NEPOOL Participants Committee Report

September 2016

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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was $508M over the period, up $64M from July 2016 and up $83M from August 2015
  - August natural gas prices over the period were 12.8% higher than July 2016 average values
  - Average RT Hub Locational Marginal Prices ($40.19/MWh) over the period were 37% higher than July 2016 averages
  - Average August 2016 natural gas prices and RT Hub LMPs over the period were up 31% and 13.7%, respectively, from August 2015 averages
- Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.3% during August 2016, up from 97.9% during July

Underlying natural gas data furnished by: ICE Global markets in clear view

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - August NCPC payments totaled $6.5M over the period, up $2.6M from July and up $758K from August 2015
  - First Contingency payments totaled $5.4M, up $3.0M from July
    - $5.3M paid to internal resources, up $3.1M from July
      - $413K charged to DALO, $4.9M to RT Deviations
    - $91K paid to resources at external locations, down $160K from July
      - $0 charged to DALO at external locations, $91K to RT Deviations
  - Second Contingency payments totaled $1.0M, down $465K from July
  - Voltage payments were $34K, up $14K from July
  - Distribution payments were $52K, up $52K from July
  - NCPC payments over the period as percent of Energy Market value were 1.3%

Highlights, cont.

- 2016 Economic Study - NEPOOL Scenario Analysis
  - Discussion of the five-scenario draft results held at the August 17 PAC meeting and further discussions are planned for the September 21 PAC meeting
- Keene Road ‘Market Efficiency Transmission Upgrade Needs Assessment’ scope of work to be discussed at the September 21 PAC meeting
- Qualification of new resources for participation in the eleventh Forward Capacity Auction (FCA) will be completed by the end of September
- ISO will be holding an informational session in November to discuss the expected state of the power system and likely capacity zones for FCA 12

Forward Capacity Market (FCM) Highlights

- CCP #5 (2014-2015) through CCP #6 (2015-2016)
  - Less than 100 MW of resources are non-commercial at this time and evaluation will continue to the end of summer
- CCP #7 (2016-2017)
  - Evaluation of new resources that were to be commercial on June 1 has commenced and will continue to the end of summer to ensure they have met their expected output
  - RTEG resources that cannot operate due to recent changes in the EPA guidelines are shedding in the monthly auctions
- CCP #8 (2017-2018)
  - Results of the second reconfiguration auction were posted on August 17 and no transactions were denied for reliability reasons
  - Third and final bilateral window will be December 1-7, and results to be posted no later than January 11, 2017

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #9 (2018-2019)
  - Second bilateral window will be May 2017
  - Second reconfiguration auction will be August 2017
- CCP #10 (2019-2020)
  - On July 1, a compliance filing was made in accordance with FERC's May 2, 2016 order in Docket No. EL16-38-000 related to self-composite offers for new summer capacity when the resource has equal or greater winter capacity
    - FERC accepted the compliance filing on August 30 but also directed the ISO to make another compliance filing (within 60 days) to automatically match new winter incremental capacity with excess summer capacity and apply the seven-year to those winter MWs (changes will be effective for FCA #11)
  - First bilateral transaction window will be April 2017
  - First reconfiguration auction will be June 2017

FCM Highlights, cont.

- CCP #11 (2020-2021)
  - On August 8, FERC accepted the ISO's waiver of certain provisions of the ISO Tariff so that RTEG resources that can no longer operate under the EPA rules can have the option of changing their demand resource type to RTDR resources
    - Review of requests to convert are under review and will be completed by October 1
  - Qualification Notification Letters for static delist bids and new generating capacity resources will be released on September 30
  - Auction to commence February 6, 2017

RTEG – Real-Time Emergency Generation
RTDR – Real-Time Demand Response

Highlights, cont.

- The lowest 50/50 and 90/10 Fall Operable Capacity Margin Week is projected for week beginning September 17, 2016.
  – ISO-NE expects heavy natural gas pipeline construction and maintenance to occur into the fall (through late November)

- The lowest 50/50 Preliminary Winter Operable Capacity Margin Week is projected for week beginning January 28, 2017, and the lowest 90/10 capacity margin occurs weeks beginning January 7 and 14, 2017.

OP-4 EVENT

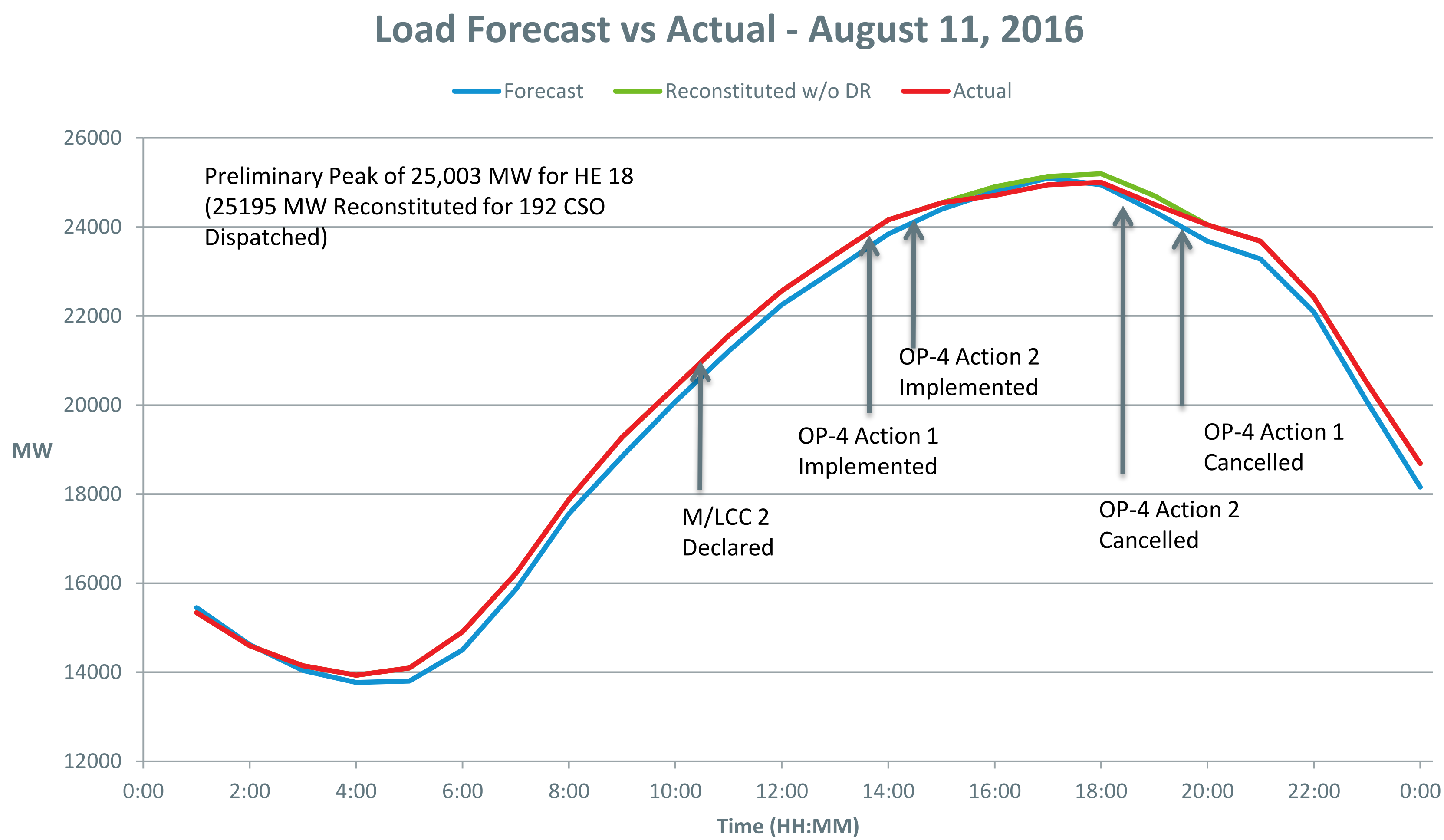
Summary

- On Thursday August 11, 2016, ISO New England implemented Operating Procedure #4 (OP#4), Action During a Capacity Deficiency, to manage a deficiency in Thirty Minute Operating Reserve
- ISO entered M/LCC 2, Abnormal Conditions Alert at 1030 due to forced generator outages, approximately 1,425 MW
- On Thursday morning the operating reserve projection was a surplus of 324 MW, based on a forecast peak load of 25,100 MW
- Peak hour forced outages and reductions total was 4,294 MW compared to 2,266 MW value from the morning report
- The actual imports total during the peak was 3,462 MW versus the 2,995 MW value from the morning report.
- Real Time Demand Resources were dispatched except for Maine, which was not dispatched due to a transmission export constraint

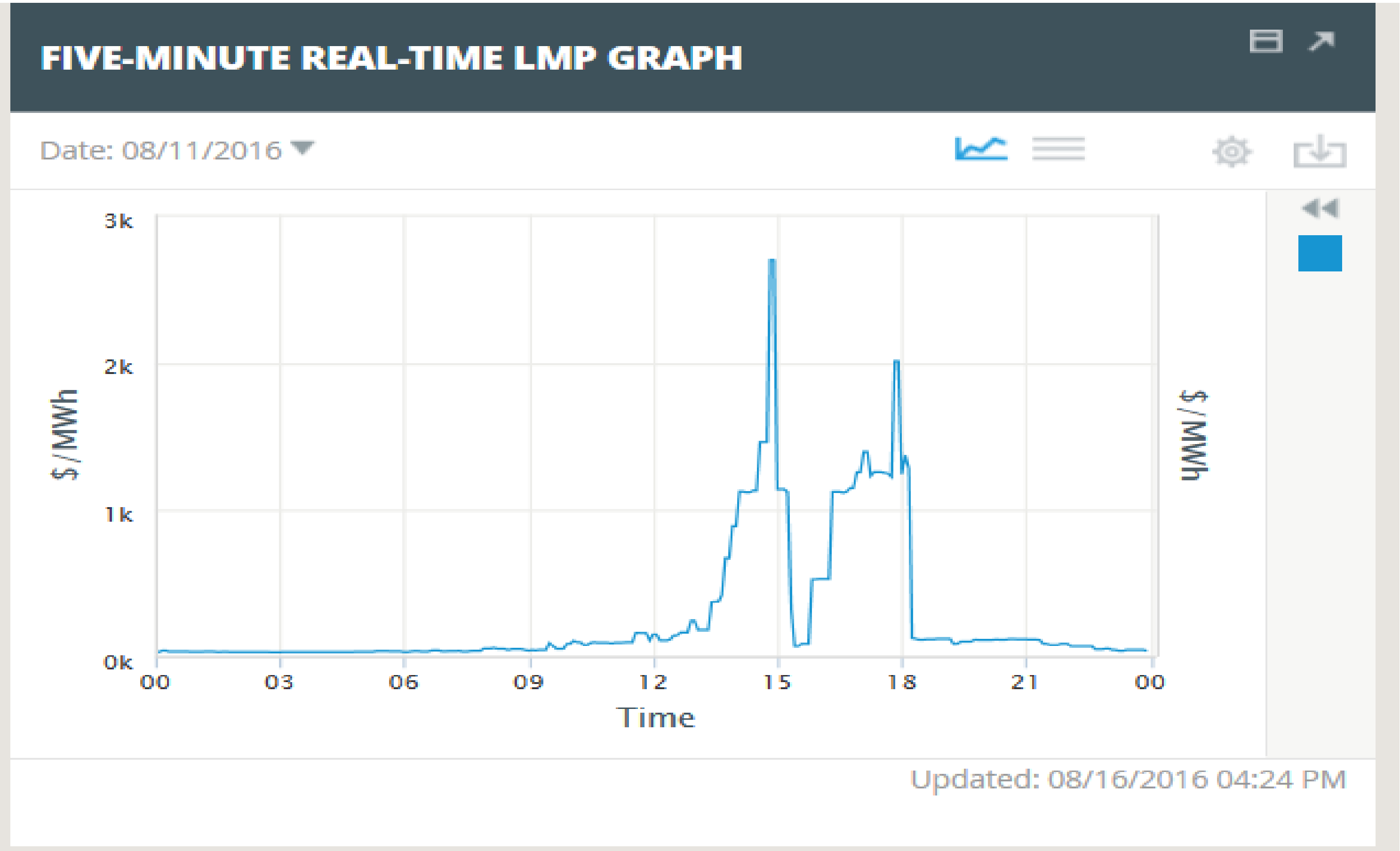
Timeline for Significant Events

- Thunder and lightning storms entered the Connecticut region during the morning of August 11th resulting in transmission line 'trips and reclosings' starting at 0930 and continuing until just before 1000
- 09:58 - Loss of a significant generator
- 10:30 - M/LCC 2 was declared for All of New England
- 13:50 - OP-4 Action 1 was implemented for All of New England
- 14:22 - Additional generation totaling 200 MW trips offline
- 14:25 - OP-4 Action 2 was implemented for NH, VT, RI, CT, MA
  - Orrington South and local western Maine 115kV line constraints did not allow for full DR dispatch in Maine
- 18:30 - OP-4 Action 2 was terminated
- 19:30 - OP-4 Action 1 was terminated

Load Forecast vs Actual



Real Time Pricing and Reserves (5 minute preliminary)



August 11, 2016 Shortage Event

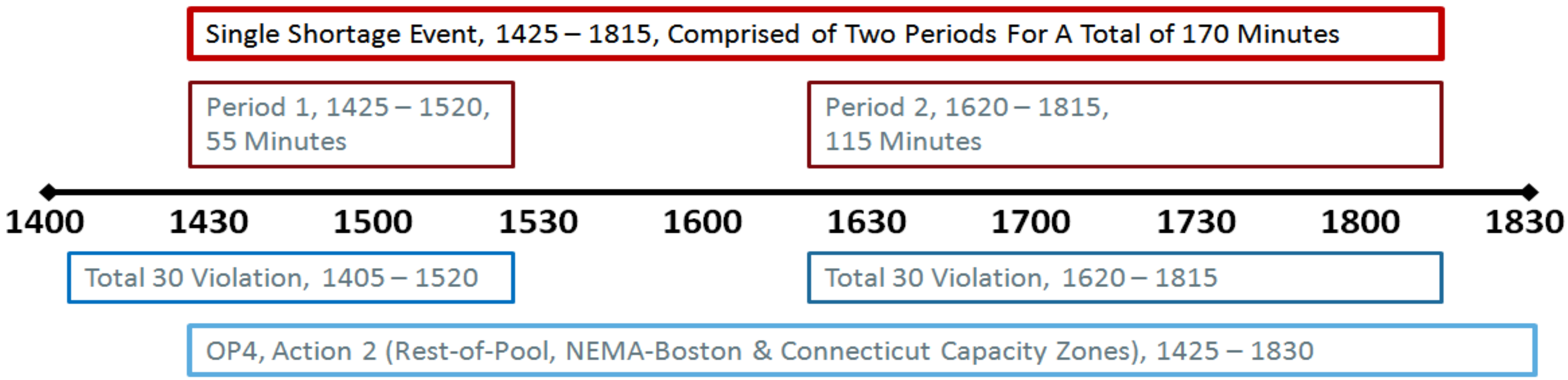
- Most of the ISO New England control area experienced a discrete Shortage Event on August 11, 2016
- The Shortage Event was declared based on the violation of TMOR RCPF ($1000) for over thirty contiguous minutes when Action 2 under Operating Procedure No. 4 was implemented for a Capacity Zone.
- The Capacity Zones affected by this Shortage Event are:
  - Connecticut
  - NEMA/Boston
  - Rest-of-Pool
- Action 2 under Operating Procedure No. 4 was not implemented for the Maine export-constrained Capacity Zone; therefore the Shortage Event was not applicable to the Maine Capacity Zone.

Shortage Event Details

- The system minimum TMOR RCPF ($1000) was violated starting at 14:05 hours on Thursday, August 11, 2016.
  - Action 2 under Operating Procedure No. 4 was implemented for the applicable Capacity Zones at 14:25 hours.
  - The OP 4 Action 2 declaration started the clock for a Shortage Event due to the TMOR RCPF violation.
  - The system minimum TMOR RCPF continued in violation until 15:20 hours on Thursday, August 11, 2016. This violation resulted in a Shortage Event period of 55 minutes.
- The system TMOR RCPF was not violated for the period 15:20 hours through 16:20 hours.
  - Action 2 under Operating Procedure No. 4 remained in effect for that period.
  - As the System TMOR RCPF was not violated during this interval, this time period is not part of the Shortage Event.
- The system minimum TMOR RCPF ($1000) was again violated starting at 16:20 hours while Action 2 under Operating Procedure No. 4 remained in effect for the applicable Capacity Zones.
  - System TMOR RCPF continued in violation until 18:15 hours on Thursday, August 11, 2016. This violation resulted in an additional Shortage Event period of 115 minutes.

Shortage Event Details, cont.

- The System TMOR RCPF violations were separated by a period of 60 minutes. As this period is less than 2.5 hours in duration, it results in a single discrete Shortage Event with a duration equal to the sum of the lengths of the underlying events.
- Subsequently, Action 2 under Operating Procedure No. 4 was cancelled at 18:30 hours on Thursday, August 11, 2016.
- The overall impact was that a Shortage Event started at 14:25 hours and ended 18:15 hours on Thursday, August 11, 2016. The single discrete Shortage Event was comprised of two periods for a total of 170 minutes.



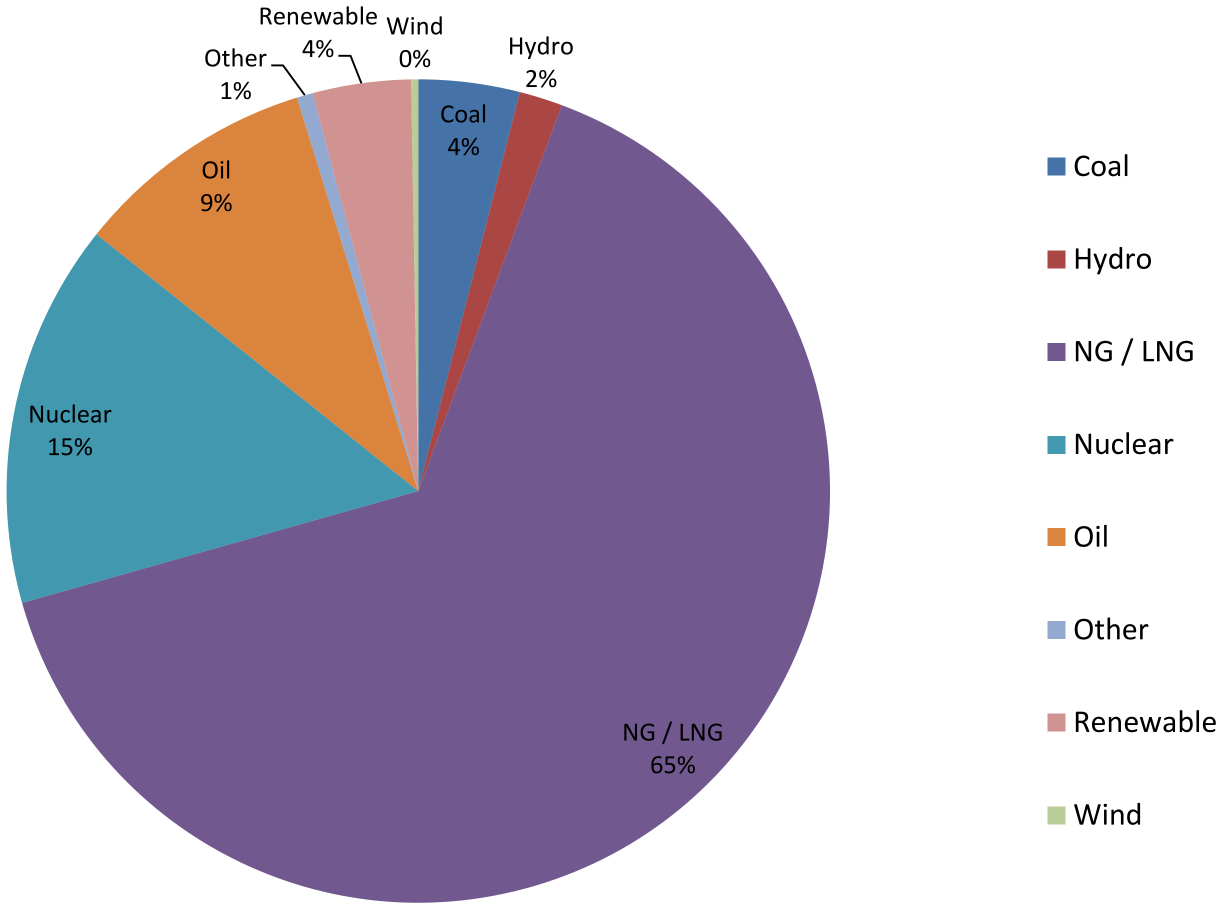
RTDR Initial Performance – August 11, 2016

Load Zone	Net CSO (MW)	Initial Performance (MW)	Percent of Initial Performance to Net CSO
CT	75.6	42.4	56%
NEMA	29.0	22.7	78%
NH	9.9	9.6	97%
RI	11.8	9.5	80%
SEMA	10.6	9.7	91%
VT	27.2	32.8	121%
West/Central Mass (WCMA)	27.6	29.2	106%
Total	191.7	155.8	81%

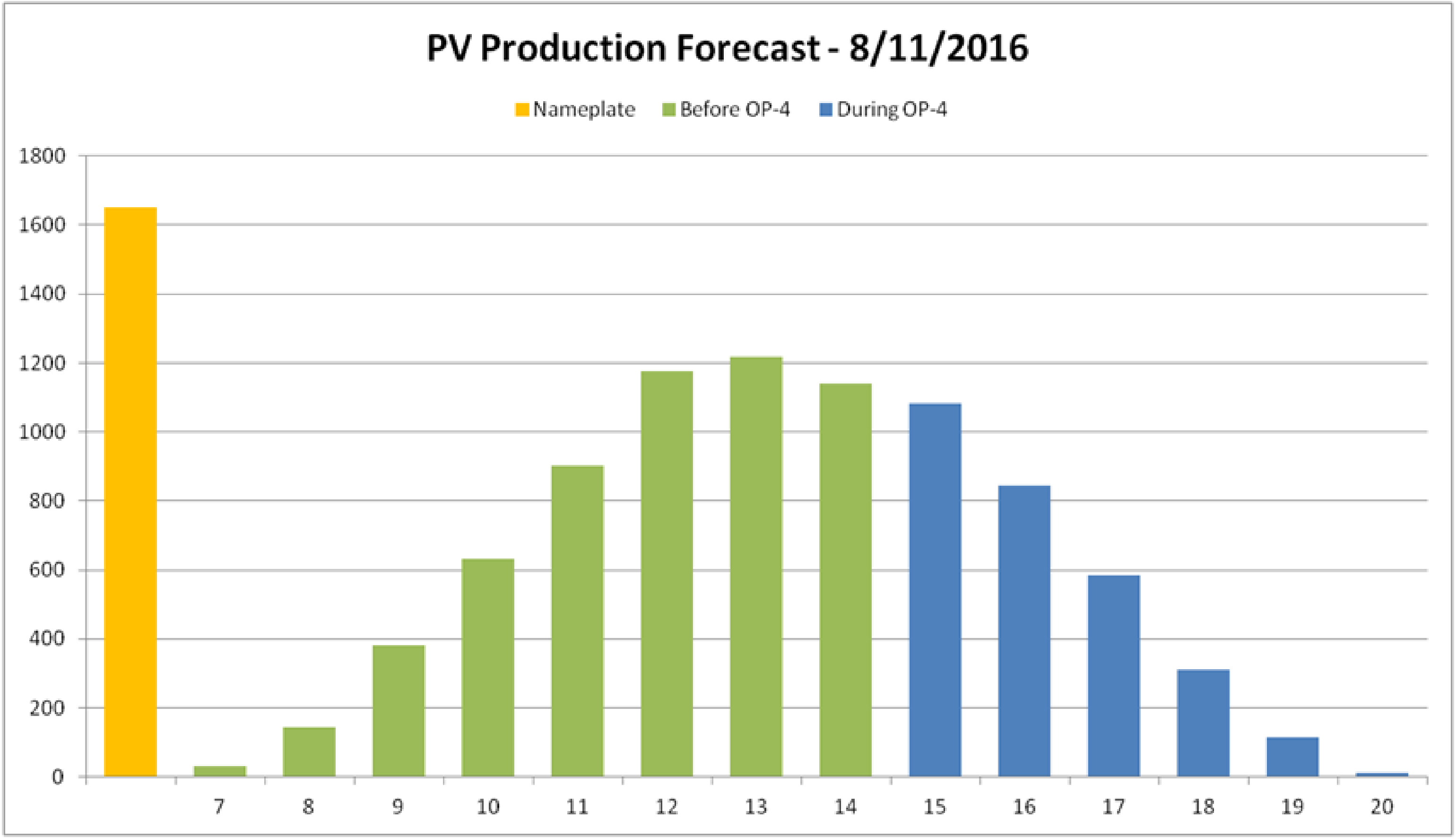
August 11, 2016 Settlement Summary

- Hub prices ($/MWh) for the hours ending 14:00 through 19:00
  - $387.32 / $1,438.97 / $518.04 / $930.55 / $1,390.82 / $407.05
- FCM Shortage Event (SE) penalties total ~ $7.3M
  - Units OOS (partial or full): ~3,113 MW, $5.7M
  - Units with availability < CSO: ~644 MW, $1.6M
- Incremental FCM Peak Energy Rent (PER) impacts
  - Total ~$101M (~$8.4M per month)
  - Charges begin in September 2016 FCM bill that will be issued in October 17
  - This PER will be reflected for 12 months of FCM billing (Sep ‘16 – Aug ‘17)

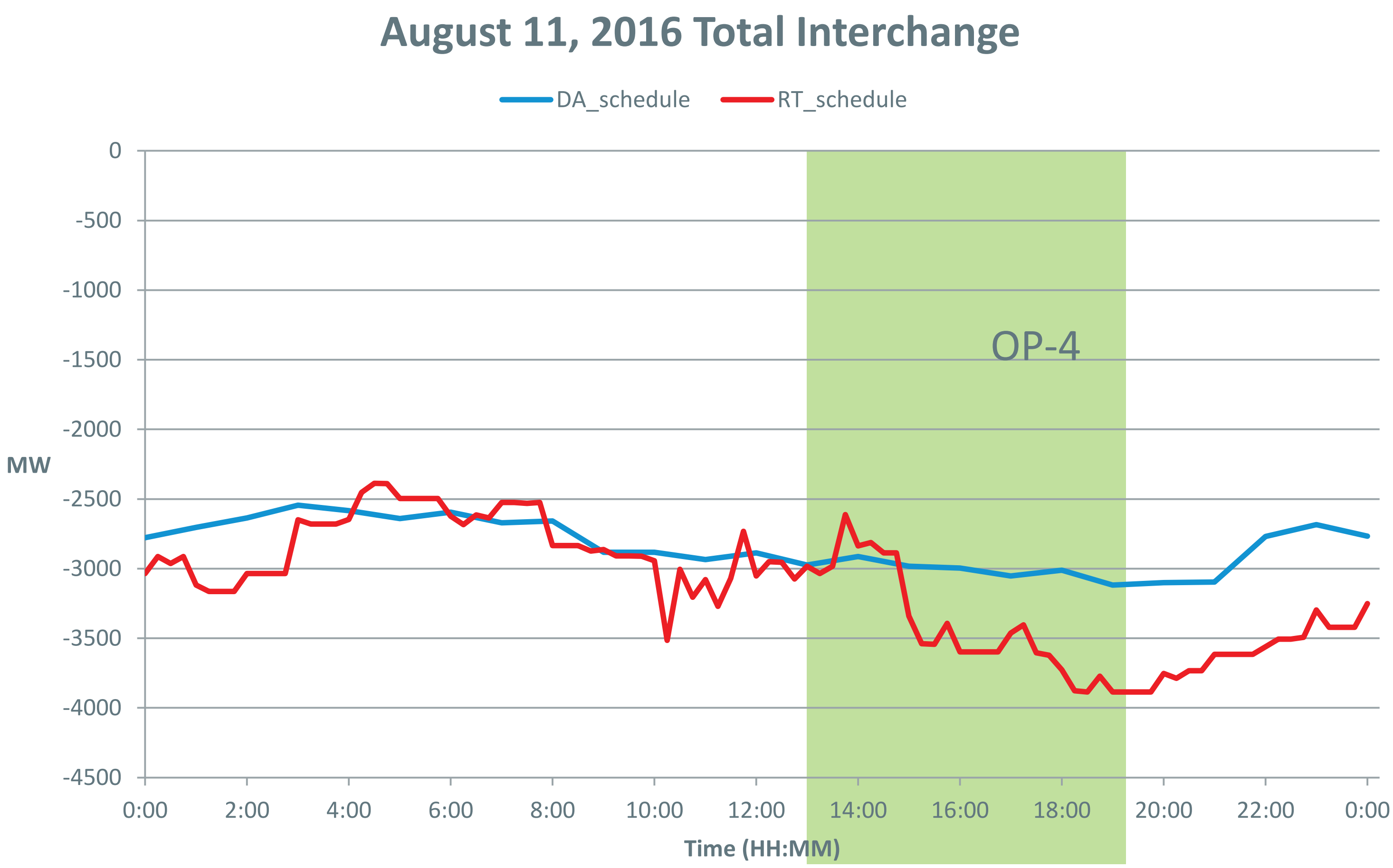
Fuel Diversity – August 11, 2016 HE 18



Estimated Solar Production and Forecast



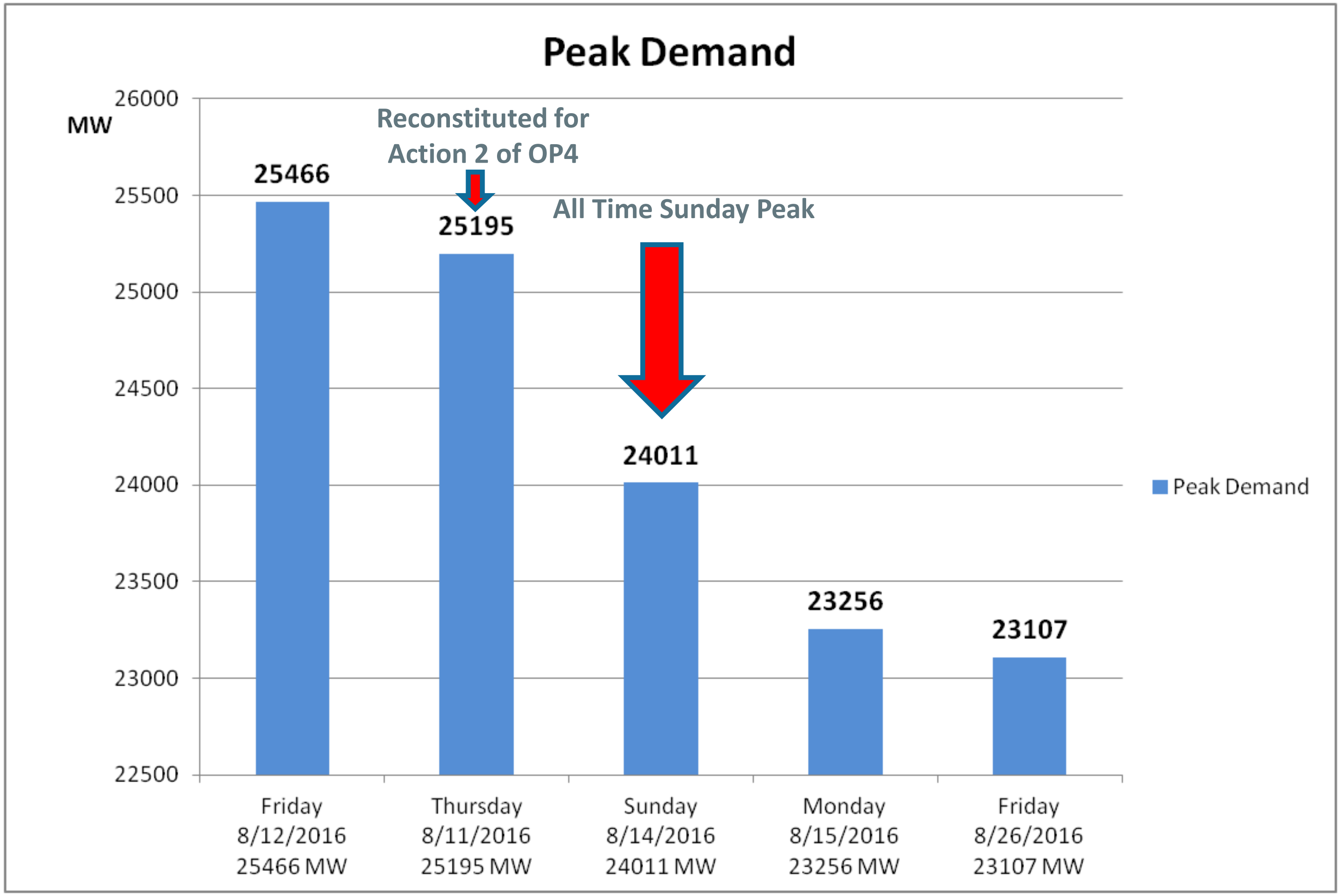
Interchange - Aggregate



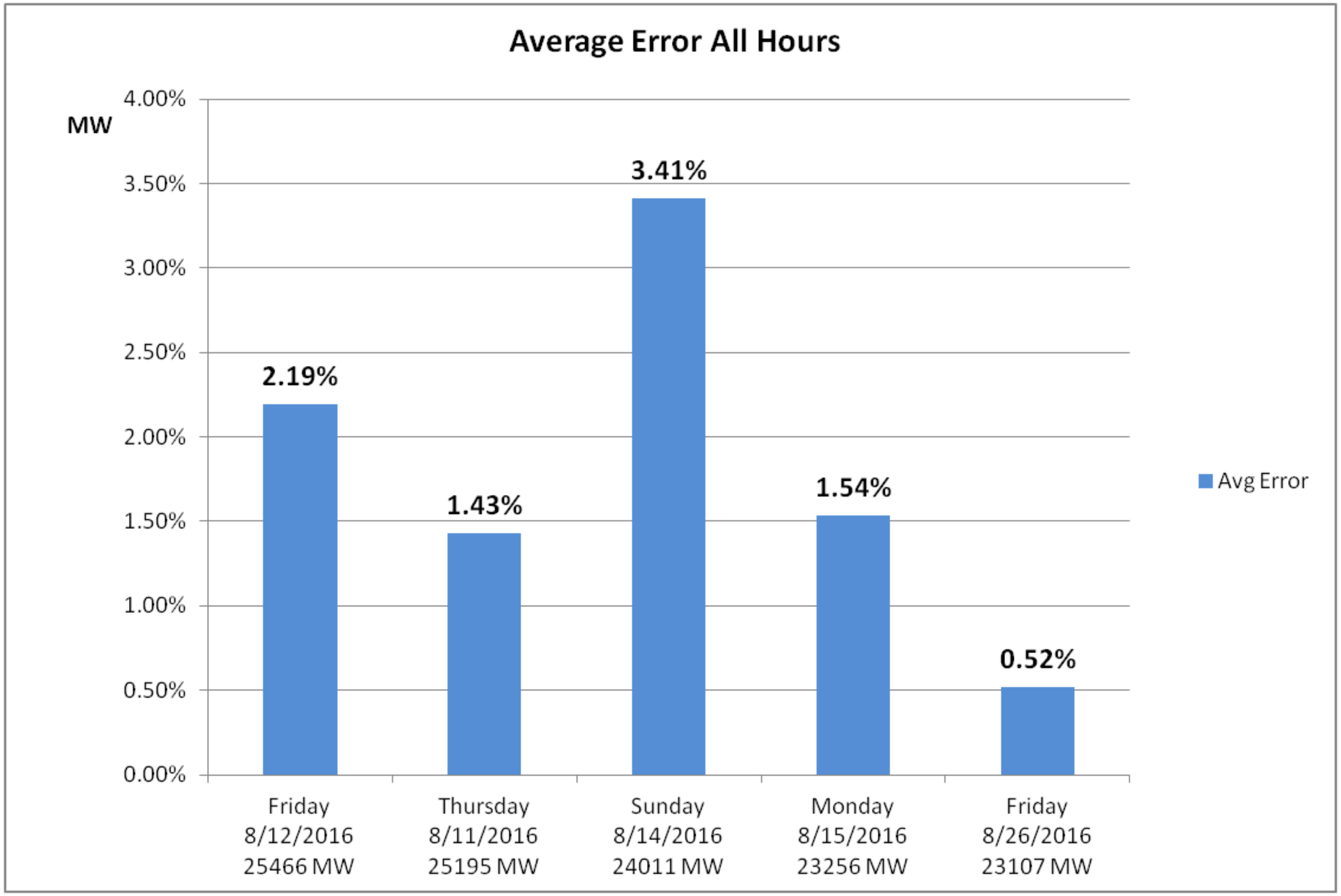
HIGHEST DEMAND DAYS AUGUST, 2016

Five Highest August Demand Days

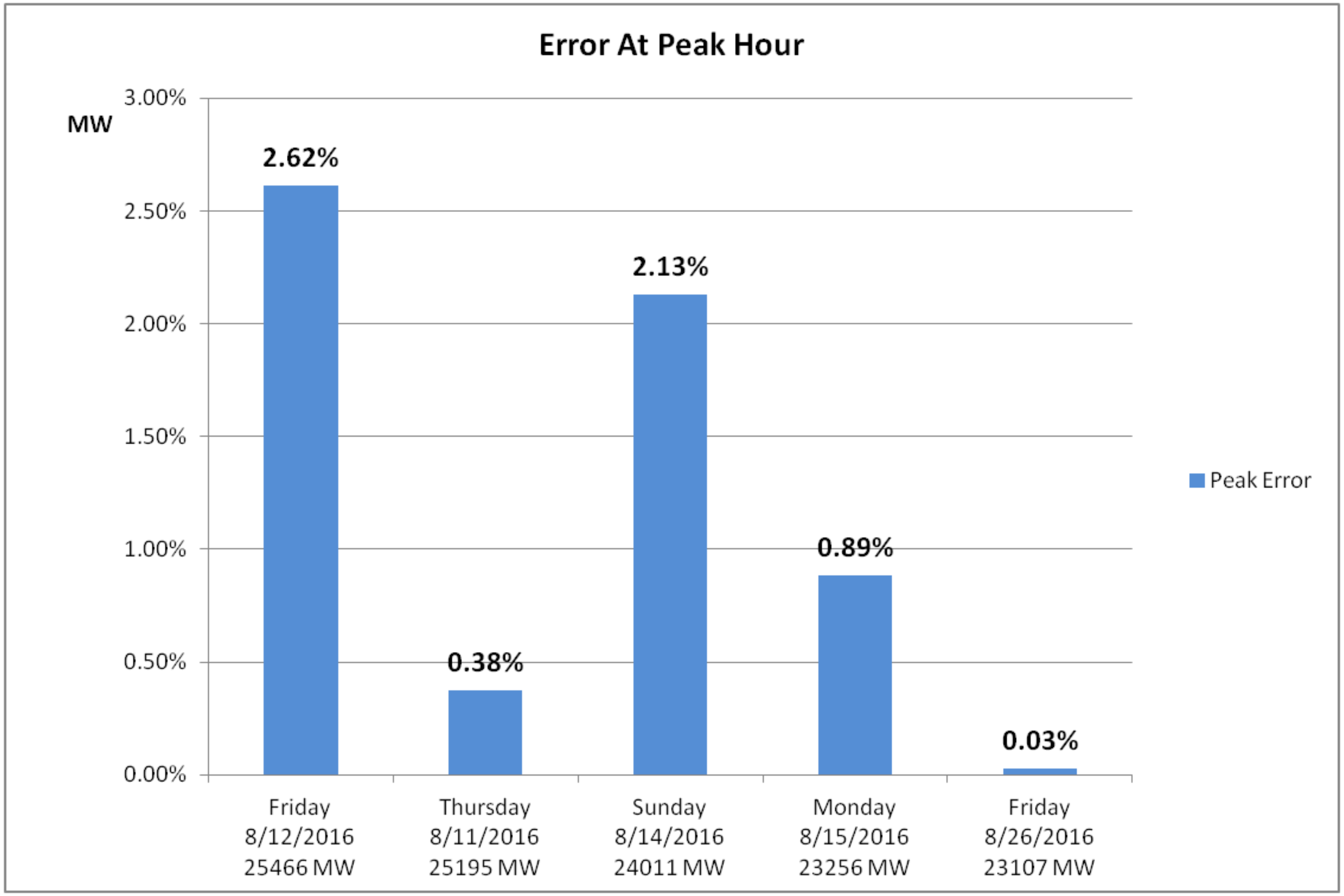
The highest demand days so far this year on the ISO New England system were in the middle of August 2016.



