Installed Capacity Requirement (ICR) Reference Guide

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System Planning

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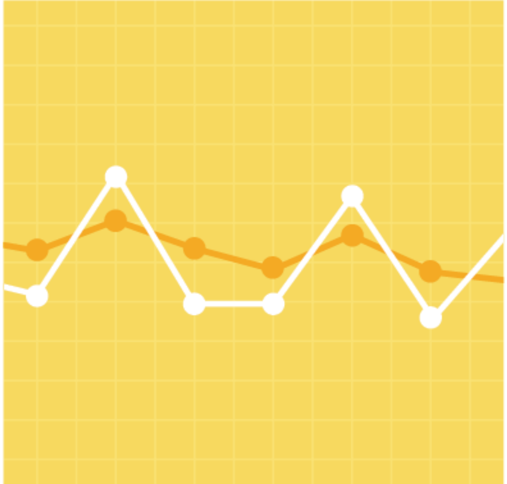

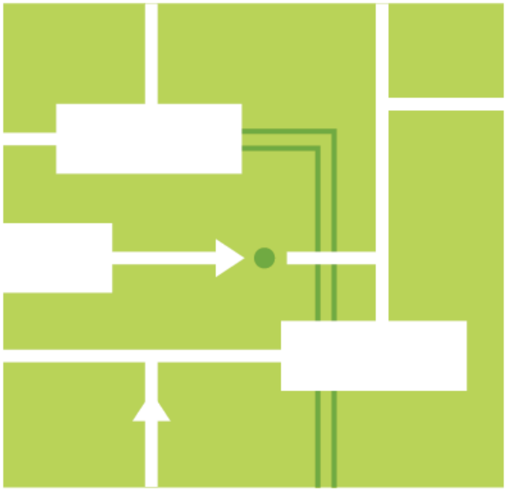

Preface/Disclaimer

This ICR Reference Guide is intended to provide participants and stakeholders with a high-level overview of the processes that ISO New England (ISO-NE or ISO) undertakes annually to develop the region's ICR-related values for use in the annual Forward Capacity Auction (FCA)[1] and annual reconfiguration auctions. This guideline does not include any Critical Energy Infrastructure Information (CEII).

This guideline does not address all issues or requirements. Accordingly, participants and other stakeholders should not rely solely on this guideline but should consult the effective Tariff and any relevant Market Manuals, Operating Procedures and Planning Procedures (Procedures). In case of a discrepancy between this guideline and the Tariff or Procedures, the Tariff and Procedures shall govern. The Tariff and Procedures are available on the ISO-NE website.

[1] Capitalized terms used but not defined in this guideline have the meaning ascribed to them in the ISO New England Transmission, Markets and Services Tariff (Tariff) or the Glossary of Terms Used in NERC Reliability Standards.

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Section 1
Introduction

ISO-NE is the not-for-profit corporation responsible for the reliable operation of New England's bulk electric power system. It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional power system. This reference guide documents a reliability criterion that is common to all of these responsibilities.

Section 2 describes the New England ICR. Section 3 describes the components of New England's ICR-related values and the calculation methodologies. Section 4 describes the software used in the simulations. Section 5 describes the assumptions needed to develop the ICR-related values. Sections 6 through 10 detail the calculation of the ICR and each of the related values. Finally, Section 11 provides an illustration of a typical annual ICR development schedule for the FCA and the Annual Reconfiguration Auctions (ARAs).

Section 2
The New England ICR

The New England ICR is the minimum level of (installed) capacity required to meet the reliability requirements defined for the New England Control Area. Section III.12 of the Tariff documents these requirements as follows:

> *The ISO shall determine the [ICR] such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period.*

The development of the ICR must also be consistent with Requirement R4 of the Northeast Power Coordinating Council's (NPCC) Regional Reliability Reference Directory #1, *Design and Operation of the Bulk Power System*[2] *Full Member Resource Adequacy Criterion* (Directory 1). Specifically, Requirement R1 of Directory 1 states:

> *"**R4** Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system 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.*
>
> ***R4.1** Make due 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."*

The net ICR (which is equal to the ICR minus the Hydro-Québec Interconnection Capability Credits [HQICCs]) is the target amount of capacity that the ISO procures through the Forward Capacity Market (FCM)[3] to ensure system reliability.

Most of the ICR calculations are single-year simulations that the ISO conducts to meet the needs of the FCA and ARAs. The ISO, however, performs multi-year simulations similar to ICR simulations to identify a representative ICR for the Regional System Plan (RSP) and to comply with NPCC's and the North America Electric Reliability Corporation's (NERC) resource adequacy reporting requirements.

Specifically, the ISO's biennial publication of the RSP includes results for up to ten years of ICR calculations to market participants of the expected future capacity needs for the region. For the ten-year outlook, the first three years use the actual ICR values, which are the latest values that the

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

[3] The ISO procures the target net ICR in the FCM using an auction and a demand curve. The net ICR is a point in the demand curve. For details relating to the FCM auctions, please see: https://www.iso-ne.com/static-assets/documents/2020/10/20201019-fcm101-lesson-5A-fca.pdf

Federal Energy Regulatory Commission (FERC) has accepted for the FCA and ARAs. The FCA is held three years in advance of the associated Capacity Commitment Period (CCP). For the remaining years (years 4-10), the ISO identifies representative ICRs in the RSP. Appendix F – ICR Timelines shows the timeline for the ICR development process for the FCM, RSP, and NPCC/NERC reporting requirements.

Section 3
ICR-Related Values

ISO-NE identifies the amount of installed capacity needed to meet the regional resource adequacy planning criterion, and uses it as a signal regarding resource needs to competitively procure resources through the FCM. Through the FCM, the ISO forward contracts with resources such that they are properly located, to the extent possible, to maximize the use of the regional bulk transmission network to serve forecast loads. Therefore, in addition to the ICR, the ISO also needs other *related values or variables* to assist in procuring the requisite amount of locational installed capacity resources in the FCA and ARAs.

3.1 Components of the ICR-Related Values

The variables that the ISO needs to conduct the FCA and ARAs include HQICCs, net ICR, Local Sourcing Requirement (LSR), Local Resource Adequacy (LRA) Requirement, Transmission Security Analysis (TSA) Requirement, Maximum Capacity Limit (MCL), and Marginal Reliability Impact (MRI) demand curves (collectively, the ICR-related values). These ICR-related values are shown categorically below.

Each year, the ICR development process calculates the following values:

1. **ICR**
2. **Capacity Zone(s)**
   - 2.1 Import-constrained
   - 2.2 Export-constrained
3. **Import-constrained Capacity Zone(s)**
   - 3.1 LRA
   - 3.2 TSA
   - 3.2 LSR
4. **Export-constrained Capacity Zone(s)**
   - 4.1 MCL
5. **Tie Benefits and HQICCs**
6. **MRI System and Capacity Zone Demand Curves**

Each ICR-related value is briefly described below.

3.2 HQICCs

HQICCs are capacity credits that are allocated to the Interconnection Rights Holders (IRH), which are entities that pay for, and consequently, hold certain rights over the Hydro Québec Phase I/II

HVDC Transmission Facilities (*HQ Interconnection*).[4] Pursuant to Sections III.12.9.5 and III.12.9.7 of the Tariff, the results of a probabilistic calculation establish the tie benefit value for the HQ Interconnection with Québec. The ISO calculates HQICCs and allocates them to IRH in proportion to their individual transmission rights over the HQ Interconnection. The ISO must file the HQICC values established for each FCA with FERC.

3.3 Net ICR

The net ICR is the ICR minus the HQICCs.

3.4 LSR

The LSR is the minimum amount of capacity that must be electrically located within a transmission import-constrained Capacity Zone. The LSR is the mechanism used to assist in valuing capacity appropriately in an import-constrained Capacity Zone (see Section 5.2.1 of this guideline). It is the amount of capacity needed to satisfy the higher of: (i) the LRA Requirement or (ii) the TSA Requirement. The ISO identifies import-constrained Capacity Zones prior to the calculation of the ICR-related values by following the Capacity Zone determination process, which is described in Section III.12.4 of the Tariff and in Appendix A to this guideline.

3.5 LRA Requirement

The LRA Requirement is the minimum amount of capacity that needs to be located in an import-constrained Capacity Zone to meet the resource adequacy planning criteria when the total system capacity is equal to the net ICR.

3.6 TSA Requirement

The TSA is a deterministic reliability screen of an import-constrained Capacity Zone and is a basic security review as defined within Section 6 of ISO New England Planning Procedure No. 10, *Planning Procedure to Support the Forward Capacity Market* (PP 10) and Section 3.0 of NPCC's Directory 1. The TSA review determines the requirements of the sub-area in order to meet its load through internal (native) generation and transmission import capacity.

3.7 MCL

The MCL is the maximum amount of resources that can be procured from an export-constrained Capacity Zone (See Section 5.2.2 of this guideline) to meet the ICR. Generally, this is the amount of capacity that can be used to fully meet the needs within the export-constrained Capacity Zone plus that amount which can reasonably be expected to be exported from the Capacity Zone to meet other regional needs.

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[4] *See* Section I.2.2 of the Tariff (stating in the definition of "HQ Interconnection Capability Credit" that "[a]n appropriate share of the HQICC shall be assigned to an IRH if the 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 Québec 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.").

3.8 MRI Demand Curves

System-wide and Capacity Zone MRI Demand Curves reflect the capacity values of the system-wide and zonal capacity, based on the MRI of that capacity at a certain capacity level. The slope of the curves that shows MRI values as a function of capacity is steeply sloped at lower capacity quantities (when adding capacity would be expected to result in a bigger improvement in reliability). The MRI values are closer to zero and the function flatter at higher capacity quantities (when adding capacity would be expected to result in smaller improvements in reliability). In other words, as additional capacity is added to the system (or to any Capacity Zone), it has a progressively diminishing MRI. Reference Appendix E – Marginal Reliability Impact (MRI) Demand Curve Supplemental for additional visual information.

Section 4
Simulation Software – General Electric Multi-Area Reliability Simulation (GE MARS) Model

The ISO uses the GE MARS model for calculating the ICR-related values. GE MARS is a licensed computer program that uses an hourly sequential Monte Carlo simulation to compute the reliability of a power system comprised of a number of interconnected areas containing capacity (resources) and demand (load). This Monte Carlo process repeatedly simulates the study year (multiple replications) to evaluate the impacts of a wide range of possible random combinations of resource capacity and load levels, taking into account random resource outages and load forecast uncertainty associated with each load component. The transmission system is modeled in terms of transfer limits (constraints) on the interfaces between interconnected areas.

