Proposed Installed Capacity Requirement (ICR) Values

- *2017-2018 Third Annual Reconfiguration Auction (2017-2018 ARA3)*
- *2018-2019 Second Annual Reconfiguration Auction (2018-2019 ARA2)*
- *2019-2020 First Annual Reconfiguration Auction (2019-2020 ARA1)*

Maria Scibelli

Objective of this Presentation

- Review the Committee voting and FERC filing schedules
- Review the proposed ICR Values* including:
  - Installed Capacity Requirement (ICR),
  - Transmission Security Analysis (TSA),
  - Local Resource Adequacy Requirement (LRA),
  - Local Sourcing Requirement (LSR), and
  - Maximum Capacity Limit (MCL)
  - System-wide Capacity Demand Curve (Demand Curve) requirement values

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

Calculation of ICR Values

- LSR and MCL Requirements and Demand Curve capacity requirement values are calculated for the following Capacity Zones (as determined by the Forward Capacity Auctions (FCAs))
  - 2017-2018 ARA3
    - LSR for Connecticut & NEMA/Boston
    - MCL for Maine
  - 2018-2019 ARA2
    - LSR for Connecticut, NEMA/Boston and the combined Load Zones of SEMA and Rhode Island - SEMA/RI Capacity Zone
    - System-wide Capacity Demand Curve requirement values
      - Demand Curve Cap at [1-in-5 LOLE capacity requirement, $17.728/kW-month]
      - Demand Curve Foot at [1-in-87 LOLE capacity requirement, $0/kW-month]
  - 2019-2020 ARA1
    - LSR for the combined Load Zones of NEMA/Boston, SEMA and Rhode Island - Southeast New England (SENE) Capacity Zone
    - System-wide Capacity Demand Curve requirement values
      - Demand Curve Cap at [1-in-5 LOLE capacity requirement, $17.296/kW-month]
      - Demand Curve Foot at [1-in-87 LOLE capacity requirement, $0/kW-month]

Installed Capacity Requirement Values Schedule

ICR Values for the following auctions will be calculated, reviewed and filed concurrently:

- **2017-2018 3rd Annual Reconfiguration Auction (ARA3) – Mar 1, 2017**
- **2018-2019 2nd Annual Reconfiguration Auction (ARA2) – Aug 1, 2017**
- **2019-2020 1st Annual Reconfiguration Auction (ARA1) – Jun 5, 2017**

  - PSPC final review of assumptions – **Aug 25, 2016**
  - PSPC review of ISO recommended ICR Values – **Sep 22 & Oct 13, 2016**
  - RC review/vote of ISO recommended ICR Values – **Oct 18, 2016**
  - PC review/vote of ISO recommended ICR Values – **Nov 4, 2016**
  - File with the FERC – by **Dec 1, 2016**

PROPOSED ICR VALUES FOR 2017-2018 ARA3, 2018-2019 ARA2 AND 2019-2020 ARA1

2017-2018 ARA3 ICR Values (MW)

2017-2018 ARA3	New England	Connecticut	NEMA/ Boston	Maine
Peak Load (50/50)	28,788	7,448	6,149	2,135
Existing Capacity Resources	35,048	9,220	4,053	4,031
Installed Capacity Requirement	34,246			
NET ICR (ICR Minus 1,108 MW of HQICCs)	33,138			
Local Resource Adequacy Requirement		6,909	2,862	
Transmission Security Requirement		7,029	3,361	
Local Sourcing Requirement		7,029	3,361	
Maximum Capacity Limit				4,295

- Existing Capacity Resources are the Qualified Capacity resources for the 2017-2018 ARA2 which are the most recent available resources at the time of the ICR calculation; updated to reflect known resource retirements and terminations

2018-2019 ARA2 ICR Values (MW)

2018-2019 ARA2	New England	Connecticut	NEMA/ Boston	SEMA/RI
Peak Load (50/50)	29,070	7,492	6,223	5,664
Existing Capacity Resources	35,960	9,941	4,079	7,431
Installed Capacity Requirement	34,374			
NET ICR (ICR Minus 953 MW of HQICCs)	33,421			
1-in-5 LOLE Demand Curve capacity value	32,395			
1-in-87 LOLE Demand Curve capacity value	36,159			
Local Resource Adequacy Requirement		7,078	2,932	6,804
Transmission Security Requirement		7,072	3,445	6,305
Local Sourcing Requirement		7,078	3,445	6,804

- Existing Capacity Resources are based on the Qualified Capacity resources for the 2018-2019 ARA1 which are the most recent available resources at the time of the calculation; updated to reflect known resource retirements and terminations

2019-2020 ARA1 ICR Values (MW)

2019-2020 ARA1	New England	Southeast New England
Peak Load (50/50)	29,344	12,022
Existing Capacity Resources	36,151	11,625
Installed Capacity Requirement	34,730	
NET ICR (ICR Minus 975 MW of HQICCs)	33,755	
1-in-5 LOLE Demand Curve capacity value	32,714	
1-in-87 LOLE Demand Curve capacity value	36,526	
Local Resource Adequacy Requirement		9,360
Transmission Security Requirement		9,637
Local Sourcing Requirement		9,637

- Existing Capacity Resources are based on the 2019-2020 FCA Existing Qualified Capacity data plus the 2019-2020 FCA New Capacity resources that cleared the FCA

ICR Calculation Details

Capacity Breakdown

	2017-2018 ARA3	2018-2019 ARA2	2019-2020 ARA1
Generating Capacity	30,081	31,104	31,542
Demand Resources	3,211	3,127	3,100
Imports	1,756	1,730	1,510
Tie Benefits	1,875	1,970	1,990
OP 4 VR - Actions 6 & 8	419	425	430
Minimum Operating Reserves	(200)	(200)	(200)
Proxy Unit Capacity			
Capacity	**37,142**	**38,155**	**38,371**

ICR Calculation

	2017-2018 ARA3	2018-2019 ARA2	2019-2020 ARA1
Annual Peak	28,788	29,070	29,344
Capacity	37,142	38,155	38,371
Tie Benefits	1,875	1,970	1,990
HQICCs	1,108	953	975
OP4 VR - Actions 6 & 8	419	425	430
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	1,660	2,208	2,083
Installed Capacity Requirements	**34,246**	**34,374**	**34,730**
Net ICR	**33,138**	**33,421**	**33,755**

Reserve Margin with HQICCs	19.0%	18.2%	18.4%
Reserve Margin without HQICCs	15.1%	15.0%	15.0%

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

- All values in the table are in MW except the Reserve Margin which is shown in percent
- ALCC is the “Additional Load Carrying Capability” used to bring the system to the 0.1 Reliability Criterion

Demand Curve Capacity Requirement Values
-for 2018-2019 ARA2

Capacity Breakdown

	1-in-5 LOLE	2018-2019 ARA2	1-in-87 LOLE
Generating Capacity	31,104	31,104	31,104
Demand Resources	3,127	3,127	3,127
Imports	1,730	1,730	1,730
Tie Benefits	1,970	1,970	1,970
OP 4 VR - Actions 6 & 8	425	425	425
Minimum Operating Reserves	(200)	(200)	(200)
Proxy Unit Capacity			400
Capacity	**38,155**	**38,155**	**38,555**

