November 6, 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.*, Docket No. ER19-___-000, 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)

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 ("FERC" or "Commission") this transmittal letter and related materials that identify the following values for the 2022-2023 Capacity Commitment Period,[3] which is associated with the thirteenth Forward Capacity Auction ("FCA 13"): (i) Installed Capacity Requirement;[4] (ii)

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[1] 16 U.S.C. § 824d (2014).

[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. As explained in this filing letter, due to the pending termination of Invenergy's Clear River Unit 1, the ISO is submitting two sets of values: one without Clear River Unit 1 in the model, and another one with Clear River Unit 1 in the model. NEPOOL supported the values without Clear River Unit 1 in the model, but it did not support the values with Clear River Unit 1 in the model. Accordingly, NEPOOL joins this filing only with respect to the values without Clear River Unit 1 in the model.

[3] The 2022-2023 Capacity Commitment Period starts on June 1, 2022 and ends on May 31, 2023.

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

Local Sourcing Requirement for the Southeast New England ("SENE") Capacity Zone;[5] (iii) Maximum Capacity Limit for the Northern New England ("NNE") Capacity Zone;[6] (iv) Hydro Quebec Interconnection Capability Credits ("HQICCs"); and (v) Marginal Reliability Impact ("MRI") Demand Curves.[7] The Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, Maximum Capacity Limit for the NNE Capacity Zone, HQICCs and MRI Demand Curves are collectively referred to herein as the "ICR-Related Values." [8]

On September 20, 2018, the ISO submitted to the Commission a resource termination filing to terminate Clear River Unit 1. The ISO requested that the Commission issue its order on the termination within 60 days of the filing (*i.e.* by November 19, 2018), which is after the date of this filing. For that reason, the ISO is filing two sets of ICR-Related Values. The first set assumes that FERC will accept the termination and, accordingly, does not include Clear River Unit 1 in the model. The second set assumes that FERC will reject the termination, and, accordingly, includes Clear River Unit 1 in the model. Of these two sets of ICR-Related Values, only the one that reflects the Commission's order on the termination of Clear River Unit 1 will be used in FCA 13.[9]

The body of this filing letter describes the set of proposed ICR-Related Values without Clear River Unit 1 in the model. The alternative set of values, *i.e.* the ICR-Related Values with Clear River Unit 1 in the model, are included in Attachment 1 to this filing. Notably, the differences between the values are very small:

- The Installed Capacity Requirement without Clear River Unit 1 in the model[10] is 20 MW

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

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

[7] As explained in this filing letter, the MRI Demand Curves include the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone, and the Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone.

[8] Pursuant to Section III.12.3 of the Tariff, the Installed Capacity Requirement must be filed 90 days prior to the applicable Forward Capacity Auction ("FCA"). FCA 13, which is the primary FCA for the 2022-2023 Capacity Commitment Period, is scheduled to commence on February 4, 2019.

[9] The HQICC values are the same regardless of whether Clear River Unit 1 is included in the model or not. Thus, only one set of HQICC values is being filed. NEPOOL supported the HQICC values.

[10] 34,719 MW (the Installed Capacity Requirement without Clear River Unit 1 in the model net of 969 MW of HQICCs is 33,750 MW).

lower than the Installed Capacity Requirement with Clear River Unit 1 in the model.[11]

- The Local Sourcing Requirement for the SENE Capacity Zone without Clear River Unit 1 in the model[12] is 20 MW higher than the Local Sourcing Requirement for the SENE Capacity Zone with Clear River Unit 1 in the model.[13]

- The Maximum Capacity Limit for the NNE Capacity Zone without Clear River Unit 1 in the model[14] is 10 MW lower than the Maximum Capacity Limit for the NNE Capacity Zone with Clear Unit 1 in the model.[15]

- The graphical representation of both sets of ICR-Related Values' MRI Demand Curves are virtually identical.

The ISO is proposing an Installed Capacity Requirement (net of HQICCs) of 33,750 MW,[16] a Local Sourcing Requirement for the SENE Capacity Zone of 10,141 MW, a Maximum Capacity Limit for the NNE Capacity Zone of 8,545 MW, HQICCs of 969 MW per month, and the following MRI Demand Curves:

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[11] 34,739 MW (the Installed Capacity Requirement with Clear River Unit 1 in the model net of 969 MW of HQICCs is 33,770 MW).

[12] 10,141 MW

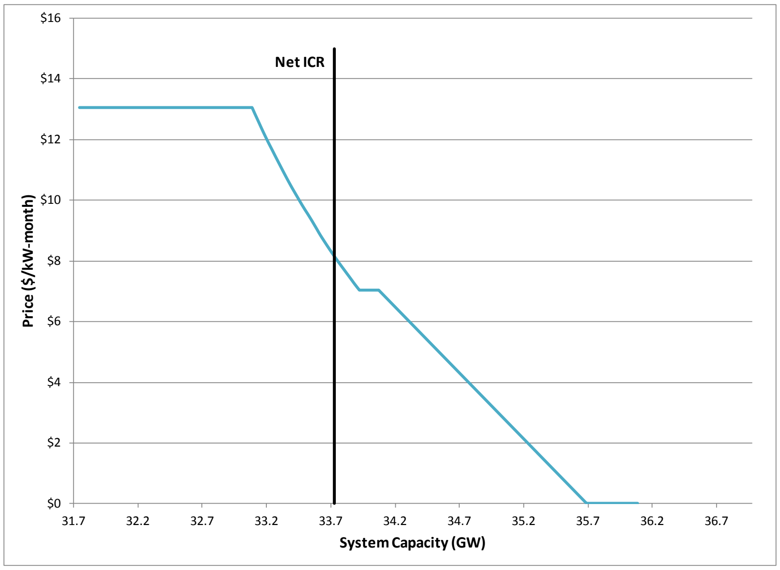
[13] 10,121 MW

[14] 8,545 MW

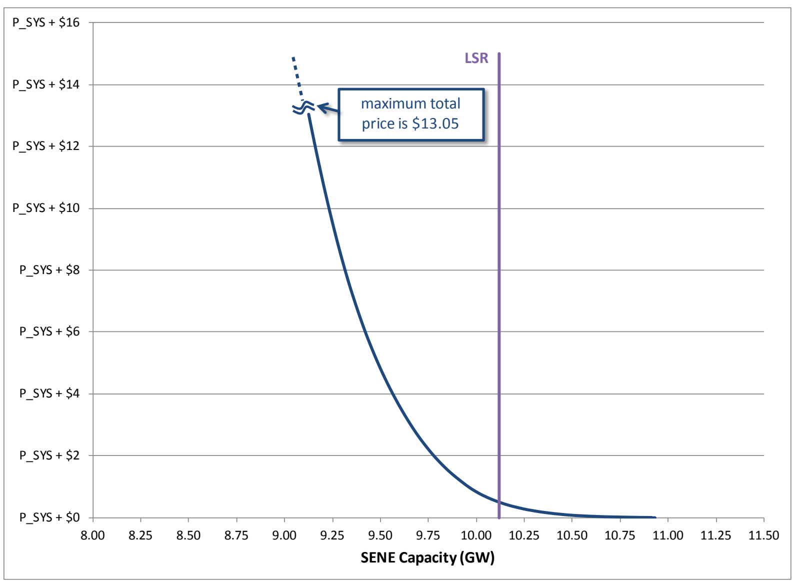
[15] 8,555 MW

[16] As explained in Section III.B.4 of this filing letter, the proposed Installed Capacity Requirement reflects tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Quebec in the aggregate amount of 2,000 MW.

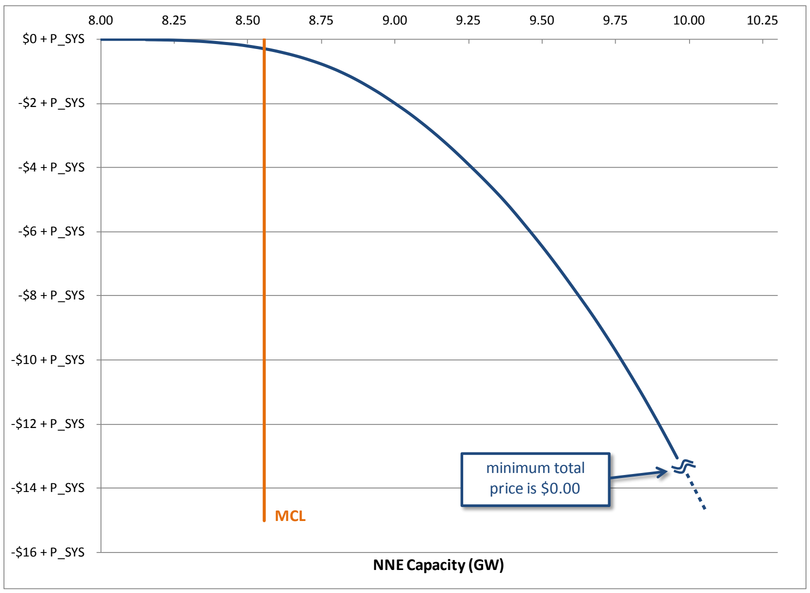
1. System-Wide Capacity Demand Curve for FCA 13



2. Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 13



3. Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 13



The derivation of the ICR-Related Values is discussed in Sections III-VI of this filing letter, in the attached joint testimony of Carissa Sedlacek, Director of Resource Adequacy at the ISO and Maria Scibelli, Principal Analyst, Resource Adequacy at the ISO (the "Sedlacek-Scibelli Testimony"), and the attached testimony of Peter Brandien, Vice President of System Operations at the ISO (the "Brandien Testimony"). The Sedlacek-Scibelli Testimony and the Brandien Testimony are sponsored solely by the ISO. With the exception of a modification in the methodology used to account for behind-the-meter ("BTM") photovoltaic ("PV") output (described in Section III.B.1 of this filing letter and in the Sedlacek-Scibelli Testimony), and a modification in the amount of system reserves assumption (described in Section III.B.4.b of this filing letter and in the Brandien Testimony), the ICR-Related Values were calculated using the same Commission-approved methodology that was used to calculate the values submitted and accepted for preceding FCAs.[17] The proposed values are therefore the result of a well-developed

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[17] *ISO New England Inc. and New England Power Pool Participants Committee*, 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 ("2021-2022 ICR Filing") (filed Nov. 7, 2017). The 2021-2022 ICR Filing was accepted by Letter Order issued on December 18, 2017 (the "2021-2022 ICR Letter Order"); *ISO New England Inc. and New England Power Pool Participants* Committee, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2020-2021 Capacity Commitment Period ("2020-2021 ICR Filing") (filed Nov. 8, 2016). The 2020-2021 ICR Filing was accepted by Letter Order issued on December 6, 2016 (the "2020-2021 ICR Letter Order"); ISO *New England Inc.*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2019-2020 Capacity

process that improves, pursuant to the Commission's direction, on the processes utilized and approved by the Commission for the development of the Installed Capacity Requirement and related values in the past. Accordingly, the Commission should accept the proposed values as just and reasonable without change to become effective on January 5, 2019.

I. DESCRIPTION OF FILING PARTIES AND COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO 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

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Commitment Period, Docket No. ER16-307-000, at 2 ("2019-2020 ICR Filing") (filed Nov. 10, 2015). The 2019-2020 ICR Filing was accepted in *ISO New England Inc.*, 154 FERC ¶ 61,008 (2016) ("2019-2020 ICR Order"); *ISO New England Inc.*, 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, at 4-6 ("2018-2019 ICR Filing") (filed Nov. 4, 2014). The 2018-2019 ICR Filing was accepted in *ISO New England Inc.*, 150 FERC ¶ 61,003 (2015) ("2018-2019 ICR Order"); *ISO New England Inc. and New England Power Pool Participants Committee*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2017-2018 Capability Year, Docket No. ER14-328-000, at 5-6 ("2017-2018 ICR Filing") (filed Nov. 5, 2013). The 2017-2018 ICR Filing was accepted by Letter Order issued December 30, 2013 (the "2017-2018 ICR Letter Order"). *ISO New England Inc. and New England Power Pool Participants Committee*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2016-2017 Capability Year, Docket No. ER13-334-000, at p. 5 ("2016-2017 ICR Filing") (filed Nov. 6, 2012). The 2016-2017 ICR Filing was accepted by Letter Order issued December 31, 2012 (the "2016-2017 ICR Letter Order"). *See also ISO New England Inc. and New England Power Pool*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2015-2016 Capability Year, Docket No. ER12-756-000, at p. 5 ("2015-2016 ICR Filing") (filed Jan. 3, 2012); *ISO New England Inc.*, Letter Order accepting filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2015-2016 Capability Year, Docket No. ER12-756-000 (Feb. 23, 2012) ("2015-2016 ICR Letter Order"); *ISO New England Inc. and New England Power Pool*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2014-2015 Capability Year, Docket No. ER11-3048-000, at 5-6 ("2014-2015 ICR Filing") (filed March 8, 2011); *ISO New England Inc. and New England Power Pool*, 135 FERC ¶ 61,135 at P 53 (2011) ("2014-2015 ICR Order"); *ISO New England Inc.*, Letter Order accepting filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2013-2014 Capability Year, Docket No. ER10-1182-000 (June 25, 2010) ("2013-2014 ICR Letter Order"); *ISO New England Inc.*, Letter Order accepting filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2012-2013 Capability Year, Docket No. ER09-1415-000 (Aug. 14, 2009) ("2012-2013 ICR Letter Order"); *ISO New England Inc.*, Order Accepting, With Conditions, Proposed Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits, and Related Values, 125 FERC ¶ 61,154 at PP 1, 26, 41 (2008) (accepting ISO-proposed Installed Capacity Requirements for the 2011-2012 Capability Year) ("2011-2012 ICR Order"); *ISO New England Inc. and New England Power Pool*, 121 FERC ¶ 61,250 at P 1 (2007); *order on reh'g*, 123 FERC ¶ 61,129 (2008) ("2010-2011 ICR Order").

reliability standards established by the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC").

