November 9, 2021

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *ISO New England Inc.*, Docket No. ER22-___-000, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the Sixteenth Forward Capacity Auction (Associated with the 2025-2026 Capacity Commitment Period)

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO"), joined by the New England Power Pool Participants Committee ("NEPOOL"),[2] hereby electronically submits to the Federal Energy Regulatory Commission ("FERC" or "Commission") this transmittal letter and related materials that identify the following values for the 2025-2026 Capacity Commitment Period,[3] which is associated with the sixteenth Forward Capacity Auction ("FCA 16"): (i) Installed Capacity Requirement ("ICR");[4] (ii) Local Sourcing Requirement (LSR) for the Southeast New England ("SENE") Capacity Zone;[5] (iii) Maximum Capacity Limits ("MCLs") for the Maine ("Maine") and Northern New England ("NNE") Capacity Zones;[6] (iv) Hydro Quebec Interconnection Capability Credits ("HQICCs"); and (v)

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[1] 16 U.S.C. § 824d (2021).

[2] Under New England's RTO arrangements, the rights to make this filing under Section 205 of the Federal Power Act are the ISO's. NEPOOL, which pursuant to the Participants Agreement provides the sole market participant stakeholder process for advisory voting on ISO matters, supported this filing and, accordingly, joins in this Section 205 filing.

[3] The 2025-2026 Capacity Commitment Period starts on June 1, 2025 and ends on May 31, 2026.

[4] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed to them in the ISO New England Transmission, Markets and Services Tariff (the "Tariff").

[5] The SENE Capacity Zone includes the Southeastern Massachusetts ("SEMA"), Northeastern Massachusetts ("NEMA")/Boston, and Rhode Island Load Zones.

[6] The NNE Capacity Zone includes the New Hampshire, Maine, and Vermont Load Zones. The Maine Capacity Zone includes the Maine Load Zone.

Marginal Reliability Impact ("MRI") demand curves.[7] The ICR, net ICR, the LSR for the SENE Capacity Zone, the MCLs for the Maine and NNE Capacity Zones, HQICCs, and MRI demand curves are collectively referred to herein as the "ICR-Related Values."[8]

The ISO is proposing the following ICR-Related Values for FCA 16:

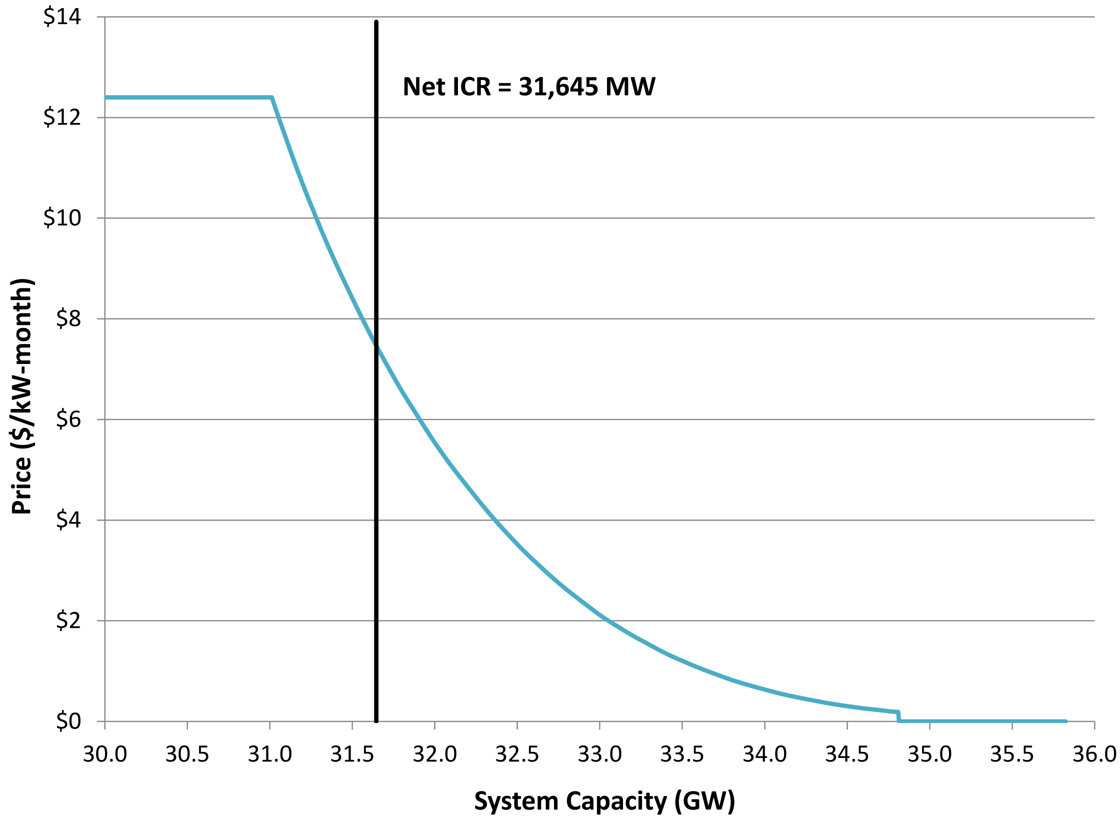
ICR	32,568 MW
Net ICR (ICR minus HQICCs)	31,645 MW
LSR for SENE Capacity Zone	9,450 MW
MCL for Maine	4,095 MW
MCL for NNE	8,555 MW
HQICCs	923 MW

Along with the following MRI demand curves:

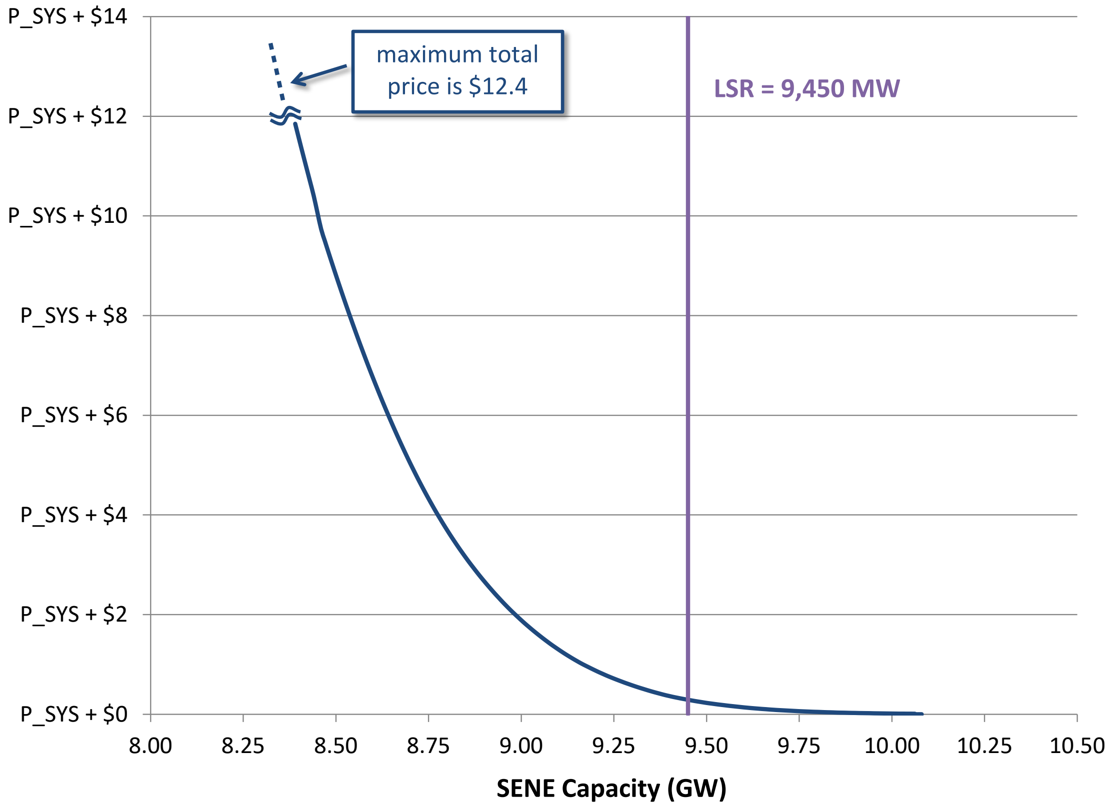
[7] As explained in this filing letter, the MRI Demand Curves include the System-Wide Capacity Demand Curve, the import-constrained Capacity Zone Demand Curve for the SENE Capacity Zone, and the export-constrained Capacity Zone Demand Curves for the Maine and NNE Capacity Zones.

[8] Pursuant to Section III.12.3 of the Tariff, the ICR must be filed 90 days prior to the applicable Forward Capacity Auction ("FCA"). FCA 16, which is the primary FCA for the 2025-2026 Capacity Commitment Period, is scheduled to commence on February 7, 2022.

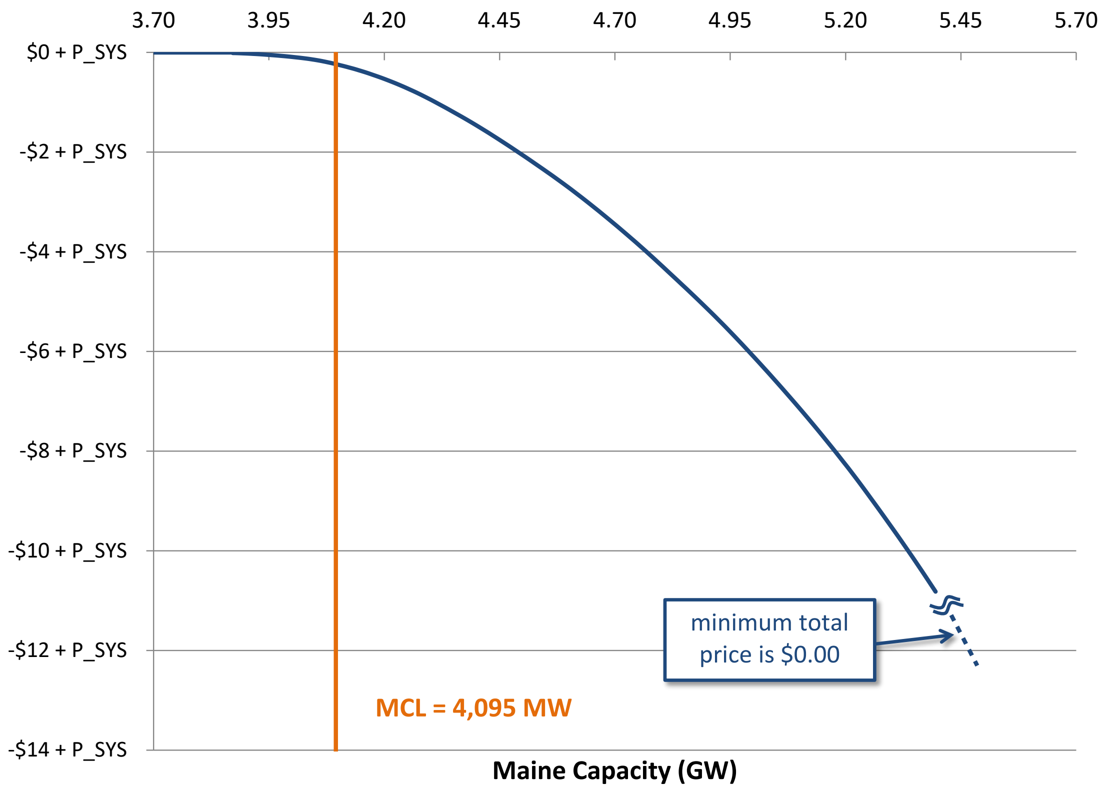
1. System-Wide Capacity Demand Curve for FCA 16



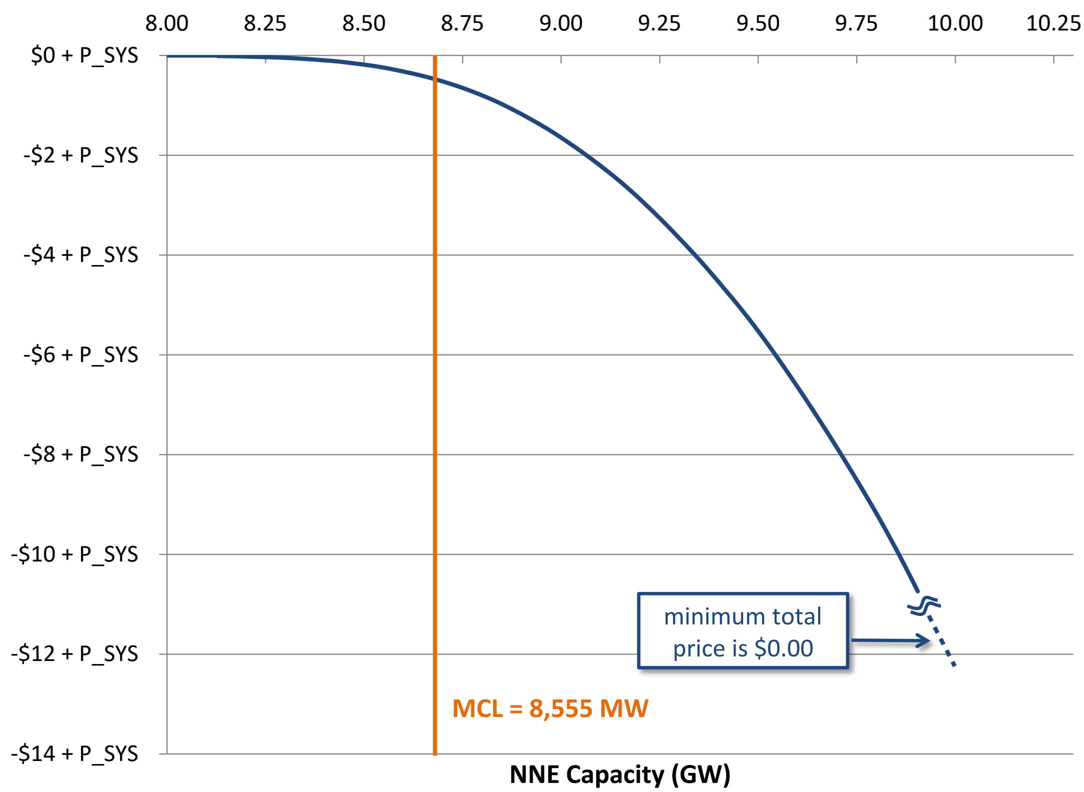
2. Import-constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 16



3. Export-constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 16



4. Export-constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 16



The derivation of the ICR-Related Values is discussed in Sections III-VI of this filing letter and in the attached Testimony of Manasa Kotha, Lead Engineer in the ISO's System Planning Department (the "Kotha Testimony"). The Kotha Testimony is solely sponsored by the ISO.

As more fully explained below in this filing letter and in the Kotha Testimony, starting this year, the ISO used new methodologies for three different components of the ICR-Related Values calculations. First, the ISO used a new modeling methodology for battery storage resources that are co-located with Intermittent Power Resources and participate in the Forward Capacity Market ("FCM") as non-intermittent resources, and a new modeling methodology for stand-alone battery storage resources. Second, the ISO used a new methodology to calculate the availability of Active Demand Capacity Resources. Finally, this year, the ISO is implementing Tariff changes that effect a new methodology for reconstituting passive demand resources ("PDR") in the load forecast. This new methodology is explained in the filing of Tariff changes that was submitted to FERC on September 11, 2020.[9] FERC accepted the changes in a letter order issued on October 30, 2020.[10] The rest of the methodology used to calculate the ICR-Related Values is the same Commission-approved methodology that was used to calculate the values submitted and accepted for the preceding FCA.[11] The proposed values are therefore the result of a well-developed process that improves, pursuant to the Commission's direction, on the processes utilized and approved by the Commission for the development of the ICR and related values in the past.[12] Accordingly, the Commission should accept the proposed values as just and reasonable without change to become effective on January 8, 2022.