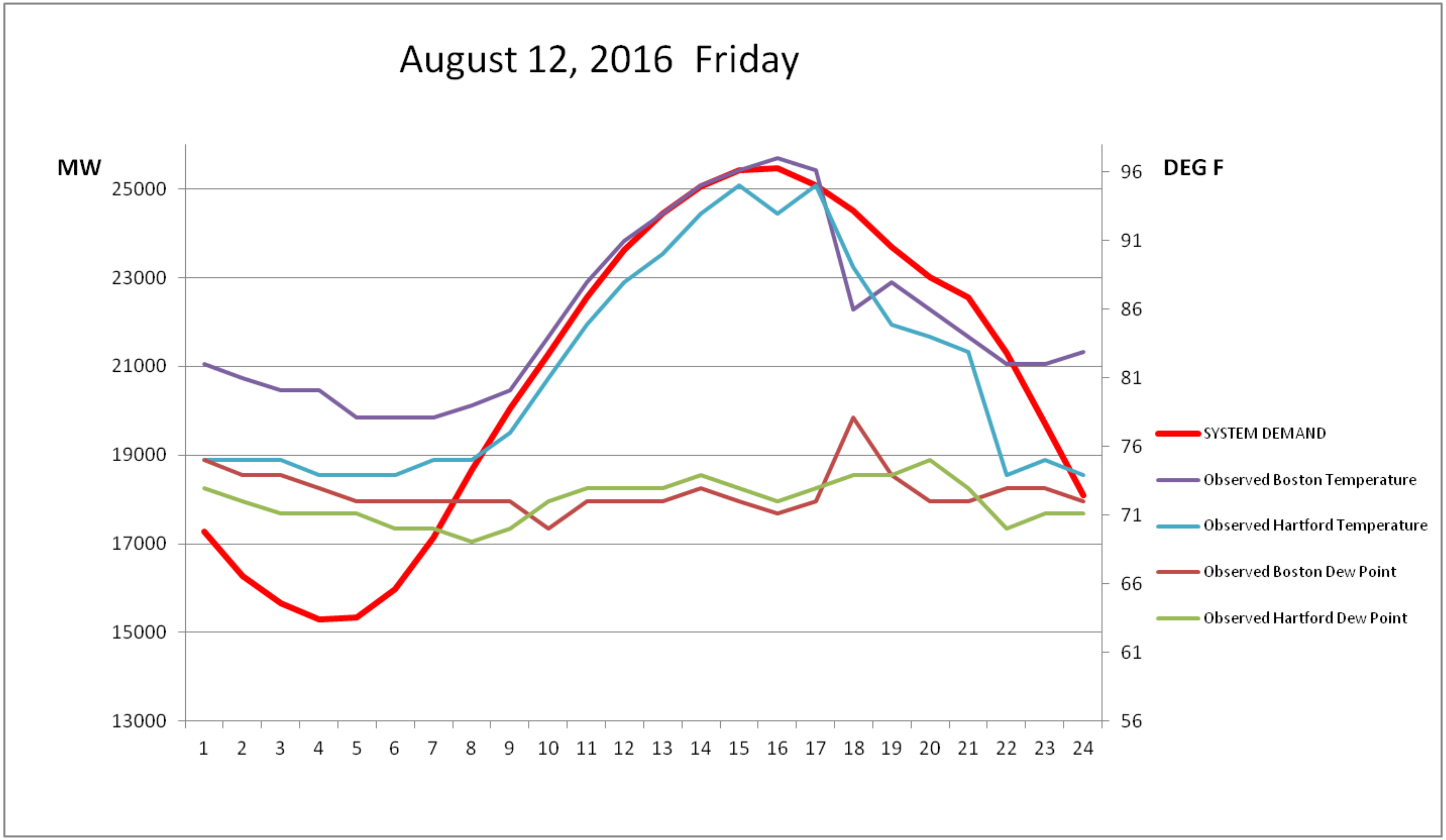
Average Load Forecast Deviation During Five Highest August Demand Days



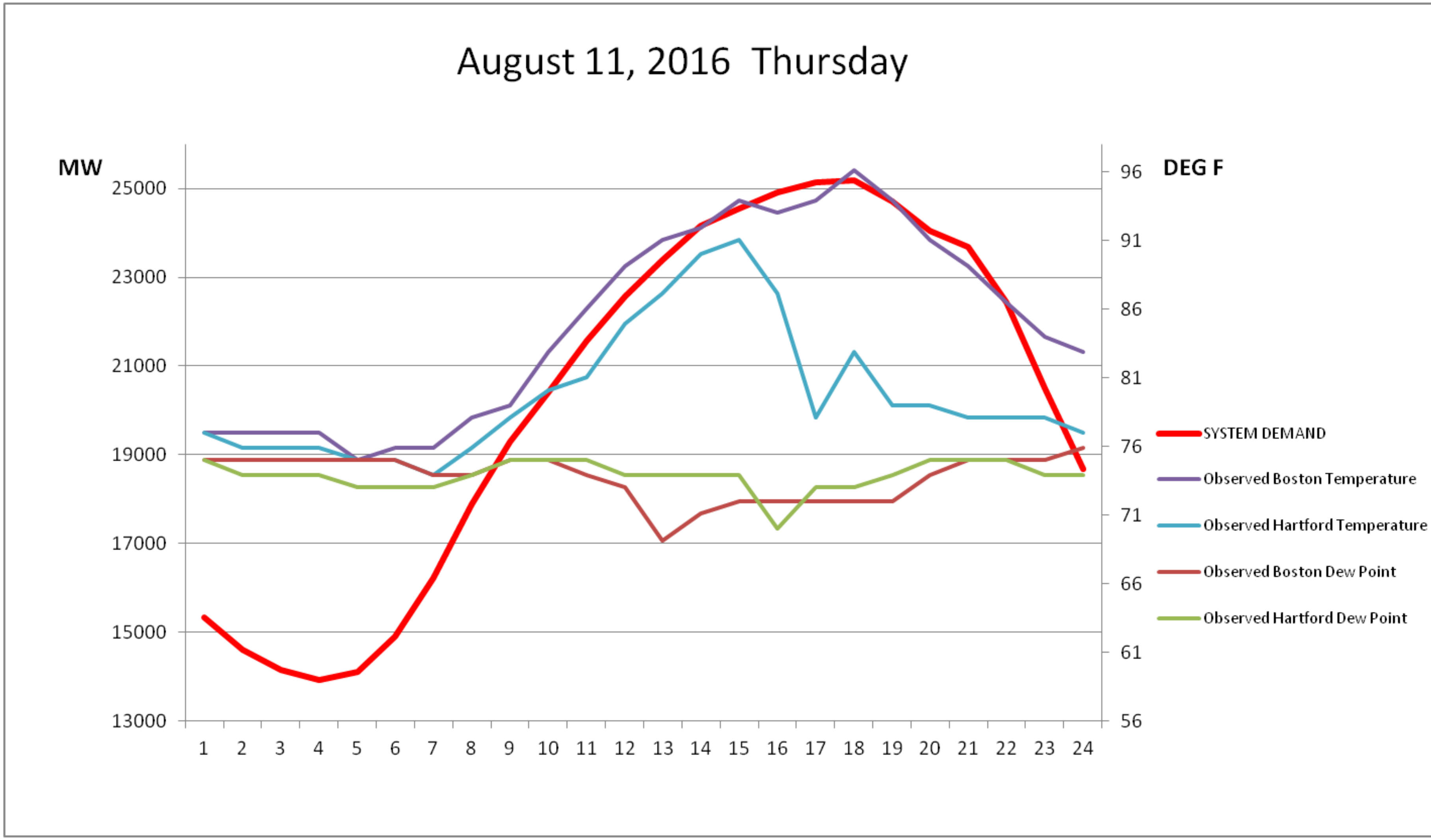
Load Forecast Deviation During Peak Hour on Five Highest August Demand Days



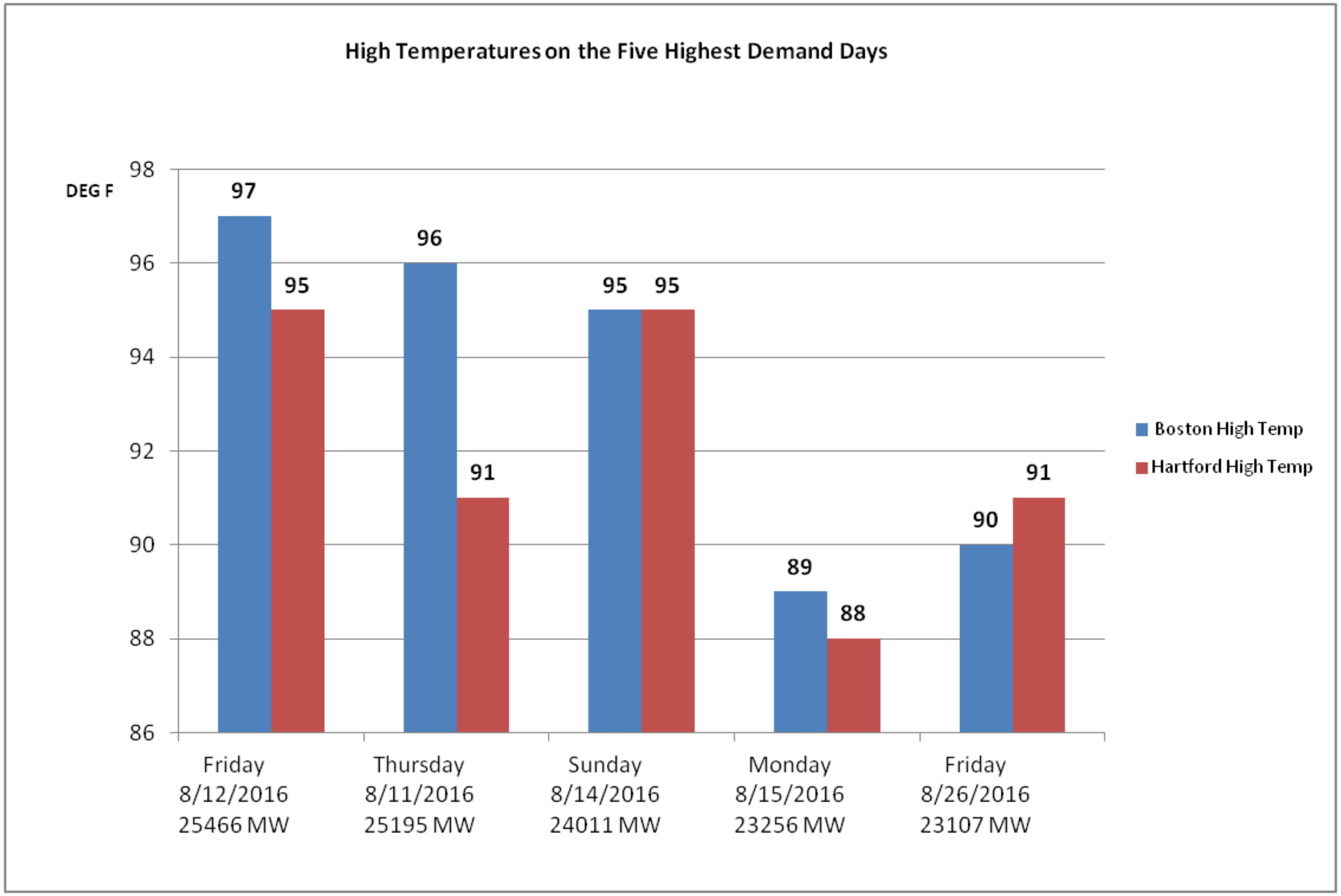
Highest August Demand Day



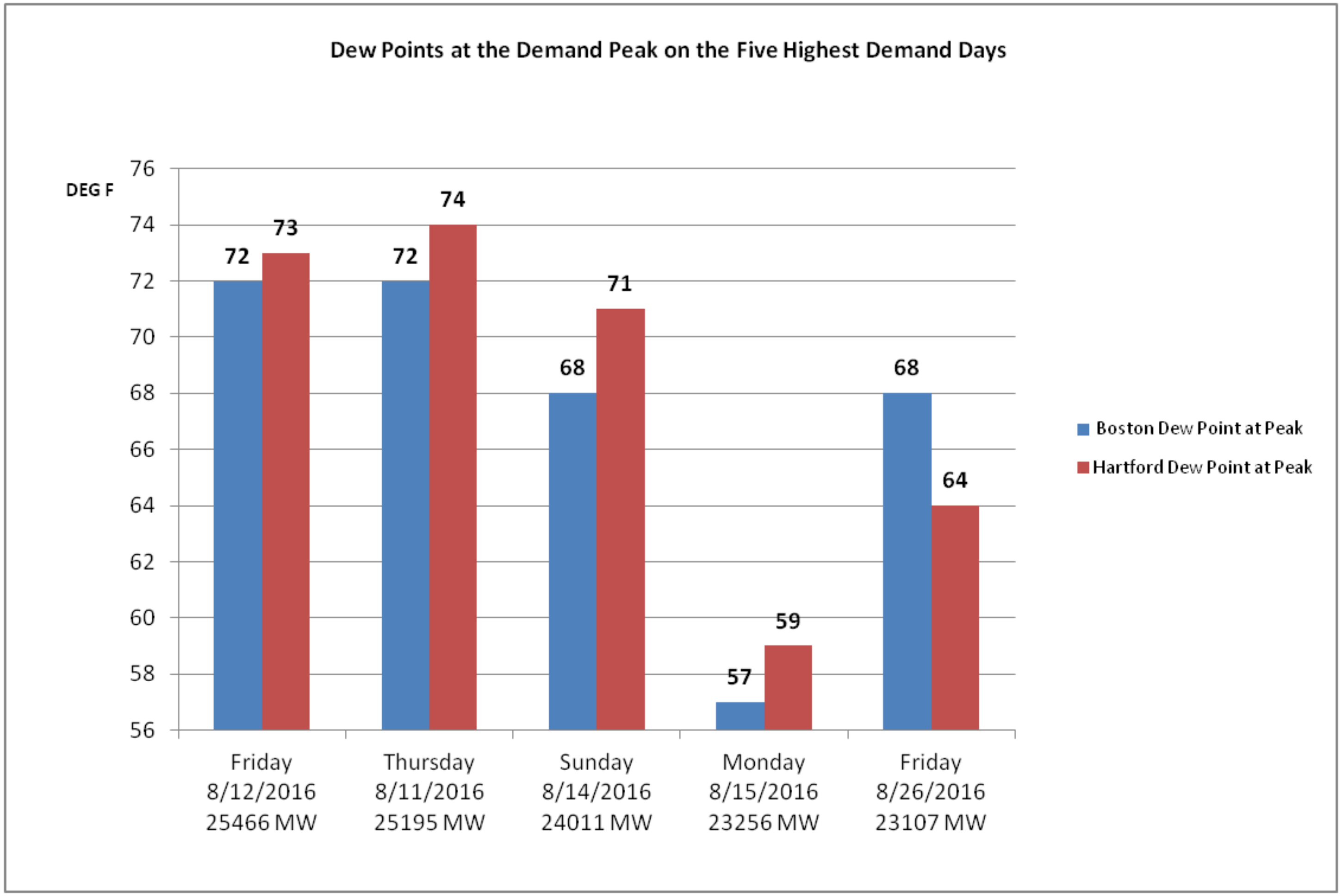
Second Highest August Demand Day



Highest August Demand Days Temperature



Highest August Demand Days Dew Points



COMPARISON OF FIVE TOP PEAK DAYS TO 2016 LONG-TERM LOAD FORECAST

Comparison of Recent Summer Peak Days to 2016 Long-Term Load Forecast

- ISO's long-term summer load forecast uses a **3-day, eight-city weighted temperature-humidity index** (WTHI)
- The table below lists the five highest peak demand days and their WTHIs this past summer with respect those of the 2016 50/50 and 90/10 summer peak load forecasts published in the 2016 CELT report

Peak Day	Day of Week	Peak Load*	WTHI
90/10 Forecast	-	29042	81.96
50/50 Forecast	-	26704	79.88
8/12/2016	Fri	25466	81.12
8/11/2016	Thu	25003**	78.45
7/22/2016	Fri	24285	77.89
8/14/2016	Sun	24011	79.95
7/26/2016	Tue	23843	76.89

Notes:
* Forecast loads are net of passive and active Demand Resources and behind-the-meter PV; Actual peak loads are those measured in real-time
** Peak is not reconstituted for Real Time Demand Resources dispatched during OP#4, Action 2

Summer Seasonal Peak: Friday – August 12, 2016

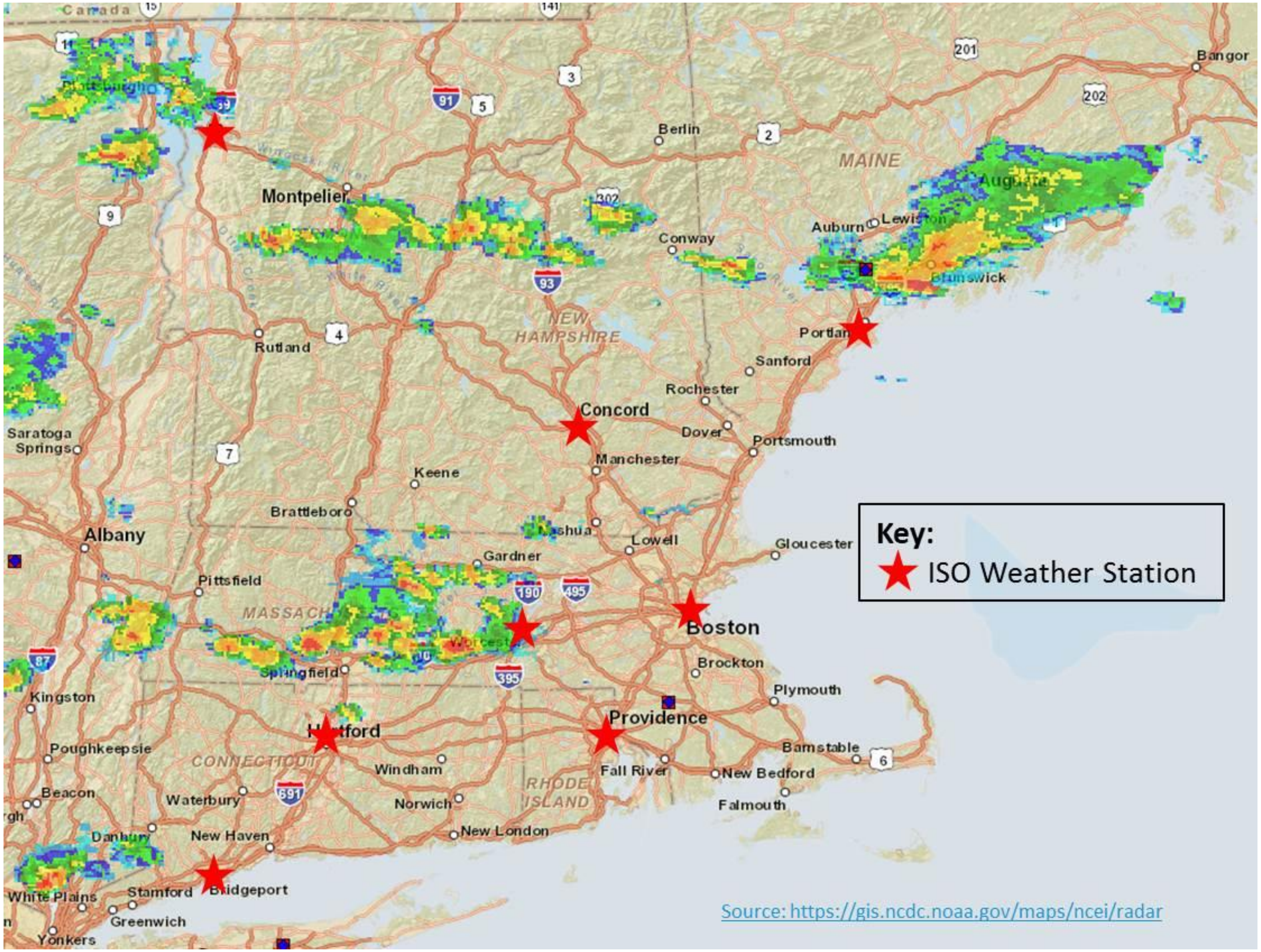
Observed Load vs. 2016 Seasonal Peak Forecast

- On August 12th, the observed weather* at ISO's eight weather stations in the region was hotter than the weather assumed for the 50/50 long-term load forecast, but less severe than the 90/10 forecast
- Despite the hot weather, the observed system peak load on August 12th was about 1,200 MW lower than the 50/50 summer load forecast, primarily due to two factors
  1. It was a Friday peak – Based on previous analysis, peaks loads on Fridays can be more than 1,000 MW lower than other non-holiday weekdays, given similar weather
  2. Areas of localized thunderstorms and rain passed through some load centers immediately preceding and during the peak, resulting in reduced loads
     - Some storms were located in areas outside of ISO's eight weather stations, and were therefore not well reflected in ISO's measured weather during the peak hour
     - Radar imagery during the peak are shown on the next slide(s)

Note: * ISO's long-term summer load forecast models use a 3-day, eight-city weighted temperature-humidity index (WTHI)

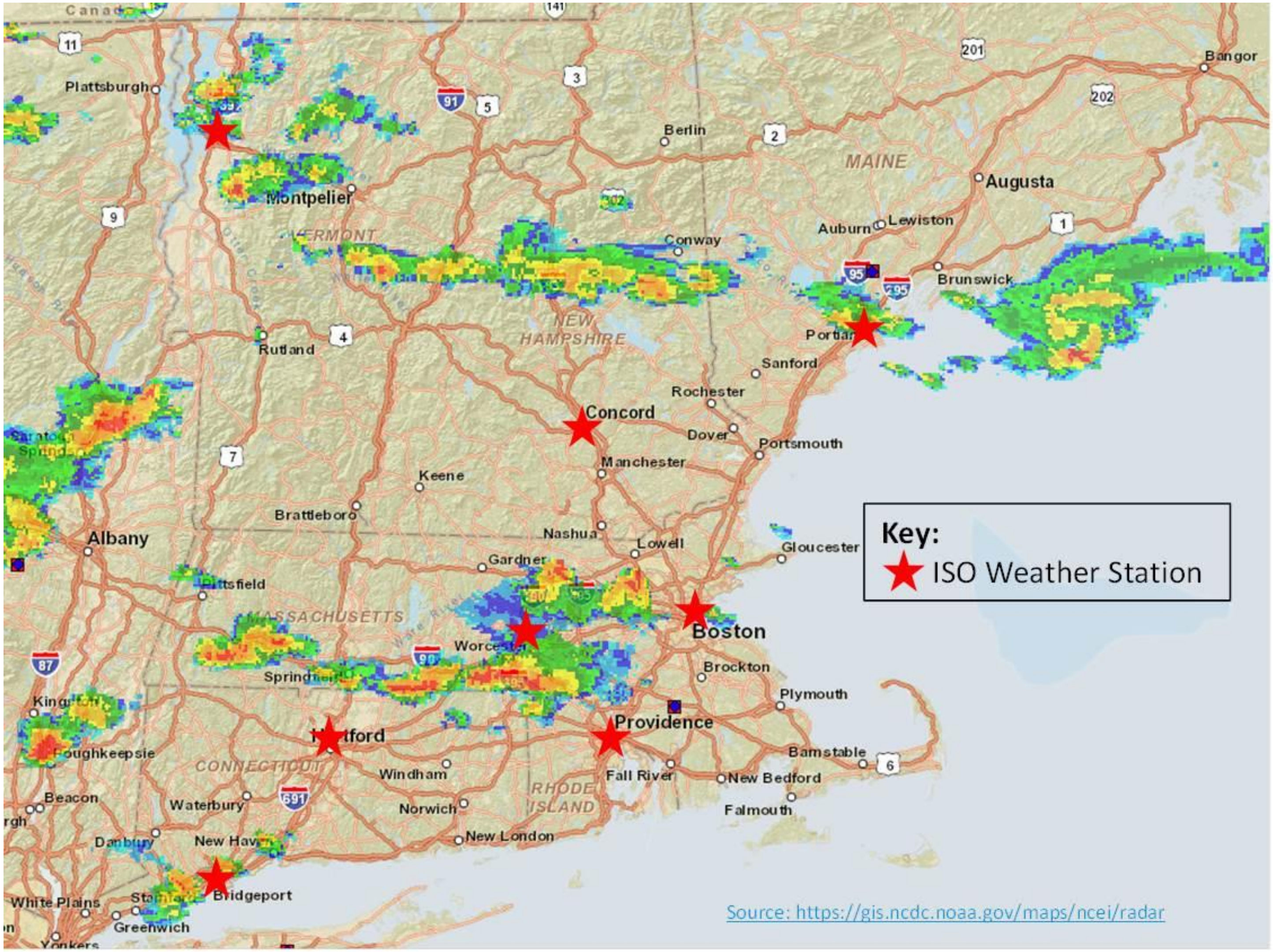
Summer Seasonal Peak: Friday – August 12, 2016

Radar at 3pm (Beginning of Peak Hour)



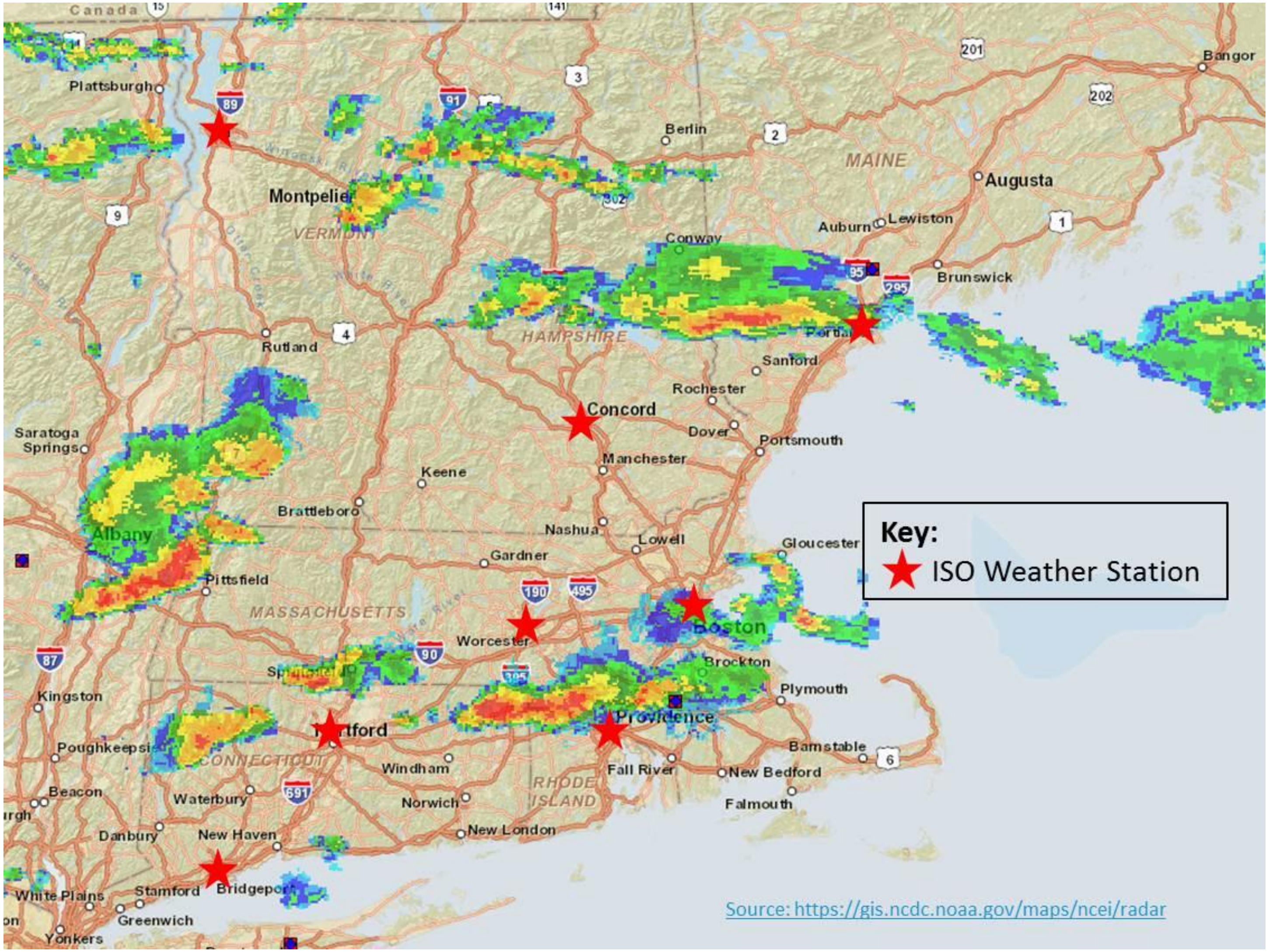
Summer Seasonal Peak: Friday – August 12, 2016

Radar at 4pm (End of Peak Hour)



Summer Seasonal Peak: Friday – August 12, 2016

Radar at 5pm (Hour After Peak)



SYSTEM OPERATIONS

System Operations

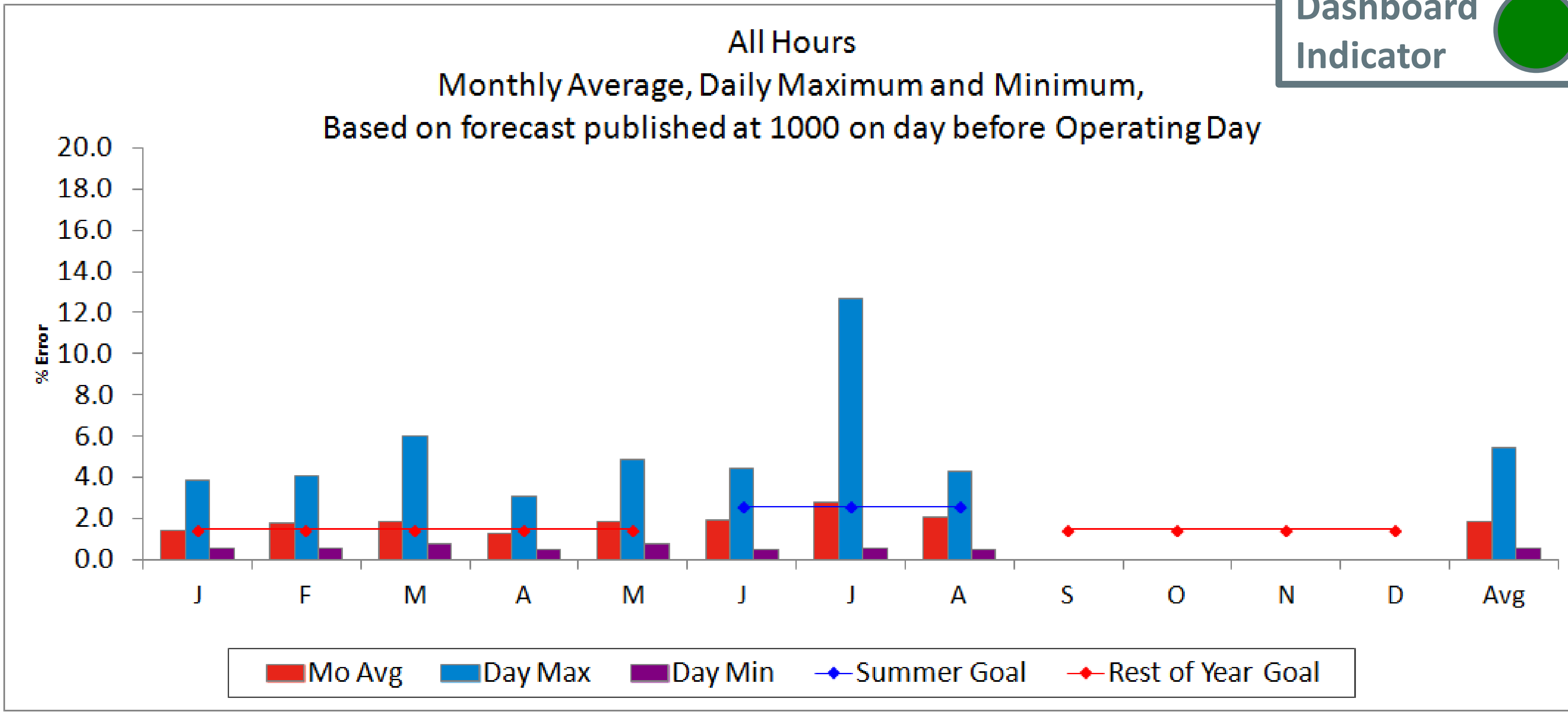
Weather Patterns	Boston	Temperature: Above Normal (4.0°F) Max: 98°F, Min: 61°F Precipitation: 1.72" – Below Normal Normal: 3.37"	Hartford	Temperature: Above Normal (3.9°F) Max: 99°F, Min: 52°F Precipitation: 4.29" – Above Normal Normal: 3.98"

Peak Load:	25,466 MW	August 12, 2016	16:00 (Hour ending)

MLCC2: 08/11/2016	Capacity Deficiency	Declared – 8/11/16 10:30 Cancelled – 8/13/16 23:45
OP-4 : 08/11/2016	Actions 1 and 2	Declared – 8/11/16 13:50 Cancelled – 8/11/16 19:30
NPCC Simultaneous Activation of Reserve Events:		
Date	Area	MW
8/11/2016	ISONE	844
8/24/2016	IESO	540
08/31/2016	PJM	1000
Minimum Generation Warnings & Events:		
Minimum Generation Warning	8/14/16, 04:00 – 8/14/16, 07:00	Self Schedules Denied Interchange Cuts

2016 System Operations - Load Forecast Accuracy

Dashboard Indicator

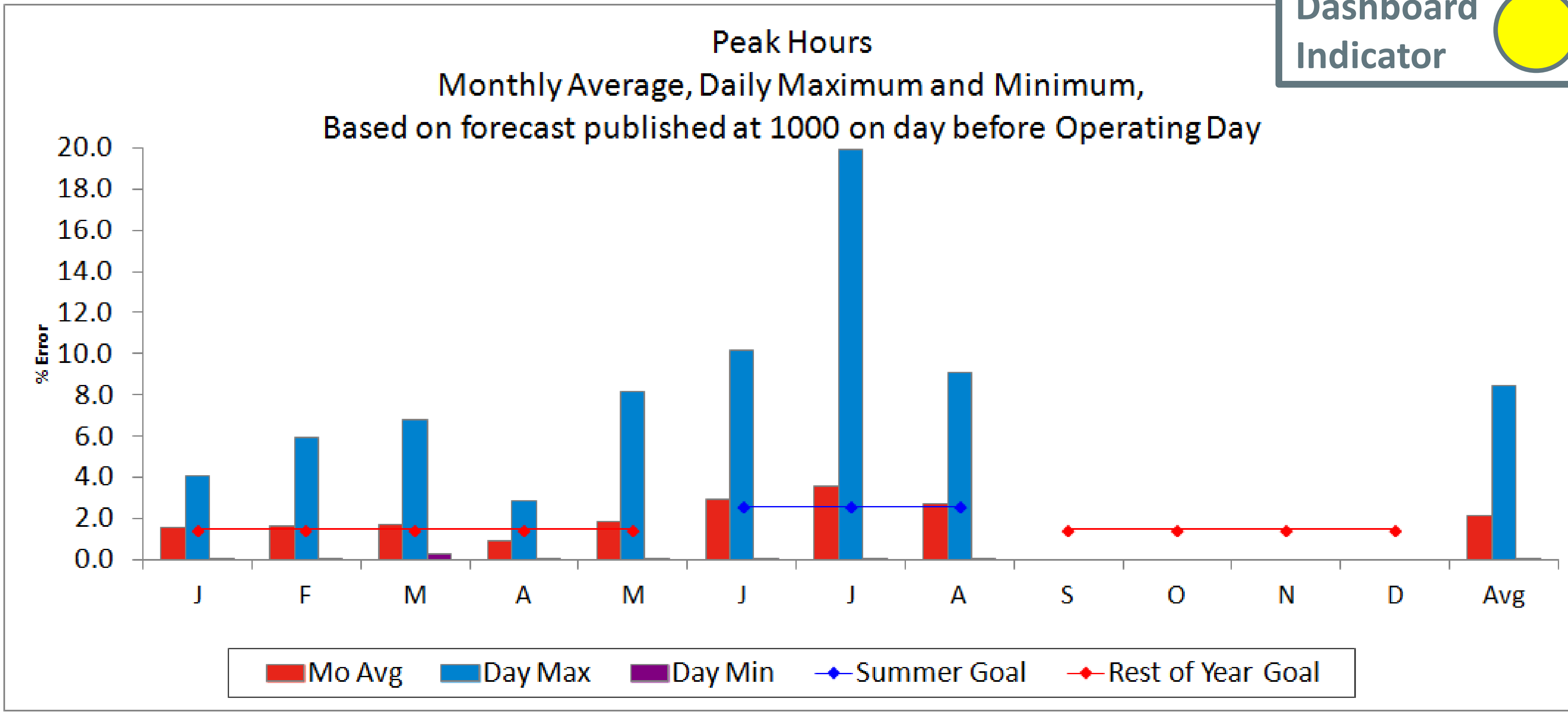


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.44	1.78	1.89	1.32	1.86	1.95	2.76	2.05					1.88
Day Max	3.88	4.12	6.05	3.08	4.90	4.45	12.71	4.30					5.46
Day Min	0.54	0.58	0.82	0.50	0.75	0.50	0.61	0.52					0.60
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.44	1.78	1.89	1.32	1.86								1.66
Summer Actual						1.95	2.76	2.05					2.26

Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2016 System Operations - Load Forecast Accuracy cont.

