November 10, 2020

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. ER21-___-000, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the Fifteenth FCA (Associated with the 2024-2025 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"), 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 2024-2025 Capacity Commitment Period,[2] which is associated with the fifteenth Forward Capacity Auction ("FCA 15"): (i) Installed Capacity Requirement ("ICR");[3] (ii) Local Sourcing Requirement for the Southeast New England ("SENE") Capacity Zone;[4] (iii) Maximum Capacity Limits ("MCLs") for the Maine ("Maine") and Northern New England ("NNE") Capacity Zones;[5] (iv) Hydro Quebec Interconnection Capability Credits ("HQICCs"); and (v) Marginal Reliability Impact ("MRI") demand curves.[6] The ICR, net ICR, the LSR for the SENE Capacity

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[1] 16 U.S.C. § 824d (2019).

[2] The 2024-2025 Capacity Commitment Period starts on June 1, 2024 and ends on May 31, 2025.

[3] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in the ISO's Transmission, Markets and Services Tariff (the "Tariff").

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

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

[6] 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, the MCLs for the Maine and NNE Capacity Zones, HQICCs, and MRI demand curves are collectively referred to herein as the "ICR-Related Values." [7]

The ISO is proposing the following ICR-Related Values for FCA 15:

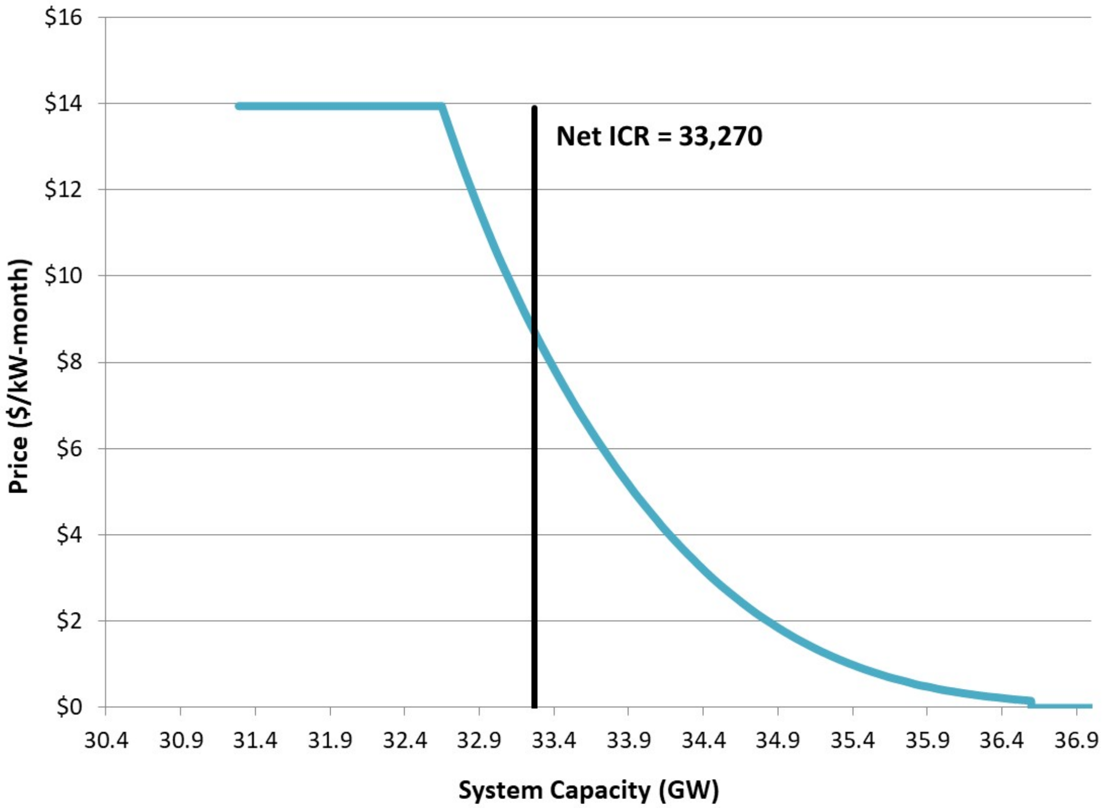
ICR	34,153 MW
Net ICR (ICR minus HQICCs)	33,270 MW
LSR for SENE Capacity Zone	10,305 MW
MCL for Maine	4,145 MW
MCL for NNE	8,680 MW
HQICCs	883 MW

Along with the following MRI demand curves:

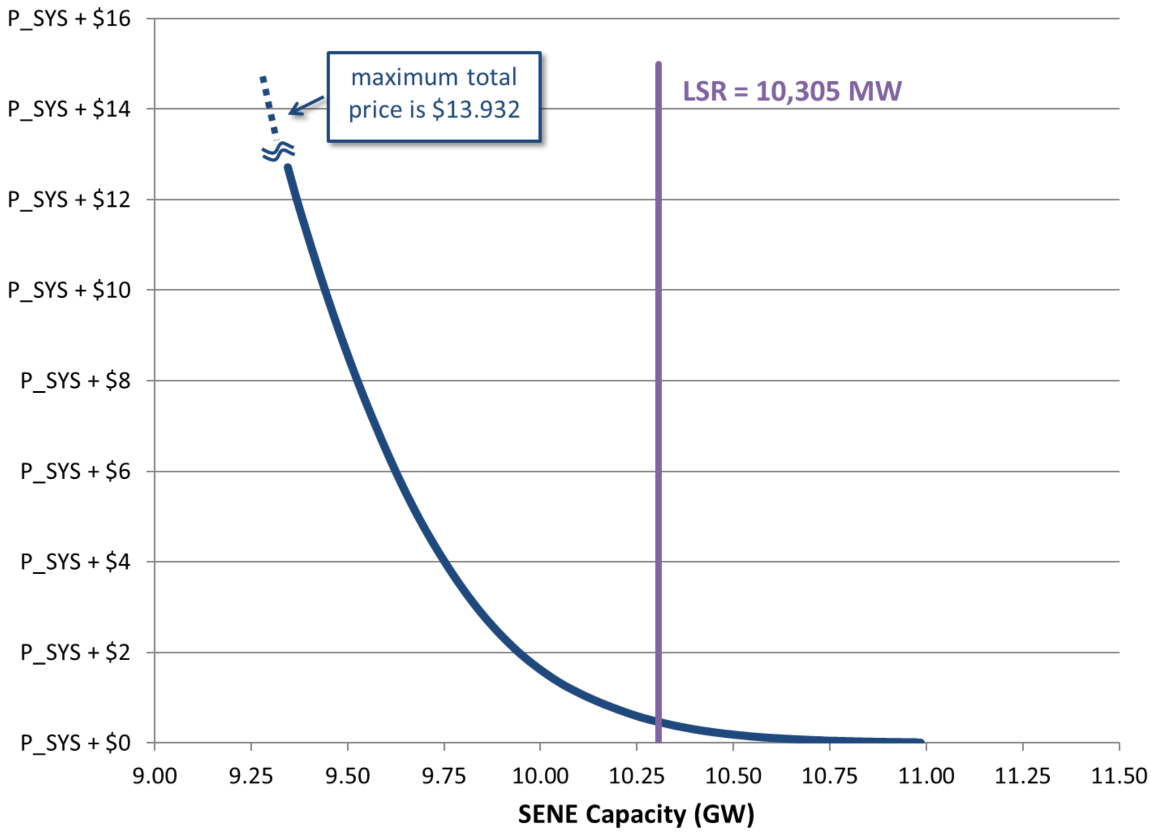
Zone Demand Curves for the Maine and NNE Capacity Zones.

[7] 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 15, which is the primary FCA for the 2024-2025 Capacity Commitment Period, is scheduled to commence on February 8, 2021.

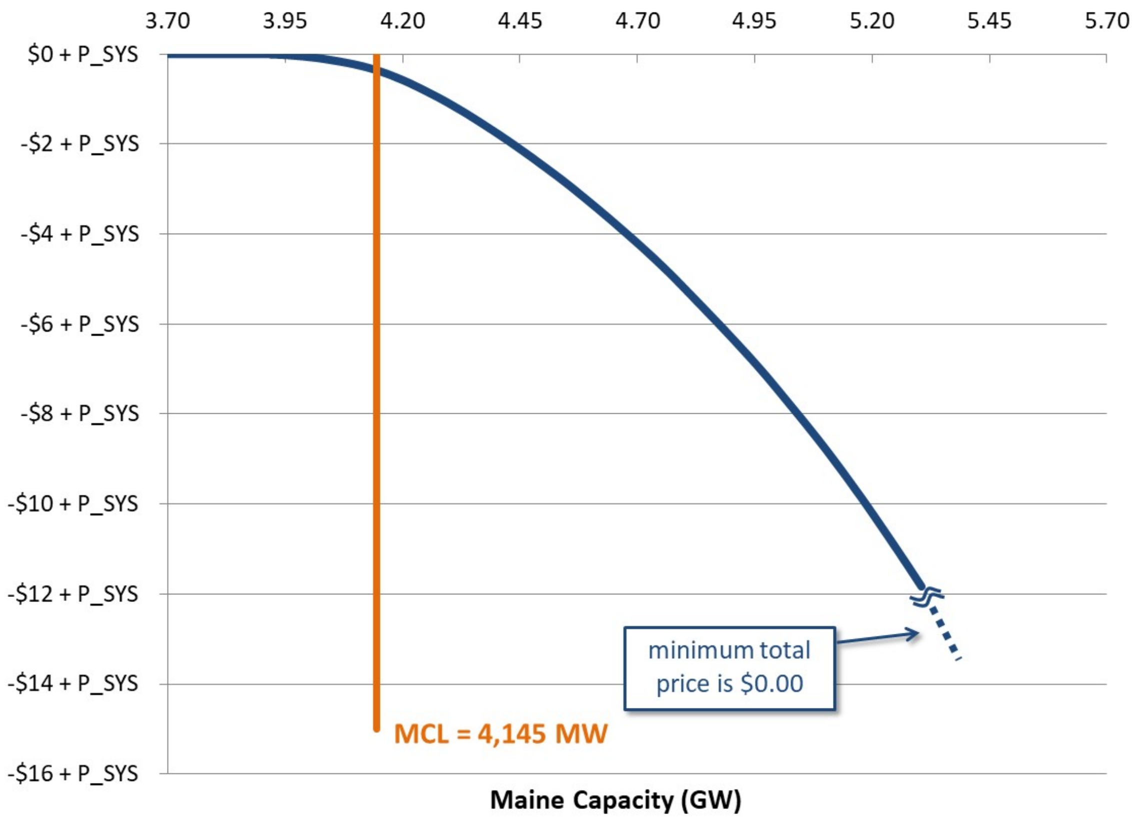
1. System-Wide Capacity Demand Curve for FCA 15