I. DESCRIPTION OF FILING PARTY AND COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO operates and plans the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC").

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 500 members. The participants

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[9] The filing is available at https://www.iso-ne.com/static-assets/documents/2020/09/ee_reconstitution_tariff_changes.pdf

[10] The letter order is available at https://www.iso-ne.com/static-assets/documents/2020/10/er20-2869-000.pdf. The effect on the ICR of using the new PDR methodology is a decrease about 1,545 MW.

[11] *ISO New England Inc.,* 170 FERC ¶ 61,002 (Jan. 3, 2020).

[12] *Id; see, also* FERC orders approving prior ICR filings: 2024-2025 ICR: *ISO New England Inc.,* Docket No. ER21-371-000 (Jan. 7, 2021) (delegated letter order); 22022-2023 ICR: *ISO New England Inc.,* Docket No. ER19-291-000 (Jan. 4, 2019) (delegated letter order); 2021-2022 ICR: *ISO New England Inc.,* Docket No. ER18-263-000 (Dec. 18, 2017) (delegated letter order); 2020-2021 ICR: *ISO New England Inc.,* Docket No. ER17-320-000 (Dec. 6, 2017) (delegated letter order); 2019-2020 ICR: *ISO New England Inc.,* 154 FERC ¶ 61,008 (2016), *order on reh'g*, 155 FERC ¶ 61,145 (2016); 2018-2019 ICR: *ISO New England Inc.,* 150 FERC ¶ 61,003 (2015), *order on reh'g*, 150 FERC ¶ 61,155 (2015); 2017-2018 ICR: *ISO New England Inc.,* Docket No. ER14-328-000 (Dec. 30, 2013) (delegated letter order); 2016-2017 ICR: *ISO New England Inc.,* Docket No. ER13-334-000 (Dec. 31, 2012) (delegated letter order); 2015-2016 ICR: *ISO New England Inc.,* Docket No. ER12-756-000 (Feb. 23, 2012) (delegated letter order); 2014-2015 ICR: *ISO New England Inc.,* Docket No. ER11-3048-000, 135 FERC ¶ 61,135 (2011); 2013-2014 ICR: *ISO New England Inc.,* Docket No. ER10-1182-000 (June 25, 2010) (delegated letter order); 2012-2013 ICR: *ISO New England Inc.,* Docket No. ER09-1415-000 (Aug. 14, 2009) (delegated letter order); 2011-2012 ICR: *ISO New England Inc.,* 125 FERC ¶ 61,154 (2008).

include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[13] the participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

All correspondence and communications in this proceeding should be addressed to the undersigned for the ISO as follows:

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[13] *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004).

[14] Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203(b)(3) of the Commission's regulations to allow the inclusion of more than two persons on the service list in this proceeding.

II. STANDARD OF REVIEW

The ISO submits the proposed ICR-Related Values for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[15] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[16] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[17] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[18] The ICR-Related Values submitted herein "need not be the only reasonable methodology, or even the most accurate."[19] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[20]

III. INSTALLED CAPACITY REQUIREMENT

A. Description of the ICR

The ICR is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for the New England Control Area and to maintain sufficient reserve capacity to meet reliability standards. More specifically, the ICR is the amount of resources needed to meet the reliability requirements defined for the New England Control Area of disconnecting non-interruptible customers (a loss of load expectation or "LOLE") no more than once every ten years (a LOLE of 0.1 days per year). The methodology for calculating the ICR is set forth in Section III.12 of the Tariff.

The ISO is proposing an ICR of 32,568 MW for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period. This value reflects tie benefits (emergency energy assistance) assumed obtainable from Quebec, Maritimes (New Brunswick) and New York in the aggregate amount of 1,830 MW. However, the 32,568 MW ICR value does not reflect a

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[15] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

[16] *Id.* at 10 (*quoting City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

[17] *Id.* at 9.

[18] *Cities of Bethany, et al. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984).

[19] *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (*citing Cities of Bethany*, 727 F.2d at 1136).

[20] *Cf. Southern California Edison Co., et al.*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) ("Having found the plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (*citing Cities of Bethany*, 727 F.2d at 1136)).

reduction in capacity requirements relating to HQICCs. The HQICC value of 923 MW per month is applied to reduce the portion of the ICR that is allocated to the Interconnection Rights Holders ("IRH"). Thus, the net ICR, after deducting the HQICC value, is 31,645 MW.[21]

B. Development of the ICR

The methodology used to develop the ICR-Related Values for FCA 16 is the same as that used to calculate the values for the previous FCA, with the exception of the three aforementioned methodology changes. As in previous years, the values submitted in the instant filing are based on assumptions relating to expected system conditions for the associated Capacity Commitment Period. These assumptions include the load forecast, resource capacity ratings, resource availability, and relief assumed obtainable by implementation of operator actions during a capacity deficiency, which includes the amount of possible emergency assistance (tie benefits) obtainable from New England's interconnections with neighboring Control Areas, load reduction from implementation of 5% voltage reductions, and maintaining a minimum level of operating reserve. All modeling assumptions have been updated to reflect expected changes in system conditions. These updated assumptions are described below.

1. Load Forecast

The forecasted peak loads of the entire New England Control Area for the 2025-2026 Capacity Commitment Period are one major input into the calculation of the ICR-Related Values. For the purpose of calculating the ICR for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, the ISO used the load forecast published in the 2021-2030 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2021 ("2021 CELT Report").[22] As in previous years, the load forecast methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee ("LFC").[23]

The projected New England Control Area summer 50/50 peak load[24] for the 2025-2026 Capacity Commitment Period is 28,025 MW. In determining the ICR, the load forecast is represented by a weekly probability distribution of daily peak loads. This probability

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[21] The net ICR is used in the development of the MRI Demand Curves, which will be used to procure capacity in FCA 16.

[22] Kotha Testimony at 10-12.

[23] The methodology is reviewed periodically and updated when deemed necessary in consultation with the LFC.

[24] The New England Control Area is a summer-peaking system, meaning that the highest load occurs during the summer. The 50/50 peak refers to the peak load having a 50% chance of being exceeded. The referenced value is the 2021 CELT "Net (with Reductions for BTM PV)" peak load forecast, as shown in CELT Section 1.1 Summer Peak Capabilities and Load Forecast.

distribution is meant to quantify the New England weekly system peak load's relationship to weather. The 50/50 peak load is used solely for reference purposes. In the ICR calculations, the methodology determines the amount of capacity resources needed to meet every expected peak load of the weekly distribution given the probability of occurrence associated with that load level.[25]

2. Resource Capacity Ratings

The ICR for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, is based on the latest available resource ratings[26] of Existing Capacity Resources that have qualified for FCA 16 at the time of the ICR calculation. These resources are described in the qualification informational filing for FCA 16 that is being submitted concurrently to the Commission on November 9, 2021.[27]

Resource additions and most resource attritions[28] are not assumed in the calculation of the ICR for FCA 16 (pursuant to the Tariff) because there is no certainty regarding which new resource additions or existing resource attritions, if any, will clear the FCA. The use of the proxy unit for potential required resource additions when the system is short of capacity, and the additional load carrying capability ("ALCC") adjustments to remove surplus capacity from the system, discussed in the Kotha Testimony, are designed to address these resource addition and attrition uncertainties.[29]

3. Resource Availability

The proposed ICR value for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, reflects generating resource availability assumptions based on historical

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[25] *See* Kotha Testimony at 10-12.

[26] The resource capacity ratings for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, were calculated in accordance with Section III.12.7.2 of the Tariff using the methods and procedures that were employed for calculating resource capacity ratings reflected in the Commission-approved ICRs for the first fifteen primary FCAs. *See* 2024-2025 ICR Letter Order; the 2023-2024 ICR Letter Order; the 2022-2023 ICR Letter Order; the 2021-2022 ICR Letter Order; the 2020-2021 ICR Letter Order; the 2019-2020 ICR Letter Order; the 2018-2019 ICR Letter Order; and the 2017-2018 ICR Letter Order.

[27] *ISO New England Inc.,* Informational Filing for Qualification in the Forward Capacity Market, filed on November 9, 2021 at Attachment C.

[28] Retirement De-List Bids that are at or above the FCA Starting Price and those retirements for resources that have elected unconditional treatment are deducted from the Existing Capacity Resources' qualified capacity data.

[29] Kotha Testimony at 7-9.

scheduled maintenance and forced outages of these capacity resources.[30] For generating resources, individual unit scheduled maintenance assumptions are based on each unit's most recent five-year historical average of scheduled maintenance. Each generating resource's forced outage assumptions are based on the resource's most recent five-year historical NERC Generator Availability Database System ("GADS") forced outage rate data submitted to the ISO. If the resource has been in commercial operation less than five years, then the NERC class average maintenance and forced outage data for the same class of units is used to substitute for the missing annual data.

The Qualified Capacity of an Intermittent Power Resource is the resource's median output during the Reliability Hours averaged over a period of five years. Based on the Intermittent Power Resources rating methodology, these resources are assumed to be 100% available because their availability impacts on reliability are already incorporated into the resource ratings.

Battery storage resource participation in the FCM has increased in the past year. Accordingly, as explained below, the ISO has refined the methodologies it uses to model these resources in the ICR-Related Values calculations. In addition, as also explained below, this year, the ISO used a new methodology to model Active Demand Capacity Resources.

New Methodologies for Modeling Two Categories of Battery Storage Resources

Based on their FCM participation, there are four categories of battery storage resources: (1) battery storage resources that participate as Intermittent Power Resources (these may be co-located with other Intermittent Power Resources and may participate in the FCM as a single Intermittent Power Resource); (2) co-located battery storage resources that participate as non-intermittent resources (while these resources are co-located with Intermittent Power Resources, they participate as non-intermittent Generating Capacity Resources); (3) stand-alone battery storage resources, which participate in the FCM as non-intermittent Generating Capacity Resources; and (4) battery storage resources that participate in the FCM as part of a Demand Capacity Resource.[31]

The ISO models battery storage resources that participate as Intermittent Power Resources using the methodology that it uses to model Intermittent Power Resources (*i.e.*, using Qualified Capacity values and 100% availability). This methodology is not changing this year.

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[30] The assumed resource availability ratings for FCA 16 which is associated with the 2025-2026 Capacity Commitment Period, are discussed in the Kotha Testimony at 17-23. The ratings were calculated in accordance with Section III.12.7.3 of the Tariff using the methods and procedures that were employed for calculating resource capacity ratings reflected in the Commission-approved ICRs for the first fifteen FCAs. *See* note 10, *supra.*

[31] Kotha Testimony at 19.

The ISO models battery storage resources that participate in the FCM as part of a Demand Capacity Resource using the established modeling methodology for Demand Capacity Resources. This methodology is also not changing this year. In previous years, the ISO modeled both types of battery storage resources that participate as non-intermittent Generation Capacity Resources (*i.e.,* battery storage resources that are co-located with Intermittent Power Resources and participate as non-intermittent resources, and stand-alone battery storage resources) as thermal generating units using NERC Class "HYDRO 1-29" as a proxy availability assumption. As explained below, this year, the ISO is replacing this methodology with two new methodologies to model these two categories of battery storage resources.

Starting this year, the ISO is modeling battery storage resources that are co-located with Intermittent Power Resources and participate in the FCM as non-intermittent Generating Capacity Resources using the methodology that it uses to model Intermittent Power Resources. Specifically, to model co-located battery storage resources that participate in the FCM as non-intermittent Generating Capacity Resources, the ISO will use the resources' Qualified Capacity values and will assume 100% availability. This methodology is an improvement over the previous methodology because, as explained in the Kotha Testimony, the configurations and characteristics of co-located battery storage resources that participate in the FCM as non-intermittent resources are similar to the configurations and operating characteristics of those participating as Intermittent Power Resources.[32] Given the similarity between these two types of resources, it is appropriate to model them using the same methodology.

Also starting this year, the ISO is modeling stand-alone battery storage resources (which participate in the FCM as non-intermittent Generating Capacity Resources) using a class model. Specifically, as detailed in the Kotha Testimony, all resources are modeled using the same typical design and operational parameters of the fleet.[33]

This methodology is an improvement over the previous methodology because the new methodology utilizes the modeling capabilities of GE MARS's recently released module for modeling battery storage resources, taking into consideration factors that affect battery storage resources' unavailability to serve demand, and the comparability to other types of resources.

New Methodology for Modeling Active Demand Capacity Resources

Previously, performance of Demand Capacity Resources in the Active Demand Capacity Resource category was measured by actual response during performance audits and dispatches that occurred in the most recent five-year period (last year, the period was 2016 through 2020).

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[32] Kotha Testimony at 20-21.

[33] The parameters are detailed in the Kotha Testimony at 21-22.

To calculate historical availability, the verified commercial capacity of each resource was compared to its monthly net Capacity Supply Obligation. Starting this year, the availability of Active Demand Capacity Resources is calculated on an annual basis for each Load Zone utilizing data from both summer and winter performance, weighting the seasons based on their relative duration throughout the year. A rolling average of the forced outage rate for Active Demand Capacity Resources is developed as a five year-rolling average. However, this year, the ISO only has three years' worth of data, and accordingly, the average for this year only took into account those three years. Next year, the average will take into account four years of data and, starting in 2023, the average will use five years of data, which will then start rolling in 2024.[34]

The new methodology is an improvement because it takes both availability and performance relative to Capacity Supply Obligations during audits into account, whereas the previous methodology only took into account performance relative to Capacity Supply Obligations. Availability in this context is the percentage of hours in each season where Demand Response Resources associated with an Active Demand Capacity Resource with a non-zero Capacity Supply Obligation offered as available and with a Maximum Reduction greater than zero.

4. Other Assumptions

a. Tie Benefits

New England's Commission-approved method for establishing the ICR requires that assumptions be made regarding the tie benefits value to be used as an input in the calculation.[35] The tie benefits reflect the assumed amount of emergency assistance from neighboring Control Areas that New England could rely on, without jeopardizing reliability in New England or the neighboring Control Areas, in the event of a capacity shortage in New England. Assuming tie benefits as a resource to meet the 0.1 days/year LOLE criterion reduces the ICR and lowers the amount of capacity to be procured in the FCA.

The ISO's proposed ICR for FCA 16 reflects tie benefits calculated from the Quebec, Maritimes (New Brunswick), and New York Control Areas.[36] The ISO utilizes a probabilistic

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[34] Kotha Testimony at 22-23.

[35] *See* Section III.12.9 of the Tariff. The methodology for calculating tie benefits to be used in the Installed Capacity Requirement for FCA 16 is the same methodology used to calculate the tie benefits used in the ICR for Capacity Commitment Periods associated with prior FCAs.