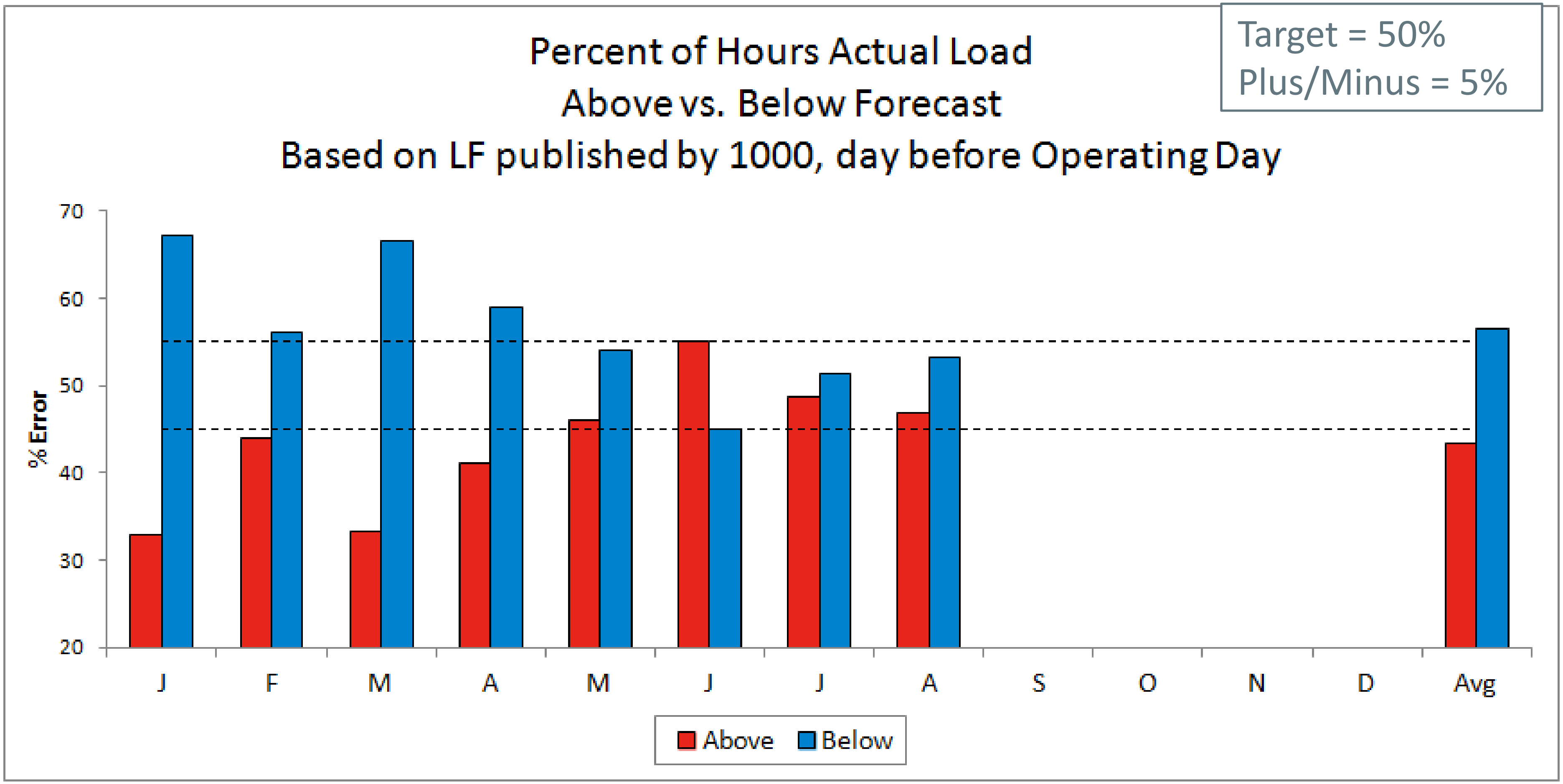
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.55	1.67	1.72	0.96	1.87	2.93	3.59	2.73					2.13
Day Max	4.10	5.95	6.80	2.85	8.19	10.17	19.94	9.12					8.43
Day Min	0.09	0.03	0.32	0.01	0.03	0.01	0.01	0.03					0.07
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.55	1.67	1.72	0.96	1.87								1.56
Summer Actual						2.93	3.59	2.73					3.09

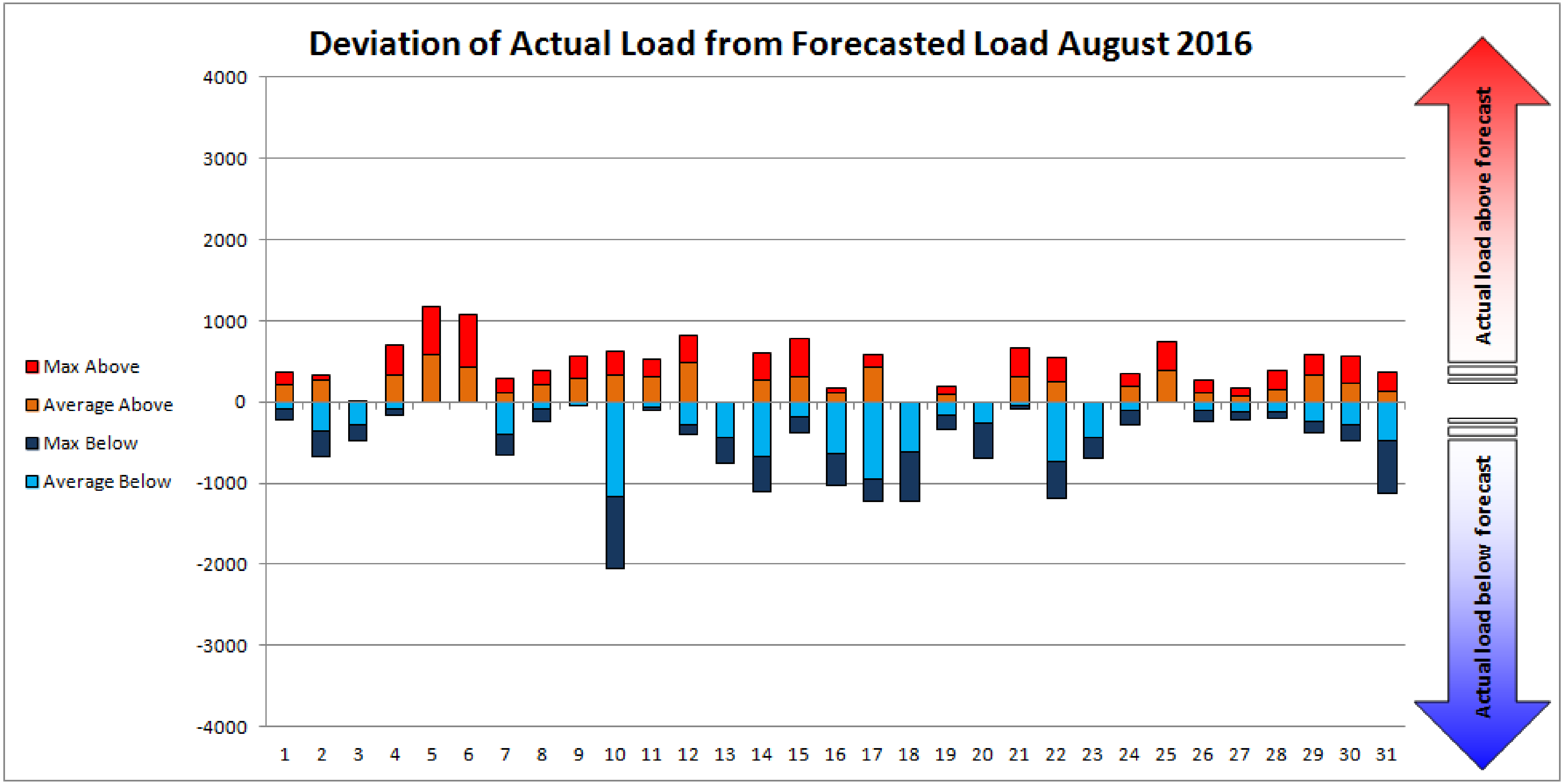
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2016 System Operations - Load Forecast Accuracy cont.

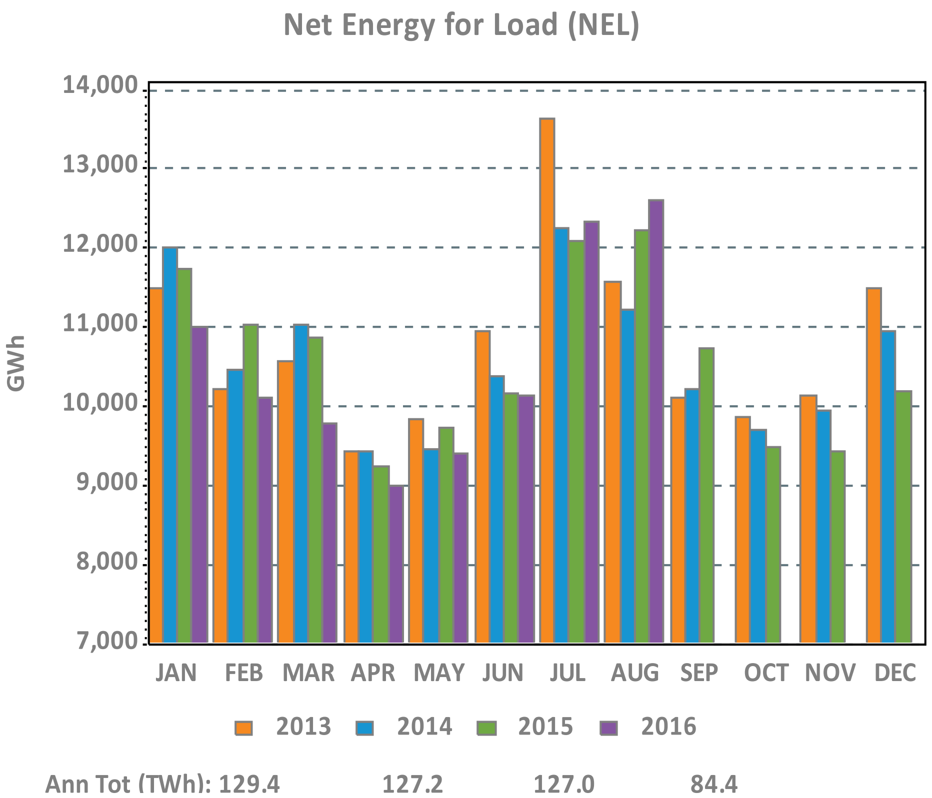


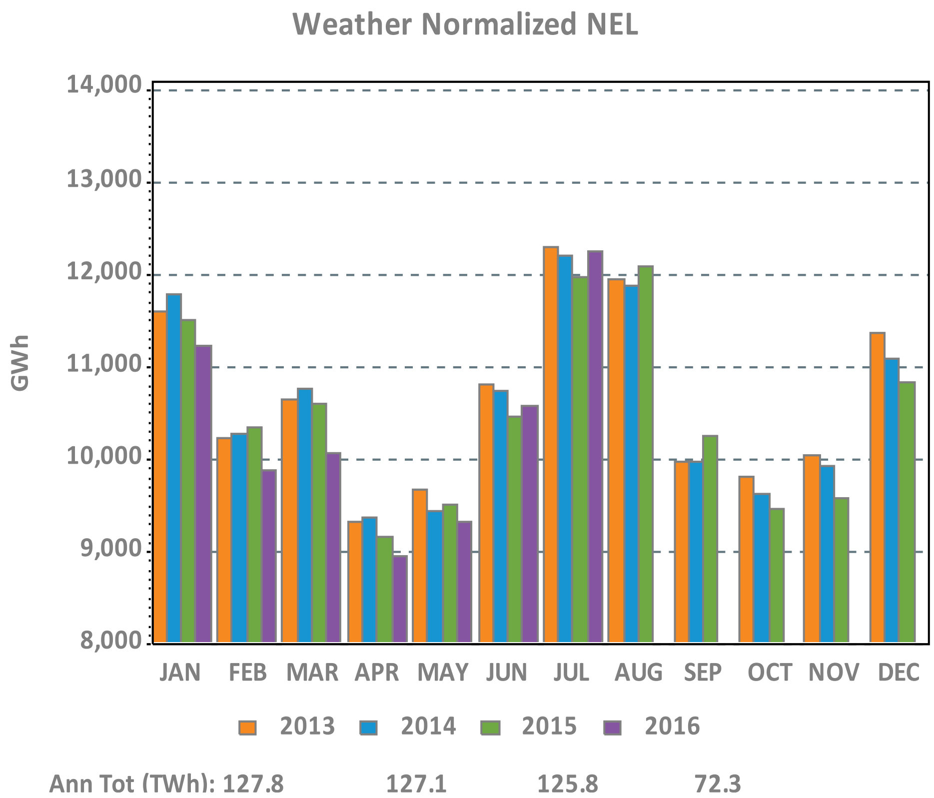
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	32.9	44	33.4	41.1	46	55	48.7	46.8					43
Below %	67.1	56	66.6	58.9	54	45	51.3	53.2					57
Avg Above	109.8	199.7	172.5	134.6	203.9	218.8	265.1	225.1					191
Avg Below	-200.6	-185.0	-201.1	-141.0	-159.7	-182.8	-369.3	-305.3					-219
Avg All	-100	-7	-59	-12	13	46	-86	-64					-34

2016 System Operations - Load Forecast Accuracy cont.



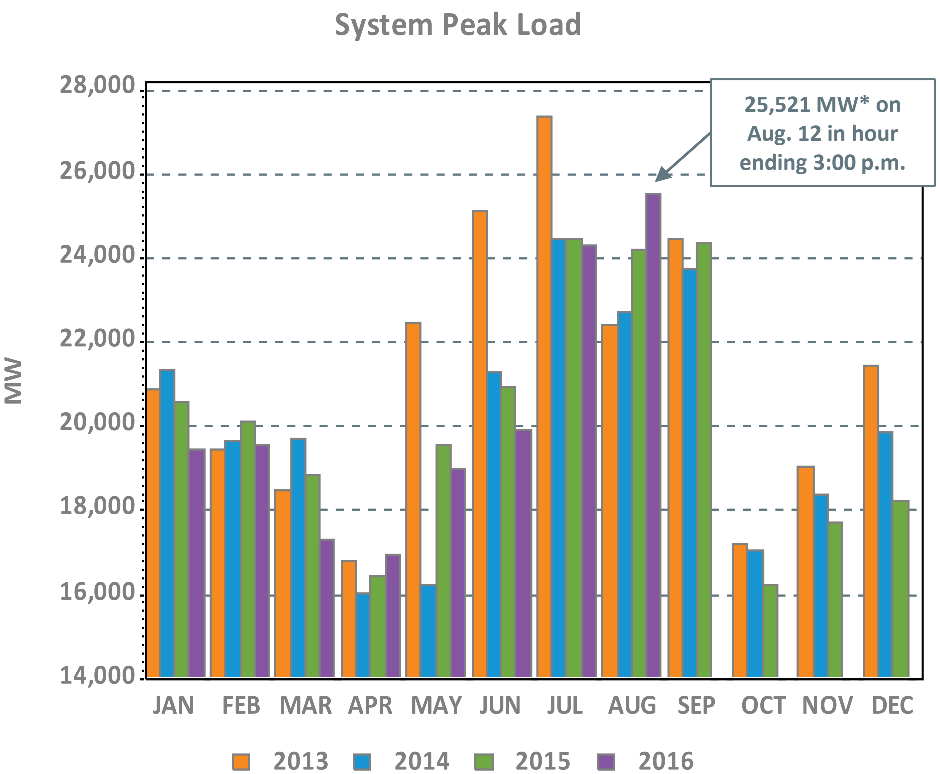
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



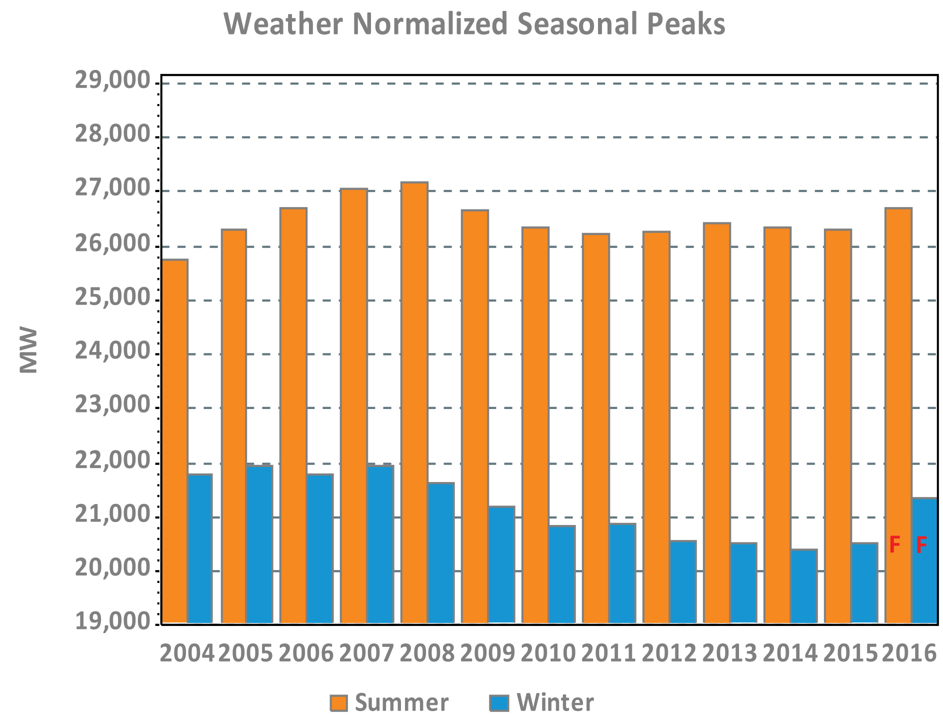


NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load'. NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

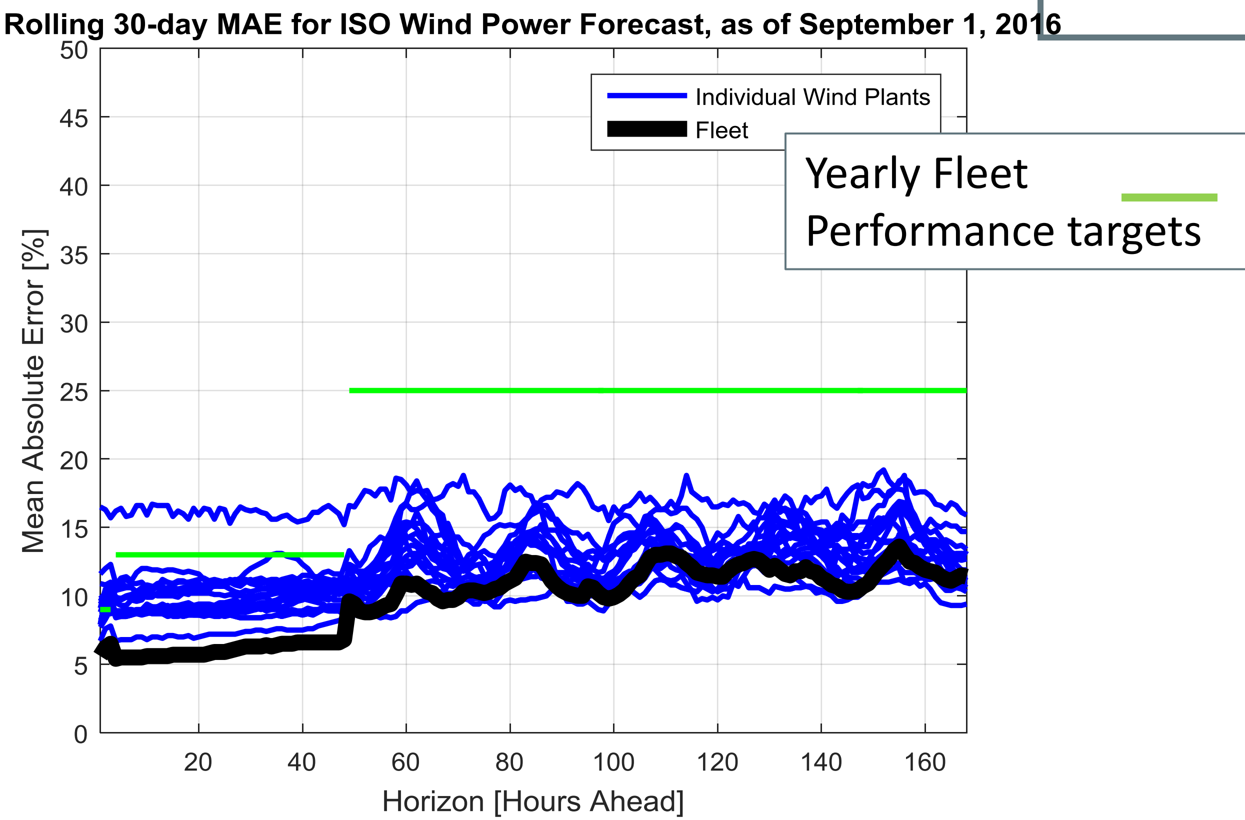


Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE

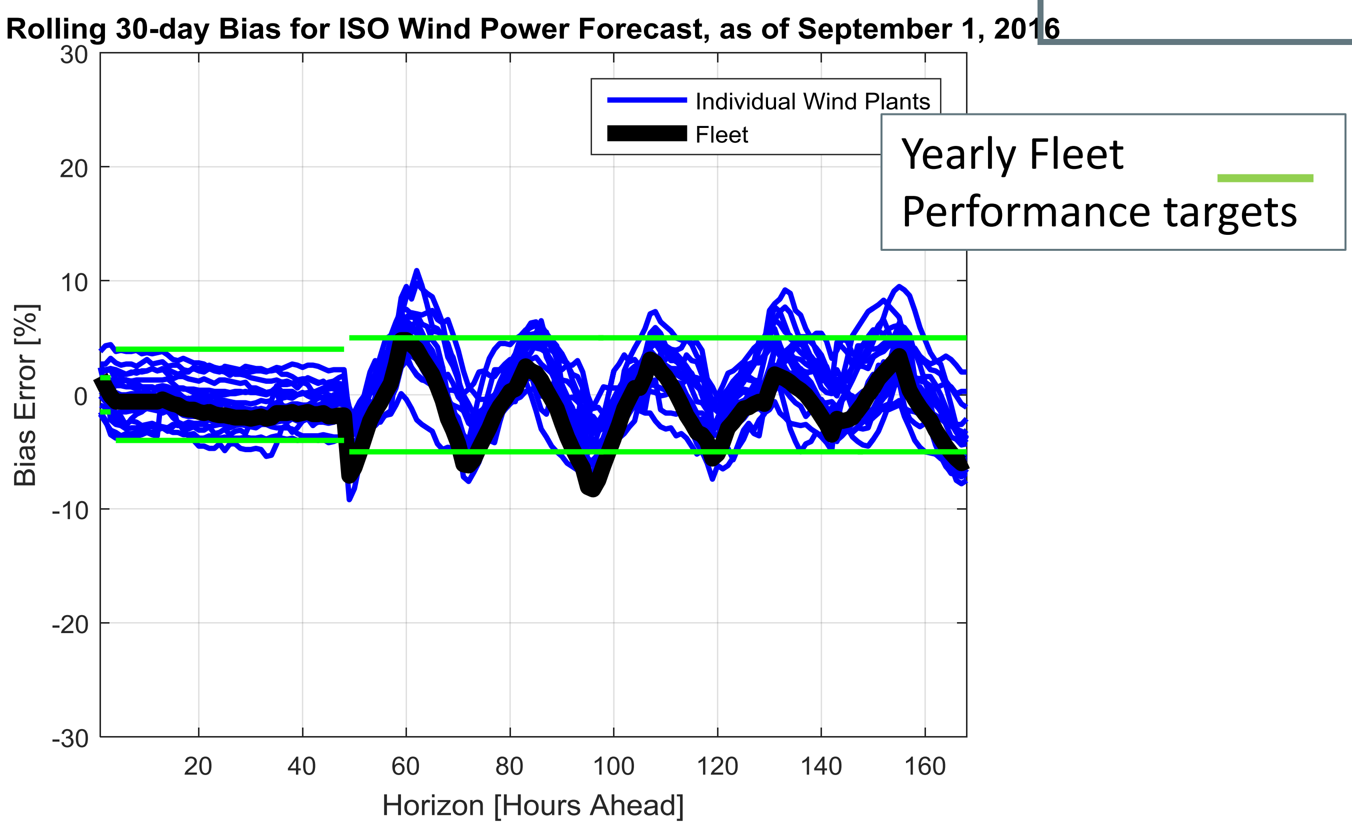
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias

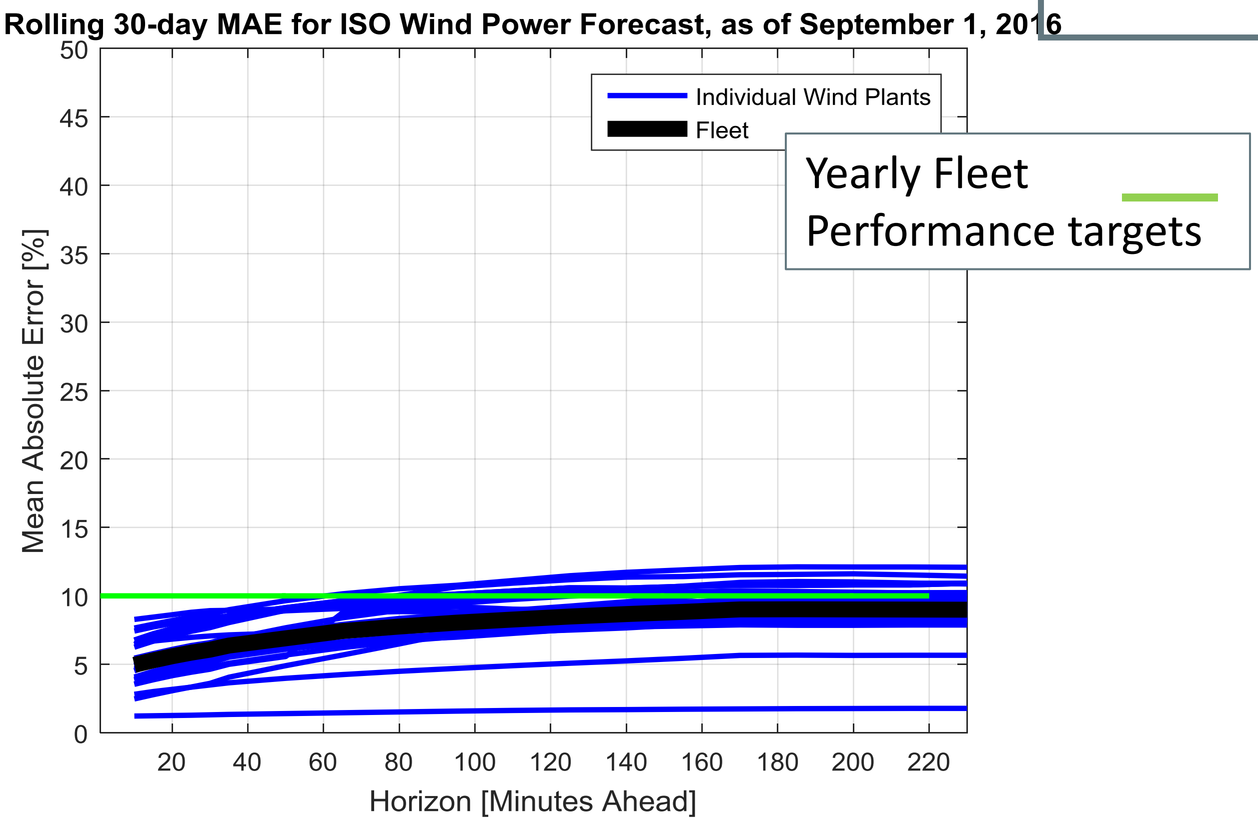
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and monthly Bias is mostly within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

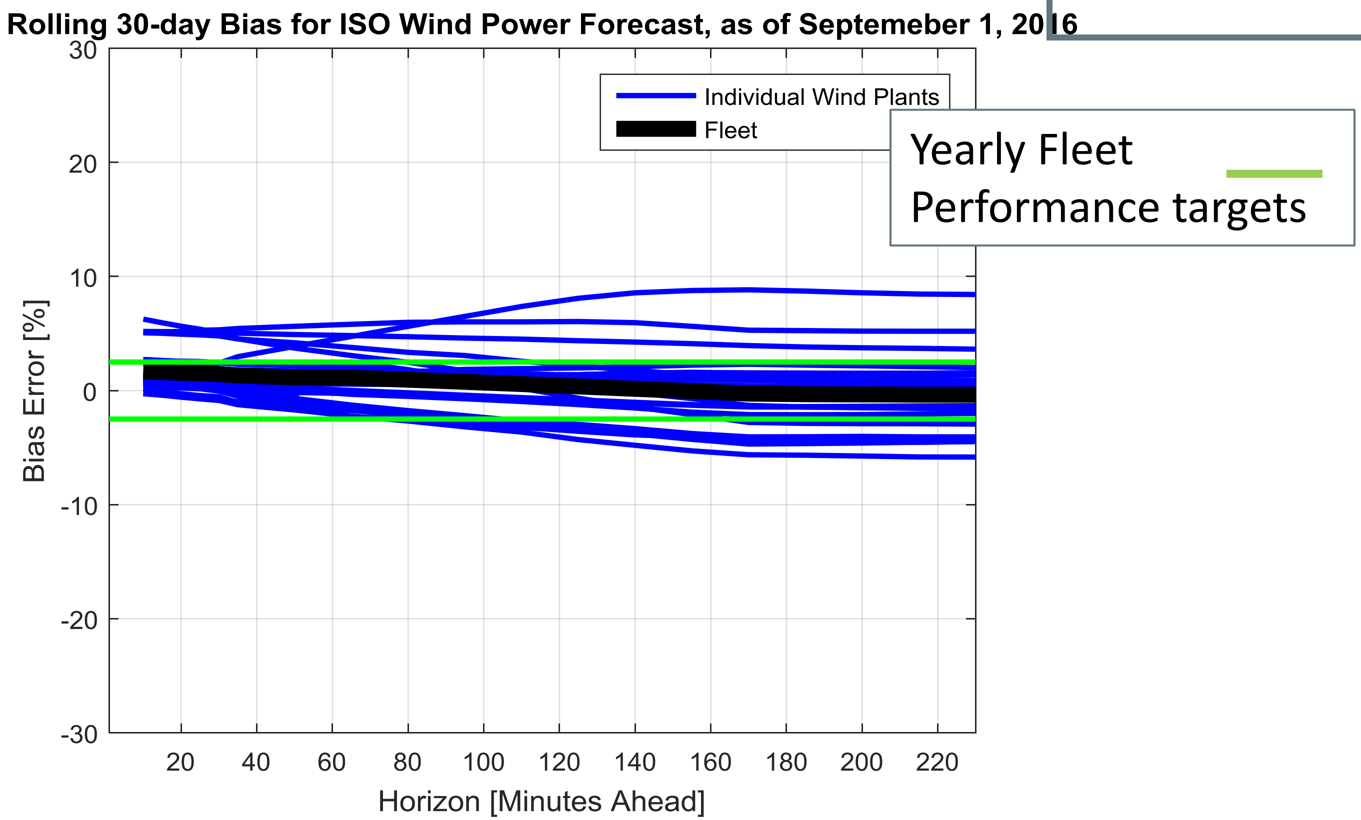
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV-GL forecast is very good compared to industry standards, and monthly MAE is well within the yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

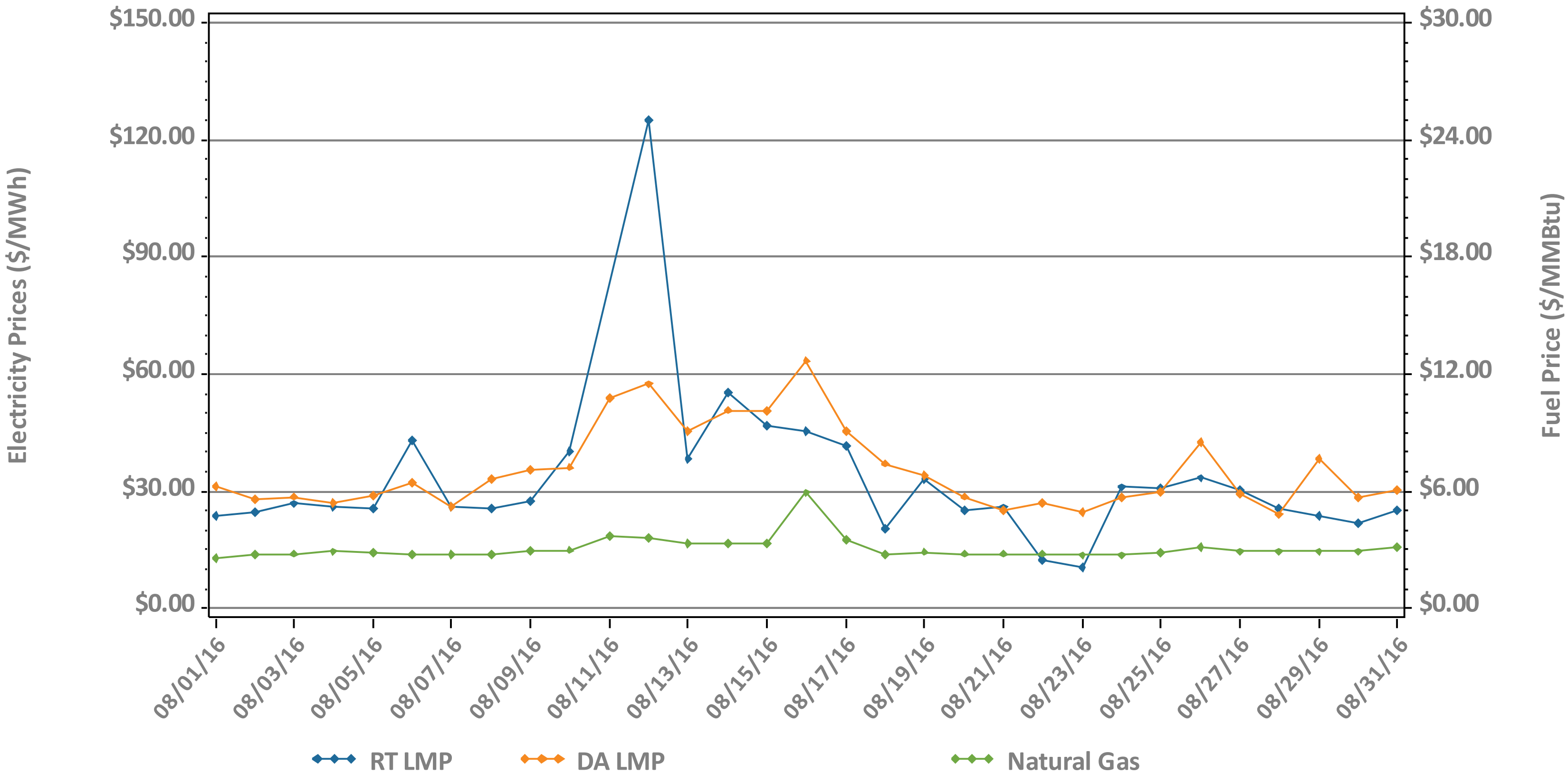
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: August 1-31, 2016

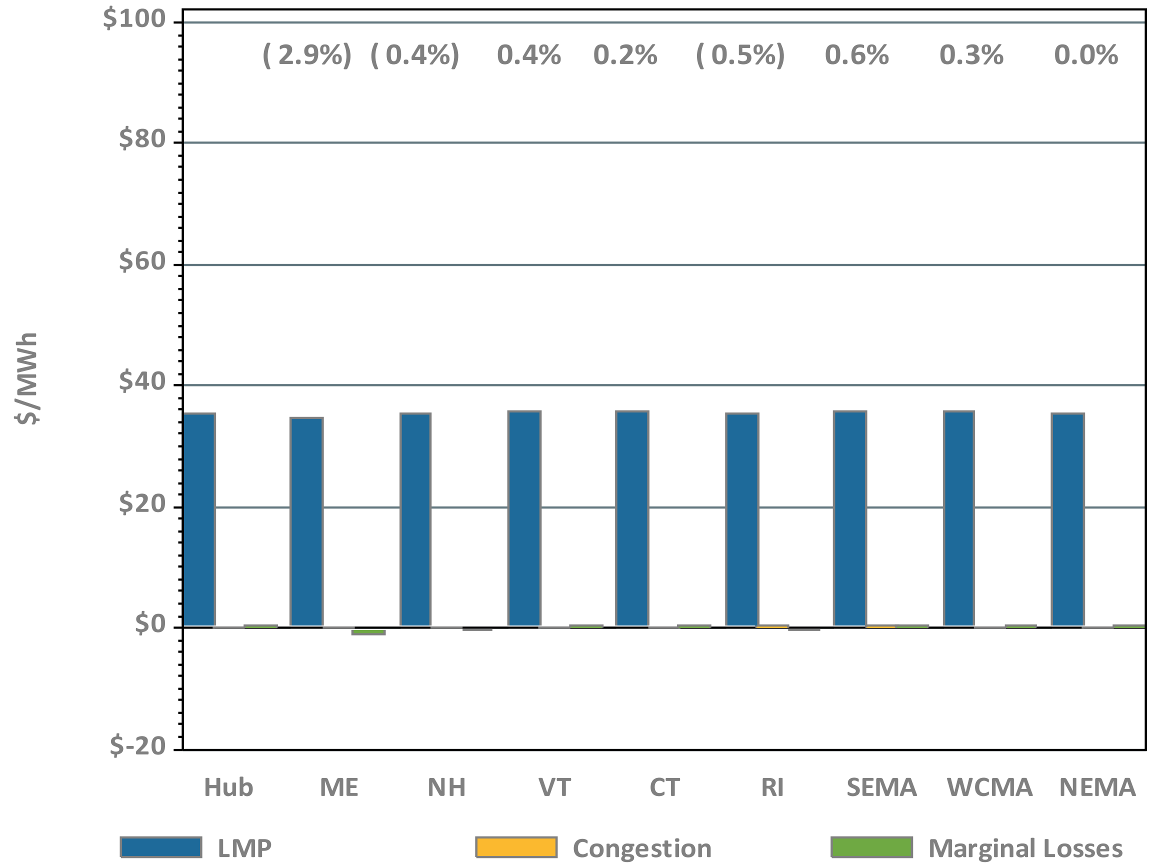


Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $-4.65
Average price difference over this period ABS(DA-RT): $14.41
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 36%
Gas price is average of Massachusetts delivery points

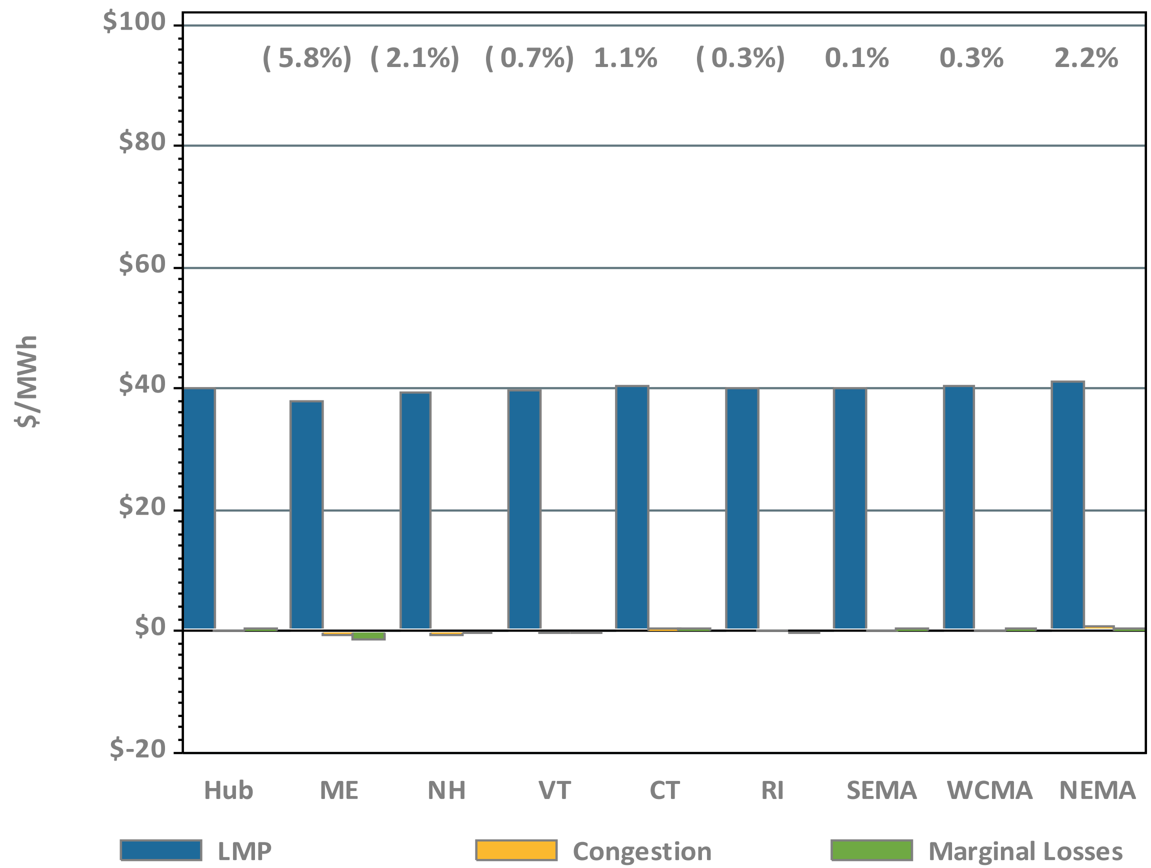
DA LMPs Average by Zone & Hub, August 2016