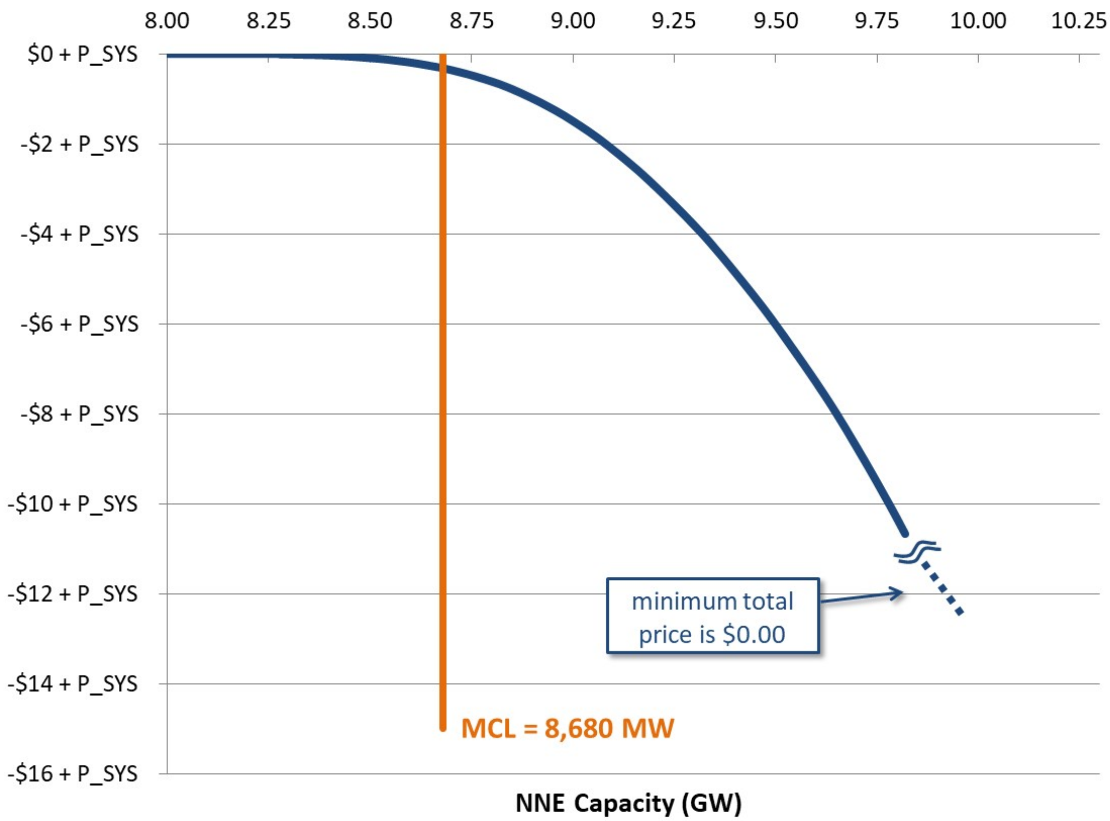
2. Import-constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 15



3. Export-constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 15



4. Export-constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 15



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, Senior Engineer in the ISO's System Planning Department (the "Kotha Testimony"). The Kotha Testimony is solely sponsored by the ISO.

For the first time this year, the ISO developed transportation electrification and heating electrification forecasts, and included them in the long-term forecast that is used as an assumption in the calculation of the ICR-Related Values. The development of these forecasts is described in Sections III.B.1.a and III.B.1.b of this filing letter and in the attached testimony of Jonathan Black, Manager, Load Forecasting in the ISO's System Planning Department (the

"Black Testimony").[8] The Black Testimony is solely sponsored by the ISO.

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.[9] 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.[10] Accordingly, the Commission should accept the proposed values as just and reasonable without change to become effective on January 9, 2021.

I. DESCRIPTION OF FILING PARTIES 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 include all of the electric utilities rendering or receiving service under the Tariff, as well as

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[8] By design, the load forecast methodology is not contained in the Tariff. Accordingly, Tariff changes are not needed to effect the improvements in the load forecast methodology. *See ISO New England Inc.,* 154 FERC ¶ 61,008 (2016); *order on reh'g*, 155 FERC ¶ 61,145 (2016).

[9] *ISO New England Inc.,* Docket No. ER20-311-000 (Jan. 3, 2020)

[10] *See id; see, also* FERC orders approving prior ICR filings: 2022-2023 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).

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,[11] 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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[11] *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004).

[12] 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 15, which is associated with the 2024-2025 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."[13] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[14] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[15] 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."[16] The ICR-Related Values submitted herein "need not be the only reasonable methodology, or even the most accurate."[17] 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.[18]

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 34,153 MW for FCA 15, which is associated with the 2024-2025 Capacity Commitment Period. This value reflects tie benefits (emergency energy assistance) assumed obtainable from Maritimes (New Brunswick), New York and Quebec in the aggregate amount of 1,735 MW. However, the 34,153 MW ICR value does not reflect a

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

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

[15] *Id.* at 9.

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

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

[18] *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 883 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 33,270 MW.[19]

B. Development of the ICR

With the exception of the inclusion of the transportation electrification and heating electrification forecasts in the load forecast assumption, the calculation methodology used to develop the ICR-Related Values for FCA 15 is the same as that used to calculate the values for the previous FCA. 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 2024-2025 Capacity Commitment Period are one major input into the calculation of the ICR-Related Values. For the purpose of calculating the ICR for FCA 15, which is associated with the 2024-2025 Capacity Commitment Period, the ISO used the load forecast published in the 2020-2029 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2020 ("2020 CELT Report").[20] As in previous years, the load forecast methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee ("LFC").[21]

The projected New England Control Area summer 50/50 peak load[22] for the 2024-2025 Capacity Commitment Period is 29,303 MW. In determining the ICR, the load forecast is

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[19] The net ICR is used in the development of the MRI demand curves, which will be used to procure capacity in FCA 15.

[20] Kotha Testimony at 9-14.

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

[22] 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 2020 CELT "Net (with reductions for BTM PV)" peak load forecast, as shown in CELT Section 1.1 Summer Peak Capabilities and Load Forecast.

represented by a weekly probability distribution of daily peak loads. This probability 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.[23]

In addition, for the first time this year, the ISO incorporated transportation electrification and heating electrification forecasts in the 2020 CELT Report's load forecast. The ISO discussed the methodology, assumptions, and related energy and demand impacts associated with the transportation electrification and heating electrification forecasts with the LFC on September 27, 2019 (background and assumptions), November 18, 2019 (background and assumptions), December 20, 2019 (draft forecasts), and February 18, 2020 (final forecasts). The transportation electrification and heating electrification forecasts are further described below and in the Black Testimony.

For probabilistic ICR-Related Values calculations, the transportation electrification and heating electrification forecasts are included in the load model. The ISO discussed the incorporation of the transportation electrification forecast and the heating electrification forecast in the ICR model with the Power Supply Planning Committee ("PSPC") on May 28, 2020. The transportation electrification and heating electrification forecasts were also included in the discussion of the assumptions for the ICR-Related Values that took place at the PSPC on June 30, 2020. The incorporation of the transportation electrification and heating electrification forecasts in the ICR model is further described below and in the Kotha Testimony.

a. Transportation Electrification Forecast

Transportation electrification is expected to play a pivotal role in the achievement of the greenhouse gas reduction mandates and goals that the New England states have established. As such, the growth of transportation electrification will impact electric energy consumption in New England. For this reason, starting this year, forecasted impacts of transportation electrification on state and regional electric energy and demand are included in the 2020 CELT Report's load forecast.[24] The 2020 transportation electrification forecast focuses on electric vehicles ("EVs") in the light duty class, including cars and light-duty trucks. Electrification of other, non-light duty vehicles classes (*e.g.*, freight vehicles, electric buses, rail, and trolley) were not considered

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[23] *See* Kotha Testimony at 9-14.

[24] Black Testimony at 4.

in 2020, but may be considered in future forecasts.

The transportation electrification forecast has two main steps. The first step is forecasting the adoption of electrified light-duty EVs for each New England state and the New England region over the next ten years. The second step is using data-driven assumptions[25] to convert the EV adoption forecast into estimated impacts on monthly energy and demand by New England state. The 2020 transportation electrification forecast includes an EV energy forecast (*i.e*., estimates of monthly energy used for EV charging) and an EV demand forecast (which uses hourly weekday EV demand profiles to estimate the demand impacts of EV adoption).[26]

Transportation electrification impacts both the summer and winter peak demands and monthly energy. As such, the impact of EV load is explicitly modeled in the ICR calculation using an hourly EV demand forecast that reflects: (1) the assumed seasonal and weekday charging pattern; and (2) an 8% gross up for assumed transmission and distribution losses. The hourly EV forecast is modeled deterministically without considering uncertainty.[27] The incorporation of transportation electrification in the ICR model will result in a higher ICR because taking transportation electrification into account increases the summer peak demand that is one of the drivers of the system LOLE. Specifically, the increase to the 50/50 summer peak for the 2024-2025 Capacity Commitment Period is estimated to be 128 MW, and the impact of transportation electrification in the ICR is an estimated increase of 100 MW.[28]

b. Heating Electrification Forecast

Like transportation electrification, heating electrification is expected to play a pivotal role in the achievement of the greenhouse gas reduction mandates and goals that the New England states have established. As such, the growth of heating electrification will also impact energy consumption in New England. For this reason, starting this year, forecasted impacts of heating electrification on state and regional electric energy and demand are included as part of the 2020 CELT Report's load forecast.[29] The 2020 heating electrification forecast, which is relevant only

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[25] All data-driven assumptions are based on analysis of historical EV charging data licensed from ChargePoint, Inc. *See* Black Testimony at 7.

[26] [26] For additional details on the development of the EV energy forecast and the EV demand forecast *see* Black Testimony at 5-9.

[27] Modeling EV uncertainty may be considered in the future as the region gains more experience with transportation electrification and additional data becomes available. *See* Kotha Testimony at 13, note 4.

[28] *Id*. at 13-14.

[29] Black Testimony at 4. The ISO recognizes that heating electrification is a nascent trend. Hence, while the 2020

for the winter months (October through April), focuses on electricity consumption resulting from the adoption of air-source heat pumps ("ASHPs"). Other technologies such as ground source heat pumps and heat pump hot water heaters may be considered in future forecasts.

