Proposed Installed Capacity Requirement (ICR) Values for the 2019/20 Forward Capacity Auction (FCA10)

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Objective of this Presentation

- Review the ICR review and FERC filing schedules
- Review the proposed ICR Values* including:
  - Installed Capacity Requirement (ICR)

  - *For the Southeast New England (SENE) Capacity Zone (combined Load Zones of NEMA/Boston, SEMA and RI)*
    - Transmission Security Analysis (TSA),
    - Local Resource Adequacy Requirement (LRA),
    - Local Sourcing Requirement (LSR)

  - Capacity requirement values for the System-Wide Capacity Demand Curve (Demand Curve)

*****The ICR, LSR and the Demand Curve capacity requirements are collectively the ICR Values.

Capacity Zone Locational Requirements

- SENE was determined to be an import-constrained Capacity Zone in the Objective Criteria analysis presented to the PSPC on June 30, 2015

- The Connecticut Load Zone was determined not to be import-constrained and will not be modeled as a Capacity Zone for FCA10

  - Presentation for both analyses available at: http://www.iso-ne.com/static-assets/documents/2015/06/fca10_zone_formation.pdf

- The combined Maine, New Hampshire and Vermont Load Zones (Northern New England (NNE)) will not be modeled as a Capacity Zone for FCA10 because NNE did not meet the export-constrained Capacity Zone Objective Criteria. This analysis was presented to the PSPC on August 14, 2015.

  - Presentation available at: http://www.iso-ne.com/static-assets/documents/2015/08/pspc_081415_a3.0_fca10_zone_formation2.pdf

ICR Review and FERC Filing Schedule

- ICR Values for 2019/20 Forward Capacity Auction (FCA10)
  - PSPC reviewed Capacity Zone determinations – **Jun 30 & Aug 14, 2015**
  - PSPC reviewed ICR assumptions – **May 28**, **Jun 30 & Jul 23, 2015**
  - PSPC reviewed ISO recommendation of ICR Values – **Aug 27, 2015**
  - RC review/vote of ISO recommendation of ICR Values – **Sep 15, 2015**
  - PC review/vote of ISO recommendation of ICR Values – **Oct 2, 2015**
  - File with the FERC – by **Nov 10, 2015**
  - FCA10 begins – **Feb 8, 2016**

PROPOSED ICR VALUES FOR THE 2019/20 FCA

ISO Proposed ICR Values for the 2019/20 FCA (MW)

2019/20 FCA	New England	Southeast New England
Peak Load (50/50)	29,861	12,282
Existing Capacity Resources*	33,484	11,194
Installed Capacity Requirement	35,126	
NET ICR (ICR Minus 975 MW HQICCs)	34,151	
1-in-5 LOLE Demand Curve capacity value	33,076	
1-in-87 LOLE Demand Curve capacity value	37,053	
Local Sourcing Requirement		10,028

- *Existing Capacity Resources are the Existing Qualified capacity resources for FCA10 at the time of the calculation and reflect early June terminations.
- In addition to the Existing Capacity Resources shown, 800 MW of proxy units are required for the ICR calculation and 3,600 MW for the 1-in-87 LOLE Demand Curve capacity requirement value calculation.

Comparison of ICR Values (MW)
- 2019/20 (FCA10) Vs 2018/19 (FCA9)

	New England		Southeast New England	
	2019/20 FCA	2018/19 FCA	2019/20 FCA	2018/19 FCA
Peak Load (50/50)	29,861	30,005	12,282	-
Existing Capacity Resources*	33,484	32,842	11,194	-
Installed Capacity Requirement	35,126	35,142		
NET ICR (ICR Minus HQICCs)	34,151	34,189		
1-in-5 LOLE Demand Curve capacity value	33,076	33,132		
1-in-87 LOLE Demand Curve capacity value	37,053	37,027		
Local Resource Adequacy Requirement			9,584	-
Transmission Security Analysis Requirement			10,028	-
Local Sourcing Requirement			10,028	-

- *Existing Capacity Resources are the Existing Qualified capacity resources for FCA10 at the time of the calculation and reflect early June terminations.
- In addition to the FCA10 Existing Capacity Resources shown, 800 MW of proxy units are required for the ICR calculation and 3,600 MW for the 1-in-87 LOLE Demand Curve capacity requirement value calculation.
- For details on the FCA9 (2018/19) ICR Values calculation see: http://www.iso-ne.com/static-assets/documents/2014/09/a6_fca9_icr_values.pdf.