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut

RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

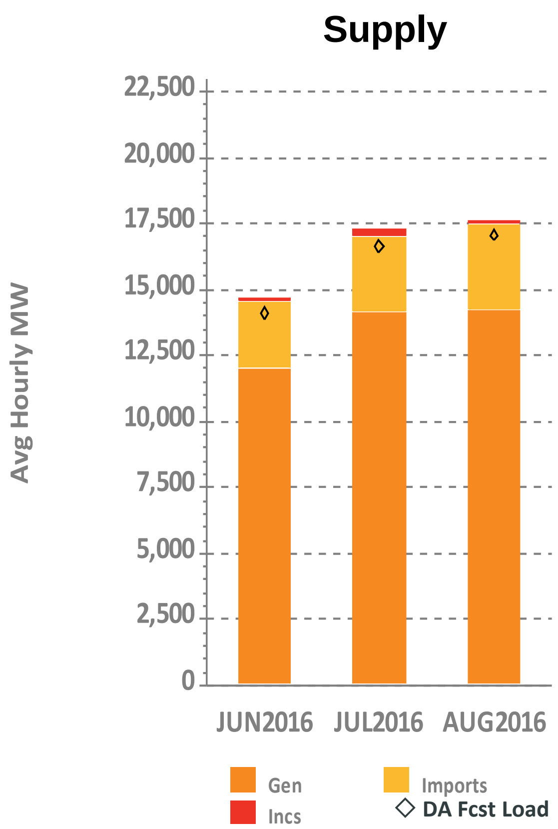
RT LMPs Average by Zone & Hub, August 2016



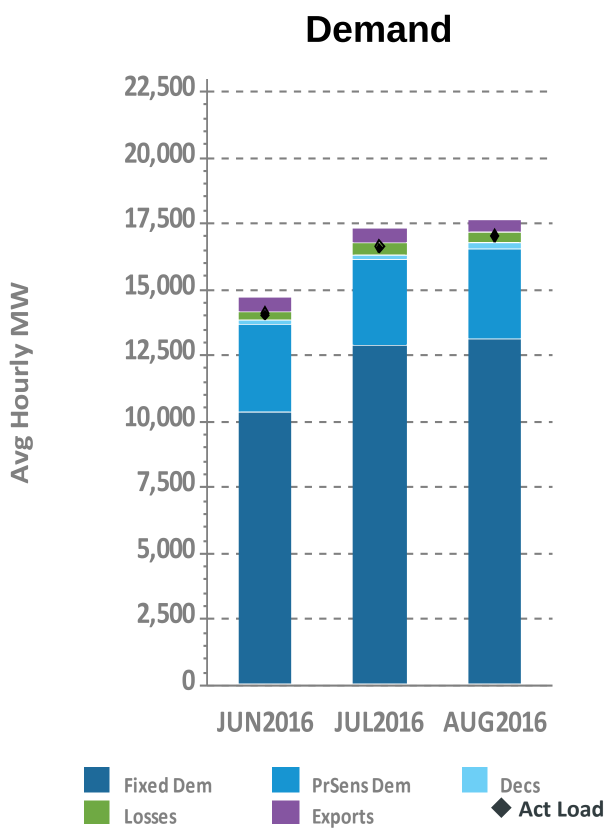
Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including pump load), exports, and virtual purchases (excluding bulk losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand – Last Three Months

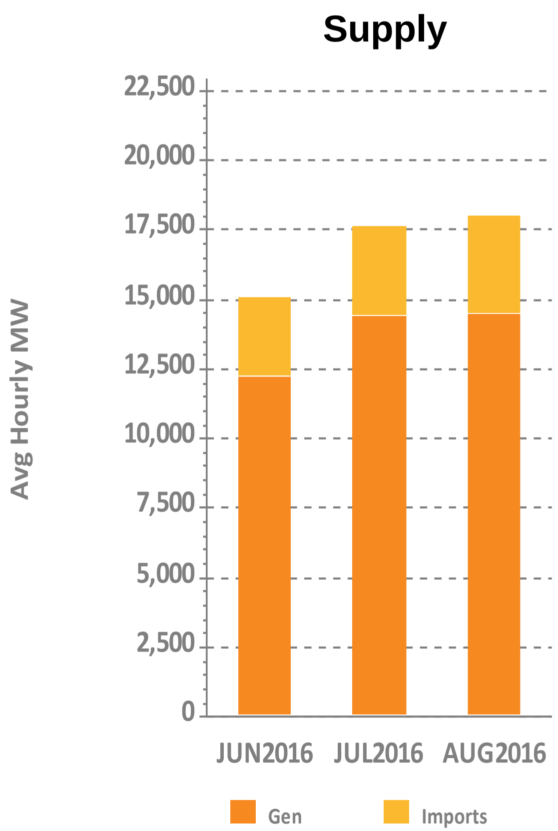


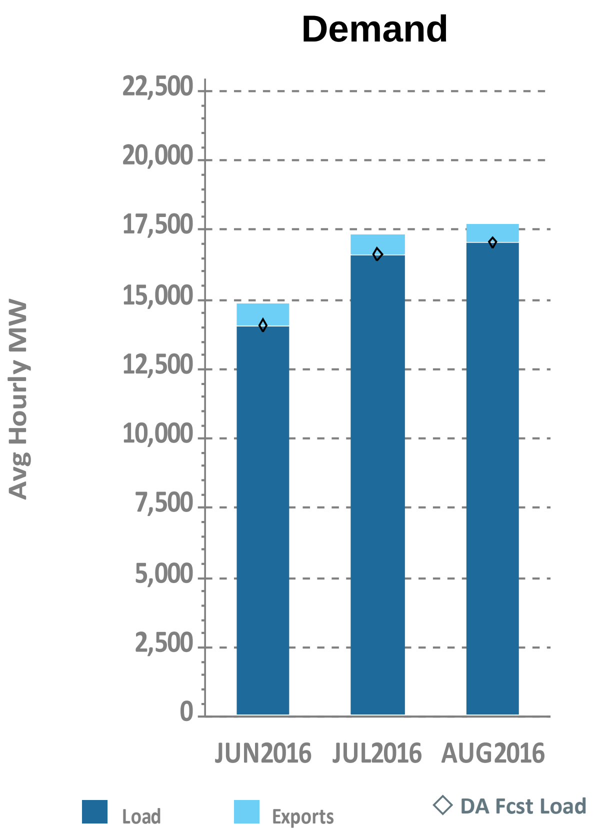
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



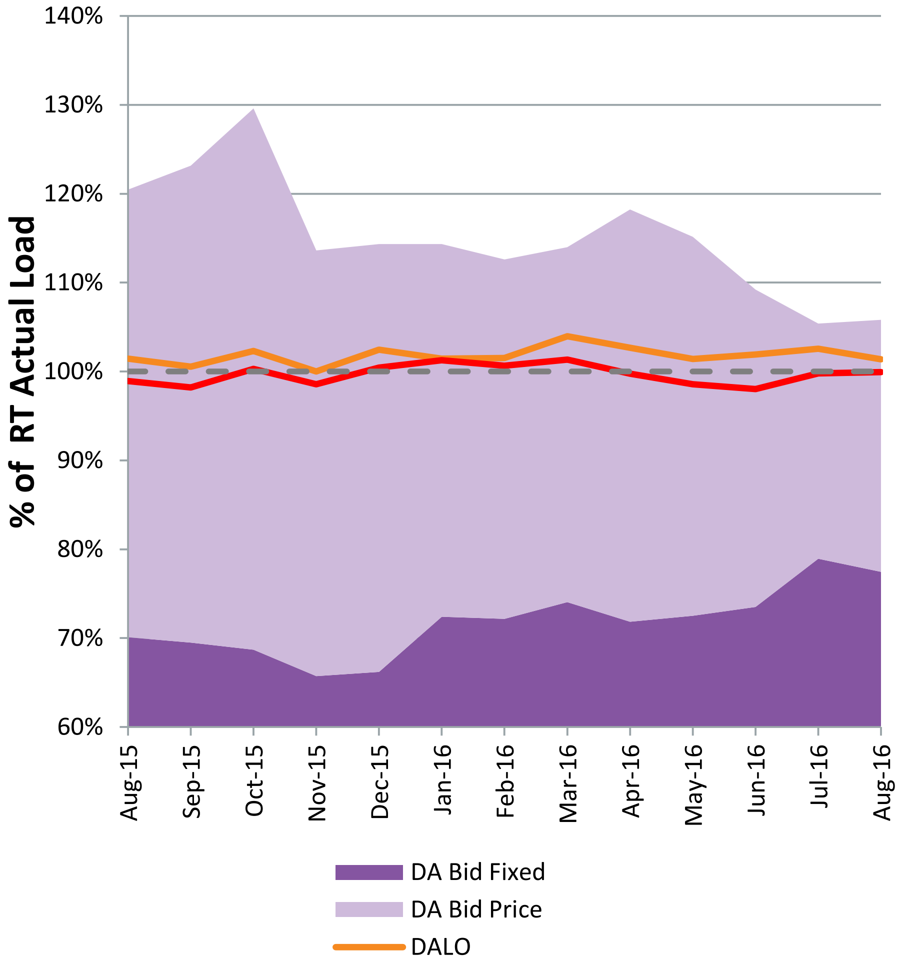
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

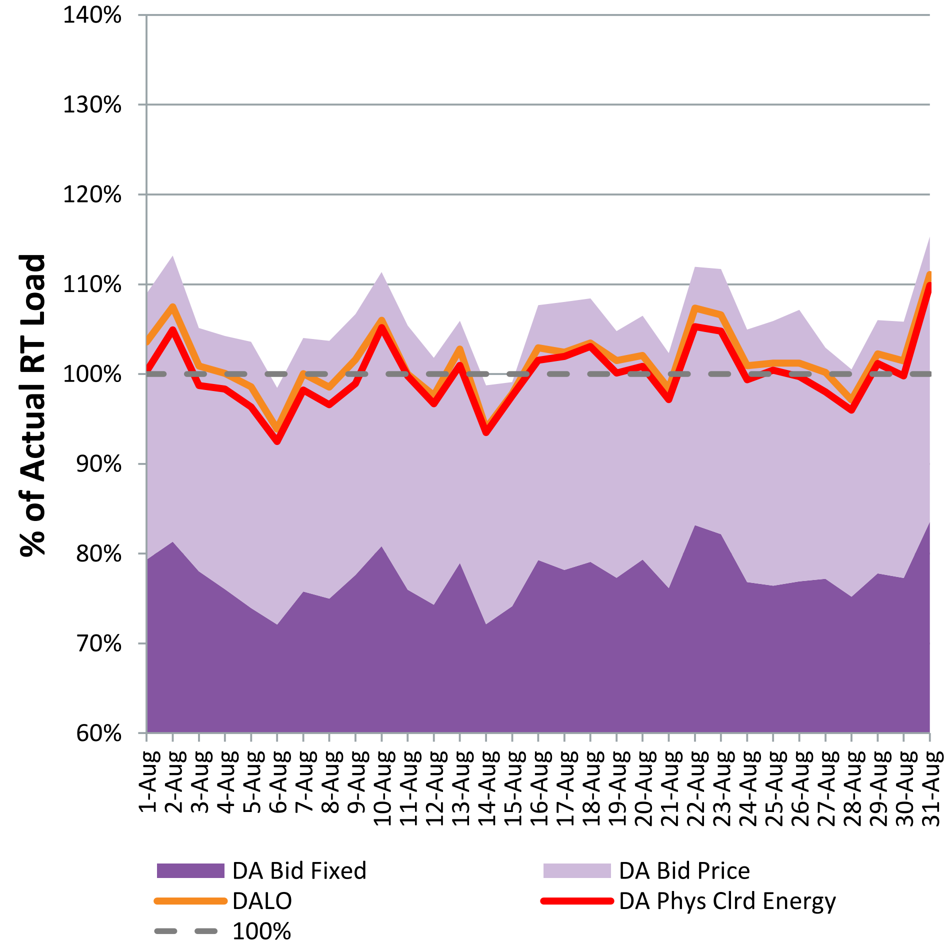
Components of RT Supply and Demand – Last Three Months





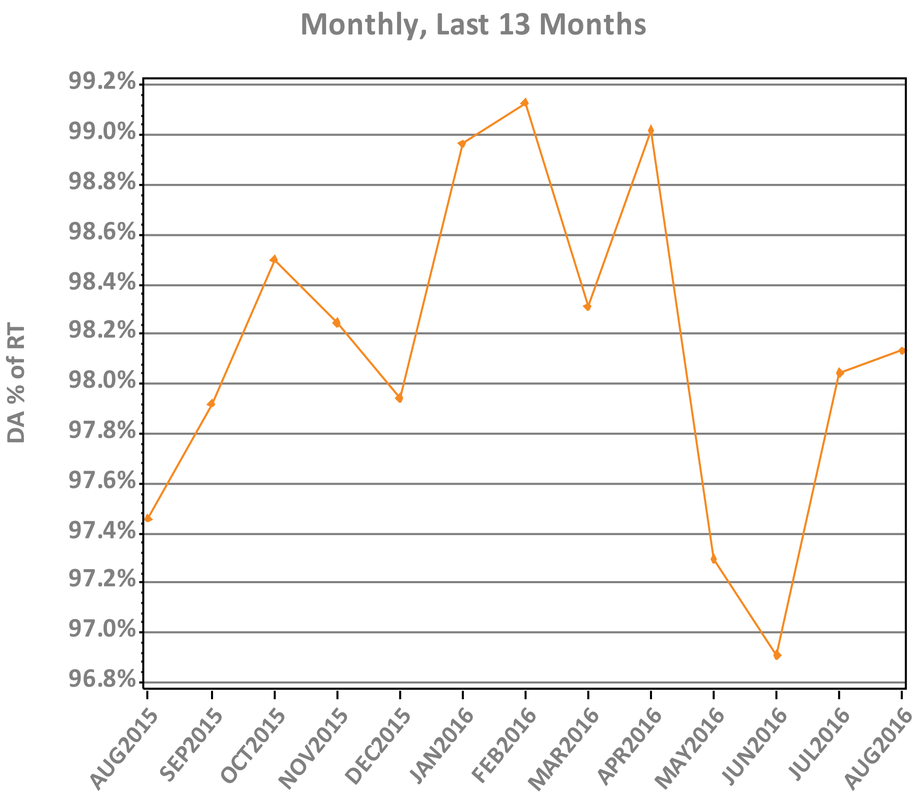
DAM Volumes as % of RT Actual Load (Peak Hour)

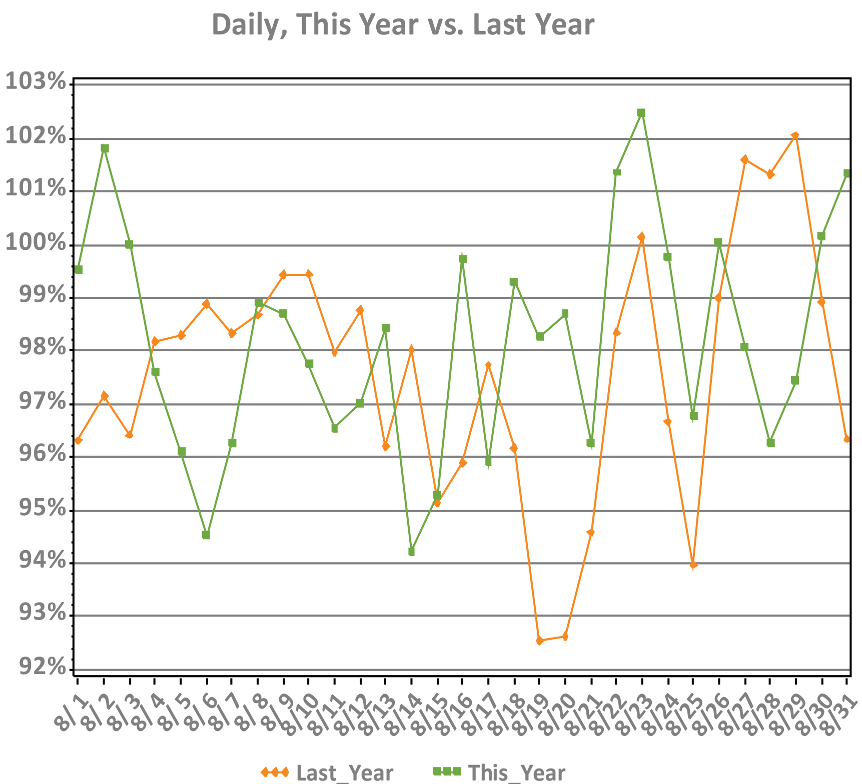




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

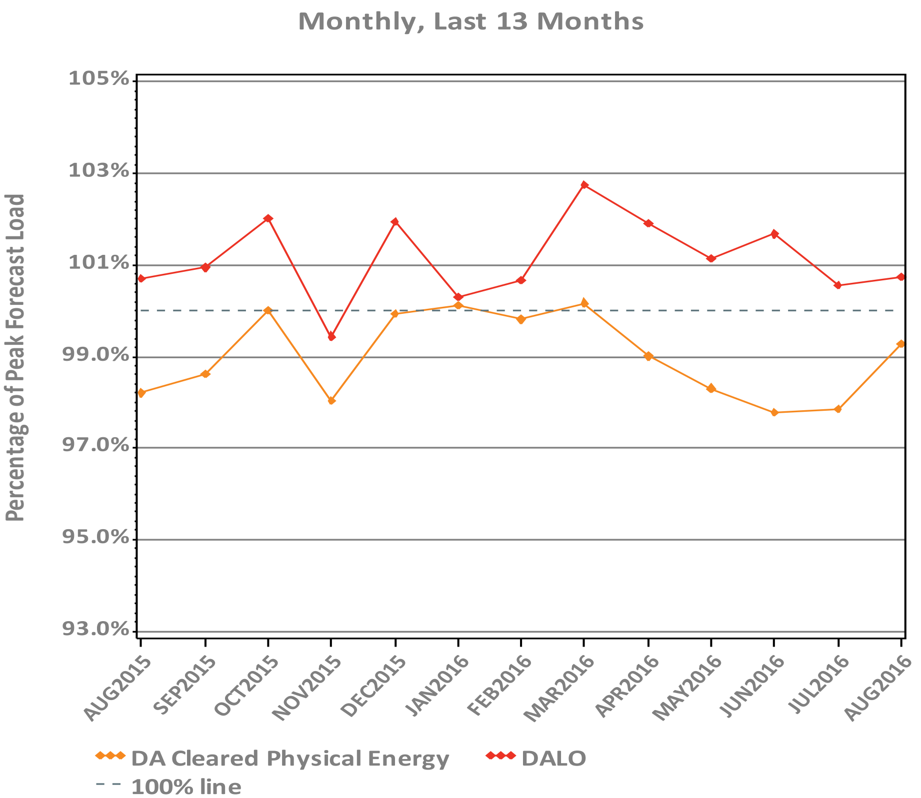
DA vs. RT Load Obligation: August, This Year vs. Last Year

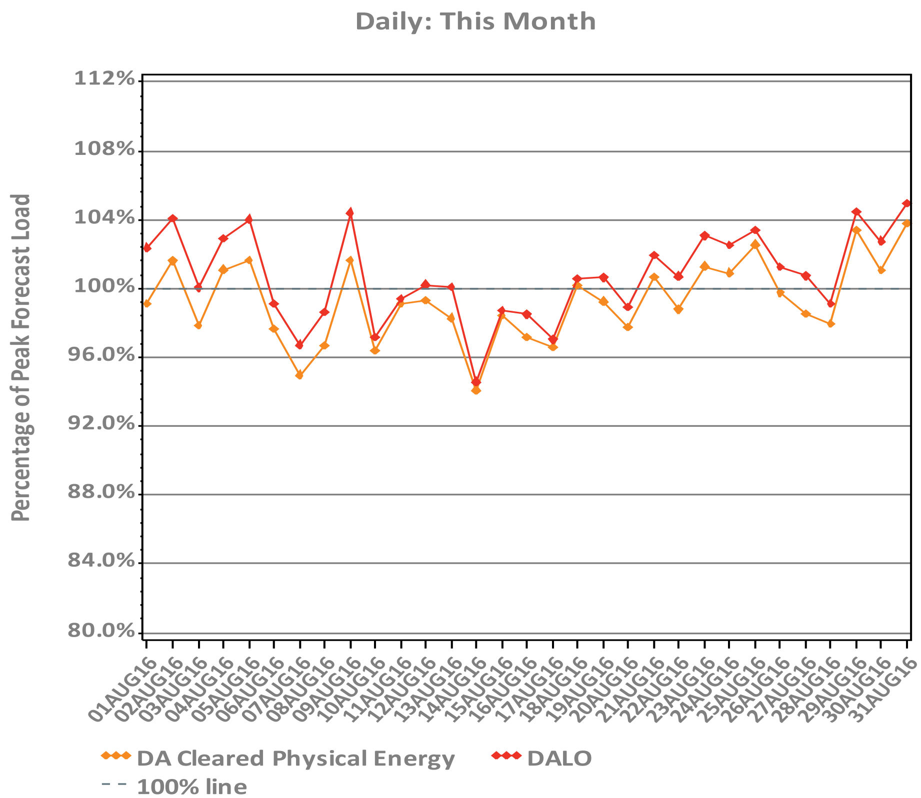




*Hourly average values

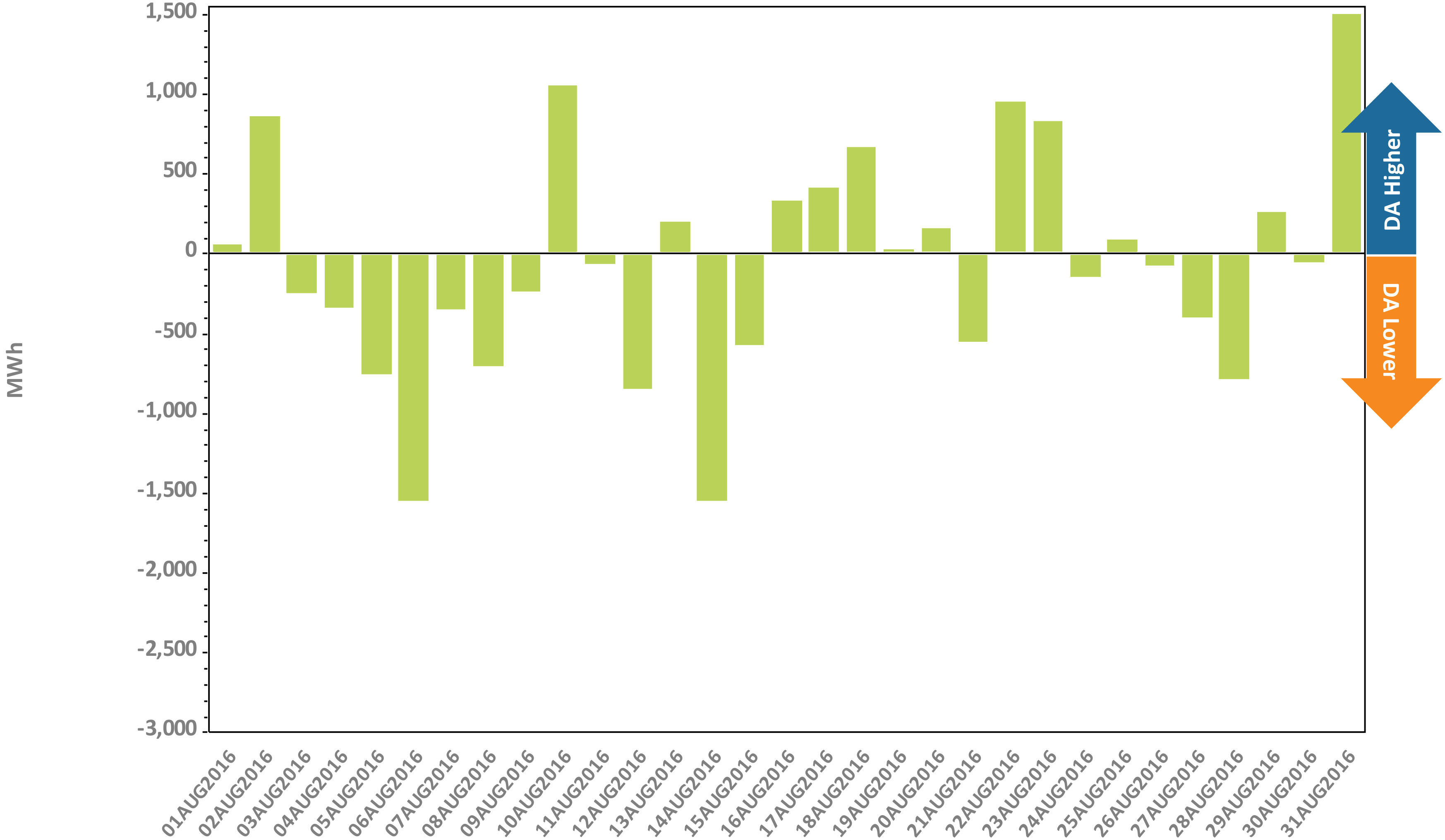
DA Volumes as % of Forecast (Peak Hour)





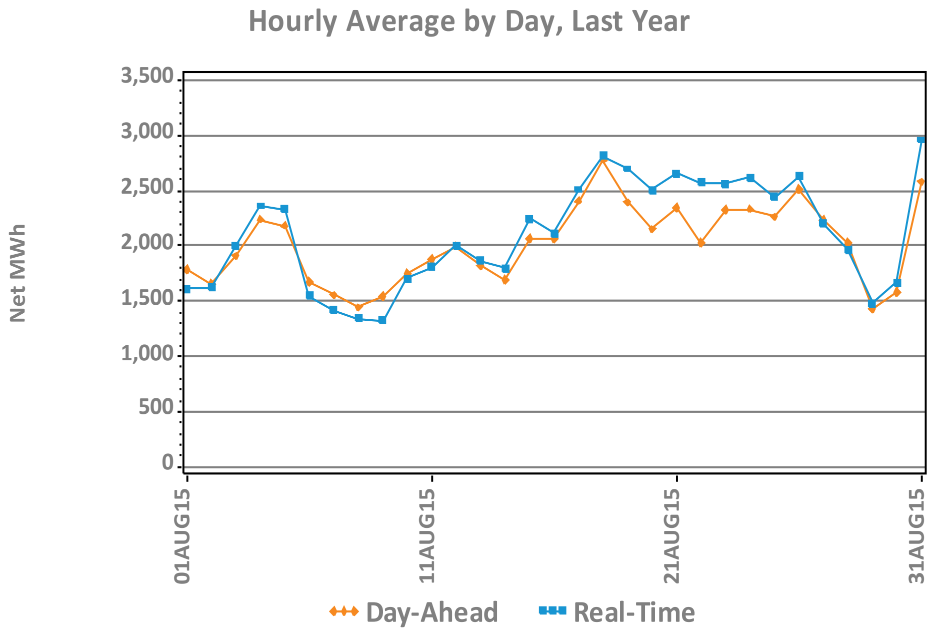
*Forecasted peak hour is reflected.

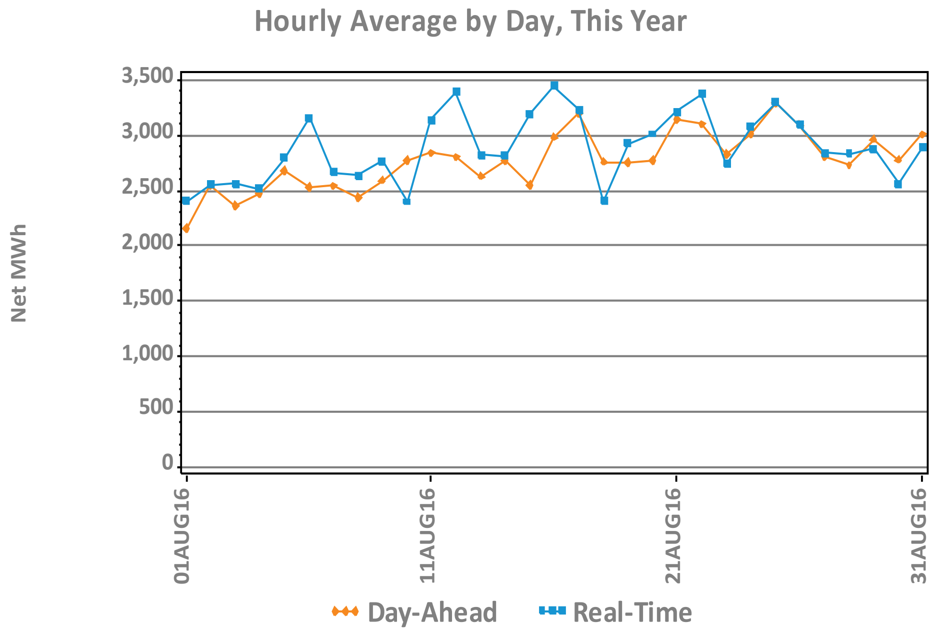
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



***Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.**

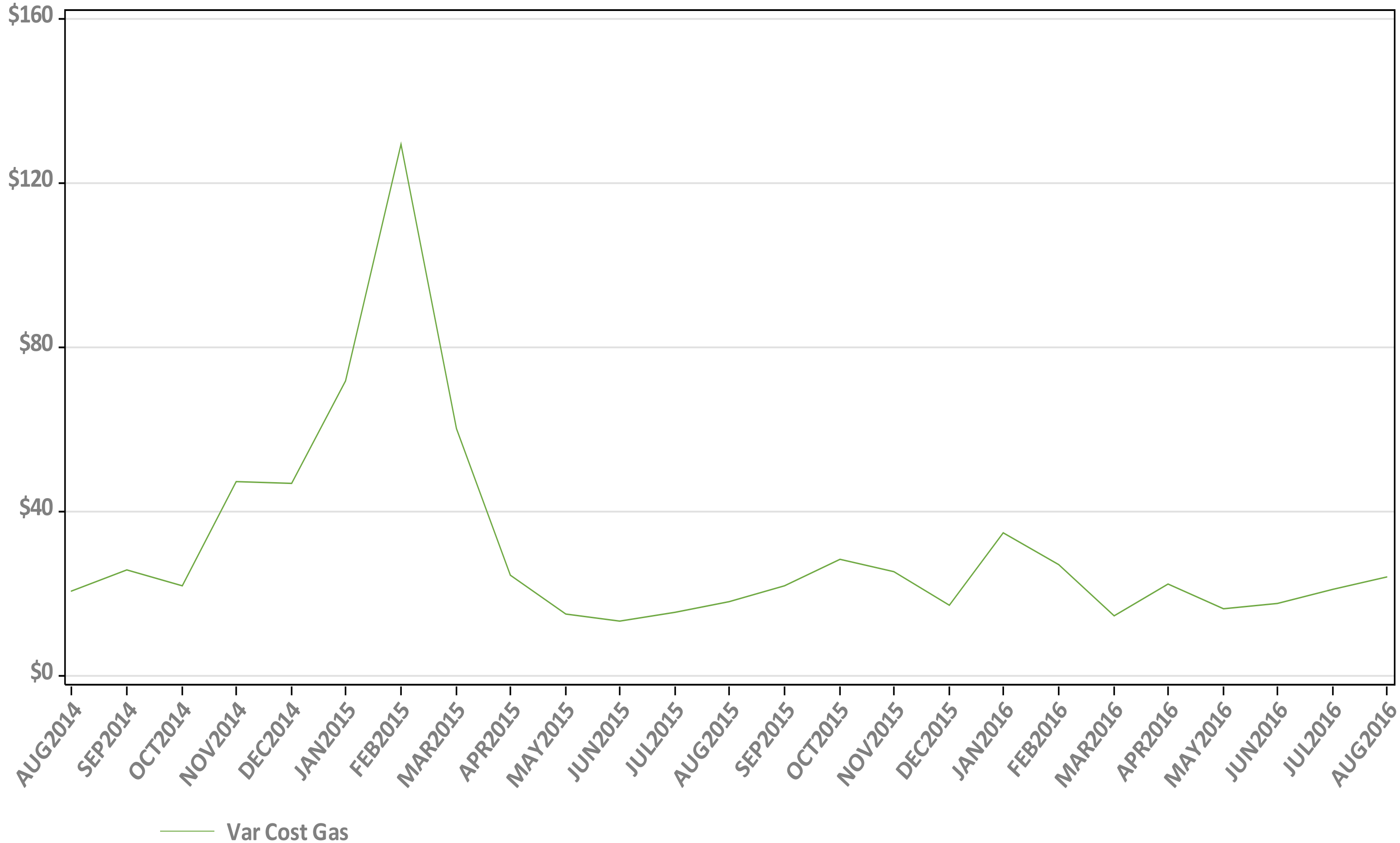
DA vs. RT Net Interchange
August 2016 vs. August 2015





Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Variable Production Cost of Natural Gas: Monthly

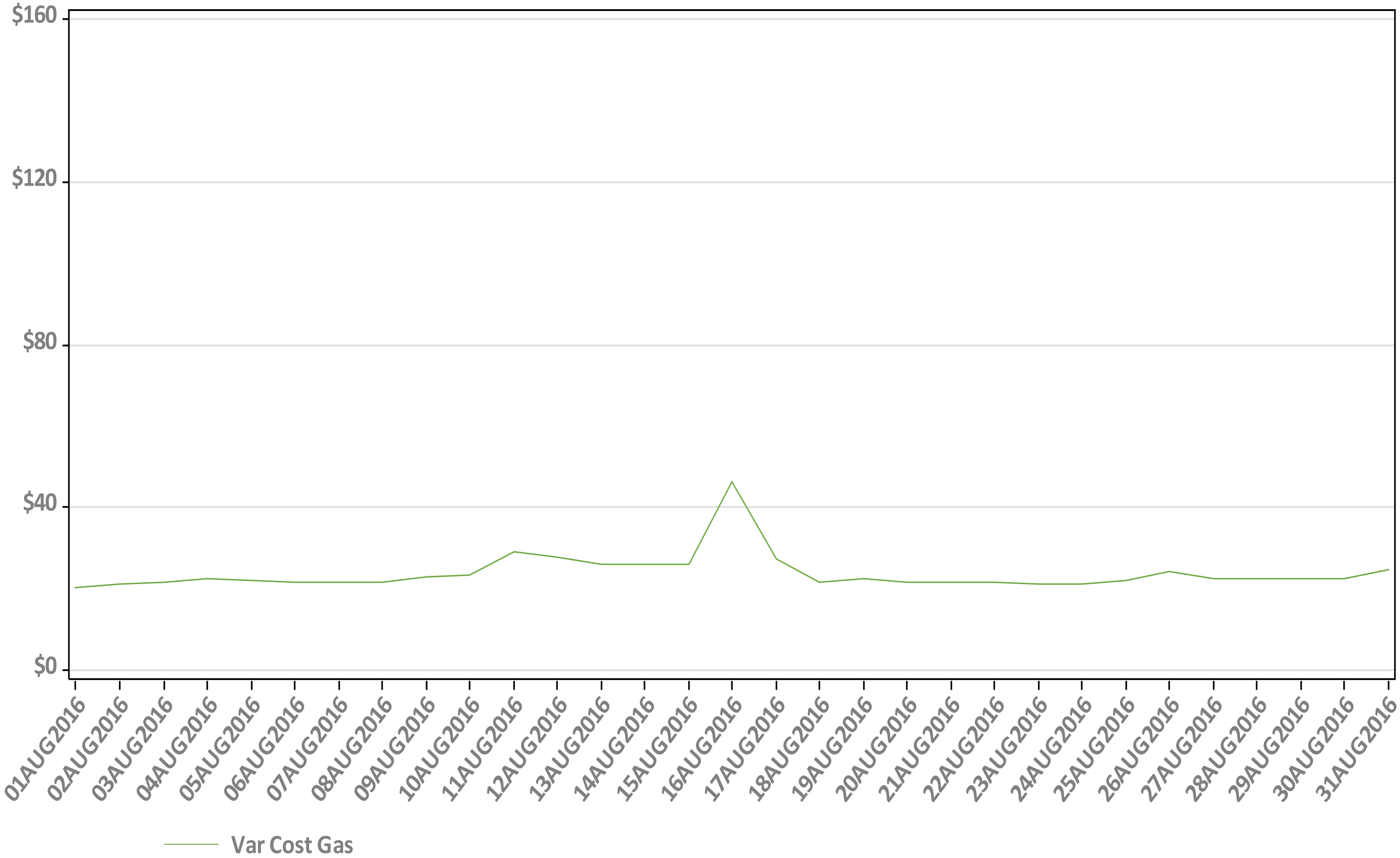


Underlying natural gas data furnished by:

ICE Global markets in clear view

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Variable Production Cost of Natural Gas: Daily

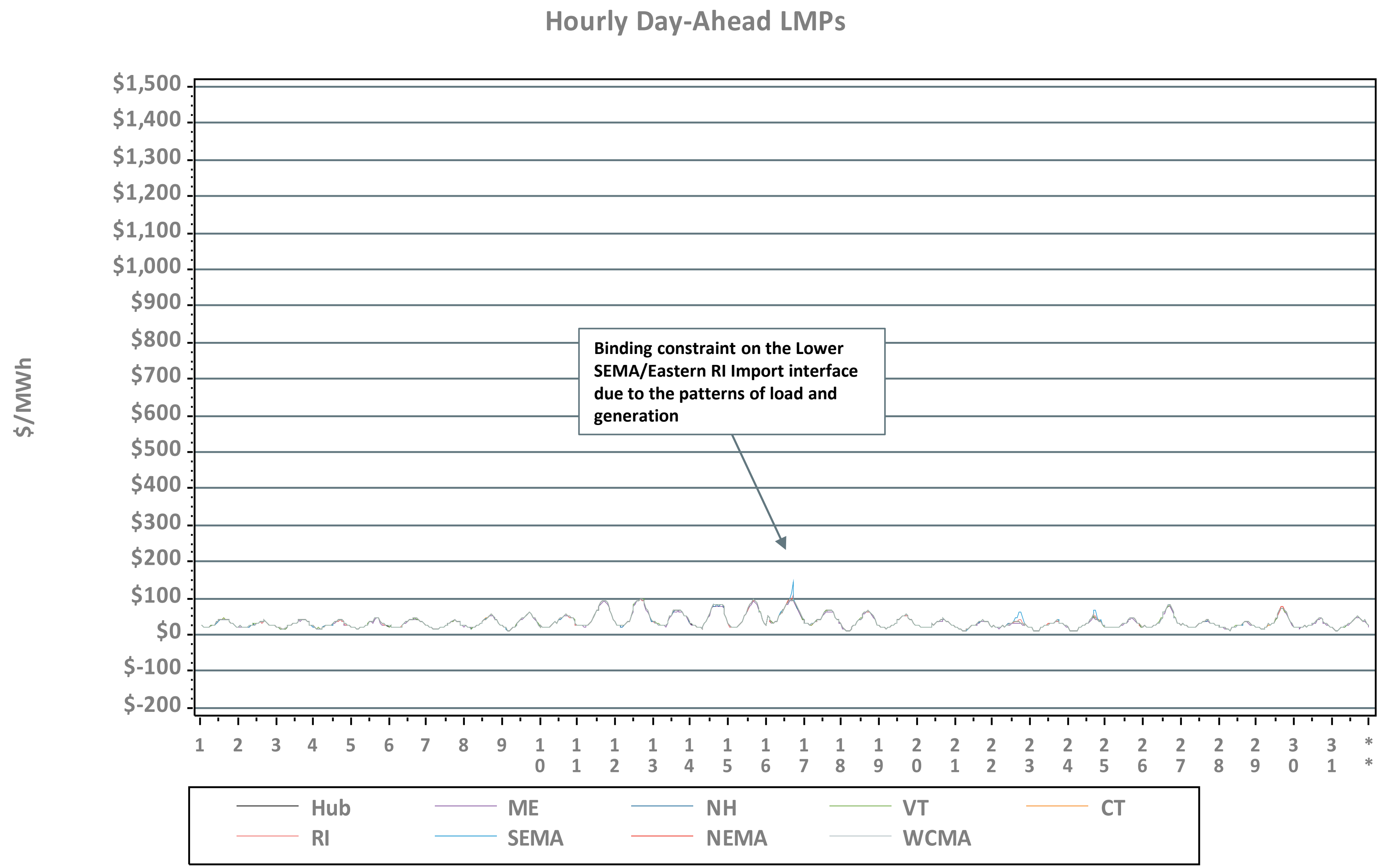


Underlying natural gas data furnished by:

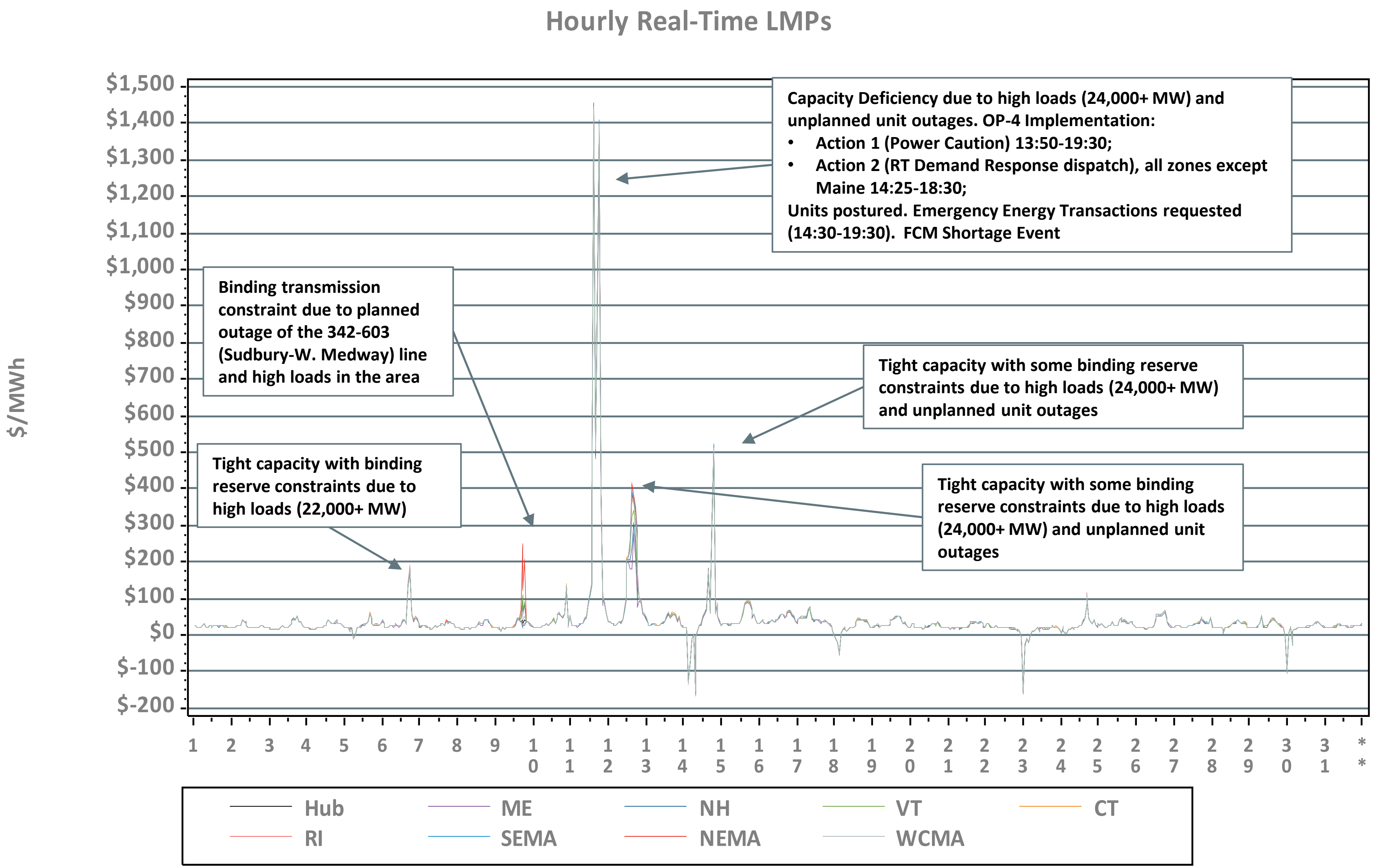
ICE Global markets in clear view

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Hourly DA LMPs, August 1-31, 2016

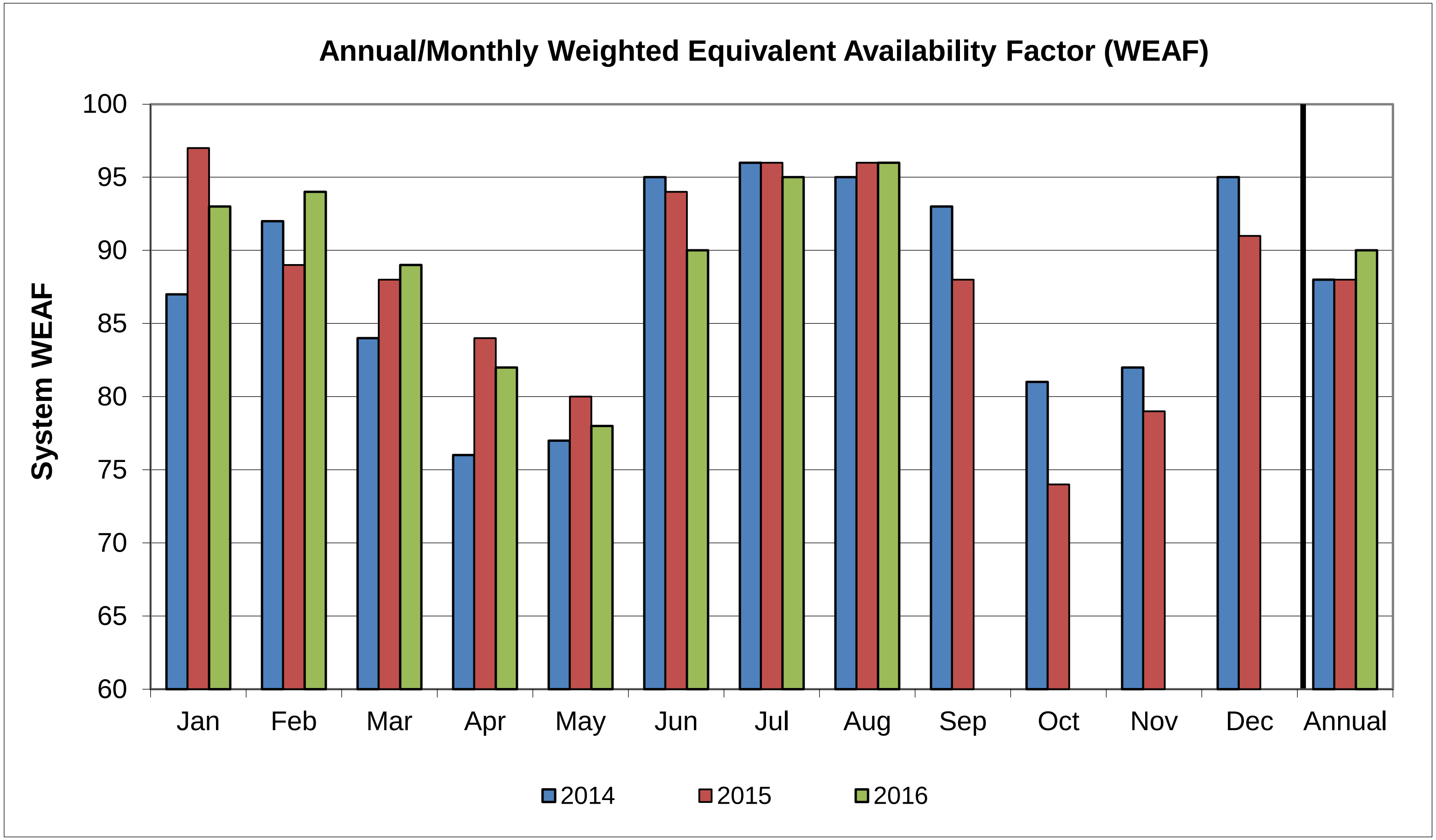


Hourly RT LMPs, August 1-31, 2016



* No Minimum Generation Emergencies were declared in August.

System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2016	93	94	89	82	78	90	95	96					90
2015	97	89	88	84	79	94	96	96	88	74	79	91	88
2014	87	92	84	76	77	95	96	95	93	81	82	95	88

Data as of 9/1/16

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for September 2016

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	97.8	0.0	133.3	0.0	231.1
NH	10.1	0.0	81.1	0.0	91.2
VT	24.9	0.0	104.4	0.0	129.3
CT	76.8	26.8	76.4	361.1	541.1
RI	11.0	0.0	177.0	0.0	188.1
SEMA	12.1	0.0	246.7	0.0	258.7
WCMA	28.9	3.9	228.4	52.5	313.7
NEMA	31.5	4.0	486.7	0.0	522.3
Total	**293.1**	**34.7**	**1,534.0**	**413.6**	**2,275.5**

*** Real Time Demand Response**

**** Real Time Emergency Generation**

NOTE: CSO values include T&D loss factor (8%) and, as applicable, a reserve margin gross-up of either 14.3% or 16.1%, respectively, for portions of resources that selected a multi-year obligation in the FCA 1 or FCA 2. Otherwise, reserve margin gross-ups were discontinued with FCA 3.

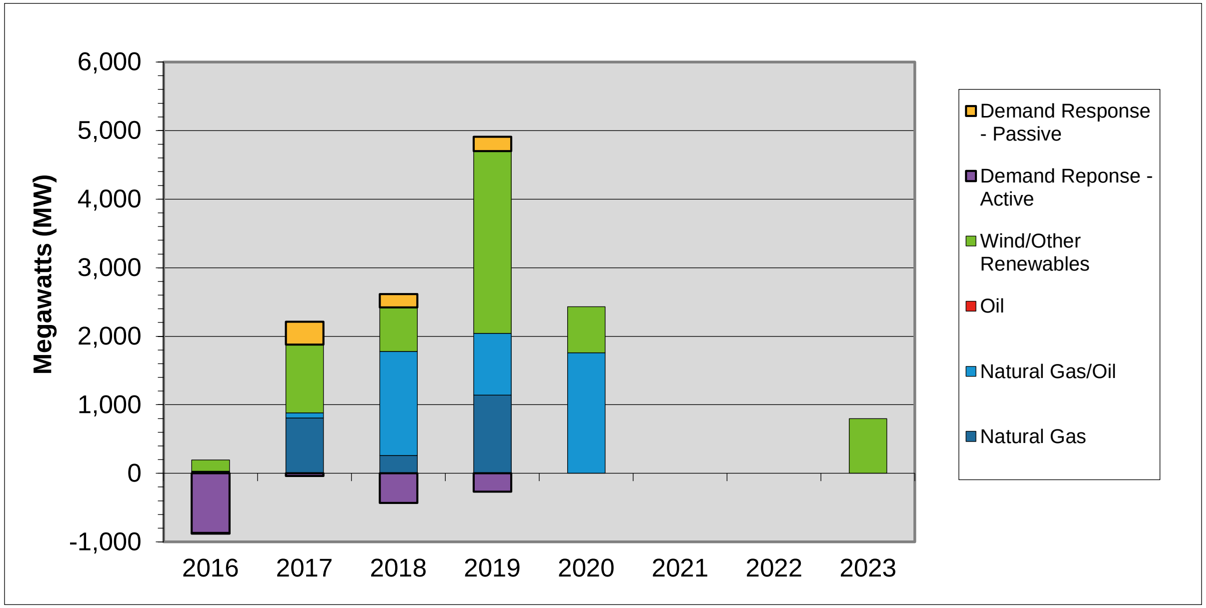
NEW GENERATION

New Generation Update

Based on Queue as of 9/1/16

- One new project, with a rating of 800 MW, has applied for interconnection study since the last update
  - The project consists of an off-shore wind project with an expected in-service date of 2023
- No projects went commercial and one project withdrew from the queue, resulting in a net increase in new generation projects of 790 MW
- In total, 81 generation projects are currently being tracked by the ISO, totaling approximately 12,300 MW

Actual and Projected Annual Capacity Additions
By Supply Fuel Type and Demand Resource Type



	2016	2017	2018	2019	2020	2021	2022	2023	Total MW	% of Total[1]
Demand Response - Passive	-12	330	196	212	0	0	0	0	726	6.3
Demand Response - Active	-868	-37	-433	-270	0	0	0	0	-1,607	-13.9
Wind & Other Renewables	163	998	640	2,656	672	0	0	800	5,929	51.4
Oil	0	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	10	74	1,519	904	1,757	0	0	0	4,264	36.9
Natural Gas	22	808	260	1,140	0	0	0	0	2,230	19.3
Totals	**-685**	**2,173**	**2,182**	**4,643**	**2,429**	**0**	**0**	**800**	**11,541**	**100.0**

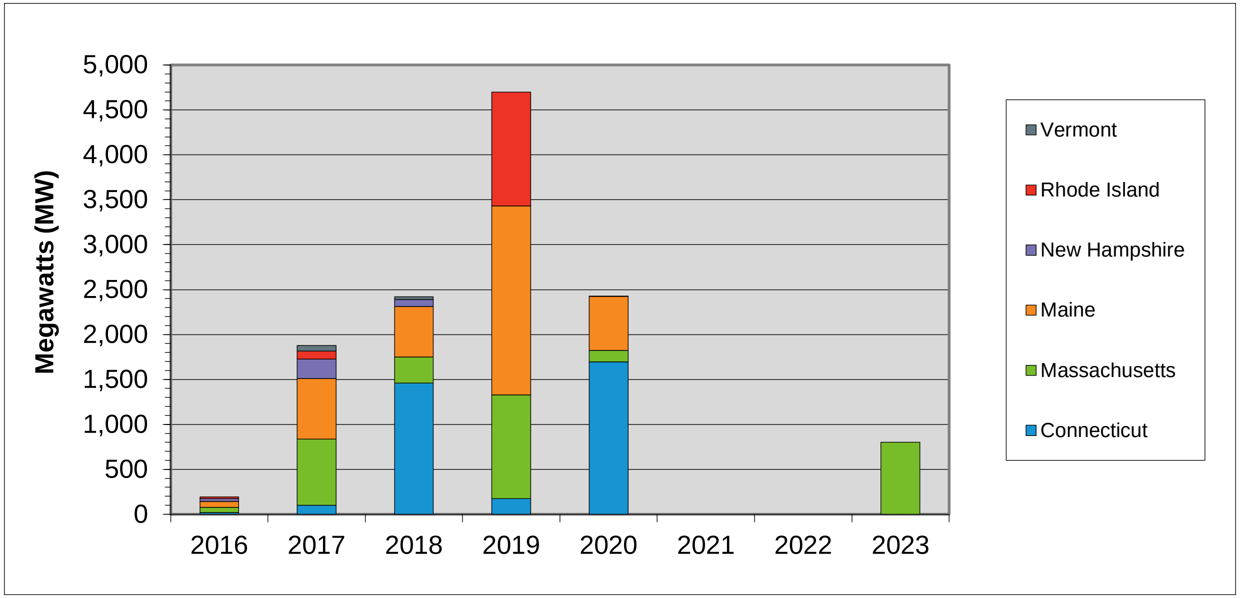
[1] **Sum may not equal 100% due to rounding**

[2] **The projects in this category are dual fuel, with either gas or oil as the primary fuel**

- 2016 values include the 94 MW of generation that has gone commercial in 2016
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2016	2017	2018	2019	2020	2021	2022	2023	Total MW	% of Total[1]
Vermont	0	62	30	0	0	0	0	0	92	0.7
Rhode Island	22	89	0	1,268	0	0	0	0	1,379	11.1
New Hampshire	30	218	75	0	5	0	0	0	328	2.6
Maine	67	676	563	2,102	601	0	0	0	4,009	32.3
Massachusetts	56	735	290	1,157	128	0	0	800	3,166	25.5
Connecticut	20	100	1,461	173	1,695	0	0	0	3,449	27.8
Totals	**195**	**1,880**	**2,419**	**4,700**	**2,429**	**0**	**0**	**800**	**12,423**	**100.0**

[1] **Sum may not equal 100% due to rounding**

- 2016 values reflect the 94 MW of generation that has gone commercial in 2016

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	3	115	0	0	3	115
Hydro	5	104	0	0	5	104
Landfill Gas	1	2	0	0	1	2
Natural Gas	13	2,293	0	0	13	2,293
Natural Gas/Oil	12	4,254	0	0	12	4,254
Oil	0	0	0	0	0	0
Solar	14	613	1	10	13	603
Wind	30	4,855	4	274	26	4,581
Battery Storage	3	93	1	16	2	77
Total	81	12,329	6	300	75	12,029

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection
By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	185	0	0	6	185
Intermediate	20	5,806	0	0	20	5,806
Peaker	25	1,483	2	26	23	1,457
Wind Turbine	30	4,855	4	274	26	4,581
Total	81	12,329	6	300	75	12,029

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	3	115	3	115	0	0	0	0	0	0
Hydro	5	104	1	5	3	33	1	66	0	0
Landfill Gas	1	2	1	2	0	0	0	0	0	0
Natural Gas	13	2,293	1	63	9	2,041	3	189	0	0
Natural Gas/Oil	12	4,254	0	0	8	3,732	4	522	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	14	613	0	0	0	0	14	613	0	0
Wind	30	4,855	0	0	0	0	0	0	30	4,855
Battery Storage	3	93	0	0	0	0	3	93	0	0
Total	81	12,329	6	185	20	5,806	25	1,483	30	4,855

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624	1,085.347	-186.64	842.791	-242.56	789.366	-53.425	638.393	-150.973
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000	1,516.504	-5.03	1,700.586	184.08	1,694.766	-5.82	1,687.458	-7.308
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624	**2,601.851**	**-191.67**	**2,543.377**	**-58.47**	**2,484.132**	**-59.245**	**2,325.851**	-158.281
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709	28,442.424	98.98	28,727.16	284.73	28,881.019	153.859	**28,971.511**	90.492
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205	829.219	0.97	820.743	-8.48	777.924	-42.819	**754.101**	-23.823
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914	**29,271.643**	**99.95**	**29,547.9**	**276.26**	**29,658.943**	**111.043**	**29,725.612**	66.669
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290	**1,616.821**	**-25.00**	**1,399.037**	**-217.78**	**1,337.037**	**-62**	**1,337.037**	0
***Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000	**33,490.315**	**-116.72**	**33,490.32**	**0.00**	**33,480.112**	**-10.208**	**33,388.5**	-91.612
Net ICR (NICR)		**33,456**	**33,456**	**0**	**33,456**	**0**	**33,456**	**0**	33,114	**-342**	**33,114**	**0.00**	**33,391**	**277**	**33,391**	**0**

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,116.698	1,043.719	-72.979	944.27	-99.45	932.721	-11.549	781.206	-151.52	671.28	-109.926	575.63	-95.65	556.453	-19.177
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482	1,544.276	0.48	1,544.119	-0.157	1,607.705	63.586	1,884.902	277.197
Demand Total		**2,748.033**	**2,563.459**	**-184.574**	**2,463.581**	**-99.88**	**2,476.514**	**12.933**	2,325.482	-151.03	2,215.399	-110.083	2,183.335	-32.064	2,441.355	258.02
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958	28,307.339	-215.66	28,791.131	483.792	28,948.677	157.546	29,152.793	204.116
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839	838.626	-74.46	824.833	-13.793	800.286	-24.547	735.174	-65.112
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**	**29,030.288**	**-10.26**	**29,436.085**	**405.797**	29,145.965	-290.12	29,615.964	469.999	29,748.963	132.999	29,887.967	139.004
Import Total		**1,830.000**	**1,606.862**	**-223.138**	**1,606.862**	**0.00**	**1,616.401**	**9.539**	1,576.401	-40.00	1,576.401	0	1,440.401	-136	1,162.202	-278.199
*****Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**	**33,100.731**	**-110.14**	**33,529.000**	**428.269**	33,047.848	-481.15	33,407.764	359.916	33,372.699	-35.065	33,491.524	118.825
Net ICR (NICR)		**32,968**	**32,968**	**0**	33,529	561	33,529	0	33,529	0.00	33,529	0	33,152	-377	33,152	0

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 8

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,080.079	887.493	-192.59	891.604	4.111	772.352	-119.252						
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211	2025.383	68.72						
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,848.267**	**1.9**	**2,797.735**	-50.532						
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,666.87	143.074	28,658.35	-8.52						
	Intermittent	876.925	898.955	22.03	922.173	23.218	918.782	-3.391						
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**	**29,577.132**	**-11.911**						
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**	**1,375.53**	**0**						
*****Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,812.84**	**306.688**	**33,750.397**	**-62.443**						
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	**0**	**34,061**	**0**						

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 9

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	647.26	596.701	-50.559	553.857	-42.844								
	Passive Demand	2,156.151	2153.94	-2.211	2150.196	-3.744								
Demand Total		**2,803.411**	**2,750.641**	**-52.77**	**2,704.053**	**-46.588**								
Generator	*Non-Intermittent*	29,550.564	29,558.181	7.617	29,783.831	225.65								
	Intermittent	891.616	864.924	-26.692	872.425	7.501								
Generator Total		**30,442.18**	**30,423.105**	**-19.075**	**30,656.256**	**233.151**								
Import Total		**1,449**	**1449**	**0**	**1449**	**0**								
*****Grand Total**		**34,694.591**	**34622.746**	**-71.845**	**34,809.309**	**186.563**								
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**								

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 10

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	377.525												
	Passive Demand	2,368.631												
Demand Total		**2,746.156**												
Generator	*Non-Intermittent*	30,387.588												
	Intermittent	982.988												
Generator Total		**31,370.576**												
Import Total		**1,449.8**												
*****Grand Total**		**35,566.532**												
Net ICR (NICR)		**34,151**												

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1246.399	603.675	1850.074
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1768.392	184.99	1953.382
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1726.548	98.227	1824.775
	Passive	861.602	211.261	1072.863
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1794.195	257.341	2051.536
	Passive	1040.113	257.793	1297.906
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2062.196	41.945	2104.141
	Passive	1264.641	221.072	1485.713
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1935.406	66.104	2001.51
	Passive	1395.885	247.449	1643.334
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1116.468	0.23	1116.698
	Passive	1386.56	244.775	1631.335
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1066.593	13.486	1080.079
	Passive	1619.147	341.37	1960.517
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1870.549	285.602	2156.151
	Grand Total	2436.415	366.996	2803.411
2019-20	Active	357.221	20.304	377.525
	Passive	2018.201	350.43	2368.631
	Grand Total	2375.422	370.734	2746.156

RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

What are Daily NCPC Payments?

- Payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area

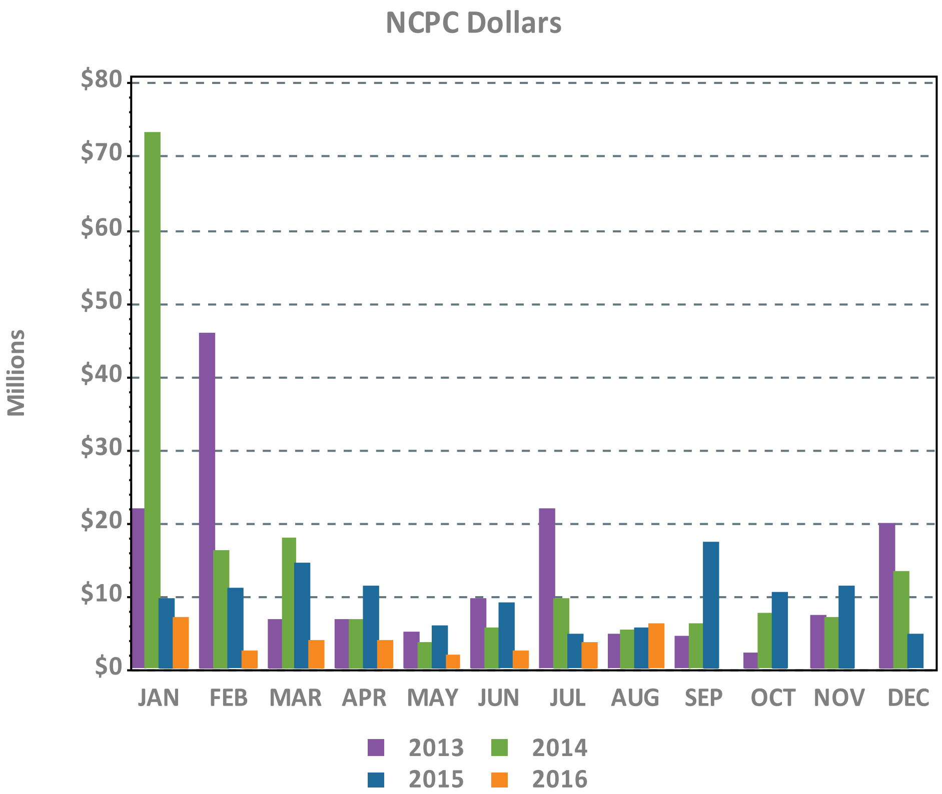
Definitions

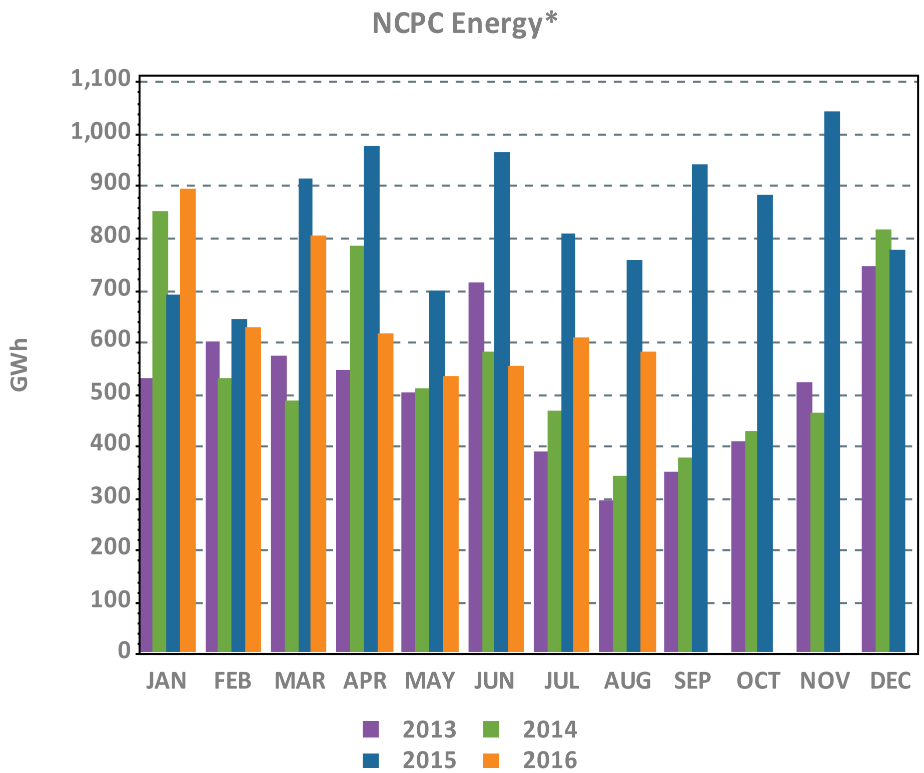
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
Delisted Units	Resources within the control area that have requested to be classified as a non-installed capacity (ICAP) resource, and as such, are not required to offer their capacity into the DA Energy Market
OATT	Open Access Transmission Tariff

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Min Generation Emergency, and Generator and DARD Posturing NCPC

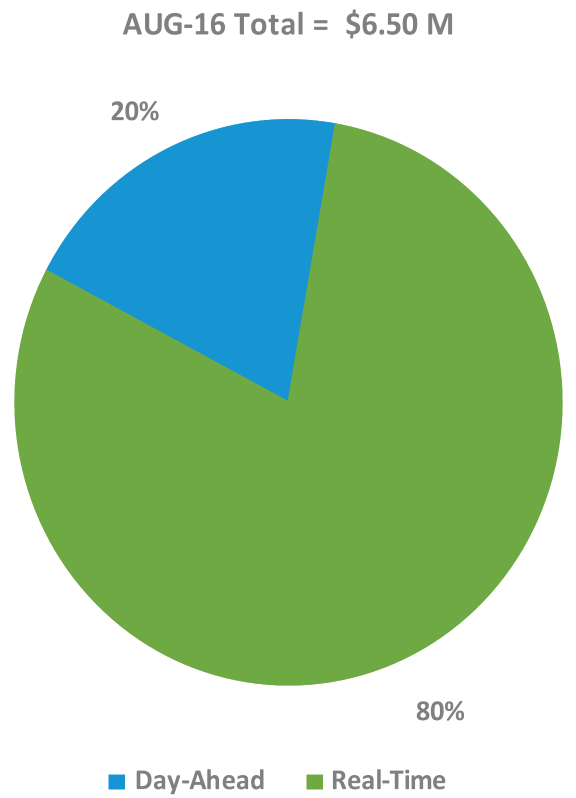
Year-Over-Year Total NCPC Dollars and Energy

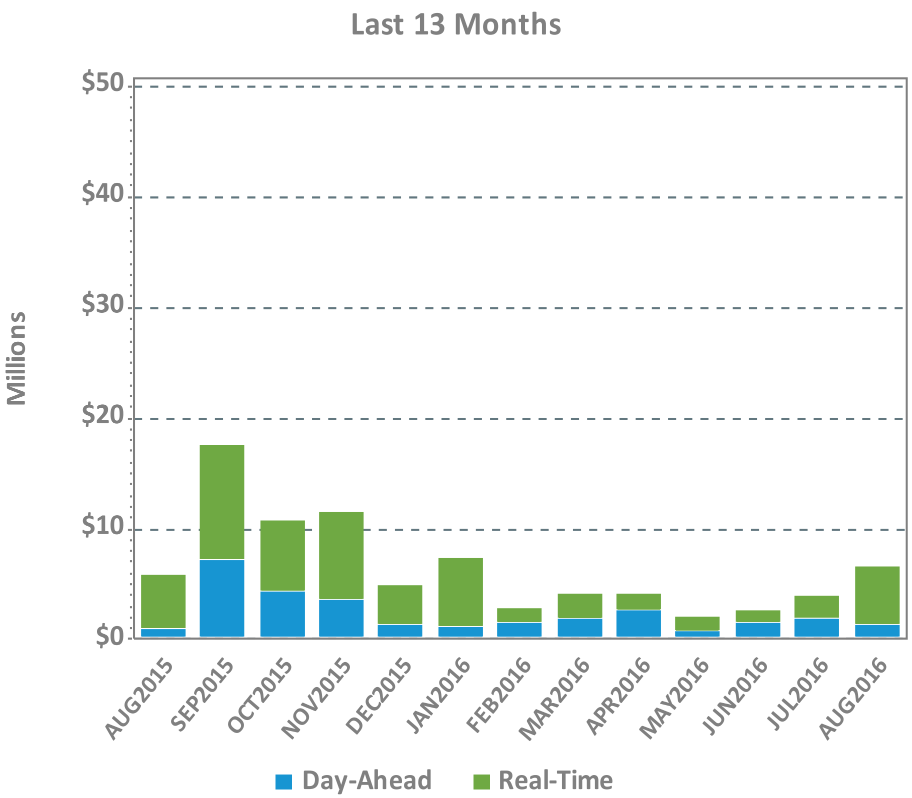




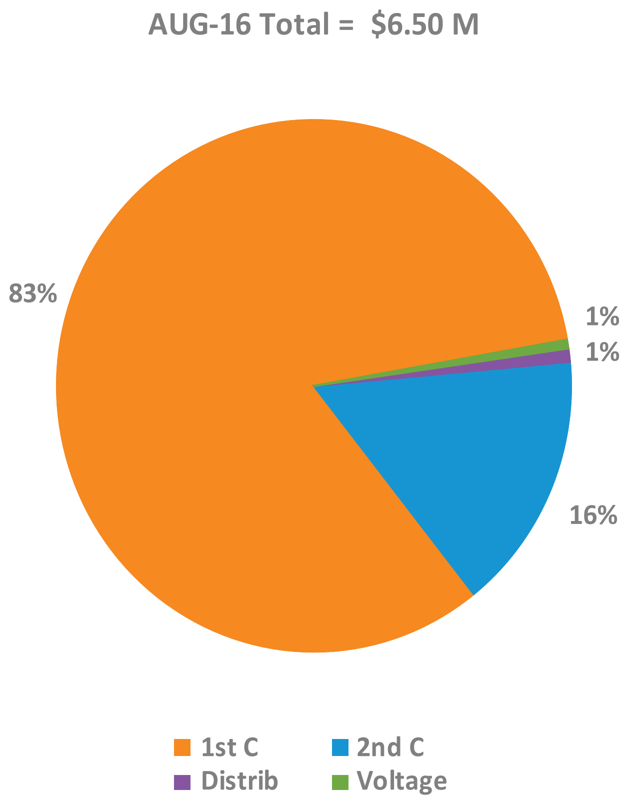
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

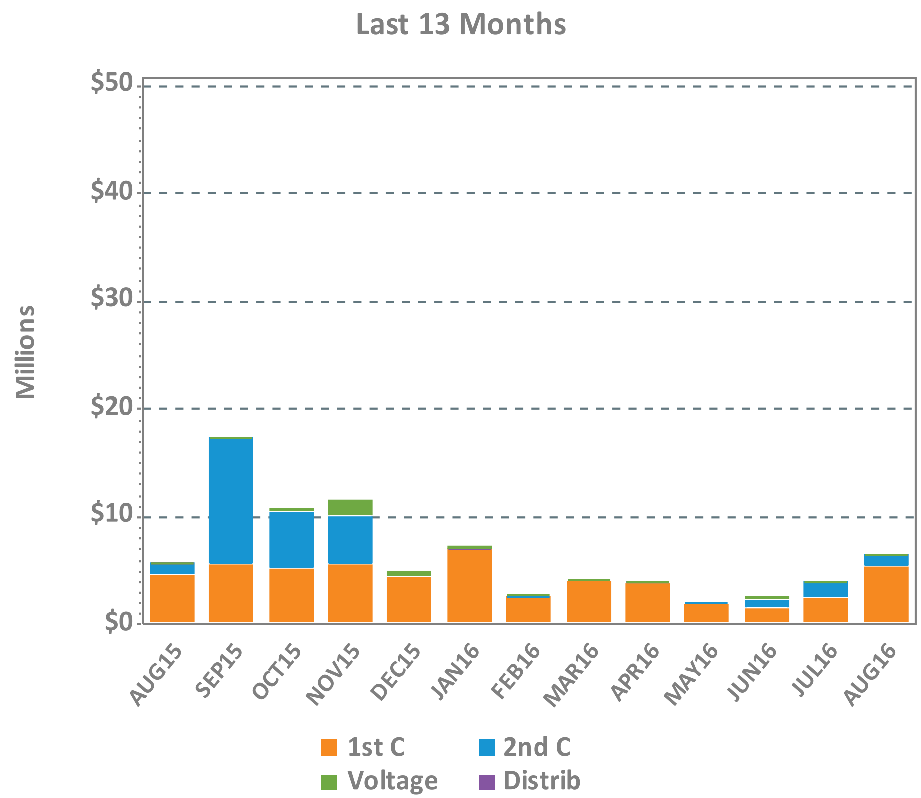
DA and RT NCPC Charges





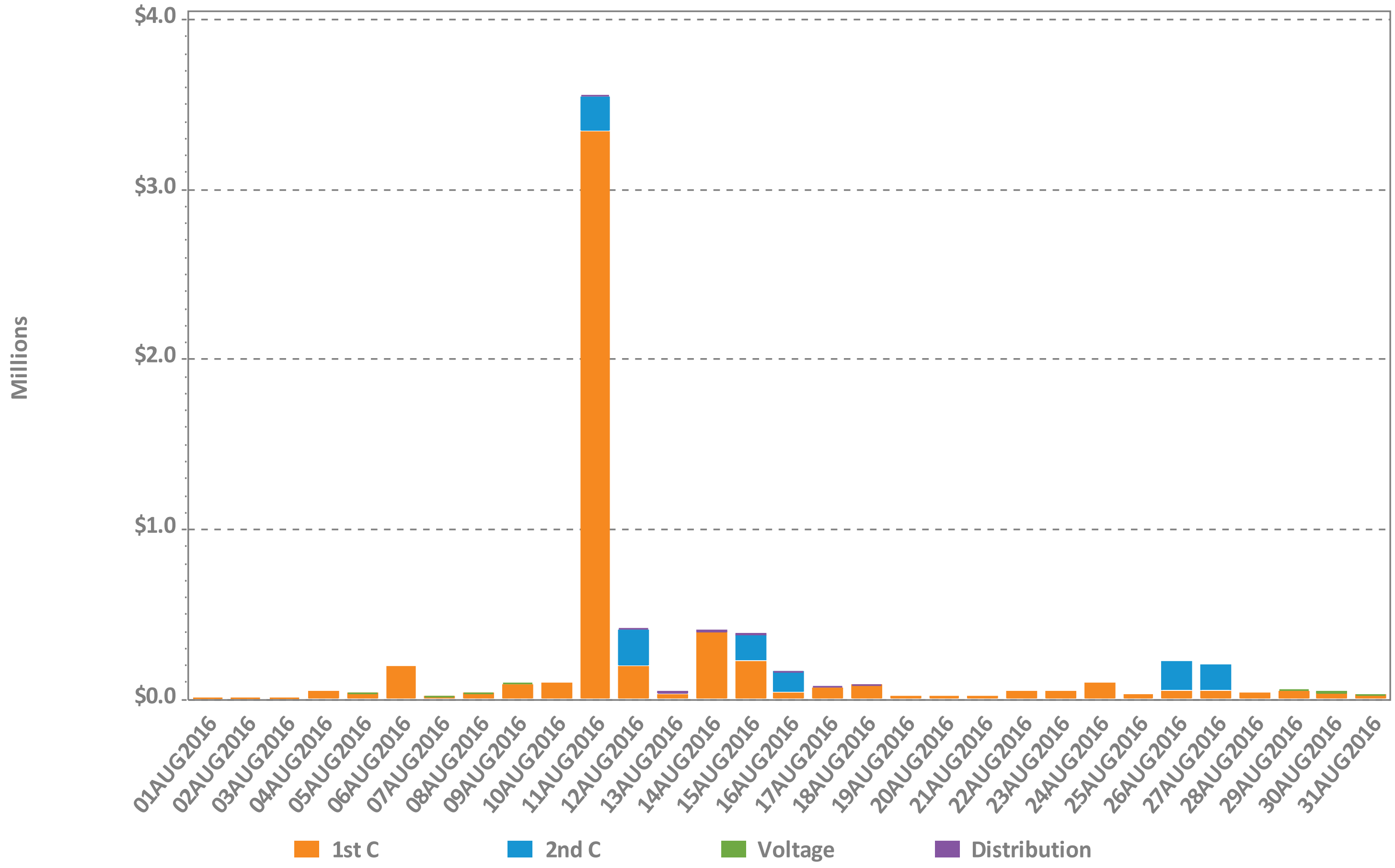
NCPC Charges by Type



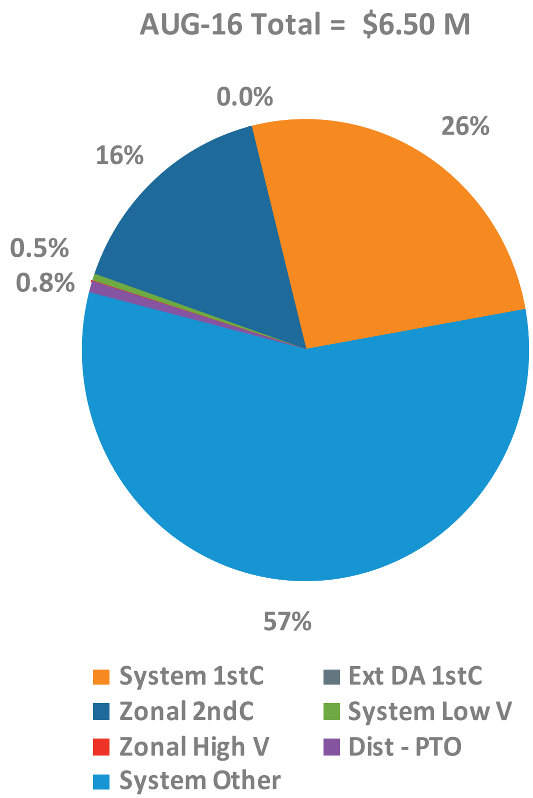


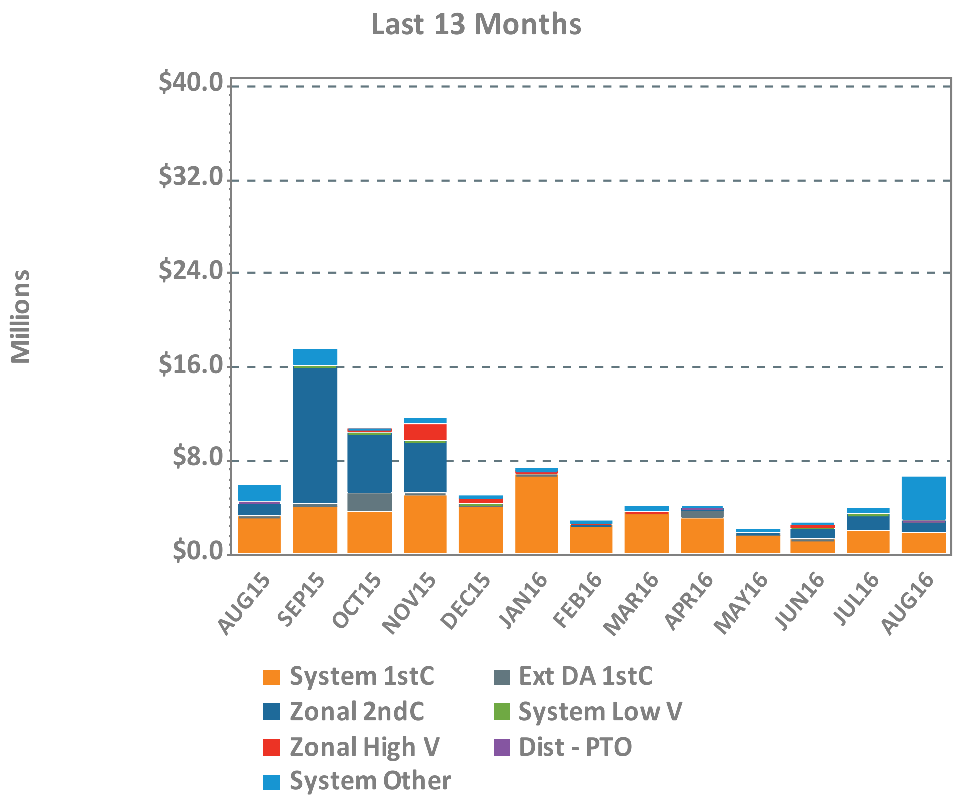
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

