- **MUTE YOUR MIC OR PHONE** when not speaking.
- **ASK AND WAIT** to be recognized by the Chair.
- **IDENTIFY** yourself/your Participant once recognized and before continuing.

SERVICE INTERRUPTIONS

- Report issues by e-mail to the Chair or Secretary.
- If WebEx 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

MEMORANDUM

FROM: Pat Gerity, NEPOOL Counsel

DATE: November 24, 2020

RE: Consideration of ISO-NE Board Incumbents for Re-election in 2021

At the December 3, 2020 Participants Committee (NPC) meeting, members will have the opportunity and are encouraged to provide the Participant representatives on the Joint Nominating Committee (JNC)[1] confidential feedback regarding the individual incumbent member of the ISO New England Board of Directors whose term will be expiring at the end of next September (2021) and who is recommended by the remaining incumbent Board members for re-election to a new term. Per Participants Committee direction, the opportunity for that feedback will take place in executive session, without guests or representatives of ISO present, and should be treated in strict confidence.

The process for selecting ISO Board members is specified in the Participants Agreement, which provides that the JNC must recommend a slate of candidates for NPC endorsement and ultimately ISO Board approval. The slate to be recommended by the JNC is composed of incumbent ISO Board members whose terms will expire and are eligible for and have been identified for reelection and any new candidates proposed to fill Board vacancies that arise because of a resignation or expiration of the term of any Board member. The NPC recently completed its participation in the Board election process for 2020, and the process for the 2021 election that will take place next year is just beginning.

The NPC discussion at the December 3 meeting is limited to discussion of the incumbent that has been identified for re-election. This NPC process was established to allow members to provide collectively confidential input to their JNC representatives early and separately on incumbents that are proposed for re-election.

There has been considerable discussion already on potential changes to the selection process for new Board members. Time will be set aside at a future meeting to continue those discussions with the benefit of preliminary feedback from the ISO Board and the new JNC.

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[1] The JNC is comprised of six NEPOOL representatives (one from each Sector), one New England state regulatory representative, and the six incumbent, independent ISO Board members whose terms are not expiring.

CONSENT AGENDA

Markets Committee

From the previously-circulated notice of actions of the Markets Committee's November 9-10, 2020 meeting, dated November 11, 2020:[1]

1. <u>Modifications to the Qualification of Energy Efficiency in the Forward Capacity Market</u>

Support the revisions to sections III.13.1.4, III.13.4.2, III.13.4.3, III.13.5.1, III.13.6.1.5, and III.13.7.2.4 of Market Rule 1, which modify the Forward Capacity Auction qualification for Demand Capacity Resources comprised of Energy Efficiency (EE) measures in order to better account for expiring measures, as recommended by the Markets Committee at its November 9-10, 2020 meeting, together 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 approved, with 2 opposed (1 in each of the Transmission and AR Sectors) and 13 abstentions (4 - Generation Sector; 2 - Transmission Sector; 4 - Supplier Sector; and 2 - AR Sector).

2. <u>Order 841 Further Compliance: Tariff Definition and Market Rule Revisions</u>

Support the revisions to Tariff section I.2.2, and Market Rule 1 sections III.1.10.6 and III.C.6, proposed in response to the FERC's August 4, 2020 Order requiring further compliance with Order 841 (Electric Storage Participation in ISO/RTO Markets), as recommended by the Markets Committee at its November 9-10, 2020 meeting, together 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 approved unanimously.

Transmission Committee

From the previously-circulated notice of actions of the Transmission Committee's October 27, 2020 meeting, dated October 27, 2020:[2]

3. <u>Order 841 Further Compliance: OATT Revisions</u>

Support the revisions to Tariff section II (Open Access Transmission Tariff (OATT)) concerning the transmission charge exemption that applies to charging electric storage resources proposed in response to the FERC's August 4, 2020 Order requiring further compliance with Order 841, as recommended by the Transmission Committee at its October 27, 2020 meeting, together with such further non-material changes as the Chair and Vice-Chair of the Transmission Committee may approve.

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

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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: November 24, 2020

RE: Revisions to Appendix K to OP-23 and OP-24 (including changes to each of its Appendices)

At the December 3, 2020 Participants Committee meeting, you will be asked to support revisions to:

(a.) Appendix K to Operating Procedure ("OP") 23 (Response Rate Auditing Calculation) ("OP-23K"); and

(b.) OP-24 (Protection Outages, Settings and Coordination), including changes to each of its Appendices.

The revisions to OP-23K and OP-24 were unanimously recommended for Participants Committee support by the Reliability Committee at its November 18, 2020 meeting. But for the timing of the votes on these revisions, they would have been on the Consent Agenda.

Summarizing, the proposed revisions to OP-23K incorporate the Tariff defined terms for ten-minute reserve, revises grammar and references the Overview section of the Appendix, and clarifies that Manual Response Rate bins are compared to adjacent bins for inconsistency.[1] The proposed revisions to OP-24 and its Appendices (A-D) include changes to improve technical language, to implement minor editorial corrections, proper references, grammar improvements, and clarity, and to process data changes.[2]

The following forms of resolutions, which can be voted together absent objection, can be used for Participants Committee consideration of these two sets of changes:

> RESOLVED, that the Participants Committee supports the revisions to Appendix K to OP-23, as recommended by the Reliability Committee at its November 18, 2020 meeting, together with such [changes agreed to at the meeting, and such] other non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.
>
> RESOLVED, that the Participants Committee supports the revisions to OP – 24 (including changes to each of Appendices A, B, C, and D to OP-24), as recommended by the Reliability Committee at its November 18, 2020 meeting, together with such [changes agreed to at the meeting, and such] other non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

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[1] The materials for the RC's consideration of the OP-23K revisions are available at: https://www.iso-ne.com/static-assets/documents/2020/11/a7_1_op_23k.zip.

[2] The materials for the RC's consideration of the OP-24 revisions are available at: https://www.iso-ne.com/static-assets/documents/2020/11/a7_2_op_24_op_24a_op_24b_op_24d.zip.

Summary of ISO New England Board and Committee Meetings

December 3, 2020 Participants Committee Meeting

Since the last update, the Board of Directors met on November 4. The Special Committee on IT and Cyber Security met on November 3, and the Audit and Finance Committee, the Compensation and Human Resources Committee, the Markets Committee, and the System Planning and Reliability Committee each met on November 5. All of the meetings were held virtually.

The Special Committee on IT and Cyber Security discussed how the Board should oversee the Company's information technology and cyber security efforts. The Committee considered various options, and agreed that it would recommend that the Board consider the establishment of a new standing committee dedicated to the oversight of information technology and cyber security matters. The Board will consider this issue at its January meeting.

The Board of Directors prepared for the upcoming meetings with NEPOOL sectors and State representatives, and reviewed topics proposed for discussion. The Board then held its annual strategic planning and risk management review, and approved the culmination of management's 15-month long effort to develop a statement of vision and values as well as overarching strategic goals. In addition, the Board received a report from the CEO, including a quarterly update on goal achievement, and reports from members of the Board on topics discussed at liaison meetings with state utilities commissions. The Board heard reports from the standing committees. During the Nominating and Governance Committee report, the Board approved revised committee assignments to move Mr. Colangelo from the Compensation and Human Resources Committee to the Nominating and Governance Committee, in order to ensure succession on the latter committee. The Board also appointed members to the Joint Nominating Committee for the upcoming search to fill two Board seats in 2021. The revised committees are as follows:

- Mses. Abernathy and VanZandt and Mr. Denis shall serve on the **Compensation and Human Resources Committee**, with Mr. Denis to serve as Chair;
- Mses. Abernathy and LaFleur and Messrs. Colangelo and Shapiro shall serve on the **Nominating and Governance Committee**, with Mr. Shapiro to serve as Chair; and
- Mses. Abernathy and LaFleur and Messrs. Colangelo, Denis, Rush, Shapiro and Vannoy shall serve on the **Joint Nominating Committee**, with Mr. Shapiro to serve as Chair.

The Board also received an update on the scope of the Regional System Plan Report from the System Planning and Reliability Committee, and approved a revision to the Compensation and Human Resources

Committee's charter to clarify its responsibility for oversight of the Company's diversity and inclusion efforts, as recommended by the Committee.

The Audit and Finance Committee met with representatives of KPMG, the Company's external auditors, to discuss the scope and preliminary results of the 2020 System and Organization Controls Report and resulting unqualified audit opinion. KPMG also provided an overview of work plans and timing for the financial statements audit. The Committee then met with the KPMG auditors in executive session. Next, the Committee received a report on internal audit activities, including a report on follow-up items related to internal reviews and the oversight of external audits. The Committee received a report on code of compliance review, and an update on the Company's use of EthicsPoint, an internet- and telephone-based anonymous reporting tool which is available to employees for reporting on financial, accounting and auditing matters. The Committee was provided with a report on current budget performance along with an update on interest rates, and approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. Finally, the Committee reviewed its calendar for the upcoming year and held an executive session to discuss corporate goals for 2021.

The Compensation and Human Resources Committee discussed key dates and deliverables for 2021 goal setting and corporate performance review for 2020, and reviewed its calendar for the upcoming year. The Committee also handled a number of compensation issues in executive session.

The Markets Committee was provided with a summary of market performance for the 2020 summer season from the internal and external market monitors. The Committee discussed Forward Capacity Market parameter updates and ongoing discussions with stakeholders. The Committee also received an update on FERC's October 30 order that rejected the Energy Security Improvements, and the Committee agreed that the issues require further discussion with the Federal Energy Regulatory Commission. The Committee then reviewed its calendar for the upcoming year and held an executive session to discuss corporate goals for 2021.

The System Planning and Reliability Committee reviewed summer operations and the outlook for Winter 2020-2021. The Committee also discussed proposed changes to scope of the Regional System Plan Report, and an overview of the plans and schedule for Forward Capacity Auction #15. Next, the Committee considered transmission planning for the clean energy transition and resources to support improvements in the assumptions used in system planning assessments, and was informed of updates to Regional System Plan projects. The Committee then reviewed its calendar for the upcoming year and held an executive session to discuss corporate goals for 2021.

NEPOOL Participants Committee Report

December 2020

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: October 2020 Energy Market value totaled $239M
  - November 2020 Energy market value was $197M over the period, down $42M from October 2020 and down $134M from November 2019
    - November natural gas prices over the period were 4.7% higher than October average values
    - Average RT Hub Locational Marginal Prices ($27.10/MWh) over the period were 0.8% higher than October averages
      - DA Hub: $26.27/MWh
    - Average November 2020 natural gas prices and RT Hub LMPs over the period were down 39% and 21%, respectively, from November 2019 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.6% during November, down from 100.8% during October*
    - The minimum value for the month was 95.3% on Saturday, November 14th

Data through November 23rd (RT NCPC through the 22nd).

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

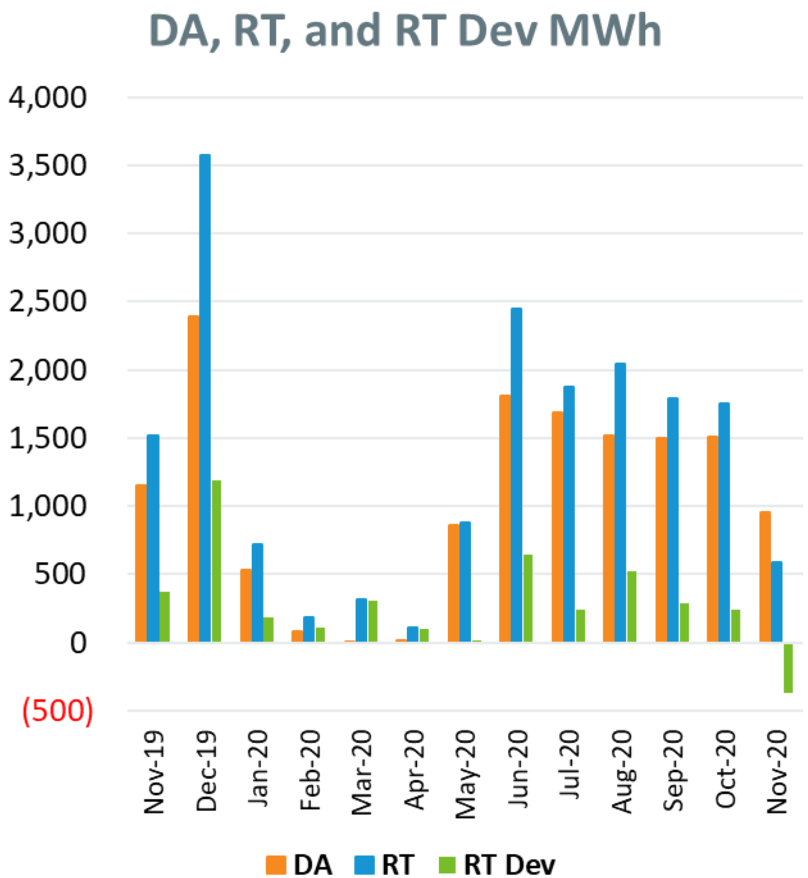
***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**

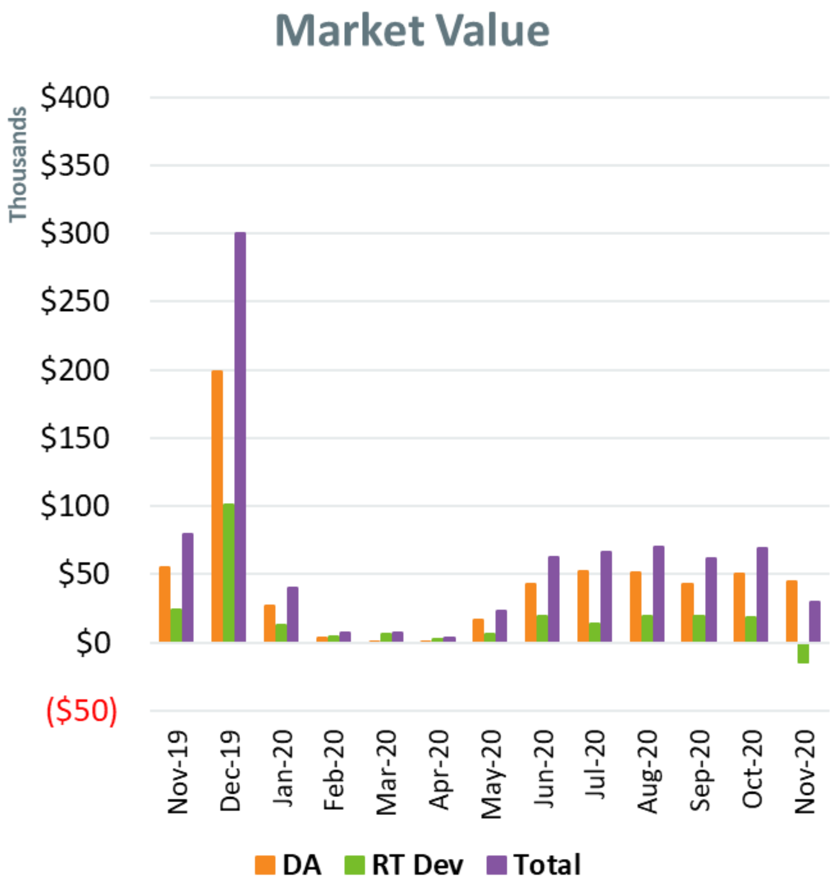
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - November 2020 NCPC payments totaled $1.6M over the period, down $1.2M from October 2020 and down $2.1M from November 2019
    - First Contingency payments totaled $1.4M, down $0.8M from October
      - $1.3M paid to internal resources, down $0.6M from October
        - » $422K charged to DALO, $352K to RT Deviations, $557K to RTLO*
      - $40K paid to resources at external locations, down $158K from October
        - » Charged to RT Deviations
    - Second Contingency payments totaled $233K, down $313K from October
    - Distribution payments totaled $9K, down $33K from October
  - NCPC payments over the period as percent of Energy Market value were 0.8%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $157K; Rapid Response Pricing (RRP) Opportunity Cost - $110K; Posturing - $5K; Generator Performance Auditing (GPA) - $285K

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.

Forward Capacity Market (FCM) Highlights

- 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)
  - ARA2 was held August 3-5 and results were posted on September 1
  - ARA3 will be held in March 2021
  - ICR and related values for ARA3 were filed with FERC on November 25

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - ARA1 was held June 1-3, and results were posted on June 25
  - ARA2 will be held in August 2021
  - ICR and related values for ARA2 were filed with FERC on November 25
- CCP 14 (2023-2024)
  - Auction results were filed with FERC on February 18 and FERC accepted the filing on April 10
  - ARA1 will be held in June 2021
  - ICR and related values for ARA1 were filed with FERC on November 25

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - FCA 15 will model the same zones as FCA 14
    - Export-constrained zones: Maine nested inside Northern New England
    - Import-constrained zone: Southeast New England
  - Both the ICR and Informational (qualification) FERC filings were made on November 10
  - Preparations are ongoing for the auction that will commence on February 8

FCA – Forward Capacity Auction

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 1
    - TOs to identify in-service dates for new transmission projects and revisions to previously certified projects
    - Approved projects to be shared with the RC at their January 2021 meeting
  - Capacity zone development discussions began at the November 19 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA

Highlights

- Order 1000/Boston 2028 Request for Proposal lessons-learned stakeholder submittals will be provided at the December 16 Planning Advisory Committee (PAC) meeting
- The 2021 Annual Reconfiguration Auction values were filed with FERC on November 25
- National Grid 2020 economic study preliminary production cost results were shared at the November 19 PAC meeting, and additional scenarios/sensitivities will be presented in the December/January timeframe
- Moody's macroeconomic forecast will be presented at PAC on December 16
- Preparations are ongoing for the auction that will commence on February 8

Competitive Solution Process: Order 1000/Boston 2028 Request for Proposal Lessons Learned

- The ISO began one-on-one discussions with each QTPS that participated in the Boston 2028 RFP where QTPS specific questions regarding their proposals and/or the process can be discussed
- The lessons-learned process, with respect to competitive transmission solutions, was discussed at the October PAC meeting
- Stakeholder feedback was due on 11/25/20
  – The results will be provided at the 12/16/20 PAC meeting
- This effort will continue through the end of 2020 and into 2021

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
  - Discussions are ongoing with industry experts regarding emerging technologies/trends and methods of incorporating these into the forecast
- The 2021 load forecast development process has commenced
  - Discussions will continue at the Load Forecast Committee, Energy-Efficiency Forecast Working Group, and Distributed Generation Forecast Working Group through the rest of 2020 and into Q1 2021
    - Moody's macroeconomic forecast will be presented at PAC on December 16
  - In the March/April timeframe, PAC will discuss the preliminary ten-year forecast
  - Publication of the final ten-year forecast will be in the May 2021 CELT report
- EE Reconstitution project
  - Tariff changes were approved by FERC on November 6
    - The new reconstitution methodology will be used for FCA 16 ICR and Related Values development

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 2, 2021.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.0°F) Max: 75°F, Min: 22°F Precipitation: 3.35" (0.50" Below Normal) Normal: 3.85"	Hartford	Temperature: Above Normal (3.5°F) Max: 79°F, Min: 18°F Precipitation: 3.40" (0.36" Below Normal) Normal: 3.76"

Peak Load:	17,034 MW	November 18, 2020	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for November 2020			

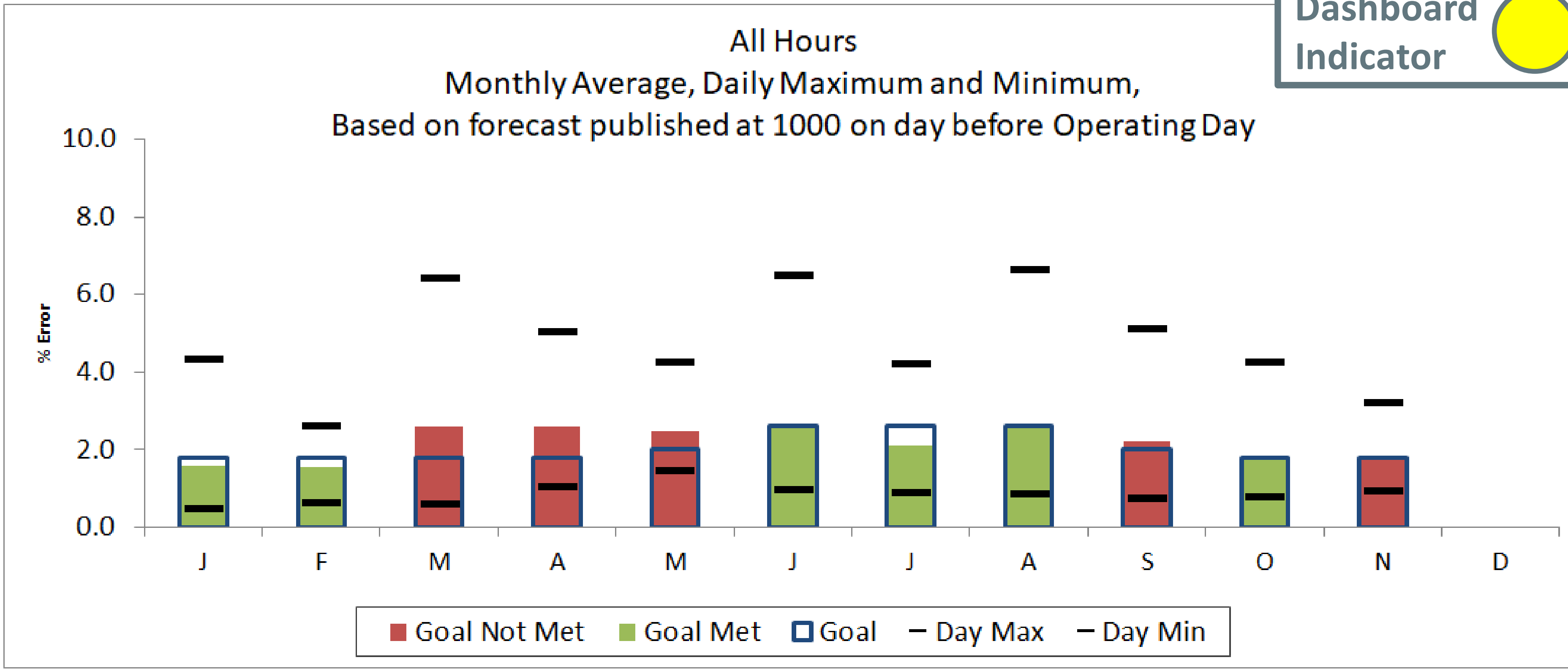
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
11/10/2020	IESO	945

2020 System Operations - Load Forecast Accuracy

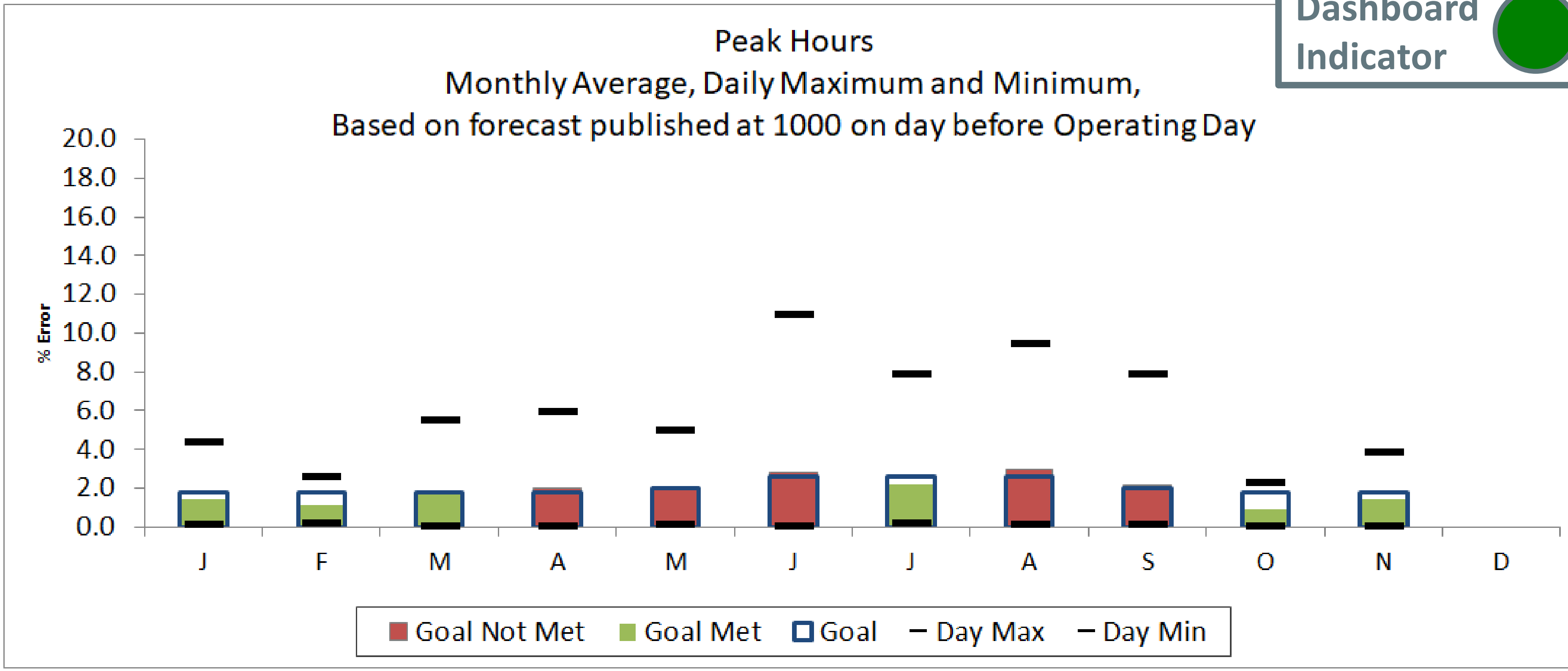
Dashboard Indicator



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	6.47	4.18	6.63	5.09	4.22	3.20		6.63
Day Min	0.46	0.61	0.58	1.03	1.42	0.96	0.88	0.84	0.72	0.75	0.89		0.46
MAPE	1.57	1.54	2.60	2.58	2.49	2.58	2.10	2.56	2.22	1.76	1.85		2.17
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

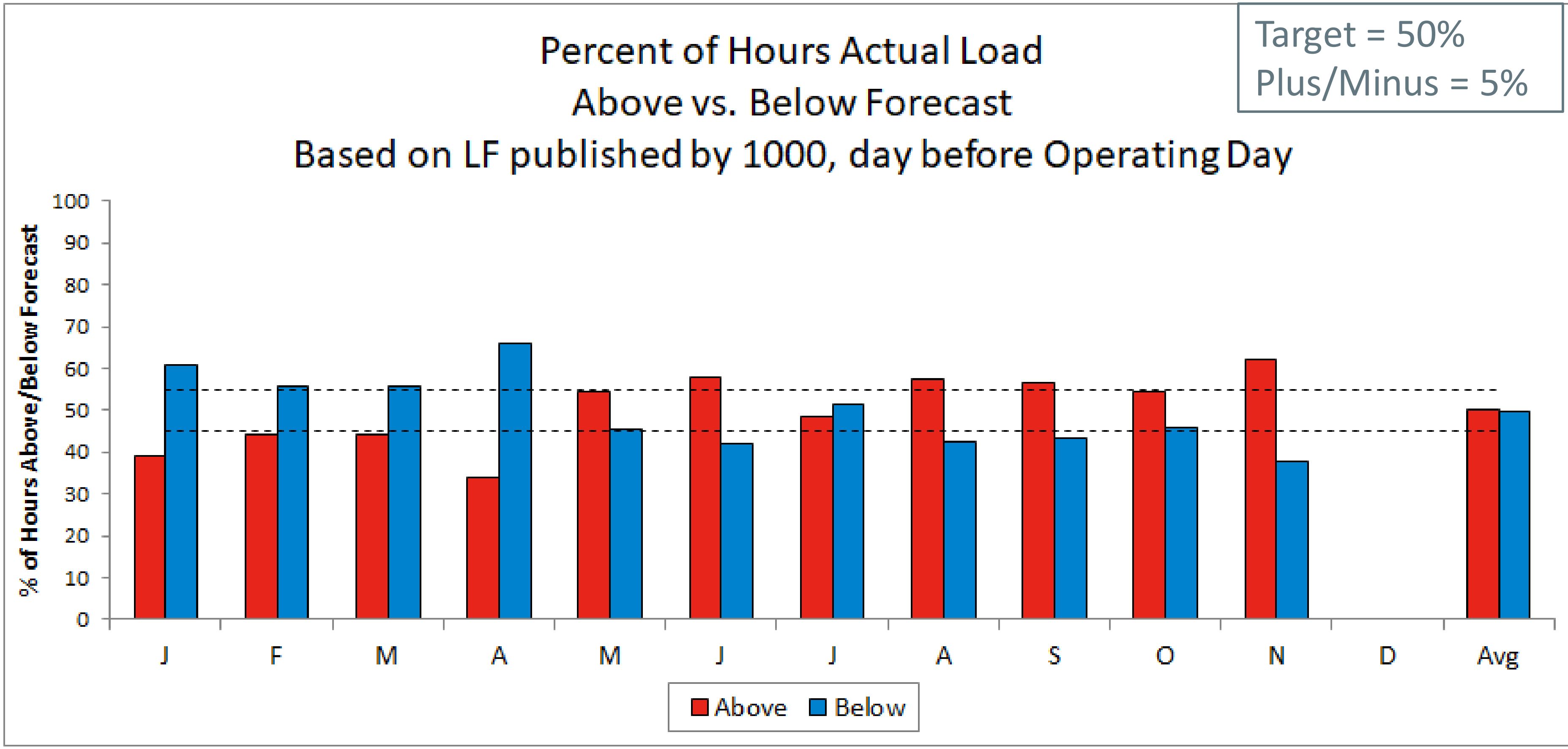
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



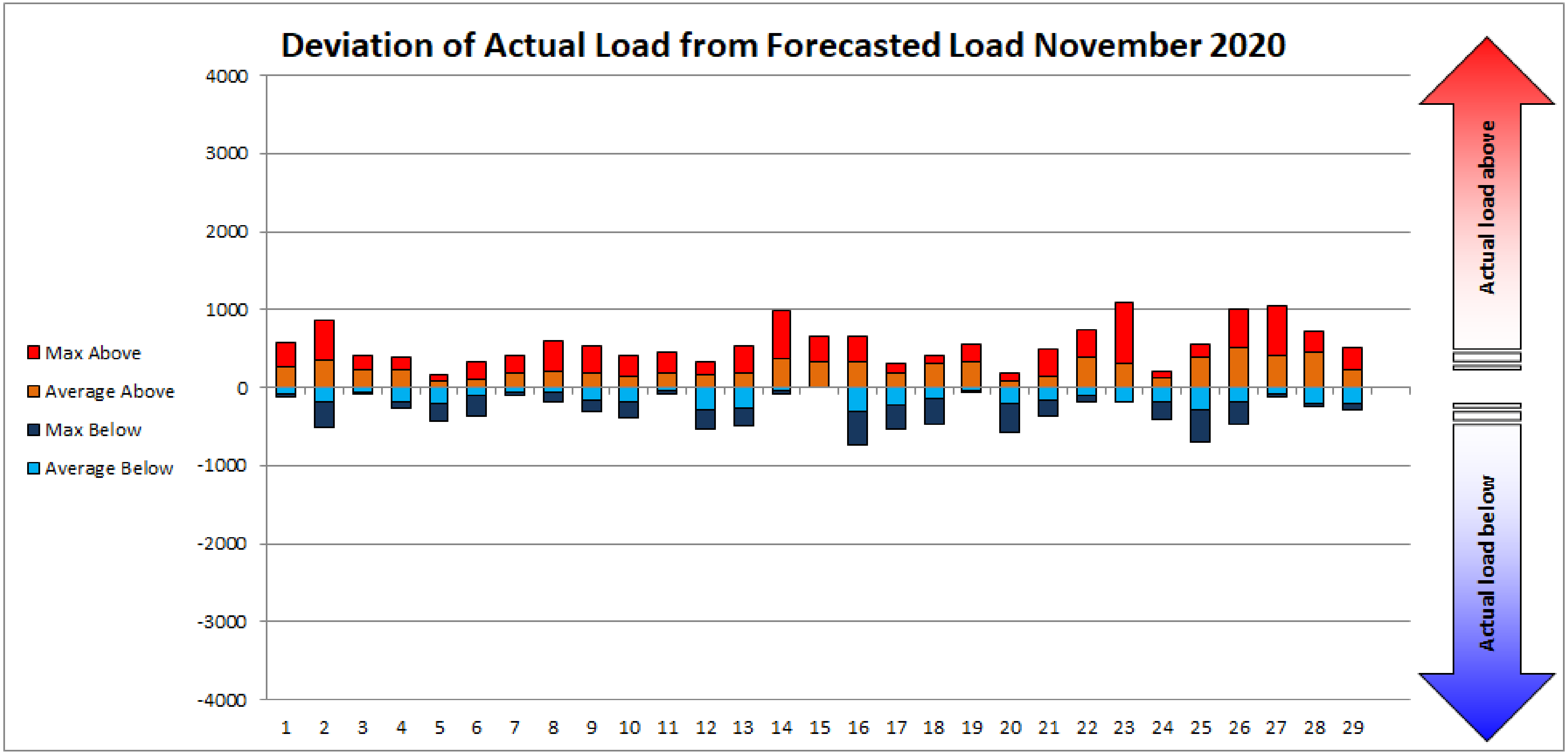
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59	5.48	5.93	4.94	10.93	7.84	9.44	7.88	2.25	3.86		10.93
Day Min	0.07	0.19	0.01	0.00	0.13	0.05	0.14	0.07	0.10	0.00	0.05		0.00
MAPE	1.41	1.12	1.72	1.97	2.11	2.83	2.18	2.97	2.17	0.95	1.45		1.90
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

2020 System Operations - Load Forecast Accuracy cont.

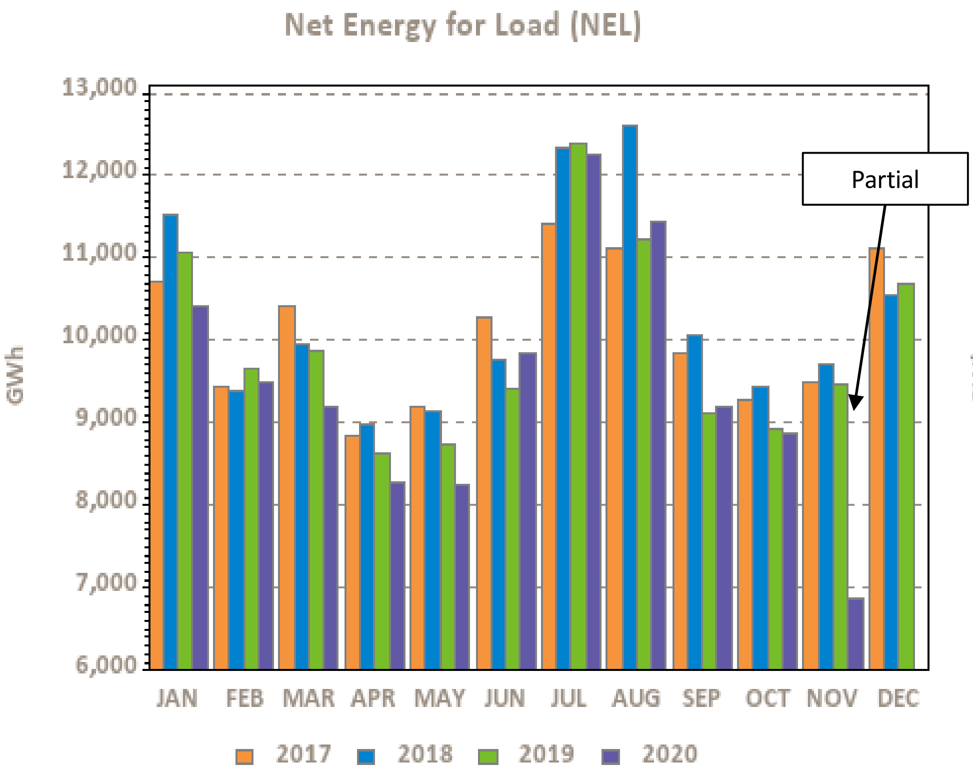


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3	44.4	33.9	54.4	57.9	48.4	57.6	56.5	54.3	62		50
Below %	61	55.7	55.6	66.1	45.6	42.1	51.6	42.4	43.5	45.7	38		50
Avg Above	136.2	169.9	207	178.9	231.9	257.5	248.3	287.2	255.5	215.2	245.8		287
Avg Below	-192.4	-157.6	-263.9	-265.3	-196.3	-243.5	-281.7	-245.5	-166.6	-156.9	-147.1		-282
Avg All	-65	-13	-56	-106	38	22	-26	73	89	52	92		9

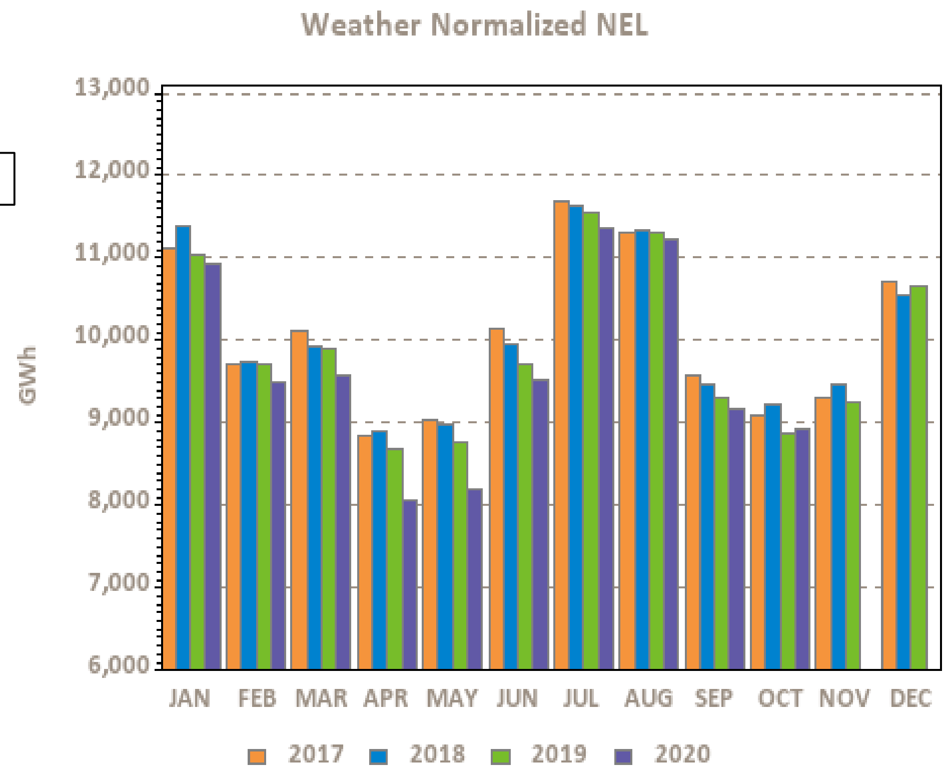
2020 System Operations - Load Forecast Accuracy cont.



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



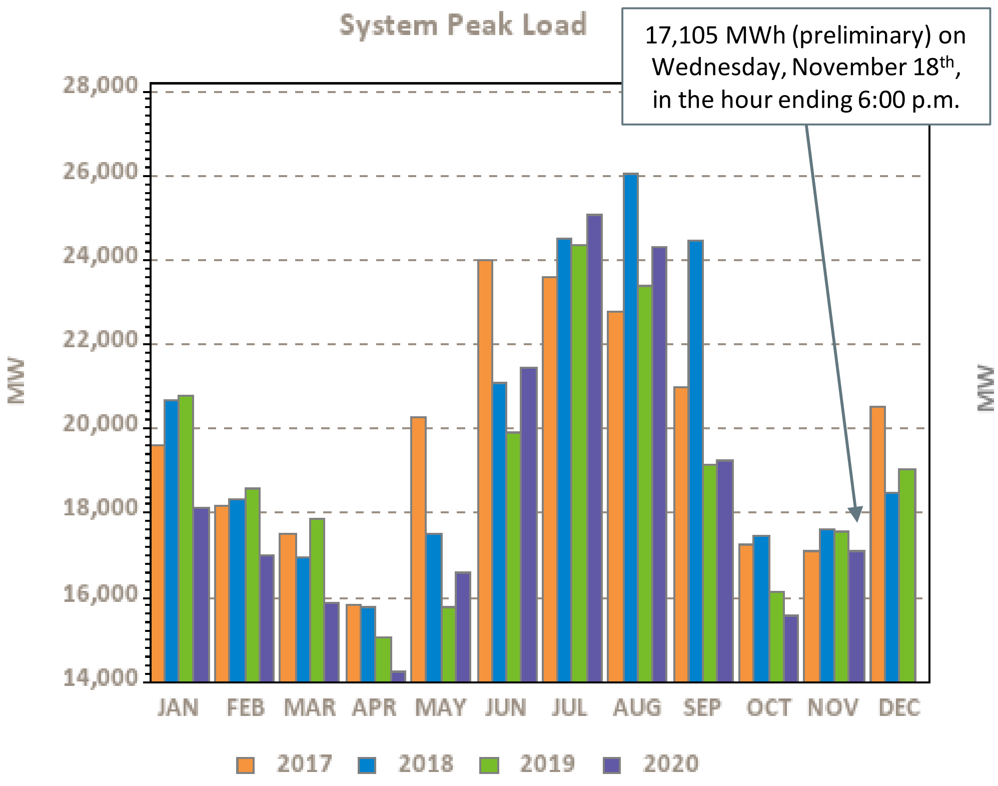
Ann Tot (TWh): 121.2 123.5 119.2 94.9



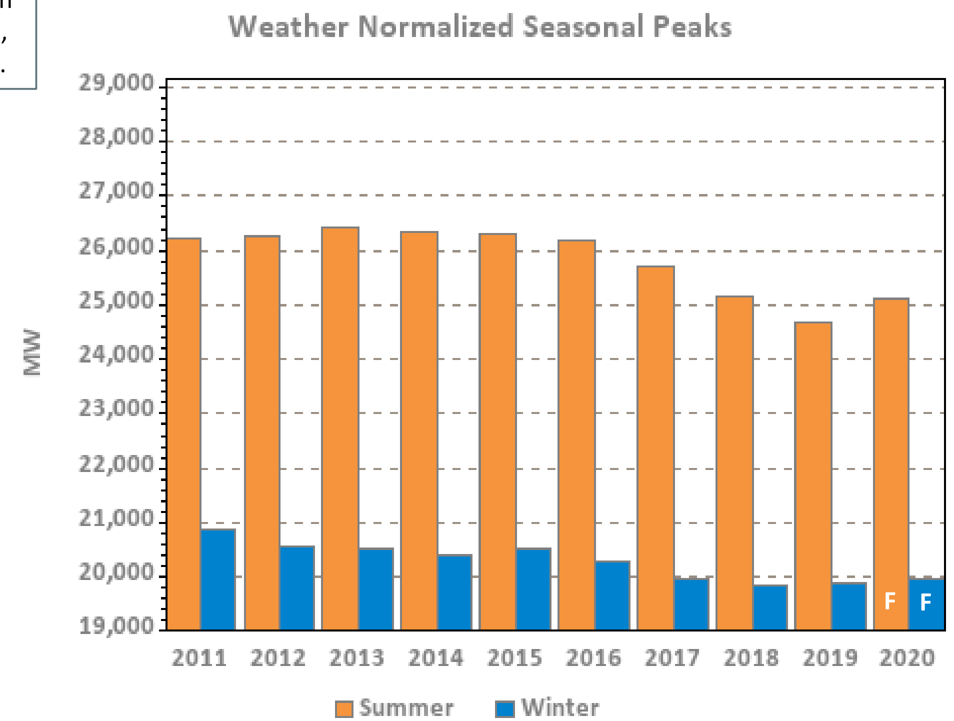
Ann Tot (TWh): 120.7 120.6 118.7 87.6

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

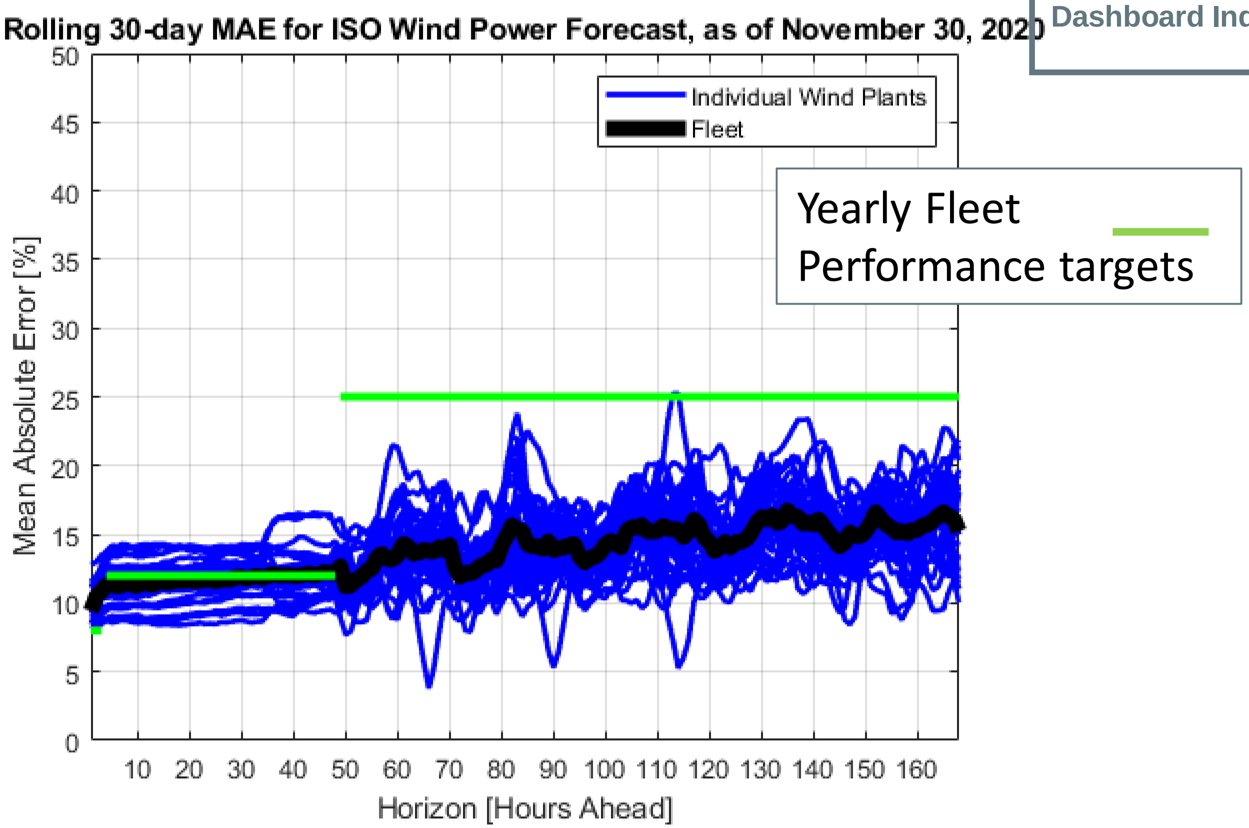


Winter beginning in year displayed

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

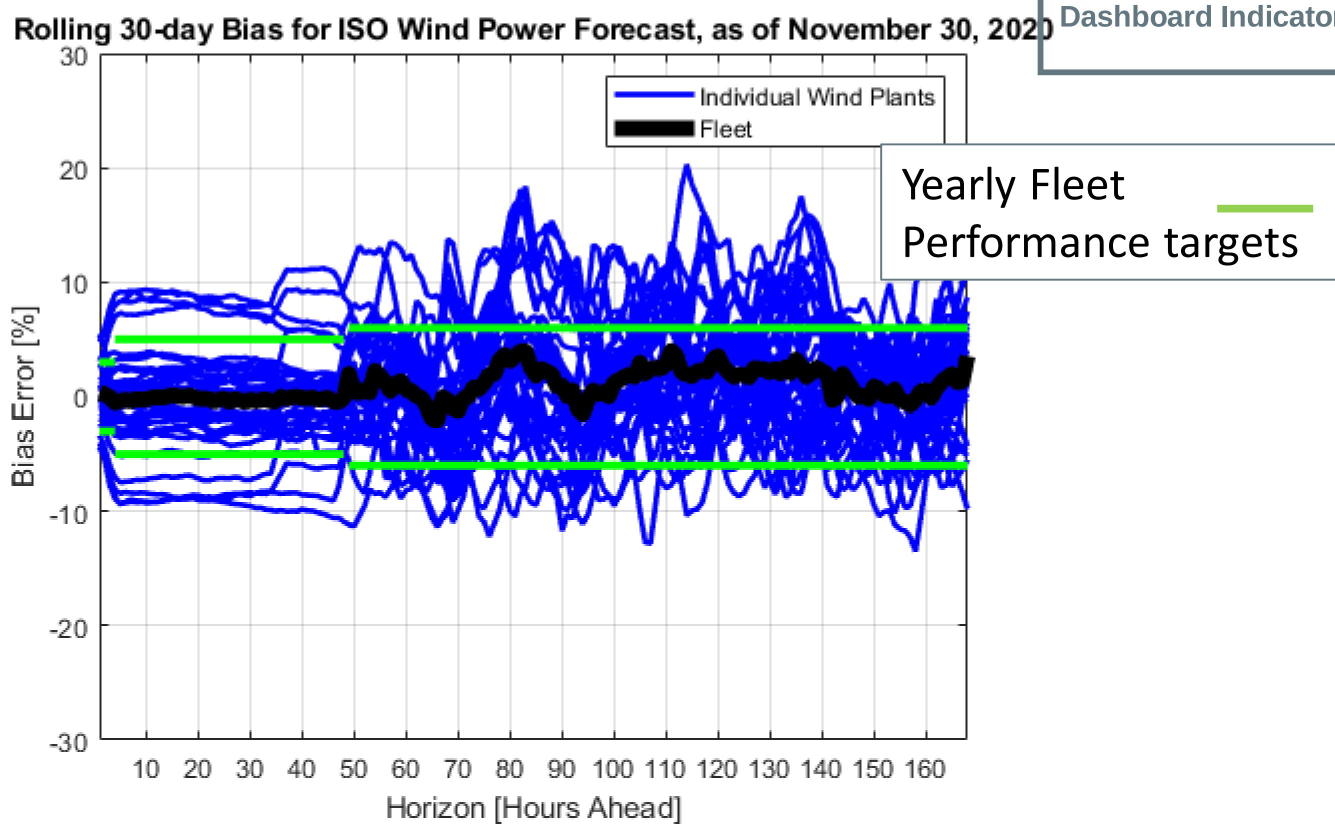
Dashboard Indicator



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

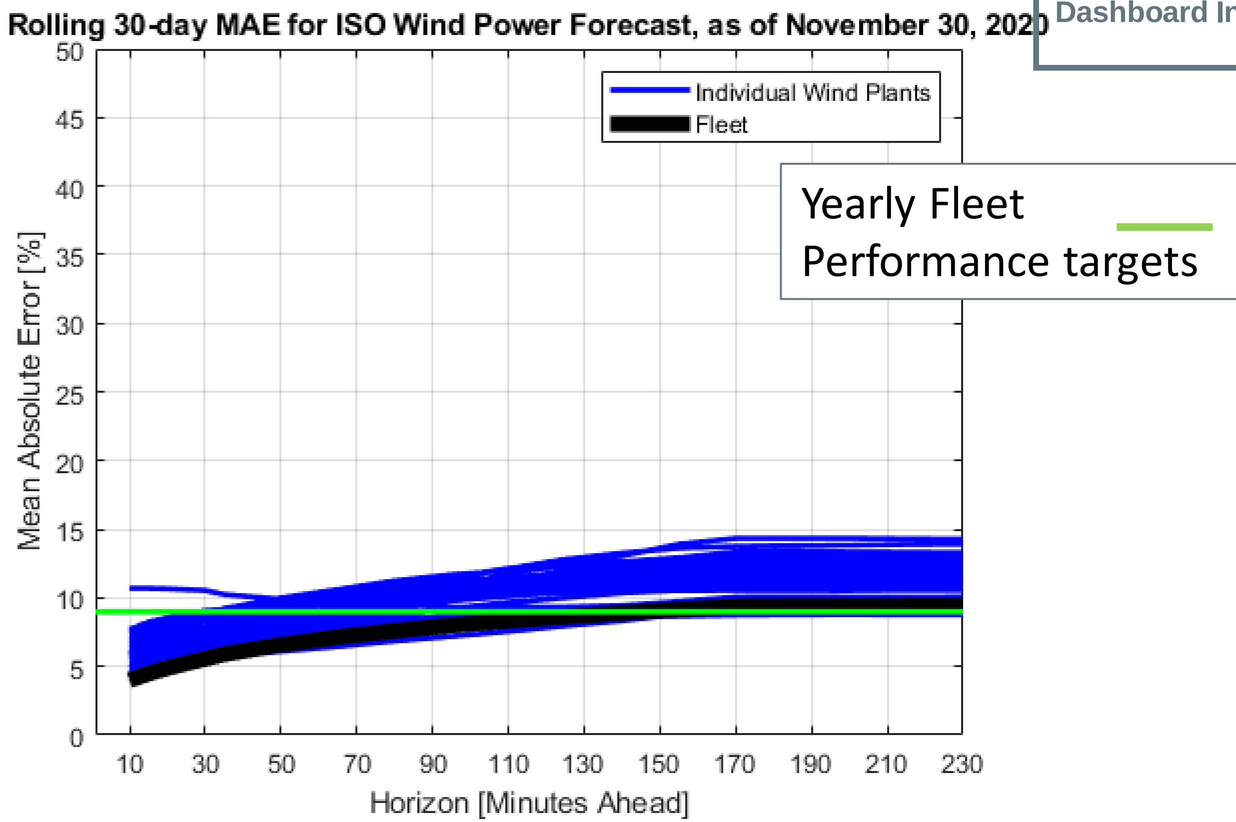
Dashboard Indicator



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 within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

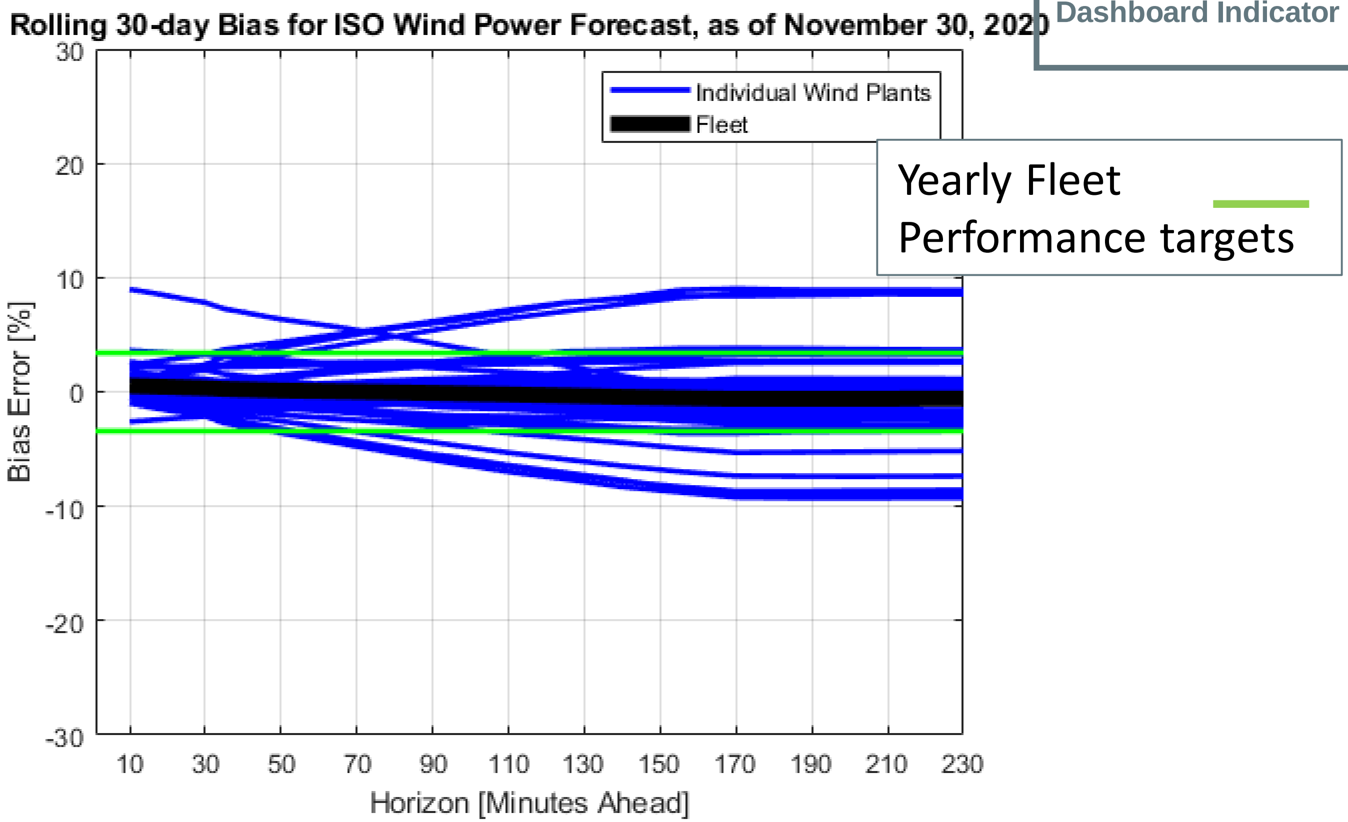
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets up to 150 minute look-ahead.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

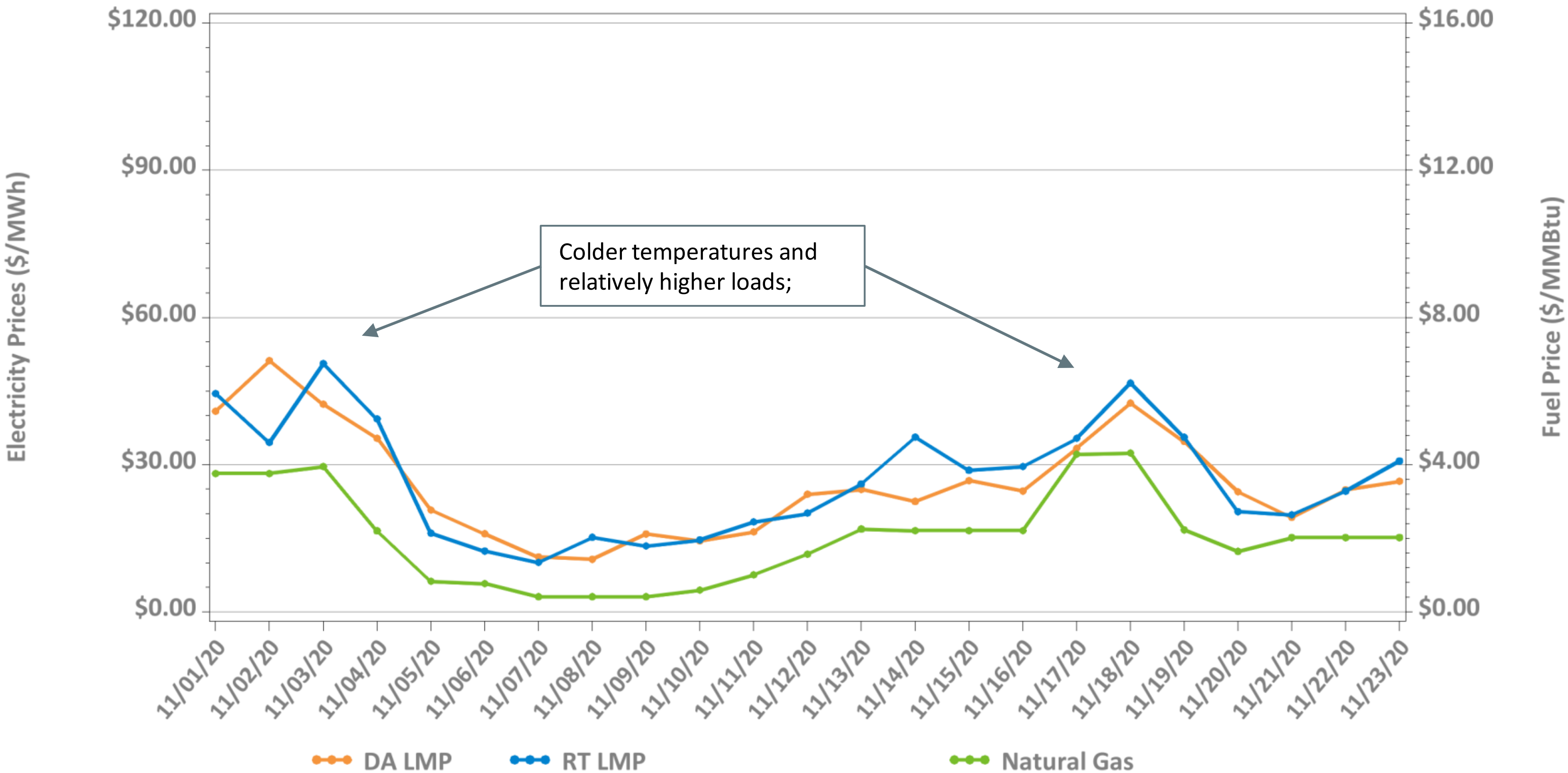
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-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: November 1-23, 2020

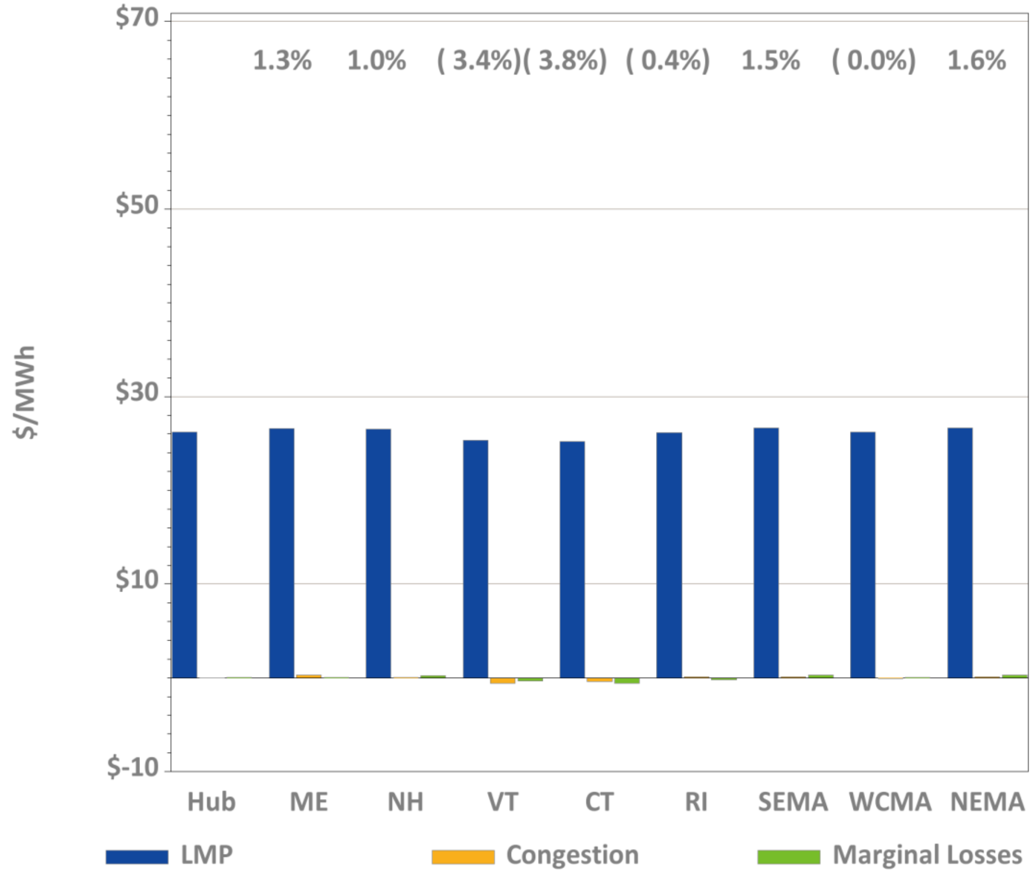


Underlying natural gas data furnished by:

ICE Global markets in clear view

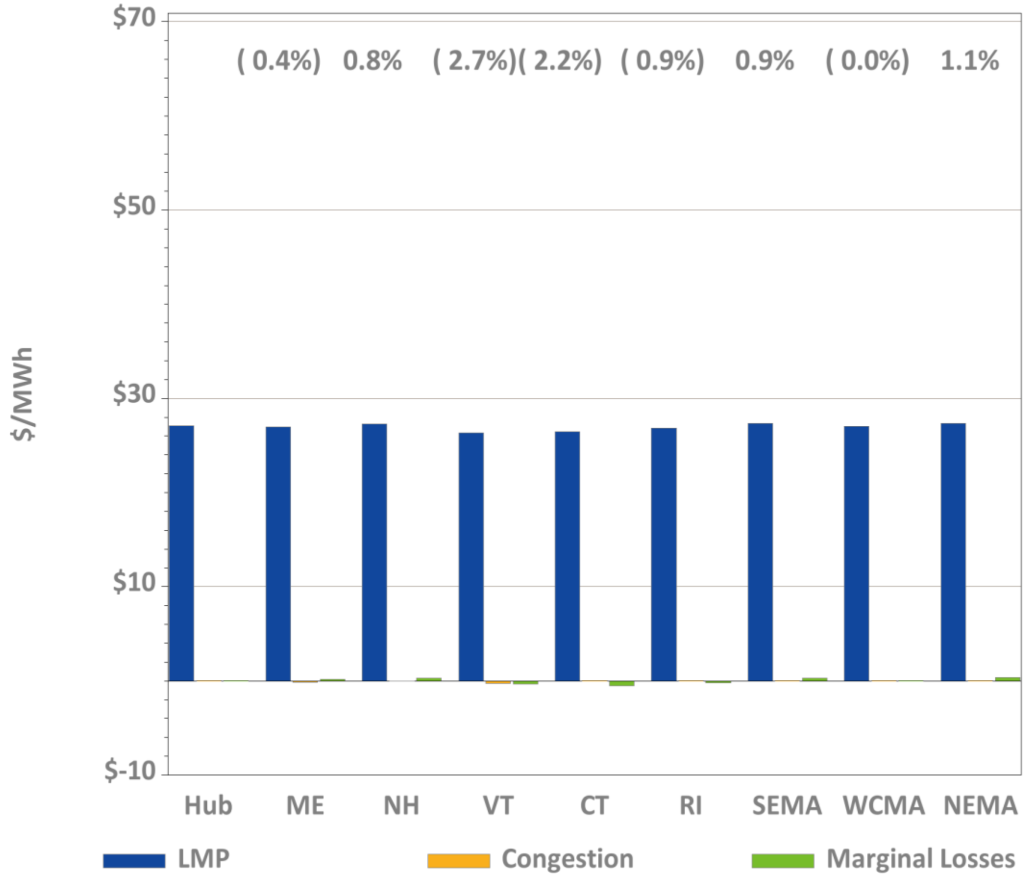
Average price difference over this period (DA-RT): $-0.82
Average price difference over this period ABS(DA-RT): $4.00
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 15%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, November 2020



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

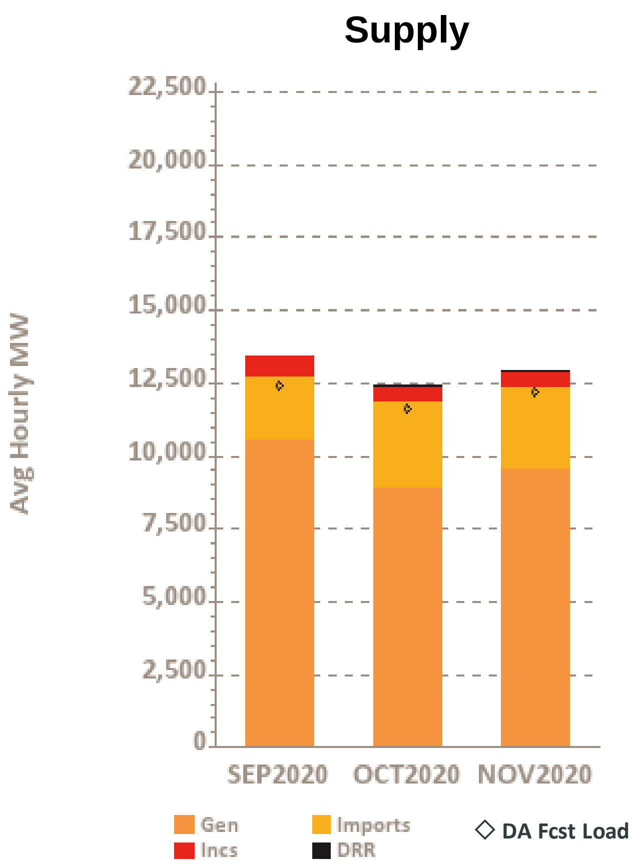
RT LMPs Average by Zone & Hub, November 2020

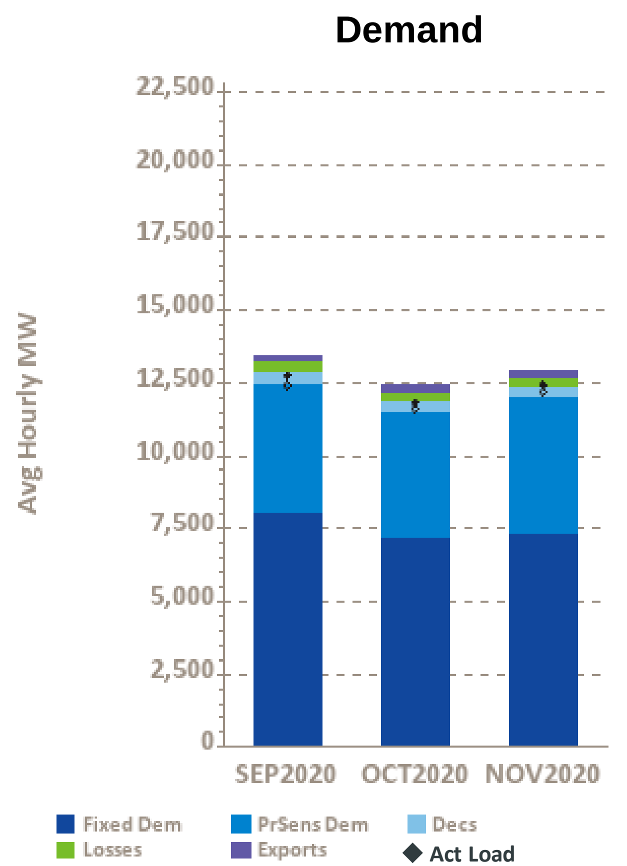


Definitions

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

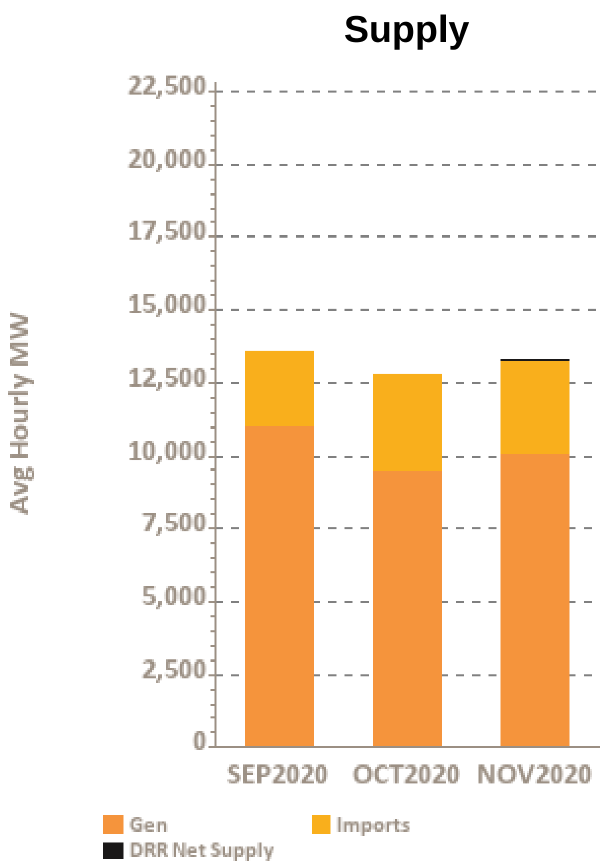


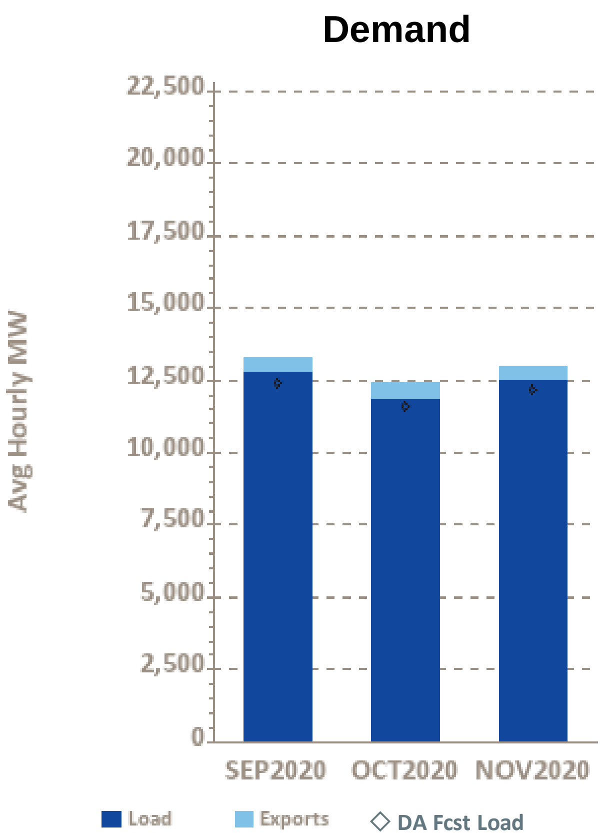


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

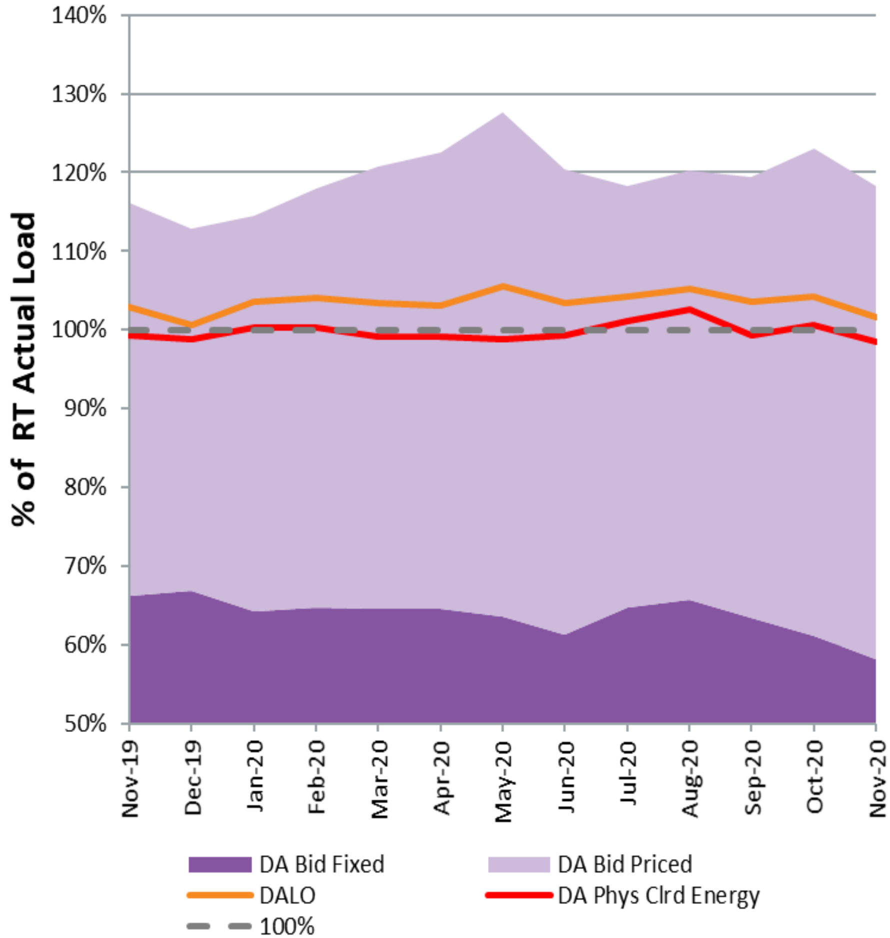
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

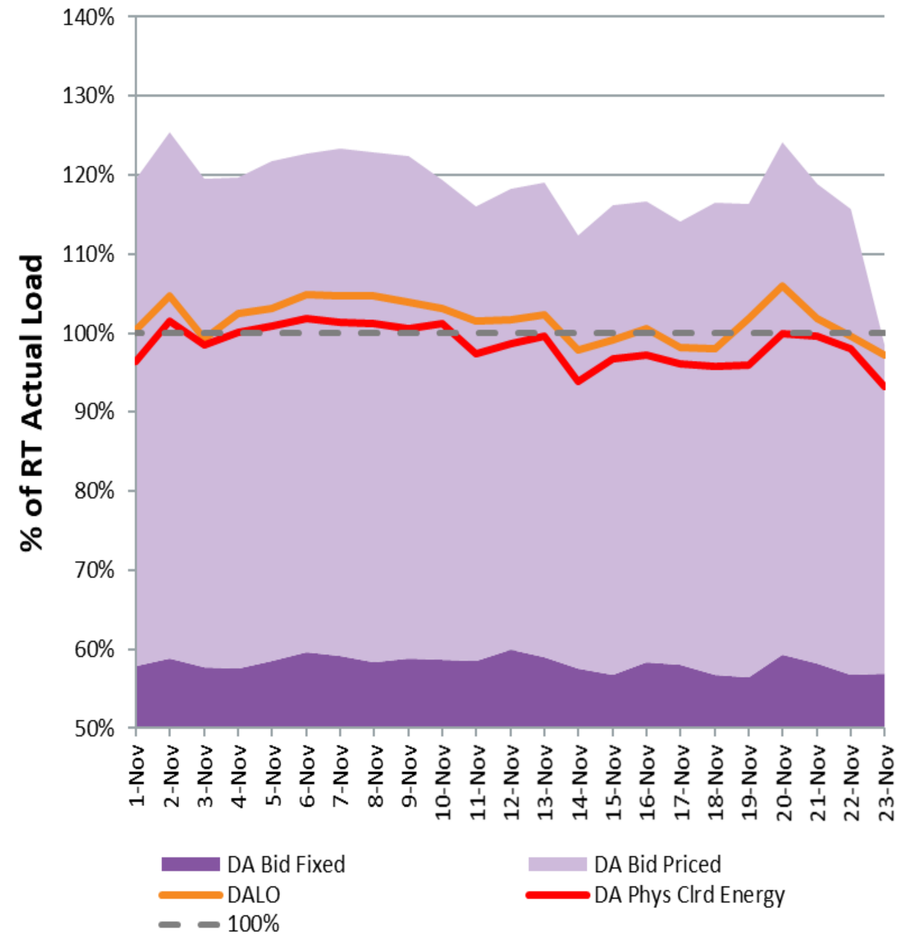
Components of RT Supply and Demand – Last Three Months





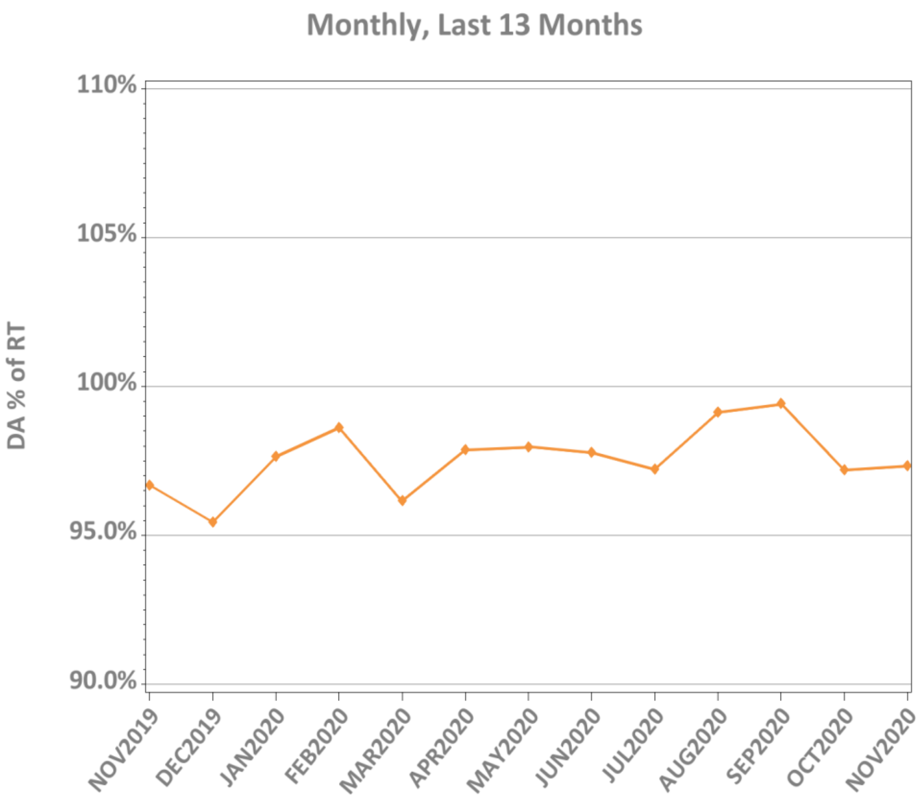
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

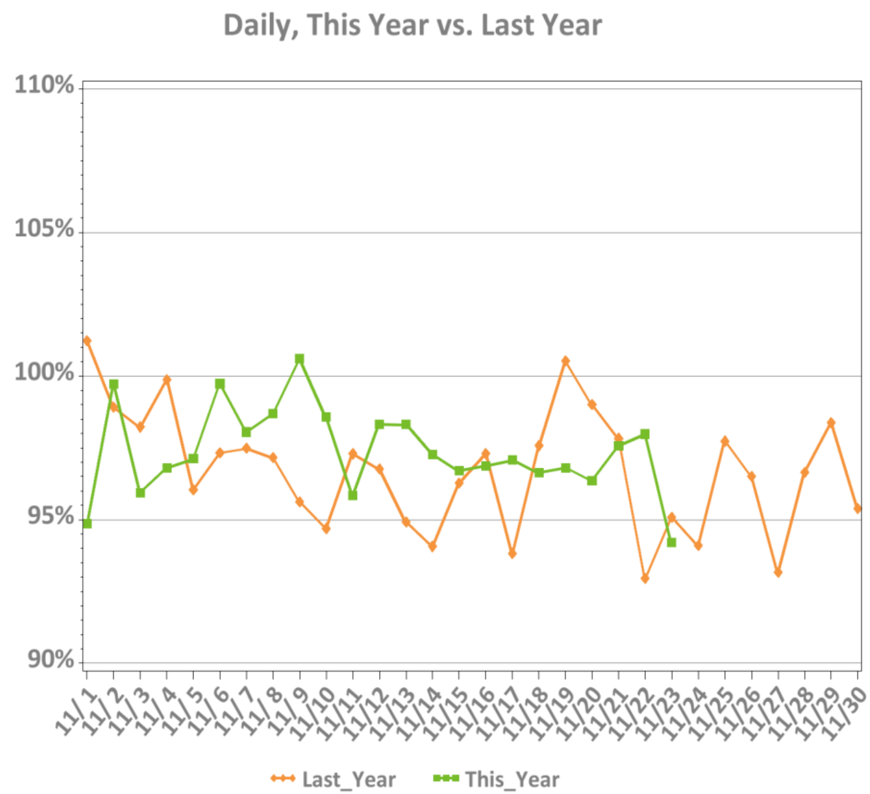




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

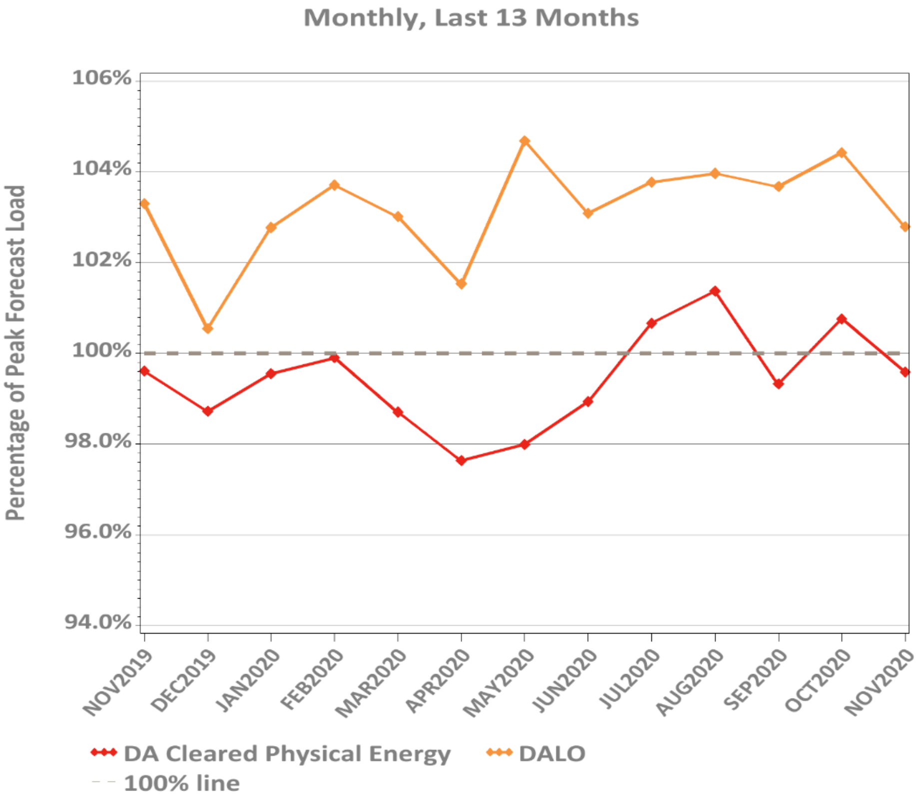
DA vs. RT Load Obligation: November, This Year vs. Last Year

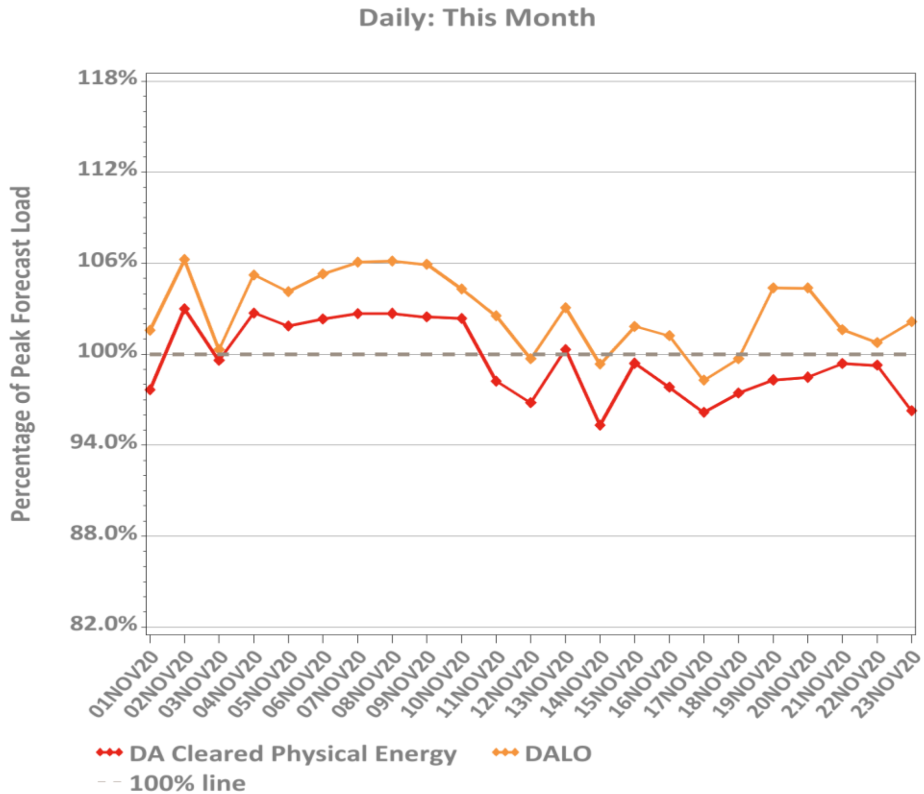




*Hourly average values

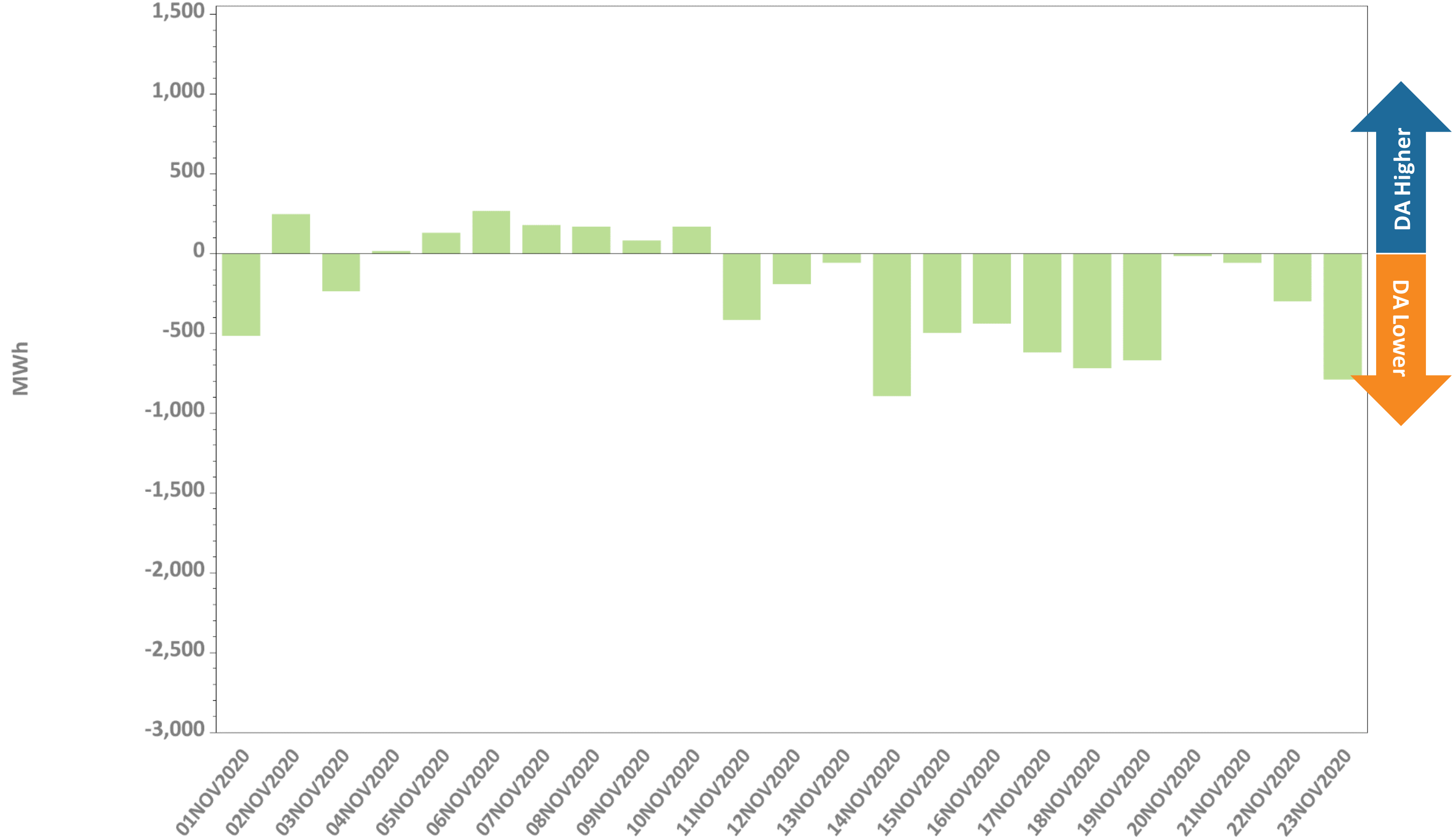
DA Volumes as % of Forecast in Peak Hour





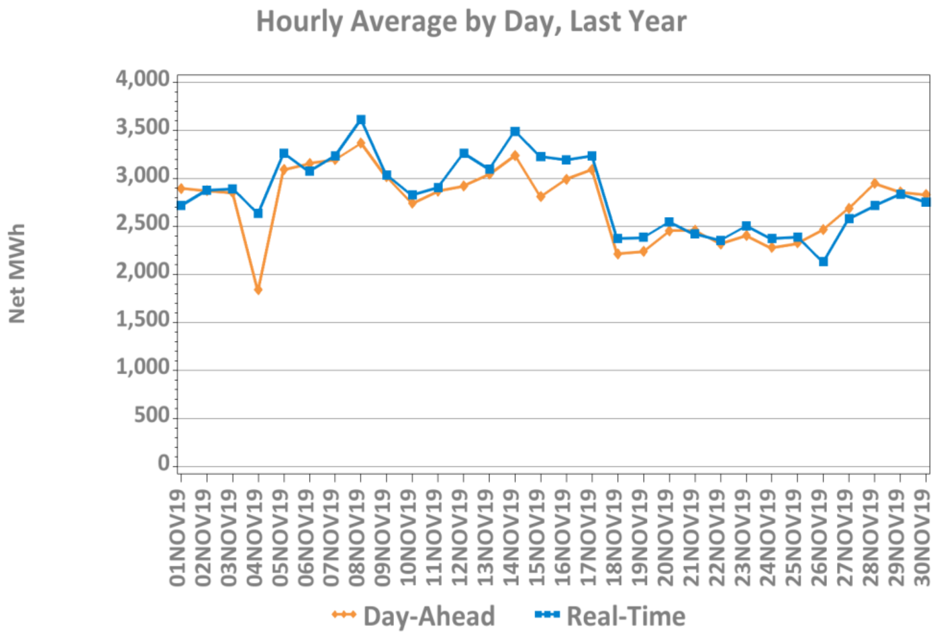
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during November.

