NEPOOL PARTICIPANTS COMMITTEE
06/03/16 MEETING, AGENDA ITEM #5

NEPOOL Participants Committee Report

June 2016

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

- Highlights Page 3
- System Operations Page 9
- Market Operations Page 20
- Back-Up Detail Page 37
  - Load Response Page 38
  - New Generation Page 40
  - Forward Capacity Market Page 47
  - Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs Page 54
  - Regional System Plan (RSP) Page 85
  - Operable Capacity Analysis – Summer 2016 Page 114
  - Operable Capacity Analysis – Appendix Page 121

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was $162M over the period, down $111M from April 2016 and down $112M from May 2015
  - May natural gas prices over the period were 26% lower than April 2016 average values
  - Average RT Hub Locational Marginal Prices ($20.79/MWh) over the period were 26% lower than April 2016 averages
  - Average May 2016 natural gas prices and RT Hub LMPs over the period were up 11% and down 20%, respectively, from May 2015 averages
- Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.3% during May, down from 99% during April

All data through May 25 (RT NCPC through May 24) except where otherwise noted.

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)
  - May NCPC payments totaled $1.6M over the period, down $2.3M from April and down $4.6M from May 2015
  - First Contingency payments totaled $1.5M, down $2.3M from April
    - $1.4M paid to internal resources, down $1.5M from April
      - $459K charged to DALO, $968K to RT Deviations
    - $67K paid to resources at external locations, down $747K from April
      - $49K charged to DALO at external locations, $18K to RT Deviations
  - Second Contingency payments totaled $129K, up $4K from April
  - NCPC payments over the period as percent of Energy Market value were 1.0%

Highlights, cont.

- 2015 Economic Studies
  - Final reports are being drafted for the three 2015 studies and will be posted to the PAC website for stakeholder comment
- 2016 Economic Study – NEPOOL Scenario Analysis
  - Scope of work and high-level assumptions were discussed at the May 19 PAC meeting
  - Detailed assumptions to be discussed at the June 10 PAC meeting
- Preparations for FCA #11 are well underway
  - Static delist bids are due by June 6 and New Qualification Packages are due by June 21

Forward Capacity Market (FCM) Highlights

- CCP #4 (2013-2014) through CCP #6 (2015-2016)
  - Less than 100 MW of resources are non-commercial at this time
  - Terminations expected in June timeframe
- CCP #7 (2016-2017)
  - ISO System Operations has worked with local Transmission Owners to develop procedures to address the NEMA/Boston Transmission Security Analysis deficiency
- CCP #8 (2017-2018)
  - Second bilateral transaction window closed on May 6 with minimal trading. Results will be posted on June 10.
  - Second reconfiguration auction will be August 1-3
- CCP #9 (2018-2019)
  - First bilateral transaction window closed on April 7 with a single transaction that was approved. Results were posted on May 12
  - First reconfiguration auction will be June 1-3

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #10 (2019-2020)
  - First bilateral transaction window will be April 2017
  - First reconfiguration auction will be June 2017
- CCP #11 (2020-2021)
  - FERC Order on the retirement reforms approach and timeline changes was received on April 15. Compliance filing was submitted on May 12.
  - FERC has yet to rule on the zonal sloped demand curve filing made on April 15
  - Static delist bids are due June 6
  - IMM determinations for the two retirement bids (approximately 27 MW) will be released on June 16
  - New Qualification Packages are due on June 21

Highlights, cont.

- The lowest 50/50 and 90/10 Summer Operable Capacity Margin Week is projected for week beginning June 4, 2016.
  - Natural Gas Pipeline restrictions due to maintenance and construction will require close gas-electric coordination through the Spring, Summer and Fall
  - Adequate natural gas pipeline capacity is anticipated through the summer, provided gas supply and transportation is scheduled within each pipelines posted capability

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (1.5°F) Max: 92°F, Min: 42°F Precipitation: 2.81” – Below Normal Normal: 3.24”	Hartford	Temperature: Below Normal (1.2°F) Max: 93°F, Min: 38°F Precipitation: 2.47” - Below Normal Normal: 4.39”

Peak Load:	18,438 MW	May 28, 2016	18:00 (ending)

MLCC2: **None**		
OP-4 : **None**		
NPCC Simultaneous Activation of Reserve Events:		
Date	Area	MW
5/14/2016	IESO	825
5/15/2016	NE	850
5/21/2016	NE	630
5/30/2016	IESO	945

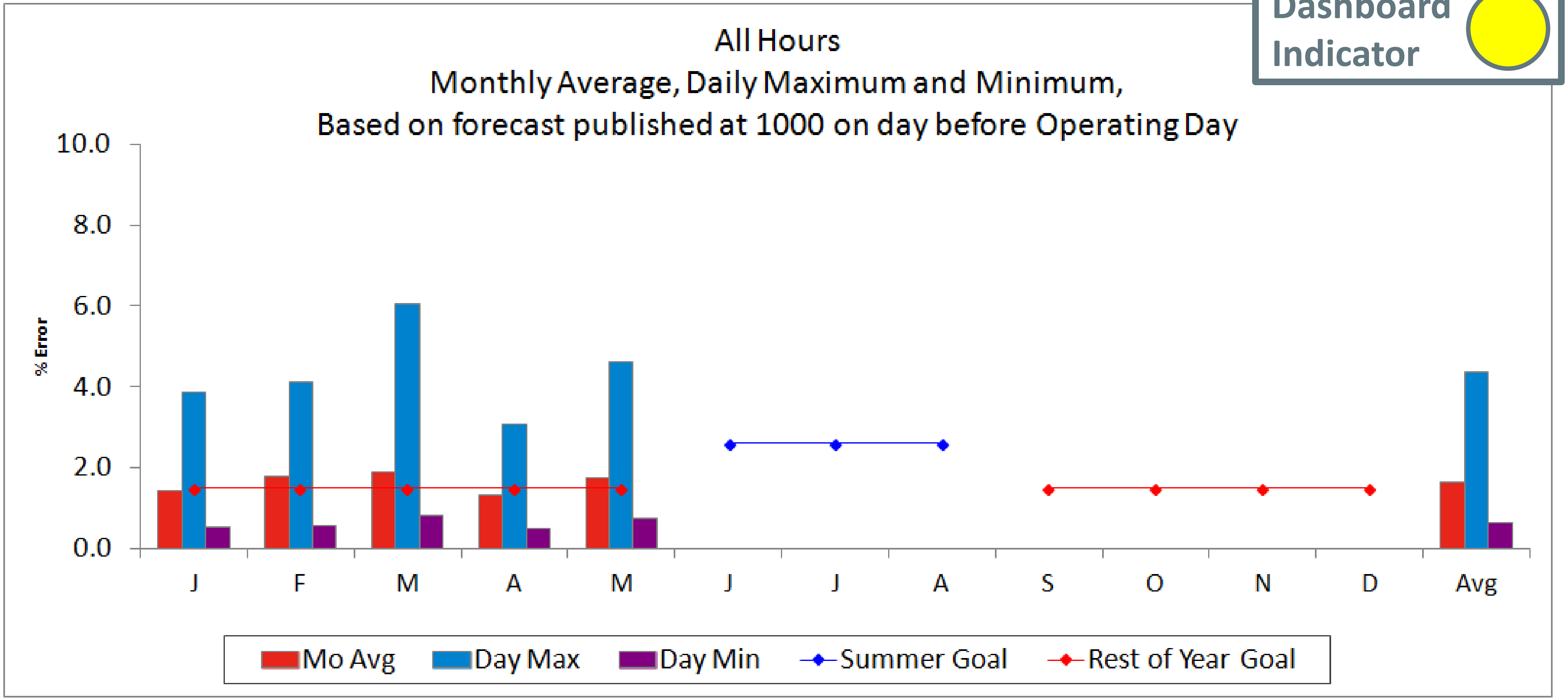
System Operations

Minimum Generation Warnings & Events:

Minimum Generation Warning	5/24/16 23:00 – 5/25/16 07:00	Interchange Cuts Only

2016 System Operations - Load Forecast Accuracy

Dashboard Indicator 🟡



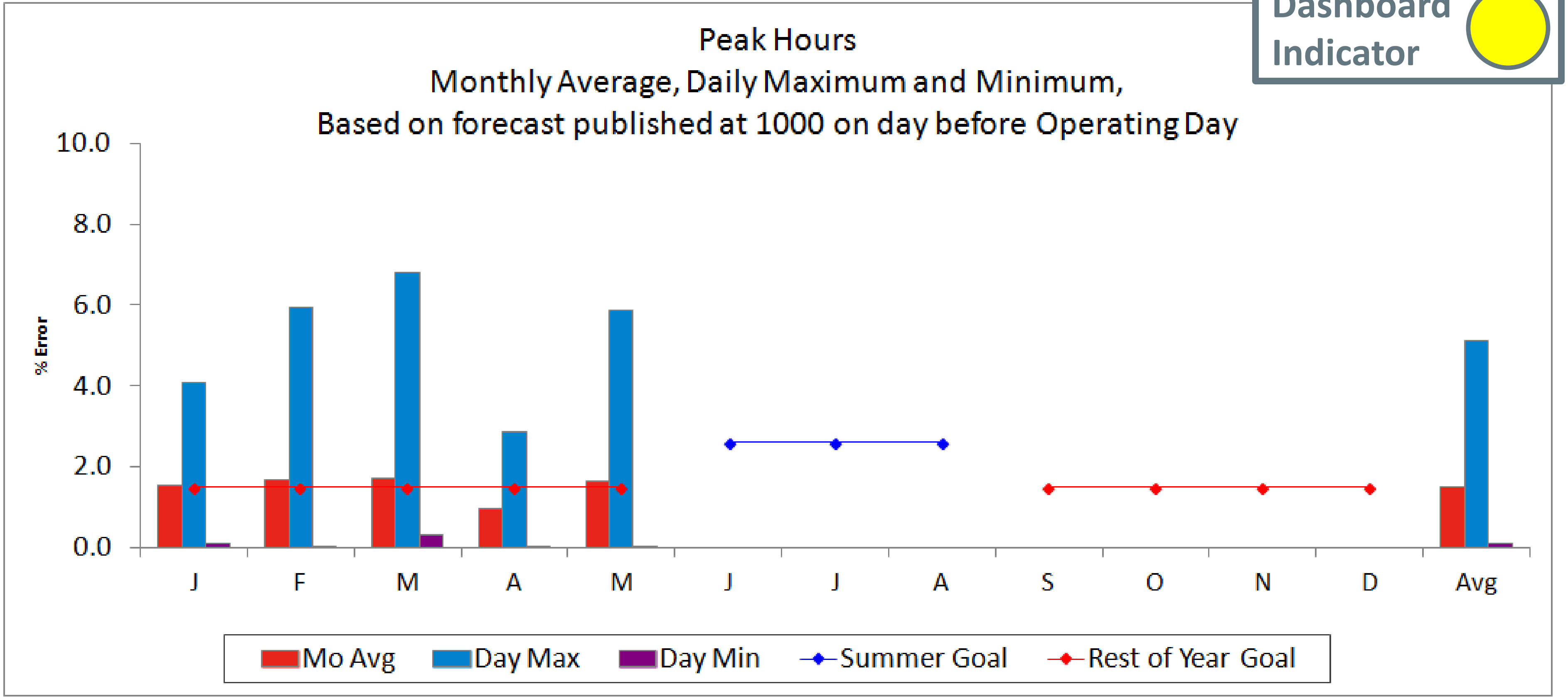
All Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published at 1000 on day before Operating Day

Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.44	1.78	1.89	1.32	1.76								1.64
Day Max	3.88	4.12	6.05	3.08	4.62								4.36
Day Min	0.54	0.58	0.82	0.50	0.75								0.64
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	1.76								1.64
Summer Actual													

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

2016 System Operations - Load Forecast Accuracy cont.

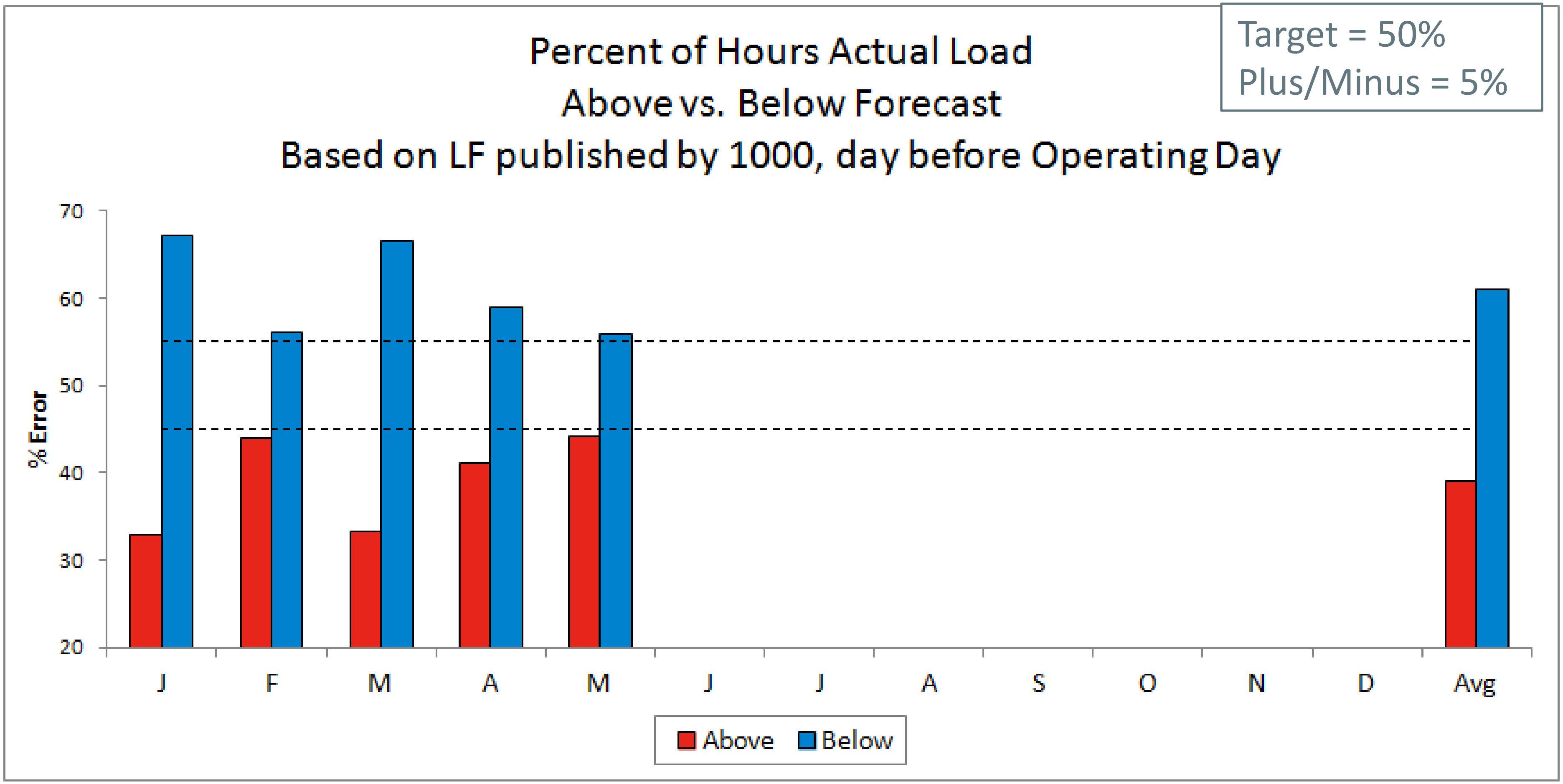
Dashboard Indicator ●



Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.55	1.67	1.72	0.96	1.66								1.51
Day Max	4.10	5.95	6.80	2.85	5.88								5.12
Day Min	0.09	0.03	0.32	0.01	0.03								0.10
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	1.66								1.51
Summer Actual													

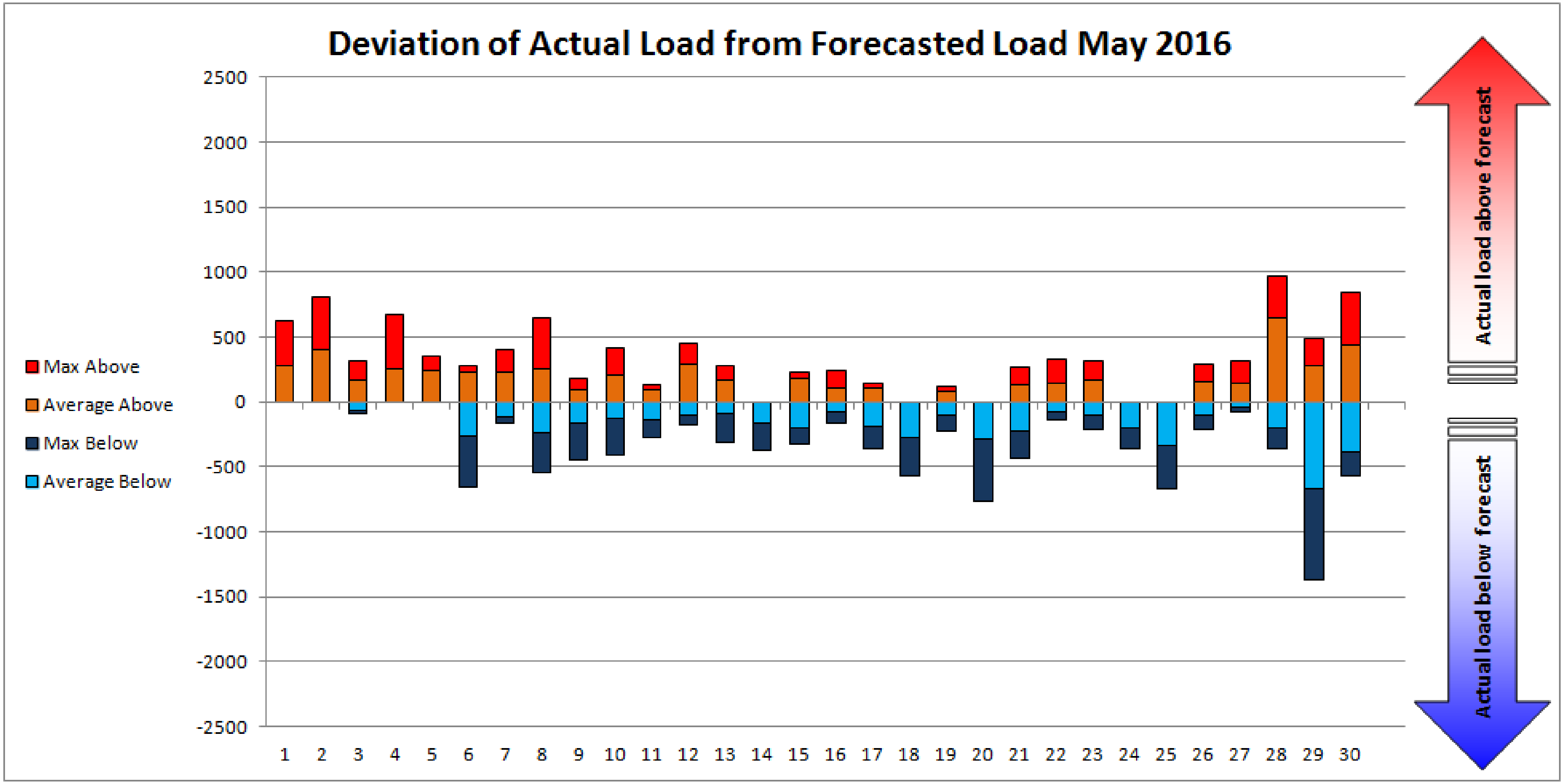
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2016 System Operations - Load Forecast Accuracy cont.

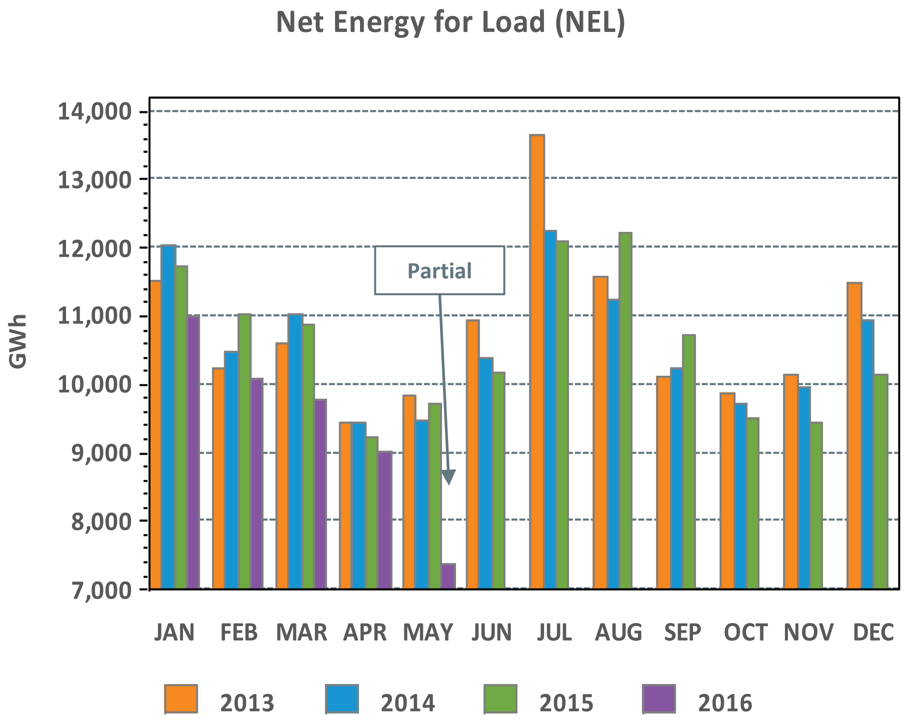


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	32.9	44	33.4	41.1	44.2								39
Below %	67.1	56	66.6	58.9	55.8								61
Avg Above	109.8	199.7	172.5	134.6	178.1								159
Avg Below	-200.6	-185.0	-201.1	-141.0	-159.7								-178
Avg All	-100	-7	-59	-12	-13								-39

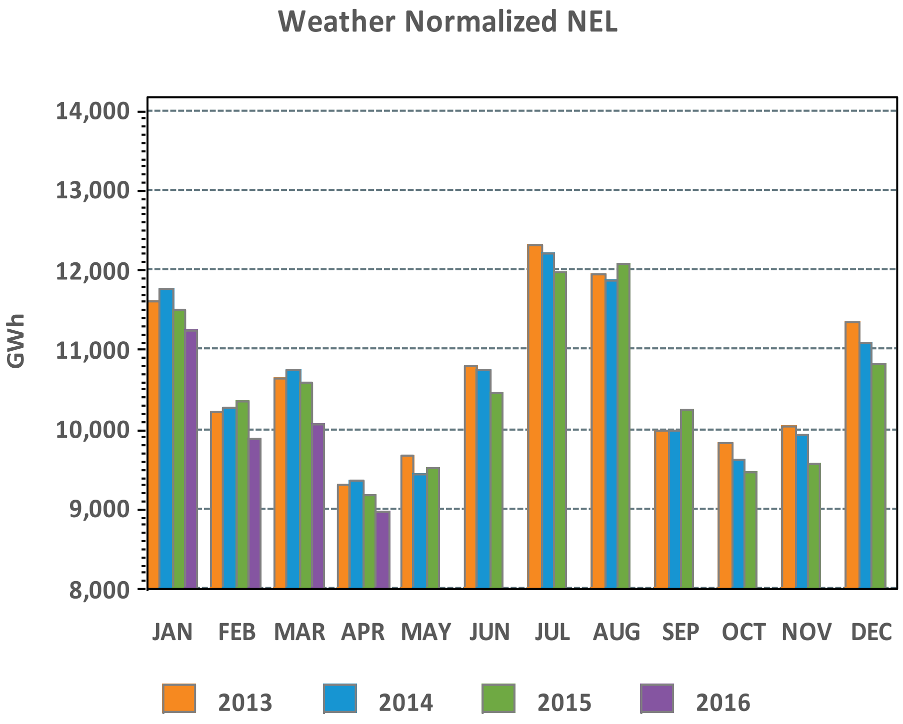
2016 System Operations - Load Forecast Accuracy cont.



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



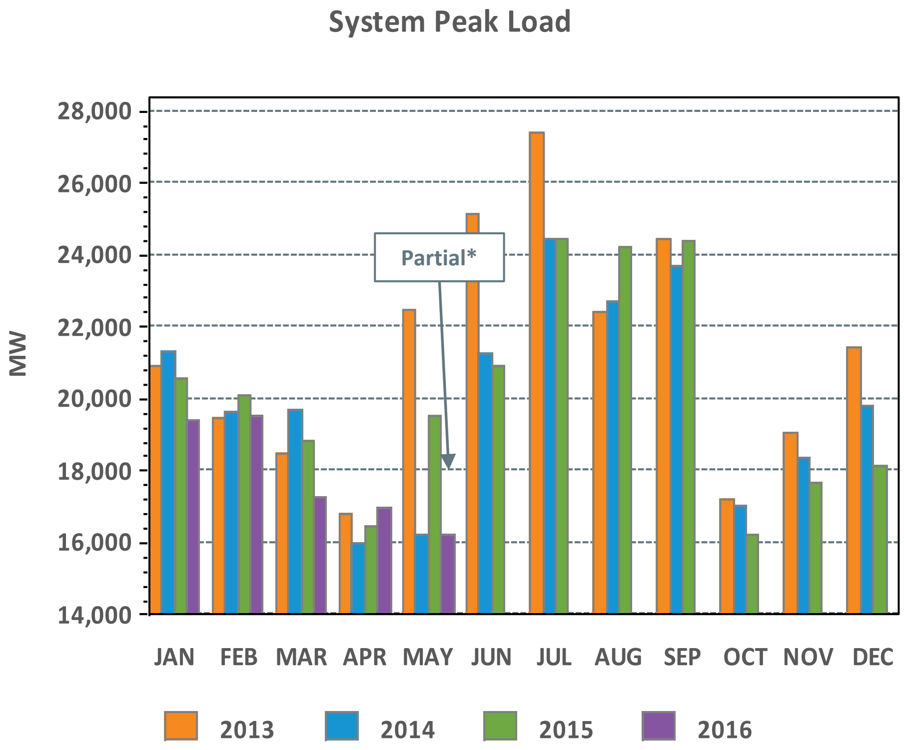
Ann Tot (TWh): 129.4 127.2 126.9 47.2



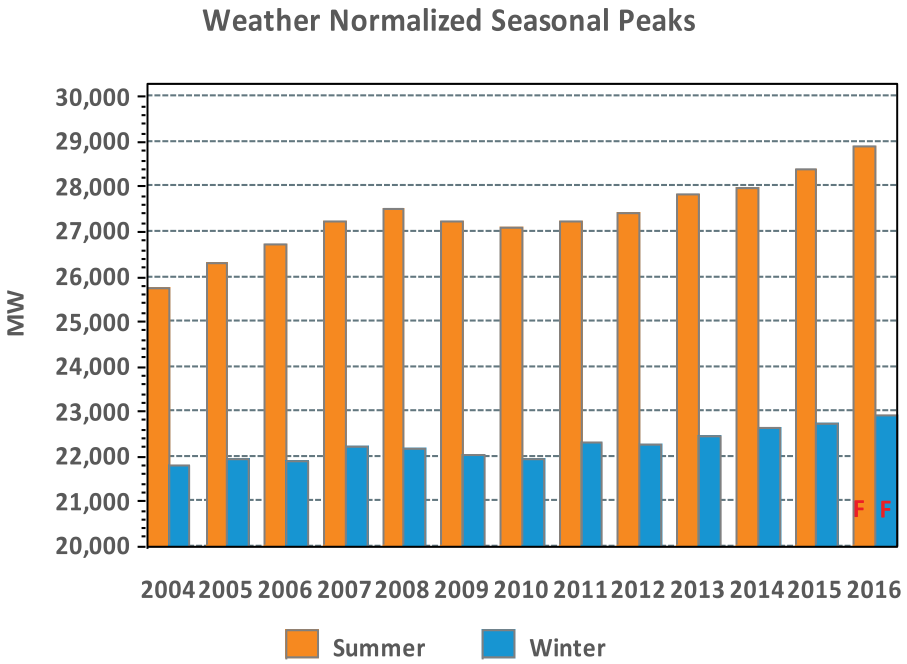
Ann Tot (TWh): 127.8 127.1 125.8 40.2

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



*Note: Reflects revenue quality metered data through May 25. Telemetered measurements suggest a peak value of closer to 18,440 MWh, recorded on May 29.

