Proposed Installed Capacity Requirement (ICR) Values for the 2022-2023 Forward Capacity Auction (FCA 13)

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Objective of this Presentation

- Review the proposed ICR Values* and FERC filing schedules
- Provide final review of assumptions that were presented at the July 26, 2018 PSPC Meeting
- Review the proposed ICR Values* including:
  - Installed Capacity Requirement (ICR)
  - For the import-constrained Southeast New England (SENE) Capacity Zone (combined Load Zones of NEMA/Boston, SEMA and RI)
    - Local Resource Adequacy Requirement (LRA)
    - Transmission Security Analysis (TSA)
    - Local Sourcing Requirement (LSR)
  - MCL for the export-constrained Northern New England (NNE) Capacity Zone (combined Load Zones of Maine, VT and NH)
  - Marginal Reliability Impact Demand Curves (MRI Demand Curves)

* The ICR, LSR, MCL and the Demand Curves and the Hydro-Quebec Interconnection Capability Credits (HQICCs) are collectively referred to as the ICR Values

ICR Review and FERC Filing Schedule

- ICR Values for FCA 13 (2022-2023)
  - PSPC to review Capacity Zone determinations – **May 29, 2018**
  - PSPC final review of all assumptions – **July 26, 2018**
  - PSPC review of ISO recommendation of ICR Values – **August 30, 2018**
  - RC review/vote of ISO recommendation of ICR Values – **September 26, 2018**
  - PC review/vote of ISO recommendation of ICR Values – **October 4, 2018**
  - File with the FERC – by **November 6, 2018**
  - FCA 13 begins – **February 4, 2019**

PROPOSED ICR VALUES FOR CAPACITY COMMITMENT PERIOD (CCP) 2022-2023 (FCA 13)

ISO Proposed ICR Values for the CCP 2022-2023 FCA 13 (MW)

2022-2023 (FCA 13)	New England	Southeast New England	Northern New England
Peak Load (50/50) Net of BTM PV	29,093	12,415	5,469
Existing Capacity Resources	34,352	11,252	8,310
Installed Capacity Requirement	34,739		
NET ICR (ICR Minus HQICCs)	33,770		
Local Sourcing Requirement		10,121	
Maximum Capacity Limit			8,555

- The Existing Capacity Resources category consists of existing resources that have Qualified Capacity for FCA 13 at the time of the ICR calculation and reflects applicable retirements and terminations
- 50/50 peak load shown for informational purposes

Comparison of ICR Values (MW)

CCP 2022-2023 (FCA 13) Vs CCP 2021-2022 (FCA 12)

	New England		Southeast New England		Northern New England	
	2022-2023 FCA 13	2021-2022 FCA 12	2022-2023 FCA 13	2021-2022 FCA 12	2022-2023 FCA 13	2021-2022 FCA 12
Peak Load Net of BTM PV (50/50)	29,093	29,436	12,415	12,327	5,469	5,711
Existing Capacity Resources	34,352	34,567	11,252	11,715	8,310	8,294
Installed Capacity Requirement	34,739	34,683				
NET ICR (ICR Minus HQICCs)	33,770	33,725				
Local Resource Adequacy Requirement			9,880	9,705		
Transmission Security Analysis Requirement			10,121	10,018		
Local Sourcing Requirement			10,121	10,018		
Maximum Capacity Limit					8,555	8,790

Notes:

- The Existing Capacity Resources category consists of existing resources that have Qualified Capacity for FCA 13 at the time of the ICR calculation and reflects applicable retirements and terminations.
- For details on the FCA 12 (2021-2022) ICR Values calculation see: : https://www.iso-ne.com/static-assets/documents/2017/09/a7_icr_and_tie_benefits_for_fca12.zip
- 50/50 peak load shown for informational purposes

ICR Calculation Details

Total Capacity/OP4 Breakdown	2022-2023 FCA ICR
Generating Resources	30,781
Demand Resources	3,490
Import Resources	80
Tie Benefits	2,000
OP4 - Action 6 & 8 (Voltage Reduction)	422
Minimum Operating Reserve Requirement	(700)
Proxy Unit Capacity	-
Total Capacity	**36,074**

Installed Capacity Requirement Calculation Details	2022-2023 FCA ICR
Annual Peak	29,093
Total Capacity/OP4	36,074
Tie Benefits	2,000
HQICCs	969
OP4 - Actions 6 & 8 (Voltage Reduction)	422
Minimum Operating Reserve Requirement	(700)
ALCC	501
Installed Capacity Requirement	**34,739**
Net ICR	**33,770**
Reserve Margin with HQICCs	19.4%
Reserve Margin without HQICCs	16.1%

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

Notes:

- 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
- OP4 is ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency

Cost of New Entry (CONE)

- for the MRI Demand Curves

- CONE for the cap of the MRI Demand Curve for FCA 13 has been calculated as:
  - Gross CONE: $11.289/kW-month
  - Net CONE : $8.156/kW-month
  - FCA Starting Price : $13.050/kW-month

- See link for Forward Capacity Market (FCM) parameters by CCP: https://www.iso-ne.com/static-assets/documents/2015/09/FCA_Parameters_Final_Table.xlsx

Effect of Updated Assumptions on ICR

Assumption	2022-2023 FCA 13		2021-2022 FCA 12		Effect on ICR (MW)
Tie Benefits	366 MW New York		413 MW New York		31
	516 MW Maritimes		506 MW Maritimes		
	969 MW Quebec (HQICCs)		958 MW Quebec (HQICCs)		
	149 MW Quebec via Highgate		143 MW Quebec via Highgate		
Total	2,000 MW		2,020 MW		
	MW	**Weighted Forced Outage (%)**	**MW**	**Weighted Forced Outage**	
Generation & IPR	30,781	7.0%	31,273	7.1%	-100
Demand Resources	3,490	1.2%	3,212	1.5%	
Imports	80	0.0%	89	0.0%	
	MW		**MW**		
Load Forecast & BTM PV	29,093		29,435		-420
Minimum Operating Reserve	700		200		550
	MW	**%**	**MW**	**%**	
OP4 5% Voltage Reduction	422	1.5%	431	1.5%	9
	MW		**MW**		
ICR	34,739		34,683		56

Notes:

- Methodology: using the model associated with the 2021-2022 FCA 12 ICR calculation, change one assumption at a time and note the change in ICR
- Generation forced outage assumption is a weighted average of individual generators’ 5-year average EFORd and Intermittent Power Resources assumed 100% available
- The peak values shown is the reference 50/50 peak load forecast (net of the published value of BTM PV). The MARS model uses hourly profiles of forecasted load and BTM PV

LRA – SENE

		Local Resource Adequacy Requirement - SENE	
Southeast New England Capacity Zone		**2022-2023 FCA 13**	**2021-2022 FCA 12**
$Resource_z$	[1]	11,252	11,715
$Proxy\ Units_z$	[2]	0	0
$Firm\ Load\ Adjustment_z$	[3]	1,269	1,848
FOR_z	[4]	0.075	0.081
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**9,880**	**9,705**
Rest of New England Zone			
Resource	[6]	23,099	22,852
Proxy Units	[7]	0	0
Firm Load Adjustment	[8] = -[3]	-1,269	-1,848
Total System Resources	[9]=[1]+[2]-[3]+[6]+[7]-[8]	34,352	34,567

Notes:

- All values in the table are in MW except the forced outage $rate_z$ (FOR_z)

TSA Requirement – SENE (MW)

SENE Capacity Zone	2022-2023 FCA 13	2021-2022 FCA 12
Sub-area 90/10 Load*	13,561	13,413
Reserves (Largest unit or loss of import capability)	1,413	1,413
Sub-area Transmission Security Need	**14,974**	**14,826**
Existing Resources	11,252	11,715
Assumed Unavailable Capacity	-941	-1,043
Sub-area N-1 Import Limit	5,700	5,700
Sub-area Available Resources	**16,011**	**16,372**
TSA Requirement	**10,121**	**10,018**

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

Notes:

- *Load forecast is net of BTM PV
- All values have been rounded off to the nearest whole number
- Information on the 2021-2022 CCP (FCA 12) TSA calculation available at: https://www.iso-ne.com/static-assets/documents/2017/09/a7_icr_and_tie_benefits_for_fca12.zip

MCL - NNE

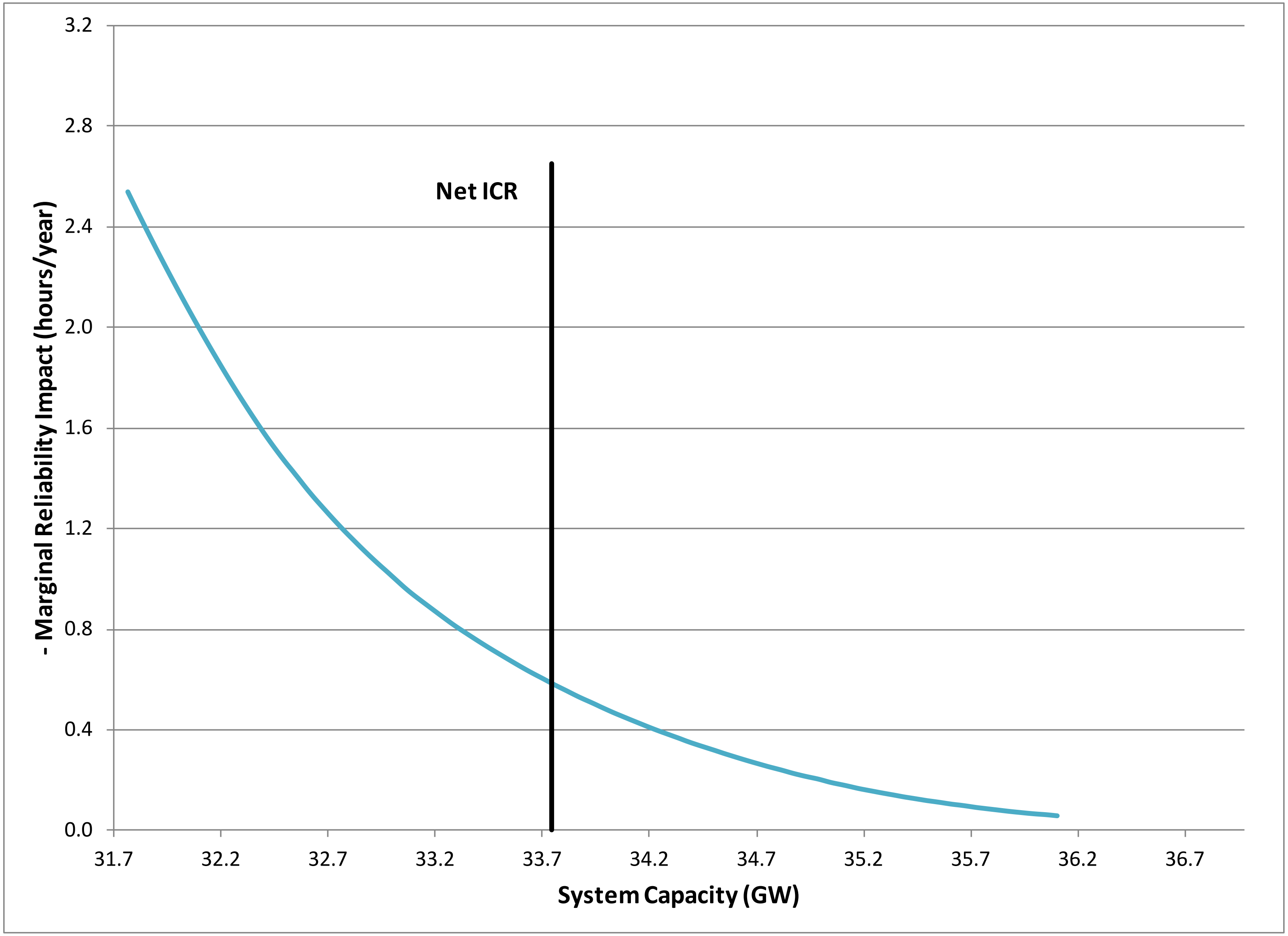
LRA - RestofNewEngland (for NNE MCL calculation)			
Rest of New England Zone		**2022-2023 FCA 13**	**2021-2022 FCA 12**
$Resource_z$	[1]	26,041	26,273
$Proxy\ Units_z$	[2]	0	0
$Surplus\ Capacity\ Adjustment_z$	[3]	580	850
$Firm\ Load\ Adjustment_z$	[4]	187	391
FOR_z	[5]	0.071	0.073
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**25,215**	**24,935**
NNE Zone			
Resource	[7]	8,310	8,294
Proxy Units	[8]	0	0
Firm Load Adjustment	[9] = -[4]	-187	-391
Total System Resources	[10]=[1]+[2]-[4]+[7]+[8]-[9]	34,352	34,567