ICR Calculation Details

Total Capacity Breakdown	1-in-5	2019/20 FCA ICR	1-in-87
Generating Resources	30,654	30,654	30,654
Tie Benefits	1,990	1,990	1,990
Imports/Sales	(41)	(41)	(41)
Demand Resources	2,871	2,871	2,871
OP4 - Action 6 & 8 (Voltage Reduction)	442	442	442
Minimum Reserve Requirement	(200)	(200)	(200)
Proxy Unit Capacity	-	800	3,600
Total Capacity	**35,716**	**36,516**	**39,316**

Installed Capacity Requirement Calculation Details	1-in-5	2019/20 FCA ICR	1-in-87
Annual Peak	29,861	29,861	29,861
Total Capacity	35,716	36,516	39,316
Tie Benefits	1,990	1,990	1,990
HQICCs	975	975	975
OP4 - Action 6 & 8 (Voltage Reduction)	442	442	442
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	368	116	25
Installed Capacity Requirements	**34,051**	**35,126**	**38,028**
Net ICR	**33,076**	**34,151**	**37,053**
Reserve Margin with HQICCs	14.0%	17.6%	27.3%
Reserve Margin without HQICCs	10.8%	14.4%	24.1%

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

- All values in the table are in MW except the Reserve Margin shown in percent.
- ALCC is the “Additional Load Carrying Capability” used to bring the system to the target Reliability Criterion.

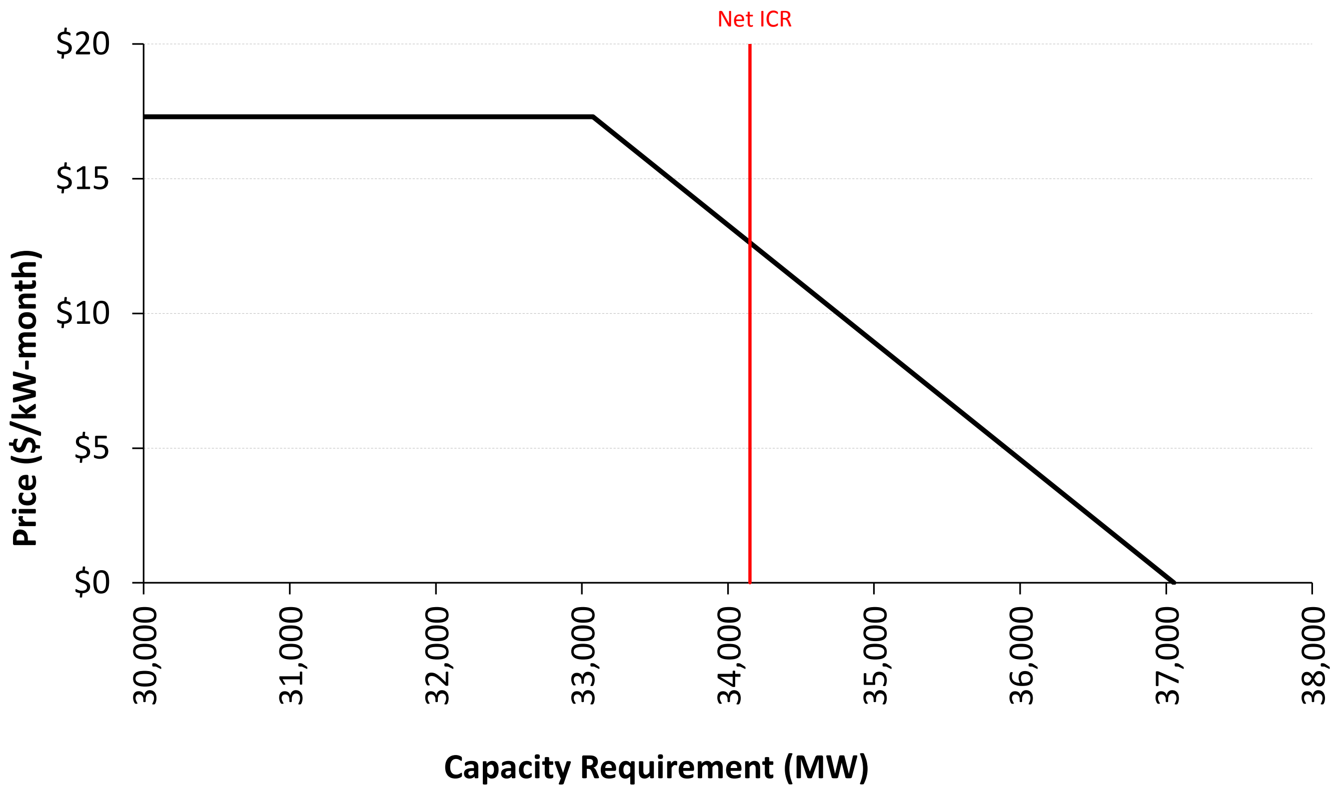
Cost of New Entry (CONE)