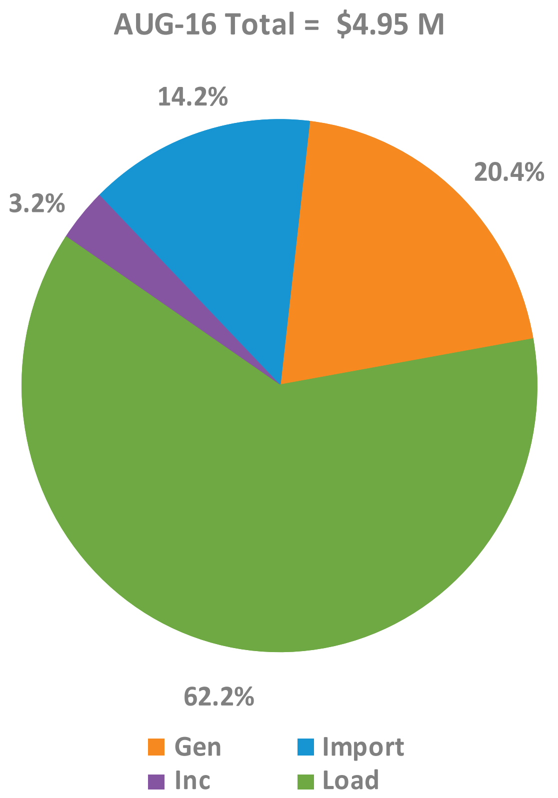


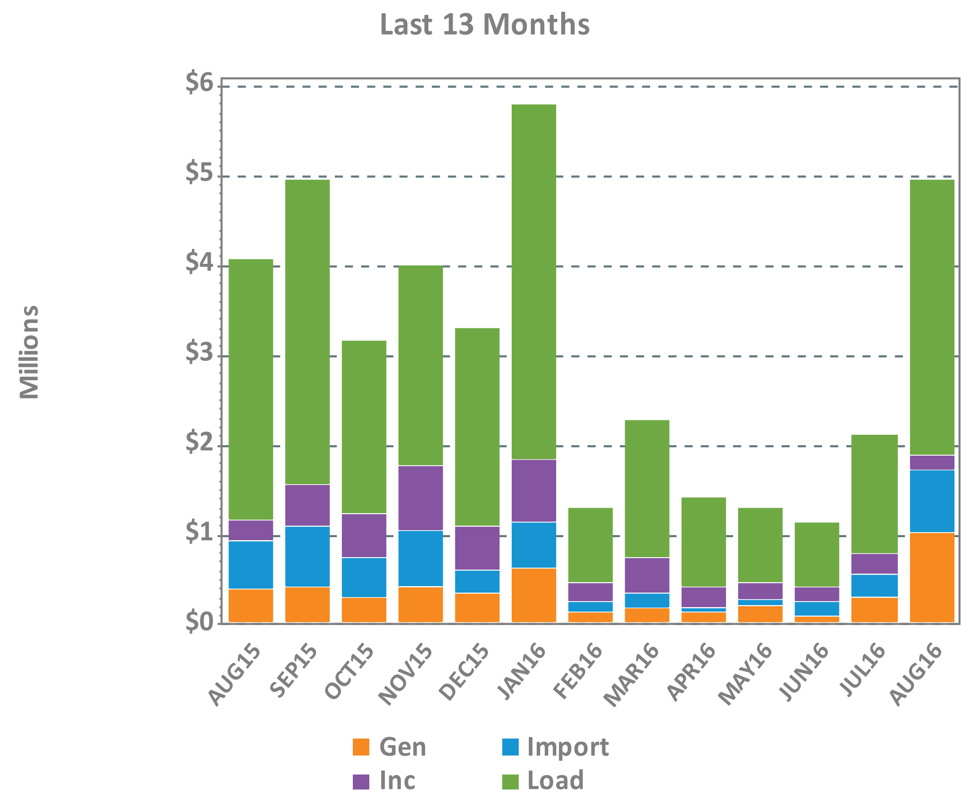
NCPC Charges by Allocation





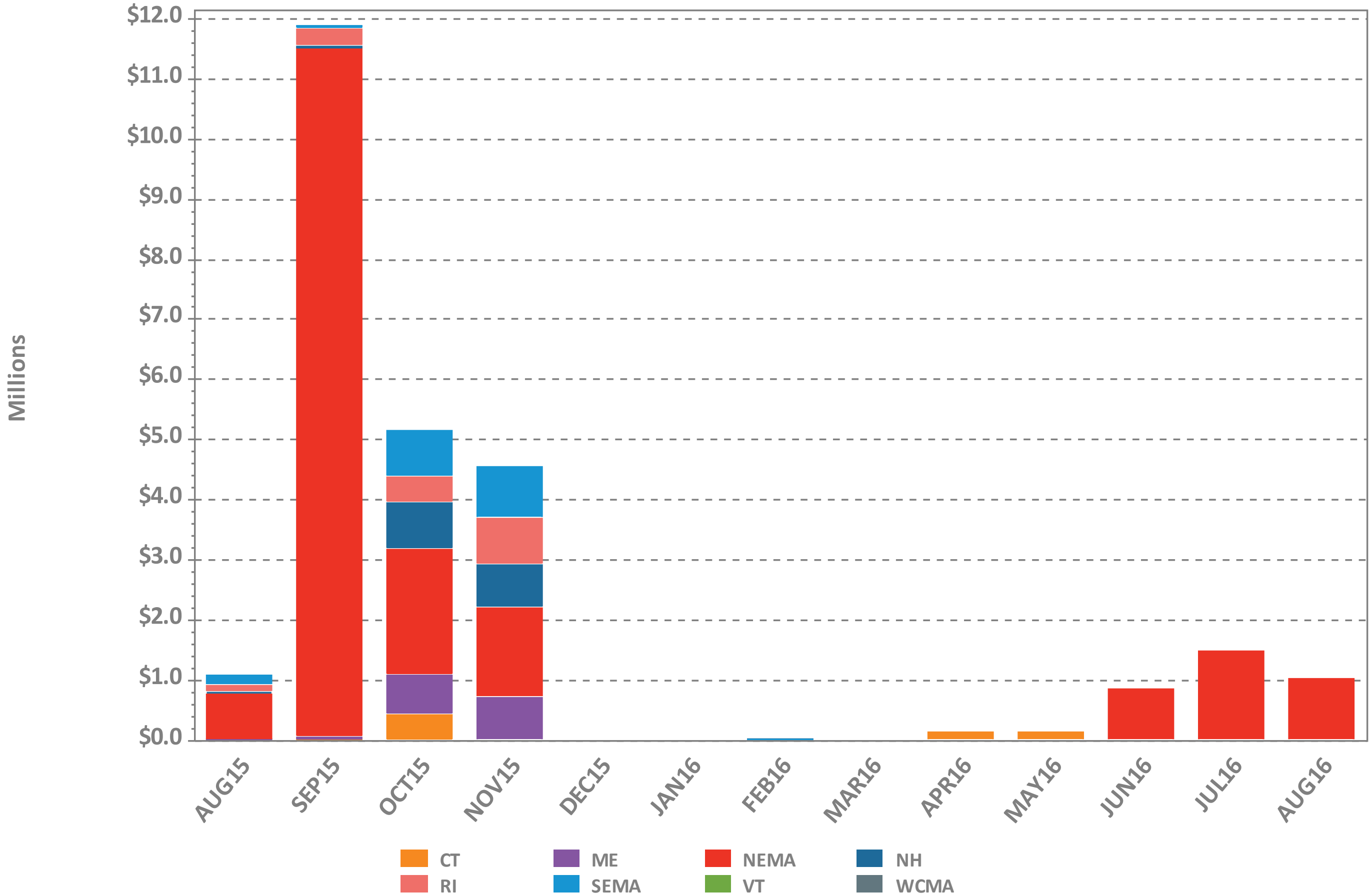
RT First Contingency Charges by Deviation Type





Gen – Generator deviations
Inc – Increment Offer deviations
Imp – Import deviations
Load – Load obligation deviations

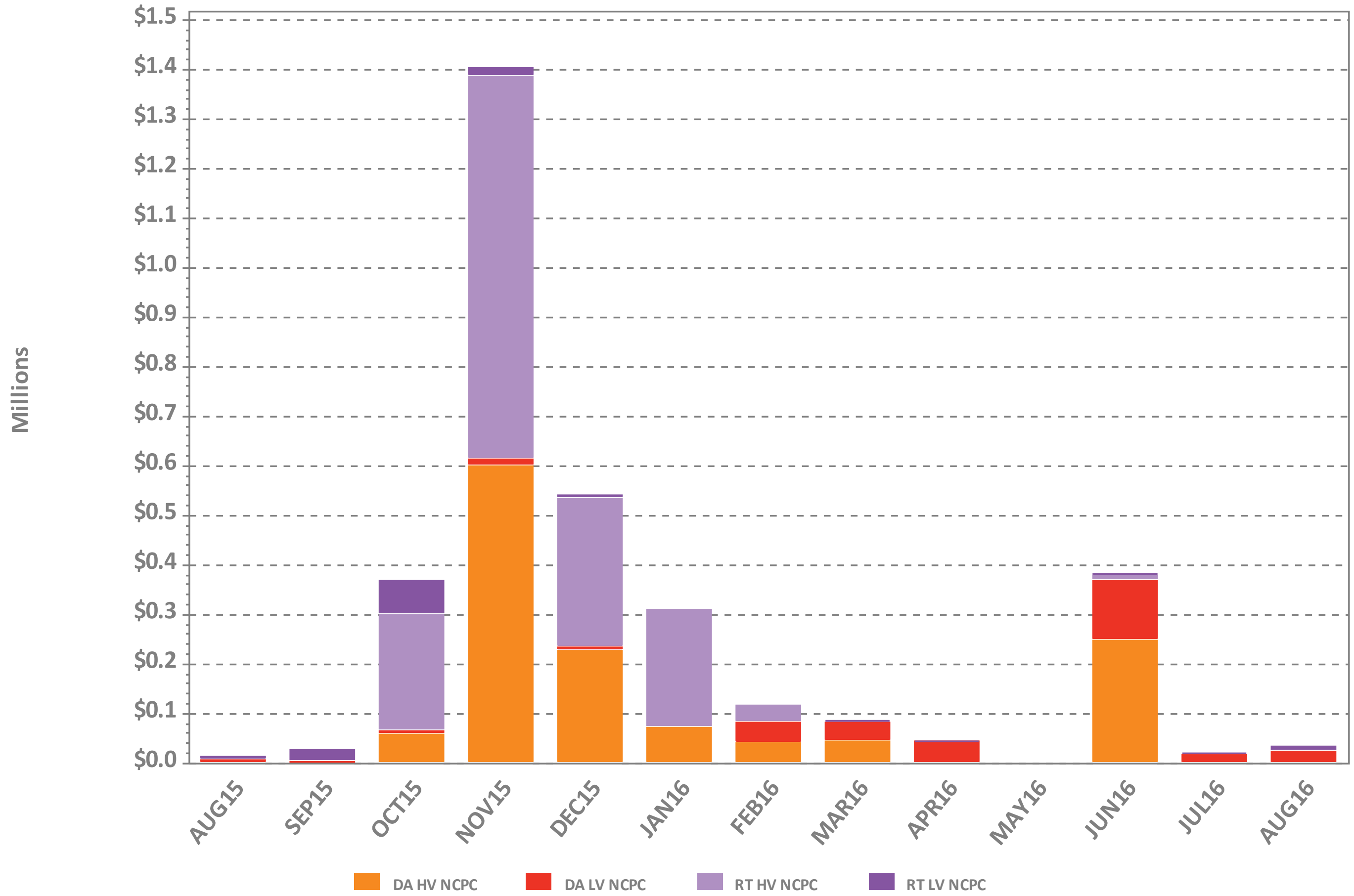
LSCPR Charges by Zone



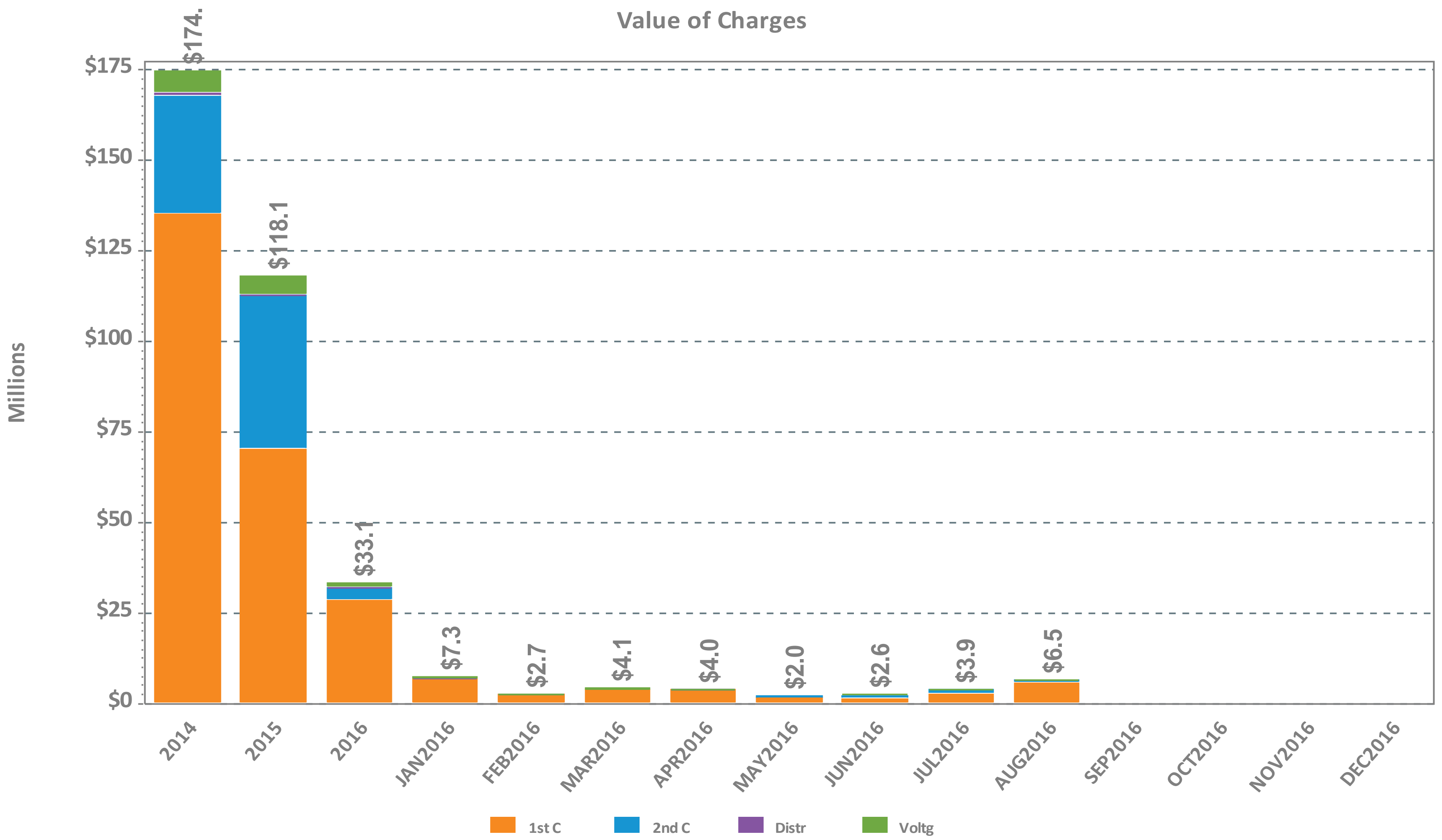
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

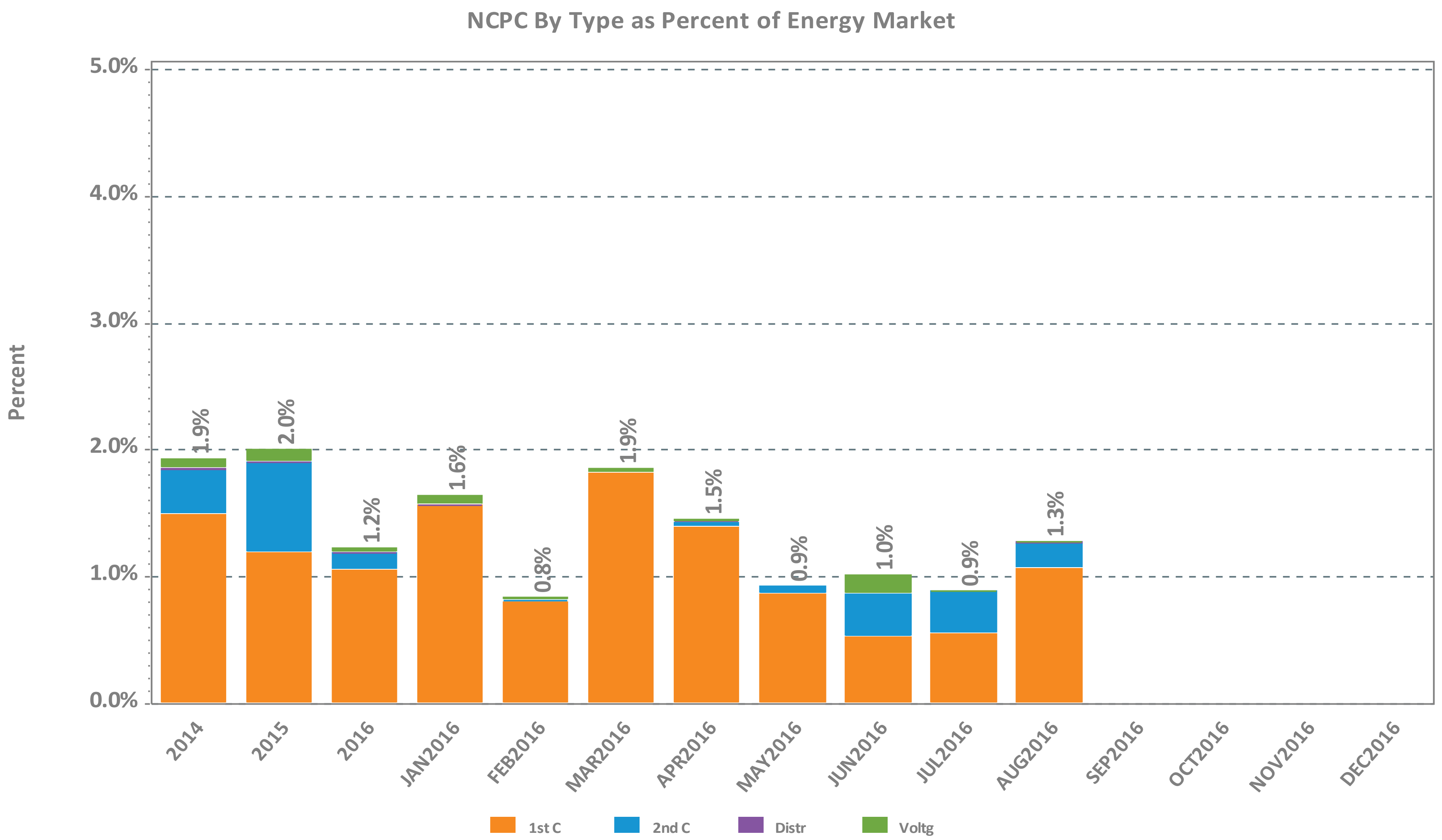
NCPC Charges for Voltage Support and High Voltage Control



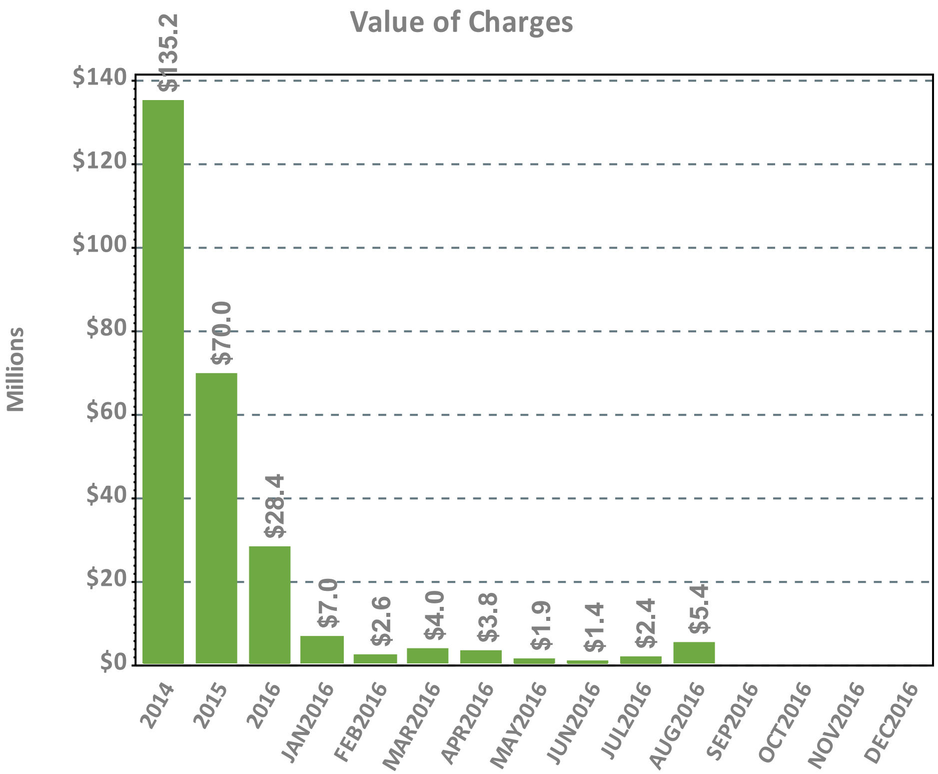
NCPC Charges by Type

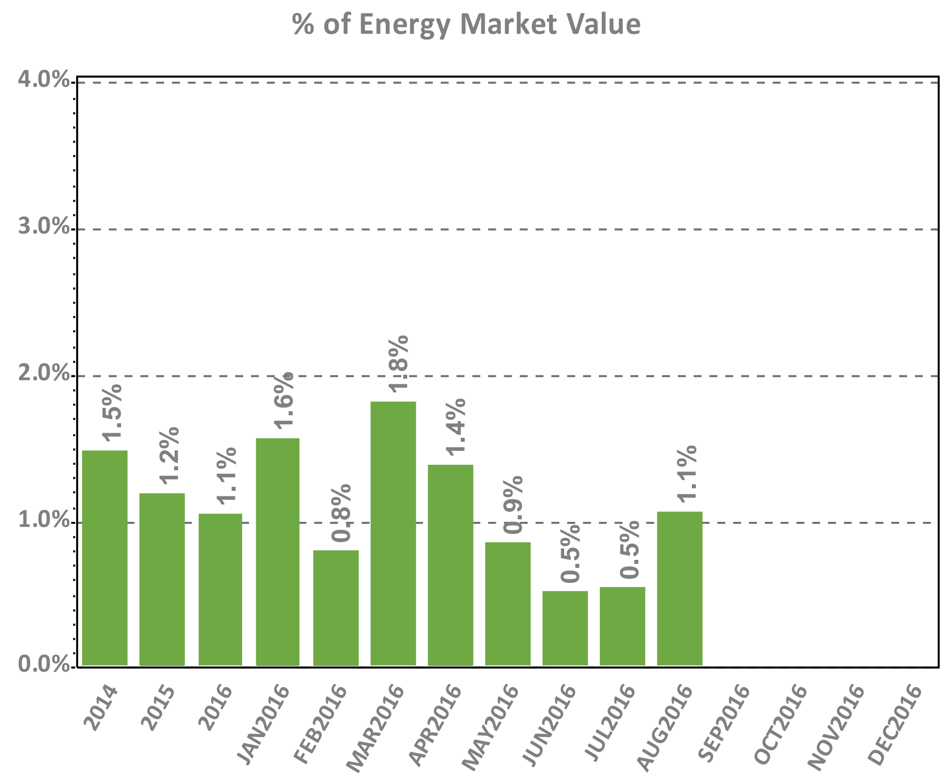


NCPC Charges as Percent of Energy Market



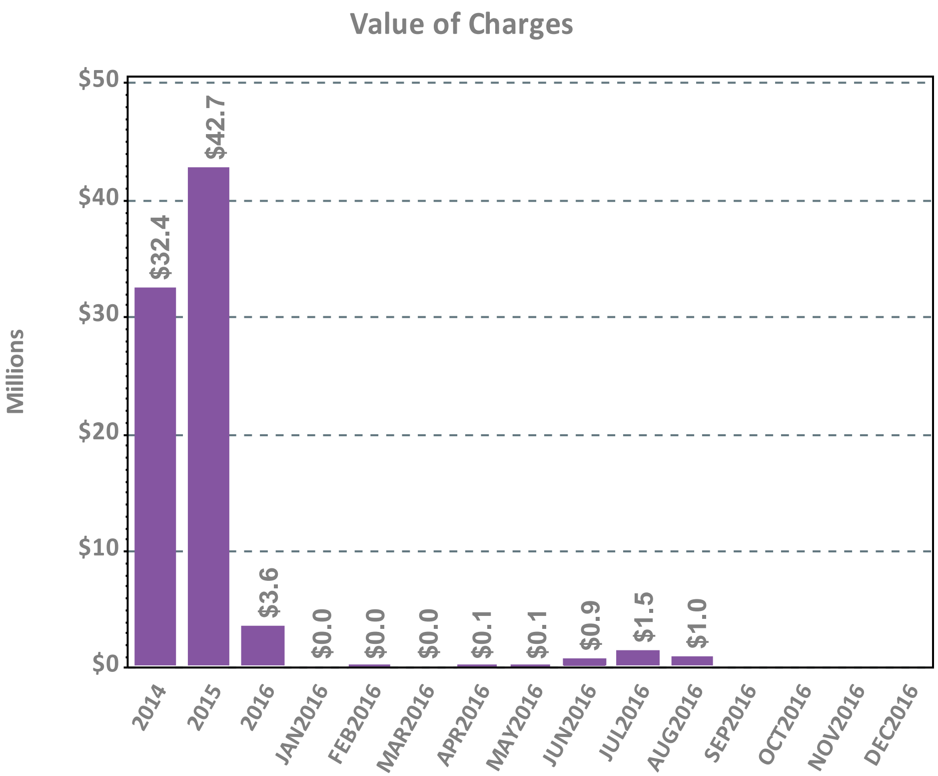
First Contingency NCPC Charges

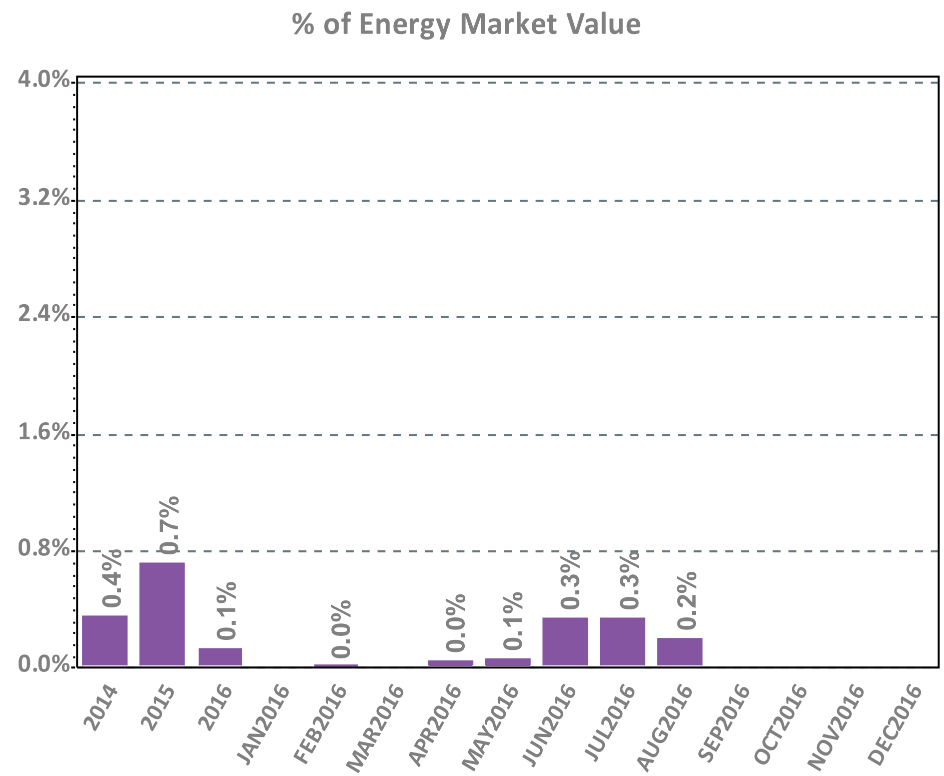




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

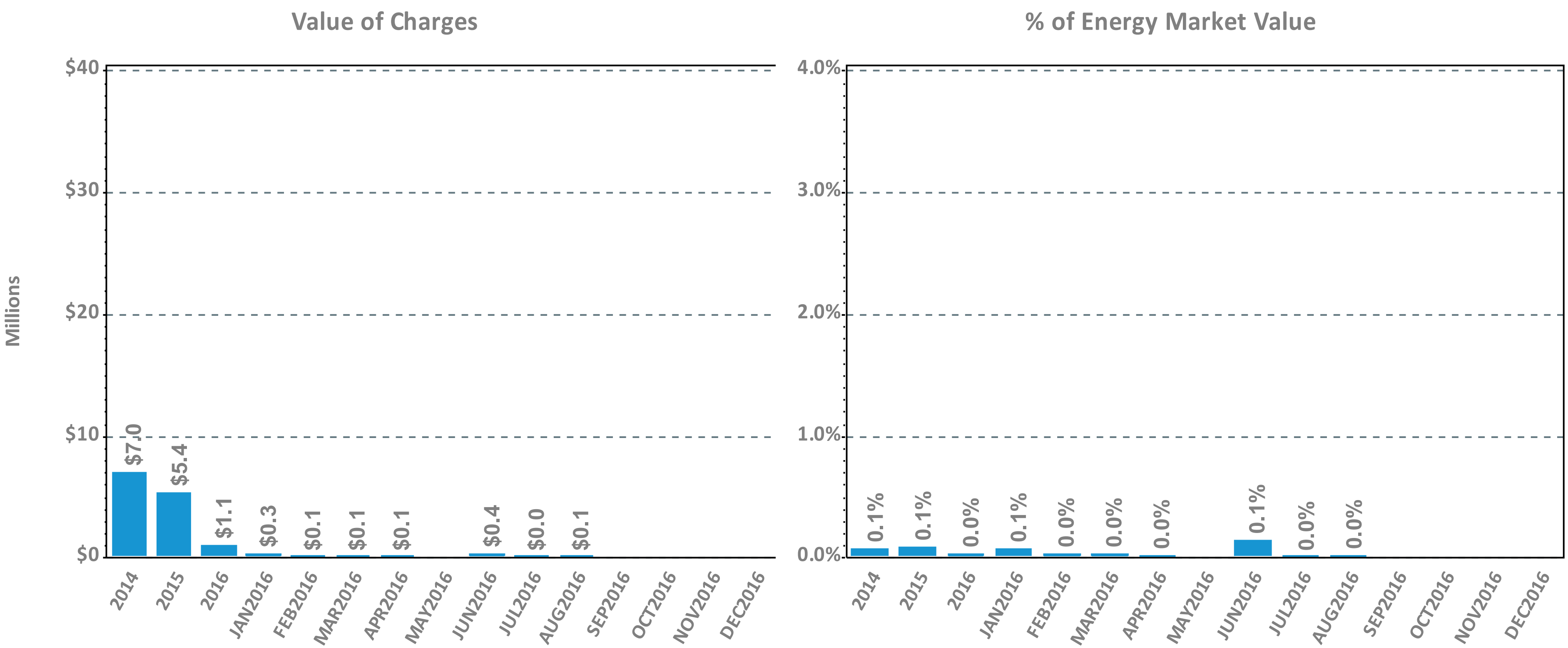
Second Contingency NCPC Charges





Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

DA vs. RT Pricing

The following slides outline:

- This month vs. prior year’s average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

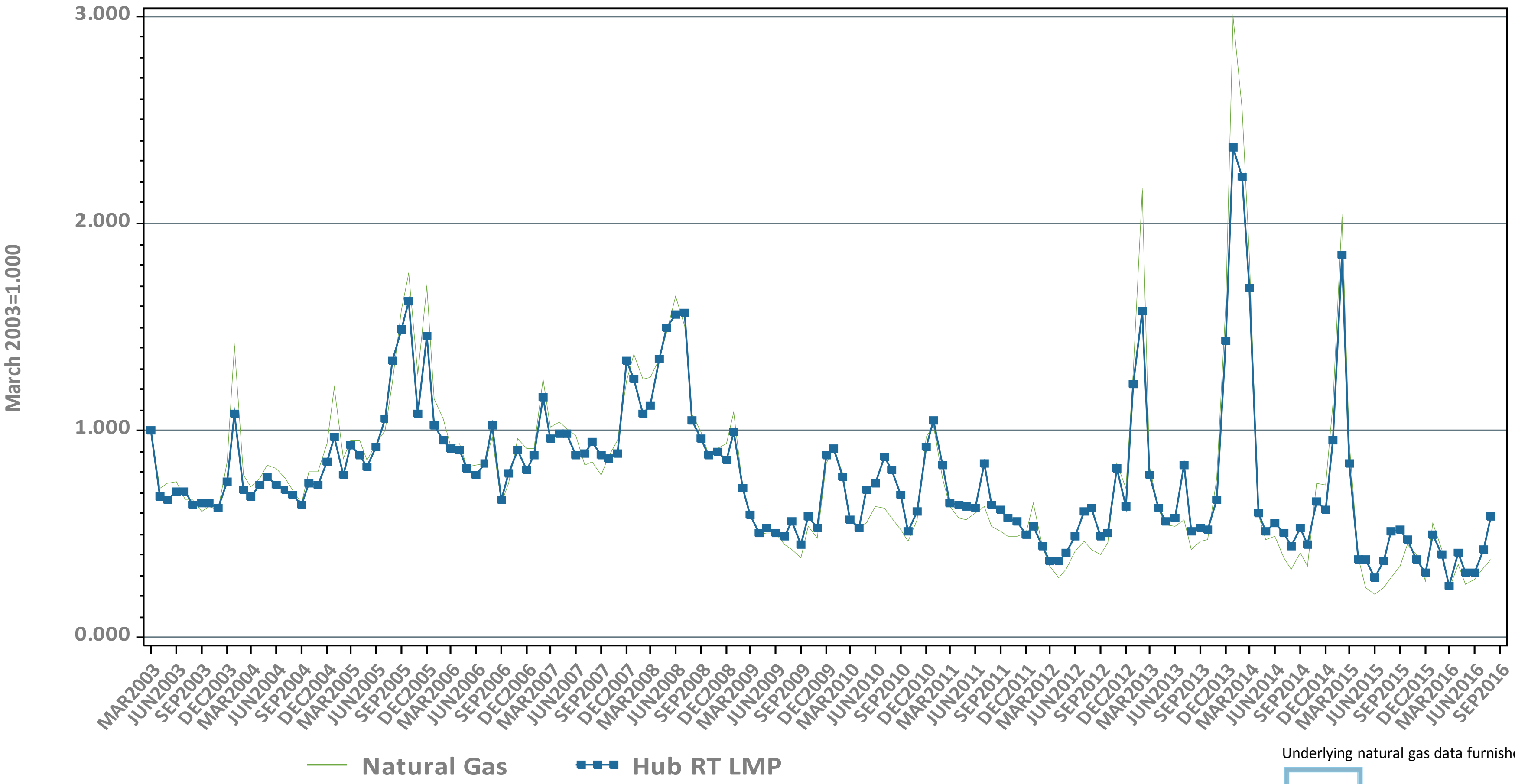
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2014	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$64.98	$64.10	$61.95	$64.12	$63.82	$64.98	$64.71	$64.66	$64.57
Real-Time	$64.03	$63.11	$59.04	$61.48	$61.60	$63.34	$63.45	$63.29	$63.32
RT Delta %	-1.5%	-1.5%	-4.7%	-4.1%	-3.5%	-2.5%	-2.0%	-2.1%	-1.9%
Year 2015	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$42.56	$41.23	$40.81	$42.11	$41.58	$42.20	$42.23	$41.93	$41.90
Real-Time	$41.58	$40.58	$39.23	$40.21	$40.22	$41.03	$41.21	$40.96	$41.00
RT Delta %	-2.3%	-1.6%	-3.9%	-4.5%	-3.3%	-2.8%	-2.4%	-2.3%	-2.2%