[36] *See* 2014-2015 ICR Filing, Karl-Wong Testimony at 27, for an explanation of the methodology that the ISO used in determining tie benefits for the 2014-2015 Capacity Commitment Period, which the ISO also used in determining tie benefits for the 2015-2016 Capacity Commitment Period, the 2016-2017 Capacity Commitment Period, the 2017-

multi-area reliability model to calculate total tie benefits from these three Control Areas. Tie benefits from each individual Control Area are determined based on the results of individual probabilistic calculations performed for each of the three neighboring Control Areas. Specifically, the tie benefits methodology comprises two broad steps. In step one, the ISO develops necessary system load, transmission interface transfer capabilities and capacity assumptions. In step two, the ISO conducts simulations using the probabilistic GE MARS modeling program in order to determine tie benefits. In this step, the neighboring Control Areas are modeled using "*at criteria*" modeling assumptions which means that, when interconnected, all Control Areas are assumed to be at the 0.1 days/year reliability planning criteria.

The tie benefits methodology is described in detail in Section III.12.9 of the Tariff. The procedures associated with the tie benefits calculation methodology were also addressed in detail in the transmittal letter for the 2014-2015 ICR Filing.[37] The total tie benefits assumption and a breakdown of this value by Control Area are as follows:

Control Area	**Tie Line**	**Tie Benefits (MW)**
Quebec	HQ Phase I/II HVDC	923
Quebec	Highgate	142
Maritimes (New Brunswick)	New Brunswick	478
New York	NY AC Ties	287
New York	Cross Sound Cable	0
		Total = 1,830

Under Section III.12.9.2.4 (a) of the Tariff, one factor in the calculation of tie benefits is the transfer capability of the interconnections for which tie benefits are calculated. In the first half of 2021, the ISO reviewed the transfer limits of these external interconnections based on the latest available information regarding forecasted topology and load forecast information, and determined that no changes to the established external interface limits were warranted. The ISO established the following capacity transfer capability values for each interconnection including their assumed forced and scheduled outage rates:

2018 Capacity Commitment Period, the 2018-2019 Capacity Commitment Period, the 2019-2020 Capacity Commitment Period, the 2020-2021 Capacity Commitment Period, the 2021-2022 Capacity Commitment Period, the 2022-2023 Capacity Commitment Period, the 2023-2024 Capacity Commitment Period, and the 2024-2025 Capacity Commitment Period.

[37] *ISO New England Inc.,* Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2014-2015 Capability Year, Docket No. ER11-3048-000 at 13-19 (2011).

External Tie Line	External Interface Import Capability (MW)	Forced Outage Rate (%)	Maintenance (Weeks)
HQ Phase I/II HVDC	1,400	1.6	3.0
Highgate	200	0.1	0.8
New Brunswick	700	0.1	2.4
NY AC Ties	1,400	0.6	6.2
Cross Sound Cable	0	0.2	6.7
	Total = 3,700	**N/A**	**N/A**

The other factor is the transfer capability of the internal transmission interfaces. In calculating tie benefits for the ICR for FCA 16, for internal transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.

b. Amount of System Reserves

Pursuant to Section III.12.7.4 (c) of the Tariff, the amount of system reserves included in the determination of the ICR and related values must be consistent with those needed for reliable system operations during emergency conditions. Using a system reserve assumption in the ICR and related values calculations assumes that, during peak load conditions, under extremely tight capacity situations, while emergency capacity and energy operating plans are being used, ISO operations would have available the essential amount of operating reserves for transmission system protection, system load balancing, and tie control, prior to invoking manual load shedding. Starting in FCA 13, the ISO determined that the minimum amount of reserves to be assumed in the determination of the ICR and related values should be 700 MW. As a result, 700 MW of system reserves is the amount that the ISO used in the determination of the ICR-Related Values for FCA 16.

IV. LOCAL SOURCING REQUIREMENTS AND MAXIMUM CAPACITY LIMITS

In the FCM, the ISO must also calculate LSRs and MCLs. An LSR is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone to meet the ICR.[38] Specifically, the LSR is calculated for an import-constrained Capacity Zone as the amount of capacity needed to satisfy the higher of (i) the Local Resource Adequacy (LRA) or (ii) the Transmission Security Analysis (TSA) requirements.[39]

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[38] *See* Section III.12.2 of the Tariff.

[39] *See* Section III.12.2.1 of the Tariff.

An MCL is the maximum amount of capacity that can be located in an export-constrained Capacity Zone to meet the ICR.[40] The general purpose of LSRs and MCLs is to identify capacity resource needs such that, when considered in combination with the transfer capability of the transmission system, they are electrically distributed within the New England Control Area contributing toward purchasing the right amount of resources in the FCA to meet NPCC's and the ISO's bulk power system reliability planning criteria.

For FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, the ISO calculated the following values for the LSR for the SENE Capacity Zone using the methodology that is reflected in Section III.12.2 of the Tariff:

Import-Constrained Capacity Zone	LRA	TSA	LSR
SENE	9,450 MW	8,962 MW	9,450 MW

The calculation methodology for determining the LSR utilizes both LRA criteria as well as criteria used in the TSA that the ISO uses to maintain system reliability when reviewing de-list bids for a FCA. Because the system ultimately must meet both resource adequacy and transmission security requirements, the LSR provisions state that both resource adequacy and transmission security-based requirements must be developed for each import-constrained zone.

The LRA is addressed in Section III.12.2.1.1 of the Tariff. It is a zonal capacity requirement calculated using a probabilistic modeling technique that ensures the zone has sufficient resources to meet the one-day-in-ten years reliability standard. The LRA analysis assumes the same set of resources used in the calculation of the ICR.

The calculation of the TSA requirement is addressed in Section III.12.2.1.2 of the Tariff, and the conditions used for completing the TSA within the FCM are documented in Section 6 of ISO New England Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market ("PP-10").[41] The TSA uses static transmission interface transfer limits, developed based on a series of discrete transmission load flow study scenarios, to evaluate the transmission import-constrained area's reliability. Using the analysis, the ISO identifies a resource requirement sufficient to allow the system to operate through stressed conditions.[42] The

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[40] *Id.*

[41] PP-10 is available at: https://www.iso-ne.com/static-assets/documents/2020/02/pp-10.pdf

[42] *See* Section III.12.2.1.2(a) of the Tariff. The Transmission Security Analysis is similar, though not identical, to analysis that the ISO utilizes during the reliability review of de-list bids. *See ISO New England Inc.*, 123 FERC ¶

TSA utilizes the same set of data underlying the load forecast, resource capacity ratings and resource availability that are used in probabilistically determining the ICR, MCL, and LRA. However, due to the deterministic and transmission security-oriented nature of the TSA, some of the assumptions utilized in performing the TSA differ from the assumptions used in calculating the ICR, MCL and other aspects of the LRA. These differences relate to the manner in which load forecast data, and OP-4 action events are utilized in the TSA. These differences are described in more detail in the Kotha Testimony.[43]

For FCA 16, the ISO also calculated the MCLs for the Maine and NNE Capacity Zones. The MCLs were calculated using the methodology that is reflected in Section III.12.2.2 of the Tariff. The MCLs for the Maine and NNE Capacity Zones are as follows:

Export-Constrained Capacity Zone	MCL
Maine	4,095 MW
NNE	8,555 MW

V. HQICCs

HQICCs are capacity credits that are allocated to the IRH, which are the entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection").[44] Pursuant to Sections III.12.9.5 and III.12.9.7 of the Tariff, the tie benefit value for the HQ Interconnection was established using the results of a probabilistic calculation of tie benefits with Quebec. The ISO calculates HQICCs, which are allocated to the IRH in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each Capacity Commitment Period's FCA. The HQICC value for FCA 16 is 923 MW per month.

61,290 at PP 26-31 (2008).

[43] Kotha Testimony at 37-38.

[44] *See* Section I.2.2 of the Tariff (stating in the definition of "Hydro-Quebec Interconnection Capability Credit" that "[a]n appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate."). *See also* Section III.12.9.7 of the Tariff ("[t]he tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.").

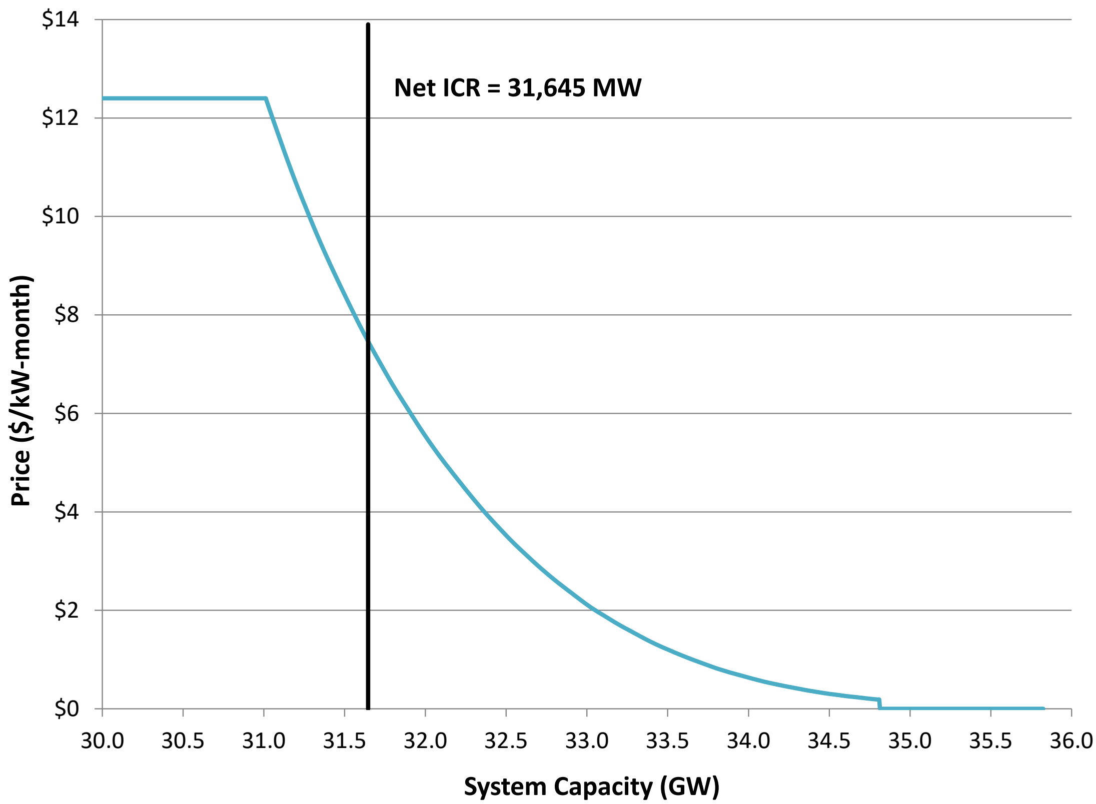
VI. MRI DEMAND CURVES

Starting with FCA 11, which was associated with the 2020-2021 Capacity Commitment Period, the ISO began using the MRI demand curve methodology to develop system-wide and zonal demand curves to be used in the FCA to procure needed capacity. Accordingly, as described below, the ISO has developed a System-Wide Capacity Demand Curve and Capacity Zone Demand Curves to be used in FCA 16.

A. System-Wide Capacity Demand Curve

Under Section III.12.1.1 of the Tariff, prior to each FCA, the ISO must determine the system-wide MRI of capacity at various higher and lower capacity levels for the New England Control Area. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used in determining the ICR. Using the values calculated pursuant to Section III.12.1.1.1, the ISO must determine the System-Wide Capacity Demand Curve pursuant to Section III.13.2.2.1 of the Tariff.[45] Below is the System-Wide Capacity Demand Curve for FCA 16.

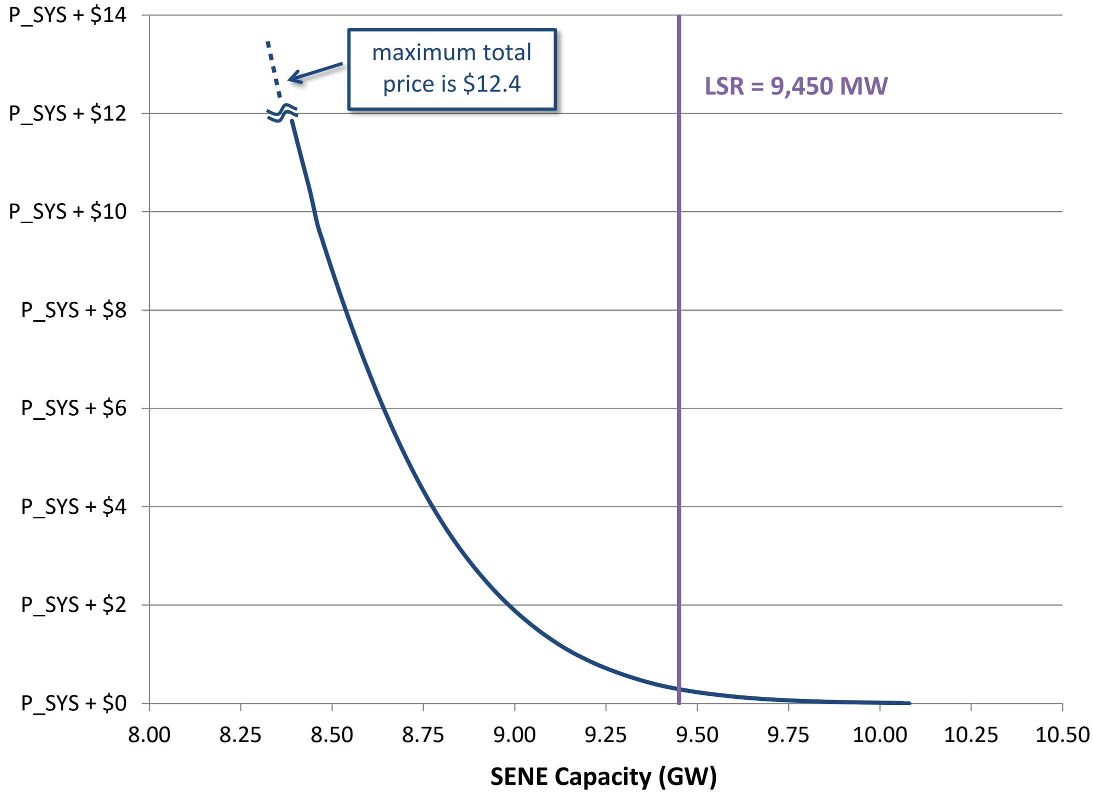
[45] Additional details regarding the calculation of the System-Wide Capacity Demand Curve are included in the Kotha Testimony at 41-42.



B. Import-constrained Capacity Zone Demand Curve

Under Section III.12.2.1.3 of the Tariff, prior to each FCA, the ISO must determine the MRI of capacity, at various higher and lower capacity levels around the requirement, for each import-constrained Capacity Zone. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used to determine the LRA pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1 (b) has to be reduced by the greater of: (i) the TSA Requirement minus the LRA, and; (ii) zero. Using the values calculated pursuant to Section III.12.2.1.3 of the Tariff, the ISO must determine the import constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.2 of the Tariff. For FCA 16, there is one import-constrained Capacity Zone and therefore, there is one import-constrained Capacity Zone Demand Curve.

