ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2016/17 Capability Year

ISO New England Inc.
January 2013

ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2016/17 Capability Year

Executive Summary

As part of the Forward Capacity Market (FCM), ISO New England Inc. (ISO-NE) is preparing to conduct the Forward Capacity Auction (FCA) for the 2016/17 Capability Year. The auction, which will be conducted on February 4, 2013, is intended to result in capacity commitments of sufficient quantities (megawatts) to meet the Installed Capacity Requirement (ICR) for the 2016/17 Capability Commitment Period (CCP). The 2016/17 CCP is the seventh Capability Year of the FCM and it begins on June 1, 2016 and ends on May 31, 2017.

In this report, ISO-NE is documenting the assumptions and results of the 2016/17 Capability Year ICR, Local Sourcing Requirements (LSR) and Maximum Capacity Limit (MCL) – (collectively the "ICR-Related Values") calculations, all of which are key inputs in the FCA, and the Hydro-Québec Interconnection Capability Credits (HQICCs), which are a key input into the calculation of the ICR.

The ICR is a measure of the installed resources that are projected to be necessary to meet both ISO-NE and the Northeast Power Coordination Council's (NPCC) reliability standards[1], with respect to satisfying the peak demand forecast for the New England Balancing Authority area while maintaining the required reserve capacity. More specifically, the ICR is the amount of resources needed to meet the reliability requirements defined for the New England Balancing Authority area of disconnecting non-interruptible customers (a loss of load expectation or "LOLE"), on average, no more than once every ten years (an LOLE of 0.1 days per year).

In general, the methodology used for calculating the ICR-Related Values for the 2016/17 FCA remains unchanged from the methodology used for calculating the ICR-Related Values for the 2015/16 FCA.

The ICR for the 2016/17 Capability Year was established through a stakeholder process in accordance with the calculation methodology prescribed in Section III.12 of Market Rule 1.[2] The stakeholder process consisted of review and comment from the NEPOOL Power Supply Planning Committee (PSPC) and the NEPOOL Reliability Committee (RC) on ISO-NE's development of load and resource assumptions and ISO-NE's subsequent calculation of the ICR-Related Values for the 2016/17 Capability Year's FCA. State Regulators and the New England States Committee on Electricity (NESCOE)[3] also reviewed and commented on the development of the ICR-Related Values, as part of their participation on the NEPOOL Committees.

---

[1] Information on the NPCC Standards is available at: https://www.npcc.org/Standards/default.aspx.
[2] Market Rule1: http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.
[3] Information on NESCOE is available at: http://www.nescoe.com/

After the PSPC's review and comment, ISO-NE developed a recommendation regarding both the ICR-Related Values and HQICCs for the 2016/17 Capability Year. ISO-NE presented this recommendation, along with the associated load and resource assumptions, to the RC for their review, comment and action. At the August 14, 2012 RC meeting, a motion to recommend that the NEPOOL Participants Committee (PC) support ISO-NE's proposed ICR-Related Values and HQICCs passed with a show of hands vote.[4]

ISO-NE then presented the ICR-Related Values, HQICCs, and results of the RC action to the PC for its review and action. At their September 14, 2012 meeting, the ICR-Related Values were placed on the Consent Agenda and subsequently passed with a show of hands.[5] After the NEPOOL committee voting process was completed, ISO-NE filed the ICR-Related Values and HQICCs for the 2016/17 Forward Capacity Auction with the FERC in a filing dated November 6, 2012.[6] The FERC accepted the ICR Values in a letter dated January 18, 2013.[7]

Table 1 shows the ICR-Related Values for the 2016/17 Capability Year. The monthly values for the HQICCs are provided in Table 2.

Table 1: Summary of 2016/17 ICR-Related Values (MW)[8,9]

	New England	Connecticut	NEMA/ Boston	Maine
Peak Load (50/50)	29,400	7,555	6,047	2,108
Total Resources	35,178	9,004	3,228	3,762
Installed Capacity Requirement	34,023			
NET ICR (ICR Minus 1,055 MW HQICCs)	32,968			
Local Sourcing Requirement		7,603	3,209	
Maximum Capacity Limit				3,709

[4] The motion to recommend Participants Committee support of the HQICC Values for 2016/17 Capability Year passed based on a show of hands with two opposed (2 Supplier Sector) and eight abstentions (4 Generation Sector, 3 Supplier Sector, 1 Alternative Resource Sector). The ICR-Related Values were also passed with a show of hands with two opposed (2 Supplier Sector) and nine abstentions (5 Generation Sector, 3 Supplier Sector, 1 Alternative Resource Sector).

[5] The Consent Agenda was approved, with oppositions and abstentions noted because of identified concerns with the HQICC Values and ICR-Related Values for the 2016/17 Capability Year.

[6] The ISO-NE filing is located at: http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-334-000_11-06-12_icr_2016-2017_filing.pdf.

[7] The FERC Order accepting the ICR Values for the 2016/17 FCA is available at: http://www.iso-ne.com/regulatory/ferc/orders/2013/jan/er13-335_er13-468_1-18-13_order_accept_7th_fca_info.pdf.

[8] The net amount of capacity to be purchased in the Forward Capacity Auction to meet the ICR, after reflecting a reduction in capacity requirements relating to the 1,055 MW of HQICCs that are allocated to the Interconnection Rights Holders (IHR), is the Net ICR value of 32,968 MW.

[9] Total Resources value for New England excludes HQICCs.

Table 2: Monthly HQICCs (MW)

2016/2017 Capacity Commitment Period Month	HQICC Values (MW)
June	1,055
July	1,055
August	1,055
September	1,055
October	1,055
November	1,055
December	1,055
January	1,055
February	1,055
March	1,055
April	1,055
May	1,055

Table of Contents

List of Tables

List of Figures

Introduction

The Installed Capacity Requirement (ICR) is an ISO-projected measure of the capacity that is necessary to satisfy the resource adequacy requirements of ISO New England's (ISO-NE) Balancing Authority area's forecasted electrical peak load requirements, which also include sufficient reserve capacity to meet regional reliability standards. More specifically, ICR is the amount of capacity needed to meet the requirements defined for the New England Balancing Authority area such that the probability of disconnecting non-interruptible customers (a loss of load expectation or "LOLE"), on average, is no more than once in every ten years (an LOLE of 0.1 days/year). This criterion takes into account: other possible levels of peak electric loads due to weather variations, the impacts of resource availability, and the potential load and capacity relief obtainable through the use of ISO New England Operating Procedure No. 4 – *Actions During a Capacity Deficiency* (OP-4).[10]

This report discusses the derivation of the ICR, Local Sourcing Requirements (LSR) and Maximum Capacity Limits (MCL), (collectively, the "ICR-Related Values") along with the Hydro-Québec Interconnection Capability Credits ("HQICCs") for the 2016/17 Capability Year's Forward Capacity Auction (FCA) to be conducted on February 4, 2013. The 2016/17 Capability Year starts on June 1, 2016 and ends on May 31, 2017.

This report also documents the general process and methodology for developing the assumptions utilized in calculating the ICR, including assumptions about load, resource capacity values and availability, and transmission interface transfer capabilities. Also discussed is the calculation of LSR for import-constrained Load Zones, including the Transmission Security Analysis (TSA) requirements and Local Resource Adequacy (LRA) Requirements that are inputs into the calculation of LSR.

[10] ISO-NE OP-4 is located at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

Summary of ICR-Related Values and Components for 2016/17

Table 3 documents the ICR-Related Values and components relating to the calculation of ICR.

Table 3: ICR-Related Values and Components for 2016/17 (MW)[11]

	New England	Connecticut	NEMA/ Boston	Maine
Peak Load (50/50)	29,400	7,555	6,047	2,108
Total Resources	35,178	9,004	3,228	3,762
Installed Capacity Requirement	34,023			
NET ICR (ICR Minus 1,055 MW HQICCs)	32,968			
Local Resource Adequacy Requirement		7,603	2,481	
Transmission Security Analysis Requirement		7,489	3,209	
Local Sourcing Requirement		7,603	3,209	
Maximum Capacity Limit				3,709

The 34,023 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to HQICCs that are allocated to the Interconnection Rights Holders in accordance with Section III.12.9.2 of Market Rule 1. After deducting the monthly HQICC value of 1,055 MW, the net Installed Capacity Requirement for use in the 2016/17 FCA is 32,968 MW, which is described as the *Net ICR.*

The 32,968 MW of Net ICR, which excludes HQICCs, results in an Annual Resulting Reserve Margin value of 12.1%. The Annual Resulting Reserve Margin is a measure of the amount of resources potentially available in excess of the 50/50 seasonal peak load forecast value and is calculated as:

Figure 1: Formula for Annual Resulting Reserve Margin (%)

Annual Resulting Reserve Margin (%) =
((ICR-HQICCs-Annual 50/50 Peak Load) / (Annual 50/50 Peak Load)) x 100

The 12.1% Annual Resulting Reserving Margin is a decrease from the 13.9% value calculated for the 2015/16 FCA. The decrease in the percent reserve margin can be attributed to an increase in the amount of tie benefits for the 2016/17 Capability Year versus the 2015/16 Capability Year combined with improvement in resource availability assumptions, particularly for the Demand Resources. The improvement in Demand

[11] Total Resource value for New England excludes HQICCs.

Resources availability is covered in more detail in the Resource Availability section of this report while the change in tie benefits is discussed in the Tie Benefits section. The overall change in ICR is covered in the report chapter entitled "*Difference from 2015/16 FCA ICR-Related Values.*"

Stakeholder Process

The ICR for the 2016/17 Capability Year was established through a stakeholder process and in accordance with the calculation methodology prescribed in Section III.12 of Market Rule 1. The stakeholder process consisted of review and comment by the NEPOOL Power Supply Planning Committee (PSPC), review and action by the NEPOOL Reliability Committee (RC), and support by the NEPOOL Participant Committee (PC).