The heating electrification forecast has two main steps. The first step is forecasting the adoption of ASHPs for each New England state and the New England region over the next ten years. The second step is using data-driven assumptions to convert the ASHP adoption forecast into estimated impacts on monthly energy and demand by state. The 2020 heating electrification forecast includes an ASHP energy forecast (which estimates monthly energy impacts for each winter month), and an ASHP demand forecast (which estimates monthly demand impacts associated with the weekly weather distributions used to generate weekly gross load forecast distributions).[30]

Because heating electrification is weather-sensitive, it carries the load uncertainty associated with weather and, as already mentioned, heating electrification only affects peak demand and energy in the winter months. 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. Heating electrification is estimated to have no impact in the ICR for FCA 15, which is associated with the 2024-2025 Capacity Commitment Period.[31]

2. Resource Capacity Ratings

The ICR for FCA 15, which is associated with the 2024-2025 Capacity Commitment Period, is based on the latest available resource ratings[32] of Existing Capacity Resources that have qualified for FCA 15 at the time of the ICR calculation. These resources are described in the qualification informational filing for FCA 15 that is being submitted concurrently to the

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forecast methodology serves as a starting point, improvements to the methodology may be needed as policy drivers and state initiatives are further developed and additional data become available.

[30] For additional details on the development of the ASHP energy forecast and the ASHP demand forecast *see* Black Testimony at 9-15.

[31] Kotha Testimony at 14.

[32] The resource capacity ratings for FCA 15, which is associated with the 2024-2025 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 fourteen primary FCAs. *See* 2023-2024 ICR Letter Order; 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; the 2017-2018 ICR Letter Order; the 2016-2017 ICR Letter Order; and the 2015-2016 ICR Letter Order.

Commission on November 10, 2020.[33]

Resource additions and most resource attritions[34] are not assumed in the calculation of the ICR for FCA 15 (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.[35]

3. Resource Availability

The proposed ICR value for FCA 15, which is associated with the 2024-2025 Capacity Commitment Period, reflects generating resource availability assumptions based on historical scheduled maintenance and forced outages of these capacity resources.[36] 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.

In the ICR calculations, passive Demand Resources are modeled as 100% available. The

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[33] *ISO New England Inc.,* Informational Filing for Qualification in the Forward Capacity Market, filed on November 10, 2020 at Attachment C.

[34] 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.

[35] Kotha Testimony at 8.

[36] The assumed resource availability ratings for FCA 15 which is associated with the 2024-2025 Capacity Commitment Period, are discussed in the Kotha Testimony. 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 fourteen FCAs. *See* note 10, *supra.*

availability of Active Demand Capacity Resources is based on actual responses during all historical ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency ("OP-4") events and ISO performance audits that occurred in summer and winter 2015 through 2019.

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.[37] 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 15 reflects tie benefits calculated from the Quebec, Maritimes (New Brunswick), and New York Control Areas.[38] The ISO utilizes a probabilistic 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

[37] *See* Section III.12.9 of the Tariff. The methodology for calculating tie benefits to be used in the Installed Capacity Requirement for FCA 15 is the same methodology used to calculate the tie benefits used in the ICR for Capacity Commitment Periods associated with prior FCAs.

[38] *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 2017-2018 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, and the 2023-2024 Capacity Commitment Period.

in the transmittal letter for the 2014-2015 ICR Filing.[39] 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	883
Quebec	Highgate	140
Maritimes (New Brunswick)	New Brunswick	454
New York	NY AC Ties	258
New York	Cross Sound Cable	0
	Total Tie Benefits	1,735

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 2020, 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:

External Tie Line	External Interface Import Capability (MW)	Forced Outage Rate (%)	Maintenance (Weeks)
HQ Phase I/II HVDC	1,400	1.3	2.9
Highgate	200	0	0.9
New Brunswick	700	0.1	2.6
NY AC Ties	1,400	0.5	5.9
Cross Sound Cable	0	0	3.4
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 15, for internal transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.

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[39] *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).

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 15.

IV. LOCAL SOURCING REQUIREMENTS AND MAXIMUM CAPACITY LIMITS

In the Forward Capacity Market ("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.[40] An MCL is the maximum amount of capacity that can be located in an export-constrained Capacity Zone to meet the ICR.[41] 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 15, which is associated with the 2024-2025 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	10,305 MW	10,005 MW	10,305 MW

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

[41] *Id.*

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. Specifically, the LSR is calculated for an import-constrained Capacity Zone as the amount of capacity needed to satisfy the higher of (i) the LRA or (ii) the TSA requirement.[42]

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 Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market ("PP-10").[43] 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.[44] The 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.[45]

For FCA 15, 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:

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42 *See* Section III.12.2.1 of the Tariff.

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

44 *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 ¶ 61,290 at PP 26-31 (2008).

45 Kotha Testimony at 33-34.

Export-Constrained Capacity Zone	MCL
Maine	4,145 MW
NNE	8,680 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").[46] 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 15 is 883 MW per month.

VI. MRI DEMAND CURVES

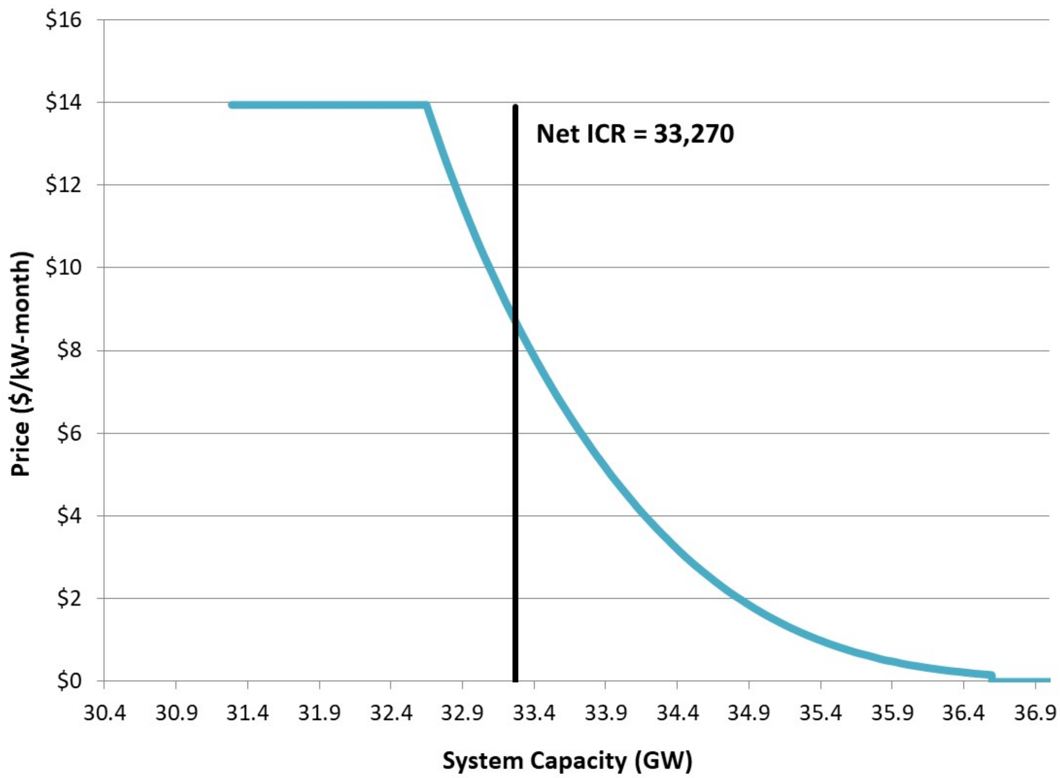
Starting with FCA 11, which was associated with the 2020-2021 Capacity Commitment Period, the ISO began using the MRI demand curve methodology to develop system-wide and zonal demand curves to be used in the FCA to procure needed capacity. Accordingly, as described below, the ISO has developed a System-Wide Capacity Demand Curve and Capacity Zone Demand Curves to be used in FCA 15.

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

[46] *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.").

Demand Curve pursuant to Section III.13.2.2.1 of the Tariff.[47] Below is the System-Wide Capacity Demand Curve for FCA 15.

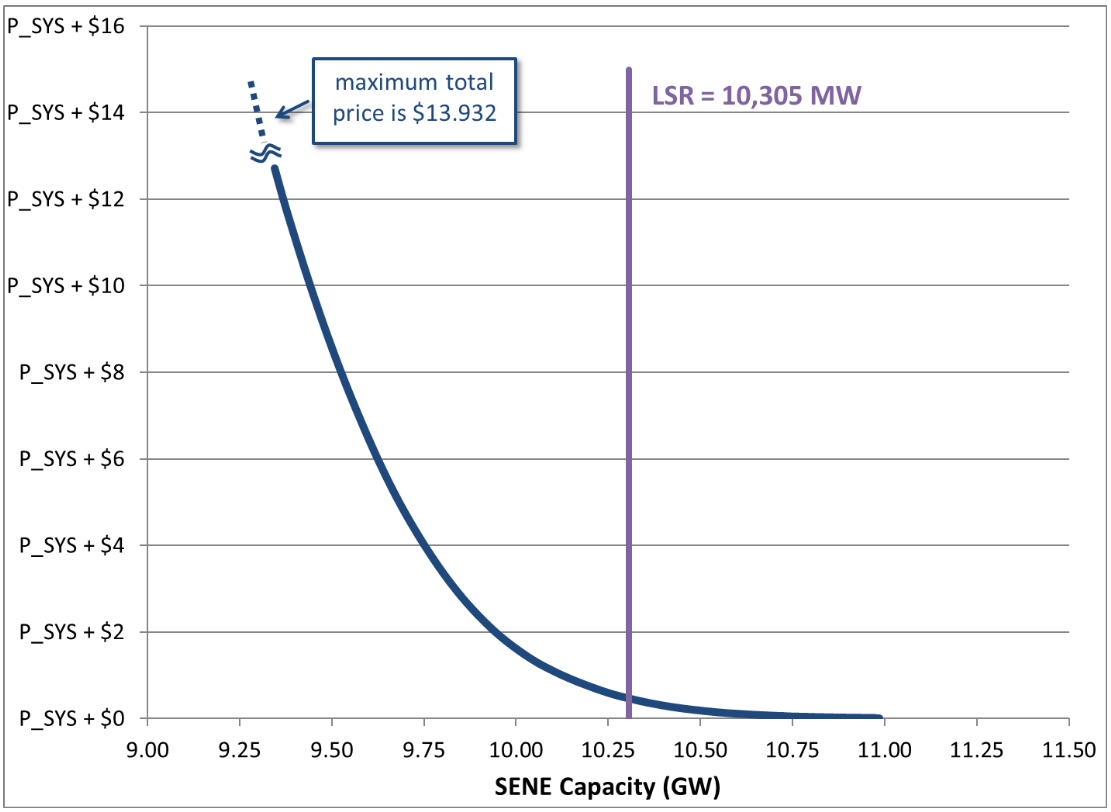


B. Import-constrained Capacity Zone Demand Curve

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

[47] Additional details regarding the calculation of the System-Wide Capacity Demand Curve are included in the Kotha Testimony at 37-40.