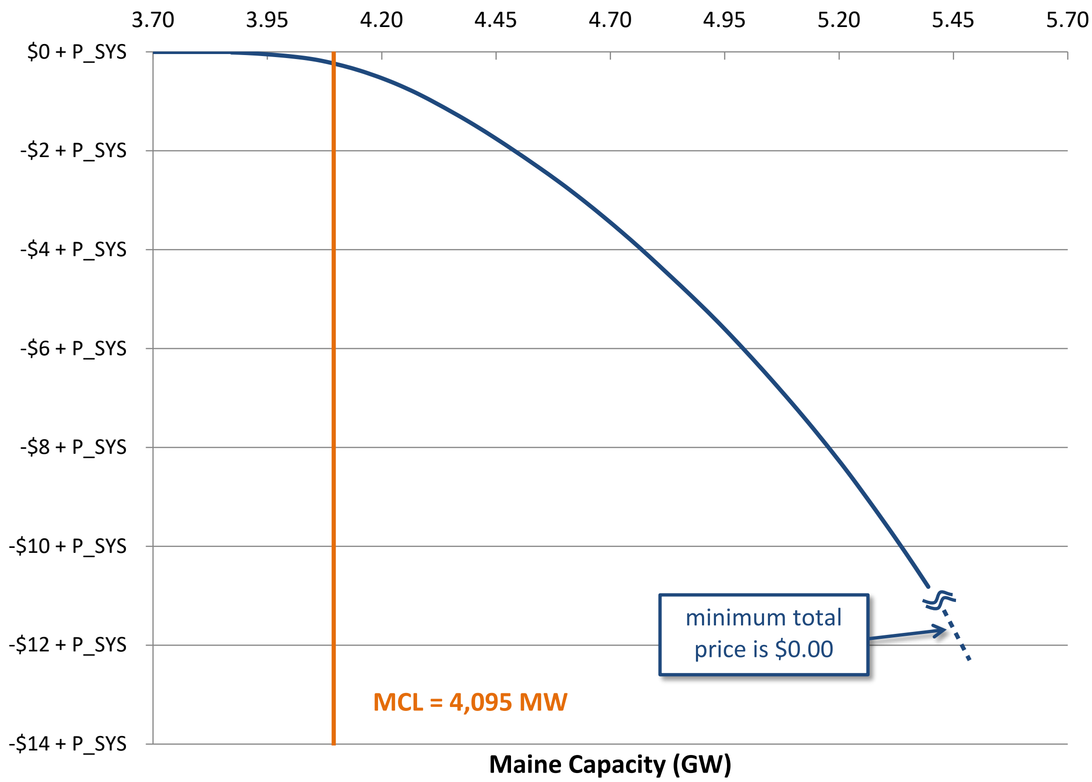
The following is the import-constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 16:



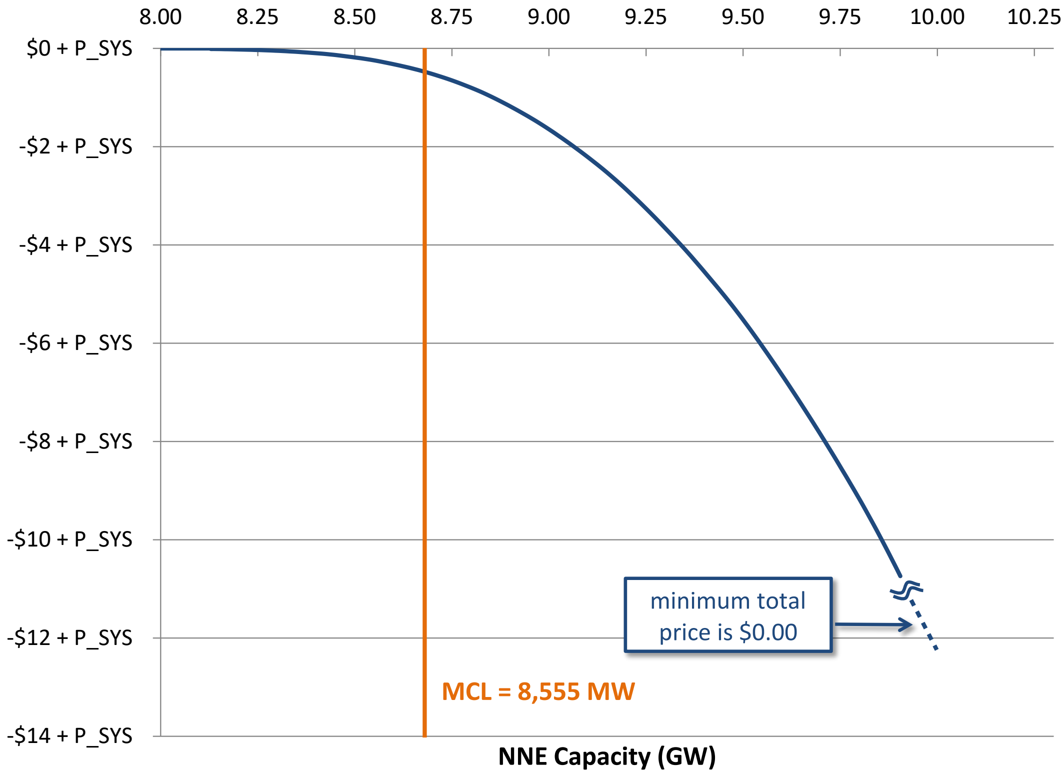
C. Export-constrained Capacity Zone Demand Curves

Under Section III.12.2.2.1 of the Tariff, prior to each FCA, the ISO must determine the MRI of capacity, at various higher and lower capacity levels around the requirement, for each export-constrained Capacity Zone. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's MCL. Using the values calculated pursuant to Section III.12.2.2.1 of the Tariff, the ISO must determine the export-constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.3 of the Tariff. For FCA 16, there are two export-constrained Capacity Zone Demand Curves, Maine and NNE.

The following is the export-constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 16:


3.70
3.95
4.20
4.45
4.70
4.95
5.20
5.45
5.70
$0 + P_SYS
-$2 + P_SYS
-$4 + P_SYS
-$6 + P_SYS
-$8 + P_SYS
-$10 + P_SYS
-$12 + P_SYS
-$14 + P_SYS
minimum total price is $0.00
MCL = 4,095 MW
Maine Capacity (GW)

The following is the export-constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 16:



VII. STAKEHOLDER PROCESS

The ISO, in consultation with NEPOOL and other interested parties, developed the proposed ICR-Related Values for FCA 16 through an extensive stakeholder process over the course of six months, during which the PSPC and the Reliability Committee reviewed the calculation assumptions and methodologies, and discussed the proposed ICR-Related Values for FCA 16.

In addition, in 2007 the New England States Committee on Electricity ("NESCOE") was formed.[46] Among other responsibilities, NESCOE is responsible for providing feedback on the

[46] *ISO New England Inc.*, Docket No. ER07-1324-000, Formation of the New England States Committee on Electricity (filed August 31, 2007) (proposing to add a new rate schedule to the Tariff for the purpose of recovering

proposed ICR-Related Values at the relevant NEPOOL PSPC, Reliability Committee and Participants Committee meetings, and was in attendance for most meetings at which the ICR-Related Values for FCA 16 were discussed.

On September 21, 2021, the Reliability Committee voted to recommend, by a voice vote (with two oppositions and eight abstentions recorded), that the Participants Committee support the HQICCs. Also on September 21, 2021, the Reliability Committee voted to recommend, by a voice vote (with two oppositions and nine abstentions recorded), that the Participants Committee support the proposed ICR-Related Values (*i.e.* the ICR, net ICR, LSR for the SENE Capacity Zone, MCLs for the Maine and NNE Capacity Zones, and MRI demand curves).

On October 7, 2021, the Participants Committee supported the HQICCs by a voice vote (with oppositions and abstentions recorded). Also on October 7, 2021, the Participants Committee supported the proposed ICR-Related Values (*i.e.* the ICR, net ICR, LSR for the SENE Capacity Zone, MCLs for the Maine and NNE Capacity Zones, and MRI demand curves) by a voice vote (with oppositions and abstentions recorded).

VIII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the proposed ICR-Related Values for FCA 16 to be effective on January 8, 2022 (which is 60 days from the filing date), so that the proposed values can be used as part of FCA 16, which will be conducted in February 2022.

IX. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for FCA 16 and is made pursuant to Section 205 of the FPA. Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of cost-of-service rates.[47] However, the proposed ICR-Related Values are not traditional "rates." Furthermore, the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations. Notwithstanding its request for waiver, the ISO submits the following additional information in compliance with the identified filing regulations of the Commission applicable to Section 205 filings.

35.13(b)(1) - Materials included herewith are as follows:

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funding for NESCOE's operation) (the "NESCOE Funding Filing"); *ISO New England Inc.*, 121 FERC ¶ 61,105 (2007) (order accepting the ISO's proposed rate schedule for funding of NESCOE's operations).

[47] 18 C.F.R. § 35.13.

- This transmittal letter;
- Attachment 1: Testimony of Manasa Kotha;
- Attachment 2: List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been emailed.

35.13(b)(2) – The ISO respectfully requests that the Commission accept this filing to become effective on January 8, 2022.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. An electronic copy of this transmittal letter and the accompanying materials has also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 2. In accordance with Commission rules and practice, there is no need for the entities identified on Attachment 2 to be included on the Commission's official service list in the captioned proceedings unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in Sections III-VI of this transmittal letter.

35.13(b)(6) - The ISO's approval of the ICR-Related Values is evidenced by this filing. The ICR-Related Values reflect the results of the Participant Processes required by the Participants Agreement and reflect the support of the Participants Committee.

35.13(b)(7) - The ISO has no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(c)(2) - The ISO does not provide services under other rate schedules that are similar to the sale for resale and transmission services it provides under the Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in order to supply service with respect to the proposed ICR and related values.

X. CONCLUSION

The ISO requests that the Commission accept the proposed ICR-Related Values reflected in this submission for filing without change to become effective January 8, 2022.

Respectfully submitted,

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Attachments

cc: Entities listed in Attachment 2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.) Docket No. ER22-___-000

PREPARED TESTIMONY OF
MANASA KOTHA
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A: My name is Manasa Kotha. I am a Lead Engineer in the System Planning Department at ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A: As mentioned above, I am currently a Lead Engineer in the System Planning Department at the ISO. In my current position, I am responsible for the development of the Installed Capacity Requirement ("ICR") and related values for the Forward Capacity Auction ("FCA") and the annual reconfiguration auctions ("ARAs") conducted in the Forward Capacity Market ("FCM").[1]

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[1] Capitalized terms used but not otherwise defined in this testimony have the meanings ascribed to them in the ISO New England Transmission, Markets, and Services Tariff (the "Tariff").

Since 2019, I have worked for the Resource Studies and Assessments group conducting ICR and related values studies for the FCM. I also performed resource adequacy studies to support the ISO's Regional System Plan and reliability reporting requirements of the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC"). Prior to that, I worked for 10 years in the Resource Analysis & Integration group, which is part of the ISO's System Planning Department. I was responsible for the qualification of Generating Capacity Resources, Demand Resources, and Import Capacity Resources for participation in the FCM. Prior to joining the ISO, I worked as a Software Engineer for Neumeric Technologies, where I developed software, carried out impact analysis, enhanced solutions by providing flexible business logic, testing code, and implementing quality management systems.

I have an M.S. in Electrical Engineering from the University of Missouri, Columbia, and a Bachelor of Technology in Electronics and Communication Engineering from Acharya Nagarjuna University, India.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: My testimony discusses the derivation of the ICR, net ICR, the Local Sourcing Requirement ("LSR") for the Southeast New England ("SENE") Capacity Zone, the Maximum Capacity Limits ("MCLs") for the Maine and Northern New England ("NNE") Capacity Zones,[2] the Hydro-Quebec Interconnection Capability Credits ("HQICCs"), and

[2] As explained in the ISO's Informational Filing for the sixteenth Forward Capacity Auction ("FCA 16"), which is being submitted to the Federal Energy Regulatory Commission ("Commission") concurrently with this filing, in accordance with Section III.12.4 of the Tariff, the ISO determined that it will model four

the Marginal Reliability Impact ("MRI") demand curves for the 2025-2026 Capacity Commitment Period, which is associated with FCA 16 to be conducted beginning on February 7, 2022. The 2025-2026 Capacity Commitment Period starts on June 1, 2025 and ends on May 31, 2026. The ICR, the LSR for the SENE Capacity Zone, the MCLs for the Maine and the NNE Capacity Zones, HQICCs and MRI demand curves for FCA 16 are collectively referred to herein as the "ICR-Related Values."

Q. ARE THERE ANY CHANGES TO THE METHODOLOGY FOR DEVELOPING THE INSTALLED CAPACITY REQUIREMENT AND RELATED VALUES?

A. Yes. This year, there are changes in the modeling methodologies for two categories of battery storage resources. Specifically, as more fully described in Section II.B.3 of my testimony, there are changes to the modeling methodology for co-located battery storage resources that participate in the FCM as non-intermittent resources, as well as the modeling methodology for stand-alone battery storage resources. In addition, starting this year, the ISO used a new methodology to calculate the availability of Active Demand Capacity Resources. This change is also described in Section II.B.3 of my testimony.

Capacity Zones in FCA 16: the SENE Capacity Zone, the Maine Capacity Zone, the NNE Capacity Zone and the Rest of Pool Capacity Zone. The SENE Capacity Zone includes the Southeastern Massachusetts ("SEMA"), Rhode Island and Northeastern Massachusetts ("NEMA")/Boston Load Zones. The SENE Capacity Zone will be modeled as an import-constrained Capacity Zone. The NNE Capacity Zone includes the New Hampshire, Vermont, and Maine Load Zones. The Maine Load Zone will be modeled as a separate nested export-constrained Capacity Zone within NNE. NNE will be modeled as an export-constrained Capacity Zone. The Rest-of-Pool Capacity Zone includes the Connecticut and Western/Central Massachusetts Load Zones.

Finally, this year, the ISO implemented Tariff changes that effect a new methodology for reconstituting passive Demand Resources ("PDR") in the load forecast. This new methodology is explained in the filing of Tariff changes that was submitted to FERC on September 11, 2020.[3] FERC accepted the changes in a letter order issued on October 30, 2020.[4] The rest of the methodology used to calculate the ICR-Related Values is the same Commission-approved methodology that was used to calculate the values submitted and accepted for preceding FCAs.

II. INSTALLED CAPACITY REQUIREMENT

A. DESCRIPTION OF THE INSTALLED CAPACITY REQUIREMENT

Q: WHAT IS THE "INSTALLED CAPACITY REQUIREMENT?"

A: The ICR is the minimum level of capacity required to meet the reliability requirements defined for the New England Control Area. These requirements are documented in Section III.12 of the Tariff, which states, in Section III.12.1, that "[t]he ISO shall determine the [ICR] such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated

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[3] The filing is available at https://www.iso-ne.com/static-assets/documents/2020/09/ee_reconstitution_tariff_changes.pdf

[4] The letter order is available at https://www.iso-ne.com/static-assets/documents/2020/10/er20-2869-000.pdf. The effect on the ICR of using the new PDR methodology is a decrease about 1,545 MW.

probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day[s] each year. The forecast ICR shall meet this resource adequacy planning criterion for each Capacity Commitment Period." Section III.12 of the Tariff also details the calculation methodology and the guidelines for the development of assumptions used in the calculation of the ICR.

The development of the ICR is consistent with NPCC's Full Member Resource Adequacy Criterion (Resource Adequacy Requirement R4),[5] under which the ISO must probabilistically evaluate resource adequacy to demonstrate that the loss of load expectation ("LOLE") of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year, while making allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

Q: PLEASE EXPLAIN THE GENERAL PROCESS FOR ESTABLISHING THE ICR-RELATED VALUES.