ICR Caclulation

	1-in-5 LOLE	2018-2019 ARA2	1-in-87 LOLE
Annual Peak	29,070	29,070	29,070
Capacity	38,155	38,155	38,555
Tie Benefits	1,970	1,970	1,970
HQICCs	953	953	953
OP 4 VR - Actions 6 & 8	425	425	425
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	3,199	2,208	162
Installed Capacity Requirements	**33,348**	**34,374**	**37,112**
Net ICR	**32,395**	**33,421**	**36,159**

Reserve Margin with HQICCs	14.7%	18.2%	27.7%
Reserve Margin without HQICCs	11.4%	15.0%	24.4%

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

- 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 0.1 Reliability Criterion

Demand Curve Capacity Requirement Values - for 2019-2020 ARA1

Capacity Breakdown

	1-in-5 LOLE	2019-2020 ARA1	1-in-87 LOLE
Generating Capacity	31,542	31,542	31,542
Demand Resources	3,100	3,100	3,100
Imports	1,510	1,510	1,510
Tie Benefits	1,990	1,990	1,990
OP 4 VR - Actions 6 & 8	430	430	430
Minimum Operating Reserves	(200)	(200)	(200)
Proxy Unit Capacity			400
Capacity	**38,371**	**38,371**	**38,771**

	1-in-5 LOLE	2019-2020 ARA1	1-in-87 LOLE
Annual Peak	29,344	29,344	29,344
Capacity	38,371	38,371	38,771
Tie Benefits	1,990	1,990	1,990
HQICCs	975	975	975
OP 4 VR - Actions 6 & 8	430	430	430
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	3,083	2,083	20
Installed Capacity Requirements	**33,689**	**34,730**	**37,501**
Net ICR	**32,714**	**33,755**	**36,526**

Reserve Margin with HQICCs	14.8%	18.4%	27.8%
Reserve Margin without HQICCs	11.5%	15.0%	24.5%

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

- 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 0.1 Reliability Criterion

Effect of Updated Assumptions on ICR
– 2017-2018 ARA3 versus FCA8

Assumption	2017-2018 ARA3		2017-2018 FCA		Effect on ICR (MW)
Tie Benefits	472 MW New York		227 MW New York		39
	224 MW Maritimes		492 MW Maritimes		
	1,108 MW Quebec (HQICCs)		1,068 MW Quebec (HQICCs)		
	71 MW Quebec via Highgate		83 MW Quebec via Highgate		
Total	1,875 MW		1,870 MW		
	MW	Weighted Forced Outage (%)	MW	Weighted Forced Outage	
Generation	30,082	7.0	32,220	5.8	277
Demand Resources	3,211	3.4	3,416	5.8	-87
Imports & Sales	1,756	1.4	-11	0	5
	MW		MW		
Load Forecast	28,788		29,790		-822
	MW	%	MW	%	
OP 4 5% VR	419	1.5	432	1.5	14
	MW		MW		
ICR	34,246		34,923		-677

- Methodology: Begin with the model for the 2017-2018 FCA ICR calculation. Change one assumption at a time and note the change in ICR caused by each change in assumption
- The change in Net ICR due to the tie benefits assumption is 2 MW
- The change in ICR due to the change in Load Forecast Uncertainty assumed is 96 MW

Effect of Updated Assumptions on ICR
– 2018-2019 ARA2 versus FCA9

Assumption	2018-2019 ARA2		2018-2019 FCA		Effect on ICR (MW)
	MW	Weighted Forced Outage (%)	MW	Weighted Forced Outage (%)	
Generation & IPR	31,104	6.9	29,699	6.5	125
Demand Resources	3,127	2.7	3,054	4.0	
Imports & Sales	1,730	2.0	89	0.0	
	MW		MW		
Load Forecast	29,070		30,005		-903
	MW		MW		
ICR	34,374		35,142		-768

- Methodology: Begin with model for the 2018-2019 FCA ICR calculation. Change one assumption at a time and note the change in ICR caused by each change in assumption

Effect of Updated Assumptions on ICR
– 2019-2020 ARA1 versus FCA10

Assumption	2019-2020 ARA1		2019-2020 FCA		Effect on ICR (MW)
	MW	Weighted Forced Outage (%)	MW	Weighted Forced Outage (%)	
Generation & IPR	31,542	7.0	30,524	6.7	95
Demand Resources	3,100	1.7	2,871	2.5	
Imports & Sales	1,510	2.5	89	0	
	MW		MW		
Load Forecast	29,344		29,861		-507
	MW		MW		
ICR	34,730		35,126		-396

- Methodology: Begin with model for the 2019-2020 FCA ICR calculation. Change one assumption at a time and note the change in ICR caused by each change in assumption

TSA Requirements – 2017-2018 ARA3

2017-18 ARA3 TSA Requirement (in MW)	Connecticut	NEMA/Boston
2016 Sub-area 90/10 Load*	8133	6612
Reserves (Largest unit)	1225	1413
Sub-area Transmission Security Need	**9358**	**8025**
Existing Resources	9220	4053
Assumed Unavailable Capacity	-815	-225
Sub-area N-1 Import Limit	2950	4850
Sub-area Available Resources	**11355**	**8679**
TSA Requirement	**7029**	**3361**

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

***Behind the Meter Load Forecast (BTM-PV) is modeled as a reduction to the load forecast**

TSA Requirements – 2018-19 ARA2

2018-19 ARA2 TSA Requirement (in MW)	Connecticut	NEMA/Boston	SEMA/RI
2016 Sub-area 90/10 Load*	8182	6693	6198
Reserves (Largest unit)	1225	1412	740
Sub-area Transmission Security Need	**9407**	**8105**	**6938**
Existing Resources	9941	4079	7431
Assumed Unavailable Capacity	-864	-225	-763
Sub-area N-1 Import Limit	2950	4850	1280
Sub-area Available Resources	**12027**	**8704**	**7948**
TSA Requirement	**7072**	**3445**	**6305**

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

***Behind the Meter Load Forecast (BTM-PV) is modeled as a reduction to the load forecast**

TSA Requirements – 2019-2020 ARA1

2019-20 ARA2 TSA Requirement (in MW)	SENE
2016 Sub-area 90/10 Load*	13043
Reserves (Largest unit)	1413
Sub-area Transmission Security Need	**14456**
Existing Resources	11625
Assumed Unavailable Capacity	-1063
Sub-area N-1 Import Limit	5700
Sub-area Available Resources	**16262**

TSA Requirement **9637**

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

Behind the Meter Load Forecast (BTM-PV) is modeled as a reduction to the load forecast