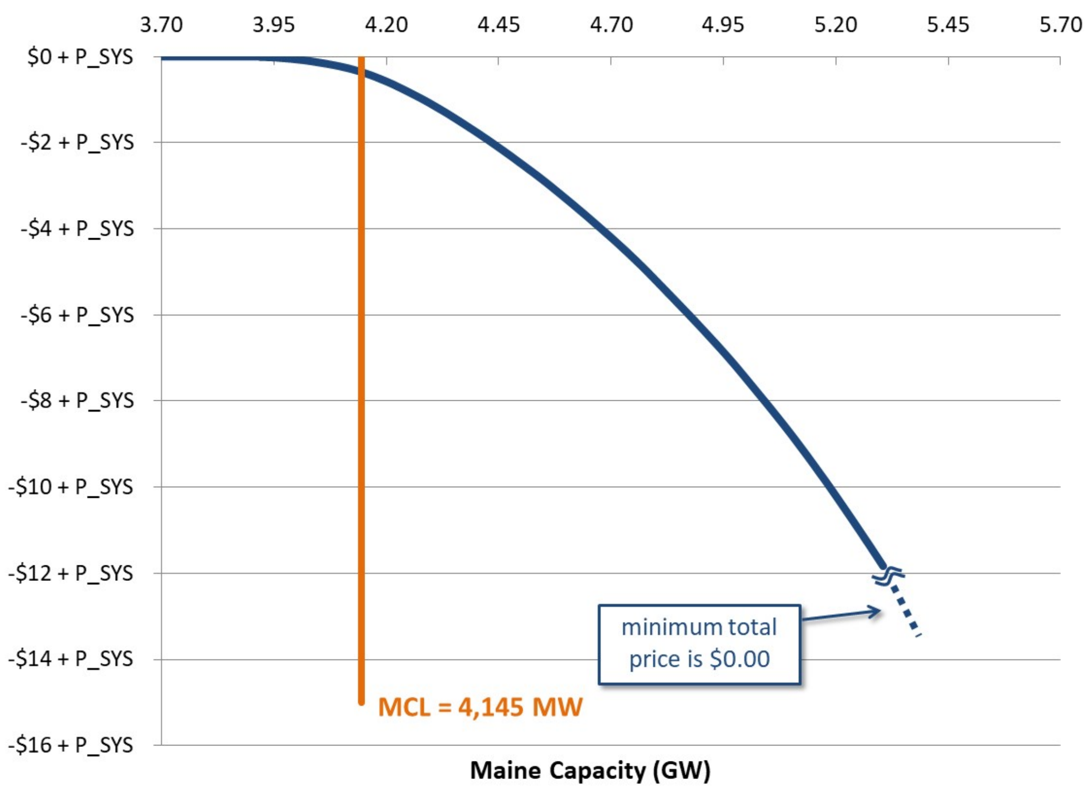
of the Tariff. For FCA 15, there is one import-constrained Capacity Zone and therefore, there is one import-constrained Capacity Zone Demand Curve. The following is the import-constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 15:



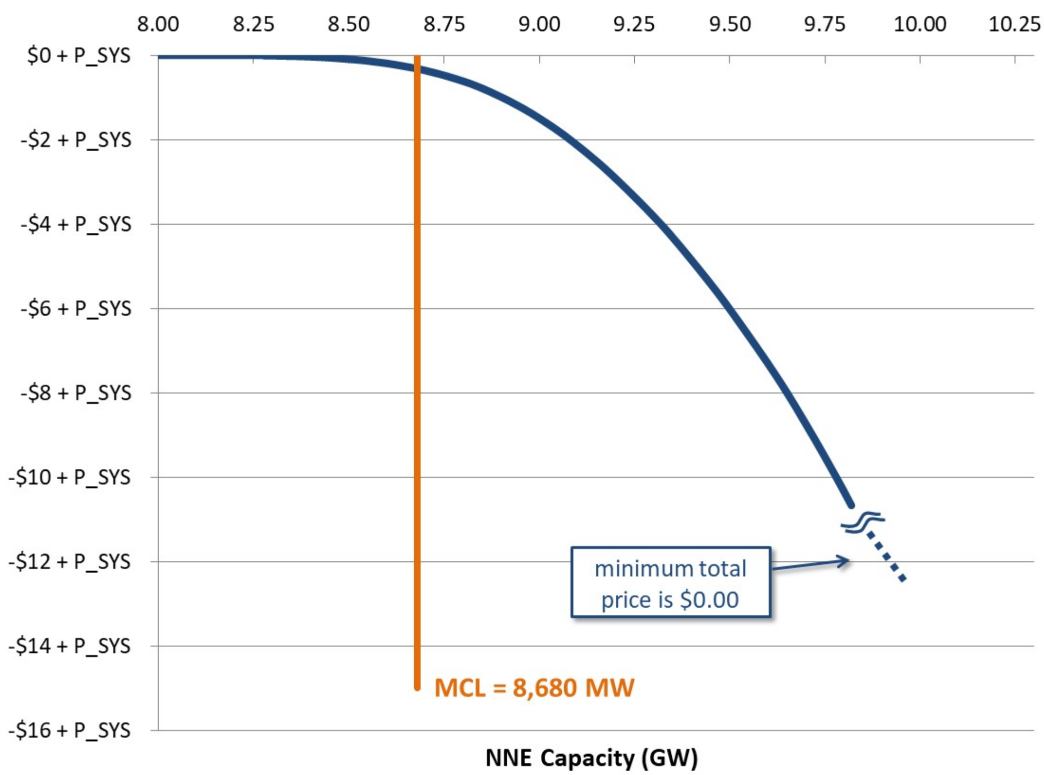
C. Export-constrained Capacity Zone Demand Curves

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 15, 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 15:



The following is the export-constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 15:



VII. STAKEHOLDER PROCESS

The ISO, in consultation with NEPOOL and other interested parties, developed the proposed ICR-Related Values for FCA 15 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 15.

In addition, in 2007 the New England States Committee on Electricity ("NESCOE") was formed.[48] Among other responsibilities, NESCOE is responsible for providing feedback on the

[48] *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 15 were discussed.

On September 23, 2020, the Reliability Committee voted to recommend, by a voice vote (with two oppositions and three abstentions recorded), that the Participants Committee support the HQICCs. Also on September 23, 2020, the Reliability Committee voted to recommend, by a voice vote (with three oppositions and three 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 1, 2020, the Participants Committee supported the HQICCs by a voice vote (with oppositions and abstentions recorded). Also on October 1, 2020, 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). [49]

VIII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the proposed ICR-Related Values for FCA 15 to be effective on January 9, 2021 (which is 60 days from the filing date), so that the proposed values can be used as part of FCA 15, which will be conducted in February 2021.

IX. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for FCA 15 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.[50] 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

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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).

[49] On the HQICC vote only two Participants opposed, Cross Sound Cable ("CSC") and the Long Island Power Authority ("LIPA"). They stated as the basis for their opposition the lack of recognition of reliability value for the Cross Sound Cable in the calculation of tie benefits. On the ICR-Related Values vote only three Participants opposed, CSC, LIPA and Exelon. The opposition of CSC and LIPA was for the same reason stated above, and Exelon did not state a reason for its opposition.

[50] 18 C.F.R. § 35.13.

identified filing regulations of the Commission applicable to Section 205 filings.

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

- This transmittal letter;
- Attachment 1: Testimony of Manasa Kotha;
- Attachment 2: Testimony of Jonathan Black;
- Attachment 3: 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 9, 2021.

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 9, 2021.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Attachments

cc: Entities listed in Attachment 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.) Docket No. ER21-___-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 Senior 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 Senior 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").

Since 2010, I have worked in the Resource Analysis & Integration group, which is part of the ISO's System Planning Department. I have been responsible for the qualification of Generating Capacity Resources, Demand Resources, and Import Capacity Resources for participation in the FCA and ARAs, and I have also developed the input file for the FCAs. 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,[1] the Hydro-Quebec Interconnection Capability Credits ("HQICCs"), and

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[1] As explained in the ISO's Informational Filing for the fifteenth Forward Capacity Auction ("FCA 15"), which is being submitted to the Federal Energy Regulatory Commission ("Commission") concurrently with this filing, in accordance with Section III.12.4. of the ISO New England Transmission, Markets and Services Tariff ("Tariff"), the ISO determined that it will model four Capacity Zones in FCA 15: 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.

the Marginal Reliability Impact ("MRI") demand curves for the 2024-2025 Capacity Commitment Period, which is the Capacity Commitment Period associated with FCA 15, to be conducted beginning on February 8, 2021. The 2024-2025 Capacity Commitment Period starts on June 1, 2024 and ends on May 31, 2025. 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 15 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. For the first time this year, the ISO developed transportation electrification and heating electrification forecasts, and included them in the long-term forecast that is used as an assumption in the calculation of the ICR-Related Values. The development of these forecasts is described in the testimony of Jonathan Black, Manager, Load Forecasting in the ISO's System Planning Department (the "Black Testimony"). My testimony describes how the transportation electrification and heating electrification forecasts have been included in the ICR model. 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.

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 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 the Northeast Power Coordinating Council ("NPCC") Full Member Resource Adequacy Criterion (Resource Adequacy Requirement R4),[2] under which the ISO must probabilistically evaluate resource adequacy to

[2] *See Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System* available at: https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

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 process consisted of discussions with the 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 1, 2020, the Participants Committee supported the HQICCs by a voice vote (with oppositions and abstentions recorded). Also on October 1, 2020, 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 15, which is associated with the 2024-2025 Capacity Commitment Period, were discussed and considered.

Q: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT VALUE THAT THE ISO CALCULATED FOR FCA 15, WHICH IS ASSOCIATED WITH THE 2024-2025 CAPACITY COMMITMENT PERIOD.

A: The ICR value for FCA 15, which is associated with the 2024-2025 Capacity Commitment Period, is 34,153 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 33,270 MW, which is the 34,153 MW of ICR minus 883 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 15, which is associated with the 2024-2025 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 15 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.[3] For deterministic analyses such as the Transmission Security Analysis ("TSA"), the ISO uses the reference 90/10 load forecast, as published in the 2020-2029 Forecast Report of Capacity, Energy, Loads, and Transmission ("2020 CELT Report"), which is net of BTM PV resources.