- for the System-Wide Capacity Demand Curve

- CONE for the Cap of the Demand Curve for FCA10 has been calculated as:
  - Gross CONE = $14.29/kW-month
  - Net CONE = $10.81/kW-month
- Price cap of the Demand Curve is determined as:

  Max (1.6 x Net CONE, Gross CONE)
- Price at the Demand Curve Cap = $17.296/kW-month

System-Wide Capacity Demand Curve for FCA10



Cap [1-in-5 LOLE Demand Curve capacity value = 33,076 MW, $17.296]

Foot [1-in-87 LOLE Demand Curve capacity value = 37,053 MW, $0]

Effect of Updated Assumptions on ICR

Assumption	2019/2020 FCA		2018/2019 FCA		Effect on ICR (MW)
Tie Benefits	354 MW New York		346 MW New York		8
	519 MW Maritimes		523 MW Maritimes		
	975 MW Quebec (HQICCs)		953 MW Quebec (HQICCs)		
	142 MW Quebec via Highgate		148 MW Quebec via Highgate		
Total	1,990 MW*		1,970 MW		
	MW	**Weighted Forced Outage**	**MW**	**Weighted Forced Outage**	
Generation & IPR	30,524	6.7%	29,699	6.5%	136
Demand Resources	2,871	2.5%	3,054	4.0%	-42
Imports	89	0.0%	89	0.0%	-
	MW		**MW**		
Load Forecast - Reference	29,861		30,005		-56
	MW	**%**	**MW**	**%**	
OP 4 5% VR	442	1.50%	441	1.50%	-
	MW		**MW**		
ICR	35,126		35,142		-16

- Methodology: Using the resources associated with the 2018/19 FCA ICR calculation, change one assumption at a time and note the change in ICR.

* The difference in Net ICR (ICR minus HQICCS) due to the change in tie benefits is -14 MW.