The program then develops chronological system by combining randomly-generated operating histories of the capacity resources and inter-area transfers with the hourly chronological loads. For each hour of the year, the program computes the isolated area margins based on the available capacity and demand in each area. GE MARS then uses a transportation algorithm to determine the extent to which areas with negative margins (deficiency) can be assisted by areas having positive margin (excess), subject to the available transfer constraints between the areas. The program collects the statistics for computing the reliability indices, and proceeds to the next hour. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the current study year; otherwise, it moves on to the next study year.

For calculating the New England ICR, the ISO assumes New England to be a single-bus system, meaning that the internal transmission constraints are not modeled. For calculating the LRA for an import-constrained Capacity Zone, and the MCL for an export-constrained Capacity Zone, New England is modeled as a two-area system: the Capacity Zone of interest and the *Rest-of-New England* (*or Rest-of-Pool [ROP]*) with the constrained transmission interface between the two Capacity Zones.

Appendix G to this guideline – GE MARS Model Supplemental, shows pictorially how the ISO uses the GE MARS model to determine resource adequacy within various reliability assessments. Additional information on the GE MARS model may be found on the GE website.[5]

[5] https://www.geenergyconsulting.com/content/dam/Energy_Consulting/global/en_US/pdfs/GE_MARS_Reliability_Modeling_Software_2018_1.pdf or https://www.geenergyconsulting.com/practice-area/software-products/mars

Section 5
Assumptions Needed for the Development of ICR-Related Values

This section describes the assumptions used in the calculation of the ICR-related values and documents their development process. For clarity, in this guideline, the assumptions are grouped into categories.

5.1 Transmission Transfer Capability (TTC)

Pursuant to Section III.12.5 of the Tariff, if necessary, in the first quarter of each year, the ISO updates the TTC for each internal (*i.e.*, within New England) and external (*i.e.*, from neighboring Balancing Authority Areas into New England) transmission interface for the relevant CCP.[6] The TTC values are the same as those documented biennially within the RSP.[7]

External TTC is not used directly within the ICR calculation. Rather, it is used in the determination of tie benefits and HQICCs. Internal TTC limits are used in the determination of the LRA/TSA and MCL for the import- and export- constrained Capacity Zones, respectively, and in the development of tie benefit assumptions. Specifically, N-1 internal TTCs are used in LRA, MCL and tie benefits calculations and N-1 and N-1-1 internal TTCs are used in TSA calculations.

5.2 Capacity Zones

Capacity Zones are Load Zones[8] within New England where there may be inadequate TTC associated with the Load Zone to fully utilize the resources within or outside of the Load Zone to meet the New England resource adequacy planning criterion. Pursuant to Section II of Attachment K to the ISO Open Access Transmission Tariff ("OATT"), the Capacity Zones for each CCP are identified prior to the FCA associated with that CCP as part of the annual assessment of TTC . The Capacity Zones are established for a given CCP during the development of the ICR –related values and they remain the same for all the auctions (*i.e.*, FCA and ARAs) to be conducted for the same CCP.

There are three types of Capacity Zones defined for use within the FCM: (1) an import-constrained Capacity Zone; (2) an export-constrained Capacity Zone; and (3) a Rest-of-New England Capacity Zone. For more information, please see Section III.12.4 of the Tariff and Appendix A to this guideline. The Capacity Zones defined for each relevant CCP may be found on the ISO-NE website.[9]

5.2.1 Import-Constrained Capacity Zones

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 (*i.e.*, native)

[6] The CCP is the period for which a resource is committed to provide capacity. The CCP starts on June 1 of each year and ends on May 31 of the following year.

[7] For more detailed information on the recent TCCs for the sixteenth FCA, (TTCs), see the March 17, 2021 Planning Advisory Committee (PAC) meeting materials available at: https://www.iso-ne.com/static-assets/documents/2021/03/a8_fca_16_transmission_transfer_capability_and_capacity_zonal_development.pdf

[8] Currently, there are eight Load Zones (aggregations of load nodes) within New England. A map of these Load Zones is available at: https://www.iso-ne.com/about/key-stats/maps-and-diagrams#load-zones

[9] https://www.iso-ne.com/about/key-stats/maps-and-diagrams#capacity-zones

resources within the zone and enough inbound transmission capability to reliably serve local (*i.e.*, internal) demand.

5.2.2 Export-Constrained Capacity Zones

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

5.2.3 Rest-of-New England Capacity Zone

The Rest-of-New England Capacity Zone is the area of the ISO-NE power grid excluding the identified Capacity Zone(s) for the CCP.

5.3 Tie Benefits

Tie benefits represent possible emergency energy assistance from the [directly interconnected] neighboring Control Areas of Québec, New York, and the Maritimes during a capacity, energy, or operating reserve shortage in New England. Tie benefits associated with the HQ Phase II Interconnection are referred to as HQICCs. Please see Section III.12.9 of the Tariff and Section 5.7.1/Appendix B of this guideline for details on the calculation methodology for tie benefits.

5.4 Loads

Pursuant to Section III.12.8 of the Tariff, each year, the ISO produces a long-term forecast for the New England Control Area and for each Load Zone within the New England Control Area. This long-term load forecast, published in the Forecast Report of Capacity, Energy, Loads and Transmission (CELT),[10] is used in: (1) determining New England's resource adequacy requirements for future years; (2) evaluating reliability and economic performance of the electric power system under various conditions; (3) planning the transmission improvements/expansions needed for reliability, economics, and policy goals; and (4) coordinating maintenance and outages of generation and transmission infrastructure assets. The following sections describe how the load forecast is used in GE MARS for calculating ICR-related values.

5.4.1 Hourly Loads

GE MARS employs an 8,760-hour chronological sub-area load model. The load model that GE MARS currently uses is based on the actual historical hourly load profile from the year 2002. The 2002 hourly load profile is used because it represents a weather year with multiple days of exposure to heat waves that resulted in the NPCC Control Areas experiencing a number of high coincident peak loads[11]. Each year, ISO-NE and the other NPCC Control Areas jointly review this assumption to determine the most suitable weather year to be used in resource adequacy planning studies. Although more recent years have not produced the same number of high and coincident peak loads as weather year 2002, as of the publication of this reference guide, NPCC and the NPCC Control Areas agreed that weather year 2002 is still the most suitable weather year to use in resource adequacy planning. The reason for that determination is that weather conditions similar to those experienced in 2002 could occur in the future; therefore, ISO-NE believes it is appropriate to plan for an adequate amount of resources to meet what demand would be under such

[10] https://www.iso-ne.com/system-planning/system-plans-studies/celt/

[11] The NPCC Control Areas are Quebec, Maritimes, New York, New England and Ontario.

conditions. Accordingly, to model any simulation year, the 2002 hourly load profile is used to scale up to the seasonal peak loads for the study year. The MARS model reflects the hourly "base loads" in calendar year format. The "base loads" include the heating electrification load, but exclude the transportation electrification load and the load reduction associated with behind-the-meter (BTM) photovoltaic (PV), and energy efficiency (EE) that is treated as supply in the FCM.

5.4.2 Weekly Load Forecast Uncertainty

As noted earlier, GE MARS is a probabilistic model. As such, hourly loads are modeled with uncertainty distributions. The ISO develops a forecast distribution of typical daily peak loads for each week of the year. This is based on each week's historical weather distribution combined with an econometrically-estimated monthly model of typical daily peak load. Each weekly distribution of typical daily peak load includes the possible range of daily peaks that could occur over the full range of weather experienced within that week, along with their associated probabilities.

Modeling hourly loads with load forecast uncertainty allows GE MARS to develop "*per unit*" uncertainty multipliers for up to ten different load levels used for computing loads, and to calculate the weighted-average system LOLE reliability indices. Each per-unit multiplier represents a load level, which is assigned a probability of occurrence. The mean, or 1.0 multiplier, represents the 50/50 peak load forecast. GE MARS allows these uncertainty multipliers to vary by month.

5.4.3 BTM PV

GE MARS models the load reductions associated with BTM PV installations separately from hourly base loads because BTM PV load reductions follow a different set of load forecast uncertainties. Each year, the ISO and the New England Power Pool (NEPOOL) Load Forecast Committee (LFC) develop a BTM PV forecast, which is published in the CELT Report (additional details are posted on the Load Forecast section of the ISO website).

GE MARS models the load reductions associated with BTM PV using an hourly profile with an uncertainty component incorporated to account for BTM PV output variability. To capture the correlation between BTM PV output and load, hourly load reductions are developed based on the expected BTM PV installation level for the year and the profile of the 2002 hourly weather history. Uncertainty is modeled through the random selection of the daily profile of BTM PV from within a seven-day window surrounding the day under study (three days before and three days after the modeling day). The ISO chose a seven-day window because it reflects a level of uncertainty consistent with the variability shown in the analysis of the output of PV resources during historical peak load days.

5.4.4 Heating and Transportation Electrification

The ISO started developing heating[12] and transportation[13] electrification forecasts beginning in 2020. Heating electrification is modeled in the "base loads" because heating loads are subject to uncertainty occurrences related to weather. Transportation electrification loads are modeled separately using an hourly profile, including the transmission and distribution gross-up. Transportation electrification hourly loads take into consideration the expected electric vehicle (EV) adoption level and the seasonal/weekly/daily charging patterns within New England. Currently, the GE MARS simulations do not model the charging uncertainty associated with transportation electrification load due to lack of charging data.

5.5 Resource Capacity

5.5.1 FCA ICR–Related Values Calculations

- Existing Capacity Resources (other than Intermittent Power Resources) are modeled at their existing summer Qualified Capacity (QC)
- Intermittent Power Resources are modeled using summer/winter existing QC.
- Resources that have submitted Retirement or Permanent De-list Bids for their capacity at or above the FCA Starting Price or that have elected unconditional retirement[14] are not modeled.
- Capacity associated with Export Bids cleared in previous FCAs and obligated for the relevant CCP is not modeled.