Q: PLEASE DESCRIBE THE FORECASTED LOAD WITHIN CAPACITY ZONES FOR FCA 15, WHICH IS ASSOCIATED WITH THE 2024-2025 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.

[3] 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 NPCC uses for resource adequacy studies.

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 2024-2025 CAPACITY COMMITMENT PERIOD?

A: The following table shows the 50/50 and 90/10 peak load forecast for the 2024-2025 Capacity Commitment Period based on the 2020 load forecast as documented in the 2020 CELT Report. These values are reported as the "Net (with reductions for BTM PV)" load forecast.

Table 2 – 50/50 and 90/10 Peak Load Forecast (MW)

	50/50	90/10
New England	29,303	31,377
SENE	12,679	13,739
Maine	2,230	2,332
NNE	5,645	5,908

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 15?

A: For FCA 15, 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: WHY DID THE ISO DEVELOP TRANSPORTATION ELECTRIFICATION AND HEATING ELECTRIFICATION FORECASTS THIS YEAR?

A: As explained in the Black Testimony, the ISO decided to develop transportation electrification and heating electrification forecasts starting this year because both transportation electrification and heating electrification are expected to play a pivotal role in the achievement of the greenhouse gas reduction mandates and goals that the New England states have established. As such, both transportation electrification and the growth of heating electrification will impact electric energy consumption in New England.

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.[4]

Q: WHAT IS THE EFFECT OF INCORPORATING TRANSPORTATION ELECTRIFICATION IN THE ICR MODEL FOR FCA 15?

A: The incorporation of transportation electrification in the ICR model will result in an increase in the ICR because taking transportation electrification into account increases the summer peak demand that is one of the drivers of the system LOLE. Specifically, the increase to the 50/50 summer peak for the 2024-2025 Capacity Commitment Period is

[4] Modeling EV uncertainty may be considered in the future as the region gains more experience with transportation electrification and additional data becomes available.

estimated to be 128 MW, and the impact of transportation electrification in the ICR is an estimated increase of 100 MW.

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: WHAT IS THE EFFECT OF REFLECTING HEATING ELECTRIFICATION IN THE ICR MODEL FOR FCA 15?

Heating electrification is estimated to have no impact in the ICR for FCA 15, which is associated with the 2024-2025 Capacity Commitment Period. The heating electrification forecast has no impact on the ICR for FCA 15 because, while the ICR is currently driven by summer reliability needs, the adjustments for heating electrification occur in the winter months, as explained in the Black Testimony.

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 2020 long-term forecast on the net ICR were derived thru simulations using preliminary load forecast data prior to finalizing the 2020 CELT forecast. While the loads used are very close to the 2020 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 15, WHICH IS ASSOCIATED WITH THE 2024-2025 CAPACITY COMMITMENT PERIOD.

A: The ISO developed the ICR-Related Values for FCA 15 based on the Existing Qualified Capacity Resources for the 2024-2025 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 2024-2025 CAPACITY COMMITMENT PERIOD?

A: The following tables illustrate the make-up of the 33,332 MW of capacity resources assumed in the calculation of the ICR-Related Values.

Table 3– Qualified Existing Non-Intermittent Generating Capacity Resources By Load Zone (MW)[5]

Load Zone	Summer
MAINE	2,844.953
NEW HAMPSHIRE	4,152.612
VERMONT	206.814
CONNECTICUT	9,741.155
RHODE ISLAND	1,826.126
SEMA	4,460.967
WESTERN/CENTRAL MASSACHUSETTS	3,740.827
NEMA/BOSTON	1,296.241
Total New England	**28,269.695**

Table 4– Qualified Existing Intermittent Power Resources by Load Zone (MW)[6]

Load Zone	Summer	Winter
MAINE	281.313	329.956
NEW HAMPSHIRE	82.170	161.120
VERMONT	64.118	107.785
CONNECTICUT	120.887	99.409
RHODE ISLAND	47.318	41.508
SEMA	289.751	357.617
WESTERN/CENTRAL MASSACHUSETTS	173.579	109.119
NEMA/BOSTON	54.483	43.609
Total New England	**1,113.619**	**1,250.123**

Table 5– Qualified Existing Import Capacity Resources (MW)

Import Resource	Summer	External Interface
NYPA - CMR	68.000	New York AC Ties
NYPA - VT	14.000	New York AC Ties
Total	**82.000**	

[5] Values reflect the existing resources with Qualified Capacity for FCA 15 at the time of the ICR calculation and reflect applicable resource retirements and resource terminations.

[6] 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 6– Qualified Existing Demand Capacity Resources by Load Zone (Summer MW)

Load Zone	On-Peak	Seasonal Peak	Active Demand Capacity Resource (ADCR)	Total
MAINE	224.411	0.000	137.803	362.214
NEW HAMPSHIRE	136.625	0.000	48.408	185.033
VERMONT	111.485	0.000	51.904	163.389
CONNECTICUT	130.311	561.440	192.829	884.580
RHODE ISLAND	270.390	0.000	44.736	315.126
SEMA	463.678	0.000	56.954	520.632
WESTERN/CENTRAL MASSACHUSETTS	476.249	20.010	112.074	608.333
NEMA/BOSTON	727.791	0.000	99.906	827.697
Total New England	**2,540.940**	**581.450**	**744.614**	**3,867.004**

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 15.

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 $13.932 $/kW-month) are not assumed in the calculation of the ICR-Related Values for FCA 15, which is associated with the 2024-2025 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 15, WHICH IS ASSOCIATED WITH THE 2024-2025 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 North American Electric Reliability Corporation ("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 GADS 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.[7]

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.

Performance of Demand Capacity Resources in the Active Demand Capacity Resource category is measured by actual response during performance audits and Operating Procedure No. 4 events that occurred in the summer and winter of the most recent five-year period, currently 2015 through 2019. To calculate historical availability, the verified commercial capacity of each resource is compared to its monthly net Capacity Supply Obligation. 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.

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

4. OTHER ASSUMPTIONS

Q: PLEASE DESCRIBE THE ASSUMPTIONS RELATING TO INTERNAL TRANSMISSION TRANSFER CAPABILITIES FOR THE DEVELOPMENT OF ICR-RELATED VALUES FOR FCA 15.

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 7 – Internal Interface Transfer Capabilities (MW)

Interface	Contingency	2024-2025
Southeast New England Import (for SENE LSR)	N-1	5,150
	N-1-1	4,300
Maine-New Hampshire (for Maine MCL)	N-1	1,900
North-South (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 15.

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 275 MW for June through September 2024 and 212 MW for October 2024 through May 2025.

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 which 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 15.

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 15 assume total tie benefits of 1,735 MW based on the results of the tie benefits study for the 2024-2025 Capacity Commitment Period. A breakdown of this total value is as follows: 883 MW from Quebec over the Hydro-Quebec Phase I/II HVDC Transmission Facilities, 140 MW from Quebec over the Highgate interconnection, 454 MW from Maritimes (New Brunswick) over the New Brunswick interconnections, and 258 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 15 THE SAME AS THE METHODOLOGY USED FOR FCA 14?

A: Yes. The methodology for calculating the tie benefits used in the ICR for FCA 15 is the same methodology used to calculate the tie benefits used in the ICR for FCA 14. 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 15.

A: The ISO conducted the tie benefits study for FCA 15 using the probabilistic GE MARS program to model the expected system conditions of New England and its directly interconnected neighboring Control Areas of New Brunswick, New York, and Quebec. 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 Maritimes (New Brunswick), New York and Quebec 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 15:

Table 8 – External Interface Import Capability (MW)

External Transmission Interconnections/Interfaces	Capacity Import Capability into New England
Maritimes (New Brunswick) Interconnections	700
Highgate Interconnection	200
Hydro-Quebec Phase I/II HVDC Transmission Facilities	1,400
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 2020, 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 2024-2025 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 14.

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 15?

A: After applying the import-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 15, 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,[8] 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.[9] 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 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

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[8] 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.

[9] Available at https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

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 15.

A: For FCA 15, the LRA, TSA Requirement and the LSR for the SENE import-constrained Capacity Zone for FCA 15 Capacity Zones are as follows:

Table 9 – Import Capacity Zone Requirements for the 2024-2025 Capacity Commitment Period (MW)

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	10,005	10,305	10,305

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 15?

A: After applying the export-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 15, 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 15 AND HOW WERE THEY CALCULATED?

A: The MCL for the Maine Capacity Zone for FCA 15 is 4,145 MW and the MCL for the NNE Capacity Zone is 8,680 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").[10] 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

[10] *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 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.").

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 15, WHICH IS ASSOCIATED WITH THE 2024-2025 CAPACITY COMMITMENT PERIOD?

A: The HQICC values are 883 MW for every month of the 2024-2025 Capacity Commitment Period.

VI. MRI DEMAND CURVES

Q: PLEASE DESCRIBE THE METHODOLOGY USED FOR CALCULATING THE MRI DEMAND CURVES FOR FCA 15.

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 15, 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.

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,[11] 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 Zones 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.

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

[11] 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.

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 15 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").[12] 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 15 was developed for the System-Wide Capacity Demand Curve, the import-constrained Capacity Zone Demand Curve for the SENE import-constrained Capacity Zones, 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.

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

[12] For FCA 15, Net CONE has been determined as $8.707/kW-month.

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 15, there is one import-constrained Capacity Zone and therefore, there is one import-constrained Capacity Zone Demand Curve.

