November 30, 2018

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. and New England Power Pool*, Docket No. ER19-___-000, Filing of Installed Capacity Requirements, Hydro-Quebec Interconnection Capability Credits and Related Values for 2019-2020, 2020-2021 and 2021-2022 Annual Reconfiguration Auctions

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 ("NEPOOL") Participants Committee, (together, the "Filing Parties"),[2] hereby electronically submits to the Federal Energy Regulatory Commission ("Commission")[3] this transmittal letter and related materials, which identify the Installed Capacity Requirements ("ICRs"), Local Sourcing Requirements ("LSRs"), Maximum Capacity Limits ("MCLs"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), capacity requirement values for the System-Wide Capacity Demand Curve ("Demand Curve Values"), and Marginal Reliability Impact ("MRI") Capacity Demand Curves ("MRI Demand Curves")[4] (collectively, the "ICR-Related Values") for (1) the third annual reconfiguration

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1 16 U.S.C. § 824d (2013).

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

3 Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

4 Capacity requirement values for the System-Wide Capacity Demand Curve are calculated for Forward Capacity Auctions ("FCAs") and annual reconfiguration auctions ("ARAs") for the 2018-2019 and 2019-2020 Capacity Commitment Periods. Accordingly, the ISO calculated Demand Curve Values for ARA 3 for the 2019-2020 CCP.

auction for the 2019-2020 Capacity Commitment Period ("ARA 3 for the 2019-2020 CCP"), (2) the second annual reconfiguration auction for the 2020-2021 Capacity Commitment Period ("ARA 2 for the 2020-2021 CCP"), and (3) the first annual reconfiguration auction for the 2021-2022 Capacity Commitment Period ("ARA 1 for the 2021-2022 CCP").[5] The joint testimony of Ms. Carissa Sedlacek and Ms. Maria Scibelli (the "Sedlacek-Scibelli Testimony"), which is sponsored solely by the ISO, is included in support of this submittal.

Pursuant to Section III.13 of the Tariff, the ISO administers the FCA for a Capacity Commitment Period to procure capacity needed in the New England Control Area for that Capacity Commitment Period. Subsequent to the FCA, the ISO administers reconfiguration auctions. The ISO uses the reconfiguration auction process: (1) to balance changes in the amount of the ICR-Related Values due to changes in system conditions that have occurred since the calculation of the ICR and related values for the associated Capacity Commitment Period's FCA; and (2) to adjust resources' Qualified Capacity so that a qualified resource can acquire or shed a Capacity Supply Obligation for a Capacity Commitment Period.

ARA 3 for the 2019-2020 CCP is to be held starting on March 1, 2019, ARA 2 for the 2020-2021 CCP is to be held starting on August 1, 2019, and ARA 1 for the 2021-2022 CCP is to be held starting on June 3, 2019. In this filing, the Filing Parties are submitting updated ICR-Related Values, which are key inputs in each ARA. The values are included in Section V of this filing letter.[6] The Filing Parties are submitting the ICR-Related Values at least 90 days prior to the ARAs. Because these values were considered together in the stakeholder process, the Filing Parties submit them together for Commission acceptance.

In accordance with the Code of Federal Regulations, the Filing Parties request that the Commission accept the values submitted for the ARAs in this filing, effective January 29, 2019, which is 60 days from the filing date.[7]

MRI Demand Curves are calculated starting with the FCA and ARAs for the 2020-2021 Capacity Commitment Period. Accordingly, the ISO calculated MRI Demand Curves for ARA 2 for the 2020-2021 CCP, and ARA 1 for the 2021-2022 CCP.

[5] The 2019-2020 Capacity Commitment Period runs from June 1, 2019 to May 31, 2020, the 2020-2021 Capacity Commitment Period runs from June 1, 2020 to May 31, 2021, and the 2021-2022 Capacity Commitment Period runs from June 1, 2021 to May 31, 2022.

[6] The ICR-Related Values submitted in this filing reflect the termination of the Capacity Supply Obligation of Clear River Unit 1, as accepted by the Commission's November 19, 2018 order in Docket Nos. ER18-2457-000 and ER19-94-000.

[7] 18 C.F.R. § 35.3(a)(1) (2014).

I. COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO plans and operates 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 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 independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and merchant transmission providers. Pursuant to revised governance provisions accepted by the Commission,[8] 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, Transmission Operating Agreement (TOA) and the Market Participant Services Agreement included in the Tariff."

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

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II. STANDARD OF REVIEW

The ISO submits the proposed ICR-Related Values 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."[10] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[11] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[12] 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."[13] The ICR-Related Values submitted herein "need not be the only reasonable methodology, or even the most accurate."[14] 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.[15]

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9 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.

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

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

12 *Id.* at 9.

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

14 *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

15 *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)).

III. BACKGROUND

A. ICR

The ICR is a measure of the installed capacity 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. More specifically, the ICR is the amount of resources needed to meet the reliability criteria 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 (an LOLE of 0.1 days per year). The methodology for calculating the ICR is set forth in Section III.12 of the Tariff. The ICRs for each of the ARAs are included in Section V of this filing letter.

B. Local Sourcing Requirements and Maximum Capacity Limits

In the FCM, the ISO must also calculate LSRs and MCLs, if necessary, to be used in each FCA and ARA. The ISO calculates the LSRs and MCLs under Section III.12.2 of the Tariff. An LSR is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone, and an MCL is the maximum amount of capacity that can be electrically located in an export-constrained Capacity Zone to meet the ICR. LSRs and MCLs help to ensure that capacity resources are distributed geographically within the New England Control Area in a manner that ensures compliance with reliability criteria.

The LSR is calculated for an import-constrained Capacity Zone as the amount of capacity needed to satisfy the higher of (i) the Local Resource Adequacy ("LRA") Requirement or (ii) the Transmission Security Analysis ("TSA") Requirement.[16] The LRA Requirement is a local zonal capacity requirement calculated using a probabilistic modeling technique that ensures the zone meets the one-day-in-ten years reliability criteria. The LRA Requirement is calculated with "at criteria" system conditions. The calculation of the TSA Requirement is addressed in Section III.12.2.1 of the Tariff. The TSA is a deterministic reliability analysis of an import-constrained area. It uses a series of transmission load flow studies aimed at determining the performance of the transmission system under future stressed conditions and develops a resource requirement sufficient to allow the system to operate through the stressed situation.[17]

The TSA utilizes the same set of data underlying the load forecast, resource capacity ratings and resource availability that are used in calculating the ICR, MCL, and LRA Requirement. However, due to the deterministic nature of the TSA, some of the assumptions utilized in performing the TSA differ from the assumptions used in calculating the ICR, MCL,

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[16] Section III.12.2.1 of the Tariff.

[17] Section III.12.2.1.2(a) of the Tariff. *See also* Sedlacek-Scibelli Testimony at 32-33.

and LRA Requirement. These differences relate to the manner in which load forecast data, forced outage rates for certain resource types, and Operating Procedure No. 4 action events are utilized in the TSA. These differences are described in more detail in the Sedlacek-Scibelli Testimony.[18]

Pursuant to Section III.13.4.1 of the Tariff, Capacity Zones designated for each FCA must be held constant for the relevant ARAs for the associated Capacity Commitment Period. Accordingly, the ISO calculated LSRs for all three ARAs for the import-constrained Southeast New England ("SENE")[19] Capacity Zone, and MCLs for ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP for the export-constrained Northern New England ("NNE")[20] Capacity Zone. These values are included in Section V of this filing letter.

C. HQICCs

HQICCs are capacity credits that are allocated to the Interconnection Rights Holders, which are the entities that pay for and hold certain rights over the Hydro-Quebec ("HQ") Interconnection. Capacity requirements, net of HQICCs, are used in the development of the Demand Curve Values and MRI Demand Curves, which will be used to procure capacity in the ARAs. The HQICCs for each ARA are included in Section V of this filing letter.

D. Demand Curve Values and MRI Demand Curves

In the FCA for the 2019-2020 Capacity Commitment Period, System-Wide Capacity Demand Curves were used to procure needed capacity. Accordingly, the ISO calculated the Demand Curve Values for ARA 3 for the 2019-2020 CCP. Specifically, Section III.12.1 of the Tariff states that "[t]he ISO shall determine, by applying the same modeling assumptions and methodology used in determining the ICR, the capacity requirement value for each LOLE probability specified in Section III.13.2.2 for the System-Wide Capacity Demand Curve." Hence, capacity requirements for the Demand Curve have been calculated using the same methodology as that used for calculating the ICR. Section III.13.2.2 of the Tariff establishes that the demand curve capacity requirement values are those calculated (net of HQICCs) at 1-in-5 (0.200) LOLE and 1-in-87 (0.011) LOLE. The 1-in-5 LOLE and 1-in-87 LOLE Demand Curve

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[18] Sedlacek-Scibelli Testimony at 33-34.

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

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

Values associated with the System-Wide Capacity Demand Curve for ARA 3 for the 2019-2020 CCP are included in Section V of this filing letter.

In the FCAs for the 2020-2021 and 2021-2022 Capacity Commitment Periods, MRI Demand Curves were used to procure needed capacity. Therefore, the ISO calculates MRI Demand Curves for all ARAs for the 2020-2021 and 2021-2022 Capacity Commitment Periods using the same methodology as that used for calculating the ICR.[21] The MRI Demand Curves for ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP are included in Section V of this filing letter.

IV. DEVELOPMENT OF THE ICR-RELATED VALUES

The calculation methodology used to develop the ICR-Related Values for the ARAs is the same as that used to calculate the values for the corresponding FCAs. As in previous years, the values for this year's filing are based on assumptions relating to expected system conditions for the relevant Capacity Commitment Periods.[22] 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 and load reduction from implementation of 5% voltage reductions.

With the exception of a modification in the methodology used to account for behind-the-meter ("BTM") photovoltaic ("PV") output, and a modification in the amount of system reserves assumption, the methodology used to develop the assumptions is generally the same as that used to calculate the ICR and related values for the ARAs conducted in 2018. Most of the modeling assumptions have been updated to reflect changed system conditions since the development of the ICR and related values for the applicable FCAs. As in past years, the ISO developed the ICR-Related Values with stakeholder input, including NEPOOL participants and representatives of the New England states,[23] which is provided in part through the NEPOOL committee processes

[21] The development of the MRI Demand Curves is explained in the Sedlacek-Scibelli Testimony at 42-44.

[22] *See* Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2018-2019 Capacity Commitment Period, Docket No. ER15-325-000 (filed Nov. 4, 2014); Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2019-2020 Capacity Commitment Period; Docket No. ER16-307-000 (filed Nov. 10, 2015); Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2020-2021 Capacity Commitment Period, Docket No. ER17-320-000 (filed Nov. 8, 2016); Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the Twelfth FCA (Associated with the 2021-2022 Capacity Commitment Period), Docket No. ER18-263-000 (filed Nov. 7, 2017).