Maximum Capacity Limit - NNE			
Commitment Period		**2022-2023 FCA 13**	**2021-2022 FCA 12**
NICR for New England	[1]	33,770	33,725
$LRA_{RestofNewEngland}$	[2]	25,215	24,935
$Maximum\ Capacity\ Limit_Y$	[3]=[1]-[2]	**8,555**	**8,790**

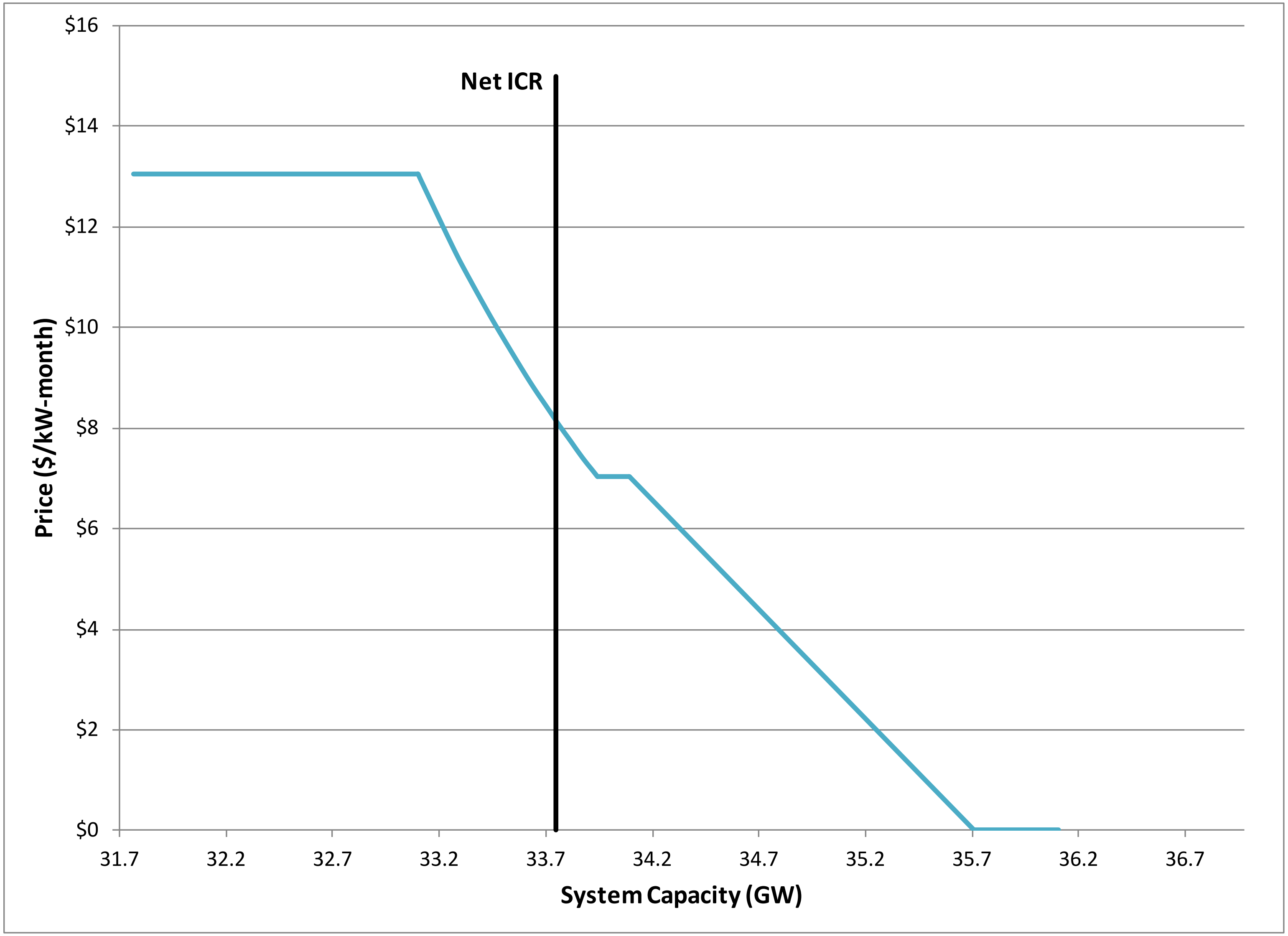
Notes:

