NEPOOL PARTICIPANTS COMMITTEE
04/07/17 MEETING, AGENDA ITEM #4

NEPOOL Participants Committee Report

April 2017

Vamsi Chadalavada

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 $382M, up $78M from February and up $162M from March 2016
    - March natural gas prices over the period were 22% higher than February 2016 average values
    - Average RT Hub Locational Marginal Prices ($35.43/MWh) over the period were 26% higher than February 2016 averages
    - Average March 2017 natural gas prices and RT Hub LMPs over the period were up 142% and up 106%, respectively, from March 2016 averages
- Average DA cleared physical energy during the peak hours as percent of forecasted load was 96.4% during March, down from 97.2% during February*

Data are through March 29 (RT NCPC through March 28), 2017 unless 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)
  - March NCPC payments totaled $5.4M over the period, down $1.7M from February and up $1.3M from March 2016
    - First Contingency payments totaled $3.7M, up $273K from February
      - $3.4M paid to internal resources, down $9K from February
        - » $1.5M charged to DALO, $1.2M to RT Deviations, $631K* to RTLO
      - $285K paid to resources at external locations, up $282K from February
        - » $138K charged to DALO at external locations, $147K to RT Deviations
    - Second Contingency payments totaled $760K, down $2.3M from February
    - Voltage payments totaled $988K, up $282K from February
    - Distribution payments totaled $0, unchanged from February
  - NCPC payments over the period as percent of Energy Market value were 1.4%

*** NCPC types reflected in the Fist Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $331K; Rapid Response Pricing (RRP) Opportunity Cost - $222K; Posturing - $73K; Generator Performance Auditing (GPA) - $5K**

Highlights, cont.

- Power System Update during Spring Maintenance
  - During light loads in April and May, the ISO will require additional commitments to control high voltage on the New Hampshire 345 kV due to both a forced transmission outage and generator maintenance in NH
  - Connecticut will require additional generation commitments in April and May due to unplanned generation outages and ongoing transmission work
  - Currently scheduled NEMA/Boston upgrades are unlikely to require commitments in April and May
    - This could change in case of early hot weather or if other transmission lines and/or area generation resources are out of service due to unplanned outages

2016/17 Winter Reliability Program As of December 1

- **Oil Program**
  - As of December 1st, participation from 84 units for a total of 4.394 million barrels of oil
  - 3.052 million barrels of the total inventory on December 1 are eligible for compensation per the winter program rules
  - Total oil program cost exposure is expected to be $31.16M (@$10.21/barrel)
- **LNG Program**
  - As of December 1st, participation from 2 units, representing 171 thousand MMBTU
  - Total LNG program cost exposure is expected to be $291K (@$1.70/MMBTU)
- **DR Program**
  - As of December 1st, participation from 6 assets providing 23.0 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $70.5K

2016/17 Winter Program Usage

- Winter Program Oil Inventory Changes:
  - Dec 2016: 76,967 BBLs
  - Jan 2017: 12,737 BBLs
  - Feb 2017: 18,663 BBLs
  - Mar 2017 : 5,643 BBLs
- Winter Program LNG usage:
  - Dec 2016: none
  - Jan 2017: none
  - Feb 2017: none
  - Mar 2017: none
- Winter Program DR Events:
  - Dec 2016: none
  - Jan 2017: 1 event; January 10th 6:39 AM – 9:04 AM, all assets dispatched
  - Feb 2017: none
  - Mar 2017: none
- Final Program Ending Oil Eligible Inventory
  - 3,034,668 BBLs

Winter Reliability Program Costs & Billing

- Expected Program Costs:
  - Oil: $30.9M ($23.4M collected; $7.5M outstanding)
  - LNG: $291K ($218K collected; $73K outstanding)
  - DR: $126K ($126K collected), includes energy payments for dispatch on January 10

- Billing/Payment Schedule:
  - Initial Billings were based on 75% of initial inventory
  - Trued-up charges for unused fuel will be issued on April 18, 2017
  - Payment to generators for unused fuel inventory will be in May 15, 2017 bill

Highlights, cont.

- 2016 Economic Study - NEPOOL Scenario Analysis
  - Phase I observations and key messages are complete, and the report is expected to be issued in the second quarter
  - Phase II is underway, reviewing certain market and operations impacts
- 2017 long-term load forecast, energy-efficiency forecast, and solar PV forecast are nearly complete. The overall trend is lower net energy and seasonal peak demand for New England
- Order 1000 Planning for Public Policy process is underway
  - Stakeholder input on state and federal policies was provided to NESCOE by the March 1 deadline
  - NESCOE input to the ISO is expected by May 1

Forward Capacity Market (FCM) Highlights

- CCP #8 (2017-2018)
  - Third and final reconfiguration auction is complete and results were posted on March 17
    - All transactions were approved for a total exchange of approximately 278 MW
  - As much as 700 MWs will not be commercial for June 1, 2017
  - These late new resources result in capacity margins being tight
    - Similar to Summer 2016, ISO System Operations has worked with local transmission owners to develop procedures to address potential reliability impacts

CCP – Capacity Commitment Period
RTEG – Real-Time Emergency Generation

FCM Highlights, cont.

- CCP #9 (2018-2019)
  - Second bilateral window will be May 1-5
  - Second reconfiguration auction will be August 1-3
  - Beginning with this CCP, RTEG will no longer be able to participate in the FCM. FERC issued this order on February 16.
- CCP #10 (2019-2020)
  - First bilateral transaction window will be April 3-7
  - First reconfiguration auction will be June 5-7
- CCP #11 (2020-2021)
  - First bilateral transaction window will be April 4-6, 2018
  - First reconfiguration auction will be June 1-5, 2018

FCM Highlights, cont.

- CCP #12 (2021-2022)
  - Retirement de-list bids and permanent de-list bids were due March 24 and approximately 521 MW chose to exit
    - Approximately 2 MW of permanent de-list bids
    - Approximately 499 MW of priced retirement de-list bids
    - IMM to make their cost determinations no later than June 22
    - Participant action to retire must be made no later than July 7
    - Reliability reviews to be completed by August 18
  - Show of Interest window will be April 14-28
  - The Renewable Technology Resource (RTR) election cap is approximately 514 MW

Highlights, cont.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 13, 2017.
- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for three consecutive weeks, weeks beginning June 3, 10, and 17, 2017.
- Forecasted summer outages/reductions:
  - Seasonal Claimed Capability (SCC) margins reflect generator retirements at Brayton Point and delays in commercial operation of new resources

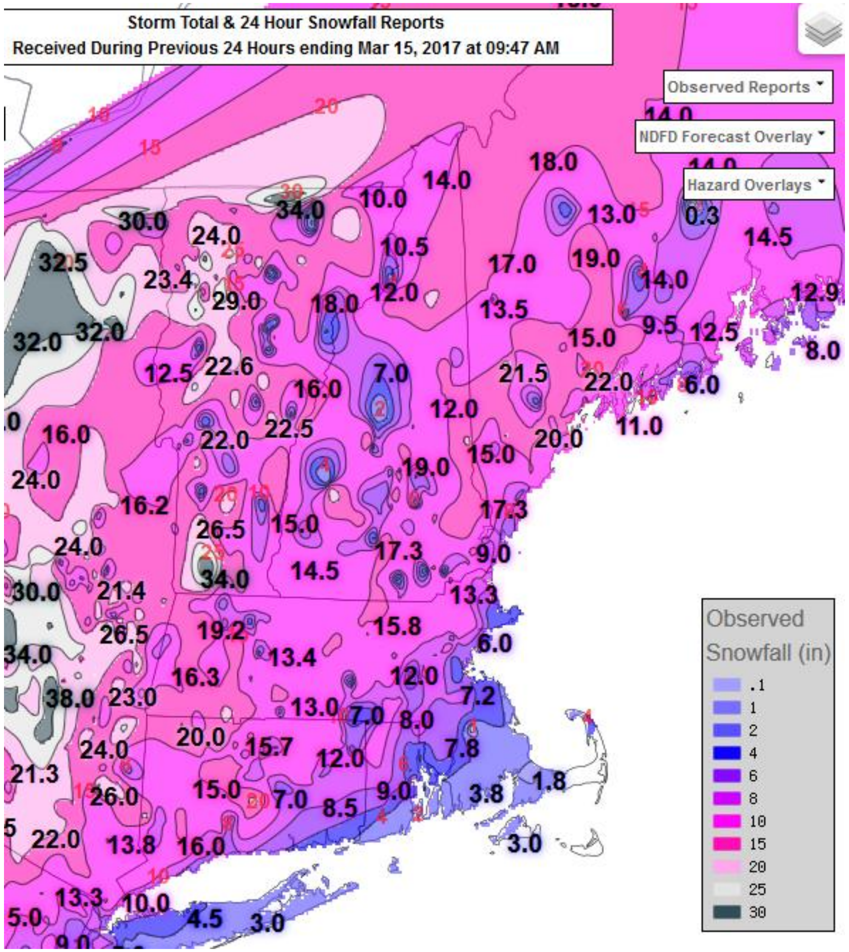
WINTER STORM – MARCH 14, 2017

Preparations Prior to Storm

- Recalled Transmission and Generation work
- NPCC plus PJM and MISO Conference Calls on readiness
- MLCC Heads Calls on Readiness
- NOAA Conference calls on storm situational awareness
- Calls with interstate Pipelines and data sharing on situational awareness

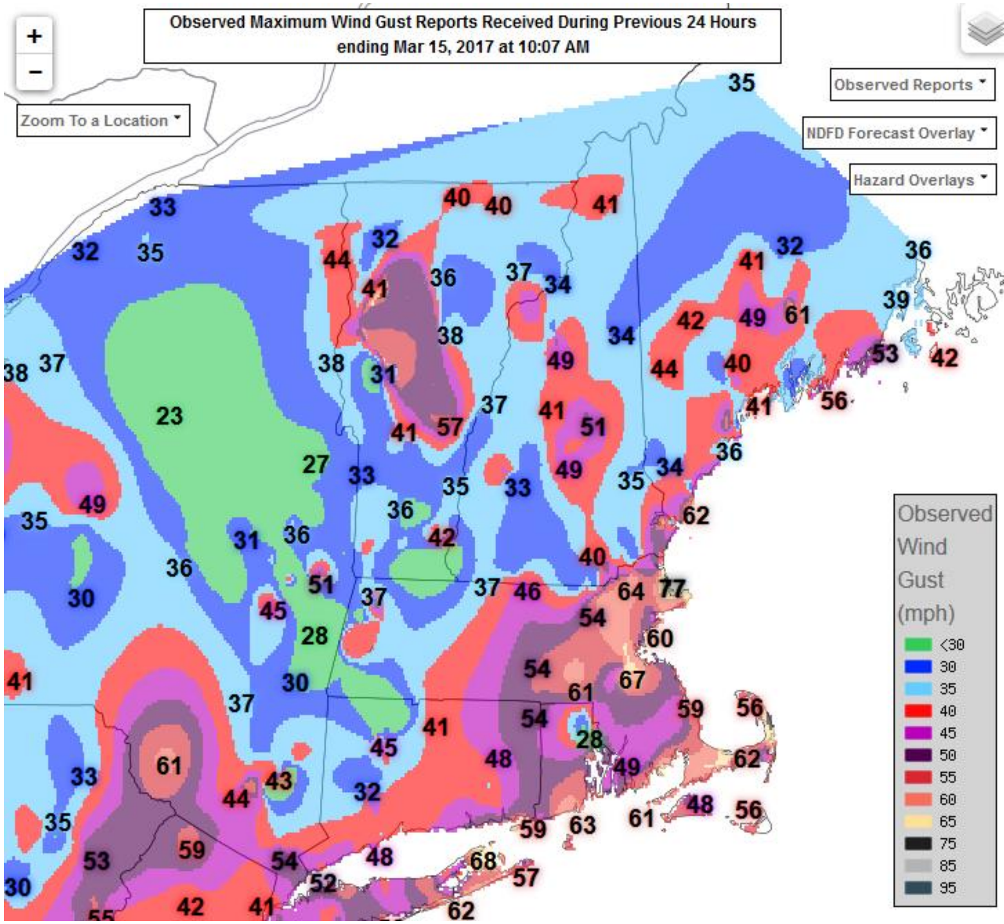
Final Snowfall Totals

- Snow totals (inches)
  - Significant snow in NY
  - Greatest New England snowfall in southern VT
- Mixed precipitation in southeast New England


Storm Total & 24 Hour Snowfall Reports
Received During Previous 24 Hours ending Mar 15, 2017 at 09:47 AM

Wind Gusts

- Heaviest winds in southeast New England
- Near Blizzard conditions throughout the region



Observed Maximum Wind Gust Reports Received During Previous 24 Hours ending Mar 15, 2017 at 10:07 AM

Transmission Related Events

- Equipment failure at a major Eastern Massachusetts substation caused the loss of 5 major transmission elements at 12:09 on Tuesday during the storm
- The Transmission Owner was able to clear the damaged equipment at the substation during the storm and restoration of four of the five lines began at 14:30 with the last line restored 15:54
- At 13:04, a fault of a 23kV cable in the Boston Area resulted in the loss of one of the two feeders providing service to Distrigas
  - The Transmission Owner was able to restore the second feeder at approximately 14:15

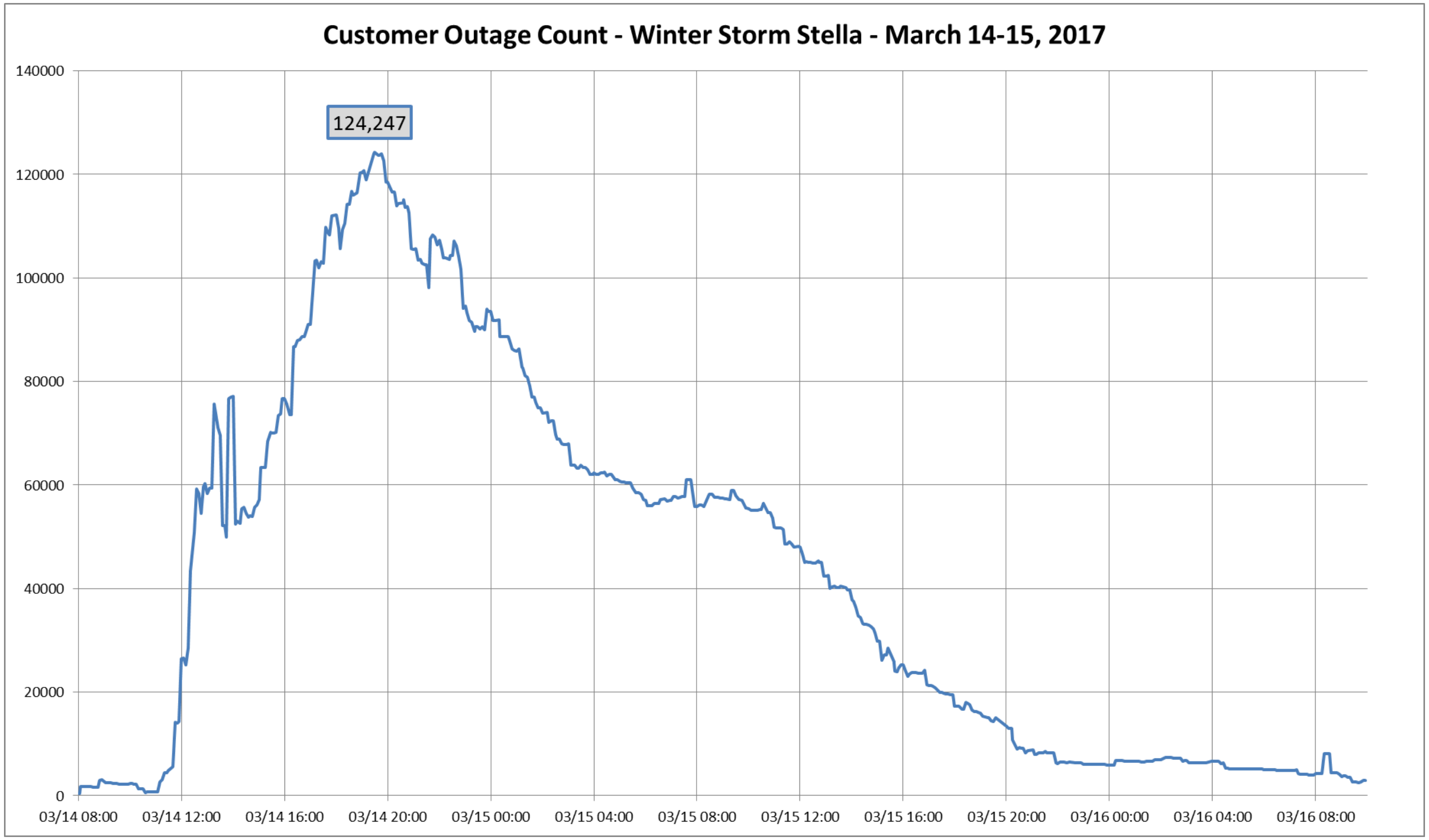
Supplemental Generation Commitment

- Due to the transmission event and subsequent ramp down of a major unit in SE Massachusetts on the day of the storm, additional units were committed in SE Massachusetts to secure the area

Customer Outages

(These are estimates)