5.5.2 ARA ICR–Related Values Calculations

- All resources are modeled at their QC for the relevant ARA, including New Capacity Resources that have elected critical path schedule (CPS) monitoring to deliver capacity in an earlier CCP than the CCP they have qualified to participate for an FCA.
- The total amount of QC from Import Capacity Resources cleared in the FCA over a transmission interface is limited by the assumed transmission interface limit after accounting for tie benefits.

5.6 Resource Availability

The availability assumptions for capacity resources in the FCA and ARA ICR–related values calculations are determined based on the resource's technology types and Tariff-defined calculation methodology.

5.6.1 Non-Intermittent Generating Resources

A non-intermittent Generating Capacity Resource's equivalent forced outage rate demand (EFORd) assumption is calculated based on the resource's average five-year historical data from

[12] More information on the development of the heating electrification forecast can be found at: https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_heat_elec_forecast.pdf

[13] More information on the development of the transportation electrification forecast can be found at: https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_transp_elec_forecast.pdf

[14] Refer to Market Rule 1 Section III.13.1.2.4.1 (a)

the ISO's database of NERC's Generator Availability Database System (GADS).[15] If the individual resource has not been operational for a full 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 calculations for the entire study year.

A non-intermittent Generating Capacity Resource's scheduled outage assumptions are based on the resource's average five-year historical annual maintenance and short-term outages, scheduled more than fourteen days in advance of their outage start date. If the individual resource has not been operational for a full five years, then NERC class average data is used to substitute for the missing annual data.

The GE MARS model includes a representative EFORd and allotment of maintenance hours for all non-intermittent Generating Capacity Resources.

5.6.2 Intermittent Power Resources

The QC of an Intermittent Power Resource is based on the resource's historical median output during the Summer Intermittent Reliability Hours and Winter Intermittent Reliability Hours averaged over a period of five years. Summer Intermittent Reliability Hours and Winter Intermittent Reliability Hours are specific, defined hours during, respectively, summer and winter, and hours during the year in which the ISO has declared a system-wide or a Capacity Zone-specific shortage event. Because this method already takes into account the resource's availability, Intermittent Power Resources are assumed 100% available in the GE MARS model and no EFORd or maintenance hours are allocated to these resources.

5.6.3 Active Demand Capacity Resources

ISO-NE models Active Demand Capacity Resources by Load Zone. The forced outage rate (FOR) of Active Demand Capacity Resources within a Load Zone is based on the rolling average of the resources' five-year historical summer and winter performance, which includes the resources' offered availability, weighted by the summer and winter net Capacity Supply Obligations that the resources acquired each year. Active Demand Capacity Resources do not have maintenance requirements; therefore, ISO-NE does not model any maintenance hours for these resources in the GE MARS simulations to support ICR-Related Values development.

5.6.4 Passive Demand Capacity Resources

Passive Demand Capacity Resources are non-dispatchable resources that reduce load across pre-defined hours, typically by means of EE. These types of Passive Demand Capacity Resources are assumed 100% available; therefore, no maintenance hours or EFORd are allocated to them in the GE MARS model.

[15] For more information on GADS, see the NERC website located at: https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

5.6.5 Import Capacity Resources

System-backed or contract-backed Import Capacity Resources are modeled as 100% available. Resource-backed Import Capacity Resources are modeled using the "Hydro Plus 30" NERC category and incorporating the de-ratings associated with tie-line availability.

5.7 Modeling Battery Storage Capacity Resources

Battery Storage Resources can participate as an Intermittent Power Resource (IPR) or non-intermittent Generating Capacity Resource (non-IPR) or demand capacity resource. Battery Storage Resources participating as IPRs are modeled in accordance to 5.6.1 of this guide. Battery Storage Resources participating as demand resources are modeled in accordance to 5.6.3 and 5.6.4 of this guide. For the Battery Storage Resources participating as non-IPRs, ISO-NE uses the following approaches to model battery storage resources in ICR-Related Value calculations:

5.7.1 Modeled as an non-intermittent co-located resource

This type of battery storage resource is co-located with a variable energy resource. The configurations and characteristics of this type of resources are similar to the configurations and operating characteristics of those participating as IPRs. ISO-NE models the non-IPR co-located battery resources the same way to model IPR, using its Qualified Capacity and 100% availability.

5.7.2 Modeled as a non-intermittent stand-alone resource

This type of battery storage resource is modeled using a class model where all battery storage resources are modeled using the same typical design and operational parameters of the fleet. ISO-NE models the stand-alone energy storage resources reflecting some or all of the following:

a) Qualified Capacity (Generation Maximum - MW)

b) Storage Energy (MWh)

c) Round Trip Efficiency (per unit)

d) MW Rating for Charging (default to Generation Maximum)

e) Minimum Dispatch Duration (hours)

f) Maximum Dispatch Duration (hours)

g) Energy per Call (MWh)

h) Calls per Year

i) Calls per Month

j) Calls per Day

k) First Emergency Operating Procedure for Dispatch

l) Last Emergency Operating Procedure for Dispatch

m) Assistance for Other Control Areas

The EFORd of non-IPR standalone battery storage resources is 5%[16] with zero weeks of maintenance. The ISO understands stand along battery storage is a fairly new technology participating in the New England markets and as such as more data becomes available, the EFORd and maintenance weeks will be re-evaluated on an annual basis.

5.8 Load and Capacity Relief from ISO-NE Operating Procedure No. 4

To meet its 0.1 days/year LOLE resource adequacy planning criterion, the ISO allows the use of load or capacity relief assumed obtainable through system operator actions during expected capacity shortage conditions. Currently, the ICR-Related Values calculations account for load relief assumed obtainable from implementing Action 5 (obtain emergency assistance/tie benefits from neighboring Control Areas), and Actions 6 and 8 (implement 5% voltage reduction) of ISO-NE Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP-4).[17]

5.8.1 Tie Benefits

Tie benefits reflect the amount of emergency assistance assumed obtainable from neighboring Control Areas, without jeopardizing system reliability in either New England or its neighboring Control Areas. ICR–related values simulations model tie benefits from interconnections with Québec (HQ Phase II and Highgate HVDC ties), Maritimes (New Brunswick AC ties), and New York (New York AC Interface ties and Cross Sound Cable VSC DC line tie). These tie benefits are annual values assumed available every hour of the simulation. GE MARS also models the unavailability of these external interconnections/transmission interfaces. The assumption is based on tie line's forced outage rate, which is a five-year historical rolling average.[18]

5.8.2 5% Voltage Reduction

The amount of load relief assumed obtainable from invoking a 5% voltage reduction under OP 4 conditions is based on the performance standard established within ISO-NE Operating Procedure No. 13, *Standards for Voltage Reduction and Load Shedding Capability* (OP-13).[19]

The amount of load relief obtainable from implementing 5% voltage reduction is assumed to be 1% of the seasonal 90/10 net peak load. This 90/10 net peak load includes the loads associated with heating and transportation electrification and load reductions associated with BTM PV. It is assumed that all Demand Resources have already been triggered/implemented when the system operators invoke this voltage reduction action.

[16] Current availability factors are based on MISO's information which can be found at: https://cdn.misoenergy.org/20180808%20RASC%20Item%2003b%20Capacity%20Determination%20for%20ESR263475.pdf

[17] See the ISO-NE website at: https://www.iso-ne.com/participate/rules-procedures/operating-procedures/

[18] More information on the development of the methodology for the external ties annual maintenance and forced outage rates can be found at : https://www.iso-ne.com/static-assets/documents/2019/05/a5_tie_line_availability_05302019.pdf

[19] Appendix A of ISO-NE OP 4 is located at: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4a_rto_final.pdf

The amount of load relief associated with implementing the 5% voltage reduction is calculated for the summer (June through September) and winter (October through May) months using the following seasonal formula:

[90/10 Seasonal net Peak Load MW - Total Demand Resource MW] × 0.01

5.9 Operating Reserve

Under extremely tight capacity situations, ISO-NE system operators will maintain a minimum level of at least 700 MW of operating reserves for transmission system protection, prior to invoking manual load shedding procedures. This pre-load shedding OP-4 situation is modeled as operating reserve within the ICR calculation by withholding this amount of capacity from serving regional peak load.

Section 6
Developing the ICR

For calculating the ICR, the ISO assumes that the New England transmission system has no internal transmission constraints (*i.e.,* the ISO assumes one bus model). For each hour, GE MARS computes the capacity available to meet demand while taking into account scheduled maintenance, random forced outages of resources, operating reserve requirements, and expected demand. The program then determines the probability of loss of load for the system. After simulating all hours of the year, the program computes the annual reliability indices of LOLE, expected loss of hours (LOLH), and expected energy not served (EENS). The program tests the LOLE value for convergence, which is currently set to be 5% of the standard deviation. If the simulation does not converge, then it proceeds to another replication[20] of the study year until the program obtains an annual reliability index under the convergence guideline. If the system reliability index is less reliable than the resource adequacy criterion (*i.e.*, the LOLE is greater than 0.1 days per year), then additional resources (proxy units)[21] are added to the system to meet the criterion. The Tariff methodology calls for adding proxy units until the New England LOLE is less than or equal to 0.1 days/year.

If the system is more reliable than or meets the resource adequacy criterion (*i.e.*, the system LOLE is less than or equal to 0.1 days/year), additional resources are not required, and the ICR is determined by identifying the additional load carrying capability (ALCC) of the system so that New England's LOLE is exactly at 0.1 days/year.

Once the GE MARS simulation results show a reliability index of less than or equal to 0.1 days/year, the ICR is calculated using the following formula:

$$ICR = \frac{capacity - tie\ benefits - OP4\ load\ relief}{1 + \frac{ALCC}{APk}} + HQICCs$$

Where:

APk = CCP 50/50 peak load forecast.

Capacity = Total installed capacity assumed for the CCP including proxy units.

Tie benefits = Emergency assistance assumed available from the directly interconnected neighboring Control Areas.

OP-4 load relief = Load relief assumed obtainable from system operators implementing Actions 6 and 8 (5% voltage reduction) of OP-4. 700 MW of capacity is held back from dispatch to model the system reserve requirement for transmission security.

ALCC = The amount of additional load that the installed capacity can serve without violating the 0.1 days/year LOLE reliability criterion.

HQICCs = The tie reliability benefits associated with the HQ Phase II Interconnection.[22]

[20] ISO-NE currently users a fixed number of replications which is 5,000.