[23] In 2007 the New England States Committee on Electricity ("NESCOE") was formed. Among other responsibilities, NESCOE is responsible for providing feedback on the proposed ICR-Related Values at the relevant Power Supply

through review by the Load Forecast Committee, Power Supply Planning Committee ("PSPC"), Reliability Committee and Participants Committee. All of the load and resource assumptions needed for the General Electric Multi-Area Reliability Simulation ("GE MARS") model used to calculate the ICR-Related Values were reviewed by the PSPC, a subcommittee of the Reliability Committee.

A. Load Forecast

The forecasted peak loads of the New England Control Area and the Capacity Zones for the 2019-2020, 2020-2021 and 2021-2022 Capacity Commitment Periods are major inputs into the calculation of the ICR-Related Values.[24] For the purpose of calculating the ICR-Related Values, the ISO used the forecast published in the 2018-2027 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2018 ("2018 CELT Report").[25] The 2018 CELT Report load forecast was developed by the ISO using the same methodology that the ISO has used for determining load forecasts in previous years. This methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee.[26]

In determining the ICR, the load forecast is 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 given the probability of occurrence associated with that load level. The 50/50 peak load values (net of BTM PV) for each ARA are included in Section V of this filing letter.

As was done last year for the ARAs that were conducted in 2018, all probabilistic[27] ICR-Related Values calculations for the ARAs to be conducted in 2019 use an hourly profile of BTM PV corresponding to the load shape for the year 2002, used by NPCC for reliability studies. The hourly profile is modeled by subarea in the GE MARS model. The values of BTM PV published

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Planning Committee, Reliability Committee and Participants Committee meetings, and was in attendance for the meetings at which the ICR-Related Values filed herewith were discussed.

[24] The forecasted peak loads for the New England Control Area and the relevant Capacity Zones are shown in the Sedlacek-Scibelli Testimony at 14.

[25] *Id.* at 13.

[26] The methodology is reviewed periodically and updated when deemed necessary in consultation with the Load Forecast Committee.

[27] The probabilistic ICR-Related Values calculations include the ICRs, LRA Requirements, MCLs, Demand Curve Values and MRI Demand Curves. The TSA is a deterministic analysis.

in the 2018 CELT Report are the values of BTM PV subtracted from the gross load forecast to determine the net load forecast used in the deterministic ICR-Related Values calculations and other planning studies. In addition, as explained in the Sedlacek-Scibelli Testimony, this year, BTM PV was modeled using an uncertainty methodology. Because the load forecast is modeled probabilistically with a series of uncertainty multipliers, it is appropriate to also model the BTM PV profile with an uncertainty component. This component recognizes that, while high BTM PV outputs are consistently associated with New England peak load conditions, a certain level of variability exists. This variability was captured by using a seven-day uncertainty window methodology (three days before and three days after the day under study).

B. Resource Capacity Ratings

The ICR-Related Values submitted in this filing are based on the latest available Qualified Capacity of the Existing Capacity Resource dataset for the 2019-2020, 2020-2021, and 2021-2022 Capacity Commitment Periods, at the time of the calculation of the ICR-Related Values. The Qualified Capacity values of resources that have cleared FCAs, annual bilateral transactions and/or previous ARAs (*i.e.* resources that have acquired Capacity Supply Obligations) are those included in the set of Existing Capacity Resources used for the calculation of the ICR-Related Values for each of the ARAs. Resource additions, beyond those classified as Existing Capacity Resources for the ARAs, are not assumed in the calculation of the ICR-Related Values for the ARAs because there is no certainty that qualified new resources will clear the ARA and obtain a Capacity Supply Obligation. Similarly, only resource attritions (*i.e.* resources that Market Participants have sought to retire or de-list) that have cleared the relevant FCA are assumed in the calculation of the ICR-Related Values for the ARAs.[28] The Qualified Capacity of the Existing Capacity Resources for each ARA are included in Section V of this filing letter.

C. Resource Availability

The ICR-Related Values reflect resource availability assumptions based on historical availability of capacity resources. For generating resources, scheduled maintenance assumptions are based on each individual resource's most recent historical five-year average of scheduled maintenance.[29] If the individual resource has not been operational for five years, then NERC class average data is used to substitute for the missing annual data. An individual resource's forced outage assumptions are based on the resource's most recent five-year historical NERC Generator Availability Database System ("GADS") forced outage data submitted to the ISO. If the resource

[28] The Sedlacek-Scibelli Testimony provides the total MWs for each type of capacity resource assumed in the ICR-Related Values calculations for the 2019-2020, 2020-2021, and 2021-2022 Capacity Commitment Periods. *See* Sedlacek-Scibelli Testimony at 20.

[29] *Id*. at 21.

has been in commercial operation for less than five years, the NERC class average data for the same class of resource type is used to substitute for the missing annual data.[30]

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 historical outages are already incorporated into the resource ratings.[31]

In the ICR calculations, availability assumptions for passive Demand Resources are modeled as 100% available. Active Demand Capacity Resources' availability are based on actual responses during all historical ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency ("Operating Procedure No. 4") events and ISO performance audits that occurred in summer and winter 2013 through 2017.[32]

D. Other Assumptions

In the development of the ICR, LRA Requirement, MCL, Demand Curves Values and MRI Demand Curves, emergency assistance (tie benefits) is assumed to be available from neighboring Control Areas and the load reduction from implementation of 5% voltage reductions are used. These all constitute actions that system operators invoke under Operating Procedure No. 4 in Real-Time to balance system demand with supply under capacity shortage conditions. The amount of load relief assumed obtainable from invoking 5% voltage reductions is based on the performance standard established in ISO New England Operating Procedure No. 13, Standards for Voltage Reduction and Load Shedding Capability.[33]

Tie benefits reflect the amount of emergency assistance that is assumed to be available to New England from its neighboring Control Areas in the event of a capacity shortage in New England, without jeopardizing reliability in New England or its neighboring Control Areas. Assuming tie benefits as a resource to meet the 0.1 days/year LOLE criterion reduces ICR and lowers the amount of capacity to be procured in the FCM.

For each Capacity Commitment Period, as stated in Section III.12.9.1.1 of the Tariff, tie benefits shall be calculated for FCAs and third ARA. For the first and second ARAs for a Capacity Commitment Period, the tie benefits calculated for the associated FCA shall be utilized

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[30] Sedlacek-Scibelli Testimony at 21.

[31] *Id*. at 21-22.

[32] *Id.* at 22.

[33] *Id.* at 24.

in determining the probabilistic ICR-Related Values except as adjusted, if necessary, to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6 of the Tariff.[34]

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 2018, the transfer limits were reviewed based on the latest available information regarding forecasted topology and load forecast information, and it was determined that no changes to the established external interface limits were warranted.[35] The other factor is the transfer capability of the internal transmission interfaces. In calculating tie benefits for the ICR for ARA 3 for the 2019-2020 CCP, for both internal and external transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.[36]

Pursuant to Section III.12.9.2 of the Tariff, tie benefits for ARA 3 for the 2019-2020 CCP were calculated using "at criterion" modeling assumptions. Using this methodology, a total of 1,945 MW of tie benefits was utilized in the calculation of the ICR for ARA 3 for the 2019-2020 CCP based on the results of the tie benefits study. A breakdown of this total value is as follows: 954 MW from Quebec over the Phase II interconnection, 142 MW from Quebec over the Highgate interconnection, 503 MW from New Brunswick (Maritimes) over the New Brunswick ties and 346 MW from New York over the AC ties.[37]

Pursuant to Section III.12.9.1.1 of the Tariff, the ICR calculation for ARA 2 for the 2020-2021 CCP assumes the same level of tie benefits calculated for the corresponding FCA of 1,950 MW total tie benefits. A breakdown of this total value is as follows: 959 MW from Quebec over the Phase II interconnection, 145 MW from Quebec over the Highgate interconnection, 500 MW

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[34] As addressed in the Sedlacek-Scibelli Testimony at 28, there have been no adjustments made to the tie benefits values calculated for the relevant FCAs and used for ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP because there have been no changes in import capability of the interconnections with neighboring Control Areas or in import capacity resources that would result in changes to the tie benefits assumptions.

[35] The ISO established transfer capability values for the following interconnections: 700 MW for the New Brunswick interconnections; 1,400 MW for the HQ Phase I/II HVDC Transmission Facilities; and 200 MW for the Highgate interconnection. The ISO also determined that there was no available transfer capability over the Cross Sound Cable for tie benefits. Finally, the ISO calculated a transfer capability for the New York-New England AC interconnections as a group, because the transfer capability of these interconnections is interdependent on the transfer capability of the other interconnections in the group. For the New York-New England AC interconnections, the transfer capability was determined to be 1,400 MW. *See* Sedlacek-Scibelli Testimony at 28.

[36] *Id.* at 29.

[37] *Id.*, Table 9.

from New Brunswick (Maritimes) over the New Brunswick ties and 346 MW from New York over the AC ties.

Pursuant to Section III.12.9.1.1 of the Tariff, the ICR calculation for ARA 1 for the 2021-2022 CCP also assumes the same level of tie benefits calculated for the corresponding FCA of 2,020 MW total tie benefits. A breakdown of this total value is as follows: 958 MW from Quebec over the Phase II interconnection, 143 MW from Quebec over the Highgate interconnection, 506 MW from New Brunswick (Maritimes) over the New Brunswick ties and 413 MW from New York over the AC ties.

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 line flow control, prior to invoking manual load shedding. Since 1980, the amount of system reserves that has been used in the determination of the ICR and related values calculations has been 200 MW.