A: The ISO established the ICR-Related Values in accordance with the calculation methodology prescribed in Section III.12 of the Tariff. The ICR-Related Values and the assumptions used to develop them were discussed with stakeholders. The stakeholder

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[5] *See Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System* available at: https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/directories/directory-01-design-and-operation-of-the-bulk-power-system.pdf

process consisted of discussions with the New England Power Pool ("NEPOOL") Load Forecast Committee, Power Supply Planning Committee ("PSPC") and Reliability Committee. These committees' review and comment on the ISO's development of load and resource assumptions and the ISO's calculation of the ICR-Related Values were followed by advisory votes from the NEPOOL Reliability Committee and Participants Committee. State regulators also had the opportunity to review and comment on the ICR-Related Values as part of their participation on the PSPC, Reliability Committee, and Participants Committee. On October 7, 2021, the Participants Committee supported the HQICCs by a voice vote (with oppositions and abstentions recorded). Also on October 7, 2021, the Participants Committee supported the rest of the proposed ICR-Related Values (*i.e.* the ICR, net ICR, LSR for the SENE Capacity Zone, MCLs for the Maine and NNE Capacity Zones, and MRI demand curves) by a voice vote (with oppositions and abstentions recorded).

Q: PLEASE EXPLAIN IN MORE DETAIL THE PSPC'S INVOLVEMENT IN THE DETERMINATION AND REVIEW OF THE ICR-RELATED VALUES.

A: The PSPC is a non-voting technical subcommittee that reports to the Reliability Committee. The ISO chairs the PSPC and its members are representatives of the NEPOOL Participants. The ISO engages the PSPC to assist with the review of key inputs used in the development of resource adequacy-based requirements such as ICRs, LSRs, MCLs and MRI demand curves, including appropriate assumptions relating to load, resources, and tie benefits for modeling the expected system conditions. Representatives of the six New England States' public utilities regulatory commissions are also invited to attend and participate in the PSPC meetings and several were present for the meetings at which the ICR-Related Values for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, were discussed and considered.

Q: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT VALUE THAT THE ISO CALCULATED FOR FCA 16, WHICH IS ASSOCIATED WITH THE 2025-2026 CAPACITY COMMITMENT PERIOD.

A: The ICR value for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, is 32,568 MW.

Q: IS THIS THE AMOUNT OF INSTALLED CAPACITY REQUIREMENT THAT WAS USED FOR THE DEVELOPMENT OF THE SYSTEM-WIDE CAPACITY DEMAND CURVE?

A: No. The ISO developed the System-Wide Capacity Demand Curve based on the net ICR of 31,645 MW, which is the 32,568 MW of ICR minus 923 MW of HQICCs (which are allocated to the Interconnection Rights Holders in accordance with Section III.12.9.2 of the Tariff).

B. DEVELOPMENT OF THE INSTALLED CAPACITY REQUIREMENT

Q: PLEASE EXPLAIN THE CALCULATION METHODOLOGY FOR ESTABLISHING THE INSTALLED CAPACITY REQUIREMENT.

A: The ICR was established using the General Electric Multi-Area Reliability Simulation ("GE MARS") model. GE MARS uses a sequential Monte Carlo simulation to compute the resource adequacy of a power system. This Monte Carlo process repeatedly simulates the year (multiple replications) to evaluate the impacts of a wide range of possible combinations of resource capacity and load levels taking into account random resource outages, load forecast uncertainty, and behind-the-meter photovoltaic (BTM PV) output uncertainty. For the ICR, the system is considered to be a one bus model, in that the New England transmission system is assumed to have no internal transmission constraints in this simulation. For each hour, the program computes the isolated area capacity available to meet demand based on the expected maintenance and forced outages of the resources and the expected demand. Based on the available capacity, the program determines the probability of loss of load for the system for each hour of the year. After simulating all hours of the year, the program sums the probability of loss of load for each hour to arrive at an annual probability of loss of load value. This value is tested for convergence, which is set to be 5% of the standard deviation of the average of the hourly loss of load values. If the simulation has not converged, it proceeds to another replication of the study year.

Once the program has computed an annual reliability index, if the system is less reliable than the resource-adequacy criterion (*i.e.*, the LOLE is greater than 0.1 days per year), additional resources are needed to meet the criterion. Under the condition where New England is forecasted to be less reliable than the resource adequacy criterion, proxy resources are used within the model to meet this additional need. The methodology calls for adding proxy units until the New England LOLE is less than 0.1 days per year. For the ICR-Related Values for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, New England did not need proxy units because there is adequate qualified capacity to meet the 0.1 days/year LOLE criterion.

If the system is more reliable than the resource-adequacy criterion (*i.e.*, the system LOLE is less than or equal to 0.1 days per year), additional resources are not required, and the ICR is determined by increasing loads (additional load carrying capability or "ALCC") so that New England's LOLE is exactly at 0.1 days per year. This is how the single value that is called the ICR is established. The modeled New England system must meet the 0.1 days per year reliability criterion.

Q: WHAT ARE THE MAIN ASSUMPTIONS UPON WHICH THE ICR-RELATED VALUES FOR FCA 16 ARE BASED?

A: One of the first steps in the process of calculating the ICR-Related Values is for the ISO to determine the assumptions relating to expected system conditions for the Capacity Commitment Period. These assumptions are explained in detail below and include the load forecast, resource capacity ratings, resource availability, and the amount of load and/or capacity relief obtainable from certain actions specified in ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency ("Operating Procedure No. 4"), which system operators invoke in real-time to balance demand with system supply in the event of expected capacity shortage conditions. Relief available from Operating Procedure No. 4 actions includes the amount of possible emergency assistance (tie benefits) obtainable from New England's interconnections with neighboring Control Areas and load reduction from implementation of 5% voltage reductions.

1. LOAD FORECAST

Q: PLEASE EXPLAIN HOW THE ISO DERIVES THE LOAD FORECAST ASSUMPTION USED IN DEVELOPING THE INSTALLED CAPACITY REQUIREMENT AND RELATED VALUES.

A: For probabilistic-based calculations associated with ICR-Related Values, the ISO develops a forecasted distribution of typical daily peak loads for each week of the year based on 25 years of historical weather data and an econometrically estimated monthly model of typical daily peak loads. Each weekly distribution of typical daily peak loads includes the full range of daily peaks that could occur over the full range of weather experienced in that week and their associated probabilities. The 50/50 and the 90/10 peak loads are points on this distribution and used as reference points. The probabilistic-based calculations take into account all possible forecast load levels for the year. From these weekly peak load forecast distributions, a set of seasonal load forecast uncertainty multipliers are developed and applied to a specific historical hourly load profile to provide seasonal load information about the probability of loads being higher, and lower, than the peak load found in the historical profile. These multipliers are developed for New England in its entirety or for each subarea using the historic 2002 load profile.[6]

[6] The year 2002 is used for the load profile since it has an adequate number of peak load days for the calculation of ICR and related values and it is the year that NPCC uses for resource adequacy studies.

For deterministic analyses such as the Transmission Security Analysis ("TSA"), the ISO uses the reference 90/10 load forecast, as published in the 2021-2030 Forecast Report of Capacity, Energy, Loads, and Transmission ("2021 CELT Report"), which is net of BTM PV resources.

Q: PLEASE DESCRIBE THE FORECASTED LOAD WITHIN CAPACITY ZONES FOR FCA 16, WHICH IS ASSOCIATED WITH THE 2025-2026 CAPACITY COMMITMENT PERIOD.

A: The ISO developed the forecasted load for the SENE Capacity Zone using the combined load forecast for the state of Rhode Island and a load share ratio of the SEMA and NEMA/Boston load to the forecasted load for the entire Commonwealth of Massachusetts. The load share ratio is based on detailed bus load data from the network model for SEMA and NEMA/Boston, respectively, as compared to all of Massachusetts.

The ISO developed the forecasted load for the Maine Capacity Zone using the load forecast for the State of Maine.

The ISO developed the forecasted load for the NNE Capacity Zone using the combined load forecasts for the states of New Hampshire, Vermont, and Maine.

Q: WHAT DOES THE ISO CURRENTLY PROJECT TO BE THE NEW ENGLAND AND CAPACITY ZONE 50/50 AND 90/10 PEAK LOAD FORECAST FOR THE 2025-2026 CAPACITY COMMITMENT PERIOD?

A: The following table shows the 50/50 and 90/10 peak load forecast for the 2025-2026 Capacity Commitment Period based on the 2021 load forecast as documented in the 2021 CELT Report. These values are reported as the "Net (with reductions for BTM PV)" load forecast.

Table 1 – 50/50 and 90/10 Peak Load Forecast (MW)

	50/50	**90/10**
New England	28,025	29,988
SENE	11,991	12,960
Maine	2,129	2,240
NNE	5,462	5,739

Q: PLEASE DESCRIBE THE DEVELOPMENT OF THE BTM PV FORECAST AT A HIGH LEVEL.

A: Each year since 2014, the ISO, in conjunction with the Distributed Generation Forecast Working Group ("DGFWG") (which includes state agencies responsible for administering the New England states' policies, incentive programs and tax credits that support BTM PV growth in New England), develops forecasts of future nameplate ratings of BTM PV installations anticipated over the 10-year planning horizon. These forecasts are created for each state based on policy drivers, recent BTM PV growth trends, and discount adjustments designed to represent a degree of uncertainty in future BTM PV commercialization.

Q: WHAT METHODOLOGY DID THE ISO USE TO REFLECT THE CONTRIBUTIONS OF BTM PV TO REDUCE THE LOAD FORECAST FOR FCA 16?

A: For FCA 16, as was done for prior FCAs, the ISO used an "hourly profile" methodology to determine the amount of load reduction provided by BTM PV in all hours of the day and all days of the year. The BTM PV hourly profile models the forecast of PV output as the full hourly load reduction value of BTM PV in all 8,760 hours of the year. This reflects the actual impact of BTM PV installations in reducing system load and uncertainty associated with the BTM PV.

Q: HOW IS TRANSPORTATION ELECTRIFICATION REFLECTED IN THE ICR MODEL?

A: Transportation electrification impacts both the summer and winter peak demands and monthly energy. As such, the impact of electric vehicle ("EV") load is explicitly modeled in the ICR calculation using an hourly EV demand forecast that reflects: (1) the assumed seasonal and weekday charging patterns; and (2) an 8% gross up for assumed transmission and distribution losses. The hourly EV forecast is modeled deterministically without considering uncertainty.

Q: HOW IS HEATING ELECTRIFICATION REFLECTED IN THE ICR MODEL?

A: Because heating electrification is weather-sensitive, it carries the load uncertainty associated with weather. Heating electrification only affects peak demand and energy in the winter months. Hence, to model it in the ICR, heating electrification is added into the gross load forecast, reflecting both the impacts from its penetration level and the uncertainty associated with weather.

Q: HOW WERE THE ESTIMATED IMPACTS OF THE UPDATES TO THE LOAD FORECAST IN THE INSTALLED CAPACITY REQUIREMENT DERIVED?

A: The estimated impacts of the updates to the 2021 long-term forecast on the net ICR were derived through simulations using preliminary load forecast data prior to finalizing the 2021 CELT forecast. While the loads used are very close to the 2021 CELT forecast, they are not exactly the same. The simulations were done earlier in the process to provide stakeholders with the estimated impacts of the improvements to the long-term forecast methodology and the change in the historical period used in the model estimation.

2. RESOURCE CAPACITY RATINGS

Q: PLEASE DESCRIBE THE RESOURCE DATA THAT THE ISO USED TO DEVELOP THE ICR-RELATED VALUES FOR FCA 16, WHICH IS ASSOCIATED WITH THE 2025-2026 CAPACITY COMMITMENT PERIOD.

A: The ISO developed the ICR-Related Values for FCA 16 based on the Existing Qualified Capacity Resources for the 2025-2026 Capacity Commitment Period. This assumption is based on the latest available data at the time of the ICR-Related Values calculation.

Q: WHAT ARE THE RESOURCE CAPACITY VALUES FOR THE 2025-2026 CAPACITY COMMITMENT PERIOD?

A: The following tables illustrate the make-up of the 33,523 MW of capacity resources assumed in the calculation of the ICR-Related Values.

Table 2 – Qualified Existing Non-Intermittent Generating Capacity Resources by Load Zone (MW)[7]

Load Zone	Summer
MAINE	3,055.870
NEW HAMPSHIRE	4,064.064
VERMONT	199.623
CONNECTICUT	9,840.270
RHODE ISLAND	1,899.569
SEMA	4,778.498
WESTERN/CENTRAL MASSACHUSETTS	3,643.463
NEMA/BOSTON	1,307.215
Total New England	**28,788.572**

Table 3 – Qualified Existing Intermittent Power Resources by Load Zone (MW)[8]

Load Zone	Summer	Winter
MAINE	274.892	328.854
NEW HAMPSHIRE	79.239	161.805
VERMONT	61.180	106.158
CONNECTICUT	93.750	66.180
RHODE ISLAND	50.104	41.741
SEMA	285.234	358.085
WESTERN/CENTRAL MASSACHUSETTS	167.345	115.115
NEMA/BOSTON	54.931	44.081
Total New England	**1,066.675**	**1,222.019**

[7] Values reflect the existing resources with Qualified Capacity for FCA 16 at the time of the ICR calculation and reflect applicable resource retirements and resource terminations.

[8] All resources have only their summer capacity rating modeled in the ICR-Related Values with the exception of Intermittent Power Resources which have both their summer and winter capacity ratings modeled.

Table 4 – Qualified Existing Import Capacity Resources (MW)

There are no qualified Existing Import Capacity Resources for FCA 16.

Table 5 – Qualified Existing Demand Capacity Resources by Load Zone (Summer MW)

Load Zone	On-Peak	Seasonal Peak	Active Demand Capacity Resource (ADCR)	Total
MAINE	210.184	0.000	137.803	347.987
NEW HAMPSHIRE	136.442	0.000	48.407	184.849
VERMONT	119.904	0.000	51.904	171.808
CONNECTICUT	199.380	518.359	192.829	910.568
RHODE ISLAND	270.227	0.000	44.737	314.964
SEMA	405.098	0.000	59.395	464.493
WESTERN/CENTRAL MASSACHUSETTS	392.023	25.363	112.072	529.458
NEMA/BOSTON	643.330	0.000	99.802	743.132
Total New England	**2,376.588**	**543.722**	**746.949**	**3,667.259**

Although capacity resource data are tabulated above under the eight settlement Load Zones, only SENE (the combined SEMA, NEMA/Boston, and Rhode Island Load Zones), Maine (the Maine Load Zone), and NNE (the combined New Hampshire, Vermont and Maine Load Zones) are relevant for FCA 16.

Q: WHAT ARE THE ASSUMPTIONS RELATING TO RESOURCE ADDITIONS (THOSE WITHOUT CAPACITY SUPPLY OBLIGATIONS) AND ATTRITIONS?

A: Resource additions, beyond those classified as "Existing Capacity Resources," and attritions (with the exception of those associated with permanent de-list bids, unconditional retirements and retirements below the Forward Capacity Auction Starting

Price of $12.400 $/kW-month) are not assumed in the calculation of the ICR-Related Values for FCA 16, which is associated with the 2025-2026 Capacity Commitment Period, because there is no certainty that new resource additions or resource attritions below the Forward Capacity Auction Starting Price will clear the auction.

3. RESOURCE AVAILABILITY

Q: PLEASE EXPLAIN THE RESOURCE AVAILABILITY ASSUMPTIONS UNDERLYING THE CALCULATIONS OF THE ICR-RELATED VALUES FOR FCA 16, WHICH IS ASSOCIATED WITH THE 2025-2026 CAPACITY COMMITMENT PERIOD.