[21] Refer to Appendix C – Proxy Units.

[22] In the ICR calculation, the HQICCs are treated differently than other resources; they are not adjusted by the ALCC amount.

Section 7
Developing the Net ICR

The net ICR is the ICR minus HQICCs.

The net ICR is the amount (MW) of installed capacity needed to meet the regional resource adequacy criterion after accounting for HQICC contributions.

Section 8
Developing the Zonal Capacity Requirement

8.1 Local Sourcing Requirement (LSR)

The rules relating to the calculation of the LSR are in Section III.12.2 of Market Rule 1. The methodology for calculating LSR for Import-Constrained Capacity Zones involves calculating the amount of resources located within the Capacity Zone that would meet both a local resource adequacy requirement called the LRA Requirement and a transmission security criterion called the TSA Requirement. The LRA is a probabilistic resource adequacy analysis that uses GE MARS to identify the minimum amount of native capacity that needs to be located within an Import-Constrained Capacity Zone when modeling the New England power system as two zones – the zone under study and the Rest-of-New England. The TSA Requirement is a deterministic analysis that the ISO uses to procure native capacity within the FCM auction in order to maintain operational reliability within the constrained zone. The power system must meet both resource adequacy and the transmission security requirement; therefore, the LSR for an Import-Constrained Capacity Zone is the amount of capacity needed to satisfy "the higher of" either (i) the LRA or (ii) the TSA Requirement.

8.1.1 Local Resource Adequacy (LRA) Requirement

The LRA Requirement is calculated based on a two-zone model (the zone under study and the *Rest-of-New England*) with the transfer capability of the interface reflected between these two zones, while using the same load and resources assumptions as those used for the calculation of the system ICR, with the system LOLE at 0.1 days/year. Section III.12.2.1.1 of the Tariff specifies the calculation methodology.

The LRA Requirement is calculated using the value of the firm load adjustments and the existing resources within the zone, including any proxy units that were added as a result of the total system not meeting the LOLE criteria. As stated earlier, the LRA Requirement is the minimum amount of resources that must be located within a zone to meet the sub-area's reliability requirements, while taking into account the transfer capability of the (import) interface to import capacity from the *Rest-of-New England.* For a zone with excess capacity, the process to calculate this value involves shifting capacity out of the zone under study to the *Rest-of-New England* until the transfer capability is no longer able to effectively support the capacity import. The binding condition of the interface is identified when the system LOLE increases to 0.105 days/year, 0.005 days/year above the target LOLE of 0.1 days/year. Shifting capacity, however, may lead to skewed results, since the load carrying capability of various resources are not homogeneous. For example, one megawatt of capacity from a nuclear power plant does not necessarily have the same load carrying capability as one megawatt of capacity from a wind turbine. Consequently, in order to model the effect of shifting "generic" capacity, firm load is shifted. Specifically, as one megawatt of load is added to an import-constrained zone, one megawatt of load is subtracted from the *Rest-of-New England,* thus keeping the entire system in balance. The LRA Requirement is then calculated as the amount of existing resources within the zone including any proxy units, minus the unavailability-adjusted firm load adjustment, using the following formula:

$$LRA_z = Resources_z + Proxy\ Units_z - \left(\frac{Firm\ Load\ Adjustment_z}{1 - FOR_z}\right)$$

Where:

$\boldsymbol{LRA_z}$ = Local Resource Adequacy Requirement for Capacity Zone Z.

$\boldsymbol{Resources_z}$ = Capacity (MW) of resources (supply- & demand-side) electrically located within Capacity Zone Z, including import capacity resources on the import-constrained side of the interface, if any and excludes HQICCs.

$\boldsymbol{Proxy\ Units_z}$ = Capacity (MW) of proxy unit additions, if needed, in Capacity Zone Z.

$\boldsymbol{Firm\ Load\ Adjustment_z}$ = Demand (MW) of firm load added within Capacity Zone Z to make the LOLE of the system equal to 0.105 days per year.

$\boldsymbol{FOR_z}$ = Capacity weighted average of the forced outage rate modeled for all resources (supply & demand-side) within Capacity Zone Z, including any proxy unit additions to Capacity Zone Z.

Proxy Units Adjustment = Demand (MW) of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1 days/year.

8.1.2 TSA Requirement

The TSA is a deterministic reliability screen of a transmission Import-Constrained Capacity Zone. The TSA is a deterministic transmission reliability analysis review as defined within Section 6 of ISO-NE PP10 and Section 3.0 of NPCC RRRD1. The TSA review determines the requirement of the sub-area in order to meet its load through internal (native) generation and import capacity. In performing the analysis, static transmission interface transfer limits are established as a reasonable representation of the transmission system's capability to serve sub-area demand with available existing resources. The results are then presented in the form of a deterministic operable capacity analysis.

In accordance with PP 10 and NPCC RRRD1, the TSA includes contingency analysis 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). These deterministic analyses are currently used each day by ISO-NE System Operations to assess the amount of capacity required to be committed day-ahead within Import-Constrained Capacity Zones.

The TSA Requirement uses the following formula for its calculation:

$$\textit{TSA Requirement} = \frac{(\textit{Need} - \textit{Import Limit})}{1 - (\textit{Assumed Unavailable Capacity} / \textit{Existing Resources})}$$

Where:

Need = Load + Loss of Generator ("Line-Gen" scenario), or Load + Loss of Import Capability (going from an N-1 Import Capability to an N-1-1 Import Capability; "Line-Line" scenario).

Import Limit = Assumed transmission import limit.

Assumed Unavailable Capacity = Amount of assumed resource unavailability applied by de-rating capacity.

Existing Resources = Amount of Existing Capacity Resources within the Zone.

For the calculation of ICR, LRA and TSA, the bulk of the assumptions are the same. However, due to the deterministic and transmission security-oriented nature of the TSA, two of the assumptions for calculating the TSA requirement differ from the assumptions used in determining the ICR and LRA Requirements. The differences are as follows: the assumed loads for the TSA are the 90/10 peak loads for the Import-Constrained Capacity Zone for the relevant CCP, whereas for ICR and LRA calculations, a distribution of loads for the same sub-areas, covering the range of possible peak loads for that CCP is used. In addition, the load and capacity relief assumed obtainable from implementing Actions of OP-4, is not used within TSA calculations.

8.2 MCL

An MCL for an Export-Constrained Capacity Zone is calculated based on a two-zone model; the export-constrained zone under study and the *Rest-of-New England* with the transfer capability of the interface reflected between these two zones, using the same load and resources assumptions as those used for the calculation of the system ICR, where the system LOLE is at 0.1 days/year. Market Rule 1, Section III.12.2.2 specifies the calculation methodology.

To determine the MCL of an Export-Constrained Capacity Zone, the New England ICR and the LRA for the *Rest-of-New England*, which is New England excluding the Export-Constrained Capacity Zone, need to be identified. Given that the ICR is the total amount of resources that need to be procured within New England to meet the reliability criterion and the LRA requirement for the *Rest-of-New England* is the minimum amount of resources required for that area to satisfy its reliability criterion, the difference between the two is the maximum amount of resources that can be purchased within an Export-Constrained Capacity Zone.

After the LRA for the *Rest-of-New England* is calculated using the methodology described Section 8.11, then the MCL is calculated using the formula:

$$MCL_Y = Net\ ICR - LRA_{Rest\ of\ New\ England}$$

Where:

$\boldsymbol{MCL_y}$ = Maximum Capacity Limit for Load Zone Y

Net ICR = ICR - HQICCs

$\boldsymbol{LRA_{Rest\text{-}of\text{-}New\ England}}$ = Amount (MW) of Local Resource Adequacy Requirement for the *Rest-of-New England* area, which for the purposes of this calculation, is treated as an Import-Constrained region, determined in accordance with Market Rule 1, Section III.12.2.1

Section 9
Developing the System-Wide and Capacity Zone MRI Curves

System-wide, import-constrained Capacity Zone and export-constrained Capacity Zone MRI curves measure the marginal reliability impact, associated with various capacity levels for the system and each import-constrained or export-constrained Capacity Zone.

For developing the system-wide MRI curve, system reliability indices are first calculated using a GE MARS model for various capacity levels above and below the ICR in 10 MW increments to cover the full range of capacity conditions. For each of these capacity levels evaluated, the MRI value is estimated as an incremental change in system reliability as measured by EENS per MW capacity change. An MRI curve is developed from these values with capacity represented on the X-axis and the corresponding MRI values on the Y-axis.

Similarly, import-constrained and export-constrained Capacity Zone MRI curves are calculated as the incremental change in system reliability as measured by EENS per MW zonal capacity change for various zonal capacity levels above and below the zonal capacity requirement in 10 MW increments. The calculation uses the same modeling assumptions and methodology as those used to determine the LRA Requirement for import-constrained Capacity Zones (with the exception of the modification of the TTC for the import-constrained Capacity Zone[23] when the TSA sets the LSR for the import-constrained Capacity Zone) and the MCL for export-constrained Capacity Zones.

Please see Appendix E to this guideline – Marginal Reliability Impact (MRI) Demand Curve Supplement for additional details.

[23] For import-constrained Capacity Zones, the LRA Requirement and TSA Requirement values both play a role in defining the MRI-based Capacity Zone Demand Curves as they do in setting the LSR for the import-constrained Capacity Zone. The same modeling assumptions and methodology used to determine the LRA Requirement is used to derive the import-constrained Capacity Zone Demand Curve, except that the TTC between the Capacity Zone under study and the rest of the New England Control Area is reduced by the greater of: (i) the TSA Requirement minus the LRA Requirement, or (ii) zero. By using a TTC that accounts for both the TSA Requirement and the LRA Requirement, the ISO applies the same "higher of" logic used in the LSR to the development of import-constrained Capacity Zone Demand Curves.

Section 10
Developing the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves

The System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves are developed by applying a scaling factor to the system-wide and Capacity Zone MRI curves, which are developed as described in Section 9.0 of this guideline. 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 net Cost of New Entry (net CONE). In other words, 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. To satisfy this requirement, the demand curve scaling factor is set in accordance with Section III.13.2.2.4 of the Tariff.