The appropriateness of the continued use of a 200 MW minimum operating reserves assumption in the ICR and related values calculations has been discussed with stakeholders during the last several years. Specifically, in 2010, the system reserve assumption was discussed at the Reliability Committee as part of the review of the tie benefits methodology.[38] In 2017, during the discussions of the calculations of the ICR and related values for the twelfth FCA Capacity Auction, some PSPC members asked the ISO to review this assumption. This year, the ISO conducted a review and, due to changes in the peak load, an increase in the size of credible contingencies on the New England Transmission System, New England's limited tie capability to the Eastern Interconnection, and changes in the resource mix, it concluded that the 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 the ARAs.[39]

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[38] *See* https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2010/aug252010/a2_iso_ne_tie_benefits_operational.ppt

[39] The 700 MW system reserves assumption was used in all the probabilistic ICR-related values calculations, which include the ICR, LRA Requirement, MCL, the Demand Curve Values, and the MRI Demand Curves. The assumption was not used in the TSA, because that is not a probabilistic calculation. The change is explained in the Testimony of Peter Brandien, submitted in the filing of the ICR and related values for the thirteenth FCA. *See ISO New England*

V. PROPOSED VALUES AND DEMAND CURVES

A. ARA 3 for the 2019-2020 CCP ICR-Related Values (MW)

	New England	**Southeast New England**
Peak Load (50/50) net of BTM PV	28,577	12,114
Existing Capacity Resources	36,591	11,416
ICR	34,344	
HQICCs	954	
Net ICR (ICR minus HQICCs)	33,390	
1-in-5 LOLE Demand Curve Capacity Value	32,315	
1-in-87 LOLE Demand Curve Capacity Value	36,040	
LRA Requirement		9,936
TSA Requirement		10,083
LSR (higher of the LRA or TSA Requirements)		10,083

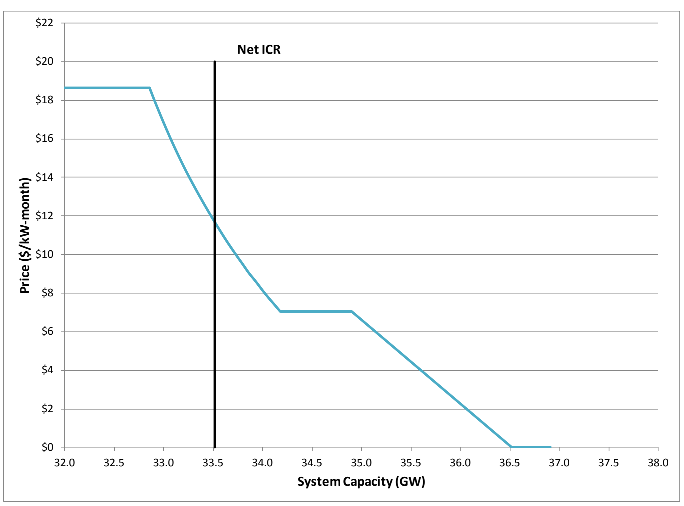
MCLs were not calculated for ARA 3 for the 2019-2020 Capacity Commitment Period because MCLs were not calculated for the 2019-2020 Capacity Commitment Period's FCA.

Inc., Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the Thirteenth FCA (Associated with the 2022-2023 Capacity Commitment Period); Docket No. ER19-295-000; Testimony of Peter Brandien.

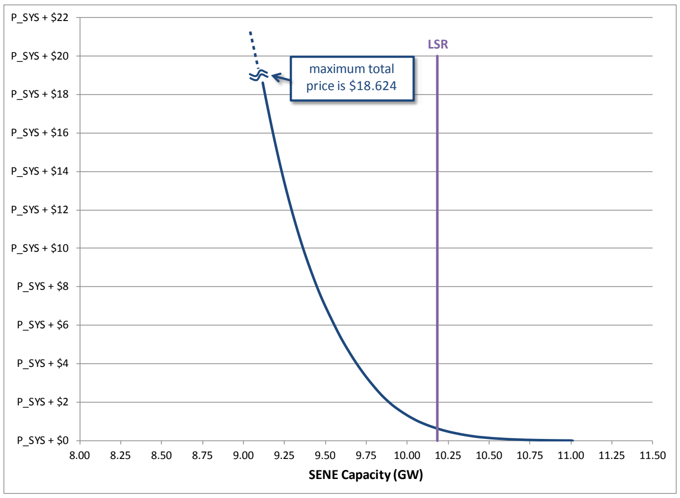
B. ARA 2 for the 2020-2021 CCP ICR-Related Values (MW)

	New England	Southeast New England	Northern New England
Peak Load (50/50) net of BTM PV	28,714	12,203	5,402
Existing Capacity Resources	37,164	11,577	8,863
ICR	34,479		
HQICCs	959		
Net ICR (ICR minus HQICCs)	33,520		
LRA Requirement		10,000	
TSA Requirement		10,182	
LSR (higher of the LRA or TSA Requirements)		10,182	
MCL			8,660

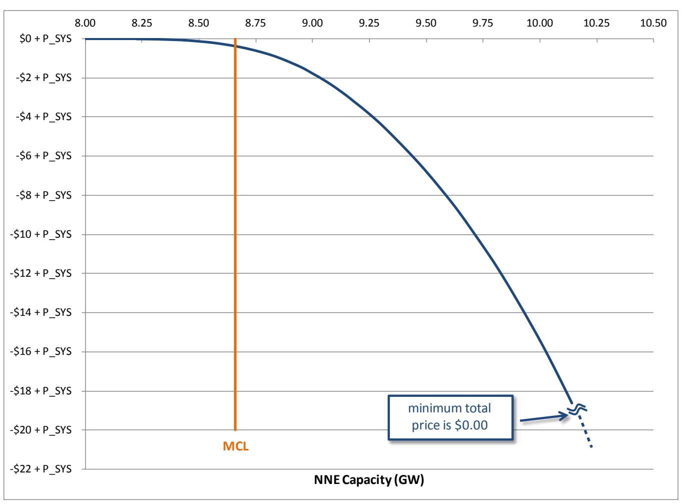
System-Wide MRI Demand Curve for ARA 2 for the 2020-2021 CCP



Import-Constrained Capacity Zone MRI Demand Curve for the SENE Capacity Zone for ARA 2 for the 2020-2021 CCP



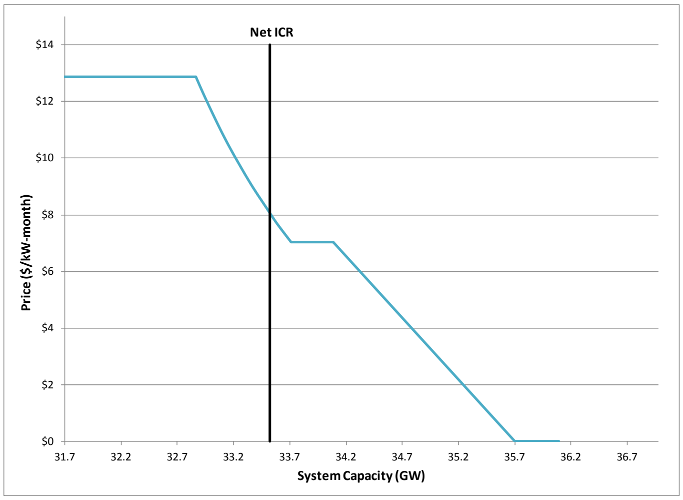
Export-Constrained Capacity Zone MRI Demand Curve for the NNE Capacity Zone for ARA 2 for the 2020-2021 CCP



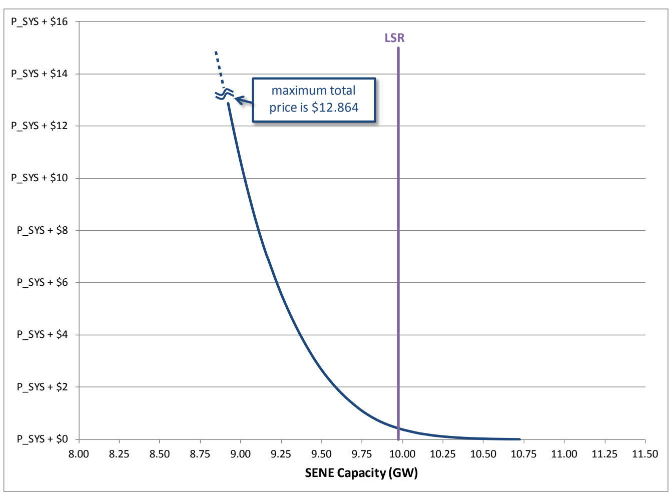
C. ARA 1 for the 2021-2022 CCP ICR-Related Values (MW)

	New England	**Southeast New England**	**Northern New England**
Peak Load (50/50) net of BTM PV	28,893	12,306	5,433
Existing Capacity Resources	36,519	11,459	8,713
ICR	34,508		
HQICCs	958		
Net ICR (ICR minus HQICCs)	33,550		
LRA Requirement		9,760	
TSA Requirement		9,973	
LSR (higher of the LRA or TSA Requirements)		9,973	
MCL			8,670

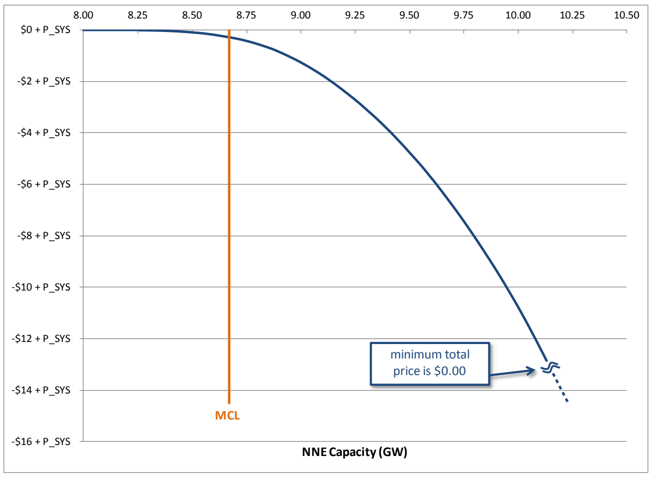
System-Wide MRI Demand Curve for ARA 1 for the 2021-2022 CCP



Import-Constrained Capacity Zone MRI Demand Curve for the SENE Capacity Zone for ARA 1 for the 2021-2022 CCP



Export-Constrained Capacity Zone MRI Demand Curve for the NNE Capacity Zone for ARA 1 for the 2021-2022 CCP



VI. STAKEHOLDER PROCESS

At its October 16, 2018 meeting, the Reliability Committee reviewed and considered the ICR-Related Values for the ARAs. A motion that the Reliability Committee recommend Participants Committee support for the ISO's proposed HQICC values passed by a show of hands with three oppositions and two abstentions noted. A separate motion that the Reliability Committee recommend Participants Committee support for the ISO's proposed ICRs, LSRs, MCLs, Demand Curve Values, and MRI Demand Curves passed by a show of hands with three oppositions and two abstentions noted. During the discussions of these ICR-Related Values similar concerns were raised by some Participants as those outlined in the "Supplemental Comments of the New England Power Pool Participants Committee" ("NEPOOL Supplemental Comments") to the ICR filing for the thirteenth FCA in Docket No. ER18-291-000.[40] At its November 2, 2018 meeting, the Participants Committee voted to support the proposed HQICC values and the proposed ICRs, LSRs, MCLs, Demand Curve Values, and MRI Demand Curves as part of its consent agenda with oppositions and abstentions recorded.[41]

[40] *See*, NEPOOL Supplemental Comments at 4-5, which can be accessed here: https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15097627.