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 500 members. The participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[18] the participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

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

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[18] *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 for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[20] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[21] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[22] 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."[23] The ICR-Related Values submitted herein "need not be the only reasonable methodology, or even the most accurate."[24] 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.[25]

III. INSTALLED CAPACITY REQUIREMENT

A. Description of the Installed Capacity Requirement

The Installed Capacity Requirement is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for the New England Control Area and to maintain sufficient reserve capacity to meet reliability standards. More specifically, the Installed Capacity Requirement is the amount of resources needed to meet the reliability requirements defined for the New England Control Area of disconnecting non-interruptible customers (a loss of load expectation or "LOLE") no

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[19] 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.

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

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

[22] *Id.* at 9.

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

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

[25] *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)).

more than once every ten years (a LOLE of 0.1 days per year). The methodology for calculating the Installed Capacity Requirement is set forth in Section III.12 of the Tariff.

The ISO is proposing an Installed Capacity Requirement of 34,719 MW for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period. This value reflects tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Quebec in the aggregate amount of 2,000 MW. However, the 34,719 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 969 MW per month is applied to reduce the portion of the Installed Capacity Requirement that is allocated to the Interconnection Rights Holders ("IRH"). Thus, the net Installed Capacity Requirement, after deducting the HQICC value, is 33,750 MW.[26]

B. Development of the Installed Capacity Requirement

With the exception of the modification in the BTM PV methodology to account for uncertainty in the BTM PV output, and the change in the amount of system reserves assumed in the calculations of the ICR-Related Values, the calculation methodology used to develop the ICR-Related Values for FCA 13 is the same as that used to calculate the values for previous FCAs. As in previous years, the values submitted in the instant filing are based on assumptions relating to expected system conditions for the associated Capacity Commitment Period. These assumptions include the load forecast, resource capacity ratings, resource availability, and relief assumed obtainable by implementation of operator actions during a capacity deficiency, which includes the amount of possible emergency assistance (tie benefits) obtainable from New England's interconnections with neighboring Control Areas, load reduction from implementation of 5% voltage reductions, and a minimum level of operating reserve.[27] The Tariff provisions that establish the assumptions used to calculate the ICR-Related Values are the same as those used to calculate the values for the twelfth FCA ("FCA 12") and previous FCAs.[28] The modeling assumptions have been updated to reflect expected changes in system conditions since the development of the Installed Capacity Requirement and related values for FCA 12. These updated assumptions are described below.

1. Load Forecast

The forecasted peak loads of the entire New England Control Area for the 2022-2023

[26] The net Installed Capacity Requirement is used in the development of the MRI Demand Curves, which will be used to procure capacity in FCA 13.

[27] Sedlacek-Scibelli Testimony at 24-25.

[28] *See* note 9, *supra*.

Capacity Commitment Period are one major input into the calculation of the ICR-Related Values. For the purpose of calculating the Installed Capacity Requirement for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, the ISO used the load forecast published in the 2018-2027 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2018 ("2018 CELT Report").[29] The ISO developed the 2018 CELT Report's load forecast by using the same methodology that the ISO has used in previous years to determine load forecasts and develop the peak load assumptions reflected in the Commission-approved Installed Capacity Requirement.[30] This methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee.[31]

The projected New England Control Area summer 50/50 peak load[32] for the 2022-2023 Capacity Commitment Period is 29,093 MW. In determining the Installed Capacity Requirement, 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 Installed Capacity Requirement calculations, the methodology determines the amount of capacity resources needed to meet every expected peak load of the weekly distribution given the probability of occurrence associated with that load level.[33]

As was done last year for FCA 12, all probabilistic ICR-Related Values calculations for FCA 13 use an hourly profile of BTM PV corresponding to the load shape for the year 2002, used by the Northeast Power Coordinating Council (NPCC) for reliability studies.[34] The hourly profile is modeled by subarea in the General Electric Multi-Area Reliability Simulation ("GE MARS") model. The values of BTM PV published 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

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[29] Sedlacek-Scibelli Testimony at 14.

[30] *See, e.g.*, 2021-2022 ICR Letter Order; 2020-2021 ICR Letter Order; 2019-2020 ICR Order; 2018-2019 ICR Order; 2017-2018 ICR Letter Order; 2016-2017 ICR Letter Order; 2015-2016 ICR Order; 2014-2015 ICR Order at PP 53, 69; 2013-2014 ICR Letter Order; 2012-2013 ICR Letter Order; 2011-2012 ICR Order at PP 5-6; 2010-2011 ICR Order at PP 5-6.

[31] The methodology is reviewed periodically and updated when deemed necessary in consultation with the NEPOOL Load Forecasting Committee.

[32] The New England Control Area is a summer-peaking system, meaning that the highest load occurs during the summer. The 50/50 peak refers to the peak load having a 50% chance of being exceeded, and is expected to occur at a weighted New England-wide temperature of 90.4 ºF. The value shown is the 2018 CELT "*Net Forecast – With Reductions for BTM PV*" peak load forecast.

[33] *See* Sedlacek-Scibelli Testimony at 13.

[34] For more information on the development of the hourly profile see: https://www.iso-ne.com/static-assets/documents/2017/06/pspc_6_22_2017_2002_PV_profile.pdf

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).

2. Resource Capacity Ratings

The Installed Capacity Requirement for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, is based on the latest available resource ratings[35] of Existing Capacity Resources that have qualified for FCA 13 at the time of the Installed Capacity Requirement calculation. These resources are described in the qualification informational filing for FCA 13 that is being submitted concurrently to the Commission on November 6, 2018.[36]

Resource additions and most resource attritions[37] are not assumed in the calculation of the Installed Capacity Requirement for FCA 13, pursuant to the Tariff, because there is no certainty which new resource additions or existing resource attritions, if any, will clear the FCA. The use of the proxy unit for potential required resource additions when the system is short of capacity, and the additional load carrying capability ("ALCC") adjustments to remove surplus capacity from the system, discussed in the Sedlacek-Scibelli Testimony, are designed to address these resource addition and attrition uncertainties.[38]

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[35] The resource capacity ratings for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, were calculated in accordance with Section III.12.7.2 of the Tariff using the methods and procedures that were employed for calculating resource capacity ratings reflected in the Commission-approved Installed Capacity Requirements for the first twelve primary FCAs. *See* 2021-2022 ICR Letter Order; 2020-2021 ICR Letter Order; 2019-2020 ICR Order at 15; 2018-2019 ICR Order at 7; 2017-2018 ICR Filing at 11-12 and 2017-2018 ICR Letter Order; 2016-2017 ICR Filing at 11-12; 2015-2016 ICR Filing at 11-12 and 2015-2016 ICR Order; 2014-2015 ICR Filing at 12-13 and 2014-2015 ICR Order at P 53; 2013-2014 ICR Filing at 10-11 and the 2013-2014 ICR Letter Order; 2012-2013 ICR Filing at 11-13 and the 2012-2013 ICR Letter Order; 2011-2012 ICR Filing at 11-12 and the 2011-2012 ICR Order at PP 1, 7; 2010-2011 ICR Filing at 11-12 and the 2010-2011 ICR Order at PP 1, 7.

[36] *ISO New England Inc.*, Informational Filing for Qualification in the Forward Capacity Market, filed on November 6, 2018 at Attachment C.

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

[38] Sedlacek-Scibelli Testimony at 12.

3. Resource Availability

The proposed Installed Capacity Requirement value for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, reflects generating resource availability assumptions based on historical scheduled maintenance and forced outages of these capacity resources.[39] For generating resources, individual unit scheduled maintenance assumptions are based on each unit's most recent five-year historical average of scheduled maintenance. The individual generating resource's forced outage assumptions are based on the resource's most recent five-year historical NERC Generator Availability Database System ("GADS") forced outage rate data submitted to the ISO. If the resource has been in commercial operation less than five years, the NERC class average maintenance and forced outage data for the same class of units is used to substitute for the missing annual data.

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

In the Installed Capacity Requirement 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) events and ISO performance audits that occurred in summer and winter 2013 through 2017.

4. Other Assumptions

a. Tie Benefits

New England's Commission-approved method for establishing the Installed Capacity Requirement requires that assumptions be made regarding the tie benefits value to be used as an input in the calculation.[40] The tie benefits reflect the assumed amount of emergency assistance from neighboring Control Areas that New England could rely on, without jeopardizing reliability

[39] The assumed resource availability ratings for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, are discussed in the Sedlacek-Scibelli Testimony at 22-23. The ratings were calculated in accordance with Section III.12.7.3 of the Tariff using the methods and procedures that were employed for calculating resource capacity ratings reflected in the Commission-approved Installed Capacity Requirements for the first eleven primary FCAs. *See* note 9, *supra*.

[40] *See* Section III.12.9 of the Tariff. The methodology for calculating tie benefits to be used in the Installed Capacity Requirement for FCA 13 is the same methodology used to calculate the tie benefits used in the Installed Capacity Requirement for Capacity Commitment Periods associated with prior FCAs.

in New England or the neighboring Control Areas, in the event of a capacity shortage in New England. Assuming tie benefits as a resource to meet the 0.1days/year LOLE criterion reduces the Installed Capacity Requirement and lowers the amount of capacity to be procured in the FCA.

The Installed Capacity Requirement for FCA 13 proposed by the ISO reflects tie benefits calculated from the New Brunswick, New York and Quebec Control Areas.[41] The ISO utilizes a probabilistic multi-area reliability model to calculate total tie benefits from these three Control Areas. Tie benefits from each individual Control Area are determined based on the results of individual probabilistic calculations performed for each of the three neighboring Control Areas. Specifically, the tie benefits methodology is comprised of two broad steps. In step one, the ISO develops necessary system load, transmission interface transfer capabilities and capacity assumptions. In step two, the ISO conducts simulations using the probabilistic GE MARS modeling program in order to determine tie benefits. In this step, the neighboring Control Areas are modeled using "*at criteria*" modeling assumptions which means that, when interconnected, all Control Areas are assumed to be at the 0.1 days/year reliability planning criteria.

The Installed Capacity Requirement calculations for FCA 13 assume total tie benefits of 2,000 MW based on the results of the tie benefits study for the 2022-2023 Capacity Commitment Period. A breakdown of this total value by Control Area is as follows: 516 MW from New Brunswick (Maritimes) over the New Brunswick ties, 366 MW from New York over the AC ties, 969 MW from Quebec over the Phase II interconnection, and 149 MW from Quebec over the Highgate interconnection.[42] The tie benefits methodology is described in detail in Section III.12.9 of the Tariff. The procedures associated with the tie benefits calculation methodology were also addressed in detail in the transmittal letter for the 2014-2015 ICR Filing.[43]

Under Section III.12.9.2.4(a), 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 of these external interconnections 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. The ISO established transfer capability values for the following interconnections: 700 MW for the New Brunswick

[41] *See* 2014-2015 ICR Filing, Sedlacek-Scibelli Testimony at 29, for an explanation of the methodology employed by the ISO in determining tie benefits for the 2014-2015 Capacity Commitment Period, which was also employed by the ISO in determining tie benefits for the 2015-2016 Capacity Commitment Period, the 2016-2017 Capacity Commitment Period, the 2017-2018 Capacity Commitment Period, 2018-2019 Capacity Commitment Period, the 2019-2020 Capacity Commitment Period, the 2020-2021 Capacity Commitment Period, and the 2021-2022 Capacity Commitment Period.

[42] Sedlacek-Scibelli Testimony at 28.