Section 11
Annual FCM Auction Timelines

Each year, the ISO conducts four FCM annual auctions (one FCA and three ARAs). The schedule for these four auctions, for each CCP, is available on the ISO's website.[24]

Table 1 below is a high-level depiction of the FCM auction schedule. The far left column of the table shows the CCPs for which ICR-related values will be calculated. CCP_N is the CCP associated with the present calendar year "N."

Specific dates associated with FCM auctions may be found on the FCM Auctions Calendar page on the ISO's website.[25]

Table 1 – ISO FCM Auctions

Capacity Commitment Period	FEB	MAR	JUN	AUG
CCP_{N+4} – CCP_{N+5}	FCA			
CCP_{N+3} – CCP_{N+4}			ARA 1	
CCP_{N+2} – CCP_{N+3}				ARA 2
CCP_{N+1} – CCP_{N+2}		ARA 3		

Example on how to use the table:

Assuming that N equals calendar year 2021, then, according to the table, ICR-related values will be calculated in 2022 for the following auctions:

The FCA to be conducted in February 2022 is for CCP 2025-2026

ARA 1 to be conducted in June 2022 is for CCP 2024-2025

ARA 2 to be conducted in August 2022 is for CCP 2023-2024

ARA 3 to be conducted in March 2022 is for CCP 2022-2023.

[24] https://www.iso-ne.com/system-planning/resource-planning/installed-capacity-requirements/

[25] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/?document-type=FCM%20Auction%20Calendars&sort=normalized_document_title_s.asc

11.1 Stakeholder Review

The ISO develops the ICR-related values according to the Tariff and through a stakeholder review process. The stakeholder review process starts approximately ten months before a relevant FCA. The New England Power Pool (NEPOOL) Load Forecast Committee (LFC), Power Supply Planning Committee (PSPC), Reliability Committee (RC), and Participants Committee (PC) are all involved in the development of the of the ICR-related values either through the development of the assumption sets or the ICR-related values.

Prior to filing the ICR-related values with the FERC for approval to be used within the FCM auctions, the ICR-related values are voted upon only by the RC and the PC for their support/non-support of these values. A typical (stakeholder) schedule to develop these ICR-related values for the FCA and ARAs, respectively, is shown in Tables 2 & 3.

Table 2 – Development of ICR-Related Values for FCA

PSPC review of Capacity Zone determinations	**May**
PSPC final review of all assumptions	**June/July**
PSPC review of ISO recommendation of ICR-related values	**August**
RC review/vote of ISO-recommended of ICR-related values	**September**
PC review/vote of ISO-recommended of ICR-related values	**October**
File with the FERC	**November**

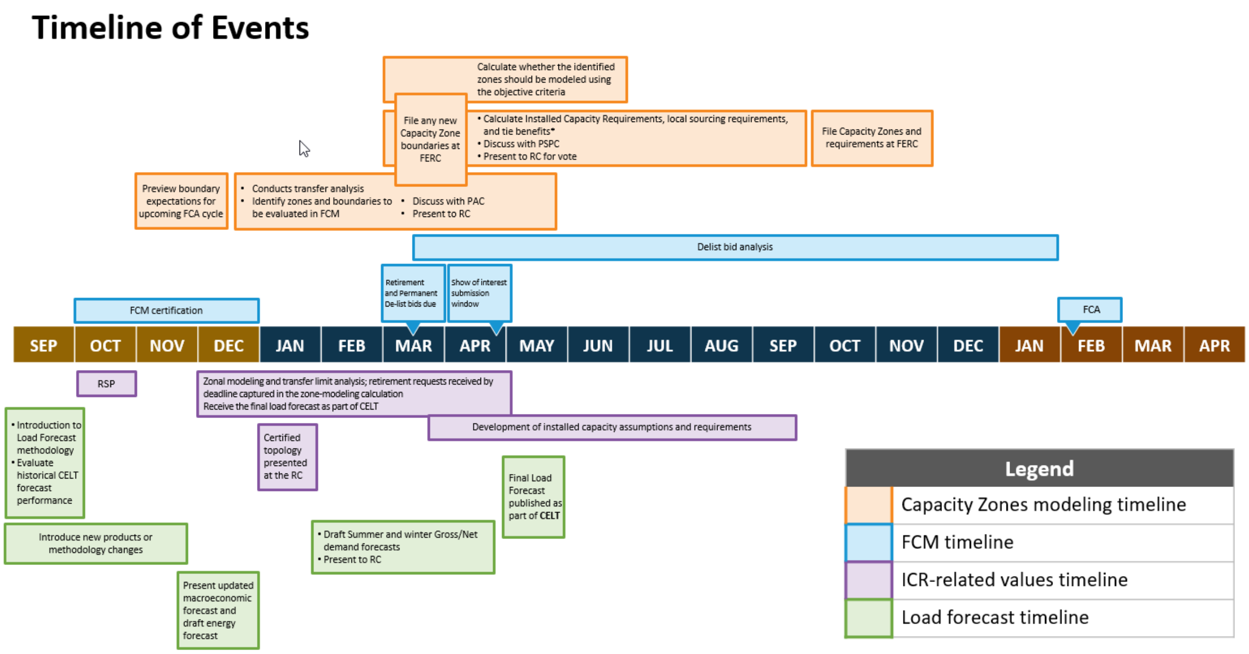
Table 3 – Development of ICR-Related Values for ARAs

PSPC final review of all assumptions	**August**
PSPC review of ISO-recommended of ICR-related values	**September**
RC review/vote of ISO-recommended of ICR-related values	**October**
PC review/vote of ISO-recommended of ICR-related values	**November**
File with FERC	**December**

Section 12
Appendices

Appendix A – Capacity Zone Determination Timeline

Each year, prior to each FCA, ISO-NE reviews the transmission system with stakeholders to identify the Capacity Zone formation determinations for the FCA. This process begins in the November timeframe with discussions at Planning Advisory Committee (PAC). The ISO reviews the Capacity Zones with the PSPC as part of the ICR-related values assumptions discussions.



Determination of Capacity Zones

The ISO identifies the Capacity Zones for each CCP three years in advance during the annual assessment of transmission transfer capability pursuant to Section II of Attachment K to the OATT.

Import-Constrained Capacity Zone

An import-constrained Capacity Zone is a zone for which the second contingency transmission capability results in a line-line TSA Requirement (calculated pursuant to Section III.12.2.1.2 of the Tariff and ISO-NE Planning Procedures) that is greater than the existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model as out-of-service all retirement requests (including any received for the current FCA at the time of this calculation) and Permanent De-List Bids as well as rejected-for-reliability Static and Dynamic De-List Bids from the most recent previous FCA.

Export-Constrained Capacity Zone

An export-constrained Capacity Zone is a zone for which the MCL is less than the sum of the existing Qualified Capacity and proposed new capacity that could qualify to be procured in the export-constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

Rest-of-New England Capacity Zone (Rest-of-Pool)

A *Rest-of-New England* Capacity Zone refers to all areas except the import-constrained or export-constrained Capacity Zone under study. The number of different *Rest-of-New England* Capacity Zones for any CCP corresponds to the total number of import-constrained and export-constrained Capacity Zones identified for that CCP.

Appendix B – Tie Benefits Calculation Methodology

The ISO conducts the tie benefits study for the relevant CCP using a probabilistic analysis based on the same assumptions used for calculating the ICR-related values for the CCP. The methodology for calculating total tie benefits, individual Balancing Authority Area tie benefits, and tie benefits associated with an individual tie or group of ties is documented it Table 4 below.

Table 4 – Methodology for Conducting Total and Individual Tie Benefits

PROCESS	PROCESS DESCRIPTION
1.0	Calculate the tie benefits values for all possible interconnection states using the isolated New England system as the reference.
2.0	Calculate the initial total tie benefits for New England from all the neighboring Balancing Authority Areas.
3.1	Calculate the initial tie benefits for each individual neighboring Balancing Authority Area.
3.2	Pro-rate the tie benefits values of the individual Balancing Authority Areas based on the total tie benefits, if necessary.
4.1	Calculate the initial tie benefits for an individual interconnection or group of interconnections.
4.2	Pro-rate the tie benefits values of an individual interconnection or group of interconnections, based on the individual Balancing Authority Area tie benefits, if necessary.
5.0	Adjust the tie benefits of an individual interconnection or group of interconnections to account for capacity imports.
6.0	Calculate the final tie benefits for each individual neighboring Balancing Authority Area.
7.0	Calculate the final total ties benefits for New England.

Summary of the Tie Benefits Calculation Process

The New England Control Area is modeled with all internal transmission interfaces not addressed by either an LSR or an MCL Requirement. Table 5 below shows the interface transfer capability of all interfaces modeled in a typical CCP tie benefits study.

Table 5 – Example of Internal Interface Modeled in the FCA 15 Tie Benefits Study (MW)

Internal Interfaces Not Addressed by LSR or MCL	Summer N-1 TTC
Orrington South Export	1,325
Surowiec South	1,500
Maine-New Hampshire	1,900
North-South	2,675
East-West	3,500
West-East	2,200
Boston Import	5,700
SEMA/RI Export	3,400
SEMA/RI Import	1,280
Connecticut Import	2,950
Norwalk-Stamford	1,650
Southwest Connecticut Import	3,200

Total Tie Benefits

The ISO calculates total tie benefits using the results of a probabilistic analysis is that determines LOLE indices for the New England Balancing Authority Area and neighboring Balancing Authority Areas. The LOLE calculations are first done by bringing ISO-NE and neighboring Balancing Authority Areas to 0.1 days/year of LOLE simultaneously on an interconnected basis that includes all existing connections (tie lines) between ISO-NE and its directly-connected neighboring Balancing Authority Areas. This establishes the minimum amount of capacity that each area needs in order to comply with NPCC's resource adequacy requirement of 0.1 days per year LOLE.

The LOLE calculations are then repeated with the New England Balancing Authority Area isolated from all neighboring Balancing Authority Areas. The tie benefits are then quantified by adding firm capacity resources within the isolated New England Balancing Authority Area, until the LOLE is returned back to 0.1 days per year. The resources which are added to return the New England Balancing Authority Area to a LOLE of 0.1 days per year are called "firm capacity equivalents" and are assumed to be the New England Balancing Authority Area's total tie benefits.

Based on the methodology described above, a total amount (MW) of tie benefits are assumed within the ICR-related values calculations for the relevant CCP.