The PSPC, which is chaired by ISO-NE, is a non-voting, technical subcommittee under the RC. Most PSPC members are representatives of NEPOOL Participants. The PSPC assists ISO-NE with the development of resource adequacy based requirements such as the ICR, LSR and MCL, including the use of appropriate load and resource assumptions for modeling expected power system conditions. Representatives of the six New England States' public utility regulatory commissions and the New England States Committee on Energy (NESCOE) also participate in these NEPOOL Committees. Members of these regulatory agencies were present at the PSPC meetings at which the ICR-Related Values and HQICCs for the 2016/17 FCA were discussed and considered.

After the PSPC's review and comment, ISO-NE developed a recommendation regarding the ICR-Related Values and HQICCs for the 2016/17 Capability Year. ISO-NE then presented this recommendation, along with the associated load and resource assumptions, to the RC for their review, comment and action. At their August 14, 2012 meeting, the RC voted to recommend that the PC support both the ICR-Related Values and HQICCs with a vote taken by show of hands.[12] ISO-NE then presented the RC supported ICR-Related Values and HQICCs to the PC for their review and support. At their September 14, 2012 meeting, the PC approved the Consent Agenda, of which the ICR-Related Values and HQICCs were a part of, with a show of hands vote along with oppositions and abstentions noted because of identified concerns with the HQICCs and ICR-Related Values. ISO-NE subsequently filed the ICR-Related Values and HQICCs with the FERC for the 2016/17 Forward Capacity Auction on November 6, 2012.[13] The FERC accepted the ICR Values in a letter dated January 18, 2013.[14]

[12] The motion to support the HQICC values passed based on a show of hands with two opposed (2 Supplier Sector) and eight abstentions (4 Generation Sector, 3 Supplier Sector, 1 Alternative Resource Sector). The motion to support the ICR-Related Values passed based on a show of hands with two opposed (2 Supplier Sector) and nine abstentions (5 Generation Sector, 3 Supplier Sector, 1 Alternative Resource Sector).

[13] A copy of the filing is available at: http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-334-000_11-06-12_icr_2016-2017_filing.pdf.

[14] The FERC Order accepting the ICR Values for the 2015/16 FCA is available at: http://www.iso-ne.com/regulatory/ferc/orders/2013/jan/er13-335_er13-468_1-18-13_order_accept_7th_fca_info.pdf.

Methodology

Reliability Planning Model for ICR-Related Values

The ICR is the minimum level of capacity required to meet the reliability requirements defined for the New England Balancing Authority area. This requirement is documented in Section 2 of ISO New England Planning Procedure No. 3,[15] *Reliability Standards for the New England Area Bulk Power Supply System*, which states:

> *"Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting non-interruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year."*

Included as variables within the reliability model are:

a. The possibility that load forecasts may be exceeded as a result of weather variations.
b. Immature and mature equivalent forced outage rates appropriate for resources of various sizes and types, recognizing partial and full outages.
c. Due allowance for generating unit scheduled outages and deratings.
d. Seasonal adjustments of resource capability.
e. Proper maintenance requirements.
f. Available operating procedures.
g. The reliability benefits of interconnections with systems that are not Governance Participants.
h. Such other factors as may be appropriate from time to time.

The ICR for the 2016/17 Capability Year was established using the General Electric Multi-Area Reliability Simulation Model (GE MARS). GE MARS is a computer program that uses a sequential Monte Carlo simulation to compute the resource adequacy of a bulk electric power system by simulating the random behavior of both loads and resources. For the ICR calculation, the GE MARS model is used as a one-bus model and the New England transmission system is assumed to have no constraints within this simulation. In other words, all the resources modeled are assumed to be able to deliver their full output to meet forecast load requirements.

To calculate the expected days per year that the bulk electric system would not have adequate resources to meet peak demands and required reserves, the GE MARS Monte Carlo process repeatedly simulates the year using multiple replications and evaluates the impacts of a wide-range of possible random combinations of resource outages. Chronological system histories are developed by combining randomly generated operating histories of the resources serving the hourly chronological demands. For each hour, the

[15] Available at: http://www.iso-ne.com/rules_proceds/isone_plan/

program computes the isolated area margins based on the available capacity and demand within each area. The program collects the statistics for computing the reliability indices and then proceeds to the next hour to perform the same type of calculation. 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 study year.

Installed Capacity Requirement (ICR) Calculation

The formula for calculating the New England ICR is:

Figure 2: Formula for ICR Calculation

$$Installed\ Capacity\ Requirement\ (ICR) = \frac{Capacity - Tie\ Benefits - OP4\ Load\ Relief}{1 + \dfrac{ALCC}{APk}} + HQICCs$$

Where:	APk	= Annual 50-50 Peak Load Forecast for summer
	Capacity	= Total Capacity (sum of all supply and demand resources)
	Tie Benefits	= Tie Reliability Benefits
	OP-4 Load Relief	= Load relief from ISO-NE OP-4 - Actions 6 & 8 and the modeling of the minimum 200 MW Operating Reserve limit
	ALCC	= Additional Load Carrying Capability (as determined by the % of peak load)
	HQICCs	= Monthly Hydro-Québec Interconnection Capability Credits

The ICR formula is designed such that the results identify the minimum amount of capacity required to meet New England's resource adequacy criterion of expecting to interrupt non-interruptible load, on average, no more than once every ten years. If the actual system, as modeled, is more reliable than the resource adequacy criterion, an adjustment is made in the amount of capacity needed or additional load required to attain the resource adequacy criterion is also identified. If the system is more reliable than the resource adequacy criterion (i.e., the system LOLE is less than or equal to 0.1 days per year), additional resources are not required, and the ICR is determined by increasing loads (*Additional Load Carrying Capability* or ALCC) so that New England's LOLE is exactly at 0.1 days per year. For the 2016/17 Capability Year, the New England system using the resources qualified as Existing Capacity is more reliable than the resource adequacy criterion requires. This results in a positive value for the ALCC. Therefore, no adjustments of additional capacity in the form of proxy units were required to be added to the model.[16] In the ICR calculation, the HQICCs are treated differently than other resources; they are not adjusted by the ALCC amount. Table 4 shows the details of the variables used to calculate the ICR for the Capability Year 2016/17.

[16] Proxy units are used if existing capacity resources are insufficient to meet the resource adequacy planning criterion, as provided by Section III.12.7.1 of Market Rule 1. Proxy units are assigned availability characteristics such that when proxy resources are used in place of all the resources assumed to be available to the system, the resulting LOLE is unchanged. The use of proxy units to meet the system LOLE criterion is intended to neutralize the size and availability impact of unknown resource additions on the ICR.

Table 4: Variables Used to Calculate ICR (MW)

Installed Capacity Requirement Calculation Details	2016/17 FCA
Annual 50/50 Peak Load	29,400
Total Modeled Capacity & OP4 Load Relief	37,270
Tie Benefits	1,870
HQICCs	1,055
OP4 - Actions 6 & 8 (Voltage Reduction)	422
Minimum Reserve Requirement	(200)
ALCC	1,971
Installed Capacity Requirement	34,023
Net Installed Capacity Requirement	32,968

Local Sourcing Requirements (LSR) Calculation

The methodology for calculating LSR for import-constrained Load Zones involves calculating the amount of resources located within the load zone that would meet both a local resource adequacy criteria called the Local Resource Adequacy (LRA) Requirement and a transmission security criterion called the Transmission Security Analysis (TSA) Requirement. The TSA Requirement is a tool that ISO-NE uses to maintain system operational reliability when reviewing de-list bids of resources within the FCM auctions.[17] The system must meet both resource adequacy and transmission security requirements; therefore, the LSR for an import-constrained zone is the amount of capacity needed to satisfy *"the higher of"* either (i) the LRA or (ii) the TSA Requirement.

Local Resource Adequacy (LRA) Requirement

The LRA Requirements are calculated using the same assumptions for forecasted load and resources as those used within the calculation of the ICR. To determine the locational requirements of the system, the LRA Requirements are calculated using multi-area reliability model, GE MARS, according to the methodology specified in Section III.12.2 of Market Rule 1.

The LRA Requirements are calculated using the value of the firm load 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. Because the LRA Requirement is the minimum amount of resources that must be located in a zone to meet the system-reliability requirements for a 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, is achieved. If a zone has insufficient capacity, capacity would be shifted into that zone. Shifting capacity, however, may lead to skewed results, as capacity is not homogeneous. For example, one megawatt of capacity from a nuclear plant is not

[17] ISO Tariff revisions filed with the FERC on February 22, 2010 in Docket No. ER10-787-000

necessarily the same 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, a megawatt of load is subtracted from the rest of New England, thus keeping the entire system load constant. The load that was shifted must be subtracted from the total resources (including proxy units) to determine the minimum amount of resources that are required in that zone. Before the shifted load is subtracted, it is first converted to equivalent capacity by using the average resource-unavailability rate within the zone. Thus, the LRA Requirement is calculated as the existing resources in the zone, plus proxy units in the zone, minus the unavailability-adjusted, load-shift amount.

As this load shift test is being performed over a transmission interface internal to the New England Balancing Authority Area, an allowance for transmission-related LOLE must also be applied. This transmission-related LOLE allowance is 0.005 days per year and is only applied when determining the LRA Requirement of a Load Zone. An LOLE of 0.105 days per year is the point at which it becomes clear that the remaining resources within the zone under study are becoming insufficient to satisfy capacity requirements. Further reduction in local resources would cause the LOLE in New England to rapidly increase above the criterion.

For each import-constrained transmission Load Zone, the LRA Requirement is calculated using the following methodology, as outlined in Market Rule 1, Section III.12.2.1:

> Model the Load Zone under study and the *Rest of New England* area using the GE MARS simulation model, reflecting load and resources (supply & demand-side) electrically connected to them, including external Balancing Authority area support from tie benefits.

a) If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

b) Model the transmission interface constraint between the Load Zone under study and the *Rest of New England*.

c) Add proxy units, if required, within the ISO-NE Balancing Authority Area to meet the resource adequacy planning criterion of once in 10 year disconnection of non-interruptible customers. If the system LOLE with proxy units added is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year. Proxy units are to be modeled as stated in Section III.12.7.1 of Market Rule 1.

d) Adjust the firm load within the Load Zone under study until the LOLE of the ISO-NE Balancing Authority Area reaches 0.105 days per year LOLE. As firm load is added to (or subtracted from) the Load Zone under study, an equal amount of firm load is removed from (or added to) the *Rest of New England*.