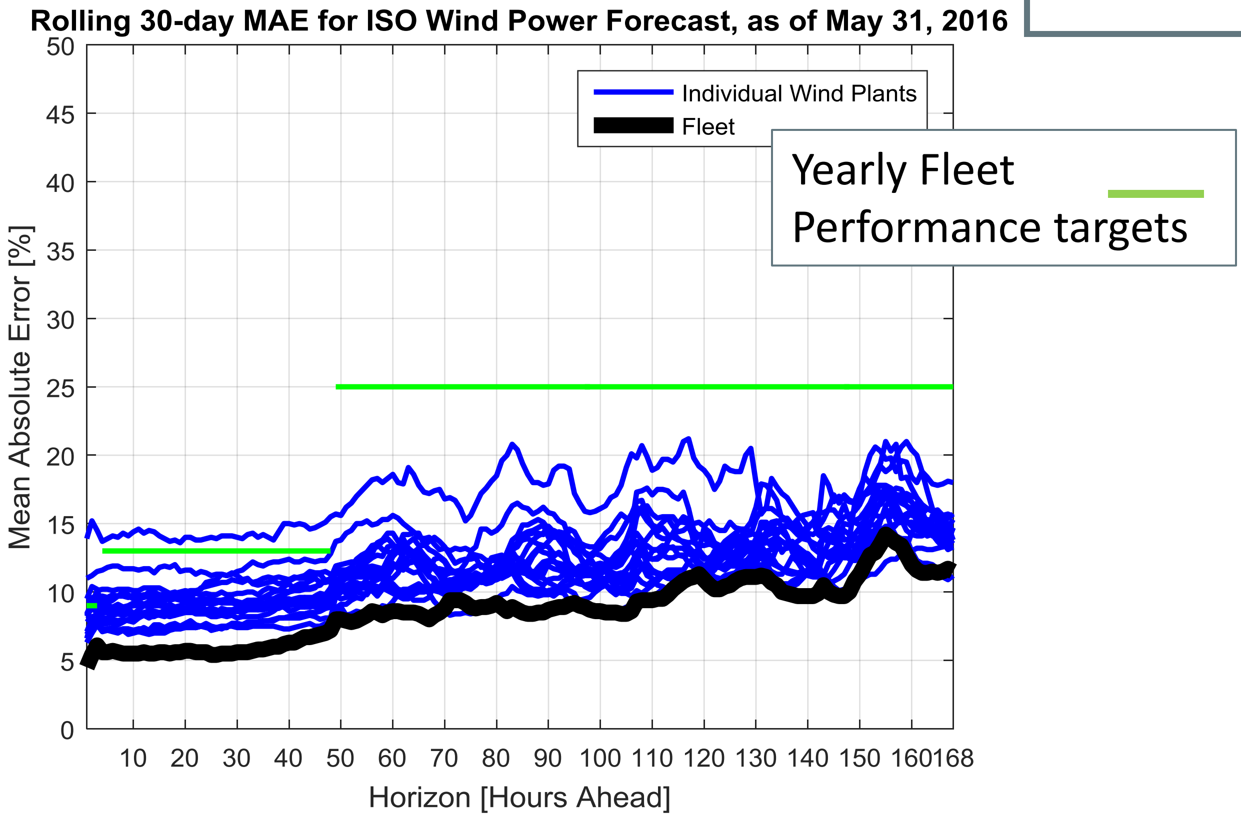


Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents "gross forecast"

Wind Power Forecast Error Statistics: MAE

Dashboard Indicator ●

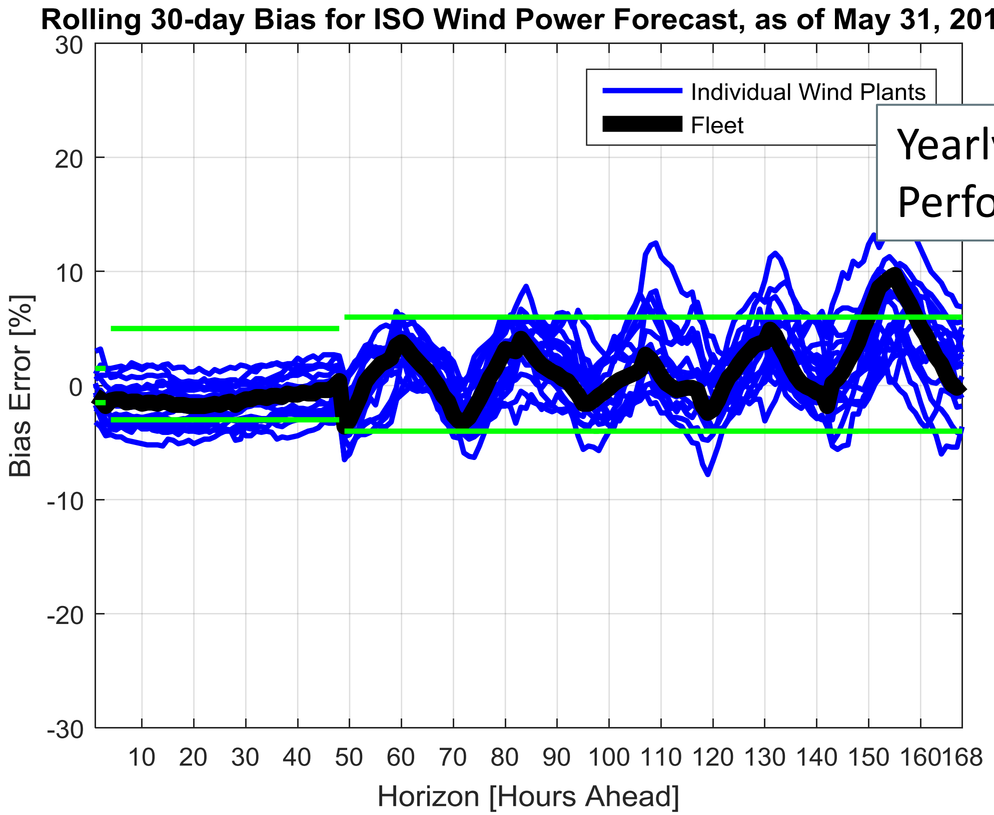


Yearly Fleet Performance targets

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 specified in the forecast RFP.

Wind Power Forecast Error Statistics: Bias

Dashboard Indicator ●



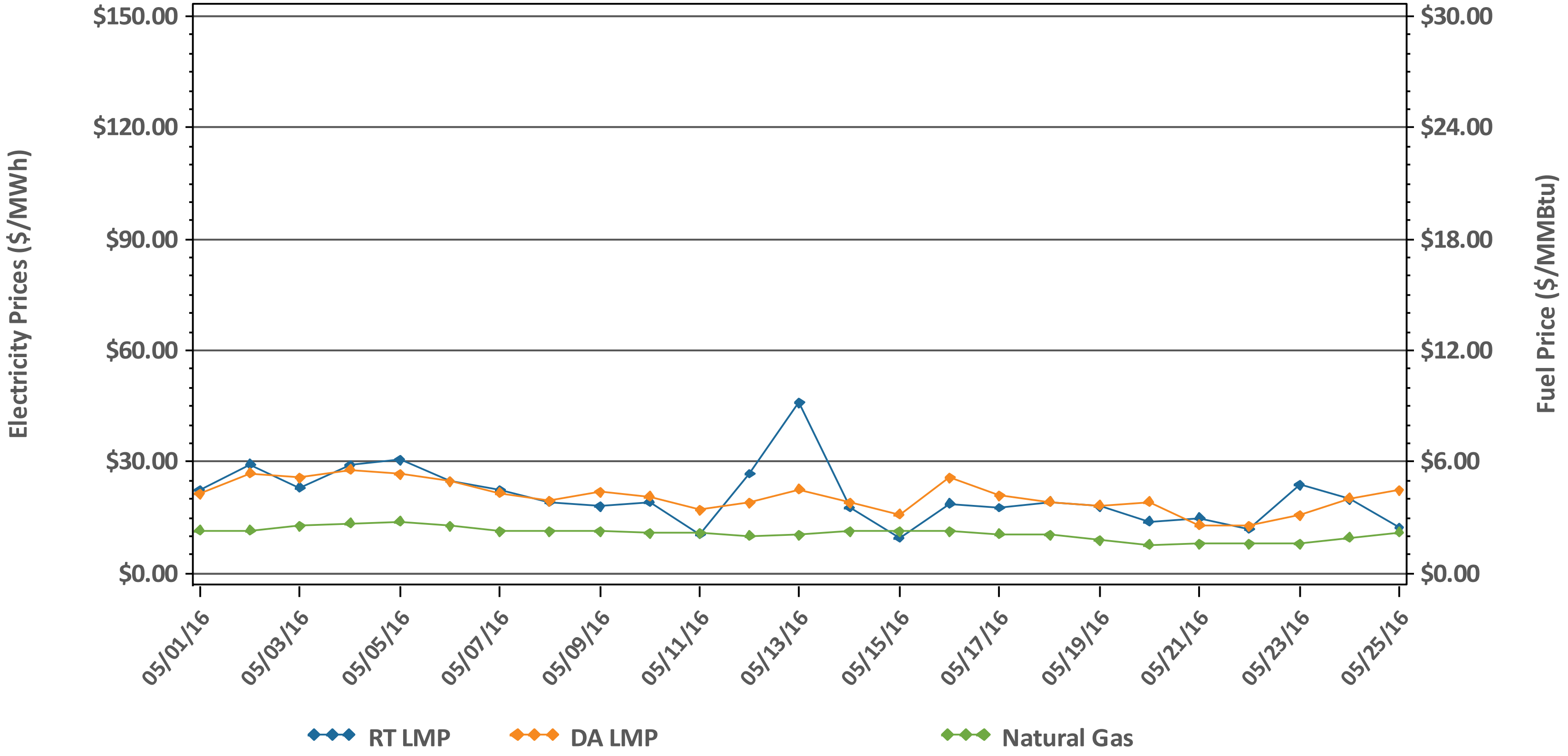
Rolling 30-day Bias for ISO Wind Power Forecast, as of May 31, 2016

Yearly Fleet Performance targets ▬

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 is compares well with industry standards, and May’s monthly values are mostly within yearly performance targets specified in the forecast RFP.

MARKET OPERATIONS

Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: May 1-25, 2016

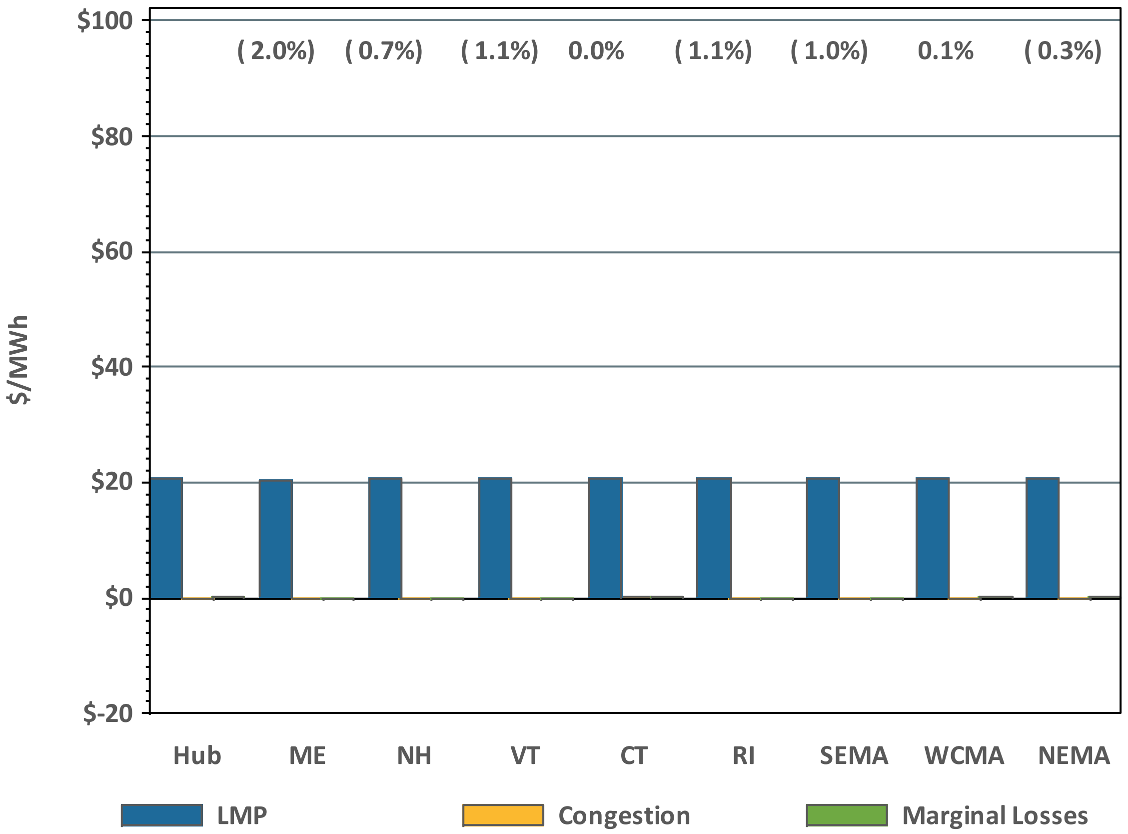


Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $-0.01
Average price difference over this period ABS(DA-RT): $4.00
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

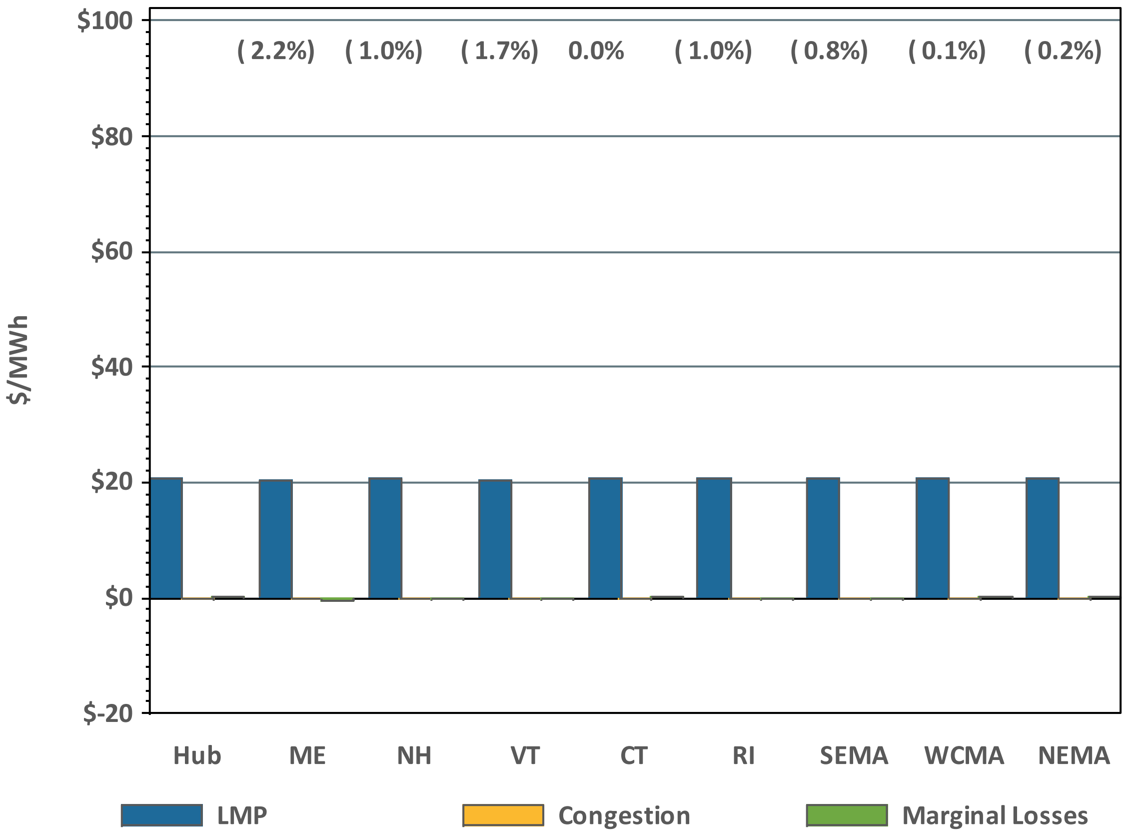
DA LMPs Average by Zone & Hub, May 2016



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

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

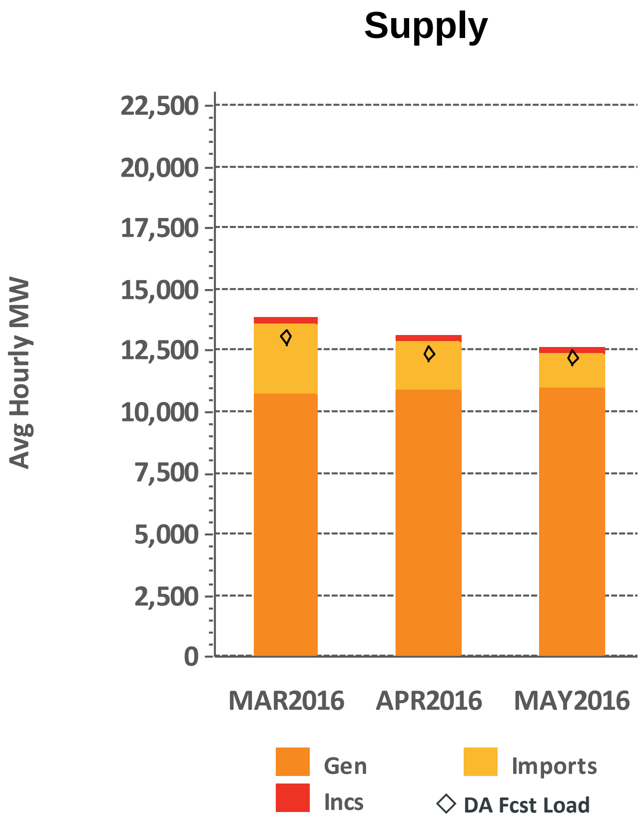
RT LMPs Average by Zone & Hub, May 2016



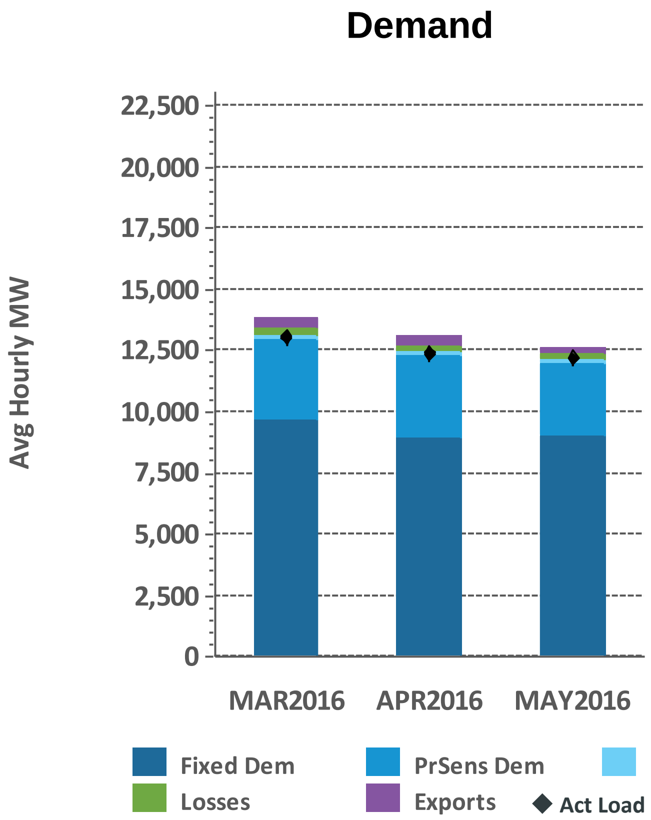
Definitions

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

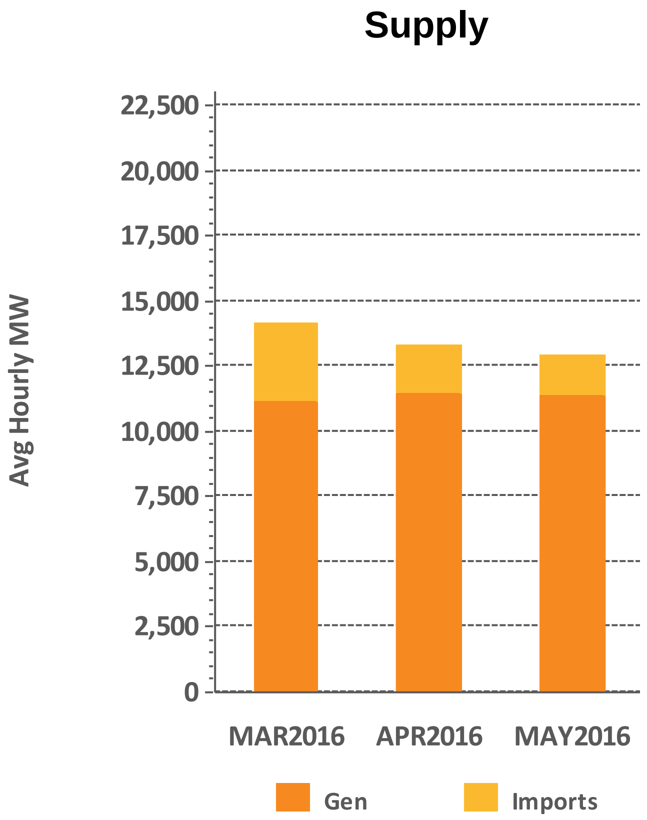


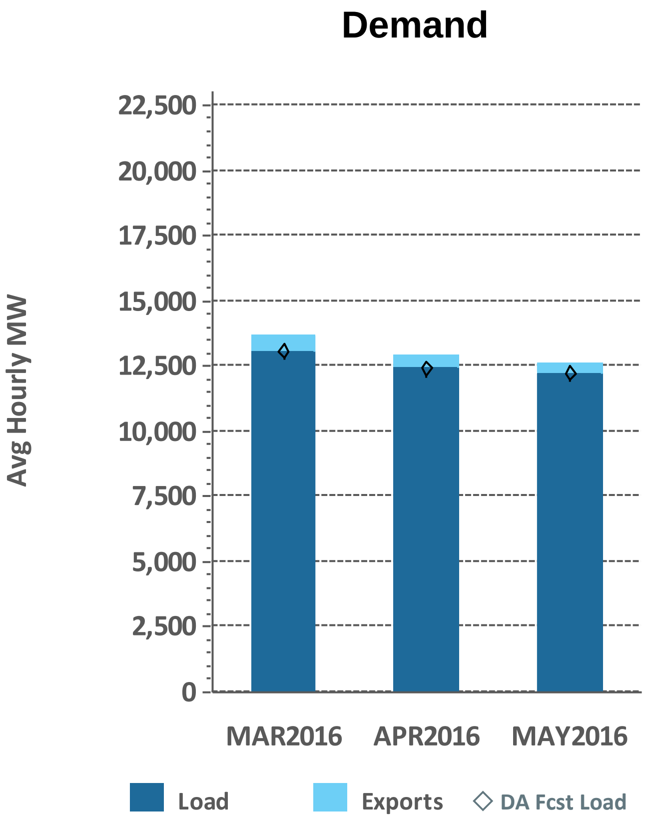
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



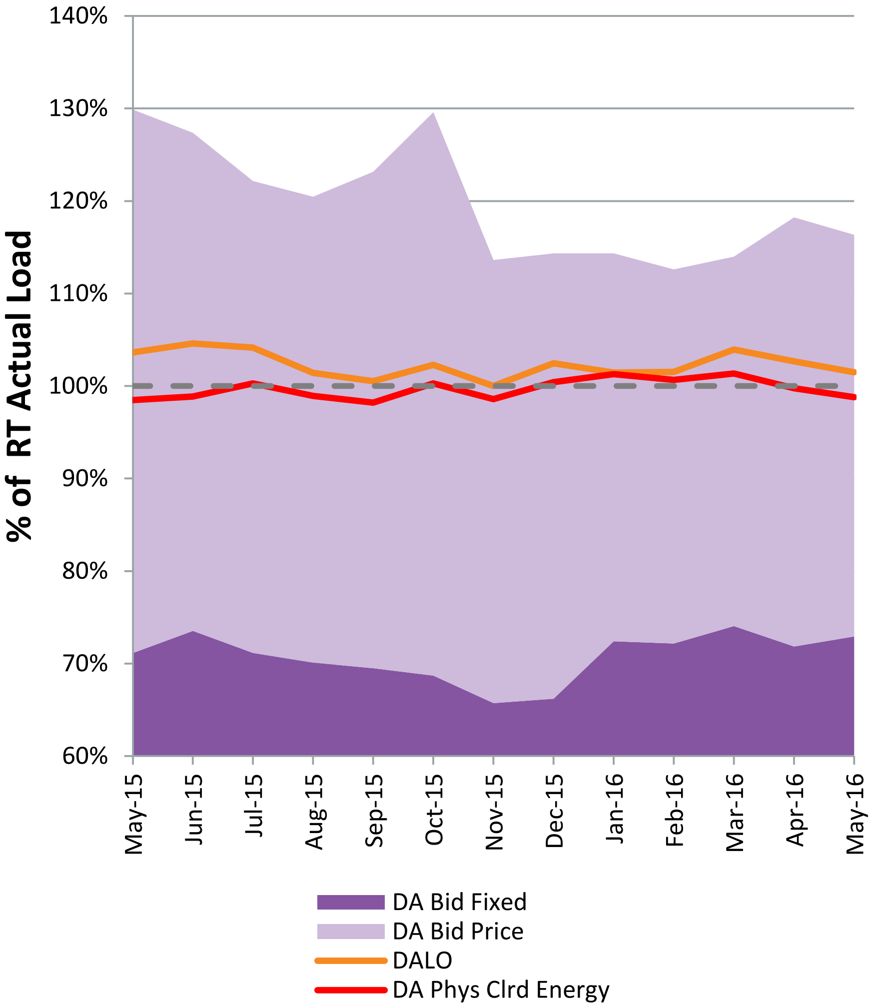
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