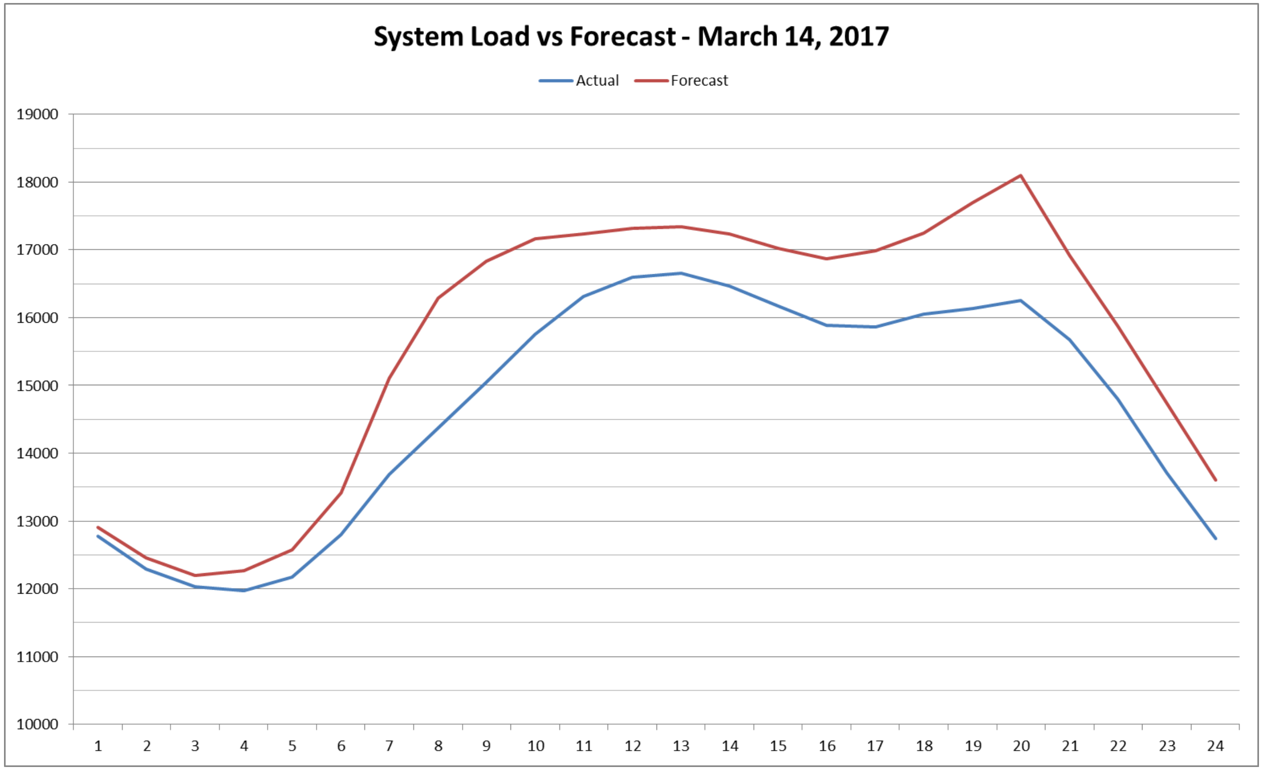
- Customer outages peaked at around 8 PM on 3/14



Data imported from utility company websites

Actual Load vs Forecast Load

- Day-ahead Load Forecast published prior to 10:00 am
- Load below Forecast for all 24 hours
  - Widespread closures of schools, businesses, and government offices



MARCH 2 PRICING

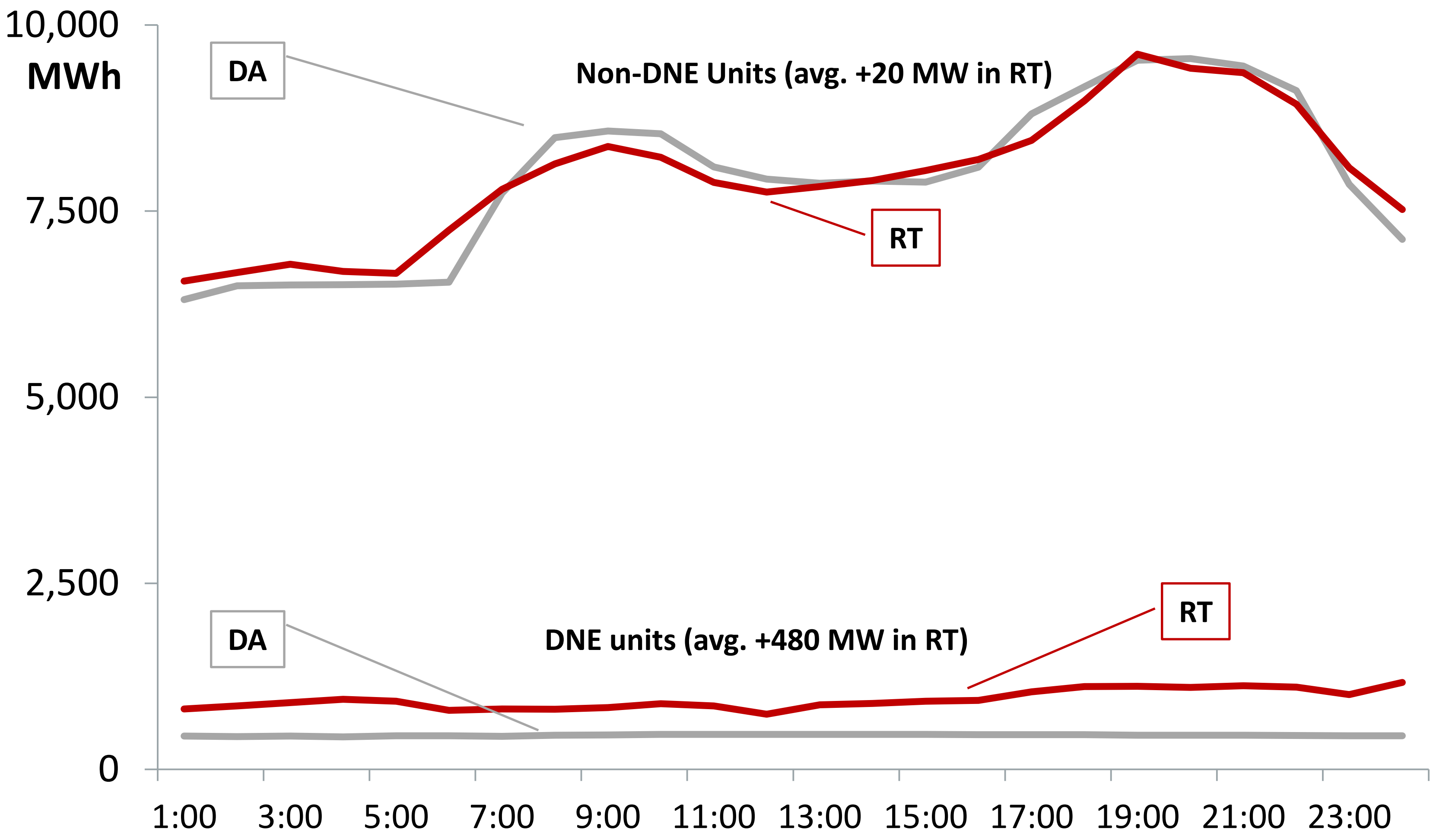
Pricing Assessment: March 2, 2017

- Negative pricing experienced at various times throughout the day; most notable around noon
- Binding reserve constraints during peak load hours
- Key drivers:
  - Real-Time generation supply above Day-Ahead cleared amounts
  - Loads under forecast early; Over the forecast during peak hours
  - Binding reserve constraint raises pricing over peak hours

LMPs at Three Key Points During the Day

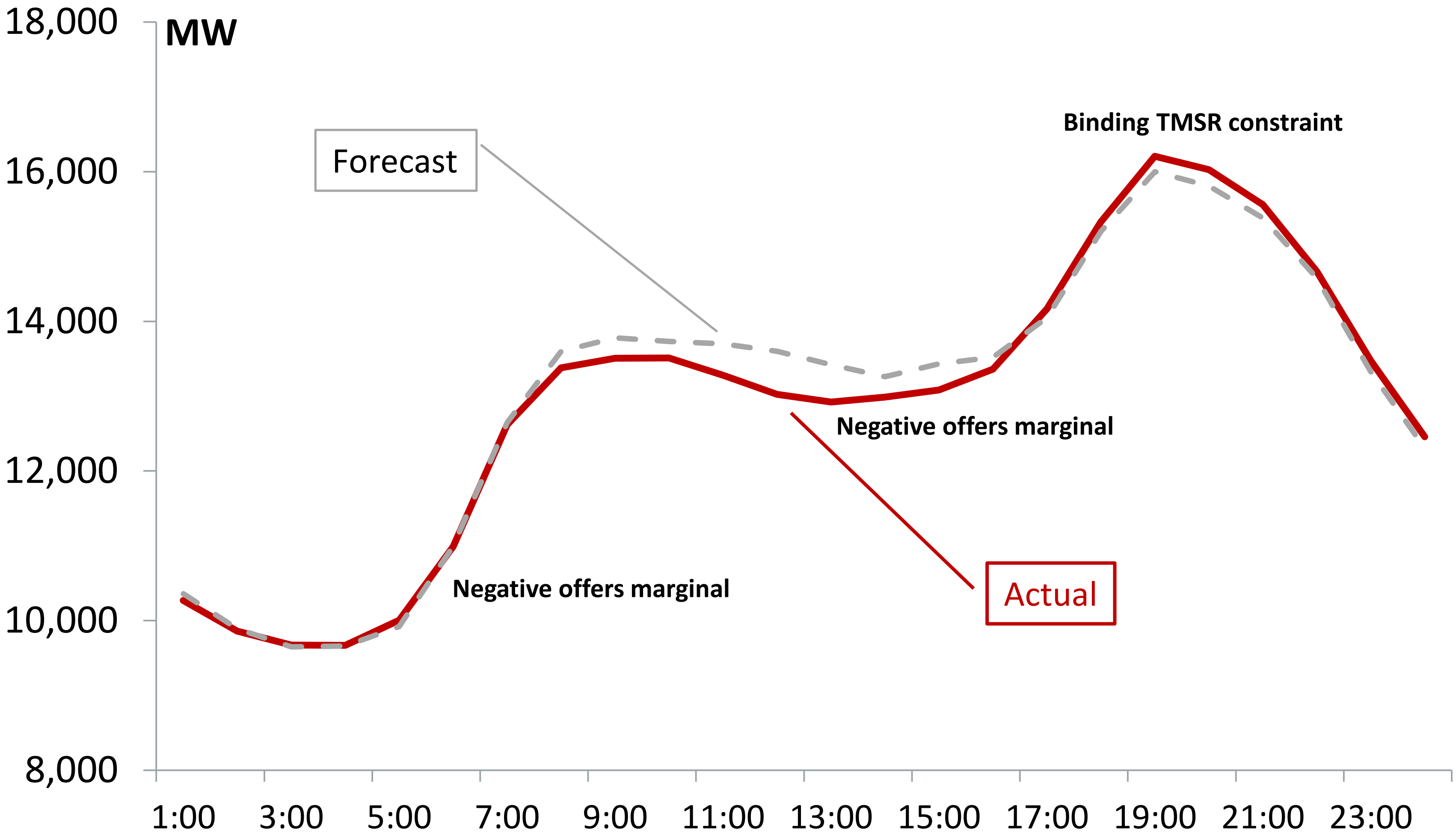
- **Around 6:00 a.m.**
  - ($28.26)/MWh
  - Negative offers become marginal
  - ~1,000 MWh offered economically below $0/MWh
- **12:00-1:00 p.m.**
  - ($49.58)/MWh
  - Mid-day loads at 13,000 MW (500 MW below forecast)
  - Negative offers become marginal
  - ~700 MWh offered economically below $0/MWh
- **7:00 p.m.**
  - $65.07/MWh
  - Load pick-up over peak hours caused binding TMSR constraint from 6:05 p.m. until 9:35 p.m.

DA Cleared vs. RT Generation

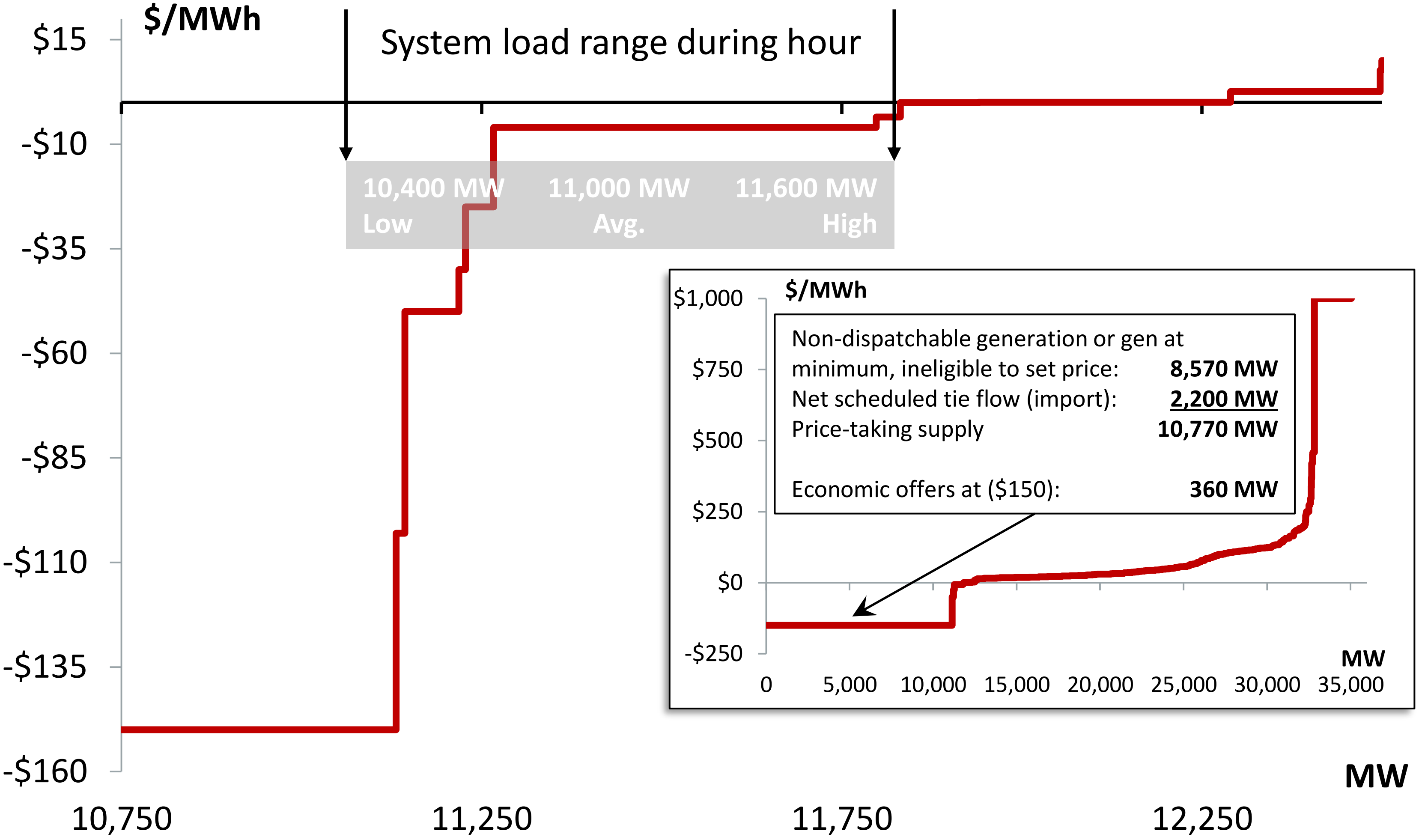


ISO-NE PUBLIC

Loads Below Forecast Midday; Above Forecast at Peak

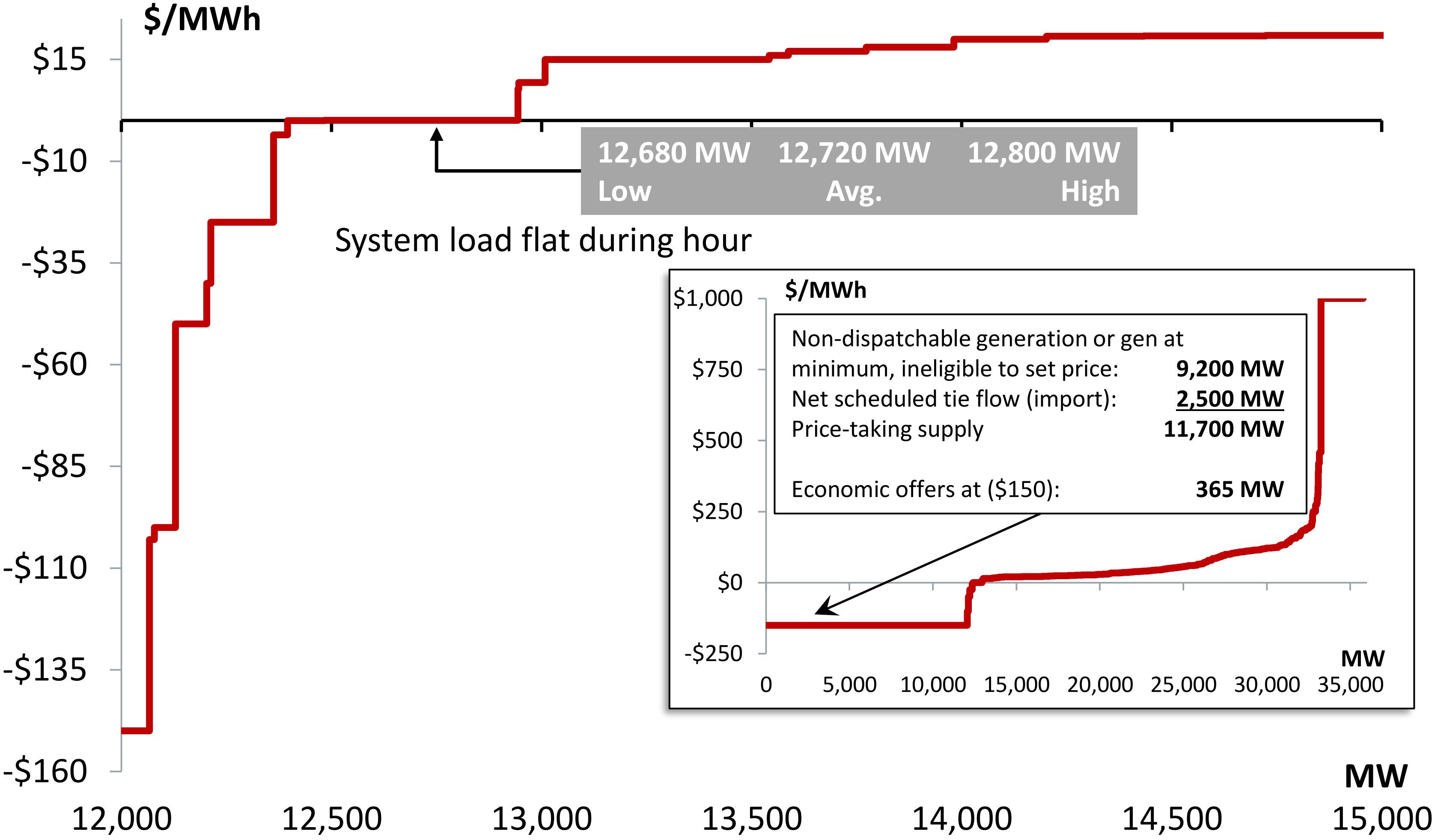


System Supply Curves: Hour Ending 6:00 a.m.