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

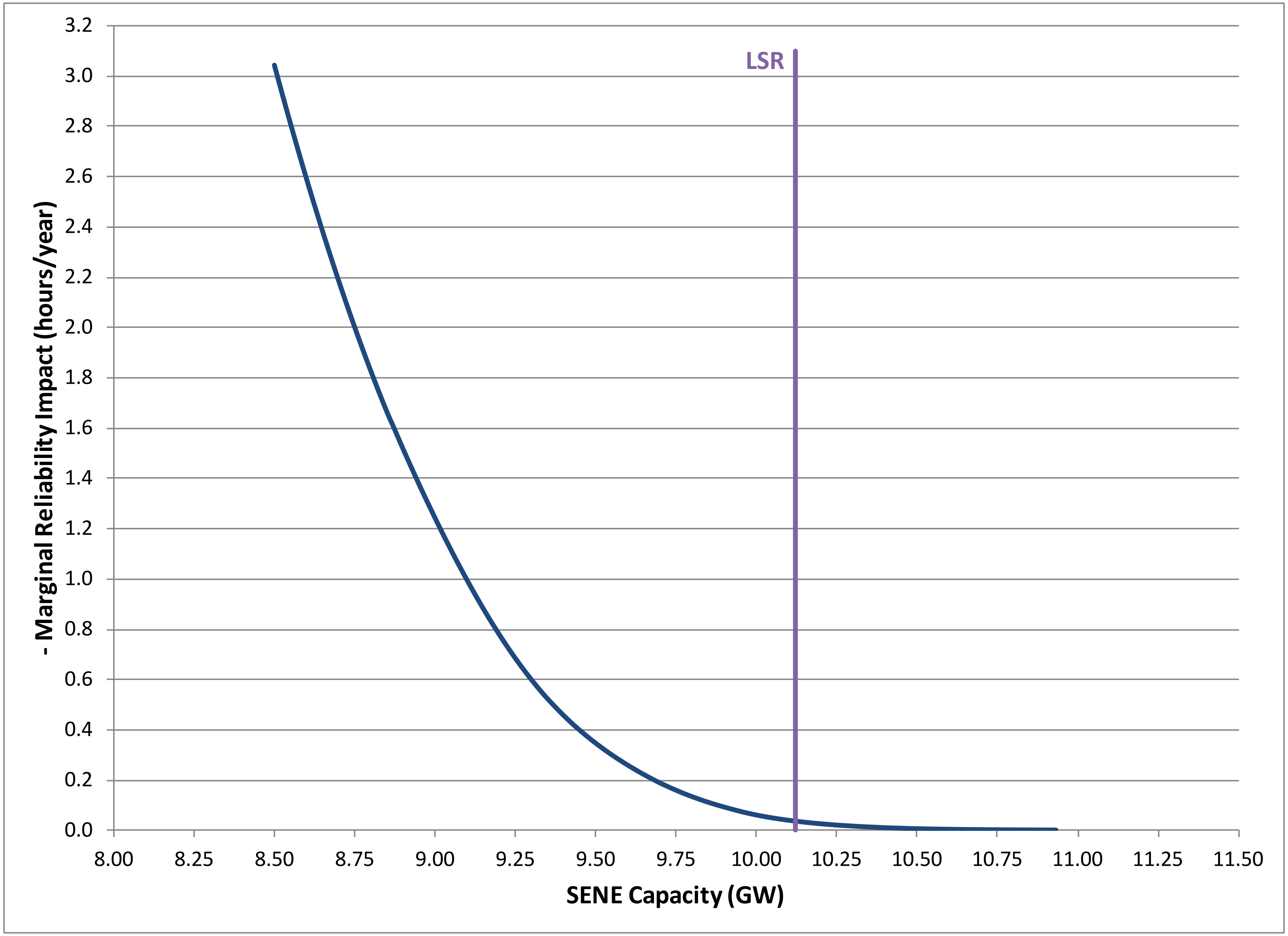
FCA 13 System-Wide MRI Curve



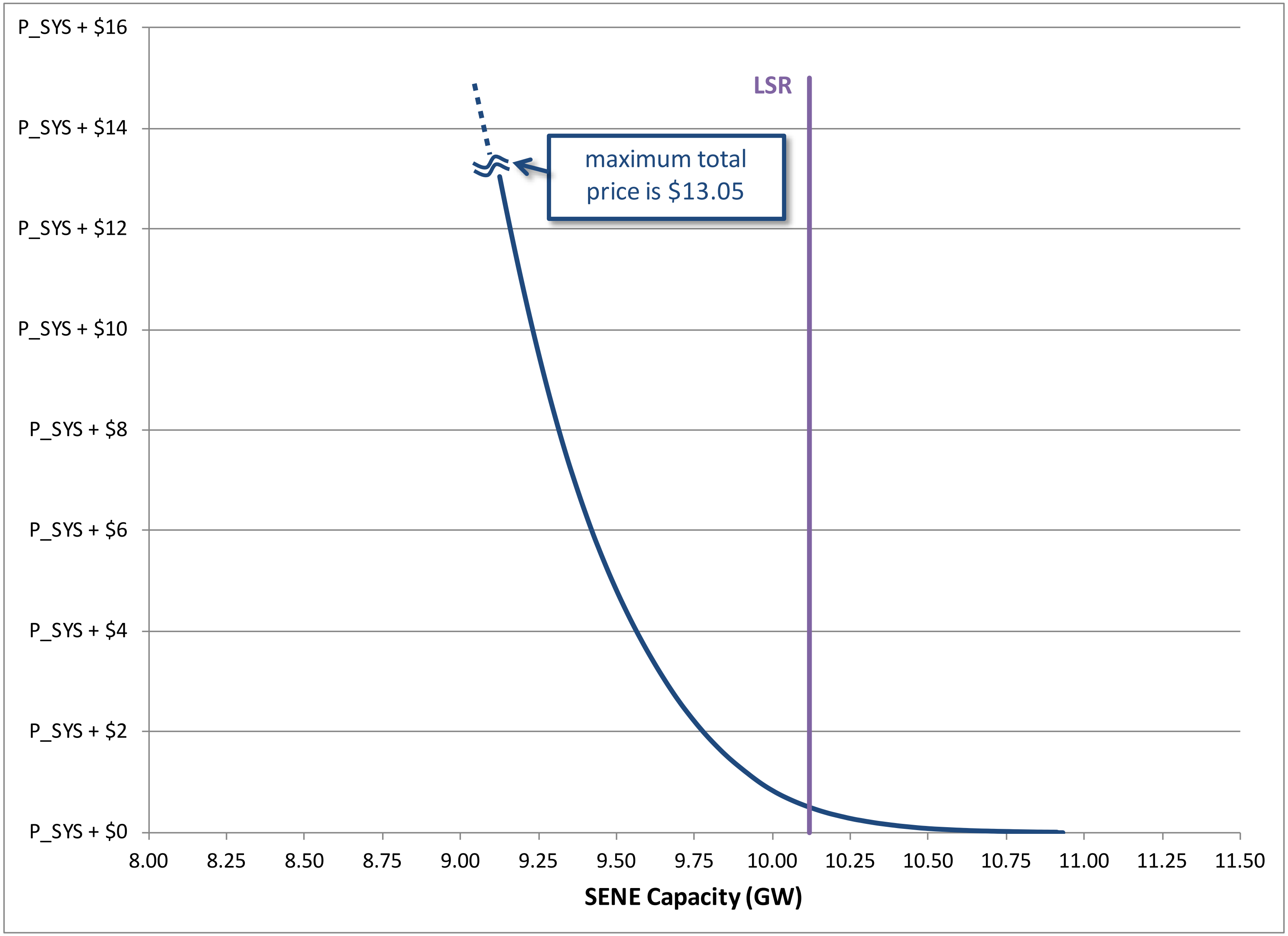
FCA 13 System-Wide Demand Curve



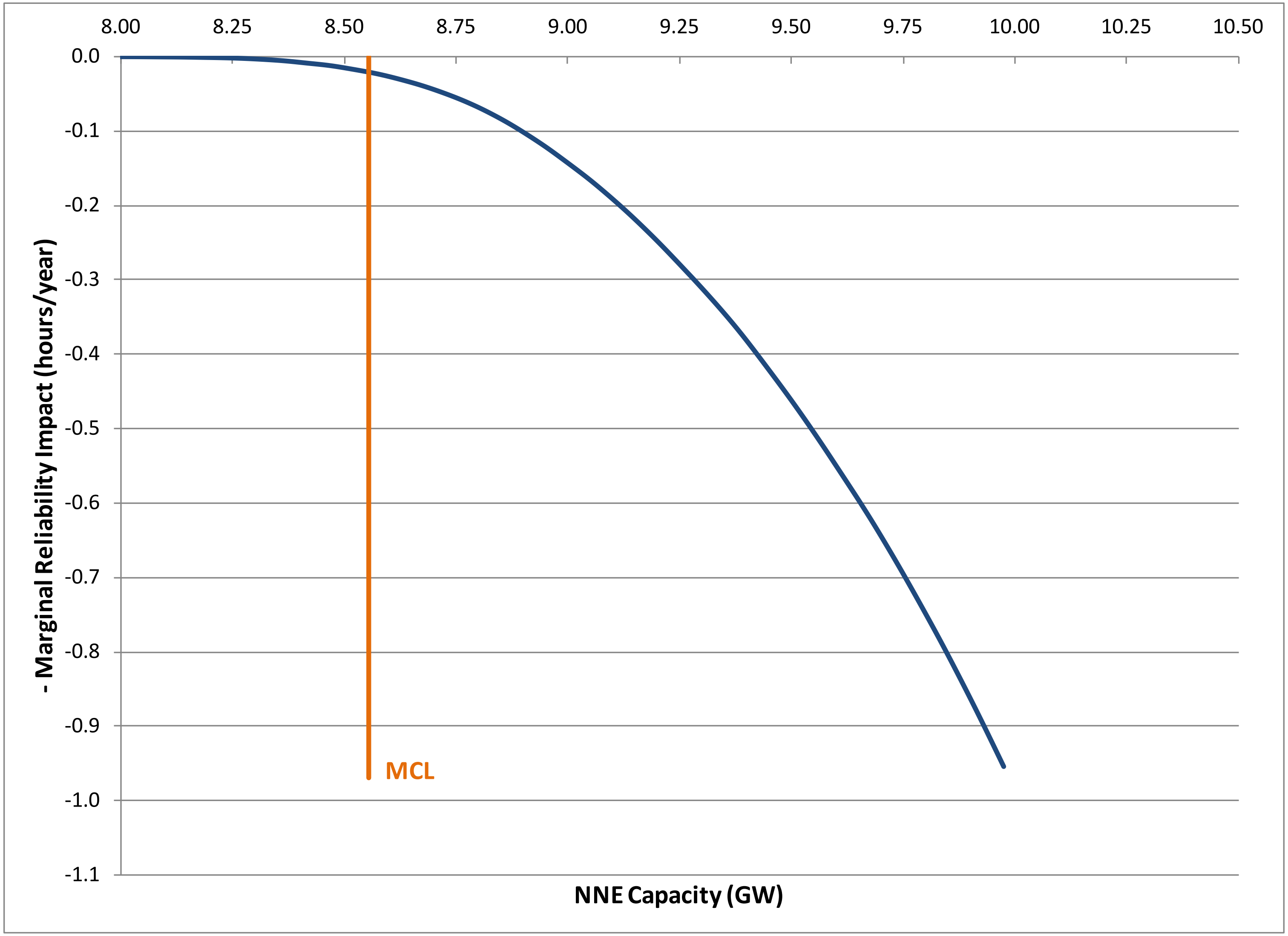
FCA 13 SENE MRI Curve