[43] 2014-2015 ICR Filing at 13-19.

interconnections; 1,400 MW 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; 1,400 MW for the Hydro-Quebec 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. The other factor is the transfer capability of the internal transmission interfaces. In calculating tie benefits for the Installed Capacity Requirement for FCA 13, for internal transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.[44]

b. Amount of System Reserves

Pursuant to Section III.12.7.4 (c) of the Tariff, the amount of system reserves included in the determination of the Installed Capacity Requirement and related values must be consistent with those needed for reliable system operations during emergency conditions. Using a system reserve assumption in the Installed Capacity Requirement and related values calculations assumes that, during peak load conditions, under extremely tight capacity situations, while emergency capacity and energy operating plans are being used, ISO operations would have available the essential amount of operating reserves for transmission system protection, system load balancing, and tie control, prior to invoking manual load shedding. Since 1980, the amount of system reserves that has been used in the determination of the Installed Capacity Requirement and related values calculations has been 200 MW.

The appropriateness of the continued use of a 200 MW minimum operating reserves assumption in the Installed Capacity Requirement 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.[45] In 2017, during the discussions of the calculations of the Installed Capacity Requirement and related values for FCA 12, some Power Supply Planning Committee (“PSPC”) members asked the ISO to review this assumption. This year, the ISO conducted a review and, as fully explained in the Brandien Testimony, 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 Installed

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[44] Sedlacek-Scibelli Testimony at 33.

[45] *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

Capacity Requirement and related values should be 700 MW.[46] As a result, 700 MW of system reserves is the amount that the ISO used in the determination of the Installed Capacity Requirement and related values for FCA 13.[47]

IV. LOCAL SOURCING REQUIREMENT AND MAXIMUM CAPACITY LIMIT

In the Forward Capacity Market ("FCM"), the ISO must also calculate Local Sourcing Requirements and Maximum Capacity Limits. A Local Sourcing Requirement is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone to meet the Installed Capacity Requirement.[48] A Maximum Capacity Limit is the maximum amount of capacity that can be located in an export-constrained Capacity Zone to meet the Installed Capacity Requirement.[49] The general purpose of Local Sourcing Requirements and Maximum Capacity Limits is to identify capacity resource needs such that, when considered in combination with the transfer capability of the transmission system, they are electrically distributed within the New England Control Area contributing toward purchasing the right amount of resources in the FCA to meet NPCC's and the ISO's bulk power system reliability planning criteria.

For FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, the ISO calculated the Local Sourcing Requirement for the SENE Capacity Zone using the methodology that is reflected in Section III.12.2 of the Tariff. The Local Sourcing Requirement for the SENE Capacity Zone is 10,141 MW.

The calculation methodology for determining Local Sourcing Requirements utilizes both Local Resource Adequacy criteria as well as criteria used in the Transmission Security Analysis that the ISO uses to maintain system reliability when reviewing de-list bids for a FCA. Because the system ultimately must meet both resource adequacy and transmission security requirements, the Local Sourcing Requirement provisions state that both resource adequacy and transmission security-based requirements must be developed for each import-constrained zone. Specifically, the Local Sourcing Requirement is calculated for an import-constrained Capacity Zone as the

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[46] Brandien Testimony at 2. Given that Section III.12.7.4(c) of the Tariff requires that the amount of system reserve be "consistent with those needed for reliable system operations during emergency conditions," a Tariff change was not needed to update the system reserves assumption.

[47] The 700 MW system reserves assumption was used in all the probabilistic ICR-related values calculations, which include the Installed Capacity Requirement, the Local Resource Adequacy Requirement, the Maximum Capacity Limit, and the Marginal Reliability Impact Demand Curves. The assumption was not used in the Transmission Security Analysis, because that is not a probabilistic calculation.

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

[49] *Id.*

amount of capacity needed to satisfy the higher of (i) the Local Resource Adequacy Requirement or (ii) the Transmission Security Analysis Requirement.[50]

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

The calculation of the Transmission Security Analysis Requirement is addressed in Section III.12.2.1.2 of the Tariff, and the conditions used for completing the Transmission Security Analysis within the FCM are documented in Section 6 of ISO Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market ("PP-10").[51] The Transmission Security Analysis uses static transmission interface transfer limits, developed based on a series of discrete transmission load flow study scenarios, to evaluate the transmission import-constrained area's reliability. Using the analysis, the ISO identifies a resource requirement sufficient to allow the system to operate through stressed conditions.[52] The Transmission Security Analysis utilizes the same set of data underlying the load forecast, resource capacity ratings and resource availability that are used in probabilistically determining the Installed Capacity Requirement, Maximum Capacity Limit and Local Resource Adequacy Requirement. However, due to the deterministic and transmission security oriented nature of the Transmission Security Analysis, some of the assumptions utilized in performing the Transmission Security Analysis differ from the assumptions used in calculating the Installed Capacity Requirement, Maximum Capacity Limit and other aspects of the Local Resource Adequacy Requirement. These differences relate to the manner in which load forecast data, forced outage rates for certain resource types, and ISO New England Operating Procedure No. 4 action events are utilized in the Transmission Security Analysis. These differences are described in more detail in the Sedlacek-Scibelli Testimony.[53]

The Local Resource Adequacy Requirement value and Transmission Security Analysis Requirement value for the SENE Capacity Zone calculated for FCA 13 are, respectively, 9,885 MW and 10,141 MW. Applying the "higher of" standard contained in Section III.12.2.1 of the Tariff, the resulting Local Sourcing Requirement value for the SENE Capacity Zone is 10,141

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

[51] Copy available at https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp10/pp10.pdf.

[52] *See* Section III.12.2.1.2(a) of the Tariff. The Transmission Security Analysis is similar, though not identical, to analysis that the ISO utilizes during the reliability review of de-list bids. *See ISO New England Inc.*, 123 FERC ¶ 61,290 at PP 26-31 (2008).

[53] Sedlacek-Scibelli Testimony at 40-41.

MW.

For FCA 13, the ISO also calculated the Maximum Capacity Limit for the NNE Capacity Zone. The Maximum Capacity Limit was calculated using the methodology that is reflected in Section III.12.2.2 of the Tariff. The Maximum Capacity Limit for the NNE Capacity Zone is 8,545 MW.

V. HQICCs

HQICCs are capacity credits that are allocated to the IRH, which are the entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection").[54] Pursuant to Sections III.12.9.5 and III.12.9.7 of the Tariff, the tie benefit value for the HQ Interconnection was established using the results of a probabilistic calculation of tie benefits with Quebec. The ISO calculates HQICCs, which are allocated to the IRH in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each Capacity Commitment Period's FCA. The HQICC value for FCA 13 is 969 MW per month.

VI. MRI DEMAND CURVES

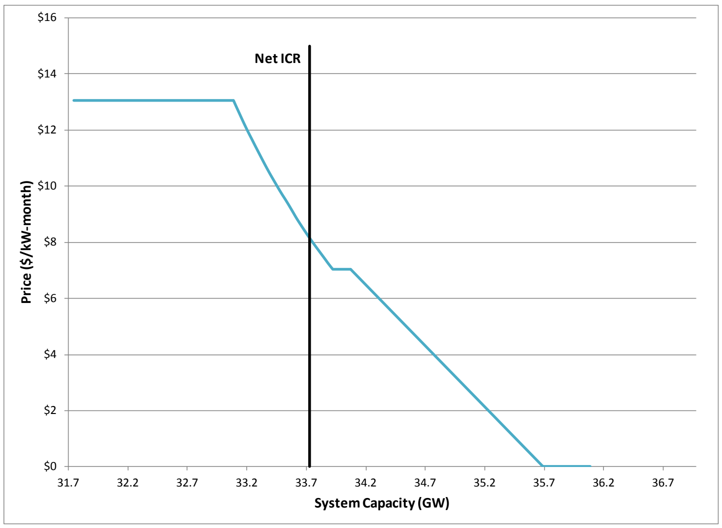
Starting with FCA 11, which is associated with the 2020-2021 Capacity Commitment Period, the ISO began using the MRI Demand Curve methodology to develop system-wide and zonal demand curves to be used in the FCA to procure needed capacity. Accordingly, as described below, the ISO has developed system-wide and zonal MRI demand curves to be used in FCA 13.

A. System-Wide Capacity Demand Curve

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

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

Tariff. Note that, for this year, the ISO used the transition provisions in Section III.13.2.2.1 to determine the System-Wide Demand Curve. The transition curve is a hybrid of the previous linear demand curve design and the new MRI-based design. The following is the System-Wide Capacity Demand Curve for FCA 13:[55]

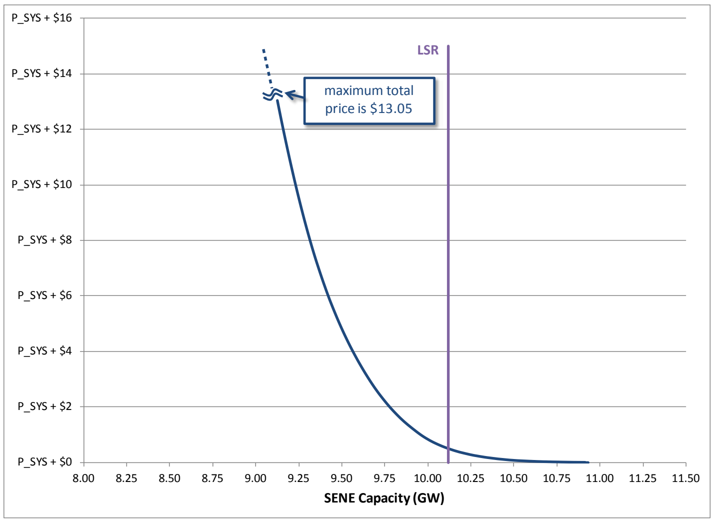


B. Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone

Under Section III.12.2.1.3 of the Tariff, prior to each FCA, the ISO must determine the MRI of capacity, at various higher and lower capacity levels around the requirement, for each import-constrained Capacity Zone. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) has to be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero. Using the values calculated pursuant to Section III.12.2.1.3 of the Tariff, the ISO must determine the Import-Constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.2 of the Tariff. For FCA 13, the only import-constrained Capacity Zone is SENE and,

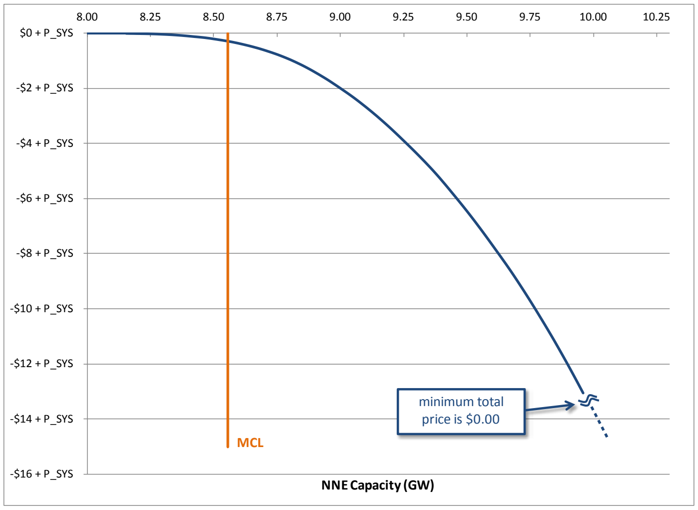
[55] Additional details regarding the calculation of the System-Wide Capacity Demand Curve are included in the Sedlacek-Scibelli Testimony at 45-46.

therefore, there is only one Import-Constrained Capacity Zone Demand Curve. The following is the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 13:



C. Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone

Under Section III.12.2.2.1 of the Tariff, prior to each FCA, the ISO must determine the MRI of capacity, at various higher and lower capacity levels around the requirement, for each export-constrained Capacity Zone. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit. Using the values calculated pursuant to Section III.12.2.2.1 of the Tariff, the ISO must determine the Export-Constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.3 of the Tariff. For FCA 13, the only export-constrained Capacity Zone is NNE and, therefore, there is only one Export-Constrained Capacity Zone Demand Curve. The following is the Export-Constrained Capacity Zone Demand Curve for NNE for FCA 13:



VII. STAKEHOLDER PROCESS

The ISO, in consultation with NEPOOL and other interested parties, developed the proposed ICR-Related Values for FCA 13 through an extensive stakeholder process over the course of eight months. The Reliability Committee discussed the proposed ICR-Related Values for FCA 13 as well as the proposed change in the minimum operating reserve assumption and the BTM PV uncertainty modeling methodology during the course of six meetings. The NEPOOL PSPC also reviewed the proposed values and changes in assumptions during the course of five meetings.[56]

In addition, in 2007 the New England States Committee on Electricity ("NESCOE") was formed.[57] Among other responsibilities, NESCOE is responsible for providing feedback on the proposed ICR-Related Values at the relevant NEPOOL PSPC, Reliability Committee and Participants Committee meetings, and was in attendance for the meetings at which the ICR-Related Values for FCA 13 were discussed.[58]

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[56] All of the load and resource assumptions needed for the General Electric Multi-Area Simulation ("GE MARS") model used to calculate tie benefits and the ICR-Related Values were reviewed by the PSPC, a subcommittee of the NEPOOL Reliability Committee.