[41] The consent agenda for a Participants Committee meeting, similar to the consent agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. In this case, the Participants Committee's approval of the November 2, 2018 Consent Agenda included its support for the proposed HQICCs and proposed ICRs, LSRs, MCLs, Demand Curve

VII. REQUESTED EFFECTIVE DATE

The Filing Parties request that the Commission accept the proposed ICR-Related Values for the ARAs to be effective on January 29, 2019.[42]

VIII. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for the ARAs 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.[43] However, the proposed ICR-Related Values are not traditional "rates." Furthermore, the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations. Notwithstanding its request for waiver, the ISO submits the following additional information in compliance with the identified filing regulations of the Commission applicable to Section 205 filings.

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

- This transmittal letter;
- Joint Testimony of Carissa Sedlacek and Maria Scibelli, sponsored solely by the ISO;
- 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 sent.

35.13(b)(2) – The ISO respectfully requests that the Commission accept this filing to become effective on January 29, 2019.

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 http://www.iso-ne.com/committees/nepool_part/index.html. An electronic copy of this transmittal letter and the accompanying materials have 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

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Values, and MRI Demand Curves. The oppositions and abstentions recorded were specifically attributed to this consent agenda item.

[42] 18 C.F.R. § 35.3.

[43] 18 C.F.R. § 35.13.

these governors and regulatory agencies are shown in the attachment hereto. In accordance with Commission rules and practice, there is no need for the entities identified in the attachment 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 Section VIII.

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

35.13(b)(6) - As explained above, the ISO has sought the advisory input from Governance Participants pursuant to Section 11.4 of the Participants Agreement.

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 ISO 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 ICRs and related values.

IX. CONCLUSION

The Filing Parties request that the Commission accept the proposed ICR-Related Values and HQICC values reflected in this submission for filing without change to become effective January 29, 2019.

Respectfully submitted,

ISO NEW ENGLAND INC.

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NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE

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Attachments

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER19-___-000**
New England Power Pool	**)**	

PREPARED TESTIMONY OF
MS. CARISSA SEDLACEK and MS. MARIA SCIBELLI
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

A: **Ms. Sedlacek:** My name is Carissa Sedlacek. I am the Director of Resource Adequacy in the System Planning Department at ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Ms. Scibelli: My name is Maria Scibelli. I am a Principal Analyst, Resource Adequacy in the System Planning Department at the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: MS. SEDLACEK, PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A: In 2015, I was promoted to Director of Resource Adequacy in the System Planning Department at the ISO. In this position, I have overall responsibility for developing the parameters needed for the operation of the Forward Capacity Market ("FCM"), including the development of the Installed Capacity Requirement ("ICR") and related values for all auctions; the resource qualification processes for new and existing resources; the conduct of the critical path schedule monitoring process for new resources; and the performance of reliability reviews for resources seeking to opt out of the market. In addition, I have the responsibility for conducting resource adequacy/reliability assessments to meet North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC") reporting requirements, long-term load forecast development, fuel diversity analyses, and resource mix evaluations to ensure regional bulk power system reliability into the future.

Before becoming Director of Resource Adequacy, I was Manager, Resource Integration & Analysis in the System Planning Department at the ISO. In that role I was responsible for implementing the FCM qualification process for Generating Capacity Resources, Demand Resources, and Import Capacity Resources; for analyzing capacity de-list bids; and for developing market resource alternatives as a substitute to building new transmission facilities. Prior to that, between 1999 and 2006, I led various generation planning and availability studies to ensure system reliability as well as transmission planning assessments related to transmission facility construction, system protection, and line ratings. I have published in the IEEE Power Engineering Review for analysis of Generator Availabilities under a Market Environment. I have been with the ISO since 1999, working in the System Planning Department.

Prior to joining the ISO, I worked at the New York Power Authority's Niagara Power Project for eleven years providing engineering support to ensure the reliable operation of the 2,500 MW hydroelectric facility and its associated transmission system.

I have a B.S. in Electrical Engineering from Syracuse University and an M.B.A. from State University of New York at Buffalo.

Q: MS. SCIBELLI, PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A: I am the Chair of the New England Power Pool ("NEPOOL") Power Supply Planning Committee ("PSPC"), the NEPOOL technical committee that assists the ISO in the review and development of all assumptions used for the calculation and development of ICR, Local Sourcing Requirements ("LSRs"), Transmission Security Analysis ("TSA") Requirements, Local Resource Adequacy ("LRA") Requirements, Maximum Capacity Limits ("MCLs") and demand curves. Prior to becoming Chair, I was the secretary of the PSPC for nine years.

Since 2006, I have worked in the Resource Adequacy group in the ISO's System Planning Department, where I have been the ISO's lead for the calculation of the Installed Capacity Requirement and associated values, including the development of the assumptions used in the calculations. I am also responsible for discussion and review of the Installed Capacity Requirement and related values at the PSPC and NEPOOL Reliability Committee.

I hold a Bachelor of Science degree in Chemistry from Western New England University. I have over 30 years of electric industry experience with over 20 years at the ISO and its planning department predecessor New England Power Planning ("NEPLAN") and prior to that at Northeast Utilities (now Eversource Energy).

I. BACKGROUND

Q: WHAT IS THE PURPOSE OF THIS TESTIMONY?

A: This testimony explains the derivation of the ICRs, LSRs, MCLs, Hydro-Quebec Interconnection Capability Credits ("HQICCs"), capacity requirement values for the System-Wide Capacity Demand Curve ("Demand Curve Values"), and Marginal Reliability Impact ("MRI") Capacity Demand Curves ("MRI Demand Curves")[1] (collectively, the "ICR-Related Values") for: (1) the third annual reconfiguration auction for the 2019-2020 Capacity Commitment Period ("ARA 3 for the 2019-2020 CCP"); (2) the second annual reconfiguration auction for the 2020-2021 Capacity Commitment Period ("ARA 2 for the 2020-2021 CCP"); and (3) the first annual reconfiguration auction for the 2021-2022 Capacity Commitment Period ("ARA 1 for the 2021-2022 CCP").[2] Our testimony also explains the assumptions used in the calculations of the ICR-Related Values for the ARAs.

[1] Capacity requirement values for the System-Wide Capacity Demand Curve are calculated for Forward Capacity Auctions ("FCAs") and annual reconfiguration auctions ("ARAs") for the 2018-2019 and 2019-2020 Capacity Commitment Periods. Accordingly, the ISO calculated Demand Curve Values for ARA 3 for the 2019-2020 CCP. MRI Demand Curves are calculated starting with the FCA and ARAs for the 2020-2021 Capacity Commitment Period. Accordingly, the ISO calculated MRI Demand Curves for ARA 2 for the 2020-2021 CCP, and ARA 1 for the 2021-2022 CCP.

[2] The 2019-2020 Capacity Commitment Period runs from June 1, 2019 to May 31, 2020, the 2020-2021 Capacity Commitment Period runs from June 1, 2020 to May 31, 2021, and the 2021-2022 Capacity Commitment Period runs from June 1, 2021 to May 31, 2022.

Q: WHAT IS AN ANNUAL RECONFIGURATION AUCTION?

A: An ARA is conducted as part of the ISO-administered Forward Capacity Market ("FCM"). An ARA is conducted annually after the FCA for a Capacity Commitment Period and before the start of that Capacity Commitment Period. The purposes of the ARA are: (1) to balance changes in the amount of the ICR-Related Values due to changes in system conditions that have occurred since the calculation of the ICR and related values for the associated Capacity Commitment Period's FCA; and (2) to adjust resources' Qualified Capacity so that a qualified resource can acquire or shed a Capacity Supply Obligation for a Capacity Commitment Period.

Q: IS THE PROCESS FOR DEVELOPING THE ICR-RELATED VALUES FOR THE ARAs THE SAME AS THAT USED LAST YEAR?

A: Generally, yes. With the exception of a modification in the methodology used to account for behind-the-meter ("BTM") photovoltaic ("PV") output, and a modification in the amount of system reserves assumption, the methodology used to develop the assumptions is generally the same as that used to calculate the ICR and related values for the ARAs conducted in 2018.

Q: FOR WHICH IMPORT-CONSTRAINED AND EXPORT-CONSTRAINED CAPACITY ZONES DID THE ISO CALCULATE LSRs OR MCLs FOR EACH OF THE ARAs?

A: Pursuant to Section III.13.4.1 of the Tariff, Capacity Zones designated for each FCA must be held constant for the relevant ARAs for the associated Capacity Commitment

Period. Accordingly, using the methodology described in Section III.12.2 of the Tariff, the ISO calculated the following:

- For ARA 3 for the 2019-2020 CCP: LSR for the Southeast New England ("SENE") Capacity Zone[3]
- For ARA 2 for the 2020-2021 CCP: LSR for the SENE Capacity Zone, and MCL for the Northern New England ("NNE") Capacity Zone[4]
- For ARA 1 for the 2021-2022 CCP: LSR for the SENE Capacity Zone, and MCL for the NNE Capacity Zone

Q: FOR WHICH ARAs DID THE ISO CALCULATE DEMAND CURVE VALUES?

A: The ISO calculated Demand Curve Values for ARA 3 for the 2019-2020 CCP because a System-Wide Capacity Demand Curve was used in the FCA for that Capacity Commitment Period.

Q: FOR WHICH ARAs DID THE ISO DEVELOP MRI DEMAND CURVES?

A: The ISO developed MRI Demand Curves for ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP for the system, SENE and NNE Capacity Zones because MRI Demand Curves were developed for the FCAs for those Capacity Commitment Periods.

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[3] The SENE Capacity Zone includes the Southeastern Massachusetts ("SEMA"), Northeastern Massachusetts ("NEMA")/Boston and Rhode Island Load Zones. MCLs were not calculated for ARA 3 for the 2019-2020 Capacity Commitment Period because MCLs were not calculated for the 2019-2020 Capacity Commitment Period's FCA.

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

II. CALCULATION OF THE INSTALLED CAPACITY REQUIREMENT – OVERVIEW

Q: WHAT IS THE "INSTALLED CAPACITY REQUIREMENT?"

A: The ICR is the minimum level of capacity required to meet the reliability criterion defined for the New England Control Area. This is documented in Section III.12 of the Tariff, which states, in relevant part, 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 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 NPCC Full Member Resource Adequacy Criterion (Resource Adequacy Requirement R4), under which the ISO must probabilistically evaluate resource adequacy to demonstrate that the 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 ICRs.