LRA – SENE

Local Resource Adequacy Requirement - SENE			
Southeast New England Capacity Zone		**2019/20 FCA**	**2018/19 FCA**
$Resource_z$	[1]	11,194	-
$Proxy\ Units_z$	[2]	0	-
$Firm\ Load\ Adjustment_z$	[3]	1,482	-
FOR_z	[4]	0.079	-
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**9,584**	**-**
Rest of New England Zone			
Resource	[6]	22,290	-
Proxy Units	[7]	800	-
Firm Load Adjustment	[8] = -[3]	-1,482	-
Total System Resource	[9]=[1]+[2]-[3]+[6]+[7]-[8]	34,284	-

- All values in the table are in MW except the FORz

TSA Requirement - SENE

FCA10 TSA Requirement for SENE

Sub-area 2015 90/10 Load*	13,342
Reserves (Largest unit)	1,413
Sub-area Transmission Security Need	**14,755**
Existing Resources**	11,194
Assumed Unavailable Capacity	-1,086
Sub-area N-1 Import Limit	5,700
Sub-area Available Resources	**15,808**

TSA Requirement (14755-5700)/(1-1086/11194)

= 10,028

*Behind the Meter not Embedded in the Load Forecast (BTMNEL) PV is modeled as a reduction to the load forecast

The 2019-20 Qualified Existing Capacity amount as of 06/04/2015**

NOTE: All values have been rounded off to the nearest whole number

Questions

ASSUMPTIONS FOR CALCULATING THE ICR VALUES FOR THE 2019/20 FCA

Modeling the New England Control Area

The GE MARS model is used to calculate the ICR and Related Values

- Internal transmission constraints are not modeled in the ICR calculation. All loads and resources are assumed to be connected to a single electric bus.
- Internal transmission constraints are addressed through LSR and MCL
- LSR was calculated for the SENE Capacity Zone
- The Demand Curve capacity values are the capacity requirement values net of Hydro-Quebec Interconnection Capability Credits (HQICCs) at the cap and foot of the System-Wide Capacity Demand Curve and are calculated at 1-in-5 Loss of Load Expectation (LOLE) and 1-in-87 LOLE, respectively.

Assumptions for the ICR Calculations

- *Load Forecast*
  - Load Forecast distribution
  - Net of Behind the Meter not Embedded in the Load Forecast (BTMNEL) Photovoltaic (PV) resource forecast
- *Resource Data Based on Existing Qualified Capacity Resources for FCA10 (reflects terminations which occurred in June 2015)*
  - Generating Capacity Resources
  - Intermittent Power Capacity Resources (IPR)
  - Import Capacity Resources
  - Demand Resources (DR)
- *Resource Availability*
  - Generating Resources Availability
  - Intermittent Power Resources Availability
  - Demand Resources Availability
- *Load Relief from OP 4 Actions*
  - Tie Reliability Benefits
    - Quebec
    - Maritimes
    - New York
  - 5% Voltage Reduction

Load Forecast Data

- **Load forecast assumption from the 2015 CELT Report Load Forecast**

- **The load forecast weather related uncertainty is represented by specifying a series of multipliers on the peak load and the associated probabilities of each load level occurring**
  - derived from the 52 weekly peak load distributions described by the expected value (mean), the standard deviation and the skewness.

Modeling of PV in ICR (MW)

Month	2019/2020
Jun	367.1
Jul	369.2
Aug	371.4
Sep	373.8
Oct	0
Nov	0
Dec	0
Jan	0
Feb	0
Mar	0
Apr	0
May	389.3

- Table shows the monthly sum of Seasonal Claimed Capability (SCC) of BTMNEL PV resources modeled in ICR (includes 8% Transmission & Distribution Gross-up)
- Developed using 40%* of PV nameplate forecast from the Distributed Generation Forecast Working Group (DGFWG)
- Modeled as a load modifier in GE MARS by Regional System Plan (RSP) 13-subarea representation for hours ending 14:00 – 18:00

* 40% value based on 3 years of historical PV resource ratings during reliability hours

Load Forecast Data – New England System Load Forecast

Monthly Peak Load (MW) – 50/50 Forecast

Year	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
2019/20	26,508	29,861	29,861	24,276	19,190	20,955	23,430	23,430	22,160	20,370	18,410	21,021

There is a distribution associated with each monthly peak. The distribution associated with the Summer Seasonal Peak (July & August) is show below:

Probability Distribution of Annual Peak Load (MW)

Year	10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
2019/20	28,686	28,951	28,996	29,406	29,861	30,341	30,831	31,541	32,341	33,051

- Corresponds to the reference forecast labeled "*1.2 REFERENCE - With reduction for BTM PV*" from section 1.1 of the 2015 CELT Report.

