Assumptions for Calculating the Installed Capacity Requirement (ICR) Values for the 2020-2021 Forward Capacity Auction (FCA11)

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Objective of this Presentation

- Review the ICR Values* development and FERC filing schedules

- Review the assumptions for calculating:
  - Installed Capacity Requirement (ICR),
  - Transmission Security Analysis (TSA),
  - Local Resource Adequacy Requirement (LRA),
  - Local Sourcing Requirement (LSR), and
  - Maximum Capacity Limit (MCL)
  - Marginal Reliability Impact Demand Curve (MRI Demand Curve)

- Review the Indicative MCL calculation for Northern New England (NNE)

***The ICR, LSR, MCL and the Demand Curves are collectively called the ICR Values**

Proposed ICR Review and FERC Filing Schedule

- ICR for 2020-2021 Forward Capacity Auction (FCA11)
  - PSPC to review Capacity Zone determinations – **May 26, 2016**
  - PSPC final review of all assumptions – **Jun 30, 2016**
  - PSPC review of ISO recommendation of ICR Values – **Jul 28, 2016**
  - RC review/vote of ISO recommendation of ICR Values – **Aug 9-10, 2016***
  - PC review/vote of ISO recommendation of ICR Values – **Sep 9, 2016** *
  - File with the FERC – by **Nov 8, 2016***
  - FCA11 begins – **Feb 6, 2017***

*tentative – See alternate ICR voting schedule on next slide

Alternate ICR Review and FERC Filing Schedule

- Alternate ICR Voting schedule
  - RC review/vote of ISO recommendation of ICR Values – **Sep 20, 2016**
  - PC review/vote of ISO recommendation of ICR Values – **Oct 14, 2016**
  - File with the FERC – **by Nov 8, 2016**
  - FCA11 begins – **Feb 6, 2017**

Assumptions for the 2020-2021 FCA ICR Values Calculation

Cost of New Entry (CONE)

- for the Demand Curve

- CONE for the Cap of the Demand Curve for FCA11 has been calculated as:
  - Gross CONE = $14.387/kW-month
  - Net CONE = $11.640/kW-month

- See link for Forward Capacity Market (FCM) parameters by CCP:

http://www.iso-ne.com/markets-operations/markets/forward-capacity-market

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 will be calculated for the combined Load Zones of NEMA/Boston, SEMA and RI (Southeast New England (SENE) Capacity Zone)
- An Indicative MCL is calculated for the combined Maine, New Hampshire and Vermont Load Zones (Northern New England (NNE)) as a step in the review of Capacity Zone determination. The NNE combined zones will be modeled as a Capacity Zone. A final MCL value will be calculated once tie benefit assumptions for 2020-2021 are available
- Connecticut will not be modeled as a Capacity Zone
- The Marginal Reliability Impact (MRI) method for calculating Demand Curves will be used to determine System and Capacity Zone Demand Curves

Assumptions for the ICR Calculations

- *Load Forecast*
  - Load Forecast distribution
  - Net of Behind the Meter not Embedded (BTM) Photovoltaic (PV) resource forecast
- *Resource Data Based on Existing Qualified Capacity Resources for FC11*
  - The 27.262 MWs of retirement de-list bids for FCA11 have not been deducted from the Existing resources
  - 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 2016 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	2020-2021
Jun	672
Jul	676
Aug	680
Sep	684
Oct	0
Nov	0
Dec	0
Jan	0
Feb	0
Mar	0
Apr	0
May	709

- Table shows the monthly estimated Peak Load Reduction. These are the value of BTM PV resources modeled in ICR (includes 8% Transmission & Distribution Gross-up)
- Developed using 36%* of PV nameplate forecast from the Distributed Generation Forecast Working Group (DGFWG) for 2020-2021
- Modeled as a load modifier in GE MARS by Regional System Plan (RSP) 13-subarea representation for hours ending 14:00 – 18:00

*Future net load scenarios are based on coincident, historical hourly load and PV production data for the years 2012-2015. For more info, see http://www.iso-ne.com/static-assets/documents/2016/03/2016_draftpvforecast_20160224revised.pdf