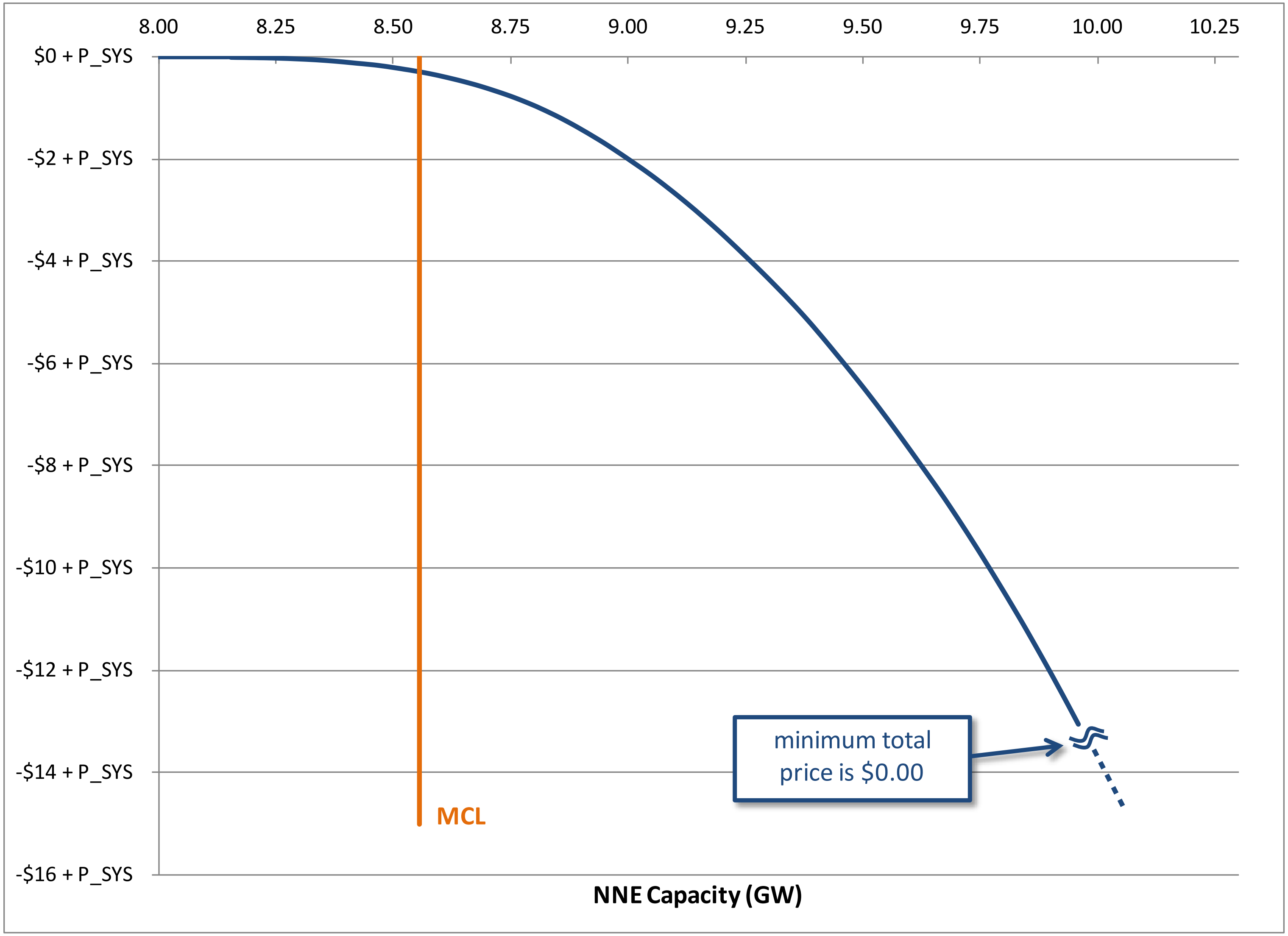
FCA 13 SENE Demand Curve



FCA 13 NNE MRI Curve

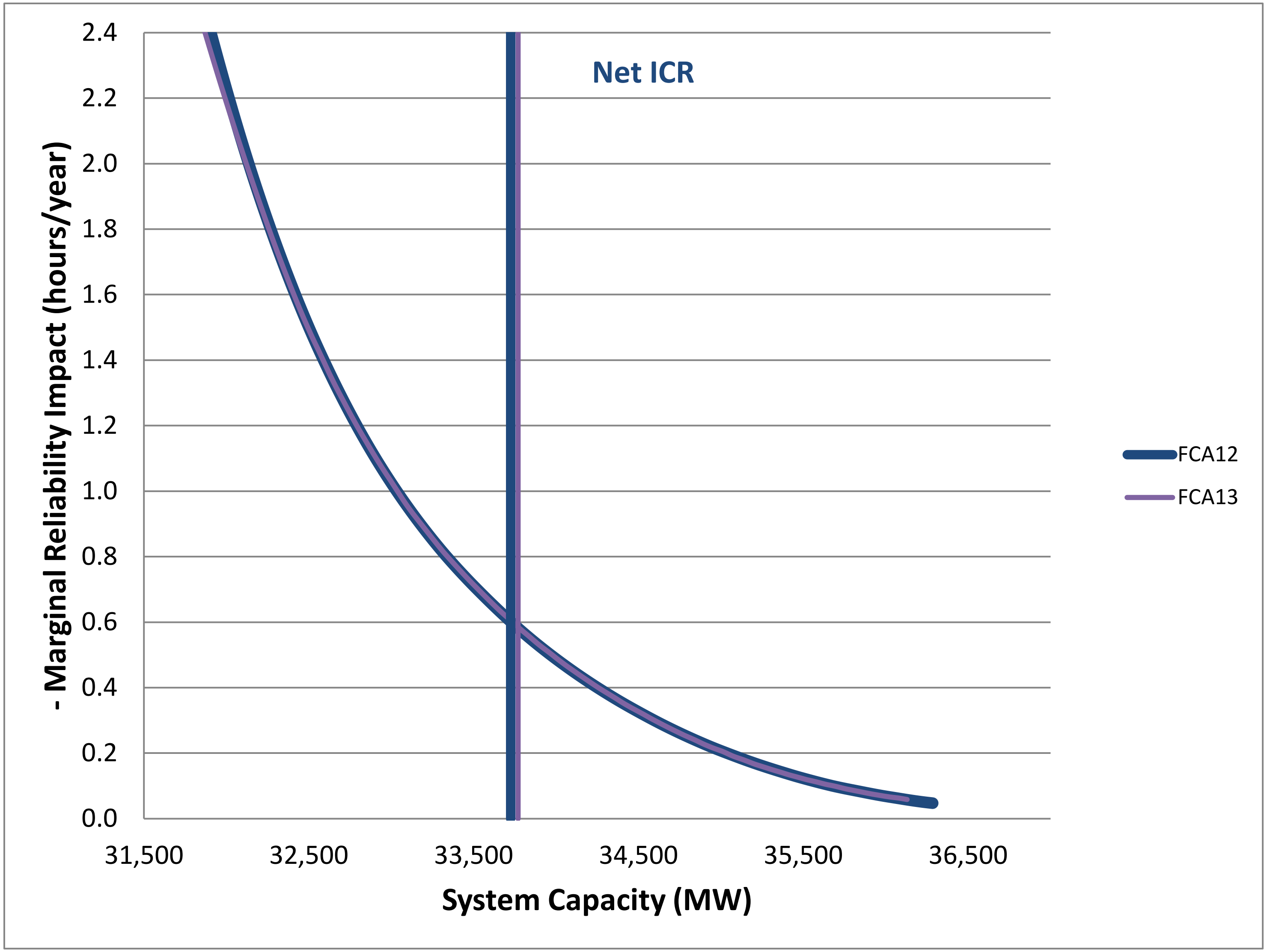


FCA 13 NNE Demand Curve

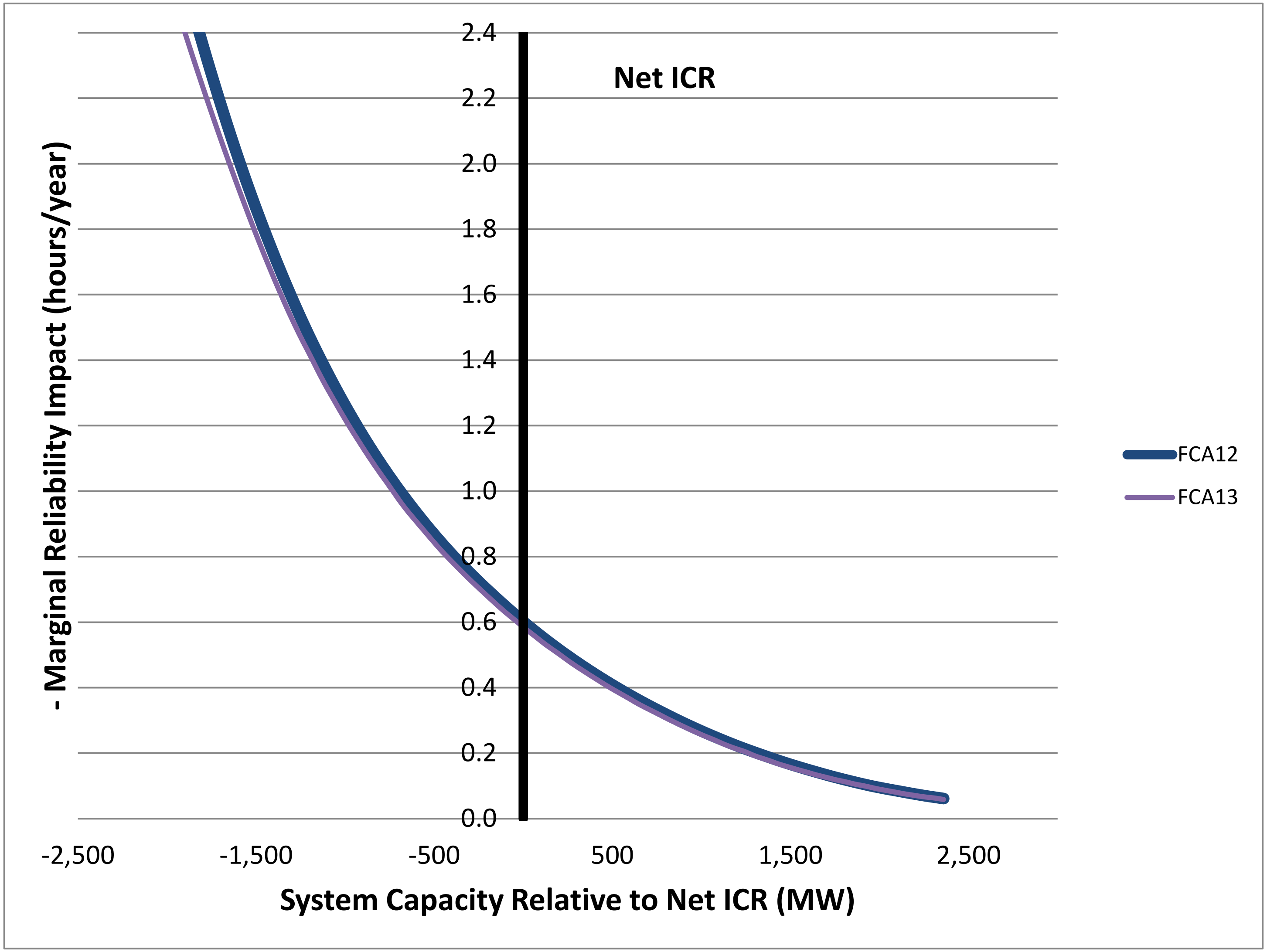


FCA 13 & FCA 12 DEMAND CURVE COMPARISONS

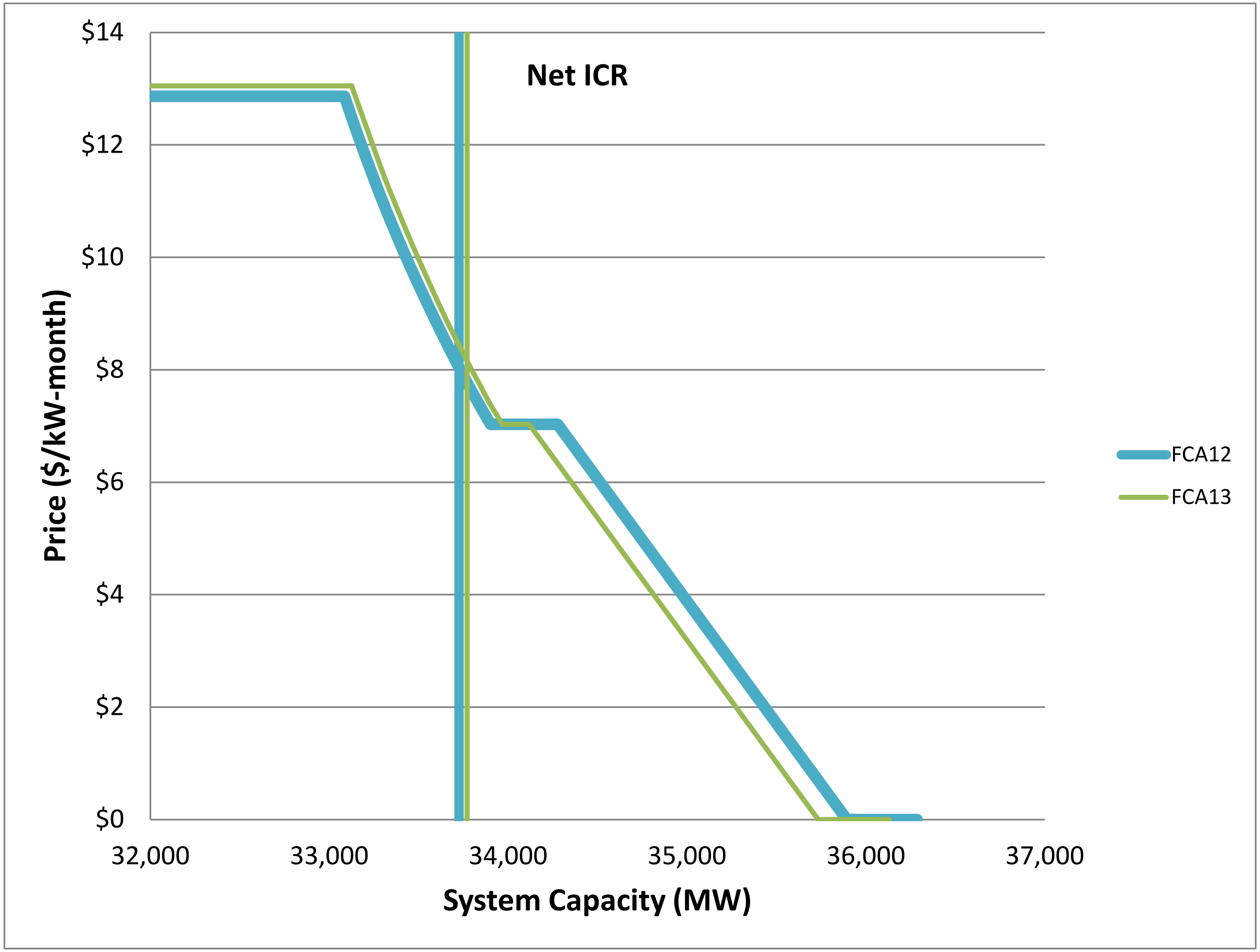