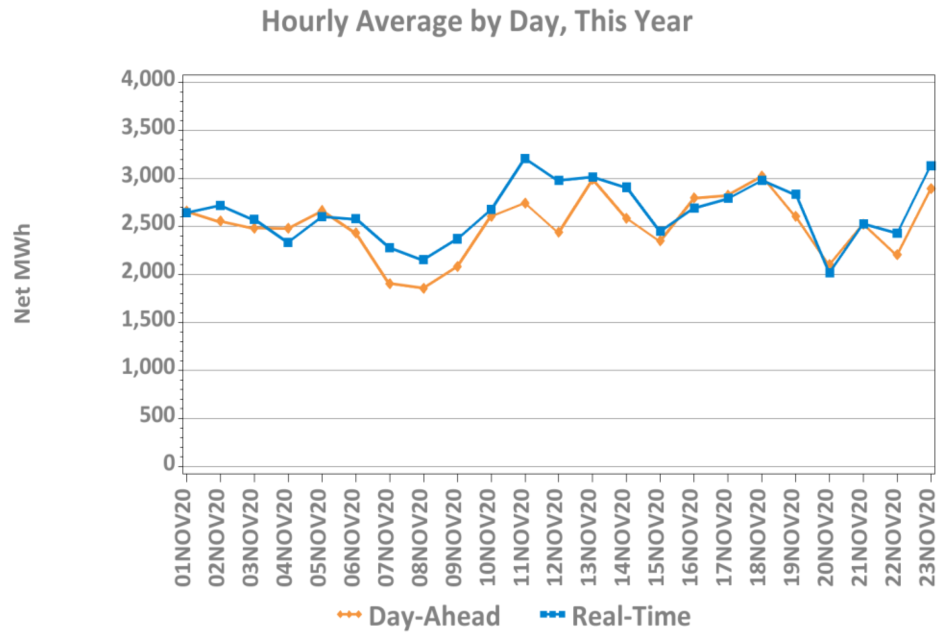
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

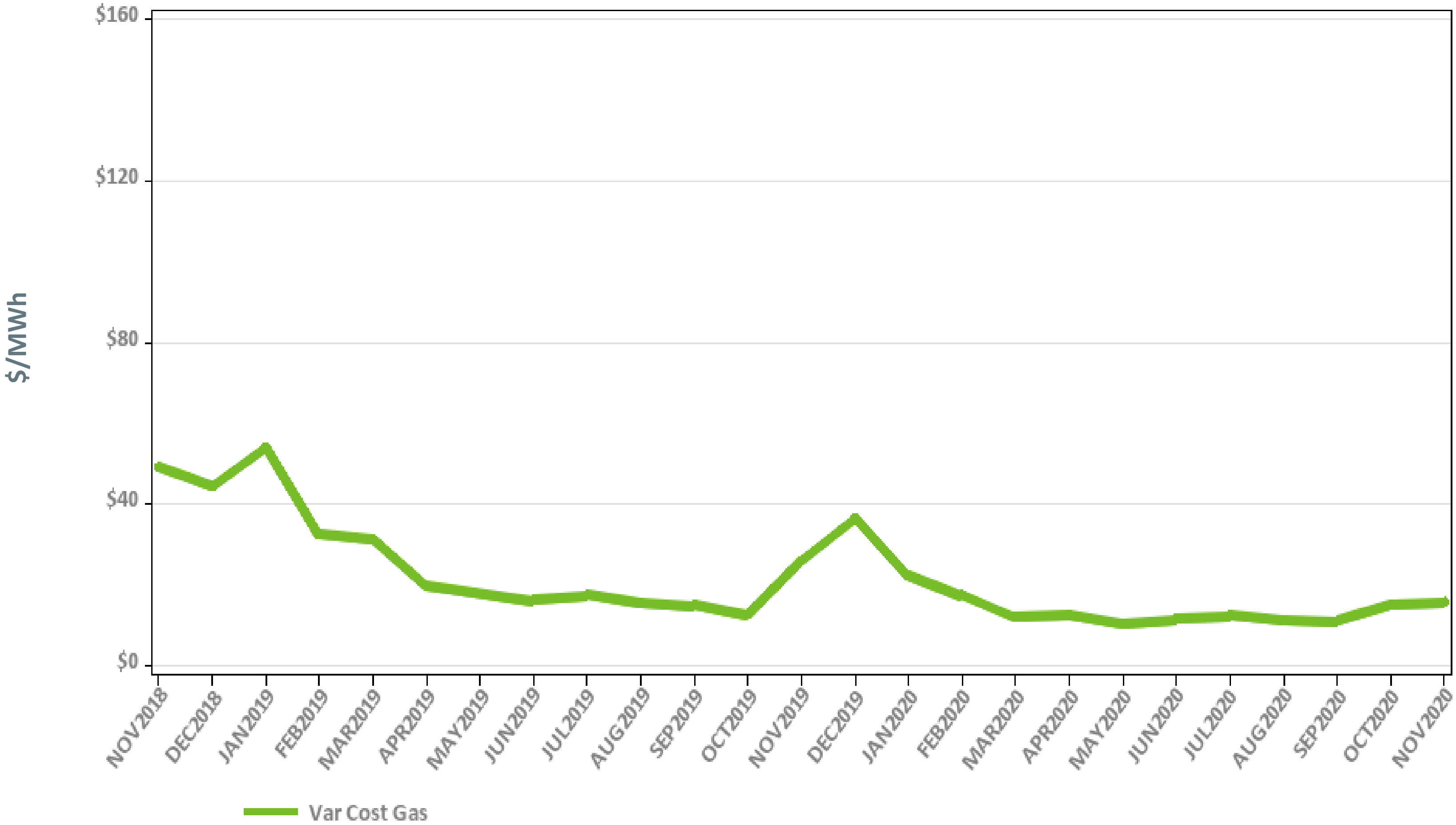
DA vs. RT Net Interchange November 2019 vs. November 2020





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

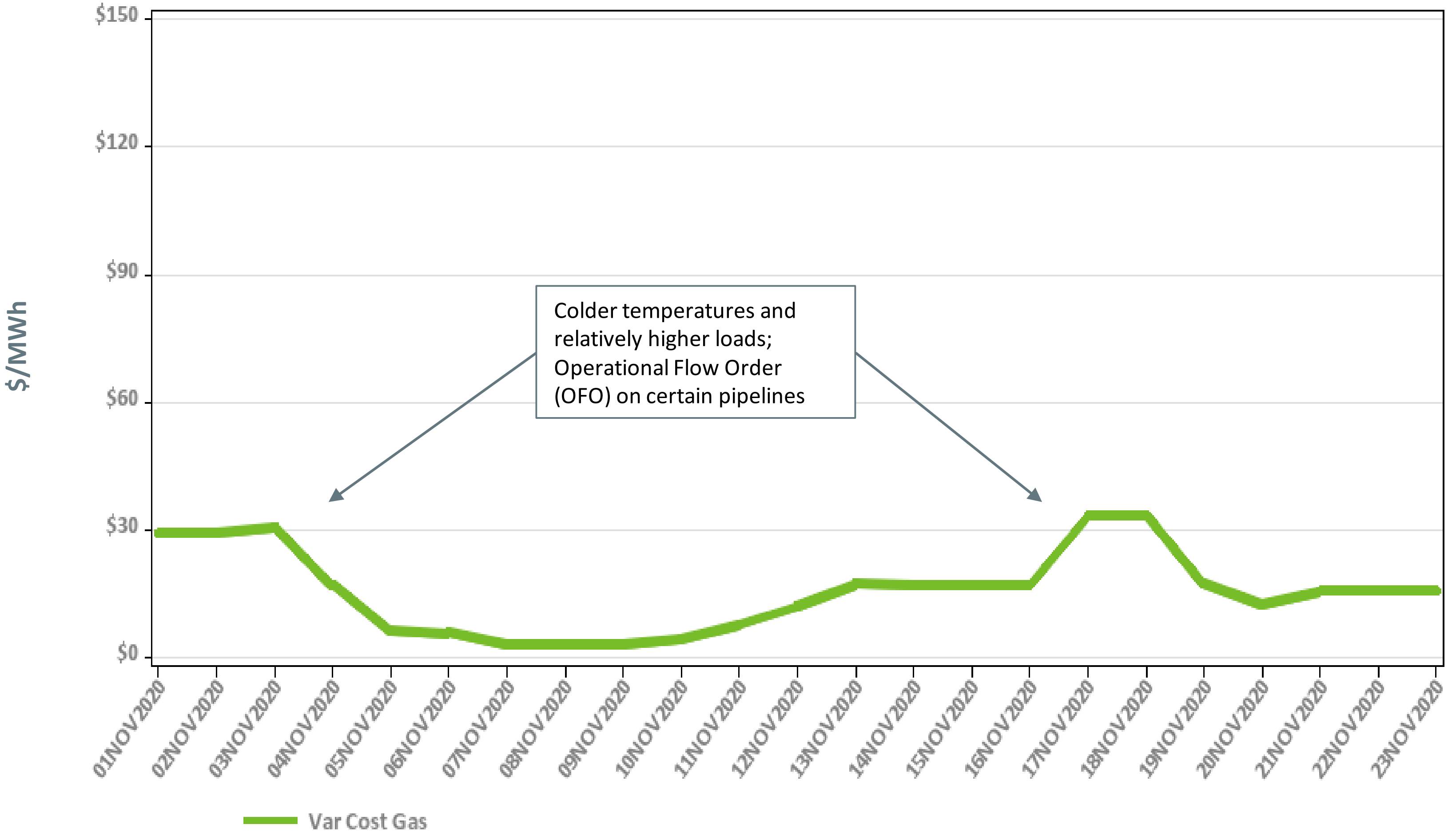


Underlying natural gas data furnished by:

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

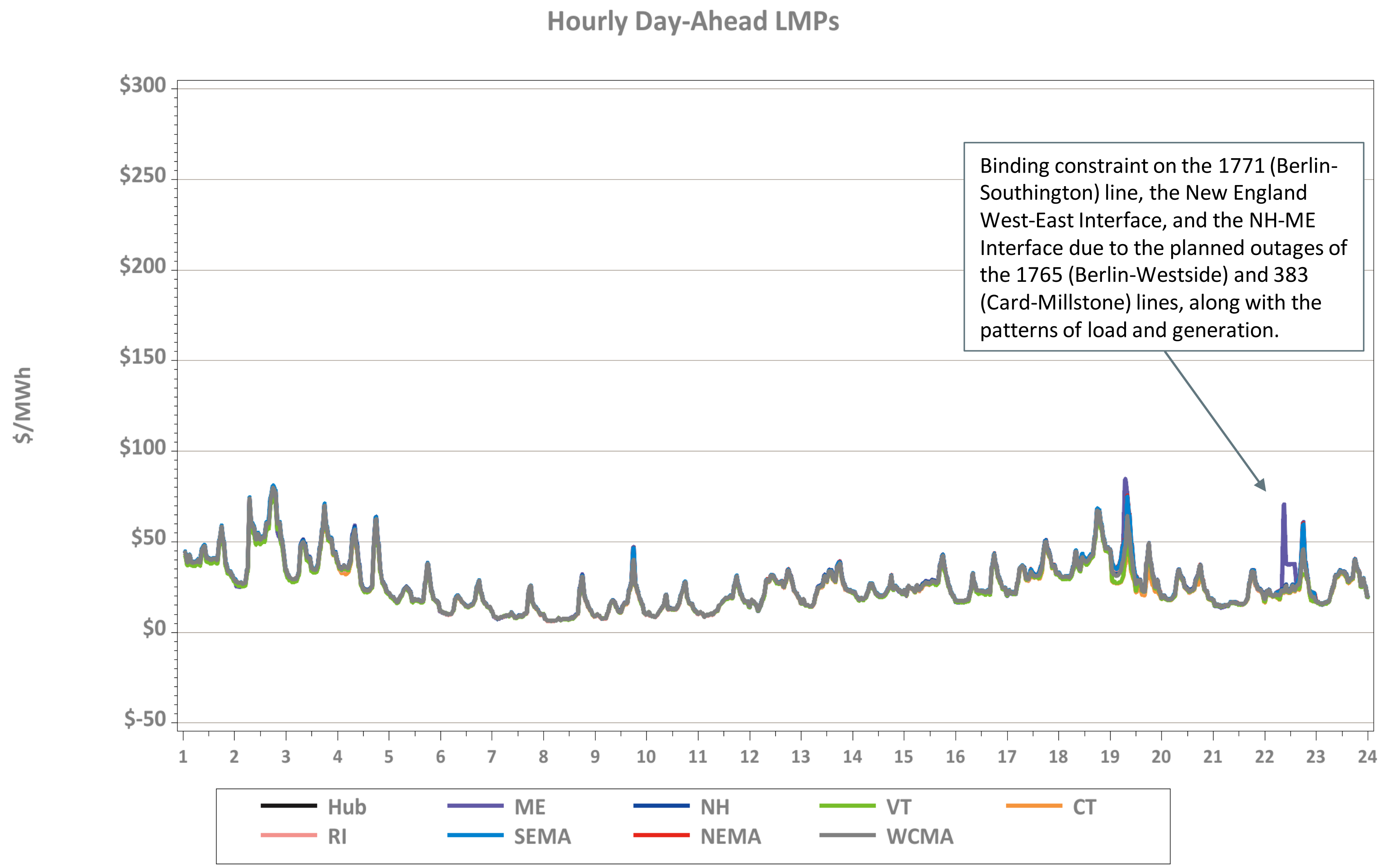


Underlying natural gas data furnished by:

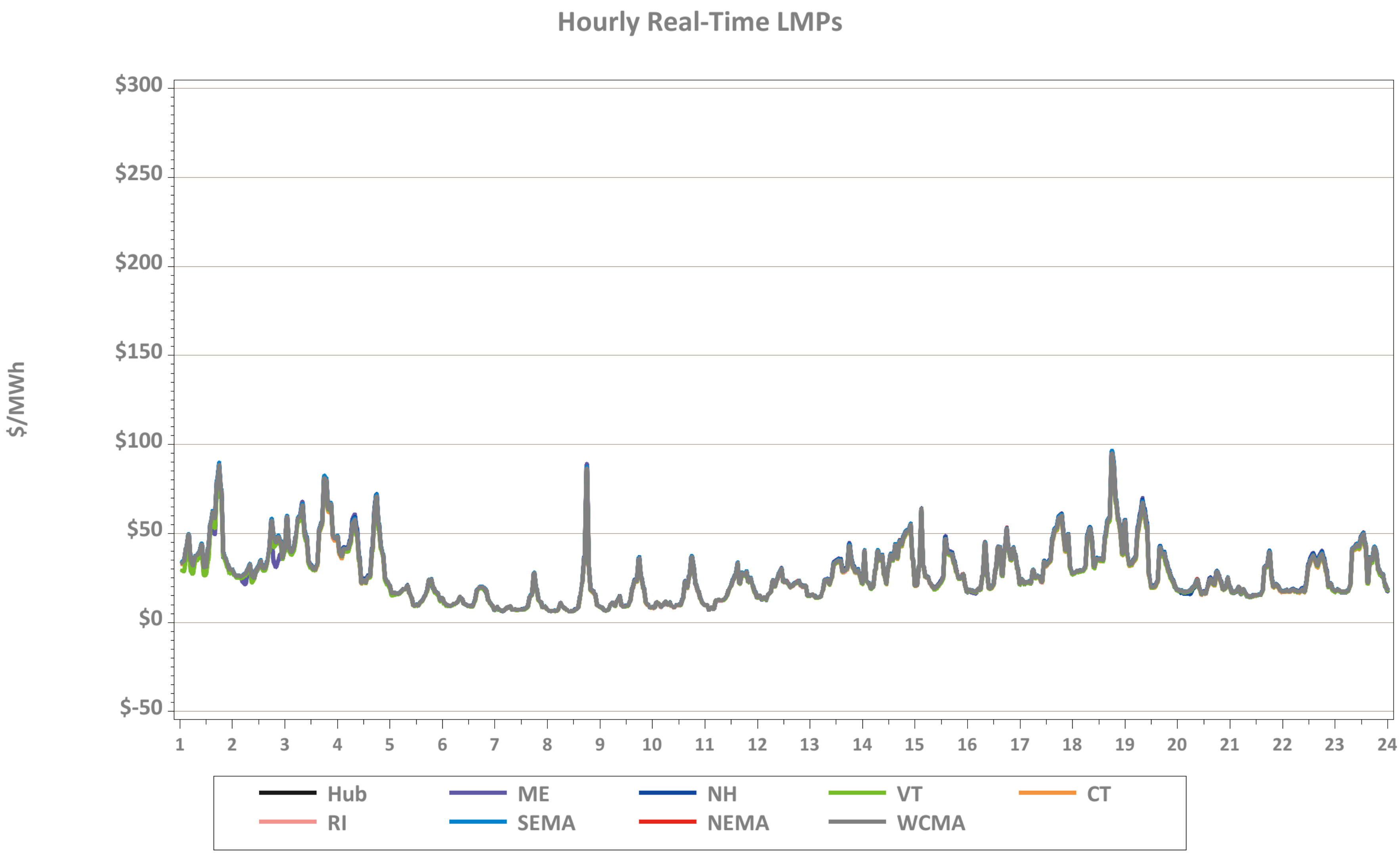
ice Global markets in clear view

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

Hourly DA LMPs, November 1-23, 2020

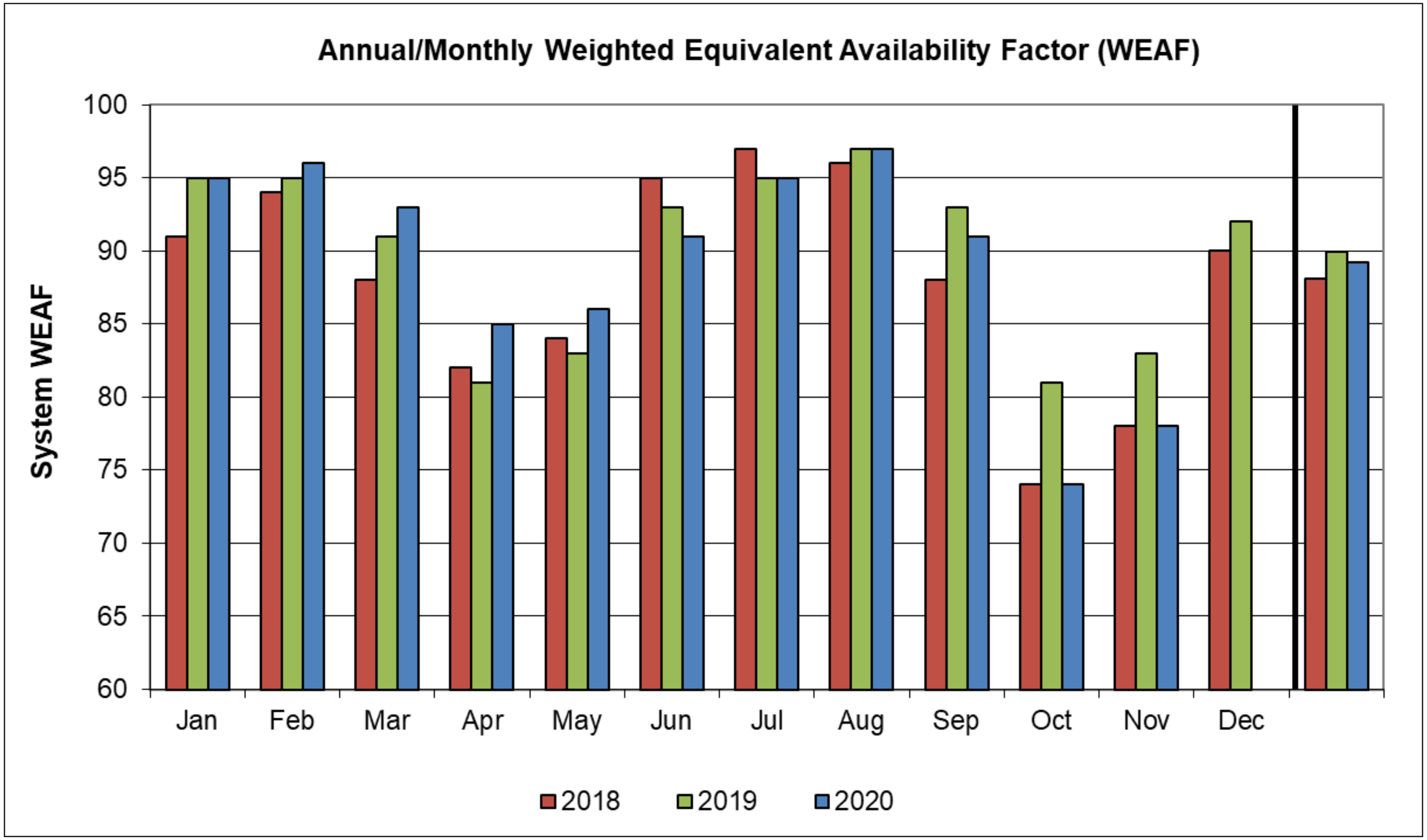


Hourly RT LMPs, November 1-23, 2020



- No Minimum Generation Emergencies were declared during November.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95	96	93	85	86	91	95	97	91	74	78		89
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 11/23/2020

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	79.8	142.0	0.0	221.8
NH	35.1	131.3	0.0	166.4
VT	33.8	135.5	0.0	169.3
CT	103.3	100.8	567.2	771.4
RI	36.4	267.6	0.0	304.0
SEMA	39.5	416.6	0.0	456.1
WCMA	71.2	444.6	26.0	541.7
NEMA	59.1	761.7	0.0	820.7
Total	**458.1**	**2,400.1**	**593.2**	**3,451.3**

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

NEW GENERATION

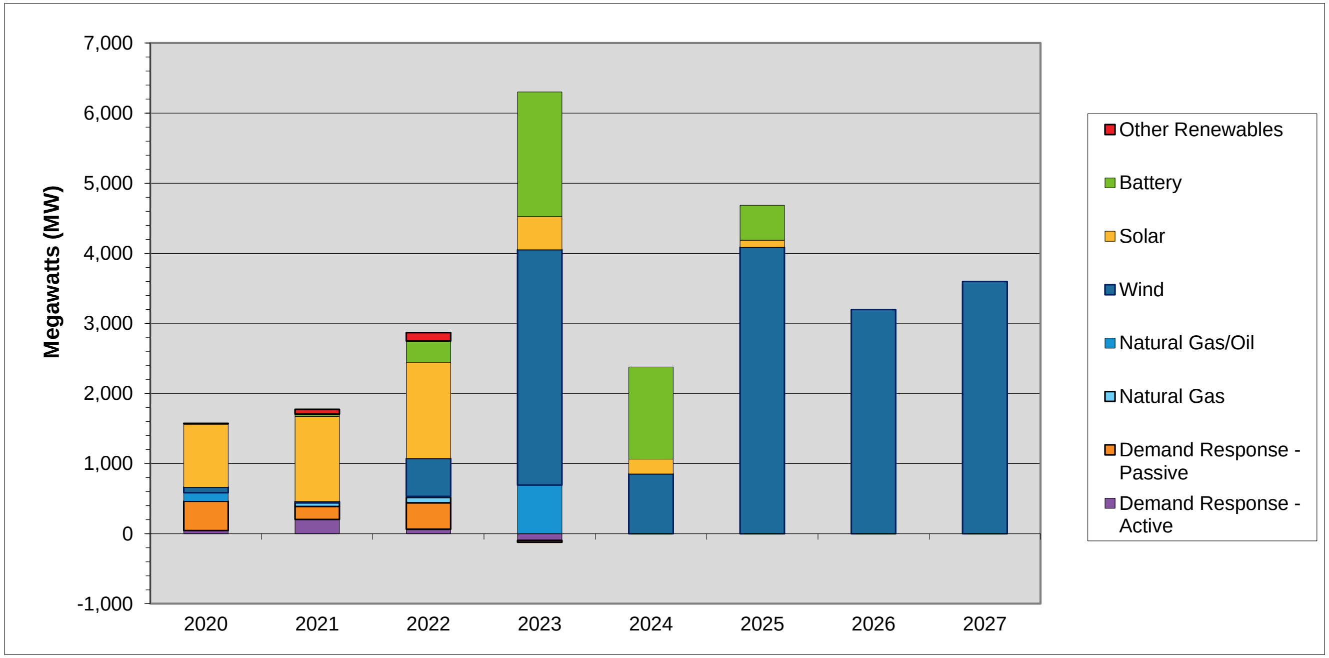
New Generation Update

Based on Queue as of 11/24/20

- Two new projects totaling 202 MW applied for interconnection study since the last update
  - They consist of one new solar and one battery project, with in-service dates in 2023 and 2024
- Two projects went commercial and one was withdrawn, resulting in a net increase in new generation projects of 70 MW
- In total, 265 generation projects are currently being tracked by the ISO, totaling approximately 25,000 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2020	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	8	68	122	0	0	0	0	0	198	0.8
Battery	0	34	304	1,781	1,316	500	0	0	3,935	15.0
Solar[2]	903	1,212	1,374	473	211	100	0	0	4,273	16.3
Wind	78	19	540	3,355	852	4,087	3,200	3,600	15,731	59.9
Natural Gas/Oil[3]	121	0	16	695	0	0	0	0	832	3.2
Natural Gas	0	53	73	0	0	0	0	0	126	0.5
Demand Response - Passive	422	184	380	-28	0	0	0	0	958	3.6
Demand Response - Active	42	204	62	-94	0	0	0	0	214	0.8
Totals	1,575	1,774	2,871	6,182	2,379	4,687	3,200	3,600	26,268	100.0

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

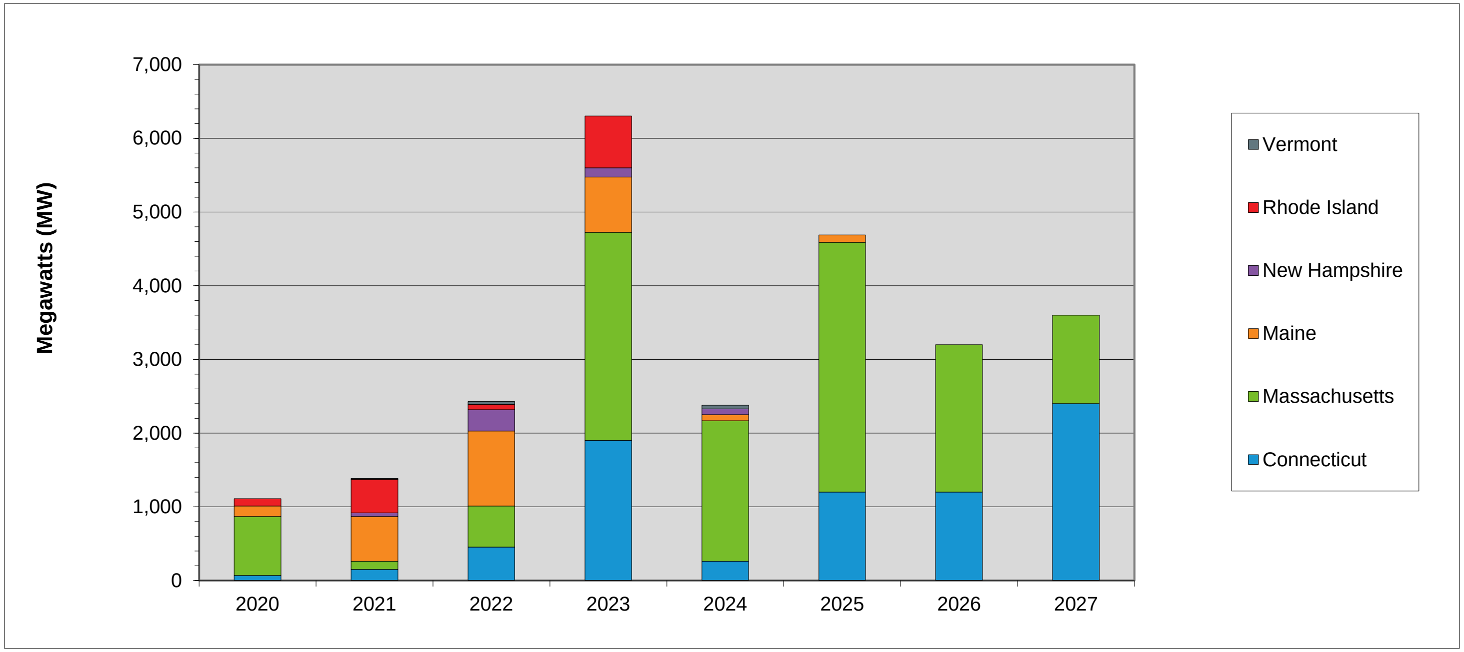
[2] This category includes both solar-only, and co-located solar and battery projects

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

- 2020 values include the 166 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	2027	Total MW	% of Total[1]
Vermont	0	15	40	0	50	0	0	0	105	0.4
Rhode Island	100	454	73	704	0	0	0	0	1,331	5.3
New Hampshire	0	50	289	126	81	0	0	0	546	2.2
Maine	141	607	1,015	750	81	100	0	0	2,694	10.7
Massachusetts	802	110	560	2,824	1,907	3,387	2,000	1,200	12,790	51.0
Connecticut	67	150	452	1,900	260	1,200	1,200	2,400	7,629	30.4
Totals	**1,110**	**1,386**	**2,429**	**6,304**	**2,379**	**4,687**	**3,200**	**3,600**	**25,095**	**100.0**

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

- 2020 values include the 166 MW of generation that has gone commercial in 2020

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0
Battery Storage	22	3,935	0	0	22	3,935
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	1	66	2	33
Natural Gas	7	126	0	0	7	126
Natural Gas/Oil	5	787	1	14	4	773
Nuclear	1	37	0	0	1	37
Solar	197	4,157	10	184	187	3,973
Wind	25	15,726	2	88	23	15,638
Total	265	24,929	16	370	249	24,559

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	132	2	18	6	114
Intermediate	9	822	1	14	8	808
Peaker	223	8,249	11	250	212	7,999
Wind Turbine	25	15,726	2	88	23	15,638
Total	265	24,929	16	370	249	24,559

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0	0	0	0	0
Battery Storage	22	3,935	0	0	0	0	22	3,935	0	0
Fuel Cell	4	54	4	54	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	126	0	0	6	120	1	6	0	0
Natural Gas/Oil	5	787	0	0	3	702	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	197	4,157	0	0	0	0	197	4,157	0	0
Wind	25	15,726	0	0	0	0	0	0	25	15,726
Total	265	24,929	8	132	9	822	223	8,249	25	15,726

- 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**

* 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				ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445	659.137	34.692	603.776	-55.361		
	Passive Demand	2,975.36	3,045.073	69.713	31,23.232	78.159		
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**37,27.008**	**22.798**		
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159		
	Intermittent	880.317	806.609	-73.708	660.932	-145.677		
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**		
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**		
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**		
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,320**	**-230**		

* 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	683.116	-2.438				
	Passive Demand	3,354.69	3,407.507	52.817				
Demand Total		**4,040.244**	**4,090.623**	**50.38**				
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157				
	Intermittent	1,024.792	901.672	-123.12				
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**				
Import Total		**1,187.69**	**1,292.41**	**104.72**				
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**				
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**				

* 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**						

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

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

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

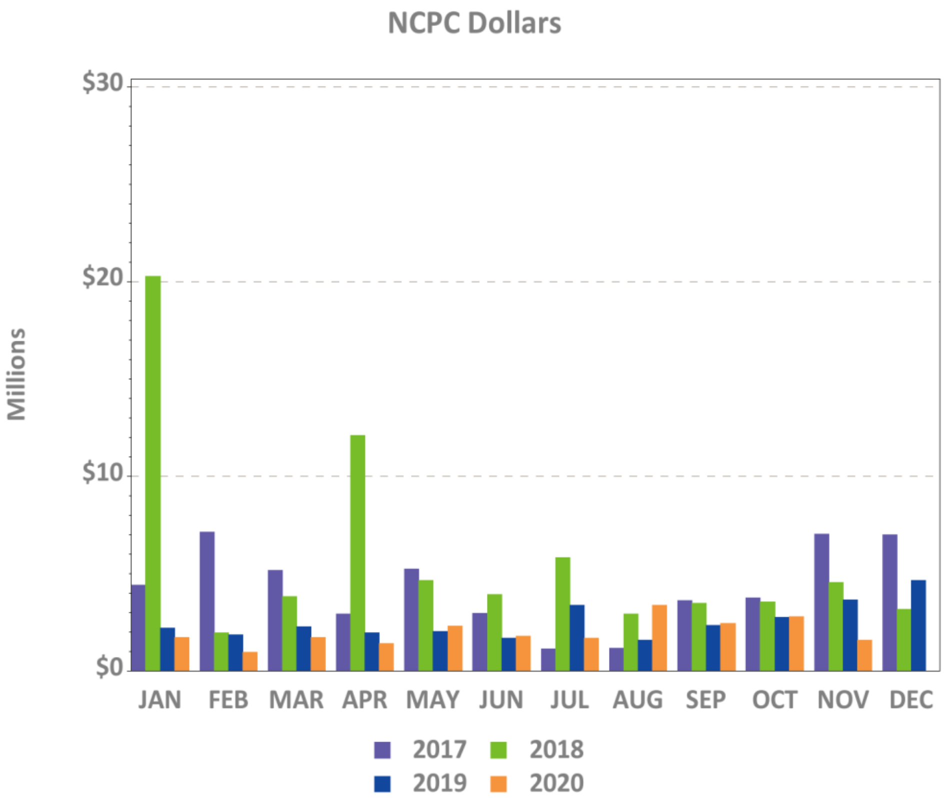
Definitions

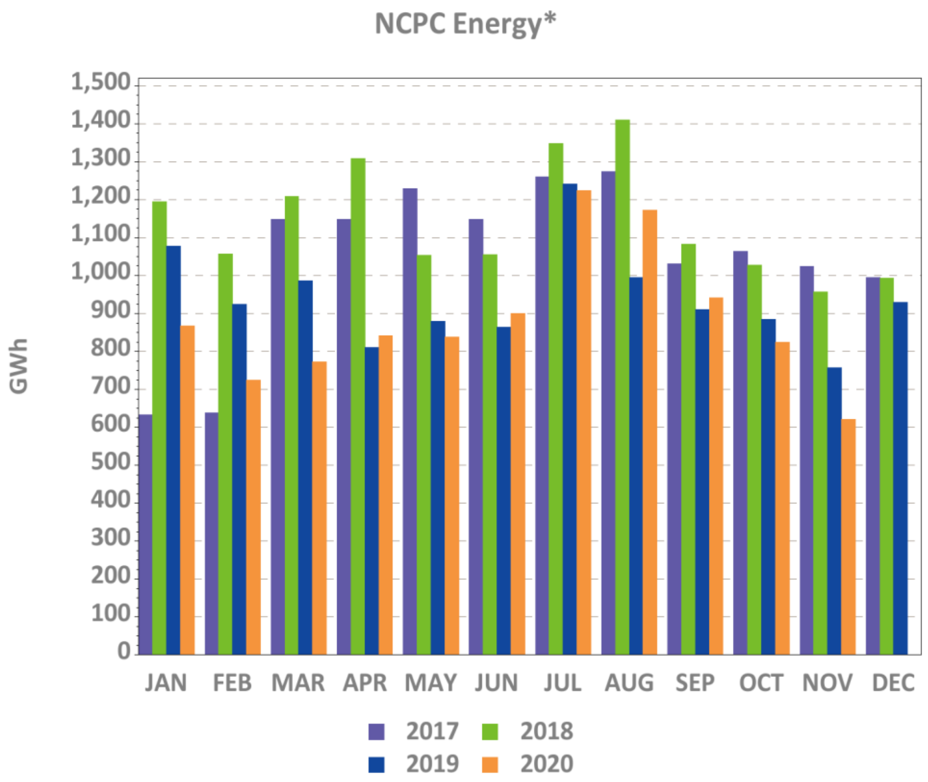
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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).

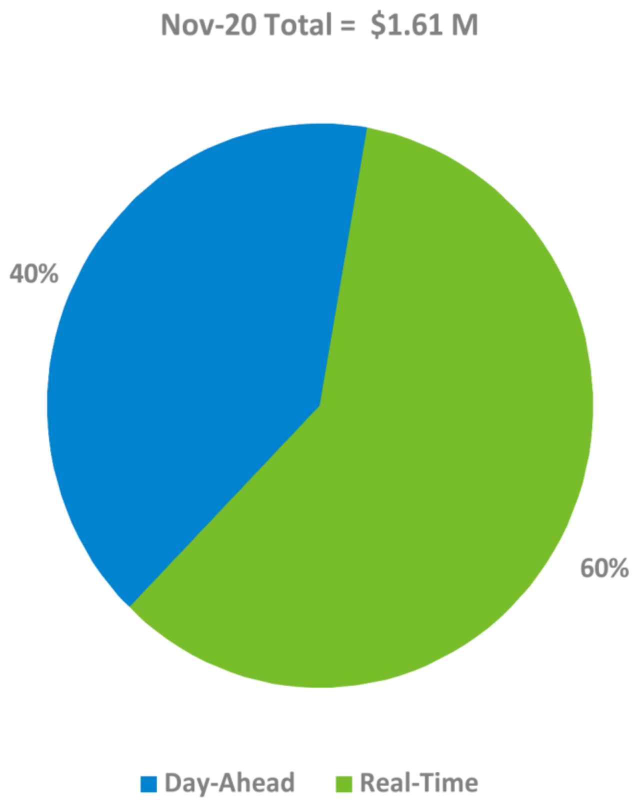
Year-Over-Year Total NCPC Dollars and Energy

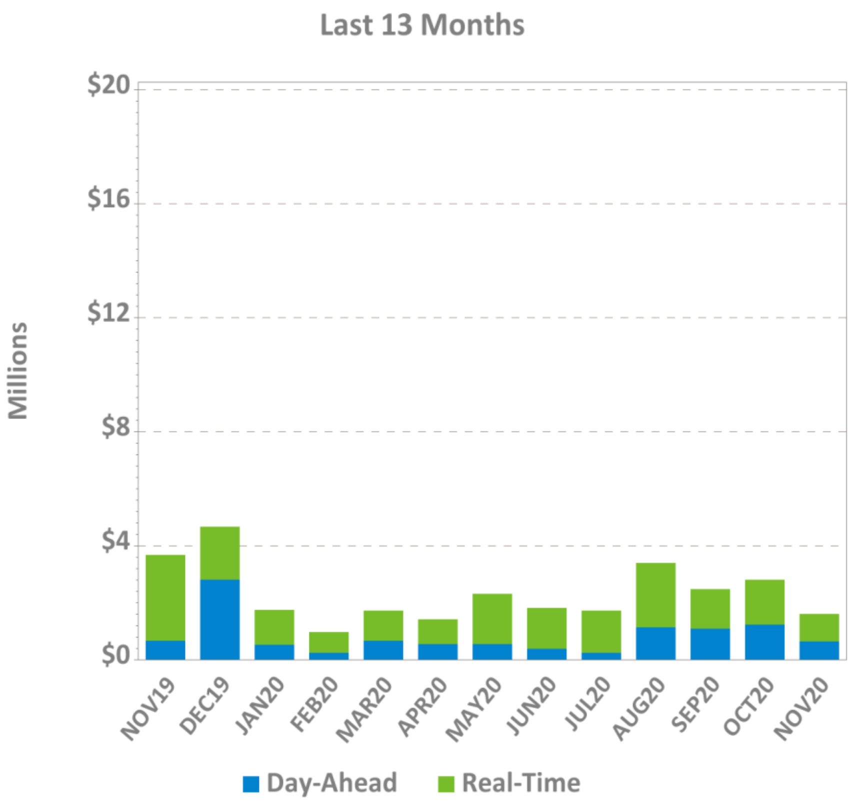




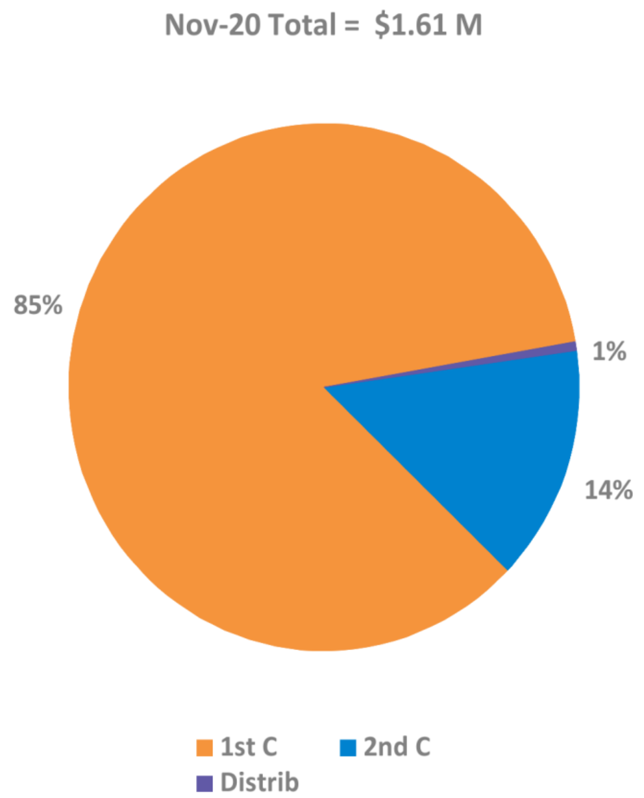
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

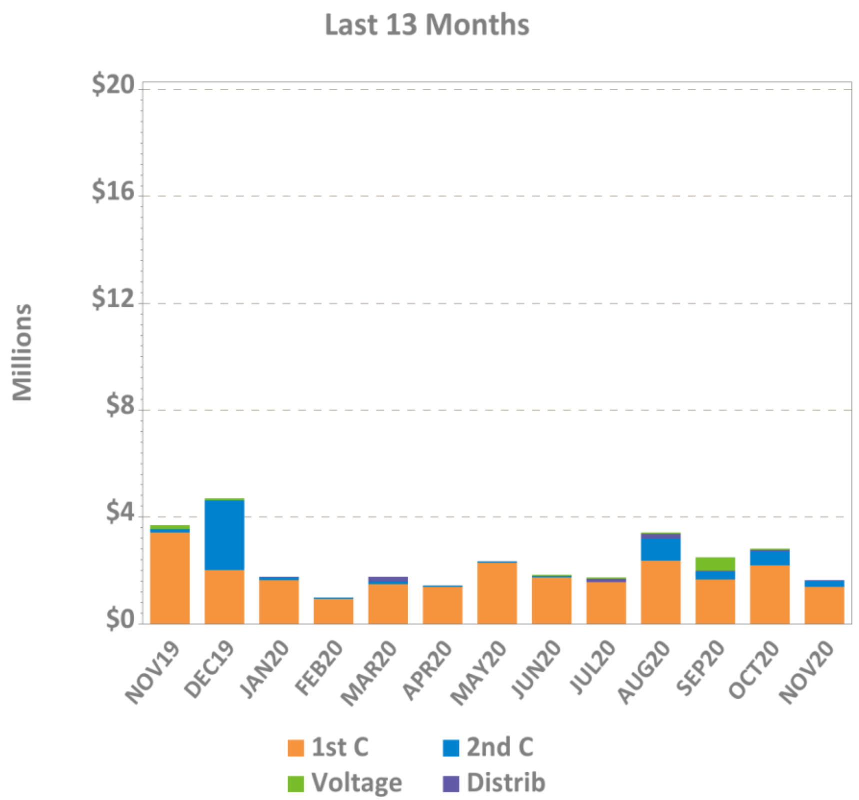
DA and RT NCPC Charges





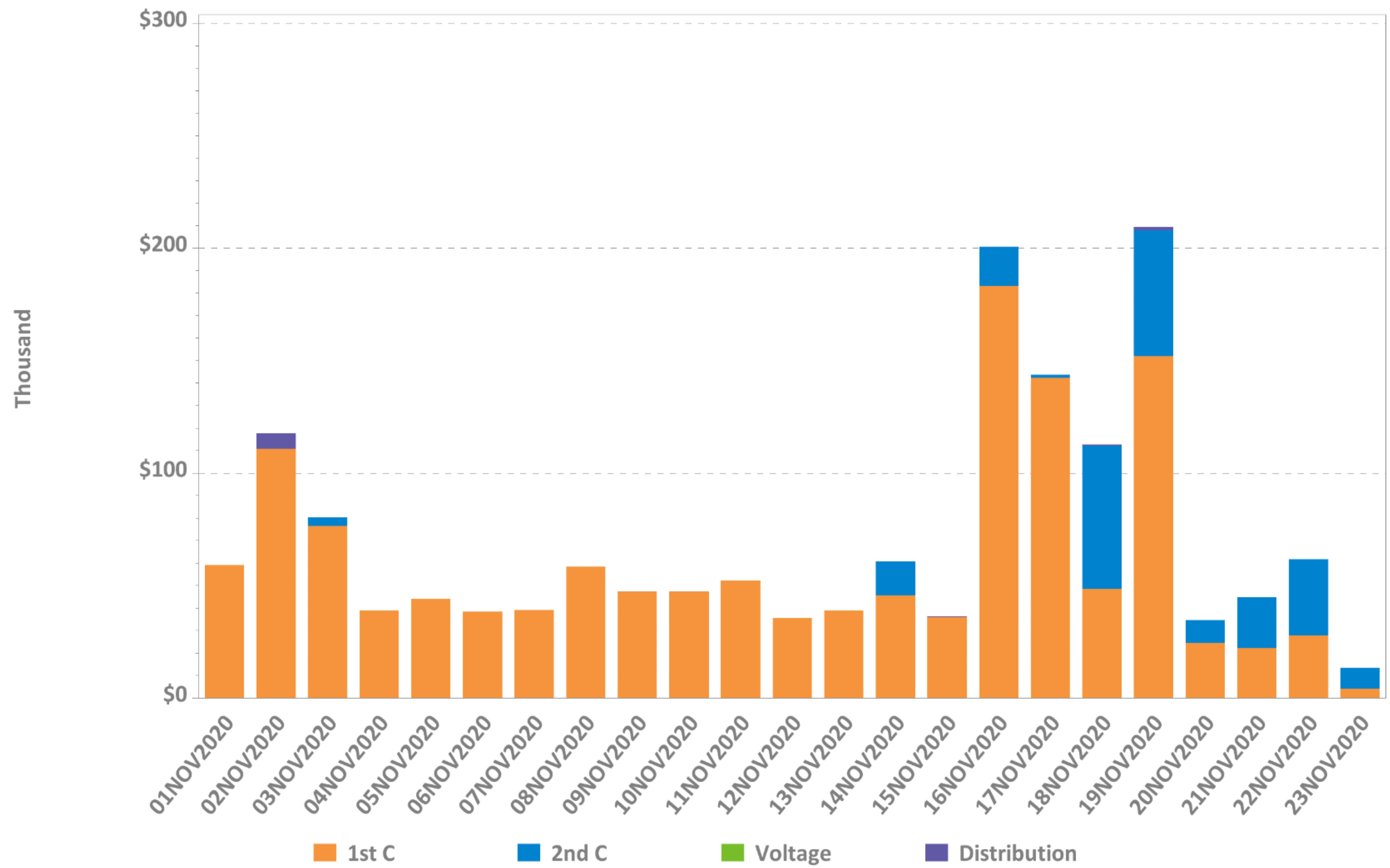
NCPC Charges by Type



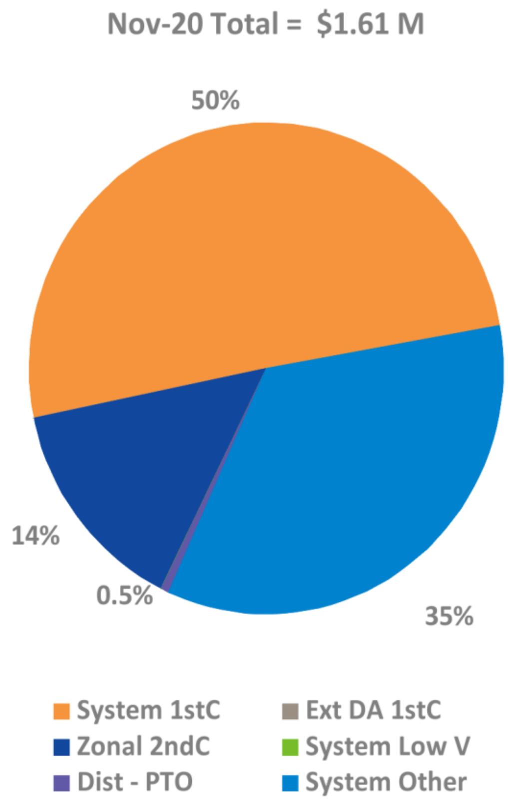


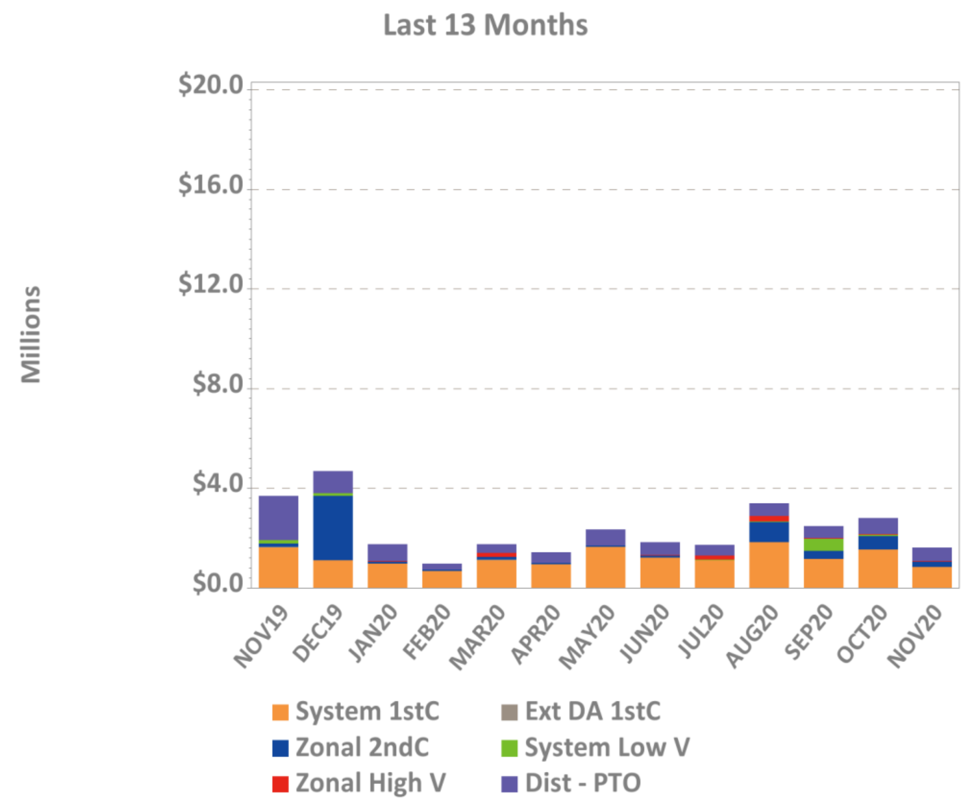
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



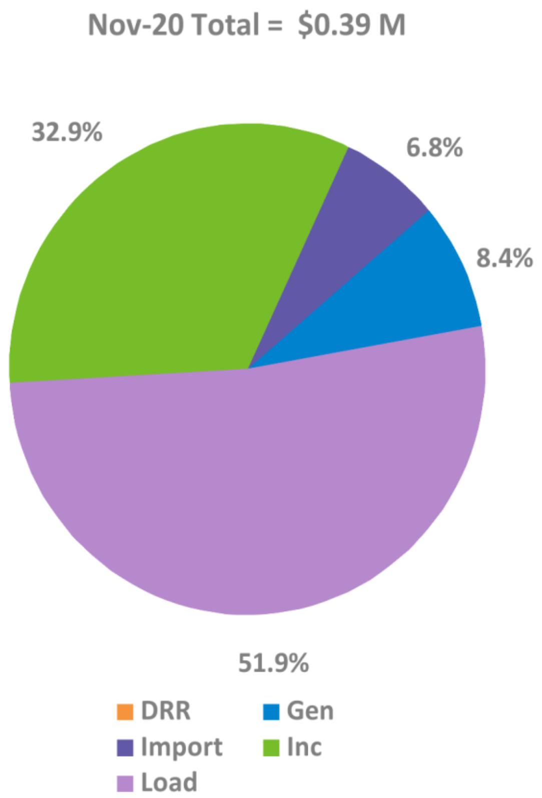
NCPC Charges by Allocation

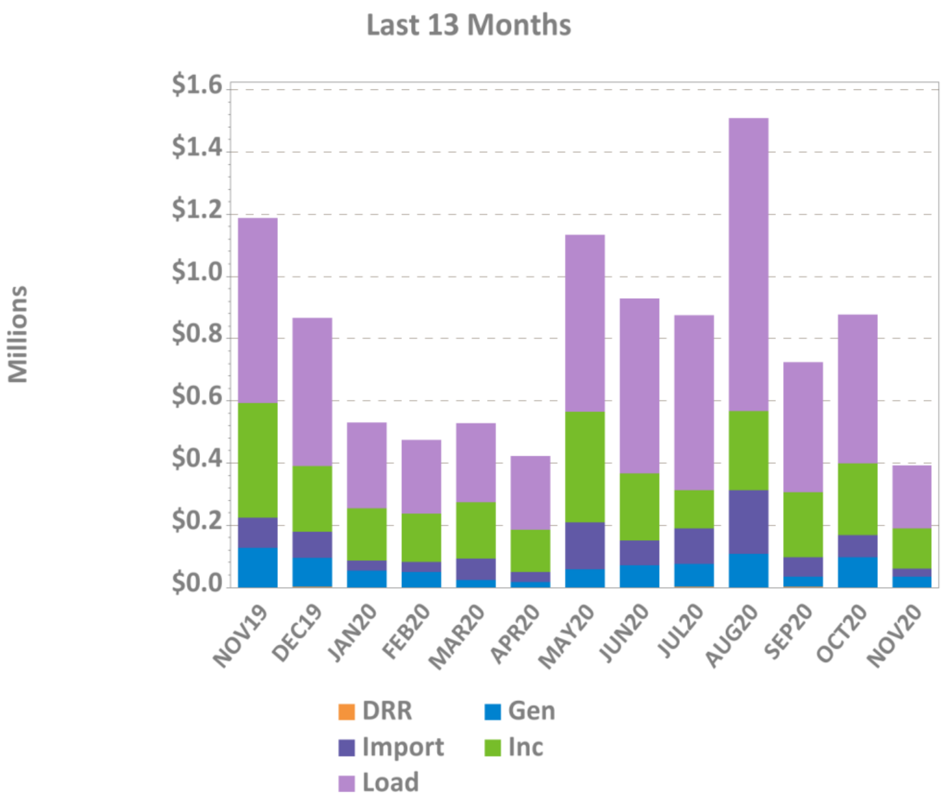




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

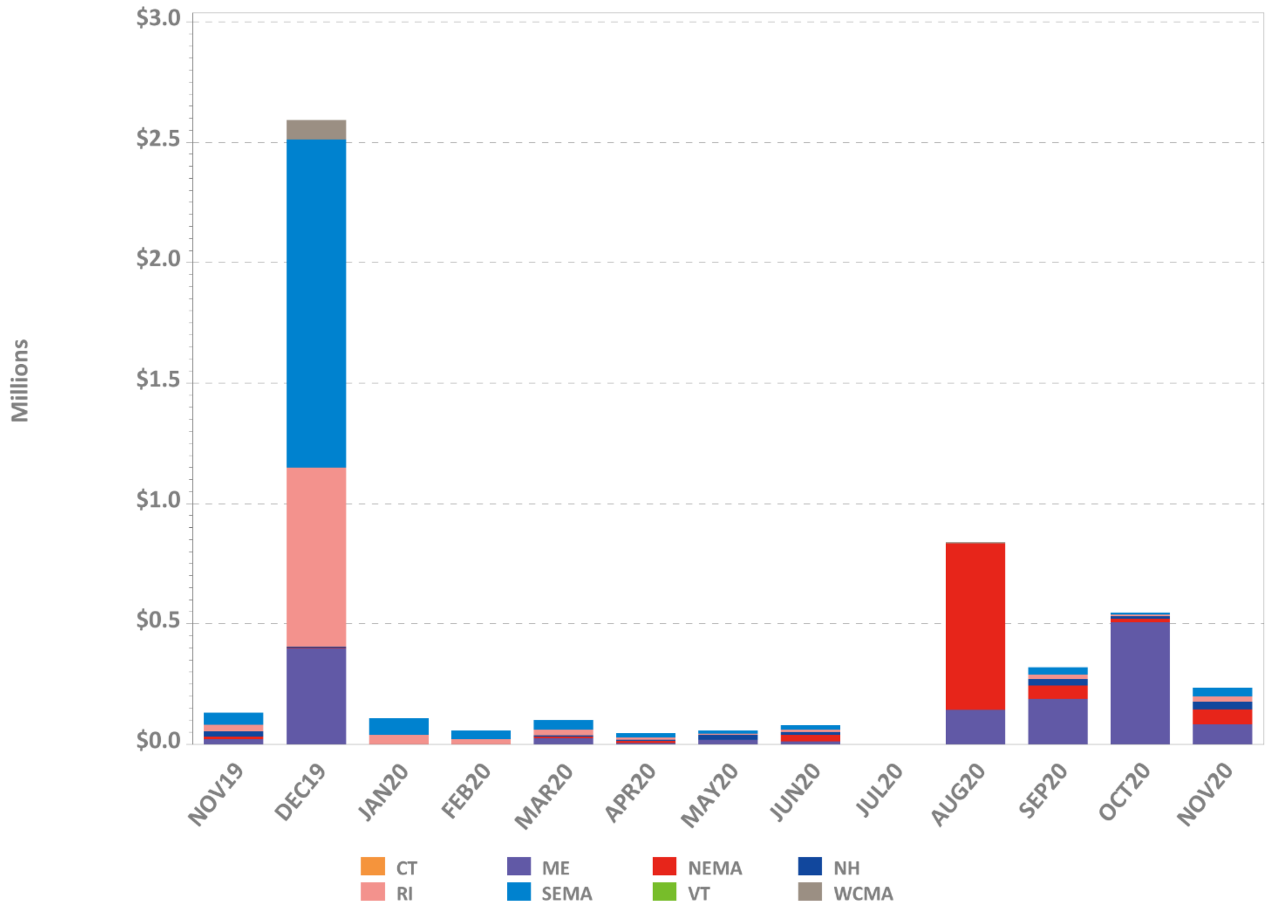
RT First Contingency Charges by Deviation Type





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

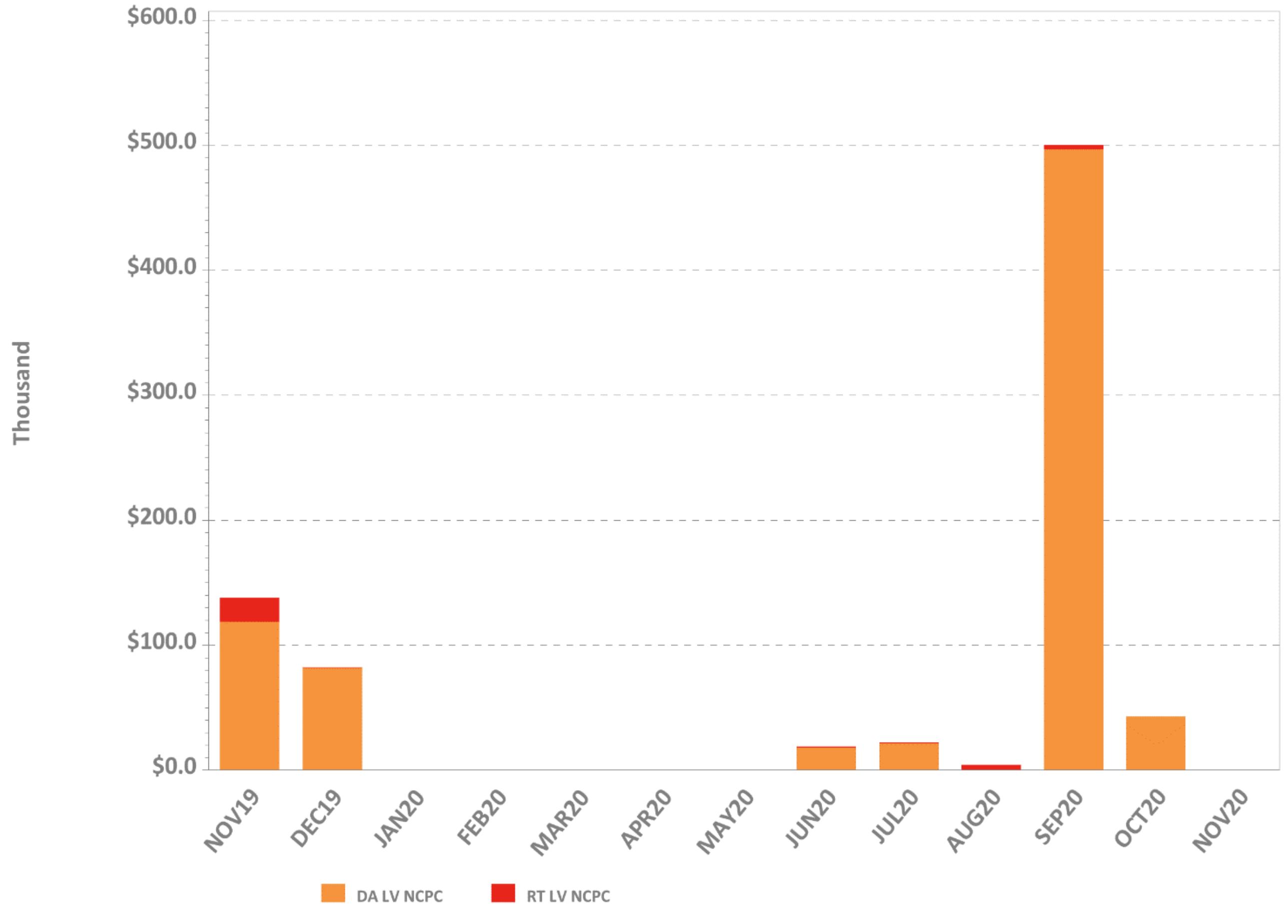
LSCPR Charges by Reliability Region



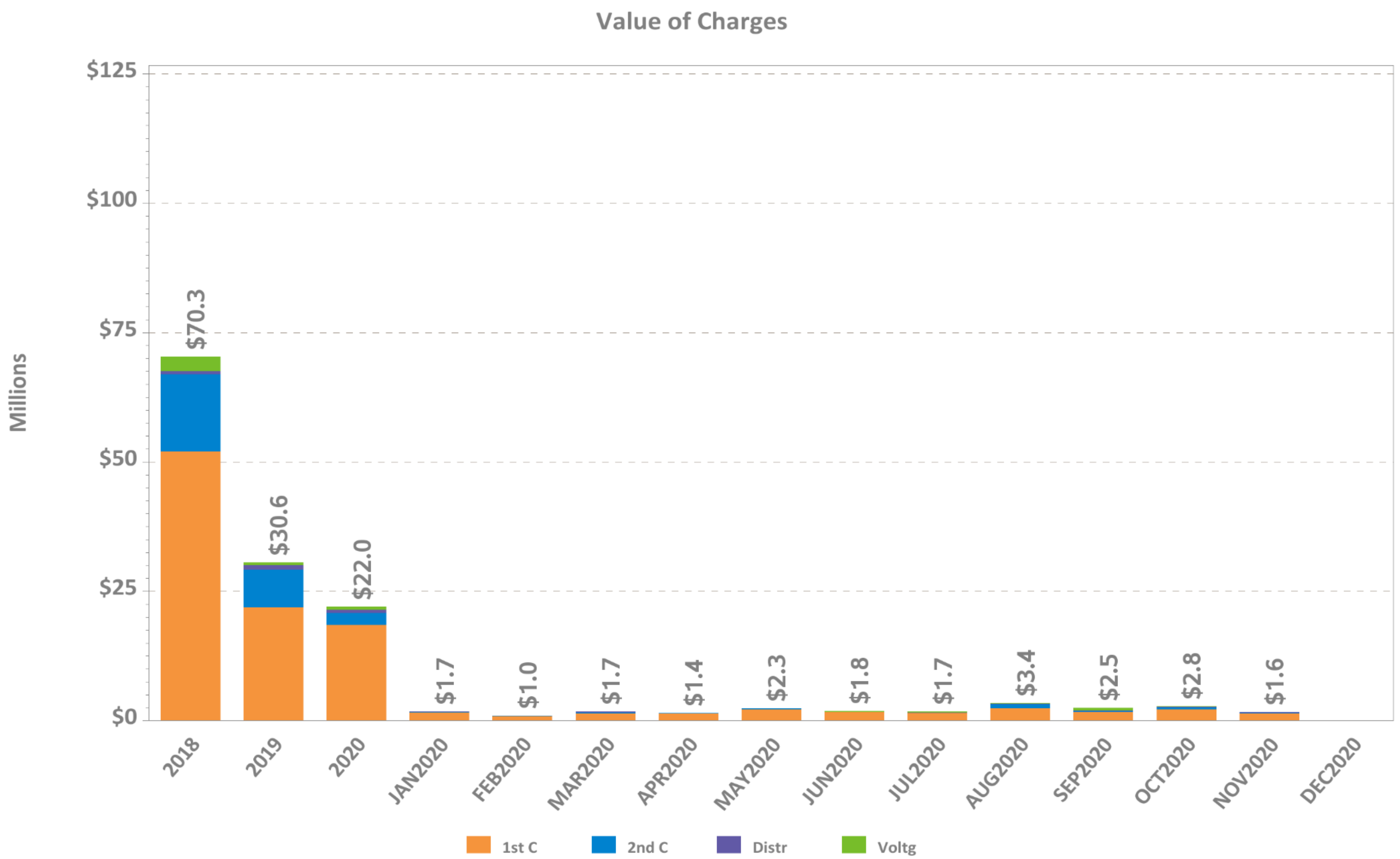
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

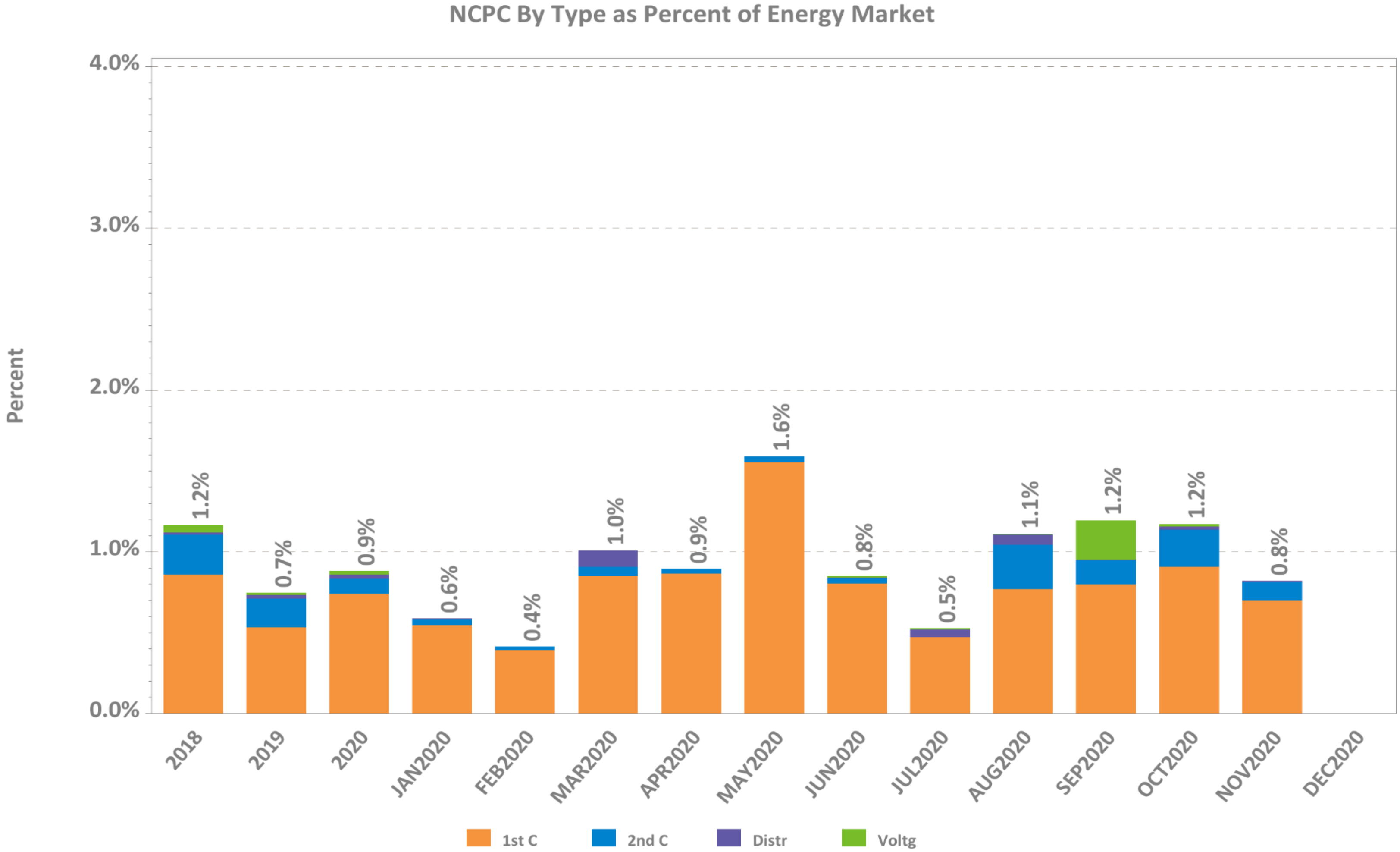
NCPC Charges for Voltage Support and High Voltage Control