Non-dispatchable generation or gen at minimum, ineligible to set price:	**8,570 MW**
Net scheduled tie flow (import):	**2,200 MW**
Price-taking supply	**10,770 MW**
Economic offers at ($150):	**360 MW**

System Supply Curves: Hour Ending 1:00 p.m.



System load flat during hour

Non-dispatchable generation or gen at minimum, ineligible to set price:	**9,200 MW**
Net scheduled tie flow (import):	**2,500 MW**
Price-taking supply	**11,700 MW**
Economic offers at ($150):	**365 MW**

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-5.2°F) Max: 63°F, Min: 9°F Precipitation: 3.05” – Below Normal Normal: 3.85” Snow: 9.02”	Hartford	Temperature: Below Normal (-5.7°F) Max: 61°F, Min: 7°F Precipitation: 4.79” – Above Normal Normal: 3.88” Snow: 18.78”

Peak Load:	17,454 MW	Mar 15, 2017	HE20

MLCC2: March 13/14, 2017	**Reason: Severe Weather**	**Declared: March 13, 2017 16:00** **Cancelled: March 14, 2017 23:00**
OP-4 : None		
NPCC Simultaneous Activation of Reserve Events:		
March 15, 2017	NE	540MW
March 16, 2017	IESO	825MW

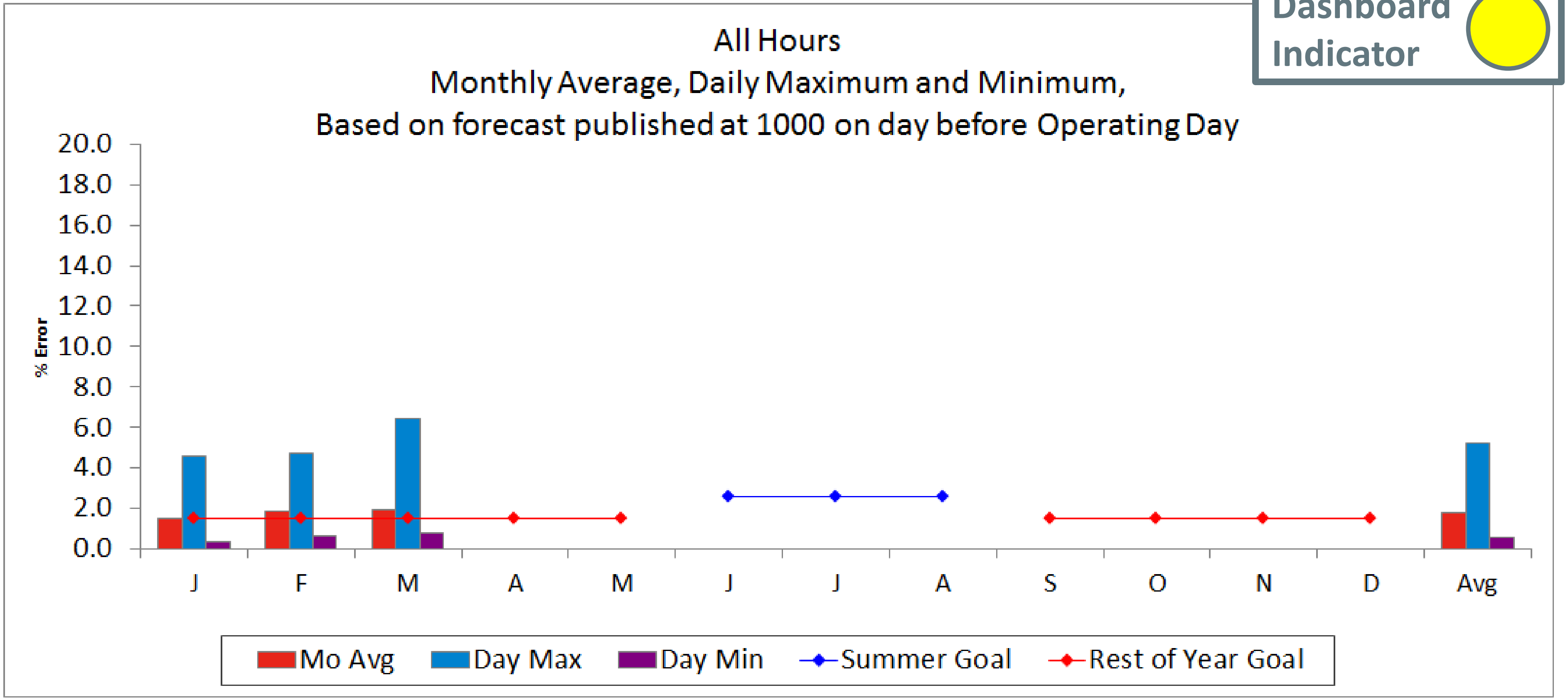
System Operations, cont.

Minimum Generation Warnings & Events:

Minimum Generation Warning	None	
Minimum Generation Emergency	None	

2017 System Operations - Load Forecast Accuracy

Dashboard Indicator ●

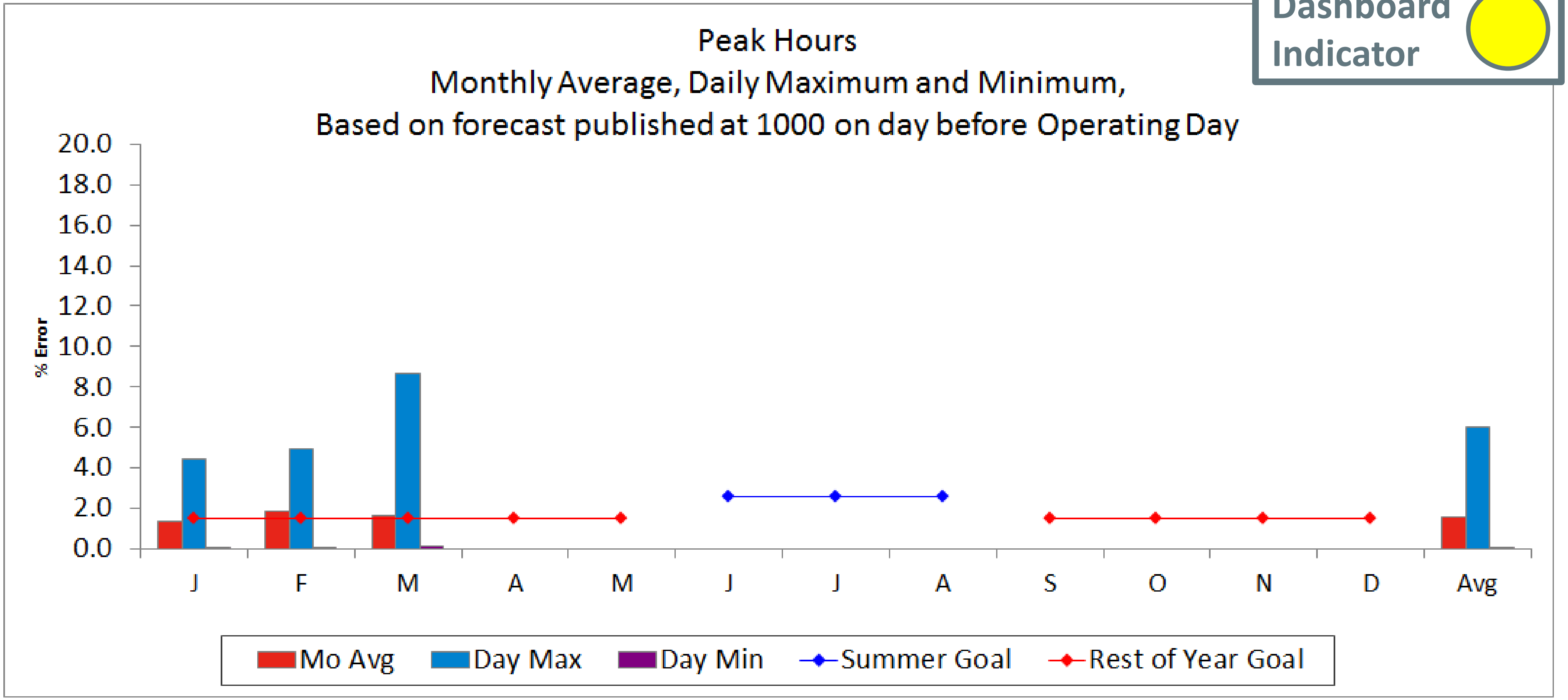


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.51	1.84	1.95										1.76
Day Max	4.58	4.72	6.43										5.26
Day Min	0.33	0.62	0.77										0.57
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.51	1.84	1.95										1.76
Summer Actual													

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

2017 System Operations - Load Forecast Accuracy, cont.

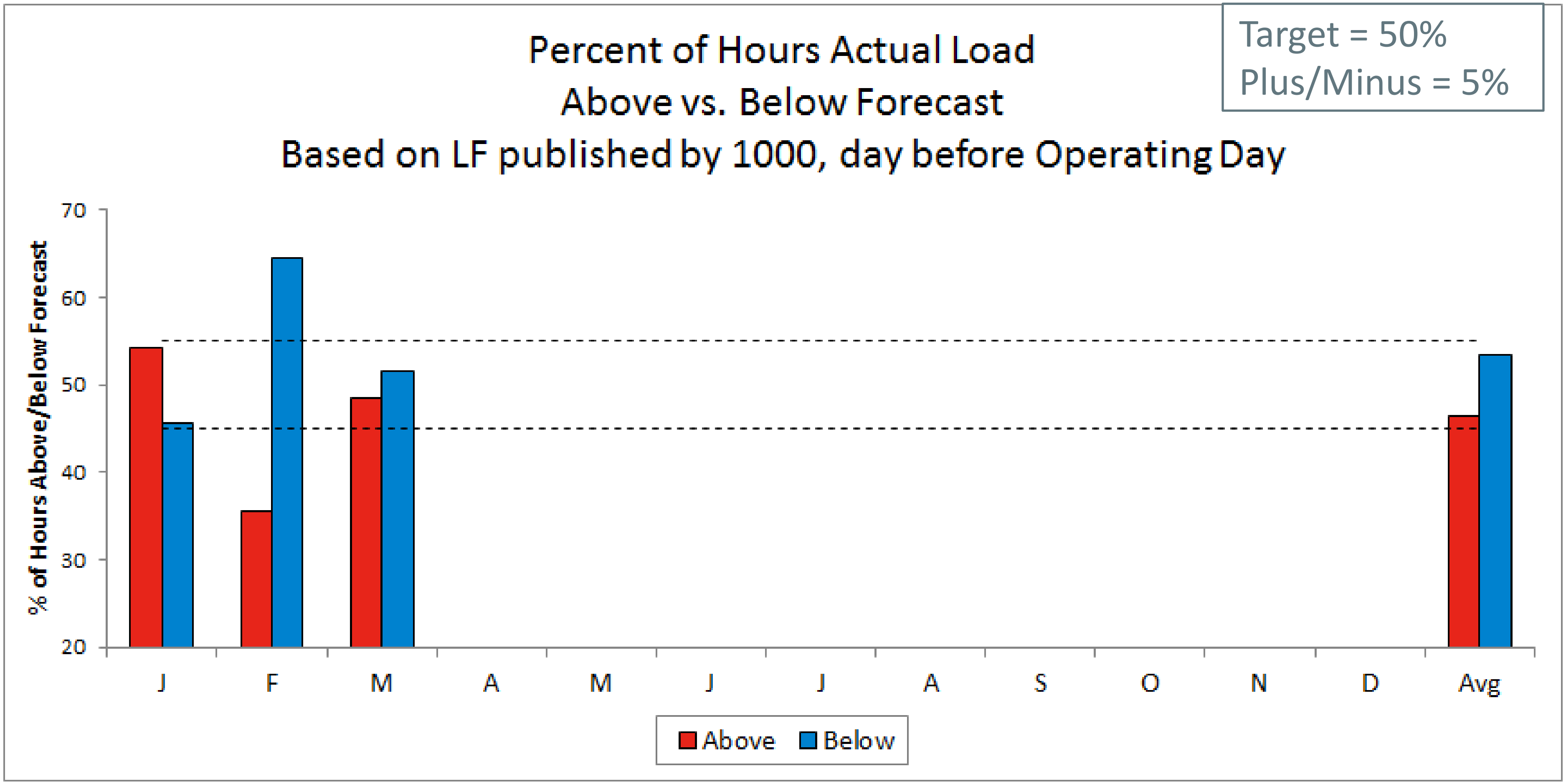
Dashboard Indicator ●



Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.38	1.83	1.63										1.61
Day Max	4.41	4.91	8.70										6.04
Day Min	0.01	0.05	0.14										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	1.38	1.83	1.63										1.61
Summer Actual													

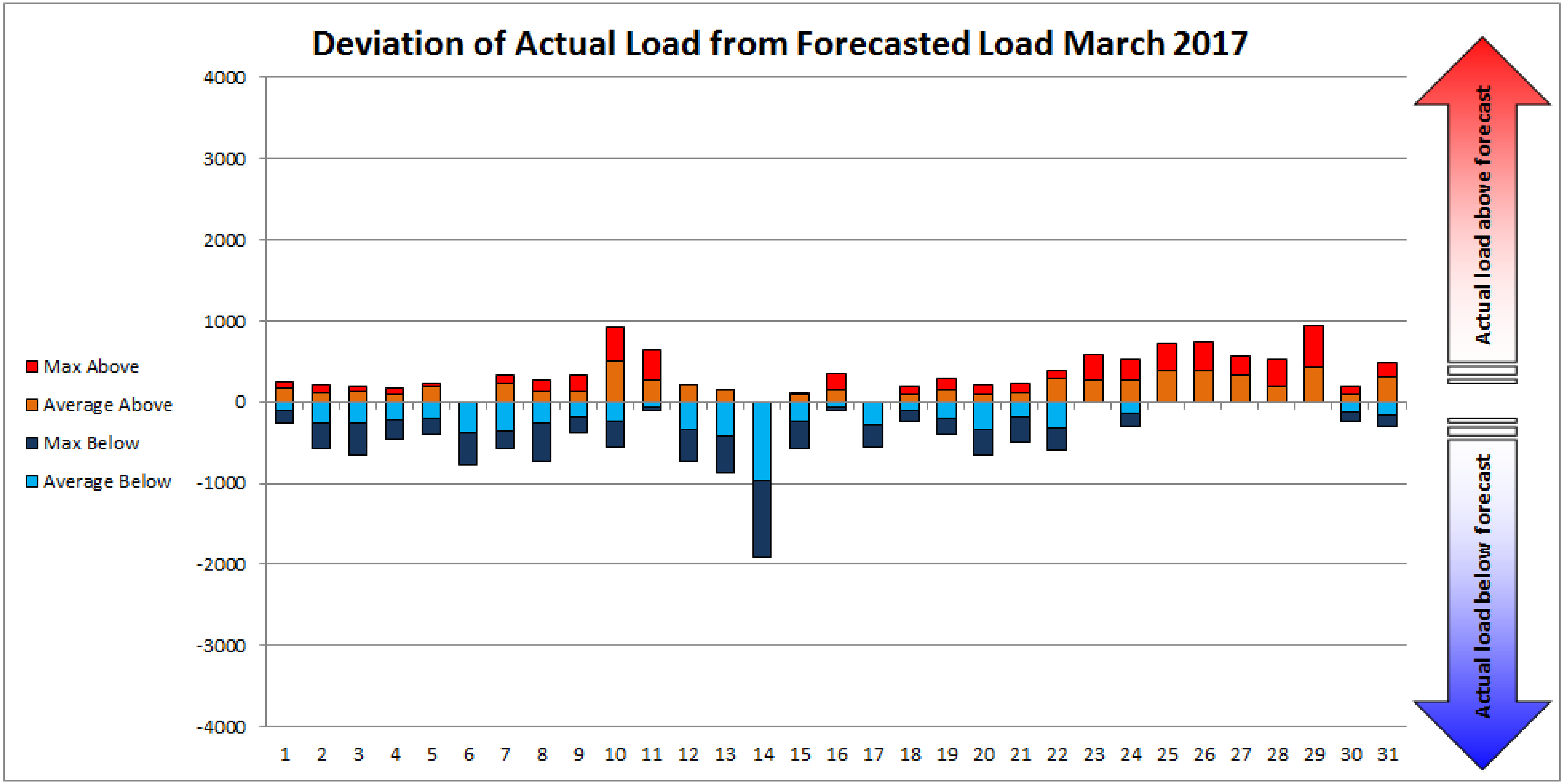
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2017 System Operations - Load Forecast Accuracy, cont.