[57] *ISO New England Inc.*, Docket No. ER07-1324-000, Formation of the New England States Committee on Electricity (filed August 31, 2007) (proposing to add a new rate schedule to the Tariff for the purpose of recovering funding for NESCOE's operation) (the "NESCOE Funding Filing"); *ISO New England Inc.*, 121 FERC ¶ 61,105 (2007) (order accepting the ISO's proposed rate schedule for funding of NESCOE's operations).

[58] *See* the NESCOE Funding Filing at 14.

On September 26, 2018, the Reliability Committee voted to recommend, by a show of hands, that the Participants Committee support the HQICCs. Also on September 26, 2017, the Reliability Committee voted to recommend that the Participants Committee support the rest of the proposed ICR-Related Values calculated without Clear River Unit 1 included in the model (*i.e.* the Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, Maximum Capacity Limit for the NNE Capacity Zone, and MRI Demand Curves) with a vote of 65.11% in favor. However, the Reliability Committee did not recommend that the Participants Committee support the values with Clear River Unit 1 in the model (the vote was 50.01 % in favor).

On October 4, 2018, the Participants Committee supported the HQICCs by a show of hands (with oppositions and abstentions recorded). Pursuant to Section 11.4 of the Participants Agreement, the Participants Committee also took an advisory vote on the rest of the proposed ICR-Related Values calculated without Clear River Unit 1 in the model (*i.e.* the Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, Maximum Capacity Limit for the NNE Capacity Zone, and MRI Demand Curves). The Participants Committee supported the proposed values with 60.16% in favor. The Participants Committee did not support the proposed values with Clear River Unit 1 in the model (the motion was determined to have failed by assessment of those votes that changed from the prior vote on the values without Clear River Unit 1 in the model).

VIII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the proposed ICR-Related Values for FCA 13 to be effective on January 5, 2019 (which is 60 days from the filing date), so that the proposed values can be used as part of FCA 13, which will be conducted in February 2019.

IX. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for FCA 13 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.[59] 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.

[59] 18 C.F.R. § 35.13.

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

- This transmittal letter;
- Attachment 1: Set of ICR-Related Values with Clear River Unit 1 in the Model
- Attachment 2: Joint Testimony of Carissa Sedlacek and Maria Scibelli;
- Attachment 3: Testimony of Peter Brandien;
- Attachment 4: List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been emailed.

35.13(b)(2) – The ISO respectfully requests that the Commission accept this filing to become effective on January 5, 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 https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. An electronic copy of this transmittal letter and the accompanying materials has also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 2. In accordance with Commission rules and practice, there is no need for the entities identified on Attachment 2 to be included on the Commission's official service list in the captioned proceedings unless such entities become intervenors in this proceeding.

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

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

35.13(b)(6) - 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 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 Installed Capacity Requirement and related values.

X. CONCLUSION

The ISO requests that the Commission accept the two sets of proposed ICR-Related Values reflected in this submission for filing without change to become effective January 5, 2019. When FCA 13 is conducted, the ISO will only use the set of values that reflect the Commission's order on the termination of Clear River Unit 1.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Attachments
cc : Entities listed in Attachment 2

Attachment 1

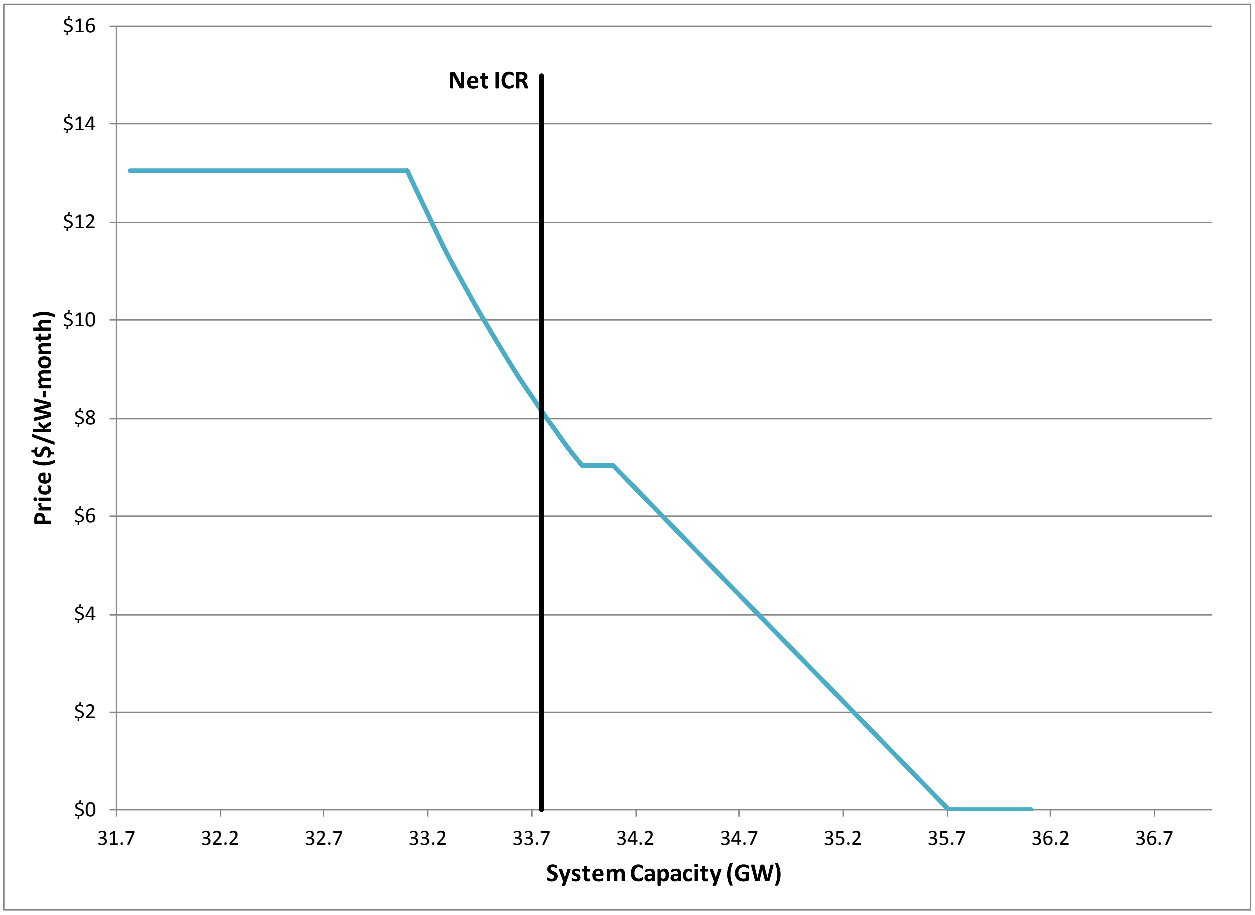
ISO Proposed ICR Values for CCP 2022-2023 (FCA 13) (MW)
with Clear River Unit 1 in the Model

2022-2023 (FCA 13)	New England	Southeast New England	Northern New England
Peak Load (50/50) Net of BTM PV	29,093	12,415	5,469
Existing Capacity Resources	34,352	11,252	8,310
Installed Capacity Requirement	34,739		
NET ICR (ICR Minus HQICCs)	33,770		
Local Sourcing Requirement		10,121	
Maximum Capacity Limit			8,555

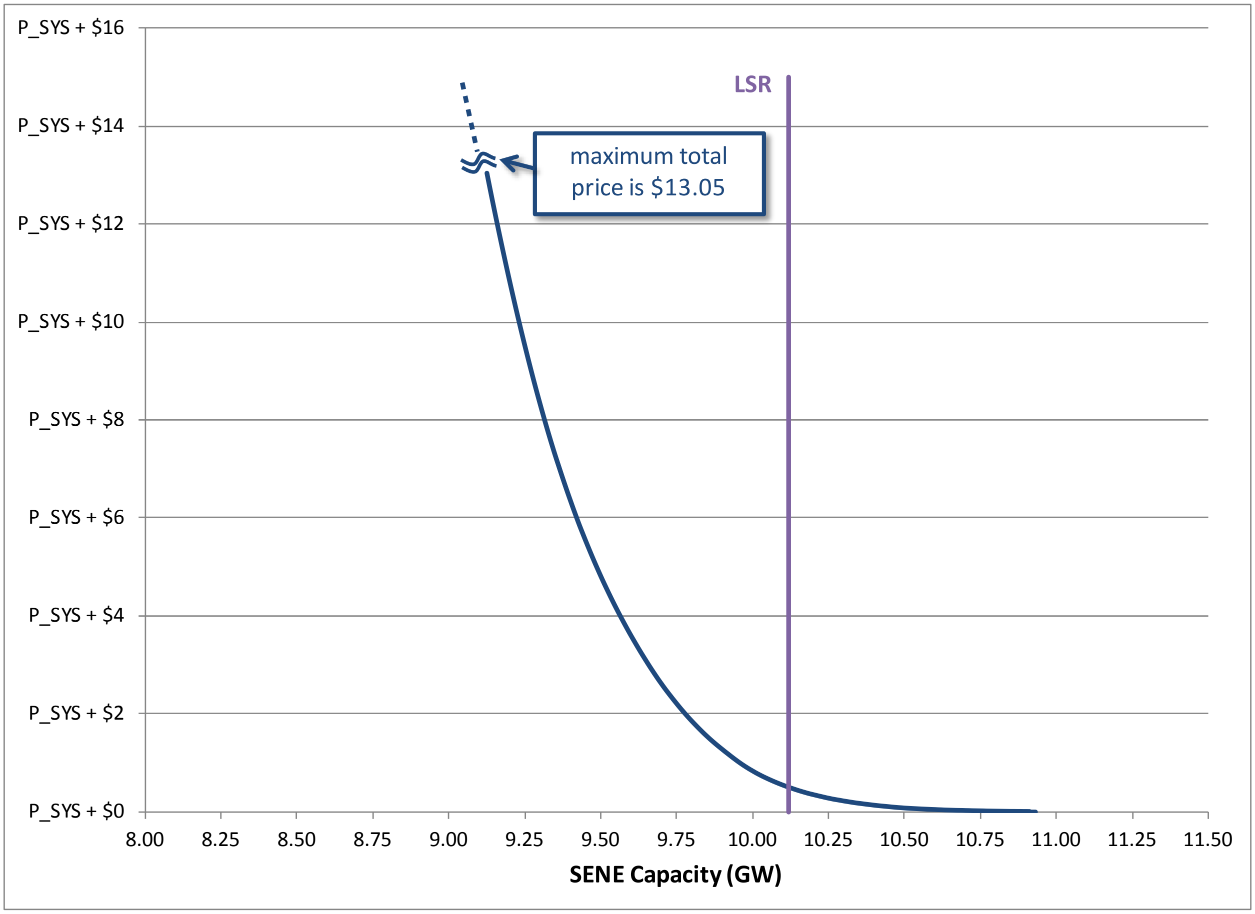
- The Existing Capacity Resources category consists of existing resources that have Qualified Capacity for FCA 13 at the time of the ICR calculation and reflects applicable retirements and terminations (with the exception of the pending termination of Clear River Unit 1)