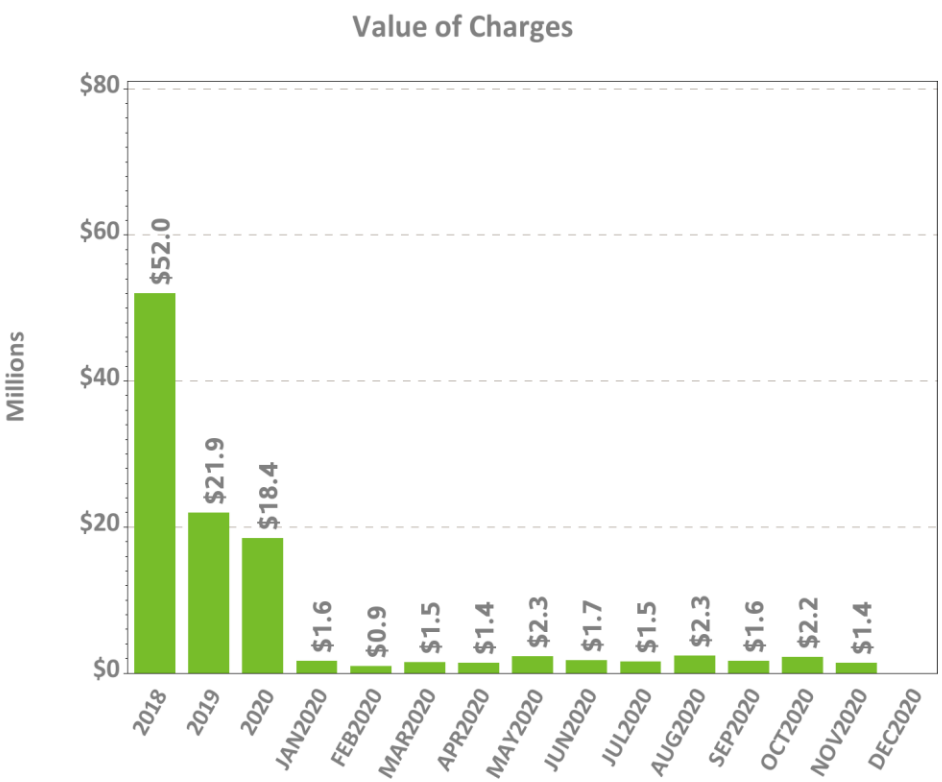
NCPC Charges by Type

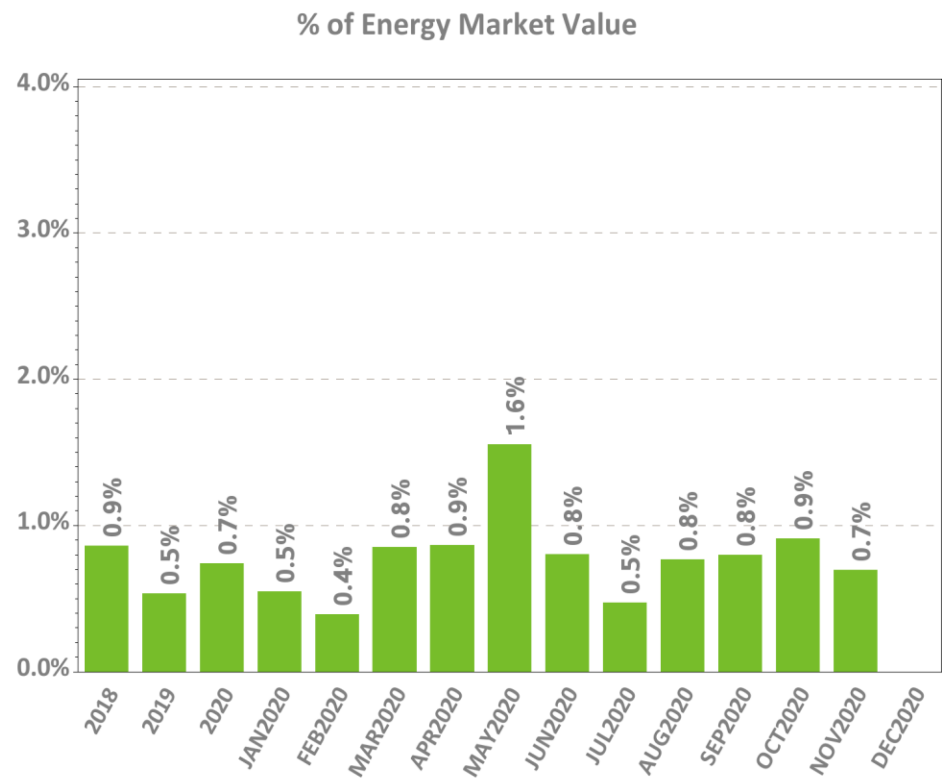


NCPC Charges as Percent of Energy Market



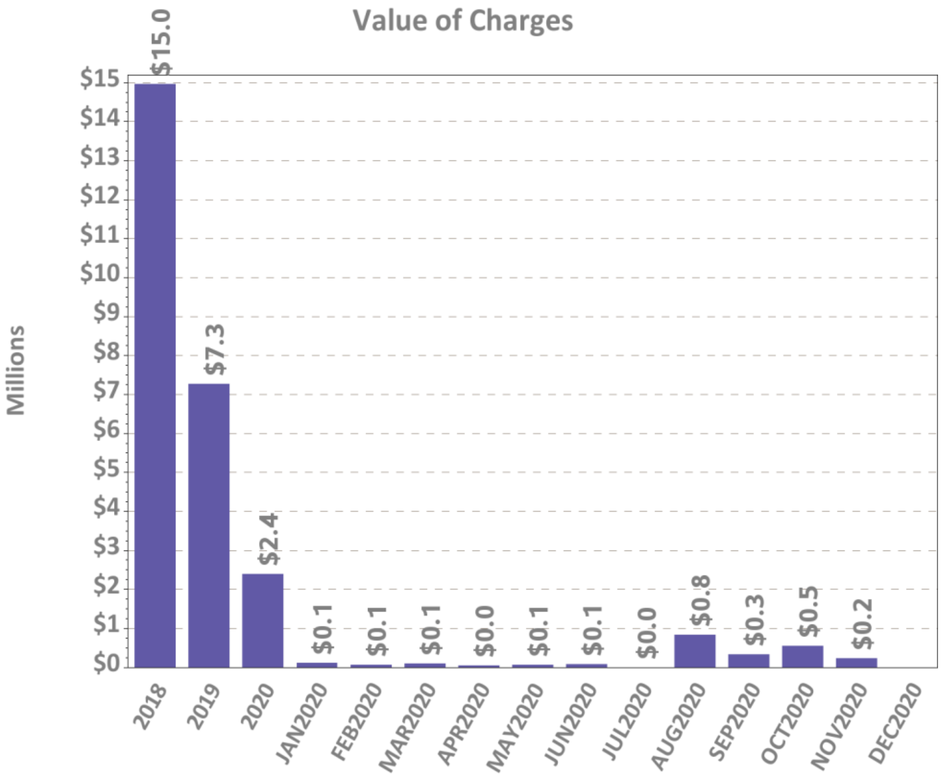
First Contingency NCPC Charges

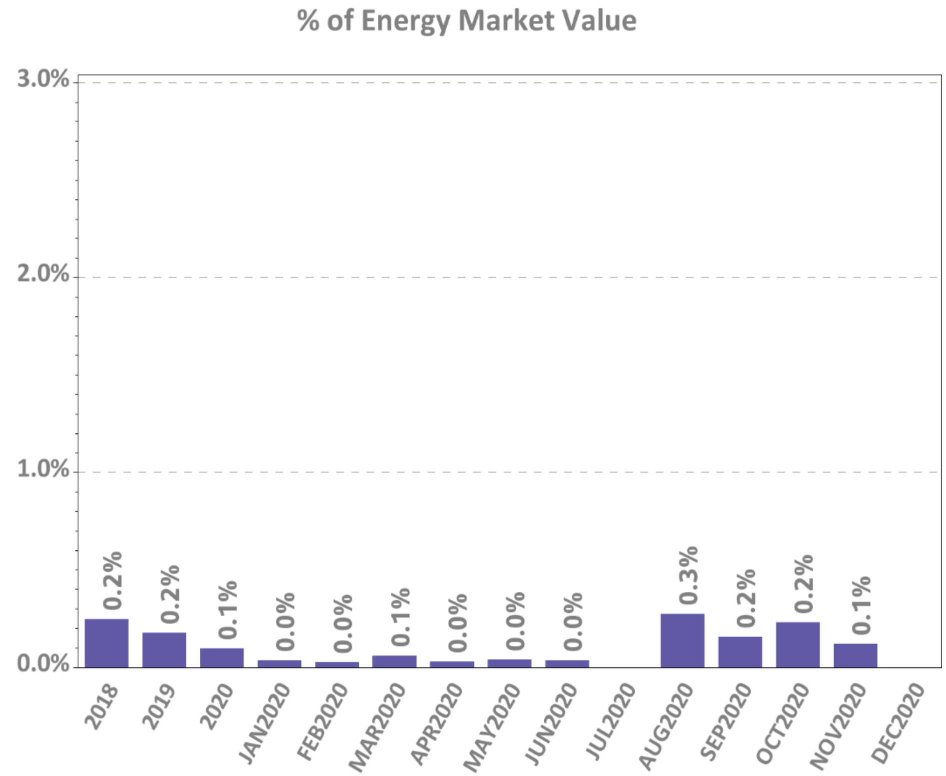




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

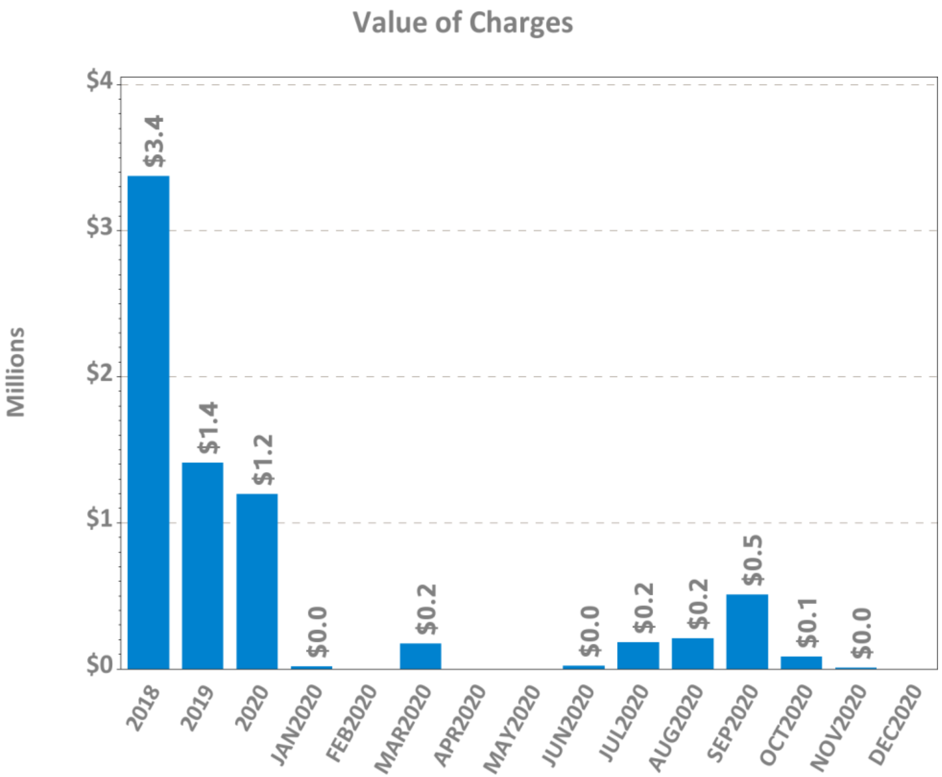
Second Contingency NCPC Charges

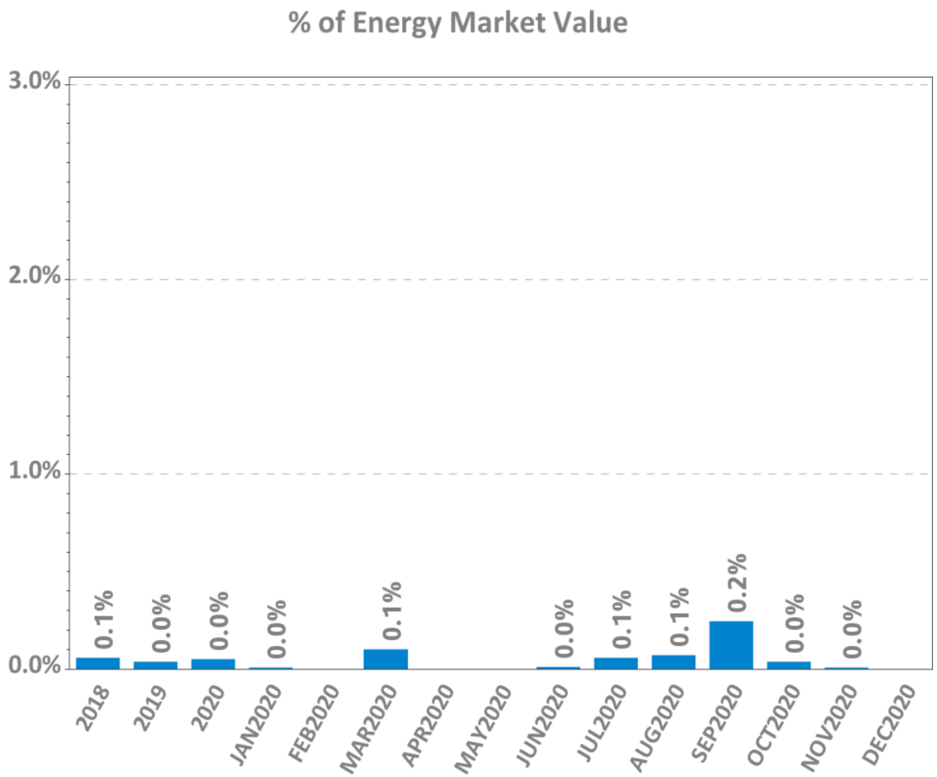




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

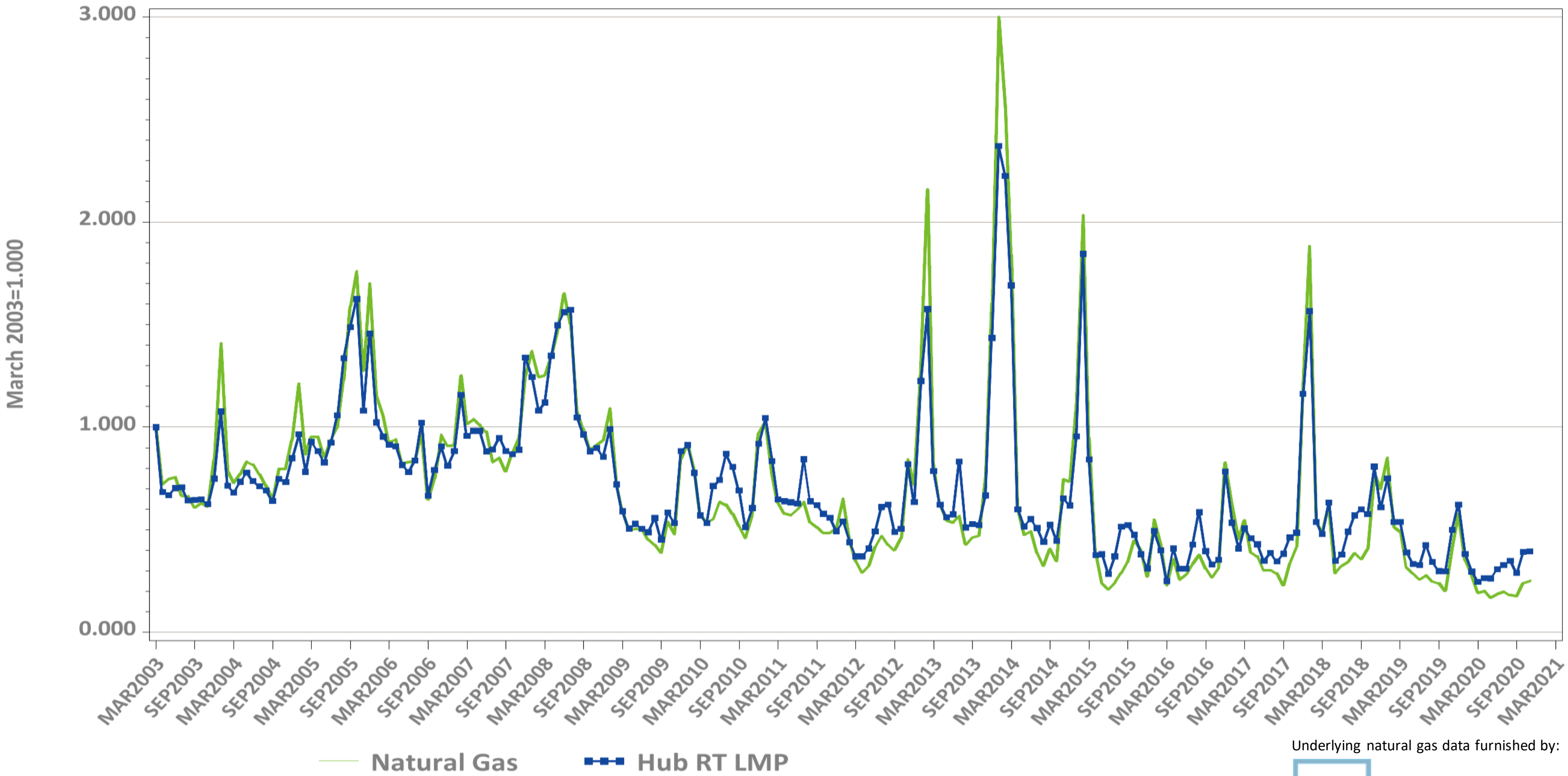
DA vs. RT LMPs ($/MWh)

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%

November-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$32.52	$31.48	$31.62	$32.35	$31.69	$32.16	$32.57	$32.31	$32.29
Real-Time	$34.52	$33.15	$33.16	$34.45	$33.59	$34.08	$34.51	$34.28	$34.27
RT Delta %	6.1%	5.3%	4.9%	6.5%	6.0%	6.0%	6.0%	6.1%	6.1%
November-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$26.69	$25.27	$26.61	$26.54	$25.37	$26.18	$26.68	$26.26	$26.27
Real-Time	$27.38	$26.50	$27.00	$27.31	$26.37	$26.85	$27.35	$27.08	$27.10
RT Delta %	2.6%	4.9%	1.5%	2.9%	3.9%	2.6%	2.5%	3.1%	3.1%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-17.9%	-19.7%	-15.9%	-17.9%	-19.9%	-18.6%	-18.1%	-18.7%	-18.6%
Yr over Yr RT	-20.7%	-20.1%	-18.6%	-20.7%	-21.5%	-21.2%	-20.7%	-21.0%	-20.9%

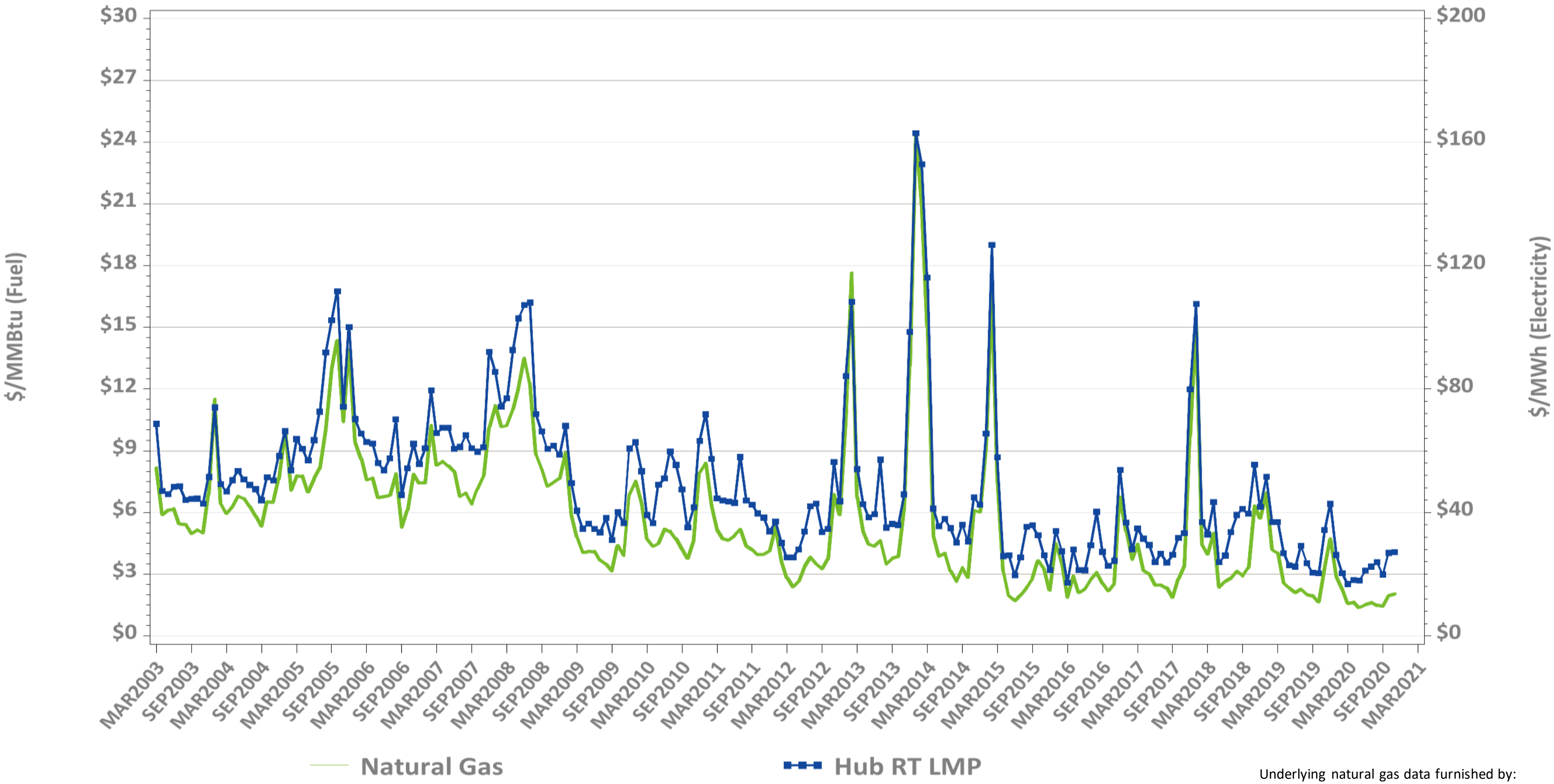
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

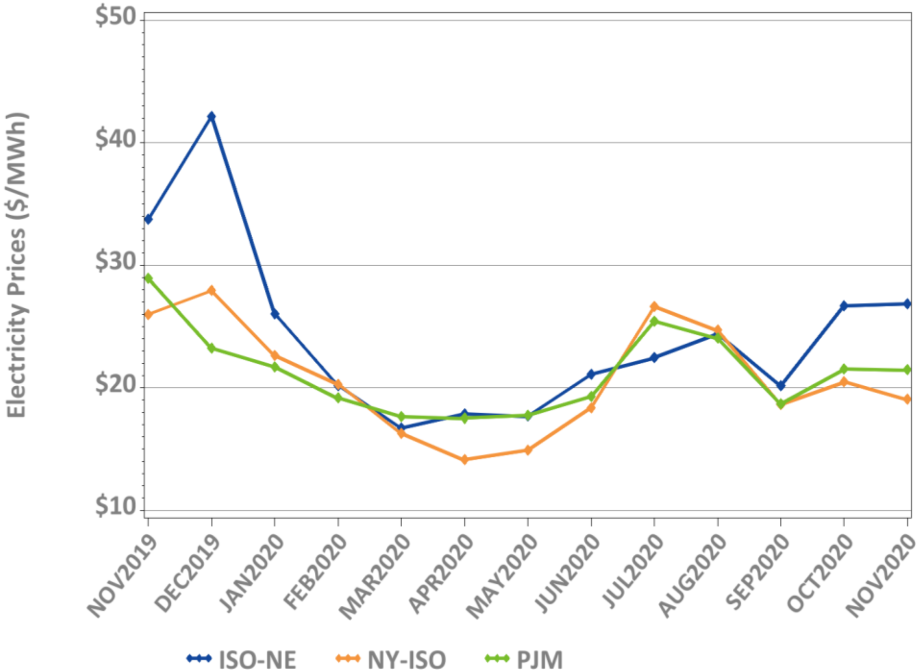
Monthly Average Fuel Price and RT Hub LMP



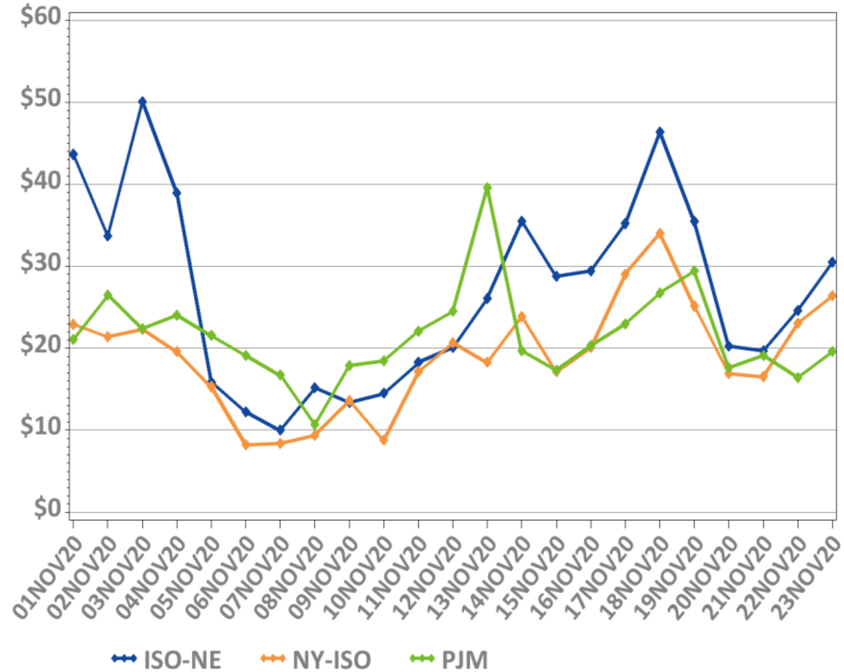
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

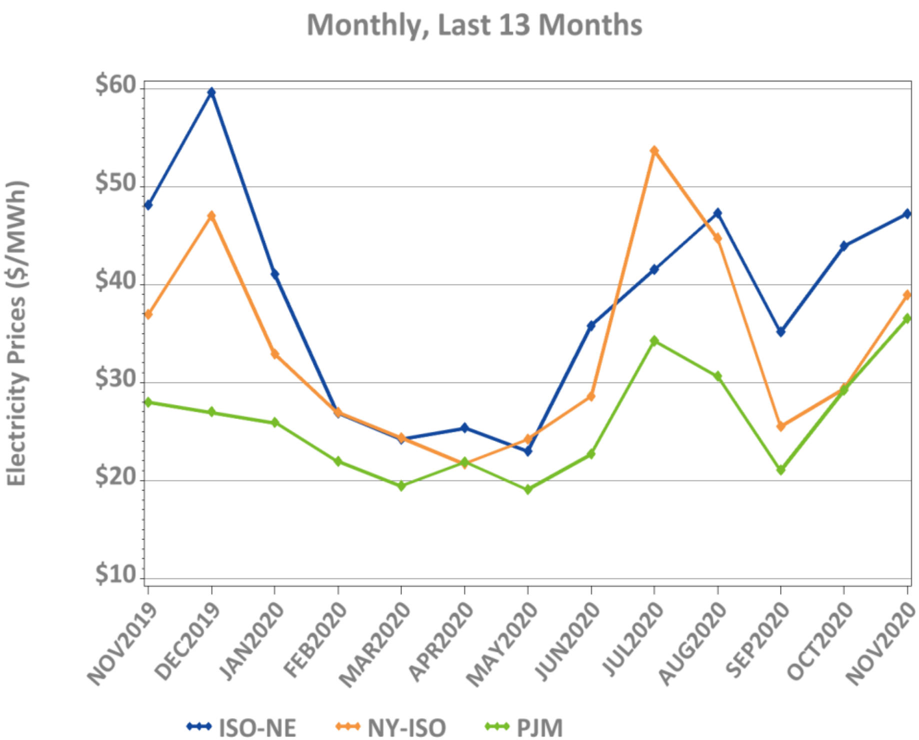


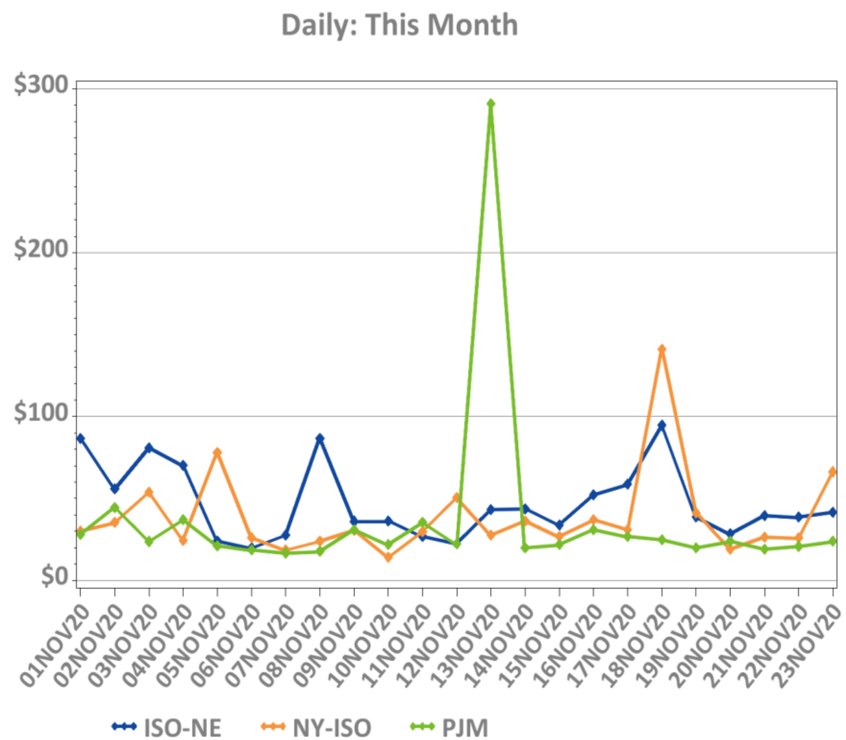
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





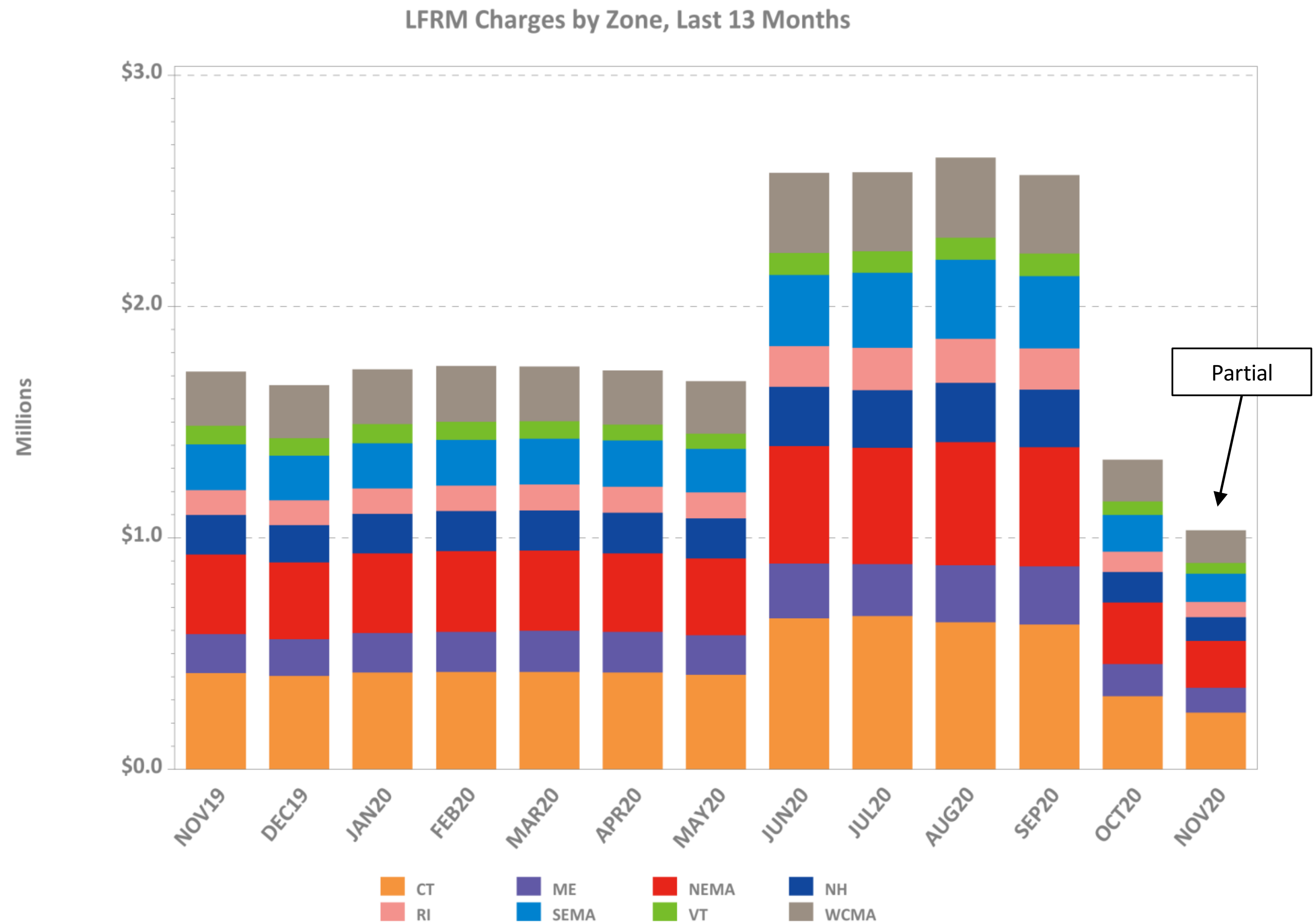
***Forecasted New England daily peak hours reflected**

Reserve Market Results – November 2020

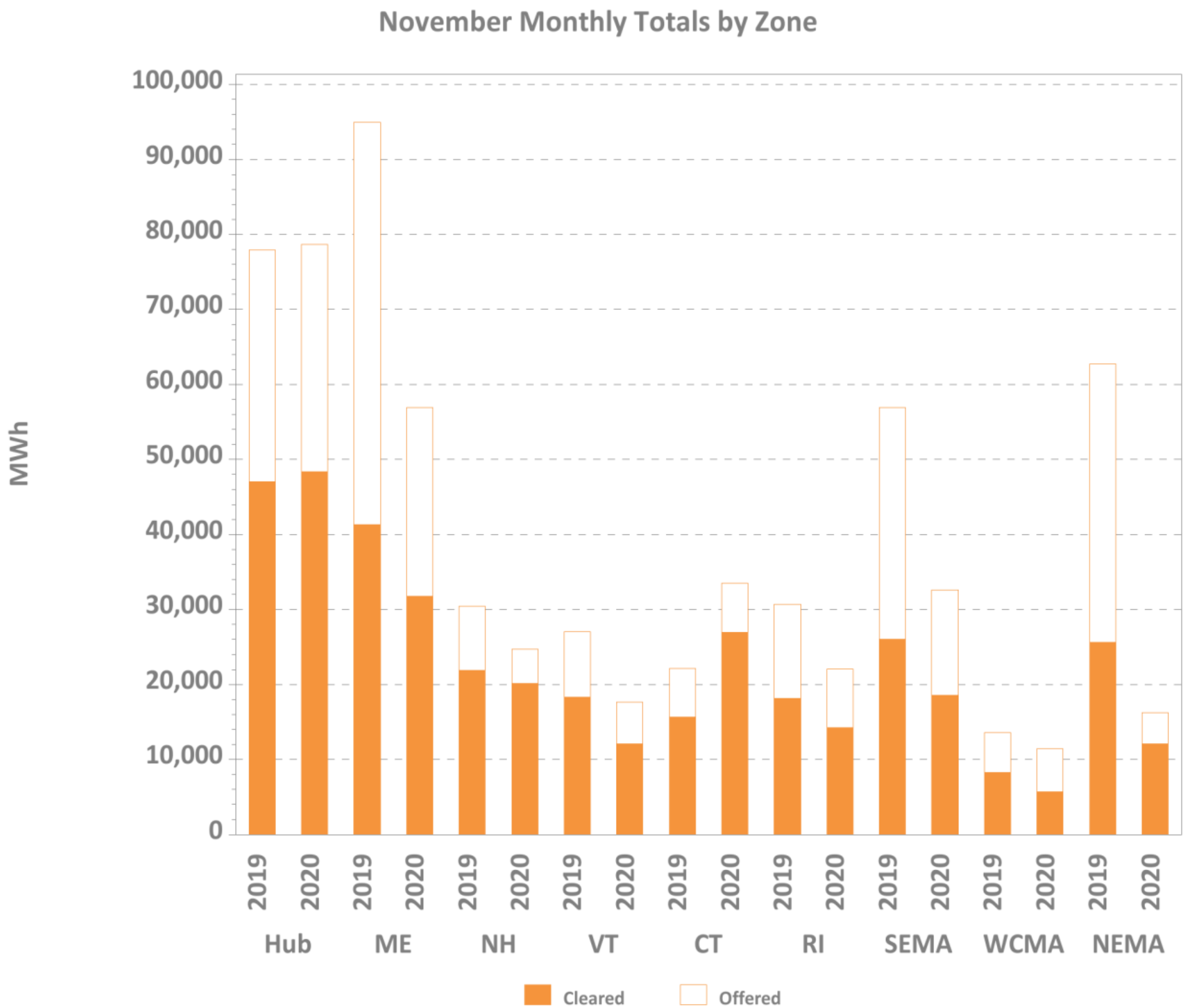
- Maximum potential Forward Reserve Market payments of \$1.1M were reduced by credit reductions of \$43K, failure-to-reserve penalties of \$64K and no failure-to-activate penalties, resulting in a net payout of \$1M or 91% of maximum
  - Rest of System: \$0.79M/0.89M (89%)
  - Southwest Connecticut: \$0.03M/0.03M (83%)
  - Connecticut: \$0.22M/0.22M (99%)
- \$416K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of \$416K in Real-Time Reserve payments
  - Rest of System: 200 hours, \$314K
  - Southwest Connecticut: 200 hours, \$61K
  - Connecticut: 200 hours, \$29K
  - NEMA: 200 hours, \$13K

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.

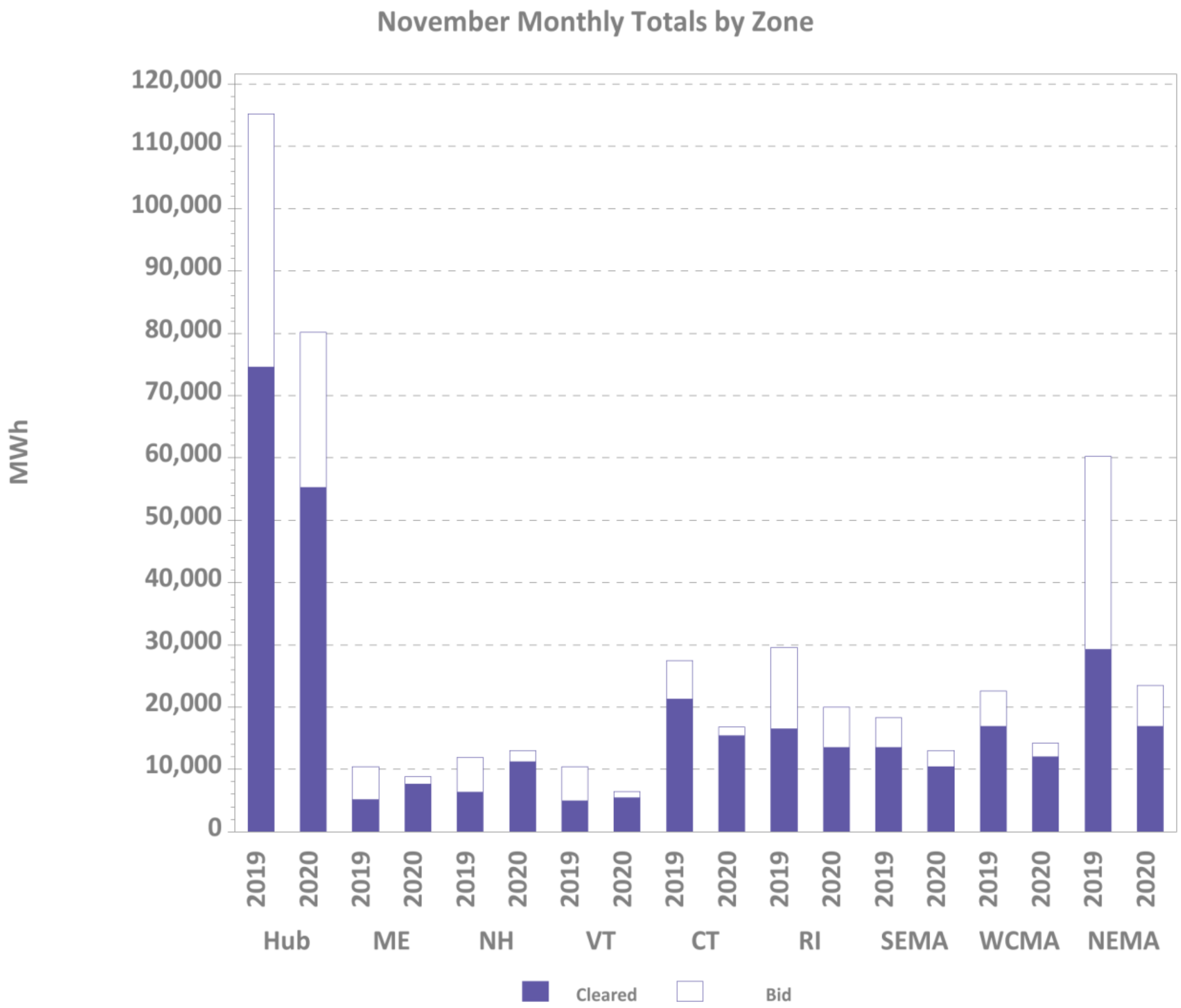
LFRM Charges to Load by Load Zone ($)



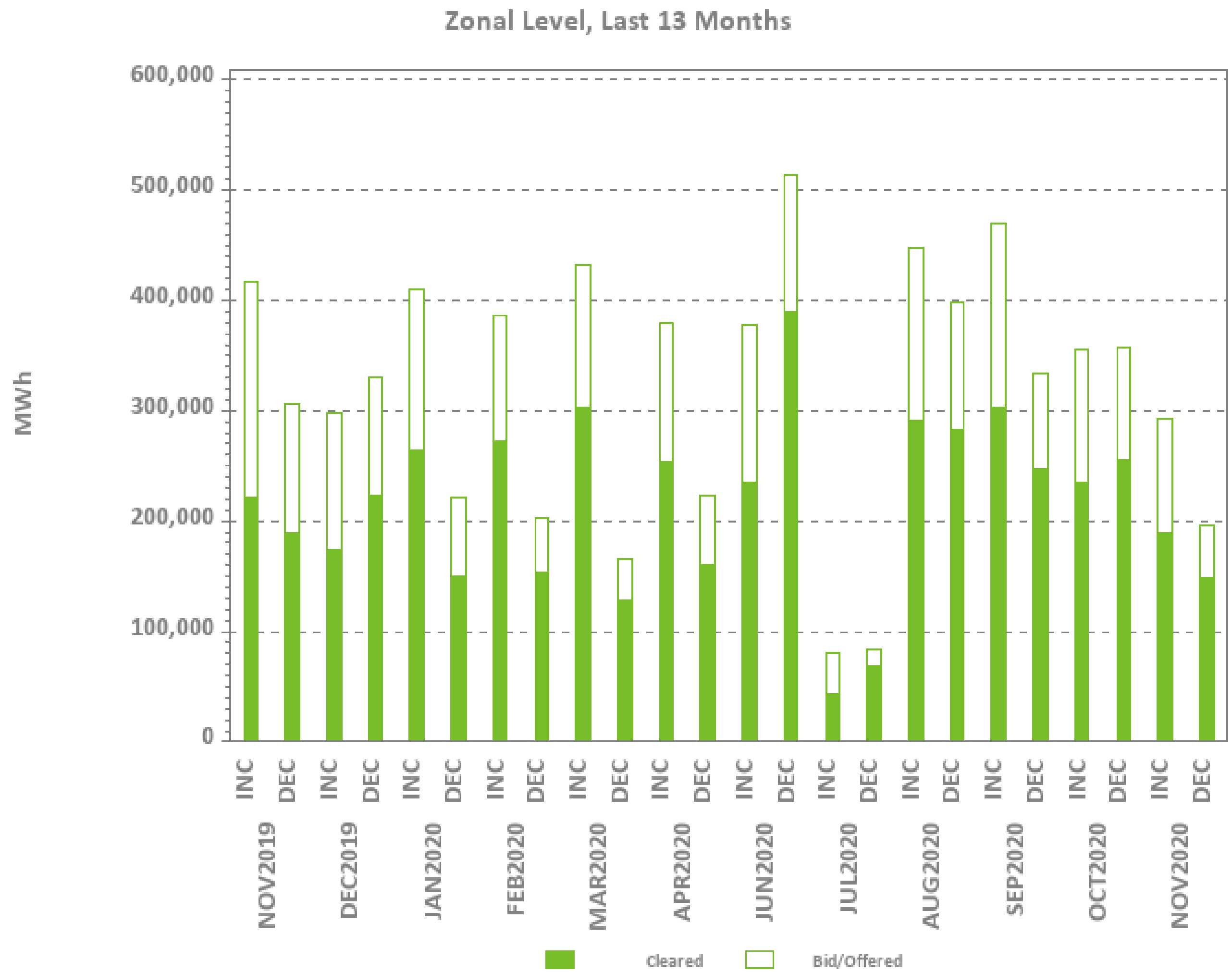
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

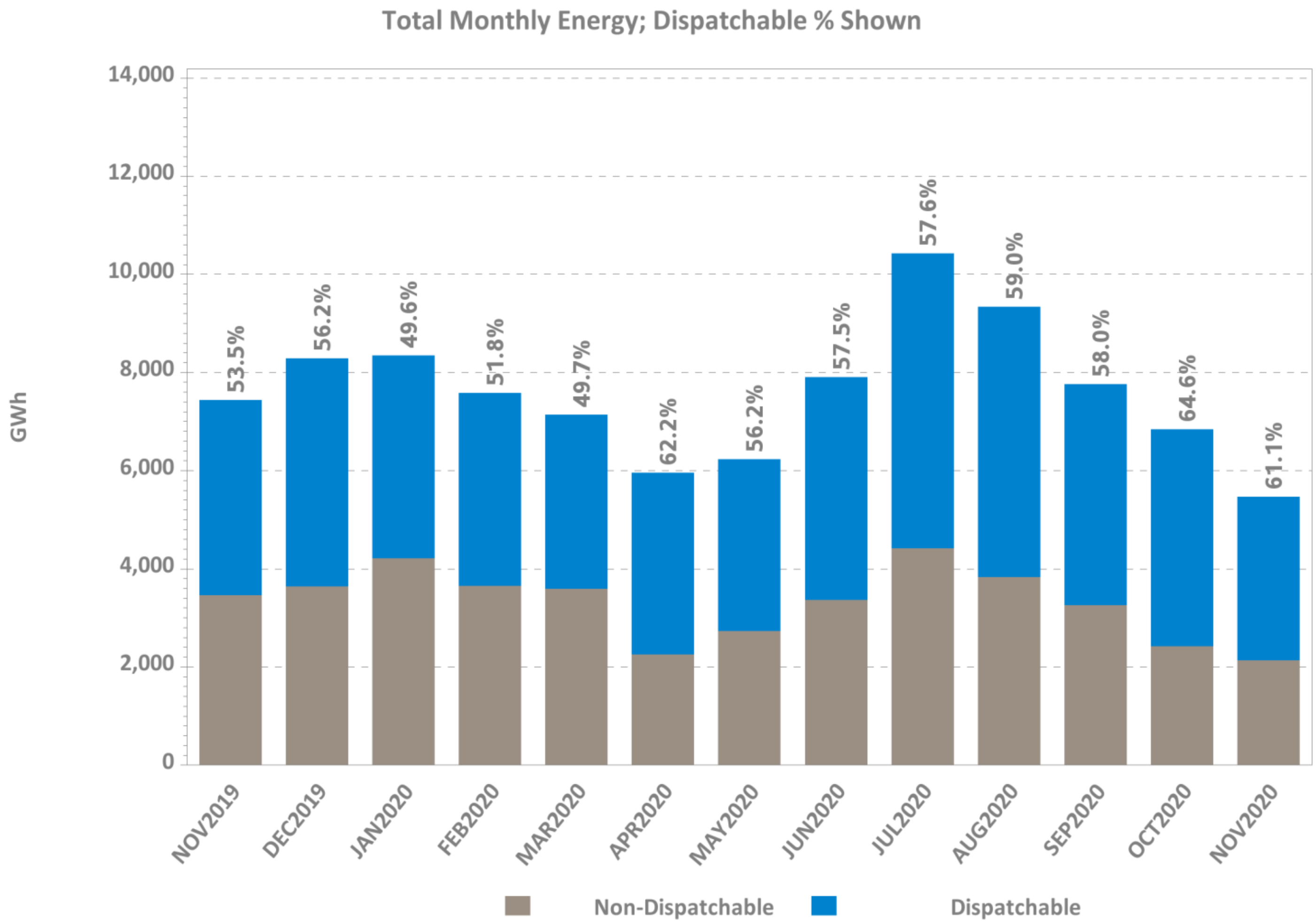


Total Increment Offers and Decrement Bids



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)

- December 16 PAC Meeting Agenda Topics*
  - Moody's Analytics 2020 Economic Update
  - Competitive Solution Process Lessons Learned
  - Prior Year Wood Structure Asset Condition Replacements - Eversource
  - 455-507 115 kV Line Wood Structure Asset Condition Project - Eversource
  - 2020 NGRID Economic Study - Follow-up to the November PAC Meeting
  - 2020 NGRID Economic Study Assumptions
  - Transmission Planning for the Clean Energy Transition: System Conditions and Dispatch Assumptions

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

Transmission Planning for the Clean-Energy Transition

- On September 24, the ISO initiated discussions with the PAC about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the November 19 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- Additional discussion is expected at the December 16 PAC meeting and into 2021

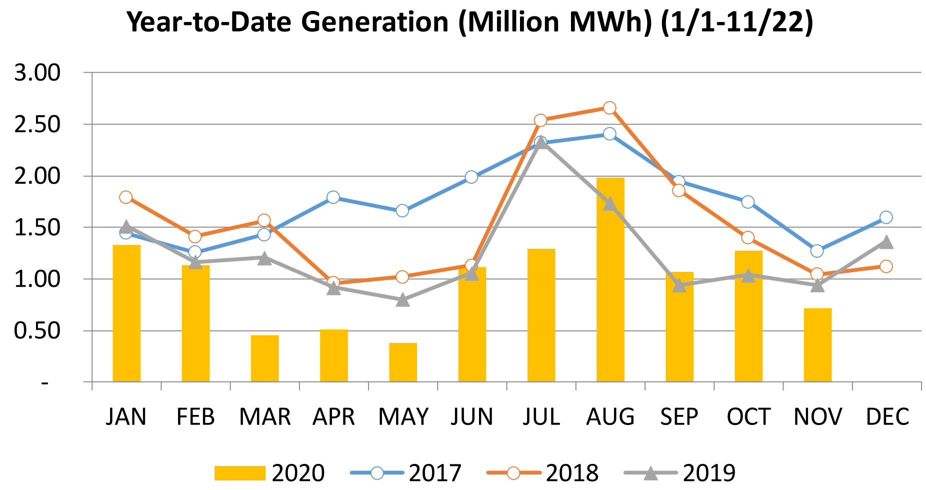
Economic Studies

- National Grid submitted a 2020 economic study request
  - Assumptions have been agreed upon and were presented to PAC in May, June and July
  - Preliminary production cost results were shared at the November 19 PAC meeting, and additional scenarios/sensitivities will be presented in the December/January timeframe
    - The goal is to complete all study work by Q2 2021
    - Ancillary Services study work to be presented to PAC in early 2021
    - Study results expected to influence the NEPOOL Future Grid study

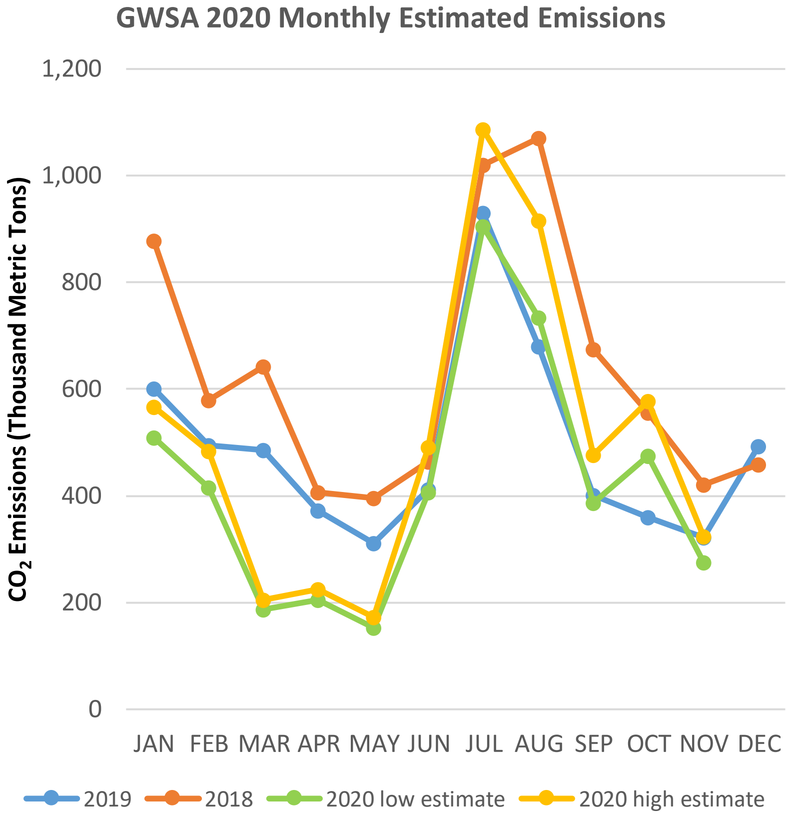
Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2020 CO_2 Emissions Higher Than 2019, Still Well Below Cap

- 2020 CO_2 emissions estimated between 4.6 – 5.5 million metric tons (MMT); 2020 cap is 8.5 MMT
- 2019 YTD emissions were 5.4 MMT



2020 Estimated Past Monthly Emissions (Thousand Metric tons)



GWSA - Global Warming Solutions Act

RSP Project Stage Descriptions

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

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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 11/23/20

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 11/23/20

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	Sep-20	4
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 11/23/20

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)	Jul-20	4
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 11/23/20

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 11/23/20

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 11/23/20

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 11/23/20

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 11/23/20

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 11/23/20

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 11/23/20

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*	May-22	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 11/23/20

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	Sep-20	4
Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
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 11/23/20

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	Mar-21	3

*Mystic to Chelsea line portion of the project is a present stage 4 as of October 2020.

Greater Boston Projects, cont.

Status as of 11/23/20

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	May-22	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 11/23/20

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

SEMA/RI Reliability Projects

Status as of 11/23/20

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

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

SEMA/RI Reliability Projects, cont.

Status as of 11/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-21	3
Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Jun-24	2
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	Jun-23	2
Extend the Line 114 from the Dartmouth town line (Eversource-NGRID border) to Bell Rock substation	Dec-23	2
Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 11/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	2
Retire the Barnstable SPS	Dec-21	2
Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 11/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	2
Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	1
Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
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

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

SEMA/RI Reliability Projects, cont.

Status as of 11/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
Reconductor the J16S line	Dec-21	2
Replace the Kent County 345/115 kV transformer	Mar-22	2
West Medway 345 kV circuit breaker upgrades	Dec-21	3
Medway 115 kV circuit breaker replacements	Oct-20	4

Eastern CT Reliability Projects

Status as of 11/23/20

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Reconductor the L190-4 and L190-5 line sections	Dec-26	1
Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
Upgrade Card 115 kV to BPS standards	Mar-23	2
Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-21	1

Eastern CT Reliability Projects, cont.

Status as of 11/23/20

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	1
Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	1
Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	1
Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-21	3
Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-21	1
Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Mar-22	2

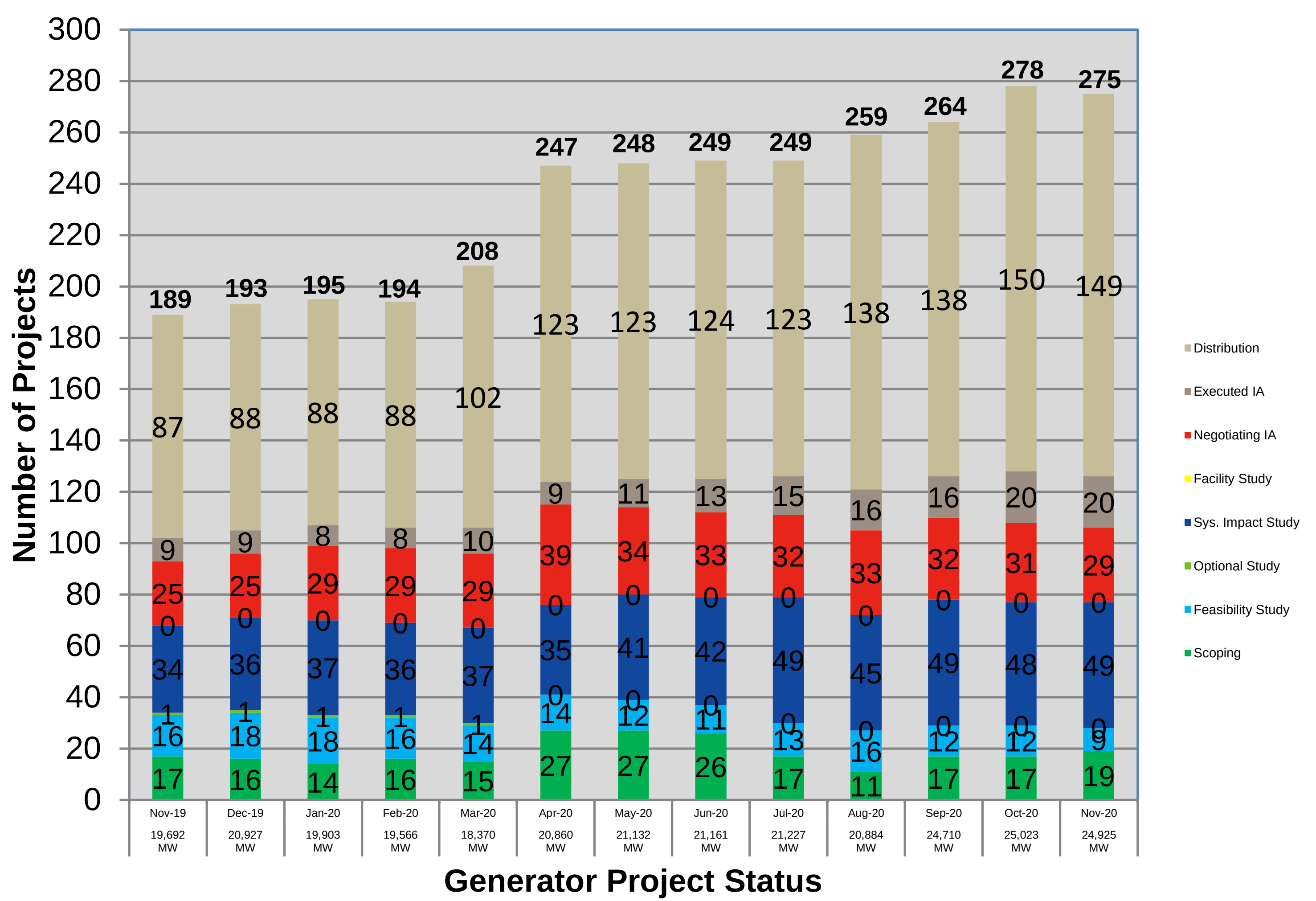
Eastern CT Reliability Projects, cont.

Status as of 11/23/20

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

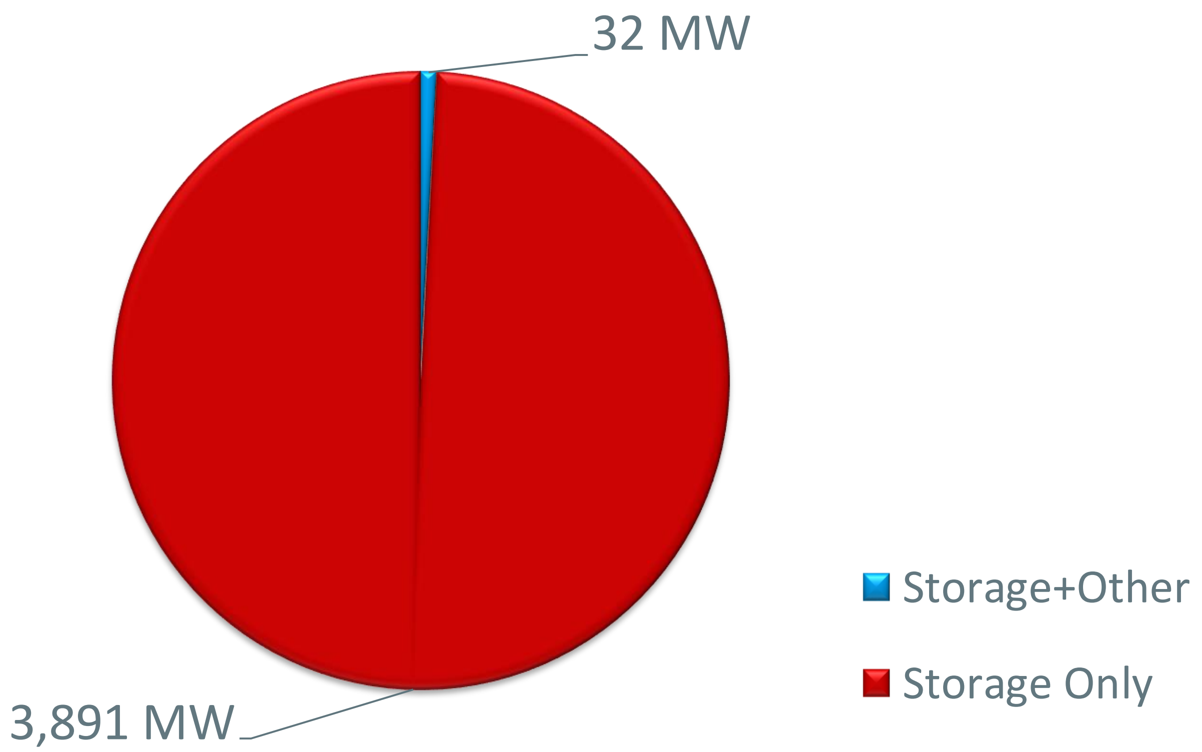
Status of Tariff Studies



Note: November 2020 is based on partial data.
As of November 2020, there are 4 ETU's in Scoping, 1 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 2 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of November 19, 2020)

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



OPERABLE CAPACITY ANALYSIS

Winter 2020/21 Analysis

Winter 2020/21 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2021[2] CSO (MW)	Jan. - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,489	33,692
Active Demand Capacity Resource (+) [5]	505	377
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	336	433
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,892	4,444
Net Capacity (NET OPCAP SUPPLY MW)	25,010	27,436
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,166	20,166
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,471	22,471
Operable Capacity Margin	2,539	4,965

[1]Operable Capacity is based on data as of **November 23, 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 **November 23, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 2, 2021.**

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

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

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

Winter 2020/21 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	Jan. - 2021[2] CSO (MW)	Jan. - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,489	33,692
Active Demand Capacity Resource (+) [5]	505	377
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	336	433
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,594	5,246
Net Capacity (NET OPCAP SUPPLY MW)	24,308	26,634
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,806	20,806
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,111	23,111
Operable Capacity Margin	1,197	3,523

[1] Operable Capacity is based on data as of **November 23, 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 **November 23, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 2, 2021.**

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

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

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

Winter 2020/21 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

November 25, 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]
12/5/2020	30480	424	1080	19	1954	571	3200	1907	24371	19313	2305	21618	2753
12/12/2020	30480	424	1080	19	1927	575	3200	2110	24191	19325	2305	21630	2561
12/19/2020	30480	424	1025	19	352	306	3200	2602	25488	19390	2305	21695	3793
12/26/2020	30480	424	1080	19	339	0	3200	3269	25195	19390	2305	21695	3500
1/2/2021	**30489**	**505**	**1025**	**19**	**336**	**0**	**2800**	**3892**	**25010**	**20166**	**2305**	**22471**	**2539**
1/9/2021	30489	505	1025	19	332	0	2800	3887	25019	20166	2305	22471	2548
1/16/2021	30489	505	1025	19	381	0	2800	3736	25121	20166	2305	22471	2650
1/23/2021	30489	505	1025	19	396	0	2800	3269	25573	19933	2305	22238	3335
1/30/2021	30459	533	1025	19	306	0	3100	2958	25672	19933	2305	22238	3434
2/6/2021	30459	533	1025	19	314	0	3100	2646	25976	19652	2305	21957	4019
2/13/2021	30459	533	1025	19	774	0	3100	2335	25827	19622	2305	21927	3900
2/20/2021	30459	533	1025	19	764	0	3100	1868	26304	19346	2305	21651	4653
2/27/2021	30459	533	1025	19	1089	0	2200	1557	27190	18308	2305	20613	6577
3/6/2021	30459	533	1025	19	1753	0	2200	1245	26838	17941	2305	20246	6592
3/13/2021	30459	533	1025	19	1769	245	2200	378	27444	17736	2305	20041	7403
3/20/2021	30459	533	1025	19	1340	202	2200	0	28294	17352	2305	19657	8637
3/27/2021	30446	537	1025	19	864	239	2700	0	28224	16759	2305	19064	9160

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)

Winter 2020/21 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

November 25, 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 [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
12/5/2020	30480	424	1080	19	1954	571	3200	2936	23342	19930	2305	22235	1107
12/12/2020	30480	424	1080	19	1927	575	3200	3138	23163	19942	2305	22247	916
12/19/2020	30480	424	1025	19	352	306	3200	3766	24324	20009	2305	22314	2010
12/26/2020	30480	424	1080	19	339	0	3200	4462	24002	20009	2305	22314	1688
1/2/2021	**30489**	**505**	**1025**	**19**	**336**	**0**	**2800**	**4594**	**24308**	**20806**	**2305**	**23111**	**1197**
1/9/2021	30489	505	1025	19	332	0	2800	4731	24175	20806	2305	23111	1064
1/16/2021	30489	505	1025	19	381	0	2800	4515	24342	20806	2305	23111	1231
1/23/2021	30489	505	1025	19	396	0	2800	4203	24639	20566	2305	22871	1768
1/30/2021	30459	533	1025	19	306	0	3100	4203	24427	20566	2305	22871	1556
2/6/2021	30459	533	1025	19	314	0	3100	3736	24886	20278	2305	22583	2303
2/13/2021	30459	533	1025	19	774	0	3100	3425	24737	20247	2305	22552	2185
2/20/2021	30459	533	1025	19	764	0	3100	2802	25370	19963	2305	22268	3102
2/27/2021	30459	533	1025	19	1089	0	2200	2335	26412	18897	2305	21202	5210
3/6/2021	30459	533	1025	19	1753	0	2200	2179	25904	18520	2305	20825	5079
3/13/2021	30459	533	1025	19	1769	245	2200	1312	26510	18309	2305	20614	5896
3/20/2021	30459	533	1025	19	1340	202	2200	888	27406	17915	2305	20220	7186
3/27/2021	30446	537	1025	19	864	239	2700	384	27840	17305	2305	19610	8230

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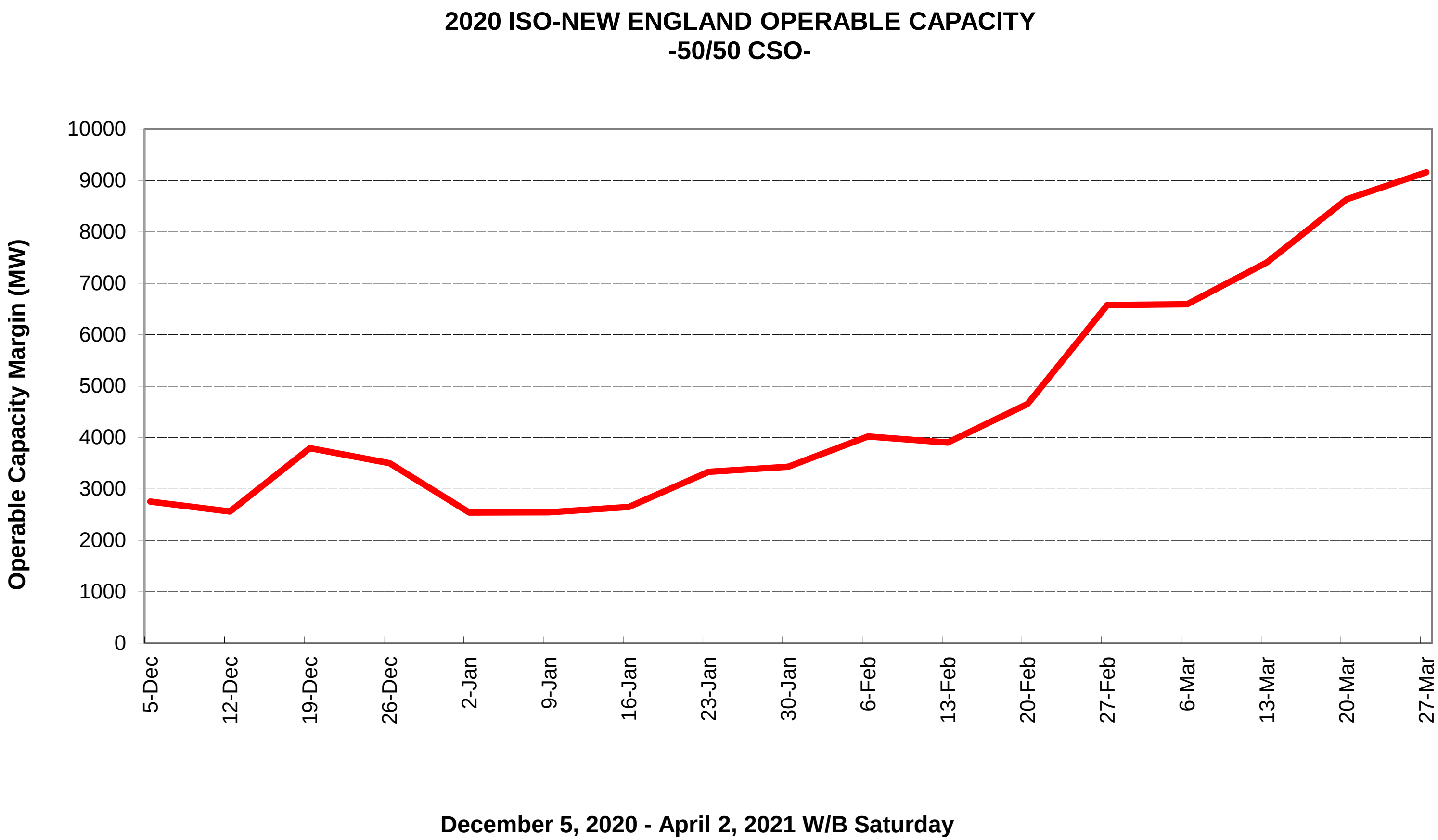
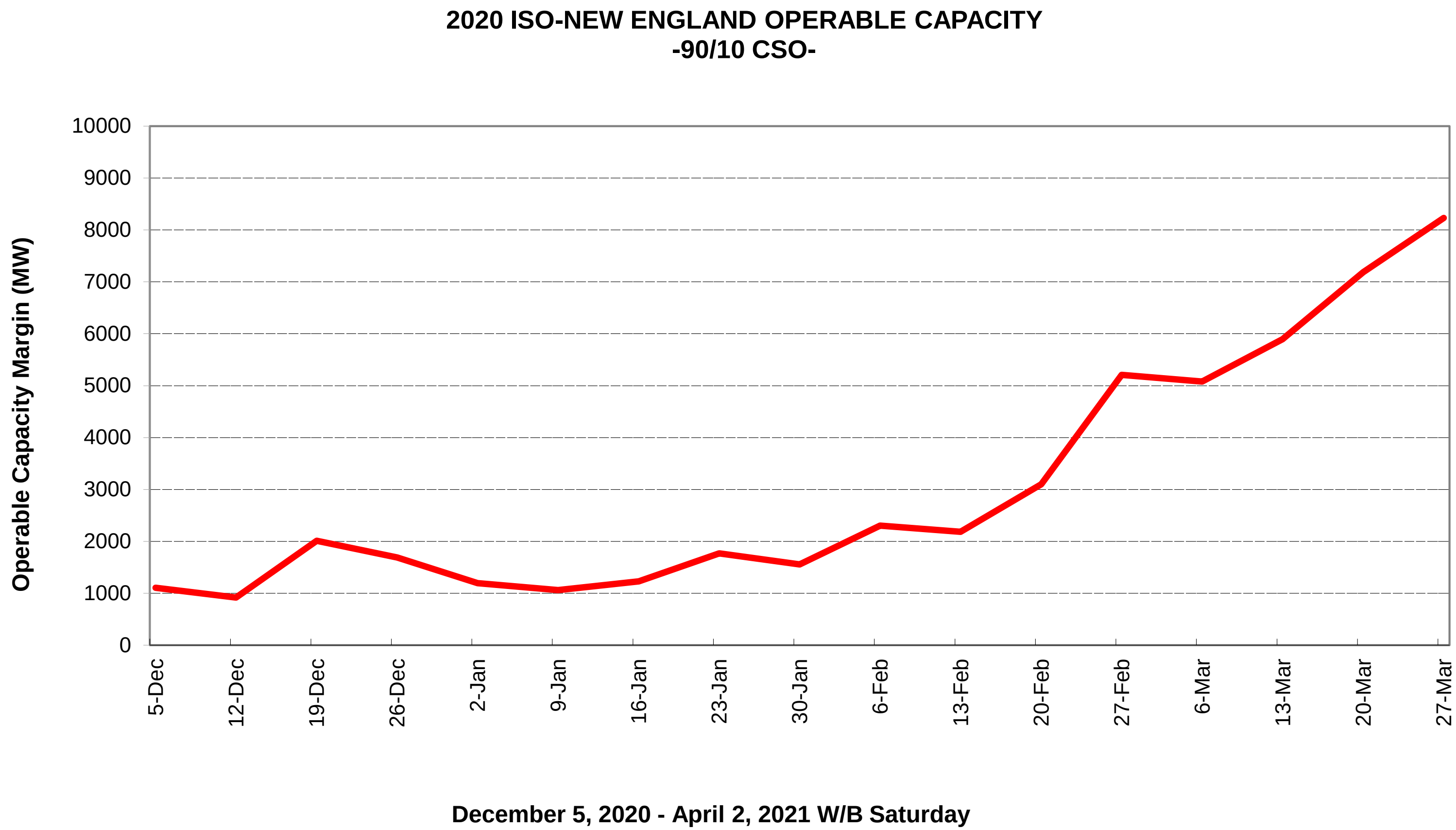
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Winter 2020/21 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2020/21 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

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING

December 3, 2020

RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2021

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

WHEREAS, pursuant to those procedures the individuals indentified in the following resolution were nominated and elected for 2020 to the offices of Chair and Vice-Chair, as set forth opposite their names; and

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

NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2021 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	David A. Cavanaugh
Vice-Chair	Christina H. Belew
Vice-Chair	Nancy P. Chafetz
Vice-Chair	Francis J. Ettori, Jr.
Vice-Chair	Michelle C. Gardner
Vice-Chair	Douglas Hurley
Secretary	David T. Doot
Assistant Secretary	Sebastian M. Lombardi

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Tom Kaslow, Chairman, NEPOOL Budget & Finance Subcommittee
Paul Belval, NEPOOL Counsel

DATE: November 24, 2020

RE: Estimated Budget for 2021 Participant Expenses

The Participants Committee will be asked at its December 3 meeting to approve the estimated NEPOOL expense budget for 2021, which is attached to this memorandum (the "2021 Budget"). As in prior years, the proposed 2021 Budget estimates are compared to both the current-year estimated expenses approved by the Participants Committee at its last annual meeting and the current forecast of actual expenses for this year (Attachment A). Also as in prior years, an estimated calculation of the per-Participant share of the 2021 Budget expenses are compared to per-Participant shares of expenses five years ago (Attachment B), generally showing decreasing per-Participant expenses for five of the six Sectors, with the Transmission Sector's per-Participant expenses impacted by consolidation which has reduced the members sharing in that Sector's allocated, though lower in aggregate, expenses.

Consistent with the practice in previous years, the NEPOOL Budget & Finance Subcommittee (the "Subcommittee") has worked with NEPOOL Counsel, the GIS Administrator, the ISO and NEPOOL's Independent Financial Advisor to develop the 2021 Budget. At its November 20 teleconference, the Subcommittee discussed the proposed 2021 Budget, and none of the Participant representatives attending that teleconference objected to the 2021 Budget.

The following form of resolution may be used in acting on the 2021 Budget:

> RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2021 as presented at this meeting.

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ATTACHMENT A

ESTIMATED 2021 NEPOOL BUDGET COMPARED TO 2020 NEPOOL BUDGET AND 2020 PROJECTED ACTUAL EXPENSES

Line Items	2020 Approved Budget	2021 Proposed Budget	2020 Current Forecast
NEPOOL Counsel Fees (1)	$4,100,000	$4,100,000	$4,100,000
NEPOOL Counsel Disbursements (1)	$ 40,000	$ 20,000	$ 20,000
Independent Financial Advisor Fees and Disbursements (2)	$ 45,000	$ 45,000	$ 45,000
Committee Meeting Expenses (3)(4)	$ 725,000	$ 510,000	$ 210,000
Generation Information System (5)	$ 945,000	$ 1,070,600	$ 845,000
Credit Insurance Premium (3)	$ 510,000	$ 475,000	$ 434,000
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (6)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$6,365,000	$6,220,600	$5,654,000
Revenue			
NEPOOL Membership Fees (3) (7)	($2,070,000)	($2,110,000)	($2,238,000)
Generation Information System (5) (8)	($ 945,000)	($1,070,600)	($ 845,000)
Credit Insurance Premium (3) (9)	($ 510,000)	($ 475,000)	($ 434,000)
TOTAL REVENUE	($3,525,000)	($3,655,600)	($3,517,000)
TOTAL NEPOOL EXPENSES	**$2,840,000**	**$2,565,000**	**$2,137,000**

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Notes

(1) 2021 proposed estimate provided by Day Pitney LLP, NEPOOL counsel.

(2) 2021 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2021 proposed estimate provided by ISO New England Inc. ("ISO").

(4) Committee meeting expense for 2020 includes amounts to be paid to consultants for assistance with Future Grid. The 2021 proposed budget assumes no in-person meetings for the first part of 2021.

(5) Based on new fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the fixed fee for 2021 is projected to be $950,000, plus $120,600 projected expense related to changes associated with Massachusetts Clean Peak Energy Standard, which will be charged in 2021 when changes are completed.

(6) If NEPOOL determines that an audit should be performed in 2021, funding for that audit will be addressed separately.

(7) The 2021 proposed estimate is based on the 2020 actual receipts through October 2020, plus a forecast for new members for the remainder of the year. The breakdown for the proposed budget is approximately: 392 members at $5,000 each, 29 members at $1,000 each, 16 members at $500 each, 25 members at $1,500 each, and 31 members of large end users and MPEU's. This estimate takes into account the terminations throughout the year.

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

(9) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy. The 2021 premium is based on 2020 annual policy sales.

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ESTIMATED BREAKDOWN OF PROJECTED 2021 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

(2021 figures assume no change in current NEPOOL membership)
(2016 figures as projected and budgeted at 2015 Annual Meeting)

CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS			
		2021	**2016**
A.	Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately)	**4,675,000**	**4,489,000**
B.	Projected NEPOOL Membership Fees	**2,110,000**	**1,856,000**
C.	Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B)	**2,565,000**	**2,633,000**
D.	Projected Amount to be paid by all Market Participant End Users (based on highest hourly load in any month in preceding calendar year) (figure used here for 2020 is based on 2018 peak loads of MPEU members)	**44,678**	**42,335**
E.	Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2020 is estimated amount based on 2019 membership data)	**84,553**	**60,041**
F.	[Reserved]	**0**	**0**
G.	Large Renewable Generation Sub-Sector Share (C-(D+E)) x RG%	**243,577**	**210,640**
H.	Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors (“Remaining Sectors”) (C – (D+E+G))	**2,192,192**	**2,319,984**

CALCULATION OF SECTOR ALLOCATIONS			
		2021	**2016**
I.	Amount to be allocated to each of the Remaining Sectors (H ÷ 4)	**548,448**	**579,996**
J.	Total Amount paid by Related Person Suppliers (2 voting members) $(I \div s_y) \times rps_y$	**8,497**	**9,431**
K.	Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers ((I x 2) + G – J)	**1,331,176**	**1,361,201**
L.	[Reserved]	**0**	**0**
M.	Remainder of Aggregate Share to be paid, on a per member basis, by voting members in the Generation Sector, Supplier Sector (excluding Related Person Suppliers), and Large Renewable Generation Resource Providers $(K \div (g_y + (s_y - rps_y) + lrg_y))$	**8,934**	**9,936**
N.	Transmission Sector Share per full voting member $(I \div t_y)$	**109,610**	**96,666**
O.	[Reserved]	**0**	**0**
P.	Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members)[i] $(I \div poe_y)$	**9,289**	**10,175**

ANNUAL VARIABLES			
		2021	**2016**
s_y	# Supplier Sector voting members	**129**	**123**
rps_y	# Supplier Sector Related Person Suppliers	**2**	**2**
g_y	# Generation Sector voting members	**11**	**12**
lrg_y	# AR Sector Large Renewable Generation Resource Providers	**11**	**4**
RG%	Lesser of (lrg_y*2%) or 10%	**10%**	**8%**
t_y	# Transmission Sector voting members	**5**	**6**
poe_y	# Publicly Owned Entity voting members	**59**	**57**

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: November 24, 2020

RE: Updated Forward Capacity Market (FCM) Values/Parameters for FCA16

At the December 3, 2020 Participants Committee teleconference meeting, you will be asked to consider Tariff revisions to update the Cost of New Entry (CONE), Net CONE, and Payment Performance Rate (PPR) values, as well as the Offer Review Trigger Prices (ORTPs) used in the FCM. The Markets Committee has recommended a set of ORTP-related Tariff revisions that are different from those proposed by ISO-NE. This memorandum summarizes information pertaining to this matter, discusses potential Participant-sponsored amendments to the Markets Committee-recommended proposal of which we have been advised, and includes a form of resolution. ***Please note that since the Markets Committee vote there is updated information related to the FCM values that the Participants Committee will be asked to act upon.***

This memorandum includes the following Attachments:

- Attachment A: The Markets Committee-recommended Tariff redlines.
- Attachment B: The ISO-proposed Tariff redlines.
- Attachment C: The ISO's voting memorandum.
- Attachment D: The Markets Committee's Notice of Actions.
- Attachment E: Jericho Power's presentation on a proposed amendment offered on behalf of the New England Power Generators Association (NEPGA) to the ISO's updated Net CONE values that was previously circulated and presented to the Markets Committee.
- Attachment F: RENEW Northeast's memorandum (dated Nov. 24) explaining the cumulative impact of the four amendments offered at the Markets Committee and providing further support for the MC-recommended proposal.