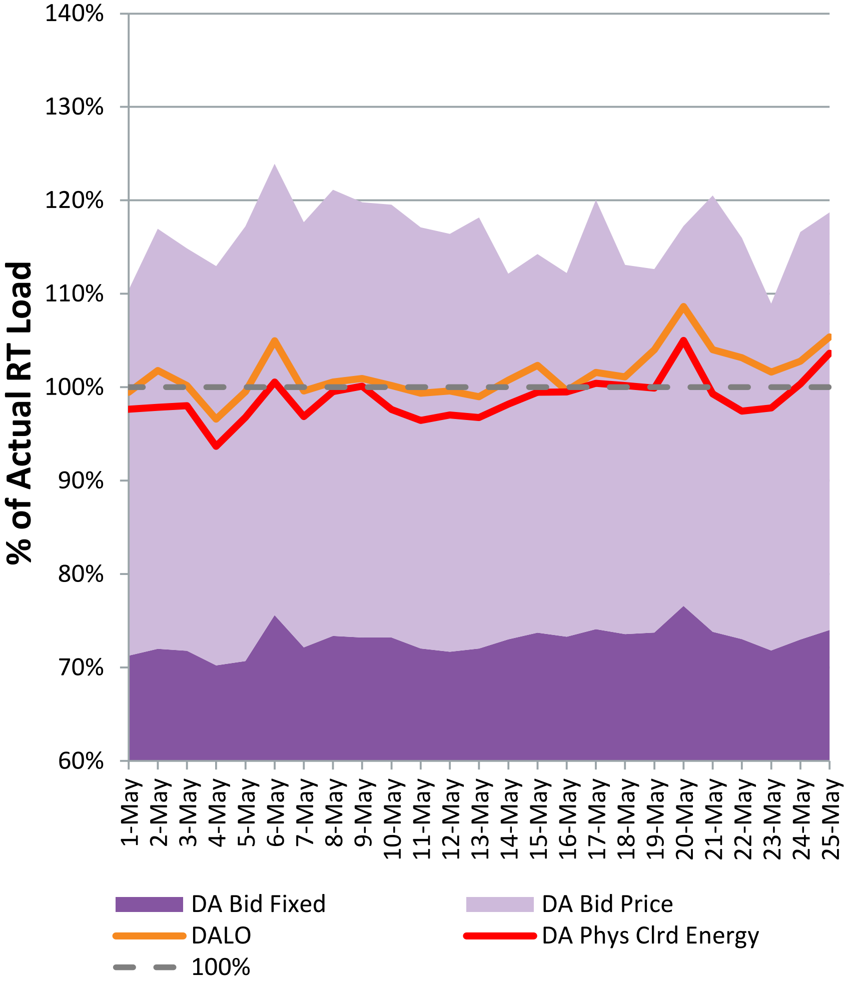
Components of RT Supply and Demand – Last Three Months





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

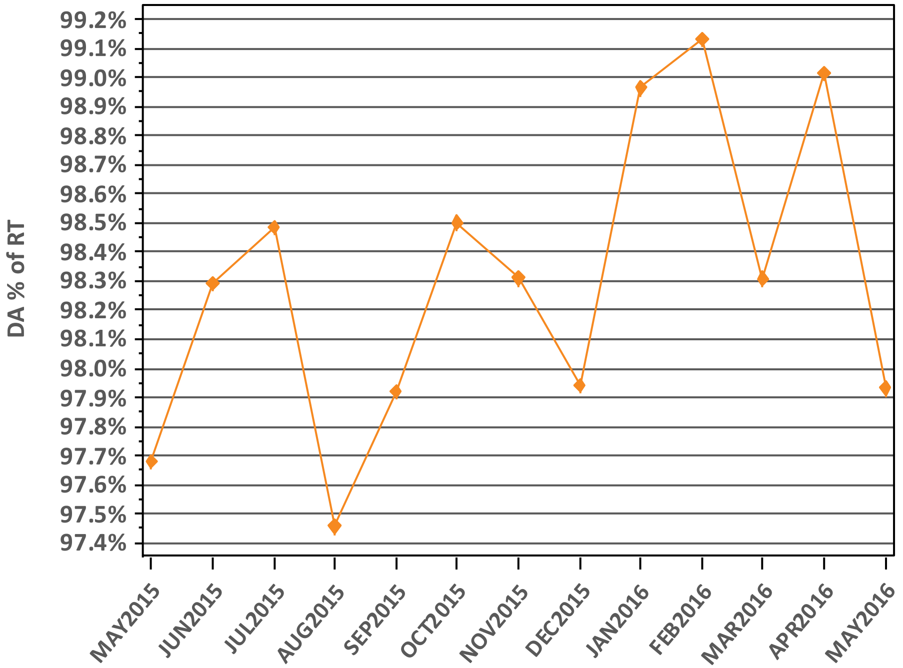




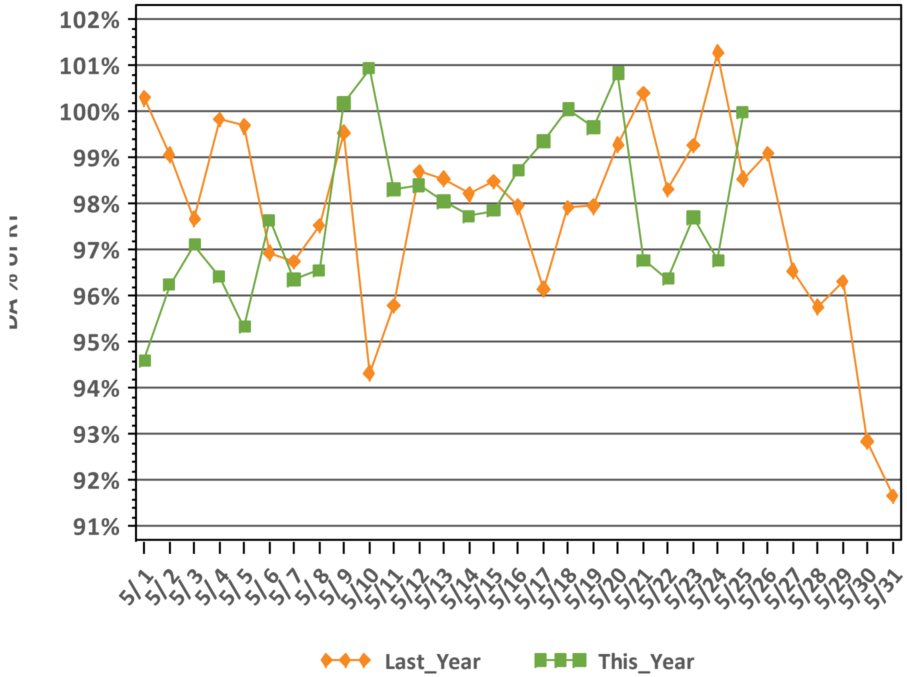
Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

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

Monthly, Last 13 Months

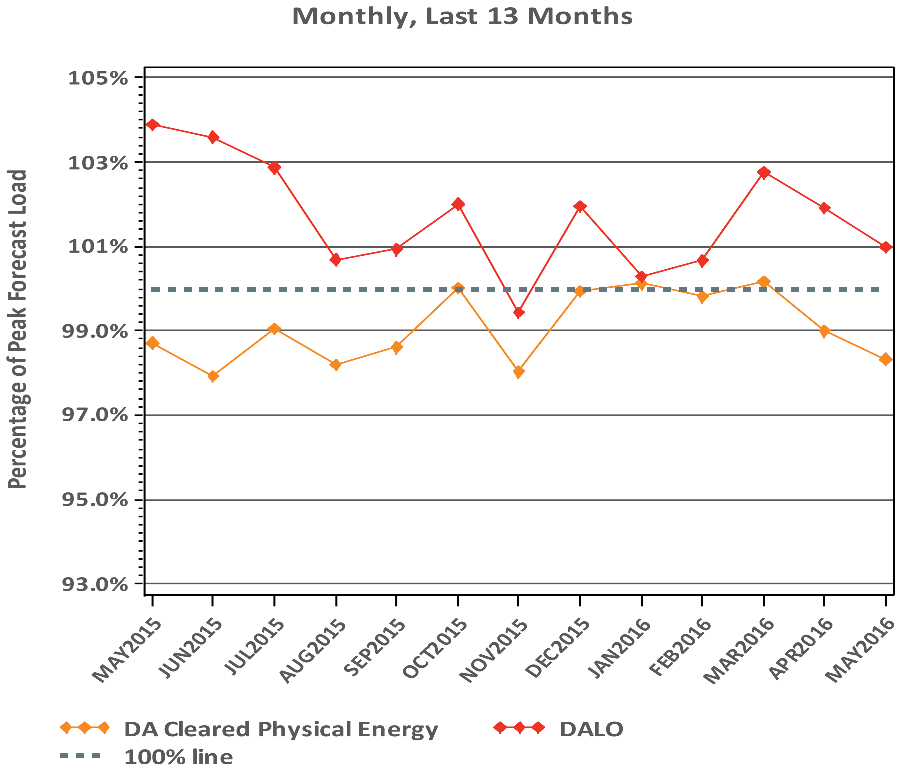


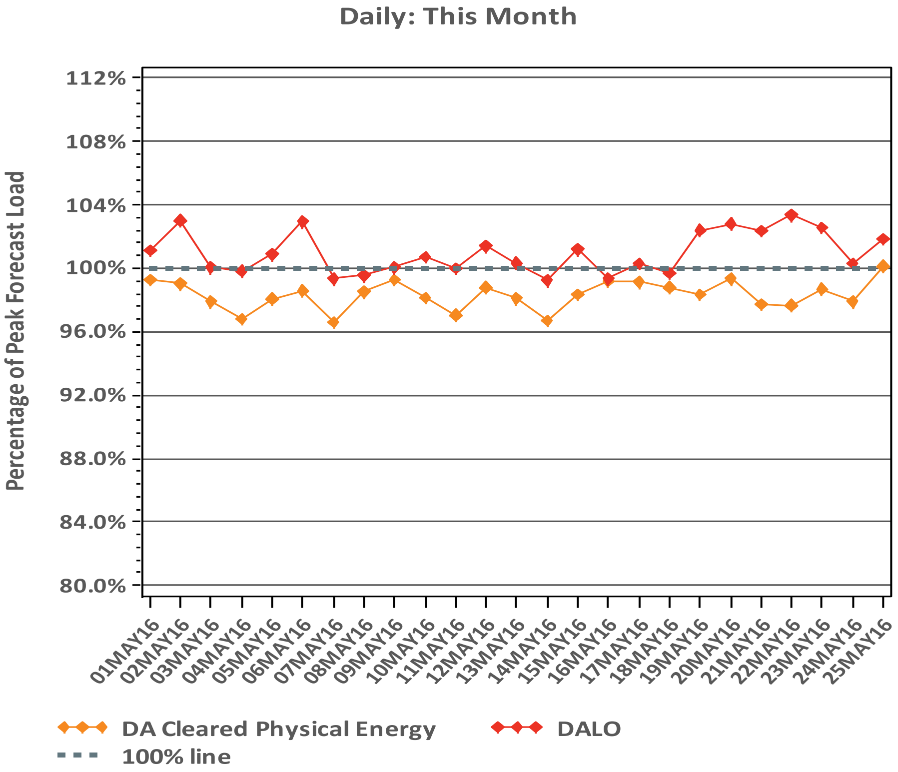
Daily, This Year vs. Last Year



*Hourly average values

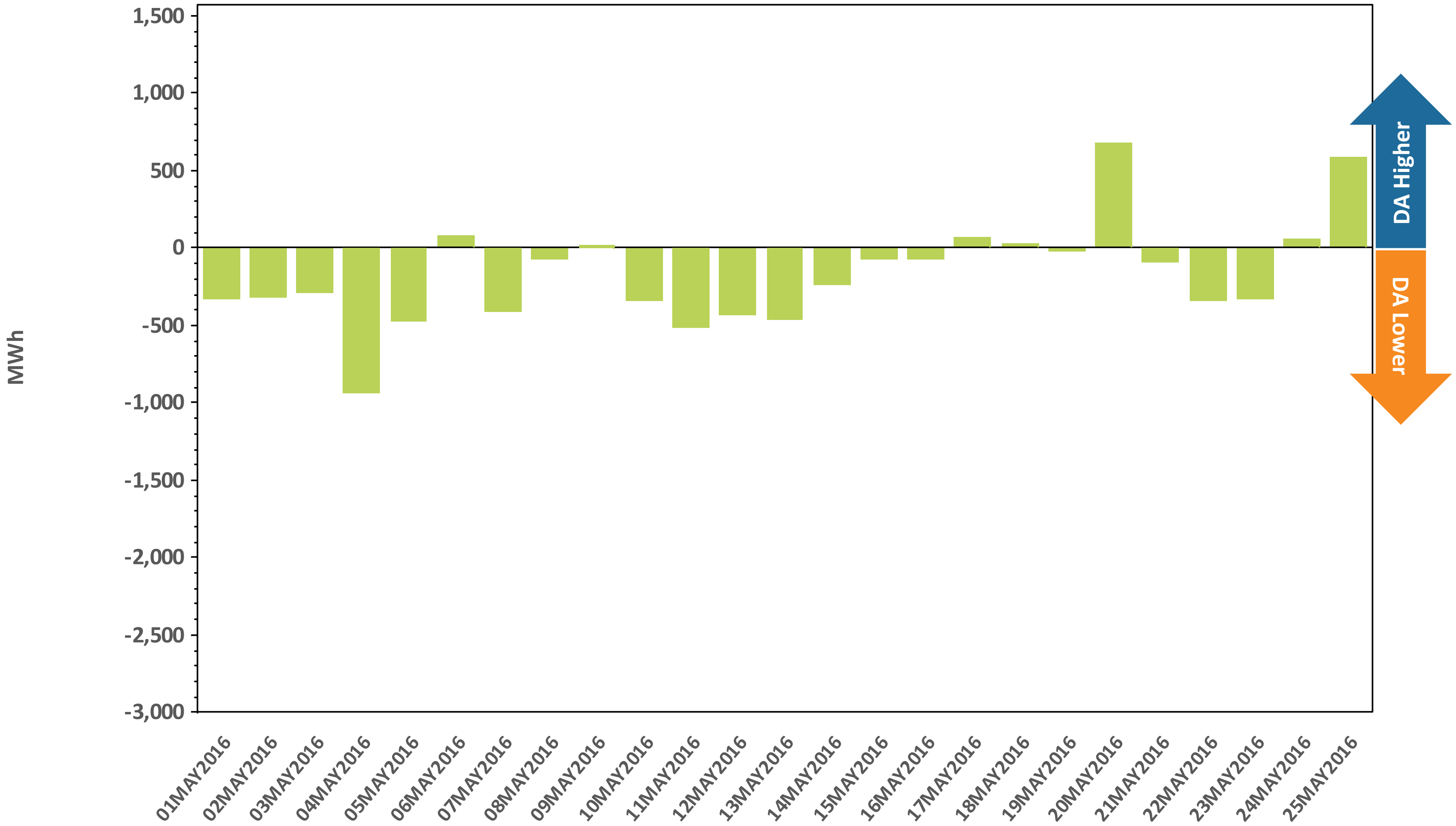
DA Volumes as % of Forecast (Peak Hour)





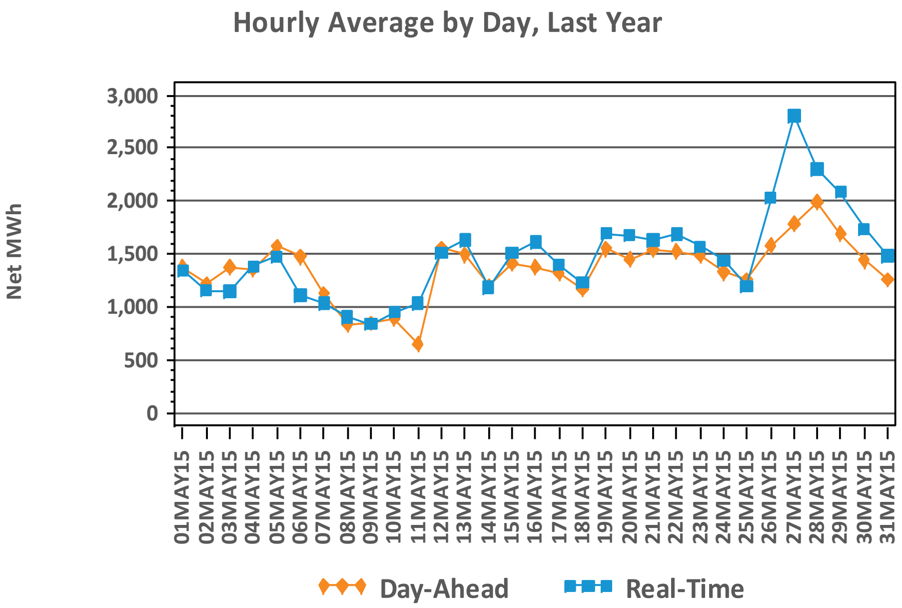
*Forecasted peak hour is reflected.

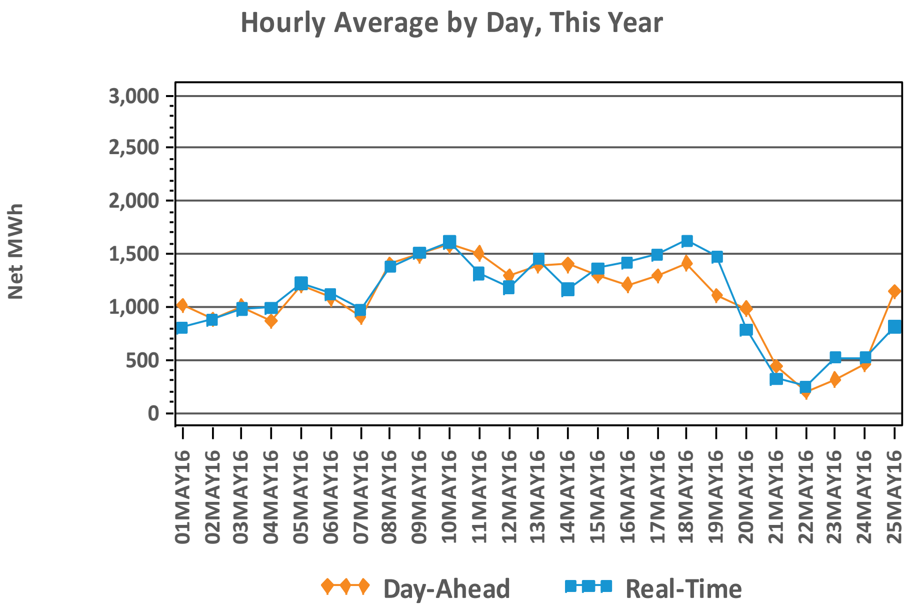
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

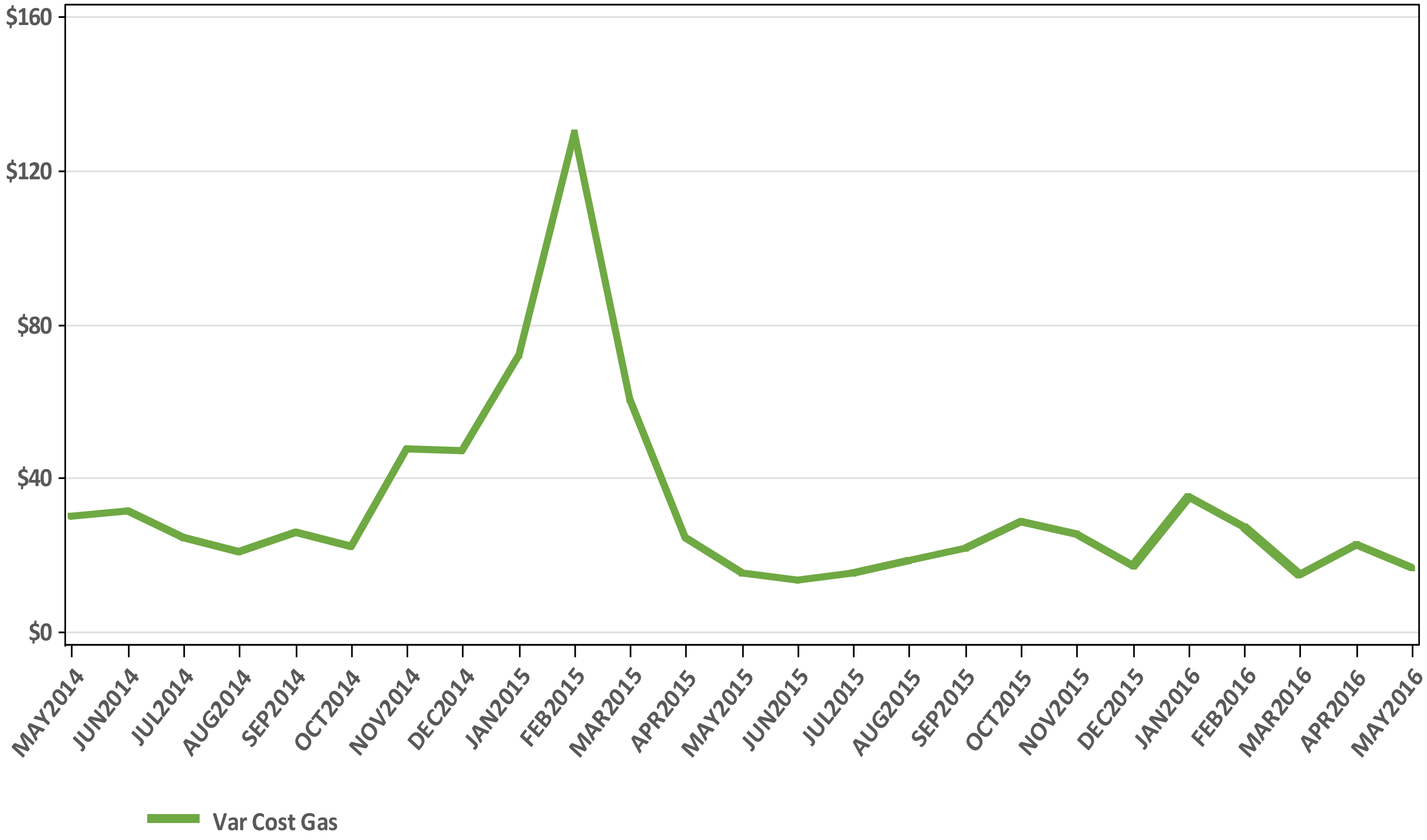
DA vs. RT Net Interchange
May 2016 vs. May 2015