- 50/50 peak load shown for informational purposes

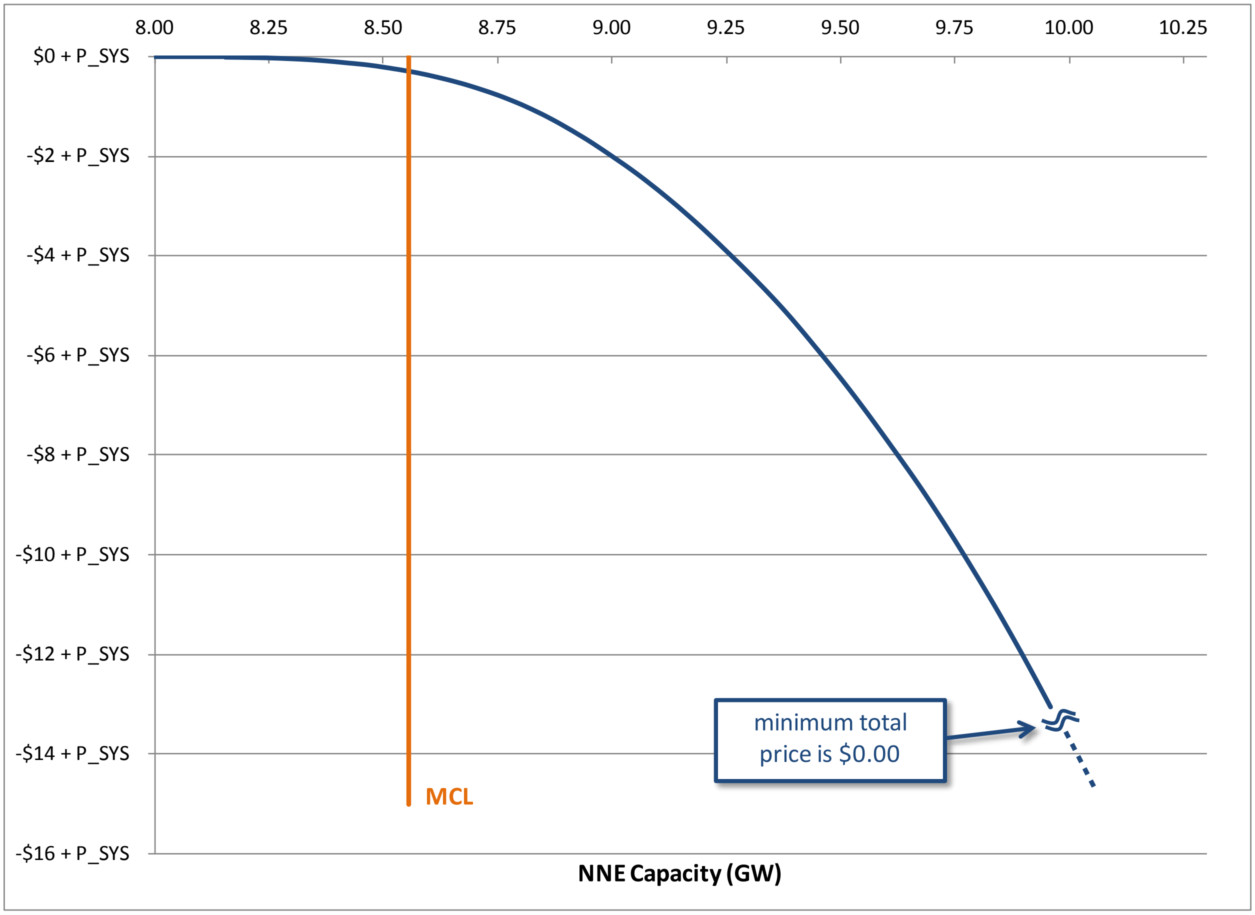
FCA 13 System-Wide Demand Curve
with Clear River Unit 1 in the Model



FCA 13 SENE Demand Curve with Clear River Unit 1 in the Model



FCA 13 NNE Demand Curve with Clear River Unit 1 in the Model



Attachment 2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

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 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 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 Installed Capacity Requirements, Local Sourcing Requirements, Transmission Security Analysis Requirements, Local Resource Adequacy Requirements, Maximum Capacity Limits 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).

Q: WHAT IS THE PURPOSE OF THIS TESTIMONY?

A: This testimony discusses the derivation of the Installed Capacity Requirement, the Local Sourcing Requirement for the Southeast New England ("SENE") Capacity Zone, the Maximum Capacity Limit for the Northern New England ("NNE") Capacity Zone,[1] the Hydro-Quebec Interconnection Capability Credits ("HQICCs"), and the Marginal Reliability Impact ("MRI") Demand Curves for the 2022-2023 Capacity Commitment Period, which is the Capacity Commitment Period associated with the thirteenth Forward Capacity Auction to be conducted beginning on February 4, 2019 ("FCA 13"). The 2022-2023 Capacity Commitment Period starts on June 1, 2022 and ends on May 31, 2023. The Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, Maximum Capacity Limit for the NNE Capacity Zone, HQICCs and MRI Demand Curves for FCA 13 are collectively referred to herein as the "ICR-Related Values."

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[1] As explained in the ISO's Informational Filing for FCA 13, which is being submitted to the Federal Energy Regulatory Commission ("Commission") concurrently with this filing, in accordance with Section III.12.4. of the ISO New England Transmission, Markets and Services Tariff ("Tariff"), the ISO determined that it will model three Capacity Zones in FCA 13: the SENE Capacity Zone, the NNE Capacity Zone, and the Rest-of-Pool Capacity Zone. The SENE Capacity Zone includes the Southeastern Massachusetts ("SEMA"), Rhode Island and Northeastern Massachusetts ("NEMA")/Boston Load Zones. The SENE Capacity Zone will be modeled as an import-constrained Capacity Zone. The NNE Capacity Zone includes the Maine, New Hampshire, and Vermont Load Zones. The NNE Capacity Zone will be modeled as an export-constrained Capacity Zone. The Rest-of-Pool Capacity Zone includes the Connecticut and Western/Central Massachusetts Load Zones.

Q: PLEASE EXPLAIN WHY TWO SETS OF VALUES ARE BEING SUBMITTED TO THE COMMISSION THIS YEAR.

A: On September 20, 2018, the ISO submitted to the Commission a resource termination filing to terminate Clear River Unit 1. The ISO requested that the Commission issue its order on the termination within 60 days of the filing (*i.e.* by November 19, 2018), which is after the date of this filing. For that reason, the ISO is filing two sets of ICR-Related Values. The first set assumes that FERC will accept the termination and, accordingly, does not include Clear River Unit 1 in the model. The second set assumes that FERC will reject the termination, and, accordingly, includes Clear River Unit 1 in the model.

Q: WHICH SETS OF VALUES WILL YOUR TESTIMONY DESCRIBE?

A: Our testimony will describe the set of proposed ICR-Related Values without Clear River Unit 1 in the model. The alternative set of values, *i.e.* the ICR-Related Values with Clear River Unit 1 in the model, are included in Attachment 1 to this filing.

Q: PLEASE DESCRIBE THE DIFFERENCES BETWEEN THE TWO SETS OF VALUES.

A: The differences in the values are very small, as shown in the table below.

Table 1 – Comparison of ICR-Related Values Without Clear River Unit 1 in the Model and ICR-Related Values With Clear River Unit 1 in the Model (MW)

	Value Without Clear River Unit 1 in the Model	**Value With Clear River Unit 1 in the Model**	**Impact of Not Including Clear River Unit 1 in the Model**
Installed Capacity Requirement	34,719	34,739	20 MW lower
Net Installed Capacity Requirement net of HQICCs (969 MW)	33, 750	33,770	20 MW lower
Local Sourcing Requirement for SENE	10,141	10,121	20 MW higher
Maximum Capacity Limit for NNE	8,545	8,555	10 MW lower

Q: WHICH SET OF VALUES WILL THE ISO USE IN FCA 13?

A: The ISO will use the set of values that reflects the Commission's order on the termination of Clear River Unit 1 in FCA 13.

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

A. Yes, our testimony describes how the uncertainty of the behind-the-meter ("BTM") photovoltaic ("PV") output has been accounted for in the calculations of the ICR-Related Values. In addition, the Testimony of Peter Brandien, Vice President of System

Operations at the ISO, explains a change in the amount of system reserve assumed in the probabilistic ICR-Related Values model[2] from 200 MW to 700 MW.

The other processes and methodology for developing the ICR-Related Values are the same as those used in the calculation of the Installed Capacity Requirement and related values for the twelfth FCA ("FCA 12"), which is associated with the 2021-2022 Capacity Commitment Period.

II. INSTALLED CAPACITY REQUIREMENT

A. DESCRIPTION OF THE INSTALLED CAPACITY REQUIREMENT

Q: WHAT IS THE "INSTALLED CAPACITY REQUIREMENT?"

A: The Installed Capacity Requirement is the minimum level of capacity required to meet the reliability requirements defined for the New England Control Area. These requirements are documented in Section III.12 of the Tariff, which states, in relevant part, that "[t]he ISO shall determine the Installed Capacity Requirement 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

[2] The ICR-Related Values calculated with a probabilistic model include the Installed Capacity Requirement, HQICCs, Local Resource Adequacy Requirement, Maximum Capacity Limit and MRI Demand Curves. The Transmission Security Analysis Requirement is calculated using a deterministic transmission reliability screen. It does not consider load or capacity relief from emergency operating procedures, and therefore, it is not impacted by the change in the amount of system reserves assumption.

Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement 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 Installed Capacity Requirement.

The development of the Installed Capacity Requirement 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 loss of load expectation ("LOLE") of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year, while making allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

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

A: The ISO established the ICR-Related Values in accordance with the calculation methodology prescribed in Section III.12 of the Tariff. The ICR-Related Values and the assumptions used to develop them were discussed with stakeholders. The stakeholder process consisted of discussions with the NEPOOL Load Forecast Committee, PSPC and

Reliability Committee. These committees' review and comment on the ISO's development of load and resource assumptions and the ISO's calculation of the ICR-Related Values were followed by advisory votes from the NEPOOL Reliability Committee and Participants Committee. State regulators also had the opportunity to review and comment on the ICR-Related Values as part of their participation on the PSPC, Reliability Committee and Participants Committee. The NEPOOL Participants Committee supported the HQICCs (which are described in Section V of this testimony). The Participants Committee also supported the other ICR-Related Values without Clear River Unit 1 in the model. However, the Participants Committee did not support the other ICR-Related Values with Clear River Unit 1 in the model. The ISO is filing with the Commission the ICR-Related Values to be used in FCA 13, which is associated with the 2022-2023 Capacity Commitment Period (as we already mentioned above, only the set of values that reflects the Commission's order on the termination of Clear River Unit 1 will be used in FCA 13).

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

A: The PSPC is a non-voting technical subcommittee that reports to the Reliability Committee. The 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 resource adequacy-based requirements such as Installed Capacity Requirements, Local Sourcing Requirements, Maximum Capacity Limits and MRI Demand Curves, including appropriate assumptions relating to load, resources, and tie benefits for modeling the expected system conditions. Representatives of the six New England States' public utilities regulatory commissions are also invited to attend and participate in the PSPC meetings and several were present for the meetings at which the ICR-Related Values for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, were discussed and considered.

Q: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT VALUE CALCULATED BY THE ISO FOR FCA 13, WHICH IS ASSOCIATED WITH THE 2022-2023 CAPACITY COMMITMENT PERIOD.

A: The Installed Capacity Requirement value for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, is 34,719 MW.

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

A: No. The System-Wide Capacity Demand Curve was developed based on the net Installed Capacity Requirement of 33,750 MW, which is the 34,719 MW of Installed Capacity Requirement minus 969 MW of HQICCs (which are allocated to the Interconnection Rights Holders in accordance with Section III.12.9.2 of the Tariff).

B. DEVELOPMENT OF THE INSTALLED CAPACITY REQUIREMENT

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

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

Once the program has computed an annual reliability index, if the system is less reliable than the resource-adequacy criterion (*i.e.*, the LOLE is greater than 0.1 days per year), additional resources are needed to meet the criterion. Under the condition where New England is forecasted to be less reliable than the resource adequacy criterion, proxy resources are used within the model to meet this additional need. The methodology calls for adding proxy units until the New England LOLE is less than 0.1 days per year. For the ICR-Related Values for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, 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 Installed Capacity Requirement is determined by increasing loads (additional load carrying capability or "ALCC") so that New England's LOLE is exactly at 0.1 days per year. This is how the single value that is called the Installed Capacity Requirement is established. The modeled New England system must meet the 0.1 days per year reliability criterion.

Q: WHAT ARE THE MAIN ASSUMPTIONS UPON WHICH THE ICR-RELATED VALUES FOR FCA 13 ARE BASED?

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

1. LOAD FORECAST

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

A: For probabilistic-based calculations of 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 could occur over the full range of weather experienced in that week and their associated probabilities. The 50/50 and the 90/10 peak loads are points on this distribution and used as reference points. The probabilistic-based calculations take into account all possible forecast load levels for the year. From these weekly peak load forecast distributions, a set of seasonal load forecast uncertainty multipliers are developed and applied to a specific historical hourly load profile to provide seasonal load information about the probability of loads being higher, and lower, than the peak load found in the historical profile. These multipliers are developed for New England in its entirety or for each subarea using the historic 2002 load profile.[3] For deterministic analyses such as the Transmission Security Analysis, the ISO uses the reference 90/10 load forecast, as published in the 2018 – 2027 Forecast Report of Capacity, Energy, Loads, and Transmission ("2018 CELT Report"), which is net of BTM PV resources.

Q: PLEASE DESCRIBE THE FORECASTED LOAD WITHIN CAPACITY ZONES FOR FCA 13, WHICH IS ASSOCIATED WITH THE 2022-2023 CAPACITY COMMITMENT PERIOD.

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

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

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

Q: WHAT IS CURRENTLY PROJECTED TO BE THE NEW ENGLAND AND CAPACITY ZONE 50/50 AND 90/10 PEAK LOAD FORECAST FOR THE 2022-2023 CAPACITY COMMITMENT PERIOD?

A: The following table shows the 50/50 and 90/10 peak load forecast for the 2022-2023 Capacity Commitment Period based on the 2018 load forecast as documented in the 2018 CELT Report. These values are reported as the "Reference – with Reduction for BTM PV" load forecast.

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

	50/50	**90/10**
New England	29,093	31,593
SENE	12,415	13,561
NNE	5,469	5,837

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?