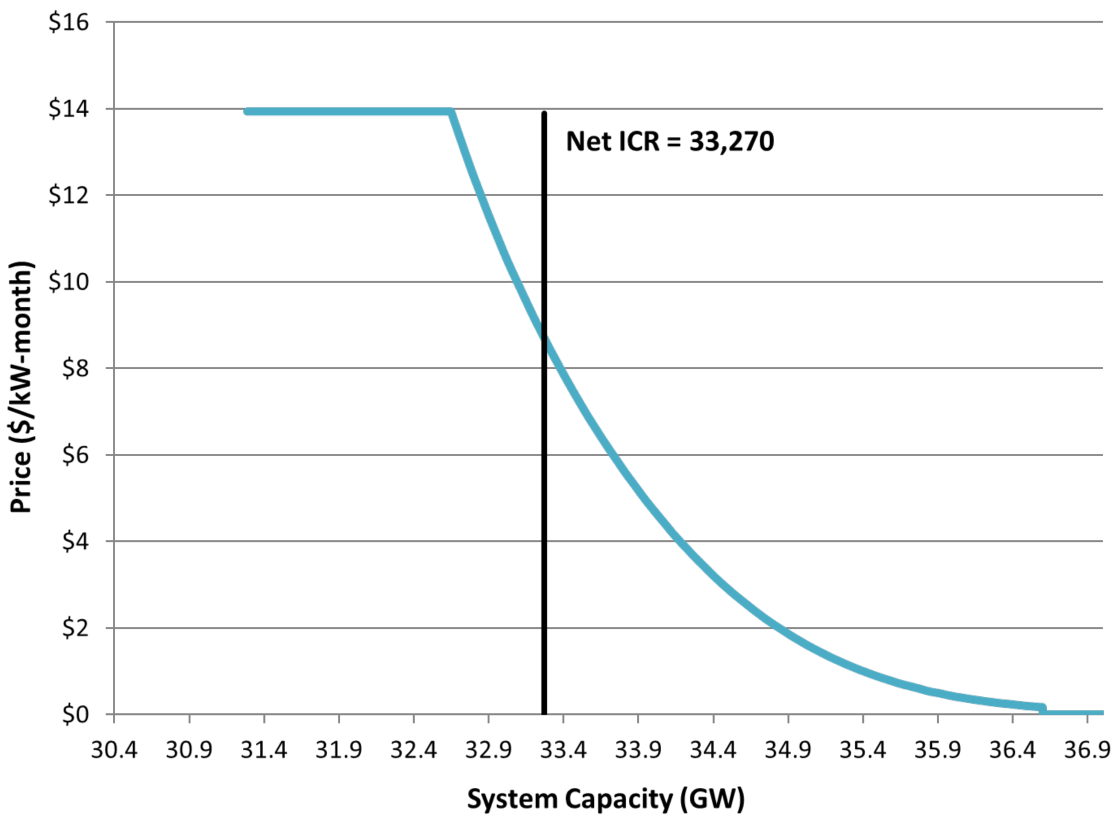
Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE EXPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVES FOR THE MAINE AND NNE CAPACITY ZONES.

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 15, the export-constrained Capacity Zones are Maine and NNE, and, therefore, there are two export-constrained Capacity Zone Demand Curves.

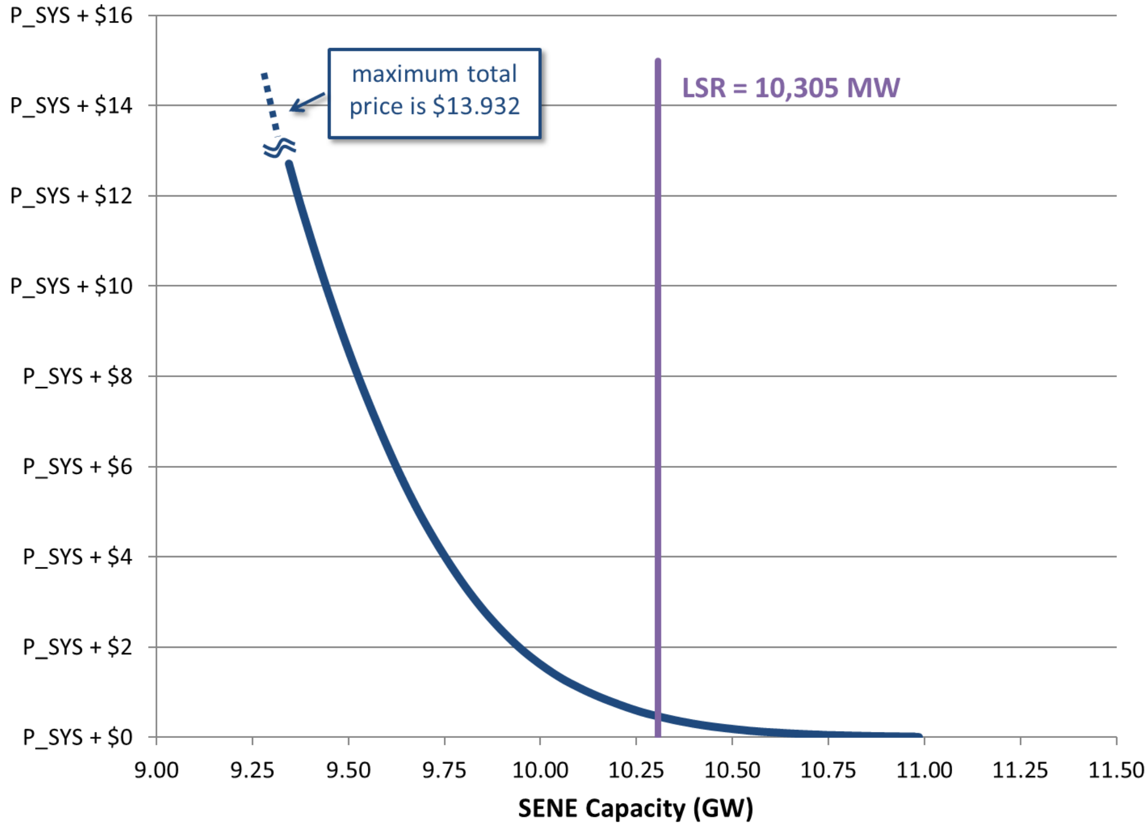
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR FCA 15?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI demand curves for FCA 15.

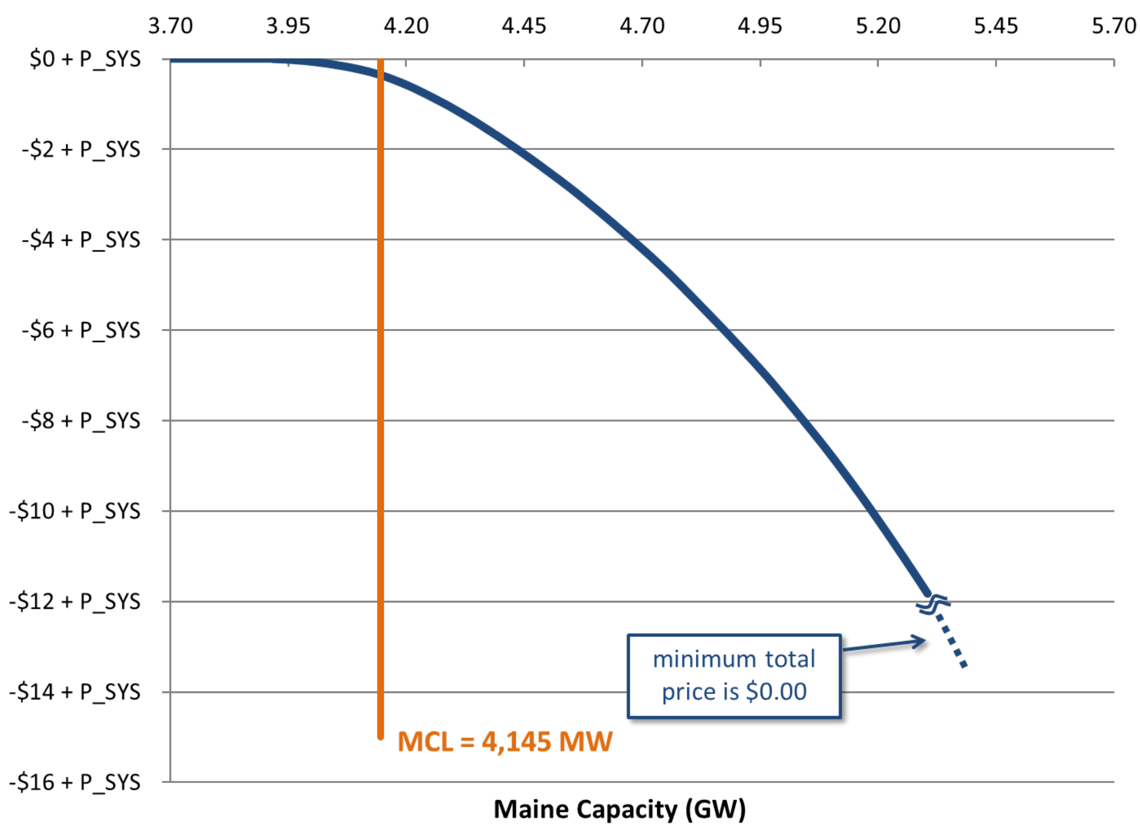
1. System-Wide Capacity Demand Curve for FCA 15



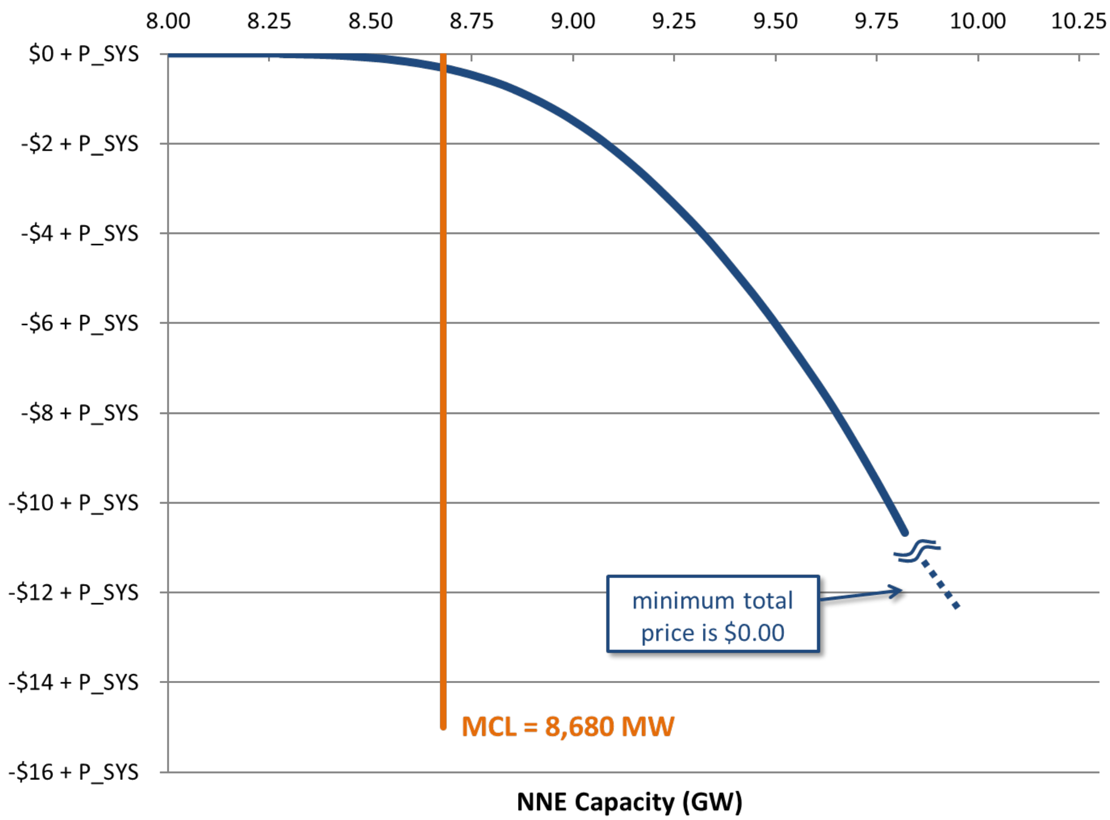
2. Import-constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 15