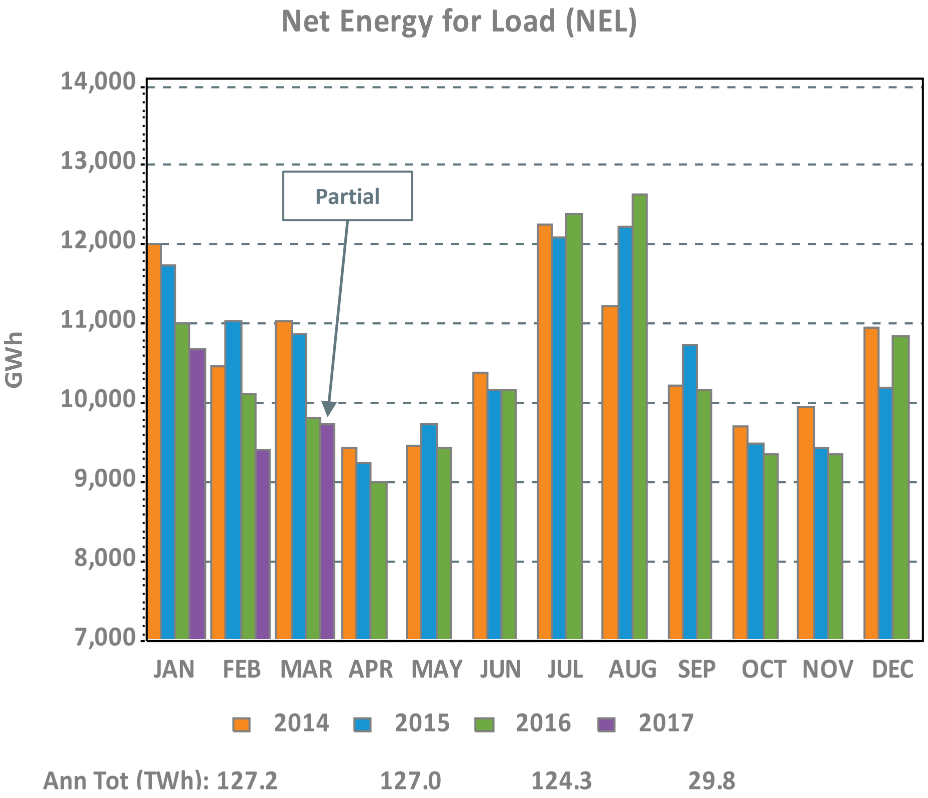


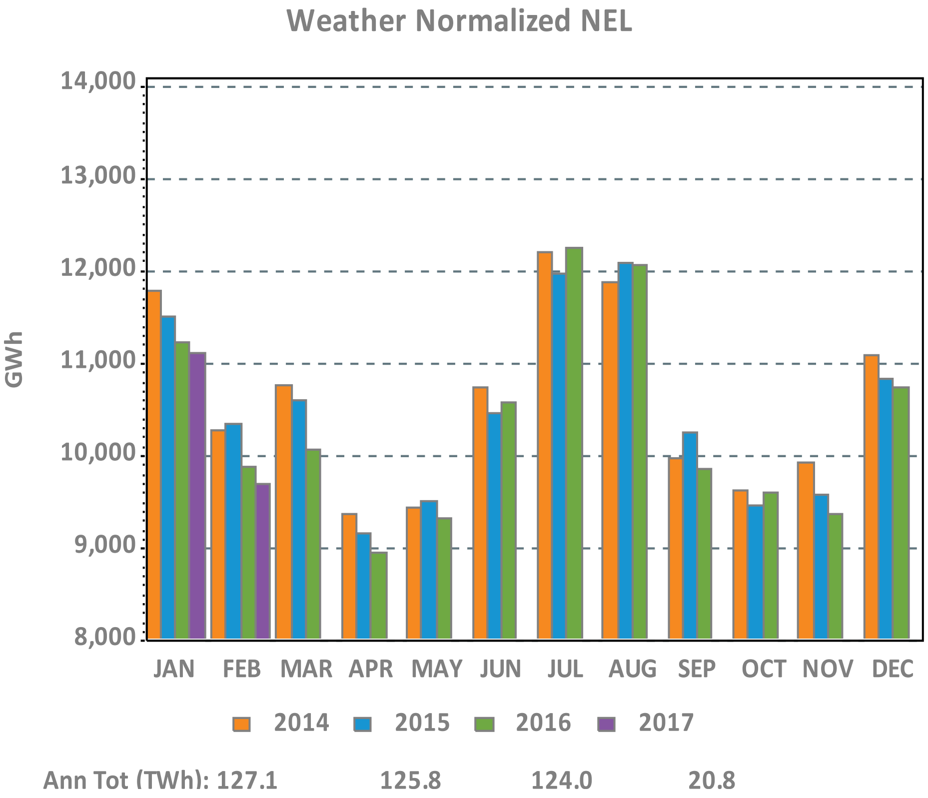
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	54.3	35.6	48.5										46
Below %	45.7	64.4	51.5										54
Avg Above	175.5	137.4	192.2										169
Avg Below	-174.1	-209.5	-206.6										-196
Avg All	20	-76	-32										-28

2017 System Operations - Load Forecast Accuracy, cont.



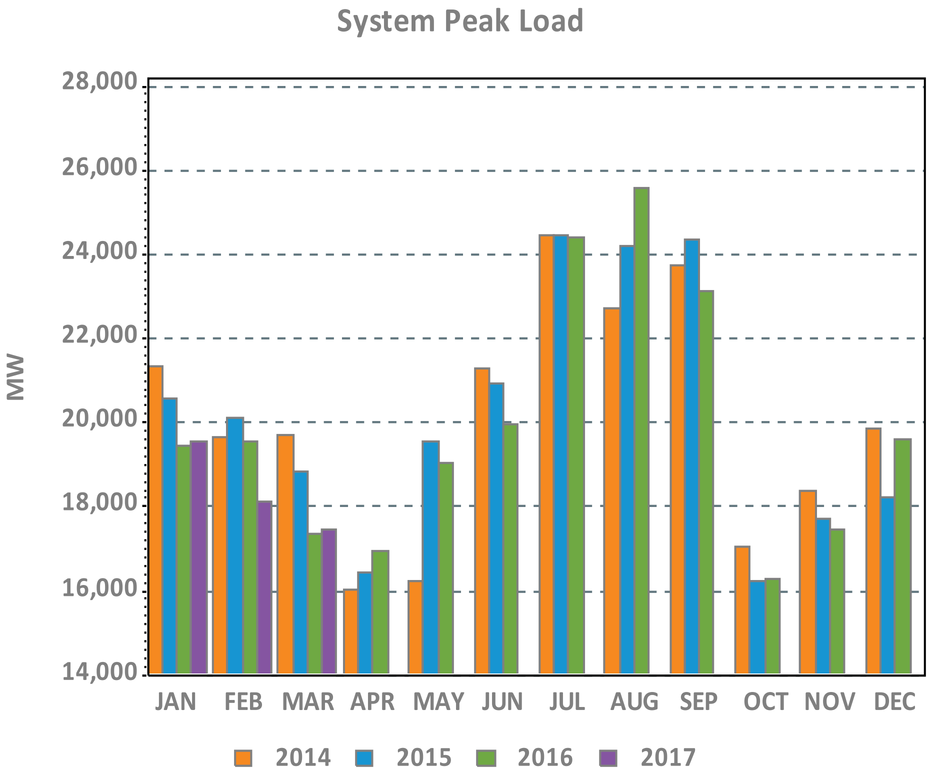
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



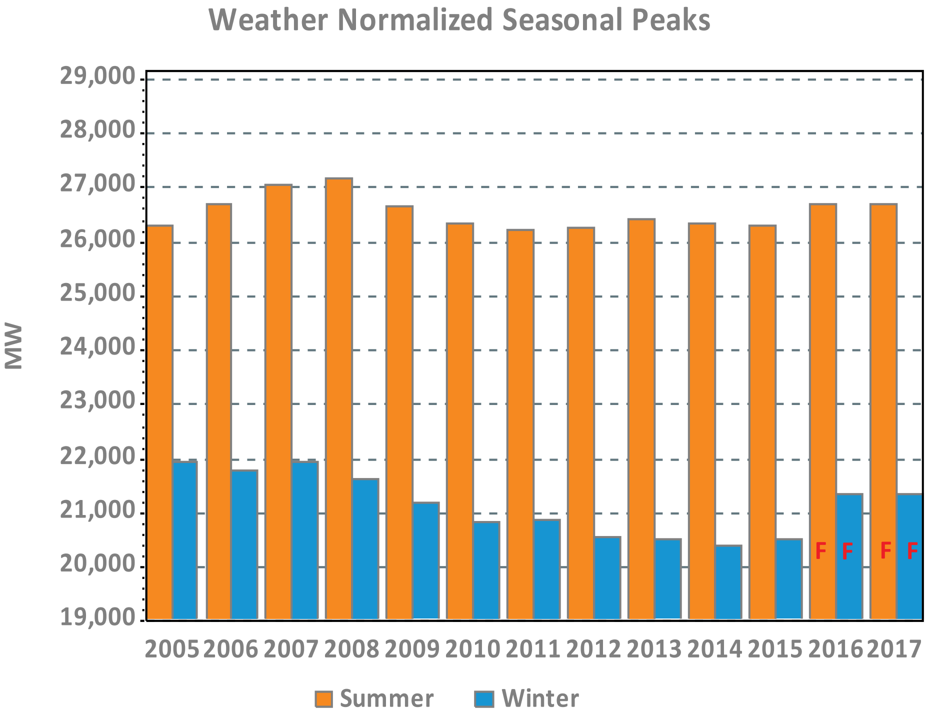


NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

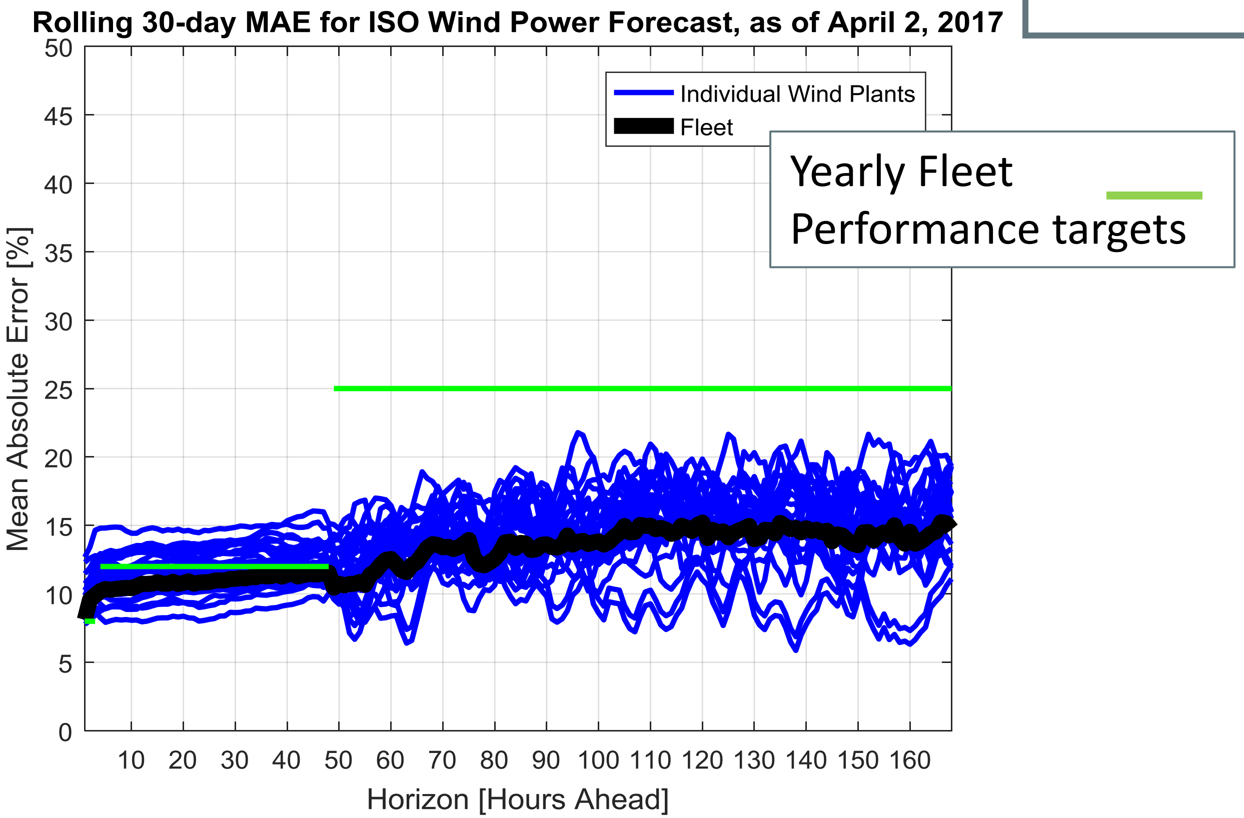


Winter beginning in year displayed

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 ●

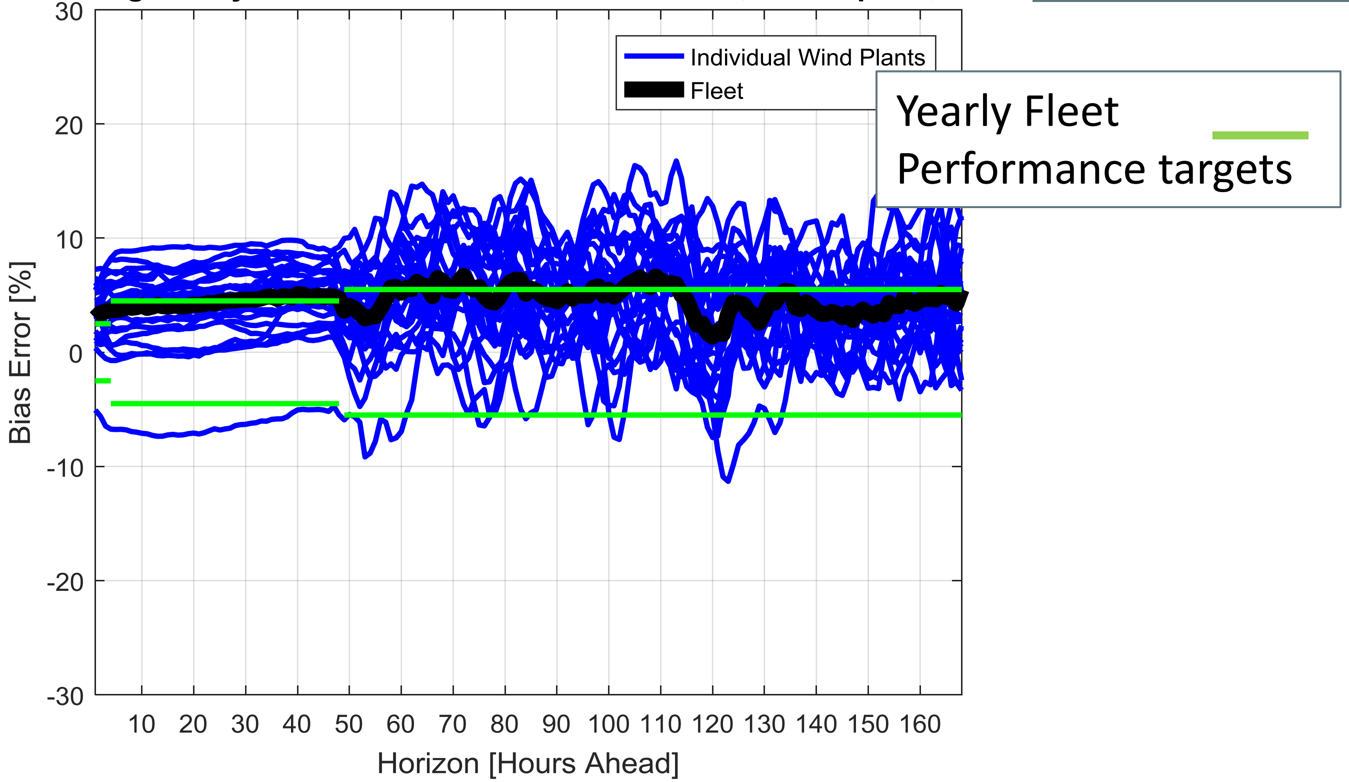


Yearly Fleet Performance targets

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 within the yearly performance targets.

