Investigation of Bias in the Installed Capacity Requirement (ICR)

FCA 1 through FCA 10

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Background

- At the February 13th Reliability Committee (RC) meeting, Synapse Energy Economics* presented on the changes in Net Installed Capacity Requirement (NICR) values from the third annual reconfiguration auction (ARA 3) to the corresponding Forward Capacity Auction (FCA) calculated for the first ten Forward Capacity Market (FCM) Capacity Commitment Periods (CCPs)
  - The average decrease in NICR for the ARA 3* versus FCA was 560 MW over the ten CCPs (see next slide)
    - See: https://www.iso-ne.com/static-assets/documents/2018/02/a7_1_comparison_of_net_icr_values.pdf

- At the April 18th Power Supply Planning Committee (PSPC) meeting, the ISO made a presentation that describes various ICR model assumption changes over these past ten CCPs and the impact on NICR
  - See: https://www.iso-ne.com/static-assets/documents/2018/04/a8_pspc_review_icr_load_frcst_final_04182018.pdf

*Acting on behalf of the New Hampshire Office of Consumer Advocate

**The 2019-2020 FCA is compared to the ARA 2 NICR value which is the latest available

Comparison of Net ICR values

Table 1. Net ICR Values for Each FCA and Corresponding Final ARA

CP	FCA	Final ARA	Diff	Source
1	32,305	31,110	-1,195	1
2	32,528	31,552	-976	1
3	31,965	32,010	45	1
4	32,127	31,552	-575	1
5	33,200	32,588	-612	1
6	33,456	33,391	-65	1
7	32,968	33,152	184	1
8	33,855	33,138	-717	1
9	34,189	33,247	-942	2
10	34,151	33,407	-744	2
		Average	-560	

Source 1: Summary of ICR Values workbook dated December 31, 2016
Source 2: ARA3-9 and ARA2-10 values from October 17 RC, agenda item 6.

- Copy of Table 1 from the Synapse Energy Economics presentation. See: https://www.iso-ne.com/static-assets/documents/2018/02/a7_1_comparison_of_net_icr_values.pdf

Background, cont.

- At the April 24th RC meeting, Synapse Energy Economics presented a proposal for adjustment of the ICR and asked for referral to the PSPC to discuss this topic
  - See: https://www.iso-ne.com/static-assets/documents/2018/04/a6_synapse_proposal_for_adjustments_to_icr.pptx
- The RC refined the referral and requested that the PSPC review the NICR results for past FCAs and third ARAs (and any other data relevant to the request), and explore whether any consistent bias exists in the NICR calculation methodology and report its findings to the RC. If any consistent bias is determined to exist, the PSPC was asked to recommend changes in modeling assumptions or methodology to the RC to address such bias
  - Section III.12.1. of the Tariff states that "*[i]f the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement*."
- Today, ISO-NE will present a high level analysis that examines the topic of bias in the ICR values for the first ten CCPs

Discussion of Bias

- As shown in the discussion of the impact of assumptions on ICR presented at the April 18th PSPC meeting, over the ten CCPs being reviewed, some assumption changes increased ICR and some decreased ICR
  - See Appendix II to this presentation
- ISO-NE has reviewed the historical ICR values and identified three distinct issues, determined by different factors affecting the load forecast, which have been investigated separately

Main Issues Affecting ICR During CCPs 1 - 11

Three main issues affecting ICR during CCPs 1 - 11

1. The effects of the Great Recession which began in 2009
   - Mainly affected ICR values for CCPs 1 -3 (2010 – 2012) and had lingering effects until even the present time
2. A continuing decline in the relationship between economic growth and growth in electricity consumption driven in part by increased end-use efficiency
   - Affected ICR values for all CCPs
3. Rapid growth of BTM PV and new methods to include this in the ICR model as a reduction to the load forecast
   - Affected ICR values for CCPs 7 – 11 (2016 -2020)