3. Export-constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 15



4. Export-constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 15



Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Manasa K

Manasa Kotha

November 10, 2020

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER21-___-000**

PREPARED TESTIMONY OF
JONATHAN BLACK
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

A: My name is Jonathan Black. I am employed by ISO New England Inc. (the "ISO") as the Manager of Load Forecasting in the System Planning Department. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A: I joined the ISO in 2010 and have been the Manager of Load Forecasting for the past four years. In my current capacity, I am primarily responsible for the annual development of the long-term load, energy efficiency, heating and transportation electrification, and solar photovoltaic forecasts, as well as providing technical modeling support for short-term (*i.e.*, next seven days) load forecasting. As part of this role, my group applies a variety of data science, machine learning, and statistical techniques to perform predictive modeling and ongoing analytics for the growing number of factors that impact electricity consumption in New England. This work includes research on and modeling of emerging technologies and trends, as well as developing novel data processes to enable such modeling. Prior to joining the ISO, I spent seven years working as an environmental scientist for Pioneer Environmental, Inc., where I managed hazardous waste site assessment and remediation projects. I have a B.S. in Civil and Environmental Engineering and an M.S. in Mechanical Engineering, both from the University of Massachusetts at Amherst. I am currently pursuing my Doctorate in the interdisciplinary Infrastructure and Environmental Systems program at the University of North Carolina in Charlotte, where I am researching advanced load forecasting techniques.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to explain the development of the transportation electrification and heating electrification forecasts that the ISO incorporated into the load forecast assumption used in the calculation of the Installed Capacity Requirement[1] and related values for the fifteenth Forward Capacity Auction, which is associated with the 2024-2025 Capacity Commitment Period.

II. TESTIMONY

A. BACKGROUND

Q: WHAT IS THE LONG-TERM LOAD FORECAST?

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

A: The ISO's long-term load forecast is a 10-year projection of gross and net load for states and the New England region. It includes annual gross and net energy, as well as seasonal gross and net peak demand (50/50 and 90/10). The gross peak demand forecast is probabilistic in nature. Weekly load forecast distributions are developed for each year of the forecast horizon. Annual 50/50 and 90/10 seasonal peak values are based on calculated percentiles for the peak week in the appropriate month (*i.e.*, July for summer, and January for winter).

Q: WHY DOES THE ISO DEVELOP THE LONG-TERM LOAD FORECAST?

A: Pursuant to Section III.12.8 of the Tariff, the ISO is required to forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecast must be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs, and assumptions must be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

Q: WHAT IS THE LONG-TERM LOAD FORECAST USED FOR?

A: The long-term load forecast is used in: (1) determining New England's resource adequacy requirements for future years; (2) evaluating reliability and economic performance of the electric power system under various conditions; (3) planning-needed transmission improvements; and (4) coordinating maintenance and outages of generation and transmission infrastructure assets.

Q: PLEASE DESCRIBE, AT A HIGH LEVEL, HOW THE ISO DEVELOPS THE LONG-TERM LOAD FORECAST FOR THE NEW ENGLAND REGION.

A: Historical monthly gross energy and macroeconomic variables are used to estimate econometric monthly gross energy models, which in turn are used to forecast gross energy. Historical gross daily peak loads, weather, and gross monthly energy are used to estimate econometric monthly demand models, which in turn are used to forecast gross peak demand. Weekly weather distributions are input to the gross demand models to create a probabilistic demand forecast for each week of the forecast horizon. The 95th and 99th percentiles (*i.e.*, "P95" and "P99", respectively) of these weekly forecast distributions are then calculated, and the maximum weekly P95 and P99 of each month is used as the "50/50" and "90/10" gross demand forecasts for that month.[2]

Q: WHY DID THE ISO DECIDE TO DEVELOP TRANSPORTATION ELECTRIFICATION AND HEATING ELECTRIFICATION FORECASTS STARTING THIS YEAR?

A: The ISO decided to develop transportation electrification and heating electrification forecasts starting this year because both transportation electrification and heating electrification are expected to play a pivotal role in the achievement of economy-wide greenhouse gas reduction mandates and goals that the New England states have established. As such, both transportation electrification and the growth of heating electrification will impact electric energy consumption in New England.

[2] More detailed information on the forecast methodology is available at: https://www.iso-ne.com/static-assets/documents/2019/09/p1_load_forecast_methodology.pdf

B. TRANSPORTATION ELECTRIFICATION FORECAST

Q: WHAT IS THE FOCUS OF THE 2020 TRANSPORATION ELECTRIFICATION FORECAST?

A: The 2020 transportation electrification forecast focuses on electric vehicles ("EVs") in the light duty class, including cars and light-duty trucks that are either battery electric vehicles ("BEVs") or plug-in hybrid electric vehicles ("PHEVs"). Electrification of other, non-light duty vehicles classes (*e.g.*, freight vehicles, electric buses, rail, and trolley) were not considered in 2020, but may be considered in future forecasts.

Q: WHAT ARE THE TWO MAIN STEPS OF THE TRANSPORTATION ELECTRIFICATION FORECAST AND WHAT DOES IT INCLUDE?

A: The first step is forecasting the adoption of electrified light-duty EVs (*i.e.*, the number of EVs purchased, registered, and driven over the forecast horizon) for each New England state and the New England region over the next ten years. The second step is using data-driven assumptions to convert the EV adoption forecast into estimated impacts on monthly energy and demand by New England state. The 2020 transportation electrification forecast includes an EV energy forecast (*i.e.*, estimates of monthly energy used for EV charging) and an EV demand forecast (which uses hourly weekday EV demand profiles to estimate the demand impacts of EV adoption).

Q: WHAT DID THE ISO USE AS THE EV ADOPTION FORECAST AND WHY?

A: The ISO used the Energy Information Administration's ("EIA") 2019 Annual Energy Outlook ("AEO") forecast for BEV/PHEV sales in New England as the final 2020 EV adoption forecast. The ISO also considered the EIA's 2020 AEO forecast, but chose the 2019 AEO forecast because it reflects EV adoption that better aligns with the New England state policy objectives.

Q: WHAT IS THE FINAL 2020 EV ADOPTION FORECAST?

A: The final 2020 EV adoption forecast is shown in the table below.

Year	NE	CT	MA	ME	NH	RI	VT
2020	35,653	8,449	18,329	2,181	2,672	1,499	2,523
2021	43,199	10,237	22,209	2,642	3,238	1,816	3,057
2022	47,020	11,143	24,173	2,876	3,524	1,976	3,327
2023	49,783	11,798	25,594	3,045	3,731	2,092	3,523
2024	53,005	12,561	27,250	3,242	3,973	2,228	3,751
2025	55,737	13,209	28,655	3,409	4,177	2,343	3,944
2026	55,921	13,252	28,750	3,420	4,191	2,351	3,957
2027	57,136	13,540	29,374	3,495	4,282	2,402	4,043
2028	58,032	13,753	29,835	3,549	4,349	2,439	4,107
2029	60,197	14,266	30,948	3,682	4,512	2,530	4,260
Estimated Total	**515,683**	**122,208**	**265,119**	**31,540**	**38,649**	**21,675**	**36,492**

The ISO allocated forecasted sales for New England to states based on state shares of total New England EV registrations at the end of 2018. To approximate the impacts of anticipated EV fleet turnover, the ISO incorporated the following assumptions: 50% of sales turn over after 8 years, 25% of sales turn over after 9 years, and 25% of sales turn over after 10 years.

Q: WHAT EV CHARGING DATA DID THE ISO USE TO INFORM ASSUMPTIONS REGARDING EV IMPACTS ON REGIONAL ELECTRICITY CONSUMPTION PATTERNS?

A: To inform assumptions regarding EV impacts on regional electricity consumption patterns, the ISO analyzed historical EV charging data licensed from ChargePoint, Inc. The data are from ChargePoint Network charging stations within New England, and cover complete years from June 2018 through May 2019. The dataset utilized includes over 671 MWh of charging and reflects 78% residential charging and 22% non-residential charging (based on energy).

Q: PLEASE DESCRIBE HOW THE ISO ESTIMATED THE IMPACTS OF EV ADOPTION ON ENERGY AND DEMAND.

A: The ISO based monthly energy and demand forecasts on the EV adoption forecast coupled with the results of the ChargePoint data analysis. Based on the results of this analysis, the ISO used monthly kWh/day per EV to estimate monthly energy, and incorporated a 6% gross-up for assumed transmission and distribution losses (as is done in other forecast processes). To estimate demand impacts, the ISO used hourly weekday EV demand profiles, and included an 8% gross-up for assumed transmission and distribution losses, consistent with other forecast processes.[3]

[3] The 6% and 8% gross-up values for energy and demand, respectively, have been established as the values to be used in the reconstitution of energy efficiency ("EE") and behind-the-meter photovoltaics ("BTM PV") in historical loads used to develop the gross energy and demand forecasts, and in developing the annual EE and BTM PV energy and demand forecasts that are used to develop net energy and demand forecasts. Accordingly, the same values have been used in the transportation electrification and heating electrification forecasts.

Q: WHAT IS THE FINAL ANNUAL EV ENERGY FORECAST FOR 2020?

A: The final annual EV energy forecast for 2020 is shown below.

	Annual Energy (GWh)									
State	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Connecticut	17	53	94	138	185	233	284	335	379	410
Massachusetts	37	115	204	299	401	506	616	727	823	888
Maine	4	14	24	36	48	60	73	86	98	106
New Hampshire	5	17	30	44	58	74	90	106	120	130
Rhode Island	3	9	17	24	33	41	50	59	67	73
Vermont	5	16	28	41	55	70	85	100	113	122
Total	73	224	396	581	780	985	1,198	1,413	1,601	1,728

Q: WHAT ARE THE FINAL 2020 EV DEMAND FORECASTS FOR SUMMER AND WINTER?

A: The final 2020 EV demand forecasts for summer and winter are shown below.