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
2020-2021	25,730	29,601	29,601	24,051	18,904	20,592	23,633	23,633	22,846	22,038	18,454	20,463

- Corresponds to the reference forecast labeled“*1.2 REFERENCE - With reduction for BTM PV“* from section 1.1 of the 2016 CELT Report

There is a distribution associated with each monthly peak. The distribution associated with the Seasonal Peak Load Forecast is show below:

Probability Distribution of Seasonal Peak Load (MW)

	10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
Summer 2020	28,120	28,385	28,744	29,149	29,601	30,080	30,571	31,273	32,081	32,788
Winter 2020-2021	23,199	23,320	23,417	23,480	23,633	23,787	23,959	24,063	24,321	24,696

- From Table 1.6 - Seasonal Peak Load Forecast Distributions (Forecast is Reference with reduction for BTM PV) from the 2016 CELT

Resource Data – Generating Capacity Resources (MW)

Load Zone	Non-Intermittent Generation		Intermittent Generation		Total	
	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	2,949.645	3,134.407	217.875	338.053	3,167.520	3,472.460
NEW HAMPSHIRE	4,075.922	4,240.694	162.576	229.151	4,238.498	4,469.845
VERMONT	248.351	288.055	74.693	124.751	323.044	412.806
CONNECTICUT	9,655.575	10,133.915	166.590	180.804	9,822.165	10,314.719
RHODE ISLAND	2,360.257	2,563.851	9.261	18.088	2,369.518	2,581.939
SOUTH EAST MASSACHUSETTS	4,357.821	4,756.516	95.076	78.189	4,452.897	4,834.705
WEST CENTRAL MASSACHUSETTS	3,739.406	4,010.360	103.052	120.676	3,842.458	4,131.036
NORTH EAST MASSACHUSETTS & BOSTON	3,227.698	3,654.013	77.056	72.834	3,304.754	3,726.847
Total New England	**30,614.675**	**32,781.811**	**906.179**	**1,162.546**	**31,520.854**	**33,944.357**

- Existing Qualified generating capacity resources for FCA11. The 16.030 MWs of Retirement De-List bids for FCA11 have not been deducted.
- Intermittent resources have both summer and winter values modeled; non-Intermittent winter values provided for informational purpose
- Reflects a 30 MW derating to model the firm contract value of the Vermont Joint Owners (VJO) capacity import

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 FCA11
- 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)

- There were no export delist bids modeled for 2020-2021

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	148.224	132.642	-	-	136.536	154.432	6.402	4.550	291.162	291.624
NEW HAMPSHIRE	106.299	85.822	-	-	10.067	9.347	13.914	11.937	130.280	107.106
VERMONT	93.335	69.217	-	-	31.900	39.833	5.458	4.789	130.693	113.839
CONNECTICUT	75.583	54.942	440.158	416.045	59.951	58.721	59.097	58.151	634.789	587.859
RHODE ISLAND	207.499	187.966	-	-	42.213	38.712	15.720	11.329	265.432	238.007
SOUTH EAST MASSACHUSETTS	311.925	271.180	-	-	46.340	44.465	12.722	12.722	370.987	328.367
WEST CENTRAL MASSACHUSETTS	343.751	310.843	45.251	25.964	49.596	45.941	25.530	24.976	464.128	407.724
NORTH EAST MASSACHUSETTS & BOSTON	590.347	524.669	-	-	62.097	62.097	9.430	9.202	661.874	595.968
Total New England	1,876.963	1,637.281	485.409	442.009	438.700	453.548	148.273	137.656	2,949.345	2,670.494

- Existing Qualified Demand Resource capacity for FCA11. The 11.232 MWs of DR Retirement De-List bids for FCA11 have not been deducted.
- Includes the Transmission and Distribution (T&D) Loss Adjustment (Gross-up) of 8%