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 did not reflect the BTM PV forecast in the calculations of the Installed Capacity Requirement and related values for the ninth FCA ("FCA 9"). For that reason, NEPOOL did not support the Installed Capacity Requirement and related values for FCA 9. While FERC accepted the ISO's proposed Installed Capacity Requirement and related values, it directed the ISO to fully explore the incorporation of distributed generation into the Installed Capacity Requirement calculations for the tenth FCA ("FCA 10").[4] Accordingly, the BTM PV forecast has been reflected in the calculations of the Installed Capacity Requirement and related values starting with FCA 10.

[4] 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.

Q: WHAT METHODOLOGY DID THE ISO USE TO REFLECT THE CONTRIBUTIONS OF BTM PV TO REDUCE THE LOAD FORECAST FOR FCA 13?

A: For FCA 13, as was done for FCA 12, the ISO used an "hourly profile" methodology to determine the amount of load reduction provided by BTM PV in all hours of the day and all 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?

A: During the development of the ICR and related values for 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 FCA 13.

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 since it is the historical year the ISO uses for the calculation of Installed Capacity Requirement and related values and the 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.

Q: WHAT IS THE IMPACT OF ACCOUNTING FOR BTM PV OUTPUT VARIABILITY?

A: When analyzing the impacts of using a 7-day window of the GE MARS uncertainty methodology for variable resources, capturing the uncertainty associated with New England BTM PV output translates into an increase in the Installed Capacity Requirement of 30 MW.

2. RESOURCE CAPACITY RATINGS

Q: PLEASE DESCRIBE THE RESOURCE DATA USED TO DEVELOP THE ICR-RELATED VALUES FOR FCA 13, WHICH IS ASSOCIATED WITH THE 2022-2023 CAPACITY COMMITMENT PERIOD.

A: The ICR-Related Values for FCA 13 were developed based on the Existing Qualified Capacity Resources for the 2022-2023 Capacity Commitment Period. This assumption is based on the latest available data at the time of the ICR-Related Values calculation.

Q: WHAT ARE THE RESOURCE CAPACITY VALUES FOR THE 2022-2023 CAPACITY COMMITMENT PERIOD?

A: The following tables illustrate the make-up of the 33,867 MW of capacity resources assumed in the calculation of the ICR-Related Values.

Table 3– Qualified Existing Non-Intermittent Generating Capacity Resources by Load Zone (MW)[5, 6]

Load Zone	Summer
MAINE	2,970.327
NEW HAMPSHIRE	4,077.887
VERMONT	206.795
CONNECTICUT	9,340.725
RHODE ISLAND	1,888.080
SOUTH EAST MASSACHUSETTS	4,448.144
WEST CENTRAL MASSACHUSETTS	3,826.439
NORTH EAST MASSACHUSETTS & BOSTON	2,721.129
Total New England	29,479.526

Table 4– Qualified Existing Intermittent Power Resources by Load Zone (MW)[7]

Load Zone	Summer	Winter
MAINE	201.023	317.816
NEW HAMPSHIRE	164.276	221.506
VERMONT	77.899	123.689
CONNECTICUT	92.536	109.006
RHODE ISLAND	32.665	25.993
SOUTH EAST MASSACHUSETTS	101.082	79.860
WEST CENTRAL MASSACHUSETTS	99.073	100.869
NORTH EAST MASSACHUSETTS & BOSTON	48.309	43.135
Total New England	816.863	1,021.874

[5] A 30 MW derate is applied to resources located in the Vermont Load Zone to reflect the value of the firm Vermont Joint Owners contract.

[6] Including Clear River Unit 1 in the model adds 485 MW to the Rhode Island and Total New England non-intermittent generating capacity values.

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

Table 5– Qualified Existing Import Capacity Resources (MW)

Import Resource	Summer	External Interface
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	11.000	New York AC Ties
Total	79.800	

Table 6– Qualified Existing Demand Resources by Load Zone (Summer MW)

Load Zone	On-Peak	Seasonal Peak	Active Demand Capacity Resource (ADCR)	Total
MAINE	150.099	-	139.535	289.634
NEW HAMPSHIRE	116.798	-	42.325	159.123
VERMONT	110.601	-	52.664	163.265
CONNECTICUT	83.419	581.225	141.786	806.430
RHODE ISLAND	264.611	-	44.581	309.192
SOUTH EAST MASSACHUSETTS	385.830	-	46.422	432.252
WEST CENTRAL MASSACHUSETTS	411.016	35.176	97.900	544.092
NORTH EAST MASSACHUSETTS & BOSTON	710.980	-	75.524	786.504
Total New England	2,233.354	616.401	640.737	3,490.492

Although capacity resource data are tabulated under the eight settlement Load Zones, only SENE (the combined SEMA, NEMA/Boston, and Rhode Island Load Zones) and NNE (the combined Maine, New Hampshire and Vermont Load Zones) are relevant for FCA 13.

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

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

Price of $13.050 $/kW-month) are not assumed in the calculation of the ICR-Related Values for FCA 13, which is associated with the 2022-2023 Capacity Commitment Period, because there is no certainty that new resource additions or resource attritions below the Forward Capacity Auction Starting Price will clear the auction.

3. RESOURCE AVAILABILITY

Q: PLEASE EXPLAIN THE RESOURCE AVAILABILITY ASSUMPTIONS UNDERLYING THE CALCULATIONS OF THE ICR-RELATED VALUES FOR FCA 13, WHICH IS ASSOCIATED WITH THE 2022-2023 CAPACITY COMMITMENT PERIOD.

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

An individual generating resource's forced outage assumption is based on the resource's five-year historical data from the ISO's database of NERC Generator Availability Database System ("GADS"). If the individual resource has not been operational for a total of five years, then NERC class average data is used to substitute for the missing annual data. The same resource availability assumptions are used in all the calculations except for the Transmission Security Analysis, which requires the modeling of the availability of peaking generating resources with a deterministic adjustment factor.[8]

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

Performance of Demand Resources in the Active Demand Capacity Resource category is measured by actual response during performance audits and Operating Procedure No. 4 events that occurred in the summer and winter of the most recent five-year period, currently 2013 through 2017. To calculate historical availability, the verified commercial capacity of each resource is compared to its monthly net Capacity Supply Obligation. Demand Resources in the On-Peak Demand and Seasonal Peak Demand categories are

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

non-dispatchable resources that reduce load across pre-defined hours, typically by means of energy efficiency. These types of Demand Resources are assumed to be 100% available.

4. OTHER ASSUMPTIONS

Q: PLEASE DESCRIBE THE ASSUMPTIONS RELATING TO INTERNAL TRANSMISSION TRANSFER CAPABILITIES FOR THE DEVELOPMENT OF ICR-RELATED VALUES FOR FCA 13.

A: The assumed N-1 and N-1-1 transmission import transfer capability of the Southeast New England Import interface used to calculate the SENE Capacity Zone Local Sourcing Requirement and N-1 transmission export transfer capability of the North-South interface used to calculate the NNE Capacity Zone Maximum Capacity Limit are shown in the table below.

Table 7 – Internal Transmission Import Capabilities (MW)

Interface	Contingency	2022-2023
Southeast New England Import (for SENE Local Sourcing Requirement)	N-1	5,700
	N-1-1	4,600
North-South (for NNE Maximum Capacity Limit)	N-1	2,725

Q: PLEASE DISCUSS THE ISO'S ASSUMPTIONS REGARDING THE ACTIONS OF OPERATING PROCEDURE NO. 4 IN DEVELOPING THE ICR-RELATED VALUES FOR FCA 13.

A: In the development of the Installed Capacity Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit and MRI Demand Curves, assumed emergency assistance (*i.e.* tie benefits, which are described below) available from neighboring Control Areas, and load reduction from implementation of 5% voltage reductions 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 expected or actual 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").[9] 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 demand, the assumed voltage reduction load relief values, which offset against the Installed Capacity Requirement, are 422 MW for June through September 2022 and 311 MW for October 2022 through May 2023.

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.

[9] Copy available at: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op13/op13_rto_final.pdf.

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

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

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

A: Internal transmission transfer capability constraints that are not addressed by either a Local Sourcing Requirement or Maximum Capacity Limit are modeled in the tie benefits study. The results of the tie benefits study are used as an input in the Installed Capacity Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit, and MRI Demand Curves calculations.

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

A: The New England resource planning reliability criterion requires that adequate capacity resources be planned and installed such that disconnection of firm load would not occur more often than once in ten years due to a capacity deficiency after taking into account the load and capacity relief obtainable from implementing Operating Procedure No. 4. In other words, load and capacity relief assumed obtainable from implementing Operating

Procedure No. 4 actions are direct substitutes for capacity resources for meeting the once in 10 years disconnection of firm load criterion. Calling on neighboring Control Areas to provide emergency energy assistance ("tie benefits") is one of the actions of Operating Procedure No. 4. Therefore, the amount of tie benefits assumed obtainable from the interconnected neighboring Control Areas directly displaces that amount of installed capacity resources needed to meet the resource planning reliability criterion. When determining the amount of tie benefits to assume in Installed Capacity Requirement calculations, it is necessary to recognize that, while reliance on tie benefits can reduce capacity resource needs, over-reliance on tie benefits decreases system reliability. System reliability would decrease because each time emergency assistance is requested there is a possibility that the available assistance will not be sufficient to meet the capacity deficiency. The more tie benefits are relied upon to meet the resource planning reliability criterion, and the greater the amount of assistance requested, the greater the possibility that they will not be available or sufficient to avoid implementing deeper actions of Operating Procedure No. 4, and interrupting firm load in accordance with ISO New England Operating Procedure No. 7, Action in an Emergency. For example, some of the resources that New York has available to provide tie benefits are demand response resources which have limits on the number of times they can be activated. In addition, none of the neighboring Control Areas are conducting their planning, maintenance scheduling, unit commitment or real-time operations with a goal of maintaining their emergency assistance at a level needed to maintain the reliability of the New England system.

Q: PLEASE DESCRIBE THE TIE BENEFITS ASSUMPTIONS UNDERLYING THE ICR-RELATED VALUES FOR FCA 13.

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

Pursuant to Section III.12.9 of the Tariff, the Installed Capacity Requirement calculations for FCA 13 assume total tie benefits of 2,000 MW based on the results of the tie benefits study for the 2022-2023 Capacity Commitment Period. A breakdown of this total value is as follows: 969 MW from Quebec over the Hydro-Quebec Phase I/II HVDC Transmission Facilities, 149 MW from Quebec over the Highgate interconnection, 516 MW from New Brunswick (Maritimes) over the New Brunswick interconnections, and 366 MW from New York over the AC interconnections. Tie benefits are assumed not available over the Cross Sound Cable because the import capability of the Cross Sound Cable was determined to be zero.

Q: IS THE ISO'S METHODOLOGY FOR CALCULATING TIE BENEFITS FOR FCA 13 THE SAME AS THE METHODOLOGY USED FOR FCA 12?

A: Yes. The methodology for calculating the tie benefits used in the Installed Capacity Requirement for FCA 13 is the same methodology used to calculate the tie benefits used in the Installed Capacity Requirement for FCA 12. This methodology is described in detail in Section III.12.9 of the Tariff.

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

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

Q: PLEASE EXPLAIN THE ISO'S METHODOLOGY FOR DETERMINING THE TIE BENEFITS FOR FCA 13.

A: The tie benefits study for FCA 13 was conducted using the probabilistic GE MARS program to model the expected system conditions of New England and its directly interconnected neighboring Control Areas of New Brunswick, New York, and Quebec. All of these Control Areas were assumed to be "at criterion," which means that the capacity of all three neighboring Control Areas was adjusted so that they would each have a LOLE of once in ten years when interconnected to each other.

The "at criterion" approach was applied to represent the expected amounts of capacity in each Control Area since each of these areas has structured its planning processes and markets (where applicable) to achieve the "at criterion" level of reliability.

The total tie benefits to New England from New Brunswick (Maritimes), New York and Quebec were calculated first. To calculate total tie benefits, the interconnected system of New England and its directly interconnected neighboring Control Areas were brought to 0.1 days per year LOLE and then compared to the LOLE of the isolated New England system. Total tie benefits equal the amount of firm capacity equivalents that must be added to the isolated New England Control Area to bring New England to 0.1 days per year LOLE.

Following the calculation of total tie benefits, individual tie benefits from each of the three directly interconnected neighboring Control Areas were calculated. Tie benefits from each neighboring Control Area were calculated using a similar analysis, with tie benefits from the Control Area equaling the simple average of the tie benefits calculated from all possible interconnection states between New England and the target Control Area, subject to adjustment, if any, for capacity imports as described below.
If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits was pro-rationed so that the sum of each Control Area's tie benefits equals the total tie benefits for all Control Areas.
Following this calculation, tie benefits were calculated for each individual interconnection or qualifying group of interconnections, and a similar pro-rationing was performed if the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits.