Individual Balancing Authority Area Tie Benefits

For the relevant CCP, the individual Balancing Authority Area tie benefits are a calculated amount of capacity (MW) for Québec, the Maritimes, and New York.

To calculate each Balancing Authority Area's individual tie benefits, all the tie lines associated with the Balancing Authority Area of interest are treated on an aggregate basis. The tie benefits from each Balancing Authority Area are calculated for all possible interconnection states. The simple average of these tie benefits from each of these states will represent the calculated tie benefits from that specific Balancing Authority Area.

If the sum of the Balancing Authority Areas tie benefits is different from the total tie benefits for the New England Balancing Authority Area, then each Balancing Authority Area's tie benefits are adjusted (up or down) based on the ratio of the individual Balancing Authority Area's tie benefits to total tie benefits.

Individual Tie (or Group of Ties) Tie Benefits

For the relevant CCP, individual interconnection tie benefits are determined from Québec over the HQ Phase II HVDC facility, from Québec over the Highgate HVDC facility, from the Maritimes over the New Brunswick AC ties, and from New York, delivered via the New York AC ties and from the Cross-Sound Cable VSC DC line.

The tie benefits methodology (described in Section 5.3 of this guideline) requires the ISO to calculate benefits for an individual tie or group of ties to the extent that a discrete and material transfer capability can be identified for it. To calculate tie benefits for each tie or group of ties from the external Balancing Authority Area of interest into the New England Balancing Authority Area, each is treated independently. The ISO calculates tie benefits for each individual tie or group of ties for all the interconnection states and the simple average of the tie benefits associated with these interconnections states is the resultant tie benefits for each tie or group of ties.

If the sum of the tie benefits from the individual tie or group of ties relative to their Balancing Authority Area's total tie benefits are different, then the tie benefits of each individual tie or group of ties are adjusted (up or down) based on the ratio of the tie benefits of the individual tie or group of ties to the Balancing Authority Area's total tie benefits.

Adjustments to Tie Benefits to Account for Capacity Imports

Process step 5.0 of the current tie benefits methodology requires that the tie benefit values of individual interconnections or a group of interconnections be adjusted, if necessary, to account for the existing qualified Import Capacity Resources for the relevant CCP. If the sum of the tie benefits value and the import capacity is greater than the transfer capability of the individual interconnection or group of interconnections under study, then the tie benefits value will be reduced.

HQICCs[26]

HQICCs are an allocation of the tie benefits over the Hydro-Québec Interconnection to the IRH, which are regional entities that hold certain contractual entitlements (*i.e.*, rights) over this specific transmission interconnection. These rights are monetized as credits in the form of reduced capacity requirements.

The HQICC value (MW) is determined by the tie benefits from Québec over the Phase II Interconnection facility, and are applicable for every month during the relevant CCP.

[26] The 2024-2025 CCP HQICCs values were filed with the Commission in the November 10, 2020 ICR filing (ER21-371-000): https://www.iso-ne.com/static-assets/documents/2020/11/icr_for_fca_15.pdf

Step 6.0 of the tie benefits methodology determines the final tie benefits for each neighboring Balancing Authority Area as the sum of the tie benefits from the individual interconnections or groups of interconnections with that Balancing Authority Area, after accounting for any adjustment for capacity imports as determined under Step 5.0 of the tie benefits methodology.

The ISO determines final total tie benefits for the New England Balancing Authority Area from all neighboring Balancing Authority Areas under Step 7.0 of the tie benefits methodology as the sum of these neighboring area tie benefits after accounting for any adjustment for capacity imports as determined under Step 6.0 of the tie benefits methodology.

Appendix C – Proxy Units

Section III.12.7.1 of the Tariff describes the addition of proxy units to the ICR model. Proxy units are required when the available resources are insufficient for the unconstrained New England Balancing Authority Area to meet the resource adequacy planning criterion specified in Section III.12.1 of the Tariff. In the model, the ISO uses proxy units as additional capacity to determine the ICR, LRA, MCL, and MRI demand curve requirement values.

Proxy units used in the ICR model reflect the resource capacity and outage characteristics such that when proxy units are used in place of all other resources in the New England Balancing Authority Area, the reliability, or LOLE, of the New England Balancing Authority Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Balancing Authority area as determined in accordance with Section III.12.7.3 of the Tariff. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Balancing Authority Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2 of the Tariff.

The proxy unit characteristics are based on a study conducted in 2014. The results of that study, which are summarized in Table 6 below, indicated that there are many possible combinations of FOR and proxy unit size that would be neutral to the ICR calculations. It was decided that the proxy unit be 400 MW in size, with an average system forced outage rate of 5.47%, and four weeks of maintenance.

Table 6 – Results of the Proxy Unit Characteristics Study

Proxy Unit Size (MW)	Average Resource FOR						
	4.92%	5.20%	5.47%	5.69%	5.80%	5.91%	6.02%
100							0.0294
150						0.0296	
200					0.0295		
250							
300				0.0299			
350							
400			0.0296				
450							
500		0.0301					
550							
600							
650	0.0295						

When modeling transmission constraints for the determination of LRA, the same proxy unit (s) may be added to the import-constrained Capacity Zone (if needed); otherwise, they will be added elsewhere in the rest of the New England Balancing Authority Area. For the import-constrained Capacity Zone LRA calculation, proxy units may or may not be needed to be added to the Capacity Zone. Additional proxy unit information is provided below.

Proxy Units

Why use proxy units when calculating ICR-Related Values?

- Use of proxy units avoids an unjustified increase or decrease in the system LOLE that may result from assuming a specific type of resource addition
- *Proxy unit* is effectively neutral to ICR calculations

What are proxy unit* characteristics?

- 400 MW generator
- Scheduled outage – 4 weeks/year
- Forced outages – 5.47 EFORd

Proxy Unit, *continued*

One megawatt (MW) of:		
***Neutral* (proxy) resource adjustment capacity** • Worth 1.00 MW of typical capacity • Zero change in ICR	**Perfect capacity** • Could be worth, 1.10 MW of typical capacity • 0.10 MW reduction in ICR per MW of installed capacity	**Poorly performing resource** • Could be worth (something like) only 0.80 MW of typical capacity • ICR would increase by some amount • Depends upon size and forced outage rates

*Based on a study conducted in 2014. ISO plans to conduct a new study this year. Copy of the presentation is available at: https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf

Appendix D – Assumptions Summary Table to Support Calculations of ICR-Related Values

ASSUMPTIONS	ICR CALCULATION
Resources Data	
Non-intermittent Generating Capacity Resources	Existing Qualified Capacity values adjusted for certain Retirement/Permanent De-List Bids. Use EFORDs, maintenance weeks and transition rate.
Intermittent Power Resources	Existing Qualified Capacity values adjusted for certain Retirement/Permanent De-List Bids with zero unavailability.
Active Demand Capacity Resources	Existing Qualified Capacity values adjusted for certain Retirement/Permanent De-List Bids; uses EFORd.
Passive Demand Resources	Existing Qualified Capacity values adjusted for certain Retirement/Permanent De-List Bids with zero unavailability.
Import Capacity Resources	Existing Qualified Capacity values with FOR, maintenance weeks for the ties and import resources (system/resource backed)
Tie Benefits and OP 4 Load Relief	
Tie benefits	Determined in accordance with Appendix B of this ICR Reference Guide and uses the Tie Line Availability and maintenance weeks.
5% voltage reduction	Calculation based on the formula in Section 3.2.4.
System reserves	700 MW
Load Data	
Gross load forecast data	Most recent CELT forecast, hourly profile using weather-related uncertainties.
BTM PV	Most recent CELT forecast, hourly profile with uncertainty using a three day window.
Electrification forecast data	Most recent CELT forecast, hourly profile with no uncertainties.
Heating forecast data	Most recent CELT forecast, this is part of gross load forecast and uses weather-related uncertainties.
Transfer Limits	
Internal transmission transfer capability	N-1 and N-1-1 limits, as projected for study year.
External transmission transfer capability	N-1 limits, as projected for study year.

Appendix E – MRI Demand Curves

Demand Curves: MRI Approach

Beginning with CCP 2020-2021 (associated with the eleventh FCA), MRI-based system-wide and Capacity Zone demand curves were implemented. This approach combines both engineering and economics to derive a sloped demand curve that represents the incremental value of capacity across a range of total capacity amounts and Capacity Zones. The engineering method employs the same techniques used to calculate the ICR-related values, but rather than calculating only one value, the ISO calculates many values to develop a curve. Economics is used to convert the engineering into a demand curve based on net CONE.

MRI

The MRI represents incremental impacts on system reliability. The MRI reflects incremental improvement in reliability associated with adding incremental capacity and is calculated at various capacity levels in 10 MW blocks. The ISO develops an MRI curve using the same GE MARS model and inputs it uses to calculate ICR-related values.

The MRI demand curve is derived from an EENS curve generated by the GE MARS model, which is the expected *lost load* amount calculated on a MWh-per-year basis at various capacity levels. A sample MRI demand curve is shown in Figure 1 below.

$$MRI_{(capacity\ i)} = \Delta EENS / \Delta Capacity$$

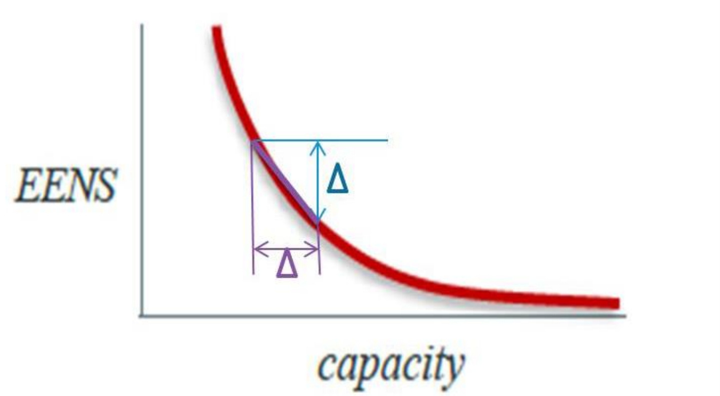


Figure 1: Sample MRI Demand Curve

MRI Curve Characteristics

When the system is short on capacity, deficiencies can occur more frequently, so an additional MW of capacity significantly reduces EENS because, at low MW quantities, MRI value is high, and as capacity is added, MRI decreases quickly, meaning the slope is relatively steep. Conversely, when the system is long on capacity, deficiencies are infrequent, so an additional MW of capacity has a small impact on EENS. At high MW quantities, the MRI value is low and relatively flat. Both of these scenarios are shown in Figure 2 below.