A: The three ICRs submitted in this filing were established through a single stakeholder process and in accordance with the ICR calculation methodology prescribed in Section III.12 of the Tariff.

The stakeholder process consisted of discussions with the New England Power Pool ("NEPOOL") Load Forecast Committee ("LFC"),[5] the Power Supply Planning Committee ("PSPC") and the NEPOOL Reliability Committee. These committees reviewed and commented on the ISO's development of load and resource assumptions. The ISO's calculation of the ICR-Related Values for the ARAs was followed by advisory votes from the NEPOOL Reliability Committee and NEPOOL Participants Committee. Both the NEPOOL Reliability Committee and the Participants Committee supported the ICR-Related Values for the ARAs.

Representatives of the six New England States' public utilities regulatory commissions are also invited to attend and participate in the PSPC, Reliability Committee and Participants Committee meetings, and were present for the meetings at which the ICR-Related Values were discussed and considered.

[5] The LFC is a non-voting technical subcommittee under the NEPOOL Reliability Committee that reviews and comments on the development of the annual load forecast for the New England region.

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 of the Reliability Committee. The PSPC is chaired by the ISO 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 the ICR-Related Values, including appropriate assumptions relating to load, resources, tie benefits, and the resource adequacy-related issues surrounding the appropriate incorporation of PV resources from the PV forecast for modeling the expected system conditions. The PSPC reviewed the assumptions relating to the calculation of the ICR-Related Values for the ARAs over the course of five meetings in April, May, July, August, and September 2018.

Q: PLEASE EXPLAIN THE CALCULATION METHODOLOGY FOR ESTABLISHING THE ICRs FOR THE ARAs.

A: As it is done for each FCA, the ICRs for the ARAs were established using the General Electric Multi-Area Reliability Simulation ("GE MARS") program. 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 random combinations of resource capacity and load levels taking into account resource outages and load forecast 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 resources until the New England LOLE is less than 0.1 days per year. For the ICR-Related Values for the ARAs, the ISO did not need to use 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 load (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: PLEASE IDENTIFY THE ICR ESTABLISHED FOR EACH OF THE ARAs.

A: The proposed ICR for ARA 3 for the 2019-2020 CCP is 34,344 MW. The 34,344 MW ICR value does not reflect the deduction of the HQICCs that are allocated to the Interconnection Rights Holders, as required by the Tariff. Those HQICCs are 954 MW per month.[6] Thus, the net ICR for use in ARA 3 for the 2019-2020 CCP is 33,390 MW.

The proposed ICR for ARA 2 for the 2020-2021 CCP is 34,479 MW. The 34,479 MW ICR value does not reflect the deduction of the HQICCs that are allocated to the Interconnection Rights Holders, as required by the Tariff. Those HQICCs are 959 MW per month. Thus, the net ICR for use in ARA 2 for the 2020-2021 CCP is 33,520 MW.

The proposed ICR for ARA 1 for the 2021-2022 CCP is 34,508 MW. The 34,508 MW ICR value does not reflect the deduction of the HQICCs that are allocated to the Interconnection Rights Holders, as required by the Tariff. Those HQICCs are 958 MW per month. Thus, the net ICR for use in ARA 1 for the 2021-2022 CCP is 33,550 MW. [7]

III. THE ASSUMPTIONS UNDERLYING THE ICR-RELATED VALUES

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

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[6] The HQICC is a monthly value.

[7] A presentation to the Reliability Committee which contains comparison of the proposed ICRs for the ARAs with the ICRs calculated for the corresponding FCAs is available at https://www.iso-ne.com/static-assets/documents/2018/10/a6_icr_requirements_for_ara3_2019_2020_ara2_2020_2021_ara1_2021_2022.zip This presentation also provides details on changes to the assumptions used in the calculation of the ICR-Related Values for the ARAs versus the ICRs and related values calculated for the FCAs.

A: One of the first steps in the process of determining the ICR-Related Values for the ARAs is for the ISO to identify reasonable assumptions relating to expected system conditions for the relevant Capacity Commitment Periods. 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 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 DERIVED THE LOAD FORECAST ASSUMPTION USED IN DEVELOPING THE ICR-RELATED VALUES.

A: For probabilistic[8] ICR-Related Values, the ISO develops a forecasted distribution of typical daily peak loads for each week of the year based on 40 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

[8] Probabilistic ICR-Related Values include the ICRs, LRA Requirements, MCLs, Demand Curve Values and the MRI Demand Curves. The TSA is a deterministic analysis.

could occur over the full range of weather experienced in that week and their associated probabilities.

From this weekly peak load forecast distribution, a monthly set of load forecast uncertainty multipliers are developed and applied to a specific historical hourly load profile to provide information about the probability of loads higher, and lower, than the peak load found in the historical profile. These multipliers can be developed for New England in its entirety or for each subarea using the historic 2002 load profile.

For deterministic analyses such as the TSA, the ISO used the reference 90/10 peak load forecast, which is net of BTM PV resources as published in the 2018 – 2027 Forecast Report of Capacity, Energy, Loads, and Transmission ("2018 CELT Report").

Q: PLEASE DESCRIBE THE PROJECTED RELEVANT CAPACITY ZONES AND NEW ENGLAND CONTROL AREA 50/50 AND 90/10 PEAK LOADS FOR THE 2019-2020, 2020-2021, AND 2021-2022 CAPACITY COMMITMENT PERIODS.

A: The following table shows the 50/50 and 90/10 peak load forecast (MW) values, net of BTM PV, for the 2019-2020, 2020-2021, and 2021-2022 Capacity Commitment Periods as documented in the 2018 CELT Report for the relevant Capacity Zones and New England.

Table 1 – 50/50 and 90/10 Peak Load Forecast Values for the Relevant Capacity Zones and New England (MW)

	SENE		NNE		New England	
CCP	**50/50**	**90/10**	**50/50**	**90/10**	**50/50**	**90/10**
2019-2020	12,114	13,212	-	-	28,577	30,995
2020-2021	12,203	13,318	5,402	5,764	28,714	31,160
2021-2022	12,306	13,437	5,433	5,798	28,893	31,366

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

A: In 2014, the rapid growth of BTM PV resources led the ISO to develop a forecast that captures the effects of recently installed BTM PV resources and BTM PV resources expected to be installed within the forecast horizon in order to forecast the potential future peak loads as accurately as possible. Hence, 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: WHY IS THE BTM PV FORECAST ACCOUNTED FOR IN THE CALCULATIONS OF THE ICR-RELATED VALUES?

A. Growth of BTM PV reduces the amount of load that needs to be served during daylight hours, which include summer peak load hours. As mentioned above, in 2014, the ISO developed its first ever long-term BTM PV forecast. However, that year, the ISO did not reflect the BTM PV forecast in the calculations of the ICR and related values for the ninth FCA ("FCA 9"). For that reason, NEPOOL did not support the ICR and related values for FCA 9. While FERC accepted the ISO's proposed ICR and related values, it directed the ISO to fully explore the incorporation of distributed generation into the ICR calculations for the tenth FCA ("FCA 10").[9] Accordingly, the BTM PV forecast has been reflected in the calculations of the ICR and related values starting with FCA 10.

Q: WHAT METHODOLOGY DID THE ISO USE TO REFLECT THE CONTRIBUTIONS OF BTM PV TO REDUCE THE LOAD FORECAST FOR THE ARAs TO BE CONDUCTED IN 2019?

A: For the ARAs to be conducted in 2019, as was done for the ARAs conducted in 2018, the ISO used an "hourly profile" methodology to determine the amount of load reduction

[9] ISO *New England Inc.*, 150 FERC ¶ 61,003 at P 20; FCA 9 is associated with the 2019-2020 Capacity Commitment Period; FCA 10 is associated with the 2020-2021 Capacity Commitment Period.

provided by BTM PV in all hours of the day and all months 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.

Q: WHY DID THE ISO ANALYZE THE UNCERTAINTY OF BTM PV OUTPUT THIS YEAR?

A: During the development of the ICR and related values for the twelfth FCA ("FCA 12"), some PSPC members requested that the ISO investigate the uncertainty associated with BTM PV. Using a new capability of GE MARS to model the uncertainty of variable resources, the possibility of capturing such uncertainty of BTM PV output probabilistically is now possible. The ISO has utilized this new methodology for the thirteenth FCA ("FCA 13") and the ARAs to be conducted in 2019.

Q: PLEASE DESCRIBE THE ISO'S ANALYSIS AND OBSERVATIONS RELATED TO THE UNCERTAINTY OF BTM PV OUTPUT ON PEAK DAYS.

A: In order to gauge the amount of uncertainty surrounding the forecast of BTM PV output during peak load conditions, the ISO analyzed simulated BTM PV outputs during the all-time 15 highest peak load days to determine the extent of variability of BTM PV output. The results of the analysis indicate that, while high BTM PV outputs are consistently associated with New England peak load conditions, a certain level of variability exists. The BTM PV output varies for different hours, and the variation is slightly over 10% during the period of hour ending 14 to hour ending 17 when actual peak loads occur.

In addition, because the 15 highest peak load days occurred in a span of time from 2006 to 2013, the ISO also analyzed BTM PV output within a more homogeneous period, the historical year 2002, where the weather condition is the main variable, and other possible impacts do not need to be considered. The year 2002 was chosen because it is the historical year that the ISO uses for the calculation of ICR and related values and that NPCC uses for resource adequacy studies. The analysis showed that during the top five highest peak days in 2002, a similar level of variability (within the approximate 10% bandwidth) exists for the peak hours. This analysis demonstrated that a certain level of variability does exist and that the variability can likely be attributed to load and BTM PV having slightly different sensitivity to various weather conditions.

Q: WHAT METHODOLOGY DID THE ISO USE TO ACCOUNT FOR BTM PV OUTPUT VARIABILITY IN THE ICR-RELATED VALUES CALCULATIONS?

A: To account for BTM PV output variability in the ICR-Related Values calculations, the ISO specified that the GE MARS model randomly select a daily profile of BTM PV from within a 7-day window surrounding the day under study (3 days before and 3 days after the particular day). The length of the uncertainty window as 7 days was chosen because it is consistent with the development of the load forecast using weekly distributions of peak load and also because it adequately captures an amount of uncertainty consistent with the 10% variability shown in the analysis of historical peak load days. The ISO believes this is a reasonable way to capture the uncertainty associated with the BTM PV performance.

2. RESOURCE CAPACITY RATINGS

Q: PLEASE DESCRIBE THE RESOURCE DATA USED TO DEVELOP THE ICR-RELATED VALUES FOR THE 2019-2020, 2020-2021, AND 2021-2022 CAPACITY COMMITMENT PERIODS.