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

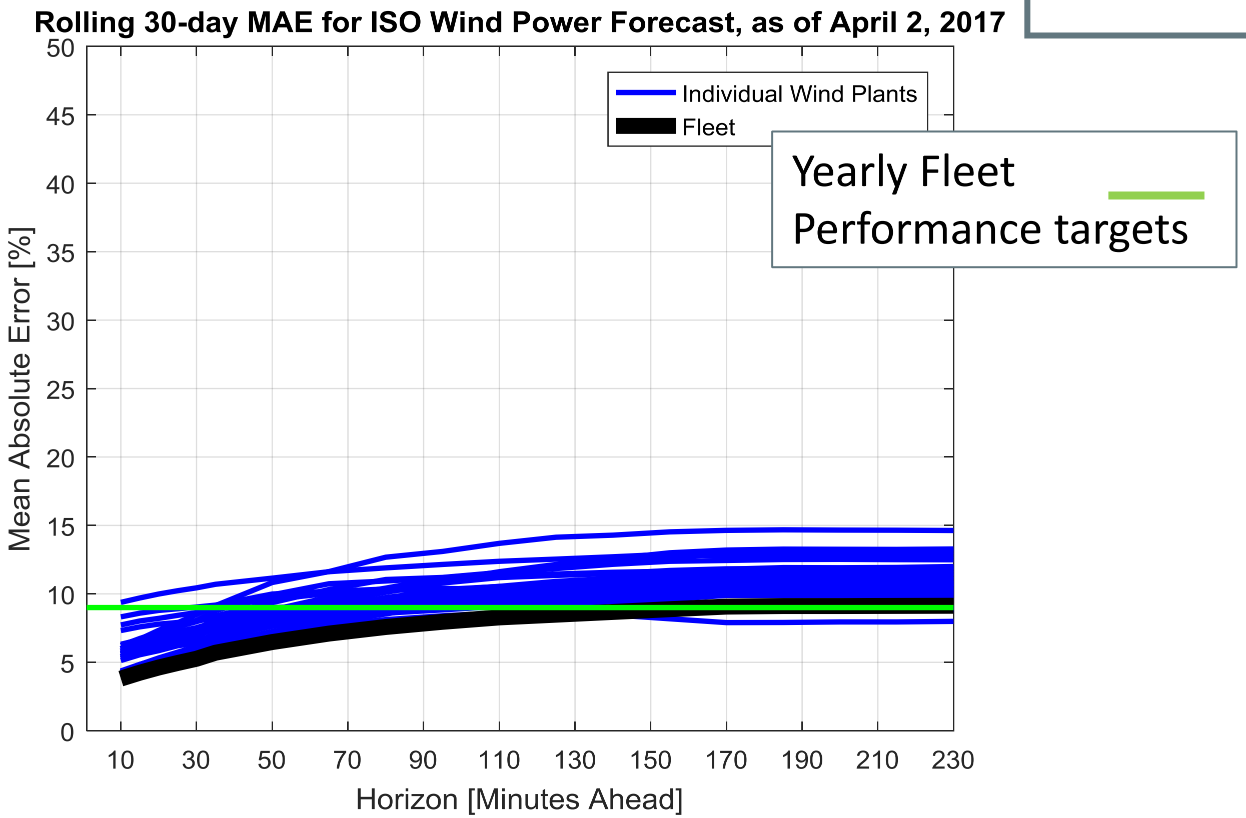
Dashboard Indicator ●


Rolling 30-day Bias for ISO Wind Power Forecast, as of April 2, 2017

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 ●



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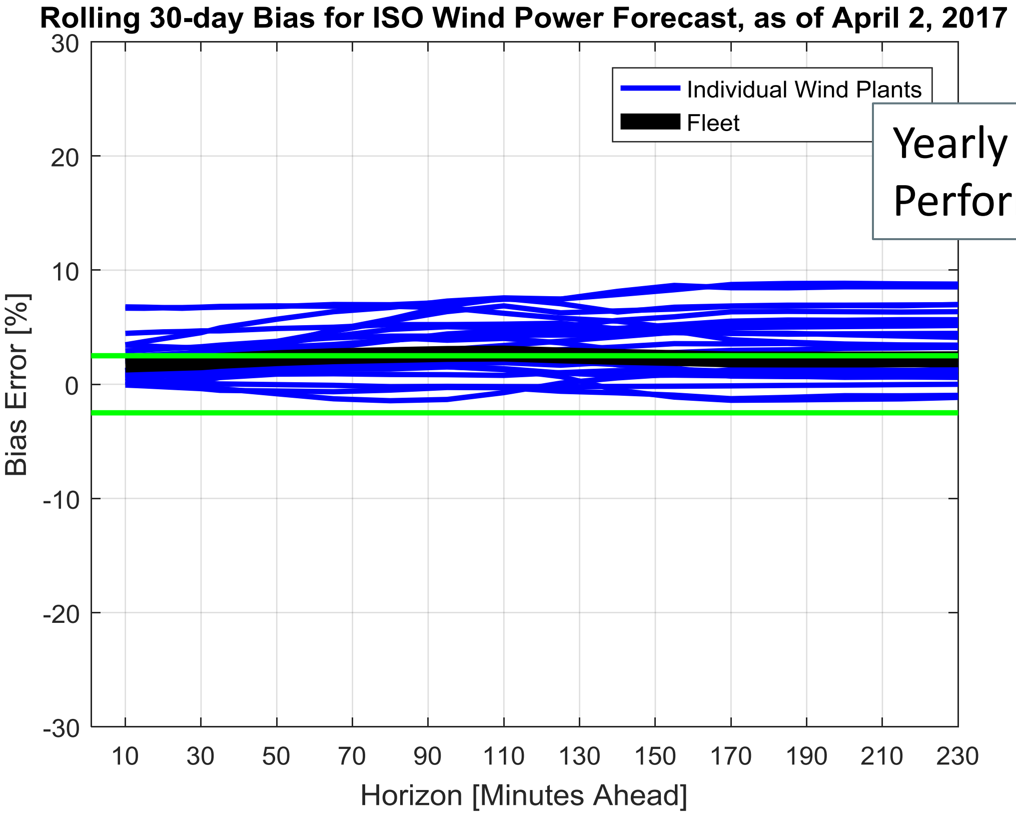
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator ●


Rolling 30-day Bias for ISO Wind Power Forecast, as of April 2, 2017

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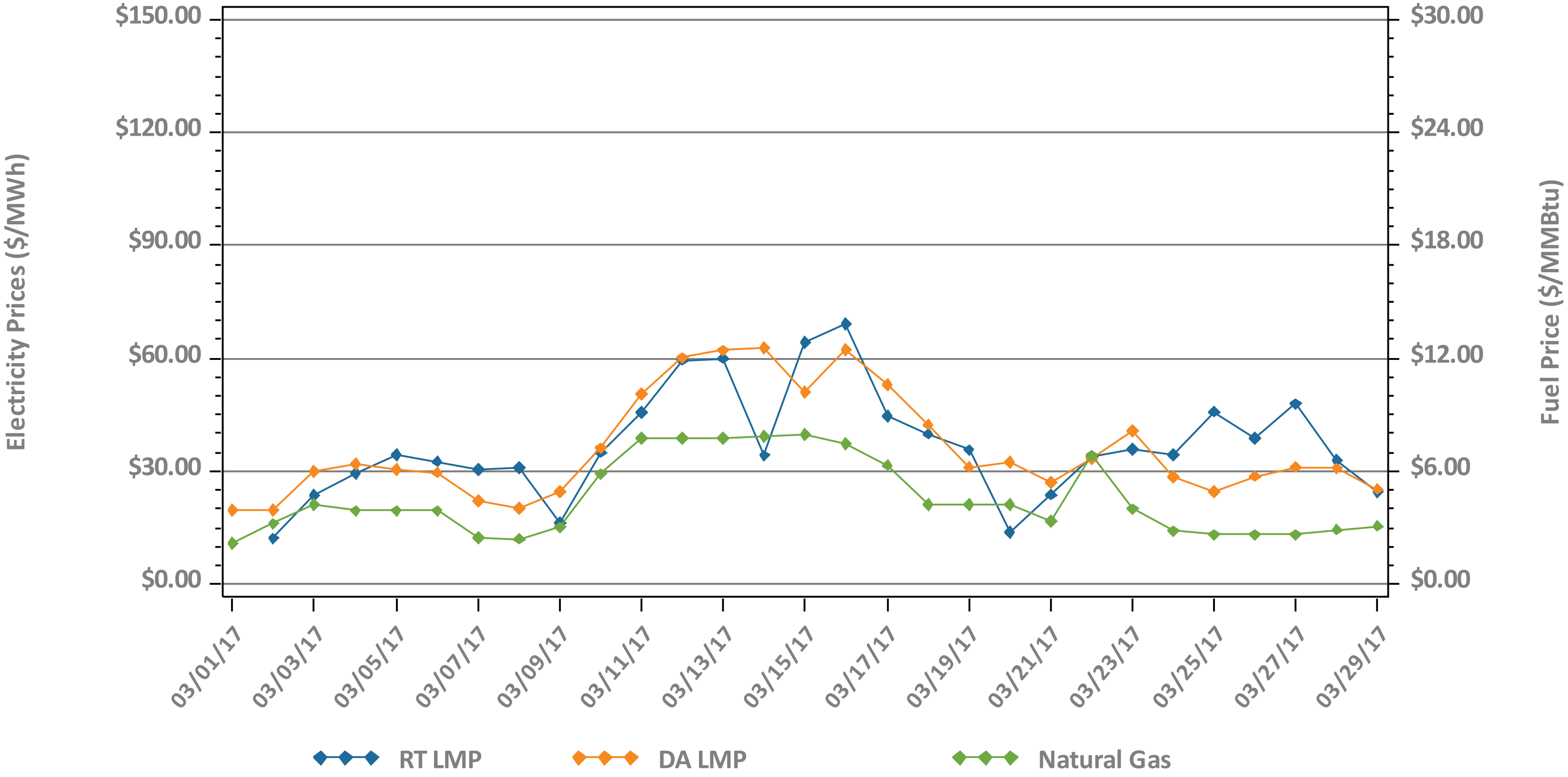
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: March 1-29, 2017



Underlying natural gas data furnished by:

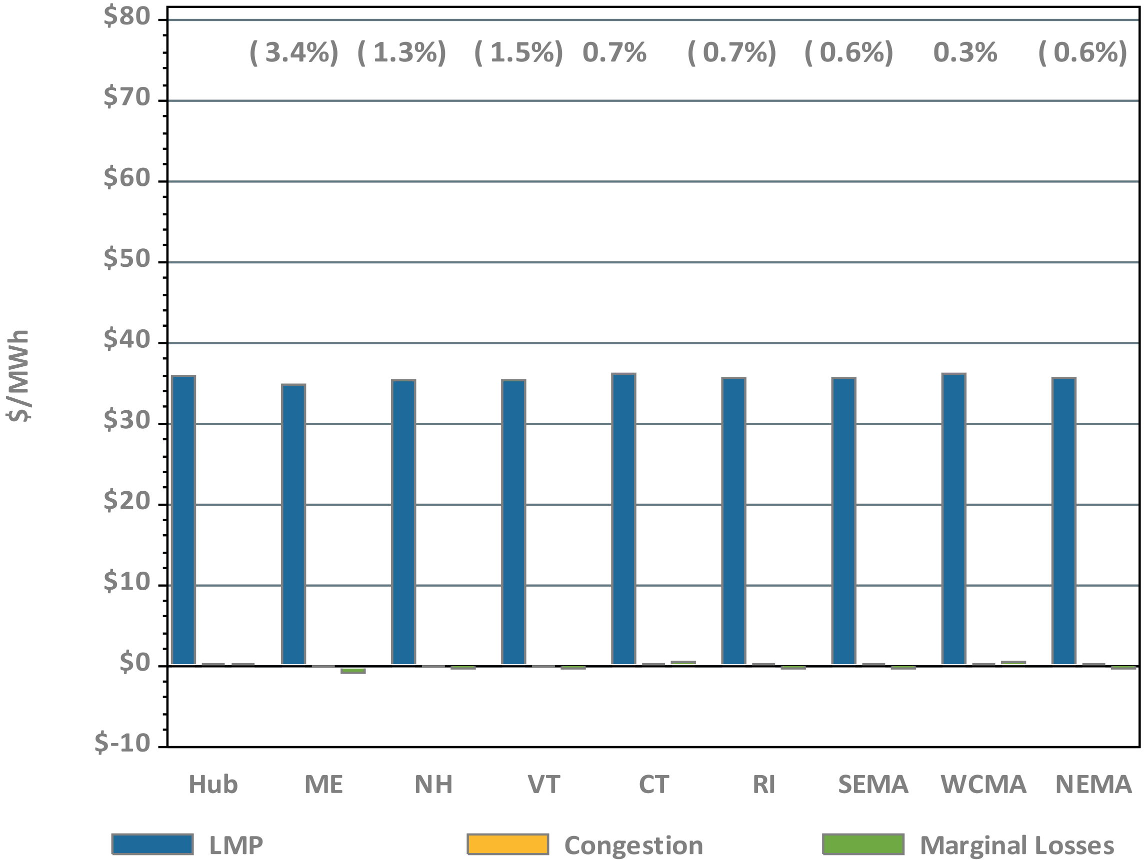
Average price difference over this period (DA-RT): $0.48

Average price difference over this period ABS(DA-RT): $7.90

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 22%

Gas price is average of Massachusetts delivery points

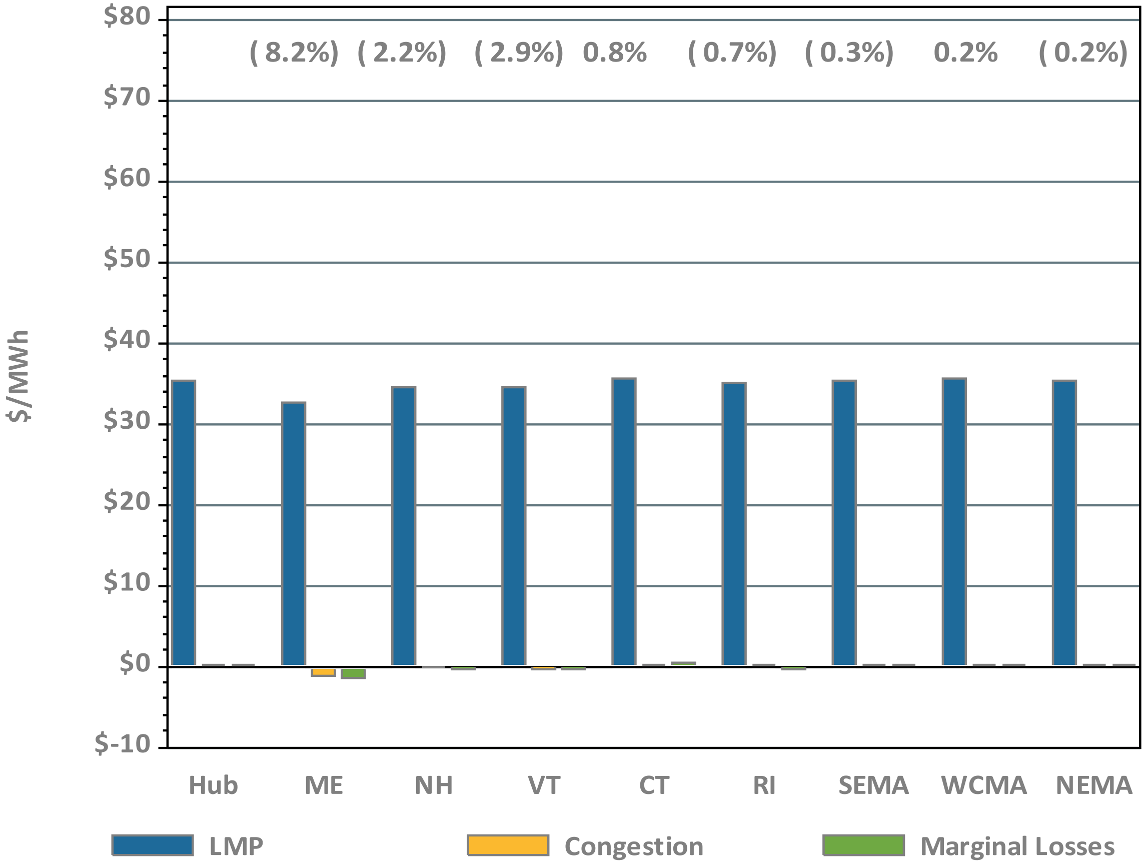
DA LMPs Average by Zone & Hub, March 2017



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

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

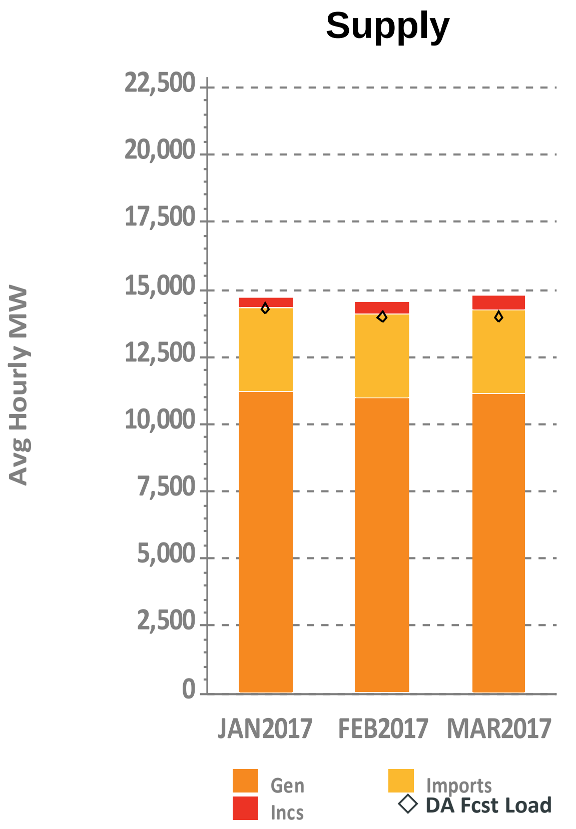
RT LMPs Average by Zone & Hub, March 2017