Factors Impacting Load Forecast

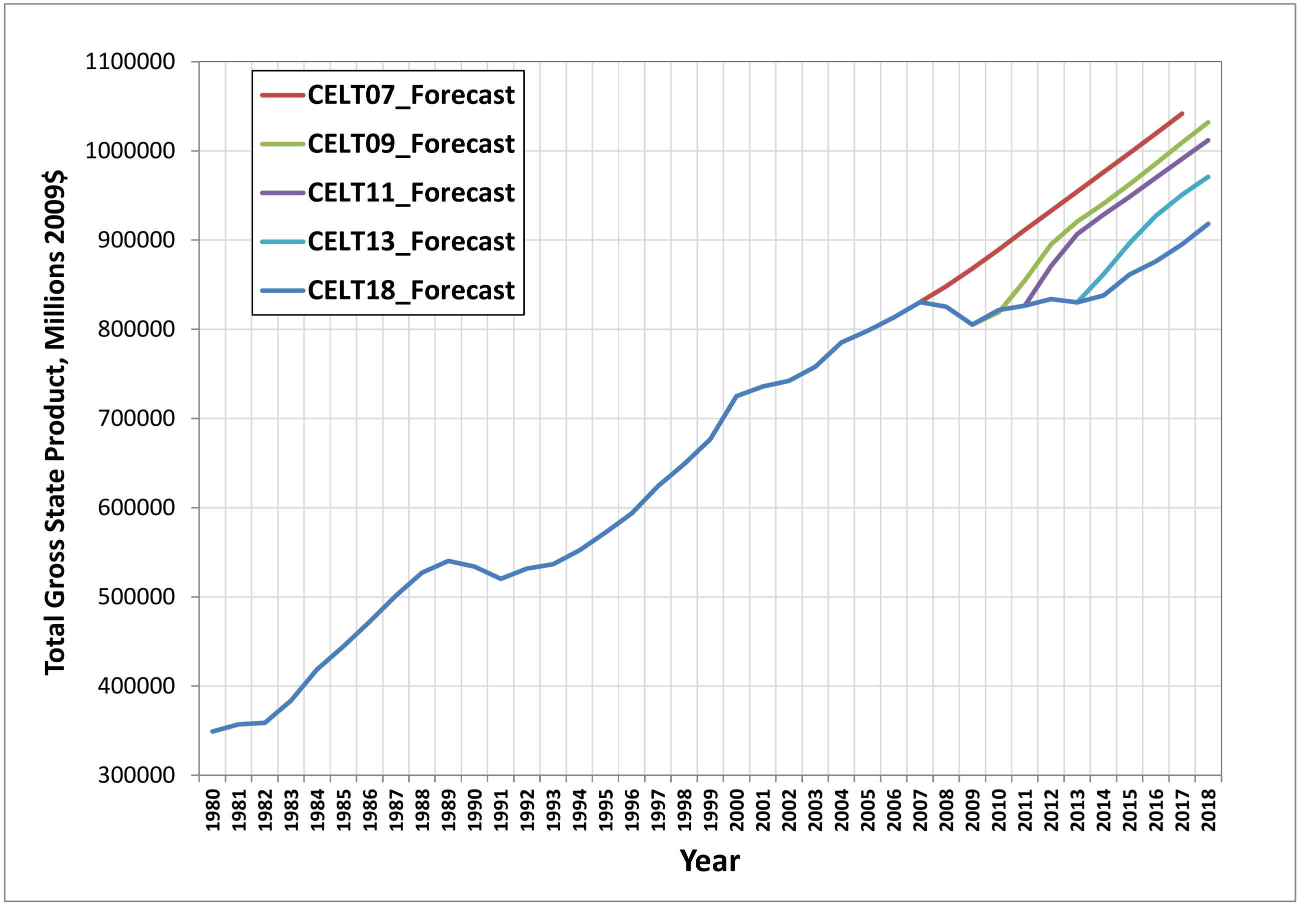
- Trends in New England's electricity demand have changed significantly in recent years and continue to be driven by a growing number of factors, many of which have some implicit uncertainty
- These factors include, but are not limited to:
  - Macroeconomic forecast inputs that reflect the expected outlook for economic growth across the region
  - Evolving end-use efficiency standards that are outside of FCM (*e.g.*, federal appliance standards)
  - Emerging technologies:
    - Rapid growth of BTM PV driven largely by technology cost reductions and evolving state policy support
    - Future trends that the ISO is now monitoring include the expected impacts of the electrification of the heating and transportation sectors triggered in part by New England state greenhouse gas reduction mandates or aspirations
- The annual updates to the inputs, assumptions and methodology used in the development of the load forecast are meant to help capture these changes in demand trends and new factors that warrant consideration