By way of brief background, the CONE, Net CONE,[1] and ORTP[2] values are specifically enumerated in the ISO-NE Tariff and were last updated (and approved by the FERC) in 2017.

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[1] The Market Rules provide that the system demand curve must be calculated such that the capacity quantity associated with the Net CONE is equal to New England's resource adequacy reliability standard. The CONE and Net CONE values are also used to set the Forward Capacity Auction Starting Price, which is the higher of CONE or 1.6 multiplied by Net CONE.

[2] A project developer with a new capacity resource can submit an offer at a price equal to or greater than the resource-assigned ORTP without requiring further review by the ISO's Internal Market Monitor (IMM). Offers below the ORTP require the submission of resource-specific cost data to the IMM for evaluation and approval.

The Market Rules require that these values be recalculated at least once every three years.[3] The current PPR was set in 2013. The ISO will use the set of updated values approved by the FERC beginning with FCA16.

MARKETS COMMITTEE CONSIDERATION

At its November 9–10, 2020 meeting, the Markets Committee considered the ISO's proposed Tariff revisions to update FCM parameter values,[4] as well as thirteen amendments to the ISO's proposal. Of the thirteen amendments offered, the Markets Committee supported the following five motions to amend, as well the five-time amended main motion reflecting those changes. During the meeting, the ISO indicated that it did not support any of those five amendments at that time.

1. ***Union of Concerned Scientists (UCS) (on behalf of RENEW Northeast) Amendment #1: ORTP Project Economic Lifetime Modeling Assumption***[5]

The first amendment that was offered and passed at the Markets Committee concerned UCS's proposal to add a defined term to Tariff Section I.2.2 (Tariff Definitions), i.e., "New Capacity Resource Economic Life." In addition, this amendment proposed two changes to Tariff Section III.A.21.1.2(b) that would: (1) eliminate the current requirement that the financial model used in calculating ORTPs include exactly 20 years of cash flows (both revenues and expenses); and (2) add language requiring the financial model to reflect cash flows over a resource's New Capacity Resource Economic Life . Finally, UCS's amendment included a photovoltaic solar ORTP of $1.872/kW-month, reflecting a New Capacity Resource Economic Life of 30 years. This motion to amend passed at the Markets Committee with a 64.732% Vote in favor.

2. ***Borrego Solar Systems and Enel X Amendment: Changes to the Unit-Specific ORTP Review Process***[6]

The Markets Committee next considered Borrego and Enel X's joint amendment, which applied to the unit-specific review process used by the Internal Market Monitor.[7] The amendment proposed to change Tariff Section III.A.21.2(b) by including language that would allow a New Capacity Resource to propose a unique New Capacity Economic Life instead of the life time used for the default reference unit, provided that the project's sponsor submits sufficient

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[3] In between full recalculations, the CONE, Net CONE, and ORTP values are updated annually using indices specified in the Tariff. The ISO's proposal would change the current indices used.

[4] The ISO retained Concentric Energy Advisors (CEA), who were assisted by Mott MacDonald (MM), to calculate the CONE, Net CONE, and ORTP values. At the time of posting this memorandum, the CEA/MM report explaining their methodology to calculate these values was unavailable. The ISO has informed NEPOOL Counsel that the final report is forthcoming.

[5] To review UCS's presentation discussed at the Markets Committee meeting, please click here.

[6] Borrego and Enel X's presentation summarizing their amendment can be reviewed here.

[7] Of note, this amendment also proposed to add the "New Capacity Resource Economic Life" definition. This aspects of the proposal became moot when UCS's first amendment passed.

documentation to support the claimed New Capacity Resources Economic Life. In Tariff Section III.A.21.2(b)(iv), the amendment detailed a non-exhaustive list of the type of documentation that could be offered to support a New Capacity Resource's claimed New Capacity Resources Economic Life. This amendment passed with a 68.065% Vote in favor.

3. *UCS Amendment #2: ORTP Off-Shore Wind Capital Cost and Investment Tax Credit (ITC) Assumptions*[8]

Utilizing $3,326/kW (2019$) as the overnight capital cost assumption and including an 18 percent ITC,[9] this amendment proposed reduced ORTP value for off-shore wind of $1.533/kW-month.[10] This amendment passed with a Markets Committee Vote of 66.784% in favor.

4. *UCS Amendment #3: Production Tax Credit (PTC)/ITC Assumptions in the ORTP Annual Updates for FCAs 17 and 18*[11]

UCS's third amendment proposed to add language to Tariff Section III.A.21.1.2 that would require ORTPs to be adjusted during the recalculations in advance of FCAs 17 and 18 by including PTC and ITC inputs into the capital budgeting model that reflect the most current tax law regarding these credits. This amendment passed with a 66.815% Vote in favor.

5. *UCS Amendment #4: ORTP Battery Energy and Ancillary Services (E&AS) Revenue Model Assumption*[12]

UCS's fourth and final amendment proposed an ORTP of $2.615/kW-month for the Energy Storage Device – Lithium Ion Battery technology. To arrive at this result, UCS used the battery model developed by the Massachusetts Attorney General's Office (MA AGO) to calculate E&AS revenues. Using this model, a battery could expect to earn more E&AS revenue than under the ISO's model. Applying the increased E&AS revenues reduced the ORTP for a Lithium Ion Battery as compared to the ISO's proposed value. This amendment was supported by the Markets Committee with a 67.404% Vote in favor.

The Markets Committee then considered and voted eight additional amendments, all of which failed to garner sufficient support to pass. Jericho Power (on behalf of NEPGA) offered these amendments and all are described in materials previously circulated to the Markets Committee. Jericho's presentations are accessible here, and the Markets Committee votes can be

[8] The presentation of UCS Amendment #2 can be accessed here.

[9] The ISO proposed $5,358/kW for off-shore wind's overnight capital cost assumption and included a zero percent ITC.

[10] As discussed below, subsequent to Markets Committee action, this ORTP was revised to reflect the cumulative impact of this amendment and UCS's first amendment.

[11] UCS's presentation summarizing UCS Amendment #3 can be found here.

[12] The presentation summarizing UCS Amendment #4 can be reviewed by clicking here, while the MA AGO's presentation regarding the battery dispatch model can be found here.

reviewed in Attachment D. Consistent with past practice, if a decision is made not to advance these same amendments at the Participants Committee but advocate that the FERC should require any such changes, then neither NEPOOL nor the ISO will raise Participant Processes issues at the FERC based on the failure to submit the amendments for a Participants Committee vote.

After all of the amendments were voted, the Markets Committee then considered and approved for the Participants Committee to support the five-time amended main motion, with 64.040% Vote in favor.[13]

At the request of the ISO, the Markets Committee also voted on the ISO's un-amended proposal. That proposal received a 16.667% Vote in favor, and therefore was not recommended by the Markets Committee.[14]

DEVELOPMENTS SINCE THE NOVEMBER 9–10 MARKETS COMMITTEE VOTE

By way of background, in light of the number of amendments and in advance of the November meeting, the Markets Committee's Chair and Vice-Chair circulated a memorandum (the Markets Committee Chair/Vice-Chair Memorandum) explaining that many of the proposed amendments would influence more than one FCM parameter.[15] Consequently, unique challenges existed when calculating the combined effects of more than one amendment on the CONE, Net CONE, ORTP, and/or PPR values. The memorandum also noted that the ISO could neither determine the combined impact of the various combinations of amendments in advance of the November Markets Committee meeting nor calculate combined the results in real-time during the vote. The ISO, however, committed to calculate any cumulative impact on the CONE, Net CONE, ORTP, and/or PPR values for any Markets Committee-supported amendments prior to the December 3 Participants Committee meeting.

Since the November Markets Committee meeting, the values for the FCM parameters were updated. First, as the ISO committed, it recalculated ORTPs to account for the combined effects of the Markets Committee-supported amendments. Of the various ORTP technologies, only the off-shore wind ORTP value was affected by more than one of the supported

[13] The individual Sector votes at the Markets Committee were as follows: *Generation* – 2.381% in favor, 14.286% opposed, 0 abstentions; *Transmission* – 16.667% in favor, 0% opposed, 0 abstention; *Supplier* – 1.852% in favor, 14.815% opposed, 6 abstentions; *Publicly Owned Entity* – 16.667% in favor, 0% opposed, 0 abstentions; *Alternative Resources* – 9.723% in favor, 6.777% opposed, 0 abstentions; and *End User* – 16.667% in favor, 0% opposed, 0 abstentions. In addition, the votes from Provisional Members were 0.083% in favor, 0.083% opposed, and 0 abstentions.

[14] The individual Sector votes at the Markets Committee were as follows: *Generation* – 0% in favor, 16.667% opposed, 0 abstentions; *Transmission* – 0% in favor, 16.667% opposed, 4 abstention; *Supplier* – 0% in favor, 16.667% opposed, 6 abstentions; *Publicly Owned Entity* – 16.667% in favor, 0% opposed, 0 abstentions; *Alternative Resources* – 0% in favor, 16.5% opposed, 2 abstentions; and *End User* – 0% in favor, 16.667% opposed, 0 abstentions. In addition, the votes from Provisional Members were 0% in favor, 0.167% opposed, and 0 abstentions.

[15] To review the Markets Committee Chair/Vice-Chair Memorandum, please click here.

amendments.[16] Collectively, UCS Amendments #1 and #2 reduced the off-shore wind ORTP value to $0.000/kW-month. Thus, this updated value is reflected in the MC-recommended proposal that the Participants Committee will consider as the main motion at its December 3 meeting.

Second, after the Markets Committee meeting, the ISO incorporated changes to address a correction in the dispatch model for the Simple Cycle technology.[17] As a result, nearly all of the FCM parameter values were updated to reflect this change, including ORTP values that were amended by the Markets Committee-supported amendments. We expect the ISO's updated values for the FCM parameters will be incorporated into the ISO proposal that the Participants Committee will likely consider following its vote on the Markets Committee-recommended proposal. Furthermore, the updated ORTPs can also be included in the Markets Committee-recommended proposal unless a Participant objects. In that case, the corrections would have to be voted in the form of a motion to amend the Markets Committee-recommended proposal.

For the sake of convenience, the following table provides the Markets Committee-recommended ORTP values, as well as the ISO's updated values for all FCM parameters.

Updated Values for CONE, Net CONE, and PPR		
CONE	$11.874/kW-month	
Net CONE	$7.024/kW-month	
PPR	$8,782/MWh	
Updated ORTPs		
Generating Capacity Resources		
Technology Type	**ISO-NE's ORTP ($/kW-month)**	**Markets Committee-Supported ORTP ($/kW-month)**
Simple Cycle Combustion Turbine	$5.366	$5.366
Combined Cycle Gas Turbine	$9.819	$9.819
On-Shore Wind	$0.000	$0.000
Off-Shore Wind	N/A	$0.000
Energy Storage Device – Lithium Ion Battery	$2.923	$2.612[18]
Photovoltaic Solar	N/A	$1.861[19]

[16] The remaining ORTPs presented either by the ISO or by UCS were unaffected by UCS Amendment #1 because the project life of the technology type remained at 20 years, or the ORTP value presented at the Markets Committee meeting has already assumed a project life beyond 20 years. For example, the Simply Cycle Combustion Turbine project life remained at 20 years, while the expected project life for a Photovoltaic Solar project was assumed to be 30 years, as explained in UCS's presentation.

[17] For more information, please click here to review the CEA/MM memorandum addressing this issue.

[18] UCS Amendment #4 offered an ORTP of $2.615/kW-month, which was presented at the Markets Committee meeting. The value indicated in the table, however, reflects the revised ORTP caused by the ISO's correction in the dispatch model for the Simple Cycle.

[19] As noted at the Markets Committee, UCS's Amendment #1 applied a 30-year expected project life for photovoltaic solar projects, which resulted in an ORTP for solar of $1.872/kW-month. The value

Demand Capacity Resources	
Technology Type	**ORTP ($/kW-month)**
Load Management (Commercial / Industrial)	$0.761
Previously Installed Distributed Generation	$0.761
New Distributed Generation	Based on generation technology type
On-Peak Solar	$5.425
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$7.376
Energy Efficiency	$0.000

Pursuant to NEPOOL's process and absent objection, the Markets Committee-supported proposal, which includes the five approved amendments to the ISO proposal, with the re-calculated and updated ORTPs to reflect the correction in the dispatch model for the Simple Cycle technology, will be the main motion for Participants Committee approval. If the Markets Committee-recommended alternative proposal (regardless of whether it is further amended or not) is approved by the Participants Committee, ISO-NE may still request a separate vote on its ISO proposal.[20]

We have been advised of at least one amendment to be offered for Participants Committee consideration. First, a Jericho Power-sponsored amendment (on behalf of NEPGA) that would correct the Forward Reserve Market (FRM) clearing prices to account for the impact of the CONE unit has on FRM clearing prices and would set the obligation quantities constant across the FRM periods. For more information, please review Attachment E. As indicated, this amendment was previously considered but failed to pass at the Markets Committee. Second, we have been advised that due to an on-going discussion between the ISO/IMM and a group of Participants regarding potential ORTP-related treatment for co-located resources, one or more additional amendments may be offered at the December 3 meeting. If anyone else wishes to offer amendments for Participants Committee consideration, please provide those amendments to NEPOOL Counsel (slombardi@daypitney.com or rgarza@daypitney.com) as soon as possible so that we can circulate them in time for member review and consideration before the meeting.

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

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

indicated in the table, however, reflects the revised ORTP caused by the ISO's correction in the dispatch model for the Simple Cycle technology.

[20] The ISO is entitled to have a vote on its proposal under Section 11.1.3 of the Participants Agreement if its proposal is modified in a way that the ISO does not support, with only those changes it does find acceptable, even if an alternative proposal has already passed.

ISO-NE Public

- **Yellow highlighted values are the ISO's revised values posted on November 24, 2020**
- **Green highlighted values are ORTPs presented by Union of Concerned Scientists (on behalf of RENEW) and voted upon by the Markets Committee at the November 9–10, 2020 meeting**
- **Blue highlighted values reflect updates to the ORTPs after the ISO revised its values on November 24, 2020 to the Markets Committee-supported ORTP values that are offered for the Participants Committee consideration**

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

* * *

Net CONE is an estimate of the Cost of New Entry, net of ~~the first year~~ non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require~~, in its first year of operation,~~ to be economically viable given reasonable expectations of the ~~first year~~ energy and ancillary services revenues under long-term equilibrium conditions~~, and projected revenue for subsequent years~~.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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

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

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

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

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

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Resource Economic Life is the number of years that is the lesser of (a) the period of time that a New Capacity Resource of a given technology type or types would reasonably be expected to operate before the resource becomes unprofitable for at least two consecutive years, (b) the expected physical operating life of the resource, or (c) 35 years.

* * *

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

* * *

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

* * *

III.13.2. Annual Forward Capacity Auction.

* * *

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

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

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 ~~2021~~ is $11.874~~11.35~~/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 ~~2021~~ is $7.024~~8.04~~/kW-month.

CONE and Net CONE shall be recalculated ~~for the Capacity Commitment Period beginning on June 1, 2025 and~~ no less often than once every three years ~~thereafter~~. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section III.A.21.1.2(e)(5) shall not apply). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

* * *

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

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

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

* * *

III.13.7.2 Capacity Performance Payments.

* * *

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 ~~and thereafter~~, the Capacity Performance Payment Rate shall be $5455/MWh. For the Capacity

Commitment Period beginning on June 1, 2025 and ending on May 31, 2026 and thereafter, the Capacity Performance Payment Rate shall be $8782/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

* * *

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

* * *

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

* * *

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ~~twelfth Forward Capacity Auction (for the~~ Capacity Commitment Period beginning on June 1, 2025~~2021)~~ shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Simple Cycle ~~c~~Combustion ~~t~~Turbine	$5.366~~6.503~~

~~c~~Combined ~~c~~Cycle ~~g~~Gas ~~t~~Turbine	$9.819~~7.856~~
~~o~~On-~~s~~Shore ~~w~~Wind	$0.000~~11.025~~
Off-Shore Wind	$0.000 ~~1.533~~
Energy Storage Device – Lithium Ion Battery	$2.612 ~~2.615~~ ~~2.923~~
Photovoltaic Solar	$1.861 ~~1.872~~

Demand Capacity Resources~~ – Commercial and Industrial~~	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management (Commercial / Industrial)~~and/or previously installed Distributed Generation~~	$0.761~~1.008~~
Previously Installed Distributed Generation	$0.761
~~n~~New Distributed Generation	~~b~~Based on generation technology type
On-Peak Solar	$5.425
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$7.376
Energy Efficiency	$0.000

~~**Demand Capacity Resources – Residential**~~	
~~**Technology Type**~~	~~**Offer Review Trigger Price ($/kW-month)**~~
~~Load Management~~	~~$7.559~~

~~previously installed Distributed Generation~~	~~$1.008~~
~~new Distributed Generation~~	~~based on generation technology type~~
~~Energy Efficiency~~	~~$0.000~~

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at ~~20 years of~~ real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties), over the New Capacity Resource Economic Life of the project.

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) For the simple cycle combustion turbine and combined cycle gas turbine technology types, ~~E~~each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.~~associated with the indices included in the table below:~~

~~Cost Component~~	~~Index~~
~~gas turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~steam turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~wind turbines~~	~~Bloomberg Wind Turbine Price Index~~
~~Other Equipment~~	~~BLS-PPI "General Purpose Machinery and Equipment"~~

~~construction labor~~	~~BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay:~~ – ~~Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ – ~~On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~other labor~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ – ~~Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ – ~~On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials~~	~~BLS-PPI "Materials and Components for Construction"~~
~~electric interconnection~~	~~BLS - PPI "Electric Power Transmission, Control, and Distribution"~~
~~gas interconnection~~	~~BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"~~
~~fuel inventories~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

~~(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~
~~labor, administrative and general~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ – ~~Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ – ~~On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials and contract services~~	~~BLS-PPI "Materials and Components for Construction"~~
~~site leasing costs~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

(2~~3~~) For each line item in (1) ~~and (2)~~ above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices ~~for the FCA~~ reflected in the table in Section III.A.21.1.1 ~~above~~. The value of each line item associated with capital costs ~~and fixed operating and maintenance costs included~~ in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 ~~above~~ will be adjusted by the relevant multiplier.

(3~~4~~) The energy and ancillary services offset values for gas~~each~~ technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the ~~most recent~~ Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak ~~On-Peak~~ electricity prices, as published by ICE for the first five trading days in February, for each~~the~~ months ~~in the Capacity Commitment Period~~ ~~beginning June 1~~ of the Capacity Commitment Period to which the updated value will apply~~, 2021, as published by ICE~~.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(4~~5~~) Renewable energy credit values in the capital budgeting model shall be updated based on the first~~most recent~~ MA Class 1 REC prices published in February for the five vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The Production Tax Credit and Investment Tax Credit inputs into the capital budgeting model will be updated to reflect the most current tax law at the time of the update.

(7)~~(6)~~ The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(8)~~(7)~~ If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

> For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

> For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated

with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, New Capacity Resource Economic Life, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. For a new Capacity Resource with an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used in Section III.A.21.1.2(b) to calculate the Offer Review Trigger Price for the corresponding technology type, the Project Sponsor shall provide sufficient documentation as described in Section III.A.21.2(b)(iv) to justify its expected New Capacity Resource Economic Life. The Internal Market Monitor shall consider the documentation provided. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. For a New Capacity Resource that has an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used to calculate the Offer Review Trigger Price for the relevant technology type in Section III.A.21.1.2(b), the Project Sponsor shall provide evidence to support the expected New Capacity Resource Economic Life, including but not limited to, the asset life term for such resource as utilized in the Project Sponsor's financial accounting (e.g., independently audited financial statements); or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the Project Sponsor has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee); or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. The Project Sponsor may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an expected New Capacity Resource Economic Life other than the New Capacity Resource Economic Life of similar projects. If there are multiple technology types in the New Capacity Resource, the New Capacity Resource Economic Life should reflect the weighted average of the New Capacity Resource Economic Life of each of the technology types. For a New Capacity Resource that is receiving an out-of-market revenue source and that is seeking a different Weighted Average Cost of Capital than the Net CONE reference unit, the Project Sponsor must submit documentation to demonstrate that the requested Weighted Average Cost of Capital is consistent with that of a resource not receiving out-of-market revenues. This documentation could include but not be limited to publicly available information sources or private information relevant to projects in North America that are not receiving out-of-market revenues. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market

Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

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ISO-NE Public

(Revision Posted November 24, 2020)

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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

* * *

Net CONE is an estimate of the Cost of New Entry, net of ~~the first-year~~ non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require~~, in its first year of operation,~~ to be economically viable given reasonable expectations of the ~~first year~~ energy and ancillary services revenues under long-term equilibrium conditions~~, and projected revenue for subsequent years~~.

* * *

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

* * *

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

* * *

III.13.2. Annual Forward Capacity Auction.

* * *

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

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

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 ~~2021~~ is $11.874~~11.35~~/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 ~~2021~~ is $7.024~~8.04~~/kW-month.

CONE and Net CONE shall be recalculated ~~for the Capacity Commitment Period beginning on June 1, 2025 and~~ no less often than once every three years ~~thereafter~~. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section III.A.21.1.2(e)(5) shall not apply). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

* * *

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

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

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

* * *

III.13.7.2 Capacity Performance Payments.

* * *

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025~~ and thereafter~~, the Capacity Performance Payment Rate shall be $5455/MWh. For the Capacity Commitment Period beginning on June 1, 2025 and ending on May 31, 2026 and thereafter, the Capacity Performance Payment Rate shall be $8782/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

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SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

* * *

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

* * *

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ~~twelfth Forward Capacity Auction (for the~~ Capacity Commitment Period beginning on June 1, 2025~~2021)~~ shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Simple Cycle ~~c~~Combustion ~~t~~Turbine	$5.366~~6.503~~
~~c~~Combined ~~c~~Cycle ~~g~~Gas ~~t~~Turbine	$9.819~~7.856~~

~~o~~On-~~s~~Shore ~~w~~Wind	$0.000~~11.025~~
Energy Storage Device – Lithium Ion Battery	$2.923

Demand Capacity Resources~~ – Commercial and Industrial~~	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management (Commercial / Industrial)~~and/or previously installed Distributed Generation~~	$0.761~~1.008~~
Previously Installed Distributed Generation	$0.761
~~n~~New Distributed Generation	~~b~~Based on generation technology type
On-Peak Solar	$5.425
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$7.376
Energy Efficiency	$0.000

~~**Demand Capacity Resources – Residential**~~	
~~**Technology Type**~~	~~**Offer Review Trigger Price ($/kW-month)**~~
~~Load Management~~	~~$7.559~~
~~previously installed Distributed Generation~~	~~$1.008~~
~~new Distributed Generation~~	~~based on generation technology type~~
~~Energy Efficiency~~	~~$0.000~~

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) For the simple cycle combustion turbine and combined cycle gas turbine technology types, ~~E~~each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.~~associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~
~~gas turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~steam turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~wind turbines~~	~~Bloomberg Wind Turbine Price Index~~
~~Other Equipment~~	~~BLS-PPI "General Purpose Machinery and Equipment"~~
~~construction labor~~	~~BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay:~~ ~~– Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~– On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~

~~other labor~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ ~~– Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~– On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials~~	~~BLS-PPI "Materials and Components for Construction"~~
~~electric interconnection~~	~~BLS - PPI "Electric Power Transmission, Control, and Distribution"~~
~~gas interconnection~~	~~BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"~~
~~fuel inventories~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

~~(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~
~~labor, administrative and general~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ ~~– Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~– On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials and contract services~~	~~BLS-PPI "Materials and Components for Construction"~~
~~site leasing costs~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

(2~~3~~) For each line item in (1) ~~and (2)~~ above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices ~~for the FCA~~ reflected in the table in Section III.A.21.1.1 ~~above~~. The value of each line item associated with capital costs~~ and fixed operating and maintenance costs included~~ in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1~~ above~~ will be adjusted by the relevant multiplier.

(3~~4~~) The energy and ancillary services offset values for gas~~each~~ technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the ~~most recent~~ Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak~~ On-Peak~~ electricity prices, as published by ICE for the first five trading days in February, for each~~the~~ month~~s in the Capacity Commitment Period~~ ~~beginning June 1~~ of the Capacity Commitment Period to which the updated value will apply~~, 2021, as published by ICE~~.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(4~~5~~) Renewable energy credit values in the capital budgeting model shall be updated based on the first~~most recent~~ MA Class 1 REC prices published in February for the five vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

* * *

memo

To: NEPOOL Markets Committee

From: Deborah Cooke, Principal Analyst

Date: November 3, 2020

Subject: Cost of New Entry, Net Cost of New Entry, Offer Review Trigger Prices and Performance Payment Rate (WMPP IDs: 139 and 144)

The ISO is requesting a vote on the Cost of New Entry (CONE), Net CONE, Offer Review Trigger Prices (ORTPs), and Performance Payment Rate (PPR) parameters and associated Tariff revisions proposed for use in the sixteenth Forward Capacity Auction (FCA 16) for the 2025-26 Capacity Commitment Period. The CONE, Net CONE, ORTPs, and PPR parameters have been calculated without the inclusion of the Energy Security Improvements (ESI)[1] and assuming continuation of the Forward Reserve Market (FRM).[2]

The proposed CONE and Net CONE values are based on the estimated entry costs for a new combustion turbine unit in New England, which has been identified as the lowest cost, economically viable technology likely to be built in the region. ORTP values are being proposed for gas turbine, combined cycle, on-shore wind, battery, energy efficiency and demand response technologies. The proposed PPR value is based upon the combustion turbine technology recommended for the proposed CONE and Net CONE values. The CONE, Net CONE and ORTP values are based upon recommendations from Concentric Energy Advisors and its subcontractor, Mott MacDonald, who were retained to conduct an independent analysis of these values.

Tariff revisions are also proposed to align the calculations for updating the Energy and Ancillary Service revenues for CONE, Net CONE and ORTPs in the years where a full recalculation of the values is not performed, and to revise the indices used to update these revenues.

The ISO's proposal incorporates a number of stakeholder-suggested revisions and is the product of extensive discussion with stakeholders. The proposal for the committee's consideration at its November 9-10 meeting has been presented previously to the Markets Committee at the meeting dates outlined below:

- May 12, 2020; agenda item 7: https://www.iso-ne.com/event-details?eventId=140261

[1] On October 30, 2020, the Federal Energy Regulatory Commission rejected both ISO New England's and NEPOOL's ESI proposals. *See ISO New England Inc.,* 173 FERC ¶ 61,106 (2020).

[2] *See* ISO New England's September 30, 2020 FRM Sunset voting memo (https://www.iso-ne.com/static-assets/documents/2020/09/a4_frm_sunset_voting_memo_frm_sunset.pdf). In the event the Commission issued an order in the ESI proceeding that did not provide for the procurement of Ten-Minute Non-Spinning Reserve and Thirty-Minute Operating Reserve on a day-ahead basis starting no later than June 1, 2025, the proposed FRM Sunset changes would not be filed.

- June 10, 2020; agenda item 7: https://www.iso-ne.com/event-details?eventId=140274
- July 14-15, 2020; agenda items 5B & 5D: https://www.iso-ne.com/event-details?eventId=140277
- August 11-13, 2020; agenda items 4A & 4D: https://www.iso-ne.com/event-details?eventId=140275
- September 8-10, 2020; agenda items 6A & 6C: https://www.iso-ne.com/event-details?eventId=142578
- October 6-8, 2020; agenda item 5B: https://www.iso-ne.com/event-details?eventId=140267
- October 26, 2020; agenda item 2: https://www.iso-ne.com/event-details?eventId=144341

memo

To: Participants Committee

From: Erin Wasik-Gutierrez, Secretary, Markets Committee

Date: November 11, 2020

Subject: Actions of the Markets Committee (MC)

This memo is notification to the Participants Committee of the following actions taken by the MC at its November 9-10, 2020 meeting. All sectors had a quorum.

1. **(Agenda Item 2) Order No. 841 Electric Storage Participation in Markets: Further Compliance**

ACTION: RECOMMEND SUPPORT

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

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Tariff section I.2.2, and sections III.1.10.6 and III.C.6 of Market Rule 1 related to FERC's August 4, 2020 order requiring further compliance with Order No. 841 - Electric Storage Participation in Markets, as proposed by ISO New England and as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was then voted, and passed unanimously based on a voice vote.

2. **(Agenda Item 3) Modifications to the Qualification of Energy Efficiency in the Forward Capacity Market**

ACTION: RECOMMEND SUPPORT

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

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to sections III.13.1.4, III.13.4.2, III.13.4.3, III.13.5.1, III.13.6.1.5, and III.13.7.2.4 of Market Rule 1 modifying the Forward Capacity Auction qualification for Demand Capacity Resources comprised of Energy Efficiency (EE) measures in order to better account for expiring measures, as proposed by ISO New England and as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was then voted and passed based on a voice vote. 4 abstentions from the Generation Sector, 1 opposed and 2 abstentions from the Transmission Sector, 4 abstentions from the Supplier Sector, and 1 opposed and 3 abstentions from the AR Sector were recorded.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-540-4518
EWasikGutierrez@iso-ne.com

3. <u>(Agenda Item 4) Forward Capacity Market Parameters Updates for the 2025-26 Capacity Commitment Period: Cost of New Entry (CONE), Net CONE, Offer Review Trigger Prices (ORTPs) and Performance Payment Rate</u>

<u>ACTION: RECOMMEND SUPPORT</u>[1]

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

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Tariff section I.2.2 and sections III.13.2.4, III.13.7.2.5, III.A.21.1.1 and III.A.21.2 of Market Rule 1 reflecting updates to CONE, Net CONE, and the Performance Payment Rate, and recalculating existing and establishing new ORTPs using updated data for FCA 16, as proposed by ISO New England and as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

<u>(Vote 1 – Failed (Agenda Item No. 4(B)(i) - Jericho Power (on behalf of NEPGA) Amendment #2: Costs associated with gas delivery to the reference unit including on-site compression and lateral system upgrades))</u>

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

RESOLVED, that the main motion be amended to reflect the changes to section III.13.2.4 of Market Rule 1 as contained in the materials provided by Jericho Power, on behalf of NEPGA, adjusting the ISO's proposed calculations for costs associated with gas delivery to the reference unit including on-site compression and lateral system upgrades, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted. The motion failed to pass with a vote of 49.900% in favor. The individual Sector votes were Generation (16.700% in favor, 0.000% opposed, 1 abstention), Transmission (0.000% in favor, 16.700% opposed, 0 abstentions), Supplier (16.700% in favor, 0.000% opposed, 6 abstentions), Publicly Owned Entity (0.000% in favor, 16.700% opposed, 0 abstentions), Alternative Resources (16.500% in favor, 0.000% opposed, 1 abstention), and End User (0.000% in favor, 16.700% opposed, 3 abstentions).

<u>(Vote 2 – Failed (Agenda Item No. 4(B)(ii) - Jericho Power (on behalf of NEPGA) Amendment #3: Qualified capacity value for the reference unit))</u>

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

RESOLVED, that the main motion be amended to reflect the changes to section III.13.2.4 of Market Rule 1 as contained in the materials provided by Jericho Power, on behalf of NEPGA, adjusting the ISO's proposed calculations by using a different qualified capacity value for the reference unit, as circulated

[1] Due to rounding, the percentages in favor for Votes 8-12 and 14 vary slightly from what was reported during the meeting.

for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted. The motion failed to pass with a vote of 49.900% in favor. The individual Sector votes were Generation (16.700% in favor, 0.000% opposed, 1 abstention), Transmission (0.000% in favor, 16.700% opposed, 0 abstentions), Supplier (16.700% in favor, 0.000% opposed, 6 abstentions), Publicly Owned Entity (0.000% in favor, 16.700% opposed, 0 abstentions), Alternative Resources (16.500% in favor, 0.000% opposed, 1 abstention), and End User (0.000% in favor, 16.700% opposed, 4 abstentions).

(Vote 3 – Failed (Agenda Item No. 4(B)(iii) - Jericho Power (on behalf of NEPGA) Amendment #4A: Proposed Energy and Ancillary Service revenue offset methodologies))

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

RESOLVED, that the main motion be amended to reflect the changes to Tariff Section I.2.2. and section III.13.2.4 of Market Rule 1 as contained in the materials provided by Jericho Power, on behalf of NEPGA, adjusting the ISO's proposed calculations related to the proposed Energy and Ancillary Service revenue offset methodologies, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted by roll call. The motion failed to pass with a vote of 49.950% in favor. The individual Sector votes were Generation (16.683% in favor, 0.000% opposed, 1 abstention), Transmission (0.000% in favor, 16.683% opposed, 0 abstentions), Supplier (16.683% in favor, 0.000% opposed, 6 abstentions), Publicly Owned Entity (0.000% in favor, 16.683% opposed, 0 abstentions), Alternative Resources (16.500% in favor, 0.000% opposed, 3 abstentions), and End User (0.000% in favor, 16.683% opposed, 5 abstentions). In addition, the votes from Provisional Members were (0.083% in favor, 0.000% opposed, 0 abstentions).

(Vote 4 – Failed (Agenda Item No. 4(B)(iv) - Jericho Power (on behalf of NEPGA) Amendment #4B: Derivation of Capacity Scarcity Condition hours))

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

RESOLVED, that the main motion be amended to reflect the changes to section III.13.2.4 of Market Rule 1 as contained in the materials provided by Jericho Power, on behalf of NEPGA, adjusting the ISO's proposed calculations related to the derivation of Capacity Scarcity Condition hours, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted by roll call. The motion failed to pass with a vote of 49.950% in favor. The individual Sector votes were Generation (16.683% in favor, 0.000% opposed, 1 abstention), Transmission (0.000% in favor, 16.683% opposed, 0 abstentions), Supplier (16.683% in favor, 0.000% opposed, 6 abstentions), Publicly Owned Entity (0.000% in favor, 16.683% opposed, 0 abstentions), Alternative Resources (16.500% in favor, 0.000% opposed, 1 abstention), and End User (0.000% in favor, 16.683% opposed, 7 abstentions). In addition, the votes from Provisional Members were (0.083% in favor, 0.000% opposed, 0 abstentions).

(Vote 5 – Failed (Agenda Item No. 4(B)(v)(a) - Jericho Power (on behalf of NEPGA) Amendment #6: Owner's Development Cost Value))

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

RESOLVED, that the main motion be amended to reflect the changes to section III.13.2.4 of Market Rule 1 as contained in the materials provided by Jericho Power, on behalf of NEPGA, adjusting the ISO's proposed calculations related to the owner's development cost value, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted by roll call. The motion failed to pass with a vote of 49.950% in favor. The individual Sector votes were Generation (16.683% in favor, 0.000% opposed, 1 abstention), Transmission (0.000% in favor, 16.683% opposed, 0 abstentions), Supplier (16.683% in favor, 0.000% opposed, 6 abstentions), Publicly Owned Entity (0.000% in favor, 16.683% opposed, 0 abstentions), Alternative Resources (16.500% in favor, 0.000% opposed, 3 abstentions), and End User (0.000% in favor, 16.683% opposed, 7 abstentions). In addition, the votes from Provisional Members were (0.083% in favor, 0.000% opposed, 0 abstentions).

(Vote 6 - Failed (Agenda Item No. 4(B)(v)(b) - Jericho Power (on behalf of NEPGA) Amendment #6: Owner's Contingency Cost Value))

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

RESOLVED, that the main motion be amended to reflect the changes to section III.13.2.4 of Market Rule 1 as contained in the materials provided by Jericho Power, on behalf of NEPGA, adjusting the ISO's proposed calculations related to the owner's contingency cost value, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted by roll call. The motion failed to pass with a vote of 49.950% in favor. The individual Sector votes were Generation (16.683% in favor, 0.000% opposed, 1 abstention), Transmission (0.000% in favor, 16.683% opposed, 0 abstentions), Supplier (16.683% in favor, 0.000% opposed, 6 abstentions), Publicly Owned Entity (0.000% in favor, 16.683% opposed, 0 abstentions), Alternative Resources (16.500% in favor, 0.000% opposed, 3 abstentions), and End User (0.000% in favor, 16.683% opposed, 7 abstentions). In addition, the votes from Provisional Members were (0.083% in favor, 0.000% opposed, 0 abstentions).

(Vote 7 – Failed (Agenda Item No. 4(B)(vii) - Jericho Power (on behalf of NEPGA) Amendment: Costs associated with electrical interconnection of the reference unit, including network upgrade costs))

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

RESOLVED, that the main motion be amended to reflect the changes to section III.13.2.4 of Market Rule 1 as contained in the materials provided by Jericho Power, on behalf of NEPGA, adjusting the ISO's proposed calculations for costs associated with electrical interconnection of the reference unit, including network upgrade costs, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted by roll call. The motion failed to pass with a vote of 49.950% in favor. The individual Sector votes were Generation (16.683% in favor, 0.000% opposed, 1 abstention), Transmission (0.000% in favor, 16.683% opposed, 0 abstentions), Supplier (16.683% in favor, 0.000% opposed, 1 abstention), Publicly Owned Entity (0.000% in favor, 16.683% opposed, 0 abstentions), Alternative Resources (16.500% in favor, 0.000% opposed, 3 abstentions), and End User (0.000% in favor, 16.683% opposed, 7 abstentions). In addition, the votes from Provisional Members were (0.083% in favor, 0.000% opposed, 0 abstentions).

(Vote 8 – Passed (Agenda Item No. 4(B)(viii) - Union of Concerned Scientists (on behalf of RENEW Northeast) Amendment #2: ORTP project economic lifetime modeling assumption))

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

RESOLVED, that the main motion be amended to reflect the changes to Tariff section I.2.2, and sections III.A.21.1.1 and III.A.21.1.2 of Market Rule 1 as contained in the materials provided by Union of Concern Scientists, on behalf of RENEW Northeast, adjusting the ISO's proposed calculations related to the ORTP project economic lifetime modeling assumption, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted by roll call. The motion to amend the main motion passed with a vote of 64.732% in favor. The individual Sector votes were Generation (5.556% in favor, 11.111% opposed, 1 abstention), Transmission (11.111% in favor, 5.556% opposed, 1 abstention), Supplier (2.778% in favor, 13.889% opposed, 9 abstentions), Publicly Owned Entity (16.667% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (11.786% in favor, 4.714% opposed, 1 abstention), and End User (16.667% in favor, 0.000% opposed, 1 abstention). In addition, the votes from Provisional Members were (0.167% in favor, 0.000% opposed, 1 abstention).

(Vote 9 – Passed (Agenda Item No. 4(B)(ix) - Borrego Solar Systems and Enel X Amendment: Adding clarification to the unit-specific ORTP review process, including the maximum financial life))

Before the once-amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the once-amended main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to Tariff section I.2.2 and section III.A.21.2 of Market Rule 1 as contained in the materials provided by Borrego Solar Systems and Enel X adjusting the ISO's proposed calculations relating to the unit-specific ORTP review process including the maximum financial life, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the once-amended main motion was then voted by roll call. The motion to amend the once-amended main motion passed with a vote of 68.065% in favor. The individual Sector votes were Generation (3.333% in favor, 13.333% opposed, 2 abstentions), Transmission (16.667% in favor, 0.000% opposed, 1 abstention), Supplier (2.778% in favor, 13.889% opposed, 9 abstentions), Publicly Owned Entity (16.667% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (11.786% in favor, 4.714% opposed, 1 abstention), and End User (16.667% in favor, 0.000% opposed, 0 abstentions). In addition, the votes from Provisional Members were (0.167% in favor, 0.000% opposed, 1 abstention).

(Vote 10 – Passed (Agenda Item No. 4(B)(x) - Union of Concerned Scientists (on behalf of RENEW Northeast) Amendment #1: ORTP offshore wind capital cost and Investment Tax Credit assumptions))

Before the twice-amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the twice-amended main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to section III.A.21.1.1 of Market Rule 1 as contained in the materials provided by Union of Concerned Scientists, on behalf of RENEW Northeast, adjusting the ISO's proposed calculations related to ORTP offshore wind capital cost and Investment Tax Credit assumptions, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the twice-amended main motion was then voted by roll call. The motion to amend the twice-amended main motion passed with a vote of 66.784% in favor. The individual Sector votes were Generation (2.781% in favor, 13.903% opposed, 1 abstention), Transmission (16.683% in favor, 0.000% opposed, 1 abstention), Supplier (2.085% in favor, 14.598% opposed, 7 abstentions), Publicly Owned Entity (16.683% in favor, 0.000% opposed, 25 abstentions), Alternative Resources (11.786% in favor, 4.714% opposed, 1 abstention), and End User (16.683% in favor, 0.000% opposed, 1 abstention). In addition, the votes from Provisional Members were (0.083% in favor, 0.000% opposed, 1 abstention).

(Vote 11 – Passed (Agenda Item No. 4(B)(xi) - Union of Concerned Scientists (on behalf of RENEW Northeast) Amendment #3: ITC/PTC assumptions in the ORTP annual updates for FCAs 17 and 18))

Before the thrice-amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the thrice-amended main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to III.A.21.1.2 of Market Rule 1 as contained in the materials provided by Union of Concerned Scientists, on behalf of RENEW Northeast, adjusting the ISO's proposed calculations related to the ITC/PTC assumptions in the ORTP annual updates for FCAs 17 and 18, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the thrice-amended main motion was then voted by roll call. The motion to amend the thrice-amended main motion passed with a vote of 66.815% in favor. The individual Sector votes were Generation (2.778% in favor, 13.889% opposed, 1 abstention), Transmission (16.667% in favor, 0.000% opposed, 0 abstentions), Supplier (2.083% in favor, 14.583% opposed, 7 abstentions), Publicly Owned Entity (16.667% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (11.786% in favor, 4.714% opposed, 0 abstentions), and End User (16.667% in favor, 0.000% opposed, 0 abstentions). In addition, the votes from Provisional Members were (0.167% in favor, 0.000% opposed, 0 abstentions).

(Vote 12 – Passed (Agenda Item No. 4(B)(xiii) - Union of Concerned Scientists (on behalf of RENEW Northeast) Amendment #4: ORTP battery Energy and Ancillary Services revenue model assumption))

Before the four-time amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the four-time amended main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to III.A.21.1.1 of Market Rule 1 as contained in the materials provided by Union of Concern Scientists, on behalf of RENEW Northeast, adjusting the ISO's proposed calculations related to Energy and Ancillary Service revenue model assumption for the battery ORTP, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the four-time amended main motion was then voted by roll call. The motion to amend the four-time amended main motion passed with a vote of 67.404% in favor. The individual Sector votes were Generation (2.778% in favor, 13.889% opposed, 1 abstention), Transmission (16.667% in favor, 0.000% opposed, 1 abstention), Supplier (2.083% in favor, 14.583% opposed, 7 abstentions), Publicly Owned Entity (16.667% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (12.375% in favor, 4.125% opposed, 1 abstention), and End User (16.667% in favor, 0.000% opposed, 0 abstentions). In addition, the votes from Provisional Members were (0.167% in favor, 0.000% opposed, 0 abstentions).

(Vote 13 – Failed (Agenda Item No. 4(B)(xiv) - Jericho Power (on behalf of NEPGA) Amendment: Forecast Locational Forward Reserve Market Revenues for the Net CONE reference unit))

Before the five-time amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the five-time amended main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to section III.13.2.4 of Market Rule 1 as contained in the materials provided by Jericho Power, on behalf of NEPGA, adjusting the ISO's proposed calculations related to the Forecast Locational Forward Reserve Market for the Net CONE reference unit, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the five-time amended main motion was then voted by roll call. The motion to amend the five-time amended main motion failed to pass with a vote of 41.761% in favor. The individual Sector votes were Generation (14.286% in favor, 2.381% opposed, 0 abstentions), Transmission (0.000% in favor, 16.667% opposed, 0 abstentions), Supplier (16.667% in favor, 0.000% opposed, 6 abstentions), Publicly Owned Entity (0.000% in favor, 16.667% opposed, 0 abstentions), Alternative Resources (10.725% in favor, 5.775% opposed, 2 abstentions), and End User (0.000% in favor, 16.667% opposed, 5 abstentions). In addition, the votes from Provisional Members were (0.083% in favor, 0.083% opposed, 0 abstentions).

(Vote 14 – Passed (Five-time amended main motion))

The five-time amended main motion was voted. The five-time amended main motion passed with a vote of 64.040% in favor. The individual Sector votes were Generation (2.381% in favor, 14.286% opposed, 0 abstentions), Transmission (16.667% in favor, 0.000% opposed, 0 abstentions), Supplier (1.852% in favor, 14.815% opposed, 6 abstentions), Publicly Owned Entity (16.667% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (9.723% in favor, 6.777% opposed, 0 abstentions), and End User (16.667% in favor, 0.000% opposed, 0 abstentions). In addition, the votes from Provisional Members were (0.083% in favor, 0.083% opposed, 0 abstentions).

(Vote 15 – Failed (Unamended ISO Proposal))

The ISO proceeded to ask the Markets Committee to provide a vote on the ISO's unamended proposal. The motion failed to pass with a vote of 16.667%[2] in favor. The individual Sector votes were Generation (0.000% in favor, 16.667% opposed, 0 abstentions), Transmission (0.000% in favor, 16.667% not in favor, 4 abstentions), Supplier (0.000% in favor, 16.667% opposed, 6 abstentions), Publicly Owned Entity (16.667% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (0.000% in favor, 16.500% opposed, 2 abstentions), and End User (0.000% in favor, 16.667% opposed, 0 abstentions). In addition, the votes from Provisional Members were (0.000% in favor, 0.167% opposed, 0 abstentions).

[2] The 16.667% in favor, which correctly reflects the support of one Sector, is revised from the total reported during the meeting.

AMENDMENT TO CORRECT THE REFERENCE UNIT FORWARD RESERVE MARKET (FRM) REVENUE FORECAST

BRUCE ANDERSON
NEW ENGLAND POWER GENERATORS ASSOCIATION, INC.
NOVEMBER 9, 2020, NEPOOL MARKETS COMMITTEE MEETING

NEPGA PROPOSES MODIFICATIONS TO CORRECT THE CALCULATION OF FRM REVENUES TO ACCOUNT FOR TARIFF REQUIREMENTS AND AUCTION IMPACTS

- CEA is using the historical FRM clearing prices unadjusted, specifically without including the reference unit as FRM supply. NEPGA believes this overstates the FRM revenue potential and proposes to correct that overstatement by adjusting the FRM clearing price to account for the addition of the CONE unit to the FRM auction supply stack.

- Including the CONE unit in the FRM supply stack shows that it would supply between 7-8% of the total TMNSR procured and 30-41% of the total TMOR.

- Using foregone energy margin as FRM offer prices, the CONE unit would be inframarginal in six, and marginal in one of the seven seasonal markets CEA uses for historical FRM clearing prices. For purposes of this analysis, in the marginal case, the TMOR sale was rationed consistent with ISO-NE's operation of the FRM auction.

- Additionally, the quantity offered in the FRM winter season was set to the "standard" values. The FRM "winter" period runs 10/1 – 5/31, the FRM obligation is constant across the entire period, and significant penalties are assessed for non-performance. The CEA model assumes that the assigned FRM obligation may rise and fall monthly without regard to FRM consequences.

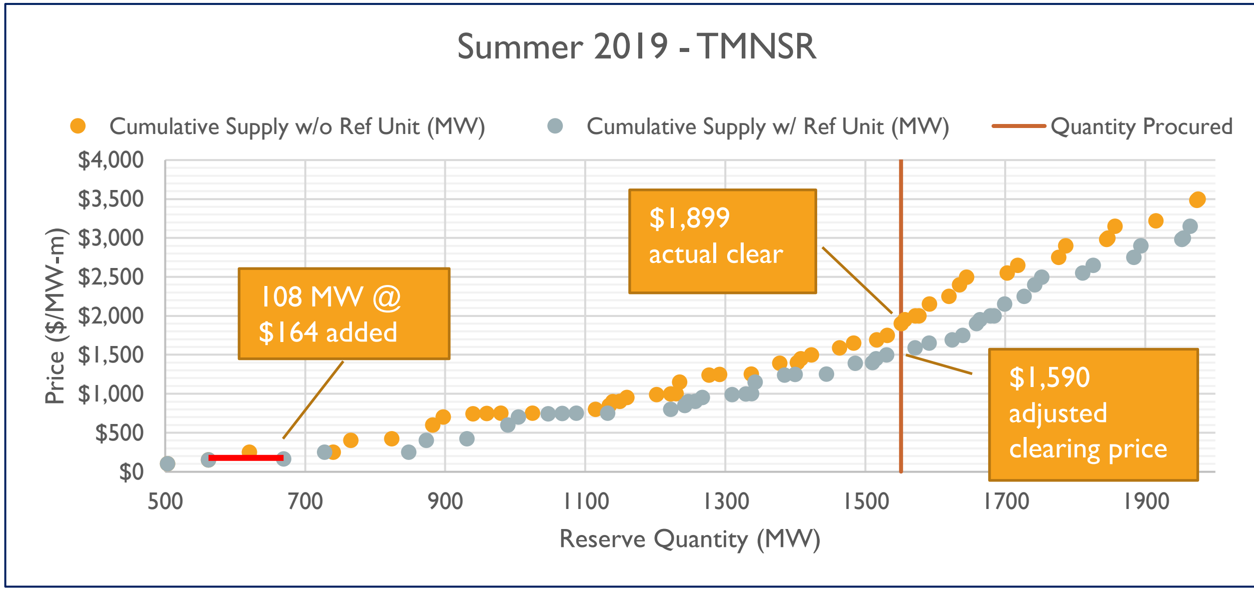
STEPS TO CORRECT FRM CLEARING PRICES – STEP 1

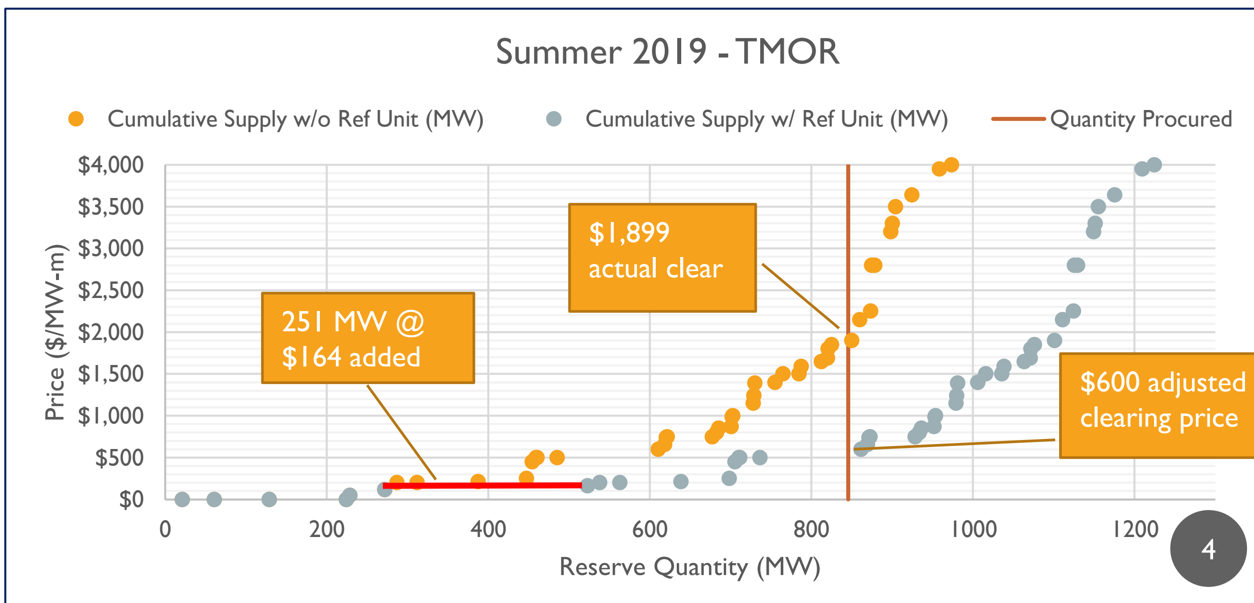
- NEPGA first calculated the gross energy margin (GEM) of the CONE unit under both (a) dispatch at actual cost (i.e., not restricted by FRM Threshold Price), and (b) with an FRM obligation.
  - GEM is defined as the total energy revenues, DA and RT, less production costs.
- The difference in GEM between those two cases is the foregone GEM the CONE unit faces under an FRM obligation (i.e., its opportunity cost).
- The opportunity cost was then used as the price of the supply offer in the FRM supply stack.

	Day-ahead market settlement ($)	RT energy payment ($)	Production costs: incremental energy ($)	Production costs: Start-up ($)	Gross Energy Margin ($)	Gross Energy Margin ($/kWm)	
FRM Case							
Winter 2016-17	$ (340,539)	$ 3,925,637	$ (1,862,133)	$ (308,000)	$ 1,414,964	$ 0.48	
Summer 2017	$ (526,351)	$ 4,272,483	$ (1,436,890)	$ (374,000)	$ 1,935,241	$ 1.35	
Winter 2017-18	$ 172,235	$ 12,578,020	$ (6,892,501)	$ (836,000)	$ 5,021,754	$ 1.69	
Summer 2018	$ 58,602	$ 8,860,069	$ (3,239,950)	$ (495,000)	$ 5,183,721	$ 3.61	
Winter 2018-19	$ 339,201	$ 7,931,146	$ (4,743,400)	$ (638,000)	$ 2,888,947	$ 0.97	
Summer 2019	$ 253,605	$ 1,877,381	$ (889,345)	$ (220,000)	$ 1,021,641	$ 0.71	
Winter 2019-20	$ -	$ 2,236,326	$ (1,308,913)	$ (209,000)	$ 718,413	$ 0.24	
							Opportunity Cost ($/MWm)
Merchant Case							
Winter 2016-17	$ (318,918)	$ 4,859,782	$ (2,535,973)	$ (308,000)	$ 1,696,890	$ 0.57	**$ 95**
Summer 2017	$ (468,852)	$ 5,717,024	$ (2,448,990)	$ (308,000)	$ 2,491,182	$ 1.74	**$ 388**
Winter 2017-18	$ 253,444	$ 14,379,546	$ (8,252,906)	$ (814,000)	$ 5,566,084	$ 1.88	**$ 184**
Summer 2018	$ (79,930)	$ 11,426,706	$ (5,077,865)	$ (418,000)	$ 5,850,911	$ 4.08	**$ 465**
Winter 2018-19	$ 694,886	$ 10,332,022	$ (6,468,154)	$ (671,000)	$ 3,887,755	$ 1.31	**$ 337**
Summer 2019	$ 250,216	$ 2,725,095	$ (1,531,198)	$ (187,000)	$ 1,257,112	$ 0.88	**$ 164**
Winter 2019-20	$ 7,896	$ 3,326,182	$ (2,118,886)	$ (187,000)	$ 1,028,191	$ 0.35	**$ 104**

STEPS TO CORRECT FRM CLEARING PRICES – STEP 2

- FRM auction supply stacks were retrieved from the ISO-NE website, ordered, and the CONE unit's supply offer was then inserted consistent with its opportunity cost under an FRM sale.
- The new, adjusted FRM clearing prices were determined by the point where the adjusted FRM supply stack and FRM demand intersected.
- Actual graphical examples from the Summer 2019 FRM auction are shown.





CORRECTED FRM CLEARING PRICES

- The corrected FRM clearing prices were converted from $/MW-month to $/MWh based on the quantity of on-peak hours in each respective period.
- The corrected FRM clearing prices were substituted into CEA's E&AS model.
- The resultant E&AS revenues were substituted into the DCF model, which yielded a Net CONE of $7.654/kWm, an increase of $0.653/kWm.

FRM period	TMNSR		TMOR	
	$/kW-mo	$/MWh	$/kW-mo	$/MWh
Winter 2019-20	$ 0.747	$ 2.20	$ 0.498	$ 1.46
Summer 2019	$ 1.590	$ 4.73	$ 0.600	$ 1.79
Winter 2018-19	$ 0.700	$ 2.05	$ 0.337	$ 0.99
Summer 2018	$ 1.500	$ 4.46	$ 0.500	$ 1.49
Winter 2017-18	$ 0.910	$ 2.68	$ 0.500	$ 1.47
Summer 2017	$ 1.950	$ 5.67	$ 0.800	$ 2.33
Winter 2016-17	$ 1.300	$ 1.92	$ 0.995	$ 1.47

SUMMARY

- CEA's use of historical FRM clearing prices without consideration of the effect the CONE unit would have on those clearing prices yields an inflated result.
  - The addition of CONE unit supply, equivalent to 7-8% of the TMNSR requirement and 31-40% of the TMOR requirement, will lower the FRM prices.
- CEA's allows the FRM obligation quantities to fluctuate monthly independent of the FRM period, which overstates the reference unit's ability to take on an FRM obligation by 7%.
- NEPGA proposes to correct the FRM clearing prices to account for the impact the CONE unit would have on those clearing prices and set the obligation quantities constant across the FRM periods.

LFRM REVENUE FORECAST – TARIFF LANGUAGE SUMMARY

Tariff Sections	Description of NEPGA LFRM Revenue Correction Amendment
III.13.2.4 Forward Capacity Auction Starting Price and the Cost of New Entry	Account for the impact the Net CONE unit has on the LFRM clearing price by including the Net CONE unit in the LFRM supply stack at its opportunity costs. ISO-NE Net CONE proposal = $7.001/kW-month Estimated impact on Net CONE = $7.654/kW-month

AMENDMENT TO CORRECT THE LFRM REVENUE FORECAST

Questions?

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MEMO

To: NEPOOL Participants Committee

From: RENEW Northeast

Date: November 24, 2020

Re: Cumulative Impact of RENEW's ORTP Amendments and Support for the Markets Committee Recommendation for the Offer Review Trigger Price Recalculation

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RENEW expresses its appreciation to NEPOOL participants for their feedback during the stakeholder process and support at the November Markets Committee (MC) meeting for its amendments. This memorandum explains the cumulative impact of the four RENEW amendments and its operation with the Borrego/Enel X amendment that were all adopted by the MC.

I. Overview of Cumulative Impact of Amendments

Following instructions for the MC meeting, each amendment was presented to the MC in isolation from the other amendments. The table below shows the cumulative impact of each RENEW amendment on ORTP values.

FCA 16 Parameters as Presented at November 9-10 MC (2025$/kW-mo)						
	ISO-NE	RENEW #1 Economic Life	RENEW #2 Offshore Wind Capex/ITC	RENEW #3 ITC/PTC Annual Updates	RENEW #4 Battery E&AS	Cumulative Impact
CONE						
Net CONE (Simple Cycle)	$7.001	No change	No change	No change	No change	No change
Gross CONE/Auction Starting Price	$11.87	No change	No change	No change	No change	No change
ORTP						
Onshore Wind	$(11.772)	$(16.439)	No change	No change	No change	$(16.439)
Offshore Wind	$44.421	$34.248	$1.533	No change	No change	$0.000
Solar	$11.893	$1.872	No change	No change	No change	$1.872
Battery Storage	$2.926	No change	No change	No change	$2.615	$2.615

Key Facts about the RENEW Amendments

- None have any effect on Net CONE or Gross CONE.

- The solar and onshore wind ORTPs are only changed by RENEW Amendment 1 on economic life.
- The battery ORTP is only changed by RENEW Amendment 4 on Battery E&AS revenues.
- The RENEW Amendment 3 on PTC/ITC annual updates does not result in any changes to the FCA 16 ORTP values (nor does the Borrego/Enel X amendment which is not shown in the table).
- The offshore wind ORTP is affected by Amendment 2 (capital cost and Investment Tax Credit) and Amendment 1 (economic life).

The cumulative effect of Amendments 1 and 2 on the offshore wind ORTP is calculated by applying the capital cost and Investment Tax Credit assumptions in Amendment 2 to the discounted cash flow model developed by RENEW for Amendment 1 that accounted for a New Capacity Resource Economic Life of 25 years for the wind technologies. This generated a value of $(3.358) in the ORTP model, which results in the Markets Committee recommended proposal containing an ORTP of $0.000/kW-month for the offshore wind technology.

Updates Since the November 9-10 MC Meeting

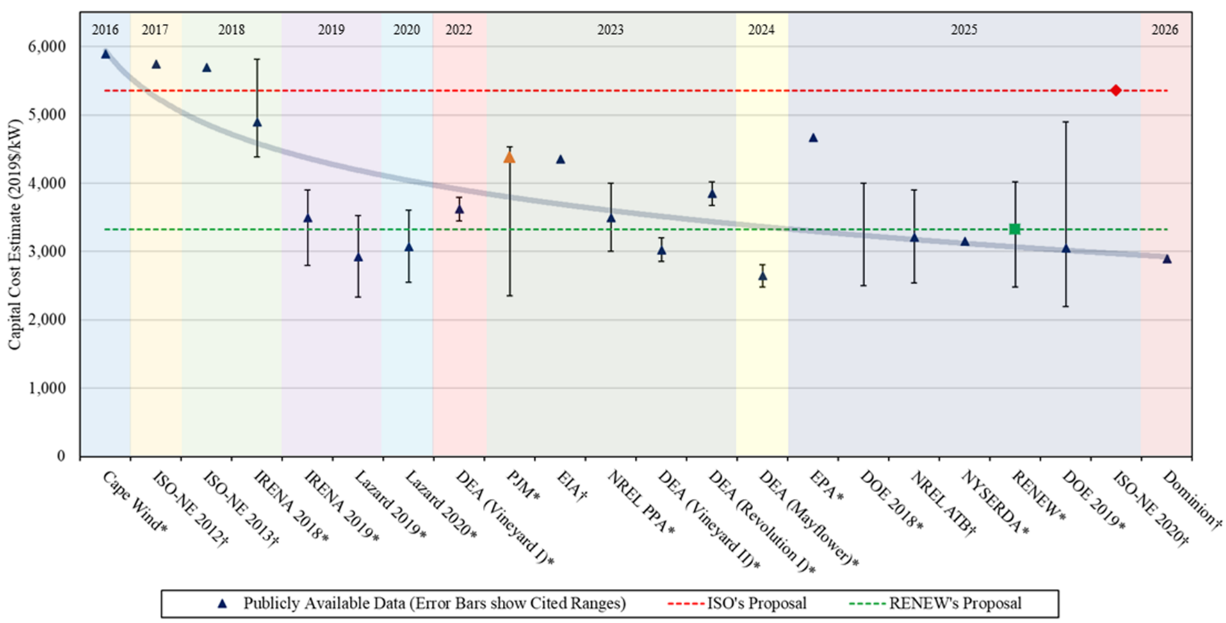
ISO-NE posted a revision to their Net CONE, ORTP, and PPR values on November 24 to reflect a correction to how they modeled FRM. The updated ISO values and resulting RENEW amendment values are shown in the following table.

FCA 16 Parameters Reflecting ISO-NE November 24 Update (2025$/kW-mo)						
	ISO-NE	RENEW #1 Economic Life	RENEW #2 Offshore Wind Capex/ITC	RENEW #3 ITC/PTC Annual Updates	RENEW #4 Battery E&AS	Cumulative Impact
CONE						
Net CONE (Simple Cycle)	$7.024	No change	No change	No change	No change	No change
Gross CONE/Auction Starting Price	$11.87	No change	No change	No change	No change	No change
ORTP						
Onshore Wind	$(11.775)	$(16.442)	No change	No change	No change	$(16.439)
Offshore Wind	$44.419	$34.246	$1.530	No change	No change	$0.000
Solar	$11.888	$1.861	No change	No change	No change	$1.861
Battery Storage	$2.923	No change	No change	No change	$2.612	$2.612

II. Markets Committee Recommendation for Offshore Wind Capital Costs and Investment Tax Credit Is Grounded in Data on Prevailing Market Expectations

The MC-recommended offshore wind amendment modifies the ISO's capital cost and Investment Tax Credit assumptions as they are far above prevailing market expectations for a project that is expected to begin commercial operation in 2025. The figure below, which RENEW presented at the November Markets Committee meeting and in an accompanying memo, shows ISO's assumption for capital costs is over sixty percent higher than the prevailing market expectations for 2025 projects. ISO-NE's consultant Mott MacDonald's bottom-up methodology to estimate the capital cost for the offshore wind ORTP is not reliable as it was not benchmarked against any publicly available data, either from a top-down or line item by line item viewpoint. RENEW's methodology for estimating expected capital costs is rooted in actual commercial commitments made by comparable projects and was extensively benchmarked against the current literature as shown in the chart below.

Publicly Available Offshore Wind Capital Cost Estimates



*Installed Capital Costs
†Overnight Capital Costs (excludes cost of interest during construction)
‡Shaded bands indicate the year of expected/actual COD

The ISO's high offshore wind capital cost assumption was developed by Mott MacDonald's offshore wind experts. On its website, Mott MacDonald highlights its work as the owner's and lender's engineer for the Block Island Wind Farm, a demonstration project built off the coast of Rhode Island in 2015/2016. While its website states it is working on several other East Coast offshore wind projects, Mott MacDonald offers no information on whether it has had experience working with any of the *winning* large-scale projects in more recent New England solicitations and whether it has the latest local cost trends in this quickly evolving industry.

Though RENEW has presented serious concerns related to the reasonableness of the offshore wind cost assumptions developed by Mott MacDonald for ISO, this does not imply any broader issue with the capital cost assumptions developed for other technologies. Mott MacDonald described to the MC how different teams of experts within the company prepared the bottom up cost estimates for each CONE/ORTP technology in accordance with the teams' specific expertise.

III. Markets Committee Recommendation on New Capacity Resource Economic Life Reflects Today's Expectations

The MC adopted an amendment by RENEW that will ensure the ORTP values reflect how renewable energy technologies currently have expected economic lives that go beyond the 20-year standard the ISO's ORTP model has previously used for all new generating technologies. The MC adopted another amendment by Borrego Solar and Enel X (Borrego/Enel) which does not change any ORTP values nor does it modify RENEW's economic lifetime amendment.

The RENEW amendment addresses the default economic life for the ORTP technologies, while the Borrego/Enel amendment addresses the determination of economic life for a project in the individual resource review process. For both amendments, a new definition was adopted that defines the New Capacity Resource Economic Life as "the number of years that is the lesser of (a) the period of time that a New Capacity Resource of a given technology type or types would reasonably be expected to operate before the resource becomes unprofitable for at least two consecutive years, (b) the expected physical operating life of the resource, or (c) 35 years.".

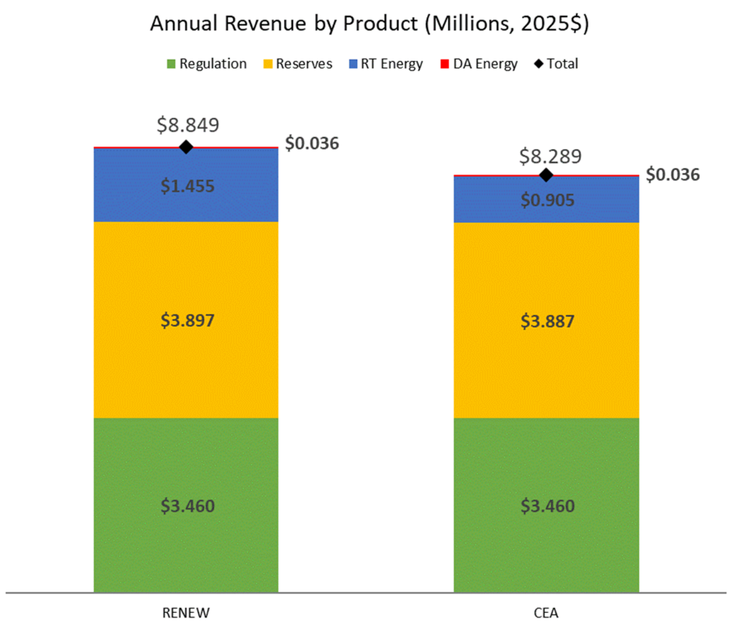
The addition of this definition and removal of the requirement in the generator ORTP calculation to model cash flows over 20 years within the Tariff enables the default economic life of the wind and solar technologies to reflect actual baseline commercial expectations—25 years for wind technologies and 30 years for solar technologies as included in the RENEW amendment.

The Borrego/Enel X amendment enhances RENEW's amendment by clarifying that a project in the individual review process may utilize a longer economic life than the default ORTP assumption, subject to a cap of 35 years, provided the project has appropriate supporting evidence. Their amendment, which aligns with recent changes approved in PJM, is technology-neutral and could allow a wind project to request a 26-year economic life, for example, or a gas unit to request a 23 year economic life.

IV. Markets Committee Recommendation for Battery Revenues Reflects an Optimized Dispatch Strategy

The RENEW battery amendment recommended by the MC corrects for the revenue a battery storage resource could expect to receive in ISO-NE's energy and ancillary services (E&AS) markets. The revised dispatch strategy in the amendment is based on a simple linear optimization algorithm that follows the External Market Monitor's guidance on modeling battery storage revenues. This optimization algorithm was developed by the Massachusetts Attorney General's Office and is described in detail in a report published with the November Markets Committee materials. When compared to the unoptimized dispatch strategy developed by ISO-NE's consultants Concentric Energy Advisors (CEA), the simple optimization strategy earns 6.8 percent more revenue that would be captured by profit maximizing storage operators.

The breakdown between energy and ancillary products under the RENEW approach and the CEA approach is shown in the figure below. The optimized dispatch strategy represents the minimum a reasonable competent developer could expect to receive in ISO-NE's markets and provides a reasonable baseline for the default revenues in the ORTP model for battery technologies.



V. Markets Committee Recommendation on Interim Year PTC/ITC Update Allows for Periodic Adjustments to Federal Tax Code

The Markets Committee recommended proposal also ensures ISO-NE reflects periodic changes to the Production Tax Credit/Investment Tax Credit law in the years where a full recalculation of the ORTP values does not happen (e.g., FCAs 17 and 18). This change is simple to update in ISO-NE's model and is analogous to other tax-based assumption changes ISO-NE already makes in the interim years. Because the PTC/ITC a project receives has a large impact on the project's economics, accurately reflecting current law ensures that the ORTPs capture market expectations.

For these reasons, RENEW respectfully urges your support for the Markets Committee recommended proposal.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Borrego Solar Systems, ENEL X, ENGIE North America, RENEW Northeast

DATE: November 25, 2020 (Revised December 2, 2020)

RE: Amendment Concerning Offer Review Trigger Price Treatment for Co-Located Assets

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The above referenced organizations are requesting a vote on an amendment revising Section III.A.21.1.1. of the Tariff to clarify how co-located assets are evaluated for Offer Review Trigger Price (ORTP) treatment. The amendment will clarify existing Tariff language to definitively state that in assigning ORTPs the Internal Market Monitor (IMM) will, for:

1. Co-located assets of multiple technology types (e.g., PV + battery) registering as a **single** Forward Capacity Market (FCM) resource, assign an ORTP equal to the weighted average of the ORTPs applicable to the asset(s) comprising the resource, as prescribed in Sections III.A.21.1.1. and III.A.21.2(c);[1] and

2. Co-located assets of multiple technology types registering as **separate** FCM resources, assign each FCM resource its own ORTP as applicable solely to the technology of the asset(s) underlying the resource.

In addition, given that the Tariff already prescribes using a weighted average for the ORTP of co-located assets of multiple technology types it is unnecessary to establish a separate ORTP for any "co-located asset" technology type. In fact, establishing a separate co-located asset ORTP, or assigning the Forward Capacity Auction (FCA) starting price to co-located assets, would conflict with current Tariff language.

It follows then that the "Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery" Demand Resource technology type proposed by ISO-NE for inclusion in Section III.A.21.1.1. of the Tariff is not necessary and conflicts with the existing Tariff language. Therefore, in addition to confirming Tariff treatment of the two forms of co-located assets referred to in (1) and (2) above, we are proposing to strike from ISO-NE's proposal the ORTP for Demand Resource technology type "Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery" to avoid the introduction of ambiguity into the Tariff provisions.

I. STAKEHOLDER PROCESS

Stakeholder concerns regarding ISO-NE's treatment of co-located projects were raised during the comment portion of the November 10, 2020 NEPOOL Markets Committee vote on ISO-NE's proposal. These comments were prompted by guidance the IMM gave to stakeholders just prior to the meeting that all co-located generator assets (i.e., assets of multiple technology types that share a common point of interconnection (POI), whether PV+battery, PV+wind, or battery+simple cycle gas turbine, etc.), whether participating in the FCM as a single generating resource or multiple generating resources, would be assigned an ORTP equal to the FCA starting price. Following the Markets Committee discussion and

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[1] Section III.A.21.2(c) of the Tariff states "For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price."

vote, stakeholders requested justification for the IMM's view in time for the submission deadline for materials for the Participants Committee meeting.

Though the proponents of this amendment had asked to do so sooner, they finally met with ISO Markets Development and the IMM on December 1 at which time the ISO provided some preliminary feedback on this proposal. This feedback has prompted the group to propose two minor change to the previously circulated redline language.

At the time of this revised memo, it remains the case that the IMM has indicated that they will not be able to provide a response or justification prior to the Participants Committee meeting or, perhaps, even prior to ISO-NE's filing at FERC.

II. BACKGROUND AND TARIFF HISTORY

a. *Co-located PV + battery assets registering as a single resource should have the weighted average ORTP calculation applied.*

ISO-NE's Tariff Section III.A.21.1.1. lays out the ORTP values for the FCA and explains that:

> *"Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c)."*

This language was incorporated into the Tariff pursuant to a series of ISO-NE filings and FERC Orders culminating in FERC's Order in ER14-1477 approving the ISO's ORTP values for FCA 9 and should be applied to co-located assets participating in the FCM as a single resource (e.g., PV + Battery in Configuration 3 and 4 from the ISO-NE's April 2020 guidance "Market Participation Options for Combined Intermittent/Electric Storage Facilities"[2]). The language of the Tariff is clear and unambiguous. However, for completeness, we provide the following review of how this provision has been modified over time.

For background on the terminology used here, capacity **resources** participate in the FCM. These **resources** must be made up of one or more **assets** that participate in the energy market. **Assets** registered in the energy market may or may not be associated with a capacity **resource**. **Co-located assets** are those in which multiple technology types share a common point of interconnection. These co-located assets, while sharing a point of interconnection, may be owned and operated by independent entities, have separate Asset IDs, and may offer, schedule, and settle independently of each other.

Initially, in the original filing ISO-NE submitted to establish the Minimum Offer Price Rule (MOPR) and ORTPs for FCA 8, ISO-NE sought to establish a different ORTP process than exists today whereby a new resource composed of assets having different technology types would have an ORTP equal to the highest of the ORTPs applicable to the underlying technologies.

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[2] *See* https://www.iso-ne.com/static-assets/documents/2020/04/20200408-co-located-market-participation.pdf which describes the following configurations for co-located assets:
Option 1 – Co-located technologies registered as separate assets and separate resources, without a common grid injection limit.
Option 2 – Co-located technologies registered as separate assets and separate resources, with a common grid injection limit.
Option 3 – Co-located technologies registered as a single hybrid asset or as multiple assets and as a single non-intermittent generating capacity resource.
Option 4 – Co-located technologies registered as a single hybrid asset and as a single intermittent generating capacity resource.

> "*New Section III.A.21.1.1. also contains a provision making clear that where a new resource is composed of assets having different resource types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices*."[3]

> *"Where a new resource is composed of assets having different resource types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices."*[4]

At the time the language was understood to apply only to demand capacity resources, the only type of resource at this time that envisioned having multiple asset or technology types within a single resource. The language was modified slightly in ISO-NE's subsequent filing setting the ORTP values for FCA 9 by replacing the term "resource types" with "technology types".

> "*Where a new resource is composed of assets having different ~~resource~~ technology types*, *the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices.*"[5]

The Commission subsequently rejected ISO-NE's approach related to this provision in ER14-616 which led to the current Tariff language that was filed and approved in ER14-1477. A March 5, 2014 IMM memorandum, ISO-NE testimony, and a FERC Order in ER14-1477 all confirm that the current method not only applies to Demand Resources but more "*generally to all capacity resources, including Generating Capacity Resources and Demand Resources.*"[6]

The IMM memorandum states "*Upon further consideration, the IMM has determined that it is appropriate to use the same weighted averaging approach for all capacity resource types that are comprised of multiple technology types, and therefore the IMM is proposing to replace references to Demand Resources in the provision with references to capacity resources generally*."[7]

In its March 13, 2014 filing ISO-NE stated that "*While the Commission raised this concern specifically in the context of Demand Resources composed in part of Distributed Generation and in part of Load Management, the concern applies more generally to any capacity resource composed of assets with more than one technology type. To address the issue, the proposed revisions replace the "higher of" ORTP formula for resources comprised of multiple asset types with a weighted-average ORTP formula*."[8]

Finally, the FERC found that "*ISO-NE's proposal to use a weighted-average ORTP for resources composed of multiple technology types sufficiently addresses our concern that tying the ORTP for such a resource to the highest ORTP of its associated technology types could result in an inappropriately high value*."[9]

Given the history of the Tariff provision in III.A.21.1.1 and the language of the provision itself, we believe this language applies unambiguously to co-located assets such as PV + Battery registering as a single resource and the Tariff should be amended to cure any ambiguity.

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[3] ER12-953 ISO-NE December 2, 2012 Filing Cover Letter at page 11.
[4] ER12-953, Tariff Redlines, Section III.A.21.1.1.
[5] ER14-616, Tariff Redline, Section III.A.21.1.1.
[6] IMM Memo dated March 5, 2014, *see* https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/mar72014/npc_20140307_addl_1.pdf, agenda item #9.
[7] *Ibid.*
[8] ER14-1477, Testimony of Robert V. Laurita at page 7.
[9] Order in ER14-1477, para. 16, issued May 12, 2014.

i. The weighting should be done according to the portion of the resource's Qualified Capacity attributable to each technology type.

The provision in III.A.21.1.1 references Tariff Section III.A.21.2(c) to determine how the weighted average formula is to be calculated. Section III.A.21.2(c) states:

> *"For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price."*

We believe this Tariff language is clear, that the portion of the resource's Qualified Capacity attributable to each technology type is to be used for weighting the ORTPs. However, in our discussion on December 1 the IMM posed the question of whether the "expected capacity contribution from each asset technology type" could potentially be interpreted in multiple ways. Though we do not believe this existing Tariff language could be reasonably interpreted in any other way, we propose to add minor clarifying language to this section to avoid any possible confusion.

ii. The portion of the resource's Qualified Capacity attributable to each technology type, used to determine the ORTP weighting, is determined by the ISO System Planning group as part of the qualification process, utilizing documentation submitted by the project sponsor in the qualification package.

The IMM also raised the question of how it would be able to determine the capacity contribution from each technology type given that ISO's System Planning group determines a resource's Qualified Capacity. The final sentence at the end of III.A.21.1.1 says that "Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price."

This Tariff provision does not require the IMM to itself determine the resource's Qualified Capacity or the portion of that Qualified Capacity attributable to each technology type. Rather, it allows the IMM to use the Qualified Capacity values determined by System Planning, which are themselves determined utilizing the documentation submitted by the project sponsor as part of its qualification package. In the qualification process as it exists today, the ISO's System Planning group determines a new resource's Qualified Capacity utilizing the documentation included in the resource's qualification package, pursuant to Sections III.13.1.1.2.2.6[10] and III.13.1.1.2.5.1[11].

[10] "III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources. In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package: (a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b); (b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource."

[11] "III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources.

Before the final qualification determinations are made, including the final ORTP applicable to the resource, the IMM would utilize the Qualified Capacity values determined by the System Planning group, in order to determine the final ORTP weighting between the technologies composing the resource. This process appears clear and without obstacle. As such, we do not believe there is a need for further Tariff revisions to address this question.

b. *Co-located PV + battery registering as two separate resources should be treated as two separate resources with each resource receiving its own ORTP.*

Likewise, we believe the Tariff language regarding assets registering as separate resources is unambiguous and calls for each to be evaluated against the technology appropriate ORTP.

To our knowledge, there is no FERC directive, Tariff language, or ISO-NE procedure, manual, or guidance that either allows or requires the IMM to assign an ORTP to a New Capacity Resource based on an asset that is not part of that resource (e.g., by assigning either the co-located PV or the co-located battery registering as two separate FCM Resources an ORTP equal to the FCA starting price rather than the battery or solar ORTP). Under the present FCM registration process for co-located facilities registering as two separate resources the intermittent generation and the battery qualify as <u>two separate</u> FCM resources. The battery and solar each have their own unique Resource ID and offer, schedule, and settle independently of each other. The battery and intermittent generation can even be owned and operated by independent entities. It is also possible that only one of the co-located assets registers as an FCM resource while the other remains an energy-only asset.

The ISO's proposed ORTP for Energy Storage Device – Lithium Ion Battery, registered as a Generating Capacity Resource, applies to all lithium ion battery generators, regardless of their size. The solar ORTP in the NEPOOL Markets Committee recommended proposal would apply to all solar photovoltaic generators, regardless of their size. As such, if there were a 100 kW battery with a POI located one bay over in the same substation as a 100 kW PV generator and each of these registered separately as a capacity resource, the battery would receive the battery ORTP and the PV would receive the PV ORTP. The same should be true if those two assets are interconnected at the same substation position.

The Tariff language regarding assets registering as separate resources is unambiguous. Absent anything to the contrary in the Tariff, the IMM is required to assign each FCM resource the appropriate ORTP for the technology underlying the resource itself.