The LRA Requirement is then calculated using the formula:

Figure 3: Formula for LRA Calculation

$$LRA_Z = Resources_Z + Proxy\,Units_Z - \left(\frac{Proxy\,Units\ Adjustment_Z}{1-FOR_Z}\right) - \left(\frac{Firm\ Load\ Adjustment_Z}{1-FOR_Z}\right)$$

Where	LRA_z	= Local Resource Adequacy Requirement for Load Zone Z.
	$Resources_z$	= MW of resources (supply & demand-side) electrically located within Load Zone Z, including Import Capacity Resources on the import-constrained side of the interface, if any and excludes HQICCs.
	Proxy $Units_z$	= MW of proxy unit additions, if needed, in Load Zone Z.
	Proxy Units $Adjustment_z$	= MW of firm load added to (or unforced capacity subtracted from) Load Zone Z until the system LOLE equals 0.1 days/year.
	Firm Load $Adjustment_z$	= MW of firm load added within Load Zone Z to make the LOLE of the New England Balancing Authority area equal to 0.105 days per year.
	FOR_z	= Capacity weighted average of the forced outage rate modeled for all resources (supply & demand-side) within Load Zone Z, including any proxy unit additions to Load Zone Z.

In addition, when performing the LRA calculation for the *Rest of New England* area, the surplus capacity adjustment used to bring the system to the 0.1 days per year reliability criterion is also included in the calculation as:

Figure 4: Surplus Capacity Adjustment in *Rest of New England*

$$-\left(\frac{Surplus\ Capacity\ Adjustment_Z}{1-FOR_Z}\right)$$

Where:

Surplus Capacity $Adjustment_z$ = MW of firm load added within Load Zone Z to make the LOLE of the New England Balancing Authority area equal to 0.1 days per year

Table 5 shows the details of the LRA Requirement calculation for the 2016/17 Capability Year. The LRA Requirement for the *Rest of New England* is used in the calculation of Maine MCL. *Rest of New England* refers to all Load Zones with the exception of the Load Zone under study.

Table 5: LRA Requirement Calculation Details (MW)

		Connecticut	NEMA/Boston	Rest of New England
$Resource_z$	[1]	9,004	3,228	31,416
$Proxy\ Units_z$	[2]	0	0	0
$Surplus\ Capacity\ Adjustment_z$	[3]	0	0	2,170
$Firm\ Load\ Adjustment_z$	[4]	1,298	717	-125
FOR_z	[5]	0.0732	0.0396	0.0520
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**7,603**	**2,481**	**29,259**
		Rest of New England	**Rest of New England**	**Maine**
Resource	[7]	26,174	31,950	3,762
Proxy Units	[8]	0	0	0
Proxy Units Adjustment	[9]	0	0	0
Firm Load Adjustment	[10] = -[4]	-1,298	-717	125
Total System Resource	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	35,178	35,178	35,178

Transmission Security Analysis (TSA) Calculation

The TSA is a deterministic reliability screen of a transmission import-constrained area and is a security review set out in Section 3 of ISO New England Planning Procedure No. 3, *Reliability Standards for the New England Area Bulk Power Supply System* and in Section 5.4 of Northeast Power Coordinating Council's (NPCC) Regional Reliability Reference Directory #1, *Design and Operation of the Bulk Power System*.[18] This TSA review determines the requirement of the sub-area to meet its load through internal generation and import capacity. It 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 demand with available existing resources. The results are then presented in the form of a deterministic operable capacity analysis.

In accordance with ISO New England Planning Procedure No. 3 and NPCC's Regional Reliability Reference Directory #1, this TSA includes evaluations of both: (1) the loss of the most critical generator and the most critical transmission element (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 load zones. Further, such deterministic sub-area transmission security analyses have consistently been used for reliability review studies performed to determine whether a resource seeking to retire or de-list would cause a violation of the reliability criteria.

Figure 5 shows the formula used in the calculation of TSA requirements.

[18] A copy can be found at https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf.

Figure 5: Formula for TSA Requirements

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

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

Methodology for Calculating the TSA

The system conditions used for the TSA analysis within the FCM are documented in Section 6 of ISO New England Planning Procedure No. 10, *Planning Procedure to Support the Forward Capacity Market*.[19] 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, some of the assumptions for calculating the TSA requirement differ from the assumptions used in determining the LRA Requirement. The differences are as follows: the assumed loads for the TSA are the 90/10 peak loads for the Load Zones for the 2016/17 Capability Year, whereas for LRA calculations, a distribution of loads covering the range of possible peak loads for that Capability Year is used. In addition, for the TSA, the forced outage of fast-start (peaking) generation is based on an assumed value of 20% instead of being based on historical five-year average generating unit performance. Finally, the load and capacity relief obtainable from actions of OP-4, with the exception of Demand Resources (which are treated as capacity resources), is not assumed within TSA calculations.

Table 5 shows the details of the TSA requirement calculation for the Connecticut and NEMA/Boston Load Zones.

19 Available at: http://www.iso-ne.com/rules_proceds/isone_plan/.

Table 6: TSA Calculation Details (MW)

2016/17 FCA7 TSA Requirement	Connecticut	NEMA/Boston
Sub-area 2016 90/10 Load	8,201	6,520
Reserves (Largest unit)	1,225	1,393
Sub-area Transmission Security Need	**9,426**	**7,913**
Sub-area Existing Resources	9,004	3,228
Assumed Unavailable Capacity	-797	-147
Sub-area N-1 Import Limit	2,600	4,850
Sub-area Available Resources	**10,807**	**7,931**
Sub-area Transmission Security Margin	**1,381**	**18**
TSA Requirement	=(9426-2600)/(1-797/9004) **=7,489**	=(7913-4850)/(1-147/3228) **=3,209**

Local Sourcing Requirement (LSR)

The LSR for the Connecticut and NEMA/Boston Load Zone is the higher of the LRA Requirement or TSA Requirement for the respective Load Zone. Table 7 summarizes the LRA and TSA for the Connecticut and NEMA/Boston Load Zones. As shown, the LRA is the highest requirement for the Connecticut Load Zone while the TSA is the highest requirement for the NEMA/Boston Load Zone. Therefore the LSR for the Connecticut and NEMA/Boston Load Zones are 7,603 MW and 3,209 MW, respectively.

Table 7: LSR for the 2016/17 Capability Year (MW)

Load Zone	Local Resource Adequacy Requirement	Transmission Security Analysis Requirement	Local Sourcing Requirement
Connecticut	7,603	7,489	7,603
NEMA/Boston	2,481	3,209	3,209

Maximum Capacity Limit (MCL) Calculation

To determine the MCL, the New England ICR and the LRA for the Rest of New England are needed. Given that the ICR is the total amount of resources that need to be procured within New England, 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 load zone.

The MCL for Maine includes qualified capacity resource imports over the New Brunswick ties and also reflects the tie benefits assumed available over the New

Brunswick ties. That is, the MCL is reduced to reflect the energy flows required to receive the assumed tie benefits from New Brunswick to assist the ISO-NE Balancing Authority Area at a time of a capacity shortage. Allowing more purchases of capacity from resources located in Maine could preclude the energy flows required to realize tie benefits.

For the export-constrained Maine transmission Load Zone, the MCL is calculated using the following method as described in Market Rule 1, Section III.12.2.2:

a) Model the Load Zone under study and the *Rest of New England* area using the GE MARS simulation model, reflecting load and resources (supply & demand-side) electrically connected to them, including external Balancing Authority area support from tie benefits.

b) If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

c) Model the transmission interface constraint between the Load Zone under study and the Rest of New England area.

d) Add proxy units, if required, within the ISO-NE Balancing Authority Area to meet the resource adequacy planning criterion of once in 10 years of disconnection of non-interruptible customers. If the system LOLE with proxy units added is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

e) Adjust the firm load within the *Rest of New England* area until the LOLE of the rest of New England area reaches 0.105 days per year LOLE. As firm load is added to (or subtracted from) the *Rest of New England* area, an equal amount of firm load is removed from (or added to) the Load Zone under study.

The MCL is then calculated using the formula:

Figure 6: Formula for MCL Calculation

$$MCL_{Y} = ICR - LSR_{Rest\ of\ New\ England}$$

Where	MCL_Y	= Maximum Capacity Limit for Load Zone Y.
	ICR	= MW of Net ICR.
	$LRA_{\text{Rest of New England}}$	= 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.

Table 8 shows the details of the MCL calculation for the 2016/17 Capability Year.

Table 8: MCL Calculation Details (MW)

		Maine
Net ICR for New England	[1]	32,968
$LRA_{RestofNewEngland}$	[2]	29,259
Maximum Capacity $Limit_Y$	[3]=[1]-[2]	**3,709**

Assumptions

Load Forecast

ISO-NE develops, for each state, a forecast distribution of typical daily peak loads for each week of the year based on each week's historical weather distribution combined with an econometrically estimated monthly model of typical daily peak demands. Each weekly distribution of typical daily peak demands includes the full range of daily peaks that could occur over the full range of weather experienced within that week along with their associated probabilities.

The load forecast models for each of the six New England states were estimated using 11 years of historical weekday daily peaks, the weather conditions at the time of the daily peak, a seasonal relationship that captures the change in peak demand response to weather over time, and a seasonal relationship that captures the change in peak demand response to base demand energy (and therefore economic and demographic factors) over time. The weather response relationships are forecast to grow at their historical rates but are adjusted for expected changes in appliance saturations. The base demand relationships are forecasted to grow at the same rate as the associated energy forecast. The weather is represented by over 35 years of historically-based weekly regional weather.

The energy forecast for each state is econometrically estimated using forecasts of the real price of electricity and either real income or real gross state product.