Post-Great Recession

CCPs 1 - 3 (2010 – 2012 and Beyond)

- The recession was not predicted and the subsequent economic recovery took longer than expected (refer to next slide)
- New England lagged behind other parts of the U.S. in its economic recovery
- As such, the ARAs load forecasts done three years later were significantly lower than the values for the FCAs
- This is not attributable to bias but rather unpredictable events that affected the entire U.S. and could not be accurately accounted for with the economic and load forecasting tools available

Comparison of Forecasts of New England Gross State Product



Note: Values are adjusted using an inflation index to reflect 2009 dollars

Electricity Consumption Trend Changes

- Coupled with the lingering effects of the Great Recession, the relationship between economic growth and growth in electricity consumption has continued to weaken over the years. As a result, New England economic growth is now associated with less growth in electricity consumption than in the past
  - One of the primary factors driving this trend is likely increased end-use efficiency resulting from evolving federal and state codes and standards, such as federal appliance standards
  - These end-use efficiencies are, by definition, not claimable savings in FCM
- These trends of slower, less energy-intensive economic growth and greater out-of-market end-use efficiency are captured as new data is added to the historical period used to estimate ISO's econometric load forecast model and the earlier data rolls off
  - This can be seen in the 629 MW decrease in the 2018 CELT Report gross load forecast for FCA 13 (2022-2023) as compared to the 2017 CELT Report gross load forecast which does not reflect any changes to the load forecast methodology

Modeling of BTM PV

CCPs 7 - 11 (2016 – 2020)

- In 2015, modeling of BTM PV in ICR calculations was a new issue for the ISO and a response to a directive from FERC.* After gaining some experience and the appropriate data, the ISO responded by modeling BTM PV as a reduction to the load forecast in ICR beginning in FCA 10 (CCP 10) and ARA 3 of 2016-2017 (CCP 7)
- By deciding to model the BTM PV in the ICR for the ARAs when it was not previously modeled in the ICR for the corresponding FCA, the ISO was able to roll this assumption change into the ICR as quickly as possible
  - However, the reduction in ICR for ARA 3 versus the corresponding FCA is greater than it would have been if BTM PV was only modeled in CCPs where it was first modeled in the FCA
- If the ARA3 methodology for BTM PV modeling had been in place for each FCA, the decline in ICR between ARA 3 and FCA would have been significantly less

*See: https://www.iso-ne.com/static-assets/documents/2015/01/er15-325-000_1-2-15_order_accept_2018-2019_icrs.pdf

Modeling of BTM PV, cont.

CCPs 7 - 11 (2016 - 2020)

- Beginning with FCA 10 (CCP 2019-2020), the ISO began modeling BTM PV as a reduction to load in the ICR model using the Reliability Hours methodology
- In the same year, the ISO also began modeling the BTM PV for ARA 3 of 2016-2017 (CCP 7), ARA 2 of 2017-2018 (CCP 8) and ARA 1 of 2018-2019 (CCP 9)
- As noted previously, modeling BTM PV as a reduction to the load forecast in the ICR for ARAs when not modeled in the corresponding FCA allowed the impacts of BTM PV to be captured more quickly; however the negative delta between the ARA 3 ICR and the FCA ICR is larger
  - Accounts for approximate decreases in NICR between ARA 3 and the FCA of:
    - 240 MW for CCP 7 (2016-2017)
    - 600 MW for CCP 8 (2017-2018)
    - 1,100 MW for CCP 9 (2018-2019)

Modeling of BTM PV, cont.

CCPs 7 - 11 (2016 – 2020)

- Beginning with FCA 12 (CCP 2021-2022), the ISO began modeling BTM PV with an improved methodology, the hourly profile methodology
  - This methodology decreased the ICR for FCA 12 by approximately 335 MW when compared to the previously used Reliability Hour methodology
- In the same year, the ISO also started using the hourly profile methodology in the ICR for ARA 3 of 2018-2019 (CCP 9), ARA 2 of 2019-2020 (CCP 10), and ARA 1 of 2020-2021 (CCP 11)
- Accounts for approximate difference in NICR:
  - For CCP 10 (2019-2020) (associated with FCA 10), 369 MW of BTM PV was modeled in the ICR for the FCA using the Reliability Hour methodology. For ARA 2, increased penetration of BTM PV (783 MW) plus the use of the hourly profile methodology accounts for approximately 630 MW of the difference between ARA 2 and FCA 10
  - For CCP 11 (2020-2021) (associated with FCA 11), the increase penetration of BTM PV: 848 MW for ARA 1 versus 676 MW for the FCA, and the use of the hourly profile methodology accounts for approximately 450 MW of the difference between ARA 1 and FCA 11