LRA- Connecticut

- for 2017-2018 ARA3 & 2018-2019 ARA2

Local Resource Adequacy Requirement - Connecticut			
Connecticut Zone		**2017-2018 ARA3**	**2018-2019 ARA2**
$Resource_z$	[1]	9,220	9,941
$Proxy\ Units_z$	[2]	0	0
$Firm\ Load\ Adjustment_z$	[3]	2,136	2,652
FOR_z	[4]	0.0758	0.0735
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**6,909**	**7,078**
Rest of New England Zone			
Resource	[6]	25,828	26,020
Proxy Units	[7]	0	0
Firm Load Adjustment	[8] = -[3]	-2,136	-2,652
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	35,048	35,960

- All values in the table are in MW except the Forced Outage $Rate_z$ (FOR_z)
- Additional CT resources for 2018-2019 ARA2 includes CPV Towantic and Wallingford 6&7

LRA – NEMA/Boston

- for 2017-2018 ARA3 & 2018-2019 ARA2

Local Resource Adequacy Requirement - NEMA/BOSTON			
NEMA/BOSTON Zone		**2017-2018 ARA3**	**2018-2019 ARA2**
$Resource_z$	[1]	4,053	4,079
Proxy $Units_z$	[2]	0	0
Firm Load $Adjustment_z$	[3]	1,127	1,086
FOR_z	[4]	0.0538	0.0530
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**2,862**	**2,932**
Rest of New England Zone			
Resource	[6]	30,995	31,881
Proxy Units	[7]	0	0
Firm Load Adjustment	[8] = -[3]	-1,127	-1,086
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	35,048	35,960

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

LRA – SEMA/RI

- for 2018-2019 ARA2

Local Resource Adequacy Requirement - SEMA/RI		
SEMA/RI		**2018-2019 ARA2**
$Resource_z$	[1]	7,431
$Proxy\ Units_z$	[2]	0
$Firm\ Load\ Adjustment_z$	[3]	562
FOR_z	[4]	0.1028
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**6,804**
Rest of New England Zone		
Resource	[6]	28,530
Proxy Units	[7]	0
Firm Load Adjustment	[8] = -[3]	-562
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	35,960

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

LRA – SENE for 2019-2020 ARA1

Local Resource Adequacy Requirement - SENE		
SENE		**2019-2020 ARA1**
$Resource_z$	[1]	11,625
$Proxy\ Units_z$	[2]	0
$Firm\ Load\ Adjustment_z$	[3]	2,076
FOR_z	[4]	0.0837
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**9,360**
Rest of New England Zone		
Resource	[6]	24,526
Proxy Units	[7]	0
Firm Load Adjustment	[8] = -[3]	-2,076
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	36,151

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

MCL – Maine for 2017-2018 ARA3

LRA Requirement - RestofNewEngland (for Maine MCL calculation)		
Rest of New England Zone		**2017-2018 ARA3**
$Resource_z$	[1]	31,018
$Proxy\ Units_z$	[2]	0
$Surplus\ Capacity\ Adjustment_z$	[3]	1,862
$Firm\ Load\ Adjustment_z$	[4]	164
FOR_z	[5]	0.0687
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**28,842**
Maine Zone		
Resource	[7]	4,031
Proxy Units	[8]	0
$Surplus\ Capacity\ Adjustment_z$	[9]	0
Firm Load Adjustment	[10] = -[4]	-164
Total System Resources	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	35,048

Maximum Capacity Limit - Maine		
Commitment Period		**2017-2018 ARA3**
NICR for New England	[1]	33,138
$LRA_{RestofNewEngland}$	[2]	28,842
$Maximum\ Capacity\ Limit_Y$	[3]=[1]-[2]	**4,295**

- All values in the table are in MW except the FOR_z
- The Maine MCL is affected by the tie benefits into New England from the Maritimes and the Transmission Transfer Capability (TTC) of the Maine-New Hampshire interface which are shown below:

	2017-2018 ARA3
Tie Benefits - Maritimes (MW)	224
Maine-New Hampshire Interface (MW)	1,900

APPENDIX II: COMPARISONS OF ICR VALUES 2017-2018 ARA3, 2018-2019 ARA2 AND 2019-2020 ARA1

2017-2018 ARA3 Comparison of ICR Values (MW)

	New England		Connecticut		NEMA/Boston		Maine	
	2017-2018 ARA3	2017-2018 FCA	2017-2018 ARA3	2017-2018 FCA	2017-2018 ARA3	2017-2018 FCA	2017-2018 ARA3	2017-2018 FCA
Peak Load (50/50)	28,788	29,790	7,448	7,650	6,149	6,260	2,135	2,115
Existing Capacity Resources	35,048	35,443	9,220	9,768	4,053	3,685	4,031	3,593
Installed Capacity Requirement	34,246	34,923						
NET ICR (ICR Minus HQICCs)	33,138	33,855						
Local Resource Adequacy Requirement			6,909	7,319	2,862	2,968		
Transmission Security Requirement			7,029	7,273	3,361	3,428		
Local Sourcing Requirement			7,029	7,319	3,361	3,428		
Maximum Capacity Limit							4,295	3,960

- Existing Capacity Resources are the Qualified capacity resources for the 2017-2018 ARA2 which are the most recent available resources at the time of the ICR calculation; updated to reflect known resource retirements & terminations
- For the details of the 2017-2018 FCA ICR calculation see: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2013/sep182013/a5_fca8_hqicc_icr_values.zip

2017-2018 ARA3 Vs. FCA LRA & MCL Comparisons

Local Resource Adequacy Requirement - Connecticut			
Connecticut Zone		**2017-2018 ARA3**	**2017-2018 FCA**
$Resource_z$	[1]	9,220	9,768
$Proxy\ Units_z$	[2]	0	0
$Firm\ Load\ Adjustment_z$	[3]	2,136	2,282
FOR_z	[4]	0.076	0.068
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**6,909**	**7,319**
Rest of New England Zone			
Resource	[6]	25,828	25,675
Proxy Units	[7]	0	0
Firm Load Adjustment	[8] = -[3]	-2,136	-2,282
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	35,048	35,443

Local Resource Adequacy Requirement - NEMA/BOSTON			
NEMA/BOSTON Zone		**2017-2018 ARA3**	**2017-2018 FCA**
$Resource_z$	[1]	4,053	3,685
$Proxy\ Units_z$	[2]	0	0
$Firm\ Load\ Adjustment_z$	[3]	1,127	685
FOR_z	[4]	0.054	0.044
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**2,862**	**2,968**
Rest of New England Zone			
Resource	[6]	30,995	31,758
Proxy Units	[7]	0	0
Firm Load Adjustment	[8] = -[3]	-1,127	-685
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	35,048	35,443

LRA Requirement - RestofNewEngland (for Maine MCL calculation)			
Rest of New England Zone		**2017-2018 ARA3**	**2017-2018 FCA**
$Resource_z$	[1]	31,018	31,850
$Proxy\ Units_z$	[2]	0	0
$Surplus\ Capacity\ Adjustment_z$	[3]	1,862	1,570
$Firm\ Load\ Adjustment_z$	[4]	164	268
FOR_z	[5]	0.069	0.060
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**28,842**	**29,894**
Maine Zone			
Resource	[7]	4,031	3,593
Proxy Units	[8]	0	0
$Surplus\ Capacity\ Adjustment_z$	[9]	0	0
Firm Load Adjustment	[10] = -[4]	-164	-268
Total System Resources	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	35,048	35,443