For purposes of determining the load forecast, ISO-NE Balancing Authority Area's load is defined as the sum of the load of each of the six New England states, calculated as described above. The forecasted loads for the Connecticut and Maine Load Zones are the forecasted loads for the states of Connecticut and Maine.[20] The forecasted load for the NEMA/Boston Load Zone is developed using a load share ratio of the NEMA/Boston load to the forecasted load for the entire state of Massachusetts. The load share ratio is based on detailed bus load data from the network model for NEMA/Boston, as compared to the entire state of Massachusetts.

[20] Maine load and capacity excludes the Northern Maine service territory of Maine Public Service which is not electrically connected to the ISO-NE Balancing Authority Area.

The overall New England and individual sub-area load forecasts used in the calculation of ICR, LSR and MCL for the 2016/17 Capability Year are documented within the *2012 Forecast Report of Capacity, Energy, Loads and Transmission (CELT)*.[21]

Load Forecast Uncertainty

GE MARS models the load forecast using hourly chronological sub-area loads and can include the effects of load forecast uncertainty by calculating the LOLE for up to ten different load levels and computes a weighted-average value based on the input probabilities. Load forecast uncertainty multipliers are then used to account for load uncertainty related to weather. These are the *"per unit"* multipliers used for computing the loads used to calculate the reliability indices. Each per unit multiplier represents a load level, which is assigned a probability of that load level occurring. The mean, or 1.0 multiplier, represents the 50/50 forecast for peak load. These multipliers are allowed to vary by month.

The summer 2016 peak load forecast distribution is shown in Table 9. The values range from the 10th percentile, representing peak loads with a 90% chance of being exceeded, to the 95th percentile peak load, which represent peak loads having only a 5% chance of being exceeded. The median (50/50) of the forecast distribution is termed the *expected value* because the realized level is equally likely to fall either above or below that median value. The median value is reported to facilitate comparisons, but the inherently uncertain nature of the load forecast is modeled by the load forecast uncertainty multipliers used as inputs to the GE MARS Model.

Table 9: Summer 2016 Peak Load Forecast Distribution (MW)

10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
27,995	28,245	28,585	28,970	29,400	29,850	30,315	30,985	31,725	32,390

Existing Capacity Resources

Market Rule 1, Section III.12.7.2 details what shall be modeled within the ICR and LSR calculations as capacity, as defined by the following:

(a) All Existing Generating Capacity Resources,

(b) Resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) All Existing Import Capacity Resources backed by a multi-year contract(s) to provide capacity into the New England Balancing Authority area, where that multi-year contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and

[21] Located on ISO-NE's website at: http://www.iso-ne.com/trans/celt/report/2012/index.html.

(d) Existing Demand Resources that are qualified to participate in the Forward Capacity Market and New Demand Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period and Other Demand Resources in existence during the ICAP Transition Period.

Section III.12.7.2 also states that the rating of the Existing Generating Capacity Resources, Existing Demand Resources and Existing Import Capacity Resources used in the calculation of the ICR-Related Values shall be the summer Qualified Capacity value of such resources for the relevant Load Zone. The Qualified Capacity value is based on a five-year median capacity rating for each resource.

Summaries of resources categorized as Existing Capacity within the ICR-Related Values calculations are provided in the sections below.[22] It should be noted that, with the exception of Intermittent Power Resources (IPR), only summer capacity values are used within the calculation of the ICR-Related Values.

For the 2016/17 FCA ICR-Related Values calculations, there were a total of 35,178 MW of capacity resources modeled. These capacity resources are made up of generating, intermittent, demand and import resources along with a reduction in generating capacity to account for exports. These resources are described in more detail in Tables 10 – 14 of this report.

Generating Resources

Market Rule 1, Section III.13.1.2.2.1.1 states that the summer Qualified Capacity of a Generating Resource is calculated as the median of the most recent five summer Seasonal Claimed Capability (SCC) ratings with only positive, non-zero ratings included in the calculation. Existing Qualified Generating Capacity, by Load Zone, used within the ICR-Related Values calculations were based on Qualified Existing Generating Resources for the 2016/17 Capability Year at the time of the ICR calculation and is summarized in Table 10.

[22] For detailed data of Qualified Existing Resources used in the calculation of ICR-Related Values see: http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-335-000_11-6-12_7th_fca_info_filing.pdf.

Table 10: Existing Qualified Generating Capacity by Load Zone (MW)

Load Zone	Summer
MAINE	3,021.666
NEW HAMPSHIRE	4,107.648
VERMONT	797.121
CONNECTICUT	7,842.842
RHODE ISLAND	2,637.969
SOUTH EAST MASSACHUSETTS	5,909.071
WEST CENTRAL MASSACHUSETTS	3,868.238
NORTH EAST MASSACHUSETTS & BOSTON	2,523.919
Total New England	**30,708.474**

Intermittent Power Resources

Section III.13.1.2.2.2 of Market Rule 1 discusses the rating of resources considered as Intermittent Power Resources (IPR). IPR are defined as wind, solar, run-of-river hydro-electric and other renewable resources that do not have direct control over their net power output.

Summer and winter capacities (by Load Zone) of existing IPR used within the ICR-Related Values calculations were those that have Qualified as Existing Generating Resources for the 2016/17 Capability Year are shown in Table 11.

Table 11: Existing IPR by Load Zone (MW)

Load Zone	Summer	Winter
MAINE	241.372	359.448
NEW HAMPSHIRE	162.990	216.636
VERMONT	88.337	143.205
CONNECTICUT	191.016	204.408
RHODE ISLAND	6.399	8.834
SOUTH EAST MASSACHUSETTS	77.385	81.277
WEST CENTRAL MASSACHUSETTS	45.022	66.128
NORTH EAST MASSACHUSETTS & BOSTON	69.535	71.143
Total New England	**882.056**	**1,151.079**

Demand Resources

To participate in the FCA as a Demand Resource, a resource must meet the definitions and requirements of Market Rule 1, Section III.13.1.4.1. Existing Demand Resources are subject to the same qualification process as Existing Generating Capacity Resources as described above.

Market Rule 1, Section III.12.7.2 states that the rating of Demand Resources used within the calculation of the ICR-Related Values shall be the summer Qualified Capacity value. The summer Qualified Capacity of a Demand Resource is rated based on measurement and verification analysis performed during the resource Qualification process.

Existing Demand Resources, by Load Zone, used within the ICR-Related Values calculations are those that have Qualified as an Existing Demand Resource Capacity for the 2016/17 FCA, are shown in Table 12. These values are the Existing Qualified values which reflect the 8% Transmission and Distribution Gross-up applied to Demand Resources.

Table 12: Existing Demand Resources by Load Zone (MW)

Load Zone	On-Peak	Seasonal Peak	Real-Time Demand Response	Real-Time Emergency Generators	Total
MAINE	154.246	-	318.067	27.344	499.657
NEW HAMPSHIRE	78.066	-	65.586	35.674	179.326
VERMONT	117.810	-	68.118	13.371	199.299
CONNECTICUT	92.396	294.961	351.794	230.543	969.694
RHODE ISLAND	135.372	-	79.645	59.975	274.992
SOUTH EAST MASSACHUSETTS	179.505	-	152.813	35.306	367.624
WEST CENTRAL MASSACHUSETTS	175.423	44.173	175.490	55.329	450.415
NORTH EAST MASSACHUSETTS & BOSTON	324.233	-	233.095	76.810	634.138
Total New England	1257.051	339.134	1444.608	534.352	3575.145

Import Resources

The Summer Qualified Capacity of an Existing Import Capacity Resource modeled within the ICR calculation follows Market Rule 1, Section III.13.1.3.3, which outlines the Qualification Process for Existing Import Capacity Resources.

The rating of imports used within the calculation of the ICR-Related Values is the summer Qualified Capacity value, reduced by any submitted de-list bids reflecting the value of the firm contract(s) or any de-ratings due to Transmission Transfer Capability (TTC). If the overall amount of Existing Qualified Import Capacity over a transmission interface is greater than the transmission interface limit, the capacity of the import(s) being modeled within the ICR calculation is subsequently reduced to a value equal to that of the transmission interface limit. Table 13 shows the Existing Qualified Import Resources used within the ICR-Related Values calculations for the 2016/17 Capability Year. There were no de-ratings for submitted de-lists bid(s) or TTC for the Existing Qualified Import Capacity Resources for 2016/17.

Table 13: Existing Import Resources (MW)

Import Resource	Summer	External Interface
NYPA - CMR	67.000	New York AC Ties
NYPA - VT	14.000	New York AC Ties
VJO - Highgate	31.000	Hydro-Quebec Highgate
Total MW	112.000	

Export Bids

An Export Bid is a bid that may be submitted by certain resources in the FCA to export capacity to an external Balancing Authority area, as described in Section III.13.1.2.3.2.3 of Market Rule 1. Only one export of capacity was modeled within the ICR-Related Values calculation assumptions. This is the 100 MW sale to the Long Island Power Authority (LIPA) over the Cross-Sound Cable, which is modeled as a reduction in capacity from the unit-specific resource supplying the export.

Table 14: Capacity Exports (MW)

Export	Summer
LIPA over Cross Sound Cable	100.000

New Capacity Resources

Market Rule 1, Section III.12.7.2 describes the capacity resources to be modeled within the ICR calculations as all Existing Generation Capacity Resources, Existing Import Capacity Resources and Existing Demand Resources. Resource capacity that qualifies as a New Capacity Resource is not modeled within the ICR calculation.

Resources Used to Calculate Locational Requirements

The LRA and TSA values, used to determine the LSR for the import-constrained Connecticut and NEMA/Boston Load Zones, and the MCL for the export-constrained Maine Load Zone are calculated with resources located within the Regional System Plan (RSP) sub-areas of Connecticut, Boston and Maine respectively. These resources are used as proxies for resources located within the Load Zones. This is done because the TTC calculated for the interfaces studied in the locational requirements analyses are performed using the 13 zone RSP sub-areas and are thus calculated for the RSP zones. For the Demand Resources, the Existing Qualified Demand Resources for the Load Zone is used since the RSP values available would have to be estimated (particularly for the Passive Demand Resources) since actual locations for some of these resources is not available.