Note: Values shown for BTM PV penetrations are those determined by the % Seasonal Peak Load Reduction value of BTM PV published in the corresponding CELT Report PV forecast for each CCP

Modeling of BTM PV, cont.

CCPs 7 - 11 (2016 - 2020)

- If the changes due to the modeling of BTM PV are netted out from the difference in NICR between ARA 3 and the corresponding FCA then the average of the difference in ARA 3 versus FCA NICR would be an increase of approximately 90 MW for CCPs 7 - 10

CCP	Year	Change in NICR (ARA 3 vs. FCA)	Change Due to BTM PV and Modeling Methodology	Change Without the Impact of BTM PV
7	2016	184	-240	424
8	2017	-717	-600	-117
9	2018	-942	-1,100	158
10*	2019	-744	-630	-114

*The 2019-2020 FCA is compared to the ARA 2 NICR value which is the latest available

Additional Considerations

- Not all assumptions caused ICR to decrease
- Other assumption changes had significant impacts on increasing ICR such as increased EFORd for generators
  - Increased EFORd causes ICR to increase, all other things being equal
  - The trend in increasing generator EFORd started in 2011 and remained through 2013 when EFORd values started to decrease
  - EFORd used in the ICR model is calculated using a 5-year rolling average so the impact lasts longer than one year
  - ICR calculations taking place during the years 2013 - 2017 were most heavily impacted by the increase in EFORd
- Changes to the ICR model and other assumptions also caused ICR to increase
  - See Appendix I & II of this presentation for more details
- This shows that the ICR model responds to assumption changes appropriately and does not indicate a bias

Conclusions

Results of the investigation show:

- ICR values were impacted by various factors
  - The unpredictability and protracted economic impacts of the Great Recession, coupled with shifting trends in electricity consumption
    - Annual updates to the inputs to the load forecast have been made as the ISO attempts to capture these issues for ARAs and as these are calculated three years after the FCA ICR is calculated, this increases the negative delta between ARA 3 and FCA ICR values
  - The unexpected rapid growth of BTM PV and its subsequent modeling as a reduction to the load forecast used in the ICR calculations
    - Modeling BTM PV in ARAs where it was not previously modeled in the corresponding FCA increased the differences between ARA 3 and FCA ICR values
  - Increased EFORd (worsening of generator availability) and other assumption changes contributed to increasing ICR values
- ICR values increased or decreased according to assumption changes which were developed according to the Tariff
  - While some of these changes have been difficult to capture, they do not indicate bias

Conclusions, cont.

- The main drivers for the decrease in ICR over CCPs 8-10 was the incorporation of BTM PV in the ARA ICR calculations as well as increased penetration rates of BTM PV in subsequent auctions as compared to the FCA
  - The change to the hourly profile methodology for modeling BTM PV in the ICR model also contributed to the decrease
- In consideration of all the changes that have already been made, using an adjustment factor to modify ICR going forward could be adjusting for issues that have already been addressed

Questions

APPENDIX I

Historical Comparisons of ARA 3 and FCA ICR Values for CCPs 8-10 from ICR Values presentations to the RC

Effect of Updated Assumptions on ICR
– 2017-2018 ARA 3 versus FCA 8

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

CCP 2018-2019 ARA 3 vs FCA 9

Assumption	2018-2019 ARA3		2018-2019 FCA #9		Effect on ICR (MW)
Tie Benefits	346 MW New York		346 MW New York		138
	425 MW Maritimes		523 MW Maritimes		
	1,030 MW Quebec (HQICCs)		953 MW Quebec (HQICCs)		
	107 MW Quebec via Highgate		148 MW Quebec via Highgate		
Total	1,908 MW		1,970 MW		
	MW	**Weighted Forced Outage**	**MW**	**Weighted Forced Outage**	
Generation & IPR	31,147	7.3	29,699	6.5	293
Demand Resources	3,036	2.0	3,054	4.0	-63
Imports	1,730	2.0	89	0	17
	MW		**MW**		
Load Forecast	28,764		30,005		-1,192
	MW	**%**	**MW**	**%**	
OP 4 5% VR	422	1.5	441	1.5	18
	MW		**MW**		
ICR	34,277		35,142		-865