Maximum Capacity Limit - Maine			
Commitment Period		**2017-2018 ARA3**	**2017-2018 FCA**
NICR for New England	[1]	33,138	33,855
$LRA_{RestofNewEngland}$	[2]	28,842	29,894
$Maximum\ Capacity\ Limit_Y$	[3]=[1]-[2]	**4,295**	**3,960**

- All values in the table are in MW except the FOR_z
- TTC and tie benefit values (MW) affecting the calculation of LRA and MCL are shown below:

2017-2018	ARA3	FCA
Connecticut Import	2,950	2,800
Boston Import	4,850	4,850
Maine-New Hampshire Interface (MW)	1,900	1,900
Tie Benefits - Maritimes (MW)	224	492

TSA Requirements Comparison – 2017-2018 ARA3 and FCA8

	ARA3 TSA Requirement (MW)		FCA 8 TSA Requirement (MW)	
	Connecticut	**NEMA/Boston**	**Connecticut**	**NEMA/Boston**
Sub-area 90/10 Load	8133	6612	8330	6745
Reserves (Largest unit)	1225	1413	1200	1395
Sub-area Transmission Security Need	**9358**	**8025**	**9530**	**8140**
Existing Resources	**9220**	4053	9768	3685
Assumed Unavailable Capacity	**-815**	-225	-729	-149
Sub-area N-1 Import Limit	**2950**	4850	2800	4850
Sub-area Available Resources	**11355**	**8679**	**11839**	**8386**
TSA Requirement	**7029**	**3361**	**7273**	**3428**

- 2017-18 FCA TSA Requirement values were initially calculated and presented during the August 22, 2013 PSPC Meeting

2018-2019 ARA2 Comparison of ICR Values (MW)

	New England		Connecticut		NEMA/Boston		SEMA/RI	
	2018-2019 ARA2	2018-2019 FCA	2018-2019 ARA2	2018-2019 FCA	2018-2019 ARA2	2018-2019 FCA	2018-2019 ARA2	2018-2019 FCA
Peak Load (50/50)	29,070	30,005	7,492	7,725	6,223	6,350	5,664	5,910
Existing Capacity Resources	35,960	32,842	9,941	9,239	4,079	3,868	7,431	6,984
Installed Capacity Requirement	34,374	35,142						
NET ICR (ICR Minus HQICCs)	33,421	34,189						
1-in-5 LOLE Demand Curve capacity value	32,395	33,132						
1-in-87 LOLE Demand Curve capacity value	36,159	37,027						
Local Resource Adequacy Requirement			7,078	7,268	2,932	3,129	6,804	7,479
Transmission Security Requirement			7,072	7,331	3,445	3,572	6,305	7,116
Local Sourcing Requirement			7,078	7,331	3,445	3,572	6,804	7,479

- Existing Capacity Resources are based on the Qualified Capacity resources for the 2018-2019 ARA1 which are the most recent available resources at the time of the ICR calculation; updated to reflect known resource retirements and terminations
- For details of the 2018-2019 FCA9 ICR calculation see: http://www.iso-ne.com/static-assets/documents/2014/09/a6_fca9_icr_values.pdf

2018-2019 ARA2 Vs. FCA LRA & MCL Comparisons

Local Resource Adequacy Requirement - Connecticut			
Connecticut Zone		**2018-2019 ARA2**	**2018-2019 FCA**
$Resource_z$	[1]	9,941	9,239
$Proxy\ Units_z$	[2]	0	0
$Firm\ Load\ Adjustment_z$	[3]	2,652	1,825
FOR_z	[4]	0.0735	0.0741
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**7,078**	**7,268**
Rest of New England Zone			
Resource	[6]	26,020	23,603
Proxy Units	[7]	0	1,600
Firm Load Adjustment	[8] = -[3]	-2,652	-1,825
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	35,960	34,442

Local Resource Adequacy Requirement - NEMA/BOSTON			
NEMA/BOSTON Zone		**2018-2019 ARA2**	**2018-2019 FCA**
$Resource_z$	[1]	4,079	3,939
$Proxy\ Units_z$	[2]	0	0
$Firm\ Load\ Adjustment_z$	[3]	1,086	775
FOR_z	[4]	0.053	0.043
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**2,932**	**3,129**
Rest of New England Zone			
Resource	[6]	31,881	28,903
Proxy Units	[7]	0	1,600
Firm Load Adjustment	[8] = -[3]	-1,086	-775
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	35,960	34,442

Local Resource Adequacy Requirement - SEMA/RI			
SEMA/RI Zone		**2018-2019 ARA2**	**2018-2019 FCA**
$Resource_z$	[1]	7,431	6,984
$Proxy\ Units_z$	[2]	0	800
$Firm\ Load\ Adjustment_z$	[3]	562	278
FOR_z	[4]	0.103	0.090
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**6,804**	**7,479**
Rest of New England Zone			
Resource	[6]	28,530	25,857
Proxy Units	[7]	0	800
Firm Load Adjustment	[8] = -[3]	-562	-278
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	35,960	34,442

- All values in the table are in MW except the FOR_z
- TTC values (MW) affecting the calculation of LRA are shown below:

2018-2019	ARA2	FCA
Connecticut Import	2,950	2,950
Boston Import	4,850	4,850
SEMA/RI Import	1,280	786

TSA Requirements Comparison – 2018-2019 ARA2 and FCA9

	ARA2 TSA Requirement (MW)			FCA 9 TSA Requirement (MW)		
	Connecticut	**NEMA/Boston**	**SEMA/RI**	**Connecticut**	**NEMA/Boston**	**SEMA/RI**
Sub-area 90/10 Load	8182	6693	6198	8415	6835	6465
Reserves (Largest unit or loss of import capability)	1225	1412	740	1225	1412	700
Sub-area Transmission Security Need	**9407**	**8105**	**6938**	**9640**	**8247**	**7165**
Existing Resources	9941	4079	7431	9239	3868	6984
Assumed Unavailable Capacity	-864	-225	-763	-808	-190	-723
Sub-area N-1 Import Limit	2950	4850	1280	2950	4850	786
Sub-area Available Resources	**12027**	**8704**	**7948**	**11381**	**8528**	**7047**
TSA Requirement	**7072**	**3445**	**6305**	**7331**	**3572**	**7116**

- 2018-19 FCA TSA Requirement values were initially calculated and presented during the August 28, 2014 PSPC Meeting

2019-2020 ARA1 Comparison of ICR Values (MW)