June-15	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$30.08	$30.27	$30.77	$34.82	$30.32	$29.86	$30.04	$30.19	$30.06
Real-Time	$35.55	$35.60	$34.80	$35.41	$35.35	$35.13	$35.43	$35.43	$35.35
RT Delta %	18.2%	17.6%	13.1%	1.7%	16.6%	17.6%	18.0%	17.3%	17.6%
June-16	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$35.55	$35.62	$34.52	$35.41	$35.67	$35.38	$35.76	$35.63	$35.54
Real-Time	$41.09	$40.63	$37.86	$39.35	$39.91	$40.07	$40.25	$40.30	$40.19
RT Delta %	15.6%	14.0%	9.7%	11.1%	11.9%	13.3%	12.6%	13.1%	13.1%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	18.2%	17.7%	12.2%	1.7%	17.6%	18.5%	19.0%	18.0%	18.2%
Yr over Yr RT	15.6%	14.1%	8.8%	11.1%	12.9%	14.1%	13.6%	13.8%	13.7%

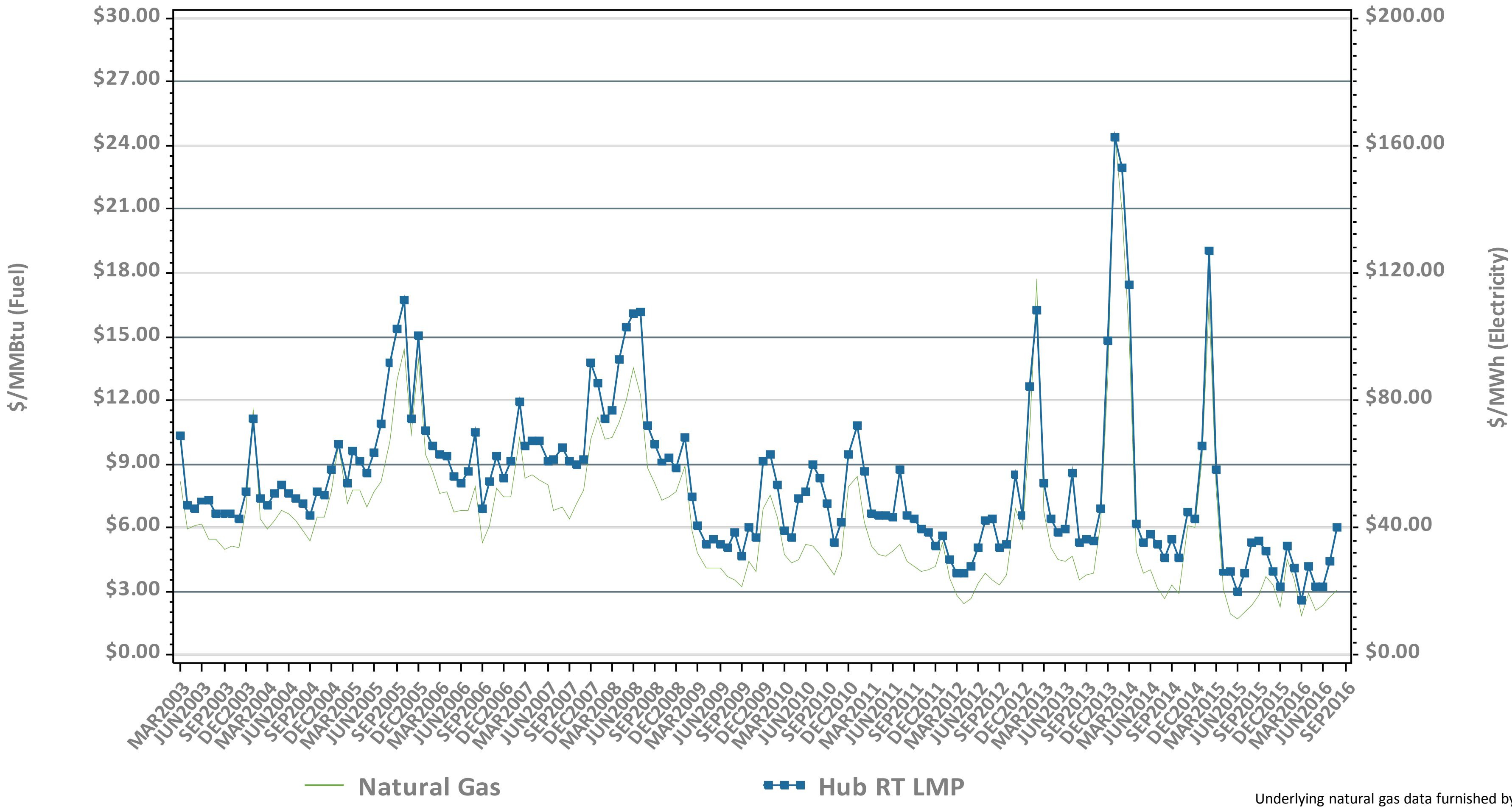
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

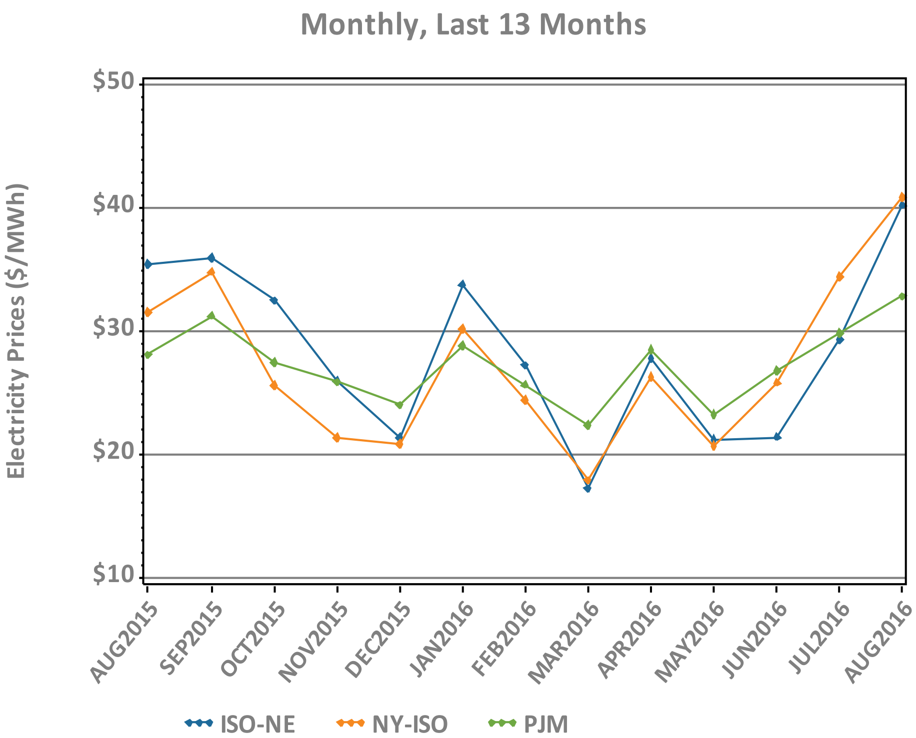
Monthly Average Fuel Price and RT Hub LMP



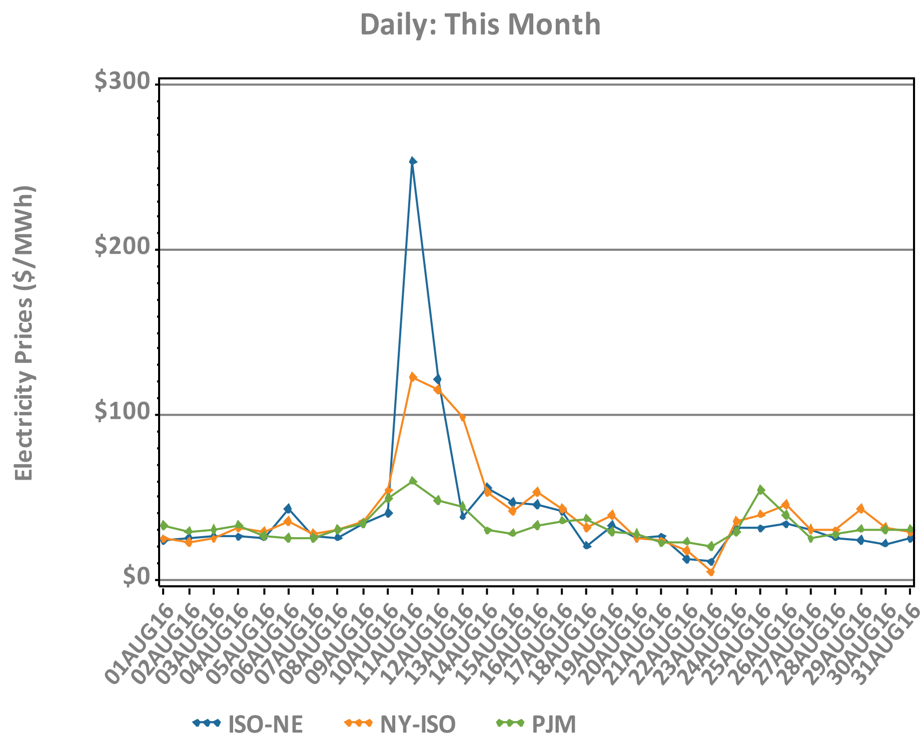
Underlying natural gas data furnished by:

ICE Global markets in clear view

New England, NY, and PJM Real Time Prices

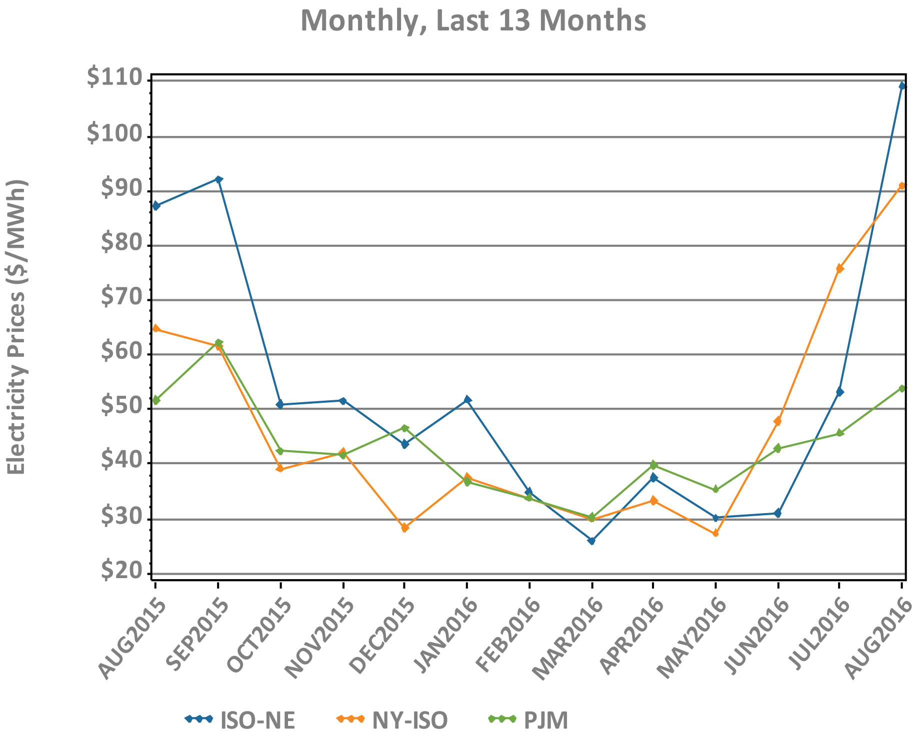


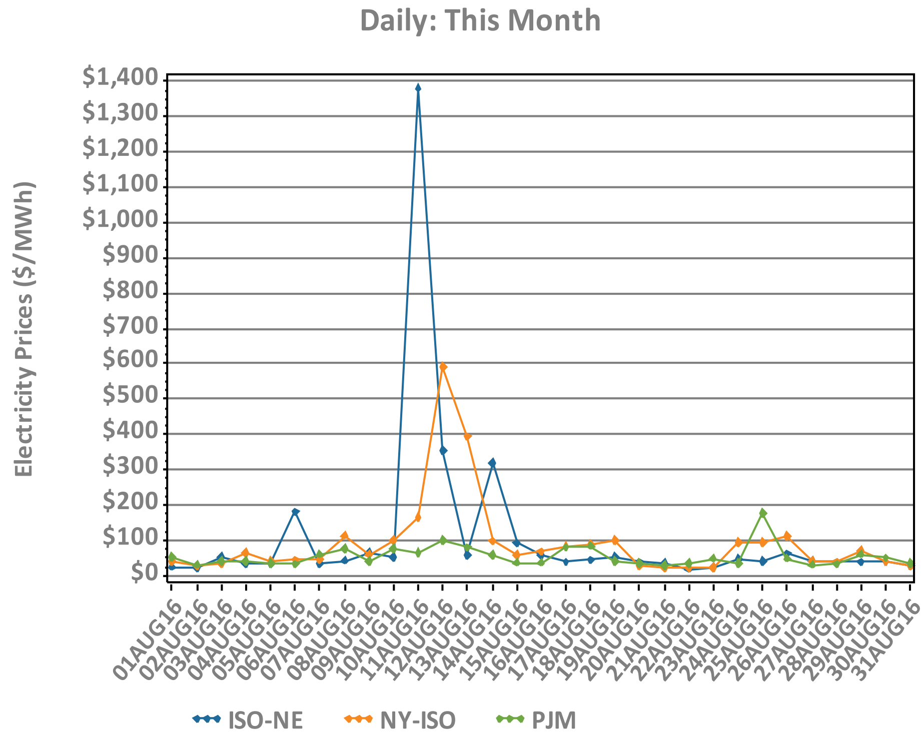
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Real Time Prices (Peak Hour)





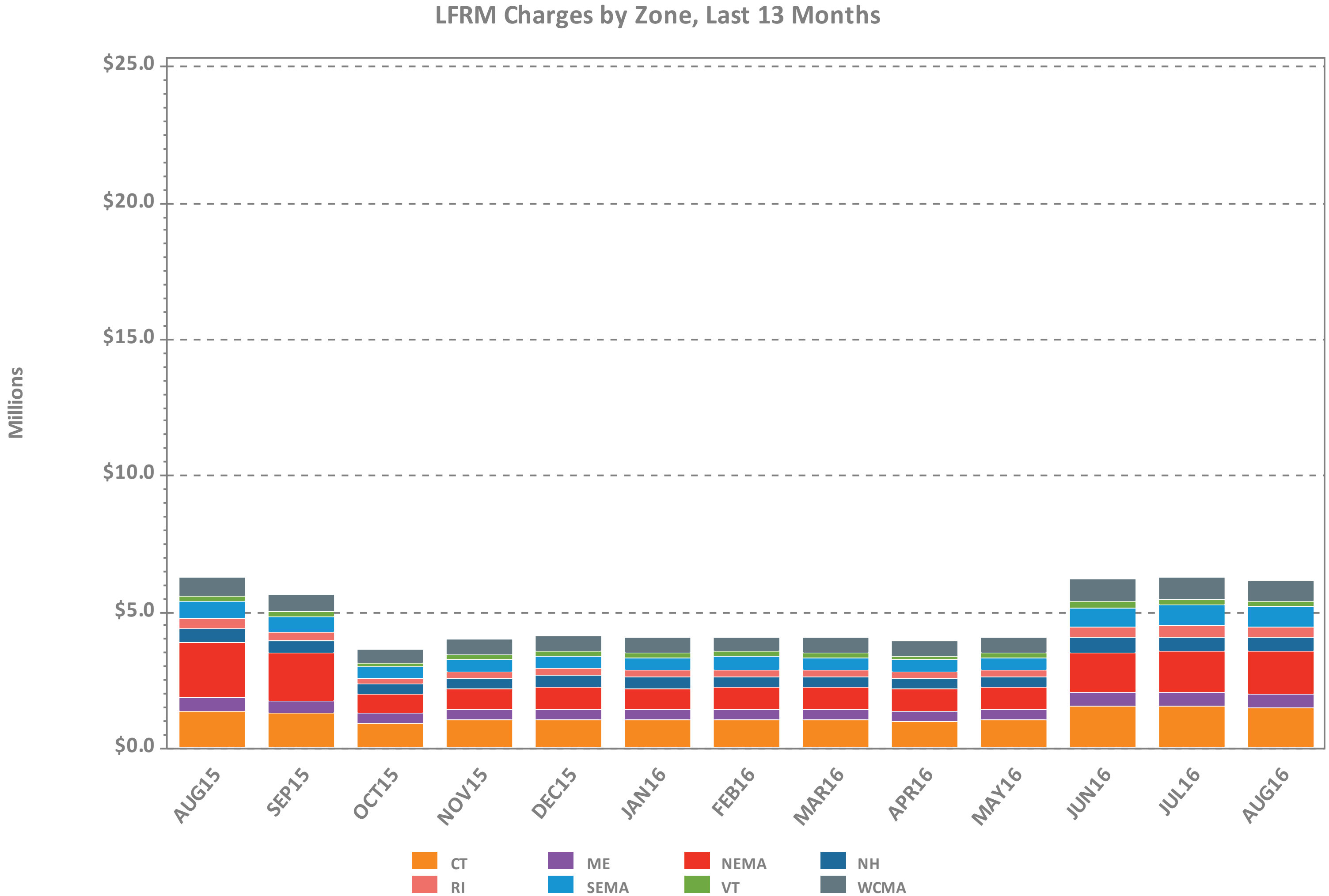
***Forecasted New England peak hour is reflected.**

Reserve Market Results – August 2016

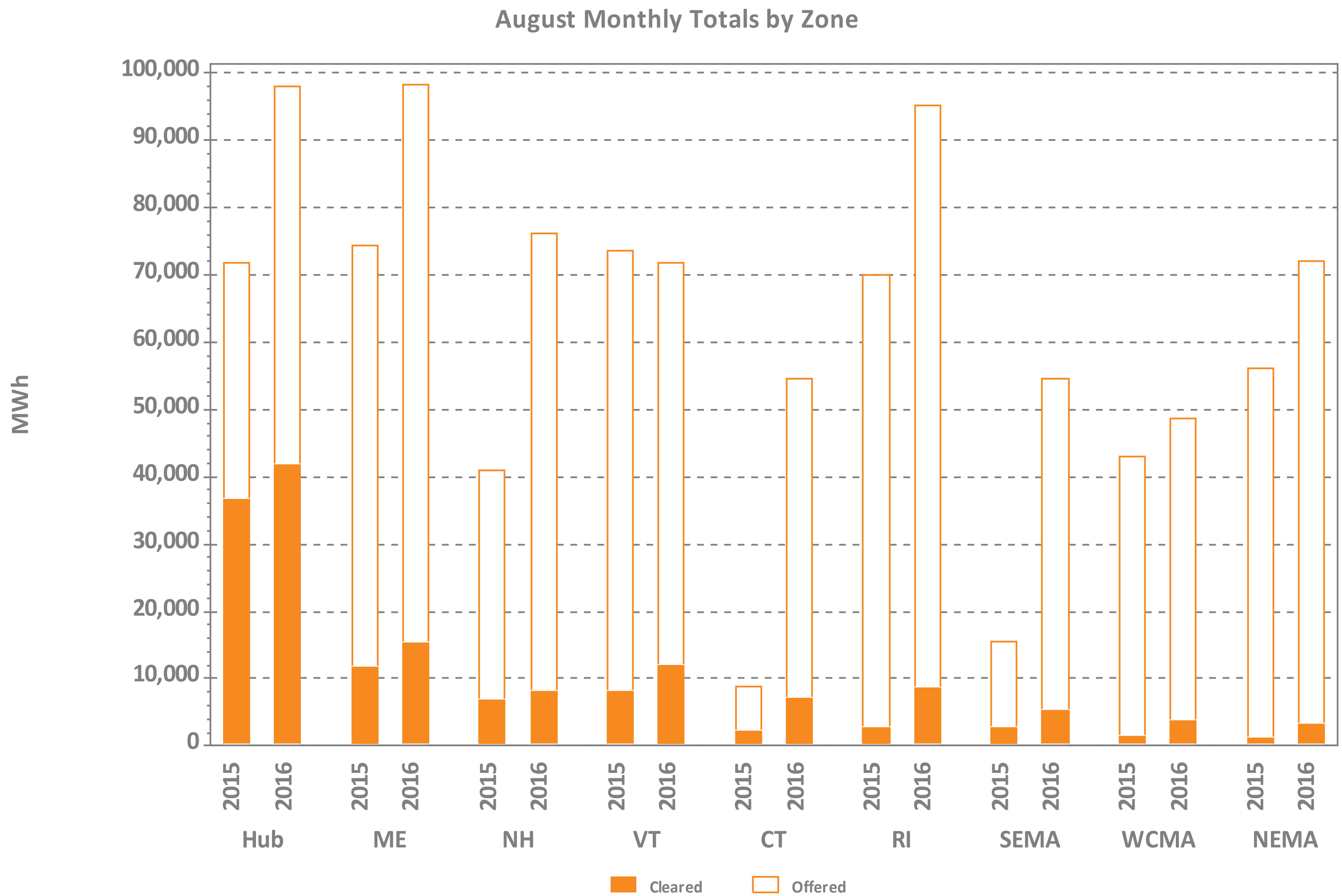
- Maximum potential Forward Reserve Market payments of $7.2M were reduced by credit reductions of $0.3M, failure-to-reserve penalties of $0.8M and failure-to-activate penalties of $0, resulting in a net payout of $6.1M or 85% of maximum
  - Rest of System: $1.8M/2M (93)%
  - Southwest Connecticut: $0.5M/0.7M (70)%
  - Connecticut: $1.6M/1.7M (98)%
  - NEMA: $2.2M/2.9M (76)%
- $11.6M total Real-Time credits were reduced by $2.5M in Forward Reserve Energy Obligation Charges for a net of $9.1M in Real-Time Reserve payments
  - Rest of System: 90 hours, $7.0M
  - Southwest Connecticut: 90 hours, $693K
  - Connecticut: 90 hours, $1.1M
  - NEMA: 90 hours, $292K

*** "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market.**

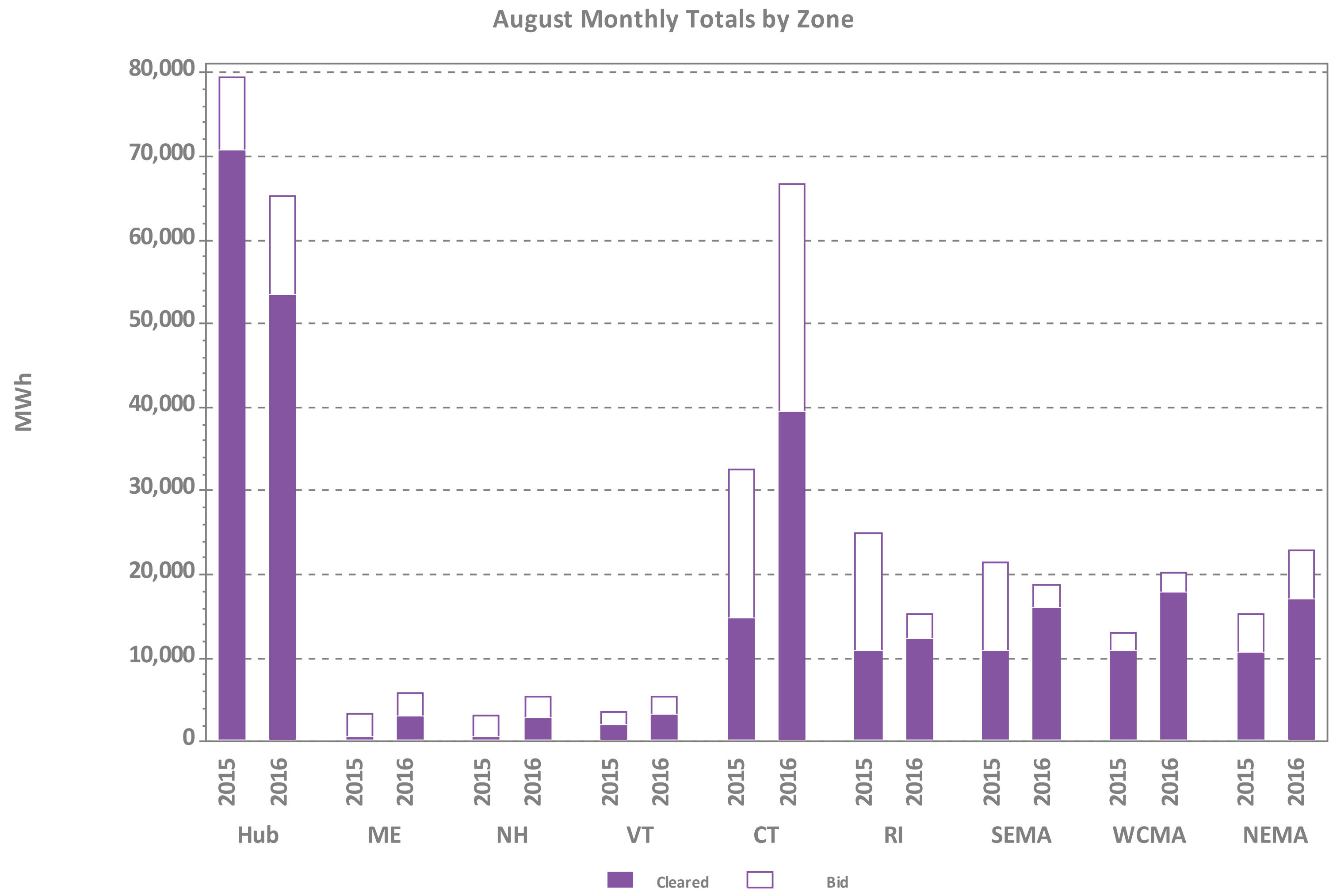
LFRM Charges to Load by Load Zone ($)



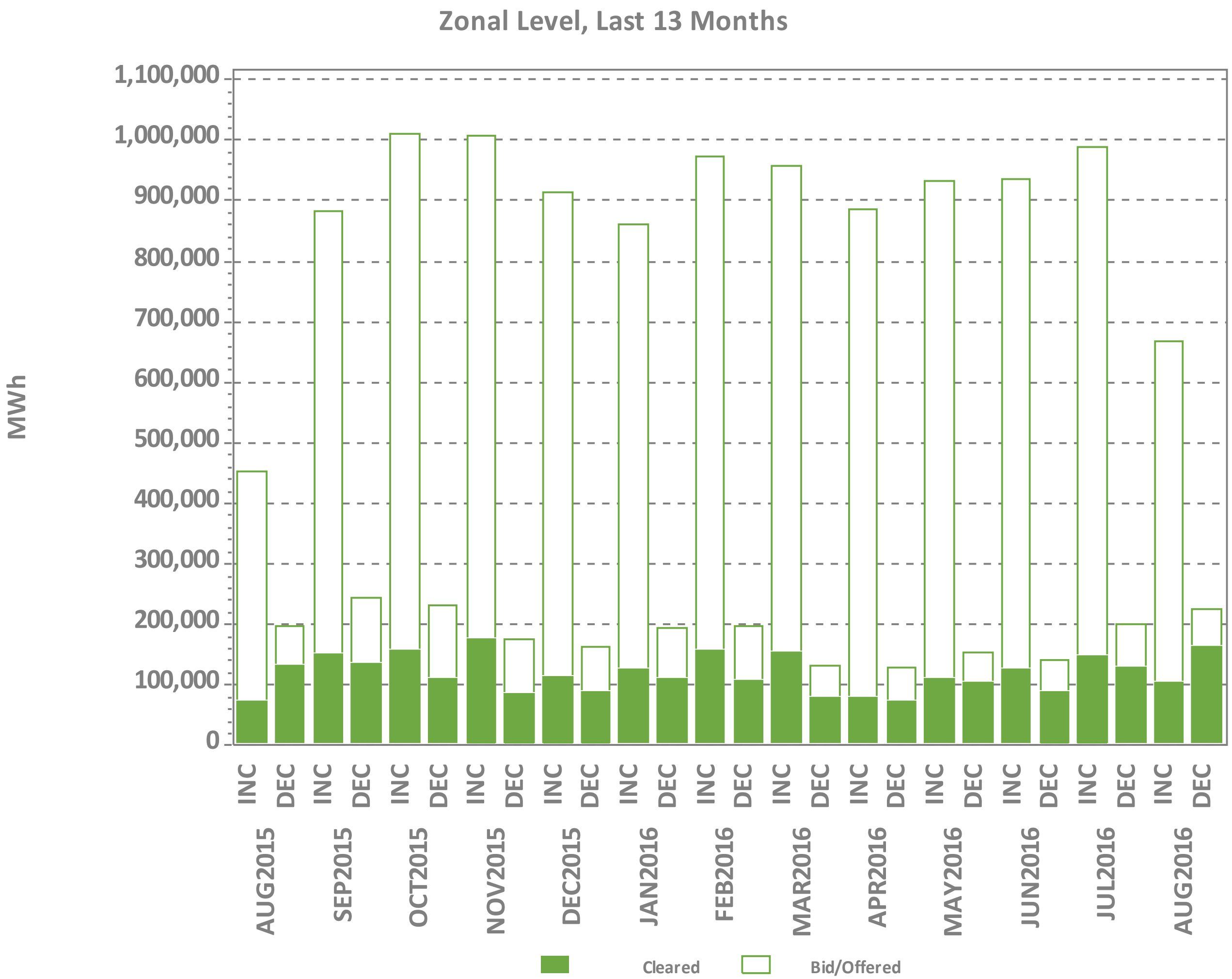
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

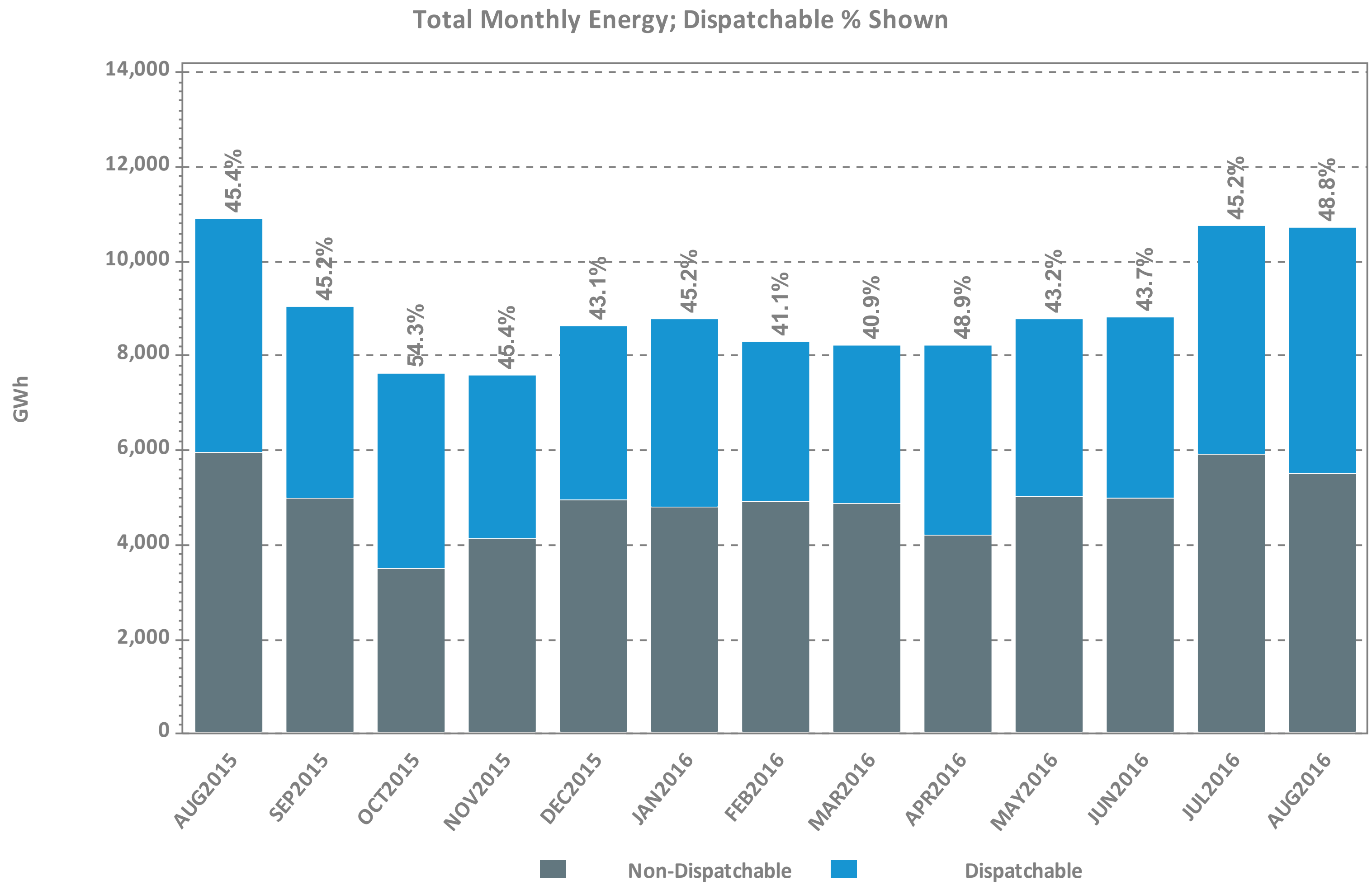


Total Increment Offers and Decrement Bids



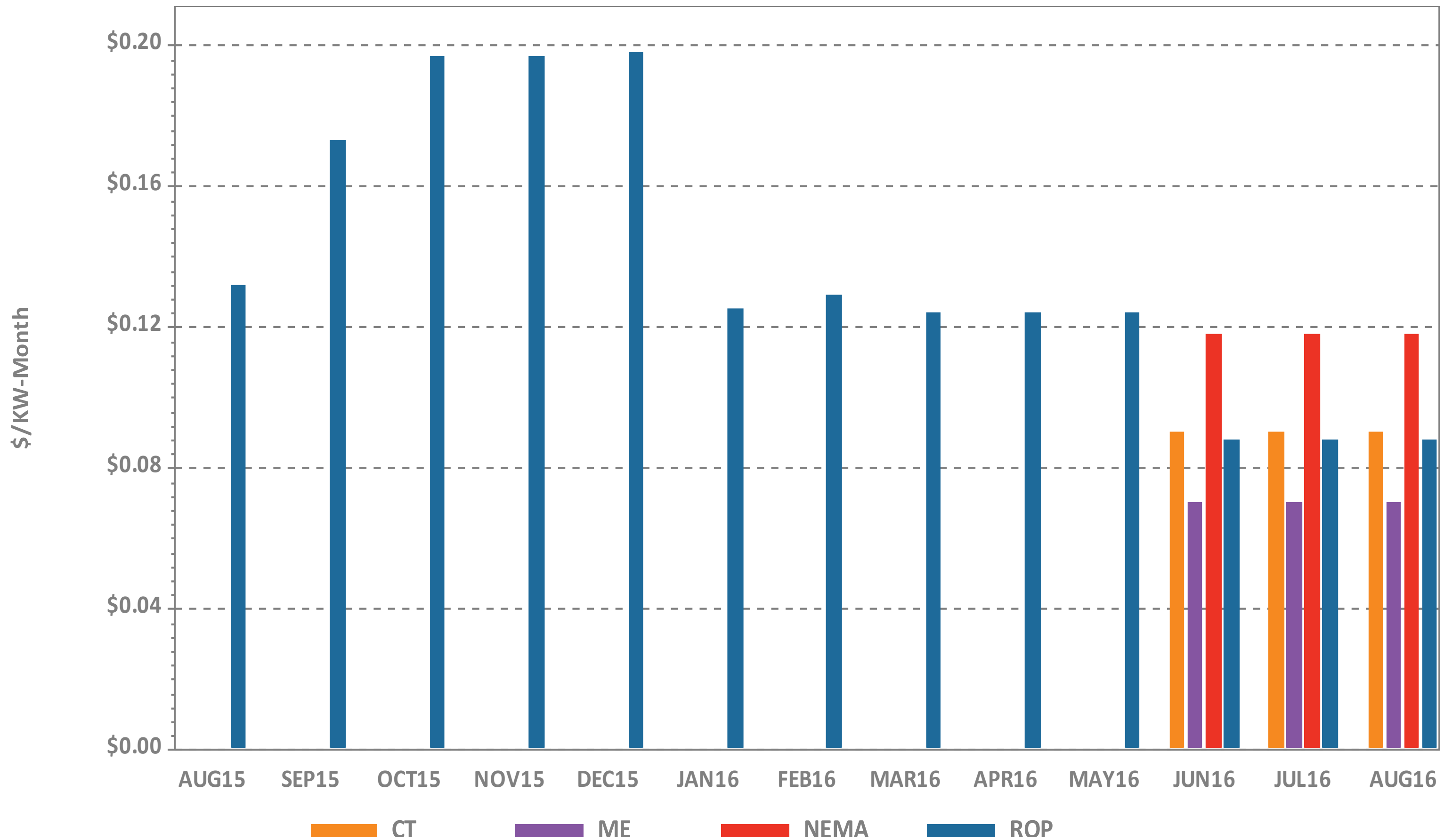
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



* Dispatchable MWh here are defined to be generation output that is not self-scheduled (i.e, not self-committed or 'must run' by the customer).

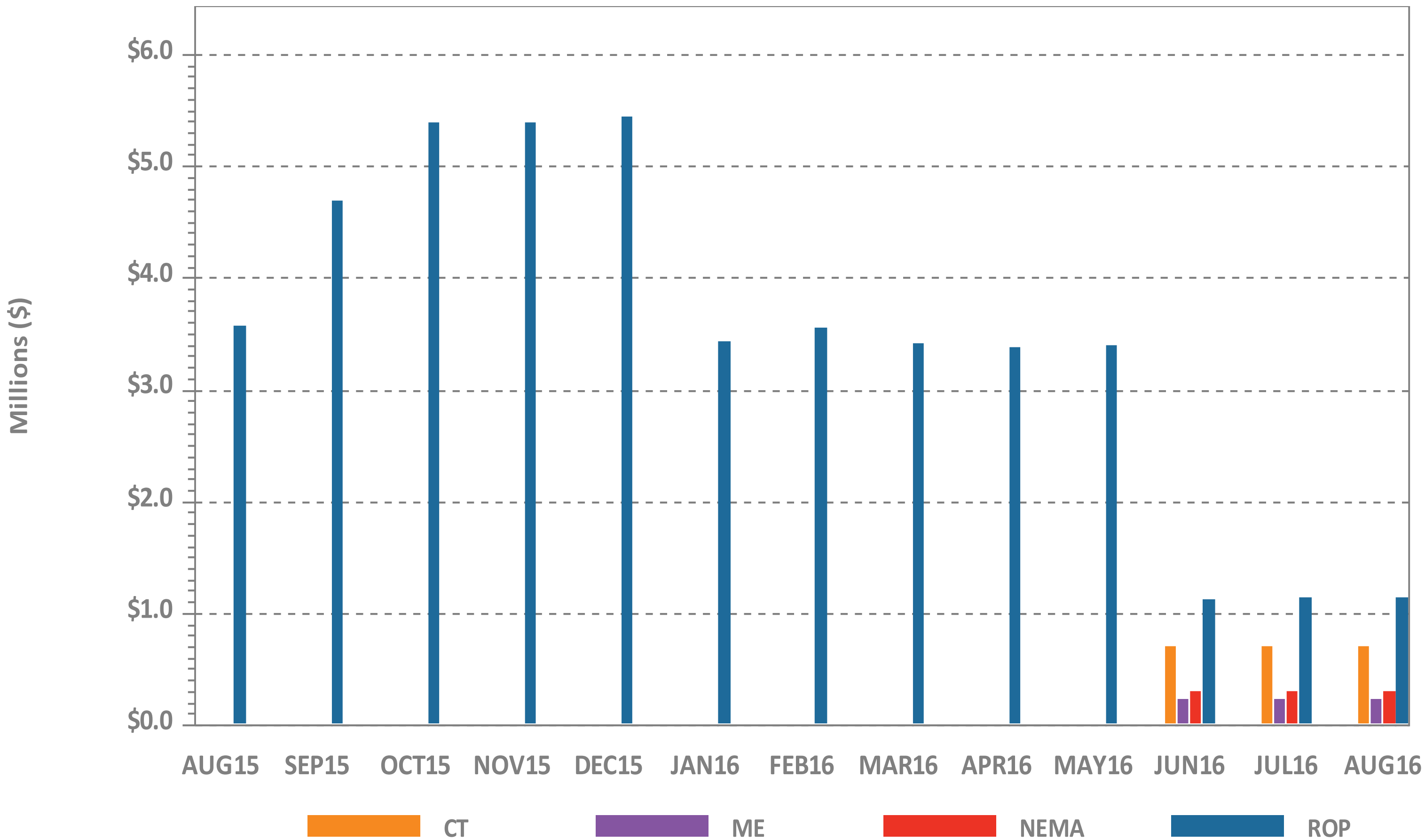
Rolling Average Peak Energy Rent (PER)



Rolling Average PER is currently calculated as a rolling twelve month average of individual monthly PER values for the twelve months preceding the obligation month.