A: Resources are modeled at their Qualified Capacity values along with their associated resource availability in the calculation of the ICR-Related Values. For generating resources, scheduled maintenance assumptions are based on each unit's historical five-year average of scheduled maintenance. If the individual resource has not been operational for a total of five years, then NERC Generator Availability Database System ("GADS") class average data is used to substitute for the missing annual data. In the ICR-Related Values model, it is assumed that maintenance outages of generating resources will not be scheduled during the peak load season of June through August.

An individual generating resource's forced outage assumption is based on the resource's five-year historical data from the ISO's database of NERC GADS. If the individual resource has not been operational for a total of five years, then NERC class average data is used to substitute for the missing annual data. The same resource availability assumptions are used in all the calculations except for the TSA, which requires the modeling of the availability of peaking generating resources with a deterministic adjustment factor.[9]

The Qualified Capacity of an Intermittent Power Resource is based on the resource's historical median output during the Reliability Hours averaged over a period of five years. The Reliability Hours are specific, defined hours during the summer and the winter, and hours during the year in which the ISO has declared a system-wide or a Load Zone-specific shortage event. Because this method already takes into account the resource's availability, Intermittent Power Resources are assumed to be 100% available in the models at their "Qualified Capacity" and not based on "nameplate" ratings. Qualified Capacity is the amount of capacity that either a generating, demand, or import resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the FCM qualification process.

Demand Capacity Resources in the On-Peak Demand and Seasonal Peak Demand categories are non-dispatchable resources that reduce load across pre-defined hours, typically by means of energy efficiency. These types of Demand Capacity Resources are assumed to be 100% available. Below I describe the new modeling methodologies for co-located non-intermittent battery storage resources and stand-alone storage resources,

[9] *See* Section III.B of this testimony.

as well as a revised methodology for establishing the availability assumptions for Active Demand Capacity Resources (which is also new this year).

Q: PLEASE LIST THE FOUR CATEGORIES OF BATTERY STORAGE RESOURCES BASED ON THEIR FCM PARTICIPATION.

A: Based on their FCM participation, the four categories of battery storage resources are: (1) battery storage resources that participate as Intermittent Power Resources (these may be co-located with other Intermittent Power Resources and may participate in the FCM as a single Intermittent Power Resource); (2) co-located battery storage resources that participate as non-intermittent resources (these resources are co-located with Intermittent Power Resources, but participate as non-intermittent Generating Capacity Resources); (3) stand-alone battery storage resources, which participate in the FCM as non-intermittent Generating Capacity Resources; and (4) battery storage resources that participate in the FCM as part of a Demand Capacity Resource.

Q: PLEASE BRIEFLY DESCRIBE HOW THE ISO MODES EACH OF THE FOUR CATEGORIES OF BATTERY STORAGE RESOURCES IN THE ICR AND RELATED VALUES IN PREVIOUS YEARS, AND INDICATE WHICH OF THOSE METHODOLOGIES ARE CHANGING THIS YEAR.

A: The ISO models battery storage resources that participate as Intermittent Power Resources using the methodology that it uses to model Intermittent Power Resources (*i.e.*, using Qualified Capacity values and 100% availability). This methodology is not changing this year. The ISO models battery storage resources that participate in the FCM as part of a Demand Capacity Resource using the established modeling methodology for Demand Capacity Resources. This methodology is also not changing this year.

In previous years, the ISO modeled both categories of battery storage resources that participate as non-intermittent Generation Capacity Resources (*i.e.,* battery storage resources co-located with Intermittent Power Resources that participate as non-intermittent resources and stand-alone battery storage resources) as thermal generating units using NERC Class "HYDRO 1-29" as a proxy availability assumption. As explained below, this year, the ISO is replacing this methodology with two new methodologies to model these two categories of battery storage resources.

Q: PLEASE DESCRIBE THE NEW METHODOLOGY FOR MODELING CO-LOCATED BATTERY STORAGE RESOURCES THAT PARTICIPATE AS NON-INTERMITTENT GENERATING CAPACITY RESOURCES, AND STATE WHY THIS METHODOLOGY IS AN IMPROVEMENT OVER THE PREVIOUS MODELING METHODOLOGY.

A: Starting this year, the ISO is modeling co-located battery storage resources that participate as non-intermittent Generating Capacity Resources in the FCM using the methodology that it uses to model Intermittent Power Resources. Specifically, to model co-located battery storage resources that participate in the FCM as non-intermittent Generating Capacity Resources, the ISO will use the resources' Qualified Capacity values and will assume 100% availability.

This methodology is an improvement over the previous methodology because the configurations and characteristics of co-located battery storage resources that participate in the FCM as non-intermittent resources are similar to the configurations and operating characteristics of those participating as Intermittent Power Resources. Specifically, both of those categories of battery storage resources are subject to shared facility constraints at the Point of Interconnection, they charge only from the co-located Intermittent Power Resources, and the timing of charging is dependent on the output of the co-located Intermittent Power Resources and the operator's discretion. The combined impact is an improvement to capacity factor, resulting in less variability on the combined output and, in most cases, increased energy output over intermittent-only facilities. Given the similarity between these two types of resources, it is appropriate to model them using the same methodology.

Q: **PLEASE DESCRIBE THE NEW METHODOLOGY FOR MODELING STAND-ALONE BATTERY RESOURCES, AND STATE WHY THIS METHODOLOGY IS AN IMPROVEMENT OVER THE PREVIOUS MODELING METHODOLOGY.**

Starting this year, the ISO is modeling stand-alone battery storage resources (which participate in the FCM as non-intermittent Generating Capacity Resources) using a class model. Specifically, all resources are modeled using the same typical design and operational parameters of the fleet. The parameters of the class model for GE MARS are as follows:

Maximum generation and charging rating: respective Qualified Capacity values

Maximum energy: respective usable AC energy

Round-trip efficiency: 84%

Number of calls per day: 1

Maximum energy per call: maximum energy x 98% (range between maximum and minimum usable state of charge).

The EFORd of these battery storage resources is assumed to be 5% with zero weeks of maintenance and mainly used in the TSA calculation.

This methodology is an improvement over the previous methodology because the new methodology utilizes the modeling capabilities of GE MARS's recently released module for modeling battery storage resources, taking into consideration factors that affect battery storage resources' unavailability to serve demand, and the comparability to other types of resources.

Q: PLEASE DESCRIBE THE PREVIOUS METHODOLOGY AND THE NEW METHODOLOGY FOR ESTABLISHING THE AVAILABILITY ASSUMPTIONS FOR ACTIVE DEMAND CAPACITY RESOURCES.

A: Previously, performance of Demand Capacity Resources in the Active Demand Capacity Resource category was measured by actual response during performance audits and other dispatches that occurred in the most recent five-year period (last year, the period was 2016 through 2020). To calculate historical availability, the verified commercial capacity of each resource was compared to its monthly net Capacity Supply Obligation.

Starting this year, the availability of Active Demand Capacity Resources is calculated on an annual basis for each Load Zone utilizing data from both summer and winter performance, weighting the seasons based on their relative duration throughout the year. A rolling average of the forced outage rate for Active Demand Capacity Resources will be developed as a five year-rolling average. However, this year, the ISO only has three years' worth of data, and accordingly, the average for this year only takes into account those three years. Next year, the average will take into account four years of data and, starting in 2023, the average will use five years of data, which will then start rolling in 2024.

Q: WHY IS THE NEW METHODOLOGY FOR ESTABLISHING THE AVAILABILITY ASSUMPTIONS FOR ACTIVE DEMAND CAPACITY RESOURCES AN IMPROVEMENT OVER THE PREVIOUS METHODOLOGY?

A: The new methodology is an improvement because it takes both availability and performance relative to Capacity Supply Obligations during audits into account, whereas the previous methodology only took into account performance relative to Capacity Supply Obligations. Availability in this context is the percentage of hours in each season where Demand Response Resources associated with an Active Demand Capacity Resource with a non-zero Capacity Supply Obligation offered as available and with a Maximum Reduction greater than zero.

4. OTHER ASSUMPTIONS

Q: PLEASE DESCRIBE THE ASSUMPTIONS RELATING TO INTERNAL TRANSMISSION TRANSFER CAPABILITIES FOR THE DEVELOPMENT OF ICR-RELATED VALUES FOR FCA 16.

A: The assumed N-1 and N-1-1 transmission contingencies for import and export constrained Capacity Zones modeled are shown in the table below.

Table 6 – Internal Interface Transfer Capabilities (MW)

Interface	Contingency	2025-2026
Southeast New England Import (for SENE LSR)	N-1	5,250
	N-1-1	4,550
Maine (for Maine MCL)	N-1	1,900
Northern New England (for NNE MCL)	N-1	2,725

Q: PLEASE DISCUSS THE ISO'S ASSUMPTIONS REGARDING THE ACTIONS OF OPERATING PROCEDURE NO. 4 IN DEVELOPING THE ICR-RELATED VALUES FOR FCA 16.

A: In the development of the ICR, Local Resource Adequacy Requirement ("LRA"), MCL and MRI demand curves, the ISO uses assumed emergency assistance (*i.e.* tie benefits, which are described below) available from neighboring Control Areas, and load reduction from implementation of 5% voltage reductions. These all constitute actions that system operators invoke under Operating Procedure No. 4 in real-time to balance system demand with supply under expected or actual capacity shortage conditions. The amount of load relief assumed obtainable from invoking 5% voltage reductions pursuant to Section III.12.7.4 (a) is 1%. Using the 1% reduction in system load demand, the assumed voltage reduction load relief values, which offset against the ICR, are 263 MW for June through September 2025 and 204 MW for October 2025 through May 2026.

5. TIE BENEFITS

Q: WHAT ARE TIE BENEFITS?

A: Tie benefits represent the possible emergency energy assistance from the interconnected neighboring Control Areas when a capacity shortage occurs.

Q: WHAT IS THE ROLE OF EXTERNAL TRANSMISSION IMPORT TRANSFER CAPABILITIES IN DEVELOPING THE ICR-RELATED VALUES?

A: While external transmission import transfer capabilities are not an input to the calculation of the ICR-Related Values, they do impact the tie benefit assumption. Specifically, the external transmission import transfer capabilities would impact the amount of emergency energy, if available, that could be imported into New England.

Q: ARE INTERNAL TRANSMISSION TRANSFER CAPABILITIES MODELED IN TIE BENEFITS STUDIES?

A: Internal transmission transfer capability constraints that are not addressed by either a LSR or MCL are modeled in the tie benefits study. The results of the tie benefits study are used as an input in the ICR, LRA, MCL, and MRI demand curves calculations.

Q: PLEASE EXPLAIN HOW TIE BENEFITS FROM NEIGHBORING CONTROL AREAS ARE ACCOUNTED FOR IN DETERMINING THE INSTALLED CAPACITY REQUIREMENT.

A: The New England resource planning reliability criterion requires that adequate capacity resources be planned and installed such that disconnection of firm load would not occur more often than once in ten years due to a capacity deficiency after taking into account the load and capacity relief obtainable from implementing Operating Procedure No. 4. In other words, load and capacity relief assumed obtainable from implementing Operating Procedure No. 4 actions are direct substitutes for capacity resources for meeting the once in 10 years disconnection of firm load criterion. Calling on neighboring Control Areas to provide emergency energy assistance ("tie benefits") is one of the actions of Operating Procedure No. 4. Therefore, the amount of tie benefits assumed obtainable from the interconnected neighboring Control Areas directly displaces that amount of installed capacity resources needed to meet the resource planning reliability criterion. When determining the amount of tie benefits to assume in ICR calculations, it is necessary to recognize that, while reliance on tie benefits can reduce capacity resource needs, over-reliance on tie benefits decreases system reliability. System reliability would decrease because each time emergency assistance is requested there is a possibility that the available assistance will not be sufficient to meet the capacity deficiency. The more tie benefits are relied upon to meet the resource planning reliability criterion, and the greater the amount of assistance requested, the greater the possibility that they will not be available or sufficient to avoid implementing deeper actions of Operating Procedure No. 4, and interrupting firm load in accordance with ISO New England Operating Procedure

No. 7, Action in an Emergency. For example, some of the resources that New York has available to provide tie benefits are demand response resources that have limits on the number of times they can be activated. In addition, none of the neighboring Control Areas are conducting their planning, maintenance scheduling, unit commitment, or real-time operations with a goal of maintaining their emergency assistance at a level needed to maintain the reliability of the New England system.

Q: PLEASE DESCRIBE THE TIE BENEFITS ASSUMPTIONS UNDERLYING THE ICR-RELATED VALUES FOR FCA 16.

A: Under Section III.12.9 of the Tariff, the ISO is required to perform a tie reliability benefits study for each FCA, which provides the total overall tie benefit value available from all interconnections with adjacent Control Areas, the contribution of tie benefits from each of these adjacent Control Areas, as well as the contribution from individual interconnections or qualifying groups of interconnections within each adjacent Control Area.

Pursuant to Section III.12.9 of the Tariff, the ICR calculations for FCA 16 assume total tie benefits of 1,830 MW based on the results of the tie benefits study for the 2025-2026 Capacity Commitment Period. A breakdown of this total value is as follows: 923 MW from Quebec over the Hydro-Quebec Phase I/II HVDC Transmission Facilities, 142 MW from Quebec over the Highgate interconnection, 478 MW from Maritimes (New Brunswick) over the New Brunswick interconnections, and 287 MW from New York over the AC interconnections. Tie benefits are assumed not available over the Cross

Sound Cable because the import capability of the Cross Sound Cable was determined to be 0 MW.

Q: IS THE ISO'S METHODOLOGY FOR CALCULATING TIE BENEFITS FOR FCA 16 THE SAME AS THE METHODOLOGY USED FOR FCA 15?

A: Yes. The methodology for calculating the tie benefits used in the ICR for FCA 16 is the same methodology used to calculate the tie benefits used in the ICR for FCA 15. This methodology is described in detail in Section III.12.9 of the Tariff.

Q: DOES THIS CALCULATION METHODOLOGY CONFORM WITH INDUSTRY PRACTICE AND TARIFF REQUIREMENTS?

A: Yes. This probabilistic calculation methodology is widely used by the electric industry. NPCC has been using a similar methodology for many years. The ISO has been using the GE MARS program and a similar probabilistic calculation methodology for tie benefits calculations since 2002. The calculation methodology conforms to the Tariff provisions filed with and accepted by the Commission.

Q: PLEASE EXPLAIN THE ISO'S METHODOLOGY FOR DETERMINING THE TIE BENEFITS FOR FCA 16.

A: The ISO conducted the tie benefits study for FCA 16 using the probabilistic GE MARS program to model the expected system conditions of New England and its directly interconnected neighboring Control Areas of Quebec, New Brunswick, and New York. All of these Control Areas were assumed to be "at criterion," which means that the capacity of all three neighboring Control Areas was adjusted so that they would each have a LOLE of once in ten years when interconnected to each other.

The ISO applied the "at criterion" approach to represent the expected amounts of capacity in each Control Area since each of these areas has structured its planning processes and markets (where applicable) to achieve the "at criterion" level of reliability. The total tie benefits to New England from Quebec, Maritimes (New Brunswick) and New York were calculated first. To calculate total tie benefits, the ISO brought the interconnected system of New England and its directly interconnected neighboring Control Areas to 0.1 days per year LOLE and then compared to the LOLE of the isolated New England system. Total tie benefits equal the amount of firm capacity equivalents that must be added to the isolated New England Control Area to bring New England to 0.1 days per year LOLE.