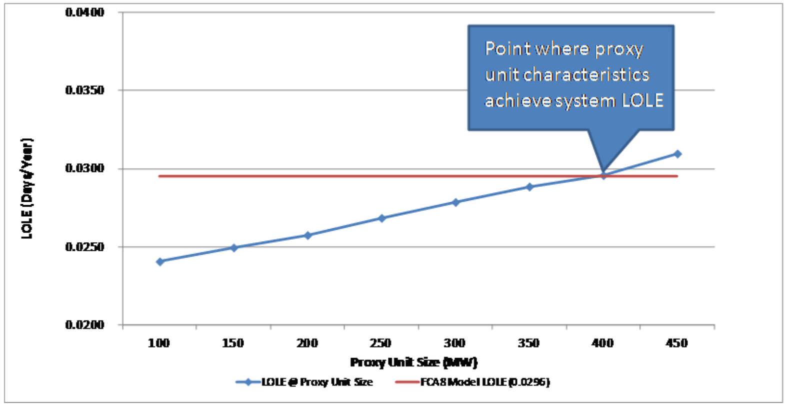
Sub-area Resource and 50/50 Peak Load Forecast Assumptions Used in LRA and MCL Calculations (MW)

Resource Type	SENE	NNE	Total New England
Generator	9,945.776	7,243.918	30,584.675
Intermittent Generator	181.393	455.144	906.179
Import	-	6.000	88.800
On-Peak DR	1,109.771	347.858	1,876.963
Seasonal-Peak DR	-	-	485.409
Real-Time DR	150.650	178.503	438.700
Real-Time Emergency Gen DR	37.872	25.774	148.273
Total	11,425.462	8,257.197	34,528.999
	SENE	NNE	New England
50/50 Load Forecast Net BTM PV	12,153	5,882	29,601

- LRA is calculated for the SENE Capacity Zones; MCL is calculated for NNE. Generating resource assumptions are based on the RSP areas used as a proxy for the Load Zones as the transmission transfer capability analysis is performed using the RSP 13-bubbles. DR values are the Load Zone values. Includes a 30 MW derating to reflect the value of the VJO contract.
- For the resources, the sum of the Load Zones and the corresponding RSP sub-areas for the Capacity Zones are the same
- Sum of the RSP area 50/50 Peak Load Forecast values may not equal total New England due to rounding. 50/50 Load Forecast shown for informational purposes.

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

LRA, TSA & MCL Internal Transmission Transfer Capability Assumptions (MW)

- Internal Transmission Transfer Capability
  - Southeast New England Import
    - N-1 Limit: 5,700
    - N-1-1 Limit: 4,600
  - Northern New England Export (North-South interface)
    - N-1 Limit: 2,725

Transmission transfer capability limits – presented at the Planning Advisory Committee (PAC) on March 22, 2016 (http://www.iso-ne.com/static-assets/documents/2016/03/a2_fca11_zonal_boundary_determinations.pdf)

Includes:
- 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 CCP9 in response to the Brayton Point retirement
- Northern New England Scobie + 394 – the stability limit has been updated

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 2011 – Dec 2015) 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 2011 – Dec 2015) 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	14,732	4.0	5.0
Fossil	6,088	17.5	5.9
Nuclear	3,344	2.1	4.5
Hydro (Includes Pumped Storage)	2,978	3.3	4.8
Combustion Turbine	3,193	10.6	2.6
Diesel	191	6.5	1.0
Miscellaneous	58	17.6	3.0
Total System	30,585	7.1	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.

Changes in Generator Availability

- ISO-NE uses a 5-year rolling calculation of GADS EFORd for each generator
  - This year's ICR calculation is using the EFORd from PowerGads software for each generator based on outages reported from the years 2011 – 2015.
- The New England total of 5-year individual EFORd for each generator weighted by its qualified capacity for FCA11 is 7.1%
  - The FCA10 New England average was 6.9%
- Some of this 0.2% increase can be attributed to the retirement of the Pilgrim nuclear generator
  - Large unit with relative low EFORd
- While 2015 annual EFORd is improved compared to recent years, it is replacing 2010 in the 5-year average which is a year that also had good availability (System EFORd of 3.85% for 2010 versus 4.07 % for 2015)
- If generator availability trends continue to improve, we will slowly see a decrease in EFORd as the years with lower availability drop out of the 5-year average, particularly 2012 and 2013