III. PROPOSED TARIFF CHANGES

a. In Section III.A.21.1.1. insert the following clarifying language after the ORTP table to clarify that co-located assets of multiple technology types registering as a single FCM

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources."

resource will be assigned an ORTP equal to the weighted average of the ORTPs applicable to the asset(s) comprising the resource:

"Where a new resource is composed of assets having different technology types (including, but not limited to, a photovoltaic solar generator co-located with an energy storage device participating in the energy market as one or more assets and participating in the capacity market as a single New Generating Capacity Resource), the resource's Offer Review Trigger price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c)."

b. In Section III.A.21.2(c) insert the following clarifying language to address the concern IMM expressed about whether the capacity contribution used for calculating the weighted average was sufficiently clear:

"For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected ~~capacity~~ contribution from each asset technology type towards the Qualified Capacity of the resource. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighed average Offer Review Trigger Price."

c. In Section III.A.21.1.1. insert the following clarifying language after the ORTP table to clarify that for co-located assets of multiple technology types registering as separate FCM resources the IMM will assign each FCM resource its own ORTP as applicable solely to the technology of the asset(s) underlying the resource (note that the term "Point of Interconnection" has been revised to "point of interconnection", as the capitalized, defined term refers only to those assets that have interconnected pursuant to the FERC-jurisdictional interconnection process, whereas the intent of this language is to apply to all co-located assets regardless of the process under which they interconnect):

Where one or more co-located assets sharing a point of interconnection register as a New Capacity Resource that does not include all of the assets sharing the point of interconnection, the Offer Review Trigger Price for the New Capacity Resource will be assigned according only to the asset or assets comprising the New Capacity Resource.

d. To avoid conflict with the existing Tariff language which prescribes use of a weighted average ORTP value, in Section III.A.21.1.1. strike the following ISO-proposed language in the "Demand Capacity Resources" table (note: this language does not exist in the currently effective version of the Tariff and is being proposed by ISO-NE for addition to the Tariff):

~~Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery~~	~~$7.495~~

***

ISO-NE Public

- **Yellow highlighted values are the ISO's revised values posted on November 24, 2020**
- **Green highlighted values are ORTPs presented by Union of Concerned Scientists (on behalf of RENEW) and voted upon by the Markets Committee at the November 9–10, 2020 meeting**
- **Blue highlighted values reflect updates to the ORTPs after the ISO revised its values on November 24, 2020 to the Markets Committee-supported ORTP values that are offered for the Participants Committee consideration**
- **Gray highlighted values reflect the amendment proposed by Borrego Solar Systems, Enel X, Engie North America, and RENEW Northeast.**

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

* * *

Net CONE is an estimate of the Cost of New Entry, net of ~~the first-year~~ non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require~~, in its first year of operation,~~ to be economically viable given reasonable expectations of the ~~first year~~ energy and ancillary services revenues under long-term equilibrium conditions~~, and projected revenue for subsequent years~~.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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

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

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

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

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

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Resource Economic Life is the number of years that is the lesser of (a) the period of time that a New Capacity Resource of a given technology type or types would reasonably be expected to operate before the resource becomes unprofitable for at least two consecutive years, (b) the expected physical operating life of the resource, or (c) 35 years.

* * *

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

* * *

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

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III.13.2. Annual Forward Capacity Auction.

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III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

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

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 ~~2021~~ is $11.874~~11.35~~/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 ~~2021~~ is $7.024~~8.04~~/kW-month.

CONE and Net CONE shall be recalculated ~~for the Capacity Commitment Period beginning on June 1, 2025 and~~ no less often than once every three years ~~thereafter~~. ~~-~~Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section III.A.21.1.2(e)(5) shall not apply). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

* * *

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

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

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

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III.13.7.2 Capacity Performance Payments.

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III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025~~ and thereafter~~, the Capacity Performance Payment Rate shall be $5455/MWh. For the Capacity

Commitment Period beginning on June 1, 2025 and ending on May 31, 2026 and thereafter, the Capacity Performance Payment Rate shall be $8782/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

* * *

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

* * *

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

* * *

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ~~twelfth Forward Capacity Auction (for the~~ Capacity Commitment Period beginning on June 1, 2025~~2021)~~ shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Simple Cycle ~~c~~Combustion ~~t~~Turbine	$5.366~~6.503~~

~~c~~Combined ~~c~~Cycle ~~g~~Gas ~~t~~Turbine	$9.819~~7.856~~
~~o~~On-~~s~~Shore ~~w~~Wind	$0.000~~11.025~~
Off-Shore Wind	$0.000 ~~1.533~~
Energy Storage Device – Lithium Ion Battery	$2.612 ~~2.615~~ ~~2.923~~
Photovoltaic Solar	$1.861 ~~1.872~~

Demand Capacity Resources~~ – Commercial and Industrial~~	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management (Commercial / Industrial)~~and/or previously installed Distributed Generation~~	$0.761~~1.008~~
Previously Installed Distributed Generation	$0.761
~~n~~New Distributed Generation	~~b~~Based on generation technology type
On-Peak Solar	$5.425
~~Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery~~	~~$7.376~~
Energy Efficiency	$0.000

~~**Demand Capacity Resources – Residential**~~	
~~**Technology Type**~~	~~**Offer Review Trigger Price ($/kW-month)**~~
~~Load Management~~	~~$7.559~~

~~previously installed Distributed Generation~~	~~$1.008~~
~~new Distributed Generation~~	~~based on generation technology type~~
~~Energy Efficiency~~	~~$0.000~~

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where one or more co-located assets sharing a ~~P~~point of ~~I~~interconnection [A1]register as a New Capacity Resource that does not include all of the assets sharing the ~~P~~point of ~~I~~interconnection[A2], the Offer Review Trigger Price for the New Capacity Resource will be assigned according only to the asset or assets comprising the New Capacity Resource.

Where a new resource is composed of assets having different technology types~~,~~ (including, but not limited to, a photovoltaic solar generator co-located with an energy storage device participating in the energy market as one or more assets and participating in the capacity market as a single New Generating Capacity Resource), the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at ~~20 years of~~ real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties), over the New Capacity Resource Economic Life of the project.

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) For the simple cycle combustion turbine and combined cycle gas turbine technology types, ~~E~~each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.~~associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~
~~gas turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~steam turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~wind turbines~~	~~Bloomberg Wind Turbine Price Index~~
~~Other Equipment~~	~~BLS-PPI "General Purpose Machinery and Equipment"~~
~~construction labor~~	~~BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay:~~ ~~– Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~– On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~other labor~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ ~~– Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~– On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials~~	~~BLS-PPI "Materials and Components for Construction"~~
~~electric interconnection~~	~~BLS – PPI "Electric Power Transmission, Control, and Distribution"~~
~~gas interconnection~~	~~BLS – PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"~~
~~fuel inventories~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

~~(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~

~~labor, administrative and general~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ ~~- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials and contract services~~	~~BLS-PPI "Materials and Components for Construction"~~
~~site leasing costs~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

(2~~3~~) For each line item in (1) ~~and (2)~~ above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices ~~for the FCA~~ reflected in the table in Section III.A.21.1.1 ~~above~~. The value of each line item associated with capital costs ~~and fixed operating and maintenance costs included~~ in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 ~~above~~ will be adjusted by the relevant multiplier.

(3~~4~~) The energy and ancillary services offset values for gas~~each~~ technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the ~~most recent~~ Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak ~~On-Peak~~ electricity prices, as published by ICE for the first five trading days in February, for each~~the~~ month~~s in the Capital Commitment Period~~ ~~beginning June 1~~ of the Capacity Commitment Period to which the updated value will apply~~, 2021, as published by ICE~~.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(4~~5~~) Renewable energy credit values in the capital budgeting model shall be updated based on the first~~most recent~~ MA Class 1 REC prices published in February for the five vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The Production Tax Credit and Investment Tax Credit inputs into the capital budgeting model will be updated to reflect the most current tax law at the time of the update.

(7)~~(6)~~ The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(8)~~(7)~~ If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, New Capacity Resource Economic Life, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. For a new Capacity Resource with an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used in Section III.A.21.1.2(b) to calculate the Offer Review Trigger Price for the corresponding technology type, the Project Sponsor shall provide sufficient documentation as described in Section III.A.21.2(b)(iv) to justify its expected New Capacity Resource Economic Life. The Internal Market Monitor shall consider the documentation provided. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. For a New Capacity Resource that has an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used to calculate the Offer Review Trigger Price for the relevant technology type in Section III.A.21.1.2(b), the Project Sponsor shall provide evidence to support the expected New Capacity Resource Economic Life, including but not limited to, the asset life term for such resource as utilized in the Project Sponsor's financial accounting (e.g., independently audited financial statements); or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the Project Sponsor has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee); or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. The Project Sponsor may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an expected New Capacity Resource Economic Life other than the New Capacity Resource Economic Life of similar projects. If there are multiple technology types in the New Capacity Resource, the New Capacity Resource Economic Life should reflect the weighted average of the New Capacity Resource Economic Life of each of the technology types. For a New Capacity Resource that is receiving an out-of-market revenue source and that is seeking a different Weighted Average Cost of Capital than the Net CONE reference unit, the Project Sponsor must submit documentation to demonstrate that the requested Weighted Average Cost of Capital is consistent with that of a resource not receiving out-of-market revenues. This documentation could include but not be limited to publicly available information sources or private information relevant to projects in North America that are not receiving out-of-market revenues. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal

Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected ~~capacity~~ contribution from each asset technology type towards the Qualified Capacity of the resources. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

* * *

Amendment to the ORTP treatment of co-located resources

Borrego Solar
Enel X
ENGIE North America Inc.
RENEW Northeast

Amendment Goals:

The amendment will clarify existing Tariff language to even more definitively state that in assigning the Offer Review Trigger Price (ORTP) the Internal Market Monitor (IMM) will for:

- Co-located assets of multiple technology types (e.g., PV + battery) registering as a single Forward Capacity Market (FCM) resource, assign an ORTP equal to the weighted average of the ORTPs applicable to the asset(s) comprising the resource, as prescribed in Sections III.A.21.1.1 and III.A.21.2(c); and

- Co-located assets of multiple technology types registering as separate FCM resources, assign each FCM resource its own ORTP as applicable solely to the technology of the asset(s) underlying the resource.

Background

Terminology

- **Capacity resources** participate in the FCM
- Resources must be made up of one or more **assets** that participate in the energy market
- **Co-located assets** are those in which multiple technology types share a common point of interconnection (POI).
  - While sharing a POI, co-located assets may be owned and operated by independent entities, have separate Asset IDs, and may offer, schedule, and settle independently of each other.

Background

Process

- The IMM informed stakeholders in November that they would assign all co-located generators a "co-located" ORTP equal to the auction starting price regardless of whether participating as a single capacity resource or separate resources. (e.g., PV+battery, battery+simple cycle gas turbine, PV+wind, etc.)
- Stakeholders subsequently raised concerns regarding IMM's treatment of co-located assets at the Nov 10 MC
- In response to a stakeholder request after the MC seeking justification for this position prior to the deadline for PC materials distribution, IMM informed stakeholders that they should not expect a response or justification prior to the PC meeting or, perhaps, even prior to ISO's filing at FERC.
- Stakeholders believe IMM's position is inconsistent with the Tariff and seek~~s~~ to make a clarifying amendment to avoid any doubt as to the Tariff meaning

Background
Co-Located Assets Registering as a Single Resource

- ISO-NE's Tariff Section III.A.21.1.1. lays out the ORTP values for the FCA and explains that:

  "Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section IIIA.21.2(c)."

- This language was incorporated into the Tariff pursuant to a series of ISO-NE filings and FERC Orders culminating in FERC's Order in ER14-1477 approving the ISO's ORTP values for FCA 9 and should be applied to co-located assets participating as a single resource.
- ISO was clear when it filed this Tariff language that it was to apply to any capacity resource composed of assets with more than one technology type.

  "While the Commission raised this concern specifically in the context of Demand Resources composed in part of Distributed Generation and in part of Load Management, the concern applies more generally to any capacity resource composed of assets with more than one technology type. To address the issue, the proposed revisions replace the "higher of" ORTP formula for resources comprised of multiple asset types with a weighted-average ORTP formula."
  - Laurita Testimony in ER14-1477

Background

Co-Located Assets Registering as Separate Resources

- To our knowledge, there is no FERC directive, Tariff language, or ISO-NE procedure, manual, or guidance that either requires or allows the IMM to assign a resource an ORTP applicable to an asset that is not part of the resource.
  - Tariff language is unambiguous and calls for each resource to be evaluated against the technology making up that resource.
- Co-located assets registering as separate FCM Resources should each be assigned ORTPs according solely to the technology of the asset(s) underlying each resource.
  - They should not be automatically assigned ORTPs equal to the FCA starting price or a "co-located ORTP".

Summary of Proposed Tariff Changes

Section	Change		Reason for Change
III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction	**Technology Type** ~~Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery~~	**Offer Review Trigger Price ($/kW-month)** ~~$7.376~~	Strikes the ISO-NE proposed *'DR combined PV/storage'* ORTP as this is inconsistent with the existing III.A.21.1.1. tariff language that states *"Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).".*

Summary of Proposed Tariff Changes

Section	Change	Reason for Change
III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction	Where a new resource is composed of assets having different technology types (including, but not limited to, a photovoltaic solar generator co-located with an energy storage device participating in the energy market as one or more assets and participating in the capacity market as a single New Generating Capacity Resource) the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).	Remove any ambiguity as to how the Tariff is applied for co-located resources by providing specific example of a new resource composed of assets with different technology types.

Summary of Proposed Tariff Changes

Section	Change	Reason for Change
III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction	Where one or more co-located assets sharing a point of interconnection register as a New Capacity Resource that does not include all of the assets sharing the point of interconnection, the Offer Review Trigger Price for the New Capacity Resource will be assigned according only to the asset or assets comprising the New Capacity Resource.	Clarify that in the case of co-located assets, resource ORTPs will be assigned based solely on the assets underlying the resource in question. The *point of interconnection* refers to the generally understood concept and the intent of this language is to apply to all co-located assets regardless of the process under which they interconnect.

Summary of Proposed Tariff Changes

Section	Change	Reason for Change
III.A.21.2(c) **New Resource Offer Floor Prices and Offer Prices**	For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected ~~capacity~~ contribution from each asset technology type towards the Qualified Capacity of the resource. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.	Provide increased clarity regarding how to calculate the capacity contribution from each of the technologies.

Questions?

memo

To: NEPOOL Participants Committee

From: Mark Karl, Vice President

Date: November 30, 2020

Subject: ISO's Feedback on the Recommendation by the NEPOOL Markets Committee on Proposed FCM Parameter Values for Forward Capacity Auction 16 (FCA 16)

Over the past six months, stakeholders discussed the ISO's proposed values for several FCM Parameters: the Cost of New Entry (CONE), Net CONE, Offer Review Trigger Prices (ORTPs), and the Performance Payment Rate (PPR), to take effect beginning with FCA 16 (associated with Capacity Commitment Period (CCP) 2025-26). Stakeholders provided constructive feedback on a number of the inputs and assumptions used to develop the ISO's proposed values, and the ISO has incorporated many of these into its final proposal.

This memorandum summarizes the ISO's perspective on several ORTP-related stakeholder amendments that the ISO did not incorporate, but that the Markets Committee supported. It also provides brief feedback on NEPGA's proposed adjustment to the FRM clearing prices in the dispatch model. Because the ISO did not have an earlier opportunity to review that FRM-related item, we indicated we would do so ahead of the Participants Committee meeting.

We hope the Participants Committee finds this information useful in advance of the discussion and vote at its upcoming December 3 meeting.

1. **Proposed changes in the estimated capital costs, Investment Tax Credit assumptions, and final ORTP value for the offshore wind technology**

The ISO assessed the assumptions and proposed values in this stakeholder amendment and found significant flaws in the data, models, and interpretations used to support the proposed zero ORTP value for offshore wind.[1] These concerns include the proponent's selective use of different data from different studies with varying levels of transparency to support their value, which may not be applicable to capital

[1] For example, the proposed value (based on modeling by Daymark Energy Advisors) *infers* capital costs from recent offshore wind power purchase agreement contract prices using questionable and non-transparent assumptions concerning new projects' tax treatments (ITC eligibility) and debt life (assumed at 25 years, *beyond* actual offshore wind PPA contract durations).

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costs for new, Eastern US offshore wind projects.[2] Moreover, the "inferred capital cost" approach used by the proponent is not based on a cost-estimation methodology that complies with existing Tariff provisions for ORTP calculations (which has generally been referred to as the "bottom-up" cost estimation method).[3]

In contrast, the ISO has access to estimated capital cost and other financial data for offshore wind projects under consideration in New England. While the ISO's Information Policy prohibits discussion of those confidential data publicly, they provide the ISO and the IMM with an independent 'benchmark' to compare to the separately-conducted CEA/MM offshore wind capital cost and ORTP estimates. This benchmarking gives the ISO confidence in the reasonableness of the CEA/MM proposed ORTP values for offshore wind that have been reviewed with stakeholders. To ensure that the FERC has the benefit of this same information, the ISO plans to submit the non-public data (confidentially) to FERC for its consideration of this matter.

Importantly, under the existing ORTP rules, offshore wind project developers can still readily participate in the FCA if they can demonstrate that the expected costs for their proposed offshore wind projects are lower than the ORTP values in the Tariff. If the proposed costs to develop an offshore wind project put forth by the Union of Concerned Scientists/RENEW are realistic, we would expect such resources to readily demonstrate their near-zero net cost values to the IMM. The projects will then receive an offer floor price informed by the actual costs of the project – as has already been conducted for the offshore wind projects that have sought to participate in the FCM to date.

The ISO recognizes that offshore wind is a newer technology with no large commercial installations operating in the United States, and that additional relevant data regarding capital costs will become available as development of large-scale installations proceeds over the course of the next several years. Therefore, in the interest of further recognizing the evolving cost structures for these resources, if the ISO finds that lower expected costs are demonstrated in the offshore wind submissions to the FCA in the next auction cycles, the ISO will propose revised ORTP values for stakeholder consideration. Meaning, the ISO will not wait three years to propose a change to the offshore wind ORTP if the data in the submissions demonstrates lower expected costs (than the FCA Starting Price).

2. Stakeholder proposed revisions to project life modeling assumptions for ORTP calculations

This stakeholder-proposed amendment proposes to define "economic life" and assign it (based on two studies from one source) to only two technologies – solar and onshore wind.[4] Conceptually, ISO is not

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[2] For example, benchmark data excluded studies with geographically-specific values for New England, which are in line with the proposed capital-cost values presented by CEA and MM.

[3] A review of the NYSERDA whitepaper, presented by RENEW Northeast as a '"bottom-up" analysis of a project comparable to the one CEA/MM modeled for the ORTP technology, suggests that the NYSERDA model does not reflect a "bottom up" approach. In addition, the paper itself notes that its base case (used by RENEW) needs to be adjusted to reflect site and technology differences, the details of which are incompletely explained. As a result, the values within that paper may materially underestimate offshore wind resources total costs.

[4] Note that the impact of this amendment for the *on*-shore (that is, land-based) wind ORTP value is moot, as on-shore wind has an ORTP value of zero under the ISO's proposal.

opposed to re-evaluating the total modeled years of a project's operation in a future triennial revision of the FCM parameters. However, this amendment is substantively incomplete as it lacks consideration of all of the assumptions and inputs that such a re-evaluation would require.[5]

Such important issues would benefit from expert assessment and the assembly and review of substantiating data, which have not been adequately performed to support this amendment. It is impractical to perform and vet these assumptions with stakeholders for the present parameter update process for FCA 16 (i.e., prior to filing in December) and, accordingly, the ISO cannot support a new ORTP value for solar that rests upon incomplete and inadequately-supported assumptions.

3. Stakeholder proposed revisions to the ORTP annual update process concerning potential future tax law changes for FCA 17 and 18

This amendment would require, generally, that the ISO adjust ORTP values during the interim update process to reflect potential changes in tax laws concerning the Investment Tax Credit or Production Tax Credit that may be applicable to certain technologies.

Every year, the ISO updates the ORTP values using certain Tariff-prescribed price indexes (to account for inflation and general annual cost changes over time). It does not automatically perform a full recalculation of ORTP values to reflect changes such as federal tax laws, which are addressed in the next subsequent triennial update (or earlier if warranted). The interim update process is intended to be a simple update to certain major cost components of the ORTPs until the next triennial review.

The ISO is not comfortable adjudicating tax matters as part of the nominally 'automatic' annual indexing process. The appropriate application of tax law and credits can be complex and controversial, may require input from tax or financial experts, and may fall well outside of the expertise of the ISO's staff that administers these provisions of the Tariff. Introducing potentially complex tax law interpretation into the process does not facilitate a transparent, annual interim update process and differing interpretations could result in protracted litigation and adversely impact the timely conduct of the annual FCAs.

4. Stakeholder proposed amendment to increase the estimated energy and ancillary service revenue offsets for the Battery-Storage ORTP Value

This amendment proposes to lower the ORTP value applicable to new battery-storage technologies seeking to enter the FCM from $2.923 to $2.615, a reduction of $0.308 per kw-month. The sponsors rely on a hypothetical model of battery-storage technologies to project energy and ancillary service revenues, which are greater than the projected energy and ancillary service revenues proposed by CEA/MM.

The dispatch model and assumed operating behavior of the battery-storage technology developed by CEA is consistent with the ISO's observed operating behavior of batteries in the ISO-NE markets. In contrast,

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[5] For example, changing the modeled economic life of technologies for ORTP purposes may necessitate revising the assumed values of other inputs that are closely related (e.g., the projects debt service life and the facility's decline in output toward the end of its assumed physical operating life).

the amendment sponsors' proposed battery-storage operating model assumes operation that is not consistent with observed practice in the ISO-NE markets and could increase battery degradation (and/or increased battery augmentation costs) under such operating conditions.

Net CONE and FRM: Additional ISO feedback on NEPGA's recently proposed amendment to adjust the FRM revenue forecast for the Net CONE reference unit

This stakeholder amendment would modify the Forward Reserve Market clearing prices, used in the calculation of energy and ancillary service revenues, by including the additional supply from the reference unit (approximately 375 MW) into models of past Forward Reserve Market auctions, and then 're-clearing' those auctions. Under this amendment, the resulting, modified FRM clearing prices would then be used in place of the actual, historical FRM clearing prices to calculate the FRM-related offsets to the reference technology's net CONE value.

This proposal to modify historical market prices, based upon assumed future supply offers (in the FRM), is not consistent with the use of historical prices as the basis for energy and ancillary service offset calculations for all of the reference technology's revenue streams. The ISO does not support this change.

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We appreciate stakeholders' time and effort over many months to review the ISO's proposed Net CONE and ORTP values, and to bring many thoughtful suggestions and recommendations to the ISO's attention. We hope the information provided in this memorandum serves to facilitate a productive understanding of the areas in which the ISO and its consultants differ from those recommendations of the Markets Committee, and the reasons that the ISO cannot support a filing to FERC that incorporates the stakeholder-proposed ORTP values discussed herein.

DRAFT

ISO-NE NET CONE AND ORTP ANALYSIS

AN EVALUATION OF THE NET COST OF NEW ENTRY AND OFFER REVIEW TRIGGER PRICE PARAMETERS TO BE USED IN THE FORWARD CAPACITY AUCTION

FCA-16 AND FORWARD

CONCENTRIC ENERGY ADVISORS, INC.

MOTT MACDONALD

November 2020

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Section 1:
Executive Summary

A. Overview

The design of the Forward Capacity Market (FCM) involves estimating the cost of developing new resources that could enter the market, known as the Cost of New Entry (CONE). At a high level, the CONE and Net CONE values are, respectively, estimates of the total and net costs of developing the most economically efficient type of new capacity resource in New England. The Offer Review Trigger Price (ORTP) values are estimates of the entry costs for all resource types that would reasonably be expected to participate in the FCM and are used to screen offers from new resources that may require further review per ISO New England's (ISO-NE) buyer-side market power mitigation provisions.

The ISO-NE Open Access Transmission Tariff (Tariff) requires that the CONE, Net CONE and ORTP values used in the FCM be re-evaluated and updated at least once every three years pursuant to Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a). In the years between such recalculations, the CONE, Net CONE and ORTP values are updated annually using indices specified in Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(e).

For the calculation of CONE and Net CONE, ISO-NE's Tariff requires the following:

> *"CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply."*
>
> *"Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e)…."*[1]

For the calculation of ORTP values, ISO-NE's Tariff requires the following:

> *"The Offer Review Trigger Price for each of the technology types… shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply".*[2]

As more fully explained in this report, the CONE and Net CONE values are parameters that are intended to reflect the compensation a cost effective new entrant would need from the capacity market (net of expected revenues) to recover its capital and fixed costs under long-term equilibrium conditions, given reasonable expectations about future market conditions and cost recovery assumptions. Along with other values, the Net CONE value is used to scale the demand curves, and

[1] Market Rule 1 Section III.13.2.4.
[2] Market Rule 1 Section III.A.21.1.2.

the CONE and Net CONE values are used to set the Forward Capacity Auction (FCA) starting price (the maximum of CONE or 1.6 times Net CONE).

This report contains the results of the estimates of both: i) the CONE and the Net CONE values, and ii) the technology specific ORTP values for use in ISO-New England's FCA-16 for the 2025/2026 Capacity Commitment Period (June 1, 2025 through May 31, 2026).[3] Net CONE estimates are made from the perspective of a hypothetical unit of a given resource and technology type in a generic location in New England, which is referred to as the "reference" unit.

B. Study Scope and Process

ISO-NE engaged Concentric Energy Advisors, Inc. (Concentric) to conduct an independent analysis of the CONE/Net CONE and ORTP values for FCA-16. Concentric and its subcontractor, Mott MacDonald, worked together to develop the recommendations presented in this report. To arrive at these results, we considered relevant market and technology issues, screened several technologies, and closely evaluated those that met the pre-specified CONE and ORTP screening criteria as described in Section 3 of this report. This evaluation included a detailed analysis of resource technical specifications, capital, and operating costs, and expected market conditions to calculate expected revenues and arrive at recommended CONE/Net CONE and ORTP values.

The study process consisted of the four basic tasks outlined below and further described in this report:

1. **Resource Screening and Selection.** The first step in the process was to develop screening criteria to identify the resource types for which Concentric and Mott MacDonald would calculate CONE/Net CONE values and ORTP benchmark values. The resource types that passed the screens were subject to a full bottoms-up evaluation of costs and revenues over the resource's expected life.
2. **Calculation of CONE.** For each of the selected resource types, we developed technical specifications, installed capital costs, and operating costs over the expected life of each facility. The study included an expected life of 20 years for technology types other than Energy Efficiency. Energy Efficiency was assumed to have a useful life of 11 years. Based on reasonable financial assumptions associated with merchant plant development in New England regarding the cost of debt, return on equity and debt to equity ratio, we used a levelized annual cost calculation to determine a revenue requirement that ensured the recovery on and of investment costs.

[3] While CONE, Net CONE, and ORTP values are normally recalculated every three years according to Market Rule 1, ISO-NE requested and received from FERC a one-year deferral to allow potential impacts of proposed market changes to be reflected in the resulting values.

3. **Calculation of Expected Revenues.** We estimated the revenues that each resource type is expected to earn during its expected lifetime, including energy revenues net of variable production costs, ancillary service revenues, renewable energy credit (REC) revenues, and Pay for Performance (PFP) revenues. Expected energy revenues were based on the estimated revenues each resource would have earned in ISO-NE's energy and ancillary services markets during the most recent three calendar years using adjusted historical prices.[4]

4. **Calculation of Net CONE and ORTP.** Based on the calculation of CONE and expected revenues, we calculated the compensation needed from the capacity market, net of non-capacity market revenues, that the resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues to determine Net CONE and ORTP values for each resource type.

    - For generation resources, capital costs, operating costs, expected energy and ancillary services revenues, and assumptions regarding depreciation, taxes and discount rate were inputted into a capital budgeting model to calculate the break-even contribution required from the FCM to yield a levelized revenue requirement with a net present value (NPV) of zero. To calculate the ORTP benchmarks, we adjusted select operating costs and financial assumptions to reflect the expected costs of a new resource with a portion of its generation output under contract. These adjustments were made pursuant to Tariff requirements to calculate ORTP benchmarks that achieve the "low end of the competitive range" objective. The Net CONE value and ORTP benchmarks are equal to the net present value of the levelized costs of each resource, net of expected revenues.
    - For Energy Efficiency, the methodology used to calculate the ORTP value was the same as that used for generation resources, except that the cash flows were discounted over an 11-year project life and took into account the costs incurred by the utility and end-use customer to deploy the efficiency measure.
    - For Demand Response Resources, the method used to calculate the ORTP benchmarks was the same as that used for new generation resources with a 20-year project life.

Each of these tasks involved a detailed review of historical data, modeling techniques and analytical methods, and the application of professional judgement to calculate estimated values for each resource type. Concentric and Mott MacDonald conducted both studies simultaneously in an open and transparent process with stakeholders and ISO-NE staff. Key assumptions and issues were presented to stakeholders for input and feedback in eight separate meetings with the New England Power Pool ("NEPOOL") Markets Committee. These meetings provided important feedback and

[4] As discussed further in Section 6 below, the historical energy prices used in the Net CONE dispatch models were adjusted to both remove the impact of energy and reserve shortage conditions and to estimate energy prices that would occur if the system were at criterion. The historical energy prices for the ORTP dispatch models were adjusted to remove the impact of energy and reserve shortage conditions.

direction on concepts and metrics relevant to the study process, and provided guidance for consideration of, and recommendations on, key study issues, assumptions, and outcomes.

C. Summary of Recommendations

Based on our analysis, we recommend that the simple cycle gas turbine technology be used as the reference technology for FCA-16, which is the auction scheduled for the 2025/2026 Capacity Commitment Period, ensuring that the capacity market will cost effectively procure capacity sufficient to meet the region's resource adequacy requirement.

To arrive at these results, Concentric and Mott MacDonald considered the active development of gas-fired resources in New England and the participation of these resources in recent FCAs. The results of our CONE analysis are shown below.

Table 1: Net CONE Values for Candidate Reference Units

Reference Technology	Nominal Installed Capacity (MW)	Qualified Capacity	Installed Cost (2019$/kW)	Real ATWACC	Gross CONE (2025$/kW-month)	Revenue Offsets (2025$/kW-month)	Net CONE (2025$/kW-month) Installed	Net CONE (2025$/kW-month) Qualified
1x1 7HA.02 (CC)	543	489	985	6.1%	15.84	4.39	11.45	12.72
1x0 7HA.02 (CT)	371	361	777	6.1%	11.40	4.66	6.74	7.02
2x0 LM6000 PF+ (Aero)	95	91	1,961	6.1%	27.02	4.50	22.52	23.46

Similarly, we have conducted an evaluation of resources that have or are reasonably expected to participate in the FCM and have an ORTP below the expected auction starting price. Based on the CONE/Net CONE analysis for the simple cycle frame combustion turbine and combined cycle combustion turbine with appropriate modifications to assumptions to reflect the low end of the competitive range consistent with Tariff requirements, and a detailed analysis of other resources meeting stated screening criteria, we recommend the resource specific ORTPs shown in Table 2 below for the base case scenario which reflects the continuation of the FRM.

Table 2: ORTP Summary for Specific Resources (2025$)

Reference Technology	Nominal Installed Capacity (MW)	Qualified Capacity (MW)	Installed Cost 2019$/kW	Real ATWACC	Gross CONE (2025$/kW-mo)	Revenue Offsets (2025$/kW-mo)	Net CONE (2025$/kW-mo) Installed	Net CONE (2025$/kW-mo) Qualified	ORTP (2025$/kW-mo)
Combined Cycle	557	501	956	4.3%	12.72	3.88	8.84	9.82	9.819
Combustion Turbine	376	361	758	4.3%	9.18	4.02	5.15	5.37	5.366

REFERENCE TECHNOLOGY	NOMINAL INSTALLED CAPACITY (MW)	QUALIFIED CAPACITY (MW)	INSTALLED COST 2019$/KW	REAL ATWACC	GROSS CONE (2025$/KW-MO)	REVENUE OFFSETS (2025$/KW-MO)	NET CONE (2025$/KW-MO) INSTALLED	NET CONE (2025$/KW-MO) QUALIFIED	ORTP (2025$/KW-MO)
ONSHORE WIND	82.5	32.4	2,097	4.3%	18.64	23.27	-4.63	-11.78	0.000
SOLAR	20	3.8	1,524	4.3%	11.61	9.42	2.24	11.89	11.888
BATTERY	150	129	938	4.3%	8.92	6.00	2.92	2.92	2.923
ENERGY EFFICIENCY				4.3%	36.95	45.52	-8.57	-8.57	0.000
DR - ON-PEAK SOLAR		1		4.3%	20.07	14.65	5.43	5.43	5.425
LOAD MGMT C&I/ PREV INSTALLED DG		2		4.3%	15.41	14.65	0.76	0.76	0.761
DR - COMBINED PV/STORAGE		0.5		4.3%	22.11	14.73	7.38	7.38	7.376

Section 2: FCM Overview

A. FCM Background

The FCM is a long-term market that ensures resource adequacy, both zonally and for the ISO-NE system as a whole. The market is designed to promote economic investment in capacity resources when and where they are needed. Resources that may participate in the FCM include new and existing resources, comprised of generating resources, imports, demand response resources and energy efficiency resources.

To purchase sufficient capacity to satisfy the region's future resource adequacy needs and allow enough time to construct new capacity resources, FCAs are held each year approximately three years in advance of the 12-month Capacity Commitment Period (CCP) during which time the resources that clear in an FCA must meet their assumed obligation. The commitment that capacity resources undertake when they clear in an FCA is called a capacity supply obligation (CSO). Capacity resources with the lowest-priced offers clear the FCA and receive capacity payments based on the FCA clearing price, which is determined through a descending clock auction. The payments capacity resources receive for accepting a CSO are in addition to the revenues those resources are eligible to receive in the ISO-NE energy and ancillary services markets and other markets (e.g., REC markets). In exchange for capacity payments, the resources have an obligation to be ready to provide capacity when called upon.

B. Role of CONE and ORTP Values

The CONE, Net CONE and ORTP values are used during the annual FCA auction process. A primary use of Net CONE is as a parameter that helps to define how demand for resource adequacy in ISO-NE is represented in the FCA. Demand is represented by system and zonal demand curves that are calculated to reflect the Marginal Reliability Impact (or "MRI") of adding incremental capacity in different locations. The FCA market rules specify that the system demand curve must be scaled so that the quantity of capacity associated with the Net CONE value satisfies the ISO-NE system's resource adequacy reliability standard (which is a Loss of Load Expectation of 0.1 days per year). The CONE and Net CONE values also are used to set the FCA Starting Price. The market rules specify that the FCA Starting Price is the higher of: (1) CONE, and (2) 1.6 multiplied by Net CONE.[5]

The primary use of the ORTP values is to "screen" for resource offers in the FCA that are potentially below the competitive level. The ORTP values are designed to address the exercise of buyer-side market power that could inappropriately suppress capacity prices below the competitive level. A new capacity supply resource can submit an offer above the ORTP value without justification to the ISO-NE Internal Market Monitor (IMM). New capacity resource offers below the ORTP require IMM

5 Market Rule 1, Section III.13.2.2.4 (Capacity Demand Curve Scaling Factor).

review. Consistent with guidance from ISO-NE and the FERC, the recommended ORTP values are set at the low end of the competitive range of expected values so as to strike a reasonable balance by only subjecting resources to review which appear commercially implausible absent out-of-market revenues.[6]

Establishing the ORTP benchmarks at the low end of the range of estimated competitive costs is intended to strike a reasonable balance by not subjecting offers that are “clearly competitive” to evaluation. For resource types where it is not possible to establish a reliable ORTP value, a default ORTP is set equal to the FCA starting price.[7] Importantly, having offers subject to review by ISO-NE does not prevent any individual resource or resource type from participating in the FCM. Rather, a resource that wishes to submit an offer below the ORTP benchmark for its resource type must substantiate its costs and show that its offer will not inappropriately suppress capacity prices below the competitive level.

6 *ISO New England Inc*., 161 FERC ¶ 61,035, at P 21 (October 6, 2017)
7 Market Rule 1, Section III.A.21.1.1.

Section 3:
CONE Study

This section describes the CONE study performed on the three candidate resource types identified through the screening process: the simple cycle frame machine; the aeroderivative machine; and the combined cycle frame machine. The CONE value for a given resource type and technology is intended to reflect the annual levelized capital and fixed costs a new entrant would incur to enter the ISO-NE capacity market over its estimated project life. CONE values are used to estimate Net CONE values for each candidate reference unit. Net CONE values are calculated by subtracting a reasonable expectation of the energy, ancillary services, PFP, and other revenues the resource could earn under long-term equilibrium conditions. Section 3.B describes the key assumptions used to develop CONE estimates for the three candidate reference units.

A. Screening Process

i. General Criteria

The resource screening process used to establish the candidate technologies for a CONE calculation began with the recognition of the variety of resource types that currently participate in the FCM, and the application of the technology screening criteria that have been approved by the FERC in previous Net CONE calculation processes. Specifically, the FERC has found that important considerations in assessing the candidate reference technologies for determining Net CONE should include the following:

1. Must be likely to be economic for merchant entry under long-term equilibrium conditions;
2. Must have reliable cost information available to calculate a CONE value using a full "bottom-up" analytical approach; and
3. Must reliably be able to meet load when resource adequacy is at risk.[8]

In including each of these criteria, it is important to outline the manner in which we interpreted and applied each of these criteria. The application of this criteria is shown below.

[8] FERC Order Docket ER14-1639-000 147 FERC ¶ 61,173, May 30, 2014.
FERC Order Docket ER17-795-000 161 FERC ¶ 61,035, October 6, 2017.

Table 3: Application of CONE Analysis Criteria

SCREENING CRITERIA	APPLICATION
Must be likely to be economic for merchant entry under long-term equilibrium conditions	Net CONE value is high enough to incent new entry into the market, but not so high as to introduce unnecessary costs
Must have reliable cost information available to calculate a CONE value using a full "bottom-up" analytical approach	Demonstrated interest by developers such that capital costs and E&AS revenues can be estimated with a high level of certainty
Must reliably be able to meet load when resource adequacy is at risk	Technology is able to be dispatched whenever resource adequacy is at risk

The first principle, that the resource must be economic for merchant entry under long-term equilibrium conditions, has been expressed in past CONE filings and approved in related FERC orders as a requirement that the reference technology must result in a demand curve that "should produce prices high enough to meet the reliability standard but not so high as to add unnecessary costs".[9] This recognizes that uneconomic technologies would set Net CONE higher than required to meet ISO-NE's established reliability objectives.

The second principle is that the reference technology must have reliable cost information available to calculate a CONE and Net CONE value with confidence utilizing a "bottom-up" analytical approach. Estimating CONE and Net CONE values requires the development of assumptions about the resource's technical specifications, the analysis of potential costs and revenues, the estimation of various financial parameters and risks. Therefore, it is critical that a sufficient amount of data is available to determine a robust estimate of each resource type's CONE and Net CONE. As is shown in Table 4, there has been substantial development of the various gas-fired technologies that were included in the list of candidate resources to be evaluated. As can be seen below, both the simple cycle and combined cycle General Electric (GE) machines have participated and cleared in the most recent FCAs.

[9] *ISO New England Inc.*, 170 FERC 61,052 (January 24, 2020) at P 18 (citing *ISO New England Inc.*, 161 FERC ¶ 61,035 (2017) at PP 38 & n.67).

Table 4: Proposed Simple Cycle and Combined Cycle Projects in New England

NAME	UNIT TYPE	YEAR IN SERVICE EXPECTED IN SERVICE	TURBINE MANUFACTURER	TURBINE MODEL	LOCATION	SIZE (MW)	STATUS	CLEARED AUCTION
Killingly Energy Center	Combined Cycle	2022	Mitsubishi	M501JAC	CT	650	Early Development	FCA11
Waters River	Gas Turbine	2021	GE Energy	LM9000	MA	60	Announced	N/A
Thomas A. Watson Generating Station	Gas Turbine	2020	Not Announced	Not Announced	MA	64	Late Stage Development	N/A
West Medway II	Gas Turbine	2019	GE Energy	LMS100P A+	MA	200	Operating	FCA9
Canal 3	Gas Turbine	2019	GE Energy	7HA.02	MA	350	Operating	FCA10
Bridgeport Harbor Station	Combined Cycle	2019	GE Energy	7HA.02	CT	576	Operating	FCA9
Wallingford Energy	Gas Turbine	2018	GE Energy	LM6000	CT	100	Operating	FCA9
Towantic Energy Center	Combined Cycle	2018	GE Energy	7HA.01	CT	785	Operating	FCA9
Salem Harbor Station	Combined Cycle	2017	GE Energy	7F 5-Series	MA	674	Operating	FCA7

The third principle is that the reference technology must be able to reliably meet load when resource adequacy is at risk. In assessing the ability of different resource types to contribute to resource adequacy, it is important to ensure that the reference technology is able to contribute to the reliability standard of 1 day in 10 years. Consistent with the development of ICR and the demand curves, the proxy unit used to meet the 1 day in 10 years reliability criteria is a dispatchable unit. Therefore, we have chosen to assess resource types that are dispatchable both up and down by ISO-NE to meet loss of load expectations consistent with ICR requirements.

ii. Resources Considered

Several different resources were considered for an evaluation against the screening criteria outlined above, including gas-fired resources, coal-fired resources, nuclear resources, various renewable resources, storage resources, and demand response and energy efficiency resources. Gas-fired resources passed the screening criteria, as they have been proven to be economic for new entry in the recent past and have numerous sources of historical operating data. No new coal or nuclear resources have been developed in ISO-NE in thirty years, and therefore, these resources do not meet all of the screening criteria. Renewable resources have been developed in recent years and additional renewable and battery storage resources have been proposed. However, these resources did not pass our screening criteria, as shown in Table 5 below. As a result, our analysis focused on gas-fired resources in both simple cycle and combined cycle configurations as the appropriate technologies to consider the CONE/Net CONE analysis.

Table 5: Resource Screening Results

	Expected to Be Economic For Merchant Entry Under Long Run Equilibrium Conditions	Reliable Cost Information for a Full Bottoms-Up Approach (Including E&AS Revenues to Calculate a Net CONE Value)	Able to Reliably Meet Load When Resource Adequacy is at Risk
Onshore Wind	√	√	×
Offshore Wind	×	√	×
Coal/Nuclear	×	√	√
Solar	×	√	×
Large-Scale Battery	×	×	×

It is important to remember that the frequency with which this study is updated – every three years – is designed to capture how the Net CONE values of various resource types change in relation to each other as market conditions and resource development costs change over time. Future Net CONE/ORTP re-calculations are expected to use similar screening criteria, and the resources that meet this screening criteria may change as technology evolves, resulting in a change in the reference unit.

Regarding simple cycle gas technologies, we considered both frame and aeroderivative machines. For frame machines, we considered the following key factors:

- Can provide reliable generation to the grid for a low capital cost;
- Can be installed with fast-start capability;
- Technology being continuously improved by the manufacturers;
- Usually installed for peak power production;
- Industrial design intended for long-term operation at high efficiencies; and
- Currently being installed in New England.

The simple cycle frame technologies that were considered as candidate simple cycle units are shown in Table 6 below.

Table 6: Simple Cycle Frame Machines

FRAME TECHNOLOGY	CONSIDERATIONS
GE7HA.02	• GE's largest and most efficient machine already installed in New England in simple cycle configuration • Highest output for a currently installed Frame Gas Turbine
GE7HA.03	• Newest large frame gas turbine from GE • Most efficient and highest capacity gas turbine offered by GE • Not yet run in GE test stand • Not yet installed anywhere in the world
Siemens 8000H	• Largest installed experience base for large H-Class gas turbines • Previous generation frame machine technology • Expected to be replaced by the 9000HL • None installed in New England
Siemens 9000HL	• Newest large Frame machine from Siemens • Most efficient and highest capacity gas turbine offered by Siemens • Slightly lower capacity and efficiency than Frame machines offered by GE and Mitsubishi Hitachi Power Systems (MHPS) Not yet operated in a test stand or a plant
MHPS M501GAC	• Air cooled large frame gas turbine evolved from previous generation technology • Installed and operating globally
MHPS M501JAC Classic	• Frame Machine validated at MHPS T-Point Power Plant and 4 Simple Cycle units operated in Asian 60 Hz power plant • One unit in Engineering for New England, but unit operated in combined cycle configuration • Most efficient Frame GT currently operating globally
MHPS 501JAC	• Largest Frame machine offered by MHPS • Newest update of the M501JAC. Not considered a new Frame design, but rather an "update" of the existing machines. • Best heat rate available for an installed frame machine • Validated in MHPS T-Point Power Plant • Not yet installed in simple cycle configuration
Other Frame Machines	• MHPS H Series of smaller and less efficient Frame machines • Siemens SGT Family – Not a large installed base in New England, not being aggressively marketed by Siemens • Ansaldo GT-36 – Not yet being marketed for 60 Hz operations

As a result of the review of the above simple cycle frame combustion turbine options, and because there is a simple cycle 7HA.02 unit operating in New England, Concentric and Mott MacDonald chose the GE7HA.02 as the simple cycle frame machine as a reference unit candidate on which to conduct a full CONE/Net CONE evaluation. A project using this technology, the Canal 3 Project, achieved commercial operation in simple cycle configuration in 2019 and therefore represents the most current frame technology developed in the region.

For aeroderivative machines, we considered the following factors to be key when comparing aeroderivative technology against frame turbine technology:

- Speed to market and to engineer;
- Size makes them more expensive in $/kW (installed);
- Multiple LM6000 plants are operating in New England with the LM6000 PF+ being the latest version; and
- Can be converted to combined cycle if originally arranged properly.

The aeroderivative machines that were considered for the candidate simple cycle reference units are shown in Table 7 below.

Table 7: Simple Cycle Aeroderivative Machines

AERODERIVATIVE TECHNOLOGY	CONSIDERATIONS
GE LM6000	• One of the most widely installed machines in New England • LM6000PF+ is the latest dry-cooled version
LM2500	• High $/kW installed cost • Often utilized in combined heat and power or industrial process applications
Rolls Royce Trent	• Viable option to LM6000 family
MHI Pratt & Whitney FT8 Swiftpac	• Less efficient machine with small New England installed base
Siemens SGT 800	• Efficient competitor to LM6000 and Trent with small installed base in NE
Solar Titan 250	• Small machine with high heat rate and small installed base in NE
GE LMS100	• Hybrid aeroderivative gas turbine designed with some aeroderivative turbine sections and some frame machine sections • Only advanced aeroderivative machine available • Most efficient simple cycle machine available • Recently installed in New England after project delays but has not been proposed since

Following a review of the above aeroderivative machines, Mott MacDonald selected the GE LM6000 technology for the CONE/Net CONE evaluation. The GE LM6000 is currently installed in New England and represents a commercially acceptable and cost-effective technology.

Finally, for the combined cycle technologies, we considered the following factors:

- Can provide reliable generation to the grid;
- Can provide the best thermal efficiency available;
- Utilizes the largest and most efficient gas turbine technology available for combined cycle applications;

- Current frame designs are undergoing a step-change improvement in output and efficiency; and
- Currently operating in New England.

The combined cycle combustion turbine technologies considered for the candidate combined cycle unit are shown in Table 8 below.

Table 8: Combined Cycle Combustion Turbines

FRAME TECHNOLOGY	CONSIDERATIONS
GE7HA.02	• GE's largest and most efficient machine already installed in New England in simple cycle configuration • Highest output for a currently installed Frame GT
GE 7HA.01	• Currently offered for sale but expected to be replaced by the 7HA.02 due to improvements in capacity and efficiency • Currently in operation in New England
GE 7FA - .04 thru.06	• Will continue to be offered for sale, but are smaller and less efficient than the 7HA technologies
GE7HA.03	• Newest large frame gas turbine from GE • Most efficient and highest capacity gas turbine offered by GE • Not yet run in GE test stand • Not yet installed anywhere in the world
Siemens 8000H	• Largest installed experience for large G, H, and J frame gas turbines • Smaller and less efficient than GE's or MHPS's latest technology machines
Siemens 9000HL	• Newest large Frame machine from Siemens • Most efficient and highest capacity gas turbine offered by Siemens • Not yet operated in a test stand or a plant • Currently being installed in a test plant in the US • Slightly lower capacity and efficiency than Frame machines offered by GE and MHPS
MHPS M501GAC	• Air cooled large frame gas turbine evolved from previous generation technology • Installed and operating globally
MHPS M501JAC Classic	• Frame Machine validated at MHPS T-Point Power Plant and 4 Simple Cycle units operated in Asian 60 Hz power plant • One unit in Engineering for New England • Most efficient Frame GT currently operating globally
MHPS M501JAC	• Largest Frame machine offered by MHPS • Newest update of the M501JAC. Not considered a new Frame design, but rather an "update" of the existing machines. • Best heat rate available for an installed frame machine • Validated in MHPS T-Point Power Plant
MHPS M501J	• M501J is a steam cooled large frame gas turbine • Slightly lower capacity than the M501JAC Classic, but with equal heat rate

FRAME TECHNOLOGY	CONSIDERATIONS
Other frame machines	• MHPS H Series of smaller and less efficient Frame machines • Siemens SGT Family – Not a large installed base in New England, not being aggressively marketed by Siemens • Ansaldo GT-36 – Not yet being marketed for 60 Hz operations

Given a review of the above combined cycle combustion turbine options and the fact that there are 7HA.02 machines in both combined cycle and simple cycle operation in New England, Mott MacDonald advised the use of the GE 7HA.02 machine as the combined cycle turbine model candidate reference unit on which to conduct a full CONE/Net CONE evaluation. The Bridgeport Harbor Station 5 became operational in 2019 with 7HA.02 technology in combined cycle configuration, which supports the finding that the 7HA.02 is a commercially acceptable and cost-effective technology.

We note that all of the gas candidate reference units that underwent the full CONE/Net CONE evaluation utilize turbines developed by GE. This is because GE clearly continues to have the largest market share of new gas turbines being developed in New England at this time. Other gas-fired resources that use turbines from other manufacturers were also considered but were not fully evaluated since they did not reflect the level of activity in New England that has been demonstrated by GE.

B. Key Assumptions

General assumptions used in the CONE study that are applicable to all technologies include assumptions regarding location, plant configuration, interconnections to the natural gas pipeline and electric transmission/distribution systems, dual fuel capability, and environmental control capabilities. A summary of these assumptions is provided in Table 9 and each assumption is described in further detail below.

Table 9: Key Assumptions for Gas Candidate Reference Units

KEY ASSUMPTIONS	
Turbine model	7HA.02
Location	New London County, Connecticut
Cooling system	Fin fan coolers
Power augmentation	Evaporative coolers
Duel-fuel capability	Natural gas w/ No. 2 oil backup
Black start?	No
On-site gas compression?	No
Gas interconnection	Onsite connection
Electrical interconnection	Onsite connection

i. Location

While the CONE reference unit is a hypothetical unit of a given resource and technology type, it was necessary to identify a general location for this unit for the purposes of estimating property taxes, interconnection costs, labor rates, etc. Concentric and Mott MacDonald screened locations based on two primary criteria: i) locations where energy infrastructure already exists to allow ready access to the high voltage electric transmission system and natural gas pipeline and distribution network; and ii) locations in which retirements were likely to occur. Preference was given to locations meeting the first and second criteria that were located in close proximity to areas with a high demand for electricity.

Based on these criteria, we identified New London County Connecticut, Bristol County Massachusetts, and Rockingham County New Hampshire as potential sites. All three locations are in close proximity to the 345 kV network and natural gas infrastructure. Connecticut, however, has been far more active in terms of power plant development in recent years, with additional generating resources at risk of retirement, as shown in Figure 1. Rockingham County New Hampshire has no expected retirements near term, and Bristol County Massachusetts retirements have already occurred and were not immediately followed by development or repowering. For these reasons, New London County, CT was identified as an appropriate location for modeling the three gas candidate reference units.

Figure 1: Power Plant Development and Retirement Risk[10]

ii. Brownfield vs. Greenfield

Both greenfield and brownfield sites are currently being developed in New England and therefore both were considered for the CONE study. However, brownfield sites are highly variable in terms of characteristics and the extent of the re-use of existing equipment, making the ability to reasonably estimate development costs for brownfield sites challenging and uncertain. Because of their potentially unique re-development costs, brownfield sites tend to be an unreliable predictor of future entry costs under long-run equilibrium conditions, as the screening criteria require. In a January 2020 filing, FERC affirmed the use of a greenfield site, stating the following in calculating CONE values in ISO-NE:

> *"We continue to find it reasonable to use a greenfield site to calculate reference unit costs because cost information is more reliable and less varied at greenfield sites, in contrast to brownfield sites."*[11]

Therefore, Concentric assumed that a new entrant would be located on a greenfield site.

10 https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements
11 *ISO New England Inc*., 170 FERC 61,052 (January 24, 2020), pg. 31, PP 55.

iii. Project Life

The levelization of costs and revenues is calculated over the estimated life of the generating resource. For the calculation of the levelized revenues required from the FCM, all candidate reference units were assumed to have a project life of twenty years, consistent with assumption used in the previous Net CONE/ORTP re-calculation performed in 2016.

iv. Plant Configuration

A survey of recently developed projects in New England provides important data points on viable plant configurations. Table 10, below, contains a sample of recent gas-fired projects developed in New England with operating capacities greater than 100 MW.[12] Note that these projects represent a mix of combined cycle and simple cycle frame technologies, and all use turbines manufactured by GE. All projects are located in Southern New England.

Table 10: Recent Gas Projects Developed in New England[13]

Plant Name	Type	Year in Service	Current Operating Capacity (MW)	Primary/ Secondary Fuel	Turbine Manufacturer	Turbine Type
West Medway II	GT	2019	200	Gas/ Distillate Fuel Oil	GE Energy	LMS100 PA+
Bridgeport Harbor Station CC Project	CC	2019	576	Gas	GE Energy	7HA.02
Canal 3 (CT)	GT	2019	333	Gas/Distillate Fuel oil	GE Energy	7HA.02
Wallingford	GT	2018	100	Gas	GE Energy	LM6000
Towantic Energy Center	CC	2018	805	Gas/ Distillate Fuel oil	GE Energy	7HA.01
Footprint Power Salem Harbor	CC	2018	674	Gas	GE Energy	7F.05

[12] The projects contained in this sample are the same projects that were reviewed for the 2017 CONE Study with the exception of Clear River Energy Center which was terminated.
[13] SNL Financial

v. Dual Fuel

The candidate gas reference units were assumed to have backup fuel in the form of No. 2 oil to address any potential issues with the availability of gas supply in the general region. No. 2 oil is the most commonly installed backup fuel in New England, and publicly available data on the cost to install dual fuel capability and to operate the plant on oil are available. Given the high value the ISO-NE region places on fuel security, dual fuel capability is a reasonable assumption for the candidate gas resources.

vi. Dry and Wet Cooling Systems

The candidate gas reference units were assumed to be designed with dry cooling for primary heat sinks. This was done to maximize potential installation sites and to ease permitting. The simple cycle plants utilize dry fin fan coolers. The combined cycle plant was assumed to have an air-cooled condenser. While there are more thermally efficient designs available, air cooled condensers are the easiest to permit, do not require significant makeup water, and can be used on most sites where reasonable space is available.

vii. Evaporative Cooling

Evaporative coolers were included to provide improved performance on warm low humidity days. Evaporative cooler effectiveness was set at 85%, which is considered reasonable for standard evaporative cooler technology.

viii. Supplemental Firing

The design assumed for the combined cycle reference includes supplementary firing. The duct burners can be fired to a 1250° F burner exit gas temperature. This firing rate provides additional peaking capacity while not increasing the cost of the heat recovery steam generator and the steam turbine, or negatively impacting the base combined cycle heat rate significantly.

ix. Environmental Assumptions

All of the candidate gas plants are designed to be in compliance with federal requirements and regional requirements. This includes Carbon Monoxide (CO) Catalysts for the combined cycle design and Selective Catalytic Reduction (SCR) equipment for all simple cycle and combined cycle designs. Dry cooling is also utilized for ease of environmental permitting. Natural gas units in Connecticut must purchase SO_2 allowance permits to comply with the Federal Acid Rain Program and CO_2 allowance permits to comply with the Regional Greenhouse Gas Initiative. New gas plants in Connecticut are not required to purchase NO_x allowance permits.

x. Interconnection Assumptions

Interconnection costs include the interconnection facilities required to meet minimum interconnection standards, as well as required network upgrades beyond the point of interconnection to meet the capacity interconnection standard. Based on a review of interconnection costs for recently completed generating plants as well as generating plants currently in development, as well as the availability of gas and electric infrastructure in the Southeastern CT area, it is assumed that a two mile interconnection to both the gas and electric grids would be required.

The electrical interconnection costs are based on an assumption that the generating plants will interconnect to the 345 kV system. The costs include a three breaker ring bus, line intercept, remote end relay communications network, two miles of overhead line transmission, revenue grade current transformers and potential transformers on the high side of the generator step-up transformer, and a revenue grade power meter all in accordance with utility requirements. Network upgrade costs required to meet the Capacity Network Resource Capability (CNRC) requirements are assumed to be zero, based on consultation with ISO New England.

Gas interconnection costs are based on an assumption that the generating plants are sited on or in very near proximity to a main natural gas transmission line, with gas available at 750 psi. The gas interconnection is comprised of a 16-inch pipeline. Fuel gas metering is assumed to be onsite at a small, dedicated fuel gas metering station with a gas chromatograph for contract gas measurement. It is assumed that gas compression is not required for a generating plant that is connected to the main gas transmission line, as is assumed in this study. The need for gas compression is highly site specific. The generic site assumption used in this study, as well as Mott MacDonald's development experience in Connecticut, supports the reasonableness of this assumption.

C. Approach to Capital Cost Estimation

Mott MacDonald, in partnership with Concentric, prepared capital cost estimates for the three candidate reference technologies based on modern construction techniques and materials for electricity generating stations and related facilities. Capital costs fall into two general categories: Engineering, Procurement, and Construction (EPC) (i.e., costs related to the construction of the plant itself) and non-EPC (i.e., owner's costs, interconnection costs, etc.).

Mott MacDonald developed the major equipment cost components, such as field construction labor hours and quantities, to develop the bottoms-up cost estimates in accordance with the screening criteria. A bottoms-up estimate utilizes a technical scope as the cost basis. This technical scope identifies what is required for a system to be engineered, procured, constructed, tested, and turned over to operations. Once the technical scope is determined, it is used as the basis of estimation where the cost to complete the project is determined. In addition to the technical scope, location, labor, available craft, shipping, and scheduling are addressed in a bottoms-up estimate. The bottoms up analysis included data from Mott MacDonald's comprehensive power plant cost estimating database[14] and information contained in the Thermoflow PEACE cost system for power plants of the size and configuration selected for this project.

[14] The Mott MacDonald cost estimating database consists of actual cost estimates for several hundred power projects including simple cycle frame, combined cycle, and aeroderivative projects.

The Mott MacDonald cost estimating database consists of actual cost estimates for several hundred power projects including simple cycle frame, combined cycle, and aeroderivative projects. The database is maintained and updated on a regular basis as new project cost estimates are prepared, and information and data are received from clients indicating the results of Mott MacDonald's work. Mott MacDonald used "at-risk" quotes submitted by contractors, to produce estimates of the major equipment costs of each gas reference unit candidate. Many of the projects in the Mott MacDonald database also include as-built cost details. The database also includes project-specific information about the civil work associated with a particular new gas generation project, such as the crew and construction equipment required for concrete work.

Given that Connecticut was selected as the general location for the candidate gas reference units, which invites possible competition for labor, the cost estimates include scheduled overtime in order to attract the most productive craft labor staff. Cost estimates for the three candidate gas reference units were based on a 50-hour work week for the journeymen. This estimate is also based on past experience throughout the country, where many projects start at a forty-hour work week but eventually become sixty-hour work weeks. It is common practice to include overtime costs on major projects in order to avoid issues during construction. In addition to the 50-hour work week, additional overtime was included in each of the project estimates to account for miscellaneous extra work tasks.

i. Direct Costs

a) Major Equipment

Major equipment was priced based on the Mott MacDonald cost database and information obtained from Mott MacDonald clients that have constructed a large number of electric generating plants. The Mott MacDonald database is kept current and is checked against market conditions for the time frame basis of the cost estimates. For any specialized major equipment that was not contained in the cost estimate database, Mott MacDonald consulted directly with clients and/or the specialty manufacturers involved in that type of major equipment supply. The Mott MacDonald cost estimates contain detailed information where each piece of major equipment is identified and priced separately.

Freight costs for the major equipment are generally included within the unit major equipment costs in the direct cost section of the cost estimates. When freight costs were not available in the Mott MacDonald cost database, which was the case for a limited number of major equipment and bulk materials expenses, Mott MacDonald estimated those costs based on its judgment and experience.

b) Balance of Plant Materials

Mott MacDonald developed balance of plant bulk material quantities from a proprietary cost estimate model that was adapted for each candidate gas reference unit and updated with relevant information from other Mott MacDonald power projects. Bulk quantities and sizes were adjusted to suit the assumed major equipment location of Connecticut. If necessary, the size of various plant components was adjusted to reflect the size of each candidate gas unit. Mott MacDonald priced the balance of plant materials based on market conditions and prices in effect in the U.S., with adjustments to suit any special conditions that might apply in the New London County, Connecticut area. Concrete supply is the one item that is particularly influenced by local costs. Mott MacDonald estimated freight costs for certain plant material price estimates, which initially did not include freight.

c) Construction Labor

Construction labor rates were based on union labor rates for the New London County, Connecticut area. The construction labor rates used were composite craft labor rates for approximately 35 various crafts and included fringe benefits, worker's compensation costs, and all applicable insurance and taxes.

Mott MacDonald calculated field labor productivity based on field construction labor conditions for the New London County, Connecticut area. These productivity values are supported by previously completed projects in the general area and consistent with Mott MacDonald's past experience and construction site surveys the company prepared for projects in the Northeast.

ii. EPC Cost Estimate Details by Major Category

a) Direct Costs (Major Equipment, Installation, Labor)

Field construction installation labor hours for major equipment installation were developed based on Mott MacDonald's experience in estimating such costs for similar projects. Mott MacDonald also considered its cost estimate model and had discussions with major equipment manufacturers about installation conditions and components associated with their equipment. All labor hours were adjusted to reflect the anticipated productivity levels associated with labor in the New London County, Connecticut area. As noted above, productivity values used in the study are consistent with Mott MacDonald's experience with similar types of construction projects in the general area.

b) Site Work

The New London County location is anticipated to require a minimal amount of additional fill given that a specific site location within the county was not identified, so site-specific cut and fill measurements were not available. Pilings for foundations were not considered given the lack of a specific site. The cost estimates include site drainage, a firewater loop system, the installation of new underground piping, new electrical duct banks and manholes, sanitary sewer piping, miscellaneous light site demolition, erosion control, excavation and backfill for the new foundations, site fencing, roadwork, site restoration and landscaping. The cost estimates include utility tie-ins at the fence. The final paving of roads was assumed to be accomplished at the conclusion of construction activities.

c) Concrete

Mott MacDonald derived concrete quantities from information contained in the Mott MacDonald cost estimate model adjusted to expected conditions considering the major equipment required for each project. Construction labor hours for concrete installation were calculated and adjusted based on anticipated construction labor productivity derived from Mott MacDonald's experience with other construction projects in the general area. Major concrete work includes the gas turbine foundation, the SCR foundation, a firewall for the main transformers, a stack foundation, building foundations, pump foundations, and the switchyard area.

d) Masonry

Mott MacDonald developed masonry quantities from information available in the Mott MacDonald cost estimate model and assumed building sizes. The major work elements contained in this cost item include both interior and exterior concrete masonry unit walls where needed, scaffolding, and all grouting costs for major equipment, and structural steel base plates.

Field construction labor hours for masonry work were calculated and adjusted based on anticipated construction labor productivity derived from Mott MacDonald's experience with other construction projects in the general area.

e) Structural Steel/Metals

Structural steel quantities were developed from information available from other Mott MacDonald projects of similar size, as well as the Mott MacDonald cost estimate model used for this project. Field construction labor hours for steel installation were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

Major structural steel work in this section of the cost estimate includes structural and supplementary steel. Platforms, grating, handrails, ladders, anchor bolts, and prime coat painting of the steel are also included unless any of these items are supplied by the manufacturer of the major equipment.

f) Buildings

To determine material quantities for administration, control, machine shop, warehouse, and guard house buildings, Mott MacDonald relied on typical plant building information and the Mott MacDonald cost estimate model. Building costs include the costs of the siding, roofing, doors, carpentry, wallboard, acoustical treatment, resilient flooring, fire protection, plumbing and HVAC requirements for the buildings on the project.

Field construction labor hours for the building work were calculated and adjusted based on anticipated construction labor productivity based on Mott MacDonald's experience with other construction projects in the general area.

g) Piping/Mechanical

Piping and mechanical quantities contained in the Mott MacDonald cost estimate model were adjusted from the assumed locations of buildings and major equipment components. Piping systems included in the piping/mechanical cost estimate include auxiliary cooling water, feedwater, fuel gas, lube oil, fuel oil, wastewater, service water, raw water, demineralized water, sampling, process and instrument air and mixed chemicals. Other materials included in this estimate include various types of valves, piping insulation, equipment insulation, and fire protection systems. Insulation and electrical heat trace required for a cold climate condition were also included based on outputs from the cost estimate model for the project. Field construction labor hours for the piping systems were calculated and adjusted based on anticipated construction labor productivity derived from Mott MacDonald's experience with other construction projects in the general area.

h) Electrical

Mott MacDonald determined electrical quantities based on the assumed locations of buildings and major equipment components. In addition, the Mott MacDonald cost estimate model was used to determine cable, conduit and cable tray sizes and lengths of a number of required electrical services. The categories included in the electrical cost estimate include site electrical work, power/control and instrumentation for cable and conduit requirements, controls needed for interconnection to the system, area lighting and service requirements, building area lighting and services, public address system, building fire alarms, and a grounding system.

The site electrical cost estimate also includes site lighting, surveillance equipment, lightning protection, cathodic protection, heat tracing and aviation lighting for the stack. Mott MacDonald calculated and adjusted field construction labor hours for the electrical systems based on anticipated construction labor productivity derived from its experience with other construction projects in the general area.

i) Instrumentation

Instrumentation quantities were developed from Mott MacDonald's experience with similar projects and the Mott MacDonald cost estimate model for the applicable candidate gas unit. Instrumentation costs include the installation and supply of contractor furnished instruments, loop checks and functional check out, instrument stands and material handling and calibration. All instrumentation and control cable, conduit and cable tray associated with the instruments are included in the electrical section of the cost estimate. Mott MacDonald calculated and adjusted field construction labor hours for the instrumentation systems based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

j) Painting

Painting costs include the painting, sealer, and epoxy requirements for the project. This estimate includes the costs of painting of the masonry walls, painting of wallboard, floor sealer, epoxy coating, finish painting of all steel with two coats over shop-applied primer coat, touch up painting of major equipment, and painting of all uninsulated steel piping.

iii. Indirect EPC Costs

a) Construction Management

Construction management costs include the planned construction management team for the EPC Contractor. All owner construction management costs as well as other categories of owner's costs were included in this cost estimate.

Specific construction management costs include the following: construction manager; an assistant construction manager; civil, mechanical, structural, electrical and instrument and controls (I&C) superintendents; a field office manager; engineering support; cost engineering; planning and scheduling; safety; quality assurance and control; field purchasing and general foremen. The costs are calculated based on an estimated project schedule. The construction manager's duration on the project includes one month in advance of beginning field operations and one month to close out the project, for a total of two additional months beyond the normal construction duration.

b) Temporary Facilities and Utilities

Temporary facilities and utilities costs include the elements needed in order to support the construction management staff and construction of the project. These costs normally exclude site trailers, clean-up of trailer area, water, sanitary facilities, field office supplies, site security, fire protection, medical supplies, temporary electrical power distribution system, telephones, copy machines and computer hardware and software.

c) Construction Equipment and Operators

These costs reflect the construction equipment and operating engineers required to construct the mechanical and electrical portion of the project. Civil construction equipment and operating engineer costs are included in this section. In addition to the construction equipment and operating engineer cost, this portion of the cost estimate includes a master mechanic, teamsters, maintenance engineers, fuel, oil and grease, small tools, consumables, and scaffolding.

d) Indirect Construction Services and Support

This portion of the cost estimate includes a detailed listing of the services needed in order to support the construction management staff and field forces. Items contained in this section of the cost estimate include continuous and final site clean-up, rubbish removal, safety equipment and supplies, various testing including soils and concrete, survey costs, weather protection, dust control, snow removal, piping radiography and other testing, testing of the grounding system and mechanical, electrical and I&C journeymen support during start-up.

e) Other Project Costs

Other project costs include a detailed listing of a variety of components required in the cost estimate that are not appropriate for inclusion in other sections of the estimate. These costs consist of freight costs for major equipment and bulk materials that are not included in the cost of the major equipment as supplied by the manufacturer or in the bulk material unit cost, travel costs, off-loading of major equipment and materials, heavy hauling of major equipment components not delivered directly to the site, general liability and umbrella insurance costs, start-up spare parts, permits, and payment and performance bonds. Mott MacDonald also included architecture/engineering costs which were calculated based on current information in the EPC cost estimate model and modified as required. Start-up and testing costs were also included in this section. Payment and performance bonds for the EPC Contractor as well as any subcontractors are part of the EPC cost estimate.

f) EPC Contractor Contingency

Mott MacDonald's EPC cost estimates include the anticipated contingency that will be applied by the EPC contractor based on the conceptual level of information that is typically available at the time a request for proposal is issued for an EPC contractor's proposal. Based on Mott Macdonald's experience developing proposals for firm lump sum projects at the conceptual stage, a contingency percentage of 6% was selected for the candidate gas units.

g) EPC Contractor Profit

Mott MacDonald evaluated current profit margins of constructors of a suitable size that could adequately perform on a project of this size. Mott MacDonald used 15% overhead and profit for the civil, mechanical, and electrical and I&C subcontractors to cover these costs. Mott MacDonald also used a 5% mark-up on the total value of the project for the EPC contractor. It was assumed that, as is typically the case today, the EPC contractor would subcontract all civil, mechanical, and electrical and I&C work and function as the general contractor. Therefore, in addition to the 15% mark-up for all the subcontractors, the EPC contractor includes a 5% mark-up on top of the all the subcontractors as his fee for monitoring their work under the total EPC contract.

iv. Non-EPC Cost Estimates

a) Owner's Contingency

The owner's contingency covers unanticipated project development costs which are owner obligations and is separate from the EPC project contingency. Owner's contingency of $6.957M was included in the cost estimate for the gas-fired simple cycle resource, $13.97M for the gas-fired combined cycle resource, and $4.1 for the gas-fired aeroderivative resource.

b) Other Contingencies

The cost estimates assume that the project would involve a subcontract structure, meaning specifically that the prime EPC Contractor would be expected to outsource major portions of the project to local specialized subcontractors who are able to better control labor costs. Therefore, the total scope of the project is assumed be contracted out by major disciplines, including a Mechanical Contractor, an Electrical and Controls Contractor, a Civil Structural and Architectural Contractor, and a Construction/Erection contractor. Each of these contractors were assumed to add their own contingency equal to 5% of their respective costs. These contingencies represent the subcontractors' portion of the EPC bid and total $10.2M.

v. Escalation of Capital Costs to Start of Construction

Mott MacDonald produced capital cost estimates in 2019 dollars and Concentric escalated these amounts to the dollar value at the start of construction. EPC costs were escalated at a rate of 0.7%; Non-EPC costs were escalated at 1.9%. Both of these escalation rates are based on the Bureau of Labor Statistics Producer Price Index (PPI) escalation rates.

D. Cone Candidate Reference Unit Technical Specifications

i. 7HA.02 Simple Cycle Frame Combustion Turbine

The GE 7HA.02 is a large frame machine representing the current state-of-the-art regarding materials and combustion technology, giving it the highest efficiency available in the simple cycle technology market. In addition to a low minimum load point and high ramp rates that provide for flexible operation, the plant has relatively low capital costs. The 7HA.02 has entered commercial operation in a variety of locations throughout the country and is currently operating in New England at the Canal generating facility in simple cycle configuration and at the Bridgeport generating facility in combined cycle configuration.

The assumed nominal capacity of the 7HA.02 in the simple cycle configuration is 376 MW based on the site elevation, average ambient temperature, and coincident relative humidity over a ten-year period.[15] Based on current market trends, the unit is assumed to be equipped with evaporative coolers for power augmentation and a fin fan cooling system. The plant utilizes SCR to control emissions. The net heat rate of the facility is 9,042 Btu/kWh at average ambient conditions and the assumed plot size is eight acres. A summary of the technical specifications is shown in Table 11 below.

Table 11: GE 7HA.02 Simple Cycle Technical Specifications

TURBINE MODEL	7HA.02
Configuration	Simple cycle frame machine
Net Plant Capacity (MW)	Nominal: 371 Summer: 359 Winter: 389
Location	New London County, Connecticut
Cooling System	Fin fan coolers
Power Augmentation	Evaporative coolers
Net Heat Rate (Btu/kWh) HHV	Shoulder: 9,132 Summer: 9,225 Winter: 9,060
Environmental Controls	Selective Catalytic Reduction
Dual-Fuel Capability	Natural gas w/ No. 2 oil backup
Black Start?	No
On-site Gas Compression?	No
Gas Interconnection	2 mile onsite connection
Electrical Interconnection	2 mile onsite connection
Plot Size (acres)	8
Notes: For purposes of the ambient rate assumptions, Summer months are June, July, and August; Winter months are December, January, February, and March; and Shoulder months are all other months.	

ii. LM6000PF+ Aeroderivative Gas Turbine

The LM6000PF+ is one of the most widely installed plants in New England and is in widespread commercial use around the world. The unit, which is based on GE jet engine technology, is highly modular and can be engineered, procured, constructed, and entered into operation more quickly than any alternative technology operating above 20 MW. While the LM6000PF+ can be utilized in a

[15] Average site conditions are 57 degrees Fahrenheit, 80% relative humidity, and 250 feet above sea level.

combined cycle configuration, the simple cycle configuration is more common and was thus selected for review and analysis.

The assumed capacity of the LM6000PF+ is 98 MW nominal.[16] Based on current market trends, this unit was assumed to be equipped with evaporative coolers for power augmentation as well as a fin fan cooling system. In addition, it was assumed that the plant would utilize SCR to control emissions. The assumed net heat rate of the facility is 9,608 Btu/kWh in the shoulder months with a plot size of 4.5 acres. A summary of the technical specifications is shown in Table 12 below.

Table 12: LM6000PF+ Technical Specifications

TURBINE MODEL	LM6000PF+
Configuration	Two SC Aeroderivative GTs
Net Plant Capacity (MW)	Nominal: 95 Summer: 87 Winter: 108
Location	New London County, Connecticut
Cooling System	Fin fan coolers
Power Augmentation	Evaporative coolers
Net Heat Rate (Btu/kWh) HHV	Nominal: 9,656 Summer: 9,964 Winter: 9,498
Environmental Controls	Selective Catalytic Reduction
Dual-Fuel Capability	Natural gas w/ No. 2 oil backup
Black Start?	No
On-site Gas Compression?	No
Gas Interconnection	2-mile onsite connection
Electrical Interconnection	2-mile onsite connection
Plot Size (acres)	4.5
Notes: For purposes of the ambient rate assumptions, Summer months are June, July, and August; Winter months are December, January, February, and M arch; and Shoulder months are all other months.	

iii. 7HA.02 Combined Cycle Combustion Turbine

The combined cycle combustion turbine uses the same machine as the simple cycle machine. However, with the combined cycle combustion turbine, a heat recovery steam generator (HRSG) and steam turbine generator are added to allow for additional generation using exhaust gas energy from the simple cycle machine. Adding the HRSG steam tail increases capital costs significantly; however, doing so also increases plant's capacity and efficiency.

[16] Average site conditions are 57 degrees Fahrenheit and 80% relative humidity.

The combined cycle combustion turbine was assumed to have duct firing capability. Duct firing is an option many plant developers choose to provide a highly flexible source of quick start capacity that can be used to capture revenues during high price periods.

The assumed nominal baseload capacity of the combined cycle combustion turbine is 535 MW with 22 MW of duct firing capability for a total nominal capacity of 557 MW when duct firing is engaged. This performance is based on the site elevation, average ambient temperature, and coincident relative humidity over a ten-year period.[17] It is also equipped with both fin fan cooling and evaporative coolers for power augmentation. To control emissions, the plant has both SCR and a CO catalyst. The baseload heat rate is 6,291 Btu/kWh; when duct firing is engaged, the net heat rate increases to 6,372 Btu/kWh in the shoulder months. The plot size is 15 acres. A summary of the combined cycle's technical specifications is provided in Table 13 below.

Table 13: GE7HA.02 Combined Cycle Technical Specifications

TURBINE MODEL	7HA.02 COMBINED CYCLE
Configuration	Combined Cycle w/ Frame GT
Net Baseload Capacity (MW)	Nominal: 522 Summer: 497 Winter: 542
Net Capacity w/ Duct Firing (MW)	Nominal: 544 Summer: 526 Winter: 570
Location	New London County, Connecticut
Cooling System	Fin fan coolers
Power Augmentation	Evaporative coolers
Baseload Net Heat Rate (Btu/kWh) HHV	Nominal: 6,394 Summer: 6,573 Winter: 6,429
Duct Firing Net Heat Rate (Btu/kWh) HHV	Nominal: 6,480 Summer: 6,732 Winter: 6,521
Environmental Controls	Selective Catalytic Reduction and CO catalyst
Dual-Fuel Capability	Natural gas w/ No. 2 oil backup
Black Start?	No
On-Site Gas Compression?	No
Gas Interconnection	2-mile Onsite connection
Electrical Interconnection	2-mile Onsite connection
Plot Size (acres)	15
Notes: For purposes of the ambient rate assumptions, Summer months are June, July, and August; Winter months are December, January, February, and March; and Shoulder months are all other months.	

[17] Average site conditions are 57 degrees Fahrenheit and 80% relative humidity.

E. CONE Candidate Reference Unit Capital Costs

The capital costs for the candidate reference units were developed by Mott MacDonald through discussions with the manufacturer and reliance on the manufacturer's proprietary database. These capital cost estimates are shown in Tables 14-16, below.

i. 7HA.02 Simple Cycle Frame Combustion Turbine

Table 14: GE 7HA.02 Simple Cycle Capital Costs (2019$, in millions)[18]

COST COMPONENT	7HA.02 SIMPLE CYCLE (CONE)
EPC Costs	
Civil/Structural/Architectural	18.9
Mechanical Costs	137.7
Electrical/Instrumentation Costs	27.9
Construction Management	7.6
Other Project Costs	12.4
Project Contingency	12.3
EPC Contractor Fee	10.4
Total EPC	**227.2**
Non-EPC Costs	
Owner's Contingency	7.0
Electrical Interconnection	27.0
Gas Interconnection	11.0
Fuel Inventories	4.5
Financing Fees (4% of costs financed through debt)	9.1
Working Capital (1% of EPC costs)	2.3
Total Non-EPC	**60.8**
Total Overnight Capital Costs	**288.0**
$/KW	**776.9**

[18] Numbers may reflect rounding.

ii. LM6000PF+ Aeroderivative Gas Turbine

Table 15: LM6000PF+ Capital Costs (2019$, in millions)[19]

COST COMPONENT	LM6000 PF+
EPC Costs	
Civil/Structural/Architectural	14.0
Mechanical Costs	73.8
Electrical/Instrumentation Costs	19.5
Construction Management	5.1
Other Project Costs	8.1
Project Contingency	7.2
EPC Contractor Fee	6.1
Total EPC	**133.8**
Non-EPC Costs	
Owner's Contingency	4.1
Electrical Interconnection	27.0
Gas Interconnection	11.0
Fuel Inventories	4.5
Financing Fees (4% of costs financed through debt)	5.4
Working Capital (1% of EPC costs)	1.3
Total Non-EPC	**53.2**
Total Overnight Capital Costs	**187.0**
$/KW	**1,961.4**

[19] Ibid

iii. 7HA.02 Combined Cycle Combustion Turbine

Table 16: 7HA.02 Combined Cycle Capital Costs (2019$, in millions)[20]

COST COMPONENT	7HA.02 COMBINED CYCLE (CONE)
EPC Costs	
Civil/Structural/Architectural	49.0
Mechanical Costs	267.0
Electrical/Instrumentation Costs	54.0
Construction Management	11.4
Other Project Costs	29.0
Project Contingency	24.6
EPC Contractor Fee	20.9
Total EPC	**456.1**
Non-EPC Costs	
Owner's Contingency	14.0
Electrical Interconnection	27.0
Gas Interconnection	11.0
Fuel Inventories	4.5
Financing Fees (4% of costs financed through debt)	18.2
Working Capital (1% of EPC costs)	4.6
Total Non-EPC	**79.3**
Total Overnight Capital Costs	**535.3**
$/KW	**985.0**

F. Variable Operations and Maintenance Costs

Variable O&M (VOM) is assumed at the following rates for each of the CONE candidate resources. Mott MacDonald developed VOM estimates based on information contained in their cost database and industry experience. VOM costs, as shown in Table 17 below, are directly related to plant electrical generation, and generally include routine equipment maintenance, long-term major maintenance events, variable LTSA annual fees, makeup water, water treatment, water disposal, ammonia, SCR and CO catalyst replacements (as applicable), and other consumables not including fuel.

[20] Ibid

Table 17: Variable O&M (2025$/MWh)

RESOURCE	VOM
7HA.02 Simple Cycle	$1.75
LM6000 Aeroderivative	$1.16
7HA.02 Combined Cycle	$3.60

G. Fixed O&M Costs

Fixed O&M costs for each of the candidate reference units consist of operating expenses including management and administration costs, labor, materials, contract services, and associated costs (including the fixed price portion of a long-term service agreement (LTSA)). While major maintenance costs are allowed to be included in the VOM costs that are submitted as part of a generating unit's offer in the day-ahead and real-time market, generating units are not required to do so. A review of historical offer data revealed a wide range of approaches to pricing major maintenance costs in an energy offer, with some not including these costs, and others including nominal amounts. Fixed O&M costs also include leasing of the land on which the plant is located, property taxes, and insurance. These costs are summarized in Table 18 below and discussed in more detail in the following sections.