Load Forecast Assumption Comparisons (MW)

(Uses the Same Capacity Resources in All Model Runs)

	Model Run 1			Model Run 2			
Comparison	Load Forecast CELT Year	Load Year	Correspond-ing 50/50 Peak Load (MW)	Load Forecast CELT Year	Load Year	Correspond-ing 50/50 Peak Load (MW)	Effect on ICR (MW)
Different CELT forecasts and different years [to flush out year over year load growth and changes in the different forecasts]	2015	2019/20	30,230	2014	2018/19	30,005	323
Different CELT forecast for the same year [to flush out level changes in the different forecasts]	2015	2018/19	29,825	2014	2018/19	30,005	-132
Different CELT Load Forecast Uncertainty (LFU) *only* [reflects increased standard deviation in 2015 CELT forecast]	2015 (LFU)	2018/19	30,005	2014 (LFU)	2018/19	30,005	154
Same CELT forecast and for 2019/20 with and without reflecting BTMNEL PV [Net versus Gross load forecast]	2015	2019/20	29,861	2015	2019/20	30,230	-392

- These comparisons attempt to gauge the change in ICR attributed to the load forecast: such as year over year change, level change in the load forecast, load forecast uncertainty and the effect of incorporating the reduction in the load forecast for BTMNEL PV resources.
- Methodology: Using the resources associated with the 2018/19 FCA ICR model, change the load forecast assumptions and note the change in ICR.
- The 50/50 peak load forecasts shown here are to aid in comparisons; the models see a distribution of weekly peak loads and corresponding load forecast uncertainty for each CELT load forecast.
- These results, presented in a similar table, were reviewed with the PSPC at the August 27, 2015 meeting.

Resource Data – Generating Capacity Resources (MW)

Load Zone	Non-Intermittent Generation		Intermittent Generation		Total	
	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	2,863.774	3,018.330	292.832	401.878	3,156.606	3,420.208
NEW HAMPSHIRE	4,043.605	4,267.015	157.295	215.912	4,200.900	4,482.927
VERMONT	222.098	262.716	71.780	124.302	293.878	387.018
CONNECTICUT	9,063.732	9,543.325	172.684	188.939	9,236.416	9,732.264
RHODE ISLAND	1,867.339	2,069.400	3.372	5.220	1,870.711	2,074.620
SOUTH EAST MASSACHUSETTS	4,683.952	5,110.589	83.314	78.057	4,767.266	5,188.646
WEST CENTRAL MASSACHUSETTS	3,732.636	3,986.982	66.670	97.066	3,799.306	4,084.048
NORTH EAST MASSACHUSETTS & BOSTON	3,227.714	3,649.635	71.172	72.260	3,298.886	3,721.895
Total New England	**29,704.850**	**31,907.992**	**919.119**	**1,183.634**	**30,623.969**	**33,091.626**

- Existing Qualified generating capacity resources for FCA10
- Intermittent resources have both summer and winter values modeled; non-Intermittent winter values provided for informational purpose
- Reflects the terminations of resources in early June and a 30 MW derating to reflect the firm contract value of the Vermont Joint Owners (VJO) contract

Resource Data – Import Capacity Resources (MW)

Import Resource	Qualified Summer MW	External Interface
VJO - Highgate	6.000	Hydro-Quebec Highgate
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	14.000	New York AC Ties
Total MW	88.800	

- Existing Qualified Import capacity resources for FCA10
- A 30 MW derating is applied to Citizens Block Load (modeled as a generator) to reflect the value of the VJO contract
- All are system-backed imports modeled with 100% resource availability

Resource Data – Export Delist (MW)

Export	Summer MW
LIPA via CSC	100.000

- Based on Administrative Delist Bid
- Modeled as removed capacity from the resource supplying the export