System MRI Curves



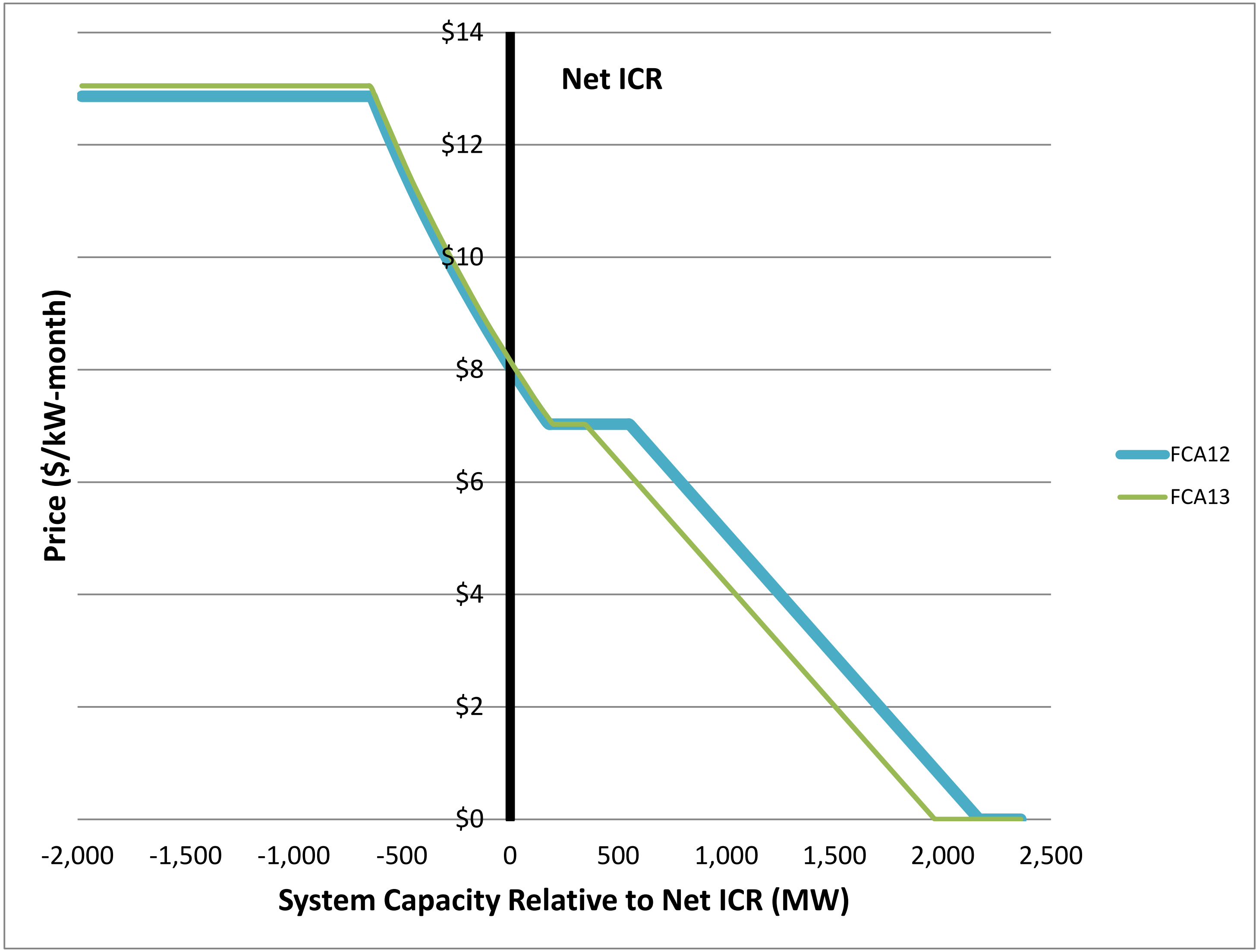
System MRI Curves - Relative to Net ICR



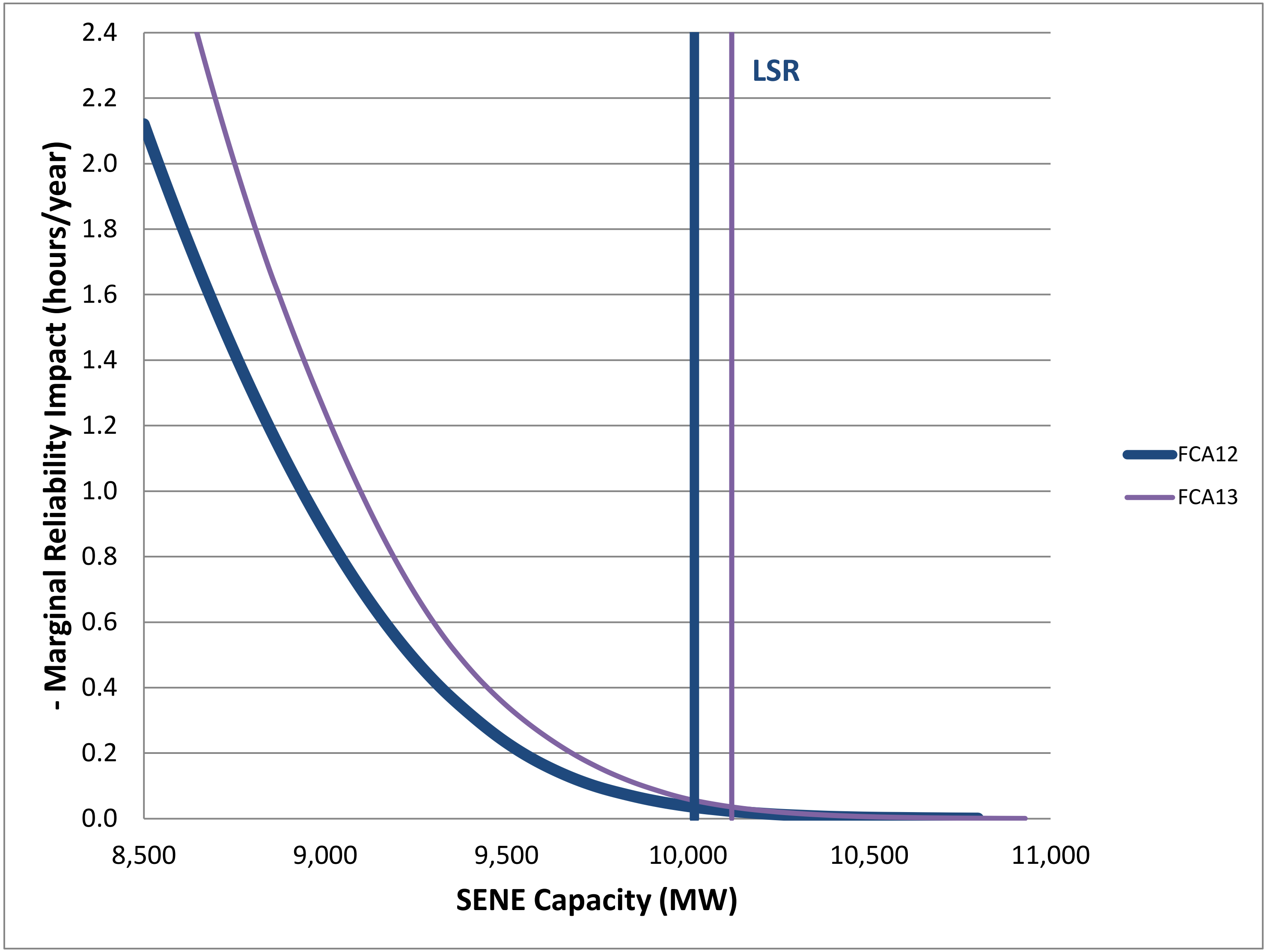
System Demand Curves



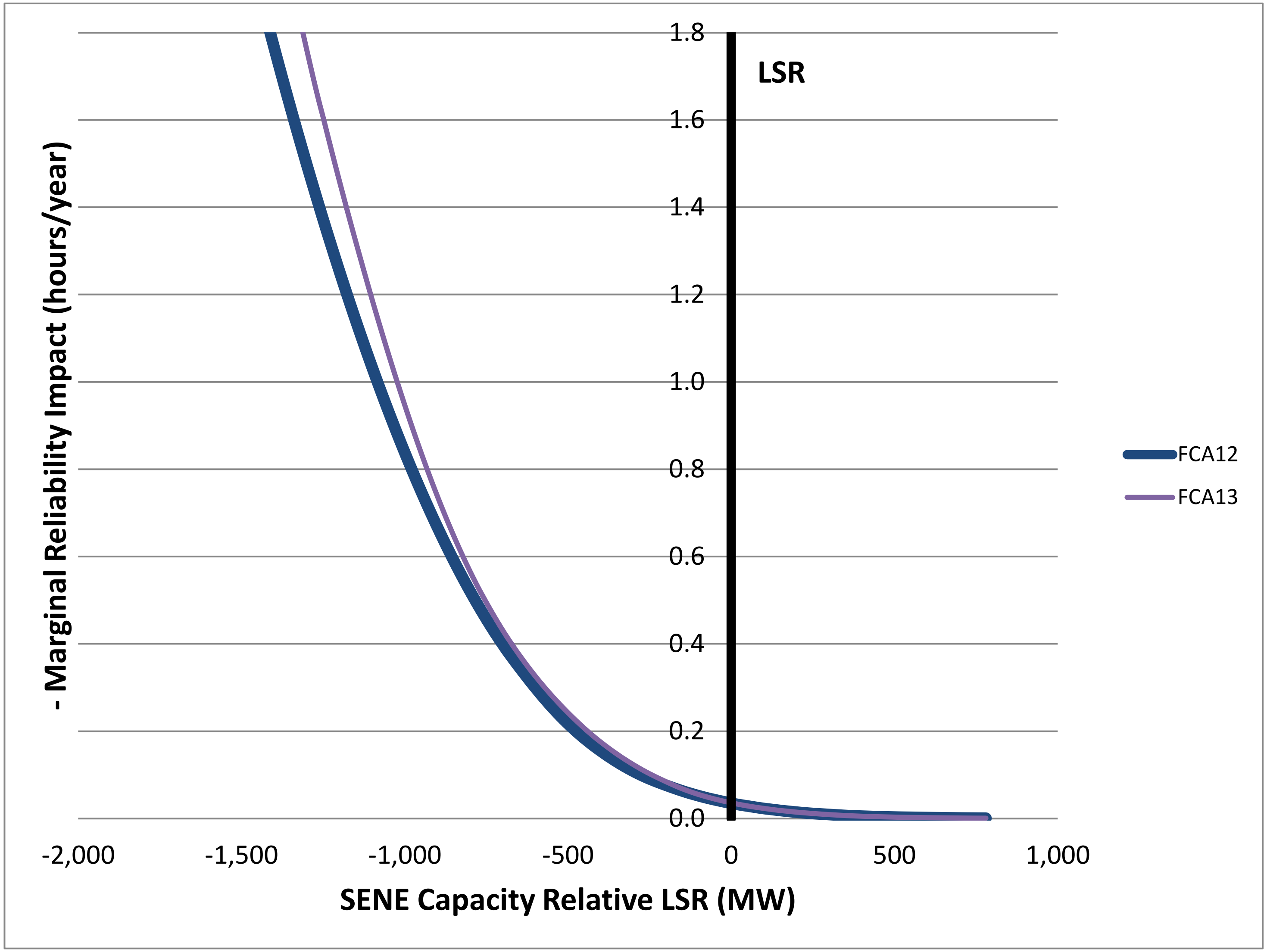
System Demand Curves - Relative to Net ICR