Table 18: Total Fixed O&M Components

	SIMPLE CYCLE	AERODERIVATIVE	COMBINED CYCLE
LTSA & Ongoing Maintenance (2025$/kW-yr)	$39.81	$80.68	$61.25
Property Taxes	2.89%	2.89%	2.89%
Site Leasing (2025$/acre/yr)	$25,000	$25,000	$25,000

i. Ongoing Maintenance / LTSA

a) GE 7HA.02 Simple Cycle

The simple cycle will have an LTSA for parts, labor, and materials for all work done up to and including the first major outage. This LTSA is assumed to have a fixed price payment structure with monthly payments. Outage frequency and durations would be agreed to, but degradation is not generally guaranteed. Planned outages would be included under the agreement, but unplanned outages would not be covered. The LTSA amount was estimated by Mott MacDonald, and Concentric verified the assumed LTSA cost by consulting several publicly available studies. The LTSA was estimated at $35/kW-year (2019$). Concentric also included an ongoing maintenance assumption of $2,500/MW-year in addition to the LTSA to account for ongoing maintenance expenses associated with required network upgrades, as allowed under the ISO-NE Tariff, resulting in a total of $39.81/kW-year (2025$).

b) LM6000PF+ Aeroderivative Gas Turbine

Like the simple cycle LTSA, the aeroderivative LTSA includes parts, labor, and materials as well as a turbine sharing program that would utilize a shared rotor for quick return to service. The removed rotor would then be serviced and used in the shared rotor program with other plant owners. This minimizes down time for the aeroderivative plants. The duration of the LTSA would be up to and including the first major outage. Planned outages would be included in the LTSA, but unplanned outages would not. The LTSA amount was provided by Mott MacDonald, and Concentric verified this number by consulting several publicly available studies. The LTSA is estimated at $75/kW-year (2019$). Concentric also included an ongoing maintenance assumption of $1,000/MW-year in addition to the LTSA, consistent with the other reference units, resulting in a total of $80.68/kW-year (2025$).

c) 7HA.02 Combined Cycle

Like the other units, the combined cycle unit's LTSA includes labor, materials, contract services, and associated costs. The LTSA amount was provided by Mott MacDonald, and Concentric verified this number by consulting several publicly available studies containing estimates of O&M costs. The LTSA is estimated at $55.20/kW-year (2019$). Concentric also included an ongoing maintenance assumption of $2,500/MW-year in addition to the LTSA to account for ongoing maintenance expenses associated with required network upgrades, as allowed under the ISO-NE Tariff, resulting in a total of $61.25/kW-year (2025$).

ii. Property Taxes

Property taxes are based on municipal tax rates, which are often differentiated by business type. The assumed property tax rate for the candidate reference units is based on a review of commercial and industrial (C&I) rates in the reference county's 21 municipalities over the 2018-2020 period. Based on the rates shown in Table 19, we assumed a property tax rate of 2.89% for all new gas units in New London County, Connecticut.

Table 19: Municipal Tax Rates for Towns in New London County[21]

Town / City	2020	2019	2018
Bozrah	2.75%	2.75%	2.85%
Colchester	3.28%	3.23%	3.24%
East Lyme	2.82%	2.74%	2.62%
Franklin	2.37%	2.57%	Not Available
Griswold	2.86%	2.80%	2.76%
Groton	2.42%	2.42%	2.36%
Lebanon	2.94%	2.94%	2.94%
Ledyard	3.51%	3.43%	3.25%

[21] State of Connecticut Office of Policy and Management, 2020, https://portal.ct.gov/OPM/IGPP-MAIN/Publications/Mill-Rates.

TOWN / CITY	2020	2019	2018
Lisbon	2.32%	2.25%	2.25%
Lyme	2.00%	1.86%	1.83%
Montville	3.25%	3.17%	3.17%
New London	3.99%	4.32%	4.32%
North Stonington	2.90%	2.82%	2.80%
Norwich	4.03%	4.10%	4.05%
Old Lyme	2.24%	2.19%	2.18%
Preston	2.64%	2.60%	2.40%
Salem	3.22%	3.22%	3.22%
Sprague	3.48%	3.33%	3.20%
Stonington	2.34%	2.27%	2.30%
Voluntown	2.92%	2.89%	2.95%
Waterford	2.80%	2.74%	2.70%
AVERAGE	**2.91%**	**2.89%**	**2.87%**

iii. Site Leasing Costs

Site leasing costs were assumed to be recorded as a Fixed O&M expense. Based on a review of industrial leasing costs, we assumed $25,000/acre based on the need to be close to gas and transmission interconnection infrastructure and consistent with the 2017 study and with other ISO CONE studies. This lease rate was multiplied by the estimated plot acreage to determine a total site leasing cost.

iv. Insurance

Insurance costs were assumed to be 0.6% of the overnight capital costs per year, consistent with the assumption in the 2013 and 2017 ISO-CONE studies, as well as the NYISO and PJM CONE studies. We continue to consider this assumption to be within a range of reasonableness.

H. Escalation to 2025$ Costs

Capital costs were escalated from 2019 dollars to the beginning of each candidate reference unit's construction period using estimates from the BLS PPI. A 10-year average annual percent change was used from two BLS PPI indices for different capital cost components.[22]

Fuel costs were escalated for the gas turbines using NY Harbor ultra-low-sulfur-diesel (ULSD) futures settlements. This estimate was based on the average percent change of ULSD futures prices at NY

[22] BLS PPI WPUID612: not seasonally adjusted, annual average percent change 2009-2018.
BLS PPI WPU1197: not seasonally adjusted, eight-year annual average percent change 2009-2018. For WPU1197, 2016 and 2017 data are missing from the BLS series. We calculated the three-year compound annual growth rate from 2015 to 2018 and applied this annual percent change (-1.62%) to the final three years in the ten-year span.

Harbor for 12-month periods beginning March 2020 and ending January 2022, when liquidity dropped off.[23]

[23] ULSD Forward Curve as of February 26, 2020; CME Group.

Section 4: Financial Assumptions

A. Approach

The CONE/Net CONE estimate for each candidate reference unit is based on the revenue required, net of cash flows from ISO-NE energy, ancillary services and other market revenues, and (if applicable) REC market revenues, by a new entrant to recover its capital and operating costs over the unit's assumed 20-year project life. This estimate includes the cost of providing a return to equity investors and debt holders and is based on the reasonable assumption that significant amounts of capital will only be invested if investors anticipate that their investment will generate returns that meet or exceed their cost of capital. Consistent with previous studies, the CONE and Net CONE values are expressed on a real, levelized annual basis. That is, the calculation produces a payment such that if the capacity payment increases at the assumed rate of inflation every year over the twenty-year period, the NPV of a unit's costs are equal to the NPV of its revenues over the 20-year period.

It is customary to discount uncertain future cash flows at an after-tax weighted average cost of capital. The appropriate discount rate should reflect systemic financial market risks, project-specific risks of a merchant developer participating in the ISO-NE markets, and the return required by investors to compensate for those risks. We recognize that generation projects can be financed under a project financing or balance sheet financing approach. Project financing uses project-specific, "non-recourse" debt, along with a required portion of equity, to finance the construction of a generation asset. Non-recourse debt is not backed by a guarantee from the equity investor (likely a larger parent company) beyond the value of the individual asset. Balance sheet financing employs debt backed by the project owner itself, which may have significant, diverse resources and assets beyond the individual asset. While some plants in ISO-NE are financed on a "stand-alone" or project-specific basis, the specifics of these financing structures are not publicly available and are diverse and difficult to estimate. Because data about project-specific financing is not publicly available, we chose a peer group of publicly traded independent power producers (IPPs) and used their financial parameters to inform our calculation of the recommended cost of capital. We then made reasonable adjustments to this proxy group data to calculate an after-tax weighted average cost of capital to reflect how a generic new entrant would likely view the risk of merchant development in New England.

Our financing paradigm assumes a reasonable balance between project-specific financing and large corporate balance sheet financing. The cost of capital is calculated as the weighted average of the required return for equity holders and cost of debt. In addition to the cost of capital, the key financial inputs to the calculation of CONE/Net CONE include inflation, depreciation, and property taxes. The derivation of each input is described below.

B. Financial Model Inputs

i. Inflation

CONE/Net CONE, and the inputs to calculate CONE/Net CONE are expressed in real (constant) dollars. Inflation is a key factor used to translate projected nominal cost and revenue streams to constant, or real, terms. It is also used in the calculation of a real discount rate, the levelization factor for CONE/Net CONE.

Three estimates of inflation were reviewed to develop the annual inflation outlook of 2.0%. The Blue Chip Financial Forecast, Long Term Consensus Forecast provides a forward looking forecast of inflation.[24] The CPI consensus estimate for 2022-2026 is 2.1%, while the 2027-2031 estimate is 2.2%.

Second, we reviewed inflation expectations from the Federal Reserve Bank of Cleveland. The Cleveland Fed reports estimates that use Treasury yields, inflation data, inflation swaps, and survey-based measures of inflation expectations.[25] The current 20 and 25-year expected inflation for the average of previous 6 months as of the time of our analysis is 1.62 and 1.74%, respectively.[26]

Finally, we review inflation expectations as included in EIA's 2020 Annual Energy Outlook. The GDP Chain-type Price Index – CPI Energy Commodities and Services 2025 estimate is 2.3%.[27]

Based on these inputs, we assumed an average long-term annual inflation rate of 2.0% to be a reasonable estimate for all CONE and ORTP calculations.

ii. Amortization Period

The amortization period is the term over which the project is expected to operate such that all upfront capital costs are returned in a manner that yields both a return of capital (i.e., depreciation) and a return on that invested capital. The CONE, Net CONE, and ORTP values are estimated over the amortization period based on an estimate of the annual levelized capital cost and ongoing costs and revenues. Consistent with the last CONE and ORTP update and the ISO-NE tariff requirements for the calculation of CONE and ORTP values,[28] this study assumes a 20-year amortization period. Finally, a 20-year amortization period and project life is consistent with a recent FERC directive to PJM regarding the calculation of default Minimum Offer Price Rule offer floors, which serve a similar role to the ORTP, based on an assumed 20-year project life for various resource types.[29]

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[24] Blue Chip Financial Forecasts®, Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them, Vol. 39, No. 6, June 1, 2020.
[25] https://www.clevelandfed.org/our-research/indicators-and-data/inflation-expectations.aspx
[26] Cleveland Federal Reserve, September 2017-September 2019, 20-year expected inflation.
[27] EIA AEO 2020. Table 20, Macroeconomic Indicators. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2020&cases=ref2020&sourcekey=0
[28] Market Rule 1 Section III.A.21.1.2.
[29] Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153.

iii. Depreciation

The tax life of each resource is based on IRS guidelines under the Modified Accelerated Cost Recovery System (MACRS) to depreciate the eligible portion of total installed costs over the amortization period.[30] The MACRs allows for recovery of depreciation over 15 years for a new combustion turbine, over 20 years for a new combined cycle turbine, over 5 years for a new wind, solar, and co-located facility, and over 7 years for a battery facility.

To calculate the annual value of depreciation, the "depreciable costs" for a new resource are the sum of the depreciable capital costs and the accumulated interest during construction (IDC). Several capital cost line items are considered non-depreciable, including fuel inventories, and working capital, and are not included in total depreciable costs. IDC is calculated based on the assumption that capital structure during the construction period is the same as the overall project, i.e., 55% debt and 6.0% cost of debt (COD).

iv. Income Taxes

The income tax rates applicable to each new project are based on current federal and state tax rates. The marginal federal income tax rate is 21%.[31] The state income tax rate for Connecticut, where the candidate reference units are located, is 7.5%.[32] The effective income tax rate is calculated to be 26.9%.

v. Cost of Capital

The Weighted Average Cost of Capital (WACC) for an investment represents the blend of rates paid on equity and debt specific to that investment's capital structure and can be expressed by the following equation:

WACC = ROE * Weight of Equity + COD * Weight of Debt

Where:
ROE = Return on Equity
COD = Cost of Debt

Derivation of each input to the WACC calculation is described below and is based on a peer group of merchant generation companies who may be likely to develop projects in New England. Our peer group consists of the following public traded companies:

[30] Table B-2, IRS Publication 946. Half-Year Convention.
[31] Internal Revenue Service, 2019 Instructions for Form 1120, U.S. Corporation Income Tax Return. January 22, 2020. Available at https://www.irs.gov/pub/irs-dft/i1120--dft.pdf
[32] Connecticut Department of Revenue Services, 2020. Available at: https://portal.ct.gov/DRS/Corporation-Tax/Tax-Information.

- AES Corporation
- Clearway Energy Group
- NRG Energy, Inc.
- Vistra
- Atlantic Power Corp.

We note that the current peer group differs from the 2016 CONE recalculation due to the fact that several IPPs are no longer publicly traded, or have merged to become new entities.[33] We received feedback from stakeholders that the full group of peers does not appropriately represent merchant entry in New England because many hold diverse portfolios with some portion of regulated assets. We considered these comments in evaluating the components of cost of capital, as well as the overall cost of capital chosen for the evaluation of CONE and Net CONE; each component is discussed in more detail below.

vi. Return on Equity

Return on equity (ROE) is the amount of return that would be required by investors to compensate for the risk of making an equity investment in a merchant generation plant. The risk environment determines the hurdle rates for investment. Equity raised for uncontracted, merchant projects requires a higher return to investors than equity raised for contracted projects. For energy and capacity that is fully contracted, the cost of equity reflects a lower level of risk, assuming a significant degree of leverage. For uncontracted merchant capacity, developers target a higher after-tax return on equity based on the perceived high risks of cost recovery in the market. A return on equity of 13.0% represents an appropriate return under equilibrium market risk conditions based on a peer group review of merchant generating companies.

To calculate the appropriate return on equity for this analysis, the Capital Asset Pricing Model (CAPM) was used. CAPM is a common analytical approach in financial modeling and assumes that equity investors base their required returns on a risk-free rate of return, the rate at which they would be compensated for an available investment that carried no risk, plus compensation for the relative risk of a specific security in relation to the broader market. CAPM is expressed by the following equation:

$$Re = Rf + \beta\ (Rm - Rf)$$

Where:

Re= Required return on equity

Rf = The risk-free rate

[33] The 2016 peer group included AES, Calpine, Dynegy, NRG, and Talen.

β = Beta, a measure of the covariance between the returns (dividends plus capital gains) of the market average and those of a specific security, and

Rm = The return required of the market as a whole

Concentric reviewed several estimates of a risk-free rate, including the 30-day average of the 30-year Treasury yield curve, as well as estimates from Blue Chip. We also reviewed beta estimates from several sources including Bloomberg and Value Line. Based on our assumed capital structure of 55/45 debt to equity, we re-levered our estimates of beta for inclusion in our CAPM calculation.

Table 20 shows beta estimates that reflect each individual IPP's historical capital structure (levered beta). Using the historical average capital structure, or debt to equity ratio (D/E Ratio), we calculate an unlevered beta which reflects the beta of each IPP without any debt. We then re-lever the beta (Re-levered Beta) using our assumed capital structure of 55/45 (D/E).

Table 20: Peer Group Beta Estimates

BLOOMBERG [1]	(2-YEAR BETA)	[3]		
	Levered Beta	D/E Ratio	Unlevered Beta	Re-levered Beta
AES	1.14	2.34	0.42	0.79
CWEN	0.67	1.04	0.38	0.72
NRG	1.20	1.39	0.59	1.12
VST	1.07	0.72	0.70	1.32
AT	0.76	1.44	0.37	0.71
Value Line [2]	(5-year Beta)			
	Levered Beta	D/E Ratio	Unlevered Beta	Re-levered Beta
AES	1.05	2.34	0.39	0.73
CWEN	NA	1.04	NA	NA
NRG	1.25	1.39	0.62	1.17
VST	1.15	0.72	0.75	1.43
AT	NA	1.44	NA	NA
Sources:				
[1] Bloomberg as of June 30, 2020				
[2] Value Line as of June 2020				
[3] Bloomberg data as of June 30, 2020; D/E ratio is calculated from 2018Q2-2020Q1 average quarter-end debt %				

We reviewed two estimates of the overall market return: a historical estimate from Duff & Phelps; and a forward-looking estimate of the S&P 500 Index. Table 21 shows the calculations for a number of historic and forward-looking estimates of peer company returns on equity.

Table 21: CAPM Results

CAPM										
		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
	Risk Free Rate	Beta- Relevered			Historical	S&P 500	Market Risk Premium		ROE Based On	
		Value Line	Bloomberg	Average	Return	Projected	Historical	Projected	Historical MRP	Projected MRP
	30-year [1a]									
AES	1.47%	0.73	0.79	0.76	8.50%	13.16%	7.03%	11.69%	6.84%	10.40%
CWEN	1.47%	NA	0.72	0.72	8.50%	13.16%	7.03%	11.69%	6.52%	9.86%
NRG	1.47%	1.17	1.12	1.15	8.50%	13.16%	7.03%	11.69%	9.53%	14.88%
VST	1.47%	1.43	1.32	1.38	8.50%	13.16%	7.03%	11.69%	11.14%	17.55%
AT	1.47%	NA	0.71	0.71	8.50%	13.16%	7.03%	11.69%	6.43%	9.71%
									8.09%	**12.48%**
	30-year [1b]									
AES	3.00%	0.73	0.79	0.76	8.50%	13.16%	5.50%	10.16%	7.20%	10.76%
CWEN	3.00%	NA	0.72	0.72	8.50%	13.16%	5.50%	10.16%	6.95%	10.29%
NRG	3.00%	1.17	1.12	1.15	8.50%	13.16%	5.50%	10.16%	9.31%	14.65%
VST	3.00%	1.43	1.32	1.38	8.50%	13.16%	5.50%	10.16%	10.56%	16.97%
AT	3.00%	NA	0.71	0.71	8.50%	13.16%	5.50%	10.16%	6.88%	10.16%
									8.18%	**12.57%**
	30-year [1c]									
AES	3.80%	0.73	0.79	0.76	8.50%	13.16%	4.70%	9.36%	7.39%	10.95%
CWEN	3.80%	NA	0.72	0.72	8.50%	13.16%	4.70%	9.36%	7.17%	10.52%
NRG	3.80%	1.17	1.12	1.15	8.50%	13.16%	4.70%	9.36%	9.19%	14.53%
VST	3.80%	1.43	1.32	1.38	8.50%	13.16%	4.70%	9.36%	10.26%	16.67%
AT	3.80%	NA	0.71	0.71	8.50%	13.16%	4.70%	9.36%	7.11%	10.40%
									8.23%	**12.62%**
								Average	**8.17%**	**12.55%**
								Average	**10.36%**	

CAPM
Notes:
[1]
a) 30-day average 30-Yr T Note Bloomberg
b) 10-year forecast of 30-year Treasury Bonds; Blue Chip Financial Forecast, Vol. 39, No. 6, June 1, 2020.
c) Average 30-year treasury yield for 2026-2030; Blue Chip Financial Forecast, Vol. 39, No. 6, June 1, 2020.
[2] Source: Value Line accessed on 7/24/20
[3] Source: Bloomberg Professional as of 6/30/20
[4] Equals average ([2], [3])
[5] https://vasdc8grscoc.blob.core.windows.net/files/ReleaseLogs/TEMPLATE_NavigatorReleaseUpdate_Master.pdf
[6] Source: Bloomberg Professional
[7] Equals [5] – [1]
[8] Equals [6] – [1]
[10] Equals [1] + ([4] x [7])
[10] Equals [1] + ([4] x [8])

We also reviewed these results in light of stakeholder feedback regarding the appropriate peer group. We performed several sensitivities on the peer group, as detailed below.

Table 22: CAPM Results – Sensitivity #1

	RISK FREE RATE	ROE BASED ON	
		Historical	Projected
		MRP	
	30-year		
AES	1.47%	6.84%	10.40%
NRG	1.47%	9.53%	14.88%
VST	1.47%	11.14%	17.55%
		9.17%	**14.28%**
	30-year		
AES	3.00%	7.20%	10.76%
NRG	3.00%	9.31%	14.65%
VST	3.00%	10.56%	16.97%
		9.03%	**14.13%**
	30-year		
AES	3.80%	7.39%	10.95%
NRG	3.80%	9.19%	14.53%
VST	3.80%	10.26%	16.67%
		8.95%	**14.05%**
		9.05%	**14.15%**
		11.60%	

Table 23: CAPM Results – Sensitivity #2

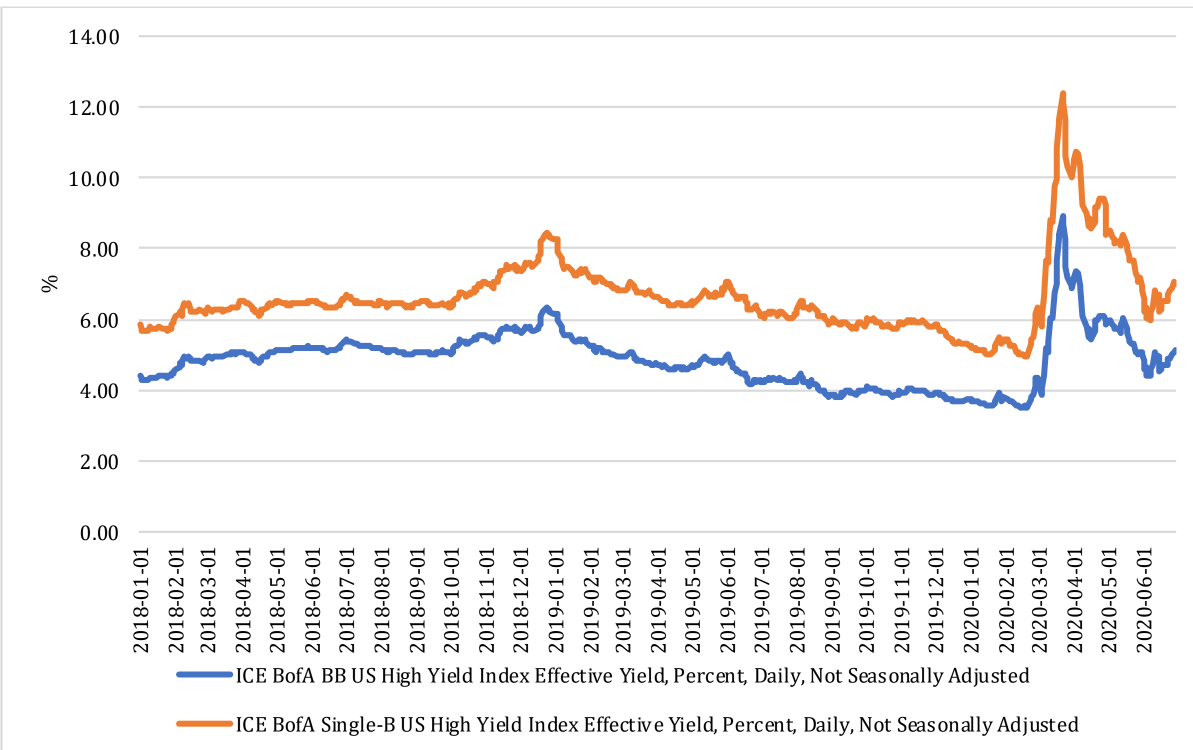
	RISK FREE RATE	ROE BASED ON	
		Historical	Projected
		MRP	
	30-year		
NRG	1.47%	9.53%	14.88%
VST	1.47%	11.14%	17.55%
		10.33%	**16.21%**
	30-year		
NRG	3.00%	9.31%	14.65%
VST	3.00%	10.56%	16.97%
		9.94%	**15.81%**
	30-year		
NRG	3.80%	9.19%	14.53%
VST	3.80%	10.26%	16.67%
		9.73%	**15.60%**
		10.00%	**15.87%**
		12.94%	

As seen in the two peer group sensitivity results above, the average CAPM result increases to 11.6% and 12.9% when subsets of the full peer group are considered. We recommend a 13% cost of equity, which is in line with the adjustments made to the peer group to better approximate merchant generation risk. We believe this appropriately reflects an upward adjustment to the full peer group of results, and is aligned with the NRG and VST-only sensitivities – the peers whose portfolio most closely reflects pure play merchant generation.

vii. Cost of Debt

To estimate the Cost of Debt (COD), Concentric reviewed credit ratings of companies active in the development and commercialization of merchant generation. Of the five comparators, each has below investment-grade senior unsecured debt ratings in the BB range (BB- to BB+).[34] We then reviewed historical generic corporate bond yields for B and BB rated companies. In calendar year 2019, bond yields for companies with a B rating averaged 6.38%, while yields for companies with a BB rating averaged 4.45%.

Figure 2: Generic Corporate Bond Yields[35]



[34] SNL Financial. Ratings are estimated by Standard & Poor's and Moody's reported by SNL, as of July 2020.
[35] BofA Merrill Lynch, BofA Merrill Lynch US High Yield B and BB Effective Yield©, retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/BAMLH0A2HYB[B]EY.

A longer-term view of generic corporate debt reveals these averages have been steadily decreasing in recent years, with levels peaking in 2016, the time this analysis was completed in the previous Net CONE recalculation. Given these trends and considering that our peer group credit ratings are primarily BB rated, we have assumed a cost of debt of 6.0%. This assessment is at the upper end of the range of BB rated bond yields and is consistent with the increased risk associated with a merchant generating plant investing in a new capacity resource without a long-term contract.

Concentric also reviewed recent bond issuances for peer companies. These showed coupon rates ranging from 3%-6%, with an unweighted average of approximately 4.5%, as shown below.

Table 24 : Recent IPP Debt Issuances[36]

NAME	TICKER	MATURITY TYPE	CURRENCY	BLOOMBERG COMPOSITE RATING	COUPON	ANNOUNCE
AES Corp/The	AES	CALLABLE	USD	BBB-	3.95	5/15/2020
AES Corp/The	AES	CALLABLE	USD	BBB-	3.3	5/15/2020
AES Corp/The	AES	CALLABLE	USD	BBB-	3.95	5/15/2020
AES Corp/The	AES	CALLABLE	USD	BBB-	3.3	5/15/2020
AES Corp/The	AES	CALLABLE	USD	BB+	4.5	3/1/2018
Atlantic Power Corp	ATPCN	CONV/CALL	CAD	#N/A N/A	6	1/22/2018
Clearway Energy Operating LLC	CWENA	CALLABLE	USD	#N/A N/A	4.75	5/19/2020
Clearway Energy Operating LLC	CWENA	CALLABLE	USD	BB	4.75	12/4/2019
Clearway Energy Operating LLC	CWENA	CALLABLE	USD	BB	4.75	12/4/2019
Clearway Energy Operating LLC	CWENA	CALLABLE	USD	BB	5.75	9/5/2019
NRG Energy Inc	NRG	CALLABLE	USD	BBB-	4.45	5/20/2019
NRG Energy Inc	NRG	CALLABLE	USD	BBB-	3.75	5/20/2019
NRG Energy Inc	NRG	CALLABLE	USD	BBB-	4.45	5/20/2019
NRG Energy Inc	NRG	CALLABLE	USD	BBB-	3.75	5/20/2019
NRG Energy Inc	NRG	CALLABLE	USD	BB	5.25	5/7/2019
NRG Energy Inc	NRG	CALLABLE	USD	BB	5.25	5/7/2019
NRG Energy Inc	NRG	CALLABLE	USD	BB	5.25	5/7/2019
NRG Energy Inc	NRG	CALLABLE	USD	BB	5.75	10/2/2018
NRG Energy Inc	NRG	CONV/PUT/CALL	USD	#N/A N/A	2.75	5/21/2018
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.7	11/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.7	11/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.55	11/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5	6/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5	6/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.55	6/4/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	4.3	6/4/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	4.3	6/4/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.55	6/4/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5.625	1/22/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5.625	1/22/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5.5	8/7/2018
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5.5	8/7/2018

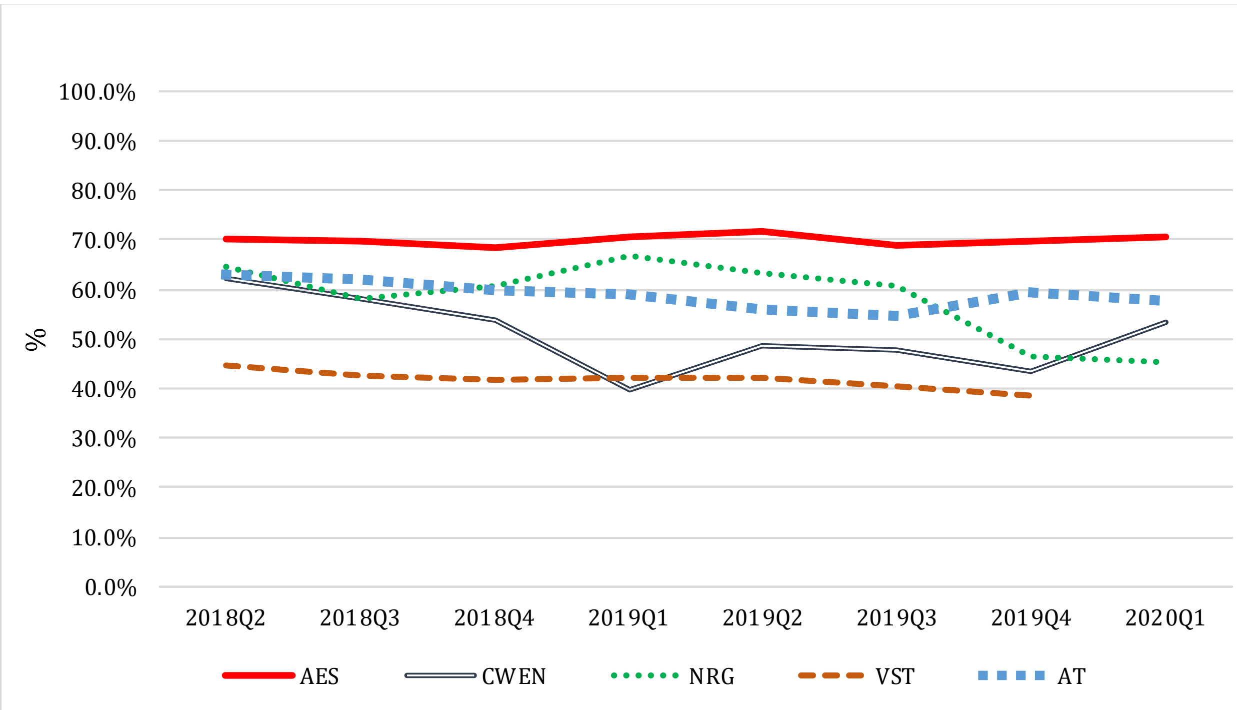
[36] As reported by Bloomberg. Debt issuances as of 8/10/2020, for years 2018-August 2020.

viii. Capital Structure

Capital structure is the ratio of debt to equity used to finance an investment. The appropriate capital structure for a merchant development project can take many forms depending on its financing.

To derive an appropriate capital structure for the CONE calculation, we reviewed the capital structures of the aforementioned peer group of companies who would be likely to make such an investment. Since each company in the peer group is public, their debt weight, the total market value of the debt outstanding as a percentage of the market value of their total capital (debt plus equity) is available in their filings with the Securities Exchange Commission (SEC). We reviewed this data as reported by Bloomberg. Debt weights for each member of the peer group are shown in Figure 3 below.

Figure 3: Peer Group Debt Weights[37]



Over the previous eight quarters, the average capital structure contained a mix of 56% debt and 44% equity. This average was also confirmed through Bloomberg as a secondary source.

[37] SNL Financial.

Table 25: Total Debt/Total Capitalization[38]

COMPANY	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2020Q1	AVERAGE
AES	70.3%	69.6%	68.4%	70.5%	71.7%	69.0%	69.9%	70.7%	70.0%
CWEN	62.2%	58.1%	53.9%	39.7%	48.7%	47.9%	43.5%	53.2%	50.9%
NRG	64.7%	58.2%	60.7%	66.8%	63.2%	60.9%	46.3%	45.3%	58.2%
VST	44.7%	42.7%	41.9%	42.3%	42.2%	40.6%	38.6%		41.8%
AT	63.0%	62.1%	59.9%	58.8%	55.7%	54.7%	59.5%	57.9%	58.9%
								Average	**56.0%**

While the debt weight of the peer group has, on average, been lower in the most recent quarters, the range of capitalization ratios is quite broad. As such, a capital structure more consistent with the longer historical period, on average, was assumed. We recommend a 55% debt, 45% equity capital structure.

ix. WACC Calculation and ATWACC

Inputting the assumptions for ROE, COD, and capital structure described above into the WACC calculation yields a WACC of 9.2%, as shown below:

WACC = 13.0% * 45% + 6.0% * 55% = 9.2%

We translated these components to a discount rate by reflecting the effect of taxes on the cost of debt to derive an after-tax WACC of 8.3%. This rate was then adjusted for inflation to derive a "real ATWACC" of 6.1%.

x. Cost of Capital Comparison

The estimate of WACC described above, as well as each of the key inputs, is consistent with findings utilized in the 2017 Net CONE estimate, the most recent calculation of Net CONE conducted by PJM and NYISO. Those values are shown in Table 26.

[38] Bloomberg Professional.

Table 26: Cost of Capital Comparison

	ISO-NE[39] (2014)	PJM[40] (2014)	NYISO[41] (2016)	ISO-NE[42] (2016)	PJM[43] (2018)	ISO-NE (2020)
ROE	13.8%	13.8%	13.4%	13.4%	12.8%	13.0%
COD	7.0%	7.0%	7.75%	7.8%	6.5%	6.0%
Debt Weight	60.0%	60.0%	55.0%	60.0%	65.0%	55.0%
WACC	9.7%	9.7%	10.3%	10.0%	8.2%	8.3%

39 FERC Docket ER14-1639-000, Testimony of Dr. Samuel A. Newell and Mr. Christopher Ungate of behalf of ISO-NE Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, April 1, 2014.

40 PJM Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, The Brattle Group and Sargent & Lundy, May 15, 2014.

41 NY-ISO Study to Establish New York Electricity Market ICAP Demand Curve Parameters, Analysis Group & Lummus Consultants International. September 13, 2016.

42 ISO-NE CONE and ORTP Analysis, An evaluation of the entry cost parameters to be used in the Forward Capacity Auction to be held in February 2018 ("FCA-12") and forward. Concentric Energy Advisors & Mott MacDonald. January 17, 2017.

43 PJM Cost of New Entry, Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, The Brattle Group & Sargent & Lundy. April 19, 2018.

Section 5: Revenue Offsets

The candidate reference units have several potential revenue streams that must be considered in the Net CONE calculation: sales of energy and ancillary services (E&AS) and PFP revenues associated with shortage events. These revenue streams, which partially offset the new resource's levelized annual carrying costs, are used to estimate Net CONE values for each candidate reference unit. Specifically, all revenue offsets are levelized and subtracted from the gross CONE estimates to produce a Net CONE value for each candidate resource unit. Each type of revenue offset is discussed in turn below with a summary of the revenue offset estimates for each candidate resource unit.

A. Energy and Ancillary Services

In the 2016 CONE/ORTP study, Concentric estimated market-based E&AS offsets for each candidate resource based on a 20-year Locational Marginal Price (LMP) forecast produced with a production cost model and a simplified dispatch model. Based on experience gained during the 2016 CONE/ORTP re-calculation, Concentric determined that using a production cost model involved complex calculations for energy revenues that were not transparent to stakeholders given the significant number of inputs, outputs, and assumptions involved, and a blunt historical add-on for ancillary services revenues since production cost models are not capable of modeling co-optimized energy and ancillary revenues. Concentric considered a simplified price forecast and the use of historical prices and ultimately determined that an E&AS estimation methodology based on adjusted historical prices would produce reasonable E&AS offsets and would afford greater transparency to ISO-NE stakeholders. Similar approaches have been approved by FERC to approve CONE values in NYISO and PJM[44].

The dispatch models used to estimate E&AS revenues for each of the candidate CONE reference units used historical prices from the January 2017- December 2019 period with two adjustments: 1) an energy and reserve scarcity adjustment ("Energy/Reserve Scarcity adjustment") to remove the impacts of energy and reserve scarcity under the excess supply conditions that have prevailed in New England; and 2) a Level of Excess adjustment ("LOE adjustment") to estimate E&AS revenues the candidate CONE reference units would earn if the system were at criteria. As discussed further below, the LOE adjustment is not applied to the prices used in the ORTP dispatch models.

Using historical prices to estimate future energy and ancillary services prices cannot perfectly capture the expected impacts of future changes to the ISO-NE system. However, market prices during the past three years produce a reasonable estimate of near-term market conditions, and to the extent that system conditions change over time, the next CONE and ORTP re-calculation, which will be based on then prevailing market conditions, will reflect such changes. The Energy/Reserve Scarcity and LOE adjustments are discussed in turn below.

[44] See e.g., PJM Tariff, Attachment DD, sections 5.10(v)(A) & (B).

The historical LMPs used in the dispatch models for the CONE units were first adjusted for energy and reserves shortages with an Energy/Reserve Scarcity Adjustment. Specifically, the Energy/Reserve Scarcity Adjustment sought to remove the impacts of administrative shortage pricing set by the Reserve Constraint Penalty Factor (RCPF), which is reflected in the historical prices during periods of scarcity. Scarcity pricing was then included as a separate adjustment based upon the expected number of scarcity hours being modeled, as described further below. Given that the RCPF only affects prices in the real-time market, a comparable adjustment had to be made to remove the expected impacts of energy and reserve revenue scarcity from the day-ahead LMPs. In an efficient market, the day-ahead and real-time prices converge in expectation, and in equilibrium the expected impact of real-time energy and reserve scarcity would be reflected in day-ahead LMPs.

The Energy/Reserve Scarcity adjustment was only applied in hours over the 2017-2019 period when the RCPF impacted real-time clearing prices (i.e., hours when the RCPF was non-zero). These hours are shown in Table 27 below. The top panel of Table 27 shows the actual real-time market clearing prices for energy and reserves for the Connecticut Load Zone in the hours when the RCFP was non-zero. The last two columns of the top panel show the RCPF for TMNSR and TMOR. The bottom panel of Table 27 reflects prices in the same hours with the impact of the non-zero RCPF values removed, through subtraction, from the actual real-time prices. For example, the \$357.69/MWh Energy/Reserve Scarcity adjusted LMP on October 18, 2017 hour ending 19 is the actual integrated hourly real-time LMP of \$691.02/MWh minus the integrated hourly RCPF impact of \$333.33/MWh. Note that the values in Table 27 are presented on an integrated hourly basis. For example, an integrated hourly TMOR RCPF value of \$333.33/MWh reflects the hourly integrated value of an TMOR RCPF of \$1,000/MWh for 20 minutes and an TMOR RCPF value of zero in 40 minutes.

Table 27: Energy/Reserve Scarcity Adjustments (Nominal $/MWh)

Actual Prices (.Z.CONNECTICUT)							
Date	Hour End	Real-time LMP	Real-time TMSR price	Real-time TMNSR price	Real-time TMOR price	TMNSR RCPF	TMOR RCPF
10/18/2017	19	691.02	648.6	644.44	507.14	333.33	333.33
10/22/2017	19	422.60	396.08	395.49	390.82	250.00	250.00
9/3/2018	16	562.86	480.55	480.55	477.51	333.33	333.33
9/3/2018	17	1,092.46	1,061.57	1,061.57	1,000.00	1,000.00	1,000.00
9/3/2018	18	2,375.72	2,313.30	2,313.30	1,000.00	2,000.00	1,000.00
9/3/2018	19	763.05	720.16	720.16	595.16	458.33	333.33
		Energy/Reserve Scarcity Adjusted Prices					
Date	Hour End	Adj. Real-time LMP	Adj. Real-time TMSR price	Adj. Real-time TMNSR price	Adj. Real-time TMOR price		
10/18/2017	19	357.69	315.27	311.11	173.81		
10/22/2017	19	172.60	146.08	145.49	140.82		
9/3/2018	16	229.53	147.22	147.22	144.18		
9/3/2018	17	92.46	61.57	61.57	0.00		
9/3/2018	18	375.72	313.30	313.30	0.00		
9/3/2018	19	304.72	261.83	261.83	261.83		

The total market impact of the RCPF during the 2017-2019 period (the hours shown in Table 27) was $4,374.99 of energy and reserve scarcity revenue. In equilibrium, the expected real-time impact of the RCPF would be included in day-ahead LMPs. However, this impact is not observable in practice. Therefore, to maintain the historical convergence between day-ahead and real-time prices in expectation, the same amount of real-time energy and reserve scarcity revenue is reflected in the day-ahead market in all on-peak hours. Assuming the expected price impact of the RCPF is applied equally across all on-peak hours yields in the day-ahead market, a downward adjustment to day-ahead LMPs of $0.36/MWh is applied in on-peak hours ($4,375/12,224 hours = $0.36/MWh). A summary of the Energy/Reserve Scarcity adjustment is provided in Table 28 below.

Table 28: Summary of Energy/Reserve Scarcity Price Adjustment[45]

Historical Day-ahead LMP				DA Adjustment			Adjusted DA LMP		
Year	Super Peak	Peak	Off-Peak	Super Peak	Peak	Off-Peak	Super Peak	Peak	Off-Peak
2017	$43.88	$36.36	$29.36	($0.36)	($0.36)	$0.00	$43.52	$36.00	$29.36
2018	$56.23	$47.95	$38.61	($0.36)	($0.36)	$0.00	$55.88	$47.59	$38.61
2019	$38.08	$33.54	$27.53	($0.36)	($0.36)	$0.00	$37.72	$33.18	$27.53
Historical Real-time LMP				**RT LMP Adjustment**			**Adjusted RT LMP**		
Year	Super Peak	On	Off	Super Peak	Peak	Off-Peak	Super Peak	Peak	Off-Peak
2017	$44.85	$36.40	$30.28	($0.76)	$0.00	$0.00	$44.08	$36.40	$30.28
2018	$58.08	$46.28	$38.59	($4.94)	$0.00	$0.00	$53.13	$46.28	$38.59
2019	$35.57	$33.05	$27.42	$0.00	$0.00	$0.00	$35.57	$33.05	$27.42

Next, historical energy and real-time reserve prices during the 2017-2019 period were adjusted by the LOE adjustments to account for long-run equilibrium conditions. The LOE adjustment was calculated by successively removing resources from the supply stack until the system was at criteria and estimating what prices would have been if the installed capacity was at criteria.[46] This involved constructing a 'base case" energy market curve and an "LOE-adjusted" supply curve for each hour of the day that represented what the clearing price would have been if that price were determined by the intersection of the demand curve and the LOE-adjusted supply curve. The average LMPs for the base case and the LOE-adjusted case were derived for three periods in each month and year:

- On-peak hours: HE 08 through HE 23, non-holiday weekdays
- High on-peak hours: a subset of on-peak hours, coincident with summer and winter intermittent reliability hours and all summer hours with a system-wide capacity scarcity condition
- Off-peak hours: all non-on-peak hours

Next, an LOE adjustment factor ("LOE AF") was calculated specific to each hourly period in every month (36 LOE AFs per year and 108 for the 2017-2019 period) as follows:

$$LOE\ AF = 〖Monthly\ Average\ LMP〗\_(Base\ Case) / 〖Monthly\ Average\ LMP〗\_(LOE\ Adj\ Case)$$

A summary of the LOE adjustment factors is provided in Table 29. These LOE adjustments were applied by dividing the historical LMPs in the Connecticut zone (where the candidate CONE units are

45 Connecticut zonal prices.

46 Offers removed from the supply stack were associated with resources pending retirement. See ISO New England, Cost of New Entry and Offer Review Trigger Prices, Energy and Ancillary Service Revenue Adjustments for Level of Excess Supply and Energy Security Improvements, July 14-15, 2020.

assumed to be located) by the applicable LOE adjustment factor based on the month, year, and period (i.e., high on-peak, on-peak, and off-peak).

Table 29: Level of Excess Adjustment Factors

2017	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC
High On-Peak	0.99	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.00	1.00	1.00
On-Peak	0.99	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Off Peak	0.98	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99
2018												
High On-Peak	0.98	1.00	1.00	1.00	1.00	0.94	0.87	0.82	0.88	0.94	0.93	0.92
On-Peak	0.98	1.00	1.00	1.00	1.00	0.95	0.90	0.88	0.95	0.96	0.95	0.95
Off Peak	0.98	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.99	0.99	0.96	0.97
2019												
High On-Peak	0.94	0.93	0.94	0.96	1.00	0.97	0.93	0.96	0.99	0.99	0.97	0.96
On-Peak	0.94	0.96	0.96	0.97	1.00	0.98	0.96	0.98	0.99	0.99	0.98	0.96
Off Peak	0.95	0.97	0.97	0.99	1.00	0.99	0.96	1.00	1.00	1.00	0.98	0.98

Source: ISO New England, Cost of New Entry and Offer Review Trigger Prices, Energy and Ancillary Service Revenue Adjustments for Level of Excess Supply and Energy Security Improvements, July 14-15, 2020, at 9

Table 30 illustrates the mechanics of the LOE adjustment factor in a sample hour - September 3, 2018 in hour ending 16. The Energy/Reserve Shortage adjustment for this hour is shown in Table 27. The applicable LOE AF for High On-peak in September 2018 is 0.88 (see Table 29 above). The LOE and Energy/Reserve Scarcity adjusted prices are calculated by dividing the Energy/Reserve Scarcity price by the applicable LOE AF (i.e., 0.88). The Energy/Reserve Scarcity and LOE adjusted prices reflecting this calculation are shown in the bottom panel of Table 30.

Table 30: Level of Excess Adjustment Example

ENERGY/RESERVE SCARCITY ADJUSTED PRICES ($/MWH)	
Adj. day-ahead LMP	57.31
Adj. real-time LMP	229.53
Adj. TMSR price	147.22
Adj. TMNSR price	147.22
Adj. TMOR price	144.18
Level of Excess Adjustment	
Hour type	High On-Peak
LOE AF	0.88
Level of Excess Adjusted Prices ($/MWh)	
LOE Adj. day-ahead LMP	65.13
LOE Adj. real-time LMP	260.83
LOE Adj. TMSR	167.30
LOE Adj. TMNSR	167.30
LOE Adj. TMOR	163.84
Note: the actual day-ahead LMP in this hour was $57.31/MWh and there was no Energy/Reserve Scarcity adjustment in this hour because this hour occurred on Labor Day, an off-peak day.	

With the energy and reserve shortage effects removed from the LMPs and real-time reserve prices, it was then necessary to add back the energy and reserves shortage revenues for a system at-criteria, which was done outside of the dispatch models as a standalone adder. The Energy/Reserve Scarcity adder for each CONE unit was based on the expected number of scarcity hours that the ISO-NE system would experience at criterion, which is assumed to be 11.3 hours. With these assumptions, the Energy/Reserve Scarcity adjustment is $0.874/kW-month for the combined cycle and 0.923/kW-month for the simple cycle and aeroderivative.[47]

i. E&AS Methodology Overview

Concentric estimated E&AS revenue offsets estimates for each candidate reference unit resource type based on adjusted historical prices from the three-year period starting on January 1, 2017 and ending on December 31, 2019. A unique EA&S estimate, which is defined as energy and ancillary service revenues net of production costs, was produced for each candidate resource type based on a simple average of the three (inflation-adjusted) E&AS estimates from each calendar year and applied as an E&AS offset to each candidate reference unit. This annual E&AS offset is held constant (in real terms) throughout each resource's assumed 20-year life. Before discussing the specifics of the EAS

[47] Note: These figures are provided in 2025 dollars.

methodology for each candidate reference unit, it is helpful to review ISO-NE's energy and ancillary services markets.

Resources in ISO-NE can currently receive market-based compensation for generating electricity or providing one or more of the following ancillary services: regulation, ten-minute synchronized reserves (TMSR), ten-minute non-synchronized reserve (TMNSR); and thirty-minute operating reserves (TMOR). ISO-NE operates both day-ahead and real-time energy markets and the three candidate reference units are eligible to offer energy into these markets. Provided they meet the technical specifications, the candidate reference units may also be eligible to provide ancillary services. Based on their technical specifications, none of the candidate reference units also provide regulation.

ISO-NE currently procures reserves (i.e., TMSR, TMNSR, and TMOR) on a forward basis in the Forward Reserve Market (FRM) or in real time by designating eligible resources for Real-Time reserves.[48] Table 32 below summarizes the energy and ancillary services products that each candidate reference unit is assumed to offer in the E&AS dispatch models based on the technical capabilities of each resource and the products that each resource can economically offer.

Table 31 : Energy and Ancillary Service Products Offered in E&AS Estimates

Candidate Reference Unit	Day-Ahead Energy	Real-Time Energy	Forward Reserve Market			Real-Time Reserve Market	
			TMNSR	TMOR	TMSR	TMNSR	TMOR
Simple cycle	●	●	●	●		●	●
Aeroderivative	●	●	●	●		●	●
Combined cycle	●	●			●		

The dispatch models for the CONE units also reflect estimated lifecycle non-recoverable degradation to each unit's capacity factor and heat rate. The lifecycle non-recoverable degradation factors in Table 33 were applied in the dispatch models for the candidate CONE units (see Table 12, Table 13, and Table 14 for the ambient adjusted capacity factor and heat rate of each CONE unit). The lifecycle capacity degradation factors were applied to the ambient adjusted capacity of each unit resulting in a decrease in unit capacity by the amounts shown in Table 33.[49] The lifecycle heat rate degradation factors were used increase each unit's ambient-adjusted heat rate upward by the amounts shown in in Table 33.[50]

[48] ISO-NE's Energy Security Improvement proposal, filed at FERC on April 15, 2020 (Docket No. ER20-1567-000), would procure various ancillary service "options" in the Day-Ahead market.
[49] For example, the simple cycle's ambient-adjusted capacity was multiplied by (1-0.0141).
[50] For example, the simple cycle's ambient-adjusted heat rate was multiplied by (1+0.01).

Table 32: Lifecycle Degradation for CONE Units

	LIFECYCLE NON-RECOVERABLE CAPACITY DEGRADATION	LIFECYCLE NON-RECOVERABLE HEAT RATE DEGRADATION
Combined Cycle	2.43%	1.63%
Simple Cycle	1.41%	1.00%
Aeroderivative	2.70%	0.50%

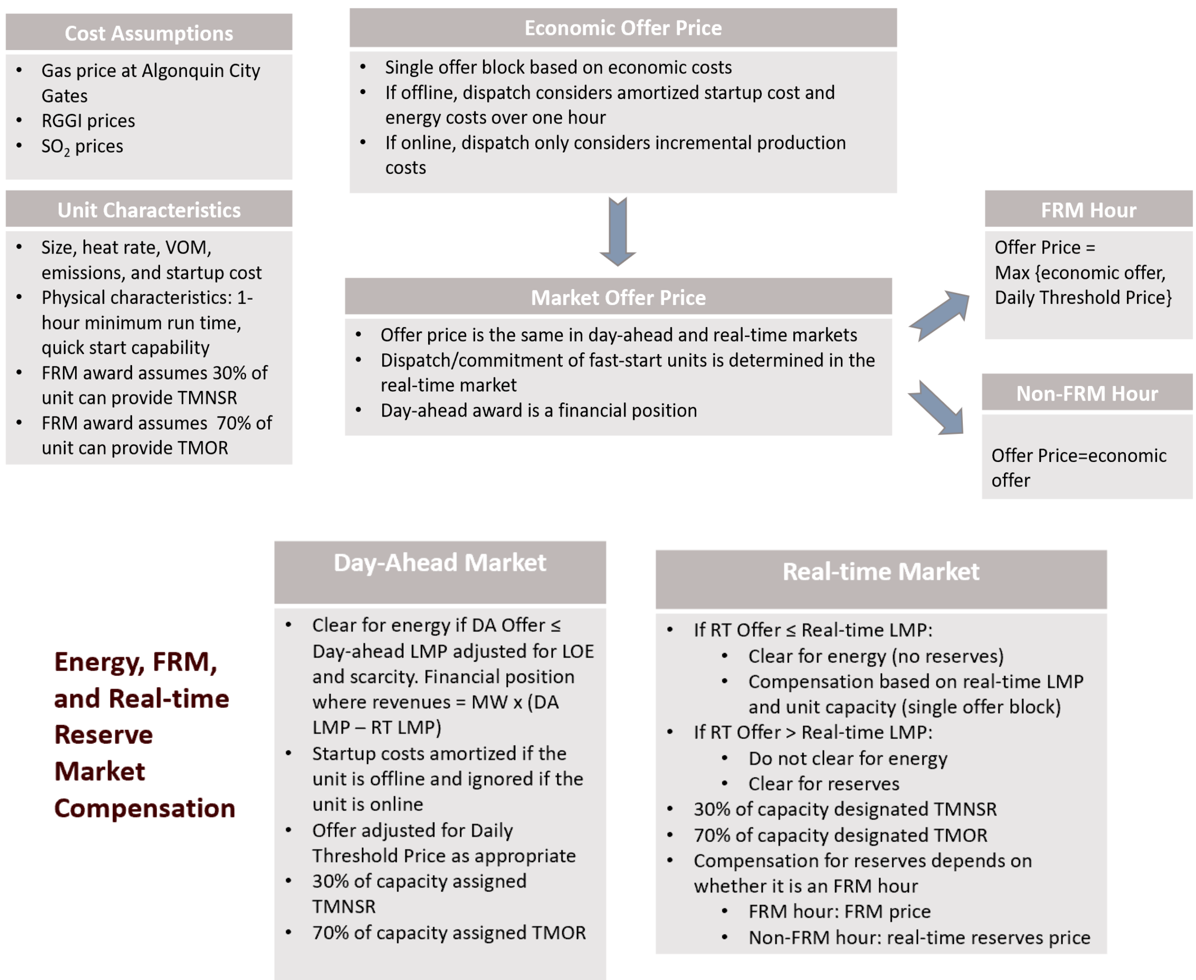
The remainder of this section discusses the methods used to estimate the E&AS revenues each candidate reference unit is expected to earn over its project life. Given their technical similarities, the same method was used to estimate E&AS revenues for the simple cycle and aeroderivative units. An alternate method was used for the combined cycle unit. While the candidate reference units included dual fuel capability, the unit are not dispatched on oil under normal operating conditions, and therefore were not dispatched on oil in the Net CONE dispatch models. As a final step for each candidate reference unit, net E&AS revenues (i.e., E&AS revenues net of production costs) were calculated for each candidate reference unit to produce the E&AS offset.

ii. Simple Cycle and Aeroderivative E&AS methodology

As indicated in Table 32, the simple cycle and aeroderivative candidate reference units are expected to participate in the day-ahead and real-time energy markets and are designated to provide TMNSR and TMOR in the FRM and RTM.[51] Concentric developed a simplified economic dispatch model to estimate the net E&AS revenues these units can be reasonably expected to receive in ISO-NE day-ahead and real-time markets. The simple cycle and aeroderivative dispatch model committed and dispatched the units economically based on the adjusted historical day-ahead and real-time energy and reserve prices and each unit's production costs. An overview of the dispatch methodology for the simple cycle and aeroderivative units is shown in Figure 4 below.

[51] These assumptions are consistent with the approach employed in the 2016 CONE/ORTP Study. See 2016 CONE/ORTP Study at 65.

Figure 4 : Overview of Dispatch Methodology for Simple Cycle and Aeroderivative Units



Unit production costs include start-up costs,[52], fuel costs, VOM, and CO_2 and SO_2 emission allowance costs. Fuel costs are based on the unit's nominal heat rate (in non-summer and non-winter months; this heat rate is 9,042 Btu/kW for the simple cycle unit and 9,608 Btu/kW for the aeroderivative unit) multiplied by the gas price at Algonquin City Gates.[53] The gas price is also adjusted for a 5% state gross earnings tax which is applicable in Connecticut.[54]

52 Start -up costs consist mainly of consumables such as water and chemicals. The assumed startup costs are $11,000 per start for the simple cycle and $3,000 per start for the aeroderivative.

53 Algonquin City Gates is the most liquid natural gas hub in ISO-NE and is geographically close to all three gas candidate reference units, which the study assumes are located in Connecticut. The next day gas price is appropriate to use for the gas-fired resources because the natural gas resources in ISO-NE purchase the majority of their gas from the natural gas spot market rather than through long-term gas contracts.

54 Concentric reviewed a redacted natural gas invoice provided by a natural gas generator in Connecticut and confirmed that natural gas purchases include this 5% tax.

The simple cycle and aeroderivative units rarely clear the day-ahead market in the dispatch model. This is also generally true for these unit types in ISO-NE's day-ahead market. Without a day-ahead award, the simple cycle and aeroderivative units are unlikely to purchase gas in the next-day gas market, and instead purchase gas in the intraday gas market if they are dispatched in real-time. Analysis of historical natural gas price data for next-day and intraday (or "same day") indicated that an intraday gas premium existed on the days the simple cycle and aeroderivative were dispatched in real-time. Accordingly, the dispatch models for the simple cycle and aeroderivative include the intraday fuel price seasonal premiums show in Table 34.

Table 33: Intraday Gas Premiums

SEASON	INTRADAY GAS PREMIUM
Summer (June-August)	4%
Winter (December-February)	20%
Shoulder (all other months)	11%

These intraday gas premiums are based on the average, by season, of actual intraday gas premiums (i.e., intraday price minus the next-day price for the same operating day) during the 2017-2019 period on the days when the simple cycle was dispatched in real time. The intraday gas premium is applied to the day-ahead and real-time energy offers of the simple cycle and aeroderivative units in the dispatch models.

The E&AS models assumed that reserves (TMNSR and TMOR for the simple cycle and aeroderivative) had a production cost of zero. The simple cycle and aeroderivative units were assumed to offer their full capacity into both the day-ahead and real-time markets in a single block with a one-hour minimum run time. The units also have fast-start capability, which is required of FRM resources. Thirty percent of each unit's capacity can be deployed from a cold start within 10 minutes and the remaining capability can be deployed within 30 minutes. The reserves products assumed to be provided are shown in Table 35 below:

Table 34 : Reserves Amounts Provided (Shoulder Months)

	TMNSR (MW)	TMOR (MW)
Simple Cycle Unit	111	260
Aeroderivative Unit	29	67

The first step in the E&AS dispatch model involves determining the unit commitment and dispatch schedule in the day-ahead market based on the unit's day-ahead energy offer and the day-ahead market clearing prices. For each hour, the model evaluates each unit's commitment (startup) and dispatch (fuel, VOM, and emissions) costs and commits the unit if the day-ahead LMP is high enough to recover the unit's startup and variable energy costs within the hour. If the unit is already online, the dispatch model will keep the unit online if its variable costs are less than or equal to the day-ahead LMP. The unit is de-committed (i.e., shut down) if its variable energy costs exceed the day-ahead LMP.

As noted above, the simple cycle and aeroderivative resources participate in the FRM (in the case with the continuation of the FRM market). An award in the FRM market affects the way a resource can offer into the day-ahead energy market during Forward Reserve Delivery Period hours.[55] Forward Reserve Delivery Period hours are specified as hours ending 8 through 23, Monday through Friday, excluding NERC holidays. Market Participants with FRM awards must assign resources to meet the obligation and those resource are required to submit a day-ahead energy offer that is at least as high as the Forward Reserve Threshold Price (FRTP) established by ISO-NE.[56] The FRTP is designed to be high enough to sufficiently reduce the likelihood that the FRM resource clears the day-ahead energy market for energy, which reduces (and in some cases eliminates) the resource's ability to provide reserves. Accordingly, the simple cycle and aeroderivative units offer energy into the day-ahead market at the higher of their production costs and the FRTP.[57] Any day-ahead energy award is treated as a financial position and creates a charge for the MW quantity of that award at the real-time energy price.

The second step in the E&AS model involves determining the unit's real-time unit commitments and dispatch. The unit commitment and dispatch algorithm for the real-time market is identical to the day-ahead algorithm described above. However, the unit's energy offers, which remain unchanged from the day-ahead market, are evaluated against real-time LMPs rather than day-ahead LMPs. If the unit is offline, it will be designated to provide TMNSR and TMOR reserves and compensated at prices determined by the real-time reserves market.[58] Given that all commitments and dispatches are economic, the units do not require any Net Commitment Period Compensation payments.

The simple cycle and aeroderivative units are subject to potential penalties for non-performance in the FRM.[59] Based on a review of actual FRM penalties assessed to FRM suppliers with gas-fired resources with commercial online dates of June 2016 or later that participated in the LFRM, the average penalties assessed were just below 1% of the total LFRM obligation in MWh. To account for

[55] Forward Reserve Auction awards are not resource-specific but rather a market participant with an FRM obligation is required to assign an asset to supply reserves for the delivery period and location of its award. The FRM offer cap is $9,000/MW-month. Note that FCA price-netting, a practice that reduced the payment a resource received for assuming a forward reserve obligation by the value of the applicable FCA clearing price, was eliminated in 2016. As such, the 2017-2019 historical FRM prices do not reflect the impact of FCA netting.

[56] See e.g., ISO-NE, *Forward Reserve Daily Threshold Price Report,* available at https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/fwd-cap-daily-threshold-price

[57] Consistent with FRM requirements, if the unit is offline, its day-ahead offer is equal to the higher of the FRMDTP and the sum of its variable production costs and startup cost amortized over its total capacity. If the unit is online, its day-ahead offer is equal to the higher of the FRMDTP and its variable energy production costs.

[58] When providing forward reserves and designated for real-time reserves, the total reserve payment is reduced by the product of the Forward Reserve MW multiplied by the Real-time reserve price to ensure the unit is not doubly compensated for providing the same reserve MW.

the LFRM penalty rate, the simple cycle and aeroderivative unit capacity was de-rated by 1% in all hours.

Separate dispatch models were prepared for the simple cycle and aeroderivative units to estimate E&AS revenues for these units in the event of an FRM Sunset. The dispatch models without the FRM assume that the simple cycle and aeroderivative units will offer into the day-ahead market based on their short-run production costs (i.e., fuel costs times the heat rate, VOM, and emissions), and clear accordingly. Given the uncertainty about the future of the FRM, E&AS offset estimates for the simple cycle and aeroderivative are provided with and without the FRM.

iii. Combined Cycle E&AS methodology

A similar unit commitment and dispatch model was used for the combined cycle as was used for the simple cycle and aeroderivative units. However, the model was adapted to reflect the fact that the combined cycle does not participate in the FRM, and thus was not required to submit offers at or above the FRTP during certain intervals. Instead, the combined cycle dispatch model assumes the unit offers competitively through a two-block energy offer. The first block is based on the production costs of its 535 MW baseload capacity and the second block is based on the production costs of its 34 MW duct firing capability. For any given operating day, the combined cycle's 2-block offer is the same in the day-ahead and real-time markets.[60] An overview of the dispatch methodology for the simple cycle and aeroderivative units is shown in Figure 5 below.

60 Adjusted to reflect degradation.

Figure 5: Overview of Dispatch Methodology for Combined Cycle Units

Cost Assumptions

- Next-day gas price at Algonquin City Gates
- RGGI prices
- SO_2 prices

Unit Characteristics

- Size, heat rate, VOM, emissions, and $11,000 startup cost
- Physical characteristics: 2-hour minimum run time, quick start capability
- Duct-firing capability can provide synchronized reserves

Economic Offer Price

- Two offer blocks
    - Block 1: baseload capacity (MW total)
    - Block 2: Duct firing (MW total)
- If offline, dispatch considers amortized startup cost and energy costs over its 2-hour minimum run time
- If online, dispatch only considers incremental production costs

Market Offer Price

Offer Price = economic offer

- Offer price is the same in day-ahead and real-time markets
- Day-ahead award is a financial position
- Combined cycle does not participate in the FRM

Energy and Real-time Reserve market compensation

Day-Ahead Market

- Clear for energy if DA Offer ≤ Day-ahead LMP adjusted for LOE and scarcity. Financial position where revenues = DA MW x (DA LMP – RT LMP)
- Startup costs amortized if the unit is offline and ignored if the unit is online
- Offer adjusted for Daily Threshold Price as appropriate

Real-time Market

- If RT Offer block ≤ Real-time LMP:
    - If block 1 clears for energy, the 2nd block is designated as TMSR
    - If block 1 and block 2 both clear for energy, the unit cannot provide TMSR
- If RT Offer > Real-time LMP:
    - Does not clear for energy
    - Is not designated for TMSR

Like the other candidate reference units, the combined cycle's production costs consist of fuel costs (ambient adjusted heat rate multiplied by the Algonquin next day gas price plus the 5% gross earnings tax), VOM and emissions allowance costs. The combined cycle unit has a six-hour minimum run-time and is limited to two starts per day and the unit commitment and dispatch model honors both of these operating constraints. If the combined cycle is online but only dispatched at its baseload capacity, the combined cycle is designated to provide TMSR in real-time, based on its available ambient adjusted duct firing capability, and compensated accordingly at the real-time TMSR price. No intraday gas price adjustment was applied to the combined cycle unit since this unit was expected to receive a financially binding day-ahead commitment and purchase natural gas at the next-day price.

B. Pay for Performance

ISO-NE's PFP mechanism is designed to encourage resource performance consistent with its assumed capacity obligation. Under PFP, a resource that underperforms will forfeit some or all capacity payments awarded in an FCA. Resources that perform beyond their CSO will receive PFP payments. Exposing resource owners to the risk of forfeiting capacity payments for underperformance, as well as providing them the opportunity to receive more compensation for over performance, is designed to incent resource owners to make investments that ensure their resource can perform.

The ISO-NE experienced its first capacity shortage conditions under the PFP market rules on September 3, 2018. The New England system experienced 2.4 hours of shortage resulting in $44.2 million in PFP credits to overperformers and $36.3 million in PFP charges to under-performers..[61]

In calculating expected compensation for CONE technologies, we consulted with ISO-NE and stakeholders, and reviewed and discussed ISO-NE's most recent study on expected system conditions and shortage hours over the life of the generating facilities. A review of historical data shows relatively few shortage hours since the PFP mechanism was implemented. For example, ISO-NE's November 2019 shortage hour event analysis shows relatively few shortage hours in recent years, with ten shortage events between May 2015 and October 2019. However, it is important to note that the objective of the CONE/Net CONE analysis is to calculate what a merchant developer would need to enter the market with a future system condition that is at criterion.

Based on ISO-NE's most recently published analysis,[62] we have assumed 11.3 hours for the CONE analysis and 7.4 hours for the ORTP analysis. We have also assumed a Performance Payment Rate of $8,782/MWh. For the Balancing Ratio, we assumed a value of 0.847 for the CONE analysis and 0.816 for the ORTP analysis, consistent with ISO-NE's updated analysis.

The study assumes a performance score of 0.9277 for a combined-cycle machine based on manufacturer expectations.[63] For a simple cycle machine, we have assumed a performance score of 0.98 consistent with the expected forced outage rate for this technology based on consultation with Mott MacDonald and the assumption that a state-of-the-art fast-start unit would generally be expected to capture shortage hour revenues unless on a forced outage. Our shortage hour and performance payment rate assumptions are shown in Table 36 below.

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[61] ISO-NE, *2018 Annual Markets Report*, at 20. The Internal Market Monitor notes that the $7.9 million difference between PFP credits and charges was due to energy efficiency exemption rules and were charged *pro rata* to resources holding a capacity supply obligation (see note 30).

[62] https://www.iso-ne.com/static-assets/documents/2020/10/a00_iso_presentation_scarcity_hours_and_balancing_ratios.pptx

[63] Testimony of Dr. Matthew White, Docket No. ER14-1050-000, January 17, 2014, pg. 110.

Table 35: Pay for Performance Assumptions

TECHNOLOGY	SCARCITY HOURS (HRS)	PERFORMANCE PAYMENT RATE ($/MWH)	AVERAGE ACTUAL PERFORMANCE (%)	AVERAGE BALANCING RATIO (%)	NET PERFORMANCE PAYMENTS ($/KW-MO)
Combined Cycle	11.3	8,782	92.77	84.7	0.67
Simple Cycle	11.3	8,782	98.00	84.7	1.10
LM6000	11.3	8,782	98.00	84.7	1.10

C. Summary of Revenue Offsets

Table 37 presents a summary of the estimated revenue offsets of the three candidate reference units evaluated in the CONE study. These revenue offsets are subtracted from the CONE values presented in Section 7 below to calculate Net CONE values.

Table 36: Summary of Revenue Offsets for Candidate Reference Units (2025$/kW-mo)

CANDIDATE REFERENCE UNIT	PAY FOR PERFORMANCE REVENUES	SCARCITY	E&AS REVENUES	TOTAL OFFSETS
Combined Cycle	0.590	0.681	3.117	4.388
Simple Cycle	1.037	0.767	2.852	4.656
Aeroderivative	1.037	0.767	2.698	4.502

Section 6:
CONE Calculation and Results

The CONE/Net CONE is calculated as the minimum revenue required for entry, or CONE, less expected revenue offsets. A summary of the CONE/Net CONE values for the candidate reference units evaluated are shown in Table 38 below.

Table 37: Net CONE Summary for Candidate Reference Technologies

REFERENCE UNIT	INSTALLED CAPACITY (MW)	QUALIFIED CAPACITY	INSTALLED COST (2019/ kW)	REAL ATWACC	GROSS CONE (2025$/ kW - MO)	REVENUE OFFSETS (2025$/ kW - MO)	NET CONE (2025$/ kW -MO) INSTALLED	NET CONE (2025$/ kW -MO) QUALIFIED
Combined Cycle 7HA.02 (CC)	543	489	985	6.1%	15.840	4.388	11.452	12.724
Simple Cycle 7HA.02 (CT)	371	361	777	6.1%	11.399	4.656	6.743	7.024
LM6000 PF+ (Aero)	95	91	1,961	6.1%	27.018	4.502	22.517	23.455

Based on our analysis, we recommend that the simple cycle frame combustion turbine be used as the reference unit for FCA-16. The simple cycle frame machine is substantially more economic under the parameters of the current study than the combined cycle machine and the aeroderivative machines and is an established technology in New England. This recommendation is consistent with the selection of the simple cycle combustion turbine in the last CONE/Net CONE update performed in 2016.

Section 7: ORTP Study

A. Introduction

The FCM ensures that sufficient capacity is available to meet ISO-NE's current and expected future resource adequacy needs. Under the FCM design, capacity auctions (i.e., FCAs) are held annually, three years in advance of the Capacity Commitment Period. New and existing resources compete in the FCAs to obtain a CSO in exchange for a market-based capacity payment. Capacity payments support the development of new capacity resources and retain existing resources when and where they are needed.

The FCM design includes a mechanism to protect against the potentially price suppressing effects of new resource offers that are below the competitive level. This buyer-side market power mitigation mechanism requires IMM review of any new capacity resource offer at or below a benchmark known as the ORTP (Offer Review Trigger Price). The ORTP acts as a proxy for the price at which a given resource type would offer into the FCA were it not to receive out-of-market revenues as defined in Market Rule 1. It does so by setting benchmark prices intended to represent the low end of the range of competitive offers in order to prevent new resources from offering at prices significantly below their true net cost of entry. Offers submitted by new resources that are above the ORTP level are presumed to be competitive and not reviewed. ORTPs are calculated for specific resource types every three years and adjusted annually between calculation periods.

B. Approach

The objective of this ORTP study was to develop ORTP values for FCA-16 for the 2025/2026 Capacity Commitment Period. Consistent with guidance from ISO-NE and FERC, the recommended ORTPs presented in this report were set at the low end of the competitive range of expected values to strike a reasonable balance by only subjecting resource offers that appear commercially implausible absent out-of-market revenues to IMM review. In addition, consistent with Tariff requirements, all resources were assumed to have a contract for their output.[64]

The study process consisted of the four basic steps outlined below and further described in the balance of this report:

1. **Resource Screening and Selection**. The first step in the process was to develop screening criteria to select the resource types to calculate ORTP values for. The resource types that pass the screening criteria are subject to a full evaluation of costs and revenues over the facility's expected life.
2. **Calculation of CONE.** The second step was to develop technical specifications, installed capital costs and operating costs over the 20-year expected life of the facility (11 years

[64] Market Rule 1 Appendix A Section III.A.21.1.2

for Energy Efficiency and 20 years for Demand Response) for each resource type selected in step 1 above. The CONE calculations for each ORTP resource type are intended to reflect the low end of the competitive range requirement for the ORTP values. Based on reasonable financial assumptions associated with merchant plant development in New England regarding the cost of debt, return on equity and debt to equity ratio, we calculated a first-year revenue requirement that ensured the recovery on and of investment costs.

3. **Calculation of Expected Revenues.** The third step is to estimate the expected revenues for each of the selected resource types, which include energy revenues and ancillary services revenues (net of production costs), REC revenues, and PFP revenues.
4. **Calculation of Net CONE/ORTP.** The final step is to calculate the break-even contribution required from the FCM, based on the calculation of CONE, and expected revenues above, to yield a discounted cash flow with a net present value of zero for each project. The ORTP is set equal to the project's revenue requirement such that the project's net present value from participating in the ISO-NE's wholesale energy and capacity markets is equal to zero.

Each of the steps above involved a detailed bottoms-up analysis that included a review of engineering and construction costs, historical data, forecast of future prices, and professional judgement. The ORTP values were informed through consultation with ISO-NE and stakeholders in eight separate meetings in order to ensure the effectiveness and appropriateness of the methods and data used.

C. Resource Screening Criteria, Process and Selection

We began our ORTP study by establishing the criteria to identify which resource types required ORTP values. The screening criteria used and reviewed with stakeholders are consistent with the criteria accepted by the FERC in previous ORTP studies. These criteria remain appropriate and are as follows:

- Must represent technologies that have been installed in the region and participated in recent FCAs;
- Must have reliable cost information available to calculate an ORTP using a full "bottom-up" analytical approach; and
- Must have a first-year revenue requirement below the FCA starting price.[65]

These criteria were applied consistently to potential resource types identified in consultation ISO-NE and stakeholders. The resources types that were considered in the screening process and the outcome of that process are shown in Table 39 below.

[65] Order Accepting Filing, 161 FERC ¶ 61,035 (October 6, 2017) PP 48.

Table 38: Resource Screening Results

TECHNOLOGY TYPE	INSTALLED IN NEW ENGLAND AND PARTICIPATED IN RECENT FCAS*	RELIABLE "BOTTOM UP" COST DATA	VALUE < FCA STARTING PRICE
Simple Cycle Gas Turbine	Yes	Yes	Yes
Combined Cycle Gas Turbine	Yes	Yes	Yes
Onshore Wind	Yes	Yes	Yes
Offshore Wind	Yes	Yes	No
Solar	Yes	Yes	Yes
Biomass	Yes	No	No
Battery Storage	Yes	Yes	Yes
Co-Located	Yes	Yes	No
Energy Efficiency	Yes	Yes	Yes
Demand Response	Yes	Yes	Yes

We were asked by stakeholders to consider offshore wind for an ORTP value. While the 30MW Block Island Wind facility is the only offshore wind facility in operation in the U.S., offshore wind has seen significant increased attention from renewable developers and state regulators. Connecticut and Massachusetts both have specific offshore wind capacity targets in place at 2,000 MW and 3,200 MW, respectively, and several projects are in early development off the coast of New England. A few of these projects have been awarded contracts, increasing their likelihood of reaching commissioning.

An ORTP for an offshore wind unit ultimately was not recommended, although the industry has seen significant public policy interest in recent years. We consulted with Mott MacDonald to develop capital cost estimates for offshore wind projects based on available information in their proprietary database, as well as publicly available information on offshore wind projects currently in development. The offshore wind capital cost estimate was largely based on benchmarking against large scale projects in the North Sea in which Mott MacDonald has been directly involved. Reasonable adjustments were made to account for US-specific requirements such as permitting, idiosyncratic technical requirements for the onshore portion including cable landing, distance to shore, upland routing, grid connection and labor rates. Offshore wind construction costs were benchmarked against projects where European EPCs were used, as well as publicly available estimates of construction costs. It warrants mention that there is no completed large scale offshore wind project in the US, so the overnight capital cost estimates for this resource type involves more uncertainty than estimates for other resource types which have more publicly available cost and operational data. We reviewed several sources of publicly available information from the New York State Energy Research and Development Authority (NYSERDA), the Environmental Protection Agency (EPA), the Department of Energy (DOE), among others, but found them to not be comparable due to differences in distance from shore, water depth, interconnection requirements, and larger locational differences.

Based on bottoms-up analysis of installed costs, we estimated the cost to construct an offshore wind facility in New England at approximately $5,358/kW (in 2019$). According to the publicly available data published by Energy Information Administration (EIA), a principal agency of the U.S.

Department of Energy, they estimated the overnight capital cost for an offshore wind facility to be approximately $5,446 (2019$ per kW). The $/kW value stated above is within an acceptable range of this value. When also considering operating costs and expected revenues, we determined that costs remain too high to justify an ORTP below the expected auction starting price based on our recommended Net CONE technology and the associated value presented in this report.

The study also involved an analysis of a co-located photovoltaic/battery resource for a potential ORTP value. For reasons similar to the offshore wind facility, co-located resources have become increasingly active in New England, warranting at least a high-level analysis of costs and revenues to determine if an indicative ORTP value would be above the implied auction starting price. Based on our analysis, we determined that an ORTP value for a co-located resource would not be warranted at this time.

It is important to note that FERC has opined on the absence of a resource-specific ORTP value. In its February 2013 Order, the FERC confirmed that the lack of a resource-specific ORTP value does not create undue uncertainty or impose an unduly discriminatory burden on a developer. The FERC went on to state:

> "To the extent that a resource owner, including a consumer-owned utility, believes that its costs are lower than the applicable trigger price, it can seek a lower offer floor by submitting its unit-specific costs to the IMM."[66]

Based on the screening process as described above, we selected the following resources to evaluate for ORTP values:

- Simple Cycle Combustion Turbine
- Combined Cycle Combustion Turbine
- Onshore Wind
- Solar
- Battery
- Energy Efficiency
- Demand Resources

D. Financial Assumptions

Similar to the calculation of CONE, the calculation of ORTP requires a real discount rate to translate uncertain future cash-flows to a levelized revenue requirement. The approach to determining the appropriate discount rate for ORTP values is identical to the approach taken for the calculation of Net CONE, except that the Tariff provisions for calculating ORTPs specifies a contract for non-capacity revenues. As such, the inputs for cost of capital have to be adjusted accordingly to reflect a lower risk than that of the CONE calculation. Ultimately, the ORTP values reflect the "low end of the competitive range," and therefore require lower returns to equity and debt holders.

[66] FERC Order Docket No. ER12-953-001, pg 13.

We determined that 6.4% is an appropriate nominal after-tax weighted average cost of capital at which to evaluate ORTP values. To derive this ATWACC, we adjusted inputs to the cost of capital used in the CONE study above to reflect the low end of the competitive range and to account for the lower risk associated with contract-backed energy revenues.

First, we adjusted the cost of debt to more closely reflect the generic corporate debt of a higher rated company. Instead of a cost of debt of 6.0% assumed for the gas-fired candidate reference units, which assumes a premium on top of recent debt issuances for IPPs, and which assumes a premium on top of B and BB rated corporate bond yields, we assumed a lower cost of debt of 4.5%, which does not assume a premium and is more in line with the average costs of debt for a company with a BB rating, and is in line with recent debt issuances for IPP peer companies.

Second, we adjusted the return on equity two percentage points lower to reflect contracted revenues according to the Power Purchase Agreement (PPA) assumption specific in the Tariff. We estimated ROE using the CAPM, equal to a risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." As discussed in Section 5.B, we reviewed estimates from Blue Chip, Value Line, Ibbotson, and Bloomberg for the inputs to the CAPM. We maintained the same approach for the calculation of beta as that of CONE. Instead of basing our ROE on the high end of the competitive range using a forward-looking estimate, we relied on the average results from the historical and forward-looking estimates, with a resulting return on equity of 11.0%.

We adjusted the assumed capital structure to 60/40 (D/E) in favor or more leverage and lower returns to equity. A summary of the financial assumptions on which the ORTP calculations are based is shown in Table 40 below.[67]

Table 39: ORTP Financial Assumptions

ROE	11.0%
COD	4.5%
Capital structure:	
Debt weight	60%
Equity weight	40%
WACC	7.1%
Nominal ATWACC	6.4%
Real ATWACC	4.3%

Finally, the addition to the relevant MACRs depreciation schedule, the ORTP calculation assumes an allowance for bonus depreciation. The Tax Cuts and Jobs Act, enacted at the end of 2018, increases first-year bonus depreciation for generating facilities to 100%. After January 1, 2023, first-year bonus depreciation decreases to 40% for property placed in service after December 31, 2024 and before January 1, 2026, and will decrease further thereafter. While an election to take advantage of bonus depreciation may not be feasible for every new entrant, and the expected cash flows do not justify

[67] Brattle 2014, Concentric 2017.

including it in the CONE analysis, we believe it is reasonable to assume that some new entrants could seek to maximize the economic benefit available to them, including those available through tax credits or effective tax shields, and therefore including bonus depreciation in the ORTP values conservatively represents a low end of the range of possible tax efficient parameters. We note that FERC has previously opined on this issue in its acceptance of PJM's most recent cost of new entry reset. FERC noted:

> "[b]ecause corporate structures and tax planning strategies can vary, we find that PJM reasonably assumes that generation investment is taxed at the full corporate and state tax rate without considering tax planning strategies that companies can use to lower or eliminate their income tax liability. Moreover, we agree that it is reasonable to assume that entities will attempt to minimize their income tax liability through the use of tax benefits, such as increased bonus depreciation. Accordingly, we are not persuaded by LS Power's arguments that PJM has failed to meet its burden that its treatment of bonus depreciation is just and reasonable."[68]

If bonus depreciation is applied in addition to the ITC, the unit's taxable basis is reduced by one half of the ITC benefit.

E. PTC/ITC for Qualifying Resources

Tax credits currently available to eligible renewable energy resources were considered in the calculation of ORTP values. Assumptions about possible further extensions of these tax credits in the future are considered speculative and were not included in calculations. The Production Tax Credit (PTC) or an Investment Tax Credit (ITC) are currently available for eligible renewable resources. However, the PTC is not available to facilities that begin construction after December 31, 2020. Accordingly, the PTC is not considered in this ORTP analysis. However, the ORTP study does include the value of the ITC for the solar, wind and co-located resources. The ITC is scheduled to step down from 2020 to 2024 and beyond. For eligible facilities that are constructed before 2022 and placed in service beginning in 2024, or constructed in or after 2022 and placed in service after that time, the ITC is stepped down to 10%.[69] The ITC is estimated to be $137/kW for the solar ORTP and $143/kW for the co-located resource ORTP, both in 2025 dollars, based on current IRS rules and the assumed inflation rate.

F. Project Life

ORTP resources were assumed to have a project life of 20 years. While it is possible for different resource technologies to have varying project life assumptions, it is important to have consistent financial assumptions across resource types in order to evaluate these ORTP values on a comparable basis. This assumption is consistent with FERC guidance in PJM in the Minimum Offer Price Rule (MOPR) proceeding, where the FERC found that "default MOPR values should maintain the same

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68 FERC Order Accepting Tariff Revisions, Docket No. ER19-105, April 15, 2019, at 34.

69 Internal Revenue Service, Notice 2018-59. Available at: **https://www.irs.gov/pub/irs-drop/n-18-59.pdf**.

basic financial assumptions, such as the 20-year asset life, across resource types" in keeping with the Commission's previous determination "that standardized inputs are a simplifying tool appropriate for determining default offer price floors…. "it is reasonable to maintain these basic financial assumptions for default offer price floors in the capacity market to ensure resource offers are evaluated on a comparable basis."[70]

G. ORTP Technical Specifications

For the ORTP calculation, the technical specifications for the gas units are consistent with those assumed in the CONE study. The remaining ORTP resource technical specifications are described below.

i. Onshore Wind

General assumptions utilized in calculating the ORTP value for an onshore wind unit include location, number and size of turbines, interconnections to the electric distribution systems, and required electric system upgrades. Each assumption is described in further detail below.