	New England		Southeast New England	
	2019-2020 ARA1	2019-2020 FCA	2019-2020 ARA1	2019-2020 FCA
Peak Load (50/50)	29,344	29,861	12,022	12,282
Existing Capacity Resources	36,151	33,484	11,625	11,194
Installed Capacity Requirement	34,730	35,126		
NET ICR (ICR Minus HQICCs)	33,755	34,151		
1-in-5 LOLE Demand Curve capacity value	32,714	33,076		
1-in-87 LOLE Demand Curve capacity value	36,526	37,053		
Local Resource Adequacy Requirement			9,360	9,584
Transmission Security Requirement			9,637	10,028
Local Sourcing Requirement			9,637	10,028

- Existing Capacity Resources are based on the 2019-2020 FCA Existing Qualified Capacity data plus the 2019-2020 FCA New Capacity resources that cleared the FCA
- For the details of the 2019-2020 FCA10 ICR calculation see: https://www.iso-ne.com/static-assets/documents/2015/09/a9_icr_results.pdf

2019-2020 ARA1 Vs. FCA LRA Comparisons

Local Resource Adequacy Requirement - SENE			
SENE		**2019-2020 ARA1**	**2019-2020 FCA**
$Resource_z$	[1]	11,625	11,194
$Proxy\ Units_z$	[2]	0	0
$Firm\ Load\ Adjustment_z$	[3]	2,076	1,482
FOR_z	[4]	0.084	0.079
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**9,360**	**9,584**
Rest of New England Zone			
Resource	[6]	24,526	22,290
Proxy Units	[7]	0	800
Firm Load Adjustment	[8] = -[3]	-2,086	-1,482
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	36,151	34,284

- All values in the table are in MW except the FOR_z
- TTC and load forecast values (MW) affecting the calculation of LRA are shown below:

2019-2020	ARA1	FCA
SENE Load Forecast	12,022	12,282
SENE Import	5,700	5,700

TSA Requirements Comparison – 2019-2020 ARA1 and FCA10

	ARA1 TSA Requirement (MW)	FCA #10 TSA Requirement (MW)
	SENE	**SENE**
Sub-area 90/10 Load	13043	13342
Reserves (Largest unit)	1413	1413
Sub-area Transmission Security Need	**14456**	**14755**
Existing Resources	11625	11194
Assumed Unavailable Capacity	-1063	-1086
Sub-area N-1 Import Limit	5700	5700
Sub-area Available Resources	**16262**	**15808**
TSA Requirement	**9637**	**10028**

- 2019-20 FCA TSA Requirement values were initially calculated and presented during the August 27, 2015 PSPC Meeting

APPENDIX III: ASSUMPTIONS FOR THE 2017-2018 ARA3, 2018-2019 ARA2 AND 2019-2020 ARA1 ICR VALUES CALCULATION

Modeling the New England Control Area

The New England ICR is calculated using the GE MARS model

- Internal transmission constraints are not modeled. All loads and resources are assumed to be connected to a single electric bus.

- Internal transmission constraints are addressed through Local Sourcing Requirements and Maximum Capacity Limits.

Assumptions for the ICR Calculations

- *Load Forecast*
  - Load Forecast distribution
  - Net of Behind-the-Meter (BTM) Photovoltaic (PV) forecast
- *Existing Qualified Capacity Resources**
  - Generating Resources
  - Intermittent Power 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 (includes HQICCs)
    - Maritimes
    - New York
  - 5% Voltage Reduction

* Known resource retirements are removed; Terminations are reflected; new cleared capacity resources are added; Capacity imports are derated

Load Forecast Data

- Load forecast assumption from the 2016 CELT Report Load Forecast
  - This is based on the load forecast labeled *"1.2 REFERENCE - With Reduction for BTM PV"* on page 1.1 of the 2016 CELT

- 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 Calculations (MW)

Month	2017-2018	2018-2019	2019-2020
Jun	513	578	628
Jul	520	582	632
Aug	527	588	636
Sep	533	592	640
Oct	0	0	0
Nov	0	0	0
Dec	0	0	0
Jan	0	0	0
Feb	0	0	0
Mar	0	0	0
Apr	0	0	0
May	574	625	669

- Table shows the monthly estimated Peak Load Reduction. These are the value of BTM PV resources modeled in ICR calculations (includes 8% Transmission & Distribution Gross-up)
- Developed using the PV nameplate forecast from the Distributed Generation Forecast Working Group (DGFWG) of:
  - 2017-2018 = 38.2%; 2018-2019 = 37.3%; 2019-2020 = 36.7%
- 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. Final PV forecast documentation available at: http://www.iso-ne.com/static-assets/documents/2016/05/2016_pvforecast.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
2017-2018	25,545	28,788	28,788	23,971	18,621	20,192	23,170	23,170	22,306	21,587	18,139	20,653
2018-2019	25,854	29,070	29,070	24,251	18,733	20,350	23,353	23,353	22,511	21,759	18,258	20,838
2019-2020	26,139	29,344	29,344	24,506	18,827	20,484	23,507	23,507	22,678	21,898	18,356	21,005

There is a distribution associated with each monthly peak. The distribution associated with the Summer Seasonal Peak (July & August) is shown 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
2017	27,370	27,624	27,967	28,355	28,788	29,247	29,716	30,388	31,161	31,837
2018	27,632	27,889	28,238	28,631	29,070	29,536	30,012	30,695	31,479	32,166
2019	27,884	28,145	28,499	28,898	29,344	29,816	30,300	30,992	31,788	32,485

- Corresponds to the reference forecast labeled “*1.2 REFERENCE - With Reduction for BTM PV*“ from Sections 1.1 and 1.6 of the 2016 CELT Report

Resource Data – Capacity Modeled in ICR

- Qualified Capacity (QC) data for 2017-2018 ARA2, 2018-2019 ARA1 and 2019-2020 FCA Existing Qualified & New cleared for FCA10
  - Latest available dataset of QC resources for each Capacity Commitment Period (CCP)
  - Known resources that are retired and no longer operational plus any terminated resources are removed
  - Updated for any changes in Commercial Operation Date (COD)
  - Includes CPV-Towantic, Medway Peaker and Wallingford 6&7 for the 2018-2019 ARA2 & 2019-2020 ARA1 models (Total = 1,010 MW)
  - Includes Burrillville Energy Center 3, Bridgeport Harbor 5 & Canal 3 (Total = 1,302 MW) for the 2019-2020 ARA1 model
  - Pilgrim (677 MW) is removed from the 2019-2020 ARA1 ICR models, reflecting its retirement
  - Movement of Real-time Emergency Generators (RTEG) into Real-time Demand Response (RTDR) and RTEG CSOs that are brought to 0 MW are reflected
  - Import resources are derated to reflect the tie benefit assumptions used for those CCPs and Transmission Transfer Capability (TTC) assumptions

Resource Data – Generating Capacity Resources (MW)

Load Zone	Non-Intermittent Generation	
	Summer	Winter
MAINE	2,952.394	3,160.864
NEW HAMPSHIRE	4,088.960	4,285.837
VERMONT	228.501	267.369
CONNECTICUT	8,297.745	8,825.145
RHODE ISLAND	1,905.796	2,123.170
SOUTH EAST MASSACHUSETTS	4,591.030	4,977.138
WEST CENTRAL MASSACHUSETTS	3,657.348	3,917.843
NORTH EAST MASSACHUSETTS & BOSTON	3,264.005	3,666.948
Total New England	**28,985.779**	**31,224.314**