Resource Data – Demand Resources (MW)

Load Zone	On-Peak		Seasonal Peak		RT Demand Response		RT Emergency Gen		Total	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	164.811	162.115	-	-	149.386	167.281	7.482	5.198	321.679	334.594
NEW HAMPSHIRE	101.215	80.645	-	-	12.798	12.078	14.022	12.045	128.035	104.768
VERMONT	120.090	111.095	-	-	31.900	39.833	4.918	4.357	156.908	155.285
CONNECTICUT	78.815	56.637	371.437	341.026	77.374	75.541	52.941	52.427	580.567	525.631
RHODE ISLAND	197.599	187.599	-	-	60.362	56.831	15.720	11.329	273.681	255.759
SOUTH EAST MASSACHUSETTS	292.685	259.806	-	-	51.987	50.112	12.722	12.722	357.394	322.640
WEST CENTRAL MASSACHUSETTS	293.340	266.117	49.645	33.939	58.684	53.826	25.098	24.544	426.767	378.426
NORTH EAST MASSACHUSETTS & BOSTON	548.466	506.968	-	-	67.329	67.329	10.439	10.211	626.234	584.508
Total New England	1,797.021	1,630.982	421.082	374.965	509.820	522.831	143.342	132.833	2,871.265	2,661.611

- Existing Qualified Demand Resource capacity for FCA10
- Includes the Transmission and Distribution (T&D) Loss Adjustment (Gross-up) of 8%
- Reflects terminations of resources in early June

LSR Internal Transmission Transfer Capability Assumptions (MW)

- Transfer Limits – 2015 Regional System Plan (RSP) for 2019/20
  - Internal Transmission Transfer Capability
    - Southeast New England Import
      - N-1 Limit: 5,700 MW
      - N-1-1 Limit: 4,600 MW

Includes:

- the New England East West Solution (NEEWS) Interstate Reliability Program – the certification of this project to be in service by December 2015 has been accepted by ISO New England
- the Greater Boston Upgrades - the certification of this project to be in service by June 2019 has been accepted by ISO New England
- upgrades to Rhode Island facilities which are certified for FCA10 in response to the Brayton Point retirement

Sub-area Resource and 50/50 Peak Load Forecast Assumptions Used in LRA Calculations (MW)

Resource Type	Southeast New England (SENE)	Total New England
Generator	9,779.005	29,604.850
Intermittent Generator	157.858	919.119
Import	-	88.800
On-Peak DR	1,038.750	1,797.021
Seasonal-Peak DR	-	421.082
Real-Time DR	179.678	509.820
Real-Time Emergency Gen DR	38.881	143.342
Total	11,194.172	33,484.034

	SENE	New England
50/50 Load Forecast Net BTMNEL PV	12,282	29,861

- Generating resource assumptions are based on the RSP sub-areas, used as a proxy for the Load Zones as the transmission transfer capability is determined using the RSP 13 sub-areas. DR values are the Load Zone values.
- Generating resources for New England reflects the 100 MW export and 30 MW derating to reflect the value of the firm VJO contract
- For the SENE Capacity Zone, the sum of the Load Zone resources equals the corresponding RSP sub-areas. The 50/50 load forecast value shown is the sum of the corresponding RSP sub-areas.

Availability Assumptions - Generating Resources

- **Forced Outages Assumption**
  - Each generating unit's Equivalent Forced Outage Rate on Demand (non-weighted EFORd) modeled
  - Based on a 5-year average (Jan 2010 – Dec 2014) of generator submitted Generation Availability Data System (GADS) data
  - NERC GADS Class average data is used for immature units

- **Scheduled Outage Assumption**
  - Each generating unit weeks of Maintenance modeled
  - Based on a 5-year average (Jan 2010 – Dec 2014) of each generator's actual historical average of planned and maintenance outages scheduled at least 14 days in advance
  - NERC GADS Class average data is used for immature units