- Methodology: begin with the 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
- The change in net ICR due to the tie benefits assumption is 61 MW
- The change in load forecast reflects the 2017 CELT load forecast versus the 2014 CELT load forecast for 2018-2019 and reflecting BTM PV, which was not modeled for FCA #9, versus 690 MW peak load reduction value for 2018-2019 ARA 3 as determined by the % Seasonal Peak Load Reduction value of BTM PV published in the 2017 CELT. In the ARA ICR calculations the BTM PV Hourly Profile methodology was used

Effect of Updated Assumptions on ICR

CCP 2019-2020 ARA 2 vs FCA 10

Assumption	2019-2020 ARA2		2019-2020 FCA #10		Effect on ICR (MW)
	MW	Weighted Forced Outage (%)	MW	Weighted Forced Outage (%)	
Generation & IPR	31,352	7.3	30,524	6.7	202
Demand Resources	3,393	2.4	2,871	2.5	
Imports & Sales	1,510	2.5	89	0	
	MW		MW		
Load Forecast	28,970		29,861		-861
	MW		MW		
ICR	34,382		35,126		-744

- 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
- The change in load forecast is the result of both the difference between the 2017 CELT versus the 2015 CELT load forecasts for 2019-2020 and the increase in the BTM PV penetration: 369 MW for FCA #10 versus 783 MW peak load reduction value for 2019-2020 ARA 2 as determined by the % Seasonal Peak Load Reduction value of BTM PV published in the CELT. In the ARA ICR calculations the BTM PV Hourly Profile methodology was used