For the 2016/2017 FCA ICR Values, there are no between the resources located in the RSP zones versus the resources located within the Load Zones for Connecticut and NEMA/Boston and there is a difference of less than one MW difference for Maine. Table 15 shows the resources modeled in each of the Load Zones with a locational requirement along with the New England values.

Table 15: Resources Used in the LSR & MCL Calculations (MW)

Type of Resource	New England	Connecticut	NEMA/Boston	Maine
Generating Resources	30,608.474	7,842.842	2,523.919	3,021.666
Intermittent Power Resources	882.056	191.016	69.535	240.555
Passive Demand Resources	1,596.185	387.357	324.233	154.246
Active Demand Resources	1,978.960	582.337	309.905	345.411
Import Resources	112.000	-	-	-
Total MW Modeled in LRA and MCL	35,177.675	9,003.552	3,227.592	3,761.878

Transmission Transfer Capability

Market Rule 1, Section III.12.5 requires that ISO-NE update the transmission interface transfer capability for each internal and external transmission interface for the Capability Year 2016/17, if necessary. Although external transmission transfer capability is currently not used within the ICR calculation, they are used in the determination of tie benefits, including HQICCs, and will also be used within the FCA to limit the purchases of external installed capacity. Internal transmission transfer capability limits are used in the determination of the LSR and MCL.

External Transmission Transfer Capability

Table 16 shows the External Transmission Transfer Capabilities that were used within the tie benefits study.

Table 16: Transmission Transfer Capability of New England External Interfaces Modeled in the Tie Benefits Study (MW)

External Interfaces: Canada and New York to New England	Summer Limit
Hydro-Quebec to New England (Phase II)	1,400
Hydro-Quebec to New England (Highgate)	200
New Brunswick to New England	700
New York to New England (New York AC Ties)	1,400
New York to New England (Cross Sound Cable DC Interface)	0

External Transmission Interface Availability

Last year, the forced outage rate and scheduled outage rate of the interfaces connecting ISO-NE to its neighboring Balancing Authorities were updated from previously used historical values. These values are shown in Table 17 below and include the average forced outage rate (%) and maintenance outage rate (weeks) as used in the models.

Table 17: External Interface Outage Rates (% and Weeks)

External Tie	Forced Outage Rate (%)	Maintenance (Weeks)
HQ Phase II	0.39	2.7
Highgate	0.07	1.3
New Brunswick Ties	0.08	0.4
New York AC Ties	0	0
Cross Sound Cable	0.89	1.5

Internal Transmission Transfer Capability

For the 2016/17 FCA, ISO-NE evaluated three Load Zones relating to their LRA Requirement and MCL, using the Load Zone and *Rest of New England* methodology. The first is the Connecticut (CT) Load Zone, which is modeled as import-constrained into CT. The second is the NEMA/Boston Load Zone, which is modeled as import-constrained into NEMA/Boston. The third is the Maine (ME) Load Zone, which is modeled as export-constrained into the *Rest of New England*. In addition, the TSA analysis, which uses both the N-1 limit and the N-1-1 limit, was performed for the import constrained zones of Connecticut and NEMA/Boston.

Table 18 shows the N-1 Internal Transmission Transfer Capability for the CT and NEMA/Boston Load Zones as used in the calculation of LRA requirement, and the ME Load Zone as used in the calculation of MCL. In addition, the N-1-1 Transfer Capability is also shown as an input into the TSA for Connecticut and NEMA/Boston.

Table 18: Internal Transmission Transfer Capability Modeled in the LSR and MCL Calculations (MW)

Interface	N-1 Limit	N-1-1 Limit
Connecticut Import	2,600	1,400
NEMA/Boston Import	4,850	4,175
Maine-New Hampshire	1,600	-

OP-4 Load Relief

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 10 years due to a capacity deficiency, after taking into account the load and capacity relief obtainable from implementing Emergency Operating Procedures (EOPs). ISO New England Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP-4) is the EOP for New England. In other words, load and capacity relief assumed obtainable from implementing certain OP-4 actions are direct substitutes for capacity resources for meeting the once in 10 years disconnection of firm load criterion.

Under the FCM, the assumed emergency assistance (i.e. tie benefits) available from neighboring Balancing Authority areas, load reduction from implementation of 5% voltage reduction[23], and capacity available from the dispatch of Real-Time Demand Resources[24] and Real-Time Emergency Generating Demand Resources[25] all constitute actions that ISO-NE System Operators can invoke under OP-4 to balance real-time system supply with demand (as applicable under both actual or forecast capacity shortage conditions). These actions are used as load and capacity relief assumptions within the development of the ICR-Related Values.

Tie Benefits

In the event of a capacity shortage in New England, tie benefits reflect the amount of emergency assistance that is assumed will be available to ISO-NE from its neighboring Balancing Authority areas, without jeopardizing system reliability in either the ISO-NE Balancing Authority Area or its neighboring Balancing Authority areas. Tie Benefits are an input into the determination of the ICR-Related Values, and in fact, displace the MW amount of resources that need to be purchased internal to New England within the FCA by an almost one to one ratio.

Tie Benefits Calculation Methodology

ISO-NE used the procedures for calculating tie benefits documented in Section III.12.9 of Market Rule 1. The tie benefits calculation methodology includes the calculation of tie benefits at the system-wide level and for each of the directly interconnected neighboring Balancing Authority areas of Québec, New Brunswick (Maritimes) and New York and also for the individual interconnections between New England and these same Balancing Authority areas.

The tie benefits study for the 2016/17 Capability Year was conducted using the probabilistic GE MARS program to model projected system conditions for that timeframe. The methodology for calculating the total tie benefits, individual Balancing Authority tie benefits and the tie benefits assumed for individual interconnections is documented in more detail in the graphic below.

[23] Action 6 and 8 of OP4.
[24] Action 2 of OP4.
[25] Action 6 of OP4.

Figure 7: Summarization of the Tie Benefits Calculation Process[26]

- ***Process 1.0***
  - Calculate the tie benefits values for all possible interconnection states using isolated New England system as the reference
- ***Process 2.0***
  - Calculate initial total tie benefits for New England from all neighboring Balancing Authority Areas
- ***Process 3.0***
  - Calculate initial tie benefits for each individual neighboring Balancing Authority Area
  - Pro-rate tie benefits values of individual Balancing Authority Areas based on the total tie benefits, if necessary
- ***Process 4.0***
  - Calculate initial tie benefits for individual interconnection or group of interconnections
  - Pro-rate tie benefits values of individual interconnection or group of interconnections based on the individual Balancing Authority Area tie benefits, if necessary
- ***Process 5.0***
  - Adjust tie benefits of individual interconnection or group of interconnections to account for capacity imports
- ***Process 6.0***
  - Calculate the final tie benefits for each individual neighboring Balancing Authority Area
- ***Process 7.0***
  - Calculate the final total tie benefits for New England

Total Tie Benefits

Total tie benefits were calculated using the results of a probabilistic analysis that determines LOLE indices for the ISO-NE Balancing Authority Area and neighboring Balancing Authority areas. LOLE calculations were first done on an interconnected basis that included all existing connections (tie lines) between ISO-NE's directly connected neighboring Balancing Authority areas. This established the minimum amount of capacity that each area needed in order to comply with the NPCC resource adequacy requirements of 0.1 days per year LOLE.

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

Based on the methodology described above, a total of 1,870 MW of tie benefits are assumed within the ICR calculations for the 2016/17 Capability Year.

[26] A presentation on the 2016/17 Tie Benefits Study was presented to the RC on July 17, 2012 which provides more details on the calculation process and study assumptions and is available here: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2012/jul172012/a5_fca_7_tie_benefits_assumptions.pptx.

Individual Balancing Authority Area Tie Benefits

For calculating each Balancing Authority area's 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 Balancing Authority area.

If the sum of the Balancing Authority areas tie benefits is different from the total tie benefits for ISO-NE, then each Balancing Authority area's tie benefits are adjusted based on the ratio of the individual Balancing Authority area tie benefits to the total tie benefits.

For the 2016/17 Capability Year, the individual Balancing Authority area tie benefits were calculated as 1,164 MW for Québec, 392 MW for New Brunswick, and 314 MW for New York.

Individual Tie (or Group of Ties) Tie Benefits

The tie benefits methodology calls for tie benefits to be calculated 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 to ISO-NE, each is treated independently. The tie benefits for each individual tie or group of ties is calculated 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 to their relative Balancing Authority area's total tie benefits are different, then the tie benefits of each individual tie or group of ties are adjusted 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.

For the 2016/17 Capability Year, individual interconnection tie benefits were determined from Québec over the HQ Phase II facility of 1,055 MW, 109 MW from Québec over the Highgate facility, 314 MW of the New York tie benefits are delivered over the New York AC ties and 0 MW from the Cross-Sound Cable.

Hydro-Québec Interconnection Capability Credits (HQICCs)[27]

Hydro-Québec Interconnection Capability Credits, or HQICCs, are an allocation of the tie benefit over the Hydro-Québec Interconnection to the Interconnection Rights Holders (IHR), which are regional entities that hold certain entitlements (i.e. rights) over this interconnection. These rights are monetized as credits in the form of reduced capacity requirements.

[27] The 2016/17 Capability Year HQICCs values were filed with the Commission in the 2016/17 ICR filing: http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-334-000_11-06-12_icr_2016-2017_filing.pdf.

The HQICC values are 1,055 MW as determined by the tie benefits from Québec over the Phase II facility, and are applicable for every month during the 2016/17 Capability Year.

Processes 5.0 of the tie benefits methodology require that that individual interconnections or group of interconnections tie benefit values be adjusted, if necessary to account for the Existing Qualified Import Capacity Resources for 2016/17. If the sum of the tie benefits value and the import capacity is greater than the TTC of the individual interconnection or group of interconnections under study, then the tie benefits value will be reduced.

Process 6.0 of the 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 in Process 5.0.

Final total tie benefits for the New England Balancing Authority Area from all neighboring Balancing Authority Areas is determined in Process 7.0 as the sum of these neighboring area tie benefits after accounting for any adjustment for capacity imports as determined in Process 6.0.