A: The ICR-Related Values submitted in this filing are based on the latest available Existing Capacity Resource dataset for the 2019-2020, 2020-2021, and 2021-2022 Capacity Commitment Periods, at the time of the calculation of the ICR-Related Values. The Qualified Capacity of resources that have cleared FCAs and/or annual reconfiguration auctions, or acquired an obligation as part of a bilateral transaction (*i.e.* resources that have acquired Capacity Supply Obligations) are those included in the set of Existing Capacity Resources used for the calculation of the ICR-Related Values for each of the ARAs. Resource additions, beyond those classified as Existing Capacity Resources, are not assumed in the calculation of the ICR-Related Values for the ARAs because there is no certainty that qualified new resources will clear the annual reconfiguration auction and obtain a Capacity Supply Obligation. Similarly, only resource attritions (*i.e.* resources that Market Participants sought to retire or de-list) that have cleared the relevant FCA and therefore are not expected to acquire a Capacity Supply Obligation in the ARA have been excluded from the calculations of the ICR-Related Values for the ARAs.[10]

[10] Any resources that are no longer in physical operation are also excluded from the set of resources used to calculate the ICR-Related Values for the ARAs. This year, there are no resources in that category.

Q: WHAT ARE THE RESOURCE CAPACITY VALUES ASSUMED IN THE ICR-RELATED VALUES CALCULATIONS FOR THE 2019-2020, 2020-2021 AND 2021-2022 CAPACITY COMMITMENT PERIODS?

A: The following tables[11] summarize the total MWs of capacity resources for the relevant Capacity Zones and New England assumed in the ICR-Related Values calculations for the 2019-2020, 2020-2021, and 2021-2022 Capacity Commitment Periods for the Non-Intermittent Generating Capacity Resource, Intermittent Generating Capacity Resource,[12] Import Capacity Resource[13] categories and Demand Capacity Resources in the On-Peak, Seasonal Peak and Active Demand Capacity Resource categories.

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[11] For detailed information relating to the resources assumed in the ICR-Related Values, see the presentation to the Reliability Committee at https://www.iso-ne.com/static-assets/documents/2018/10/a6_icr_requirements_for_ara3_2019_2020_ara2_2020_2021_ara1_2021_2022.zip

[12] 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.

[13] In the ARA, Import Capacity Resources compete for the amount of available transmission transfer capability ("TTC") of an external interface into New England; therefore, the total MW from Existing Import Capacity Resources that are qualified to participate in the ARAs may be higher than the amount of available TTC. For that reason, the values used in ICR-Related Values calculations for the ARAs are derated to reflect: (1) the TTC interface limit of the external interfaces, which was determined after the ISO conducted a review in early 2018; and (2) the amount of TTC that must be reserved for tie benefits into New England over these external interfaces. Hence, the Existing Import Capacity Resources shown in Tables 3-5 reflect the Qualified Capacity values of those resources, derated for TTC and the tie benefits values for the 2019-2020, 2020-2021, and 2021-2022 Capacity Commitment Periods.

Table 3 – Qualified Existing Capacity Resources Used in the ICR-Related Values Calculations for ARA 3 of the 2019-2020 CCP (MW)

Resource Type	SENE	New England
Non-Intermittent Generating Capacity Resources	9,701	30,449
Intermittent Generating Capacity Resources	200	1,056
Import Capacity Resources	-	1,510
On-Peak Demand Capacity Resources	1,299	2,209
Seasonal Peak Demand Capacity Resources	-	511
Active Demand Capacity Resources	215	856
Total	11,416	36,591

Table 4 – Qualified Existing Capacity Resources Used in the ICR-Related Values Calculations for ARA 2 of the 2020-2021 CCP (MW)

Resource Type	SENE	NNE	New England
Non-Intermittent Generating Capacity Resources	9,669	7,324	30,450
Intermittent Generating Capacity Resources	198	630	1,105
Import Capacity Resources	-	255	1,750
On-Peak Demand Capacity Resources	1,485	387	2,406
Seasonal Peak Demand Capacity Resources	-	-	596
Active Demand Capacity Resources	225	267	858
Total	11,577	8,863	37,164

Table 5 – Qualified Existing Capacity Resources Used in the ICR-Related Values Calculation for ARA 1 of the 2021-2022 CCP (MW)

Resource Type	SENE	NNE	New England
Non-Intermittent Generating Capacity Resources	9,552	7,303	30,050
Intermittent Generating Capacity Resources	195	513	957
Import Capacity Resources	0	251	1,680
On-Peak Demand Capacity Resources	1,512	412	2,493
Seasonal Peak Demand Capacity Resources	-	-	656
Active Demand Capacity Resources	201	235	683
Total	11,459	8,713	36,519

3. RESOURCE AVAILABILITY

Q: PLEASE EXPLAIN THE RESOURCE AVAILABILITY ASSUMPTIONS UNDERLYING THE CALCULATIONS OF THE ICR-RELATED VALUES FOR THE ARAs.

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 five years, then NERC class average data is used to substitute for the missing annual data. It is assumed that generating resources will not have scheduled maintenance outages 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, covering January 2013 through December 2017, from the ISO's database of NERC Generator Availability Database System ("GADS"). If the individual resource has not been operational for five years, then NERC class average data is also used to substitute for the missing annual data. As explained in Section IV of this testimony, the same resource availability assumptions are used in all the calculations except for the TSA, which requires modeling the availability of the fast-start (*i.e.* peaking) resources with a deterministic adjustment factor.

The 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 with Capacity Supply Obligations are assumed to be 100% available in the models.

In the ICR calculations, passive Demand Resources are modeled as 100% available. Active Demand Capacity Resources' availability are based on actual responses during all historical ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency ("Operating Procedure No. 4") events and ISO performance audits that occurred in summer and winter 2013 through 2017.

4. OTHER ASSUMPTIONS

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

A: Prior to the calculation of the ICR-Related Values for the ARAs, a change was made to the TTC assumptions for the SENE Import interface for the 2019-2020 and 2020-2021 Capacity Commitment Periods.[14] As such, the N-1 and N-1-1 TTC values for the SENE

[14] The local permitting approval processes and appeals has delayed the expected in-service date for portions of the planned upgrades for the SENE Import interface and the Boston Import interface. For more details, see: https://www.iso-ne.com/static-assets/documents/2018/08/a2_pspc_transfer_lmt_update_08302018.pdf

import-constrained Capacity Zone for ARA 3 for the 2019-2020 CCP and ARA 2 for the 2020-2021 CCP were reduced from 5,700 MW to 5,400 MW and from 4,600 MW to 4,500 MW, respectively.

The assumed N-1 and N-1-1 transmission interface import transfer capabilities for the SENE Capacity Zone and the assumed N-1 transmission interface export limit for the NNE Capacity Zone are summarized in the table below for the relevant Capacity Commitment Periods.

Table 6 – N-1 and N-1-1 Transmission Transfer Capability Limits Used in the ICR-Related Values Calculations (MW)

	Southeast New England Import (for SENE LSR)		North-South Interface (for NNE MCL)
CCP	**N-1**	**N-1-1**	**N-1**
2019-2020	5,400	4,500	-
2020-2021	5,400	4,500	2,725
2021-2022	5,700	4,600	2,725

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

A: In developing the ICRs, LRA Requirements, MCLs, Demand Curve Values and MRI Demand Curves, emergency assistance (tie benefits) is assumed to be available from neighboring Control Areas and load reduction from implementation of 5% voltage reductions are used. These all constitute actions that system operators invoke under Operating Procedure No. 4 in Real-Time to balance system demand with supply under capacity shortage conditions. The amount of load relief assumed obtainable from invoking 5% voltage reductions is based on the performance standard established in ISO New England Operating Procedure No. 13, Standards for Voltage Reduction and Load Shedding Capability ("Operating Procedure No. 13"). Operating Procedure No. 13 requires that "…each Market Participant with control over transmission/distribution facilities must have the capability to reduce system load demand at the time a voltage reduction is initiated by at least one and one-half (1.5) percent through implementation of a voltage reduction." Using the 1.5% reduction in system load, the assumed voltage reduction load relief values, which offset against the ICR, are shown in Table 7 for the summer and winter seasons in each of the Capacity Commitment Periods.

Table 7 – Load Relief Assumed Obtainable from Operating Procedure No. 4 Actions 6 and 8 - 5% Voltage Reduction (MW)

CCP	Summer	Winter
2019-2020	411	306
2020-2021	410	302
2021-2022	413	303

The details of the tie benefit assumptions are described below.

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 assumptions. 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 an LSR or MCL are also modeled in the tie benefits study, the results of which are used as an input in the ICR, LRA Requirement, MCL, Demand Curve Values, and MRI Capacity Demand Curve calculations.

Q: PLEASE EXPLAIN HOW TIE BENEFITS WITH NEIGHBORING CONTROL AREAS ARE ACCOUNTED FOR IN DETERMINING THE ICR-RELATED VALUES.

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 in meeting the once in ten 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 the 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 that 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 reliability criterion, and the greater the amount of assistance requested, the greater the possibility that it will not be available or sufficient to avoid implementing deeper actions of Operating Procedure No. 4, and interrupting firm load in accordance with Operating Procedure No. 7 – Action in an Emergency. In addition, none of the neighboring Control Areas is conducting its planning, maintenance scheduling, unit commitment or Real-Time operations with a goal of maintaining its emergency assistance at a level needed to maintain the reliability of the New England system.

Q: PLEASE DESCRIBE WHAT TIE BENEFITS WERE USED FOR THE 2019-2020, 2020-2021 AND 2021-2022 CAPACITY COMMITMENT PERIODS.

A: Under Section III.12.9 of the Tariff, the ISO is required to perform a tie reliability benefits study, which provides the total overall tie benefit value available from all interconnections with adjacent Control Areas and the contribution of tie benefits from each of these adjacent Control Areas, for the FCA and third ARA for each Capacity Commitment Period. For the first and second annual ARAs for a Capacity Commitment Period, Section III.12.9 of the Tariff states that the tie benefits calculated for the associated FCA shall be utilized in determining the ICR, LRA Requirements, MCLs, Demand Curve Values, and MRI Demand Curves adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in Import Capacity Resources using the methodologies in Section III.12.9.6 of the Tariff.

Therefore, for ARA 3 for the 2019-2020 CCP, a tie reliability benefits study was performed. For ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP, the associated FCA tie benefits value was utilized in the ICR calculations. No adjustments were necessary to these tie benefit values to account for changes in import capability of interconnections with neighboring Control Areas and changes in Import Capacity Resources.