APPENDIX II

Slides on detailed assumption impacts from the April 18th PSPC Presentation

High Level Reasons Causing an Increase in NICR

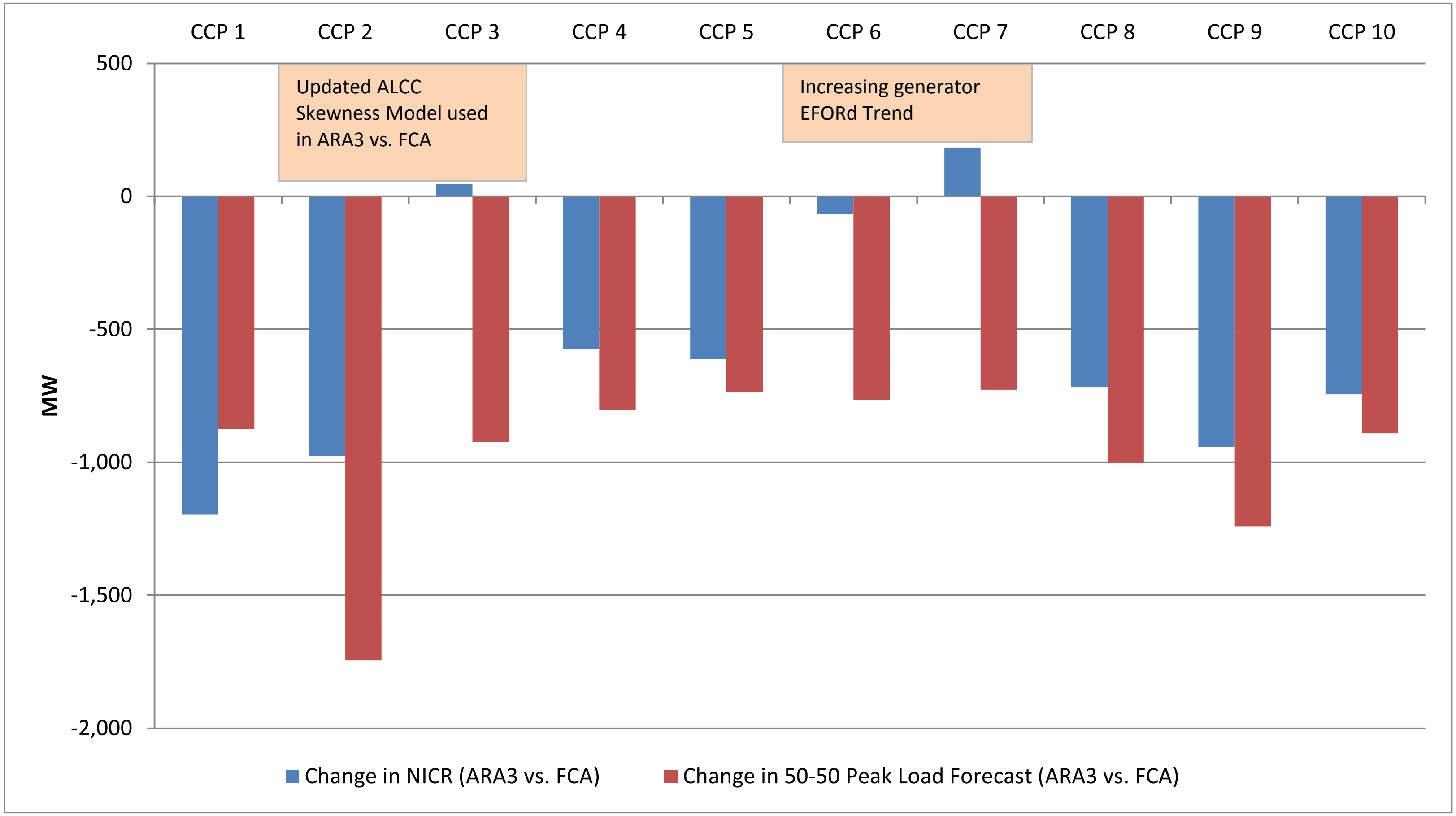
- In ARA 3 of CCP 1 & CCP 2, ISO-NE applied an adjustment to ICR to account for the under-procurement of resources in the auction due to the reserve margin gross-up of the demand resources and NYPA resources qualified capacity
- In 2010, ISO-NE began using an updated model that incorporated the effect of skewness in the Additional Load Carrying Capability (ALCC) term
  - This was discussed at the May 27, 2010 RC meeting
  - Skewness has minimal impact on ALCC when the installed resource base is close to the one day in ten LOLE requirement but a larger impact when the system is surplus
  - For 2011-2012 ARA3 and 2012-2013 ARA2, the impact was a 480 MW increase in ICR versus the corresponding FCA
- Increases in New England generator EFORd
  - This trend in increasing EFORd started in 2011 and remained through 2013 when EFORd values started to decrease
  - EFORd for the ICR model is calculated using a 5-year rolling average; ICR calculations taking place in 2013-2017 are most heavily impacted by the increasing EFORd trend

High Level Reasons Causing a Decrease in NICR

- A stalled recovery of the Great Recession of 2009
  - The recovery took longer than anticipated by leading economic forecasters which caused the load forecast to decrease in the early to mid 2010s for ARAs versus FCAs
  - Recovery in New England lagged behind the national recovery; impacts of the recession were felt for a longer period
  - Continuing deterioration of the relationship between energy demand and economic activity
- Load forecast modeling change introduced a cap on summer weather in 2012 which decreased the load forecast by approximately 500 MW
- ISO-NE began modeling BTM PV as a reduction to load in 2015 which especially impacts NICR in ARA3 versus FCA in CCPs 2016-2017 through 2018-2019 since BTM PV was not modeled in the FCA
- In 2017, ISO-NE began modeling BTM PV using the hourly profile methodology which further impacted the difference between the FCA and ARA3 NICR values for CCPs 2018-2019 through 2020-2021 (approximately 300 MW decrease)

Changes in NICR Shown with Decrease in Load Forecast for ARA 3 vs. FCA

- Movement of ICR primarily follow the changes to the load forecast with the exceptions noted in the text boxes