Individual monthly PER values are published to the ISO web site here: Home > Markets > Other Markets Data > Forward Capacity Market > Reports and are subject to resettlement.

PER Adjustments



PER Adjustments are reductions to Forward Capacity Market monthly payments resulting from the rolling average PER. Impact of August 11 FCM Shortage Event <u>not</u> reflected until next month.

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- September 21 PAC Meeting Agenda
  - 2016 Economic Study - Draft Results, continued
  - UI Coastal Substation Flood Mitigation Study
  - Eastern Connecticut 2022 Solution Study Update
  - Planning Process Guide Update
  - Keene Road Market Efficiency Transmission Upgrade Needs Assessment Scope of Work
  - Maine Resource Integration Study

Load, Energy Efficiency and Photovoltaic Forecast

- Load Forecast
  - 2016 ten-year load forecast is documented in the 2016 CELT
  - Preparations for preparing the 2017 ten-year forecast have begun
  - Next Load Forecast Committee meeting will be December 16
- Energy Efficiency Forecast
  - Data collection process has began and next working group meeting will be held on September 9
- Photovoltaic Forecast
  - The next Distributed Generation Forecast Working Group meeting is scheduled for December 16 (rescheduled from October 21)

Environmental Matters

- EAG meeting scheduled for September 6 to discuss regulatory updates including:
  - 2016 Regional Greenhouse Gas Initiative (RGGI) program review
    - States considering extending a 2.5% annual reduction target through 2020, or adopting 5% annual reduction target
    - Review expected to end in early 2017
  - RGGI published 2014 emissions report showing increased CO2 emissions from smaller generators in New England
  - 2016 summer ozone season exceedances (YTD) appears considerably worse than five-year average (CT particularly affected)
  - CT and MA pursuing additional NOx control rules affecting various classes of generators
  - Follow-up on ISO actions regarding RTEGs after EPA prohibited their use under OP-4 after May 2016

Economic Studies and Keene Road Market Efficiency Transmission Upgrade Needs Assessment

- 2016 Economic Study - NEPOOL Scenario Analysis
  - Draft Phase I results were discussed at the August 17 PAC meeting
  - Discussions of additional metrics are scheduled for the September 21 PAC meeting
  - Overall project remains on schedule to complete Phase I production cost analysis by the end of 2016 and to begin Phase II analysis in 1st quarter 2017
- Final 2015 Economic Studies Posted
  - Evaluation of Increasing the Keene Road Export Limit
  - Evaluation of Offshore Wind Development
  - Strategic Transmission Analysis - Onshore Wind Integration
- Keene Road Market Efficiency Transmission Upgrade needs assessment scope of work to be discussed at the September 21 PAC meeting

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

Connecticut River Valley

Status as of 9/1/16

Project Benefit: Addresses system needs in the Connecticut River Corridor in Vermont

Upgrade	Expected In-Service	Present Stage
Rebuild 115 kV line K31, Coolidge-Ascutney	May-18	2
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	May-18	2
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	April-17	2
Chelsea Station - Rebuild to a three-breaker ring bus	Oct-17	2

Note: The above listing focuses on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades

Status as of 9/1/16

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	3
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Dec-16	3
New 115 kV overhead line, Scobie Pond-Huse Road	Nov-15	4*
New 115 kV overhead/submarine line, Madbury-Portsmouth	Jun-18	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 9/1/16

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Aug-16	4
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Apr-15	4*
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 9/1/16

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Mar-15	4*
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Jun-17	3
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Dec-17	2
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Dec-17	2
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-16	4**
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Dec-17	2
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Dec-17	2
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	2

*Replaces the NEEWS Central Connecticut Reliability Project

**Placed in-service ahead of schedule

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	2
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-18	2
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	2
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-17	2
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-18	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	2
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	2
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	2
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-17	2
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	2
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-17	2
Add a new 115 kV line from Frost Bridge to Campville	Jun-18	2
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-18	2
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Mar-17	3
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-16	4**
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-16	4**
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-16	4**

* Replaces the NEEWS Central Connecticut Reliability Project

** Placed in-service ahead of schedule

Southwest Connecticut (SWCT) Projects

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Dec-16	4*
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-17	2
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	2
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration	Dec-18	1
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	3
Loop the 1990 line in and out the Bunker Hill substation	Dec-18	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Dec-17	2
Loop the 1570 line in and out the Pootatuck substation	Dec-17	2
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	1
Add a new 115 kV line from Plumtree to Brookfield Junction	Dec-18	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-18	1
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-18	1
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-18	1
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-18	1
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-18	2
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-18	1

Southwest Connecticut Projects, cont.

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Dec-17	2
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-16	4*
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4*
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Dec-16	3
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	1
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	1

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4*
Upgrade the 115 kV bus at the Baird substation	May-18	2
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Apr-19	2
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-20	1

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Remove the Sackett phase shifter	Mar-17	2
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Jan-17	3
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Jan-17	3
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers	Dec-18	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	2
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Nov-16	3
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	2
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Dec-17	3
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	3
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	3
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-17	2
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn	Dec-18	2
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Dec-17	2

Greater Boston Projects, cont.

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-17	2
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	3
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-19	2
Install third 115 kV line from West Walpole to Holbrook	Sep-19	2
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	3
Install a new 115 kV line from Sudbury to Hudson	May-19	1

Greater Boston Projects, cont.

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-17	3
Install a 345 kV breaker in series with breaker 104 at Woburn	Dec-16	3
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	3
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	3
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	3
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	Jun-18	3
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jun-19	2
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-18	2

Greater Boston Projects, cont.

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-18	2
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station	Dec-18	1
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Dec-17	2
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	3

Greater Boston Projects, cont.

Status as of 9/1/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	May-17	3
Install a 200 MVAR STATCOM at Coopers Mills	Sep-18	1
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	2
Install a 345 kV 160 MVAR shunt reactor at K Street	May-18	1
Install a 115 kV breaker in series with the 5 breaker at Framingham	Jun-17	3
Install a 115 kV breaker in series with the 29 breaker at K Street	Mar-17	3

Pittsfield/Greenfield Projects

Status as of 9/1/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Mar-17	3
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Mar-17	3
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Dec-16	3
Build a new 115 kV three-breaker switching station (Erving) ring bus	Dec-16	3
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Dec-16	3
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 9/1/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	3
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Mar-17	3
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

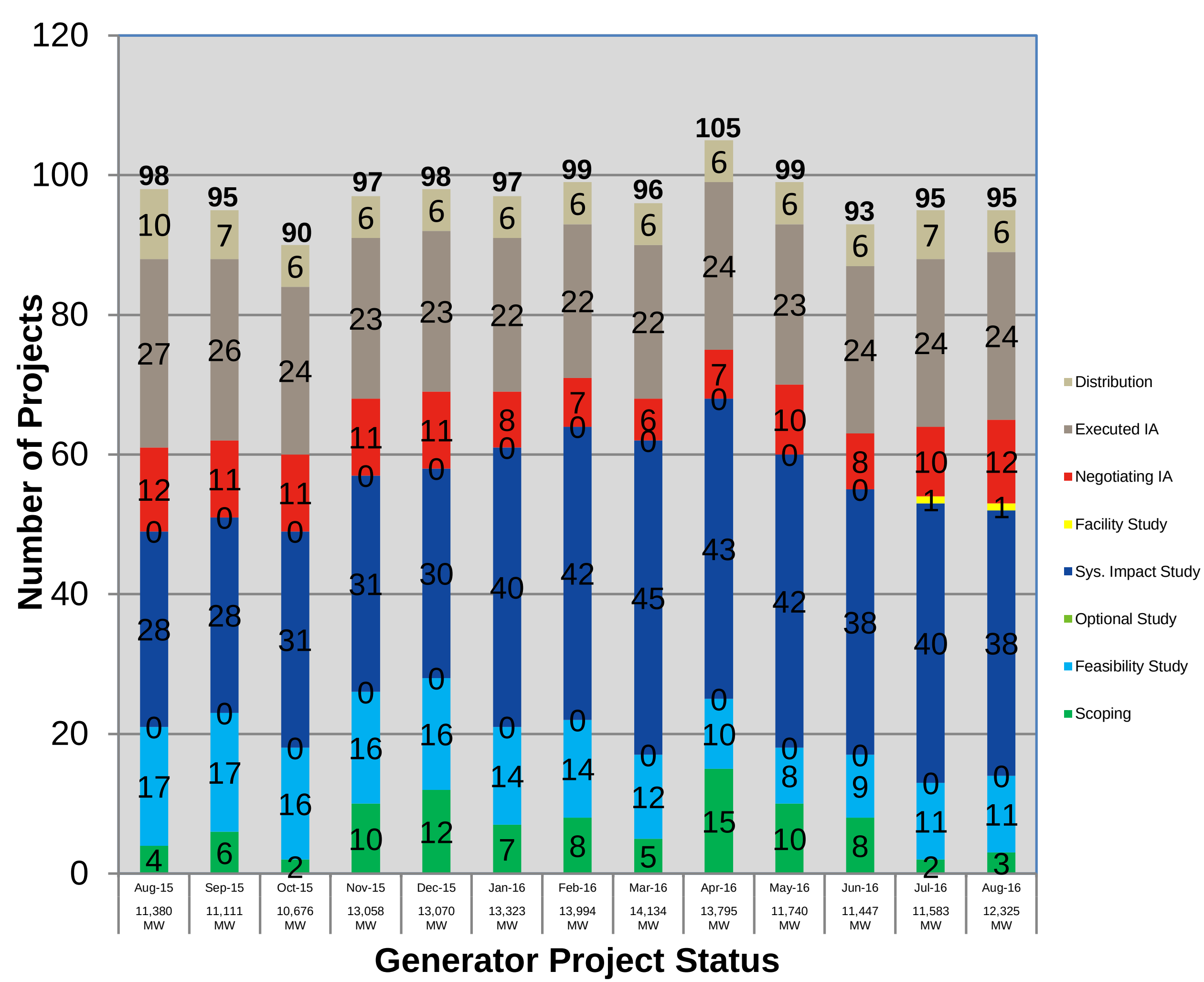
Pittsfield/Greenfield Projects, cont.

Status as of 9/1/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Dec-17	1
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	1
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	1
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Dec-19	1

Status of Tariff Studies



Note: As of August 2016, there are 11 ETU's in SIS, 2 in FS, and 1 in Neg. IA

https://irtt.iso-ne.com/external.aspx

OPERABLE CAPACITY ANALYSIS

Fall 2016

Fall 2016 Operable Capacity Analysis

50/50 Load Forecast (Reference)	September - 2016[2] CSO	September - 2016[2] SCC
Generator Operable Capacity MW [1]	29,914	30,228
OP CAP From OP-4 RTDR (+)	293	293
OP CAP From OP-4 RTEG (+)	35	35
Operable Capacity Generator with OP-4 DR and RTEG	30,242	30,556
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	898	898
Non Commercial Capacity (+)	3	3
Non Gas-fired Planned Outage MW (-)	2,201	2,417
Gas Generator Outages MW (-)	1,243	1,252
Allowance for Unplanned Outages (-) [5]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	25,599	25,688
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,553	22,553
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,858	24,858
Operable Capacity Margin [3]	741	830

[1] Generator Operable Capacity is based on data as of **August 16, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, Photo Voltaic, and external capacity. SCC value is based on data as of **August 16, 2016**

[2] Load based on 2016 CELT report and week with lowest Operable Capacity Margin, week beginning **September 17, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Fall 2016 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	September - 2016[2] CSO	September - 2016[2] SCC
Generator Operable Capacity MW [1]	29,914	30,228
OP CAP From OP-4 RTDR (+)	293	293
OP CAP From OP-4 RTEG (+)	35	35
Operable Capacity Generator with OP-4 DR and RTEG	30,242	30,556
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	898	898
Non Commercial Capacity (+)	3	3
Non Gas-fired Planned Outage MW (-)	2,201	2,417
Gas Generator Outages MW (-)	1,243	1,252
Allowance for Unplanned Outages (-) [5]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	25,599	25,688
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,555	24,555
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,860	26,860
Operable Capacity Margin [3]	(1,261)	(1,172)

[1] Generator Operable Capacity is based on data as of **August 16, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, Photo Voltaic, and external capacity. SCC value is based on data as of **August 16, 2016**

[2] Load based on 2016 CELT report and week with lowest Operable Capacity Margin, week beginning **September 17, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Fall 2016 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2016 OPERABLE CAPACITY ANALYSIS

September 9, 2016 - 50/50 FORECAST using CSO values with RTDR and RTEG

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
9/10/2016	29,914	1,017	3	52	241	2,100	0	28,541	26,704	2,305	29,009	(468)	293	(175)	35	(140)
9/17/2016	29,914	898	3	2,201	1,243	2,100	0	25,271	22,553	2,305	24,858	413	293	706	35	741
9/24/2016	29,914	712	3	2,222	772	2,100	0	25,535	22,458	2,305	24,763	772	293	1,065	35	1,100
10/1/2016	29,964	1,037	3	5,823	1,242	2,800	0	21,139	16,240	2,305	18,545	2,594	372	2,966	184	3,150
10/8/2016	29,964	1,037	3	5,557	1,237	2,800	0	21,410	16,276	2,305	18,581	2,829	372	3,201	184	3,385
10/15/2016	29,964	1,137	3	5,917	1,237	2,800	0	21,150	17,233	2,305	19,538	1,612	372	1,984	184	2,168
10/22/2016	29,964	1,037	15	4,796	943	2,800	0	22,477	17,610	2,305	19,915	2,562	372	2,934	184	3,118
10/29/2016	29,964	1,037	15	4,637	699	3,600	0	22,080	17,824	2,305	20,129	1,951	372	2,323	184	2,507
11/5/2016	29,964	1,037	15	4,314	2,016	3,600	0	21,086	17,943	2,305	20,248	838	372	1,210	184	1,394
11/12/2016	29,964	1,037	15	3,568	1,033	3,600	0	22,815	18,300	2,305	20,605	2,210	372	2,582	184	2,766
11/19/2016	29,964	1,037	15	2,143	454	3,600	678	24,141	19,063	2,305	21,368	2,773	372	3,145	184	3,329
11/26/2016	29,964	1,037	15	487	454	3,600	1,583	24,892	19,808	2,305	22,113	2,779	372	3,151	184	3,335

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
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8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2016 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
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15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Fall 2016 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)

ISO-NE 2016 OPERABLE CAPACITY ANALYSIS

September 9, 2016 - 90/10 FORECAST using CSO values with RTDR and RTEG

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
9/10/2016	29,914	1,017	3	52	241	2,100	0	28,541	29,041	2,305	31,346	(2,805)	293	(2,512)	35	(2,477)
9/17/2016	29,914	898	3	2,201	1,243	2,100	0	25,271	24,555	2,305	26,860	(1,589)	293	(1,296)	35	(1,261)
9/24/2016	29,914	712	3	2,222	772	2,100	0	25,535	24,452	2,305	26,757	(1,222)	293	(929)	35	(894)
10/1/2016	29,964	1,137	3	5,823	1,242	2,800	0	21,239	16,781	2,305	19,086	2,153	372	2,525	184	2,709
10/8/2016	29,964	1,037	3	5,557	1,237	2,800	0	21,410	16,818	2,305	19,123	2,287	372	2,659	184	2,843
10/15/2016	29,964	1,037	3	5,917	1,237	2,800	0	21,050	17,804	2,305	20,109	941	372	1,313	184	1,497
10/22/2016	29,964	1,037	15	4,796	943	2,800	0	22,477	18,192	2,305	20,497	1,980	372	2,352	184	2,536
10/29/2016	29,964	1,037	15	4,637	699	3,600	0	22,080	18,412	2,305	20,717	1,363	372	1,735	184	1,919
11/5/2016	29,964	1,037	15	4,314	2,016	3,600	0	21,086	18,535	2,305	20,840	246	372	618	184	802
11/12/2016	29,964	1,137	15	3,568	1,033	3,600	843	22,072	18,902	2,305	21,207	865	372	1,237	184	1,421
11/19/2016	29,964	1,037	15	2,143	454	3,600	1,891	22,928	19,688	2,305	21,993	935	372	1,307	184	1,491
11/26/2016	29,964	1,037	15	487	454	3,600	3,063	23,412	20,456	2,305	22,761	651	372	1,023	184	1,207

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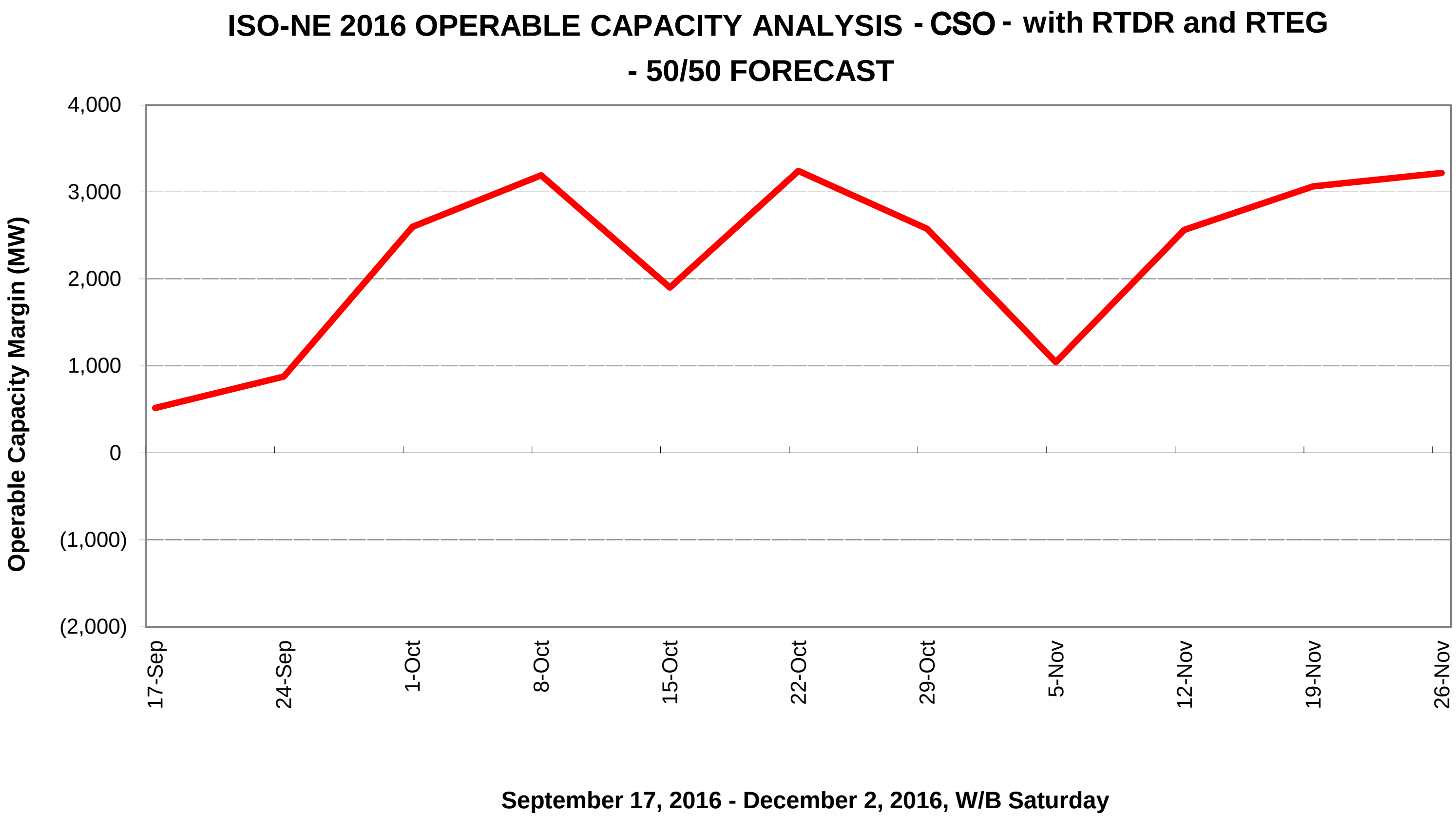
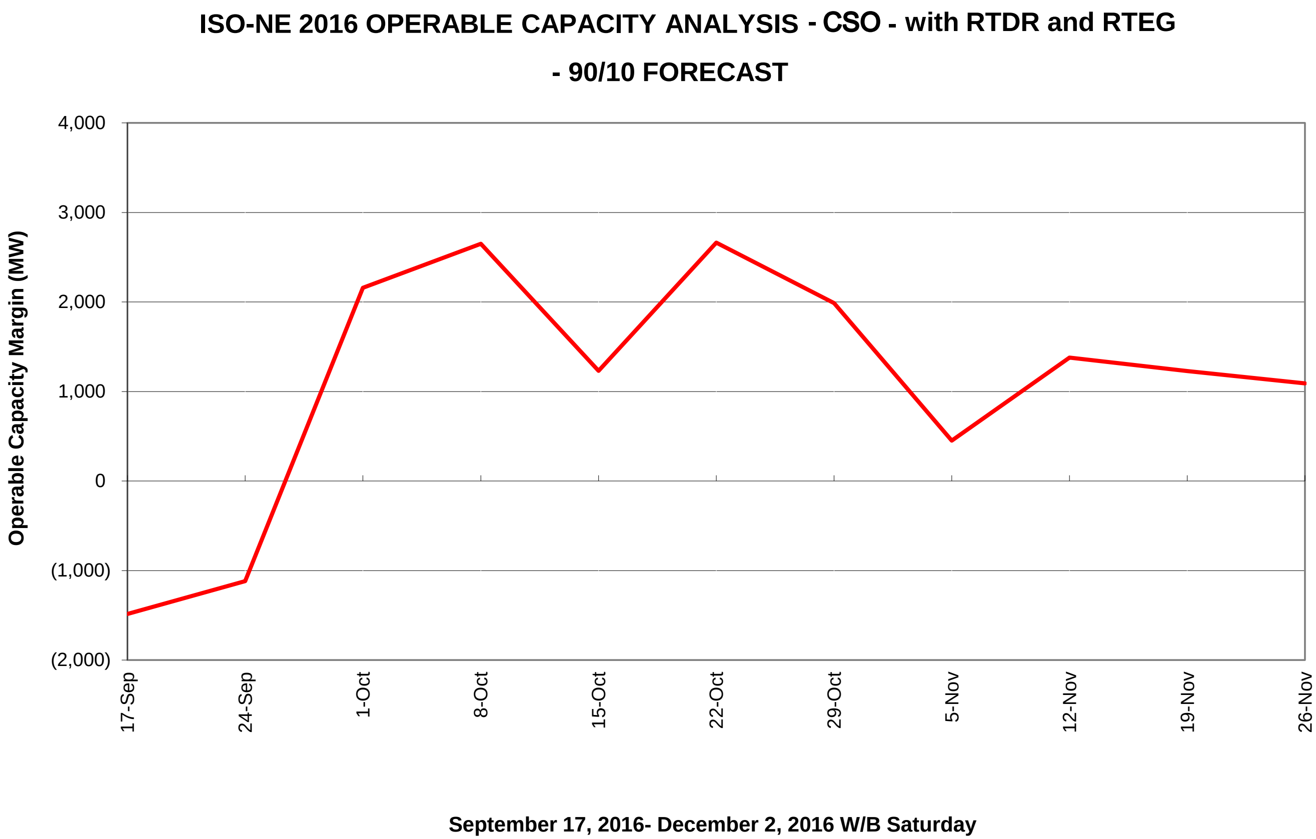
Fall 2016 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Fall 2016 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2016/17

Winter 2016/17 Operable Capacity Analysis

50/50 Load Forecast (Reference)	January - 2017[2] CSO	January - 2017[2] SCC
Generator Operable Capacity MW [1]	29,982	32,827
OP CAP From OP-4 RTDR (+)	366	366
OP CAP From OP-4 RTEG (+)	177	177
Operable Capacity Generator with OP-4 DR and RTEG	30,525	33,370
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,037	1,037
Non Commercial Capacity (+)	82	82
Non Gas-fired Planned Outage MW (-)	222	325
Gas Generator Outages MW (-)	489	562
Allowance for Unplanned Outages (-) [5]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [4]	3,296	3,643
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,537	26,859
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,110	21,110
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,415	23,415
Operable Capacity Margin [3]	1,122	3,444

[1] Generator Operable Capacity is based on data as of **August 16, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, Photo Voltaic, and external capacity. SCC value is based on data as of **August 16, 2016**

[2] Load based on 2016 CELT report and week with lowest Operable Capacity Margin, week beginning **January 28, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Winter 2016/17 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	January - 2017[2] CSO	January - 2017[2] SCC
Generator Operable Capacity MW [1]	29,982	32,827
OP CAP From OP-4 RTDR (+)	366	366
OP CAP From OP-4 RTEG (+)	177	177
Operable Capacity Generator with OP-4 DR and RTEG	30,525	33,370
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,037	1,037
Non Commercial Capacity (+)	82	82
Non Gas-fired Planned Outage MW (-)	222	326
Gas Generator Outages MW (-)	489	562
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	4,045	4,476
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,088	26,325
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,028	22,028
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,333	24,333
Operable Capacity Margin [3]	(245)	1,992

[1] Generator Operable Capacity is based on data as of **August 16, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, Photo Voltaic, and external capacity. SCC value is based on data as of **August 16, 2016.**

[2] Load based on 2016 CELT report and week with lowest Operable Capacity Margin, weeks beginning **January 7, and 14, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Winter 2016/17 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2016/17 OPERABLE CAPACITY ANALYSIS

September 9, 2016 - 50/50 FORECAST using CSO values with RTDR and RTEG

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
12/3/2016	29,982	1,037	31	980	702	3,200	2,240	23,928	20,202	2,305	22,507	1,421	366	1,787	177	1,964
12/10/2016	29,982	1,037	31	980	528	3,200	2,910	23,432	20,501	2,305	22,806	626	366	992	177	1,169
12/17/2016	29,982	1,037	48	270	226	3,200	3,255	24,116	20,512	2,305	22,817	1,299	366	1,665	177	1,842
12/24/2016	29,982	1,037	48	270	0	3,200	3,524	24,073	20,577	2,305	22,882	1,191	366	1,557	177	1,734
12/31/2016	29,982	1,037	82	216	242	2,800	3,413	24,430	20,859	2,305	23,164	1,266	366	1,632	177	1,809
1/7/2017	29,982	1,037	82	222	489	2,800	3,252	24,338	21,340	2,305	23,645	693	366	1,059	177	1,236
1/14/2017	29,982	1,037	82	222	489	2,800	3,339	24,251	21,340	2,305	23,645	606	366	972	177	1,149
1/21/2017	29,982	1,037	82	222	489	2,800	3,339	24,251	21,340	2,305	23,645	606	366	972	177	1,149
1/28/2017	29,982	1,037	82	222	489	3,100	3,296	23,994	21,110	2,305	23,415	579	366	945	177	1,122
2/4/2017	29,982	1,037	82	423	489	3,100	3,166	23,923	20,834	2,305	23,139	784	366	1,150	177	1,327
2/11/2017	29,982	1,037	82	232	489	3,100	3,079	24,201	20,804	2,305	23,109	1,092	366	1,458	177	1,635
2/18/2017	29,982	1,037	82	232	489	3,100	2,992	24,288	20,533	2,305	22,838	1,450	366	1,816	177	1,993
2/25/2017	29,982	1,037	82	570	742	3,100	2,652	24,037	19,512	2,305	21,817	2,220	366	2,586	177	2,763
3/4/2017	29,982	1,037	82	1,214	500	2,200	2,215	24,972	19,151	2,305	21,456	3,516	366	3,882	177	4,059
3/11/2017	29,982	1,037	82	1,875	482	2,200	1,780	24,764	18,949	2,305	21,254	3,510	366	3,876	177	4,053
3/18/2017	29,982	1,037	82	2,557	482	2,200	1,328	24,534	18,572	2,305	20,877	3,657	366	4,023	177	4,200
3/25/2017	29,982	1,037	82	3,206	482	2,200	423	24,790	17,988	2,305	20,293	4,497	366	4,863	177	5,040

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
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Winter 2016/17 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)

ISO-NE 2016/17 OPERABLE CAPACITY ANALYSIS

September 9, 2016 - 90/10 FORECAST using CSO values with RTDR and RTEG

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERAT OR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
12/3/2016	29,982	1,037	31	980	702	3,200	2,995	23,173	20,856	2,305	23,161	12	366	378	177	555
12/10/2016	29,982	1,037	31	980	528	3,200	3,349	22,993	21,164	2,305	23,469	(476)	366	(110)	177	67
12/17/2016	29,982	1,037	48	270	226	3,200	3,696	23,675	21,176	2,305	23,481	194	366	560	177	737
12/24/2016	29,982	1,037	48	270	0	3,200	4,081	23,516	21,242	2,305	23,547	(31)	366	335	177	512
12/31/2016	29,982	1,037	82	216	242	2,800	4,179	23,664	21,533	2,305	23,838	(174)	366	192	177	369
1/7/2017	29,982	1,037	82	222	489	2,800	4,045	23,545	22,028	2,305	24,333	(788)	366	(422)	177	(245)
1/14/2017	29,982	1,037	82	222	489	2,800	4,045	23,545	22,028	2,305	24,333	(788)	366	(422)	177	(245)
1/21/2017	29,982	1,037	82	222	489	2,800	3,932	23,658	22,028	2,305	24,333	(675)	366	(309)	177	(132)
1/28/2017	29,982	1,037	82	222	489	3,100	3,705	23,585	21,791	2,305	24,096	(511)	366	(145)	177	32
2/4/2017	29,982	1,037	82	423	489	3,100	3,705	23,384	21,507	2,305	23,812	(428)	366	(62)	177	115
2/11/2017	29,982	1,037	82	232	489	3,100	3,433	23,847	21,476	2,305	23,781	66	366	432	177	609
2/18/2017	29,982	1,037	82	232	489	3,100	3,343	23,937	21,197	2,305	23,502	435	366	801	177	978
2/25/2017	29,982	1,037	82	570	742	3,100	2,910	23,779	20,145	2,305	22,450	1,329	366	1,695	177	1,872
3/4/2017	29,982	1,037	82	1,214	500	2,200	3,017	24,170	19,774	2,305	22,079	2,091	366	2,457	177	2,634
3/11/2017	29,982	1,037	82	1,875	482	2,200	2,800	23,744	19,565	2,305	21,870	1,874	366	2,240	177	2,417
3/18/2017	29,982	1,037	82	2,557	482	2,200	1,863	23,999	19,177	2,305	21,482	2,517	366	2,883	177	3,060
3/25/2017	29,982	1,037	82	3,206	482	2,200	1,160	24,053	18,575	2,305	20,880	3,173	366	3,539	177	3,716

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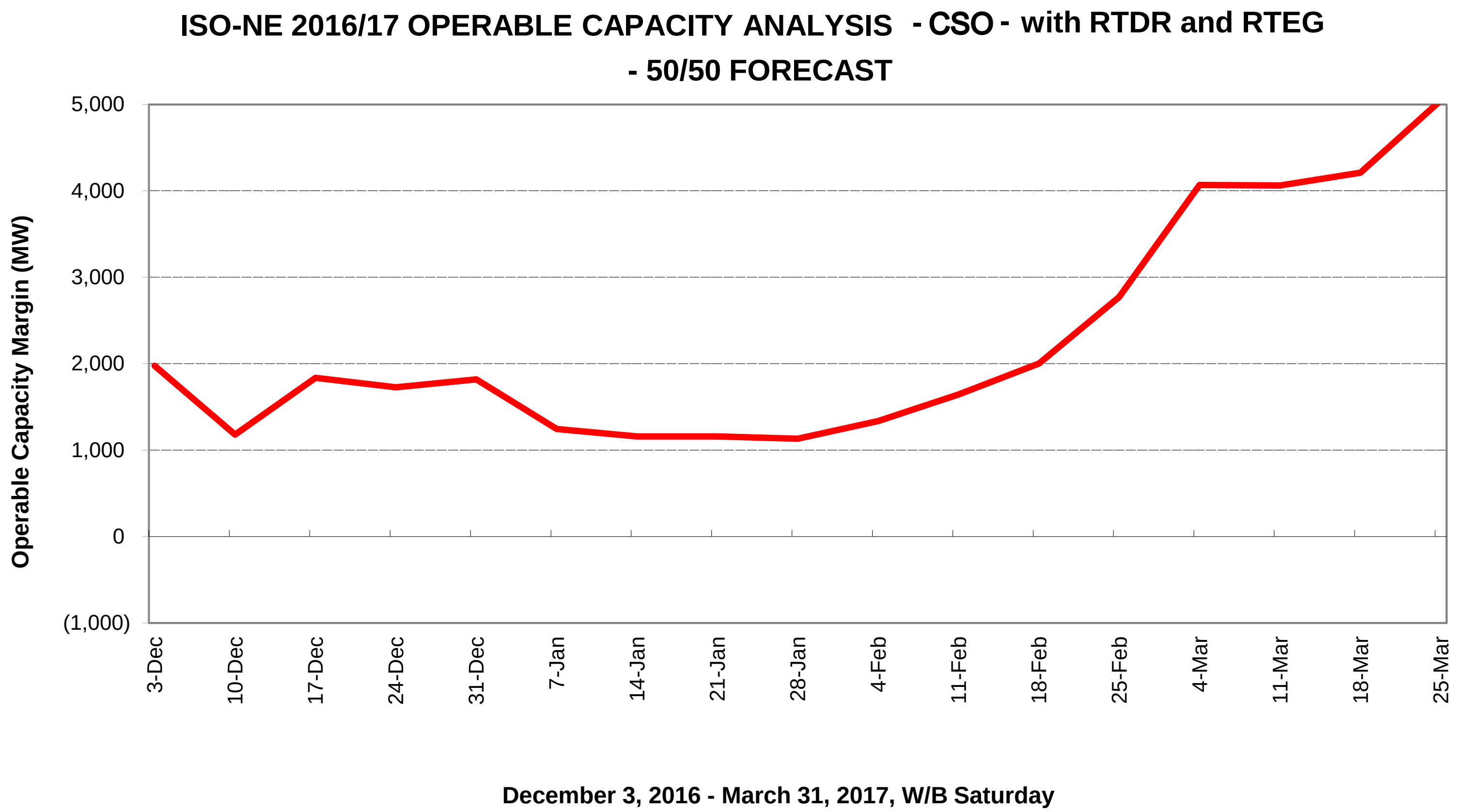
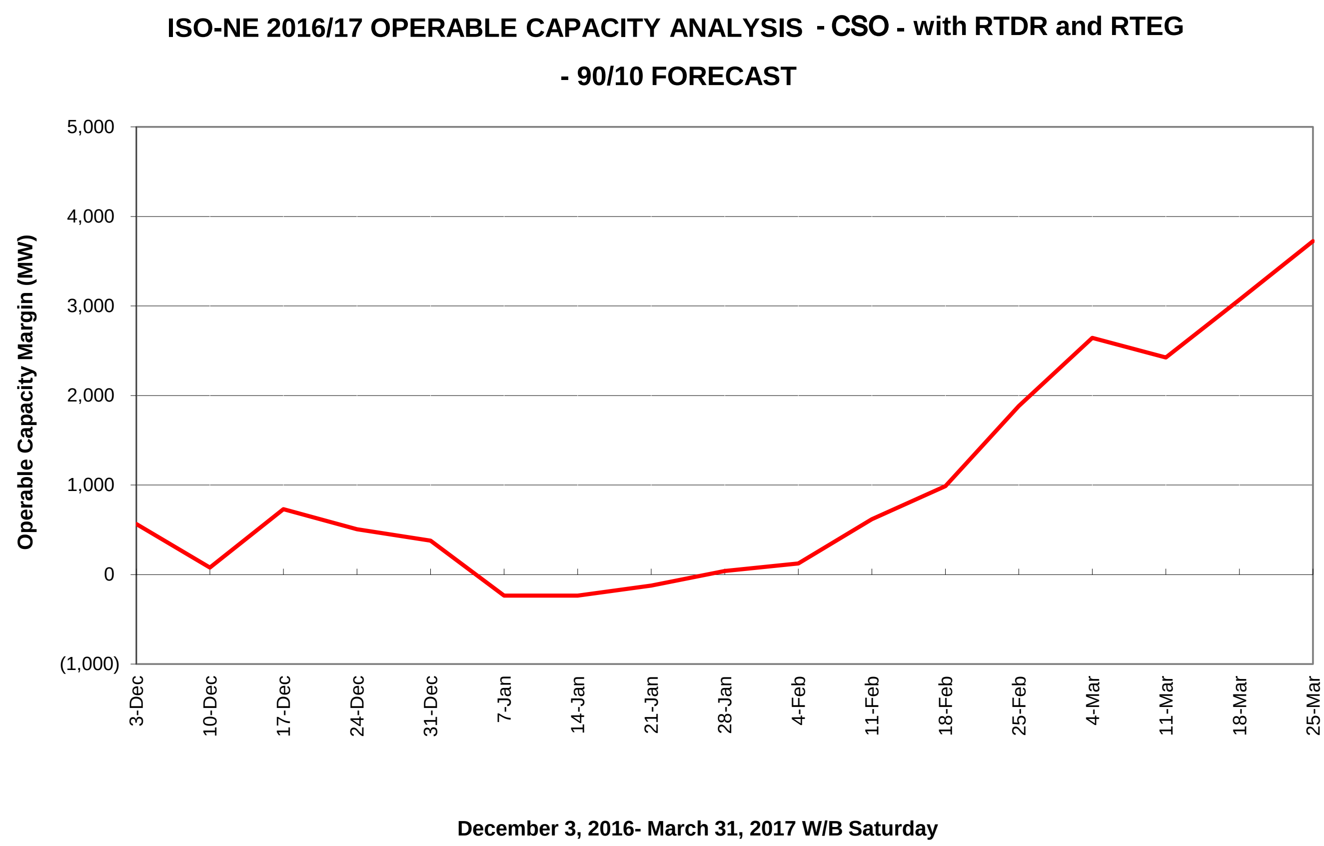
Winter 2016/17 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Winter 2016/17 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 [1] 600
2	Dispatch real time Demand Resources.	**September 293[3]** **October-November 372[3]** **December 366[3]**
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	134 [4] **September 35[3]** **October-November 184[3]** **December 177[3]**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of August 16, 2016.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	267 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**September 2,874[3]** **October-November 3,102[3]** **December 3,089[3]**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of August 16, 2016.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.