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

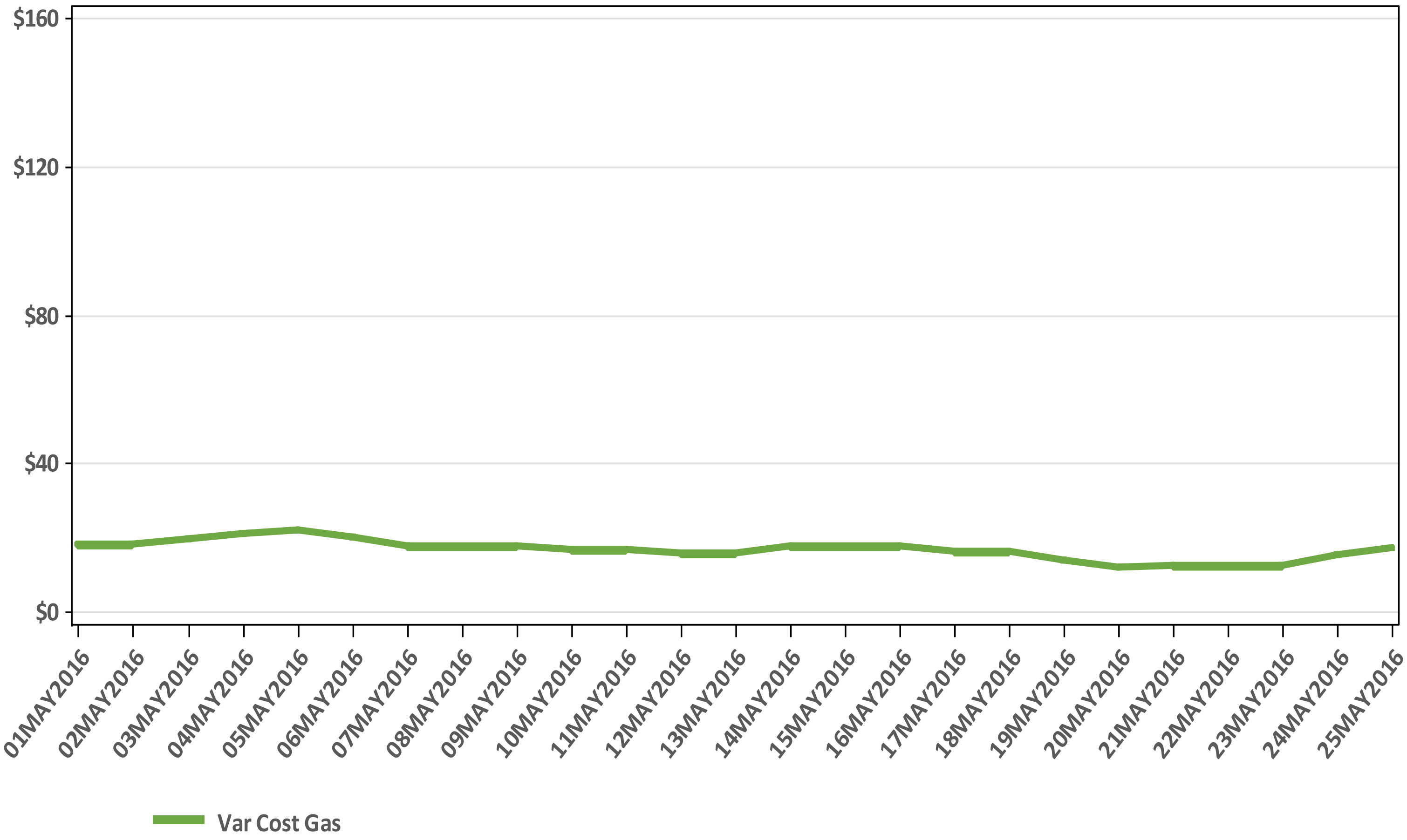


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

ice Global markets in clear view

Variable Production Cost of Natural Gas: Daily

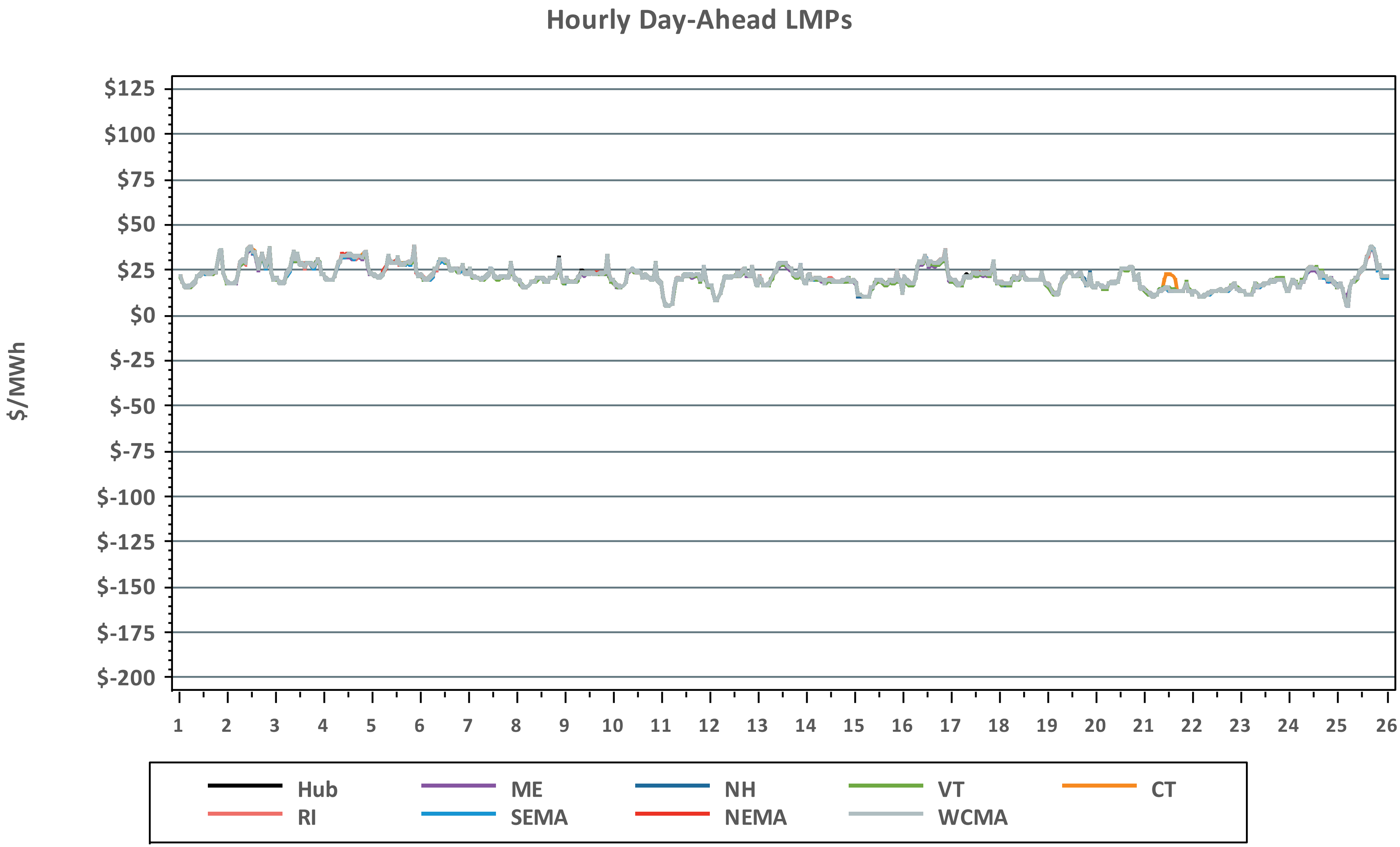


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

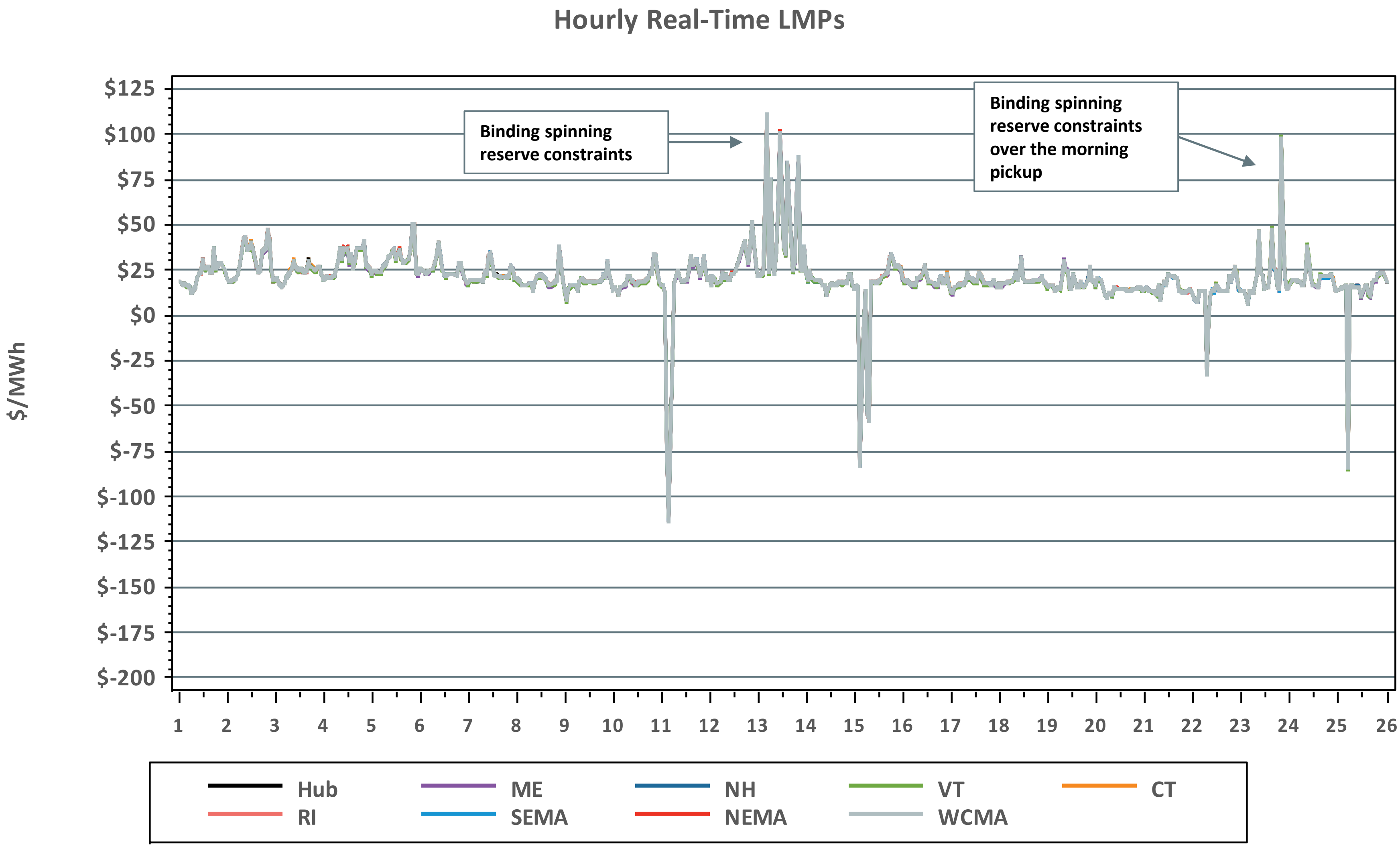
Underlying natural gas data furnished by:

ICE Global markets in clear view

Hourly DA LMPs, May 1-25, 2016



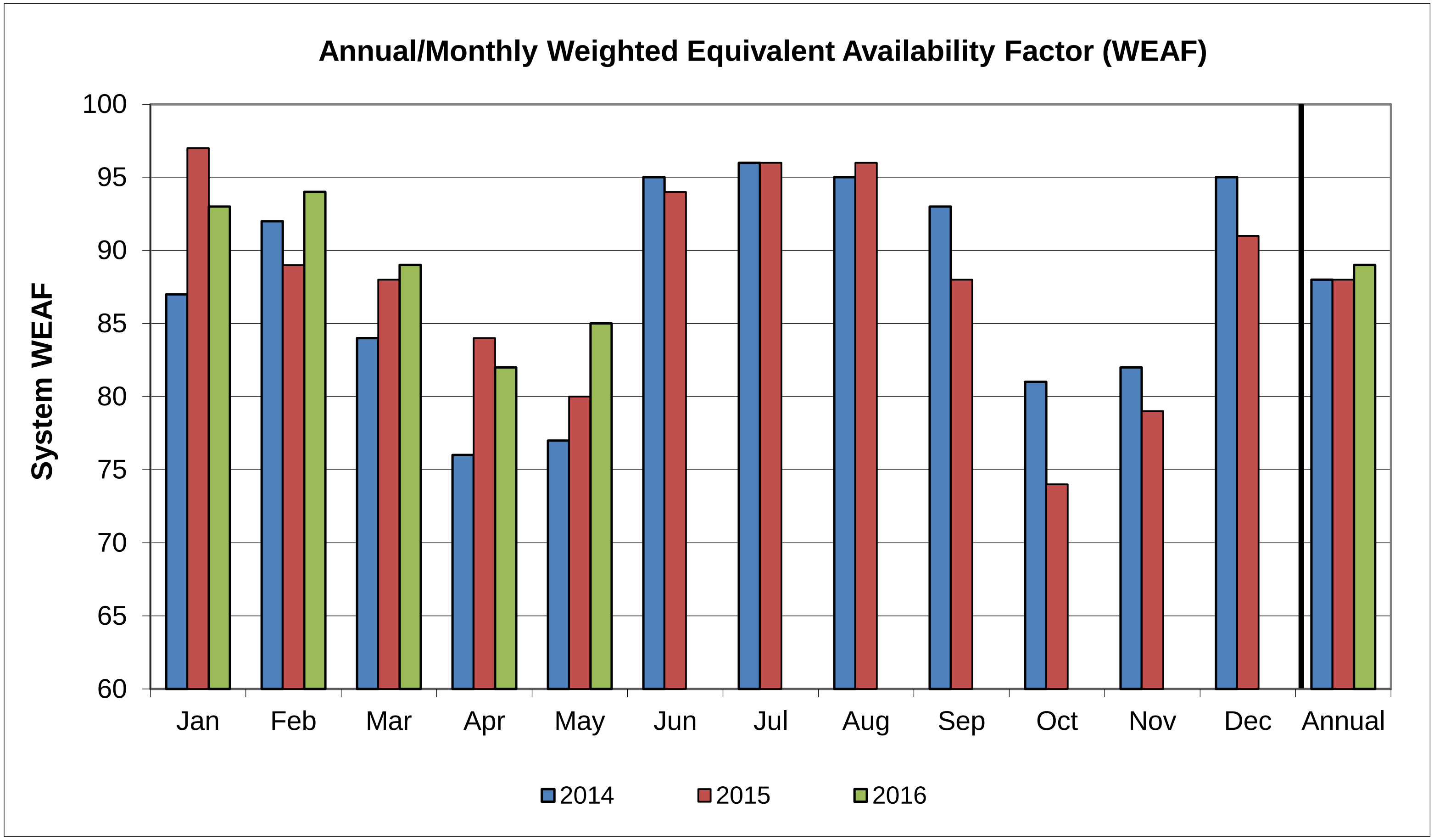
Hourly RT LMPs, May 1-25, 2016



Binding spinning reserve constraints

Binding spinning reserve constraints over the morning pickup

System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2016	93	94	89	82	85								89
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
2013	89	87	85	76	81	90	90	92	88	80	81	92	86

Data as of 5/31/16

BACK-UP DETAIL

LOAD RESPONSE

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

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	85.4	4.9	125.2	0.0	215.5
NH	7.4	13.5	82.9	0.0	103.7
VT	27.1	4.3	103.0	0.0	134.4
CT	83.6	97.6	60.4	355.4	597.0
RI	10.1	17.5	176.6	0.0	204.3
SEMA	11.2	11.1	240.3	0.0	262.6
WCMA	29.0	24.1	227.0	52.4	332.5
NEMA	40.4	12.0	487.5	0.0	540.0
Total	**294.3**	**184.9**	**1,502.9**	**407.9**	**2,390.0**

* 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

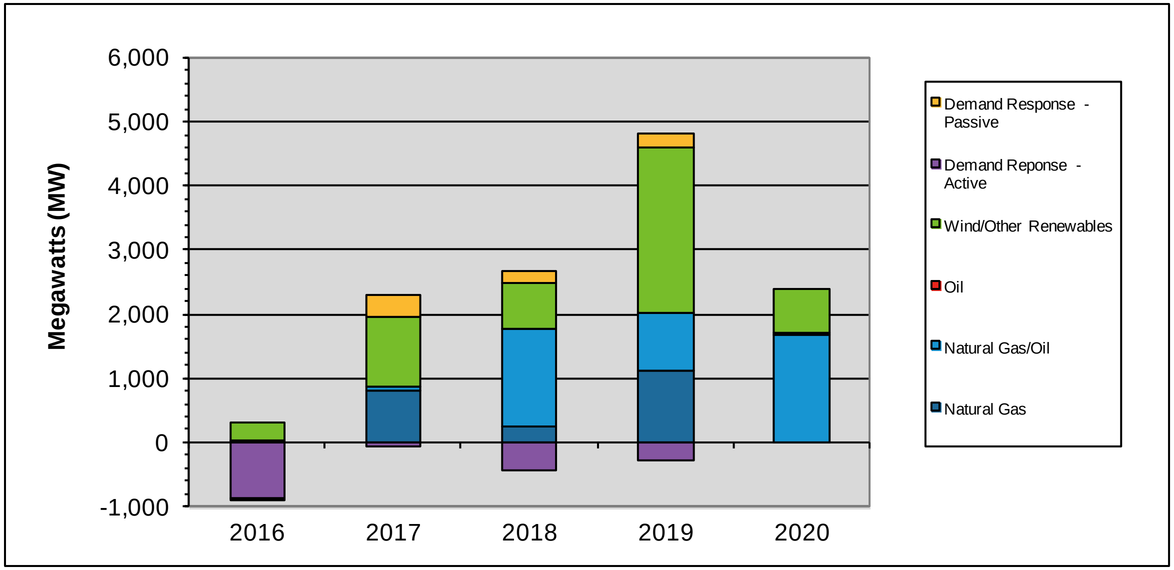
New Generation Update

Based on Queue as of 5/31/16

- No new projects have applied for interconnection study since the last update
- No projects went commercial and three projects withdrew from the queue, resulting in a net decrease in new generation projects of 2,045 MW
- In total, 88 generation projects are currently being tracked by the ISO, totaling approximately 11,800 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Demand Response - Passive	-12	330	196	212	0	726	6.6
Demand Response - Active	-868	-37	-433	-270	0	-1,607	-14.7
Wind & Other Renewables	280	1,087	719	2,586	672	5,344	48.9
Oil	0	0	0	0	24	24	0.2
Natural Gas/Oil[2]	10	74	1,519	904	1,695	4,202	38.5
Natural Gas	22	808	260	1,140	0	2,230	20.4
Totals	**-568**	**2,262**	**2,261**	**4,573**	**2,391**	**10,918**	**100.0**

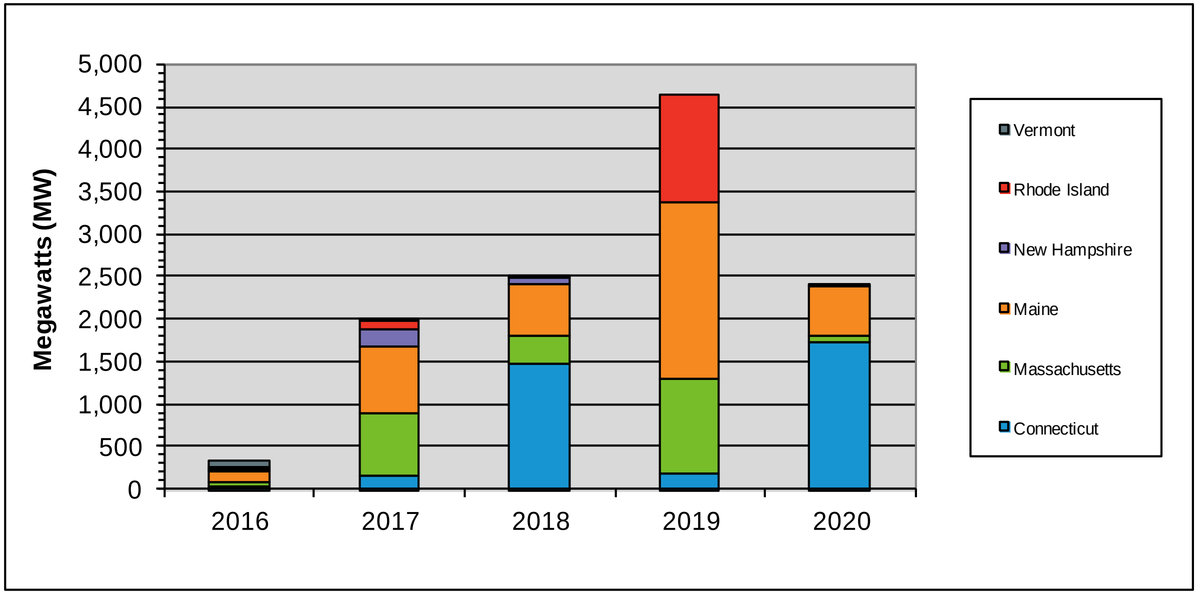
[1] Sum may not equal 100% due to rounding

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

- 2016 values include the 44 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	Total MW	% of Total[1]
Vermont	77	2	30	0	0	109	0.9
Rhode Island	22	89	0	1,268	0	1,379	11.7
New Hampshire	30	218	75	0	5	328	2.8
Maine	107	774	607	2,069	601	4,158	35.2
Massachusetts	56	737	325	1,120	66	2,304	19.5
Connecticut	20	149	1,461	173	1,719	3,522	29.8
Totals	**312**	**1,969**	**2,498**	**4,630**	**2,391**	**11,800**	**100.0**

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

- 2016 values reflect the 44 MW of generation that has gone commercial in 2016

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Fuel Type	**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	15	2,293	0	0	15	2,293
Natural Gas/Oil	13	4,202	0	0	13	4,202
Oil	1	24	0	0	1	24
Solar	14	662	3	50	11	612
Wind	33	4,261	5	317	28	3,944
Battery Storage	3	93	0	0	3	93
Total	88	11,756	8	367	80	11,389

- 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

	Total		Green		Yellow	
Operating Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Baseload	6	185	0	0	6	185
Intermediate	24	5,816	0	0	24	5,816
Peaker	25	1,494	3	50	22	1,444
Wind Turbine	33	4,261	5	317	28	3,944
Total	88	11,756	8	367	80	11,389

- 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

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	**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	15	2,293	1	63	11	2,041	3	189	0	0
Natural Gas/Oil	13	4,202	0	0	10	3,742	3	460	0	0
Oil	1	24	0	0	0	0	1	24	0	0
Solar	14	662	0	0	0	0	14	662	0	0
Wind	33	4,261	0	0	0	0	0	0	33	4,261
Battery Storage	3	93	0	0	0	0	3	93	0	0
Total	88	11,756	6	185	24	5,816	25	1,494	33	4,261

- 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								
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211								
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,848.267**	**1.9**								
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,666.87	143.074								
	Intermittent	876.925	898.955	22.03	922.173	23.218								
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**								
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**								
*****Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,812.84**	**306.688**								
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**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										
	Passive Demand	2,156.151	2153.94	-2.211										
Demand Total		**2,803.411**	**2750.641**	**-52.77**										
Generator	*Non-Intermittent*	29,550.564	29558.181	7.617										
	Intermittent	891.616	864.924	-26.692										
Generator Total		**30,442.18**	**30423.105**	**-19.075**										
Import Total		**1,449**	**1449**	**0**										
*****Grand Total**		**34,694.591**	**34622.746**	**-71.845**										
Net ICR (NICR)		**34,189**	**33883**	**-306**										

* 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

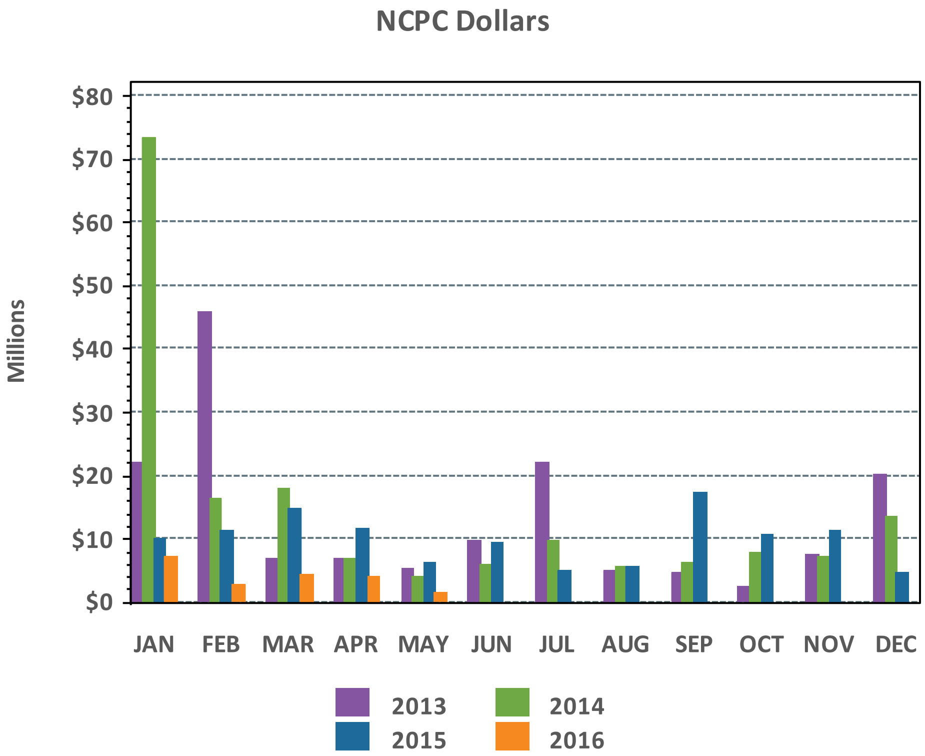
Definitions

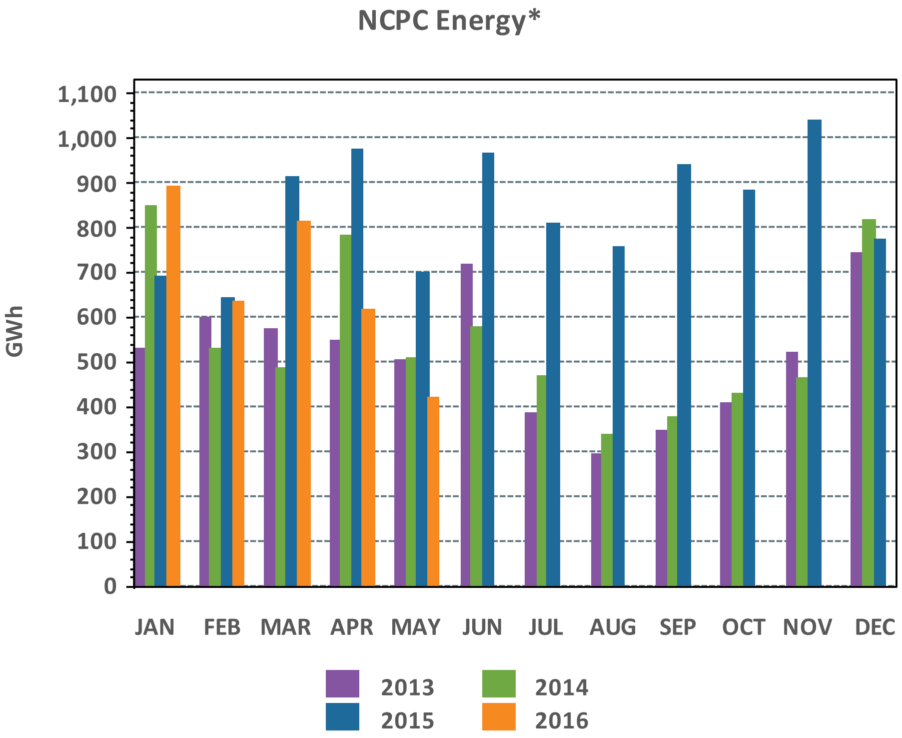
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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 NCPC

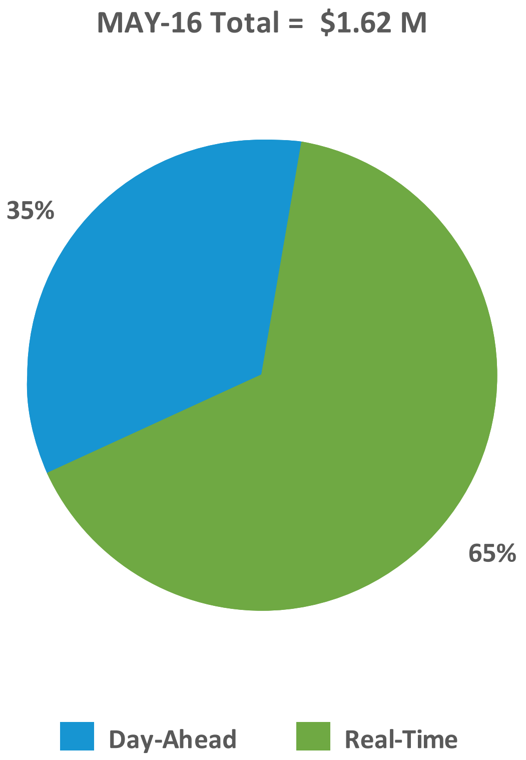
Year-Over-Year Total NCPC Dollars and Energy