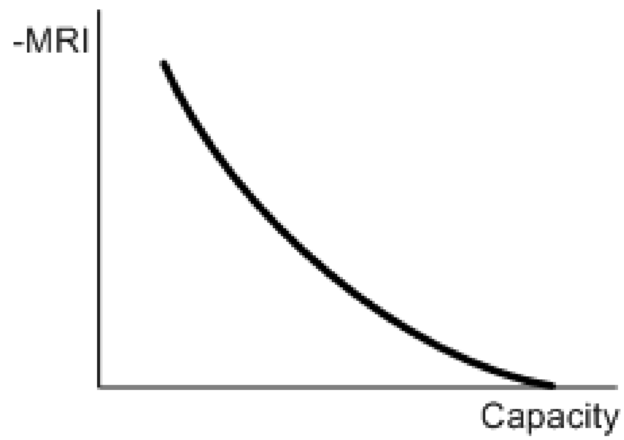


Figure 2: Characteristics of an MRI Curve

The figure shows that as the system capacity increases, the incremental capacity impact on system reliability decreases. Please note that the plot uses negative MRI value to provide a visual impact of capacity increase to the MRI.

Economics of a MRI Based Demand Curve

As shown in Figure 4 below, the system-wide MRI curve is converted into a price-quantity curve, which is done by scaling the curve so price at intersection of net ICR is equal to net cost of new entry (net CONE).

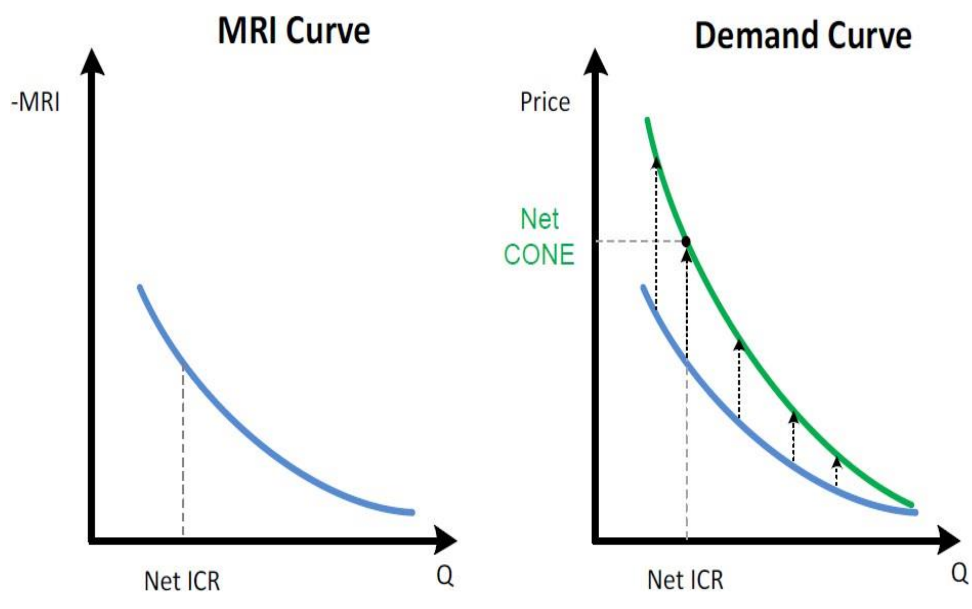


Figure 3: An MRI Curve Converted to a Demand Curve

Appendix F – ICR Timelines

ICR Development Process Timeline for FCM

Annual process involving stakeholders normally runs from April through December and consists of the following:

ISO develops necessary assumptions, according to Section III.12 of Tariff, and reviews them with PSPC **(May – August)**

ISO calculates ICR-related values and reviews them with PSPC **(August – October)**

After PSPC reviews and comments, ISO may recalculate ICR-related values **(August – October)**

Presents ISO recommended ICR-related values and assumptions to RC for comment **(August – September)**

RC takes action on the ISO recommended **FCA** ICR-related values **(September)**

PC takes action on the ISO recommended **FCA** ICR-related values **(October)**

ICR-related values for **FCA** filed with FERC **(Early November)**

RC takes action on the ISO recommended **ARAs** ICR-related values **(October)**

PC takes action on the ISO recommended **ARAs** ICR-related values **(November)**

ICR-related values for three **ARAs** to be conducted in following year filed with FERC **(December 1 for ARAs)**

ICR Development Process Timeline for RSP, NPCC, and NERC Assessments

Actual and representative ICR values are developed in around May of RSP publication year

ISO reviews with PAC

New England resource needs for NPCC Resource Adequacy Review are developed in September

ISO reviews with NPCC CP 8 Working Group, NPCC Task Force on Coordination of Planning and Reliability Coordinating Committee

GE MARS

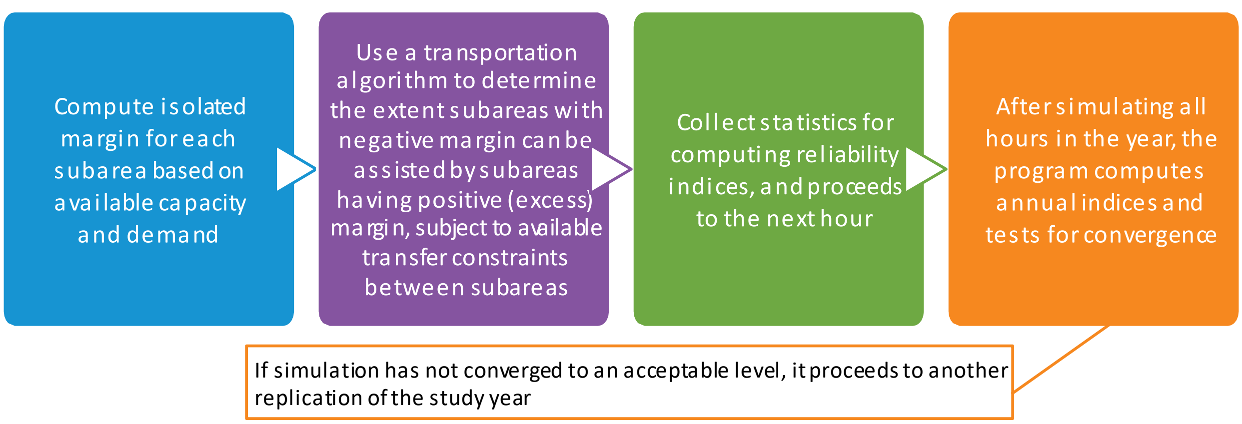
- Computer program that uses a sequential Monte Carlo simulation to probabilistically compute the resource adequacy of the system by simulating the random nature of resources and the uncertainty of load forecast
- Major transmission interfaces are modeled by using the pipe and bubble approach (subarea presentation with limitations between subareas)

  between subareas
  - Loads and generators are assumed to be connected to different subareas within the system

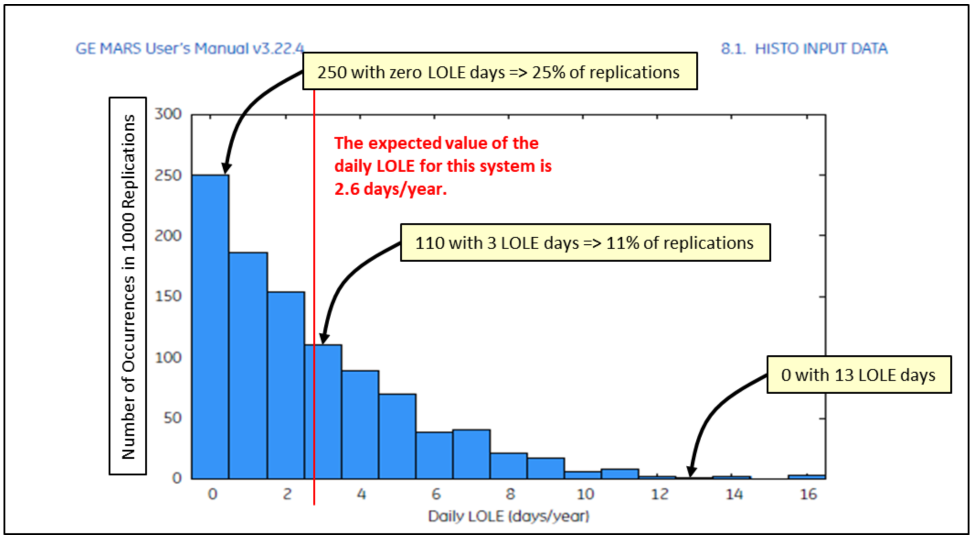
Monte Carlo Simulation Process

Simulates system for all 8760 hours of the year repeatedly (multiple replications) to evaluate impact of a wide-range of possible random combinations of generator forced outages

Chronological system histories are developed for each hour



Results from Monte Carlo *Synthetic* Histories



ICR Simulation Produced Reliability Indices

LOLE [days/years]

- Expected number of days during year where loss of load events (interrupting firm customer load) occur in the system
  - Firm customer load interrupted when system reserve is below 700 MW
- A loss of load day may consist of loss of load events that last one hour or multiple hours during the day
- System is considered to have a loss of load day whenever capacity is not able to meet load and minimum amount of reserve system-wide or in any of the subareas