Facility size is an important consideration in the calculation of a CONE value for the candidate onshore wind reference unit. These scale economies drive the per-kW installed cost of project down. Mott MacDonald's estimates found that economies of scale yield per-kW installed savings for onshore wind facilities when the number of installed turbines is approximately 15 or higher. Therefore, Mott MacDonald assumed a minimum of 15 turbines for the candidate onshore wind facility. The Vestas V150 5.5 MW machine was selected for this project due to its overall efficiency and economics. A facility with 15 5.5 MW Vestas turbines results in a total facility capacity of 82.5 MW.

In addition to size, location is another important consideration for a new wind facility. Mott MacDonald considered locations in ISO-NE with elevation differential (which typically results in high wind velocities) and reasonable access to the ISO-NE transmission system with minimal need for network upgrades. The location selected for the onshore wind resource is approximately 7 miles east of Berlin, New Hampshire.

Mott MacDonald considered two publicly available data sources for wind speed information at the selected location for the wind facility: the National Renewable Energy Laboratory (NREL) wind speed map and reanalysis data. Based on a review of this windspeed information and climate data from the nearby Mount Washington, the predicted gross yield is 380 GWh with a gross capacity factor of 51.6%. Mott MacDonald estimated a total efficiency factor of 0.834 based on project efficiency estimates including assumed indicative wake efficiency, electrical efficiency, availability, scheduled maintenance, BOP availability, possible curtailment by the ISO (i.e., congestion on the transmission system), power curve performance, suboptimal operation, performance degradation due to icing,

[70] Order Establishing Just and Reasonable Rate, Docket Nos. EL16-49-000, EL18-178-000, December 19, 2019, pg. 63.

blade degradation, and hysteresis. The net yield is estimated to be 317GWh with a net capacity factor of 43.1%.

ii. Solar

The previous ORTP study conducted in the 2016 - 2017 timeframe did not include an ORTP value for solar resources since a high-level analysis indicated that the ORTP would be well above the FCA starting price. However, the installed cost of solar facilities has decreased dramatically since that time, so Concentric evaluated a solar resource in this ORTP study. Based on consultation with Mott MacDonald, the solar photovoltaic (PV) facility will be 20 MW and located in Connecticut. The assumed size of the solar facility was based on recent and expected entry by similar resource types in the FCA. Connecticut was selected as an appropriate location for the solar facility because there are currently similar facilities of this type located nearby. The PV facility will consist of 69,984 400-Watt modules mounted on fixed racks at a tilt of 30 degrees. Power will be transmitted to a central switchyard, converted to AC, transformed up to 115 kV, and injected into the site adjacent 115 kV network.

The solar scope of work included fixed position solar PV arrays, as opposed to single-axis solar tracking designs. This fixed position design was selected because solar tracking has been found to be difficult to cost justify, due to the historically low irradiance that occurs in the New England region. Fixed position solar arrays are also consistent with a majority of the solar projects already developed in the New England region, as well as solar projects participating in recent FCAs.

iii. Battery

The previous ORTP study conducted in 2017 did not include an ORTP value for battery resources. However, these resources are becoming increasingly active in the FCM. Therefore, Concentric calculated an ORTP value for these facilities. The battery storage facility selected for the ORTP analysis is a Lithium Ion storage facility capable of delivering 150 MW, 300 MWh at the point of interconnection. This size is consistent with projects proposed in the ISO-NE queue, as well as data Mott MacDonald collected from New England developers. The two-hour duration is consistent with projects that are focused on E&AS revenues, which is how the unit is modeled to participate, as opposed to arbitrage opportunities. This facility utilizes 73 storage containers that contain 3,200 Lithium Ion racks. Lithium Ion technology was chosen because it is the most common battery type being installed in the United States, and there are multiple operating Lithium Ion batteries operating in the New England region. We assumed that the Lithium Ion battery storage facility provides ancillary services in support of the grid, consistent with the characteristics of the battery resources that have participated in recent FCAs. For this reason, the selected site is near a critical node where renewable energy is expected to be injected in the near future; adjacent to the Kent County Substation in Rhode Island, which has readily 345 kV transmission on site.

H. Capital/Operating Costs

The table below summarizes operating costs for the ORTP units, described in further detail in the following sections. The capital cost estimates for each ORTP resource are also described in detail below.

Table 40 : Summary of ORTP Operating Costs (2025$ Levelized)

	CC	SC	Onshore Wind	Solar	Battery
$/kW-year					
Property Taxes	4.65	2.72	1.97	1.42	1.27
Site Leasing	0.67	0.53	9.97	9.98	1.67
Insurance	3.10	2.45	6.63	4.77	2.93
Fixed O&M (LTSA plus ongoing O&M)	59.66	38.21	32.91	14.86	24.41
Total Fixed Expenses	**66.08**	**43.92**	**51.48**	**31.03**	**30.28**
$/kW-month					
Property Taxes	0.39	0.23	0.16	0.12	0.11
Site Leasing	0.06	0.04	0.83	0.83	0.14
Insurance	0.26	0.20	0.55	0.40	0.24
Fixed O&M (LTSA plus ongoing O&M)	4.97	3.18	2.74	1.24	2.03
Total Fixed Expenses	**5.67**	**3.66**	**4.29**	**2.59**	**2.52**

i. Gas-Fired Resources

The overnight capital costs for both simple cycle and combined cycle combustion turbines were based on the capital costs calculated as part of the CONE/Net CONE analysis. Costs for insurance, electrical interconnection, property taxes, and contingency were reduced consistent with calculating a "low-end of the competitive range" value. Specifically, insurance was adjusted from 0.6% of overnight costs used in the CONE study to 0.3% for the ORTP study; property taxes were reduced from 2.89% to 1% to represent the negotiation of a Payment In-Lieu-of Taxes (PILOT) agreement, and capital costs were reduced by 1% from the CONE values. The resulting overnight costs and fixed O&M costs are shown below.

Table 41: Summary of Overnight Capital Costs (2025$)

Cost Component	7HA.02 Combined Cycle	7HA.02 Simple Cycle	Onshore Wind	Solar	Battery
Total Overnight Capital Costs (2019$M)	532.3	285.0	173.0	30.5	140.7
Total Overnight Capital Costs $/KW	956	758	2,097	1,524	938

ii. Onshore Wind

The site for onshore wind was selected based on the Mott MacDonald "X marks the spot" methodology where a quality wind resource location crosses installed transmission and is able to sell the power into a competitive renewable energy market. Locations evaluated led Mott MacDonald to focus on northern New England where multiple good wind resources are located. Historically, onshore wind projects have had difficulty finding existing transmission capable of wheeling power to market without extremely high system upgrade or system construction requirements. This project is in an area where some upgrade costs are required to enable wheeling, but they are not significant enough to overwhelm the project. Upgrades are assumed to include new wires and towers and some upgrades to substations as well as the installation of fiber optic controls to bring the system up to current design standards.

Capital costs for onshore wind facilities vary significantly from project to project due to site specific conditions and development and installation costs. In calculating an appropriate capital cost for the reference wind facility, Concentric consulted Mott MacDonald and reviewed publicly available data about the wind facility capital costs. The assumed overnight costs for the reference onshore wind facility are shown in Table 43. The overnight costs represent a 45% decrease in the assumed cost for the reference onshore wind farm from the previous ORTP study of approximately $2,500/kW, reflecting the declining cost trajectory for wind farm installations.

Table 42: Onshore Wind Facility Overnight Costs (2019$, in millions)

COST COMPONENT	ONSHORE WIND (ORTP)
EPC Costs	
Civil/Structural/Architectural	84.1
Mechanical Costs	4.3
Electrical/Instrumentation Costs	11.3
Construction Management	2.4
Medium Voltage Collection System	5.7
Project Substation and O&M Building	5.4
Meteorological Towers	0.4
Project Contingency	8.0
Owners Development Costs	0.3
Total EPC	**121.9**
Non-EPC Costs	
Owner's Contingency	0.0
Electrical Interconnection	7.0
Electrical System Upgrade Costs/Substation Upgrades	38.0
Financing Fees (4% of costs financed through debt)	4.9
Working Capital (1% of EPC costs)	1.2
Total Non-EPC	**51.1**
Total Overnight Capital Costs	**173.0**
$/KW	**2,097**

Concentric estimated Fixed O&M costs for the onshore wind unit based on an LTSA estimate provided by Mott MacDonald. The LTSA includes labor, materials, contract services, and associated costs with an estimated cost of $2.50/kW-month (2019$). To confirm the reasonableness of this assumption, Concentric also reviewed several publicly available studies which include estimates of onshore wind fixed O&M costs. Ongoing maintenance costs were assumed to be approximately $1,000/MW-year, reflecting a low end of the range.

We assumed that 4,700 acres of land would be leased at an annual cost of approximately $822,500 or $175/acre based a review of publicly available site leasing agreements, described below in section iii.

We determined that a property tax rate of 1% was representative of projects that have entered into PILOT agreements with local cities and towns. This rate was applied to an average of net plant values on an annual basis. Concentric also reviewed property taxes for Coos County, New Hampshire to ensure the reasonableness of the ORTP property tax assumption. Property taxes for Coos County from 2017-2019 range from 1.2% to 4.0%, with an average of 2.26%. A 1% tax rate based on a PILOT agreement is sufficiently lower than this range and therefore conservative. Based on this assumed rate, the property taxes for the onshore wind farm were estimated at approximately $73,000 per year, or $0.88/kW-year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with the assumption contained in the 2017 ORTP study, which continues to be reasonable. Annual insurance costs were estimated to be approximately $409,000 in 2025 dollars.

Based on these assumptions, the levelized fixed O&M cost of the wind facility over its 20-year life is $51.48/kW-year. This all-in fixed O&M cost is less than the $63.60/kW-year assumed in the 2017 ORTP study.

iii. Solar

To estimate capital costs for the reference solar PV unit, Concentric reviewed recently developed and current planned projects in New England to get a sense of appropriate size and location. We then consulted with Mott MacDonald to estimate capital costs for the reference solar unit. The largest components of the solar unit's capital costs include major equipment, racking system, foundations, SCADA and monitoring systems, electrical plant, interconnection, testing/energization, and other indirect costs as well as owner's costs. These estimates are based on Mott MacDonald's proprietary database of project costs. This database is continuously developed using active Mott MacDonald Solar PV projects. A summary of the assumed overnight capital costs for the solar PV unit are included in Table 44 below.

Mott MacDonald assumed the electrical interconnection of a nearby 115 kV transmission line, as previously stated. Analyzing the estimated costs associated with the necessary electrical infrastructure to complete this interconnect along with the consideration of a reference system impact study within the interconnection queue, Mott MacDonald developed the Electrical Interconnection cost below.

Table 43: Reference Solar PV Overnight Costs (2019$, in millions)

COST COMPONENT	SOLAR
EPC Costs	
Civil/Structural/Architectural	1.3
Electrical/Instrumentation Costs	1.6
Construction Management	0.8
Major Equipment - Wind Turbines, PV Modules, PV Inverters, PV Racks, Batteries	15.1
Solar SCADA & Monitoring	0.2
Testing & Energization	0.1
Other Indirect Costs	2.5
Project Contingency	1.1
Owners Development Costs	0.7
Total EPC	**23.5**
Non-EPC Costs	
Owner's Contingency	0.1
Electrical Interconnection	5.7
Electrical System Upgrade Costs/Substation Upgrades	0.0
Financing Fees (4% of costs financed through debt)	0.9
Working Capital (1% of EPC costs)	0.2
Total Non-EPC	**7.0**
Total Overnight Capital Costs	**30.5**
$/KW	**1,524**

Concentric estimated fixed O&M costs for solar through consultation with Mott MacDonald and a review of solar leasing agreements. Land lease costs are typically negotiated and are therefore difficult to calculate. Concentric reviewed data from several publicly available solar land lease agreements to estimate a reasonable range of land lease costs on a $/MW/year basis. The range of these costs was $7,500/MW/year to $38,100/MW/year. For purposes of the ORTP study, Concentric focused on the lower half of available land lease costs. The average of this selection was approximately $10,000/MW-year, which was also relatively near the land lease costs for the project reviewed in Connecticut (the location of the reference resource used in the ORTP study). This resulted in a land leasing cost of approximately $1,500/acre or $9.98/kW-year.

As noted above, we determined that a property tax rate of 1% was representative of projects that have entered into PILOT agreements with local cities and towns. This rate was applied to an average of net plant values on an annual basis. Concentric also reviewed property taxes for Windham County, Connecticut to ensure the reasonableness of the ORTP property tax assumption. Property taxes for Windham County from 2018-2020 range from 2.0% to 4.3%, with an average of 2.84%. A 1% tax rate based on a PILOT agreement is sufficiently lower than this range. Based on this assumed rate, the property taxes for the solar farm were estimated at approximately $15,000 per year, or $0.76/kW-year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with the other technologies evaluated in this study. Annual insurance costs were estimated to be approximately $83,000 in 2025 dollars, or $4.13/kW-year.

LTSA and ongoing maintenance costs were assumed to be approximately $16/kW-year in 2025$ based on consultation with Mott MacDonald. To check the reasonableness of this assumption, Concentric also reviewed several publicly available studies which include estimates of solar fixed O&M costs. The results of this review ranged confirmed the assumed $16/kW-year as a conservative, low-end of the range assumption.

Each of the above assumptions are an estimation of costs, since information on each of these cost categories is very limited and extremely site specific. Based on these assumptions, we calculated a levelized fixed O&M cost for the reference solar farm of $2.59/kw-month.

iv. Battery

Through consultation with Mott MacDonald, we estimated capital costs for lithium-ion battery energy storage system projects based on available information in their database as well as any publicly available information on recently developed projects. Mott MacDonald's proprietary database of project costs was utilized to develop this estimate. This database is continuously developed using active Mott MacDonald Battery projects. The assumed battery unit's EPC costs fall into the following major categories: major equipment, foundations, plant electrical, site work, substation and tie line, general conditions, testing and energization, and indirect costs. Table 44 below contains our assumed overnight capital cost for the reference battery storage project.

Mott MacDonald assumed an electrical interconnection at the nearby Kent County 345 kV substation, as previously stated. Mott MacDonald analyzed the estimated costs associated with the necessary electrical infrastructure to complete this interconnect and reviewed a reference feasibility study within the interconnection queue. The estimated electrical interconnection cost is included below.

Table 44: Reference Battery Storage Overnight Costs (2019$, in millions)

COST COMPONENT	BATTERY
EPC Costs	
Civil/Structural/Architectural	0.4
Mechanical Costs	0.0
Electrical/Instrumentation Costs	1.3
Construction Management	1.5
Project Substation and O&M Building	6.8
Major Equipment - Wind Turbines, PV Modules, PV Inverters, PV Racks, Batteries	101.6
Testing & Energization	0.3
Other Indirect Costs	10.2
Project Contingency	5.8
Owners Development Costs	1.0

COST COMPONENT	BATTERY
Total EPC	**128.8**
Non-EPC Costs	
Electrical Interconnection	5.4
Financing Fees (4% of costs financed through debt)	5.2
Working Capital (1% of EPC costs)	1.3
Total Non-EPC	**11.9**
Total Overnight Capital Costs	**140.7**
$/KW	**938**

Concentric estimated fixed O&M costs for the battery through consultation with Mott MacDonald and the use of assumptions consistent with the other ORTP units. Land lease costs are typically negotiated and are therefore difficult to calculate. Public documentation and data on leasing costs for battery systems are very limited, and although we considered using the same $10,000/MW leasing estimate from the solar ORTP calculation, through consultation with stakeholders it was determined that battery sites are more likely to resemble that of the gas units than the solar unit. Therefore, we assumed that 10 acres of land would be leased at a cost of $25,000/acre, consistent with the per-acre cost used for the gas units.

Similar to the ORTP assumptions for the other studies, the study assumes a property tax rate of 1% for the battery, which was applied to an average of net plant values on an annual basis and reflects actual PILOT agreement structures. Concentric also reviewed property taxes for Kent County, Rhode Island to ensure the reasonableness of the ORTP property tax assumption. Property taxes for Kent County from 2017-2019 range from 2.3% to 3.3%, with an average of 2.70%. A 1% tax rate based on a PILOT agreement is sufficiently lower than this range. Based on this assumed rate, the property taxes for the battery storage system were estimated at approximately $110,000 per year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with other technologies evaluated in this study. Annual insurance costs were estimated to be approximately $422,000 in 2025 dollars, or $2.93/kW-year.

LTSA and ongoing maintenance costs, which do not include augmentation costs, were assumed to be approximately $25/kW-year in 2025$ based on consultation with Mott MacDonald. To assess the reasonableness of this assumption, Concentric also reviewed publicly available EIA data which include estimates of battery fixed O&M costs. The EIA data showed an expense of approximately $36/kW-year, which is in line with the all-in fixed O&M assumption made here. Based on these assumptions, we calculated a levelized fixed O&M cost for the reference battery storage system of $2.52/kw-month or approximately $30/kW-year.

I. Revenue Offsets for ORTP Generating Resources

This section summarizes the estimated revenue offsets used for each ORTP resource. ORTP revenue offsets come from one or more of the following potential revenue streams: E&AS revenues, FRM revenues, PFP revenues, and REC revenues. All of the E&AS estimates for the ORTP resources, excluding regulation revenue for the battery technology, were developed with simplified dispatch models that used historical energy prices during the 2017-2019 period that were adjusted with Energy/Reserve Scarcity adjustment noted above. The prices used in the ORTP dispatch models do not include an LOE adjustment since the ISO-NE Tariff does not require that ORTP units be modeled at criterion.

i. Scarcity

Similar to the CONE units, estimated revenues from energy and reserve shortages were added back as a separate line item outside of the ORTP dispatch models. However, the Energy/Reserves Scarcity adder for the ORTP units assumed 7.4 scarcity hours, which is based on current excess supply conditions in New England. This scarcity hours estimate is lower than the 11.3 scarcity hours assumed in the CONE unit Energy/Reserve Scarcity adder, which assumed installed capacity equal to the system's installed capacity requirement. The Energy/Reserve Scarcity unit adders are shown in Table 46.

Table 45 : ORTP Energy/Reserve Scarcity Adjustment

UNIT	AVAILABILITY FACTOR	ADJUSTMENT $/KW-MO
Combined Cycle	92.77%	0.57
Simple Cycle	98.00%	0.60
Onshore Wind	26.46%	0.16
Solar	47.81%	0.29
Battery	98.00%	0.60

ii. Pay for Performance

Pay for performance for ORTP resources was calculated in same way as the CONE units, with updated parameters for "H", "A", and "Br". As noted above, scarcity hours were reduced from 11.3 to 7.4. Balancing ratios were also adjusted downward.

Estimating the expected performance during scarcity hours for the intermittent unit ORTPs (the onshore wind and solar technologies) requires a different set of assumptions than using a forced-outage rate. To estimate the average performance during scarcity hours, or "A", we assumed that the unit's average performance during scarcity hours would, on average, be equal to the forecasted generation during Summer Intermittent Reliability Hours and Winter Intermittent Reliability Hours. These summer/winter performance values are then weighted by the expected amount of seasonal scarcity hours. Peak load scarcity hours are assumed to occur in the summer, transient scarcity hours are assumed to occur randomly through the year, and winter scarcity hours are assumed to occur in the winter. These values are shown in the table below.

Table 46 : Renewable Resource 'A' Values

Technology	Nameplate (MW)	Summer Performance MW	Winter Performance MW	Scarcity Type Weighted Performance	Scarcity Weighted [A]
Onshore Wind	82.5	19.4	39.0	21.8	26.5%
Solar	20.0	10.9	0.2	9.6	47.8%

In addition to calculating the expected performance value for each; the expected incremental PFP revenues earned by the intermittent units needs to account for the seasonal variation in the CSO MW that these units receive. Assuming that the unit receives a seasonal CSO MW equal to its QC MW, the percent of nameplate having CSO MW is applied on the same scarcity-hour specific dimension.

iii. E&AS: Gas-Fired Generating Resource

The dispatch models used to estimate the E&AS revenue offsets for the candidate two gas units ORTP (combined cycle and simple cycle) employed the same dispatch logic as the dispatch models used to estimate E&AS offset for the CONE/Net CONE value of each unit. However, as noted above, the historical prices used in the dispatch models to estimate E&AS offsets for the ORTP units include an Energy/Reserve Scarcity adjustment but do not include an LOE Adjustment. Accordingly, the estimated E&AS offsets for the gas units in the ORTP study are lower than the estimated E&AS offsets for the same units in the CONE study because the dispatch models use lower market clearing prices. As noted above, the Energy/Reserve Scarcity adjustment was added back outside of the ORTP dispatch model assuming scarcity hours of 7.4. Similarly, expected PFP revenues for the natural gas resources are equal to those used in the CONE/Net CONE analysis, but are based on 7.4 scarcity hours. The ORTP estimates for the gas-fired units did not include an adjustment for lifecycle degradation given the nature of the ORTP estimates, which are designed to be at the lower end of the range.

iv. E&AS: Onshore Wind Resource

As noted above, this study assumes the onshore wind unit will be located in New Hampshire and have an annual capacity factor of 43.1%. The onshore wind unit's generation is based on hourly DNV-GL data modeled from onshore wind data for the 2017-2019 period.[71] The hourly offshore DNV-GL data, which had an average capacity factor of 32.2%, were adjusted upward to achieve the assumed onshore wind unit's annual capacity factor of 43.1%. The dispatch model to estimate E&AS revenues for the onshore wind unit assumed the wind unit offered 53% of its assumed generation into the day-ahead energy market at a price equal to negative one times its average annual average REC price (i.e., the unit's opportunity cost). This percentage is based on the average proportion of real-time generation that wind facilities in ISO-NE offered into the day-ahead market during the June 2019-July 2020 period.[72] The dispatch model also assumes the onshore wind facility offers all of its

[71] See e.g., https://www.iso-ne.com/static-assets/documents/2020/02/a7b_wind_power_time_series_dnvgl.pdf.

[72] ISO-NE market rules changed rules related to supply offers for wind units in June 2019 after the Do Not Exceed reforms were implemented. Accordingly, day-ahead market offer behavior prior to June 2019 were not considered.

generation into the real-time market at the negative average annual REC price. The onshore wind facility's offer clears the day-ahead and real-time markets in hours when the applicable LMP exceeds the unit's energy offer. The wind facility does not provide ancillary services. The wind facility's VOM costs were assumed to be zero and dispatch model used historical energy prices in the New Hampshire zone adjusted with the Energy/Reserve Scarcity adjustment.

v. E&AS: Solar Resource

The solar facility is modeled as located in Connecticut. Historical generation data from existing solar facilities in ISO-NE were used to estimate an hourly generation profile for the solar unit. The hourly generation profile is based on a daily average hourly capacity factor (i.e., one 24-hour generation profile for each month) of solar facilities in Massachusetts and Connecticut in each month during the 2017-2019 period for all facilities with a commercial online date of January 2016 or later. The solar facility's E&AS revenues were calculated using the same dispatch logic as the onshore wind unit. The solar unit offered 53% of its generation into the day-ahead market and 100% of its output into the real-time market and the solar unit's VOM costs were zero. Given the unit's location, the solar dispatch model used prices from Connecticut zone adjusted with the Energy/Reserve Scarcity adjustment.

vi. E&AS: Battery Resource

The battery resource has a maximum injection capacity of 150 MW, a 300 MWh of storage capability, and is located in Rhode Island. The battery's storage capability is rated at 300 MWh (i.e., the battery is capable of injecting 300 MWh into the grid from a full state of charge), however given the battery's 86% roundtrip efficiency, the battery's nominal storage capability is 349 MWh (300/0.86 = 348.8 MWh). The battery is assumed to follow a strategy to maximize its expected revenues and minimize cycling due to battery wear and tear and warranty concerns. Concentric considered two modes of operation for the battery: a "reserve mode" where the battery primarily provides reserves; and an "arbitrage mode" where the battery arbitrages intra-day price differences. In both cases, Rhode Island LMPs adjusted for energy and reserve shortages were used.

In the reserve mode of operation, the battery participates in the FRM (for the case where this market continues) and is designated to provide TMNSR. The battery also offers into both the day-ahead and real-time markets at the higher of the daily threshold price and the 95th percentile of the day-ahead and real-time markets, respectively. This offer behavior satisfies the battery's FRM offer obligations and only clears the day-ahead energy market 5 percent of the time given in order to be reserve capable.[73] Given its technical capability to deploy reserves almost instantaneously, the battery is

[73] The 95% percentile price was determined for each calendar year in the 2017-2019 period based on the adjusted LMPs used in the ORTP models. If the battery is dispatched for energy because it clears the real-time energy market, it charges during the lowest price hours of the day, on average, which are hours ending 3-5. The battery also recharges 5% of its energy during these hours on the first Sunday of every month to account for losses.

eligible to provide 150 MW of TMNSR in the FRM. In real-time, the battery is designated to provide TMSR based on its available state of charge in each hour.

In the arbitrage mode, the battery cycles once per day, charging during the lowest priced hours of the day on average (hours ending 3-5) and discharging during the highest priced hours on average (hours ending 18-20). Concentric determined that the reserve mode of operation was more profitable for the battery.[74] This finding is consistent with research in the California ISO, which found that batteries in that market generally preferred to provide ancillary services (regulation and reserves) as opposed to engaging in energy arbitrage. The California ISO surmised that batteries generally preferred to provide ancillary services given concerns regarding wear and tear and the impact that excessive cycling would have on the battery's warranty.[75]

Accordingly, the battery's E&AS revenue estimate is based on the battery operating in the "reserve mode" based on the dispatch logic described above. Given the battery operates in a reserve mode, it is capable of providing both reserves and regulation at the same time in the hours it is neither charging or discharging. Studies performed by ISO-NE indicates that storage resources that provide regulation make 11% of their capacity available, on average, to provide regulation. Therefore, with the exception of TMSR, the battery dispatch model uses 89% of the battery's storage and injection capability. The battery dispatch model assumes the battery can be designated 150 MW of TMSR because the battery can be designated to provide TMSR and regulation at the same time.

Regulation revenues for the battery were calculated outside of the dispatch model and included as a standalone adder. The battery's estimated annual regulation revenues are $3,041,936 per year in 2019 dollars.[76] ISO-NE prepared this estimate based on the assumption that the battery would provide 11% of its 150 MW capacity for regulation in the hours it is neither charging nor discharging energy. Based on a review of regulation payments, ISO-NE calculated an average regulation payment rate of $24.72/MWh, which includes payments for both regulation capacity and regulation movement.[77] Based on the battery's 86% roundtrip efficiency and assuming the incremental cost of charging is equal to price of providing regulation amounts to a net average payment rate of $21.26/MWh. Given the potential FRM Sunset, E&AS offsets are provided for the battery with and without the FRM. Without the FRM, the battery is assumed to operate in a reserve mode and offers at the 95th percentile of the day-ahead and real-time energy prices. The E&AS estimate for the battery without the FRM also includes the regulation revenue adder discussed above.

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74 This was true even when assuming a zero VOM cost for the battery, which is conservative given the impact cycling has on battery warranties and wear and tear.

75 California ISO, Energy Storage and Distributed Energy Resources Phase 4, Final Proposal, , August 21, 2020, at 19. http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4.pdf.

76 The battery's estimated regulation revenues in 2025 dollars is $3,425,714.

77 This average regulation payment was calculated over the January 1, 2018-December 31, 2019 period. Regulation payments in 2017 were not used because ISO-NE market did not have 5-minute settlement in the real time market in 2017.

vii. Renewable Energy Credits

Revenue offsets for the onshore and solar resources include RECs. The REC revenues for these resources are the product of an estimated REC price and the unit's size and annual capacity factor. To estimate the REC price, Concentric relied on historical price data for MA Class I REC indices for the 2016 - 2020 vintages.[78] Concentric calculated the average price for each REC vintage based on all trades available at the time of the analysis. Concentric then averaged those five estimates (normalized to 2019$) to produce a single REC price and then escalated that to 2025 dollars.[79] The annual REC prices were used to calculate annual REC revenues for the onshore wind and solar units. The REC price was also used in the dispatch models to establish the hourly offer prices of each unit. The resulting REC price is $29.32/MWh.

J. Demand Resources

ISO-NE defines demand resources (DR) as installed measures (products, equipment, systems, services, practices, and strategies) that result in verifiable reductions in end-use consumption of electricity in the New England power system. ISO-NE separates DR into two categories – "passive" and "active". Passive DR are energy efficiency measures and non-dispatchable distributed generation). Energy efficiency can include any combination of products, equipment, systems, services, practices, and strategies an end-use customer can use to reduce the total amount of electrical energy needed at their facilities while delivering a comparable or improved level of end-use service. These measures can include the installation of more energy-efficient lighting; motors; refrigeration; heating, ventilation, and air conditioning (HVAC) equipment and control systems; envelope measures; operations and maintenance procedures; and industrial process equipment. Active DR are typically behind-the-meter generation resources and distributed generation that are activated when dispatched by the ISO. An example of what a customer might do to comply with a dispatch instruction would be the practice of powering down machines or using electricity from an on-site generator or a storage device rather than from the grid.

Various types of DR can participate in the capacity markets. Active Demand Capacity Resources (ADCR) can be made up of one or more Demand Response Resources and bid their demand reduction capability into the FCM. Demand Response Resources are dispatched economically in the energy market and may be eligible to provide ancillary services. In addition, non-dispatchable passive demand resources—the on-peak and seasonal peak resources - may only participate in the capacity market, as described below:

- On-peak resources offer on their reduced electricity consumption during summer peak hours (nonholiday weekdays, 1:00 p.m. to 5:00 p.m., during June, July, and August) and winter peak hours (nonholiday weekdays, 5:00 p.m. to 7:00 p.m., during December and January).

[78] REC price data sourced from SNL Financial.
[79] Though RECs are traded beyond their vintage year, our average does not include those prices as they would have skewed the estimate downward.

- Seasonal-peak resources offer on their reduced electricity consumption during the summer months of June, July, and August, and during the winter months of December and January, in hours on nonholiday weekdays when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" system peak-load forecast for the applicable summer or winter season

A discussion of the types of DR reviewed follows, with Energy Efficiency measures discussed in the following section.

i. Technical Specifications

Demand resources take many forms and vary in size and type. A review of past submittals into the FCA shows that many of the submittal fall into the following categories:

- On-Peak Solar Generation – collection of distributed generation facilities with a 1 MW active load reduction capability.
- Combined Photovoltaic Solar and Energy Storage - collection of distributed generation facilities with a 2 MW active load reduction capability.
- Load Management - a measure by a small commercial customer or entity that is representative of small commercial customers that control specific end-use processes and can provide 0.5 MW of demand reduction.

Increasingly, aggregators are facilitating demand response by acting as middlemen between utilities or system operators on the one hand and the ultimate users of electricity on the other.

ii. Capital and Operating Costs

To determine the appropriate level of capital costs for the types of DR resources identified above, Concentric reviewed data and analysis from new supply offers in the last five FCAs to determine an appropriate level of capital costs that is reflective of the resources that have been participating in the FCM. It is clear based on the data reviewed that determining a representative capital cost for each of the measures is challenging due to the variation in technology types and the variation in the data available.

Based on the information reviewed, we determined an average installation cost for each of the measures identified on a cost per KW as shown below. Similarly, the average operating costs represent an average of the operating costs submitted by participants for the DR measures reviewed.

Table 47: DR Capital Costs

COST COMPONENTS	COST (2025$/KW-MO)
On-Peak Solar	
Capital Costs+ Operating Costs	$20.07
Combined PV Solar and Energy Storage	
Capital Costs+ Operating Costs	$22.11
Load Management	
Capital Costs+ Operating Costs	$15.41

iii. Financial Assumptions

In terms of financial assumptions, the submitted information was similarly diverse in terms of debt to equity ratio and cost of equity. Based on the universe of data reviewed, we have assumed a 4.3% real ATWACC, a 20-year project life and a revenue stream consistent with the forecast of energy prices and REC prices used for the analysis of generating resources.

iv. DR ORTP Calculations

Based on the cost and revenue estimates detailed above as well as the financial assumptions, we recommend the ORTP values as shown in Table 50.

Table 48: DR ORTP Calculation

ASSUMPTIONS / VALUE			
	On-Peak Solar	***Combined PV Solar and Energy Storage***	**Load Management**
Demand Reduction	1 MW	2 MW	500kW
Contract Life (years)	20	20	20
Real ATWACC (%)	4.3%	4.3%	4.3%
Levelized Capital Cost (2025$/kW-mo)	$20.07	$22.11	$15.41
Revenue Offsets(2025$/kW-mo)	$14.65	$14.73	$14.65
ORTP Value ($/kW-mo)	$5.425	$7.376	$0.761

In addition to the categories above, distributed generation may participate as Demand Response. For new distributed generation, the ORTP is based upon the generation technology type. For existing distributed generation, the ORTP for Load Management is applied.

K. Energy Efficiency

Many of the existing EE programs in New England are established through state-sponsored mandates and implemented by each state's investor-owned utilities. These EE programs generally cover the residential, commercial, and industrial sectors. EE programs include a range of measures and incentives, such as rebates for purchasing new efficient equipment, process improvements, energy management systems, and energy audits. Some states also have established aggressive long-term energy-efficiency goals tied to reductions in greenhouse gas emissions and global-warming solutions. In New England, lighting and mixed-lighting measures constitute most of the savings in energy use and peak demand, and the commercial and industrial sectors provide a majority of the overall savings.

The savings in energy use resulting from EE programs result in demand reductions that can be bid into the FCM. The ISO-NE Tariff permits an energy efficiency resource program administrator to aggregate the reduction in capacity needs in New England resulting from energy efficiency and bid that capacity reduction into each FCA. As a result, providers of energy efficiency resources that are successful bidders into a FCA are compensated for the reduction in regional capacity needs that they provide in the same manner as generators are compensated for providing capacity. Like generating resources, EE resources must meet market rules for eligibility and availability. To be eligible for the auction, EE resources must demonstrate in advance their ability to perform during those hours.

i. Technical Specifications

In calculating an appropriate ORTP for EE programs, we reviewed all investor-owned utility energy efficiency programs in New England. There are currently forty-one EE programs, excluding programs targeted towards low-income customers. Low-income programs were excluded from the analysis since they are not subject to the same cost-effectiveness screening practices as standard EE programs. Cost effectiveness screening is employed to ensure that the use of ratepayer funds results in sufficient benefits. States have recognized various benefits provided by low-income EE programs that are not included in benefit/cost ratios, such as a reduction in hardship customers and a reduction in uncollectible bills. Without these benefits, many of the low-income EE programs are not cost-effective. Therefore, including these programs in the ORTP calculation, which represents the low-end estimate of the first-year revenues needed by the resource to be economically viable, is not recommended. Table 51 shows the EE programs that have been included in our ORTP calculations.

Table 49: Energy Efficiency Programs Included in ORTP Analysis[80]

CONNECTICUT	MASSACHUSETTS	MAINE	NEW HAMPSHIRE	RHODE ISLAND	VERMONT
Residential Retail Products	Residential Whole House	Commercial and Industrial Prescriptive Program - Electric	Home Performance w/ Energy Star	Residential New Construction	Business New Construction
Residential New Construction	Residential Products	Commercial and Industrial Custom Program - Electric	Energy Star Homes	Energy Star HVAC	Business Existing Facilities
Home Energy Solutions	C&I New Construction	Small Business Initiative	Energy Star Products	EnergyWise	Residential New Construction
HES - HVAC, Water Heaters	C&I Retrofit	Consumer Products Program	Home Energy Reports Energy Savings	EnergyWise Multifamily	Efficient Products
Residential Behavior		Home Energy Savings Program	Large Business Energy Solutions	Energy Star Lighting	Existing Homes
Energy Conscious Blueprint			Small Business Energy Solutions	Residential Consumer Products	
Energy Opportunities			Municipal EE Program	Home Energy Reports	
Business and Energy Sustainability			Energy Rewards RFP	Large Commercial New Construction	
Small Business Energy Program				Large Commercial Retrofit	
				Small Business Direct Install	

There are three tests that are most commonly used in determining the cost-effectiveness of EE programs – the Program Administrator Cost (PAC) test, the Total Resource Cost (TRC) test and the Societal Cost test. The PAC test includes all of the costs and benefits associated with the utility system. It includes all the costs incurred by the utility to implement efficiency programs, and all the benefits associated with avoided generation, transmission, and distribution costs. The TRC test includes all the costs and benefits to the program administrator and the program participants. It includes all of the costs and benefits of the PAC test, but also includes participant costs and participant benefits. The Societal Cost test includes all impacts to all members of society. It includes all the costs and benefits of the TRC test, but also includes societal impacts. These impacts typically fall within the following

[80] Connecticut: Eversource Energy, et al., 2018.
Massachusetts: National Grid, et al., 2018.
Maine: Efficiency Maine, 2018.
New Hampshire: Granite State Electric Company, et al., 2017.
Rhode Island: Narragansett Electric Company, 2018.
Vermont: Efficiency Vermont, 2019.

categories: environmental impacts; reduced health care costs; economic development impacts; reduced tax burdens; and national security impacts.

Each test is designed to present the costs and benefits from different perspectives. While all of these different perspectives may be considered relevant and important, and warrant consideration, states typically use one of these tests as the primary test to determine whether to invest ratepayer funds in energy efficiency programs. Because most states screen for cost-effectiveness using the TRC as the primary test, it is recommended that the ORTP calculation be based on the TRC test.

To calculate the costs and benefits of EE programs based on the TRC approach, we reviewed the investor-owned utility filings to gather information on forecasted program costs and savings. These costs and benefits associated with EE programs under the TRC test generally include the following:

- **Costs:**
  - **Program Administrator costs –** the cost for the IOU to administer the EE program
  - **Program financial incentive** – incentive amounts paid to customers or other equipment purchasers
  - **Participant contribution** – costs recognized by the customer and any involved third parties to install the EE measure
- **Benefits:**
  - **Avoided energy costs** – the value of the energy avoided by EE measure. This includes environmental costs that require expenditures to reduce emissions to comply with carbon dioxide emissions regulations (RGGI) and state clean energy standards. This includes a risk premium attributable to the reduced risk for retail electricity suppliers in the costs of acquiring energy capacity and ancillary services to meet
  - **Avoided renewable energy credit** - Energy efficiency programs reduce the cost of compliance with RPS requirements by reducing total LSE load. Reduction in load due to energy efficiency or other demand-side resources will therefore reduce the RPS obligations of LSEs and the associated compliance costs recovered from consumers. This estimate of avoided costs includes the expected impact of avoiding each class of RPS or renewable energy standards within each of the six New England states.[81]
  - **Avoided environmental costs**[82] – the includes the cost of sulphur dioxide allowances for compliance with the Cross -State Air Pollution Rule (CASPR)
  - **Avoided transmission and distribution costs –** the value that load reductions contribute to deferring or avoiding the addition of load-related transmission and distribution facilities, due to reduced load growth and reduced loading of existing equipment.
  - **Value of reliability** - One important issue in determining the value of energy efficiency-induced reliability is whether any reliability improvements can be quantified in dollar values. The value of lost load (VoLL) describes the cost to consumers of being unable to take power from the system. VoLL is not a single value,

[81] The avoided cost is a function of REC price and load obligation percentage (i.e., the RPS target percentage).
[82] Nitrogen oxide prices were assumed to be zero since the New England states are exempt from the CSAPR rule.

since the cost of an outage varies with such factors as the type of customer and the length of the outage.

- **Energy demand reduction induced price effect (DRIPE)** - Demand Reduction Induced Price Effect (DRIPE) refers to the reduction in prices in the wholesale markets for capacity and energy—relative to the prices forecast in the Reference case—resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.

A review of these filings showed a potential annualized savings of 2,633,192 MWh and approximately 383 MW of savings at the customer meter over an estimated measure life of approximately 10 years consistent with the average of existing programs. In order to present the information contained in the filings on a consistent basis, we adjusted the program size to 1 MW of capacity by the ratio of the annual energy savings to the peak load reduction. Based on this calculation, we assumed that a 1 MW EE measure would be expected to provide 6,361 MWh of annual energy savings.

ii. Capital/Operating Costs

We calculated the total operating costs of the EE programs using data from the investor-owned utility annual EE program annual reports.[83] The total costs of the programs are shown below in Table 52.

Table 50: Energy Efficiency Programs Costs

		2025 Operating Costs (2025 $)	2025 Operating Costs (2025 $/kW)
Peak Load Reduction			
At Meter	MW	383	383
At Generator Bus Bar		414	414
Total Operating Costs			
Labor & Services	$	236,815,607	572
Materials & Supplies	$	65,115	0
Incentives	$	680,956,427	1,645
Marketing, A&G, Other	$	72,604,407	175
Customer Costs	$	535,066,665	1,293
M&V	$	17,916,602	43
Total Utility Costs	$	1,543,424,822	3,729

[83] Please note: some reports are provided as fiscal years and therefore time periods likely vary.

iii. Revenue Offsets

The calculation of revenue offsets for the energy efficiency resource includes these components: energy, reliability, RECs, and DRIPE. Concentric based these categories off of a review of Synapse's 2018 Avoided Energy Supply Costs study. Energy and REC values are consistent with those used throughout the study.

The calculation of benefits includes both the value of the energy saved, as well as environmental and reliability benefits. For the energy-related savings, we used an average historical locational marginal price for all hours for 2017-2019 as well as recently published avoided cost components specific to New England.[84]

Table 51: Energy Efficiency Programs Benefits

2018$		
Energy	($/kW-mo)	$22.42
Reliability	($/kW-mo)	$0.29
RECs	($/kW-mo)	$15.66
DRIPE	($/kW-mo)	$1.26
Levelized Avoided Cost of Energy ($2018/kW-mo)	($/kW-mo)	$39.63
Levelized Avoided Cost of Energy ($2025/kW-mo)	($/kW-mo)	$45.52

iv. EE ORTP Calculations

Based on the estimated program savings and costs as shown above, the Net CONE calculation is ($8.57)/kW-month. Therefore, we recommend an ORTP value for EE programs of $0.00/kW-month.

Table 52: Energy Efficiency Programs ORTP Calculation

Levelized Capital Costs ($2025)	($/kW-mo)	$36.95
Levelized Avoided Costs of Energy ($2025)	($/kW-mo)	$45.52
ORTP	**$/kW-mo**	**$ --**

[84] Avoided Energy Supply Components in New England 2018 Report, Synapse Energy Economics, Inc. October 24, 2018

v. ORTP Summary

The CONE/Net CONE is calculated as the revenue required for entry, or CONE, less the expected revenue offsets. A summary of the CONE/Net CONE values for the evaluated technologies are shown in Table 55 below under alternative market designs.

Table 53: Summary of ORTP Values

Reference Technology	Nominal Installed Capacity (MW)	Qualified Capacity (MW)	Installed Cost 2019$/kW	Real ATWACC	Gross CONE (2025$/kW-mo)	Revenue Offsets (2025$/kW-mo)	Net CONE (2025$/kW-mo Installed)	Net CONE (2025$/kW-mo Qualified)	ORTP (2025$/kW-mo)
Combined Cycle	557	501	956	4.3%	12.72	3.88	8.84	9.82	9.819
Combustion Turbine	376	361	758	4.3%	9.18	4.02	5.15	5.37	5.366
Onshore Wind	82.5	32.4	2,097	4.3%	18.64	23.27	-4.63	-11.78	0.000
Solar	20	3.8	1,524	4.3%	11.61	9.42	2.24	11.89	11.888
Battery	150	129	938	4.3%	8.92	6.00	2.92	2.92	2.923
Energy Efficiency				4.3%	36.95	45.52	-8.57	-8.57	0.000
DR - On-Peak Solar		1		4.3%	20.07	14.65	5.43	5.43	5.425
Load Mgmt C&I		2		4.3%	15.41	14.65	0.76	0.76	0.761
DR - Combined PV/Storage		0.5		4.3%	22.11	14.73	7.38	7.38	7.376

Section 8:
CONE and ORTP Annual Update Process

For years in which no full recalculation is performed pursuant to Market Rule 1, Section III.13.2.4, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2 (e) of Market Rule 1.

In past interim year updates, ISO-NE has followed a prescribed process for updating various components of each ORTP technology's gross CONE value, as well as certain components of its revenue offset. Ultimately, Concentric recommends a simplified annual update process whereby relevant values are updated to reflect high level changes in expectations of inflation and the profitability of merchant generators entering the market.

Four components of each resource's calculation (i.e., the Net CONE reference resource, and each resource with an ORTP value below the auction starting price) should be updated during years where a full recalculation does not take place. Technology types for whom an ORTP is not calculated in this current recalculation will remain at the auction starting price for all interim year auctions. The four components to be updated are as follows:

1. Capital Costs;
2. E&AS offsets;
3. REC prices;
4. Bonus depreciation.

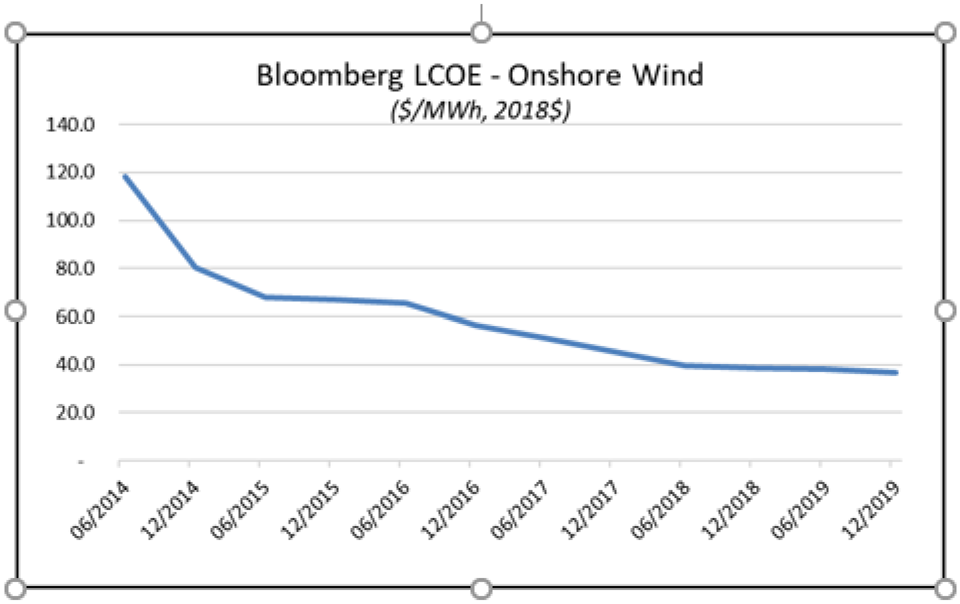
A. Gross CONE

Concentric recommends that the capital cost component of gross CONE be updated by adjusting capital costs in the financial model using publicly available cost indices representing changes to generic major equipment.[85] All capital cost line items in the financial model should be adjusted by a multiplier set according to the parameters agreed to between ISO-NE and stakeholders.

Unlike traditional/fossil/gas generation, the cost of renewables has been declining. Therefore, for the capital cost components for the renewable resources, it is more appropriate to use the levelized cost of energy (LCOE), which is a commercially available value, to capture this declining trend. The LCOE for Onshore Wind is shown in the Figure below.

[85] For example, BLS PPU Commodity Data for Machinery and Equipment; General Purpose Machinery and Equipment. Series ID WPU114.

Figure 6: LCOE – Onshore Wind



B. E&AS Offsets

Concentric is proposing to maintain the current E&AS update procedure which relies on publicly available forward prices to quantify the change in profitability expectations. For the reference unit and gas ORTP units, profitability is a function of the spread between electric prices and delivered gas prices. Therefore, the E&AS update will be based on changes to the relationship between electric forwards and gas forwards, both of which are publicly available from ICE. Calculations should be based on settlements for the farthest date forward in time for which power settlements are available.

Calculations for the gas units (Net CONE reference unit and gas ORTPs) will be based on three contracts on ICE: an Algonquin Citygate basis swap, the Henry Hub futures price, and the MA Hub Day-Ahead On-Peak Future. The basis swap is added to the Henry Hub futures prices to create an index for a delivered Algonquin CG price. The ratio of the power price to the delivered gas price is then calculated for each month, after which the twelve-monthly ratios are averaged. As an example, shows the calculation using settlements on ICE from August 31, 2020.

Table 54: Calculation of Power: Gas Ratio for E&AS Offset Update

	a	b	a+b = c	d	e = d/c
	Henry Hub (H)	**Algonquin CG Basis (ALQ)**	**Algonquin CG Delivered**	**MA Hub On-Peak (NEP)**	**Ratio**
	($/MMBtu)	($/MMBtu)	($/MMBtu)	($/MWh)	
Jan 2024	2.79	5.23	8.02	71.75	8.94
Feb 2024	2.76	5.24	8.00	69.30	8.67
Mar 2024	2.62	1.98	4.60	50.10	10.90
Apr 2024	2.32	0.48	2.80	32.20	11.50
May 2024	2.30	(0.10)	2.20	28.75	13.06
Jun 2024	2.34	(0.10)	2.24	30.50	13.62
Jul 2024	2.38	0.08	2.46	36.50	14.85
Aug 2024	2.39	0.02	2.40	34.45	14.34
Sep 2024	2.38	(0.34)	2.05	30.95	15.12
Oct 2024	2.41	(0.13)	2.28	31.10	13.62
Nov 2024	2.50	1.33	3.83	40.60	10.60
Dec 2024	2.69	4.21	6.90	60.60	8.78
				Average	**12.001**

Preceding an update, these calculations will be performed again. The average ratio that results will be compared to the ratio shown above. The percentage difference (positive or negative) in the ratios will be applied to the E&AS offsets.

For non-gas ORTP units, profitability is a function of the overall level of energy prices, not the spread between energy and gas prices. Therefore, the calculation supporting the adjustment of the E&AS portion of the revenue offset is based only on the power futures. For example, as of August 31, 2020, the average MA Hub on-peak settlement for all contracts in 2024 is $43.07/MWh. In the future, that average will be calculated again for contracts in the capacity commitment period in question. The percentage difference (positive or negative) in the averages will be applied to the E&AS portion of the revenue offset for each non-gas ORTP resource.

C. REC Prices

REC prices are currently updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial. This has resulted in significant swings in ORTP values and in addition does not necessarily reflect the final average REC price for the vintage in question if that vintage has not finished trading. Therefore, Concentric recommends that ISO-NE update REC prices based on a rolling 5-year average MA Class 1 REC price for the vintages closest to the capacity commitment period. The updated REC price adjusted to the appropriate dollar year should be input into the financial model.

D. Bonus Depreciation

For the ORTP technologies, Concentric recommends that ISO-NE account for declining bonus depreciation in subsequent years. As of the writing of this report, available guidance suggests that 20% bonus depreciation will be available for units placed in service in calendar year 2026 and will expire thereafter.

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

The following activity, as more fully described in the attached litigation report, has occurred since the report dated November 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

No Activity to Report

I. Complaints/Section 206 Proceedings

	Page	Matter	Date	Activity
	2	NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)	Nov 17	Avangrid answers NextEra's November 2 Answer
			Nov 30	NextEra answers Avangrid's November 17 answer
	3	NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)	Nov 19	NextEra answers Avangrid Nov 4 protest
	4	206 Proceeding: FCM Pricing Rules Complaints Remand (EL20-54)	Dec 2	FERC issues an order finding the New Entrant Rules no longer just and reasonable and directing ISO-NE to remove them from the Tariff; compliance filing due on or before Feb 1, 2021

II. Rate, ICR, FCA, Cost Recovery Filings

	Page	Matter	Date	Activity
*	8	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER21-496)	Nov 25	ISO-NE and NEPOOL jointly file ICR-Related Values and HQICCs for the 2021/22 ARA3, 2022/23 ARA2; and 2023/24 ARA1; comment date Dec 16
			Dec 1	Dominion, NESCOE intervene
*	8	FCA15 Qualification Informational Filing (ER21-372)	Nov 10	ISO-NE submits required FCA15 informational filing
			Nov 13-25	NEPOOL, Boston Energy Trading and Marketing, Calpine, Dominion, Eversource, National Grid, NESCOE, NRG, and Avangrid (out-of-time) intervene
			Nov 25	Andro Hydro, Mystic, NEPGA submit limited protests
*	9	ICR-Related Values and HQICCs – FCA15 (2024-25) Capacity Commitment Period (ER21-371)	Nov 10	ISO-NE files ICR-Related Values for the 2024-25 Capacity Comm. Period
			Nov 13-25	Calpine, Dominion, Eversource, MA DPU, National Grid, NESCOE, NRG, intervene
	9	2021 NESCOE Budget (ER21-113)	Nov 5	Eversource intervenes
	9	2021 ISO-NE Administrative Costs and Capital Budgets (ER21-106)	Nov 5	Eversource intervenes

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

	Page	Matter	Date	Activity
	11	ESI Alternatives (ER20-1567)	Nov 13	ISO-NE requests clarification that it may engage in communications with the FERC/FERC staff about the ESI market design, reserve market design, the option construct, and the voluntary nature of the markets, unfettered by any *ex parte* restrictions arising out of this proceeding
	16	CASPR (ER18-619)	Nov 19	FERC issues *CASPR Allegheny Order*, modified the discussion in the *CASPR Order*, but reaching the same the result

V. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

	21	CIP Standards Development: Info Filings on Virtualization & Cloud Computing Srvcs Projects (RD20-2)	Nov 13	NERC files supplement to communicate schedule changes intended to prioritize completion of the virtualization revisions earlier than reported in its Sep Info Filing

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	19	Capital Projects Report - 2020 Q3 (ER20-108)	Nov 5	Eversource intervenes
*	19	Interconnection Study Metrics Processing Time Exceedance Report Q3 2020 (ER19-1951)	Nov 13	ISO-NE files required quarterly report
*	19	IMM Quarterly Markets Reports - 2020 Summer (ZZ21-4)	Nov 12	IMM files Summer 2020 Report; to be reviewed at Dec 8-9 Markets Committee meeting
*		ISO-NE FERC Form 3Q (2020/Q3) (not docketed)	Nov 24	ISO-NE submits its 2020 Q3 FERC Form 3Q

IX. Membership Filings

*	20	December 2020 Membership Filing (ER21-499)	Nov 30	***Terminations:*** Eagle's View, Goose River Hydro, Patriot Partnership, SFE Energy CT, Emera EES No. 9; comment date Dec 21
	20	October 2020 Membership Filing (ER20-3031)	Nov 18	FERC accepts David Energy Supply, LLC (Supplier Sector) as new member
	20	Suspension Notice – Manchester Methane, LLC (not docketed)	Nov 20	ISO-NE files notice of suspension of Manchester Methane, LLC from the New England Markets

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

	21	CIP Standards Development: Info. Filings on Virtualization and Cloud Computing Srvcs Projects (RD20-2)	Nov 13	NERC provides a schedule update, noting it anticipates filing proposed Reliability Standards from each project in Dec 2021

XI. Misc. - of Regional Interest

	24	203 Application: Millennium Power Partners (EC20-103)	Nov 18	FERC authorizes Beal Bank acquisition of all of the membership interests in Millennium Power Partners, L.P.
	24	203 Application: Direct/NRG	Nov 24	FERC authorizes NRG acquisition of Direct Energy Business and Direct Energy Business Marketing
	24	VTransco Rate Schedule 2 Cancellation (ER21-256)	Nov 18	Eversource intervenes

	24	NECEC TSAs: NECEC Transmission Notice of Succession and CMP Notice of Cancellation (ER21-12 et al.)	Nov 30	FERC accepts notices addressing the transfer of the 7 TSAs with the participants that will fund the construction, operation and maintenance of the NECEC Transmission Line
	26	FERC Enforcement Action: CES/ Silkman (IN12-12; IN12-13)	Nov 25	FERC approves Stipulation and Consent Agreement with CES/Silkman, requiring CES/Silkman to pay in installments over seven years a ***$1.3 million civil penalty*** and to ***disgorge $166,841***, to resolve the FERC's investigation into violations, between Jul 2007 and Feb 2008, of the FERC's Anti-Manipulation Rules

XII. Misc. - Administrative & Rulemaking Proceedings

*	26	ISO/RTO Credit Principles & Practices (AD21-6; AD20-6)	Nov 4	FERC issues notice of Feb 25-26, 2021 tech. conf.; panelist self-nominations due Dec 11
	27	Carbon Pricing in ISO/RTO Markets Tech Conf (Sep 30, 2020) (AD20-14)	Nov 16	Comments submitted by, among others, NEPOOL, NESCOE, AEE, Brookfield, Calpine, Eversource, HQUS, LSP Power, MA AG, National Grid, NEPGA, NRG
			Dec 1	Reply comments filed by 10 parties, includ. Exelon, EPSA, NRG, NY PSC
*	30	NOPR: Managing Transmission Line Ratings (RM20-16)	Nov 19	FERC issues NOPR; comments due [60 days after the date of publication in the *Federal Register*]
	31	*Order 872-A*: Pricing and Eligibility Changes to PURPA Regulations (RM19-15)	Nov 19	FERC issues order addressing arguments raised on rehearing of *Order 872* and clarifying *Order 872* in part
	31	*Order 2222*: DER Participation in RTO/ISO Markets (RM18-9)	Nov 12	AEE and AEMA request clarify. and/or reh'g of *Order 2222*
			Nov 19	FERC issues Notice of Denial by Operation of Law of requests for reh'g of *Order 2222*, though it indicated that the requests would be addressed in a future order (which can be issued up until the record of the proceeding is filed with the Court of Appeals)
	33	*Order 676-I*: NAESB WEQ Standards v. 003.2 - Incorporation by Ref. into FERC Regs (RM05-5-027)	Nov 25	FERC issues order on clarification, in which it clarified *Order 676-I* as requested and, accordingly, dismissed Southern Companies' alternative request for rehearing

XIII. Natural Gas Proceedings

39	Iroquois ExC Project (CP20-48)	Nov 5	FERC issues data request regarding nameplate ratings
		Nov 12	Iroquois responds to Nov 5 data request
		Nov 16	FERC issues data request regarding environmental information
		Nov 20	Iroquois responds to Nov 16 data request; Iroquois submits periodic update to reflect updates to the permits, approvals, and agency consultations
39	Northern Access Project (CP15-115)	Nov	Over 70 sets of comments filed on requested extension
		Dec 1	FERC dismisses, without prejudice, Applicants' request for an additional 2-year extension of time to complete construction of the Project and enter service (finding request premature)

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

41	ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)	Nov 19	Parties file statements of issues, dispositive motions, and a Certified Index to the Record
42	CIP IROL Cost Recovery Rules (20-1389)	Nov 3 Nov 13	Court issues order establishing briefing schedule FERC files certified index to the record
42	Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368) (consolidated)	Nov 4	Court grants FERC's motion and orders that the consolidated cases be held in abeyance pending further order of the Court and that the parties file motions to govern further proceedings in these cases within 21 days of the FERC's decision on rehearing or by Jan 5, 2021, whichever occurs earlier
42	CASPR (20-1333)	Nov 5	FERC files a reply in support of its motion to dismiss, but indicating that an order on rehearing would be issued imminently and suggesting that, if the Court declines to dismiss the Petition, it should be held in abeyance until the Commission issues an order on rehearing (which, as noted above, occurred on Nov 19)
43	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)	Dec 2	Clerk issues order with briefing schedule
43	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224)	Nov 10	Court issues order establishing a revised briefing schedule; FERC files certified index to the record
45	Opinion 569/569-A: FERC's Base ROE Methodology (16-1325) (consol.)	Nov 23	Court issues an order removing these cases from abeyance, ordering the FERC to file a certified index to the record by Dec 8, 2020, and ordering the parties to submit on or before Dec 23 proposed formats for the briefing of these cases.

M E M O R A N D U M

TO:	NEPOOL Participants Committee Members and Alternates
FROM:	Patrick M. Gerity, NEPOOL Counsel
DATE:	December 2, 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 December 2, 2020. If you have questions, please contact us.

COVID-19

- **Jul 8-9 Tech Conf: Impacts of COVID-19 on the Energy Industry (AD20-17)**

On July 8-9, 2020, the FERC convened a Commissioner-led technical conference 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 included 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. Comments and speaker opening statements are posted in eLibrary.

Interested parties were invited to file, on or before August 31, 2020, post-technical conference comments on any or all of the topics discussed at the July 8-9 technical conference, as well as to respond to the questions outlined in the July 1, 2020 supplemental notice of technical conference. Comments were filed by AEP, APPA, America Forest & Paper, America's Power, EEI, IEEE Power & Energy Society, Clearview Energy Partners, TAPS, Assoc. of Oil Pipelines, Pilot Travel Centers, and Process Gas. This matter is pending before the FERC.

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

All hearings before Administrative Law Judges ("ALJs") are being held remotely through video conference software (WebEx and SharePoint) until further notice.[2] The Presiding Judge in each remote hearing will ensure that the participants have access to an "IT Day" prior to the hearing to allow all participants, witnesses, and the public who will attend the hearing to learn more about the remote hearing software and to get their technical questions answered by the appropriate FERC staff. Uniform Hearing Rules for all Office of the ALJ hearings were adopted effective September 15, 2020.[3] The "Remote Hearing Guidance

[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (June 17, 2020).

[3] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 1, 2020).

for Participants" was revised on September 23, 2020 to make three changes.[4] The Uniform Hearing Rules and Remote Hearing Guidance for Participants are publicly available in this proceeding in eLibrary and on the FERC's Administrative Litigation webpage.

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

The wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations is ***in effect through January 29, 2021***.[5] The August 20 notice extended the waiver first noticed in May.[6] As previously reported, Entities may also seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of regulations that govern the form of filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus.[7]

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

The extension of the blanket waivers of ISO/RTO Tariff *in-person*[8] meeting and notarization requirements has similarly been ***extended through January 29, 2021***.[9] The August 20, 2020 order extended the blanket waivers first granted in the FERC's April 2, 2020 order.[10]

I. Complaints/Section 206 Proceedings

- **NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)**

On October 13, 2020, NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") filed a complaint against NextEra[11] requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")." The Complaint seeks, among other things, an initial, expedited order that grants certain relief[12] and directs NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage. Comments on the Complaint were due on or before November 2, 2020. On November 2, NextEra submitted and answer to the Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, Public Citizen. On November 17, Avangrid submitted an answer to NextEra's November 2 Answer. On November 30, NextEra answered Avangrid's November 17 answer, repeating its request that the

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[4] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 23, 2020) (removing law clerk requirement to share screen when moving exhibits, revising procedures for requesting Live Litigation, and revising witness communication guidance to require that "[c]ommunications with a witness through concealed channels of communications are prohibited while the witness is providing testimony on the witness stand. Communications with a witness are allowed during breaks and when they are not on the witness stand.")

[5] See *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Aug. 20, 2020).

[6] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (May 8, 2020).

[7] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Apr. 2, 2020).

[8] The waiver only applies to a specific requirement that meetings be held *in person*. Other than the in-person requirement, such meetings must still be held consistent with the tariff, but should be conducted by other means (e.g. telephonically).

[9] *Temporary Action to Facilitate Social Distancing*, 172 FERC ¶ 61,151 (Aug. 20, 2020).

[10] *Temporary Action to Facilitate Social Distancing*, 171 FERC ¶ 61,004 (Apr. 2, 2020) (waiving notarization requirements through Sep. 1, 2020, contained in any tariff, rate schedule, service agreement, or contract subject to the FERC's jurisdiction under the Federal Power Act ("FPA"), the Natural Gas Act ("NGA"), or the Interstate Commerce Act).

[11] For purposes of this Complaint proceeding, "NextEra" is short for NextEra Energy Resources, LLC ("NextEra Energy Resources"), NextEra Energy Seabrook, LLC ("NextEra Seabrook"), FPL Energy Wyman LLC ("Wyman"), and FPL Energy Wyman IV LLC ("Wyman IV").

[12] directing NextEra to comply with the ISO-NE OATT, to comply with open access requirements, and to cease and desist unlawful interference with the NECEC Project; and to have the FERC temporarily revoke NextEra's blanket waiver under Part 358 of the FERC's regulations and to initiate an investigation and require NextEra to preserve and provide documents related to the interconnection of the NECEC Project.

FERC dismiss or deny the Complaint. 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).

- **NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)**

In a related matter initiated a week earlier, NextEra Energy Seabrook, LLC ("Seabrook") filed a Petition for a Declaratory Order ("Petition") "by which it seeks to understand the scope of its FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC". Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration"). Comments on Seabrook's Petition were due on or before November 4, 2020, and were filed by Eversource, MMWEC, and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. On November 19, NextEra answered Avangrid's protest. 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).

- **New England Generators' Exelon Complaint (EL20-67)**

On August 25, 2020, New England Generators[13] filed a complaint against Exelon[14] requesting that, if and to the extent the FERC does not grant all relief requested by the New England Generators in its August 27, 2020 request for clarification and/or rehearing of the *July 17 Orders* in the Mystic 8/9 Cost of Service Agreement ("COS Agreement") proceeding (*see* ER18-1639 below), the FERC should find that the new information about Exelon's two new queue positions and Exelon's intention to continue to operate Everett beyond the term of the Mystic Agreement makes the existing rate in the Mystic Agreement unjust and unreasonable. New England Generators further requested that the FERC change the Mystic Agreement to: (i) apply the clawback mechanisms to Exelon's two new interconnection queue positions (to prevent Exelon from using interconnection queue positions for "new" or "repowered" units to skirt restrictions imposed on Mystic's recovery of costs pursuant to the COS Agreement); (ii) delete or give no meaning to the words "that were expensed" (in order to prevent Exelon from shielding costs paid for by captive ratepayers from the application of the COS Agreement's clawback provision); and (iii) require that Mystic return any of the undepreciated Everett repair and capital expenditure costs in the event that Mystic 8 or 9 return to the market after the end of the COS Agreement.

Exelon's answer and all interventions, or protests were due on or before September 14, 2020. In addition to Exelon's answer, comments supporting the Complaint were filed by NESCOE, Public Systems[15] and Connecticut Parties.[16] On September 28, NEPGA answer Exelon's answer. Interventions only were filed by Calpine, Energy New England ("ENE"), Eversource, Massachusetts Attorney General ("MA AG") National Grid, and Public Citizen. The Complaint, as well as all of the pleadings in response, remain pending before the FERC. If you have any

[13] "New England Generators" are Vistra, Dynegy Marketing and Trade, NextEra Energy Resources, NRG Power Marketing, LS Power Associates, FirstLight Power, and Cogentrix Energy Power Management.

[14] For purposes of this Complaint, "Exelon" is short for Constellation Mystic Power, LLC ("Mystic"), Exelon Generation Company, LLC ("Exelon Generation") and Exelon Corporation ("Exelon Corp.").

[15] "Public Systems" are Mass. Municipal Wholesale Elec. Co. ("MMWEC") and New Hampshire Elec. Coop., Inc. ("NHEC").

[16] "Connecticut Parties" are CT PURA, CT DEEP, and the CT OCC.

questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **206 Proceeding: FCM Pricing Rules Complaints Remand (EL20-54)**

In response to the February 2, 2018 remand by the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit")[17] (where the DC Circuit found that the FERC did not adequately explain why it allowed ISO-NE to forego an offer floor for its seven-year price lock period despite previously rejecting PJM's request to remove the offer floor for its three-year price lock period), the FERC instituted this proceeding, pursuant to section 206 of the FPA, finding preliminarily that ISO-NE's new entrant rules may be unjust and unreasonable.[18] The FERC established paper hearing procedures and posed the following questions, which needed to be addressed in initial briefs due on or before ***August 24, 2020***:[19]

(a) ***to evaluate the need for the price lock in its entirety***: (i) how many resources have taken advantage of the price lock to date? (ii) is a price lock still needed to incent new entry in ISO-NE? (iii) does the price lock lead to unreasonable price suppression in the entry year? (iv) does the price lock with the zero-price offer rule result in unreasonable price suppression in years 2-7? (v) is the price lock unduly discriminatory? and (vi) if the price lock is retained, should the term be shortened and, if so, what would be a just and reasonable term?

(b) ***to evaluate retaining the price-lock and adding an offer floor***: (i) how would an offer floor be implemented? (2) would an offer floor require significant market redesign? and (iii) what would be the timeline for implementing an offer floor in ISO-NE?

(c) ***to evaluate whether to impose an alternative replacement rate***: (i) are there alternative approaches to the current price-lock that would be sufficient to incent new entry? (ii) how would these alternative approaches address any concerns related to unreasonable price suppression? and (iii) how would these alternative approaches address any concerns related to undue discriminatory or preferential treatment?

Interventions were due on or before July 22, 2020 and were filed by NEPOOL, ISO-NE, ISO-NE EMM, Avangrid, Brookfield, BSW Project Co. (out-of-time), Calpine, CPV Towantic, Dominion, ENE, Eversource, Exelon, FirstLight, HQ US, LS Power, MA AG, MMWEC, National Grid, NESCOE, NHEC, NextEra, NRG, NTE Energy, Talen, Vistra, NEPGA, EPSA, CT AG, CT DEEP, CT PURA, MA DPU (out-of-time), PJM IMM, Public Citizen, RENEW Northeast (out-of-time), and Energy Storage Association ("ESA") (out-of-time).

Initial briefs were filed by ISO-NE, ISO-NE External Market Monitor ("EMM"), MA AG, NEPGA, NRG, and RENEW Northeast. NEPOOL filed limited comments (urging the FERC, should it conclude that the Tariff is unjust and unreasonable and/or unduly discriminatory, to allow sufficient time and flexibility to permit meaningful opportunities for New England stakeholders to work with ISO-NE to develop any required market adjustments through the complete NEPOOL Participant Processes).

Responses to the initial briefs were due September 23, 2020 and were filed by ISO-NE, BSW Project Co, MA AG, NEPGA, MA AG, CT PURA, PJM IMM, and RENEW/ESA. No additional answers or briefs were permitted.

[17] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018) (granting NEPGA's and Exelon's petitions for review of orders accepting the Forward Capacity Market's ("FCM") 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23)).

[18] *ISO New England Inc.*, 172 FERC ¶ 61,005 (July 1, 2020) ("*FCM Pricing Rules Complaints Remand Order*").

[19] Notice of the initiation of this proceeding was published in the *Fed. Reg.* on July 9, 2020 (Vol. 85, No. 132) p. 41,237. Aug. 24, 2020 was the first Business Day that was 45 days after publication.

December 2, 2020 Order. On December 2, the FERC issued an order[20] finding the price-lock mechanism and zero-price offer rule ("New Entrant Rules") no longer just and reasonable and directing ISO-NE to remove them from the Tariff.[21] Specifically, the FERC found that, "in light of changed circumstances, the New Entrant Rules are unjust and unreasonable because they result in unreasonable price distortion."[22] The FERC further found that the FCA price assurance that the FERC previously found necessary in approving these rules is no longer required to attract new entry, with the benefits provided by price certainty no longer outweighing their price suppressive effects. The FERC clarified that the "termination of the price lock will not impact price-lock agreements in effect prior to the issuance of the order".[23] FERC directed ISO-NE to submit a compliance filing, on or before February 1, 2021, eliminating the price lock and associated zero-price offer rule for new entrants starting in FCA16.[24]

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).

- **RNS/LNS Rates and Rate Protocols Settlement Agreement II (ER20-2054; EL16-19-002)**

The uncontested Joint Offer of Settlement ("Settlement Agreement II") filed by the Transmission Owners to resolve all issues in this proceeding,[25] certified by Presiding ALJ Coffman to the Commission,[26] remains pending before the Commission.[27] 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,[28] set the TOs' Base ROE at 10.57%

[20] *ISO New England Inc.*, 173 FERC ¶ 61,198 Dec. 2, 2020) ("*December 2 Order*").

[21] *Id.* at PP 1, 77.

[22] *Id.* at P 68.

[23] *Id.*

[24] *Id.*

[25] Recall that, as previously reported, the first joint offer of settlement filed ("Settlement Agreement I") 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. 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. However, Settlement Agreement I was contested by FERC Trial Staff and "Municipal PTF Owners" (Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford) and subsequently rejected by the FERC. *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement I Order*") (finding (i) 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"); and (ii) the RNS and LNS rates themselves "unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because "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").

[26] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 172 FERC ¶ 63,017 (Aug. 18, 2020).

[27] The Tariff changes included with Settlement Agreement II were considered through the Participants Processes (Transmission and Participants Committee review), and supported by the Participants Committee at its June 4, 2020 meeting (Agenda Item # 13). NEPOOL filed comments supporting the Tariff changes included with Settlement Agreement II. FERC Trial Staff filed comments not opposing Settlement Agreement II. The TOs filed reply comments supporting Settlement Agreement II.

[28] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarif.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

(reduced from 11.14%), capped the TOs' total ROE (Base ROE <u>*plus*</u> transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[29] However, the FERC's orders were challenged, and in *Emera Maine,*[30] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[31] and third (EL14-86)[32] 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.[33] 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[34] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[35] 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.[36] Parties in this

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[29] *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*").

[30] *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).

[31] 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%.

[32] 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.

[33] *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*").

[34] 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.

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

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

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.[37] 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*[38] (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.[39]

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%.[40] 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.

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

[38] *Ass’n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) (“*Opinion 569-A*”). The refinements to the FERC’s ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[39] *Id.* at P 19.

[40] *Id.* at P 59.

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[41] 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*[42] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

These matters remain pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER21-496)**

On November 25, 2020, ISO-NE and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2021-22 Capability Year, the second ARA for the 2022-23 Capability Year, and the first ARA for the 2023-24 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 5, 2020 meeting (Consent Agenda Items 3 and 4). A January 24, 2021 effective date was requested. Comments on this filing are due December 15, 2021. Thus far, Dominion and NRG have filed doc-less interventions. If you have any questions concerning these matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA15 Qualification Informational Filing (ER21-372)**

On November 10, 2020, ISO-NE submitted its informational filing (the "FCA15 Informational Filing") for qualification in FCA15. ISO-NE is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by ISO-NE for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA15 is scheduled to begin February 8, 2021. The Informational Filing contained ISO-NE's determinations that four Capacity Zones will be modelled for FCA15 -- Southeastern New England ("SENE"), Northern New England ("NNE"), the Maine Capacity Zone ("Maine"), and Rest of Pool. SENE will again be modeled as import-constrained; NNE will be modeled as export-constrained. The Maine Load Zone will be modeled as a separate nested export-constrained Capacity Zone within NNE. The Informational Filing reported that there will be 33,662 MW of existing capacity in FCA15 competing with 7,030 MW of new capacity under a Net ICR of 33,270 MW (ICR minus HQICCs). ISO-NE reported also that there were

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

[42] *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).

a total of 813 MW of Static De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 13 demand bids, totaling 196 MW, and 116 supply offers, totaling 463 MW, to participate in the substitution auction.

Comments on the FCA15 Informational Filing were due November 25, 2020. Limited protests were filed by Andro Hydro, Mystic and NEPGA. ***Andro Hydro*** protested the basis for the IMM's mitigation of its resources. ***NEPGA***'s limited protest focused on the qualification of the Killingly Energy Center, requesting that the FERC require ISO-NE to submit additional confidential information regarding that qualification (related to the project's development progress) so that it can assess ISO-NE's determinations. Mystic, for its part, asserted that the Informational Filing is based on a flawed transmission security analysis and the FERC should direct ISO-NE to re-run its transmission security analysis to reconsider its decision to assume completion of a now delayed and contentious NECEC transmission project when conducting that analysis. Doc-less interventions were filed by NEPOOL, NEPOOL, Boston Energy Trading and Marketing, Calpine, Dominion, Eversource, National Grid, NESCOE, and NRG. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ICR-Related Values and HQICCs – FCA15 (2024-25) Capacity Commitment Period (ER21-371)**

On November 10, 2020, ISO-NE filed the ICR, LSR for SENE, MCL for the Maine and NNE Capacity Zones, HQICCs, and Marginal Reliability Impact ("MRI") Demand Curves (collectively, the "2024-25 ICR-Related Values") for the 2024-25 Capacity Commitment Period ("CCP"). The 2024-25 ICR will be 34,153 MW (reflecting tie benefits of 1,735 MW) and HQICCs of 883 MW/mo., the net amount of capacity to be purchased in FCA15 to meet the ICR will be 33,270 MW. The LSR for the SENE Capacity Zone is 10,305 MW. The MCL for the Maine Capacity Zone is 4,145 MW. The MCL for the NNE Capacity Zone is 8,680 MW. The Participants Committee supported the FAC15 ICR-Related Values at its October 1, 2020 virtual meeting. Comments on this filing were due December 1; none were filed. Doc-less interventions were filed by Calpine, Dominion, Eversource, MA DPU, National Grid, NESCOE, and NRG. His matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sophia Browning (202-218-3904; sbrowning@daypitney.com).

- **2021 NESCOE Budget (ER21-113)**

This proceeding was initiated by ISO-NE's October 15, 2020 filing of the budget for funding NESCOE's 2021 operations. The 2021 Operating Expense Budget for NESCOE is $2,428,300. The amount to be recovered reflects true-ups from 2019 (over-collections of $1,067,405). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00626 per kilowatt ("kW") of Monthly Network Load. The 2021 NESCOE budget was supported by the Participants Committee at its October 1, 2020 meeting. Comments and any interventions are due on or before November 5. NEPOOL intervened and filed comments supporting NESCOE's 2021 Budget. Eversource, NESCOE and National Grid submitted doc-les interventions. This matter is pending before the FERC. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2021 ISO-NE Administrative Costs and Capital Budgets (ER21-106)**

On October 15, 2020, ISO-NE filed for recovery of its 2021 administrative costs (the "2021 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2021 ("2021 Capital Budget", and together with the 2021 Revenue Requirement, the "2021 ISO Budgets"). The 2021 ISO-NE Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 15 filing, ISO-NE reported that the 2021 Revenue Requirement is $205 million, which increases to $205.1 million after the under-collection for 2019 is added. Of that total, ISO-NE's administrative costs (i.e., the 2021 Core Operating Budget) comprise $178.6 million; depreciation and amortization of regulatory assets, $26.3 million; and a $151,000 true-up for 2019 under-collections.

ISO-NE further reported that the 2021 Capital Budget, like the 2020 Capital Budget, is $28 million and is comprised of the following (with 2021 projected costs and target completion dates, if available, in parentheses):

nGem Market Clearing Engine Implementation (Mar 2023)	($5.3 million)	Energy Security Improvements	($3.0 million)
nGem Software Development Part II (Dec 2021)	($2.0 million)	Forward Capacity Tracking System Infrastructure Conversation Part II (Dec 2020)	($2 million)
2021 Issue Resolution Projects (June 2021 and Dec 2021)	($1.5 million)	2020 Corrective Action Preventative Actions (Mar 2021)	($100,000)
Enhanced Market Simulator	($1.5 million)	CIP Electronic Security Perimeter Redesign	($1 million)
Forward Capacity Tracking System Infrastructure Conversation Part II (Jun 2021)	($1 million)	Cyber Security Improvements (Sep 2021)	($1 million)
Identity and Access Management – Phase II (May 2021)	($700,000)	Enterprise Application Integration Phase III (Nov 2021)	($500,000)
Data Governance, Risk Management & Compliance Software Phase I (Jun 2021)	($400,000)	Data Governance, Risk Management & Compliance Software Phase II (Nov 2021)	($500,000)
IMM Data Analysis Phase III (Nov 2021)	($500,000)	Human Resources Workflow & Document Management (Jun 2021)	($500,000)
Sub-accounts for FTR Market (Aug 2021)	($500,000)	Security Information and Event Management Log Monitoring	($500,000)
TranSMART Technical Architecture Update (Dec 2021)	($500,000)	PI Historian for Short-term PMU Data Repository (Jun 2021)	($300,000)
FERC Form 1, 3-Q, 714 (Oct 2021)	($200,000)	External Website Migration to Cloud (Mar 2021)	($100,000)
Wireless Infrastructure Upgrade (Jun 2021)	($200,000)	Non-Project Capital Expenditures	($3.5 million)
2020 Issue Resolution Projects (Mar 2021)	($100,000)	Other Emerging Work	($1.9 million)
		Capitalized Interest	($500,000)

The 2021 ISO-NE Budgets were supported by the Participants Committee at its October 1, 2020 meeting. Comments on this filing are due November 5, 2020. NEPOOL filed comments supporting the 2021 Budgets on October 28. Doc-less interventions were filed by Eversource, MA AG, National Grid, and NESCOE. The 2021 ISO-NE Budgets are pending before the FERC. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the

Cost-of-Service Agreement ("COS Agreement")[43] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. As noted in Section XV below, each of the *July 17 Orders*[44] (and the earlier, underlying orders) have been appealed to the DC Circuit.

ROE Paper Hearings (-000). The *Dec 2018 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, 2019, 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. In a July 28, 2020 order,[45] the FERC reopened the record to allow parties an opportunity to present written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding. CT Parties, EMCOS, MA AG, and FERC Trial Staff filed their initial "Opinion 569-A" briefs on September 28, 2020. Responses to those initial briefs were due October 28, 2020 and were filed by Mystic, CT Parties, ENECOS, and FERC Trial Staff. The ROE issue is now pending before the Commission.

Sep 2020 Compliance Filing (-007). On September 15, 2020, Mystic filed a revised COS Agreement in response to the requirements of the *July 17 Compliance Order*. Also included were typographical edits proposed by NESCOE in its protest of the First Compliance Filing. Mystic also filed revisions to the Fuel Security Agreement ("FSA") for informational purposes because some of the compliance directives required changes to the FSA. Comments on the Sep 2020 Compliance Filing were due on or before October 6, 2020. CT Parties and ENECOS protested the compliance filing. On October 21, Mystic answered the CT Parties' and ENECOS' protests. The compliance filing is pending before the FERC.

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

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

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

On October 30, 2020, the FERC rejected as unjust and unreasonable both the ISO-NE and NEPOOL "Energy Security Improvements" or "ESI" proposals.[46] Finding that ISO-NE failed to demonstrate that ESI will materially improve fuel security, and treating the filing as submitted under FPA section 205,[47] the FERC concluded that "ESI does not strike an appropriate balance between addressing fuel security in New England while protecting

[43] 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.

[44] The "*July 17 Orders*" are the *July 2018 Rehearing Order, Dec 2018* Rehearing *Order* and the *July 17 Compliance Order*. *Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020) ("*July 2018 Rehearing Order*"); *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020) ("*Dec 2018* Rehearing *Order*"); *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

[45] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,093 (July 28, 2020).

[46] *ISO New England Inc.*, 173 FERC ¶ 61,106 (Oct. 30, 2020) ("*Order Rejecting ESI Alternatives*"), *clarif. requested*.