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 assumed import transfer capability of each of those interconnections that were used for calculating tie benefits for ARA 3 for the 2019-2020 CCP:

Table 8 – Transmission Transfer Import Capability of the New England External Transmission Interconnections (MW)

External Transmission Interconnections/Interfaces	Capacity Import Capability into New England
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

In the first half of 2018, the ISO reviewed the transfer limits for each interconnection/interface based on the latest available information regarding forecasted topology and load forecast information. The ISO determined that no changes to the established external interface limits were warranted. Accordingly, in calculating tie benefits to be used in the calculations of the ICR-Related Values for ARA 3 for the 2019-2020 CCP, the ISO used the transfer capability values from its most recent transfer capability analyses.

Q: PLEASE DESCRIBE THE TIE BENEFITS ASSUMPTIONS UNDERLYING THE ICR-RELATED VALUES FOR THE 2019-2020, 2020-2021, AND 2021-2022 CAPACITY COMMITMENT PERIODS.

A. The tie reliability benefit assumptions used in the calculations of the ICR-Related Values for ARA 3 for the 2019-2020 CCP, ARA 2 for the 2020-2021 CCP, and ARA 1 for the 2021-2022 CCP are shown in Table 9.

Table 9 – Tie Benefit Assumptions (MW)

Control Area	ARA 3 for the 2019-2020 CCP	ARA 2 for the 2020-2021 CCP	ARA 1 for the 2021-2022 CCP
Quebec over the Phase II Interconnection	954	959	958
Quebec over the Highgate Interconnection	142	145	143
Maritimes over the New Brunswick Ties	503	500	506
New York over AC Ties	346	346	413
Total	1,945	1,950	2,020

Tie benefits are assumed to not be available over the Cross Sound Cable because the import capability of the Cross Sound Cable for tie benefits was determined to be zero.

Q: IS THE ISO'S METHODOLOGY FOR CALCULATING TIE BENEFITS FOR ARA 3 FOR THE 2019-2020 CCP THE SAME AS THE METHODOLOGY USED FOR THE CORRESPONDING FCA?

A: The methodology for calculating tie benefits used in the calculations of ICR for ARA 3 for the 2019-2020 CCP is the same methodology used to calculate the tie benefits used in the calculation of the ICR for the 2019-2020 Capacity Commitment Period's FCA. This methodology is described in detail in Section III.12.9 of the Tariff.

6. AMOUNT OF SYSTEM RESERVES

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

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: This year, the ISO used 700 MW as the amount of system reserves in the determination of the probabilistic ICR-Related Values. This is an increase of 500 MW over the 200 MW value assumed in the past. The reasons for the increase from 200 MW to 700 MW of minimum system operating reserves assumed in the probabilistic ICR-Related Values model are described in the Testimony of Peter Brandien that was submitted to the Commission in support of the ICR and related values for FCA 13.[15]

IV. LOCAL SOURCING REQUIREMENTS

Q: WHAT ARE IMPORT-CONSTRAINED CAPACITY ZONES?

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

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, and 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 Requirement or (ii) the TSA Requirement. The LSR is applied to import-constrained Capacity Zones within New England.

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE LRA REQUIREMENTS.

A: For each import-constrained zone, the LRA Requirement is determined by modeling the zone under study vis-à-vis the rest of New England. This, in effect, turns the modeling

[15] *See ISO New England Inc.,* Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the Thirteenth FCA (Associated with the 2022-2023 Capacity Commitment Period); Docket No. ER19-295-000.

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.[16] Because the LRA Requirement 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, is achieved.

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE TSA REQUIREMENTS.

A: The TSA is a deterministic reliability screen of an import-constrained area and is a basic transmission 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.[17] This review determines the requirement of the sub-area to meet its load through internal generation and import capacity and is performed via a series of discrete transmission load flow study scenarios. 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

[16] An allowance for transmission-related LOLE of 0.005 days per year is applied when determining the LRA Requirement of a Capacity Zone.

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

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 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 TSA REQUIREMENT AND THE ASSUMPTIONS USED FOR THE DETERMINATION OF THE LRA REQUIREMENT?

A: There are three differences between the assumptions relied upon for determining the TSA Requirement and the assumptions relied upon for determining the LRA Requirement. The first difference relates to the load forecast assumption. Resource adequacy analyses (*i.e.*, the analysis performed in determining the ICR, LRA Requirement, MCL, Demand Curve Values, 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, Planning Procedure to Support the Forward Capacity Market, the analysis is performed using the 90/10 peak load forecast, net of BTM PV, which corresponds to a peak load that has a 10% probability of being exceeded based on weather variation.

The second difference relates to the application of assumed forced outages to peaking generating resources. For peaking generating resources, a de-rating factor of 20% was applied in the TSA as a forced outage assumption.

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

Q: PLEASE DESCRIBE THE LRA REQUIREMENTS, TSA REQUIREMENTS AND LSRs FOR EACH OF THE ARAs.

A: Tables 10-12 below show the LRA Requirements, TSA Requirements and resulting LSRs for the SENE Capacity Zone for the 2019-2020, 2020-2021, and 2021-2022 Capacity Commitment Periods.

Table 10 – Import-Constrained Capacity Zone Requirements for 2019-2020 ARA 3 (MW)

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	10,083	9,936	10,083

Table 11 – Import-Constrained Capacity Zone Requirements for 2020-2021 ARA 2 (MW)

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	10,182	10,000	10,182

Table 12 – Import-Constrained Capacity Zone Requirements for 2021-2022 ARA 1 (MW)

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	9,973	9,760	9,973

V. MAXIMUM CAPACITY LIMITS

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: WHAT IS THE MCL?

A: The MCL is the maximum amount of resources that can be electrically located within an export-constrained Capacity Zone to meet the regional ICR.

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE MCL.

A: In order to determine the MCL, the New England net ICR and the LRA Requirement 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 Requirement 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.

Q: WHY WAS AN MCL NOT CALCULATED FOR ARA 3 FOR THE 2019-2020 CCP?

A: No export-constrained zones were modeled for the 2019-2020 Capacity Commitment Period FCA. Accordingly, MCLs were not calculated for the 2019-2020 Capacity Commitment Period FCA and have not been calculated for ARA 3 for the 2019-2020 CCP.

Q. PLEASE DESCRIBE THE MCLs FOR THE NNE CAPACITY ZONE FOR ARA 2 FOR THE 2020-2021 CCP AND ARA 1 FOR THE 2021-2022 CCP.

A: For ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP, the MCLs for the NNE Capacity Zone are 8,660 MW and 8,670, respectively. These are the amounts of capacity resources that can be electrically located within the NNE Capacity Zone, including Import Capacity Resources using the New Brunswick ties for ARA 2 for the 2020-2021 CCP and ARA1 for the 2021-2022 CCP.

VI. 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").[18] 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 Interconnection Rights Holders in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each FCA.

Q: PLEASE DESCRIBE THE HQICC VALUES FOR EACH OF THE ARAs TO BE CONDUCTED IN 2019.

A: For ARA 3 for the 2019-2020 CCP, the HQICC value is 954 MW for each month of the period.

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[18] *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.").

For ARA 2 for the 2020-2021 CCP, the same 959 MW HQICC value utilized for the 2020-2021 Capacity Commitment Period FCA is used for each month of the period.

For ARA 1 for the 2021-2022 CCP, the same 958 MW HQICC value utilized for the 2021-2022 Capacity Commitment Period FCA is used for each month of the period.

VII. DEMAND CURVE VALUES AND MRI CAPACITY DEMAND CURVES

Q: WHY WERE DEMAND CURVE VALUES CALCULATED FOR ARA 3 FOR THE 2019-2020 CCP?

A: Starting with the 2018-2019 Capacity Commitment Period and continuing with the 2019-2020 Capacity Commitment Period, a System-Wide Capacity Demand Curve was used in the FCAs to procure needed capacity. As such, the Demand Curve Values need to be recalculated for the ARAs to reflect updated system conditions. Accordingly, the ISO calculated the Demand Curve Values for ARA 3 for the 2019-2020 CCP.

Q: WHAT DETERMINES THE CAPACITY REQUIREMENT VALUES FOR THE DEMAND CURVE?

A: Section III.13.2.2 of the Tariff determines that the Demand Curve Values are those calculated (net of HQICCs) at 1-in-5 LOLE and 1-in-87 LOLE.

Q: WHAT ARE THE DEMAND CURVE VALUES CALCULATED BY THE ISO FOR THE SYSTEM-WIDE CAPACITY DEMAND CURVE FOR ARA 3 FOR THE 2019-2020 CCP?

A: Section III.12.1 of Market Rule 1 states that "[t]he ISO shall determine, by applying the same modeling assumptions and methodology used in determining the [ICR], the capacity requirement value for each LOLE probability specified in Section III.13.2.2 for the System-Wide Capacity Demand Curve." The methodology for determining those values is the same as that used for calculating the ICR.

The 1-in-5 LOLE and 1-in-87 LOLE Demand Curve Values for ARA 3 for the 2019-2020 CCP are 32,315 MW and 36,040 MW, respectively.

Q: WHAT ARE THE PRICE ($/KW-MONTH) VALUES ASSOCIATED WITH THE 1-IN-5 LOLE AND 1-IN-87 LOLE CAPACITY REQUIREMENT VALUES FOR THE DEMAND CURVE FOR THE PURPOSE OF CONDUCTING ARA 3 FOR THE 2019-2020 CCP?

A. The price values associated with the 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values for the demand curve for the purpose of conducting ARA 3 for the 2019-2020 CCP are $17.296/kW-month and $0/kW-month, respectively.

Q: WHY DID THE ISO DEVELOP MRI DEMAND CURVES FOR ARA 2 FOR THE 2020-2021 CCP AND ARA 1 FOR THE 2021-2022 CCP?

A: MRI Demand Curves are calculated starting with the FCA for the 2020-2021 Capacity Commitment Period. Accordingly, the ISO calculated MRI Demand Curves for ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP.

Q: PLEASE DESCRIBE THE METHODOLOGY USED FOR CALCULATING THE MRI DEMAND CURVES FOR ARA 2 FOR THE 2020-2021 CCP AND ARA 1 FOR THE 2021-2022 CCP.

A: To calculate the MRI Demand Curves for the system, the SENE Import-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone for ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP, 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" (or "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[19] in 10 MW increments and 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

[19] The GE MARS model is the same simulation system that is already used to develop the ICR, LRA Requirements, and MCLs. For the development of the MRI Demand Curves, the 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.