Following the calculation of total tie benefits, the ISO calculated individual tie benefits from each of the three directly interconnected neighboring Control Areas. The ISO calculated tie benefits from each neighboring Control Area using a similar analysis, with tie benefits from the Control Area equaling the simple average of the tie benefits calculated from all possible interconnection states between New England and the target Control Area, subject to adjustment, if any, for capacity imports as described below.

If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits is pro-rationed so that the sum of each Control Area's tie benefits equals the total tie benefits for all Control Areas. Following this calculation, the ISO calculated tie benefits for each individual interconnection or qualifying group of interconnections, and a similar pro-rationing was performed if the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits.

After the pro-rationing, the ISO adjusted the tie benefits for each individual interconnection or group of interconnections to account for capacity imports. After the import capability and capacity import adjustments, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area then represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas then represents the total tie benefits available to New England.

Q: HOW DOES THE ISO DETERMINE WHICH INTERCONNECTIONS MAY BE ALLOCATED A SHARE OF TIE BENEFITS?

A: Tie benefits are calculated for all interconnections for which a "discrete and material transfer capability" can be determined. This standard establishes that if an interconnection has any discernible transfer capability, it will be evaluated. If this nominal threshold is met, then the ISO evaluates the interconnection to determine whether it should be evaluated independently or as part of a group of interconnections. An interconnection will be evaluated with other interconnections as part of a "group of interconnections" if that interconnection is one of two or more AC interconnections that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer capability, such that the individual lines in the group of interconnections cannot be assigned individual contributions. This standard is contained in Section III.12.9.5 of the Tariff.

Finally, one component of the tie benefits calculation for individual interconnections is the determination of the "transfer capability" of the interconnection. If the interconnection has minimal or no available transfer capability during times when the ISO will be relying on the interconnection for tie benefits, then the interconnection will be assigned minimal or no tie benefits.

Q: ARE THERE ANY INTERCONNECTIONS BETWEEN NEW ENGLAND AND ITS DIRECTLY INTERCONNECTED NEIGHBORING CONTROL AREAS FOR WHICH THE ISO HAS NOT CALCULATED TIE BENEFITS?

A: No. The ISO calculated tie benefits for all interconnections between New England and its directly interconnected neighboring Control Areas, either individually or as part of a group of interconnections.

Q: WHAT IS THE TRANSFER CAPABILITY OF EACH OF THE INTERCONNECTIONS OR GROUPS OF INTERCONNECTIONS FOR WHICH TIE BENEFITS HAVE BEEN CALCULATED?

A: The following table lists the external transmission interconnections and the transfer capability of each used for calculating tie benefits for FCA 16:

Table 7 – External Interface Import Capability (MW)

External Transmission Interconnections/Interfaces	Capacity Import Capability into New England
Hydro-Quebec Phase I/II HVDC Transmission Facilities	1,400
Highgate Interconnection	200
Maritimes (New Brunswick) Interconnections	700
Cross-Sound Cable	0
New York AC Interface	1,400

One factor in the calculation of tie benefits is the transfer capability into New England of the interconnections for which tie benefits are calculated. In the first half of 2021, the ISO reviewed transfer limits of these external interconnections based on the latest available information regarding forecasted topology and load forecast information, and determined that no changes to the established external interface transmission import limits were warranted. The other factor is the transfer capability of the internal transmission interfaces. For internal transmission interfaces, when calculating tie benefits for the 2025-2026 ICR filed herewith, the ISO used the transfer capability values from its most recent transfer capability analyses.

6. AMOUNT OF SYSTEM RESERVE

Q: WHAT AMOUNT OF SYSTEM RESERVES IS REQUIRED TO BE INCLUDED AS AN ASSUMPTION IN THE DETERMINATION OF THE ICR?

A: Section III.12.7.4(c) of the Tariff requires that the determination of the ICR and related values include an amount of system reserves that is consistent with those needed for reliable system operations during emergency conditions.

Q: WHAT AMOUNT OF SYSTEM RESERVES DID THE ISO USE IN THE DETERMINATION OF THE PROBABILISTIC ICR-RELATED VALUES?

A: The ISO used 700 MW as the amount of system reserve in the determination of the probabilistic ICR-Related Values, which is the same as the value it used for FCA 15.

III. LOCAL SOURCING REQUIREMENT AND MAXIMUM CAPACITY LIMIT

A. DESCRIPTION OF LOCAL SOURCING REQUIREMENT

Q: WHAT IS THE LOCAL SOURCING REQUIREMENT?

A: The LSR is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone. The LSR is the mechanism used to assist in valuing capacity appropriately in constrained areas. It is the amount of capacity needed to satisfy "the higher of" (i) the LRA or (ii) the TSA Requirement. The LSR is applied to import-constrained Capacity Zones within New England.

Q: WHAT ARE IMPORT-CONSTRAINED CAPACITY ZONES?

A: Import-constrained Capacity Zones are areas within New England that, due to transmission constraints, are close to the threshold where they may not have enough local resources and transmission import capability to reliably serve local demand.

Q: HOW IS AN IMPORT-CONSTRAINED CAPACITY ZONE DETERMINED?

A: A separate import-constrained Capacity Zone is identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Open Access Transmission Tariff ("OATT"), Section II, Attachment K, as a zone for which the second contingency transmission capability results in a line-line TSA Requirement, calculated pursuant to Section III.12.2.1.2 of the Tariff and pursuant to ISO New England Planning Procedures, that is greater than the Existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model as out-of-service all retirement requests (including any received for the current FCA at the time of this calculation) and Permanent De-List Bids as well as rejected for reliability Static and Dynamic De-List Bids from the most recent previous FCA.

Q: WHICH ZONES WILL BE MODELED AS IMPORT CONSTRAINED CAPACITY ZONES FOR FCA 16?

A: After applying the import-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 16, the SENE Capacity Zone, which consists of the combined Load Zones of SEMA, NEMA/Boston, and Rhode Island, will be modeled as a separate import-constrained Capacity Zone.

B. DEVELOPMENT OF THE LOCAL SOURCING REQUIREMENT

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE LOCAL SOURCING REQUIREMENT.

A: The methodology for calculating the LSR harmonizes the use of the local resource adequacy criteria and the transmission security criteria that the ISO uses to maintain system operational reliability when reviewing de-list bids for the FCA. Because the system must meet both resource adequacy and transmission security requirements, both are developed for each import-constrained zone under Section III.12.2 of the Tariff. Specifically, the LSR for an import-constrained zone is the amount of capacity needed to satisfy "the higher of" (i) the LRA or (ii) the TSA Requirement. Under this approach, the ISO calculates a zonal requirement using probabilistic resource adequacy criteria, referred to as the "Local Resource Adequacy Requirement" and a deterministic transmission security analysis referred to as the "Transmission Security Analysis Requirement." The term Local Sourcing Requirement refers to "the higher of" the Local Resource Adequacy Requirement or the requirement calculated based on the TSA.

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE LOCAL RESOURCE ADEQUACY REQUIREMENT.

A: For each import-constrained Capacity Zone, the LRA is determined by modeling the zone under study vis-à-vis the rest of New England. This, in effect, turns the modeling effort into a series of two-area reliability simulations. The reliability target of this analysis is a system-wide LOLE of 0.105 days per year when the transmission constraints between the two zones are included in the model. Because the LRA is the minimum amount of resources that must be located in a zone to meet the system-reliability requirements for a capacity zone with excess capacity, the process to calculate this value involves shifting capacity out of the zone under study until the reliability threshold, or target LOLE of 0.105,[10] is achieved.

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE TRANSMISSION SECURITY ANALYSIS REQUIREMENT.

A: The TSA is a deterministic reliability screen of an import-constrained area and is a basic security review set out in Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market, and in Section 3.0 of NPCC's Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System.[11] This review determines the requirement of the sub-area to meet its load through internal generation and import capacity. In performing the analysis, static transmission interface transfer limits are established as a reasonable representation of the transmission system's capability to serve sub-area load with available existing resources, and results are presented under the form of a deterministic operable capacity analysis. This analysis also includes evaluations of both: (1) the loss of the most critical transmission element and the most critical generator ("Line-Gen"), and; (2) the loss of the most critical transmission element followed by loss of the next most critical transmission element ("Line-Line"). Similar deterministic

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[10] An allowance for transmission-related LOLE of 0.005 days per year is applied when determining the Local Resource Adequacy Requirement of a capacity zone.

[11] Available at https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/directories/directory-01-design-and-operation-of-the-bulk-power-system.pdf

analyses are also used each day by the ISO's system operations department to assess the amount of capacity to be committed day-ahead. Further, such deterministic sub-area transmission security analyses have consistently been used for reliability review studies performed to determine if the removal of a resource that may be retired or de-listed would violate reliability criteria.

Q: WHAT ARE THE DIFFERENCES BETWEEN THE ASSUMPTIONS USED FOR THE DETERMINATION OF THE TRANSMISSION SECURITY ANALYSIS REQUIREMENT AND THE ASSUMPTIONS USED FOR THE DETERMINATION OF THE LOCAL RESOURCE ADEQUACY REQUIREMENT?

A: There are two differences between the assumptions relied upon for the TSA Requirement and the assumptions relied upon for determining the LRA. The first difference relates to the load forecast assumption. Resource adequacy analyses (*i.e.*, the analysis performed in determining the ICR, LRA, MCL, and MRI demand curves) are performed using the full probability distribution of load variations due to weather uncertainty. For the purpose of performing the deterministic TSA, single discreet points on the probability distribution are used; in accordance with ISO New England Planning Procedure No. 10, the analysis is performed using the published net 90/10 peak load forecast, which is net of the BTM PV forecasted value. The 90/10 peak load forecast corresponds to a peak load that has a 10% probability of being exceeded based on weather variation.

The second difference relates to the reliance on Operating Procedure No. 4 actions, which are not traditionally relied upon in TSAs. Specifically, no load or capacity relief obtainable from implementing Operating Procedure No. 4 actions are included in the calculation of the TSA Requirement.

Q: PLEASE DESCRIBE THE LOCAL RESOURCE ADEQUACY REQUIREMENT, TRANSMISSION SECURITY ANALYSIS REQUIREMENT, AND LOCAL SOURCING REQUIREMENT FOR THE SENE IMPORT-CONSTRAINED CAPACITY ZONE FOR FCA 16.

A: For FCA 16, the LRA, TSA Requirement, and the LSR for the SENE import-constrained Capacity Zone for FCA 16 Capacity Zones are as follows:

Table 8 – Import-Constrained Capacity Zone Requirements for the 2025-2026 Capacity Commitment Period (MW)

Capacity Zone	Local Resource Adequacy Requirement	Transmission Security Analysis Requirement	Local Sourcing Requirement
SENE	9,450	8,962	9,450

IV. MAXIMUM CAPACITY LIMIT

Q: WHAT IS THE MAXIMUM CAPACITY LIMIT?

A: The MCL is the maximum amount of capacity that is electrically located in an export-constrained Capacity Zone used to meet the ICR.

Q: WHAT ARE EXPORT-CONSTRAINED CAPACITY ZONES?

A: Export-constrained Capacity Zones are areas within New England where the available resources, after serving local load, may exceed the areas' transmission capability to export excess resource capacity.

Q: HOW IS AN EXPORT-CONSTRAINED CAPACITY ZONE DETERMINED?

A: A separate export-constrained Capacity Zone is identified in the most recent annual assessment of transmission transfer capability pursuant to OATT Section II, Attachment K, as a zone for which the MCL is less than the sum of the existing qualified capacity and proposed new capacity that could qualify to be procured in the export-constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

Q: WHICH ZONES WILL BE MODELED AS EXPORT CONSTRAINED CAPACITY ZONES FOR FCA 16?

A: After applying the export-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 16, the Maine and NNE Capacity Zones will be modeled as separate export-constrained Capacity Zones. The Maine Capacity Zone consists of the Maine Load Zone. The NNE Capacity Zone consists of the combined New Hampshire, Vermont, and Maine Load Zones.

Q: WHAT ARE THE MAXIMUM CAPACITY LIMITS FOR THE EXPORT-CONSTRAINED CAPACITY ZONES FOR FCA 16 AND HOW WERE THEY CALCULATED?

A: The MCL for the Maine Capacity Zone for FCA 16 is 4,095 MW and the MCL for the NNE Capacity Zone is 8,555 MW which also reflect the tie benefits assumed available over the Maritimes (New Brunswick) and Highgate interfaces. The ISO calculated the MCLs using the methodology that is reflected in Section III.12.2.2 of the Tariff.

In order to determine the MCLs, the New England net ICR and the LRA of the "*Rest of New England*" are needed. *Rest of New England* refers to all areas except the export-constrained Capacity Zone under study. Given that the net ICR is the total amount of resources that the region needs to meet the 0.1 days/year LOLE, and the LRA for the *Rest of New England* is the minimum amount of resources required for that area to satisfy its reliability criterion, the difference between the two is the maximum amount of resources that can be used within the export-constrained Capacity Zone to meet the 0.1 days/year LOLE.

V. HQICCs

Q: WHAT ARE HQICCs?

A: HQICCs are capacity credits that are allocated to the Interconnection Rights Holders, which are entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection").[12] Pursuant to

[12] *See* Section I.2.2 of the Tariff (stating in the definition of "Hydro-Quebec Interconnection Capability Credit" that "[a]n appropriate share of the HQICC shall be assigned to an IRH if the Hydro Quebec (HQ) Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate."). *See also* Section III.12.9.7 of the Tariff ("The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section

Sections III.12.9.5 and III.12.9.7 of the Tariff, the tie benefit value for the HQ Interconnection was established using the results of a probabilistic calculation of tie benefits with Quebec. The ISO calculates HQICCs, which are allocated to Interconnection Rights Holders in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each FCA.

Q: WHAT ARE THE HQICC VALUES FOR FCA 16, WHICH IS ASSOCIATED WITH THE 2025-2026 CAPACITY COMMITMENT PERIOD?

A: The HQICC values are 923 MW for every month of the 2025-2026 Capacity Commitment Period.

VI. MRI DEMAND CURVES

Q: PLEASE DESCRIBE THE METHODOLOGY USED FOR CALCULATING THE MRI DEMAND CURVES FOR FCA 16.

A: To calculate the System-Wide Capacity Demand Curve, the import-constrained Capacity Zone Demand Curve for SENE, and the export-constrained Capacity Zone Demand Curves for Maine and NNE for FCA 16, the ISO used the MRI methodology, which measures the marginal reliability impact (*i.e.* the MRI), associated with various capacity levels for the system and the Capacity Zones.

III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.").

To measure the MRI, the ISO uses a performance metric known as "expected energy not served" ("EENS," which can be described as unserved load.) EENS is measured in MWh per year and can be calculated for any set of system and zonal installed capacity levels. The EENS values for system capacity levels are produced by the GE MARS model,[13] in 10 MW increments, applying the same assumptions used in determining the ICR. These system EENS values are translated into MRI values by estimating how an incremental change in capacity impacts system reliability at various capacity levels, as measured by EENS. An MRI curve is developed from these values with capacity represented on the X-axis and the corresponding MRI values on the Y-axis.