[47] *Id.* at n. 2. The April 15, 2020 ESI 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*").

consumers from the significant cost of those fuel security benefits."[48] And, although the FERC noted that the NEPOOL Alternative would result in lower costs to consumers than ISO-NE's ESI proposal, they rejected the NEPOOL Alternative as unjust and unreasonable because it contained the "same deficiencies that render ISO-NE's proposal unjust and unreasonable."[49]

Because the FERC rejected both alternative ESI proposals, the FERC also rejected ISO-NE's associated proposal to sunset one year earlier than currently provided for in the Tariff the Fuel Security Retention Mechanism and the Inventoried Energy Program (the Interim Programs).[50]

The FERC made no finding on whether ISO-NE faces a fuel security or energy security issue,[51] but said ISO-NE may propose "other steps it believes are warranted to address fuel security, such as submitting a revised long-term fuel security proposal or seeking to extend one or more of the Interim Programs."[52] While the FERC did not direct ISO-NE to pursue any particular approach, if ISO-NE decides to pursue a solution to address their concerns, it encouraged ISO-NE:

> "to explore a market-based reserve product that provides resources sufficient lead time and ability to acquire fuel or take other steps necessary to be able to deliver energy when needed. We expect that such a market solution would be designed to (1) coordinate procurement of forward reserves with co-optimization of energy and reserves in the day-ahead and real-time markets; (2) incentivize resources to offer into the forward, day-ahead and real-time energy and reserves markets based on their actual costs; (3) prevent the exercise of market power, including through mitigation measures, if necessary; and (4) include financial obligations or incentives sufficient to ensure resources can deliver energy and/or reserves in real-time."[53]

The FERC noted that nothing in its order prohibits ISO-NE from proposing a Day-Ahead reserves market independent of any proposal to address the concerns at issue in the ESI proceeding.[54]

On November 13, ISO-NE requested clarification of the *Order Rejecting ESI Alternatives*. Specifically, ISO-NE asked the FERC to clarify that ISO-NE may engage in communications with the FERC and its staff about the ESI market design, the design of the reserve markets, the option construct, and the voluntary nature of the markets as of December 1, 2020, unfettered from any *ex parte* restrictions arising out of this or antecedent proceedings (e.g. ER18-1509 and EL18-182 (*see* ISO-NE Waiver Filing: Mystic 8 & 9 below)). ISO-NE further asked the FERC to act expeditiously on its request.

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).

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48 *Id.* at P 55.

49 *Id.* at P 56.

50 *Id.* at P 63.

51 *Id.* at P 57.

52 *Id.* at P 63.

53 *Id.* at P 57.

54 *Id.*

- ***Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)**

As previously reported, the FERC has now conditionally accepted both the November 22, 2019[55] and February 10, 2020[56] *Order 841*[57] compliance filings, each subject to additional compliance filing(s). In its most recent order, the *Order 841 Compliance Filing II Order*, the FERC directed that the following be addressed in further compliance (now due on or before December 7, 2020, as described below):

- ***Application of Transmission Charges***. ISO-NE directed to file proposed Tariff revisions: (i) specifying that it will not apply transmission charges to electric storage resources when they are dispatched to withdraw energy to provide voltage support and reactive control, provide operating reserves, provide regulation, balance energy supply and demand on an economic basis, or address a reliability concern; and (ii) applying transmission charges to electric storage resources when they are not being dispatched to provide one of those tariff-defined services.[58]
- ***ISO-NE Market Participation***. Section III.1.10.6(d)(ii) must be modified to either (i) eliminate any suggestion that a host utility could be allowed, through an unwillingness to support the necessary registration, metering, and accounting of the electric storage resource, to decide whether an electric storage resource may participate in the ISO-NE markets; or (ii) to clarify how the section does not serve as a barrier to the participation of electric storage resources.
- ***State of Charge and Duration Characteristics in the Day-Ahead Energy Market.*** Tariff Section III.1.10.6(d) must be modified to specify how ISO-NE will account for State of Charge and Duration Characteristics of electric storage resources in the Day-Ahead Energy Market. If new bidding parameters will be relied on, the Tariff must define those bidding parameters and the transmittal letter must explain how those bidding parameters will be incorporated into the Day-Ahead Energy Market engine. If "other means" will be relied on, the Tariff must specify those other means with sufficient detail and the transmittal letter must explain how those other means will account for State of Charge and Duration Characteristics of electric storage resources in the Day-Ahead Energy Market.

On September 10, 2020, the FERC accepted the joint request by NEPOOL and ISO-NE for a 35-day extension of time to submit all of the changes required by the *Order 841 Compliance Filing II Order* in one comprehensive compliance filing. That compliance filing must be filed on or before December 7, 2020, with plans for the Tariff changes to be proposed to be considered at the December 3 Participants Committee meeting (Consent Agenda Items 2 and 3). If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[55] *ISO New England Inc.*, 169 FERC ¶ 61,140 (Nov. 22, 2019) ("*Order 841 Initial Compliance Filing Order*").

[56] *ISO New England Inc.*, 172 FERC ¶ 61,125 (Aug. 4, 2020) ("*Order 841 Compliance Filing II Order*").

[57] *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*").

[58] *Order 841 Compliance Filing II Order* at P 52.

- **Fuel Security Retention Proposal (ER18-2364)**

Requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[59] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[60] 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.[61] On February 1, 2019, the FERC issued a tolling order to afford it additional time to consider the requests for rehearing, which remain pending. There has been no substantive activity since the Last Report. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)**

On July 2, 2018, the FERC issued an order[62] 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

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[59] *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.

[60] 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").

[61] "PIOs" for purposes of this proceeding are Sierra Club, NRDC, Sustainable FERC Project, and Acadia Center.

[62] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

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)."[63] 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."[64]

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).[65] 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.[66] 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[67] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[68]

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);
- ***Connecticut Parties***[69] (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

[63] *Id.* at P 47.

[64] *Id.* at P 48.

[65] *Id.* at P 55.

[66] *Id.* at PP 56-57.

[67] *Id.* at P 57.

[68] *Id.* at P 58.

[69] "Connecticut Parties" are CT PURA and CT DEEP.

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***[70] (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***[71] (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 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, 2018, 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, 2018, the Indicated New England EDCs answered the August 14/16 answers. On August 27, 2018, the FERC issued a tolling order to afford it additional time to consider the requests for rehearing, which remain pending.

There has been no substantive activity since the Last Report. 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)**

On November 19, 2020, the FERC issued an "Allegheny Order"[72] addressing arguments raised in requests for rehearing of the *CASPR Order*[73] by (i) ***NextEra/NRG*** (challenging the RTR Exemption Phase Out); (ii) ***ENECOS***[74]

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70 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).

71 "PIOs" are the Sierra Club, Natural Resources Defense Council ("NRDC"), and Sustainable FERC Project.

72 *ISO New England Inc.*, 173 FERC ¶ 61,161 (Nov 19, 2020) ("*CASPR Allegheny Order*")

73 *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*"), *reh'g denied* 173 FERC ¶ 61,161 (Nov. 19, 2020).

74 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,

(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***[75] (challenging the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (also challenged the CASPR construct in its entirety and the *CASPR Order*'s failure to define "investor confidence"). While "[p]ursuant to *Allegheny Defense Project v. FERC*, the rehearing requests filed in this proceeding may be deemed denied by operation of law … as permitted by section 313(a) of the FPA, [the FERC modified] the discussion in the *CASPR Order* and reach[ed] the same result."[76] As reported in Section XV below, Sierra Club, NRDC, RENEW, and CLF have petitioned the DC Circuit for review of the *CASPR Order* (Case No. 20-1333), and further developments will be summarized in that Section. 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).

IV. OATT Amendments / TOAs / Coordination Agreements

No Activities to Report

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-VP: 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, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P] 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 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-VP: 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*

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.

[75] For purposes of this proceeding, "Clean Energy Advocates" are, collectively, the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

[76] *CASPR Allegheny Order* at P 2.

Order,[77] and certified by Settlement Judge Dring[78] to the Commission,[79] 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 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).

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*[80] *and 531-B*[81] 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).

[77] *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.

[78] 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.

[79] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

[80] *Martha Coakley, Mass. Att'y Gen.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[81] *Martha Coakley, Mass. Att'y Gen.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

- **Capital Projects Report - 2020 Q3 (ER21-108)**

On October 15, 2020, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") 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) nGEM Market Clearing Engine Implementation ($13,900,500); and (ii) CELT Report Automation Phase I ($155,500) The following three projects had significant changes: (i) ESI (2020 Budget decrease of $1 million); (ii) 2020 Issue Resolution Project Part II (2020 Budget decrease of $540,000); (iii) Energy Management Platform 3.2 Upgrade Part II (2020 Budget increase of $250,000); and (iv) Enterprise Application Integration Replacement Phase I (2020 Budget increase of $100,000). Comments on this filing were due on or before November 5. NEPOOL filed comments on October 30 supporting the filing. Eversource and National Grid submitted doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q3 2020 (ER19-1951)**

On November 13, 2020, ISO-NE filed, as required,[82] public and confidential[83] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Third Quarter of 2020 ("2020 Q3"). ISO-NE reported that five of the six 2020 Q3 ***Interconnection Feasibility Study ("IFS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[84] In addition, three IFS Reports that are not yet completed have exceeded the 90 day completion expectation. The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 251.1 days (up from 240 in 2020 Q2). Three ***System Impact Study ("SIS") reports*** were delivered to Interconnection Customers, with two delivered later than the best efforts completion timeline of 270 days. The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 458 days (up from 227 in 2020 Q2). There were no Interconnection Requests with projects in the Interconnection Facilities Study phase of the interconnection process. Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

- **IMM Quarterly Markets Reports – Summer 2020 (ZZ21-4)**

On November 12, 2020, the IMM filed with the FERC its Summer 2020 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Summer 2020 Report will be discussed with the Markets Committee at the December 8-9, 2020 Markets Committee meeting.

- **ISO-NE FERC Form 3Q (2020/Q3) (not docketed)**

On November 24, ISO-NE submitted its 2020/Q3 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which

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[82] Under section 3.5.4 of ISO-NE's Large Generator Interconnection Procedures ("LGIP"), ISO-NE must submit an informational report to the FERC describing each study that exceeds its Interconnection Study deadline, the basis for the delay, and any steps taken to remedy the issue and prevent such delays in the future. The Exceedance Report must be filed within 45 days of the end of the calendar quarter, and ISO-NE must continue to report the information until it reports four consecutive quarters where the delayed amounts do not exceed 25 percent of all the studies conducted for any study type in two consecutive quarters.

[83] ISO-NE requested that the information contained in Section 3 of the un-redacted version of the Exceedance Report, which contains detailed information regarding ongoing Interconnection Studies and if released could harm or prejudice the competitive position of the Interconnection Customer, be treated as confidential under FERC regulations.

[84] 90 days from the Interconnection Customer's execution of the study agreement.

supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **December 2020 Membership Filing (ER21-499)**

On November 30, 2020, NEPOOL requested that the FERC accept the termination of the Participant status of the following: Eagle's View Partners, Ltd.; Goose River Hydro, Inc.; Patriot Partnership LLC; SFE Energy Connecticut, Inc., and Emera Energy Services Subsidiary No. 9 LLC. Comments on this filing are due on or before December 21, 2020.

- **November 2020 Membership Filing (ER21-260)**

On October 30, 2020, NEPOOL requested that the FERC accept the membership of Nautilus Solar Energy, LLC (AR Sector, RG Sub-Sector, Large AR RG Group Seat). Comments on this filing are due on or before November 20, 2020; none were filed. This matter is pending before the FERC.

- **October 2020 Membership Filing (ER20-3031)**

On November 18, 2020, the FERC accepted the membership of David Energy Supply, LLC (Supplier Sector).[85] Unless the November 18 order is challenged, this proceeding will be concluded.

- **Invenia Additional Conditions Informational Filing (ER20-2001)**

Still pending before the FERC is the June 5, 2020 informational filing submitted by ISO-NE pursuant to Section II.A.1(b) of the FAP identifying the additional condition (supplemental financial assurance) required of Invenia for participation in the New England Markets. The additional condition was supported, and made a condition of Invenia's membership, by the Participants Committee at its June 4 meeting. A doc-less intervention was submitted by Public Citizen. This informational filing is still pending before the FERC.

- **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 Market Participant was 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***	***Default Type***	***Date Reinstated***
Nov 18/20	Manchester Methane, LLC	Financial Assurance	--

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

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

85 *New England Power Pool Participants Comm.*, Docket No. ER20-3031 (Nov. 18, 2020).

- **Joint Staff White Papers on Notices of Penalty for Violations of CIP Standards (AD19-18)**

On September 23, 2020, following review of the comments submitted on their First White Paper,[86] FERC and NERC staff ("Joint Staffs") issued their second White Paper on Notices of Penalty Pertaining to Violations of Cortical Infrastructure Protection ("CIP") Reliability Standards ("Second White Paper"). Having determined based on those comments that the First White Paper proposal was insufficient to protect the security of the BPS, Joint Staffs modified the prior proposal. Going forward, CIP noncompliance submissions[87] will be filed or submitted by NERC with a request that the *entire* filing or submittal be designated as Critical Energy/Electric Infrastructure Information ("CEII") and FERC staff will designate the entire filing or submittal accordingly. Because of the risk associated with the disclosure of CIP noncompliance information, NERC will no longer publicly post redacted versions of CIP noncompliance filings and submittals.

- **CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects (RD20-2)**

On March 19, 2020, NERC submitted, as directed by the FERC,[88] an informational filing describing the activity of two NERC CIP standard drafting projects pertaining to virtualization and cloud computing services, including a schedule for Project 2016-02 (Modifications to CIP Standards) and Project 2019-02 (BES Cyber System Information Access Management) (collectively, the "NERC Projects"). Comments were submitted by a private citizen (Barry Jones) and VMware, Inc. on April 21 and 27, 2020, respectively.

In addition, NERC is required to file on an information basis quarterly status updates, until such time as new or modified Reliability Standards are filed with the FERC. NERC filed its third informational filing on September 17, 2020, reporting a three-month deferral for each Project underway. With respect to Project 2016-02, NERC reported that "the standard drafting team anticipates filing the proposed Reliability Standards with the Commission in March 2022 (deferred from the original target date of December 2021)." With respect to Project 2019-02, NERC reported that "the standard drafting team anticipates filing the proposed Reliability Standards with the Commission in March 2021 (deferred from the December 2020 target date provided in the June Informational Filing)." On November 13, NERC supplemented its filings in this proceeding to provide a schedule update. NERC anticipates filing proposed Reliability Standards from each project in December 2021.

- **Revised Reliability Standard: CIP-002-6 (RM20-17)**

On June 12, 2020, NERC filed for approval a revised Reliability Standard -- CIP-002-6 (Cyber Security – BES Cyber System Categorization), and associated implementation plan, VRFs and VSLs (together, the "CIP-002 Changes"). NERC stated that the CIP-002 Changes improve upon the currently effective standard by clarifying the criterion for Transmission Owner Control Centers and tailoring the language to better reflect the risk posed by

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[86] The first White Paper, prepared jointly by FERC and NERC staff, was issued on August 27, 2019. The First White Paper set out a proposed new format for NERC Notices of Penalty ("NOP") involving violations of CIP Reliability Standards. The First White Paper explained that the revised format was 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.

Few commenters supported the First Joint White Paper proposal without seeking modifications to either expand or reduce the amount of information that would be publicly disclosed. Comments submitted by private citizens, state representatives, and consumer advocate offices supported more disclosure of CIP noncompliance information. By contrast, most industry commenters and trade organizations raised concerns with at least some of the proposed disclosures because of the increased risk to the security of the Bulk-Power System ("BPS").

[87] Non-compliance submissions include Notices of Penalty ("NOPs"), Spreadsheet NOPs ("SNOPs"), Find, Fix and Track submissions ("FFTs") and Compliance Exceptions ("CEs")).

[88] *N. Am. Elec. Rel. Corp.*, 170 FERC ¶ 61,109 (Feb. 20, 2020).

these Control Centers if unavailable or compromised. As of the date of this Report, the FERC has still not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **NOI: Enhancements to CIP Standards (RM20-12)**

On June 18, 2020, the FERC issued a notice of inquiry ("NOI") seeking comments on certain potential enhancements to the currently-effective CIP Reliability Standards. In particular, the FERC asked for comments on whether the CIP Standards adequately address: (i) cybersecurity risks pertaining to data security, (ii) detection of anomalies and events, and (iii) mitigation of cybersecurity events. In addition, the FERC asked for comments on the potential risk of a coordinated cyberattack on geographically distributed targets and whether FERC action including potential modifications to the CIP Standards would be appropriate to address such risk.

Comments were filed by NERC, the ISO/RTO Council ("IRC"), APPA/LPPC, Canadian Electricity Assoc. ("CEA"), Cogentrix, EEI/EPSA, Forescout Technologies, MISO TOs, NJ BPU, NRECA, Reliable Energy Analytics, Southwestern Power Administration, Solar Energy Industries Association ("SEIA"), Siemen's Energy, Southern Companies, TAPS, U.S. Bureau of Reclamation, U.S Corp of Army Engineers, Western Area Power Administration ("WAPA"), Wolverine Power Supply Cooperative, XTec, and J. Applebaum, J. Christopher/T. Conway, and J. Cotter. No reply comments were filed. This matter is pending before the FERC.

- **NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)**

On February 20, 2020, the FERC issued a NOI seeking comments on (i) the potential benefits and risks associated with the use of virtualization and cloud computing services in association with bulk electric system ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization or cloud computing services.[89] On March 25, 2020, Joint Associations[90] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft. This matter is pending before the FERC.

- ***Order 873*** **- Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[91] concluding that the 18 requirements "(1) provide little or no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[92] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4

[89] *Virtualization and Cloud Computing Services*, 170 FERC ¶ 61,110 (Feb. 20, 2020).

[90] "Joint Associations" are for purposes of this proceeding: EEI, APPA, NRECA, and LPPC.

[91] *Elec. Rel. Org. Proposal to Retire Reqs. in Rel. Standards Under the NERC Standards Efficiency Review*, Order No. 873, 172 FERC ¶ 61,225 (Sep. 17, 2020) ("*Order 873*"). The four Reliability Standards being eliminated in their entirety are FAC-013-2 (Assessment of Transfer Capability for the Near-term Transmission Planning Horizon), INT-004-3.1 (Dynamic Transfers), INT-010-2.1 (Interchange Initiation and Modification for Reliability), MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operations and Reliability Coordinators). The five modified Reliability Standards are INT-006-5 (Evaluation of Interchange Transactions), INT-009-3 (Implementation of Interchange) and PRC-004-6 (Protection System Misoperation Identification and Correction), IRO-002-7 (Reliability Coordination—Monitoring and Analysis), TOP-001-5 (Transmission Operations).

[92] *Order 873* at P 2.

requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[93]

The FERC left for another day its final action on the remaining 56 requirements for which the FERC proposed to approve retirement in the *Retirements NOPR*[94] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices pending in the *NAESB WEQ v. 003.3 Standards NOPR* (*see* Section XII below).[95]

- **Amended and Restated NERC Bylaws (RR21-1)**

On October 14, 2020, NERC petitioned the FERC for approval of its amended and restated Bylaws. NERC stated that the amendments (i) address governance matters relating to the composition of NERC's membership Sectors, certain rules relating to the Member Representatives Committee, as well as the qualification of independent trustees for the Board; (ii) update certain provisions to conform with applicable state law; and (iii) improve internal consistency and introduce ministerial changes within the Bylaws with respect to capitalizing defined terms consistently and removing inoperative provisions. Comments, if any, on the Amended and Restated Bylaws were due on or before November 4, 2020; none were filed. This matter is pending before the FERC.

- **Report of Comparisons of Budgeted to Actual Costs for 2019 for NERC and the Regional Entities (RR20-3)**

Still pending before the FERC is the comparisons of actual to budgeted costs for 2019 for NERC and the seven Regional Entities operating in 2019, including NPCC, filed by NERC on May 29, 2020. 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 were due on or before June 19, 2020; none were filed. On July 21, 2020, NERC supplemented its May 29, 2020 filing to include the final, audited 2019 financial report for Texas Reliability Entity, Inc. ("Texas RE") (not available to be included at the time of the May 29 filing). As noted, this matter remains pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: CPV Towantic (EC21-16)**

On October 29, 2020, CPV Towantic, LLC ("CPV Towantic"), among others, requested authorization for a transaction whereby CPV Group LP will indirectly acquire all of the indirect voting securities owned by GIP II CPV Intermediate Holdings Partnership, L.P., ("GIP II CPV"). Upon consummation, Clearway Power Marketing and GenConn Energy will no longer be CPV Related Persons. A FERC order approving the transaction on or before December 28, 2020 was requested. Comments on this application were due on or before November 19, 2020; none were filed. This application is pending before the FERC.

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[93] *Order 873* at P 5. Pursuant to FPA section 215(d)(4), if the FERC disapproves a modification to a Reliability Standard in whole or in part, it must remand the entire Reliability Standard to NERC for further consideration. Accordingly, although it was satisfied here with the justification for the retirement of R7, the FERC was required to remand both R7 and R8 so that its concerns with the retirement of Requirement R8 could be addressed.

[94] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020) ("*Retirements NOPR*") (proposing to approve the retirement of 74 of 77 Reliability Standard requirements requested to be retired by NERC in these two dockets in connection with the first phase of work under NERC's Standards Efficiency Review, an initiative begun in 2017 that reviewed the body of NERC Reliability Standards to identify those Reliability Standards and requirements that were administrative in nature, duplicative to other standards, or provided no benefit to reliability). As previously reported, NERC withdrew its proposed changes to VAR-001-6 on May 14, 2020, reducing to 76 the number of requirements proposed to be retired.

[95] *Standards for Business Practices and Communication Protocols for Public Utilities*, 85 Fed. Reg. 55201 (September 4, 2020).

- **203 Application: Millennium Power Partners (EC20-103)**

  On November 18, 2020, the FERC authorized a transaction whereby Beal Bank USA, Beal Bank, SSB or their designee(s) ("Beal Bank") will acquire all of the membership interests in Millennium Power Partners, L.P. ("Millennium") and New Athens Generating Company, LLC (which owns facilities in New York) from Talen. Pursuant to the November 18 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.

- **203 Application: NRG/Direct (EC20-96)**

  On November 24, 2020, the FERC authorized NRG's acquisition of, among others, Direct Energy Business and Direct Energy Business Marketing (together, "Direct").[96] Pursuant to the November 24 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.

- **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.[97] 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.

- **VTransco Rate Schedule 2 Cancellation (ER21-256)**

  On October 29, 2020, Vermont Transco filed a notice of cancellation of the Vermont Yankee Transmission Agreement, which is no longer in use. A December 28, 2020 effective date was requested. Comments on the notice of cancellation were due on or before November 19, 2020; none were filed. Eversource and National Grid filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Ocean State Power (ER21-192)**

  On October 23, 2020, NSTAR filed a Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between itself and Ocean State Power. The D&E Agreement sets forth the terms and conditions under which NSTAR will undertake preliminary design and engineering activities to increase the real power capacity of Ocean State Power's large generating facility. NSTAR requested that the D&E Agreement be accepted for filing as of the date of filing, or October 23, 2020. Comments on this filing were due on or before November 13, 2020; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NECEC TSAs: NECEC Transmission Notices of Succession and CMP Notice of Cancellation (ER21-12 et al.)**

  On November 30, 2020, the FERC accepted notices addressing the transfer of the 7 transmission service agreements ("TSAs") with the participants that will fund the construction, operation and maintenance of the NECEC Transmission Line.[98] Once the transfer of the TSAs from CMP to NECEC Transmission is consummated (see EC20-24 above), NECEC will succeed to CMP's position in the TSAs and CMP will no longer be a party to the TSAs. As a result, NECEC filed notices of succession to the TSAs99 and CMP filed a notice cancelling the TSAs as CMP Rate Schedules in the FERC's eTariff database. The notices are to be effective as of

[96] *NRG Energy, Inc. et al.*, 173 FERC ¶ 62,103

[97] *Central Maine Power Co.*, 170 FERC 62,145 (Mar. 13, 2020).

[98] *NECEC Transmission LLC*, Docket No. ER21-12-000 (Nov. 30, 2020).

[99] The NECEC Transmission succession notices to the 7 TSAs were separately docketed as follows: Eversource (ER21-12); National Grid (ER20-13); Unitil (ER21-14); HQ US/Eversource (ER21-15); HQ US/National Grid (ER21-17); HQ US/Unitil (ER21-18); and HQ US Additional (ER21-19).

the date the transaction is consummated. Unless the November 30 order is challenged, these proceedings will be concluded. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Vineyard Wind (ER20-2915)**

On November 16, 2020, the FERC accepted NSTAR's notice of cancellation of its Design and Engineering Agreement ("D&E Agreement") with Vineyard Wind. The D&E Agreement set forth the terms and conditions under which CL&P undertook preliminary engineering and design activities for the Vineyard Wind interconnection facilities prior to execution of the LGIA. The D&E Agreement terminated by its terms as of the effective date of the LGIA. The notice of cancellation was accepted effective as of July 10, 2020, coinciding with the effective date of the LGIA. Unless the November 16 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).

- ***Orders 864/864-A*** **(Public Util. Trans. ADIT Rate Changes):** ***New England Compliance Filings*** **(various)**

In accordance with *Order 864*[100] and *Order 864-A,*[101] and extensions of time granted, New England's public utilities with transmission have submitted their Order 864 compliance filings, with the specific dockets and filing dates identified in the following table (all remain pending):

Date Filed	Docket	Transmission Provider	Date Accepted
Oct 30, 2020	ER21-311	Green Mountain Power	pending
Aug 5, 2020	ER20-2614	New England Power Support Agreement	pending
Aug 5, 2020	ER20-2610	CL&P	pending
Aug 5, 2020	ER20-2609	NSTAR	pending
Aug 5, 2020	ER20-2608	PSNH	pending
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594	VTransco	pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 30, 2020	ER20-2572	New England TOs	pending
Jul 15, 2020	ER20-2429	CMP	pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020	ER20-2133	Versant Power	pending
May 18, 2020	ER20-1839	VETCO	Pending
Feb 26, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

[100] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess 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.

[101] *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*").

- **FERC Enforcement Action: CES/Silkman (IN12-12; IN12-13)**

On November 23, 2020, the FERC approved a Stipulation and Consent Agreement with Competitive Energy Services, LLC and Richard Silkman (collectively "CES")[102] that resolved FERC's findings that CES violated the FERC's Anti-Manipulation Rule in its conduct, during a July 2007 to February 2008 period, with respect to its clients' (Rumford Paper Company) participation in ISO-NE's Day-Ahead Load Response Program ("DALRP"). As reported many years ago, the FERC issued orders assessing civil penalties against CES[103] and had been pursuing CES in Federal Court for payment of those penalties. The Stipulation and Consent Agreement also resolves those federal court proceedings. Under the Settlement, CES and Silkman must ***disgorge $166,841*** to ISO-NE, to be allocated by ISO-NE in its discretion for the benefit of ISO-NE customers, and ***pay $1.3 million in civil penalties*** to the United States Treasury. The settlement amount is to be paid in annual installments of $210,714.28 a year for seven years. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

XII. Misc. - Administrative & Rulemaking Proceedings

- **ISO/RTO Credit Principles and Practices (AD21-6; AD20-6)**

On November 4, 2020, the FERC issued a notice that staff will convene a February 25-26, 2021 technical conference to discuss principles and best practices for credit risk management in ISO/RTOs. The conference may address the following aspects of credit policy: ISO/RTO credit and risk management infrastructure; best practices and principles underlying capitalization requirements, financial security requirements, and unsecured credit allowances; the applicability of Know Your Customer ("KTC") protocols and other counterparty risk management tools; considerations for implementing FTR-specific credit policies, such as a mark-to-auction mechanism; and the relationship between credit policy and wholesale electric market design. Commissioners may participate in the technical conference. Individuals interested in participating as panelists should submit a self-nomination form by December 11, 2020 at: https://ferc.webex.com/ferc/onstage/g.php?MTID=e2b36f2a0411532188b8cd973144668ff. The conference will be open for the public to attend. Supplemental notice(s) will be issued prior to the technical conference with further details regarding the agenda and organization of the conference.

Recall that, as previously reported, Energy Trading Institute[104] requested that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[105] and Section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by ISO/RTOs. The FERC issued a notice of and received comments on ETI's request (AD20-6) in early 2020. The February technical conference is responsive to that request. Reporting on developments in this proceeding will continue under AD21-6 n future reports.

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[102] *Competitive Energy Services, LLC and Richard Silkman*, 173 FERC ¶ 61,176 (Nov. 25, 2020).

[103] *Richard Silkman*, 144 FERC ¶ 61,164 (2013); *Richard Silkman*, 140 FERC ¶ 61,033 (2012); *Competitive Energy Services, LLC*, 144 FERC ¶ 61,163 (2013).

[104] 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."

[105] *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.

- **Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) (AD20-18)**

On October 27, 2020, the FERC convened a staff-led technical conference to consider whether and how existing RTO and ISO interconnection, merchant transmission and transmission planning frameworks can accommodate anticipated growth in offshore wind generation in an efficient or cost-effective manner that safeguards open access transmission principles. The conference also provided an opportunity for participants to discuss possible changes or improvements to the current regulatory frameworks that may accommodate such growth. Speaker materials are posted in eLibrary.

- **Carbon Pricing in RTO/ISO Markets Tech Conf (Sep 30, 2020) (AD20-14)**

On September 30, 2020, the FERC convened a Commissioner-led technical conference to discuss considerations related to state adoption of mechanisms to price carbon dioxide emissions, commonly referred to as carbon pricing, in regions with FERC-jurisdictional organized wholesale electricity markets. The September 30 conference was a response to (i) the April 14, 2020 request by Interest Parties,[106] who asserted that a technical conference "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" complementing "state, regional, and national discussions currently taking place" as well as to (ii) the more than 30 sets of comments on the request that were filed. Speaker opening remarks (including those of Gordon van Welie, Matt White, and other New England stakeholders), and comments are posted in eLibrary, as is a transcript of the conference.

Notice of Proposed Policy Statement. Following the technical conference, on October 15, 2020, the FERC issued a Notice of Proposed Policy Statement.[107] The FERC stated that the *Proposed Policy Statement* is "to clarify the Commission's jurisdiction over RTO/ISO market rules that incorporate a state-determined carbon price and to encourage RTO/ISO efforts to explore and consider the benefits of potential [FPA] section 205 filings to establish such rules." Specifically, the FERC proposed "to make it the policy of this Commission to encourage efforts by RTOs/ISOs and their stakeholders—including States, market participants, and consumers—to explore establishing wholesale market rules that incorporate state-determined carbon prices in RTO/ISO markets."[108] The FERC solicited comment on whether the following information and considerations it identified are "germane to the Commission's evaluation of a section 205 filing to determine whether an RTO/ISO's market rules that incorporate a state-determined carbon price in RTO/ISO markets are just, reasonable and not unduly discriminatory or preferential" or whether different or additional considerations may be or must be taken into account:

a. How, if at all, do the relevant market design considerations change depending on the manner in which the state or states determine the carbon price (e.g., price-based or quantity-based methods)? How will that price be updated?

b. How does the FPA section 205 proposal ensure price transparency and enhance price formation?

c. How will the carbon price or prices be reflected in LMP?

d. How will the incorporation of the state-determined carbon price into the RTO/ISO market affect dispatch? Will the state-determined carbon price affect how the RTO/ISO co-optimizes energy and ancillary services? Are any reforms to the co-optimization rules necessary in light of the state-determined carbon price?

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[106] "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.

[107] *Carbon Pricing in Organized Wholesale Electricity Markets*, 173 FERC ¶ 61,062 (Oct. 15, 2020) ("*Proposed Policy Statement*").

[108] *Id.* at P 15.

e. Does the proposal result in economic or environmental leakage? How does the proposal address any such leakage?

Comments on the *Proposed Policy Statement* were due by November 16, 2020 and were filed by, among others: NEPOOL, NESCOE, AEE, Brookfield, Calpine, Eversource, HQUS, LSP Power, MA AG, National Grid, NEPGA, and NRG. Reply comments were due by December 1, 2020, and were filed by 10 parties, including Exelon, EPSA, NRG, the NY PSC. This matter is pending before the FERC.

- **Hybrid Resources Technical Conference Tech Conf (Jul 23, 2020) (AD20-9)**

On July 23, 2020, the FERC convened a technical conference to discuss technical and market issues prompted by growing interest in projects that are comprised of more than one resource type at the same plant location ("hybrid resources"). The focus was on generation resources and electric storage resources paired together as hybrid resources. Speaker materials have been posted to the FERC's eLibrary.

On August 10, 2020, the FERC invited interested persons to file post-technical conference comments to address issues raised during the technical conference and identified in the Supplemental Notice of Technical Conference issued July 13, 2020. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO, PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street institute, Savion, and SEIA. This matter is pending before the FERC.

- **RTO/ISOs Common Performance Metrics (AD19-16)**

With Office of Management and Budget ("OMB") approval, FERC staff has reinstated and revised its information collection form, FERC-922, on the Performance Metrics for ISOs, RTOs, and Regions Outside ISOs and RTOs. FERC staff expects to collect Common Metrics information every two years. The revised data collection, after additions and deletions, consists of twenty-nine Common Metrics.[109] RTO/ISOs were encouraged to submit responsive information by October 30, 2020. ISO-NE submitted its information on October 30, 2020. The ISO-NE submittal will not be noticed for public comment.

- **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)[110] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[111] 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

[109] There are seven ***Group 1 metrics***: Reserve Margins, Average Heat Rates, Fuel Diversity, Capacity Factor by Technology Type, Energy Emergency Alerts (("EEA") Level 1 or Higher), Performance by Technology Type during EEA Level 1 or Higher, and Resource Availability (Equivalent Forced Outage Rate Demand ("EFORd")). There are 12 ***Group 2 metrics***: Number and Capacity of Reliability Must-Run Units, Reliability Must-Run Contract Usage, Demand Response Capability, Unit Hours Mitigated, Wholesale Power Costs by Charge Type, Price Cost Markup, Fuel Adjusted Wholesale Energy Price, Energy Market Price Convergence, Congestion Management, Administrative Costs, New Entrant Net Revenues, and Order No. 825 Shortage Intervals and Reserve Price Impacts; There are 10 ***Group 3 metrics***: Net Cost of New Entry ("Net CONE") Value, Resource Deliverability, New Capacity (Entry), Capacity Retirement (Exit), Forecasted Demand, Capacity Market Procurement and Prices, Capacity Obligations and Performance Assessment Events, Capacity Over-Performance, Capacity Under-Performance, and Total Capacity Bonus Payments and Penalties. The update metrics eliminate previously-collected metrics on reliability, RTO/ISO billing controls and customer satisfaction, interconnection and transmission processes, and system lambda.

[110] *Grid Rel. and Resilience Pricing*, 162 FERC ¶ 61,012 (Jan. 8, 2018), *reh'g requested*.

[111] 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.

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 to afford 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[112] 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 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"[113] 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.

[112] 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."

[113] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

- **NOPR: Managing Transmission Line Ratings (RM20-16)**

On November 19, 2020, the FERC issued a NOPR[114] proposing to reform both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, the NOPR proposes to require: transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s). Comments on the *Managing Transmission Line Ratings NOPR* are due [60 days after the publication date of the *Managing Transmission Line Ratings NOPR* in the *Federal Register*].[115]

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

On March 20, 2020, the FERC issued a NOPR[116] proposing to revise its existing transmission incentives policy and corresponding regulations.[117] 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.
- ♦ ***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. Over 80 sets of comments on the proposed revisions were filed on or before the July

[114] *Managing Transmission Line Ratings*, 173 FERC ¶ 61,165 (Nov. 19, 2020) ("*Managing Transmission Line Ratings NOPR*").

[115] As of the date of this Report, the *Managing Transmission Line Ratings NOPR* has not been published in the *Federal Register*.

[116] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (Mar. 20, 2020) ("*Electric Transmission Incentives NOPR*").

[117] 18 CFR 35.35 (2020).

1, 2020[118] comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES. The NOPR is now pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 872-A*: Pricing and Eligibility Changes to PURPA Regulations (RM19-15)**

As previously reported, the FERC issued on July 16, 2020 its final rule[119] approving pricing and eligibility revisions to its long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[120] Requests for rehearing and/or clarification of *Order 872* were filed by California Utilities, EPSA, Northwest Coalition, One Energy Enterprises, Public Interest Organizations, SEIA, and Thomas Mattson. On September 17, 2020, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[121] The Notice confirmed that the 60-day period during which a petition for review of *Order 872* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 872*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

Consistent with its September 17, 2020 notice, the FERC issued on November 19, 2020 an order addressing arguments raised on rehearing.[122] *Order 872-A* modified the discussion in *Order 872*, reached the same result, but clarified, in part, *Order 872*. Specifically, *Order 872-A* provided clarification on (1) states' use of tiered avoided cost pricing; (2) states' use of variable energy rates in QF contracts and availability of utility avoided cost data; (3) the role of independent entities overseeing competitive solicitations; (4) the circumstances under which a small power production QF needs to recertify; (5) application of the rebuttable presumption of separate sites for the purpose of determining the power production capacity of small power production facilities; and (6) the PURPA section 210(m) rebuttable presumption of nondiscriminatory access to markets and accompanying regulatory text.

Thus far, petitions for the review of *Order 872* have been filed with the 9th Circuit Court of Appeals by SEIA and Montana Environmental Information Center (*see* Section XV below). If you have any questions, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Order 2222*: DER Participation in RTO/ISO Markets (RM18-9)**

On September 17, the FERC issued a final rule ("*Order 2222*")[123] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[124] aggregations in the RTO/ISO markets.

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[118] The *Electric Transmission* Incentives NOPR was published in the *Fed. Reg.* on Apr. 2, 2020 (Vol. 85, No. 64) pp. 18,784-18,810. Requests for extension of time to file comments were filed by American Manufacturers, APPA/TAPS, and State Entities; WIRES and EEI each opposed the requested extensions. No extension of time to file comments was granted.

[119] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (July 16, 2020) ("*Order 872*").

[120] 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.

[121] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 62,154 (Sep. 11, 2020), *clarif. granted in part*, 173 FERC ¶ 61,158 (Nov. 19, 2020).

[122] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order 872-A, 173 FERC ¶ 61,158 (Nov. 19, 2020) ("*Order 872-A*").

[123] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (Sep. 17, 2020).

[124] The FERC defined a DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."

Order 2222 requires each RTO/ISO to revise its tariff to ensure that its market rules facilitate the participation of DER aggregations. Specifically, the tariff provisions addressing distributed energy resource aggregations must:

(1) allow distributed energy resource aggregations to participate directly in RTO/ISO markets and establish distributed energy resource aggregators as a type of market participant;

(2) allow distributed energy resource aggregators to register distributed energy resource aggregations under one or more participation models that accommodate the physical and operational characteristics of the distributed energy resource aggregations;

(3) establish a minimum size requirement for distributed energy resource aggregations that does not exceed 100 kW;

(4) address locational requirements for distributed energy resource aggregations;

(5) address distribution factors and bidding parameters for distributed energy resource aggregations;

(6) address information and data requirements for distributed energy resource aggregations;

(7) address metering and telemetry requirements for distributed energy resource aggregations;

(8) address coordination between the RTO/ISO, the distributed energy resource aggregator, the distribution utility, and the relevant electric retail regulatory authorities;

(9) address modifications to the list of resources in a distributed energy resource aggregation;

(10) address market participation agreements for distributed energy resource aggregators; and

(11) Accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year. An RTO/ISO must not accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed 4 million MWhs or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers to be bid into RTO/ISO markets by a DER aggregator.

Each RTO/ISO must file the tariff changes needed to implement the requirements of *Order 2222* on or before July 19, 2021.[125] To the extent that an RTO/ISO proposes to comply with any or all of the requirements in *Order 2222* using its currently effective requirements for distributed energy resources, it must demonstrate on compliance that its existing approach meets *Order 2222*'s requirements.

Requests for Rehearing Denied by Operation of Law. Requests for clarification and/or rehearing of *Order 2222* were filed by Excel Energy Services, the Kansas Corporation Commission, AEE and AEMA, and Public Interest Organizations.[126] On November 19, 2020, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[127] The Notice confirmed that the 60-day period during which a petition for review of *Order 2222* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 2222*. The Notice also indicated that the FERC would address, as is its right,

[125] *Order 2222* was published in the *Fed. Reg.* on Oct. 21, 2020 (Vol. 85, No. 204) pp. 67,094-6,158.

[126] For purposes of this proceeding, "Public Interest Organizations" are Sierra Club, Sustainable FERC Project and NRDC.

[127] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 173 FERC ¶ 62,090 (Nov. 19, 2020).

the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

- ***Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

As previously reported, *Order 860,*[128] issued three years after the FERC's *Data Collection NOPR,*[129] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will *not* adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC 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,[130] or FERC-generated ID and that all reportable generation assets have an code from the Energy Information Agency ("EIA") Form EIA-860 database or a FERC-assigned Asset ID. Requests for rehearing and/or clarification of *Order 860* were denied,[131] other than TAPS' request that the FERC clarify that the public will be able to access the relational database. On that point, the FERC clarified "that we will make available services through which the public will be able to access organizational charts, asset appendices, and other reports, as well as have access to the same historical data as Sellers, including all market-based rate information submitted into the database. We also clarify that the database will retain information submitted by Sellers and that historical data can be accessed by the public."

MBR Database. On January 10, 2020, the FERC issued a notice that updated versions of the XML, XSD, and MBR Data Dictionary are available on the FERC's website and that the test environment for the MBR Database is now available and can be accessed on the MBR Database webpage.

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.

- **NOPR: NAESB WEQ Standards v. 003.3 - Incorporation by Reference into FERC Regs (RM05-5-029, -030)**

On July 16, 2020, the FERC issued a NOPR proposing to incorporate by reference, with certain enumerated exceptions, the latest version (Version 003.3) of certain Standards for Business Practices and

[128] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 168 FERC ¶ 61,039 (July 18, 2019) ("*Order 860*"), *order on reh'g and clarif.*, 170 FERC ¶ 61,129 (Feb. 20, 2020).

[129] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (July 21, 2016) ("*Data Collection NOPR*").

[130] An LEI is a unique 20-digit alpha-numeric code assigned to a single entity. They are issued by the Local Operating Units of the Global LEI System.

[131] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, Order No. 860-A, 170 FERC ¶ 61,129 (Feb. 20, 2020) ("*Order 860-A*").

Communication Protocols for Public Utilities adopted by the NAESB Wholesale Electric Quadrant ("WEQ").[132] Despite having only recently incorporated Version 003.2 in its regulations, the FERC proposed to move forward on Version 003.3 because this Version contains a number of major initiatives whose incorporation by reference "will improve the security and the efficiency of business transactions. These include enhanced cybersecurity standards resulting from an assessment by Sandia, improved methodologies for resolving transmission loading relief, and standards for determining available transfer capacity."[133] Comments on the *NAESB WEQ v. 003.3 Standards NOPR* were due on or before November 3, 2020[134] and were filed by Bonneville Power Administration ("BPA"), EEI, the IRC, and Open Access Technology International. The *NAESB WEQ v. 003.3 Standards NOPR* is pending before the FERC.

- ***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*,[135] 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 NAESB Wholesale Electric Quadrant.[136] The Version 003.2 Standards included NAESB's Version 003.1 revisions, which were the subject of an earlier NOPR.[137] 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* became effective April 27, 2020.[138] Requests for clarification and/or rehearing of *Order 676-I* were filed by EEI and Southern Companies. On April 6, 2020, the FERC issued a tolling order to afford it additional time to consider those requests. On November 25, 2020, the FERC issued an order on clarification, in which it clarified *Order 676-I* as requested and, accordingly, dismissed the alternative request for rehearing submitted by Southern Companies.[139] Absent challenge in the federal courts, this proceeding is now concluded.

- **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.[140] 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*:

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132 *Standards for Business Practices and Communication Protocols for Public Utilities*, 172 FERC ¶ 61,047 (July 16, 2020) ("*NAESB WEQ v. 003.3 Standards NOPR*").

133 The *NAESB WEQ v. 003.3 NOPR* at P .

134 The *NAESB WEQ v. 003.3 NOPR* was published in the *Fed. Reg.* on Sep. 4, 2020 (Vol. 85, No. 173) pp. 55,201-55,219.

135 *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*.

136 *Standards for Business Practices and Communication Protocols for Public Utilities*, 167 FERC ¶ 61,127 (May 16, 2019) ("*NAESB WEQ v. 003.2 Standards NOPR*").

137 *Standards for Business Practices and Communication Protocols for Public Utilities*, 156 FERC ¶ 61,055 (July 21, 2016), ("*WEQ v. 003.1 NOPR*").

138 *Order 676-I* was published *Fed. Reg.* on Feb. 25, 2020 (Vol. 85, No. 37) pp. 10,571-10,586.

139 *Standards for Business Practices and Communication Protocols for Pub. Utils.*, 173 FERC ¶ 61,173 (Nov. 25, 2020).

140 *Waiver of Tariff Requirements*, 171 FERC ¶ 61,156 (May 21, 2020) ("*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 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[141] 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

[141] 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.

waivers,[142] 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.

Comments on the Proposed Policy Statement were due on or before June 18, 2020 and were filed by the IRC, AEE, APPA, AWEA/SEIA, EEI, EPSA, Indicated Generators,[143] INGAA, Kansas Electric Power Coop. ("KEPC"), NGA, NGSA, NRECA, Public Citizen, Sunflower Electric Power, and TAPS. Reply comments were filed by APPA, Joint Trade Associations,[144] KEPC, and the Sustainable FERC Project. The proposed Policy Statement is pending before the FERC.

- **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*.[145] 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").[146] 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.[147] On July 7, the FERC issued a notice that pipelines choosing to file updated FERC Form No. 6, page 700 data consistent with the ROE Policy Statement should file such data on or before July 21, 2020.

Complainant-Aligned Parties[148] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[149] submitted supplemental comments arguing that the FERC should use the midpoint, rather than the median, as the measure of central tendency for public utilities that file individually to establish a ROE. Joint Parties' comments were opposed by Six Cities.[150] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the

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142 *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.

143 "Indicated Generators" are Vistra, NRG, FirstLight, Cogentrix, and LS Power.

144 "Joint Trade Associations" are AEE, AWEA, EEI, EPSA, INGAA, NGSA, NRECA and SEIA.

145 *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*").

146 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 ROE to be used in designing jurisdictional rates charged by public utilities.[146] The FERC 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).

147 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.

148 For this purpose, "Complainant-Aligned Parties" are: Connecticut Public Utilities Regulatory Authority, Connecticut Office of the Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel, Massachusetts Office of the Attorney General, Massachusetts Department of Public Utilities, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative.

149 "Joint Parties" are: AEP, Avista, Evergy Companies, Entergy Services, Exelon, FirstEnergy, Portland Gen. Elec., PG&E, Corporation, Puget Sound Energy, PacifiCorp, Idaho Power, PSEG, So. Cal. Edison, and San Diego Gas & Elec.

150 "Six Cities" are the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.

previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

- **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[151] 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,[152] 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.

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*[153] 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.[154] 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."[155] 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*

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151 The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

152 *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

153 *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

154 *BP America Inc.,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

155 *BP Penalties Order* at P 3.

Order also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[156] 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 to afford 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.[157]

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 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[158] 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.[159]

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.

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[156] *BP America Inc.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

[157] *BP America Inc.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*").

[158] *Total Gas & Power North America, Inc.,* 155 FERC ¶ 61,105 (Apr. 28, 2016) ("*TGPNA Show Cause Order*").

[159] 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.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:

  - ***Iroquois ExC Project (CP20-48)***
    - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover)
    - Three-year construction project; service request by November 1, 2023
    - Application for a certificate of public convenience and necessity pending.
    - Since the Last Report, the FERC issued data requests regarding compressor station nameplate ratings at standard conditions and certain environmental information, to which Iroquois responded on November 12 and 20, respectively. Also, Iroquois submitted on November 20 its periodic update to reflect updates to the permits, approvals, and agency consultations.

- **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.[160] 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*.[161] 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,[162] 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,

[160] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[161] *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).

[162] 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).

2017.[163] 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.[164] 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,[165] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[166]
- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. Comments on the request were due on or before November 6, 2020. More than 50 sets of comments on the requested extension were filed.
- On December1, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [167] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[168]

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[163] *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*").

[164] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[165] 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).

[166] *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).

[167] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

[168] *Id.* at P 10.

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 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 Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[169]
  Petitioner: LS Power

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the *Order 1000* exemptions for immediate need reliability projects. Since the last Report, appearances were filed by the FERC, Avangrid and MMWEC, are due November 19, 2020. LS Power filed a docketing statement and statement of issues to be raised on November 19. Dispositive motions, if any, and a Certified Index to the Record must be filed by December 4, 2020.

[169] *ISO New England Inc., 171 FERC ¶ 61,211 (June 18, 2020) ("Order Terminating Proceeding") (finding (i) "insufficient evidence in the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential; (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed"; and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption); and ISO New England Inc., 172 FERC ¶ 61,293 (Sep. 29, 2020) ("Order 1000 Exemptions Allegheny Order")* (addressing arguments raised by request for rehearing denied by operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[170]
  Petitioner: Cogentrix, Vistra

On September 25, 2020, Cogentrix and Vistra petitioned the DC Circuit Court of Appeals for review of the FERC's orders allowing for recovery of expenditures to comply with the IROL-CIP requirements, but only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing, including undepreciated costs of any such past capital expenditures to comply with the IROL-CIP requirements. On November 3, 2020, the Court adopted the proposed briefing schedule, including the following: Petitioners' Brief (January 15, 2021); Respondent Brief of FERC (Mach 16, 2021); Intervenor for Respondent Brief (April 15, 2021); Petitioners' Reply Briefs (May 14, 2021); Deferred Appendix (June 1, 2021); and Final Briefs (June 11, 2021). Dispositive motions, if any, and a Certified Index to the Record must be filed by December 4, 2020.

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[171]
  Petitioners: Mystic (1343), NESCOE (1361), MA AG (1362), CT Parties (1365, 1368)

Mystic, NESCOE, MA AG, and CT Parties separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, ExGen and ISO-NE.172 The cases have been consolidated into Case No. 20-1343. Appearances were filed October 8, 2020. On October 8 (in the case of Mystic) and October 16 (in the case of the remaining Petitioners), statements of issues and docketing statements were filed. Also on October 16, the FERC filed an unopposed motion to hold this appeal in abeyance until the earlier of December 15, 2020 (60 days) or the date of the issuance by the FERC of a further order on rehearing. In addition, the FERC asked for 21 days from that day for the parties to file motions to govern further proceedings. On November 4, 2020, the Court granted the FERC's motion and ordered that the consolidated cases be held in abeyance pending further order of the Court and that he parties file motions to govern further proceedings in these cases within 21 days of the FERC's decision on rehearing or by January 5, 2021, whichever occurs earlier.

- ***CASPR* (20-1333)**
  Underlying FERC Proceeding: ER18-619[173]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On October 29, Petitioners opposed the FERC's motion. On November 5, 2020, the FERC filed a reply, indicated that an order on rehearing would be issued imminently and suggested that, if the Court declines to dismiss the petition, it should be held in abeyance until the Commission issues an order on rehearing. As noted above, the FERC issued the *CASPR Allegheny Order* on November 19, modifying the discussion in the *CASPR Order*, but reaching the same the result. The FERC's motion to dismiss is still pending before the Court.

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[170] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*") and *ISO New England Inc.*, 172 FERC ¶ 61,251 (Sep. 17, 2020) ("*CIP IROL Allegheny Order*", and together with the CIP IROL Cost Recover Order, the "*CIP IROL Orders*").

[171] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[172] The COS Agreement is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

[173] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[174]
  Petitioners: TOs' (CMP et al.)

On August 28, 2020, the TOs[175] petitioned the DC Circuit Court of Appeals for review of the FERC's October 6, 2017 order rejecting the TOs' filing that sought to reinstate their transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[176] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the FERC granted that motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[177]
  Petitioner: TransCanada

On July 30, 2020, TransCanada Power Marketing ("Petitioner" or "TransCanada") again petitioned the DC Circuit Court of Appeals for review of the FERC's action on the 2013/2014 Winter Reliability Program, this time in the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[178] NEPGA intervened on October 15, 2020 (and its intervention granted on October 28). On October 16, TransCanada filed a docketing statement and statement of issues. On October 29, the FERC filed a certified index to the record and an unopposed motion for a 60-day briefing period. On December 2, 2020, the Court granted the FERC's October 29 motion and set the briefing schedule, including the following: Petitioners' Brief (January 11, 2021); Respondent Brief of FERC (Mach 12, 2021); Intervenors' Joint Brief in Support of Respondent (March 19, 2021); Petitioners' Reply Briefs (April 9, 2021); Deferred Appendix (April 16, 2021); and Final Briefs (April 30, 2021).

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[179]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)

As previously reported, at the unopposed request of the FERC, the Court issued an order suspending the previous briefing schedule and remanding the record back to the FERC. Subsequently, the FERC issued its *IEP Remand Order* (June 18, 2020) and its Notice of Denial by Operation of Law of the requests for rehearing of its *IEP Remand Order* (August 20, 2020). As previously reported, each of the Petitioners filed amended petitions for review in the consolidated proceeding in order to bring the FERC's *IEP Remand Order* and the post-remand FERC record before the DC Circuit. Since the last Report, on November 10, the Court ordered that the cases be removed from abeyance and set a revised briefing schedule that calls for the following: Petitioners' Opening Briefs (December 11, 2020); Respondent Brief of FERC (February 9, 2021); Intervenors' Joint Brief in Support of

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[174] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

[175] The "TOs" are CMP; Eversource Energy Service Co., on behalf of its affiliates CL&P, NSTAR and PSNH; National Grid; New Hampshire Transmission; UI; Unitil and Fitchburg; VTransco; and Versant Power.

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

[177] 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*") (accepting ISO-NE's January 23, 2017 compliance filing, finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable, and providing for this finding the further reasoning requested by the DC Circuit in *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (DC Cir. 2015) ("*TransCanada*").)

[178] In TransCanada, the DC Circuit granted TransCanada's prior petition in part, and directed the FERC to either better justify its determination or revise its disposition to ensure that the rates under the Program are just and reasonable. *TransCanada* at 1.

[179] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

Respondent (February 16, 2021); Petitioners' Reply Briefs (March 30, 2021); Deferred Appendix (April 20, 2021); and Final Briefs (May 4, 2021). As noted, Opening Briefs are due December 11, 2020.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788) (9th Cir.)**
Underlying FERC Proceeding: RM19-15[180]
Petitioner: SEIA

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[181] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance will permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion, suspended briefing, and directed the FERC to file a status report, or a motion for appropriate relief on or before that date, with a failure to timely do so potentially resulting in the termination of the stay of proceedings.

- **PennEast Project (18-1128)**
Underlying FERC Proceeding: CP15-558[182]
Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Abeyance continues of the appeal before the DC Circuit of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[183] 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"). The cases are being held in abeyance "pending final disposition of any post-dispositional 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, which is in the midst of proceedings before the Supreme Court, the DC Circuit will not take up this case. The last Joint Status Report was filed on September 28, 2020, noting developments since the June 29, 2020 Status Report, and reporting that none of the events "constitute any of the conditions that [the DC Circuit] enumerated in its October 1, 2019 Order as triggering an obligation to file a motion governing future proceedings."

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[180] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[181] *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

[182] *PennEa*st *Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[183] 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.

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1227, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1275)**
  Underlying FERC Proceeding: EL14-12; EL15-45[184]
  Petitioners: MISO TOs, FirstEnergy, Transource Energy

The MISO Transmission Owners (TOs), FirstEnergy and Transource have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Motions to govern future proceedings in the MISO TOs' case are now due August 10, 2020. The FirstEnergy case was assigned case number 20-1227; the Transource case, 12-1240. On July 10, 2020, the Court consolidated the FirstEnergy and Transource cases. Initial submissions in the FirstEnergy case were filed July 30, 2020.

On August 5, 2020, the FERC asked the Court to hold the appeals in abeyance, including the filing of the certified index to the record, for a period of four months, ending December 7, 2020, with parties to file motions to govern further proceedings at the end of that period. The FERC requested abeyance to permit it to issue a further order on rehearing of challenged orders. MISO TOs opposed the FERC's request on August 14. The FERC responded to that opposition on August 20, 2020.

On November 23, 2020, the Court issued an order removing these cases from abeyance, ordering the FERC to file a certified index to the record by December 8, 2020, and ordering the parties to submit on or before December 23 proposed formats for the briefing of these cases.

[184] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

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COVID-19

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

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

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XII. Misc: Administrative & Rulemaking Proceedings

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XIV. State Proceedings & Federal Legislative Proceedings

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Capacity As A Commodity Market Design Concept

PRESENTED TO:
NEPOOL

PREPARED BY:
Michael Borgatti – Vice President RTO Services & Regulatory Affairs

DECEMBER 3, 2020

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Gabel Associates Firm Overview & Presenter Biography

- Energy, environmental, and public utility consultancy headquartered in Highland Park, New Jersey with 25 years of experience providing quality energy consulting services and strategic insight to clients in all sectors of the energy industry
- Key practice areas include wholesale markets & energy suppliers, policy and market development, energy aggregation and procurement, customer-sited energy projects (primarily solar and efficiency), and utility tariff and energy cost forecasting
- Demonstrated success in all stages of renewable and conventional energy project development

Michael Borgatti – Vice President RTO Services & Regulatory Affairs

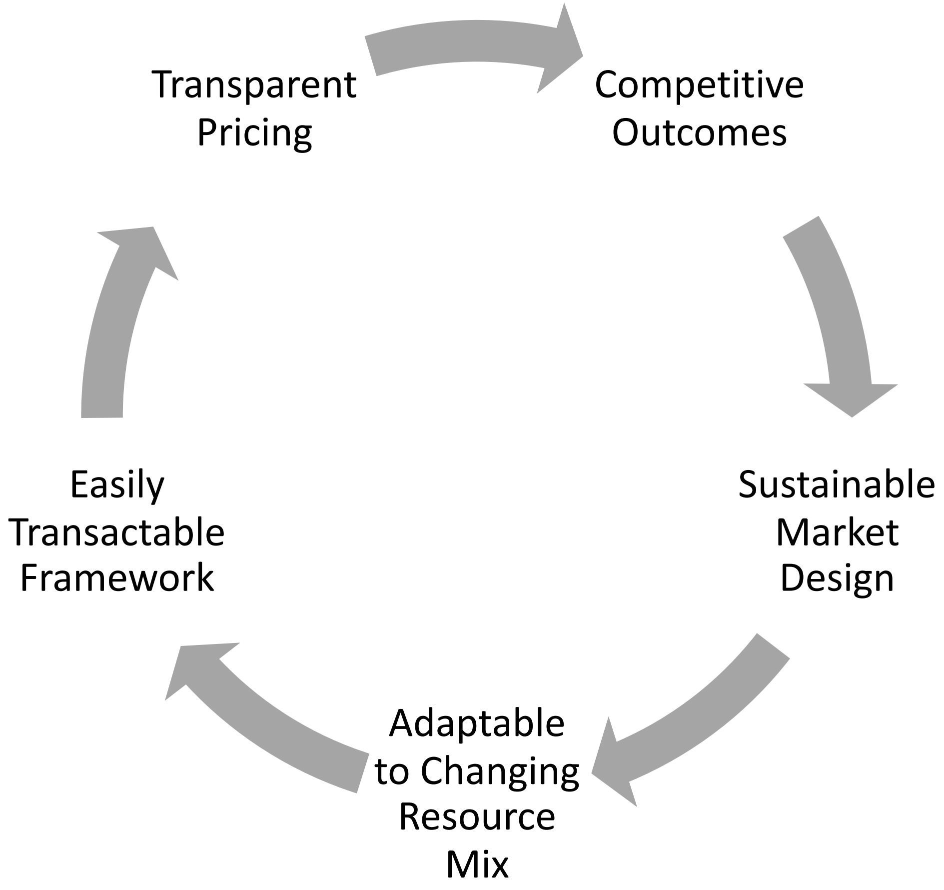
Mr. Borgatti leads Gabel Associates' RTO Services Group, which is a team of diverse energy experts supporting the firm's clients that participate in the wholesale power markets throughout North America. He is an expert in energy market design, operations, and planning fundamentals, as well as renewable and conventional project development and financial matters. Mr. Borgatti regularly appears before the Federal Energy Regulatory Commission ("FERC"), state utility commissions and RTO/ISO stakeholder processes. Prior to joining Gabel Associates, Mr. Borgatti was a legal specialist for the New Jersey Board of Public Utilities.

Challenges Currently Facing Centralized Capacity Markets

- Undifferentiated capacity models do not value different resources' contributions to reliability
- Consumer choice and and willingness to pay poorly reflected in market prices today
- No direct pathway to advance public policies within competitive markets
- Reliance on mitigation to produce competitive results

<u>Key Take Away</u>

- FCM may not represent durable, long-term solution despite historic success at maintaining reliability

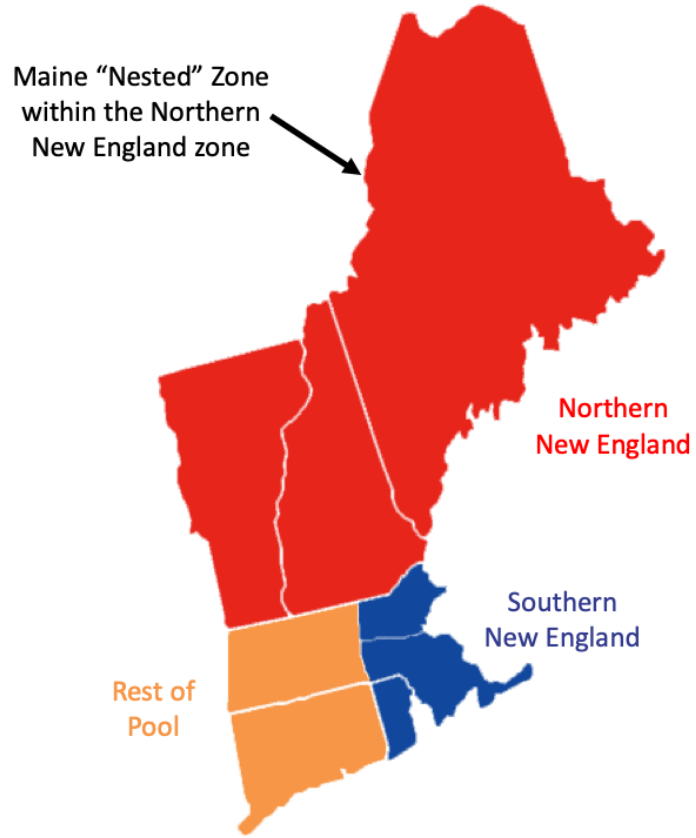


Capacity as A Commodity Framework

- ***Same*** general FCM timeline, parameters and CETL report
- ***New*** forecast capacity obligation for each LSE in ISO footprint
- ***New*** ISO Metric reflecting reliability needs based on resource fuel mix
- ***New*** "Market Specifications" describing available products and terms
- ***New*** capacity trading platform with publicly available market data
  - Bid/ask spread
  - Volume
  - Remaining capacity available
  - Pricing index

Capacity Bilateral Window

- ISO-NE opens capacity bilateral window around time of current FCA (~ three years before CCP) including locational constraints
- Suppliers offer all qualified capacity for sale when bilateral window opens
  - Sellers can use multiple price/MW points for each resource
  - Non-mitigated supply offers permitted up to Net CONE without prior approval
  - Mitigated offers between ISO-NE approved floor price and Net CONE
- Buyers can submit buy bids any time during bilateral window
  - Bids can include price, quantity, and target CSO duration
  - Have the option include desired fuel type
- ISO-NE removes buy and sell-side MWs after each transaction closes showing market remaining available capacity supply and demand by fuel type in each zone
- ISO-NE also publishes non-transaction specific prices and updates index providing transparent price signal to all market participants



Key Take Away

- Capacity Bilateral Window allows flexibility for evolving state policies to be reflected in the capacity mix

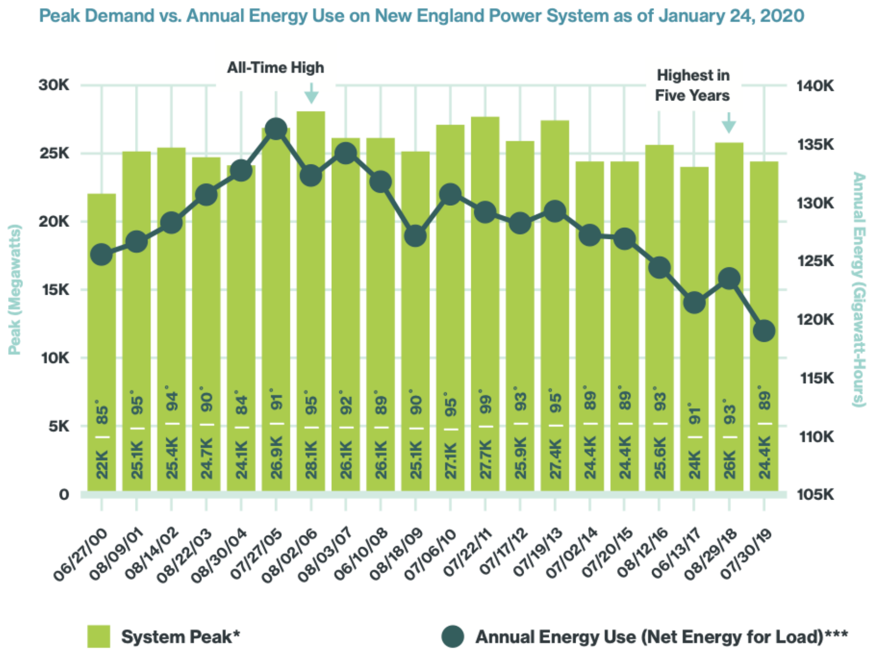
Residual Reliability Auctions (“RRAs”)

- Backstop mechanism to ensure ISO-NE maintains reliability in response to both evolving system needs, and resource mix, both of which are expected to be more dynamic in the coming decade(s)
- Patterned on current single clearing price FCA design
- Two Incremental RRAs held between bilateral window opening and start of CCP
  - Provides additional opportunity for buyers and sellers to transact
  - Also allows parties to true-up CSOs and purchases before CCP
- Final mandatory RRA opens ~ 12-months before CCP to procure any remaining capacity obligations and resource adequacy needs
  - New ISO Metric conducted as an “aggregate type ELCC approach” to better calibrate what remaining needs are left
  - Considers relationship between variable and balancing resources procured in bilateral market relative to local and regional needs
- Allows ISO to produce transparent prices that value system reliability needs and consumer choice

Key Take Away
- ISO-NE becomes buyer of last resort in final RRA
- Buyer and seller strategies can reflect bilateral and RRA pricing and market data

New Resource Adequacy Metric: Conceptual Framework

- Identify reliability services necessary to maintain regional and local resource adequacy
- Quantify how different resource impact the need for these services
- Evaluate whether ISO can meet reliability criteria with fuel mix procured during bilateral window
- RRA procures capacity from resources that satisfy any outstanding reliability needs
- RRA prices to transparently "value" region's overall resource adequacy needs

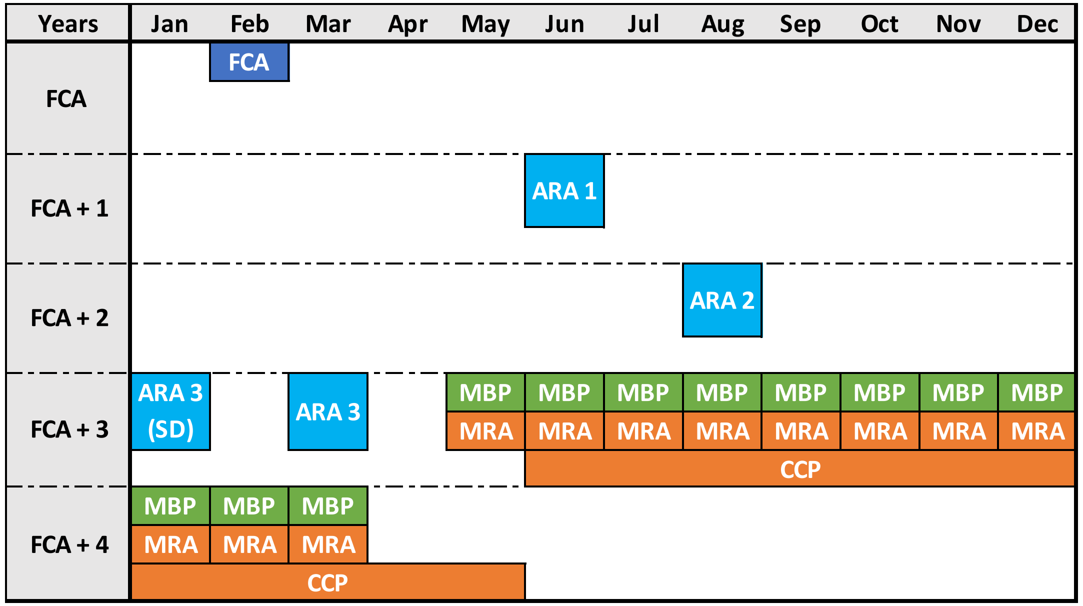


Key Take Away

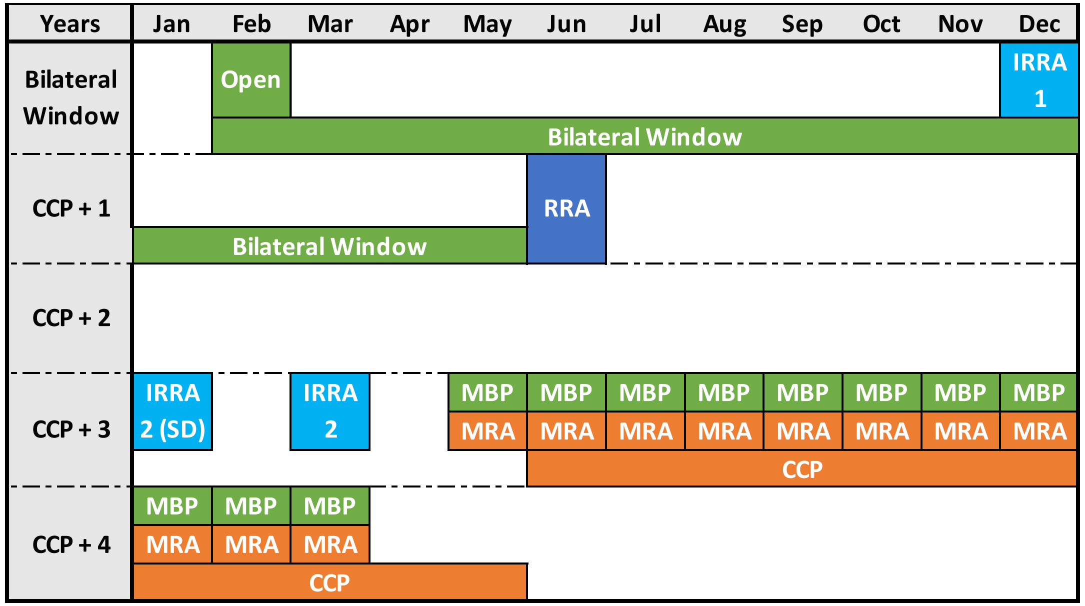
- Construct defines capacity product in terms of both energy deliverability and resource adequacy
- Product definition based on reliability services fuel neutral and adaptable to new technology types
- Transparent price signal informs market participants' investment and procurement decisions

Source: https://www.iso-ne.com/static-assets/documents/2020/03/npc-20200305-composite4.pdf

Comparing Market Timelines



FCA	Forward Capacity Auction	MRA	Monthly Reconfiguring Auction
ARA	Annual Reconfiguring Auction	CCP	Capacity Commitment Period
MBP	Monthly Bilateral Period		



RRA	Residual Reliability Auction	MRA	Monthly Reconfiguring Auction
IRAA	Incremental RAA	CCP	Capacity Commitment Period
MBP	Monthly Bilateral Period		

Key Take Away

- ~ 16-month bilateral window provides opportunity for price discovery while market participants calibrate their strategies and positions
- Holding RRA ~ one-year before CCP allows for new entry when necessary for reliability

Market Power Mitigation with Direct Path to Market

- FERC requires ISO to maintain appropriate provisions to mitigate market power
- Mitigation should target most acute market power risk consistent with FERC precedent
  - Buy side mitigation patterned consistent with FERC affiliate transaction review standards and *Mobile-Sierra* framework
  - FERC vertical and horizontal market power screens for monopoly power
  - Direct Buy-side out-of-market payments to specific suppliers or at predetermined prices
- Mitigated offer floor in bilateral window floor equals resources avoidable costs or out-of-market subsidy value net of forecast energy and ancillary revenues
  - Bilateral purchases of mitigated capacity are in market by definition
- Mitigated resources can participate in the IRRA and RRA at any price up to Net CONE ***but*** cleared offers are pay-as-bid while unmitigated suppliers receive single auction clearing price

Key Take Away
- Provides direct path to market for resources that support local energy policies
- Eliminates ISO-NE role in determining appropriate resource-specific offer price in RRAs
- Manages market power by calibrating incentives for mitigated suppliers

Summary & Conclusions

- Framework combines beneficial attributes of conventional commodity exchange and Renewable Energy Certificate ("REC") tracking and procurements models
- Straightforward market design that is understandable, implementable, and durable
- Like REC markets, allows market participants to procure and track capacity from resources that support energy policy objectives including state clean energy goals
- Resource adequacy metric allows ISO to maintain transparent price signals that communicate reliability needs
- Flexible design allows market to efficiently integrate emerging technologies and inform future investment decisions as regional resource mix evolves
- Compatible with other constructs states may desire to coordinate procurement of clean energy, i.e., FCEM
- More information available in Capacity as a Commodity White Paper developed in partnership with the American Wind Energy Association

NEPOOL Participants Committee

Future Pathways

Round 3: Standardized Fixed-price Forward Contract (SFPFC) and Summary Report

Preliminary Observations and Request for Input

Frank A. Felder

Dec. 3, 2020

Agenda

1. Preliminary Observations on Standardized Fixed-price Forward Contract (SFPFC)

2. Outline of Summary Report

3. Next Steps

4. Questions, Comments, and Request for Input

5. Appendix: Background, Abbreviations & References

Inventory of Potential Pathways

1. Forward Clean Energy Market (FCEM)
2. Integrated Clean Capacity Market (ICCM)
3. Carbon Pricing (CP)
   1. With the RGGI framework (RGGI+)
   2. Carbon pricing external to ISO-NE
   3. Net Carbon Pricing (LMP-NC)
4. Energy Only Market (EOM)
5. Alternative Resource Adequacy Constructs (ARAC)
   1. Fixed Resource Requirement (FRR)
   2. FCM with Balancing Resources (FCM-BR)
   3. Voluntary-Residual Capacity Market
   4. Standardized Fixed-price Forward Contract (SFPFC)
   5. Regional Integrated Resource Planning (Regional-IRP)
   6. State Integrated Resource Planning (State-IRPs)
   7. Net FCM
   8. Capacity as a Commodity

For Quick Reference

Project Goal

Compares Pathways across two key questions:

Whether and to what extent the Pathway supports the clean energy policies of States?

Whether and to what extent the Pathway garners efficiency of regional markets?

Project Report: Draft targeted for mid Dec.; final in late Dec.

ISO Retained Functions and Caveats

For the Pathways and variations, it is presumed that ISO-NE would continue to conduct energy dispatch, unit commitment, maintenance scheduling, transmission planning, market monitoring and mitigation, and market administration and settlement

For the Pathways and Variations, markets are used to procure energy, capacity (except for EOM and some ARACs), ancillary services, although the type, structure and administration of these markets may vary across Pathways

Pathways are inextricably linked to regional and State specific policies

Standardized Fixed-price Forward Contract (SFPFC)

1. Recap (Wolak, Frank, Long-Term Resource Adequacy with Significant Intermittent Renewables, presentation, Nov. 5, 2020)
    1. Regulators mandate LSEs purchase and hold to delivery standardized forward contracts for energy for fractions of their annual energy demand at various horizons
    2. Standardized contracts are shaped by hourly demands
    3. Clearinghouse manages counterparty risk
    4. No installed capacity requirement
2. Preliminary observations
    1. SFPFC does not explicitly address the procurement of clean energy resources to achieve States’ energy policy objectives
    2. For SFPFC to be considered a pathway, it needs to be augmented with how decarbonization occurs
    3. SFPFC may (or may not) be an improvement over the FCM

Outline of Final Summary Report

1. Reviews and discusses various pathways
2. The report summarizes pathways and leaves to the cited references to provide details and articulate the claimed advantages of pathways
3. Discusses high-level (preliminary, for discussion purposes only) findings (following slides)
4. Identifies gaps to be addressed
5. How do pathways address two questions:
    1. Whether and to what extent the Pathway supports the clean energy policies of States?
    2. Whether and to what extent the Pathway garners efficiency of regional markets?
6. More detailed findings from prior presentations are discussed

General, Overall Observation

The efforts underway to try to reconcile conflicting objectives of wholesale electricity markets and States' clean energy policies is clearly an ambitious and challenging undertaking. Any successful reconciliation is not likely to occur without some broad agreement reached among the New England States, NEPOOL stakeholders and ISO-NE, the ability of the ISO to implement a particular market mechanism, and/or some not yet specified means of procuring sufficient balancing resources.

High-Level Finding 1: Difficult to Reconcile Competing/Differing Objectives of the States and the Markets

It may not be possible to *fully* achieve each State's energy policy objectives through a regional market structure and at the same time *fully* garner the efficiency benefits of competitive regional markets that maximize social surplus. Thus, Pathways that pull or push more strongly in one direction than the other will produce a different set of tradeoffs.

For discussion purposes only; preliminary and subject to change

High Level Finding 1: Difficult to Reconcile Competing/Differing Objectives (con't)

Preliminary Observed Challenges

1. Net Carbon Pricing

Net carbon pricing mitigates, but does not necessarily solve, the double payment issue by increasing the revenues clean energy resources earn in the energy markets but does not specifically help the States tailor the timing and type of clean energy resources to meet their individual policy objectives. Net carbon pricing does not alone address the balancing resource issue.

High Level Finding 1: Difficult to Reconcile Competing/Differing Objectives (con't)

Preliminary Observed Challenges

2. FCEM and ICCM

A major claimed advantage of the FCEM and ICCM frameworks is that they would procure the least cost set of clean energy resources, but they do so by having broad definitions of clean energy resources and setting the demand for these resources that compete among each other at the regional level. However, achieving sufficient uniformity in the definition of clean energy resources to maximize the regional efficiency benefits of these auction mechanisms will likely require the States (or at least a subset of the States) to relinquish some control over the outcomes.

For the region to make substantial progress on a Pathway like the FCEM or ICCM, the New England States will need to determine if they can obtain sufficient agreement regarding regional procurement of clean energy resources to meet their individual State objectives.

High Level Finding 2: More Precise Definition of Required Balancing Services is Needed

The required types, amounts and timing of balancing services needed to accommodate increasing levels of variable renewable energy resources has not been fully articulated/defined. Without knowing these requirements, analyzing whether in choosing any of the potential pathways, the markets will continue to be successful in providing the resources needed for reliability is challenge. The ISO-NE needs to specify the reliability criteria and metrics it plans to use to establish the balancing services needed to plan and operate the bulk power system reliability given increasing penetration of VRERs. Whether an FCM-like mechanism is the preferred alternative to procure the required balancing services is an open question given that such a mechanism is designed primarily to procure new resources to maintain resource adequacy as opposed to maintain existing resources to provide balancing resources.

- Note that NEPOOL is, in parallel, engaged in the "Future Grid Reliability Study" that is examining these issues and as part of that effort and the ISO is to identify any reliability or operational gaps associated with the expected transition of the fleet/very large increased penetration of variable resources on the system.

For discussion purposes only; preliminary and subject to change

High Level Finding 3: More Details Are Needed to Fully Assess the Tradeoffs

The proposed pathways need more development and specificity before a complete analysis of their implications and impacts can be conducted. The identified Pathways at this time are really collections of similar high-level proposals that vary, in some cases substantially, within each pathway. Furthermore, the outcomes of pathways depend on how they interact with energy dispatch and curtailment, unit commitment, ancillary service definition and opportunity costs, imports and exports of power, bids and offers incentives, transmission planning and cost allocation, deployment of smart grid technologies, dynamic retail pricing, market monitoring and mitigation, wholesale and retail credit policies, and regional and State energy policies. One major example of the need for more development of pathways is the intersection of the proposed pathways with transmission expansion and cost allocation policies. The region's push for extensive development of offshore wind is a prime example. Considering the intersection of pathways and transmission policy is critical in achieving the least cost deployment of generation and transmission resources.

For discussion purposes only; preliminary and subject to change

Possible Implications of Unspecified Deliverability of Clean Energy Resources

Several proposed pathways procure resources without specifying the delivery location

Without specifying delivery locations, transmission planning may become more difficult, and the combined cost of generation and transmission may be more expensive compared to integrating generation resource procurement and transmission planning

Next Steps

1. Opportunities for written feedback and comments to this presentation are available

2. All comments will be considered, although comments that improve and contribute to the analysis of tradeoffs of Pathways and Variations will be the more helpful than advocacy

   *Please provide any written feedback on this presentation or other Pathways to NEPOOL Counsel (slombardi@daypitney.com) by COB Thursday, December 10 or sooner; all comments will be posted on the NEPOOL website

3. Goal to issue final report by end of the year, which will be circulated as a draft for comment, targeted mid Dec.

QUESTIONS AND COMMENTS

Abbreviations

ACP: Alternative Compliance Payment
ARAC: Alterative Resource Adequacy Constructs
CCS: Carbon Capture and Sequestration
CEAC: Clean Energy Attribute Credit
CONE: Cost of New Entry
CP: Carbon Pricing
EOM: Energy Only Market
ERCOT: Electricity Reliability Council of Texas
FCEM: Forward Clean Energy Market
FCM: Forward Capacity Market
FRR: Fixed Resource Requirement
ICCM: Integrated Clean Capacity Market
IRP: Integrated Resource Planning
LOLP: Loss of Load Probability
LSE: Load Serving Entities
MOPR: Minimum Offer Pricing Rule
ORDC: Operating Reserve Demand Curve
PPA: Power Purchase Agreement
RDPA: Reliability Deployment Price Adder
REC: Renewable Energy Credit
RES: Renewable Energy Standard
RGGI: Regional Greenhouse Gas Initiative
RGGI+: RGGI Plus Additional Emission Reductions
RPS: Renewable Portfolio Standard
SCED: Security Constrained Economic Dispatch
SFPFC: Standardized Fixed-price Forward Contract
VOLL: Value of Lost Load

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