- Qualified non-IPR Generating capacity resources for 2017-2018 ARA3 ICR model are shown
  - 2018-2019 ARA2 model non-IPR generating resource total is 30,035.784 MW
  - 2019-2020 ARA1 model non-IPR generating resource total is 30,629.984 MW
- Non-IPR generating capacity winter values provided for informational purpose
- Reflects a 30 MW derate of the Block Load to reflect the value of the firm VJO contract
- Reflects known retirements of resources
- Large additions for the 2018-2019 ARA2 & 2019-2020 ARA1 models includes CPV-Towantic, Medway Peaker and Wallingford 6&7 (Total = 1,010 MW); 2019-2020 ARA1 includes Burrillville Energy Center 3, Bridgeport Harbor 5, Canal 3 (total = 1,302 MW) and reflects the retirement of the 677 MW Pilgrim nuclear generating station

Resource Data – IPR Generating Capacity Resources (MW)

Load Zone	Intermittent Generation	
	Summer	Winter
MAINE	281.687	380.439
NEW HAMPSHIRE	191.431	255.473
VERMONT	113.963	154.955
CONNECTICUT	199.275	208.846
RHODE ISLAND	12.697	21.748
SOUTH EAST MASSACHUSETTS	96.231	80.780
WEST CENTRAL MASSACHUSETTS	121.968	132.978
NORTH EAST MASSACHUSETTS & BOSTON	78.652	73.681
Total New England	**1,095.904**	**1,308.900**

- Qualified IPR generating capacity resources for 2017-2018 ARA3 ICR model are shown
  - 2018-2019 ARA2 model IPR generating resource total is 1,067.825 (summer MW)
  - 2019-2020 ARA1 model IPR generating resource total is 911.693 (summer MW)
- Intermittent resources have both summer and winter values modeled in the ICR calculation
- Reflects known retirements of resources

Resource Data – Demand Resources (MW)

Load Zone	On-Peak		Seasonal Peak		RT Demand Response		Total	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	157.933	144.478	-	-	231.667	249.132	389.600	393.610
NEW HAMPSHIRE	97.893	89.478	-	-	45.638	42.944	143.531	132.422
VERMONT	114.977	120.691	-	-	53.509	62.059	168.486	182.750
CONNECTICUT	83.818	62.443	393.454	384.354	244.496	237.365	722.968	685.362
RHODE ISLAND	181.622	179.501	-	-	57.652	50.796	239.274	230.297
SOUTH EAST MASSACHUSETTS	291.410	278.465	-	-	112.471	107.084	403.881	385.549
WEST CENTRAL MASSACHUSETTS	270.232	255.328	54.798	49.016	106.966	102.007	431.996	406.351
NORTH EAST MASSACHUSETTS & BOSTON	553.842	535.175	-	-	156.968	136.498	710.810	671.673
Total New England	1,751.727	1,665.559	448.252	433.370	1,009.367	987.885	3,210.546	3,088.014

- Qualified Demand Resources for 2017-2018 ARA3 ICR calculation are shown
  - 2018-2019 ARA2 model DR total is 3,126.767 MW
  - 2019-2020 ARA1 model DR total is 3,099.726 MW
- Reflects conversions of RTEG into RTDR and QC brought to 0 MW (not shown in table for confidentiality)
- Includes the Transmission and Distribution (T&D) Loss Adjustment (Gross-up) of 8%

Resource Data – Import Capacity Resources (MW)

- The following table shows the Existing Qualified Import Capacity Resources for the 2017-2018 ARA3 ICR model in the first column
  - These values are higher than the external interface TTC minus tie benefits therefore, the import resources must be derated
  - This is the same process used for the ARA ICR calculations in previous years

- The summer CSOs for the 2017-2018 CCP as of June 2016 totaling 1,376 MW are shown in the next column. These are the values used to prorate the 2017-2018 ARA3 tie benefit study results, if necessary
  - CSOs for 2018-2019 = 1,449 MW and 2019-2020 = 1,450 MW and are used to adjust tie benefits for those CCPs, if necessary

- Also shown are the derated values of the import resources after accounting for 1,875 MW of tie benefits calculated for ARA3 and TTC of:
  - 1,400 MW for Phase II
  - 1,400 MW for NYAC ties
  - 200 MW for Highgate
  - 700 MW for New Brunswick

- The derated import QC are the values modeled in the ICR calculation

Resource Data – Import Capacity Resources (MW)

Import Resource	Qualified Capacity	Summer CSOs as of June 2016	QC Derated for TTC and Tie Benefits - Values Used in ICR calculation	External Interface
NYPA - CMR	68.800	68.800	68.800	New York AC Ties
NYPA - VT	14.000	14.000	14.000	New York AC Ties
VJO - Highgate	6.000	0.000	6.000	Hydro-Quebec Highgate
ReEnergy Fort Fairfield	29.000	29.000	29.000	New Brunswick
ReEnergy Black River	45.000	0.000	31.119	New York AC Ties
ReEnergy Lyonsdale	20.000	0.000	13.830	New York AC Ties
ReEnergy Chateaugay	18.500	0.000	12.793	New York AC Ties
ReEnergy Ashland	32.000	6.000	32.000	New Brunswick
Carr Street Generating Station Import 2017-1	86.000	86.000	59.471	New York AC Ties
Erie Boulevard HYDRO Import 2017-18	375.630	375.630	259.757	New York AC Ties
LIEVRE RIVER Import 2017-18	240.000	120.000	80.000	Phase I/II HQ Excess
Madison County FCA8	1.400	1.400	0.968	New York AC Ties
Oneida-Herkimer FCA8	3.200	3.200	2.213	New York AC Ties
High Acres I FCA8	3.200	3.200	2.213	New York AC Ties
High Acres II FCA8	6.400	6.400	4.426	New York AC Ties
Mill Seat FCA8	6.100	6.100	4.218	New York AC Ties
Chaffee FCA8	6.100	6.100	4.218	New York AC Ties
Monroe-Livingston FCA8	0.700	0.700	0.484	New York AC Ties
HQ_HG_Yearly_17-18	116.000	111.000	61.500	Hydro-Quebec Highgate
HQ_HG_Summer_17-18	116.000	0.000	61.500	Hydro-Quebec Highgate
HQ_NB_Yearly_17-18	173.000	173.000	173.000	New Brunswick
HQ_NB_Summer_17-18	173.000	0.000	173.000	New Brunswick
HQ_NY_Yearly_17-18	189.000	189.000	130.698	New York AC Ties
HQ_NY_Summer_17-18	411.000	0.000	284.216	New York AC Ties
HQ_PII_Yearly_17-18	336.000	126.000	112.000	Phase I/II HQ Excess
HQ_PII_Summer_17-18	300.000	0.000	100.000	Phase I/II HQ Excess
Seneca Energy Grandfathered FCA 8	45.000	45.000	31.119	New York AC Ties
Seneca Energy Non-Grandfathered	5.000	5.000	3.458	New York AC Ties
Totals	2,826.030	1,375.530	1,756.000	