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		Seasonal Peak		RT Demand Response		RT Emergency Gen		Total	
	Summer (MW)	Perform-ance (%)	Summer (MW)	Perform-ance (%)	Summer (MW)	Perform-ance (%)	Summer (MW)	Perform-ance (%)	Summer	Perform-ance (%)
MAINE	148.224	100	-	-	136.536	99	6.402	91	291.162	99
NEW HAMPSHIRE	106.299	100	-	-	10.067	83	13.914	95	130.280	98
VERMONT	93.335	100	-	-	31.900	96	5.458	86	130.693	99
CONNECTICUT	75.583	100	440.158	100	59.951	91	59.097	94	634.789	99
RHODE ISLAND	207.499	100	-	-	42.213	79	15.720	95	265.432	96
SOUTH EAST MASSACHUSETTS	311.925	100	-	-	46.340	80	12.722	87	370.987	97
WEST CENTRAL MASSACHUSETTS	343.751	100	45.251	100	49.596	83	25.530	96	464.128	98
NORTH EAST MASSACHUSETTS & BOSTON	590.347	100	-	-	62.097	86	9.430	95	661.874	99
Total New England	1,876.963	100	485.409	100	438.700	90	148.273	93	2,949.345	98

- Uses historical DR performance from summer & winter 2011 – 2015. See May 26, 2016 PSPC presentation more information.
- Modeled by zones and type of DR with outage factor calculated as 1- performance/100

OP4 Assumptions
- Action 6 & 8 - 5% Voltage Reduction (MW)

	90-10 Peak Load	Passive DR	RTDR	RTEG	Action 6 & 8 5% Voltage Reduction
Jun 2020- Sep 2021	32,081	2,362	439	148	437
Oct 2020 - May 2021	24,321	2,079	454	138	325

- 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 2020-2021 Tie Benefits Study currently under development

- 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/OP4	2020-2021 FCA
Generating Resources	30,644.675
Intermittent Power Resources	906.179
Demand Resources	2,949.345
Import Resources	88.800
Export Delist	-
Import Deratings	(30.000)
OP 4 Voltage Reduction	437.000
Minimum Operating Reserve	(200.000)
Tie Benefits (includes HQICCs)	
Proxy Units	
Total MW Modeled in ICR	

Notes:

- Intermittent Power Resources have both the summer and winter capacity values modeled
- Import deratings reflect the value of the firm VJO contract and is removed from the generating resources MWs
- 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

Indicative MCL for NNE

LRA - RestofNewEngland (for NNE MCL calculation)			
Rest of New England Zone		**2020-2021 FCA**	**2019-2020 FCA**
Resource_z	[1]	26,272	25,220
Proxy Units_z	[2]	0	800
$\text{Surplus Capacity Adjustment}_z$	[3]	508	106
$\text{Firm Load Adjustment}_z$	[4]	645	521
FOR_z	[5]	0.072	0.071
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**25,030**	**25,345**
NNE Zone			
Resource	[7]	8,257	8,264
Proxy Units	[8]	0	0
$\text{Surplus Capacity Adjustment}_z$	[9]	-508	-106
Firm Load Adjustment	[10] = -[4]	-645	-521
Total System Resource	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	34,529	34,284

Indicative Maximum Capacity Limit - NNE			
Commitment Period		**2020-2021 FCA**	**2019-2020 FCA**
NICR for New England*	[1]	34,010	34,175
$\text{LRA}_{\text{RestofNewEngland}}$	[2]	25,030	25,345
$\text{Maximum Capacity Limit}_Y$	[3]=[1]-[2]	**8,980**	**8,830**

Comparison of pertinent data related to the Indicative MCL calculation:

	FCA11	FCA10
North-South Interface TTC	2,725	2,675
NNE Load Forecast 50/50	5,882	5,872
Total 50/50 LF Net of BTM PV	29,601	29,849
NB Tie Benefits used for this run	519	509

- NICR used in the Indicative MCL calculation is preliminary for FCA11 and uses the final tie benefits values for FCA10 (1,990 MW)
- NICR used in the FCA10 Indicative MCL calculation used preliminary tie benefits calculated with NNE modeled as a zone (1,965 MW)
- All values in MWs except the Forced Outage Rate (FOR) which is percent

Questions