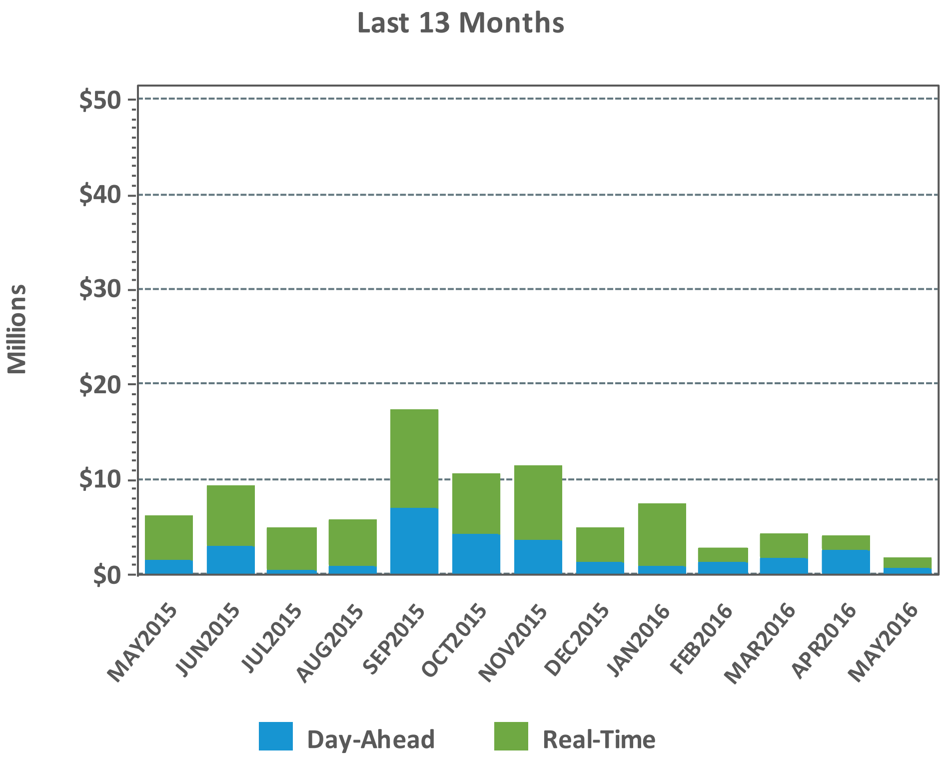




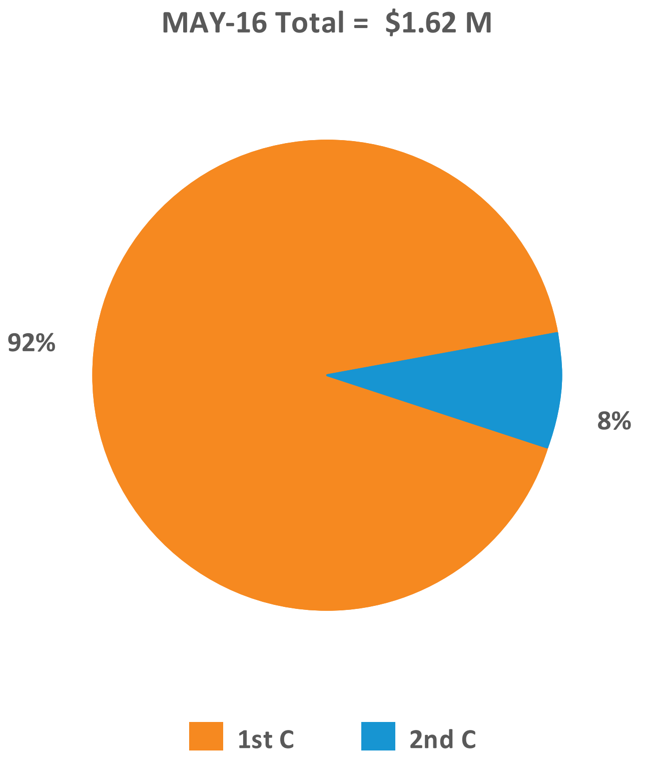
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

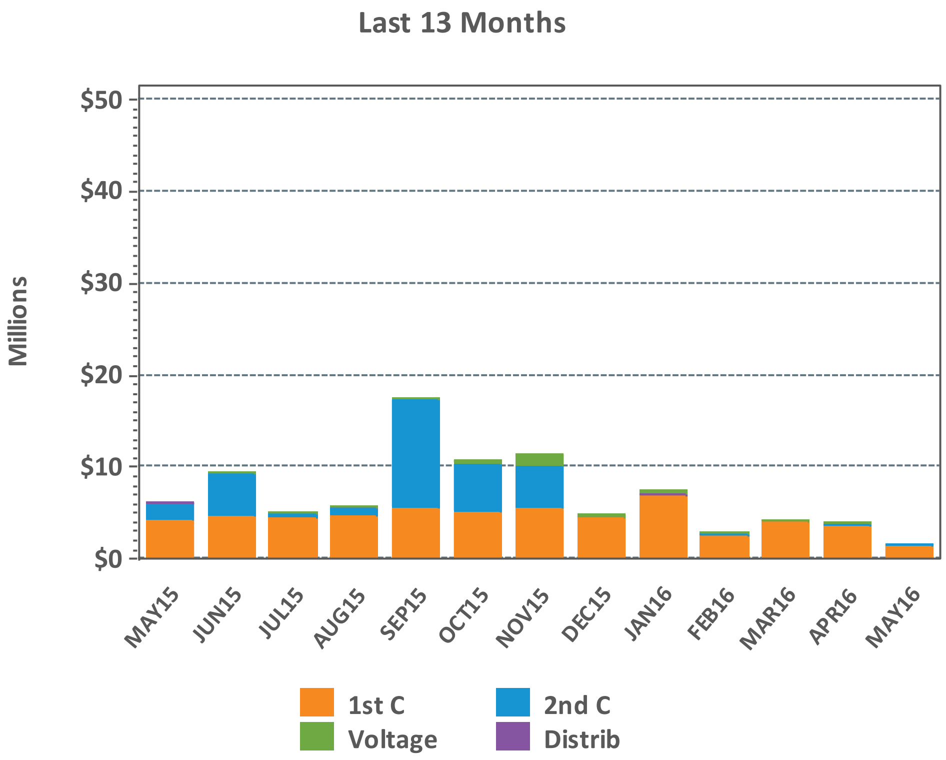
DA and RT NCPC Charges





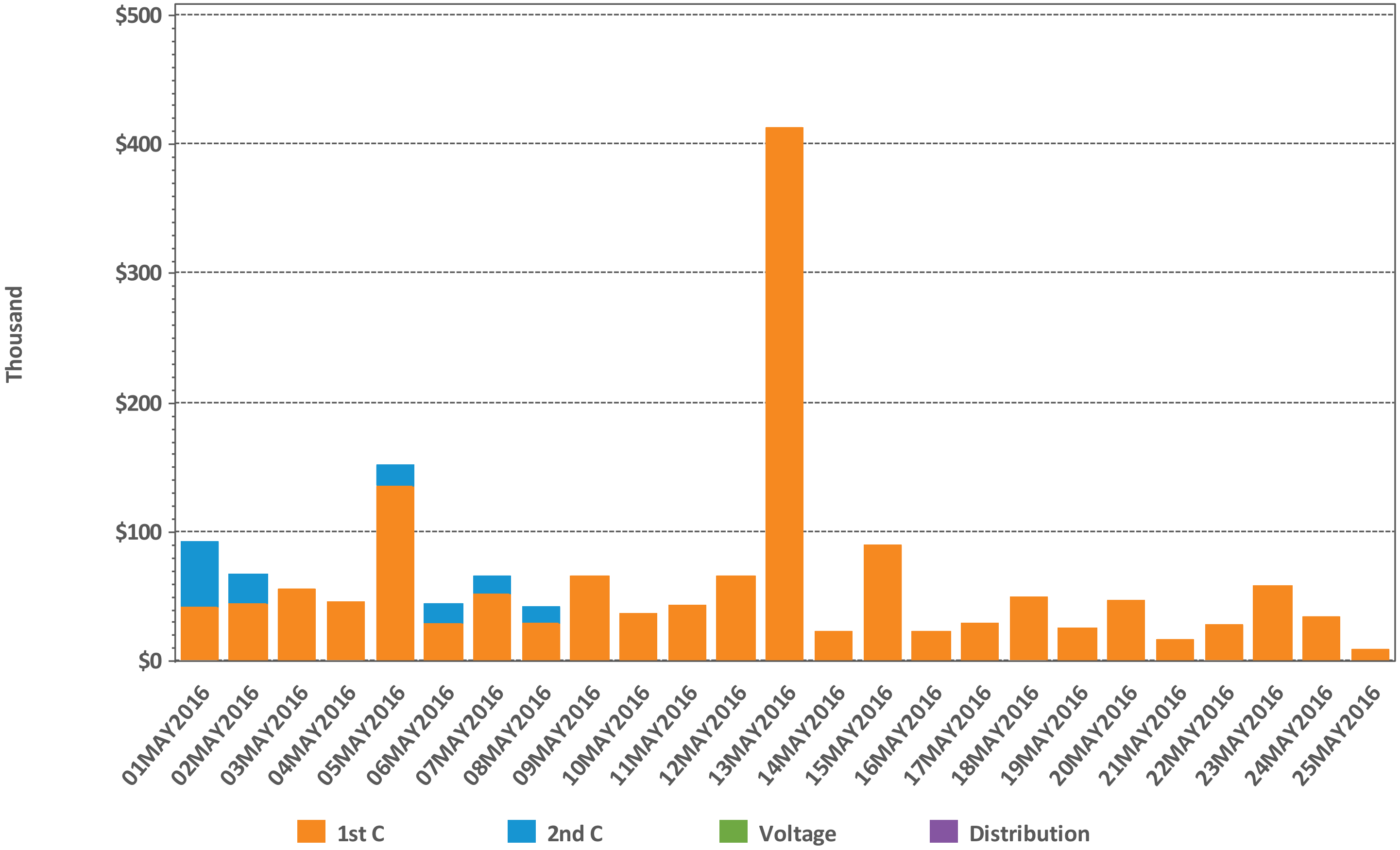
NCPC Charges by Type



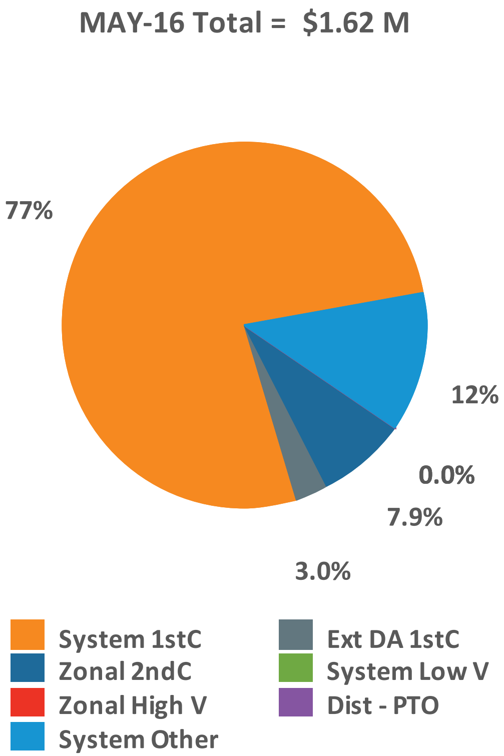


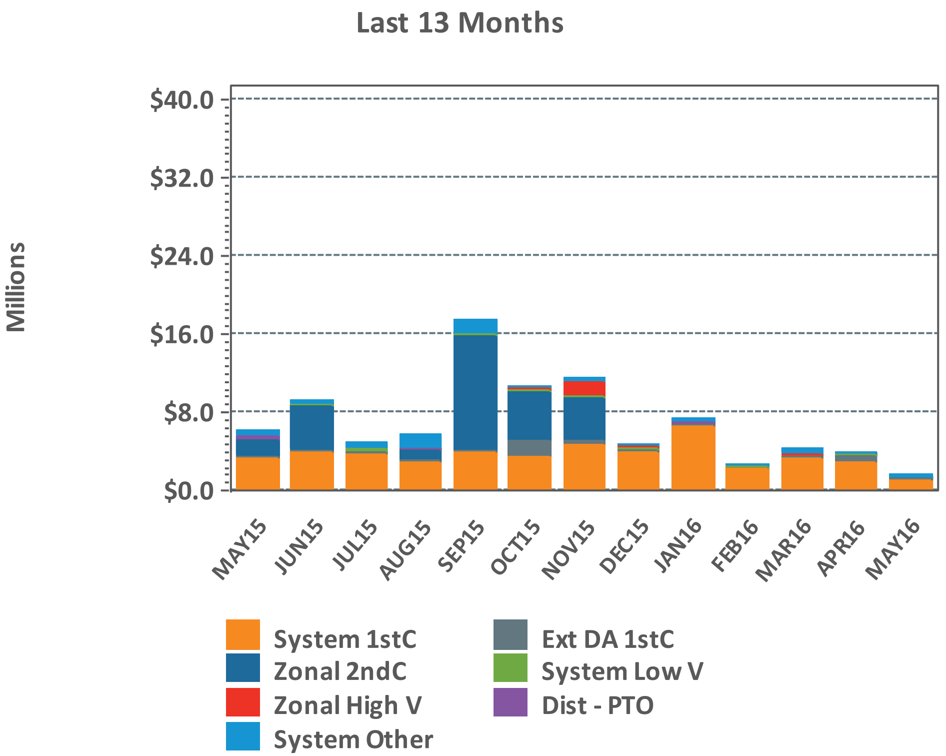
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

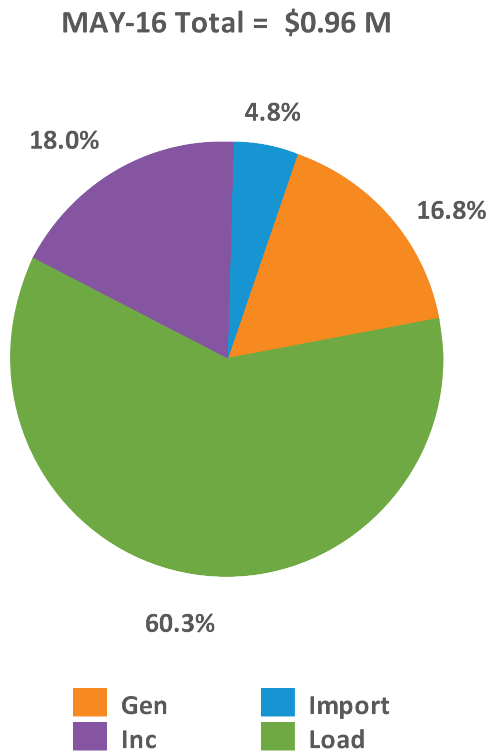


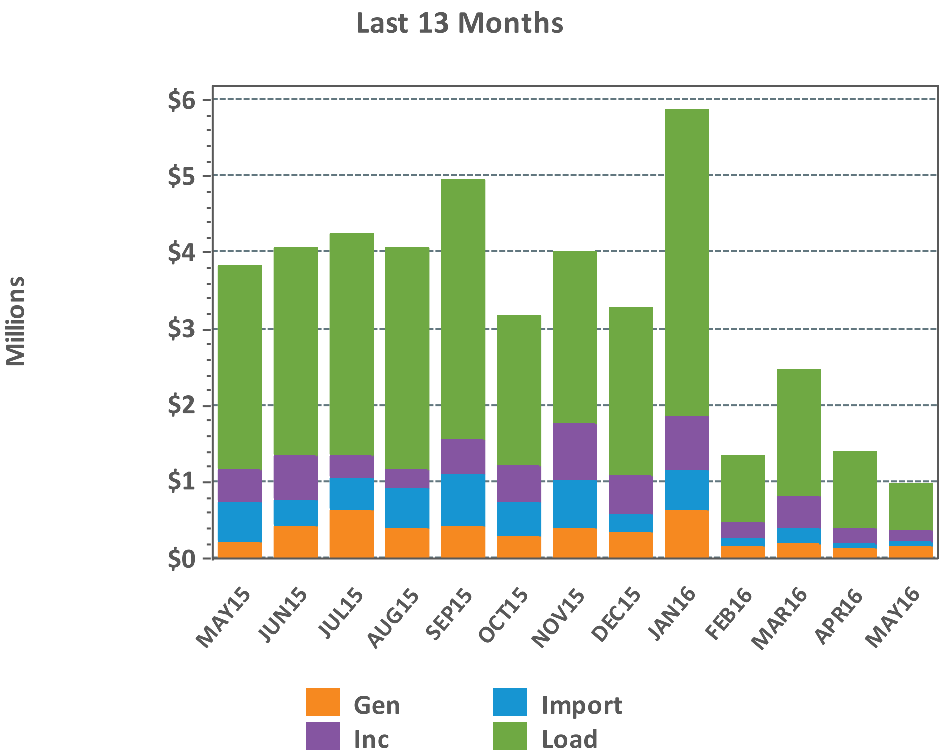
NCPC Charges by Allocation





RT First Contingency Charges by Deviation Type





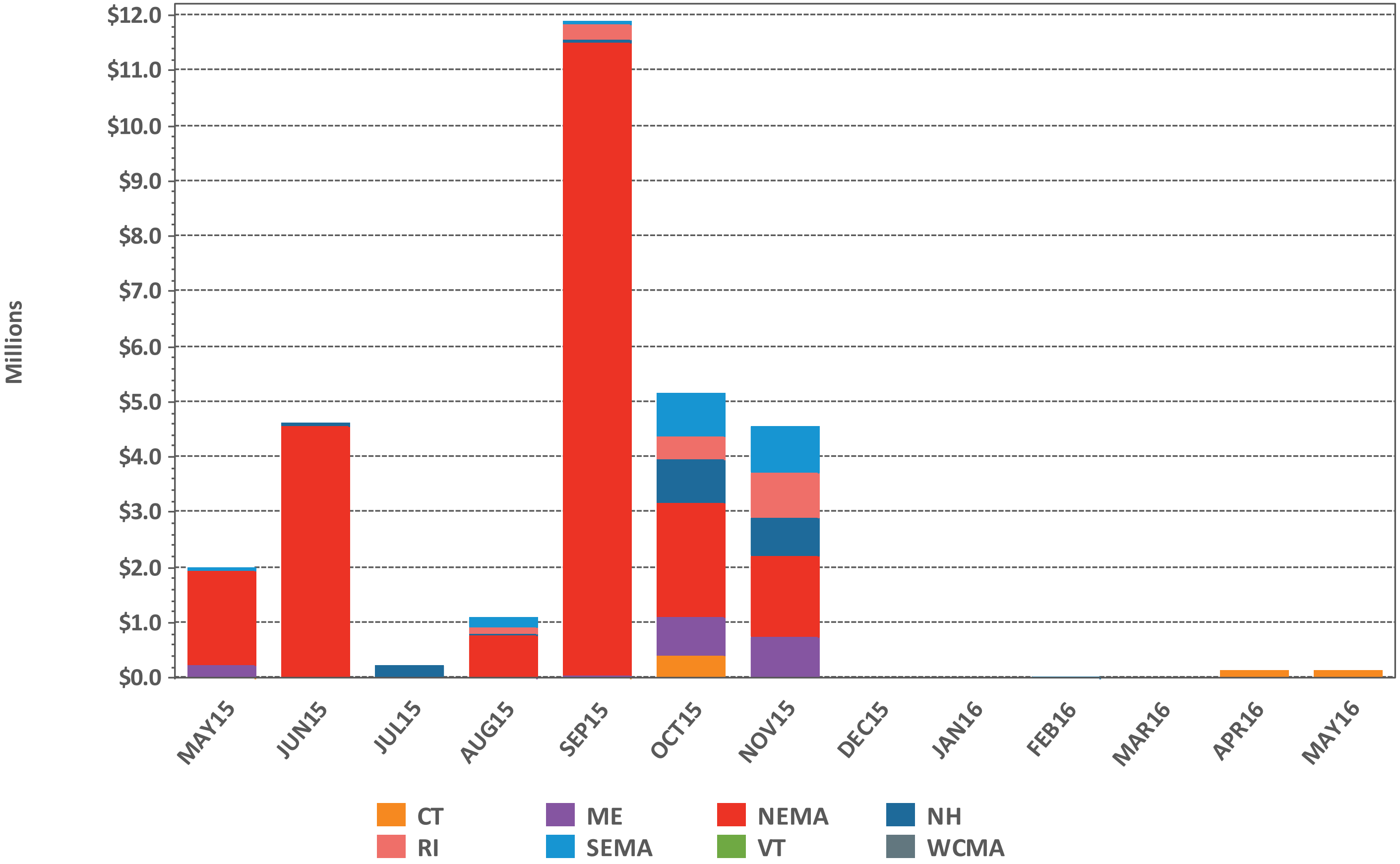
Gen – Generator deviations

Inc – Increment Offer deviations

Imp – Import deviations

Load – Load obligation deviations

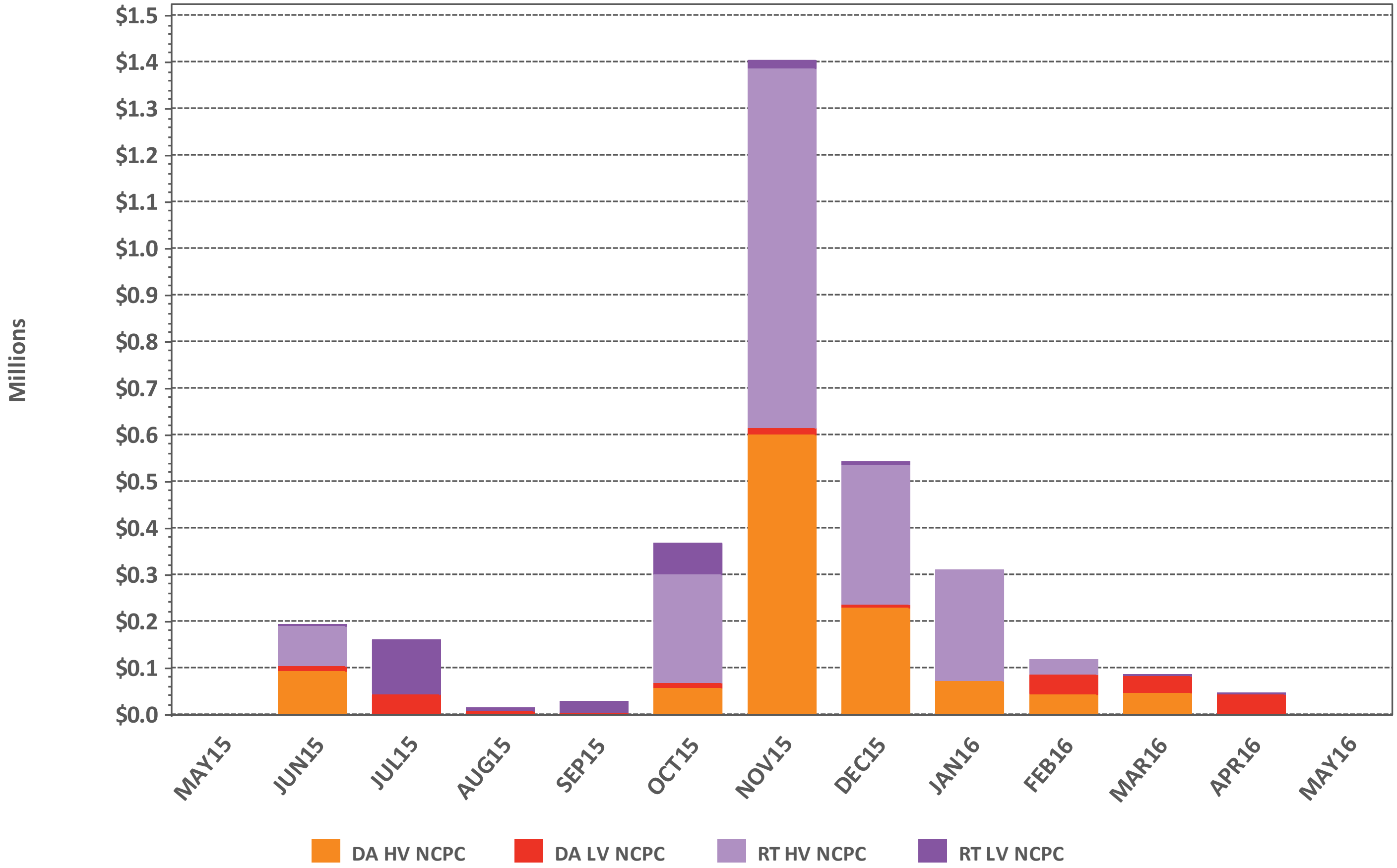
LSCPR Charges by Zone



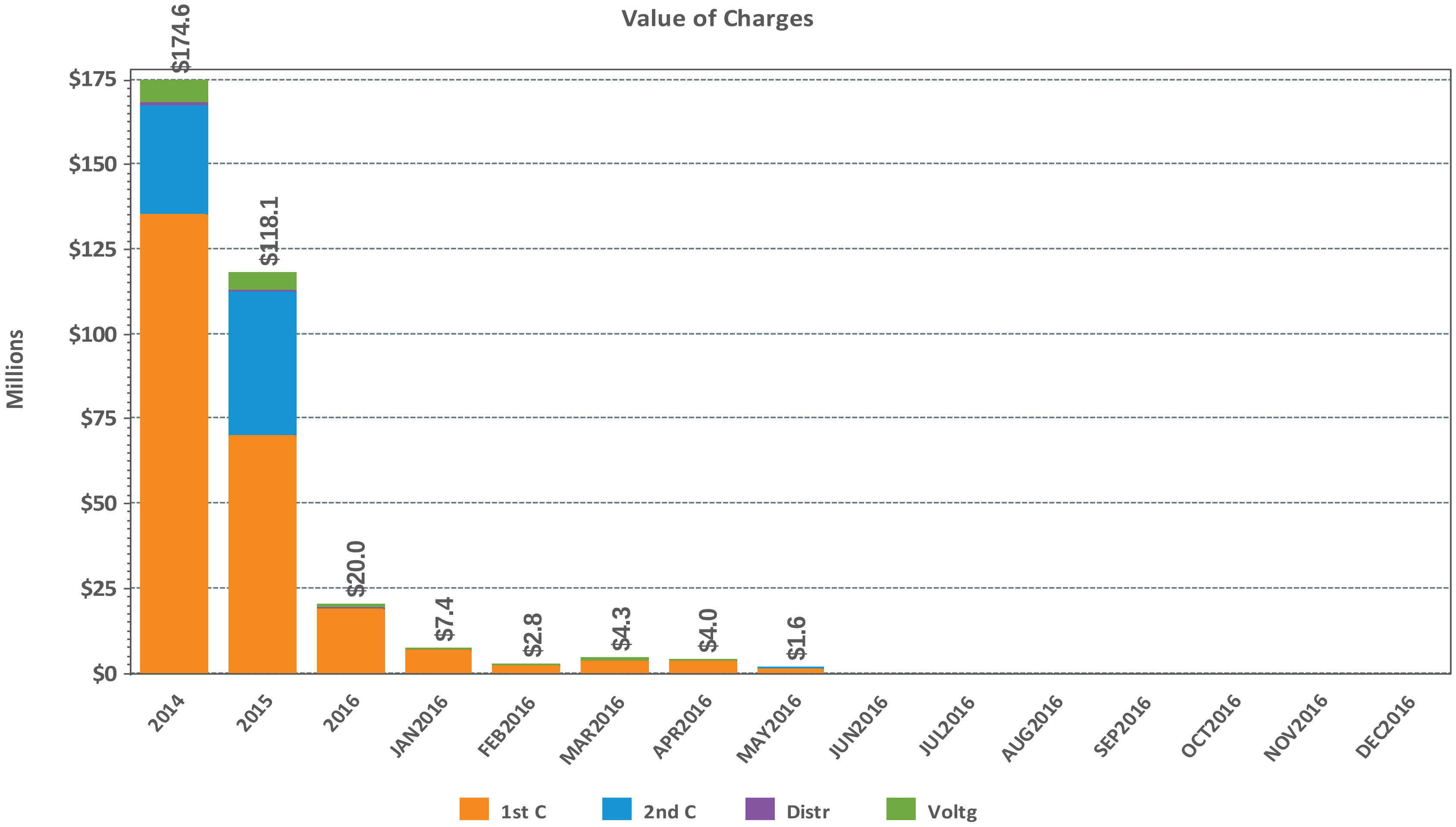
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