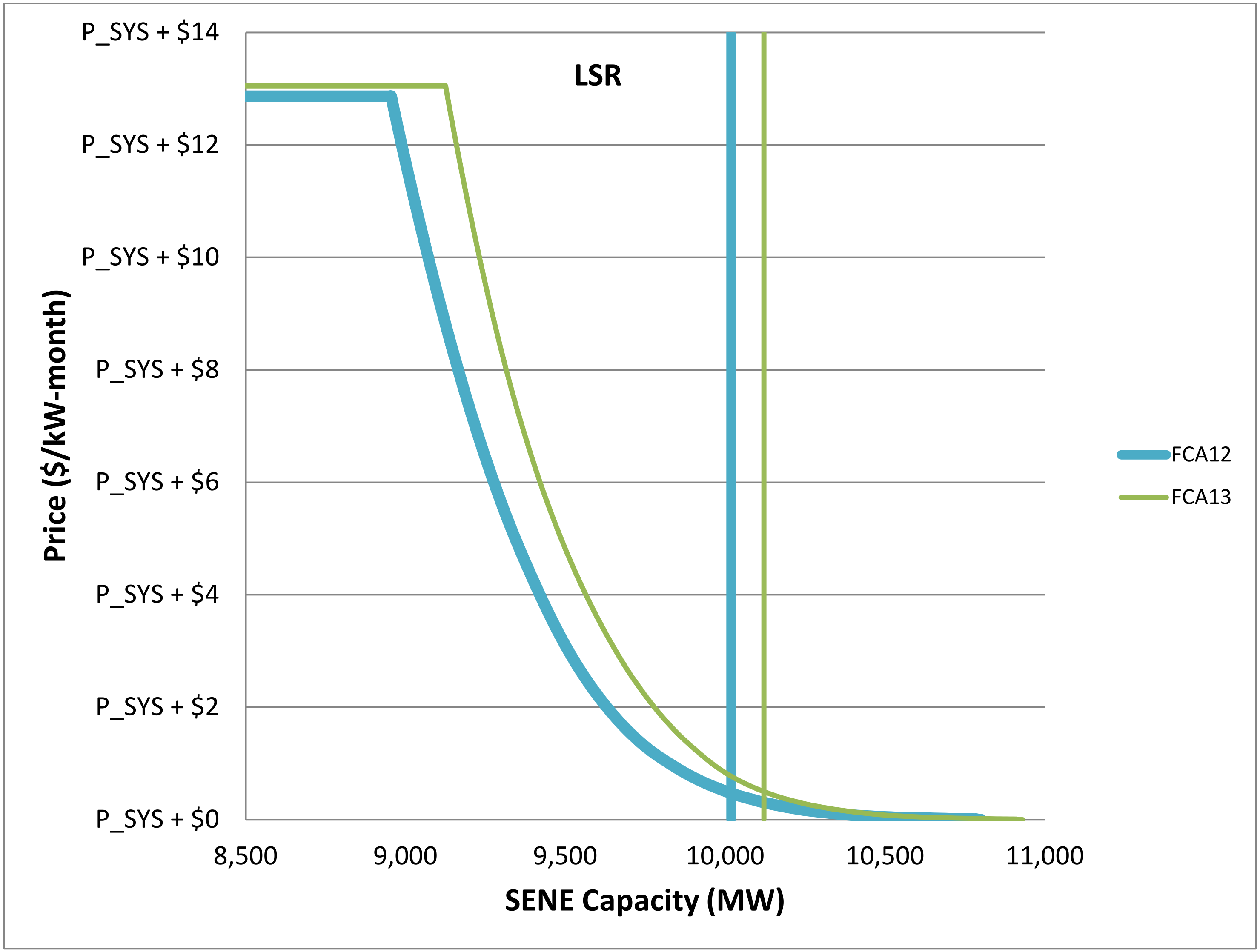
SENE MRI Curves



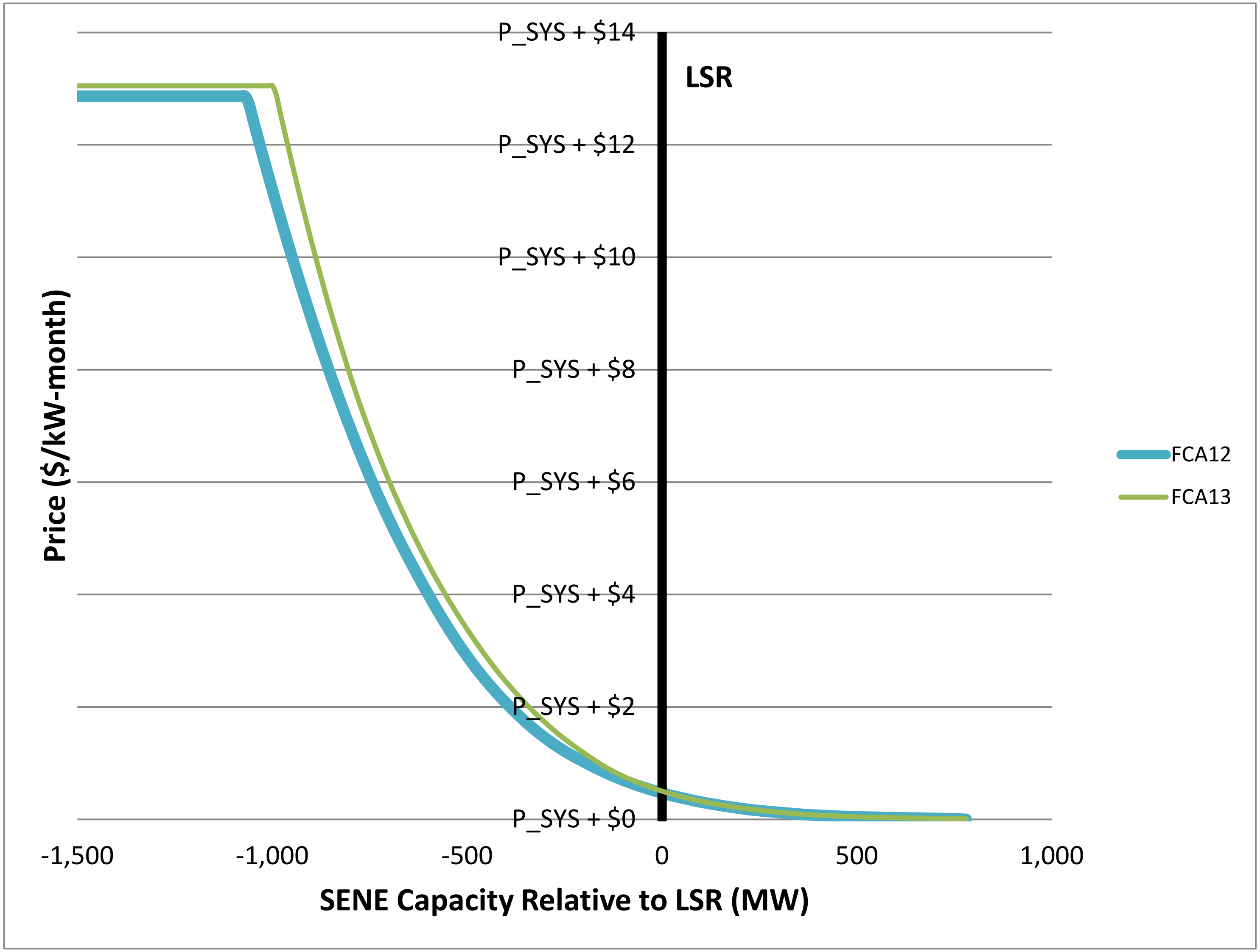
SENE MRI Curves - Relative to LSR



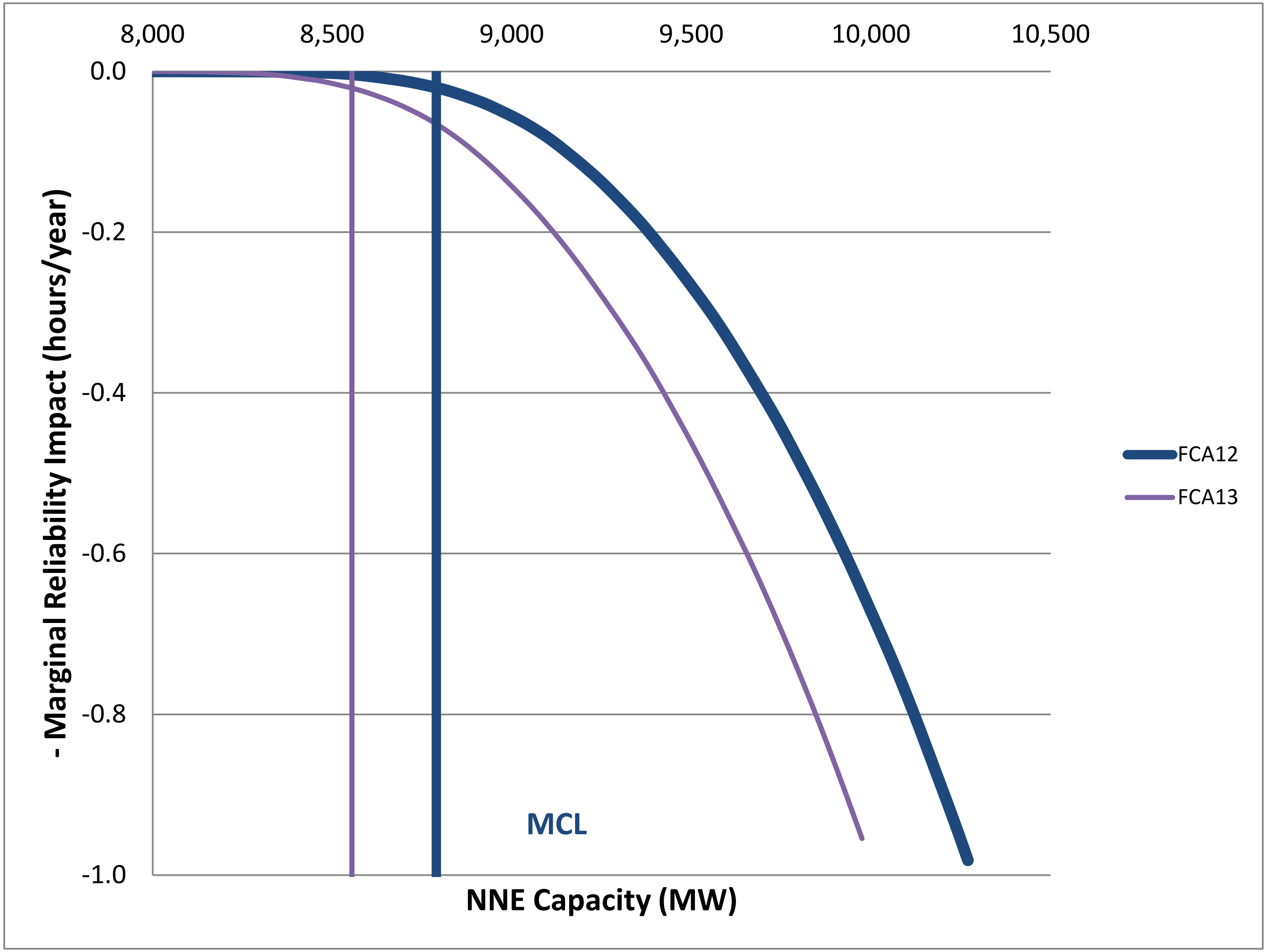
SENE Demand Curves



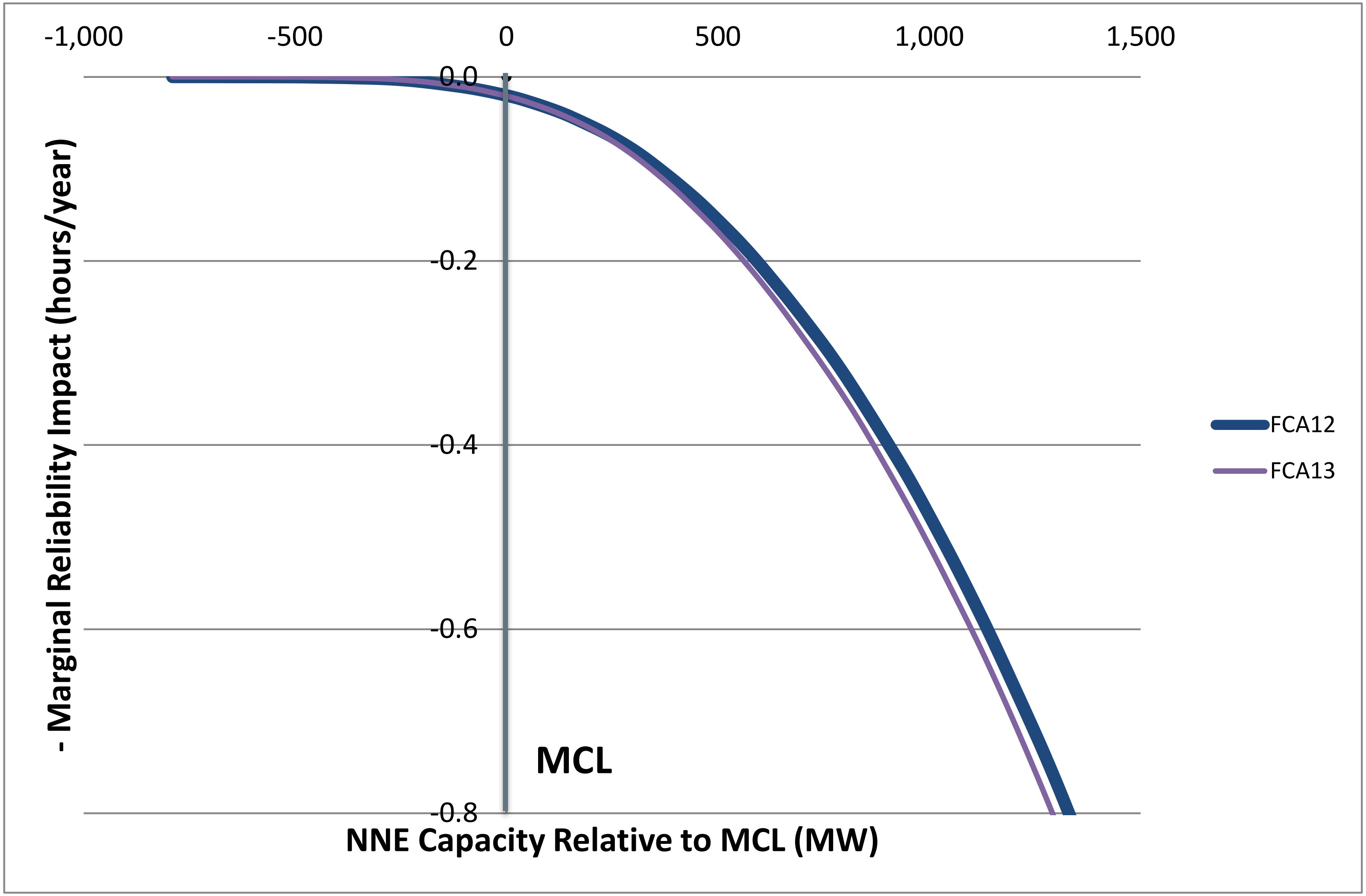
SENE Demand Curves - Relative to LSR



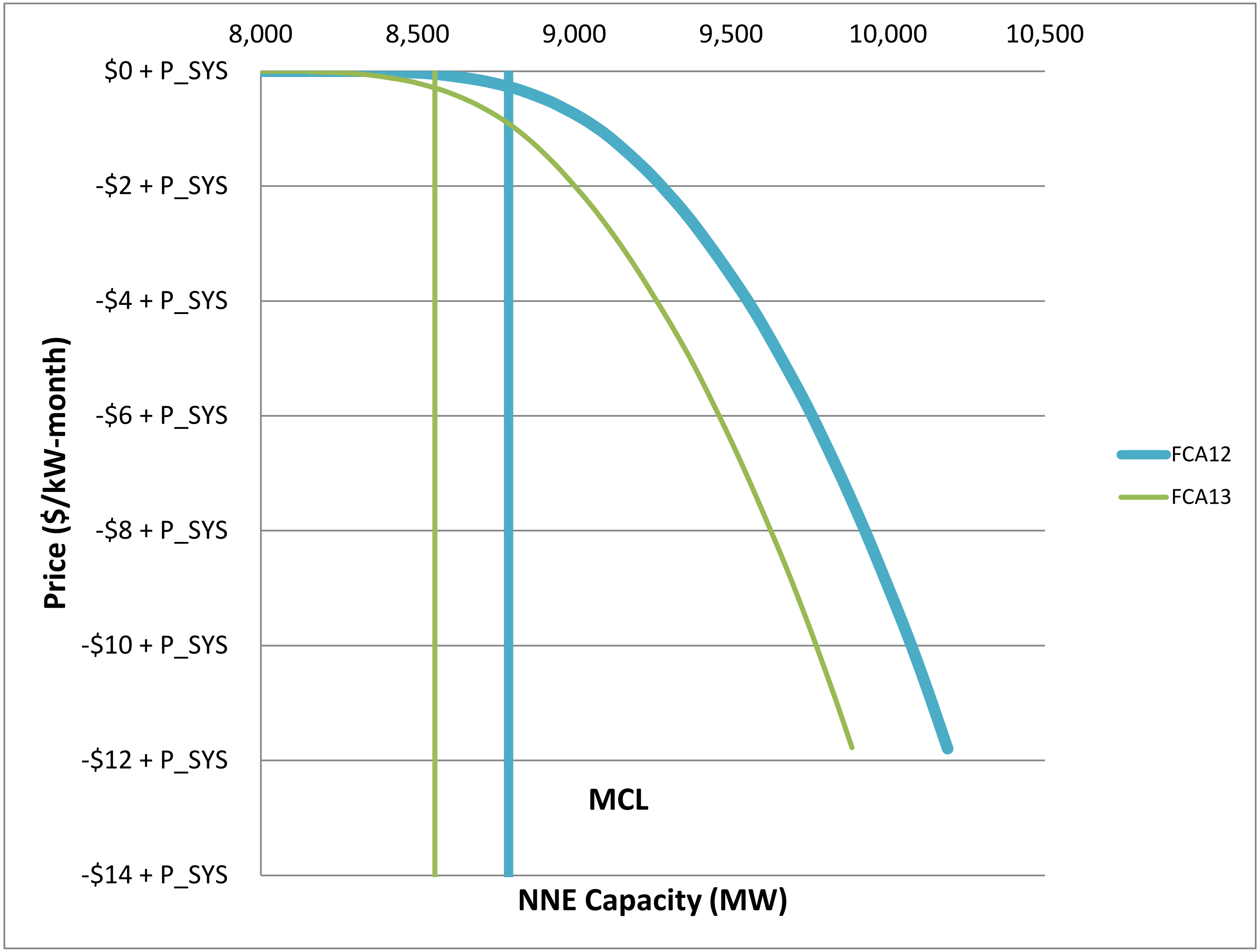
NNE MRI Curves



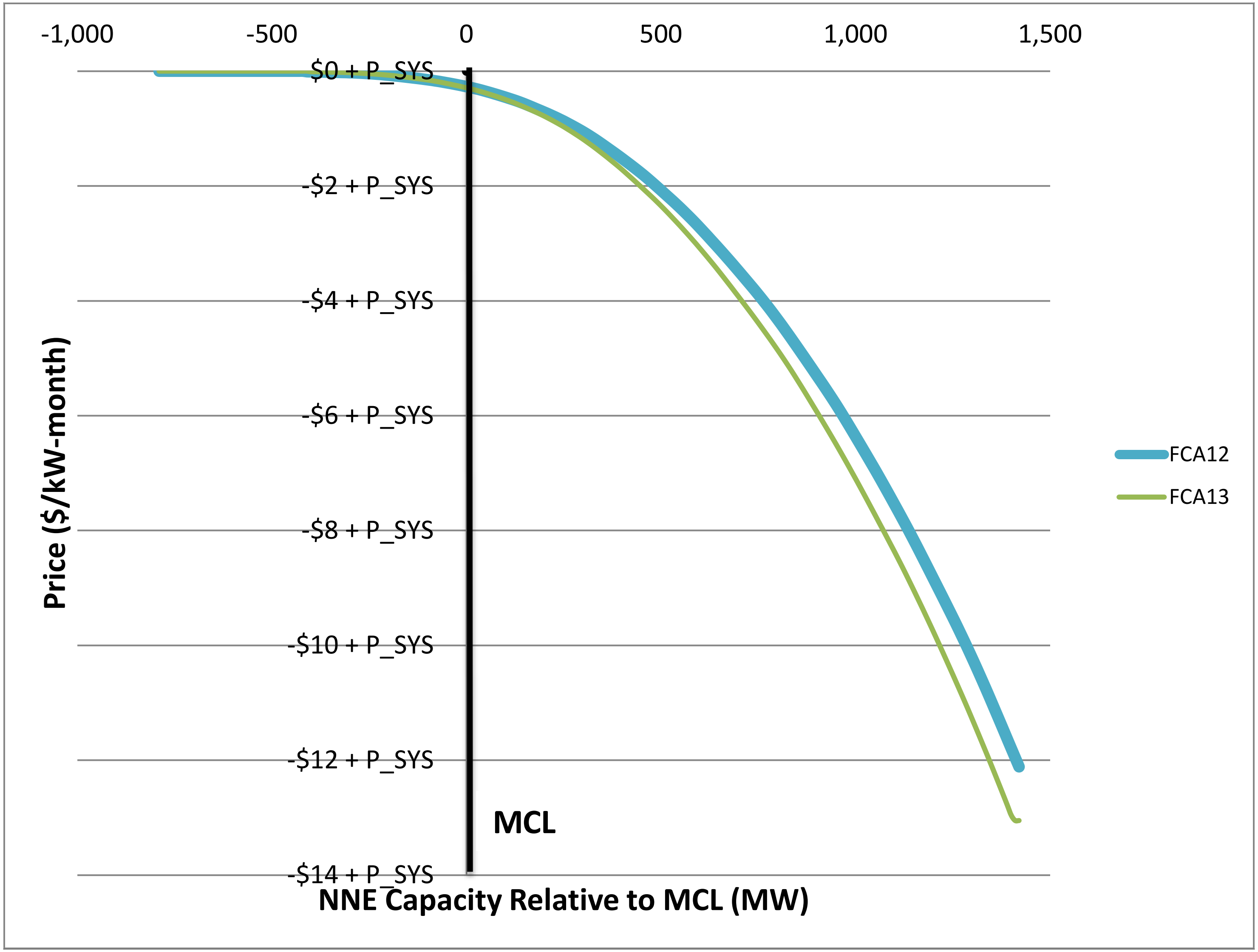
NNE MRI Curves - Relative to MCL



NNE Demand Curves



NNE Demand Curves - Relative to MCL



Questions

Assumptions for the 2022-2023 FCA ICR Values Calculation

Cost of New Entry (CONE)

- for the MRI Demand Curve

- CONE for the cap of the MRI Demand Curve for FCA 13 has been calculated as:
  - Gross CONE: $11.289/kW-month
  - Net CONE : $8.156/kW-month
  - FCA Starting Price : $13.050/kW-month

- See link for FCM parameters by CCP: https://www.iso-ne.com/static-assets/documents/2015/09/FCA_Parameters_Final_Table.xlsx

Modeling the New England Control Area

- The GE MARS model is used to calculate the probabilistic ICR 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
  - LRA is calculated for the combined Load Zones of NEMA/Boston, SEMA and RI (Southeast New England (SENE) Capacity Zone); modeled as an import-constrained Capacity Zone in FCA 13
  - MCL is calculated for the combined Load Zones of Maine, New Hampshire and Vermont (Northern New England (NNE) Capacity Zone); modeled as an export-constrained Capacity Zone in FCA 13
  - The MRI method for calculating Demand Curves are used to develop System and Capacity Zone MRI Demand Curves
- The TSA is calculated as an input in to LSR for the SENE Capacity Zone with a deterministic transmission screen

Assumptions for the ICR Calculations

- *Load forecast*
  - Net of behind-the-meter (BTM) photovoltaic (PV) forecast
  - Load forecast distribution
- *Resource data based on qualified Existing Capacity Resources for FCA 13*
  - Reflects the removal of certain Retirement de-list bids and permanent de-list bids*
  - Generating Capacity Resources
  - Intermittent Power Resources (IPR)
  - Import Capacity Resources
  - Demand Resources (DR)
- *Resource availability*
  - Generating Capacity Resources availability
  - IPR availability
  - DR availability
- *Load relief from OP4 actions*
  - Tie reliability benefits
    - Quebec
    - Maritimes
    - New York
  - 5% voltage reduction

*Qualified Capacity values reflects the removal of Retirement and Permanent De-List Bids that are at or above the FCA Starting Price, including the unconditional elections and terminations.