For the 2016/17 Capability Year, Table 19 shows the Existing Qualified Import Capacity Resources used to determine if adjustments of tie benefits are necessary in Process 5.0 through Process 7.0. For the 2016/17 Tie Benefits Study, no adjustment to tie benefits to account for capacity imports was necessary.

Table 19: Capacity Imports Used to Adjust Tie Benefits (MW)

Import	New Brunswick	Hydro-Québec Phase II	Highgate	New York AC Ties
NYPA - CMR				67
NYPA - VT				14
VJO - Highgate			31	
VJO - Phase I/II				
Total			31	81

The results of the Tie Benefits Study for the 2016/17 Capability Year are summarized in Table 20.

Table 20: 2016/17 Tie Benefits (MW)

Control Area	Summer	Winter
Québec via Phase II	1,055	1,055
Québec via Highgate	109	109
New Brunswick	392	392
New York	314	314
Total Tie Benefits	1,870	1,870

Comparison of the 2016/17 and 2015/16 Capability Year's Tie Benefits

Table 21 below gives a comparison of the 2016/17 Capability Year tie benefits calculated for FCA7 and the 2015/16 Capability Year tie benefits calculated for FCA6.

Table 21: 2016/17 versus 2015/16 Tie Benefits (MW)

Control Area	2016/17 FCA7	2015/16 FCA6
Québec via Phase II	1,055	1,042
Québec via Highgate	109	6
New Brunswick	392	328
New York	314	300
Total Tie Benefits	1,870	1,676

As the results show, the total tie benefits for the New England Balancing Authority Area has increased by 194 MW for the 2016/17 Capability Year versus the 2015/16 Capability Year. A portion of this increase can be attributed to the increase in tie benefits that is now able to come into New England from Québec on the Highgate interface due to the expiration of the Vermont Joint Owners (VJO) contract that used the Highgate interface for delivery. The expiration of this contract allows addition TTC on the Highgate facility to be freed up which therefore allows more tie benefits to flow over the interface.

Another factor contributing to the increase is the change in system conditions in the 2016/17 versus 2015/2016 Capability Years. Transmission upgrades expected to be in-service for 2016/17 has made the North-South interface in New England less constrained. The less constrained system allows more tie benefits to flow from the northern areas to the southern areas. The combined effect of these two factors is the major contributor to the increase in tie benefits from the previous year's study.

5% Voltage Reduction

Under the FCM, load reduction from implementation of 5% voltage reduction is used in the development of the ICR-Related Values. This constitutes an action that ISO-NE

System Operators can invoke in real-time under Operating Procedure No. 4, to balance system supply with demand under actual or expected capacity shortage conditions.

The amount of load relief assumed obtainable from invoking a 5% voltage reduction is based on the performance standard established within ISO New England's Operating Procedure No. 13, *Standards for Voltage Reduction and Load Shedding Capability* ("Operating Procedure No. 13" or OP13). 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."*

The calculation of the amount of 5% voltage reduction to be assumed in the ICR-Related Values calculations uses the benchmark 1.5% load relief value specified in Appendix A of Operating Procedure No. 4. This benchmark reduction value is set based on the voltage reduction requirements of Operating Procedure No. 13, rather than at the self-reported values submitted by Market Participants with control over transmission/distribution facilities.

For the 2016/17 ICR calculation, the methodology for calculating the amount of 5% voltage reduction assumed in the ICR remains the same as used in the prior year's ICR calculation. This methodology uses the 90-10 peak load forecast and assumes that all Demand Resources will have already been implemented, and thus, will have reduced the 90-10 load value at the time of peak or OP-4 invocation.

The voltage reduction load relief values assumed as offsets against the Installed Capacity Requirement are calculated as the 1.5% voltage reduction assumption times the 90/10 peak load forecast after accounting for the amount of all Demand Resources (with the exception of limiting the amount of Real-Time Emergency Generation to 600 MW, the maximum amount purchased in the auction to meet the ICR), which is assumed to be already implemented and therefore not contributing to the 1.5% reduction in load. For the 2016/17 ICR calculation, the load relief obtainable from a 5% voltage reduction is calculated as:

Figure 8: Formula for Calculating 5% Voltage Reduction Assumption

Table 22 shows the amount of voltage reduction (MW) modeled as OP-4 load relief from Actions 6 & 8 for each of the months of the 2016/17 Capability Year within the ICR calculations.

Table 22: OP-4 Action 6 & 8 Modeled (MW)

	90/10 Peak Load	Passive Demand Resources	Real-Time Demand Resources	Real-Time Emergency Generation	Actions 6 & 8 5% Voltage Reduction
Jun 2016 - Sep 2016	31,725	1,596	1,445	534	422
Oct 2016 - May 2017	23,630	1,409	1,399	523	304

Operating Reserve

It is assumed that during peak load conditions, under extremely tight capacity situations, ISO-NE System Operations will hold a minimum of at least 200 MW of operating reserves for transmission system protection, prior to invoking manual load shedding procedures, if necessary. 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 load.

Table 23 summarizes the capacity resource and OP-4 assumptions used for the calculation of the ICR-Related Values.

Table 23: Summary of Resource and OP-4 Assumptions (MW)

Type of Resource/OP-4	Summer
Generating Resources	30,708.474
Intermittent Power Resources	882.056
Demand Resources	3,575.145
Import Resources	112.000
Export Delist	(100.000)
OP 4 Voltage Reduction	422.000
Minimum Operating Reserve	(200.000)
HQICCs)	1,870.000
Total MW Modeled in ICR	37,269.675

Availability

Generating Resource Forced Outages

A five year, historical average of unit-specific forced outage assumptions is determined for each generating unit that qualified as an Existing Generating Capacity Resource, using the most recent available data of monthly Equivalent Forced Outage Rate -

Demand (EFORd) values from NERC's Generating Availability Data System (GADS).[28] The NERC GADS data, submitted by regional generators to ISO-NE for the months of February 2007 through January 2012, was used to create an EFORd value for each unit that submits such data. The NERC Class Average data is used as a substitute for immature units and for units that are not required to submit NERC GADS data.

Table 24 shows the capacity-weighted, average EFORd values resulting from summing the individual generator data by unit category, weighted by individual capacity ratings. This is provided for informational purposes only. In the GE MARS model, the calculated EFORd for each generating resource is used as an input assumption.

Generating Resource Scheduled Outages

A weekly representation of a generator's scheduled outages is another input assumption that goes into the GE MARS model. Included within the scheduled outages are annual maintenance outages and unit outages, scheduled more than 14 days in advance of their outage. A single value is then calculated for each unit, based on a five year historical average. In addition to the EFORd data, Table 24 illustrates the average annual maintenance weeks assumed for each type of unit category, weighted by the summer capability. NERC Class Average data was used to calculate the average annual maintenance weeks for new capacity additions and immature units.

Table 24: Generating Resource EFORd (%) and Maintenance Weeks by Resource Category

Resource Category	Summer MW	Assumed Average % EFORd Weighted by Summer Ratings	Assumed Average Maintenance Weeks Weighted by Summer Ratings
Combined Cycle	11,589	3.6	4.1
Fossil	8,420	7.2	5.5
Nuclear	4,628	2.4	3.4
(Includes Pumped Storage)	2,969	3.3	5.6
Combustion Turbine	2,833	7.5	2.5
Diesel	214	6.5	1.1
Miscellaneous	56	10.3	6.7
Total System	30,708	4.8	4.4

Intermittent Power Resource Availability

The Qualified Capacity of an Intermittent Power Resource is the resource's median output during the Reliability Hours, as averaged over a period of five years for the second FCA and subsequent auctions. Since this methodology takes into account the resources' historic availability as it applies to their FCM capacity ratings, these resources are assumed 100% available within the ICR model.

[28] The calculation methodology of EFORd can be found on the NERC website at: http://www.nerc.com/files/Appendix_F_Performance_Indexes_and_Equations.pdf

Demand Resources Availability

Passive Demand Resources

Table 25 tabulates the availability assumption of the Passive Demand Resources in the On-Peak and Seasonal Peak categories of Demand Resources. These resources are considered 100% available within the ICR model. These two categories consist of passive resources such as energy efficiency or conservation, which are considered always "*in service*" and as such, are subsequently assumed to be 100% available. The total average availability for all Passive Demand Resources is, therefore, 100%.

Table 25: Passive Demand Resources – Summer (MW) and Availability (%)

Load Zone	On-Peak Summer MW	On-Peak Availability %	Seasonal Peak Summer MW	Seasonal Peak Availability %
MAINE	154.246	100	-	-
NEW HAMPSHIRE	78.066	100	-	-
VERMONT	117.810	100	-	-
CONNECTICUT	92.396	100	294.961	100
RHODE ISLAND	135.372	100	-	-
SOUTH EAST MASSACHUSETTS	179.505	100	-	-
WEST CENTRAL MASSACHUSETTS	175.423	100	44.173	100
NORTH EAST MASSACHUSETTS & BOSTON	324.233	100	-	-
Total New England	1257.051	100	339.134	100

Active Demand Resources

The historical performance of Active Demand Resources (those in the Real-Time Demand Response and Real-Time Emergency Generators categories) are used to create an availability assumption for use within the ICR calculation.[29]

For the the calculation of ICR for the 2016/17 Capability Year, there was available historical Demand Resource performance data for two years under FCM. This historical data consists of both OP 4 events and performance audits that occurred during the summer and winter of 2010 and 2011. At the June 14, 2012 PSPC Meeting, ISO-NE proposed using an availability assumption for Active Demand Resources based on the summer 2010 and 2011 Active Demand performance data, weighted by the MW of the resources in each Load Zone for each year. After the presentation of this data to the PSCPC and additional stakeholder discussions, it was decided to use this proposal in the ICR-Related Values calculations.

[29] A detailed discussion of the Demand Resource availability assumption is available here: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2012/jun142012/2012_dr_availability_assumption.pdf.