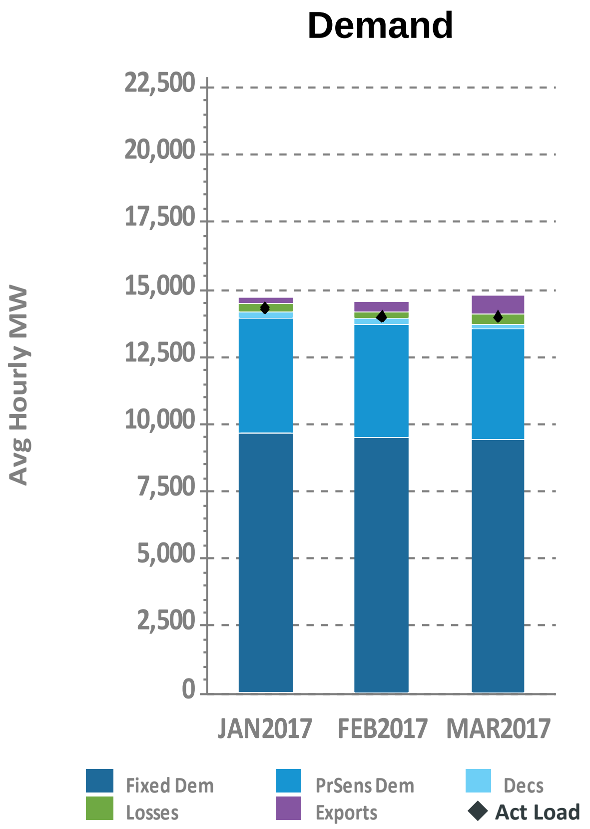
Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission 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

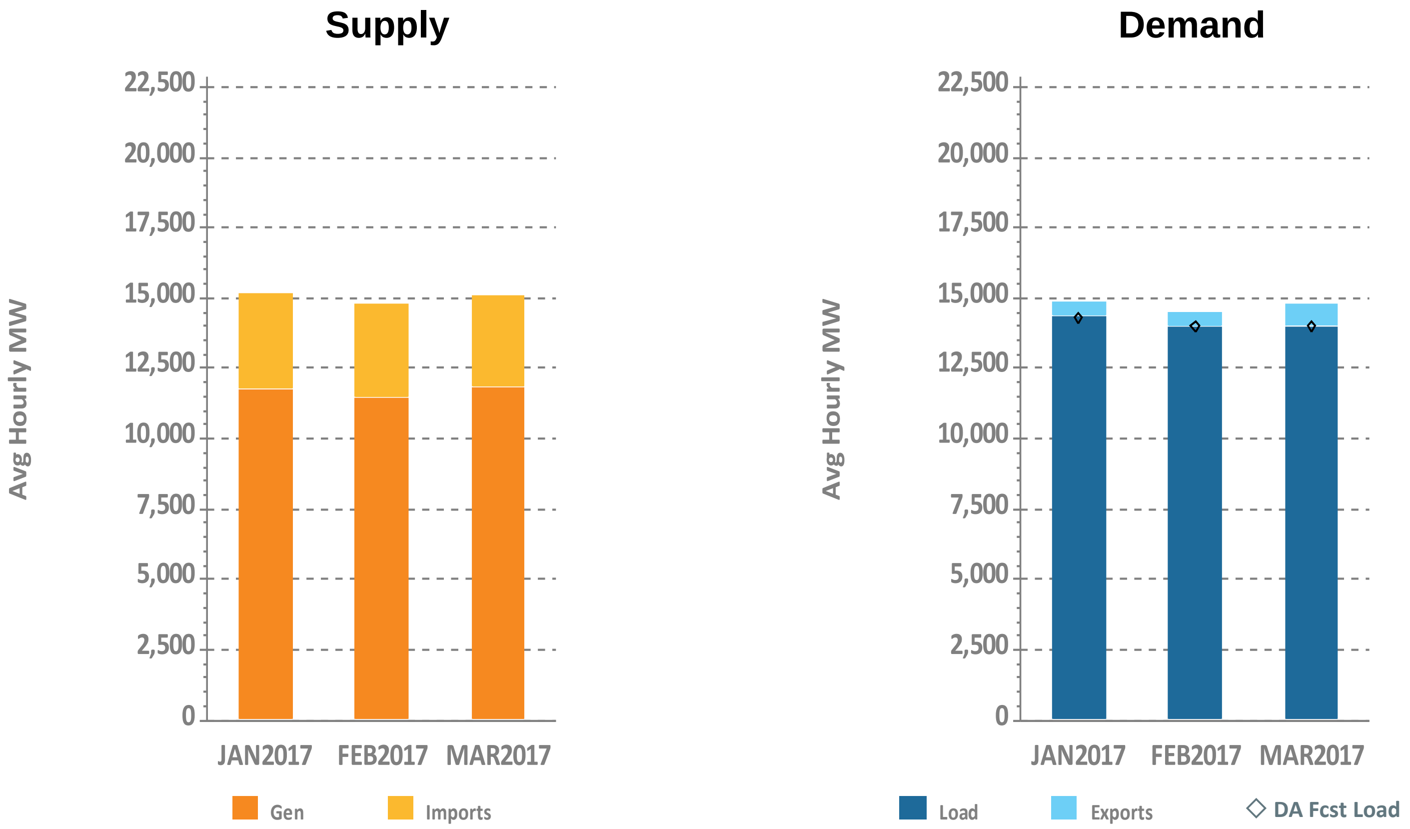


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

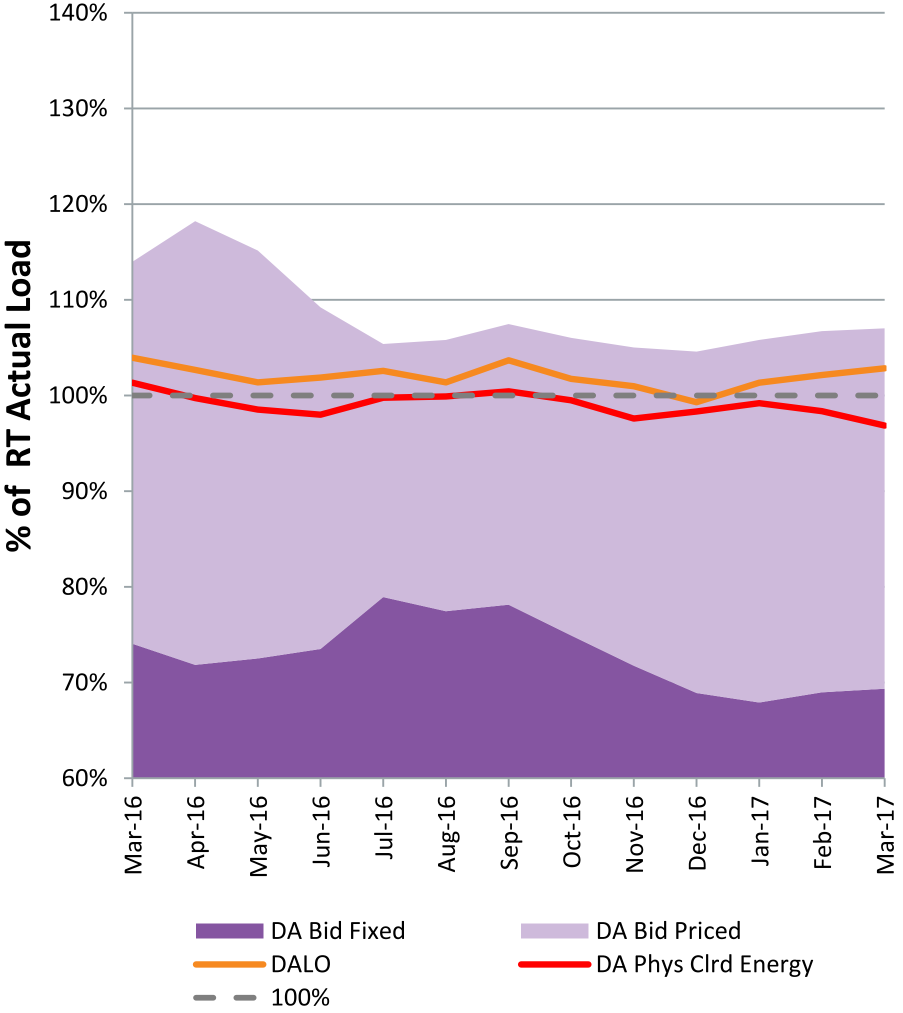


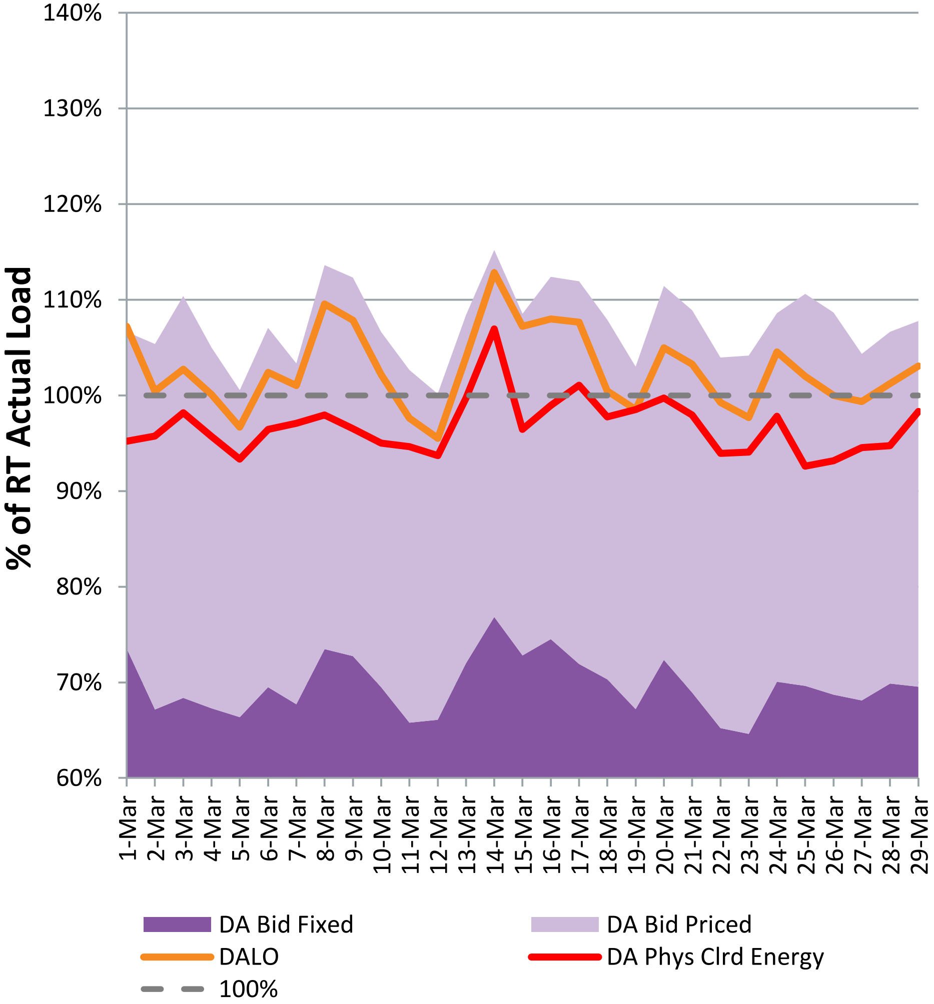
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months



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

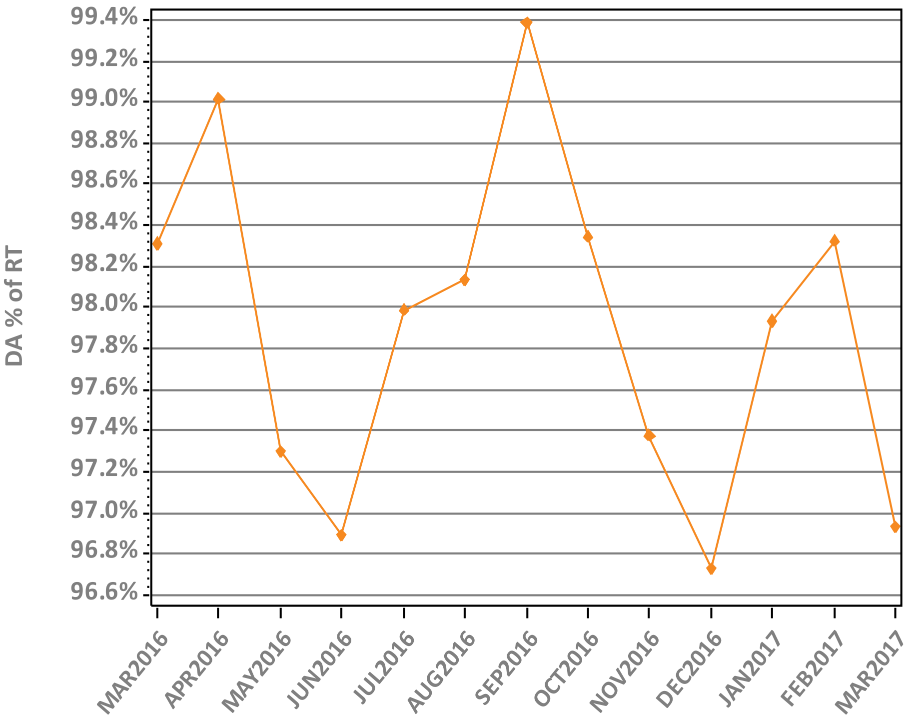




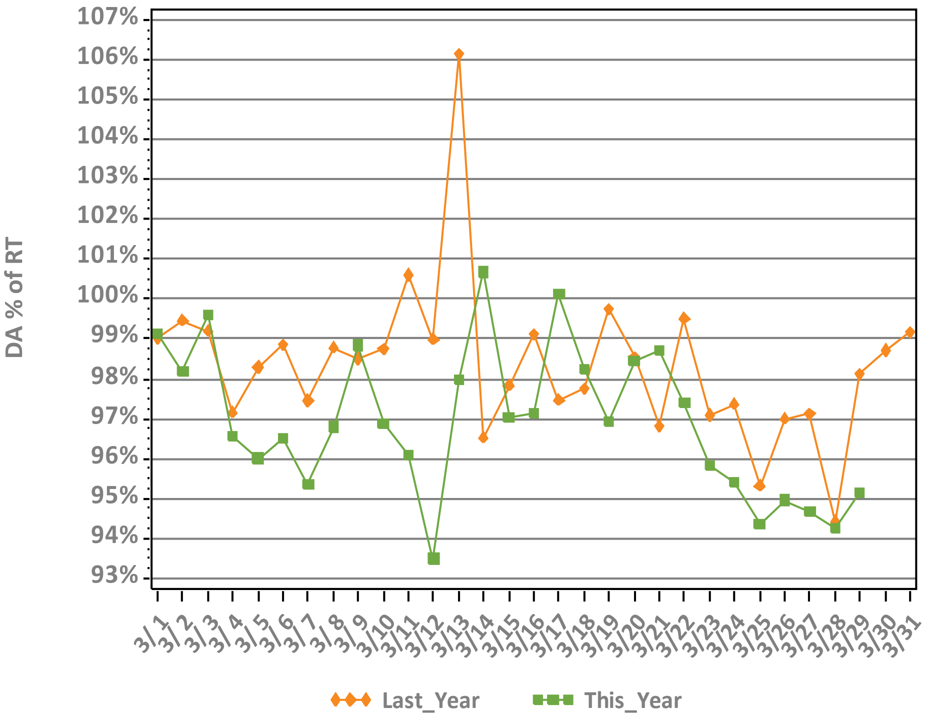
Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Dec and export bid behavior not reflected).