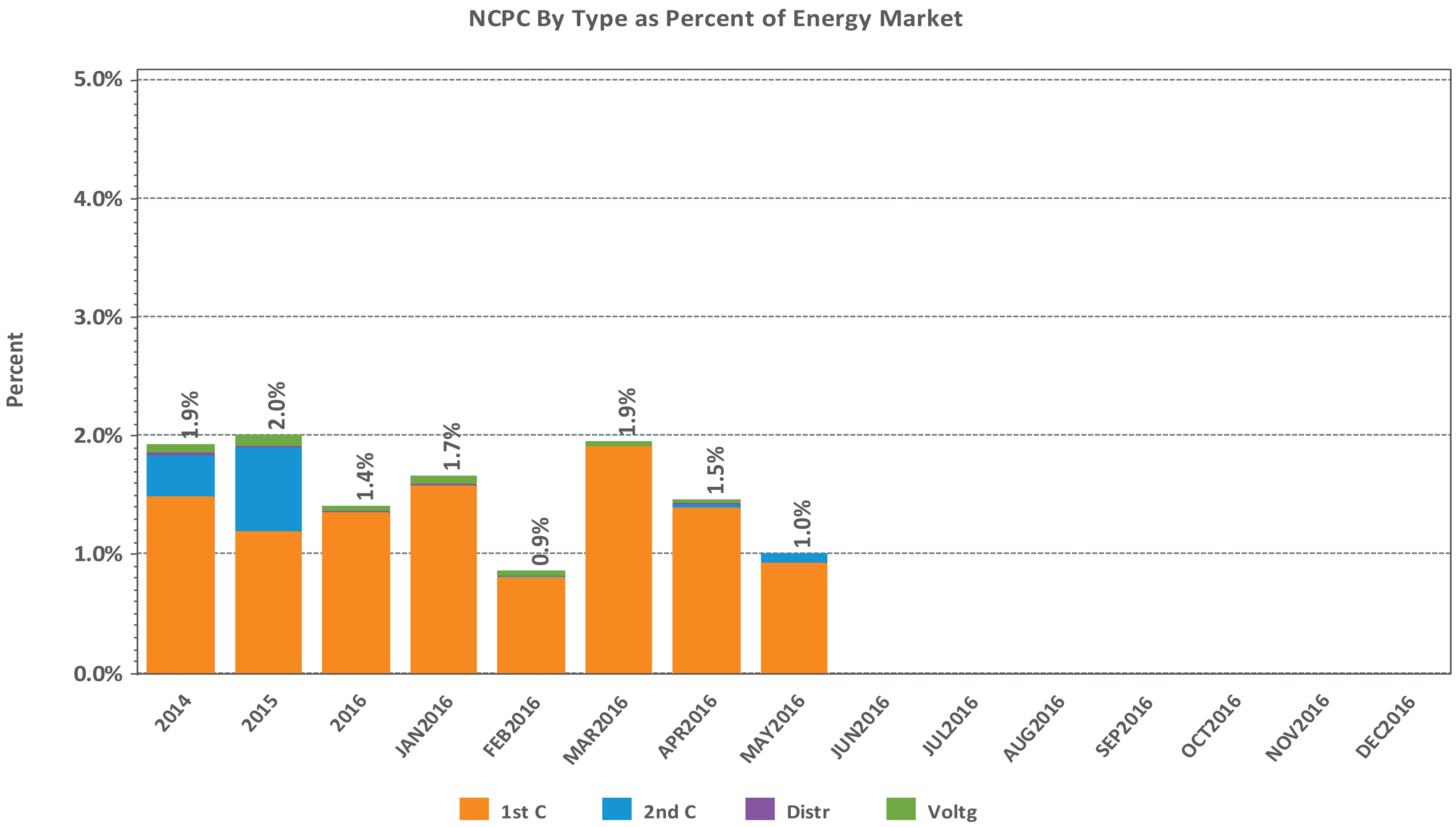
NCPC Charges for Voltage Support and High Voltage Control



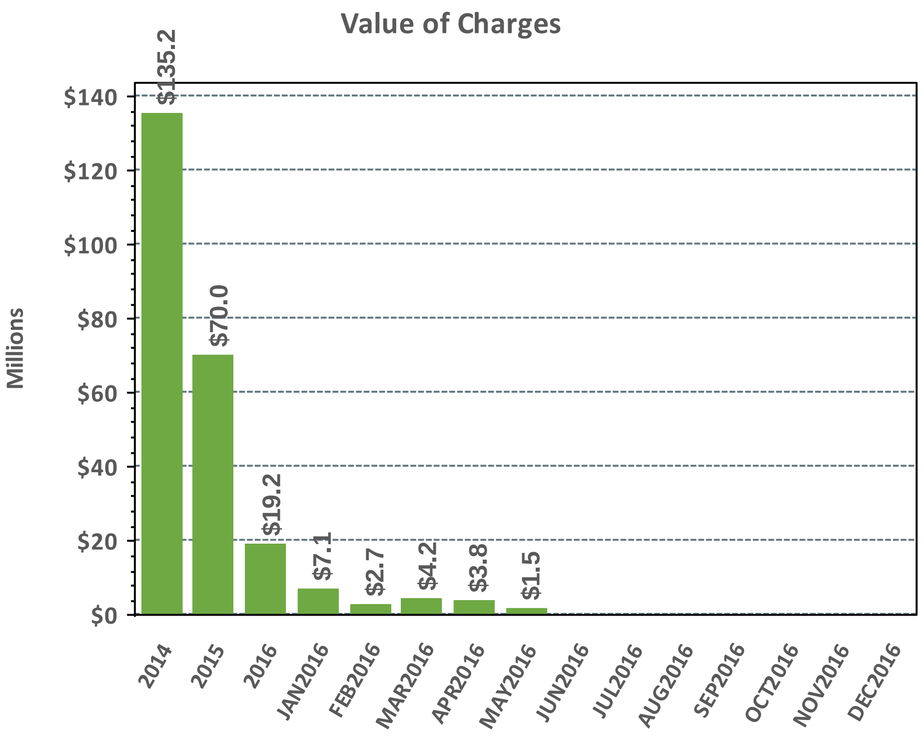
NCPC Charges by Type

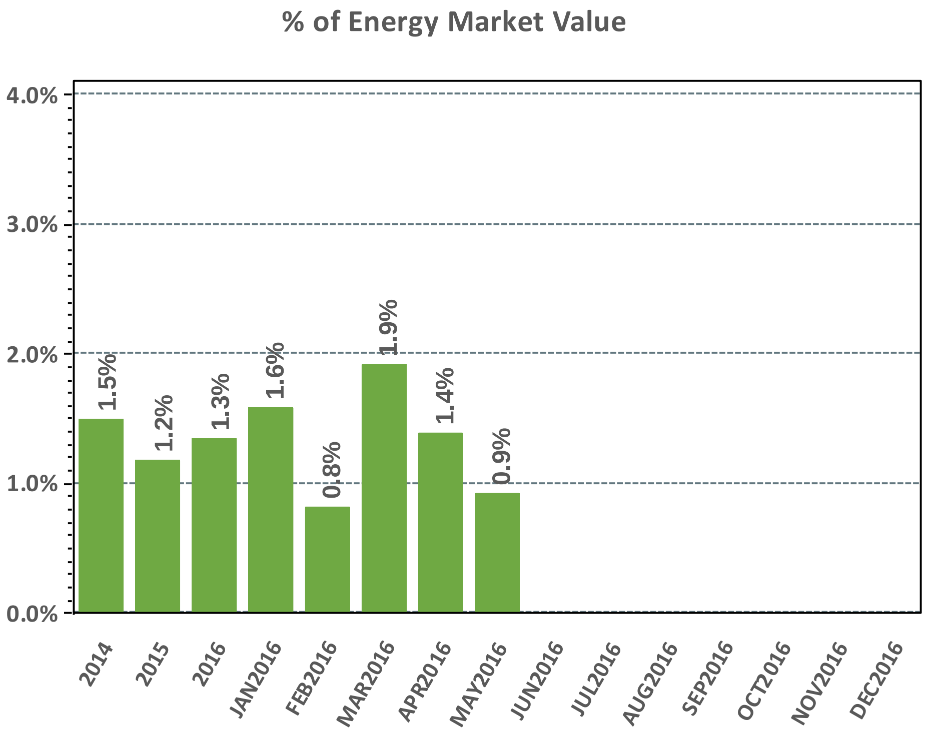


NCPC Charges as Percent of Energy Market



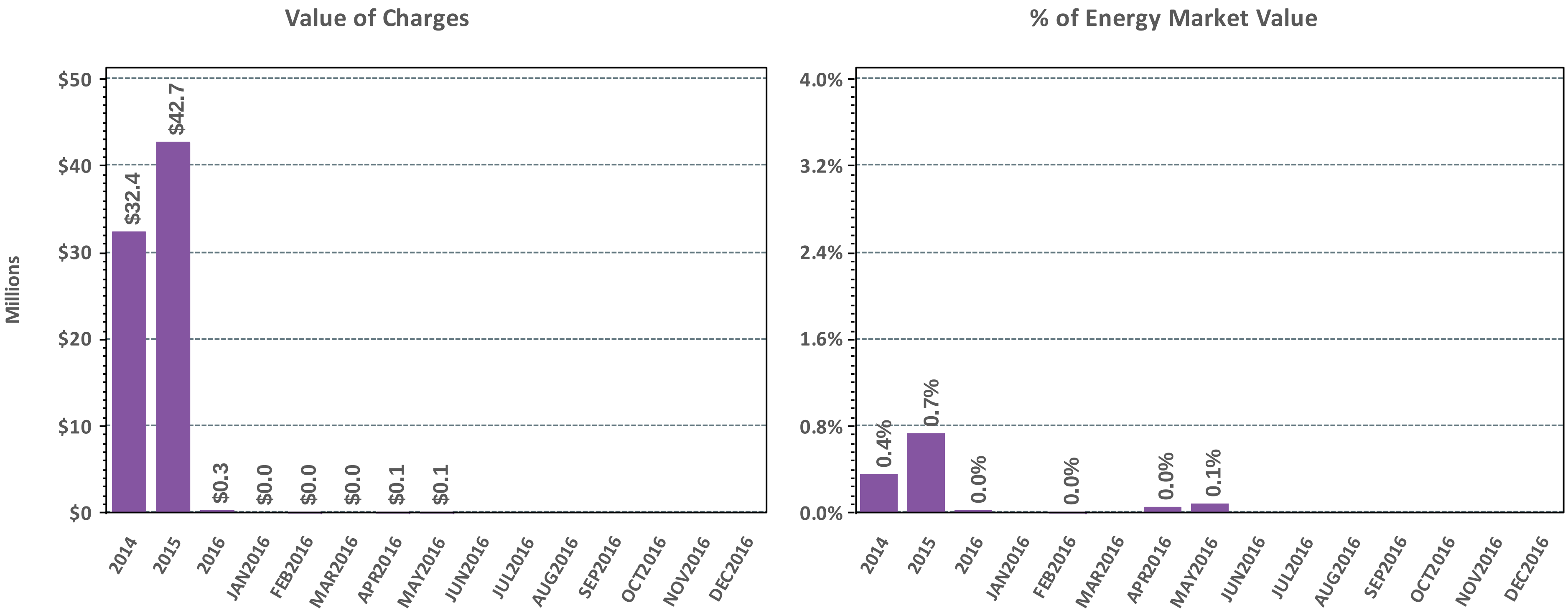
First Contingency NCPC Charges





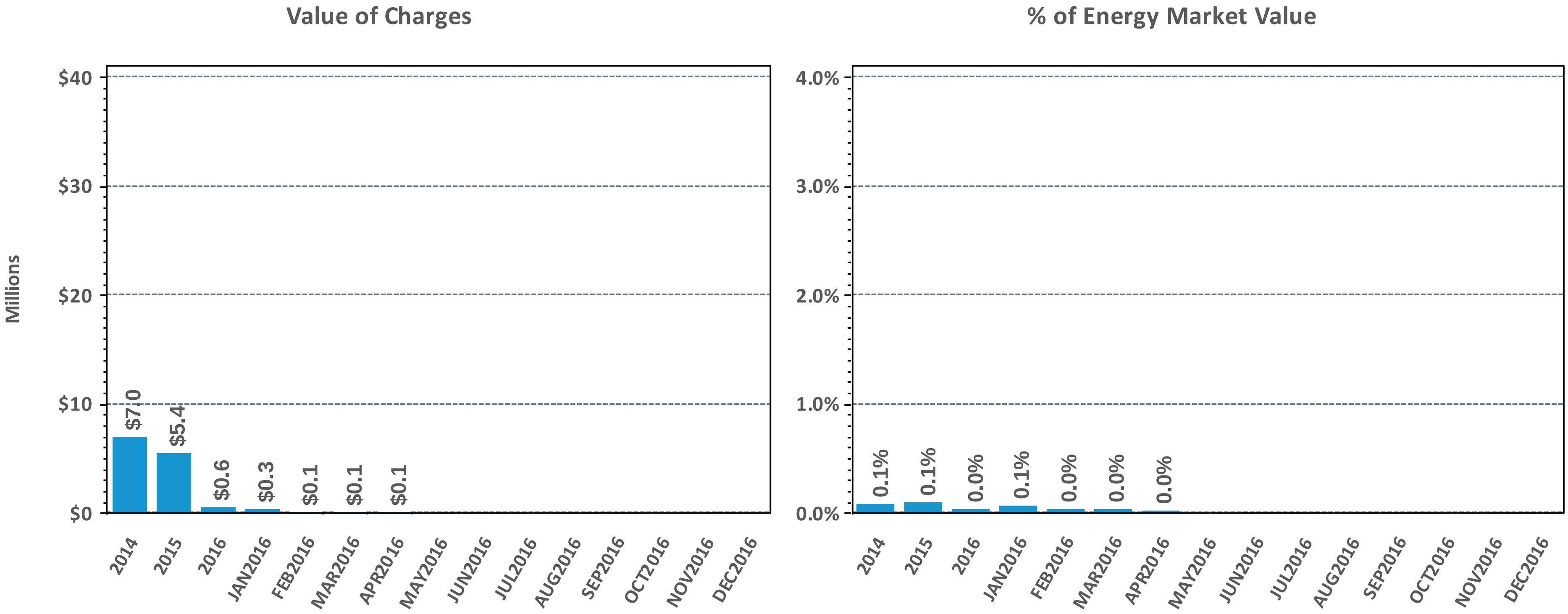
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

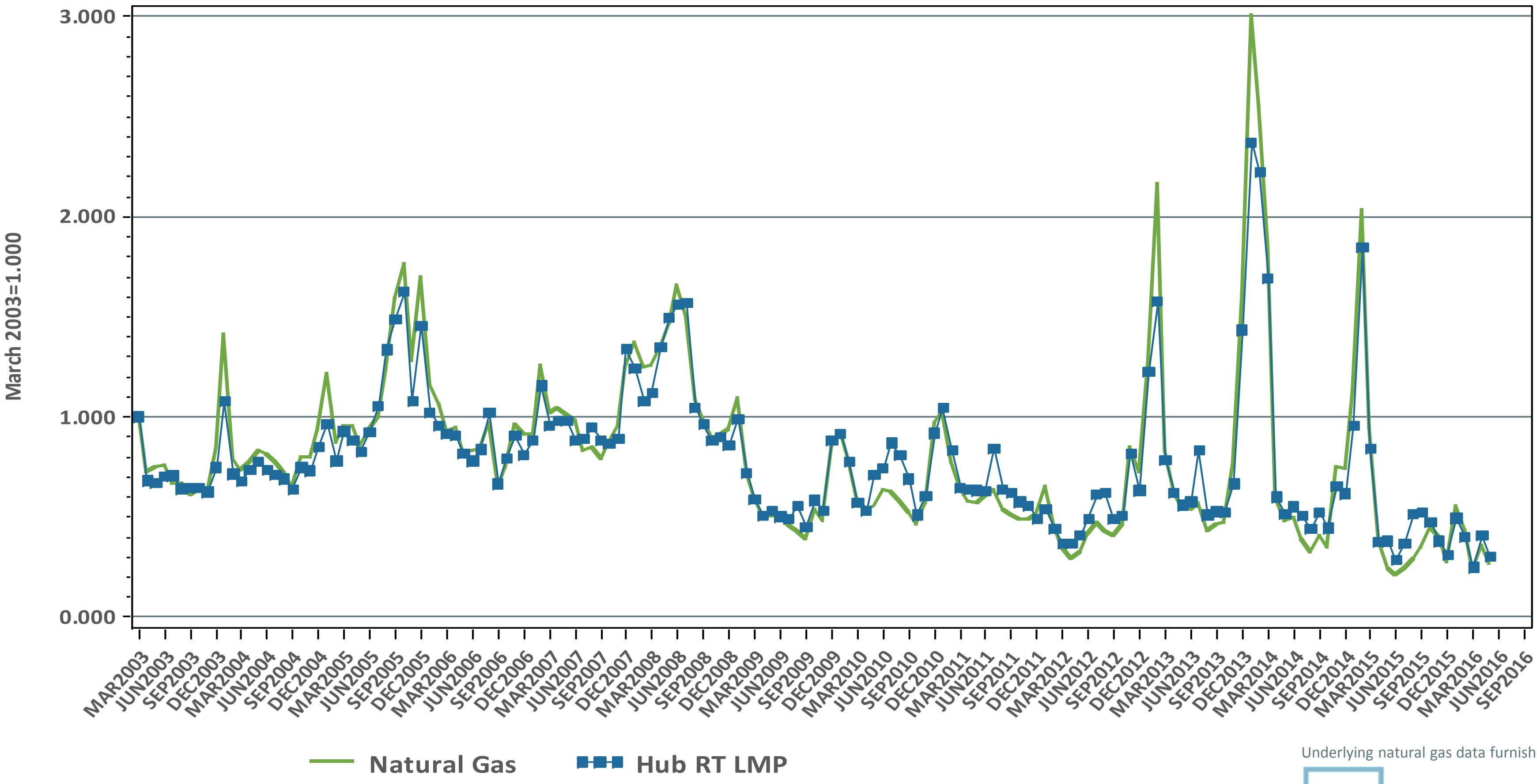
DA vs. RT LMPs ($/MWh)

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%

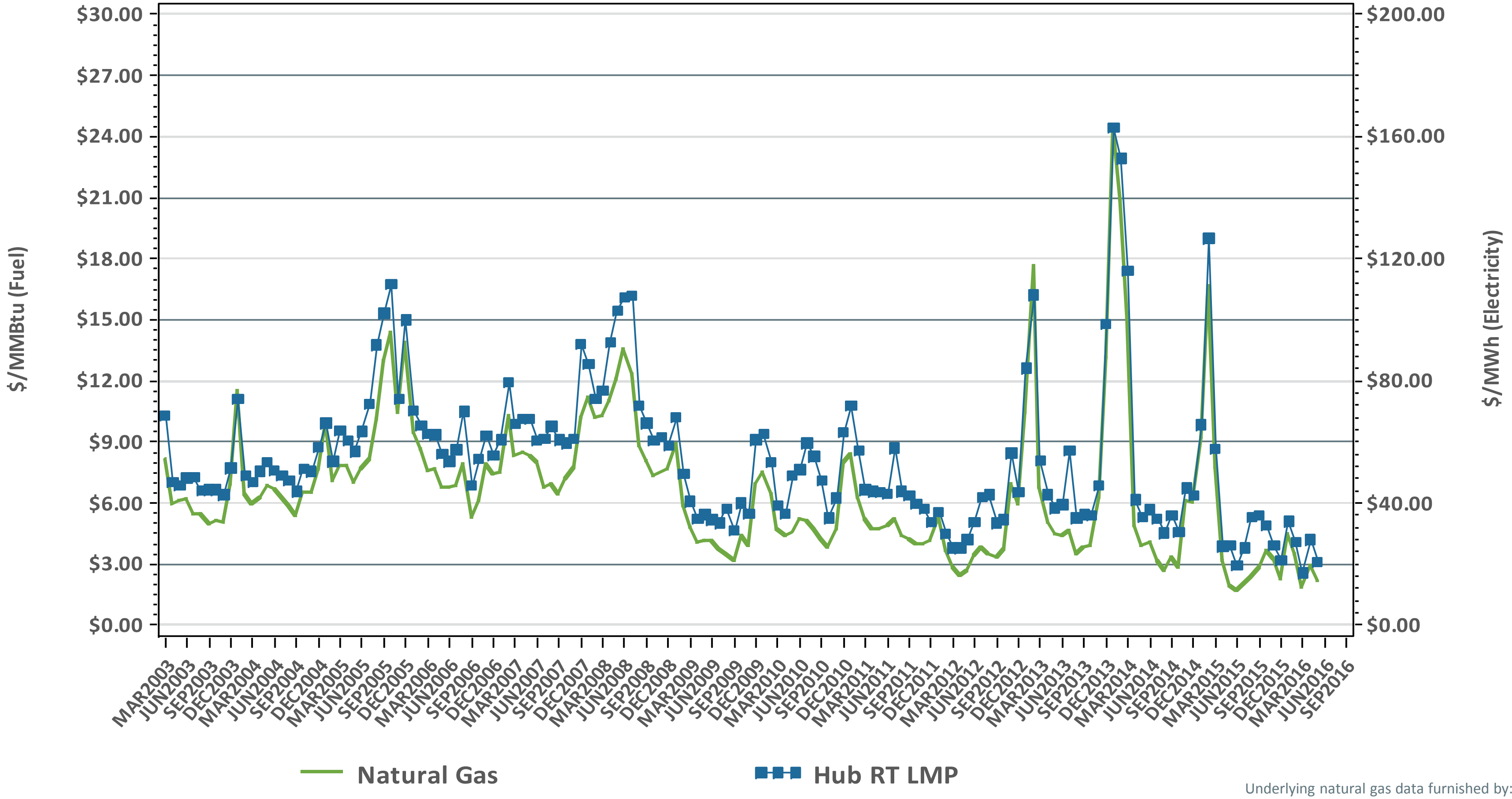
May-15	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$25.05	$25.21	$24.60	$24.88	$25.40	$24.73	$24.85	$25.05	$24.92
Real-Time	$27.43	$26.43	$25.79	$26.11	$26.17	$25.84	$26.07	$26.26	$26.12
RT Delta %	9.5%	4.9%	4.8%	4.9%	3.0%	4.5%	4.9%	4.8%	4.8%
May-16	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$20.71	$20.78	$20.36	$20.62	$20.54	$20.55	$20.57	$20.78	$20.77
Real-Time	$20.75	$20.79	$20.32	$20.59	$20.43	$20.58	$20.62	$20.77	$20.79
RT Delta %	0.2%	0.1%	-0.2%	-0.2%	-0.5%	0.2%	0.2%	0.0%	0.1%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-17.3%	-17.6%	-17.2%	-17.1%	-19.1%	-16.9%	-17.2%	-17.0%	-16.6%
Yr over Yr RT	-24.4%	-21.3%	-21.2%	-21.1%	-21.9%	-20.4%	-20.9%	-20.9%	-20.4%

Monthly Average Fuel Price and RT Hub LMP Indexes



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

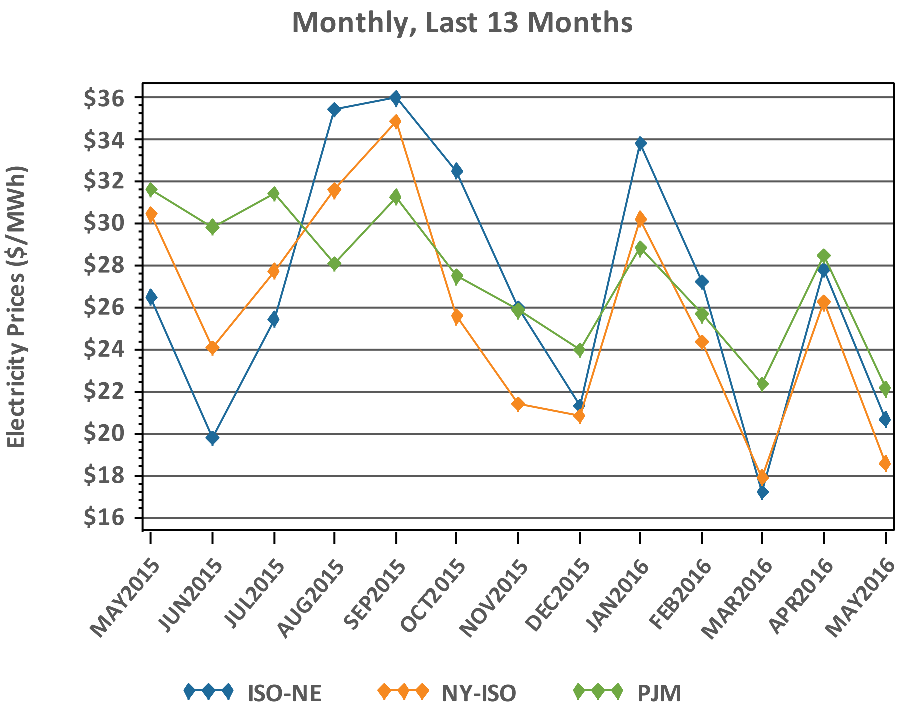
Monthly Average Fuel Price and RT Hub LMP



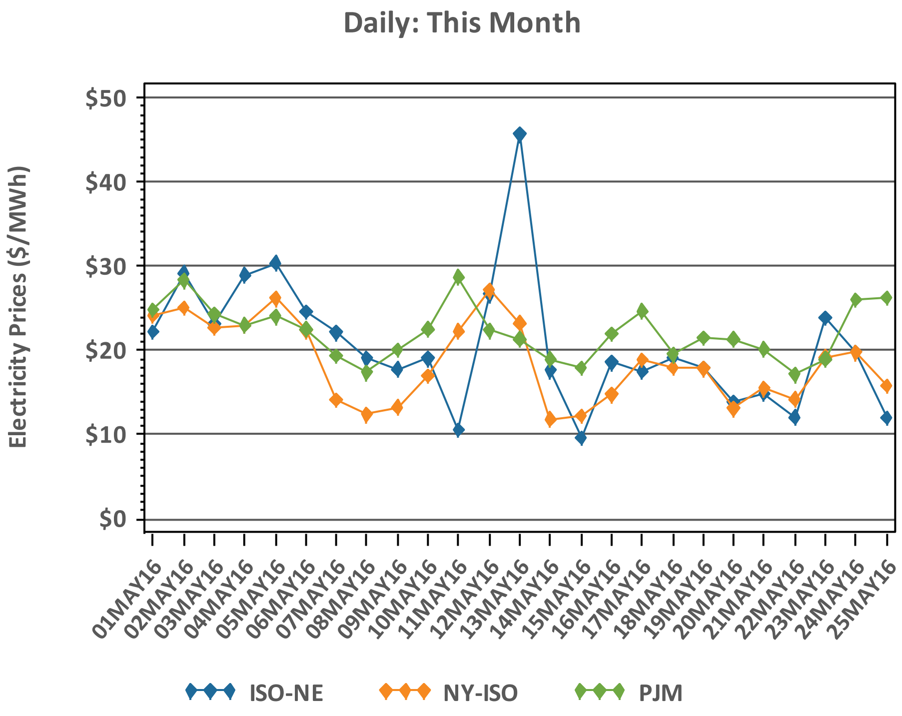
Underlying natural gas data furnished by:

ICE Global markets in clear view

New England, NY, and PJM Real Time Prices

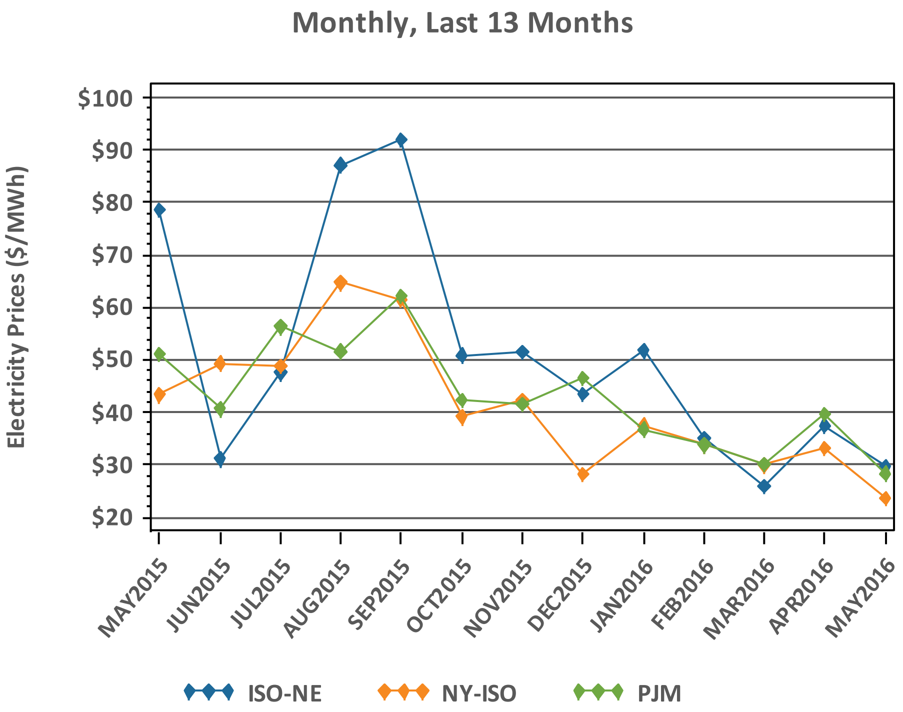


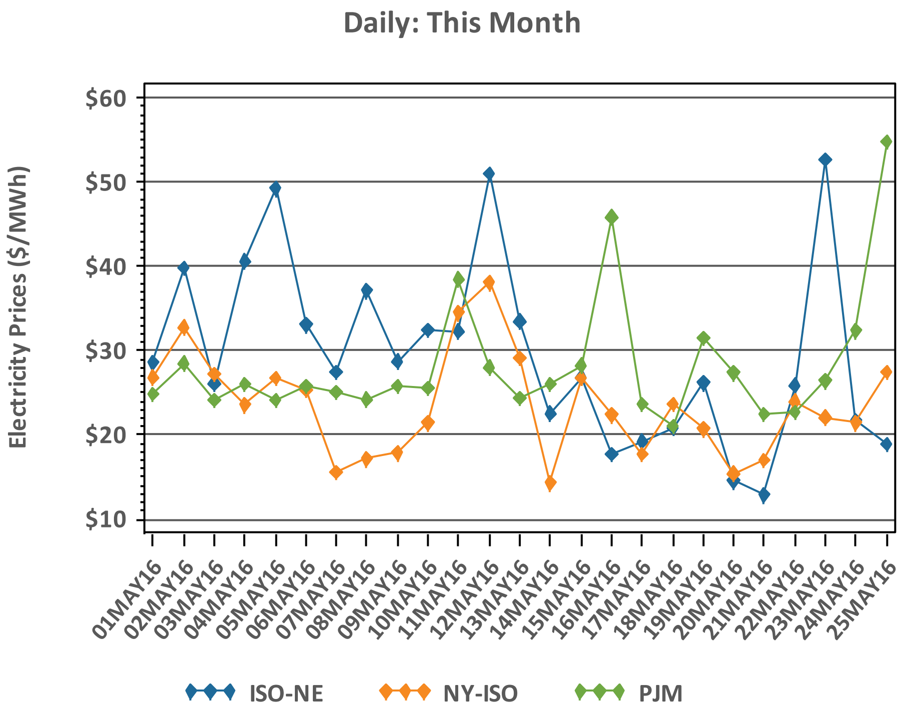
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





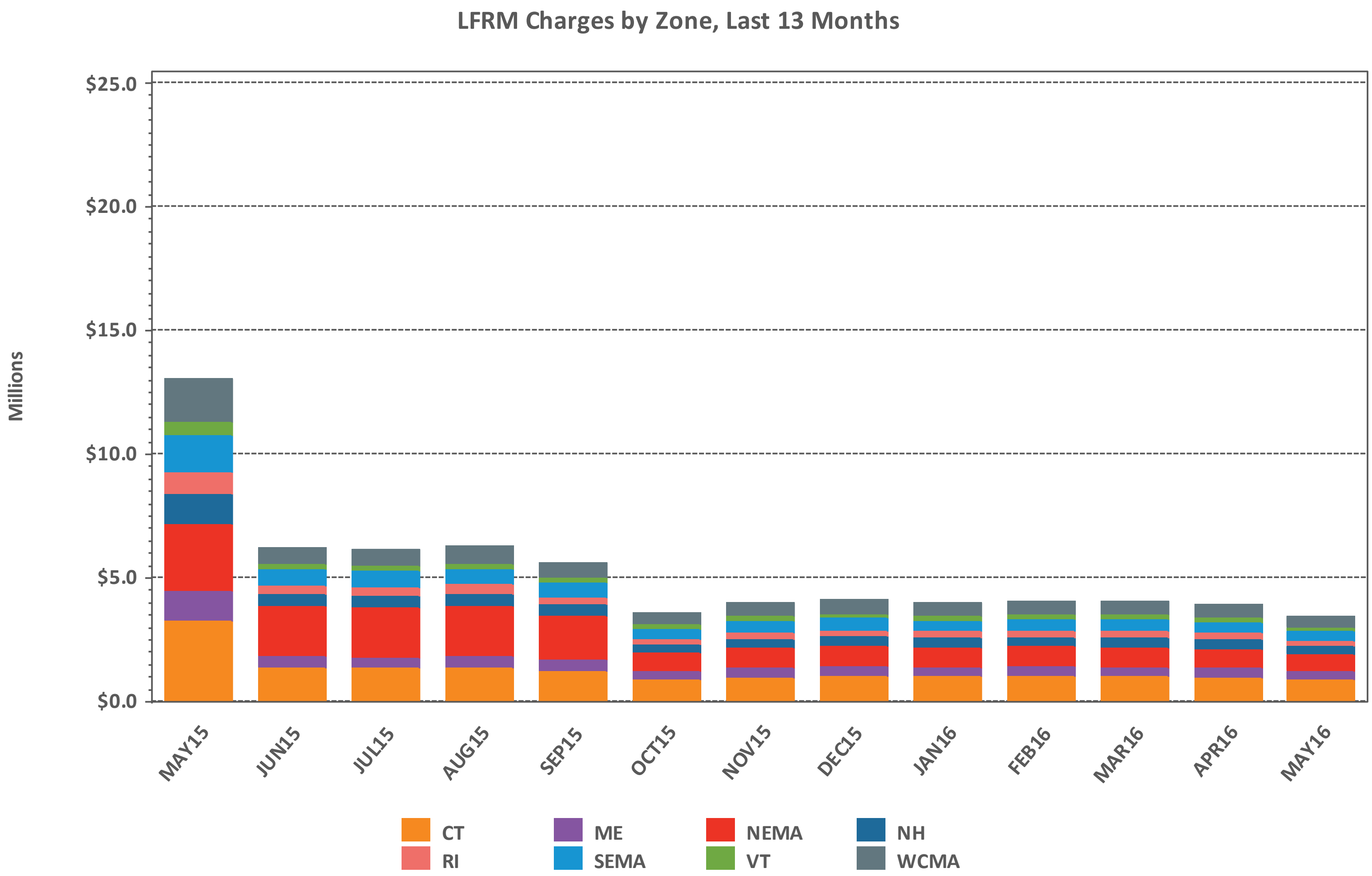
*Forecasted New England peak hour is reflected.

Reserve Market Results – May 2016

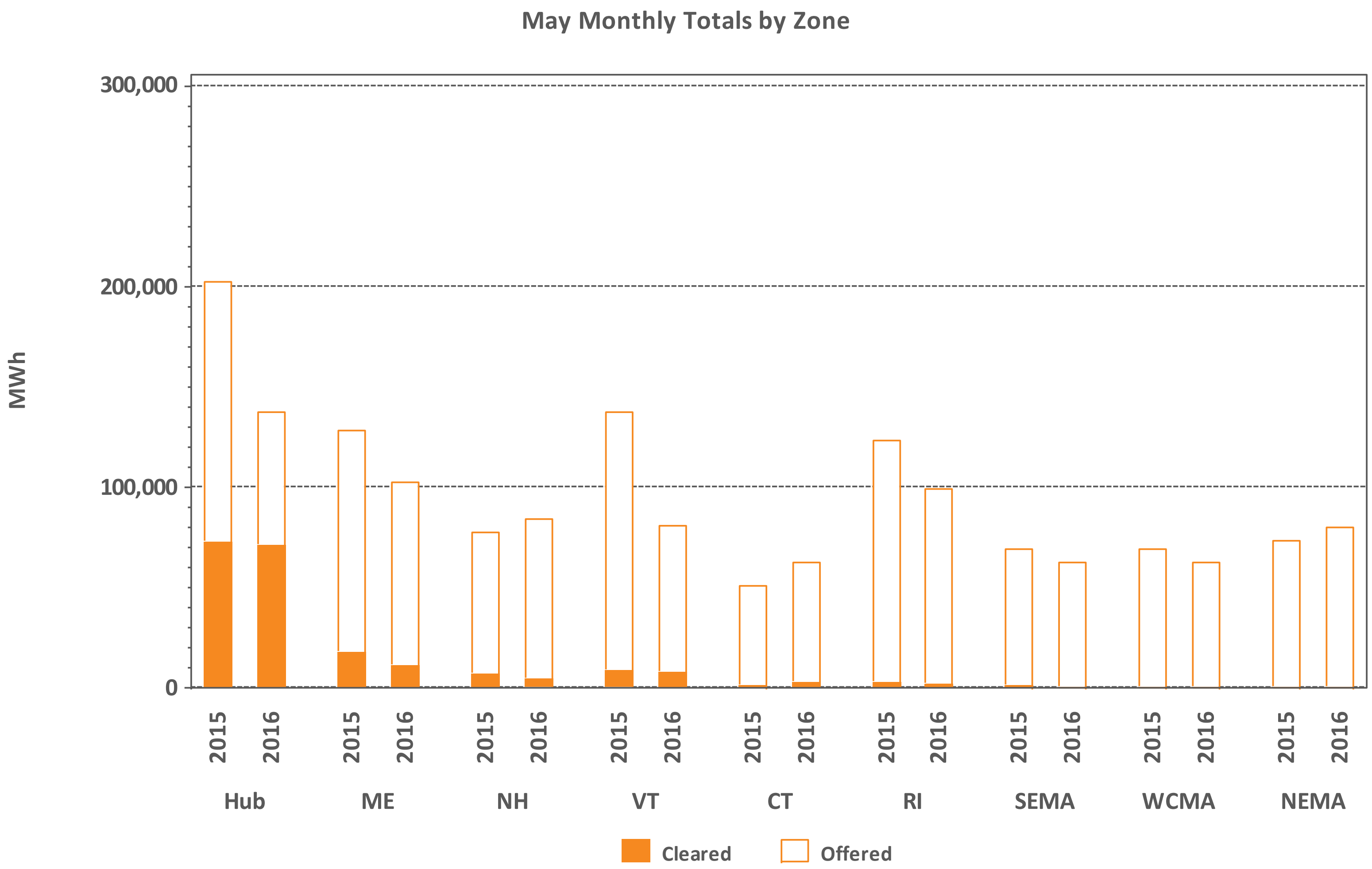
- Maximum potential Forward Reserve Market payments of $3.6M were reduced by credit reductions of $42K, failure-to-reserve penalties of $63K and failure-to-activate penalties of $0, resulting in a net payout of $3.5M or 97% of maximum
  - Rest of System: $1.66M/$1.74M (95%)
  - Southwest Connecticut: $0.31M/$0.32M (97%)
  - Connecticut: $1.49M/$1.50M (99%)
- $118K total Real-Time credits were reduced by $0 in Forward Reserve Energy Obligation Charges for a net of $118K in Real-Time Reserve payments
  - Rest of System: 83 hours, $103K
  - Southwest Connecticut: 83 hours, $5K
  - Connecticut: 83 hours, $7K
  - NEMA: 83 hours, $4K

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

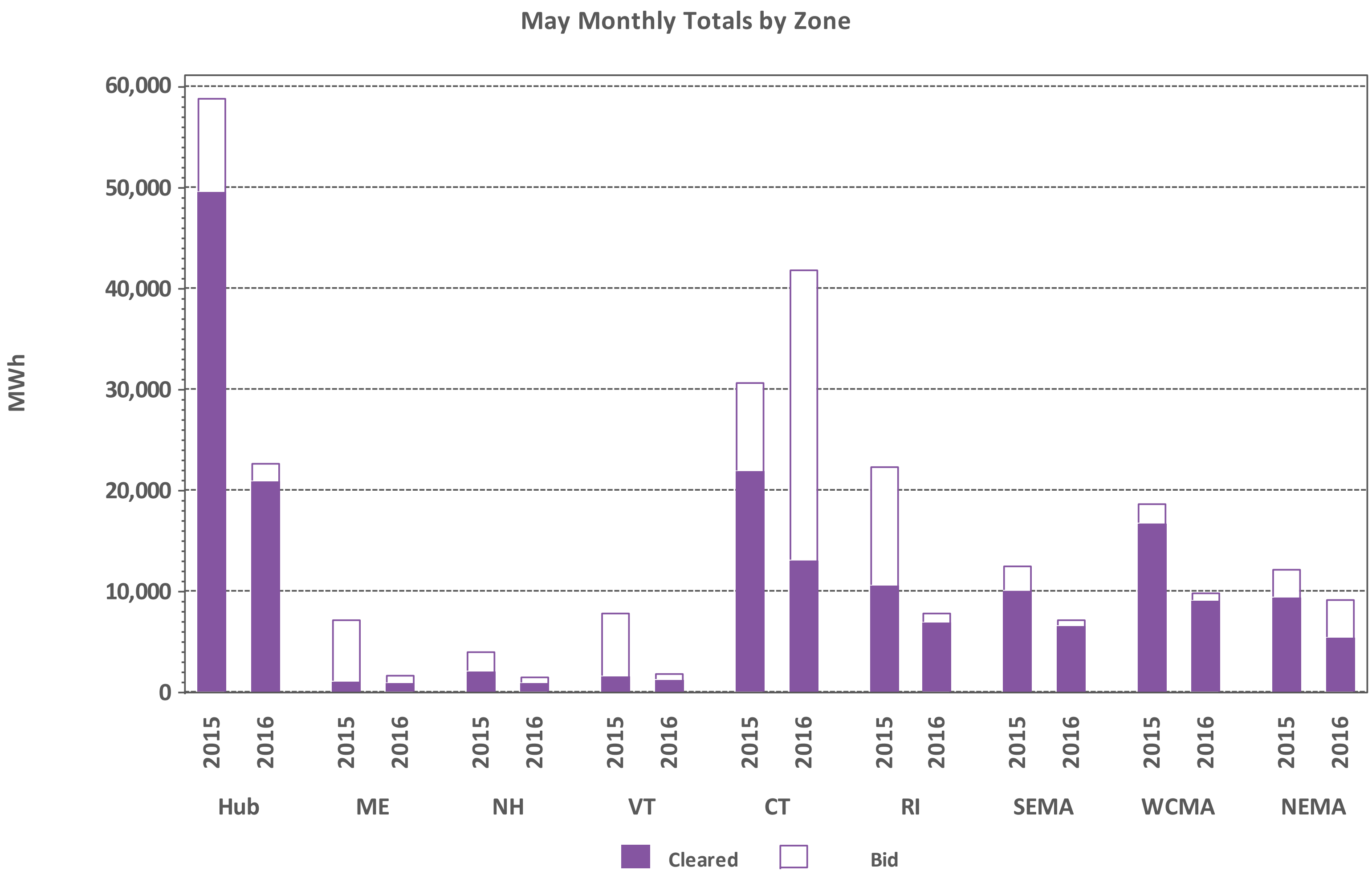
LFRM Charges to Load by Load Zone ($)



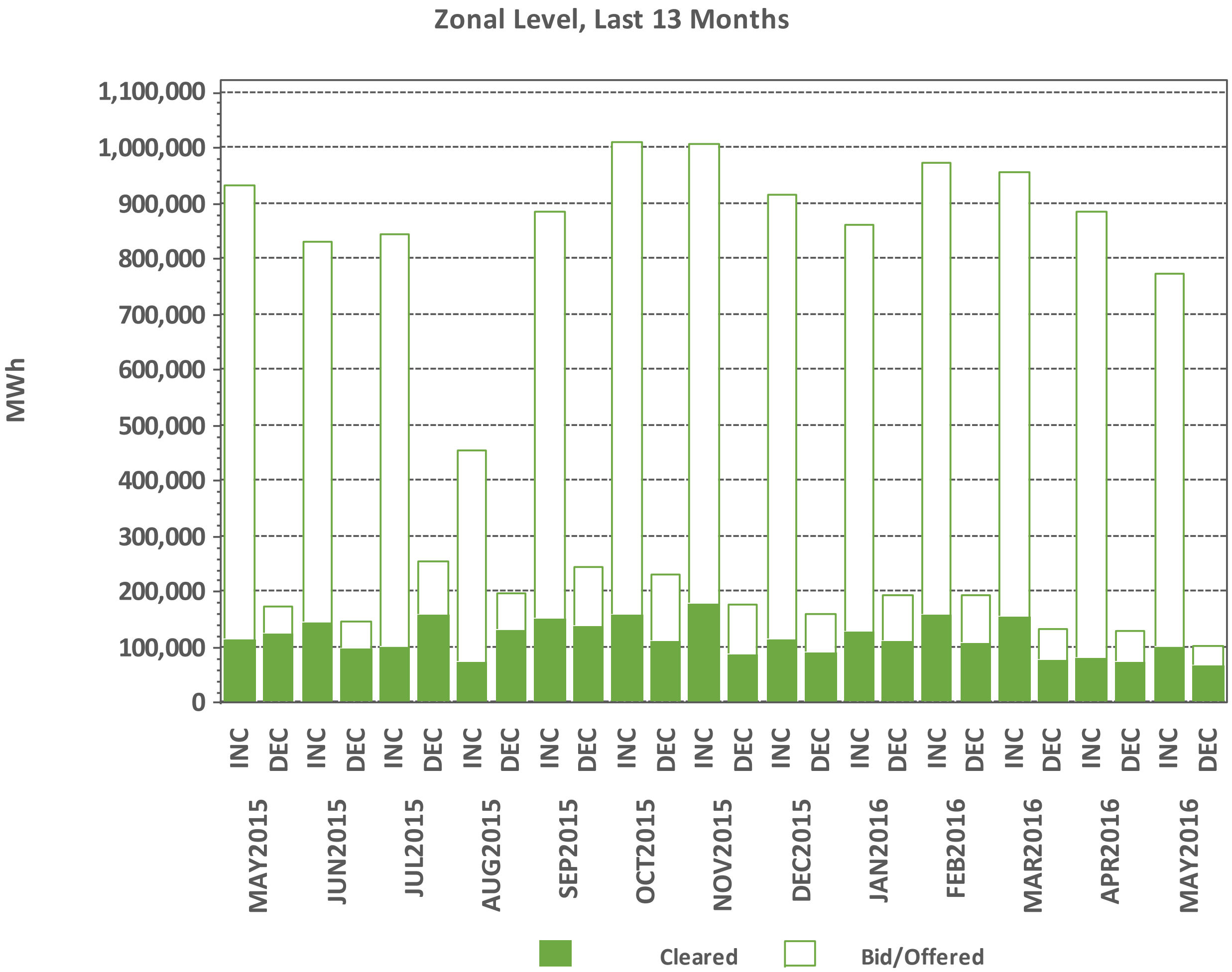
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