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

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

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

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

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

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

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

A: The following table lists the external transmission interconnections and the transfer capability of each used for calculating tie benefits for FCA 13:

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

One factor in the calculation of tie benefits is the transfer capability into New England of the interconnections for which tie benefits are calculated. In the first half of 2018, the transfer limits of these external interconnections 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 transmission import limits were warranted. The other factor is the transfer capability of the internal transmission interfaces. For internal transmission interfaces, when calculating tie benefits for the 2022-2023 Installed Capacity Requirement filed herewith, the ISO used the transfer capability values from its most recent transfer capability analyses.

6. AMOUNT OF SYSTEM RESERVE

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

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

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

A: This year, the ISO used 700 MW as the amount of system reserve 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 reserve assumed in the probabilistic ICR-Related Values model are described in the Testimony of Peter Brandien.

Q: WHY DID THE ISO REVIEW THE SYSTEM RESERVES ASSUMPTION USED IN THE DETERMINATION OF THE PROBABILISTIC ICR-RELATED VALUES THIS YEAR?

A: The appropriateness of the continued use of a 200 MW minimum operating reserves assumption in the Installed Capacity Requirement 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.[10] In 2017, during the discussions of the calculations of the Installed Capacity Requirement and related values for FCA 12, some PSPC members asked the ISO to review this assumption. For that reason, the ISO reviewed the assumption this year.

Q: WHAT IS THE IMPACT OF USING 700 MW OF SYSTEM RESERVES IN THE DETERMINATION OF THE INSTALLED CAPACITY REQUIREMENT?

A: The use of the 700 MW reserves assumption increased the Installed Capacity Requirement by 550 MW.

Q: DOES THAT MEAN THAT THE INSTALLED CAPACITY REQUIREMENT FOR FCA 13 IS 550 MW HIGHER THAN THE INSTALLED CAPACITY REQUIREMENT FOR FCA 12?

A: No. Due to the decline in the projected loads determined as part of the load forecast for 2018 versus those forecasted in 2017, the net Installed Capacity Requirement for FCA 13 (33,750 MW) is only 25 MW higher than the net Installed Capacity Requirement for FCA 12 (33,725 MW). Thus, the impact of the increase in the system reserve assumption is effectively netted out by the decline in the load forecast for 2018 used in the calculation of the FCA 13 ICR-Related Values.

[10] *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

III. LOCAL SOURCING REQUIREMENT AND MAXIMUM CAPACITY LIMIT

A. DESCRIPTION OF LOCAL SOURCING REQUIREMENT

Q: WHAT IS THE LOCAL SOURCING REQUIREMENT?

A: The Local Sourcing Requirement is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone. The Local Sourcing Requirement 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 Local Resource Adequacy Requirement or (ii) the Transmission Security Analysis Requirement. The Local Sourcing Requirement is applied to import-constrained Capacity Zones within New England.

Q: WHAT ARE IMPORT-CONSTRAINED CAPACITY ZONES?

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

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

A: A separate import-constrained Capacity Zone is identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Open Access Transmission Tariff ("OATT"), Section II, Attachment K, as a zone for which the second contingency transmission capability results in a line-line Transmission Security Analysis

Requirement, calculated pursuant to Section III.12.2.1.2 of the Tariff and pursuant to ISO New England Planning Procedures, that is greater than the Existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model as out-of-service all retirement requests (including any received for the current Forward Capacity Auction at the time of this calculation) and Permanent De-List Bids as well as rejected for reliability Static and Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

Q: WHICH ZONES WILL BE MODELED AS IMPORT CONSTRAINED CAPACITY ZONES FOR FCA 13?

A: After applying the import-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 13, the SENE Capacity Zone, which consists of the combined Load Zones of SEMA, NEMA/Boston, and Rhode Island, will be modeled as a separate import-constrained Capacity Zone.

B. DEVELOPMENT OF THE LOCAL SOURCING REQUIREMENT

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

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

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

A: For each import-constrained capacity zone, the Local Resource Adequacy Requirement is determined by modeling the zone under study vis-à-vis the rest of New England. This, in effect, turns the modeling effort into a series of two-area reliability simulations. The reliability target of this analysis is a system-wide LOLE of 0.105 days per year when the transmission constraints between the two zones are included in the model. Because the Local Resource Adequacy 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,[11] is achieved.

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

A: The Transmission Security Analysis is a deterministic reliability screen of an import-constrained area and is a basic security review set out in Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market, and in Section 3.0 of NPCC's Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System.[12] 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 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.

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

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

Further, such deterministic sub-area transmission security analyses have consistently been used for reliability review studies performed to determine if the removal of a resource that may be retired or de-listed would violate reliability criteria.

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

A: There are three differences between the assumptions relied upon for the Transmission Security Analysis Requirement and the assumptions relied upon for determining the Local Resource Adequacy Requirement. The first difference relates to the load forecast assumption. Resource adequacy analyses (*i.e.*, the analysis performed in determining the Installed Capacity Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit, 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 Transmission Security Analysis, single discreet points on the probability distribution are used; in accordance with ISO New England Planning Procedure No. 10, the analysis is performed using the published net 90/10 peak load forecast, which is net of the BTM PV forecasted value. The 90/10 peak load forecast corresponds to a peak load that has a 10% probability of being exceeded based on weather variation.

The second difference relates to the application of assumed availability of peaking generating resources. For peaking generating resources, an operational de-rating factor of 20% was applied in the Transmission Security Analysis instead of a forced outage assumption.

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

Q: PLEASE DESCRIBE THE LOCAL RESOURCE ADEQUACY REQUIREMENT, TRANSMISSION SECURITY ANALYSIS REQUIREMENT, AND LOCAL SOURCING REQUIREMENT FOR THE SENE CAPACITY ZONE FOR FCA 13.

A: For FCA 13, the Local Resource Adequacy Requirement, Transmission Security Analysis Requirement and the Local Sourcing Requirement for the SENE Capacity Zone are as follows:

Table 9 – SENE Capacity Zone Requirements for the 2022-2023 Capacity Commitment Period (MW)

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	10,141	9,885	10,141

IV. MAXIMUM CAPACITY LIMIT

Q: WHAT IS THE MAXIMUM CAPACITY LIMIT?

A: The Maximum Capacity Limit is the maximum amount of capacity that is electrically located in an export-constrained Capacity Zone used to meet the Installed Capacity Requirement.

Q: WHAT ARE EXPORT-CONSTRAINED CAPACITY ZONES?

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

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

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

Q: WHICH ZONES WILL BE MODELED AS EXPORT CONSTRAINED CAPACITY ZONES FOR FCA 13?

A: After applying the export-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 13, the NNE Capacity Zone, which consists of the combined Load Zones of Maine, New Hampshire and Vermont, will be modeled as a separate export-constrained Capacity Zone.

Q: WHAT IS THE MAXIMUM CAPACITY LIMIT FOR THE NNE CAPACITY ZONE FOR FCA 13 AND HOW WAS IT CALCULATED?

A: The Maximum Capacity Limit for the NNE Capacity Zone for FCA 13 is 8,545 MW. This number also reflects the tie benefits assumed available over the New Brunswick and Highgate interfaces. The Maximum Capacity Limit was calculated using the methodology that is reflected in Section III.12.2.2 of the Tariff.

In order to determine the Maximum Capacity Limit, the New England net Installed Capacity Requirement and the Local Resource Adequacy 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 Installed Capacity Requirement is the total amount of resources that the region needs to meet the 0.1 days/year LOLE, and the Local Resource Adequacy 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.

V. HQICCs

Q: WHAT ARE HQICCs?

A: HQICCs are capacity credits that are allocated to the Interconnection Rights Holders, which are entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection").[13] 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: WHAT ARE THE HQICC VALUES FOR FCA 13, WHICH IS ASSOCIATED WITH THE 2022-2023 CAPACITY COMMITMENT PERIOD?

A: The HQICC values are 969 MW for every month of the 2022-2023 Capacity Commitment Period.

[13] *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.").

VI. MRI DEMAND CURVES

Q: PLEASE DESCRIBE THE METHODOLOGY USED FOR CALCULATING THE MRI DEMAND CURVES FOR FCA 13.

A: To calculate the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for SENE, and the Export-Constrained Capacity Zone Demand Curve for NNE for FCA 13, 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,[14] in 10 MW increments, applying the same assumptions used in determining the Installed Capacity Requirement. These system EENS values are translated into MRI values by estimating how an incremental change in capacity impacts system reliability at various capacity levels, as measured by EENS. An MRI curve is developed from these values with capacity represented on the X-axis and the corresponding MRI values on the Y-axis.

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

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 Local Resource Adequacy Requirement and the Maximum Capacity Limit 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 FCA 13 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").[15] In other words, the scaling factor is equal to the value which produces a system demand curve that specifies a price of Net CONE at the net Installed Capacity Requirement (Installed Capacity Requirement minus HQICCs).

[15] For FCA 13, Net CONE has been determined as $8.04/kW-month.

To satisfy this requirement, the demand curve scaling factor for FCA 13 was developed for the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone, and the Export-Constrained Capacity Zone Demand Curve for the NNE 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 Capacity Demand Curve 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 CAPACITY DEMAND CURVE FOR FCA 13.

A: For FCA 13, the ISO used the transition provisions in Section III.13.2.2.1 of the Tariff to determine the System-Wide Demand Curve. The transition curve is a hybrid of the previous linear demand curve design and the new MRI-based design.

The MRI transition period aims to provide a transition from the linear system-wide capacity demand curve methodology used in FCA 9 and FCA 10 to the 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 FCA 11 and may last no longer than three FCAs. This is the last FCA to include the transition period provision in the development of the System-wide Capacity Demand Curve. During the MRI transition period, the System-Wide Capacity Demand Curve is represented as a hybrid of the previous linear demand curve design and the newer MRI-based demand curve design.

During the MRI transition period, the System-Wide Capacity Demand Curve for FCA 13 shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the MRI-based demand curve design;

(2) for prices below $7.03/kw-month, the System-Wide Capacity Demand Curve is represented by a linear segment that runs from a price of $7.03 and a capacity quantity of 34,097 MW to a price of $0 and a capacity quantity of 35,713 MW; and

(3) a horizontal line at a price of $7.03/kw-month which connects segments (1) and (2) specified above.

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

A: For import-constrained Capacity Zones, the Local Resource Adequacy Requirement and Transmission Security Analysis Requirement values both play a role in defining the MRI-based demand curves as they do in setting the Local Sourcing Requirement. Under III.12.2.1.3 of the Tariff, prior to each FCA, the ISO must determine the MRI value of various capacity levels, for each import-constrained Capacity Zone. For purposes of these calculations, the ISO applies the same modeling assumptions and methodology used to determine the Local Resource Adequacy 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 Transmission Security Analysis

Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero. By using a transfer capability that accounts for both the Transmission Security Analysis and the Local Resource Adequacy Requirements, the ISO applies the same "higher of" logic used in the Local Sourcing Requirement to the derivation of sloped zonal demand curves. For FCA 13, the only import-constrained Capacity Zone is SENE and, therefore, there is only one Import-Constrained Capacity Zone Demand Curve.

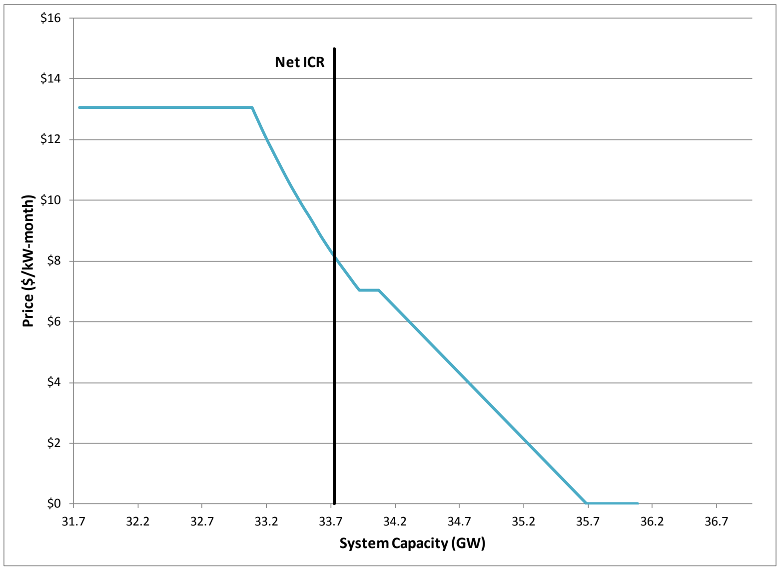
Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE EXPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVE FOR THE NNE CAPACITY ZONE.

A: Under Section III.12.2.2.1 of the Tariff, prior to each FCA, 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 Maximum Capacity Limit. Using the values calculated pursuant to Section III.12.2.2.1 of the Tariff, the ISO must determine the Export-Constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.3 of the Tariff. For FCA 13, the only export-constrained Capacity Zone is NNE and, therefore, there is only one Export-Constrained Capacity Zone Demand Curve.