MRI demand curve values at various capacity levels are also calculated for the SENE import-constrained Capacity Zone and the Maine and NNE export-constrained Capacity Zones using the same modeling assumptions and methodology as those used to determine the LRA and the MCLs for those Capacity Zones, with the exception of the modification of the transmission transfer capability for the SENE import-constrained Capacity Zone as described in more detail below. These MRI values are calculated to reflect the change in system reliability associated with transferring incremental capacity from the Rest-of-Pool Capacity Zone into the constrained capacity zone.

[13] The GE MARS model is the same simulation system that is used to develop the ICR and other values that specify how much capacity is required for resource adequacy purposes from a system planning perspective. For the development of the MRI demand curves, the same GE MARS model is used to calculate reliability values using 10 MW additions above and 10 MW deductions below the calculated requirements until a sufficient set of values that covers the full range necessary to produce the MRI demand curves is determined.

Q: PLEASE EXPLAIN THE USE OF A CAPACITY DEMAND CURVE SCALING FACTOR IN THE MRI DEMAND CURVE METHODOLOGY.

A: In order to satisfy both the reliability needs of the system, which requires that the FCM procure sufficient capacity to meet the 0.1 days per year reliability criterion and produce a sustainable market such that the average market clearing price is sufficient to attract new entry of capacity when needed over the long term, the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for FCA 16 are set equal to the product of their MRI curves and a fixed demand curve scaling factor. The scaling factor is set equal to the lowest value at which the set of demand curves will simultaneously satisfy the planning reliability criterion and pay the estimated cost of new entry ("Net CONE").[14] In other words, the scaling factor is equal to the value that produces a System-Wide Capacity Demand Curve that specifies a price of Net CONE at the net ICR (ICR minus HQICCs).

To satisfy this requirement, the demand curve scaling factor for FCA 16 was developed for the System-Wide Capacity Demand Curve, the import-constrained Capacity Zone Demand Curve for the SENE import-constrained Capacity Zone, and the export-constrained Capacity Zone Demand Curves for the Maine and NNE export-constrained Capacity Zones in accordance with Section III.13.2.2.4 of the Tariff. The demand curve scaling factor is set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the LOLE is 0.1 days per year.

[14] For FCA 16, Net CONE has been determined as $7.468/kW-month.

Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE IMPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVE FOR THE SENE CAPACITY ZONE.

A: For import-constrained Capacity Zones, the LRA and TSA Requirement values both play a role in defining the MRI-based demand curves as they do in setting the LSR. Under III.12.2.1.3 of the Tariff, prior to each FCA, the ISO must determine the MRI value of various capacity levels, for each import-constrained Capacity Zone. For purposes of these calculations, the ISO applies the same modeling assumptions and methodology used to determine the LRA except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area is reduced by the greater of: (i) the TSA Requirement minus the LRA, and; (ii) zero. By using a transfer capability that accounts for both the TSA and the LRAs, the ISO applies the same "higher of" logic used in the LSR to the derivation of sloped zonal demand curves. For FCA 16, there is one import-constrained Capacity Zone and therefore, there is one import-constrained Capacity Zone Demand Curve.

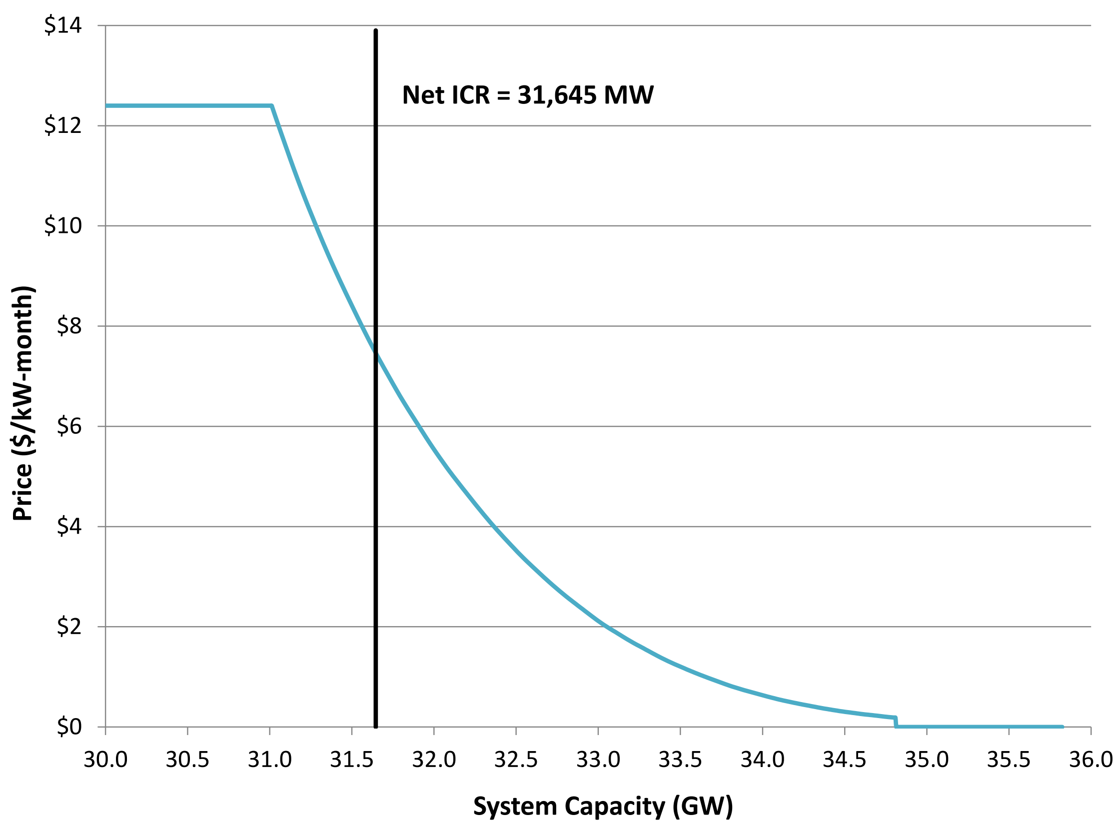
Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE EXPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVES FOR THE MAINE AND NNE CAPACITY ZONES.

A: Under Section III.12.2.2.1 of the Tariff, prior to each FCA, export-constrained Capacity Zone Demand Curves are calculated using the same modeling assumptions and methodology used to determine the export-constrained Capacity Zones' MCLs. Using the values calculated pursuant to Section III.12.2.2.1 of the Tariff, the ISO must determine the export-constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.3 of the Tariff. For FCA 16, the export-constrained Capacity Zones are Maine and NNE, and, therefore, there are two export-constrained Capacity Zone Demand Curves.

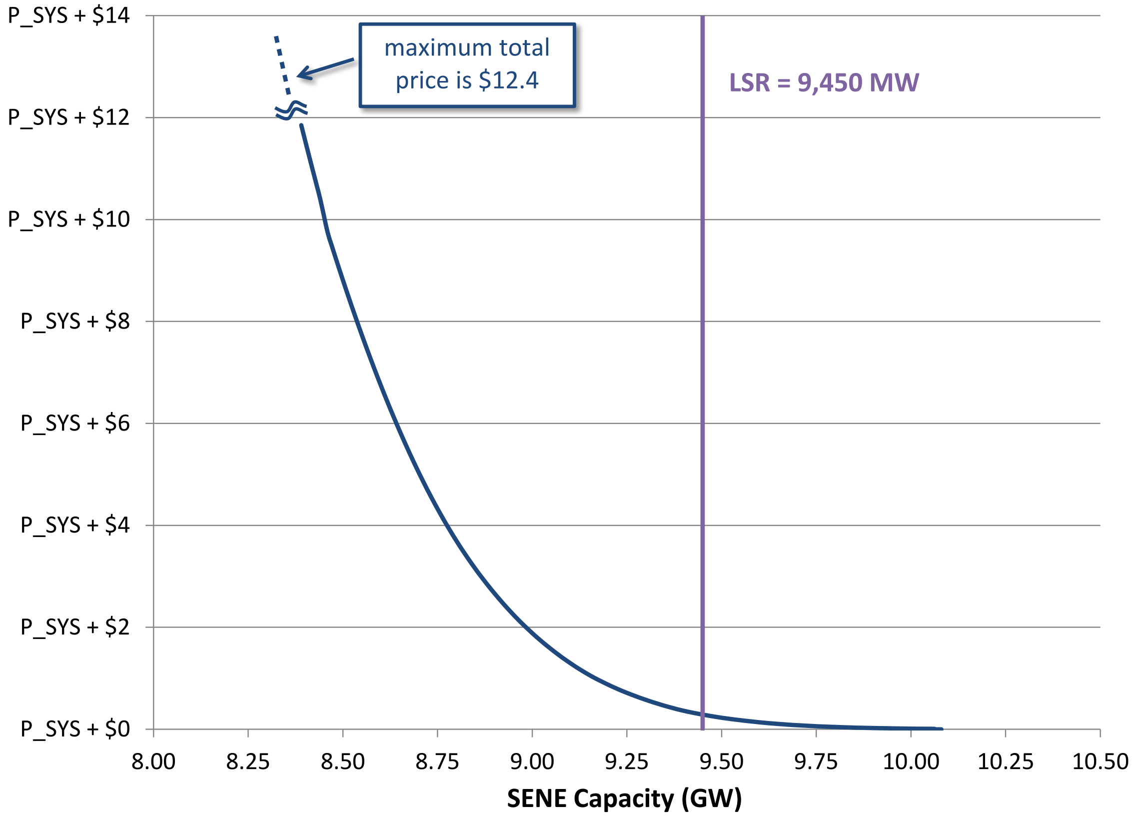
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR FCA 16?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI demand curves for FCA 16:

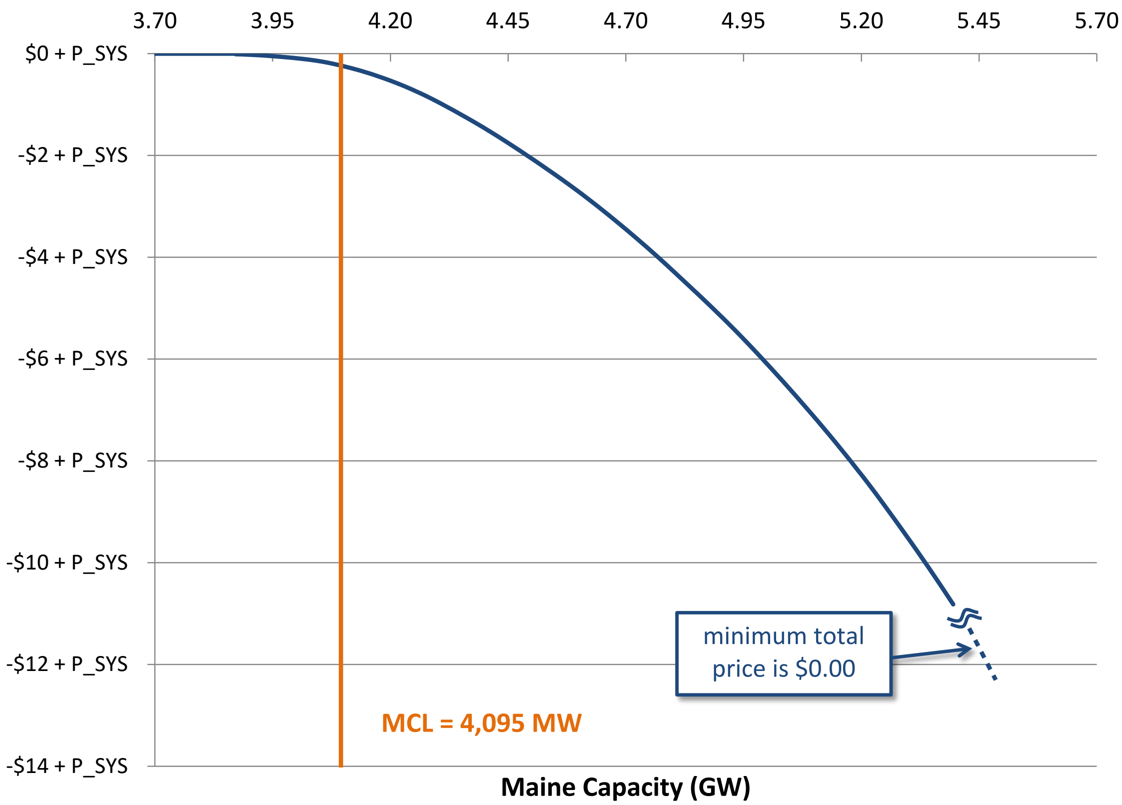
1. System-Wide Capacity Demand Curve for FCA 16



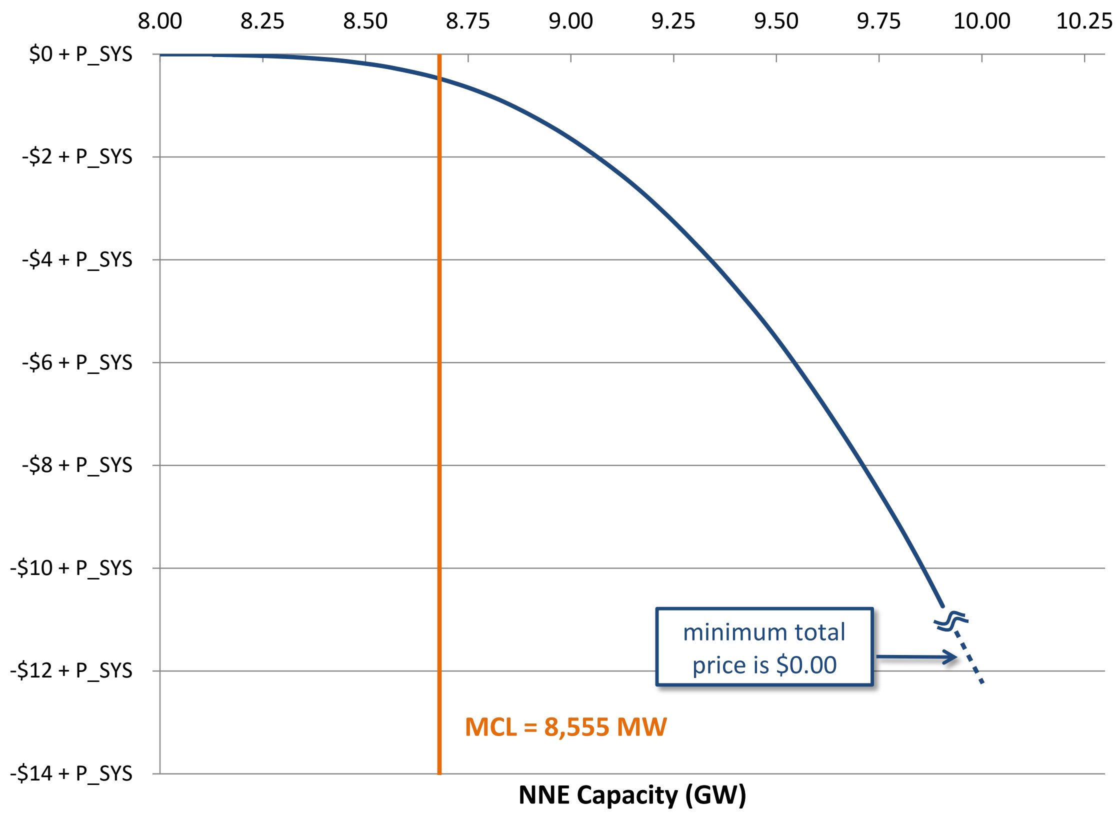
2. Import-constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 16



3. Export-constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 16



4. Export-constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 16



Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Manasa K

Manasa Kotha

November 8, 2021

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