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

Monthly, Last 13 Months

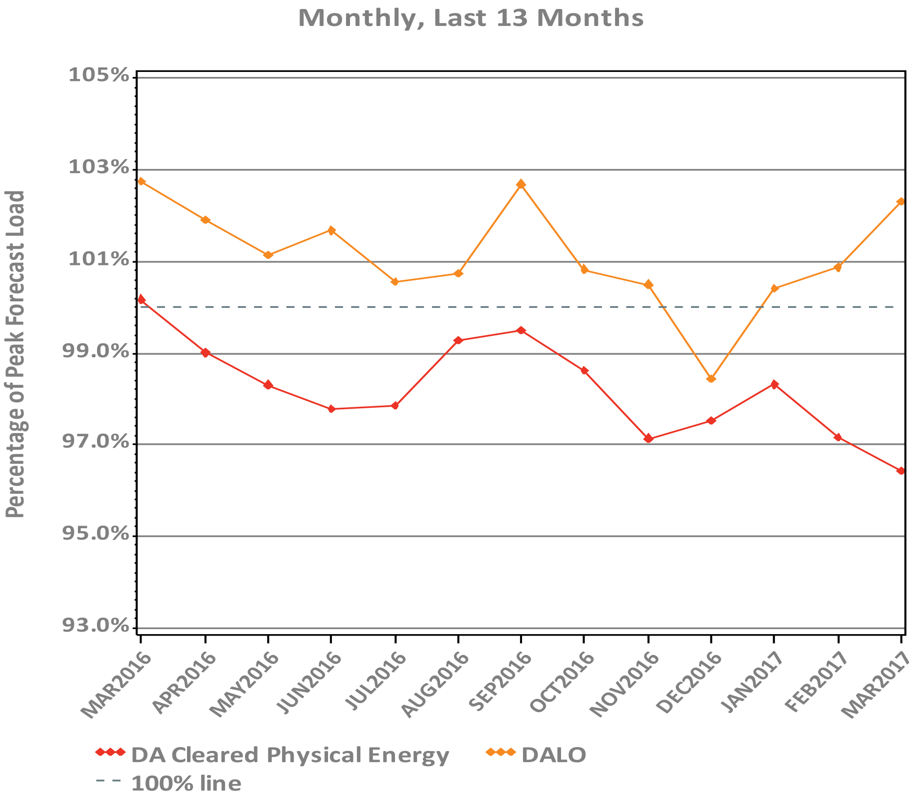


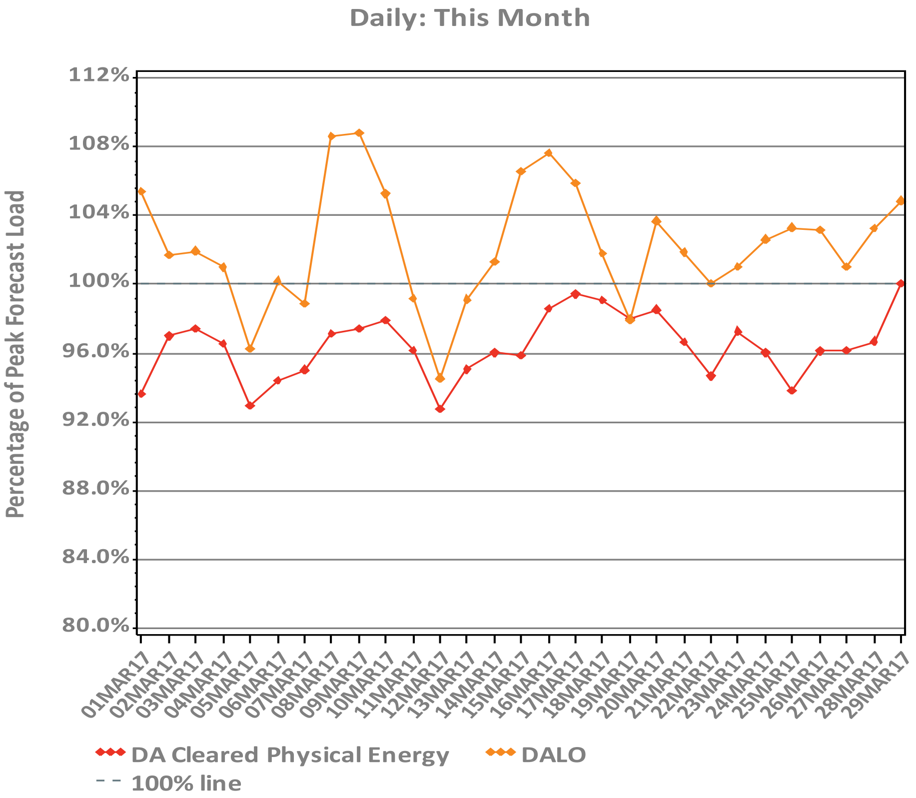
Daily, This Year vs. Last Year



*Hourly average values

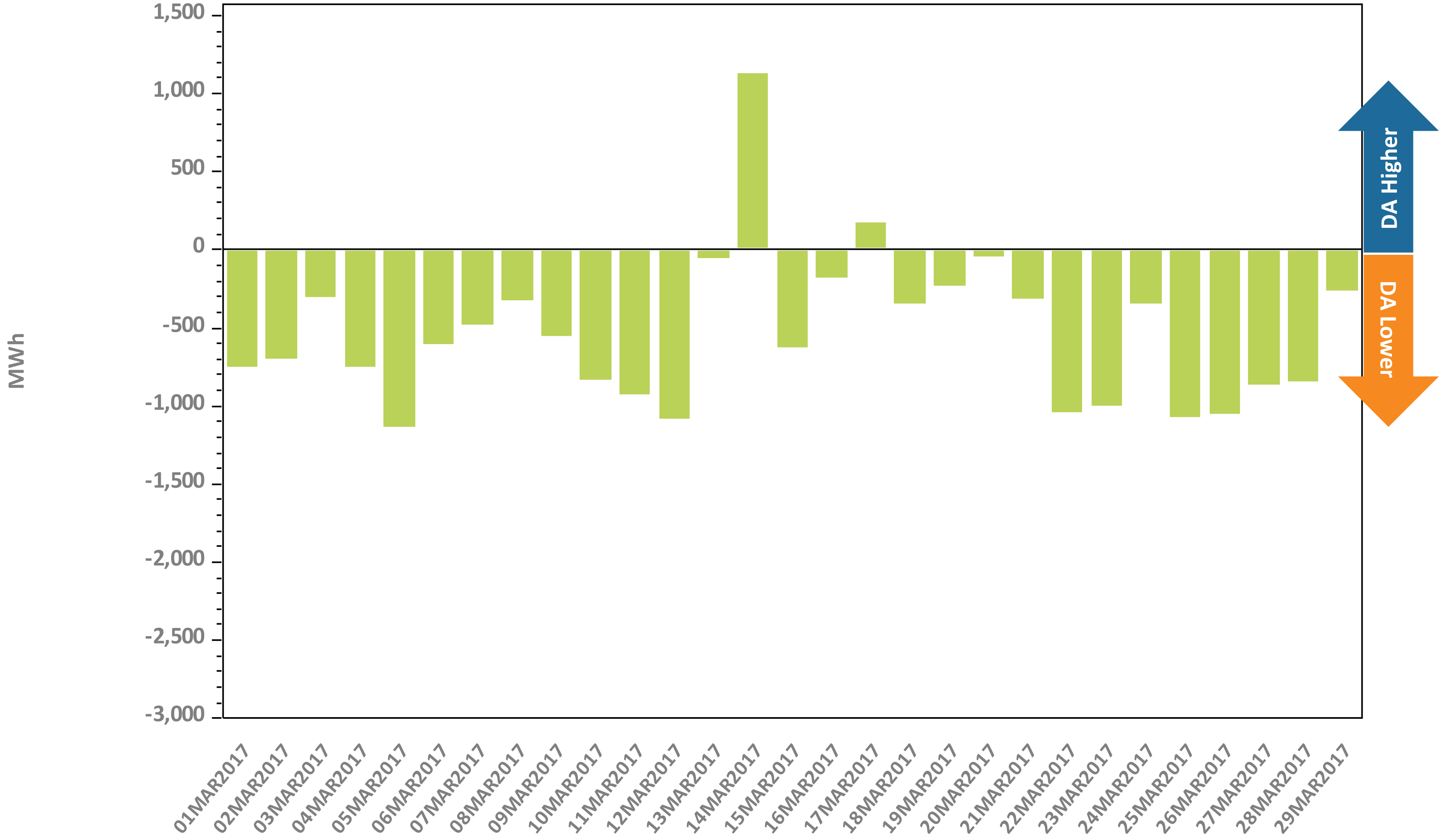
DA Volumes as % of Forecast (Peak Hour)





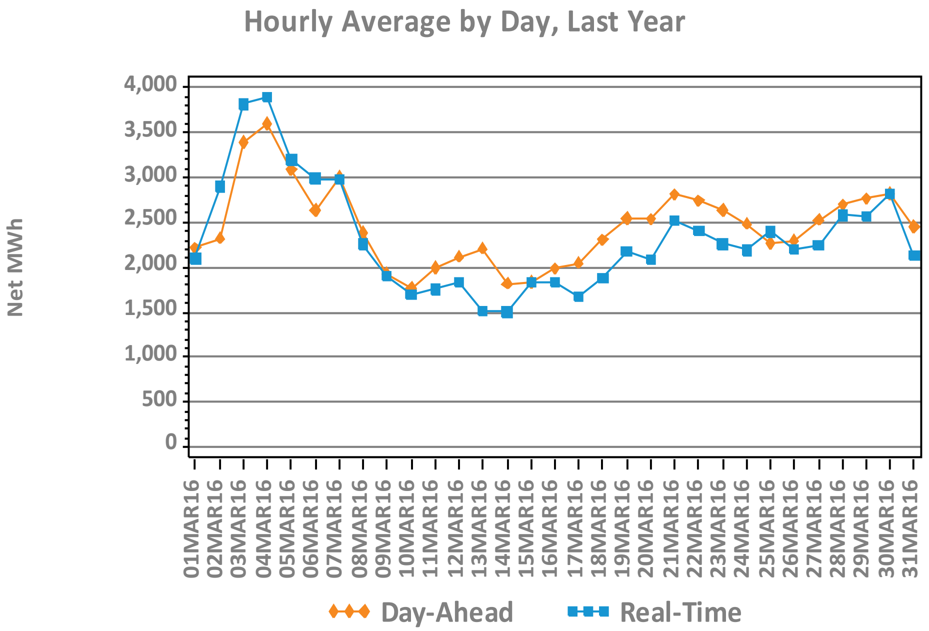
*Forecasted peak hour is reflected.

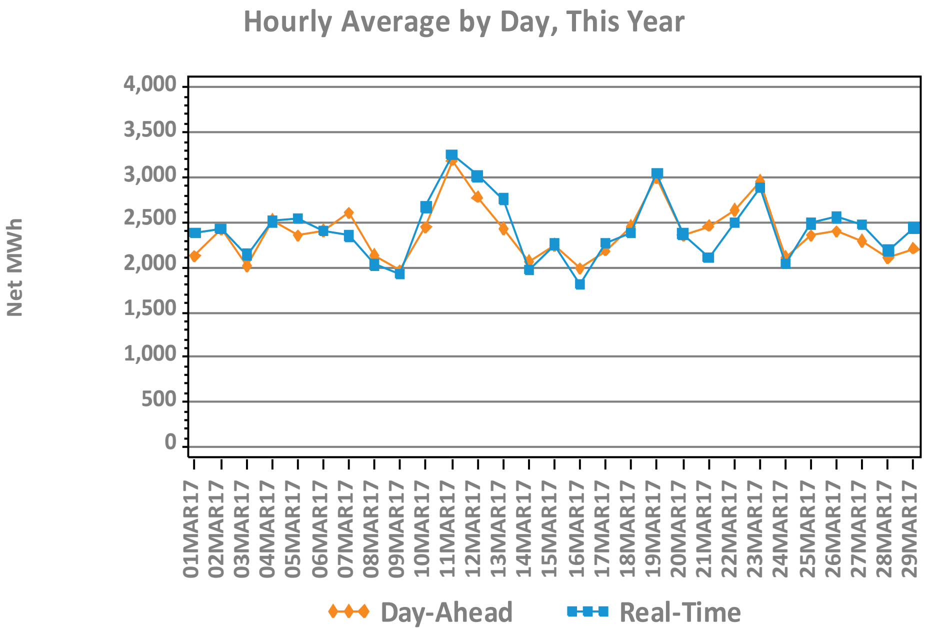
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

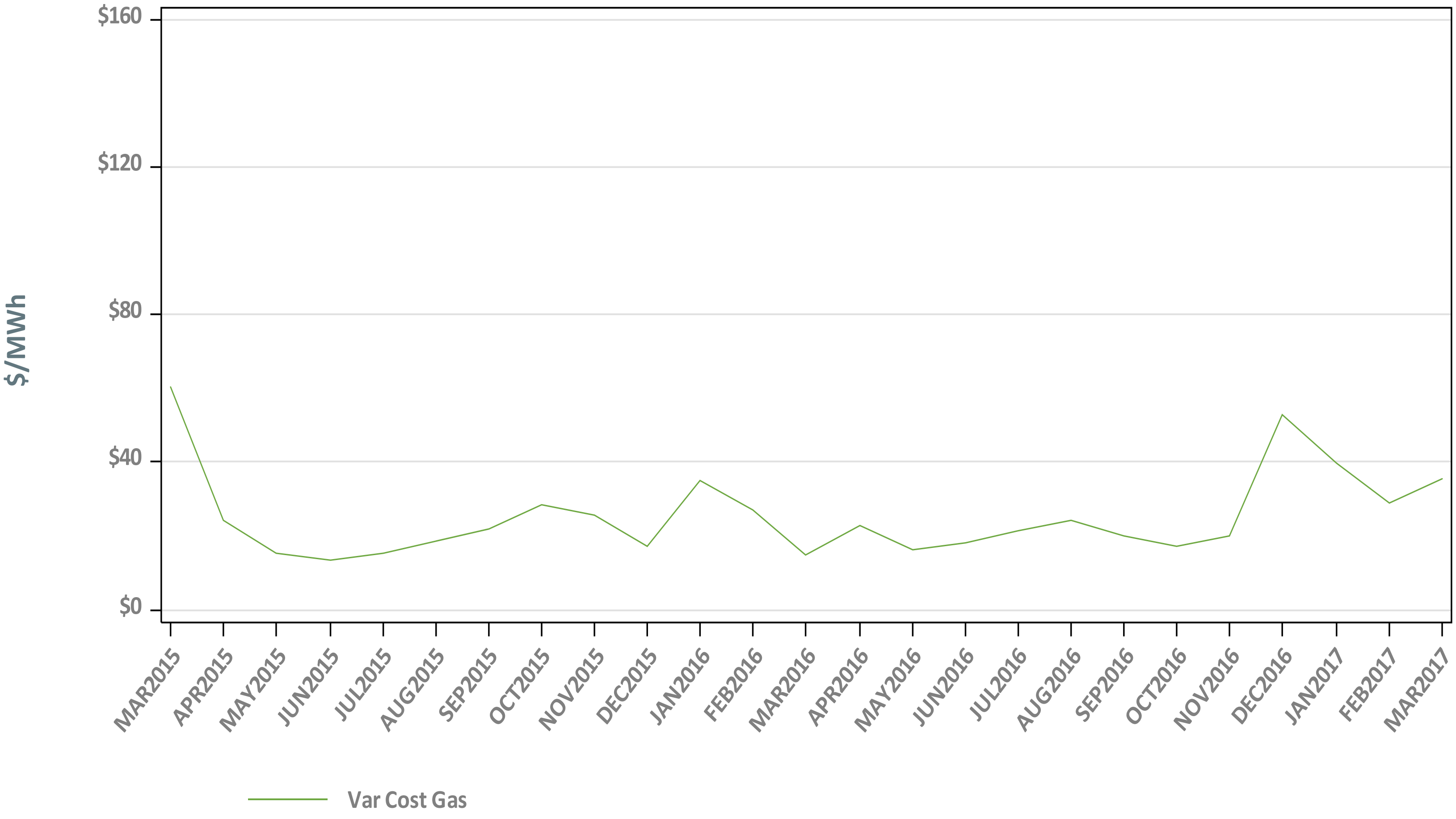
DA vs. RT Net Interchange March 2017 vs. March 2016