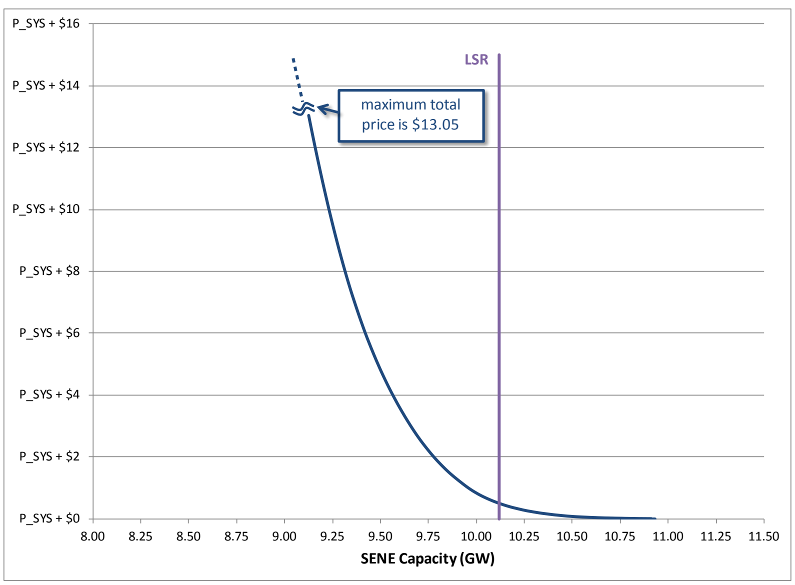
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR FCA 13?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI Demand Curves for FCA 13:

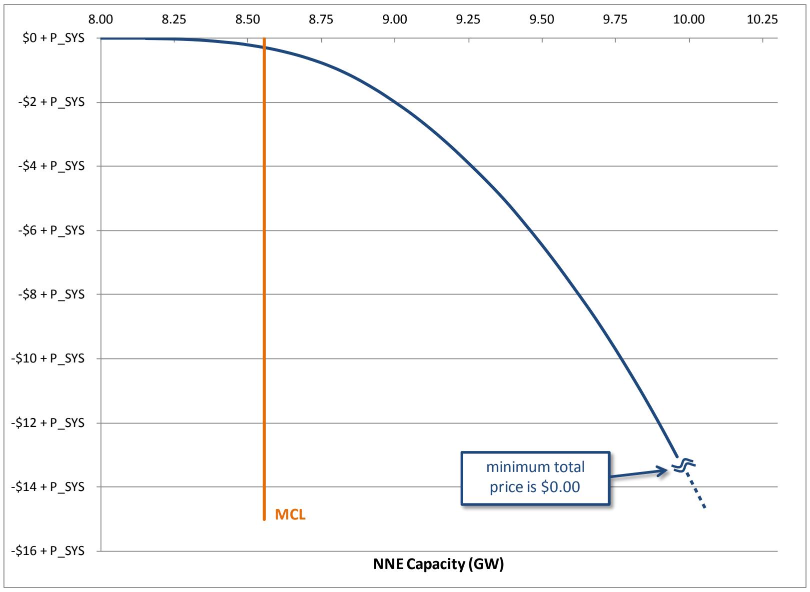
1. System-Wide Capacity Demand Curve



2. Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone



3. Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone



Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Executed on 11/1/18

Carissa Sedlacek

Executed on 11/1/18

Maria Scibelli

Attachment 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PREPARED TESTIMONY OF
PETER T. BRANDIEN
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

A: My name is Peter T. Brandien. I am employed by ISO New England Inc. (the "ISO") as the Vice President of System Operations. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A: I have a Bachelor of Science degree in Electrical Engineering from the University of Hartford. I have more than 31 years of energy industry experience in control room operations. In 2004, I joined the ISO as the Vice President of System Operations. In that capacity, I am responsible for the day-to-day operations of New England's bulk electric system and oversight of transaction management, transmission technical studies, outage coordination, unit commitment, economic dispatch, system restoration, operator training, certain compliance functions and development of operating procedures. Prior to joining the ISO, I spent 17 years at Northeast Utilities, most recently as director of transmission operations. Before joining Northeast Utilities, I served in the U.S. Navy as a submarine nuclear propulsion plant operator/electrician.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: My testimony explains why the ISO included 700 MW of system reserves in the determination of the proposed Installed Capacity Requirement ("ICR") and related values[1] for the 2022-2023 Capacity Commitment Period, which is associated with the thirteenth Forward Capacity Auction ("FCA 13").

II. TESTIMONY

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

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

Q: PLEASE EXPLAIN WHAT INCLUDING AN AMOUNT OF SYSTEM RESERVES IN THE DETERMINATION OF THE ICR MEANS IN ISO OPERATIONS.

[1] The 700 MW system reserves assumption was used in all the probabilistic ICR-related values calculations, which include the ICR, the Local Resource Adequacy Requirement, the Maximum Capacity Limit, and the Marginal Reliability Impact Demand Curves. The assumption was not used in the Transmission Security Analysis, because that is not a probabilistic calculation.

A: Including an amount of reserves in the determination of the ICR assumes that, during peak load conditions, while emergency capacity and energy operating plans are being used, ISO operations would have available the essential amount of operating reserves for transmission system protection, system load balancing, and tie control, prior to invoking manual load shedding.

Q: WHAT AMOUNT OF RESERVES WAS USED IN THE DETERMINATION OF THE ICR IN THE PAST?

A: Historically, the calculation of the ICR and related values assumed an amount of reserves of 200 MW system-wide. This level was established in 1980, and had not been modified since that time.

Q: DOES MAINTAINING ONLY 200 MW OF RESERVES IN THE DETERMINATION OF THE ICR CONTINUE TO BE APPROPRIATE?

A: No. As I explain below, given the increase in the New England peak load, the increase in the size of credible contingencies, New England's limited tie capability to the Eastern Interconnection, and the change in the resource mix, maintaining only 200 MW of reserves in the determination of the ICR and related values is no longer appropriate.

Q: PLEASE DESCRIBE THE INCREASE IN THE PEAK LOAD IN NEW ENGLAND SINCE THE TIME WHEN THE 200 MW RESERVES ASSUMPTION USED IN THE DETERMINATION OF THE ICR WAS ESTABLISHED.

A: When the 200 MW reserves assumption was established 38 years ago, the peak load on the system was approximately 15,000 MW. Today, the peak load on the system can be as high as 28,000 MW. This load growth has increased the range of load during the day, which in turn increases the resources needed to balance load and generation to maintain external tie line schedules and to regulate frequency.[2] This becomes especially important during emergency conditions when, by definition, operators are running out of resources to achieve that balance.

Q: PLEASE EXPLAIN THE INCREASE IN THE SIZE OF CREDIBLE CONTINGENCIES IN NEW ENGLAND IN THE LAST 38 YEARS AND HOW IT RELATES TO THE NEED FOR ADDITIONAL RESERVES.

A: There have been dramatic increases in the size of credible contingencies on the New England Transmission System in the last 38 years. In fact, New England has some of the largest contingencies on the Eastern Interconnection. In 1980, when the 200 MW reserves assumption for the ICR determination was established, the largest contingencies on the New England Transmission System were two nuclear units between 800 and 900 MW. Today, New England can experience up to a 2,000 MW single credible contingency on the Phase II Interconnection with Hydro Quebec. In addition, New England has three other large credible contingencies on two nuclear plants and a combined cycle facility that each is between 1,250 MW and 1,650 MW.

[2] NERC Reliability Standard BAL-001-2 requires the ISO, as the Balancing Authority, to control Interconnection frequency within defined limits. This includes frequency and external tie-line regulation.

The increased size of the contingencies, coupled with the very low reserve assumption of 200 MW during emergency conditions that has been used in the determination of the ICR, result in significant amounts of potential load shedding to meet the NERC BAL, TOP, and IRO Reliability Standards if these contingencies were to occur. For example, a loss of the Phase II facilities (*i.e.* 2,000 MW), would require activation of the entire 200 MW of reserves and shedding 1,800 MW of load to reach equilibrium within 15 minutes as required under Requirement R1 of NERC Reliability Standard BAL-002-2, and to address any transmission system overloads as required under NERC Reliability Standards IRO-009-2[3] and TOP-001-4.[4] Furthermore, additional load would need to be shed to re-establish the capability to control the Area Control Error ("ACE") as required under NERC Reliability Standard BAL-001-2,[5] and maintain the Interconnection Reliability Operating Limit ("IROL") interface with New York within limits, as required under NERC Reliability Standard IRO-009-2.[6]

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[3] Requirement R3 of NERC Reliability Standard IRO-009-2 requires that the ISO, as the Reliability Coordinator, act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment.

[4] Under Requirement R12 of NERC Reliability Standard TOP-001-4, the ISO, as the Transmission Operator, cannot operate outside any identified IROL for a continuous duration exceeding its associated IROL T_v.

[5] NERC Reliability Standard BAL-001-2 requires the ISO, as the Balancing Authority, to balance resources and demand and control the ACE to meet the Control Performance Standard 1 and its Balancing Authority ACE Limit.

[6] Requirement R2 of NERC Reliability Standard IRO-009-2 requires that the ISO, as the Reliability Coordinator, initiate Operating Processes, Procedures, or Plans that are intended to prevent and IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment.

Q: PLEASE EXPLAIN NEW ENGLAND'S LIMITED TIE CAPABILITY TO THE EASTERN INTERCONNECTIN AND ITS IMPACT ON THE OPERATION OF THE NEW ENGLAND TRANSMISSION SYSTEM.

A: New England is in a unique electrical and geographical position with limited tie capability to the Eastern Interconnection through the A.C. ties with New York. These ties consist of two 345 kV ties, one 230 kV tie, three 115 kV tie, one 138 kV tie, and one 69 kV tie, which together have a nominal transfer capability into New England of 1,400 MW. This tie capability has not changed appreciably in the last 38 years. Meanwhile, the contingency sizes have become significantly larger, and the generation mix has changed.

Notably, given New England's location on the Eastern Interconnection, only New England and the Maritimes (a much smaller system) can have impact on the flows on the New York interface to the Eastern Interconnection. This is important, especially since New England tends to be a heavy importer of power due to the higher energy prices in New England. The majority of a source loss in New England would be initially supplied by resources to the west of New England. Those resources would respond to the frequency deviation with the inertia pickup by all resources on the Eastern Interconnection. Because the only interface to the Eastern Interconnection is New York, the already heavily loaded interface would instantly increase by approximately 90% of the New England source loss. Therefore, it is important for the reliability of the interconnection that New England have an appropriate level of resources that can provide reserves to begin off-loading the New York interface while implementing load shedding to restore the interface to within thermal, voltage, or stability limits.

Q: PLEASE DESCRIBE THE CHANGES IN THE RESOURCE MIX SINCE THE TIME WHEN THE 200 MW RESERVE ASSUMPTION WAS ESTABLISHED AND HOW THOSE CHANGES AFFECT SYSTEM OPERATIONS.

A: The resource mix in New England has changed significantly since 1980, when the 200 MW reserve assumption was established. Many conventional resources such as coal- and oil-fired generators have retired and, at the same time, the number of variable resources (such as wind and solar) has greatly increased. Specifically, during the last several years, wind has grown from near 0 to 1,300 MW, and solar has grown from near 0 to over 2,700 MW (and continues to steadily grow).

While the new variable resources provide energy and environmental benefits to the public and the interconnection, they do not have the same operational characteristics related to frequency control and balancing capabilities as the conventional fleet. For instance, although wind resources have excellent maneuvering capability in the downward direction, they do not have that same maneuvering capability in the upward direction due to their variable fuel supply. The same concerns exist for solar resources; however, solar resources also tend to be ramping in the downward direction as the peak approaches in New England during both the summer and winter, *i.e.* when New England is most at risk for emergency conditions. Therefore, having additional capability in the upward direction in the form of minimum operating reserves is important during stressed conditions.

Q: WHY IS 700 MW AN APPROPRIATE LEVEL OF RESERVES TO BE USED IN THE DETERMINATION OF THE ICR?

A: 700 MW of reserves is an appropriate level of reserves to be used in the determination of the ICR because it is consistent with the amount of reserves needed for reliable system operations during emergency conditions. Specifically, a 700 MW reserve assumption provides the capability necessary to balance generation and tie capability with demand in emergency conditions. In addition, by increasing the minimum reserve requirement to 700 MW, the strains on the system caused by the contingencies described above can be reduced, and a balanced approach to meeting the NERC BAL, TOP, and IRO Reliability Standards can be maintained (thereby preventing New England from becoming a burden to the Interconnection). Moreover, the 700 MW reserve assumption will provide sufficient reserves to balance the New England Transmission System with New York. Finally, given the new resource mix, the 700 MW reserves assumption will provide additional capability in the upward direction during stressed conditions.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Executed on 11/1/18

Peter Brandien

Attachment 4

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