- Final values – QC of imports is derated with the tie benefits results for 2017-2018 ARA3 (1,875 MWs of tie benefits calculated for ARA3); Derated QC values are used in the ICR calculation
- Derated capacity imports value for 2018-2019 ARA2 ICR model is 1,730 MW; value for the 2019-2020 ARA1 ICR model is 1,510 MW
- System-backed imports modeled as 100% available
- Resource-backed imports modeled with EFORd and scheduled outage factor based on NERC class average data for large hydro
- Total average import forced outage rate weighted by summer MW is 1.4% and Maintenance is 3 weeks

Relevant LSR & MCL Internal TTC Assumptions (MW)

	Connecticut Import (for Connecticut LSR)		Boston Import (for NEMA/Boston LSR)		SEMA/RI Import (for SEMA/RI LSR)		Southeast New England Import (for SENE LSR)		Maine-New Hampshire (for Maine MCL)
Capacity Commitment Period	**N-1**	**N-1-1**	**N-1**	**N-1-1**	**N-1**	**N-1-1**	**N-1**	**N-1-1**	**N-1**
2017-2018	2,950	1,750	4,850	4,175	-	-	-	-	1,900
2018-2019	2,950	1,750	4,850	4,175	1,280	720	-	-	-
2019-2020	-	-	-	-	-	-	5,700	4,600	-

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

Relevant Sub-area Load Forecast (MW)

Peak Load Forecast	NEMA/Boston		Connecticut		SEMA/RI		SENE		Maine	
Capacity Commitment Period	50/50	90/10	50/50	90/10	50/50	90/10	50/50	90/10	50/50	90/10
2017-2018	6,149	6,612	7,448	8,133	-	-	-	-	2,135	-
2018-2019	6,223	6,693	7,492	8,182	5,664	6,198	-	-	-	-
2019-2020	-	-	-	-	-	-	12,022	13,043	-	-

- Connecticut, NEMA/Boston LSR and Maine MCL will be calculated for 2017-2018 ARA3
- Connecticut, NEMA/Boston and SEMA/RI LSR will be calculated for 2018-2019 ARA2
- SENE LSR will be calculated for 2019-2020 ARA1
- 50/50 & 90/10 Load Forecasts are the 2016 CELT Load Forecast (Reference forecast net of BTM PV) for the corresponding RSP sub-areas used in the ARA ICR Values calculations
- The 90/10 load forecast values are used directly in the calculation of TSA. The 50/50 load forecast values are shown for informational purposes. The MARS model sees a forecast distribution of which the 50/50 and 90/10 peak loads are discrete points

Sub-area Resources (MW)

2017-2018 ARA3

Type of Resource	Connecticut	NEMA/Boston	Maine	Total New England
Generators	8,297.745	3,264.005	2,952.394	28,985.779
IPR-Generators	199.275	78.652	281.687	1,095.904
DR - Passive	477.272	553.842	157.933	2,199.979
DR - Active	245.696	156.968	231.667	1,010.567
Import	-	-	407.000	1,756.000
Total Resources	9,219.988	4,053.467	4,030.681	35,048.229

2018-2019 ARA2

Type of Resource	Connecticut	NEMA/Boston	SEMA/RI	Total New England
Generators	9,162.109	3,260.530	6,690.489	30,035.784
IPR-Generators	189.928	78.652	107.338	1,067.825
DR - Passive	455.399	593.122	517.358	2,332.828
DR-Active	133.296	146.676	115.431	793.939
Import	-	-	-	1,730.000
Total Resources	9,940.732	4,078.980	7,430.616	35,960.376

2019-2020 ARA1

Type of Resource	SENE	Total New England
Generators	10,022.688	30,629.984
IPR-Generators	182.451	911.693
DR - Passive	1,234.034	2,601.188
DR-Active	186.183	498.538
Import	-	1,510.000
Total Resources	11,625.356	36,151.403

- 2018-2019 ARA2 & 2019-2020 ARA1 models includes CPV-Towantic, Medway Peaker and Wallingford 6&7 (Total = 1,010 MW);
- 2019-2020 ARA1 reflects the retirement of the 677 MW Pilgrim nuclear generating station and includes Burrillville Energy Center 3, Bridgeport Harbor 5, Canal 3 (total = 1,302 MW)
- Imports values shown are the derated values to account for tie benefits and TTC limits

2017-18 ARA3, 2018-19 ARA2 and 2019-20 ARA1 TSA Assumptions

- Resource Data
  - 2017-18 ARA3

Generating Resource Capacity	Regular Generation Resources	Intermittent Resources	Fast Start Resources
Connecticut sub-area (MW)	6776	199	1522
Boston sub-area (MW)	2958	78	306

Demand Resource Capacity	Passive Demand Resources	Real-Time Demand Resources	Real-Time Emergency Generation*
Connecticut sub-area (MW)	477	244	1.2
Boston sub-area (MW)	554	157	0

**RTEG values are changed to reflect the outcome of recent approved FERC order - ER16-1904-000 - Order Granting Limited Waiver*
NOTE: All values have been rounded off to the nearest whole number

2017-18 ARA3, 2018-19 ARA2 and 2019-20 ARA1 TSA Assumptions

- Resource Data
  - 2018-19 ARA2

Generating Resource Capacity	Regular Generation Resources	Intermittent Resources	Fast Start Resources
Connecticut sub-area (MW)	7508	190	1654
Boston sub-area (MW)	2956	79	305
SEMA-RI sub-area (MW)	6314	107	376

Demand Resource Capacity	Passive Demand Resources	Real-Time Demand Resources	Real-Time Emergency Generation*
Connecticut sub-area (MW)	455	133	0
Boston sub-area (MW)	593	146	0
SEMA- RI sub-area (MW)	517	115	0

**RTEG values are changed to reflect the outcome of recent approved FERC order-ER16-1904-000 - Order Granting Limited Waiver*
NOTE: All values have been rounded off to the nearest whole number

2017-18 ARA3, 2018-19 ARA2 and 2019-20 ARA1 TSA Assumptions

- Resource Data
  - 2019-20 ARA1

Generating Resource Capacity	Regular Generation Resources	Intermittent Resources	Fast Start Resources
SENE sub-area (MW)	9026	182	997

Demand Resource Capacity	Passive Demand Resources	Real-Time Demand Resources	Real-Time Emergency Generation*
SENE sub-area (MW)	1234	186	0

** RTEG values are changed to reflect the outcome of recent approved FERC order -ER16-1904-000 - Order Granting Limited Waiver*
NOTE: All values have been rounded off to the nearest whole number

2017-18 ARA3, 2018-19 ARA2 and 2019-20 ARA1 TSA Assumptions

- Resource Unavailability Assumptions
  - Regular Generation Resources - Weighted average EFORd