	Summer Peak (MW)									
State	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Connecticut	3	8	14	23	30	38	47	55	62	67
Massachusetts	6	18	31	49	66	83	101	119	134	145
Maine	1	2	4	6	8	10	12	14	16	17
New Hampshire	1	3	4	7	10	12	15	17	20	21
Rhode Island	0	1	3	4	5	7	8	10	11	12
Vermont	1	2	4	7	9	11	14	16	18	20
Total	**12**	**34**	**59**	**96**	**128**	**162**	**196**	**232**	**261**	**282**

	Winter Peak (MW)									
State	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Connecticut	8	17	27	38	49	60	72	84	92	98
Massachusetts	18	37	59	82	106	131	156	182	199	213
Maine	2	4	7	10	13	16	19	22	24	25
New Hampshire	3	5	9	12	15	19	23	26	29	31
Rhode Island	1	3	5	7	9	11	13	15	16	17
Vermont	2	5	8	11	15	18	22	25	27	29
Total	**35**	**73**	**115**	**159**	**206**	**255**	**304**	**353**	**388**	**414**

Q: PLEASE SPECIFY HOW THE ISO INCLUDED THE FINAL 2020 TRANSPORTATION ELECTRIFICATION FORECAST IN THE 2020-2029 FORECAST REPORT OF CAPACITY, ENERGY, LOADS, AND TRANSMISSION ("2020 CELT REPORT").

The ISO included transportation electrification in the 2020 CELT Report's load forecast by reflecting the forecasted impacts of transportation electrification on state and regional electric energy and demand.[4] Specifically, all gross and net energy and demand forecasts reported in the 2020 CELT Report are inclusive of transportation electrification. Breakouts of annual energy and seasonal demand are also reported in the 2020 CELT Report.[5]

C. HEATING ELECTRIFICATION FORECAST

Q: WHAT IS THE FOCUS OF THE 2020 HEATING ELECTRIFICATION FORECAST?

A: The 2020 heating electrification forecast, which is relevant only for the winter months (October through April), focuses on electricity consumption resulting from the adoption of air-source heat pumps ("ASHPs"). Other technologies such as ground source heat pumps and heat pump hot water heaters may be considered in future forecasts.

[4] The 2020 CELT Report is available at https://www.iso-ne.com/static-assets/documents/2020/04/2020_celt_report.xlsx Tab 1.7 includes the transportation electrification forecast.

[5] *See id.*

Q: WHAT ARE THE TWO MAIN STEPS OF THE HEATING ELECTRIFICATION FORECAST AND WHAT DOES IT INCLUDE?

A: The heating electrification forecast has two main steps. The first step is forecasting the adoption of ASHPs for each New England state and the New England region over the next ten years. The second step is using data-driven assumptions to convert the ASHP adoption forecast into estimated impacts on monthly energy and demand by state. The 2020 heating electrification forecast includes an ASHP energy forecast (*i.e.*, estimates of monthly energy impacts for each winter month), and an ASHP demand forecast (*i.e.*, estimates of monthly demand impacts associated with the weekly weather distributions used to generate weekly gross load forecast distributions).

Q: WHAT ARE THE ASSUMPTIONS UNDERLYING THE ASHP FORECAST?

A: The ISO based the 2020 ASHP adoption forecast on state guidance, which is tabulated below:

State	State Guidance on ASHP Adoption Assumptions
CT	Begin with ~5,000 installations in 2020; assume a 15% annual growth in rate of installations throughout forecast horizon
MA	Begin with 15,000 installations in 2020, with 15% annual growth in rate of installations throughout forecast horizon
ME	2020-2024 values from Efficiency Maine Trust; 5% annual growth in rate of installations assumed thereafter
NH	Begin with 2020 planned installations (2,900 installations); 12% annual growth in rate of installations throughout forecast horizon
RI	Begin with 2020 planned installations (400 installations); reasonable outlook would reflect a conversion of ~30% of existing homes that use delivered fuels as legacy heating source (results in ~50% annual growth)
VT	2020-2029 values provided by Efficiency Vermont

Q: WHAT IS THE FINAL 2020 ASHP ADOPTION FORECAST?

A: The final ASHP adoption forecast is shown below.[6]

Year	Annual ASHP Installs (Thousands)						
	CT	MA	ME	NH	RI	VT	ISO-NE
2020	4.2	12.8	12.2	2.6	0.4	5.4	35.3
2021	4.8	14.7	15.0	3.0	0.5	5.8	43.9
2022	5.6	16.9	18.3	3.3	0.8	6.4	51.2
2023	6.4	19.4	21.6	3.7	1.2	6.8	59.1
2024	7.3	22.3	25.9	4.2	1.8	7.4	68.9
2025	8.4	25.6	27.1	4.7	2.7	8.0	76.6
2026	9.7	29.5	28.5	5.2	4.1	8.6	85.6
2027	11.2	33.9	29.9	5.8	6.2	9.2	96.2
2028	12.8	39.0	31.4	6.5	9.2	9.8	108.9
2029	14.8	44.9	33.0	7.3	13.8	10.5	124.3
Cumulative Total	**85.3**	**258.9**	**243.0**	**46.3**	**40.8**	**77.9**	**749.9**

Q: WHAT DATA DID THE ISO USE TO INFORM ASSUMPTIONS REGARDING CHANGES IN ELECTRICITY CONSUMPTION DUE TO THE ADOPTION OF ASHPs?

A: To inform assumptions regarding changes in electricity consumption due to the adoption of ASHPs, the ISO licensed advanced metering infrastructure ("AMI") data from Sagewell, Inc., including: (1) anonymized building-level hourly interval energy

[6] The ASHP adoption values in the table are net of installations assumed to replace legacy electric resistance heat. Specifically, the assumed state shares of ASHP installations that replace resistance heat are based on state residential shares with electric heat listed as primary heat source in 2017 census data. In addition, in the absence of data to verify otherwise, no net impact on winter energy and demand is assumed for applications with legacy electric heat, recognizing that some installations will replace active resistance heating systems (resulting in decreased electricity use), but others may replace unused resistance heating systems (resulting in increased electricity use) or result in continued use of resistance or other pre-existing backup systems during cold weather conditions.

consumption for residential sites in northeastern Massachusetts; and (2) building characteristics and end-use details that match each AMI point. Assumptions regarding energy and demand impacts of ASHP adoption are based on analysis and regression modeling performed on the average hourly electricity consumption from 18 residential AMI profiles. Each profile corresponds to a residence where an ASHP was installed between the winters of 2017-2018 and 2018-2019, which enables a direct comparison of winter electricity consumption before and after ASHP adoption. The resulting average profile reflects a diversity of ASHP applications, including a mixture of legacy heating sources and a variety of ASHP heating capacities. The ISO recognizes this is a relatively small AMI sample, and will continue to work with stakeholders as part of future forecast cycles to seek out additional data sources as heating electrification efforts mature in the region.

Q: PLEASE DESCRIBE HOW THE ISO DEVELOPED THE ENERGY AND DEMAND IMPACTS OF THE ADOPTION OF ASHPs.

A: The ISO developed a regression-based approach to leverage AMI and weather data to derive response functions, which are used to estimate ASHP impacts as a function of weather. Specifically, the ISO developed separate regression models for energy and demand using the average of eighteen AMI data series before and after ASHP installation. Heating degree days ("HDD") was used as the weather variable since it is included in both energy and demand forecast models. The model differences associated with each HDD value reveal the incremental increase in electric energy and demand as a function of weather due to ASHP adoption.

Q: PLEASE DESCRIBE HOW THE ISO ESTIMATED THE IMPACTS OF ASHP ADOPTION ON ENERGY.

A: The process the ISO used for estimating the impacts of ASHP adoption on energy is as follows: (1) the daily HDD for each winter month over the period 1996 -2015 (*i.e.*, the "normal weather" period) used for monthly energy modeling was used to estimate monthly energy impacts; (2) input daily HDDs to each energy response function and multiply by the monthly ASHP penetration; (3) differences in response function outputs reflect the resulting daily energy due to ASHP adoption, which are then summed for each year; (4) the average of the resulting 20 monthly energy differences is the estimated monthly energy impact of ASHP adoption for that month, and (5) energy is grossed up by 6% to account for assumed transmission and distribution losses, consistent with other forecast processes.

Q: WHAT IS THE FINAL ANNUAL ASHP ENERGY FORECAST FOR 2020?

A: The final annual ASHP energy forecast for 2020 is shown below.

	Annual Energy (GWh)									
State	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Connecticut	5	15	27	41	58	76	97	122	150	182
Massachusetts	14	46	82	124	173	228	292	366	450	548
Maine	15	51	95	147	209	279	352	429	509	594
New Hampshire	3	11	19	29	39	51	65	79	96	115
Rhode Island	0	1	3	5	9	14	21	33	50	76
Vermont	7	23	39	57	77	98	121	146	172	200
Total	45	147	266	404	564	747	949	1,175	1,428	1,715

Q: PLEASE DESCRIBE HOW THE ISO ESTIMATED THE IMPACTS OF ASHP ADOPTION ON DEMAND.

A: The ISO used weekly weather distributions (which include HDDs) that are the basis of weekly gross load forecast distributions to estimate monthly demand impacts of ASHP adoption as follows: (1) input weekly distributions of HDDs to each response function for demand, and multiply by the monthly ASHP penetration; (2) differences in response function outputs are calculated, resulting in a weekly distribution of ASHP demand impacts; and (3) demand impacts are grossed up by 8% to account for assumed transmission and distribution losses, consistent with other forecast processes. The resulting weekly distribution of ASHP demand impacts are then added to the weekly gross load distributions used as the basis of the gross load percentiles (i.e. the "50/50" and "90/10") calculated as part of the gross load forecast process already described.

Q: WHAT IS THE FINAL 2020 ASHP DEMAND FORECAST FOR WINTER 2020?

A: The final 2020 ASHP demand forecast for winter 2020 is shown below.

	Winter Peak (MW)									
State	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Connecticut	4	8	12	18	24	31	39	48	60	72
Massachusetts	11	23	37	54	71	92	116	144	180	217
Maine	12	25	41	60	83	106	131	157	188	217
New Hampshire	3	5	8	11	15	19	24	29	36	42
Rhode Island	0	1	1	2	4	6	10	15	23	34
Vermont	6	11	17	24	31	39	47	55	67	77
Total	**35**	**73**	**118**	**169**	**227**	**293**	**366**	**448**	**553**	**661**

Q: PLEASE SPECIFY HOW THE ISO INCLUDED THE FINAL 2020 ELECTRIFICATION FORECAST IN THE 2020 CELT REPORT.

A: The ISO included heating electrification in the 2020 CELT Report's load forecast by reflecting the impacts of heating electrification on state and regional electric energy and demand.[7] Specifically, all gross and net energy and demand forecasts reported in the 2020 CELT Report are inclusive of heating electrification. Breakouts of annual energy and seasonal demand are also reported in the 2020 CELT Report.[8]

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

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[7] *See* 2020 CELT Report at tab 1.7.

[8] *See id*.

I declare that the foregoing is true and correct.

Jonathan Black

November 10, 2020

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