Load Forecast Data

- Load forecast assumed is from the 2018 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 BTM PV in ICR (MW)

- FCA 13 ICR calculations use an hourly profile of BTM PV corresponding to the load shape for the year 2002, used by the Northeast Power Coordinating Council (NPCC) for reliability studies For more information on the development of the hourly profile see: https://www.iso-ne.com/static-assets/documents/2017/06/pspc_6_22_2017_2002_PV_profile.pdf
  - used for all probabilistic ICR Values calculations
  - modeled in GE MARS by Regional System Plan (RSP) 13-subarea representation
  - includes an 8% transmission and distribution gross-up
- The performance uncertainty of BTM PV is modeled using a 7-day uncertainty window methodology (3 days before and 3 days after the day under study)
- The values of BTM PV published in the 2018 CELT Report are the values of BTM PV subtracted from the gross load forecast to determine the net load forecast
- The published 90/10 net load forecast for the SENE sub-areas is used in the TSA

Notes:
For more info on the PV forecast, see https://www.iso-ne.com/static-assets/documents/2018/04/final-2018-pv-forecast.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
2022-2023	24,939	29,093	29,093	23,333	18,507	20,102	23,450	23,450	22,056	21,919	18,338	20,325

- Corresponds to the reference forecast labeled "ISONE Control Area and New England States Monthly Peak Load Forecast" from worksheet-4 Mnth Peak of the 2018 Forecast Data located in: https://www.iso-ne.com/static-assets/documents/2018/05/forecast_data_2018.xlsx

There is a distribution associated with each monthly peak. The distribution associated with the seasonal peak load forecast is shown 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 2022	27,598	27,873	28,229	28,646	29,093	29,581	30,078	30,777	31,592	32,313
Winter 2022-2023	23,009	23,133	23,230	23,295	23,450	23,607	23,782	23,888	24,150	24,530

- From Table 1.6 - Seasonal Peak Load Forecast Distributions (forecast is reference with reduction for BTM PV) of the 2018 CELT

Resource Data – Generating Capacity Resources (MW)

Load Zone	Non-Intermittent Generating Resource		Intermittent Resource		Total	
	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	2,970.327	3,160.717	201.023	317.816	3,171.350	3,478.533
NEW HAMPSHIRE	4,077.887	4,243.568	164.276	221.506	4,242.163	4,465.074
VERMONT	206.795	246.931	77.899	123.689	284.694	370.620
CONNECTICUT	9,340.725	9,839.148	92.536	109.006	9,433.261	9,948.154
RHODE ISLAND	2,373.080	2,574.041	32.665	25.993	2,405.745	2,600.034
SOUTHEAST MASSACHUSETTS	4,448.144	4,800.661	101.082	79.860	4,549.226	4,880.521
WEST CENTRAL MASSACHUSETTS	3,826.439	4,093.348	99.073	100.869	3,925.512	4,194.217
NORTHEAST MASSACHUSETTS & BOSTON	2,721.129	3,123.782	48.309	43.135	2,769.438	3,166.917
Total New England	**29,964.526**	**32,082.196**	**816.863**	**1,021.874**	**30,781.389**	**33,104.070**

- Qualified Existing Generating Capacity Resources for FCA 13
- Intermittent Power Resources have both summer and winter values modeled; non-intermittent Generating Capacity Resource winter values provided for informational purposes

Resource Data – Import Capacity Resources (MW)

Import Capacity Resource	Qualified Summer MW	Modeled MW	External Interface
NYPA - CMR	68.800	68.800	New York AC Ties
NYPA - VT	11.000	11.000	New York AC Ties
Total MW	79.800	79.800	

- Qualified Existing Import Capacity Resources for FCA 13
- Modeled with 100% resource availability

Resource Data – Demand Resources (MW)

Load Zone	On-Peak Demand Resource		Seasonal Peak Demand Resource		Active Demand Capacity Resource (ADCR)		Total	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	150.099	131.886	-	-	139.535	157.431	289.634	289.317
NEW HAMPSHIRE	116.798	96.812	-	-	42.325	41.604	159.123	138.416
VERMONT	110.601	109.856	-	-	52.664	58.270	163.265	168.126
CONNECTICUT	83.419	59.644	581.225	625.940	141.786	141.081	806.430	826.665
RHODE ISLAND	264.611	267.944	-	-	44.581	41.080	309.192	309.024
SOUTHEAST MASSACHUSETTS	385.830	380.728	-	-	46.422	44.547	432.252	425.275
WEST CENTRAL MASSACHUSETTS	411.016	415.550	35.176	14.419	97.900	94.246	544.092	524.215
NORTHEAST MASSACHUSETTS & BOSTON	710.980	683.896	-	-	75.524	74.230	786.504	758.126
Grand Total	2,233.354	2,146.316	616.401	640.359	640.737	652.489	3,490.492	3,439.164

- Qualified Existing Demand Resources for FCA 13
- Includes the 8% transmission and distribution loss adjustment (gross-up)

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

Resource Type	SENE	NNE	New England
Non-Intermittent Generating Resource	9,542	7,255	29,965
Intermittent Resource	182	443	817
Import Resource	-	-	80
On-Peak Demand Resource	1,361	377	2,233
Seasonal-Peak Demand Resource	-	-	616
Active Demand Capacity Resource	167	235	641
Total	11,252	8,310	34,352

	SENE	NNE	New England
50/50 Load Forecast Net BTM PV	12,415	5,469	29,093

- LRA is calculated for the SENE Capacity Zone; MCL is calculated for the NNE Capacity Zone
- Zonal requirements are determined using the load forecast and resource assumptions for the appropriate RSP sub-areas as the transmission transfer capability analysis is performed using the RSP 13-bubbles for the import and export constrained interfaces
- The 50/50 load forecast values for the Capacity Zones are the sum of the appropriate RSP sub-areas and are shown for informational purposes

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 April 26, 2018 (CEII): https://www.iso-ne.com/static-assets/documents/2018/04/a9_fca13_zonal_development.pdf

Availability Assumptions – Non-Intermittent Generating Capacity Resources

- **Forced outages assumption**
  - Each generating unit's Equivalent Forced Outage Rate on Demand (non-weighted EFORd) modeled
  - Based on a 5-year average (January 2013 – December 2017) of Generation Availability Data System (GADS) data submitted by generators
  - NERC GADS class average data is used for immature and non-commercial units
- **Scheduled outage assumption**
  - Each generating unit's weeks of maintenance modeled
  - Based on a 5-year average (January 2013 – December 2017) 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 and non-commercial units

Availability Assumptions – Non-Intermittent Generating Capacity Resources

Resource Category	Summer MW	Assumed Average EFORd (%) Weighted by Summer Ratings	Assumed Average Maintenance Weeks Weighted by Summer Ratings
Combined Cycle	14,577	4.0	5.2
Fossil	5,224	20.4	5.2
Combustion Turbine	3,607	10.7	2.6
Nuclear	3,340	0.9	3.6
Hydro (includes pumped Storage)	3,057	2.5	5.6
Diesel	137	8.3	1.9
Miscellaneous	23	10.9	4.4
Total	29,965	7.2	4.7

- 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 - IPR

- 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 Demand Resource		Seasonal Peak Demand Resource		Active Demand Capacity Resource		Total	
	Summer (MW)	Performance (%)	Summer (MW)	Performance (%)	Summer (MW)	Performance (%)	Summer (MW)	Performance (%)
MAINE	150	100	-	-	140	100	290	100
NEW HAMPSHIRE	117	100	-	-	42	97	159	99
VERMONT	111	100	-	-	53	98	163	99
CONNECTICUT	83	100	581	100	142	95	806	99
RHODE ISLAND	265	100	-	-	45	78	309	97
SOUTHEAST MASSACHUSETTS	386	100	-	-	46	95	432	99
WEST CENTRAL MASSACHUSETTS	411	100	35	100	98	88	544	98
NORTHEAST MASSACHUSETTS & BOSTON	711	100	-	-	76	90	787	99
Total New England	2,233	100	616	100	641	94	3,490	99

- Uses historical DR performance from summer and winter 2013 – 2017. For more information see: https://www.iso-ne.com/static-assets/documents/2018/07/a4_pspc_dr_availability_2018icr_05292018.pdf
- Modeled by zones and type of DR with outage factor calculated as 1- performance/100

OP4 Assumptions – Assumed Load Relief from Actions 6 & 8 - 5% Voltage Reduction (MW)

	90-10 Peak Load	Passive DR	ADCR	Action 6 & 8 5% Voltage Reduction
June 2022-Sept 2022	31,593	2,850	641	422
October 2022-May 2023	24,150	2,787	652	311

- Uses the 90-10 Peak load forecast minus BTM PV and all passive DR and ADCR
- Multiplied by the 1.5% value used by ISO Operations in estimating relief obtainable from OP4 voltage reduction

OP4 Assumptions, Cont. - Tie Benefits (MW)

- Based on the results of the 2022-2023 tie benefits study

Control Area	FCA 13
Quebec via Phase II	969
Quebec via Highgate	149
Maritimes	516
New York	366
Total	2,000

- 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

OP4 Assumptions, Cont.
Minimum Operating Reserve Requirement(MW)

- Minimum Operating Reserve is the minimum reserves held for transmission system security
- Modeled at 700 MW in the ICR calculations*

* See April PSPC meeting: https://www.iso-ne.com/static-assets/documents/2018/04/a6_pspc_rev_volt_reduct_04182018.pdf

FCA 13 TSA Requirements Assumptions

- The Southeast New England (SENE) Capacity Zone was identified as the only import-constrained Capacity Zone for FCA 13
- The TSA Requirement is calculated for this Capacity Zone
- The calculation of the TSA Requirements rely on the latest load forecast, resource data and resource availability assumptions in addition to the transmission topology that was certified for FCA 13
- The TSA Requirement is calculated as:

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

FCA 13 TSA Requirements Assumptions – Detailed Assumptions

- Load Forecast Data
  - 2018 CELT net forecast (adjusted for BTM PV forecast)
    - SENE sub-area 90/10 peak load: 13,561 MW
- Resource Data for SENE
  - 2022-23 Existing Capacity Resource qualification data
    - Generating capacity: 9,724* MW
      - Includes 8,504 MW of regular generation resources and 1,038 MW peaking generation resources, 182 MW of intermittent generation resources
    - Passive Demand Resources: 1,361 MW
    - Active Demand Capacity Resources: 167 MW

*Retirement De-list bids at or above the FCA Starting Price or elected unconditional election are deducted from the Existing Capacity Qualification data

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

FCA 13 TSA Requirements Assumptions – Detailed Assumptions, cont.

- Resource unavailability assumptions
  - Regular Generating Capacity Resources - weighted average EFORd
    - SENE sub-area: 10%
  - Peaking generating resources: 20%
  - Passive Demand Resources: 0%
  - Active Demand Capacity Resources - de-rating based on performance factors
    - NEMA/Boston sub-area: 10.0%
    - SEMA sub-area: 5.1%
    - RI sub-area: 22.1%

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

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

Resource Type/OP4	FCA 13
Non-Intermittent Generating Resources	29,965
Intermittent Resources	817
Import Resources	80
Demand Resources	3,490
OP4 Voltage Reduction	422
Minimum Operating Reserve	-700
Tie Benefits	2,000
Proxy Units	0
Total MW Modeled in ICR	**36,074**

Notes:

- The tie benefits assumptions are the results of the 2022-2023 tie benefits study
- Intermittent Power Resources have both the summer and winter capacity values modeled
- OP4 voltage reduction includes both Action 6 and Action 8 MW assumptions
- Minimum Operating Reserve is the minimum reserves held for transmission system security

Questions