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 values at various capacity levels are also calculated for the SENE import-constrained Capacity Zone and the NNE export-constrained Capacity Zone using the same modeling assumptions and methodology as those used to determine the LRA Requirement and the MCL 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 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 and zonal demand curves for ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP 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").[20] In other words, the scaling factor is equal to the value that produces a system 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 ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP was developed for MRI Demand Curves for the system, the SENE Import-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone 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 MRI Demand Curves at a price of Net CONE, the LOLE is 0.1 days per year.

Q: PLEASE EXPLAIN THE TRANSITION METHODOLOGY USED TO DEVELOP THE SYSTEM-WIDE MRI DEMAND CURVES FOR ARA 2 FOR THE 2020-2021 CCP AND ARA 1 FOR THE 2021-2022 CCP.

A: For ARA 2 for the 2020-2021 CCCP and ARA 1 for the 2021-2022 CCP, the ISO used the transition provisions in Section III.13.2.2.1 to determine the System-Wide MRI Demand Curves.

The MRI transition period aims to provide a transition from the linear system-wide capacity demand curve methodology used for the 2018-2019 and 2019-2020 CCPs to the

[20] For ARA 2 for the 2020-2021 CCP, Net CONE has been determined as $11.640/kW-month. For ARA 1 for the 2021-2022 CCP, Net CONE has been determined as $8.04/kW-month.

MRI-based system-wide capacity demand curve methodology. This transition period will help to provide a stable and consistent market signal while balancing stakeholder interests. The transition period begins with the 2020-2021 CCP and will end with the 2022-2023 CCP. During the MRI transition period, the System-Wide MRI Demand Curve is represented as a hybrid of the previous linear demand curve design and the new MRI-based demand curve design.[21]

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

A***:*** For import-constrained Capacity Zones, the LRA Requirement and TSA Requirement values both play a role in defining the MRI-based demand curves as they do in setting the LSR. Under Section III.12.2.1.3 of the Tariff, 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 Requirement 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 Requirement, and; (ii) zero. By using a transfer capability that accounts for both the TSA Requirement and the LRA Requirement, the ISO applies the same "higher of" logic used in the LSR to the

[21] For more information relating to the MRI Demand Curve transition see the detailed data spreadsheets at: https://www.iso-ne.com/static-assets/documents/2018/10/a6_icr_requirements_for_ara3_2019_2020_ara2_2020_2021_ara1_2021_2022.zip.

derivation of sloped zonal demand curves. For ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP, the only import-constrained Capacity Zone is SENE and, therefore, there is only one Import-Constrained Capacity Zone MRI Demand Curve for each of those ARAs.

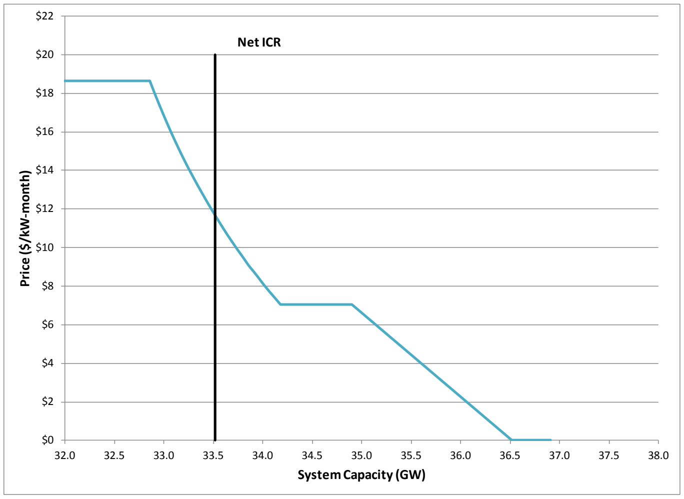
Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE EXPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVES FOR THE NNE CAPACITY ZONE.

A: Under Section III.12.2.2.1 of the Tariff, the Export-Constrained Capacity Zone Demand Curve is calculated using 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 MRI Demand Curves pursuant to Section III.13.2.2.3 of the Tariff. For ARA 2 for the 2020-2021 CCP and ARA 1 for the 2021-2022 CCP, the only export-constrained Capacity Zone is NNE and, therefore, there is only one export-constrained Capacity Zone MRI Demand Curve for each of those ARAs.

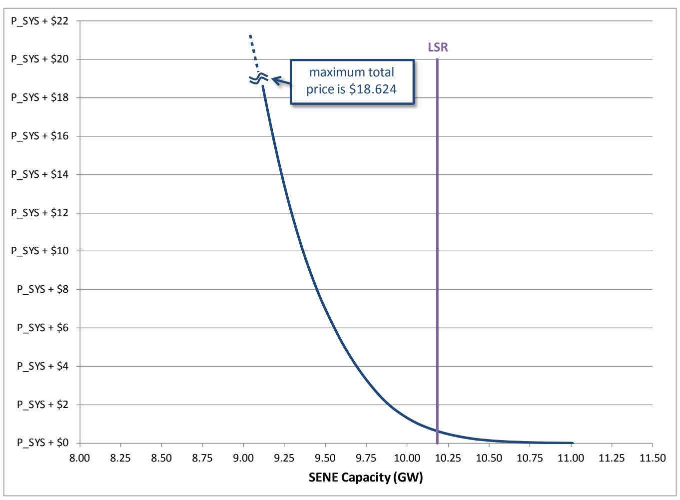
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR ARA 2 FOR THE 2020-2021 CCP?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI Demand Curves for ARA 2 for the 2020-2021 CCP:

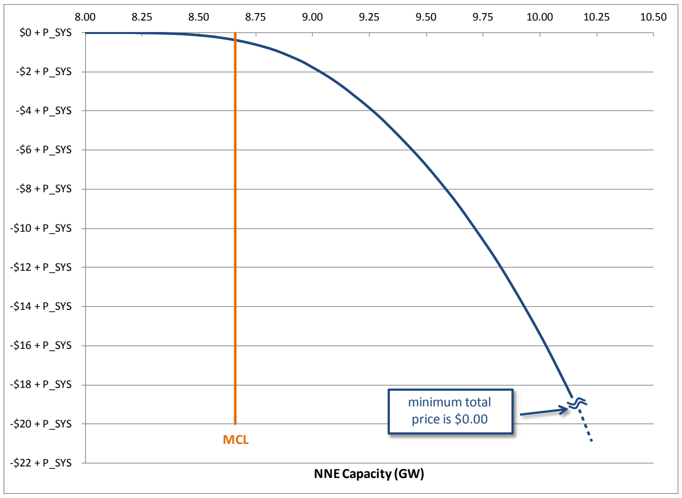
System-Wide MRI Demand Curve for ARA 2 for the 2020-2021 CCP



Import-Constrained Capacity Zone MRI Demand Curve for the SENE Capacity Zone for ARA 2 for the 2020-2021 CCP



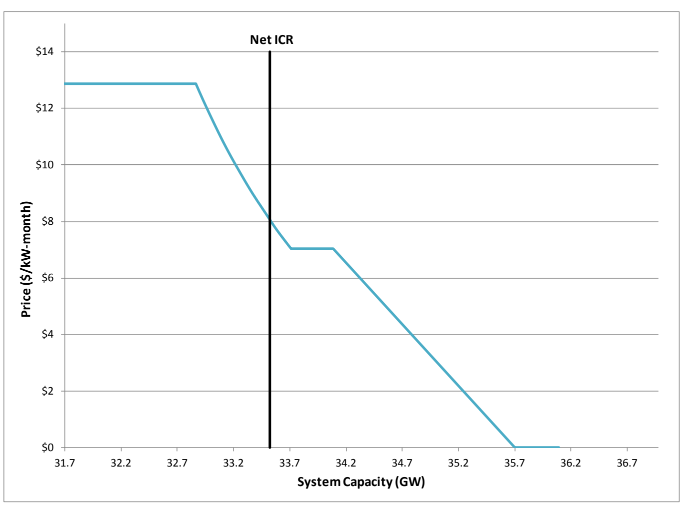
Export-Constrained Capacity Zone MRI Demand Curve for the NNE Capacity Zone for ARA 2 for the 2020-2021 CCP



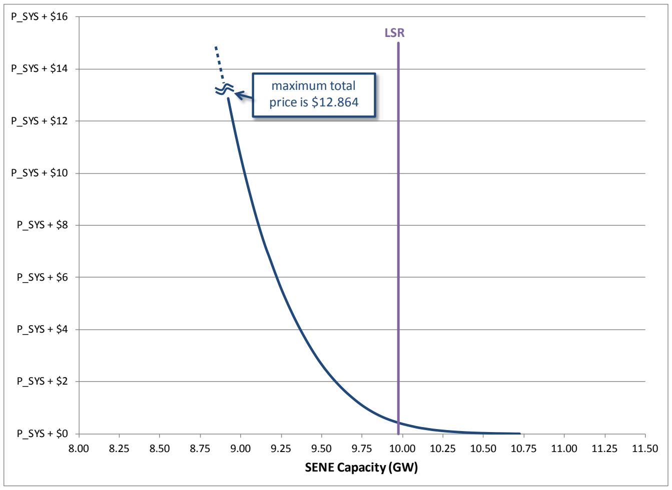
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR ARA 1 FOR THE 2021-2022 CCP?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI Demand Curves for ARA 1 for the 2021-2022 CCP:

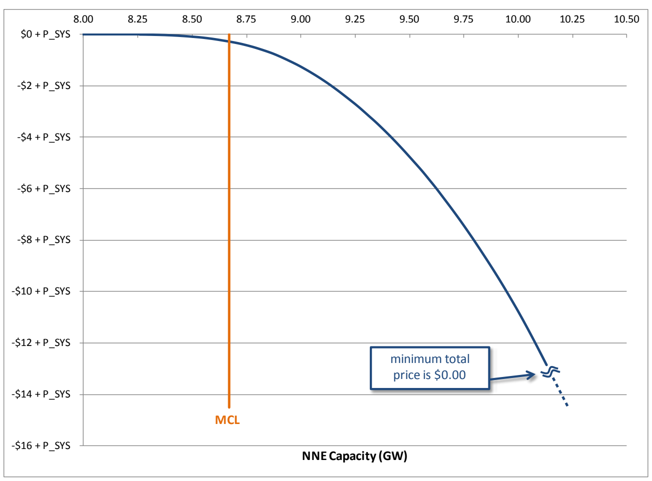
System-Wide MRI Demand Curve for ARA 1 for the 2021-2022 CCP



Import-Constrained Capacity Zone MRI Demand Curve for the SENE Capacity Zone for ARA 1 for the 2021-2022 CCP



Export-Constrained Capacity Zone MRI Demand Curve for the NNE Capacity Zone for ARA 1 for the 2021-2022 CCP



Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Executed on 11/30/18 ____________________
Carissa Sedlacek

Executed on 11/30/2018 ____________________
Maria Scibelli

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