Availability Assumptions - Generating Resources

Resource Category	Summer MW	Assumed Average EFORd (%) Weighted by Summer Ratings	Assumed Average Maintenance Weeks Weighted by Summer Ratings
Combined Cycle	13,279	4.0	5.4
Fossil	6,087	15.9	5.1
Nuclear	4,024	2.5	4.5
Hydro (Includes Pumped Storage)	2,903	4.9	4.4
Combustion Turbine	3,171	9.4	2.5
Diesel	190	7.3	1.0
Miscellaneous	51	16.1	3.8
Total System	29,705	6.9	4.8

- Assumed summer MW weighted EFORd and Maintenance Weeks are shown by resource category for informational purposes. In the LOLE simulations, individual unit values are modeled.

Availability Assumptions - Intermittent Power Resources

- Intermittent Power Resources are modeled as 100% available since their outages have been incorporated in their 5-year historical output used in their ratings determination.

Demand Resource Availability

Load Zone	On-Peak Summer (MW)	On-Peak Perform-ance	Seasonal Peak Summer (MW)	Seasonal Peak Perform-ance	RT Demand Response Summer (MW)	RT Demand Response Perform-ance	RT Emergency Gen Summer (MW)	RT Emergency Gen Perform-ance	Total Summer	Total Perform-ance
MAINE	164.811	100%	-	-	149.386	99%	7.482	92%	321.679	99%
NEW HAMPSHIRE	101.215	100%	-	-	12.798	88%	14.022	97%	128.035	98%
VERMONT	120.090	100%	-	-	31.900	97%	4.918	82%	156.908	99%
CONNECTICUT	78.815	100%	371.437	100%	77.374	83%	52.941	87%	580.567	97%
RHODE ISLAND	197.599	100%	-	-	60.362	83%	15.720	91%	273.681	96%
SOUTH EAST MASSACHUSETTS	292.685	100%	-	-	51.987	78%	12.722	83%	357.394	96%
WEST CENTRAL MASSACHUSETTS	293.340	100%	49.645	100%	58.684	90%	25.098	89%	426.767	98%
NORTH EAST MASSACHUSETTS & BOSTON	548.466	100%	-	-	67.329	83%	10.439	90%	626.234	98%
Total New England	1797.021	100%	421.082	100%	509.820	89%	143.342	89%	2,871.265	97%

- Uses historical DR performance from summer & winter 2010 – 2014. See presentation at: http://www.iso-ne.com/static-assets/documents/2015/05/2015_DR_availability.pdffor more information.
- Modeled by zones and type of DR with outage factor calculated as 1- performance/100

FCA10 TSA Requirements Assumptions
– Detailed Assumptions

- Load Forecast Data
  - 2015 CELT forecast adjusted for PV forecast*
    - SENE sub-area 90/10 peak load: 13,342 MW
- Resource Data
  - 2019-20 Existing Capacity Qualification data as of June 4, 2015
    - Generating capacity: 9,937 MW
      - Includes 9,237 MW of regular generation resources, 158 MW of intermittent generation resources and 542 MW of peaking generation resources
    - Passive Demand Resources: 1,039 MW
    - Non-RTEG Active Demand Resources: 180 MW
    - Real-Time Emergency Generation: 39 MW

Behind the Meter not Embedded in the Load Forecast (BTMNEL) PV is modeled as a reduction to the load forecast
NOTE: All values have been rounded off to the nearest whole number