Notes on Changes to NICR for ARA 3 vs. FCA

Capacity Commitment Period	ICR	Net ICR	50-50 Summer Peak Frcst	Year of CELT Load Forecast	Change in NICR for ARA3 vs FCA	Decrease in 50-50 LF for ARA3 vs FCA	Notes on Increases in NICR	Notes on Decreases in NICR
2010 FCA1	33,705	32,305	29,035	2007				
2010 3rd ARA	32,510	31,110	28,160	2009	-1,195	-875	RM Gross-up (14.3%) adjustment of 213 MW applied	2009 Load forecast decreases by 795 MW due to recession (versus 2008 CELT)
2011 FCA2	33,439	32,528	29,405	2008				
2011 3rd ARA	32,463	31,552	27,660	2010	-976	-1,745	Updated WH skewness in ALCC model used (480 MW increase in ICR); RM Gross-up (16.1%) adjustment of 288 MW applied	Recession in 2008/09 and slower than anticipated recovery reflected in 2010 load forecast
2012 FCA3	32,879	31,965	29,020	2009				
2012 3rd ARA	32,987	32,010	28,095	2011	45	-925	Updated WH skewness in ALCC model used (480 MW increase in ICR)	Load Forecasting notices a weakening relationship between energy demand and economic activity. The addition of another post-recession year to the data set better captures this relationship
2013 FCA4	33,043	32,127	28,570	2010				
2013 3rd ARA	32,550	31,552	27,765	2012	-575	-805	Updated WH skewness in ALCC model used (≈480 MW increase in ICR)	A cap on summer weather was introduced in 2012 (≈ -500 MW in LF); Continuing deterioration of the relationship between energy demand and economic activity; Addition of a post-recession year to the data set better captures this relationship
2014 FCA5	34,154	33,200	29,025	2010				
2014 3rd ARA	33,584	32,588	28,290	2013	-612	-735	System Generator EFORd increase from 5.1% to 6.1%	A cap on summer weather was introduced in 2012 (≈ -500 MW in LF); Continuing deterioration of the relationship between energy demand and economic activity; Addition of a post-recession year to the data set better captures this relationship
2015 FCA6	34,498	33,456	29,380	2011				
2015 3rd ARA	34,433	33,391	28,615	2014	-65	-765	759 MW increase due to increase in generator EFORd	515 MW decrease due to LF; 259 MW decrease due to DR availability
2016 FCA7	34,023	32,968	29,400	2012				
2016 3rd ARA	34,247	33,152	28,673	2015	184	-727	757 MW increase due to increase in generator EFORd	429 MW decrease due to LF and BTM PV (237 MW decrease in due to BTM PV modeled for the first time in ARA3 using RH methodology)
2017 FCA8	34,923	33,855	29,790	2013				
2017 3rd ARA	34,246	33,138	28,788	2016	-717	-1,002	277 MW increase due to increase in generator EFORd	822 MW decrease due to LF and BTM PV; 574 MW of BTM PV modeled with RH methodology; 87 MW decrease due to DR availability
2018 FCA9	35,142	34,189	30,005	2014				
2018 3rd ARA	34,277	33,247	28,764	2017	-942	-1,241	293 MW increase due to increase in generator EFORd; +61 due to tie benefits;	1,192 MW decrease due to LF and BTM PV; 690 MW of BTM PV based on %SCC vs. not modeled for FCA plus hourly profile method used in ARA3 vs FCA
2019 FCA10	35,126	34,151	29,861	2015				
2019 2nd ARA	34,382	33,407	28,970	2017	-744	-891	202 MW increase due to change in all resource availability	861 decrease due to LF and BTM PV; 783 MW of BTM PV based on %SCC vs 369 MW for FCA10 plus hourly profile method used in ARA3 vs. FCA

Acronyms Used in this Presentation

- ARA = Annual Reconfiguration Auction
  - ARA 1 = First ARA
  - ARA 2 = Second ARA
  - ARA 3 = Third ARA
- BTM PV = Behind the Meter Photovoltaic
- CCP = Capacity Commitment Period
- CELT = Capacity, Energy, Loads, and Transmission Report
- EFORd = Equivalent Forced Outage Rate - Demand
- FCA = Forward Capacity Auction
- FCM = Forward Capacity Market
- GE MARS = General Electric Multi-Area Reliability Simulation Program
- ICR = Installed Capacity Requirement
- LF = load forecast
- LOLE = Loss of Load Expectation
- NICR = Net ICR
- PSPC = Power Supply Planning Committee
- RC = Reliability Committee
- RH = Reliability Hours

Questions