LOLH

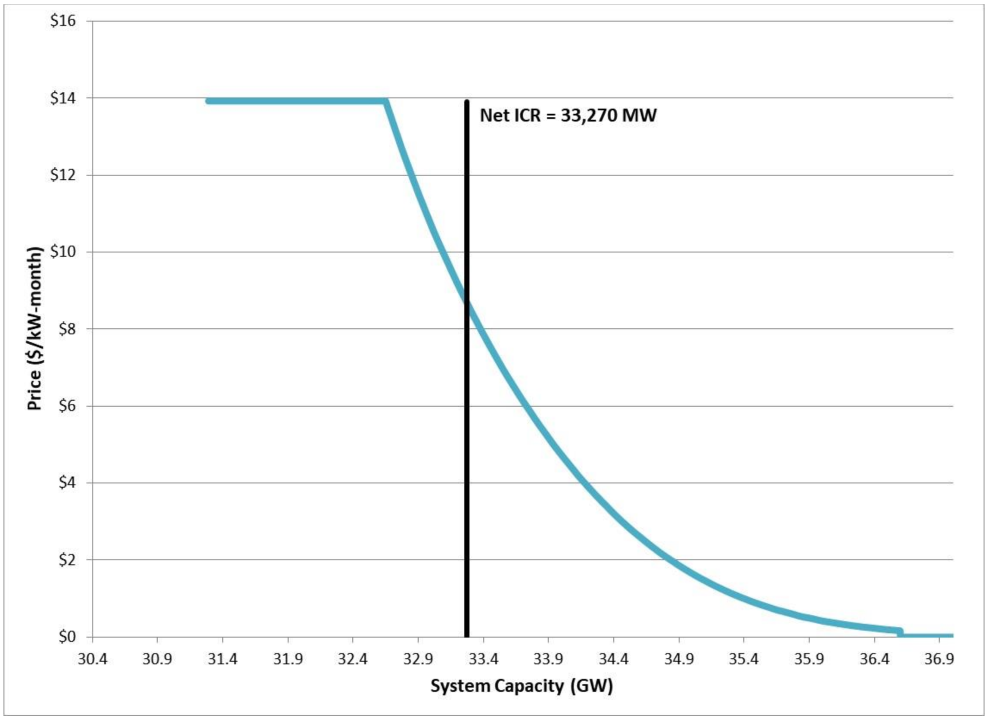
Expected hours during year where loss of load events (interrupting firm customer load) occur in the system

EENS

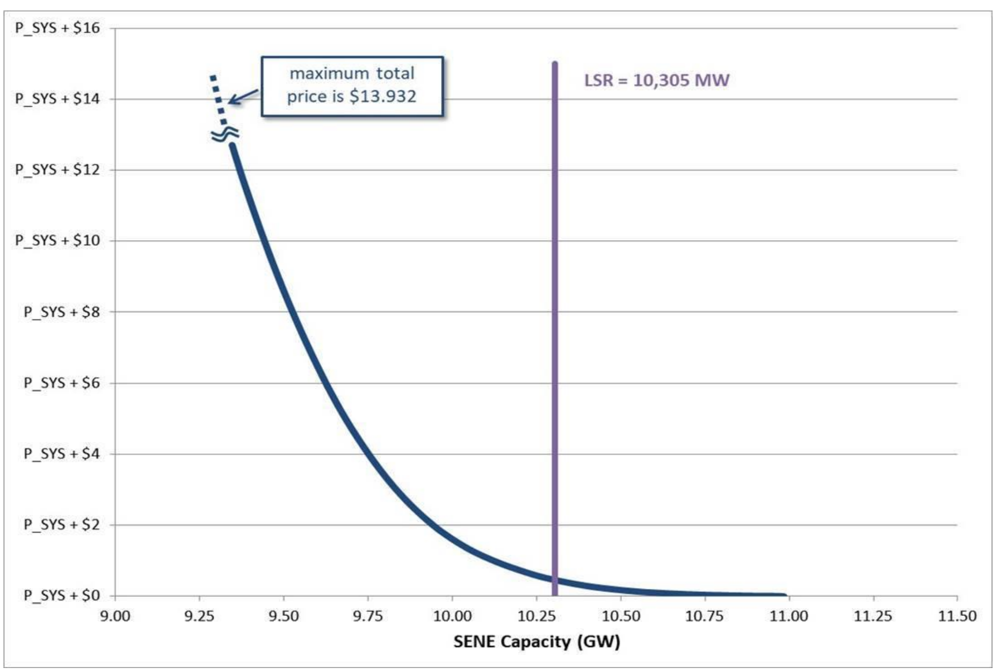
Expected amount of energy not served during the year from the loss of load events

Appendix H – Sample System-Wide Capacity Demand Curve, import-constrained Capacity Zone Demand Curve, and export-constrained Capacity Zone Demand Curve (fifteenth FCA)

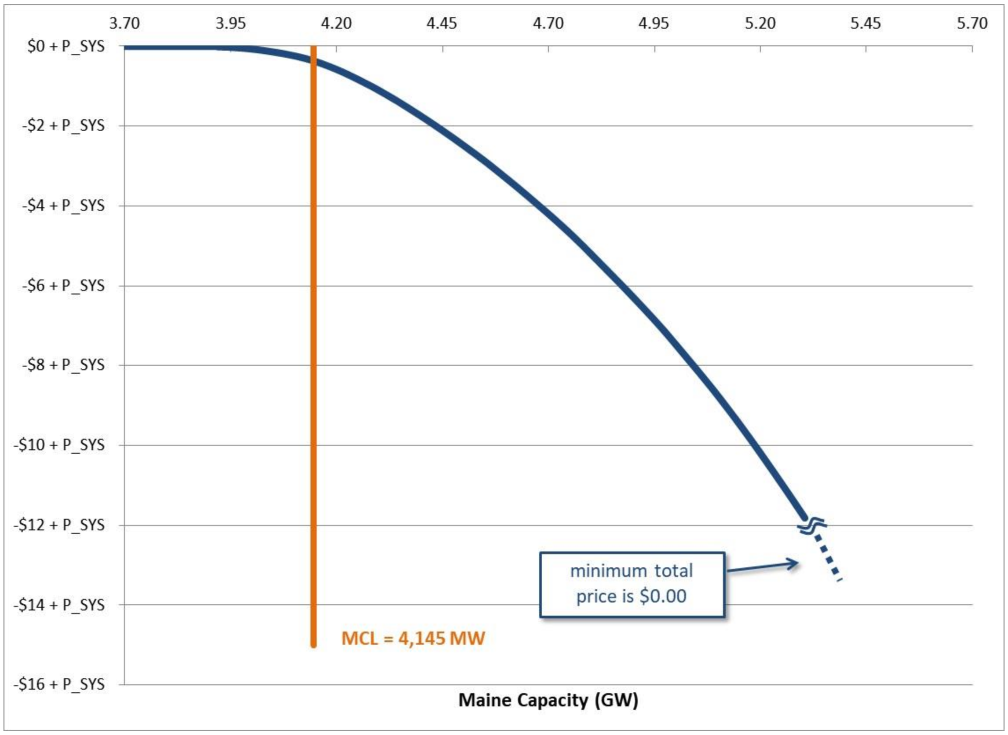
System-Wide Capacity Demand Curve (FCA 15 Example)



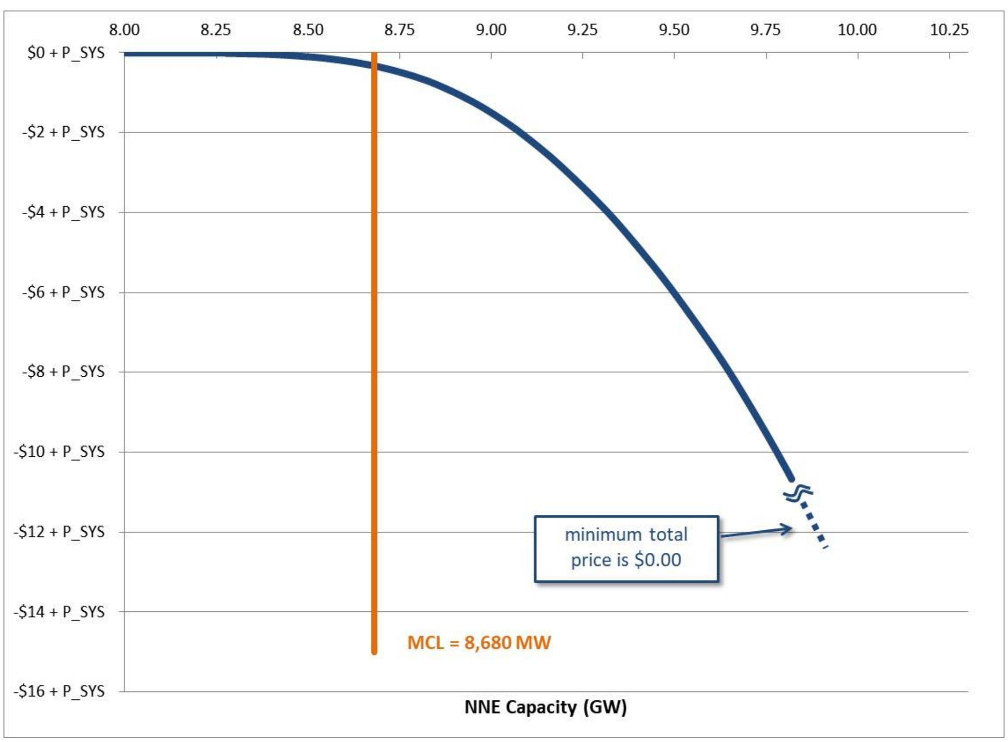
SENE import-constrained Capacity Zone Demand Curve (FCA 15 Example)



Maine export-constrained Capacity Zone Demand Curve (FCA 15 Example)



NNE export-constrained Capacity Zone Demand Curve (FCA 15 Example)



Section 13
Revision History

This revision history reflects all ISO-approved changes made to this *ICR Reference Guide* beginning with the first public domain posting/publication, which was Version 1.0 dated June 15, 2021. This document is also posted on the ISO website located at:

https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/installed-capacity-requirement.

Revision	Date	Description of Changes
1.0	06/15/21	First publication.
2.0	09/15/21	Revised sections 5.4.1 to explain the reason for using year 2002 load shape for modeling loads; and 5.6.3 to describe the new methodology to determine the forced outage rate of Active Demand Capacity Resources. Added section 5.7 to describe the modeling of the Battery Storage Capacity Resources.

Section 14
Additional Customer Support

Methods for contacting ISO customer support:

- Ask ISO is the preferred means to contact the ISO. Ask ISO is a self-service interface for submitting inquiries. We recommend that you use Google Chrome or Mozilla Firefox browsers for best connectivity results. Please see the Ask ISO User Guide for more information.

- Email: custserv@iso-ne.com

- Phone:
  - (413) 540-4220
  - (833) 248-4220

We respond to inquiries during business hours (Monday through Friday 8:00 a.m. to 5:00 p.m.) Outside of business hours, you may use the pager (877) 226-4814 for emergency inquiries.