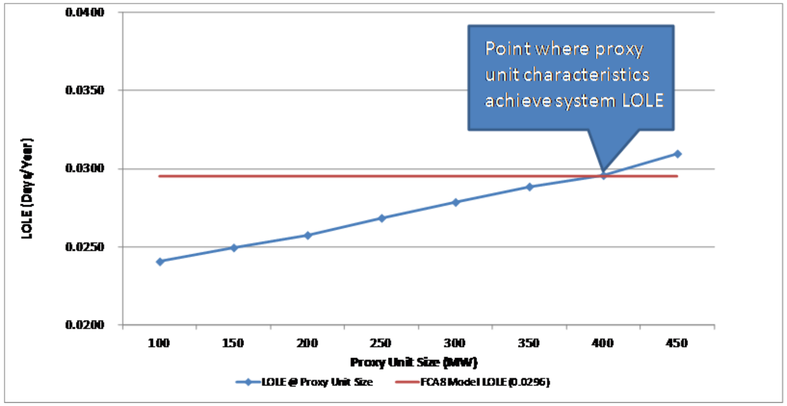
FCA10 TSA Requirements Assumptions – Detailed Assumptions, cont.

- Resource Unavailability Assumptions
  - Regular Generation Resources - Weighted average EFORd
    - SENE sub-area: 10%
  - Peaking Generation Resources - Operational de-rating factor: 20%
  - Passive Demand Resources: 0%
  - Non-RTEG Active Demand Resources - De-rating based on performance factors
    - Boston sub-area: 17%
    - SEMA sub-area: 23%
    - RI sub-area: 17%
  - Real-Time Emergency Generation - De-rating based on performance factors
    - Boston sub-area: 10%
    - SEMA sub-area: 17%
    - RI sub-area: 9%

NOTE: All values have been rounded off to the nearest whole number

Proxy Unit Characteristics

- Proxy unit characteristics based on a study conducted in 2014 using the 2017/18 FCA8 ICR Model



- Current proxy unit characteristics:
  - Proxy unit size equal to 400 MW
  - EFORd of proxy unit = 5.47%
  - Maintenance requirement = 4 weeks

- Proxy unit characteristics are determined using the average system availability and a series of LOLE calculations. By replacing all system capacity with the correct sized proxy units, the system LOLE and resulting capacity requirement unchanged.

  - The 2014 Proxy Unit Study was reviewed at the May 22, 2014 PSPC Meeting and is available at: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf

OP 4 Assumptions
- Action 6 & 8 - 5% Voltage Reduction (MW)

	90-10 Peak Load	Passive DR	RTDR	RTEG	Action 6 & 8 5% Voltage Reduction
Jun 2019 - Sep 2019	32,341	2,218	510	143	442
Oct 2019 - May 2020	24,085	2,006	523	133	321

- Uses the 90-10 Peak Load Forecast minus BTMNEL PV and all Passive & Active DR
- Multiplied by the 1.5% value used by ISO Operations in estimating relief obtained from OP4 voltage reduction

OP 4 Assumptions
- Tie Benefits (MW)

- Based on the results of the 2019/20 Tie Benefits Study (with NNE not a zone)

Control Area	2019/20 FCA10
Québec via Phase II	975
Québec via Highgate	142
Maritimes	519
New York	354
Total Tie Benefits	1,990

- Modeled in the ICR calculations with the tie line availability assumptions shown below:

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

OP 4 Assumptions
- Minimum Operating Reserve Requirement(MW)

- Minimum Operating Reserve is the 10-Minute minimum Operating Reserve requirement for ISO Operations

- Modeled at 200 MW in the ICR calculation

Summary of all MW Modeled in the ICR Calculations (MW)

Type of Resource/OP 4	2019/20 FCA
Generating Resources	29,734.850
Intermittent Power Resources	919.119
Demand Resources	2,871.265
Import Resources	88.800
Export Delist	(100.000)
Import Deratings	(30.000)
OP 4 Voltage Reduction	442.000
Minimum Operating Reserve	(200.000)
Tie Benefits (with 975 MW of HQICCs)	1,990.000
Proxy Units	800.000
Total MW Modeled in ICR	**36,516.034**

Notes:

- Intermittent Power Resources have both the summer and winter capacity values modeled
- Import deratings reflect the value of the firm VJO contract
- OP 4 Voltage Reduction includes both Action 6 and Action 8 MW assumptions.
- Minimum Operating Reserve is the 10-Minute minimum Operating Reserve requirement for ISO Operations

Questions