Generating Resource Capacity	2017-18 ARA3	2018-19 ARA2	2019-20 ARA1
Connecticut sub-area (MW)	9%	8%	-
Boston sub-area (MW)	9%	9%	-
SEMA-RI sub-area (MW)	-	12%	-
SENE sub-area (MW)	-	-	11%

  - Peaking Generation Resources - Operational de-rating factor: 20%
  - Intermittent Generation Resources: 0%

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

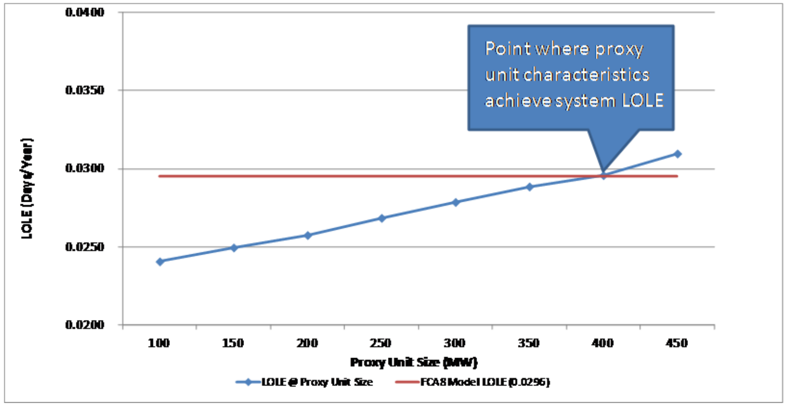
2017-18 ARA3, 2018-19 ARA2 and 2019-20 ARA1 TSA Assumptions, *cont.*

- Resource Unavailability Assumptions
  - Passive Demand Resources: 0%
  - Non-RTEG Active Demand Resources - De-rating based on performance factors
    - Connecticut sub-area: 9%
    - Boston sub-area: 15%
    - SEMA sub-area: 20%
    - RI sub-area: 21%
  - Real-Time Emergency Generation - De-rating based on performance factors
    - Connecticut sub-area: 6%
    - Boston sub-area: 5%
    - SEMA sub-area: 13%
    - RI sub-area: 3%

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 remain 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

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's 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 of the outage
  - 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	12,727	3.8	5.1
Fossil	6,145	17.6	5.9
Nuclear	4,025	2.5	4.4
Hydro (Includes Pumped Storage)	2,902	3.3	4.7
Combustion Turbine	2,930	10.8	2.5
Diesel	199	6.7	1.1
Miscellaneous	58	17.6	3.0
Total System	28,986	7.2	4.8

- Uses the same per unit EFORd and Maintenance weeks values developed for FCA11
- 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
- Each CCP will have the appropriate generators modeled along with their individual availability statistics

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.

DR Availability Assumption

Load Zone	On-Peak		Seasonal Peak		RT Demand Response		Total	
	Summer (MW)	Perform-ance (%)	Summer (MW)	Perform-ance (%)	Summer (MW)	Perform-ance (%)	Summer	Perform-ance (%)
MAINE	157.933	100	-	-	231.667	99	389.600	99
NEW HAMPSHIRE	97.893	100	-	-	45.638	83	143.531	94
VERMONT	114.977	100	-	-	53.509	97	168.486	99
CONNECTICUT	83.818	100	393.45	100	244.496	91	722.968	97
RHODE ISLAND	181.622	100	-	-	57.652	79	239.274	95
SOUTH EAST MASSACHUSETTS	291.410	100	-	-	112.471	80	403.881	94
WEST CENTRAL MASSACHUSETTS	270.232	100	54.80	100	106.966	83	431.996	96
NORTH EAST MASSACHUSETTS & BOSTON	553.842	100	-	-	156.968	85	710.810	97
Total New England	1,751.727	100	448.25	100	1,009.367	89	3,210.546	97

- Uses historical DR performance from summer & winter 2011 – 2015 (same values developed for FCA11). For more information see the May 26, 2016 PSPC presentation at: http://www.iso-ne.com/static-assets/documents/2016/05/PSPC_05262016_ICR_Demand_Resource_Assumption_A5_1.pdf
- Modeled by zones and type of DR with outage factor calculated as 1- performance/100
- The same performance values will be applied to the 2018-2019 ARA2 and 2019-2020 ARA1 models
- Reflects conversions of RTEG into RTDR and QC brought to 0 MW (not shown in table for confidentiality)

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

	90-10 Peak Load	Passive DR	RTDR	Remaining RTEG or Conversions to RTDR	Operating Procedure No. 4 Actions 6 & 8 5% Voltage Reduction
Jun 2017 - Sep 2017	31,161	2,200	1,009	1	419
Oct 2017 - May 2018	23,858	2,099	988	1	312
Jun 2018 - Sep 2018	31,479	2,333	789	5	425
Oct 2018 - May 2019	24,041	2,200	775	5	316
Jun 2019 - Sep 2019	31,788	2,601	491	8	430
Oct 2019 - May 2020	24,195	2,392	504	8	319

- Use the 90-10 Peak Load Forecast minus all Demand Resources
- Multiplied by the 1.5% value used by ISO Operations in estimating load relief obtained from OP 4 voltage reduction
- Revised to reflect final RTEG assumptions

OP 4 Assumptions
- Tie Benefits (Summer MW)

Control Area	2017-18 ARA3	2018-19 ARA2	2019-20 ARA1
Québec over the Phase II Interconnection	1,108	953	975
Québec over the Highgate Interconnection	71	148	142
Maritimes over the New Brunswick Ties	224	523	519
New York over AC Ties	472	346	354
Total	1,875	1,970	1,990

- Values for 2017-2018 ARA3 are those calculated for the 2017-2018 Tie Benefits Study
- Values for 2018-2019 ARA2 and 2019-2020 ARA1 are those calculated for the corresponding FCAs (FCA9 and FCA10, respectively)
- 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 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 Action	2017-2018 ARA3	2018-2019 ARA2	2019-2020 ARA1
Generating Resources	28,985.779	30,035.784	30,629.984
Intermittent Power Resources	1,095.904	1,067.825	911.693
Demand Resources	3,210.546	3,126.767	3,099.726
Import Resources	1,756.000	1,730.000	1,510.000
OP 4 Voltage Reduction	419.000	425.000	430.000
Minimum Operating Reserve	(200.000)	(200.000)	(200.000)
Tie Benefits (Including HQICCs)	1,875.000	1,970.000	1,990.000
Total MW Modeled in ICR	**37,142.229**	**38,155.376**	**38,371.403**

Notes:

- Generating resources include a derating to reflect the value of the firm Vermont Joint Owners (VJO) contract
- Intermittent Power Resources have both the summer and winter capacity values modeled
- Import resources reflect a derating to account for TTC and each CCP's tie benefits
- OP 4 Voltage Reduction includes both Action 6 and Action 8 MW load relief assumptions
- Minimum Operating Reserve is the 10-Minute minimum Reserve Requirement for ISO Operations
- Tie Benefits for 2017-2018 are the values calculated for ARA3; values for 2018-2019 ARA2 and 2019-2020 ARA1 are those calculated for the corresponding FCA

Questions