Table 26 shows the performance rates for Active Demand Resources applied to the Demand Resources by Load Zone and type of resource that are qualified as Existing Resources to participate in the 2016/17 FCA.

Table 26: Demand Response Resources Summer (MW) and Availability (%)

	Real-Time Demand Response		Real-Time Emergency Generators	
Load Zone	**Summer MW**	**Availability %**	**Summer MW**	**Availability %**
MAINE	318.067	100	27.344	94
NEW HAMPSHIRE	65.586	93	35.674	100
VERMONT	68.118	100	13.371	80
CONNECTICUT	351.794	72	230.543	80
RHODE ISLAND	79.645	90	59.975	75
SOUTH EAST MASSACHUSETTS	152.813	78	35.306	80
WEST CENTRAL MASSACHUSETTS	175.490	97	55.329	77
NORTH EAST MASSACHUSETTS & BOSTON	233.095	80	76.810	81
Total New England	1,444.608	86	534.352	81

This gives an average Active Demand Resource availability assumption of 85% for both Real-Time Demand Response and Real-Time Emergency Generators combined. The total average Demand Resource availability assumption for all Demand Resources, both Active and Passive, is 92%.

Difference from 2015/16 FCA ICR-Related Values

Change in ICR

In an effort to quantify the effects that each input assumption has on the determination of ICR, ISO-NE began with the input assumptions associated with the ICR calculated for the 2015/16 Capability Year and substituted each assumption individually with the corresponding 2016/17 Capability Year assumption. The net of these changes within the ICR value, as a result from each individual input assumption change, was then considered as the overall effect of the changed assumption set. Table 27 lists the assumptions for each study year and their subsequent effect on the resultant ICR value. Note that the sum of the individual assumption effects on ICR do not necessarily sum to the total difference in ICR due to the interplay of the various assumptions within the model when they are modeled concurrently.

Table 27: Summary of ICR Input Assumptions for 2016/17 vs. 2015/16

Assumption	2016/2017 FCA		2015/2016 FCA		Effect on ICR (MW)
Tie Benefits & Updated External Interface Outage Assumptions	314 MW New York		300 MW New York		-162
	392 MW Maritimes		328 MW Maritimes		
	1,055 MW Quebec (HQICCs)		1,042 MW Quebec (HQICCs)		
	109 MW Quebec via Highgate		6 MW Quebec via Highgate		
Total	1,870 MW		1,676 MW		
	MW	Weighted Forced Outage	MW	Weighted Forced Outage	
Generation & IPR	31,591	4.6%	32,155	4.7%	-31
Demand Resources	3,545	8.3%	3,745	14.0%	-202
Imports & Sales	12	0.02%	215	0.05%	11
	MW		MW		
Load Forecast	29,400		29,380		-55
	MW	%	MW	%	
OP 4 5% VR	422	1.50%	422	1.50%	-
	MW		MW		
ICR	34,023		34,498		-475

As shown in Table 27, there are two assumptions which have the greatest effect on the ICR. The first is the change in the amount and the availability of Demand Resources from the 2015/16 Capability Year to the 2016/17 Capability Year. This caused ICR to decrease by approximately 200 MW.

The decrease in ICR caused by the Demand Resources is a combination of an increase in the amount of Passive Demand Resources which are modeled as 100% available in the ICR model and also improved availability of Active Demand Resources from last year's ICR calculation. Table 28 shows a comparison of the amount of Passive Demand Resources in the 2016/17 versus the 2015/16 Capability Years.

Table 28: Comparison of the Passive Demand Resources (MW) for 2016/17 versus 2015/16 Capability Year

Load Zone	On-Peak		Seasonal Peak		Total Passive	
	2016/17 FCA7	2015/16 FCA6	2016/17 FCA7	2015/16 FCA6	2016/17 FCA7	2015/16 FCA6
MAINE	154.246	140.449	-	-	154.246	140.449
NEW HAMPSHIRE	78.066	76.787	-	-	78.066	76.787
VERMONT	117.810	105.500	-	-	117.810	105.500
CONNECTICUT	92.396	108.686	294.961	280.803	387.357	389.489
RHODE ISLAND	135.372	90.714	-	-	135.372	90.714
SOUTH EAST MASSACHUSETTS	179.505	160.086	-	-	179.505	160.086
WEST CENTRAL MASSACHUSETTS	175.423	149.178	44.173	33.037	219.596	182.215
NORTH EAST MASSACHUSETTS & BOSTON	324.233	292.618	-	-	324.233	292.618
Total New England	1257.051	1124.018	339.134	313.840	1596.185	1437.858

The increase in the amount of 100% available resources in the ICR model decreases the ICR as these resources are more reliable than the average availability of resources in the model.

Table 33 documents the decrease in the amount of Active Demand Resources along with a significant improvement in their availability from the 2015/16 Capability Year to the 2016/17 Capability Year.

Table 29: Comparison of Active Demand Resource Availability for the 2016/17 versus 2015/16 Capability Year (MW and %)

Load Zone	Real-Time Demand Response				Real-Time Emergency Generators				Total Active			
	2016/17 FCA7		2015/16 FCA6		2016/17 FCA7		2015/16 FCA6		2016/17 FCA7		2015/16 FCA6	
MAINE	318.067	100%	314.582	100%	27.344	94%	37.100	88%	345.411	100%	351.682	99%
NEW HAMPSHIRE	65.586	93%	63.059	100%	35.674	100%	41.310	100%	101.260	96%	104.369	100%
VERMONT	68.118	100%	59.306	100%	13.371	80%	18.493	77%	81.489	97%	77.799	95%
CONNECTICUT	351.794	72%	362.340	75%	230.543	80%	275.358	67%	582.337	75%	637.698	72%
RHODE ISLAND	79.645	90%	85.838	100%	59.975	75%	96.697	56%	139.620	83%	182.535	77%
SOUTH EAST MASSACHUSETTS	152.813	78%	167.811	64%	35.306	80%	77.015	59%	188.119	78%	244.826	62%
WEST CENTRAL MASSACHUSETTS	175.490	97%	176.049	100%	55.329	77%	98.643	49%	230.819	92%	274.692	82%
NORTH EAST MASSACHUSETTS & BOSTON	233.095	80%	286.568	68%	76.810	81%	147.278	60%	309.905	80%	433.846	65%
Total New England	1444.608	86%	1515.553	84%	534.352	81%	791.894	64%	1978.960	85%	2307.447	77%

The decrease in the amount of these resources reduces ICR, since their average availability is lower than the average system availability of all the resources in the ICR model. Therefore, if there is less amounts of a higher-than-average unavailable resource, ICR will subsequently decrease. Also in 2011, performance of Active Demand Resources, particularly the Real-Time Emergency Generator Demand Resources improved significantly. When the 2011 Demand Resource performance was merged with the 2010 Demand Resource performance to create the availability metric for the 2016/17 Capability Year ICR calculation, the average availability of the Active Demand Resources improved from 77% to 85%. This improvement in availability for Active Demand Resources also lowered the ICR since improvements in resource available means that fewer resources are needed for reliability.

The assumption change with the next highest effect for the decrease in the amount of ICR needed for the 2016/17 Capability Year versus the 2015/16 Capability Year is the increase in tie benefits. Tie Benefits increased from 1,676 MW for the 2015/16 Capability Year to 1,870 MW for the 2016/17 Capability Year. As noted in more detail within the section on tie benefits, this increase is due to the increase in tie benefits that is now able to come into New England from Québec on the Highgate interface due to the expiration of the Vermont Joint Owners (VJO) contract that previously used the Highgate interface for delivery and the change in system conditions within the 2016/17 versus 2015/2016 Capability Years, which causes the system to be less transmission constrained and therefore allows more tie benefits to flow into New England from neighboring Balancing Authority Areas.

Another assumption change that requires discussion is the change in the load forecast. While the 50/50 peak load forecast increased by 20 MW from the value forecasted for the 2015/16 Capability Year ICR calculation to the value forecasted for the 2016/17 Capability Year ICR calculation, the ICR decreased by 55 MW. This is due to the fact that the ICR model sees an entire distribution of possible load forecast values and the distribution for the 2012 CELT Load Forecast (used to calculate the ICR for the 2016/17 Capability Year) has less uncertainty than that of the 2011 CELT Load Forecast (used to calculate ICR for the 2015/16 Capability Year, particularly when related to skewness of the weekly distribution, which is a measure of the asymmetry of the distribution.

Skewness in the model is represented by the Third Cumulant (skewness cubed), which is one of the moments of the distribution and describes the values at the tail ends of the distributions.

The next three tables document this change in load forecast uncertainty. Table 30 shows the two load forecast's weekly means, Table 30Table 31 shows the standard deviations of the two load forecasts and Table 32 shows the Third Cumulant of the two load forecasts.