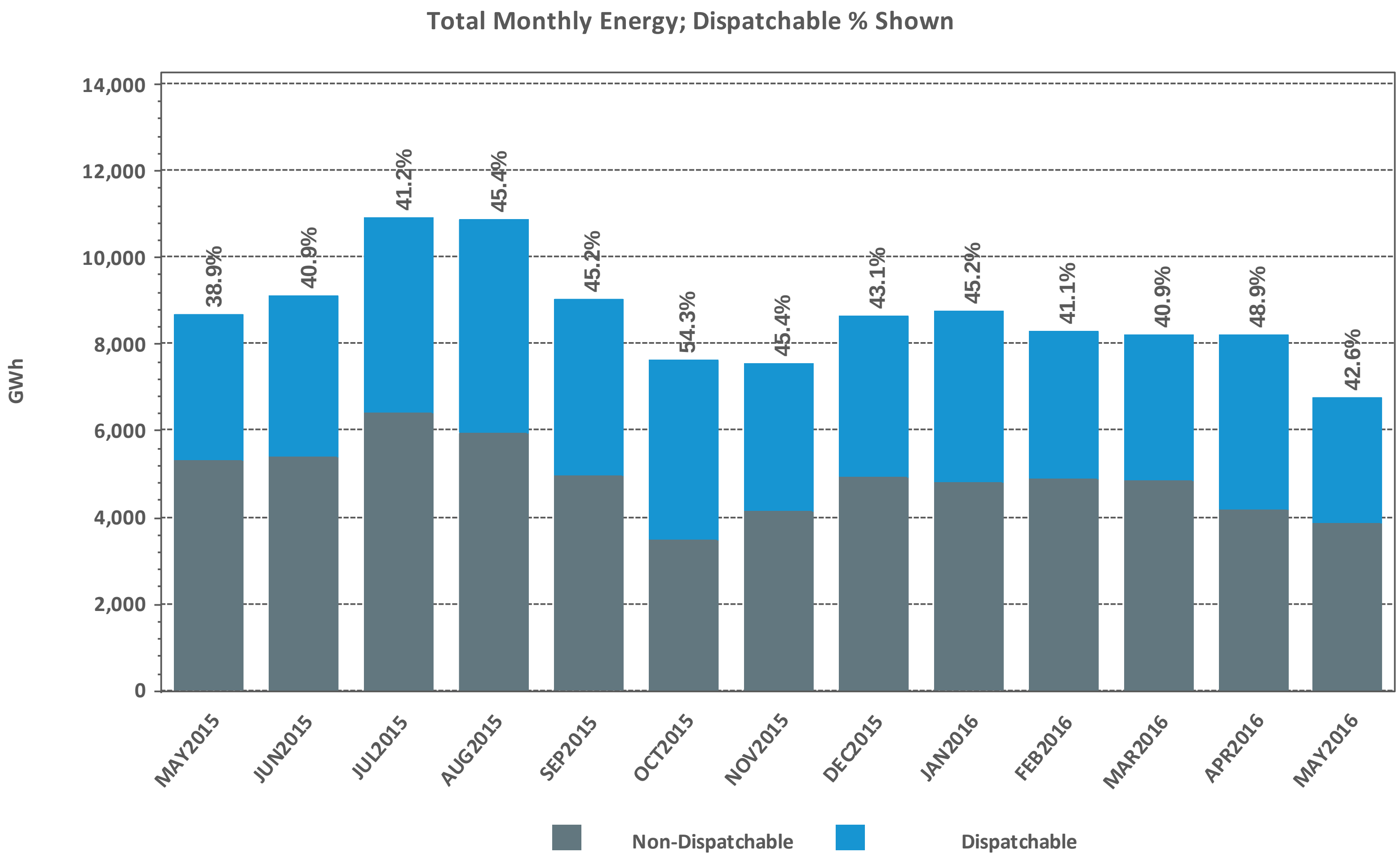


Total Increment Offers and Decrement Bids



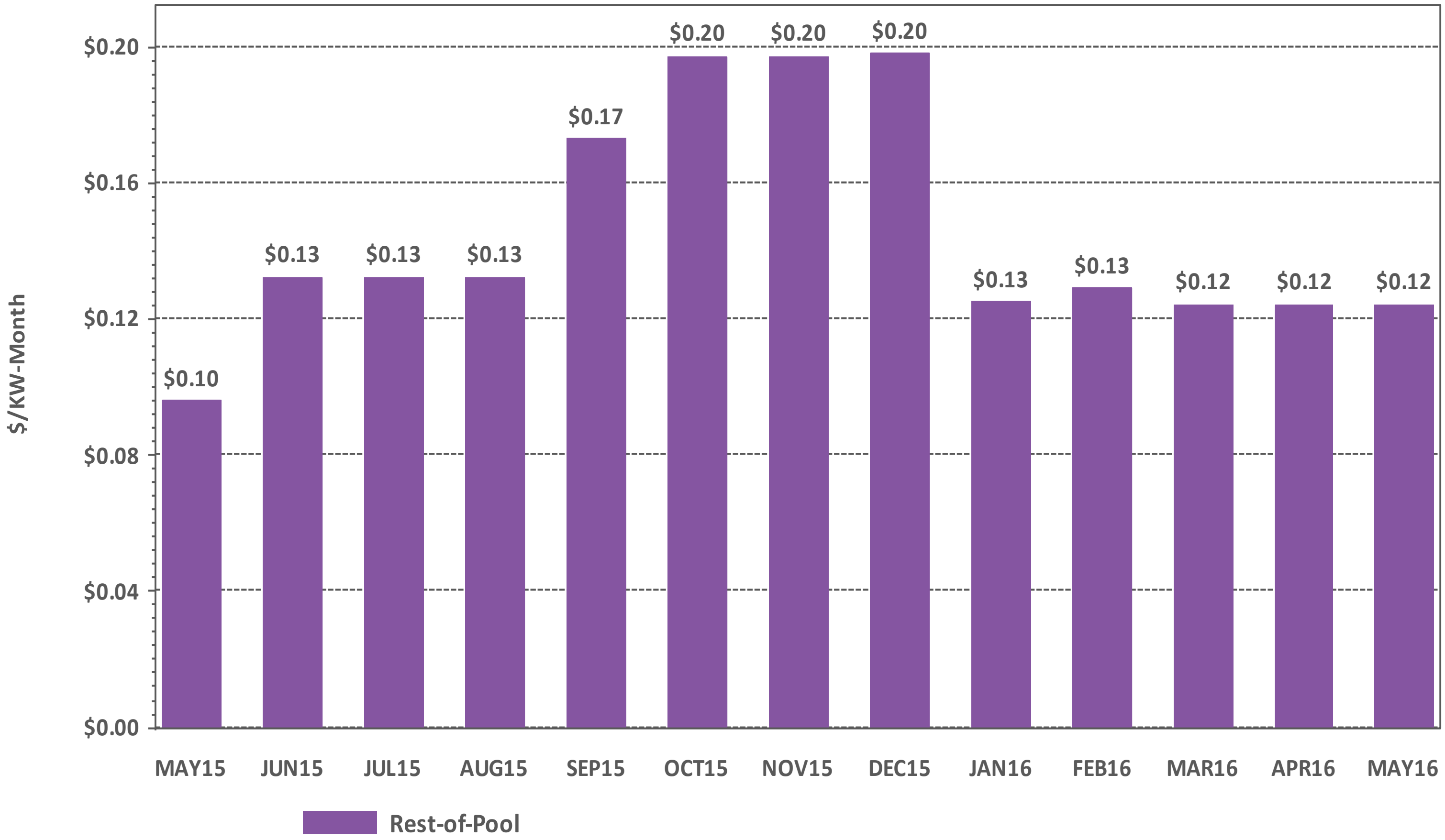
Data excludes nodal offers and bids

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).**

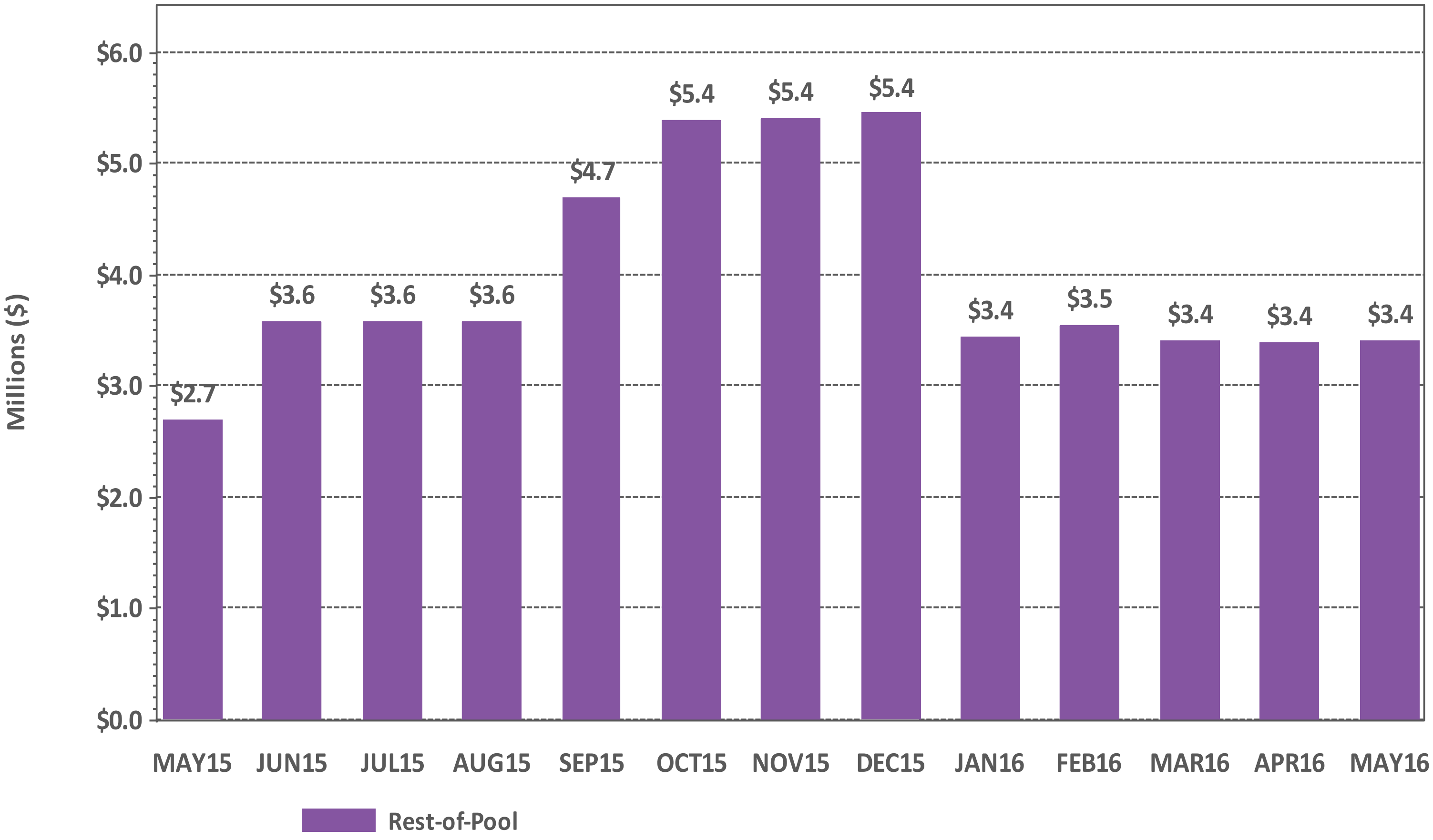
Rolling Average Peak Energy Rent (PER)



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.

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- June 10 PAC Meeting Agenda (tentative)
  - RSP16 Project List and Asset Conditions List Updates
  - 2016 Economic Study - Discussion on Assumptions
  - Transmission Transfer Capabilities Update
  - ISO-NE Net Loads with Increasing Behind-the-Meter PV
  - Wilder #16 Substation - Hartford, VT - Asset Replacement
  - Southeastern Massachusetts and Rhode Island Minimum Load Needs Assessment Scope of Work
  - Medway Station #65 - Asset Condition Needs and Preferred Solution

Load, Energy Efficiency and PV Forecast

- Load Forecast
  - The final 2016 ten-year load forecast has been completed and was discussed without objection with the Load Forecast Committee
  - Overall, the net 50/50 forecast has decreased for summer 2020
- Energy Efficiency (EE) Forecast
  - Final forecast results are largely unchanged from the 2015 forecast results due to offsetting increases and decreases in forecasted EE production
- Distributed Generation Forecast Working Group (DGFWG)
  - Final PV forecast was discussed with the DGFWG on April 15
  - 2016 solar PV forecast indicates an increase over the 2015 forecast
- All three forecasts, including individual state gross and net load forecasts, were presented to PAC on April 20 and were posted on May 2 as part of the CELT report
- Next Load Forecast Committee Meeting will be held on July 8

Environmental Matters

- EPA issued 4/15/16 guidance interpreting remaining emergency engine rules as prohibiting its use under OP-4 after 5/2/16
- EPA proposed 5/18/16 water permit renewal conditions for Pilgrim for remaining operation and post-closure
- Massachusetts Supreme Judicial Court rejected existing state rules (including Regional Greenhouse Gas Initiative) as insufficient to meet Massachusetts Global Warming Solutions Act target of 25% reduction in greenhouse gas emissions by 2020 from 1990 baseline (currently at 18% reduction)

Environmental Matters, cont.

- Connecticut is proposing updated nitrogen oxide control regulations for all classes of fossil-fired electric generators for summer and year-round operation
  - More stringent limits for all fuel and generator types – two-part schedule as follows:
    - Phase 1 (2018-2022)
    - Phase 2 (2022 and thereafter)

Economic Studies

- The ISO is drafting reports for the three economic studies requested in 2015
  - PAC will have 30 days to provide comments once the reports are posted
  - Keene Road area wind development and analysis of local interface constraints (request by SunEdison)
  - Offshore Wind Deployment (request by Massachusetts Clean Energy Center)
  - Maine Upgrades identified in ISO-NE's Strategic Transmission Analysis for Wind Integration (request by RENEW Northeast)
- 2016 Economic Study - NEPOOL Scenario Analysis
  - Scope of work and high-level assumptions were discussed at the May 19 PAC meeting
  - ISO staff continues discussions with a small group of NEPOOL representatives on the scope of work and detailed assumptions
  - PAC discussions of the detailed assumptions are scheduled for June 10

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 5/31/16

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	1
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	May-18	1
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	April-17	1
Chelsea Station - Rebuild to a three-breaker ring bus	Oct-17	1

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 5/31/16

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 5/31/16

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	Jun-16	3
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 5/31/16

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 5/31/16

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	Dec-16	3
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Dec-16	1
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-17	2

*Replaces the NEEWS Central Connecticut Reliability Project

**Placed in-service ahead of schedule

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/31/16

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-16	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-18	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 5/31/16

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 5/31/16

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	2
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 5/31/16

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	1
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	2
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	1
Loop the 1570 line in and out the Pootatuck substation	Dec-17	1
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 5/31/16

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 5/31/16

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	1
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-16	3
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	2
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 5/31/16

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	Mar-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)	Dec-18	2
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-19	1

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 5/31/16

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	Feb-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	Dec-16	2
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Dec-16	3
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 5/31/16

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	2
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	2
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	2
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	Dec-16	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	1
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	Jun-17	2

Greater Boston Projects, cont.

Status as of 5/31/16

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	Jun-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	2
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-19	1
Install third 115 kV line from West Walpole to Holbrook	Sep-19	1
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 5/31/16

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	1
Install a 345 kV breaker in series with breaker 104 at Woburn	Dec-16	2
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	2
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Jun-16	3
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	2
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	2
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	Jun-18	1
Install a 115 kV breaker on the East bus at K Street	Jun-16	3
Install 115 kV cable from Mystic to Chelsea	Dec-17	1
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	1

Greater Boston Projects, cont.

Status as of 5/31/16

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	1
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	1
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	2

Greater Boston Projects, cont.

Status as of 5/31/16

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
Upgrade Edgar 115 kV station to BPS standards	Dec-20	1
Upgrade Dover 115 kV station to BPS standards	Dec-20	1
Upgrade East Cambridge 115 kV station to BPS standards	Dec-19	1
Upgrade West Methuen 115 kV station to BPS standards	Jun-18	1
Upgrade Medway 115 kV station to BPS standards	Jun-19	3
Install a 200 MVAR STATCOM at Coopers Mills	Dec-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	2
Install a 115 kV breaker in series with the 29 breaker at K Street	Nov-16	3

Pittsfield/Greenfield Projects

Status as of 5/31/16

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)	Nov-16	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 5/31/16

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	Nov-16	2
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

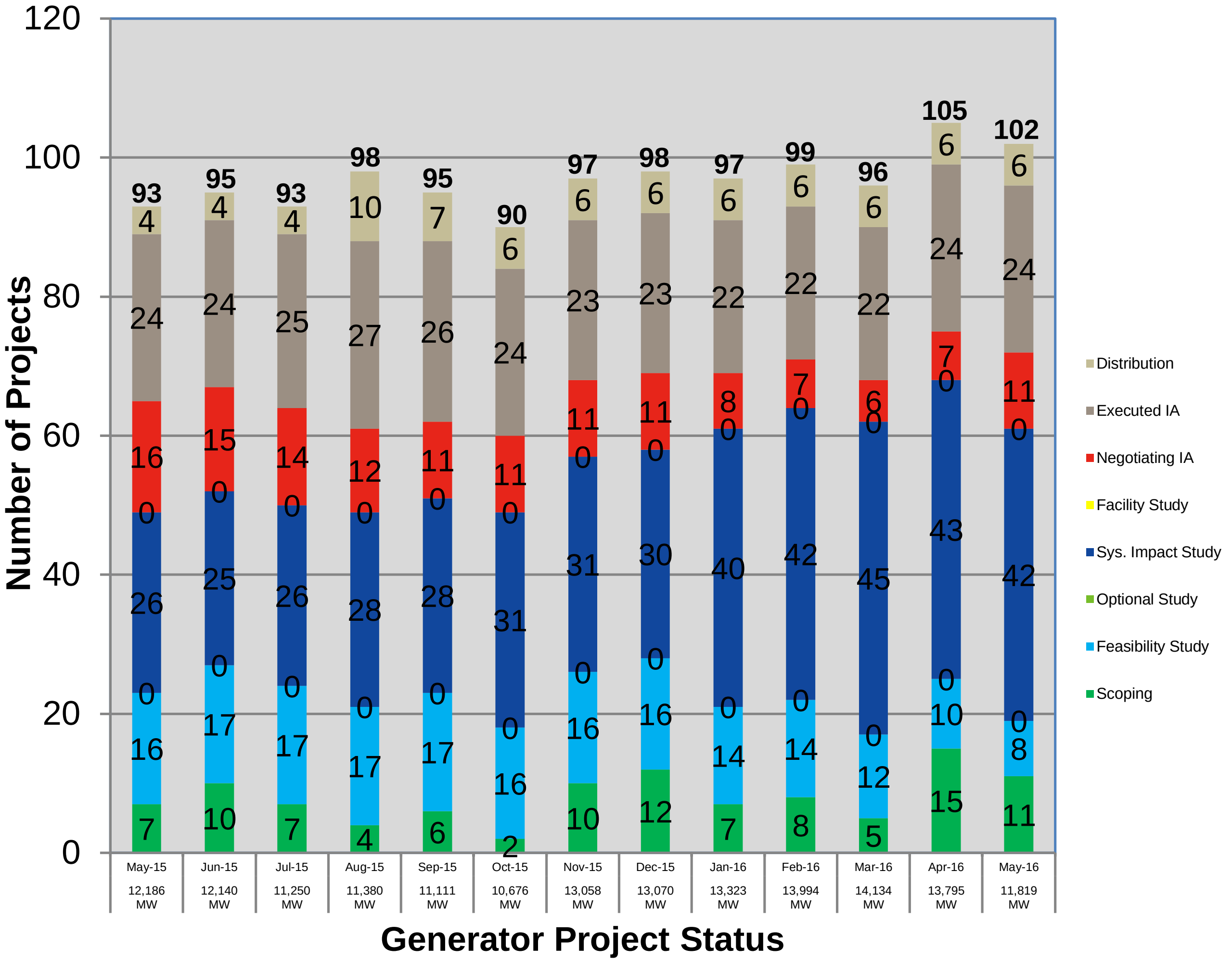
Pittsfield/Greenfield Projects, cont.

Status as of 5/31/16

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: May 2016 based on partial data

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

Note: As of May 2016, there are 12 ETU's in SIS and 2 in FS

OPERABLE CAPACITY ANALYSIS

Summer 2016

Summer 2016 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**June - 2016[2]** **CSO**	**June - 2016[2]** **SCC**
Generator Operable Capacity MW [1]	30,026	30,278
OP CAP From OP-4 RTDR (+)	294	294
OP CAP From OP-4 RTEG (+)	185	185
Operable Capacity Generator with OP-4 DR and RTEG	30,505	30,757
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	785	785
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	788	830
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	27,734	27,944
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,704	26,704
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,009	29,009
Operable Capacity Margin [3]	(1,275)	(1,065)

[1] Generator Operable Capacity is based on data as of **May 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 **May 17, 2016**

[2] Load based on 2016 CELT report and week with lowest Operable Capacity Margin, week beginning **June 4, 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.

Summer 2016 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	**June - 2016[2]** **CSO**	**June - 2016[2]** **SCC**
Generator Operable Capacity MW [1]	30,026	30,278
OP CAP From OP-4 RTDR (+)	294	294
OP CAP From OP-4 RTEG (+)	185	185
Operable Capacity Generator with OP-4 DR and RTEG	30,505	30,757
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	785	785
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	788	830
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	27,734	27,944
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	29,041	29,041
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	31,346	31,346
Operable Capacity Margin [3]	(3,612)	(3,402)

[1] Generator Operable Capacity is based on data as of **May 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 **May 17, 2016**

[2] Load based on 2016 CELT report and week with lowest Operable Capacity Margin, week beginning **June 4, 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.

Summer 2016 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2016 OPERABLE CAPACITY ANALYSIS

June 3, 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]
6/4/2016	**30,026**	**785**	**32**	**788**	**0**	**2,800**	**0**	**27,255**	**26,704**	**2,305**	**29,009**	**(1,754)**	**294**	**(1,460)**	**185**	**(1,275)**
6/11/2016	30,026	785	32	759	0	2,800	0	27,284	26,704	2,305	29,009	(1,725)	294	(1,431)	185	(1,246)
6/18/2016	30,026	785	32	326	0	2,800	0	27,717	26,704	2,305	29,009	(1,292)	294	(998)	185	(813)
6/25/2016	30,026	785	33	296	0	2,800	0	27,748	26,704	2,305	29,009	(1,261)	294	(967)	185	(782)
7/2/2016	29,734	1,062	33	19	0	2,100	0	28,710	26,704	2,305	29,009	(299)	372	73	185	258
7/9/2016	29,734	1,062	33	5	0	2,100	0	28,724	26,704	2,305	29,009	(285)	372	87	185	272
7/16/2016	29,734	1,062	33	3	0	2,100	0	28,726	26,704	2,305	29,009	(283)	372	89	185	274
7/23/2016	29,734	1,062	33	3	0	2,100	0	28,726	26,704	2,305	29,009	(283)	372	89	185	274
7/30/2016	29,734	1,062	33	16	0	2,100	0	28,713	26,704	2,305	29,009	(296)	372	76	185	261
8/6/2016	29,734	1,062	33	3	0	2,100	0	28,726	26,704	2,305	29,009	(283)	372	89	185	274
8/13/2016	29,734	1,062	33	3	0	2,100	0	28,726	26,704	2,305	29,009	(283)	372	89	185	274
8/20/2016	29,734	1,062	33	16	0	2,100	0	28,713	26,704	2,305	29,009	(296)	372	76	185	261
8/27/2016	29,734	1,062	45	6	0	2,100	0	28,735	26,704	2,305	29,009	(274)	372	98	185	283
9/3/2016	29,734	1,162	45	5	0	2,100	0	28,836	26,704	2,305	29,009	(173)	372	199	185	384
9/10/2016	29,734	1,062	45	4	243	2,100	0	28,494	26,704	2,305	29,009	(515)	372	(143)	185	42

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.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
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.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
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).

Summer 2016 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2016 OPERABLE CAPACITY ANALYSIS

June 3, 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 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]
6/4/2016	**30,026**	**785**	**32**	**788**	**0**	**2,800**	**0**	**27,255**	**29,041**	**2,305**	**31,346**	**(4,091)**	**294**	**(3,797)**	**185**	**(3,612)**
6/11/2016	30,026	785	32	759	0	2,800	0	27,284	29,041	2,305	31,346	(4,062)	294	(3,768)	185	(3,583)
6/18/2016	30,026	785	32	326	0	2,800	0	27,717	29,041	2,305	31,346	(3,629)	294	(3,335)	185	(3,150)
6/25/2016	30,026	785	33	296	0	2,800	0	27,748	29,041	2,305	31,346	(3,598)	294	(3,304)	185	(3,119)
7/2/2016	29,734	1,062	33	19	0	2,100	0	28,710	29,041	2,305	31,346	(2,636)	372	(2,264)	185	(2,079)
7/9/2016	29,734	1,062	33	5	0	2,100	0	28,724	29,041	2,305	31,346	(2,622)	372	(2,250)	185	(2,065)
7/16/2016	29,734	1,062	33	3	0	2,100	0	28,726	29,041	2,305	31,346	(2,620)	372	(2,248)	185	(2,063)
7/23/2016	29,734	1,062	33	3	0	2,100	0	28,726	29,041	2,305	31,346	(2,620)	372	(2,248)	185	(2,063)
7/30/2016	29,734	1,062	33	16	0	2,100	0	28,713	29,041	2,305	31,346	(2,633)	372	(2,261)	185	(2,076)
8/6/2016	29,734	1,062	33	3	0	2,100	0	28,726	29,041	2,305	31,346	(2,620)	372	(2,248)	185	(2,063)
8/13/2016	29,734	1,062	33	3	0	2,100	0	28,726	29,041	2,305	31,346	(2,620)	372	(2,248)	185	(2,063)
8/20/2016	29,734	1,062	33	16	0	2,100	0	28,713	29,041	2,305	31,346	(2,633)	372	(2,261)	185	(2,076)
8/27/2016	29,734	1,062	45	6	0	2,100	0	28,735	29,041	2,305	31,346	(2,611)	372	(2,239)	185	(2,054)
9/3/2016	29,734	1,162	45	5	0	2,100	0	28,836	29,041	2,305	31,346	(2,510)	372	(2,138)	185	(1,953)
9/10/2016	29,734	1,062	45	4	243	2,100	0	28,494	29,041	2,305	31,346	(2,852)	372	(2,480)	185	(2,295)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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3. New resources and generator improvements that have acquired a CSO but have not become commercial.
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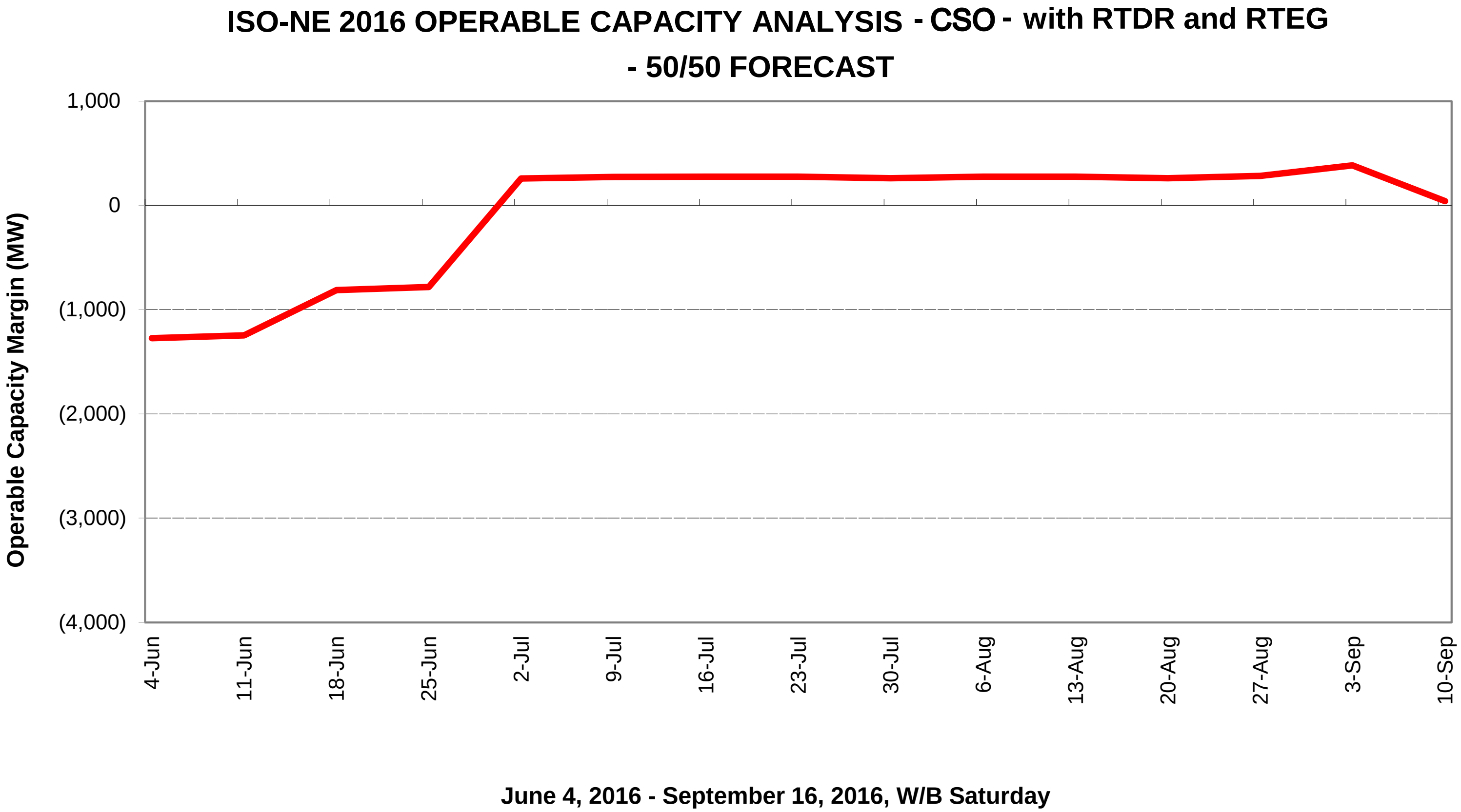
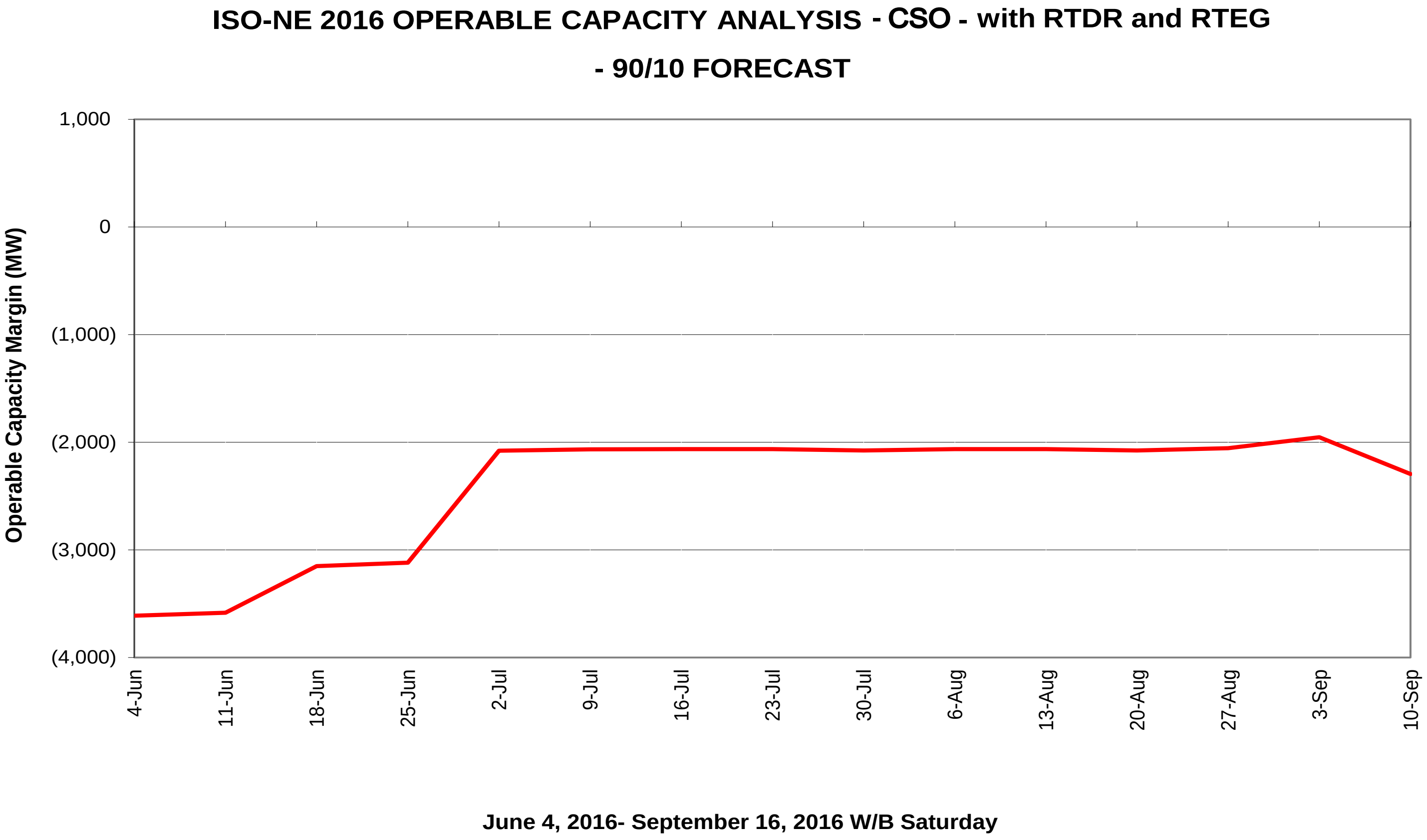
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
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.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
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).

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



Summer 2016 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.	**June 294[3]** **July - September 372[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	135 [4] **June - September 185 [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 May 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	269 [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		**June 3,028 MW** **July - September 3,106 MW**

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 May 16, 2016.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.