Table 30: 2011 CELT vs. 2012 CELT 2016/17 Capability Year Weekly Load Forecast Mean (MW)

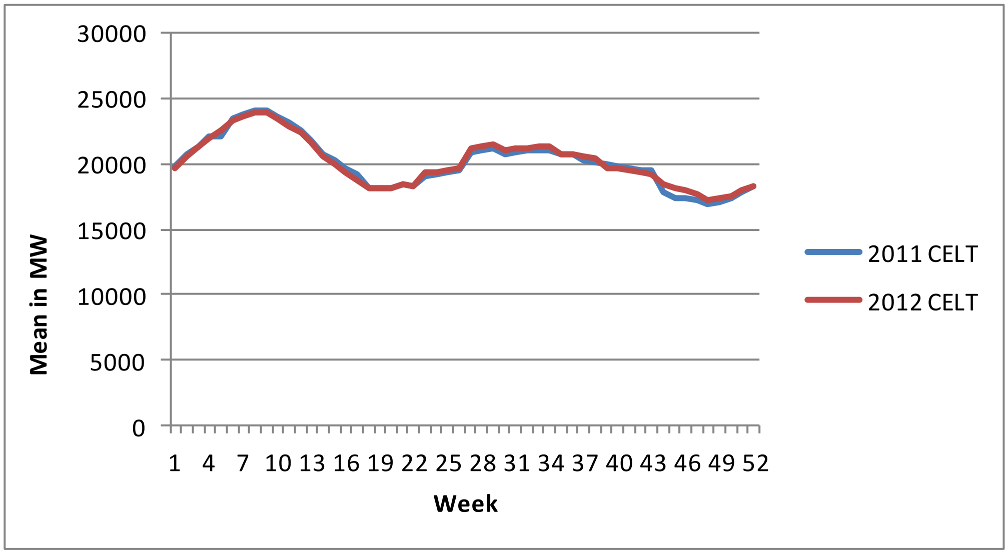


Table 31: 2011 CELT vs. 2012 CELT 2016/17 Capability Year Weekly Load Forecast Standard Deviation

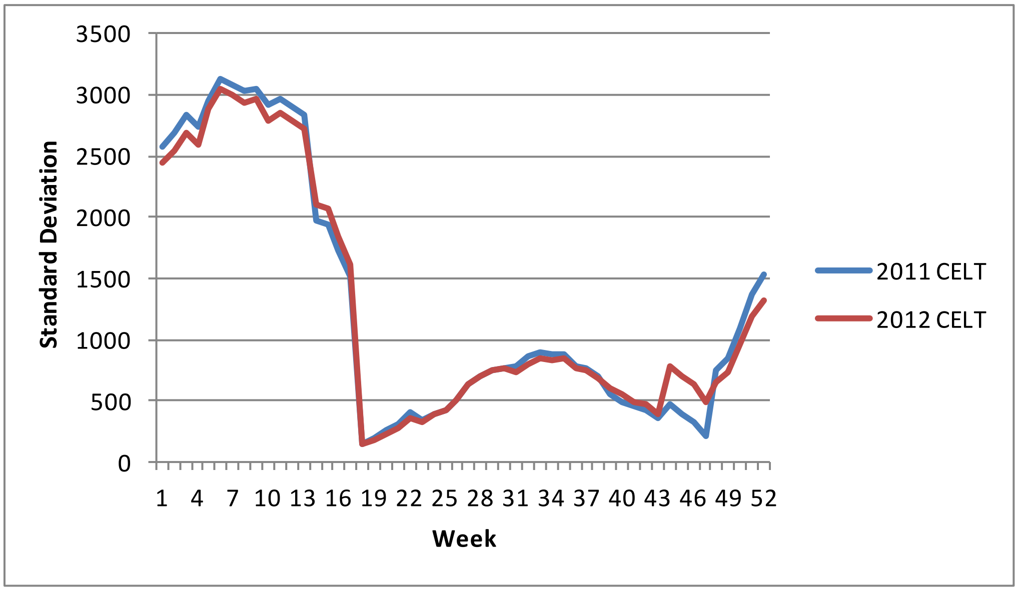
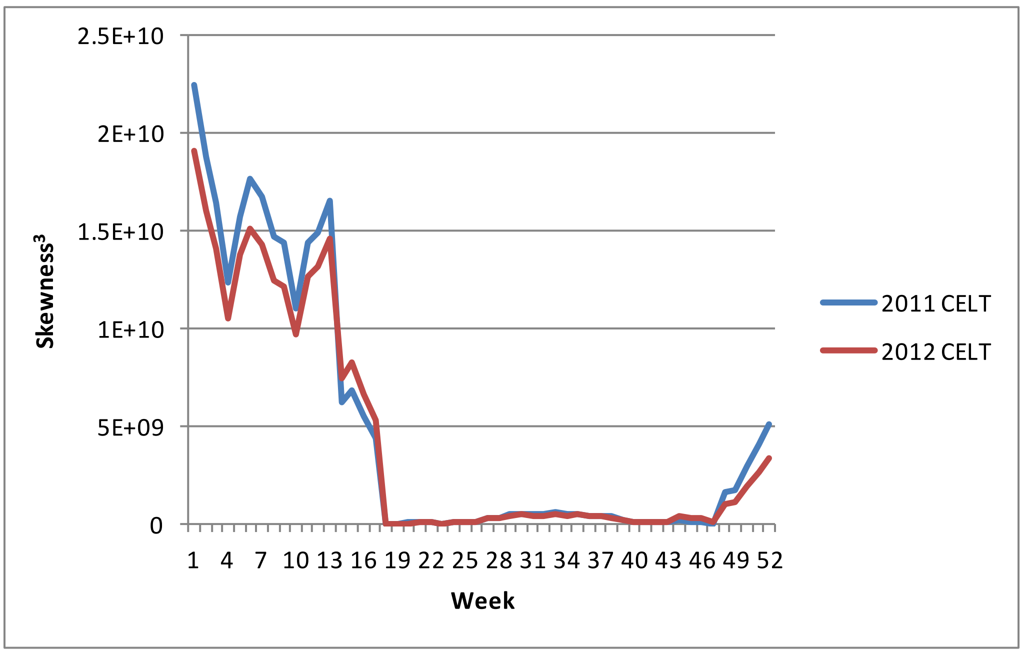


Table 32: 2011 CELT vs. 2012 CELT 2016/17 Capability Year Weekly Load Forecast Third Cumulant



Change in LRA Requirement

Table 33 shows the difference in the assumptions and results of the 2016/17 LRA Requirement calculation, as compared to the 2015/16 LRA Requirement calculations for the import-constrained Connecticut and NEMA/Boston Load Zones and the Rest of New England area, which is used in the calculation of the Maine MCL.

Table 33: Summary of Changes in LRA Requirement for 2016/17 vs. 2015/16

Local Resource Adequacy Requirement		Connecticut		NEMA/Boston		Rest of New England	
		2016/17 FCA	2015/16 FCA	2016/17 FCA	2015/16 FCA	2016/17 FCA	2015/16 FCA
$Resource_z$	[1]	9,004	9,435	3,228	3,339	31,416	32,371
$Proxy\ Units_z$	[2]	0	0	0	0	0	0
$Surplus\ Capacity\ Adjustment_z$	[3]	0	0	0	0	2,170	2,605
$Firm\ Load\ Adjustment_z$	[4]	1,298	1,755	717	690	-125	35
FOR_z	[5]	0.0732	0.0730	0.0396	0.0667	0.0520	0.0580

Change in TSA Requirement

Table 34 shows the difference in the assumptions and results of the 2016/17 TSA Requirement calculation, as compared to the 2015/16 TSA Requirement calculations for the import-constrained Connecticut and NEMA/Boston Load Zones.

Table 34: Comparison of the TSA Requirement Calculation for 2016/17 vs. 2015/16 (MW)[30]

	Connecticut		NEMA/Boston	
	2016/17 FCA7	2015/16 FCA6	2016/17 FCA7	2015/16 FCA6
Sub-area 90/10 Peak Load Forecast	8,201	8,250	6,520	6,530
Reserves (Largest unit or loss of import capability)	1,225	1,225	1,393	1,373
Sub-area Transmission Security Need	**9,426**	**9,475**	**7,913**	**7,903**
Existing Resources	9,004	9,435	3,228	3,339
Assumed Unavailable Capacity	-797	-827	-147	-239
Sub-area N-1 Import Limit	2,600	2,600	4,850	4,850
Sub-area Available Resources	**10,807**	**11,208**	**7,931**	**7,949**
Sub-area Transmission Security Margin	**1,381**	**1,733**	**18**	**47**
TSA Requirement	**7,489**	**7,536**	**3,209**	**3,289**

The decrease in the TSA requirement from the 2016/17 Capability Year versus the 2015/16 Capability Year can be attributed to the decrease in the 90/10 peak load forecast and an improvement in resource unavailability, particularly for the Demand Resources.

Change in MCL

Table 35 shows the difference in the assumptions and results of the 2016/17 MCL calculation, as compared to the 2015/16 MCL calculation for the Maine Load Zone.

[30] The 90/10 load for Connecticut and NEMA/Boston shown are the sub-area loads. The LRA and TSA analyses are preformed on a sub-area basis which is used as proxies for the load zones. This is done because the transmission transfer capabilities are calculated using a sub-area analysis only.

Table 35: Comparison of MCL Calculation for 2016/17 vs. 2015/16 for Maine (MW)

Maximum Capacity Limit		Maine	
		2016/17 FCA7	2015/16 FCA6
Net ICR for New England	[1]	32,968	33,456
$LRA_{Rest of New England}$	[2]	29,259	29,568
$Maximum Capacity Limit_{Y}$	[3]=[1]-[2]	**3,709**	**3,888**

The decrease in Maine MCL from the 2016/17 Capability Year versus the 2015/16 Capability Year can be attributed to the increase in tie benefits into Maine coming from New Brunswick over the New Brunswick Transmission Interface and also a decrease in the New England ICR. For the 2015/16 Capability Year, there were 328 MW of tie benefits calculated from New Brunswick into Maine while there is 392 MW for the 2016/17 Capability Year. Higher tie benefits means that less capacity resources located in Maine are needed to meet the ICR for the Rest of New England area resulting in a lower MCL value.

Table 36 shows the summary comparison between the all the ICR-Related Values and their inputs calculated for the 2016/17 Capability Year FCA versus the 2015/16 Capability Year FCA.

Table 36: Comparison of all ICR-Related Values (MW)[31]

	New England		Connecticut		NEMA/Boston		Maine	
	2016/17 FCA	2015/16 FCA	2016/17 FCA	2015/16 FCA	2016/17 FCA	2015/16 FCA	2016/17 FCA	2015/16 FCA
Peak Load (50/50)	29,400	29,380	7,555	7,610	6,047	6,070	2,108	2,135
Total Resources	35,178	36,116	9,004	9,435	3,228	3,339	3,762	3,745
Installed Capacity Requirement	34,023	34,498						
NET ICR (ICR Minus HQICCs)	32,968	33,456						
Local Resource Adequacy Requirement			7,603	7,542	2,481	2,600		
Transmission Security Requirement			7,489	7,536	3,209	3,289		
Local Sourcing Requirement			7,603	7,542	3,209	3,289		
Maximum Capacity Limit							3,709	3,888

[31] Total Resources value for New England excludes HQICCs.

{ End of Report }