Hourly Average by Day, Last Year


Hourly Average by Day, This Year

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

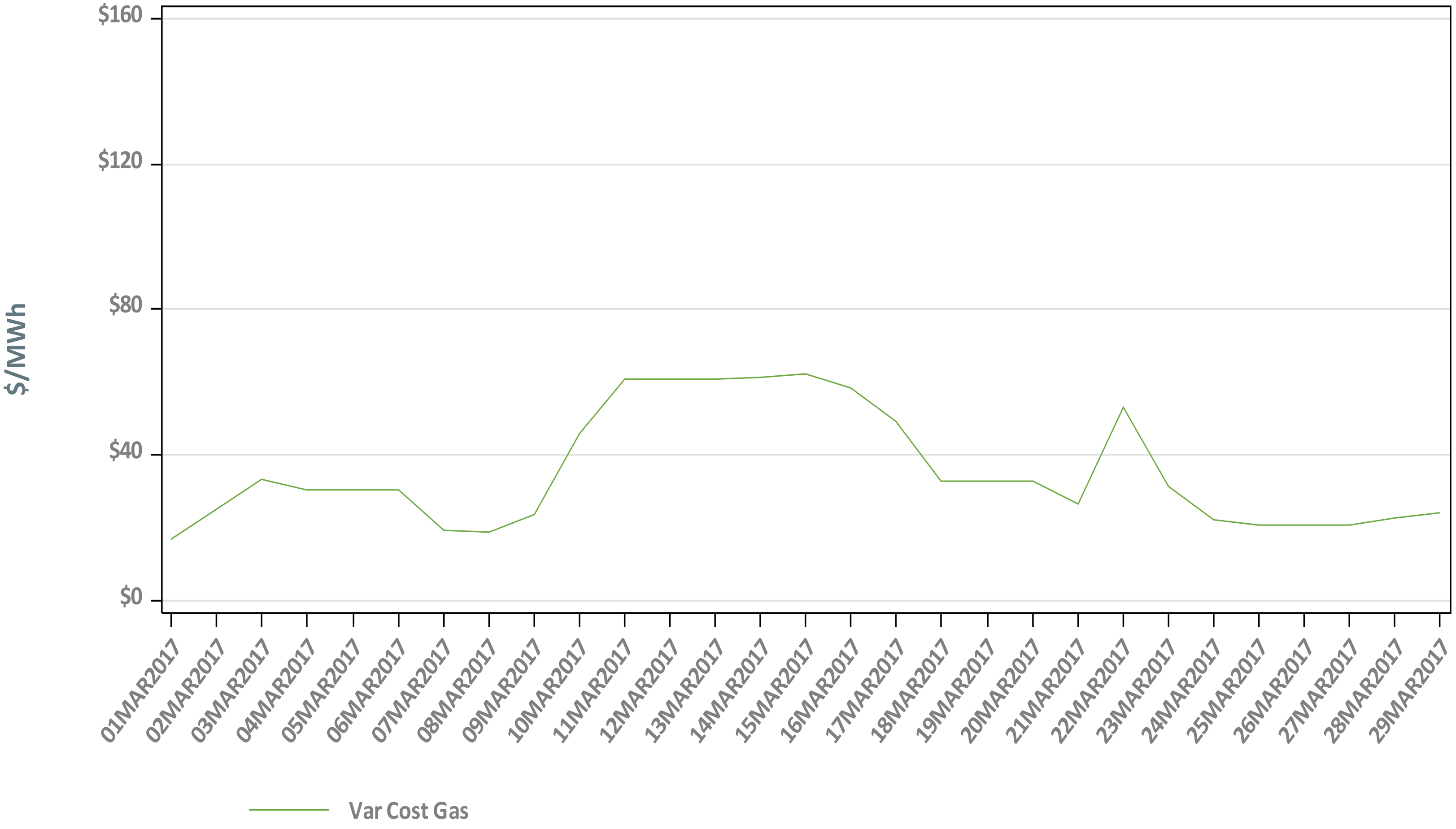


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

ICE Global markets in clear view

Variable Production Cost of Natural Gas: Daily

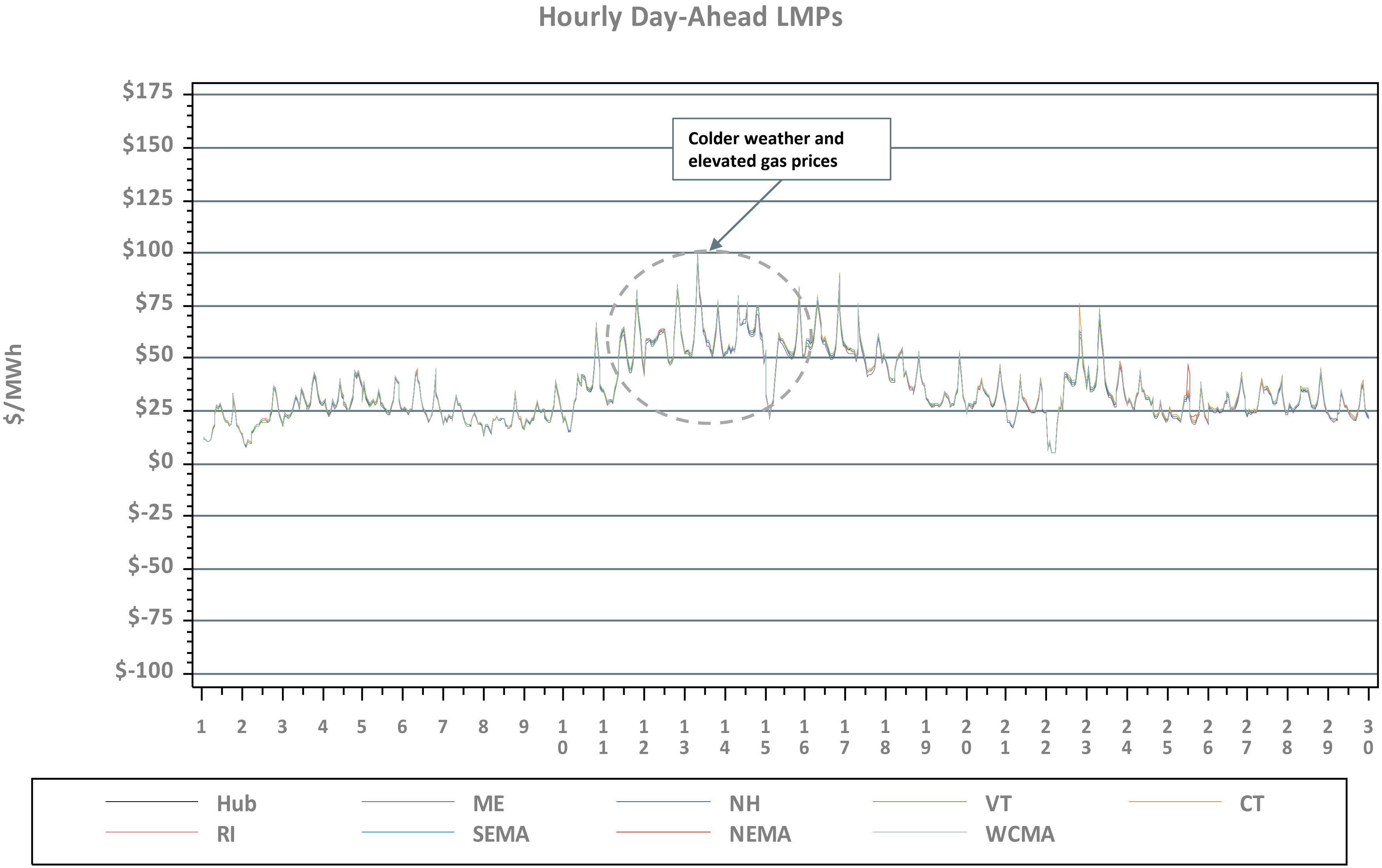


Underlying natural gas data furnished by:

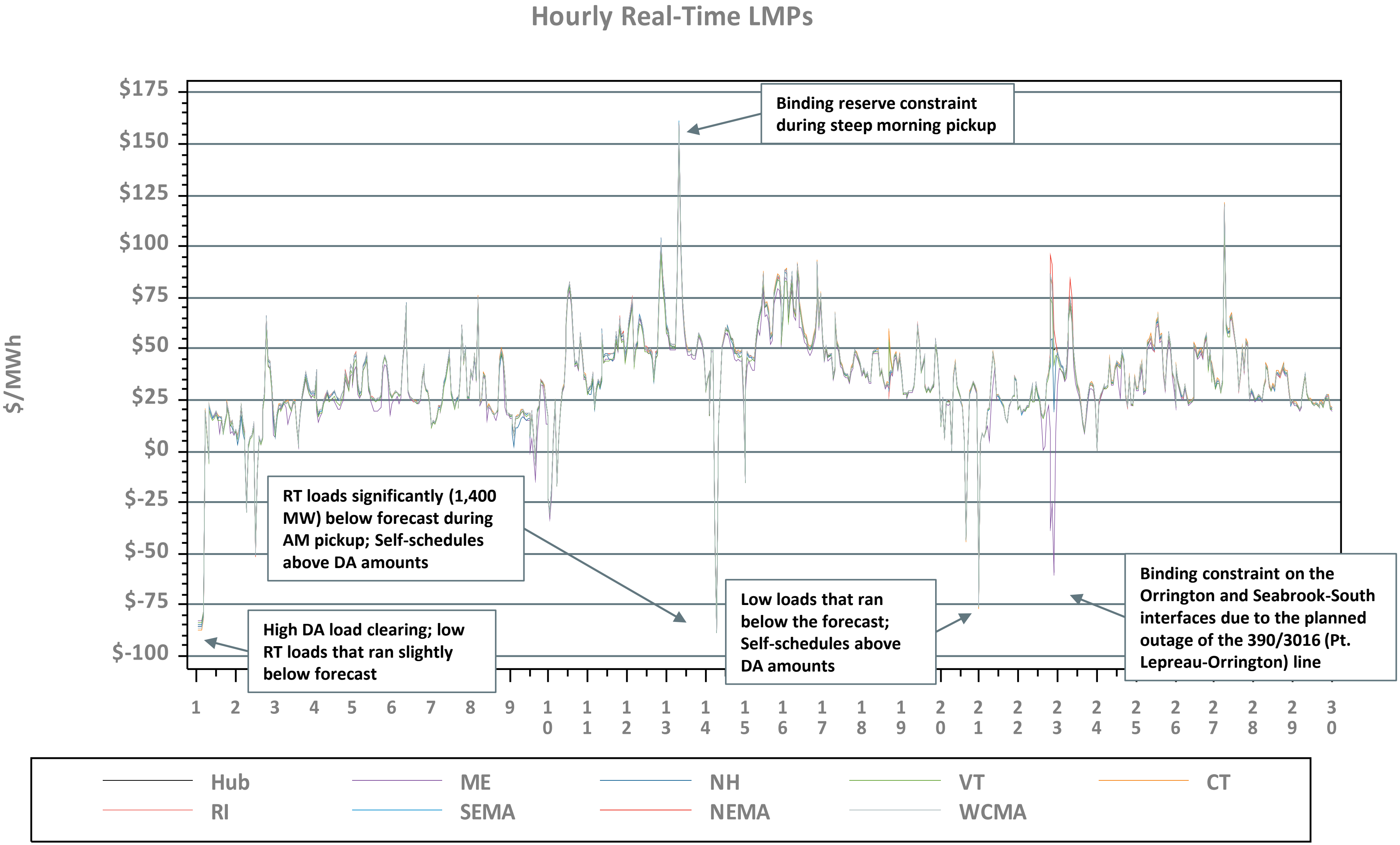
ICE Global markets in clear view

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

Hourly DA LMPs, March 1-29, 2017



Hourly RT LMPs, March 1-29, 2017



Binding reserve constraint during steep morning pickup

RT loads significantly (1,400 MW) below forecast during AM pickup; Self-schedules above DA amounts

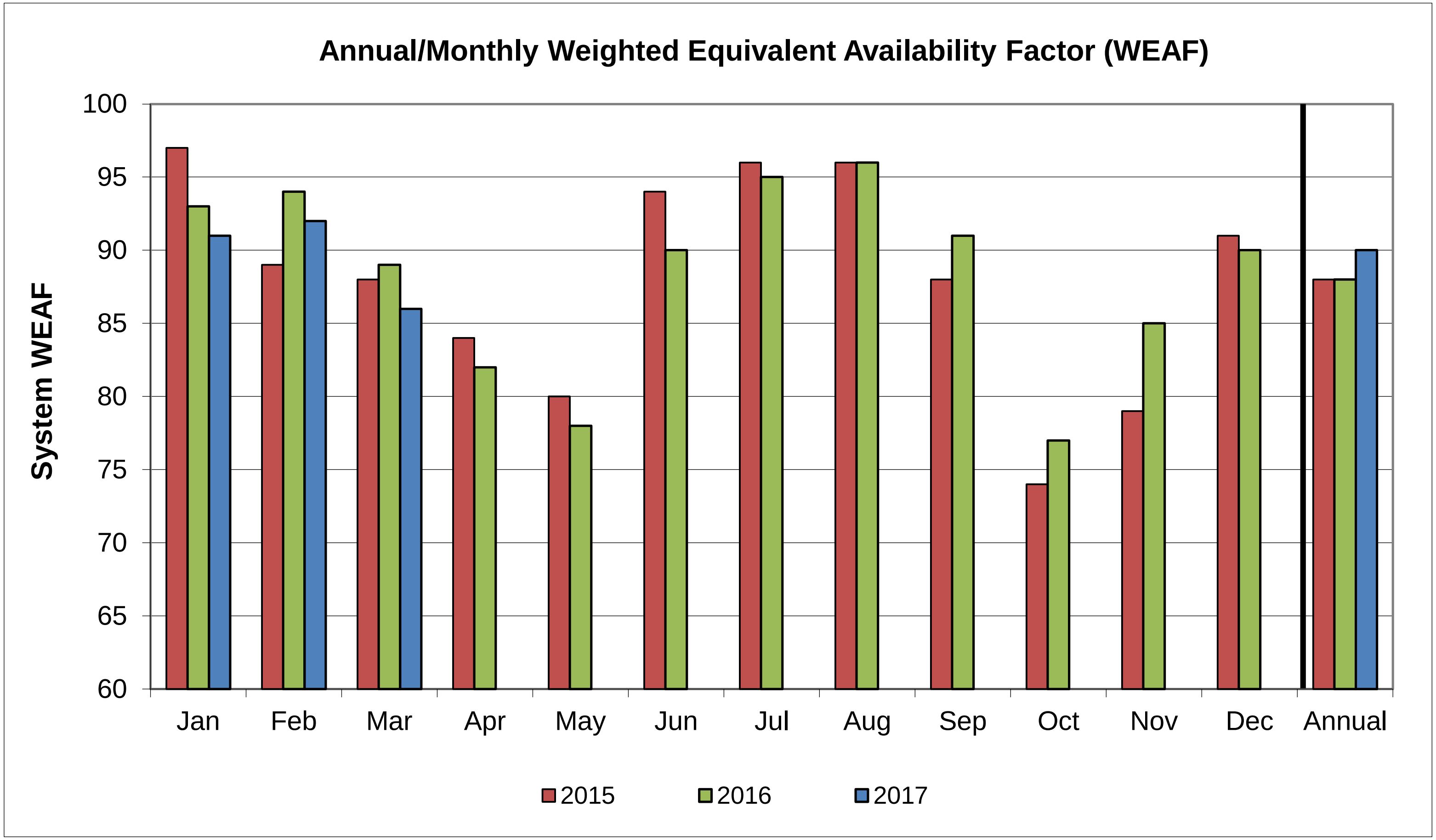
High DA load clearing; low RT loads that ran slightly below forecast

Low loads that ran below the forecast; Self-schedules above DA amounts

Binding constraint on the Orrington and Seabrook-South interfaces due to the planned outage of the 390/3016 (Pt. Lepreau-Orrington) line

* No Minimum Generation Emergencies were declared in March.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2017	91	92	86										90
2016	93	94	89	82	78	90	95	96	91	77	85	90	88
2015	97	89	88	84	80	94	96	96	88	74	79	91	88

Data as of 4/3/17

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for April 2017

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	77.2	0.0	133.3	0.0	210.6
NH	10.5	0.0	81.1	0.0	91.6
VT	25.0	0.0	104.7	0.0	129.8
CT	57.2	1.5	58.9	355.4	473.0
RI	11.2	0.0	177.0	0.0	188.2
SEMA	10.8	0.0	246.7	0.0	257.4
WCMA	27.8	0.0	228.0	52.5	308.3
NEMA	24.7	0.0	486.5	0.0	511.2
Total	**244.5**	**1.5**	**1,516.1**	**407.9**	**2,170.0**

*** Real Time Demand Response**

**** Real Time Emergency Generation**

NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

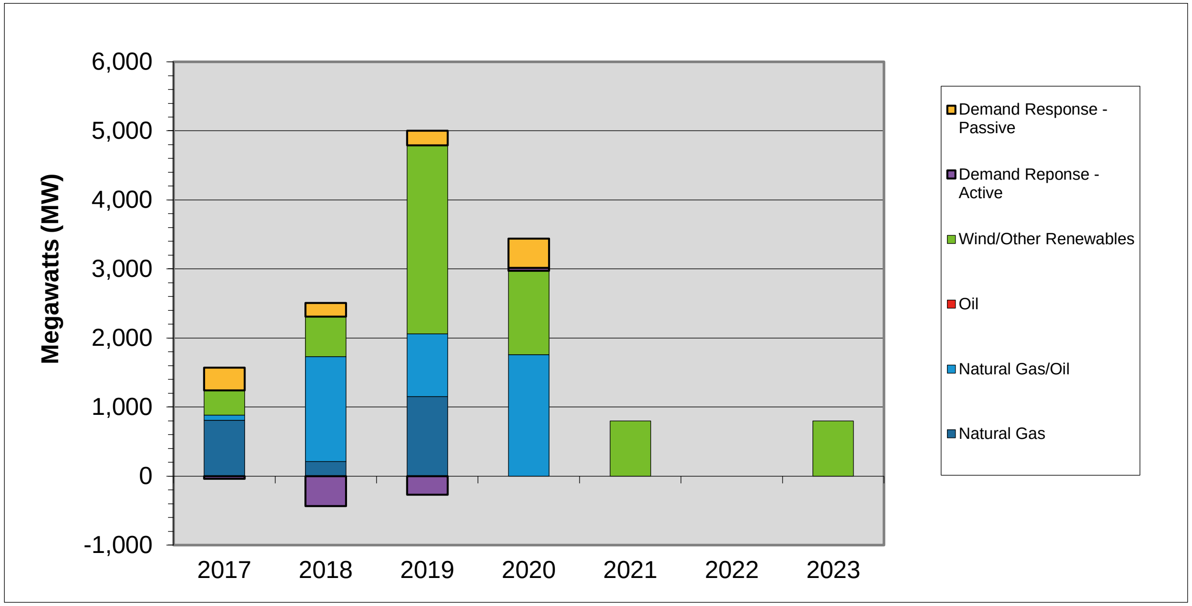
New Generation Update

Based on Queue as of 3/31/17

- Two new projects, with a total rating of 50 MW, have applied for interconnection study since the last update
  - The projects are photovoltaic facilities with expected in-service dates in 2019
- One project withdrew from the queue and no projects went commercial, resulting in a net decrease in new generation projects of 25 MW
- In total, 76 generation projects are currently being tracked by the ISO, totaling approximately 12,900 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2017	2018	2019	2020	2021	2022	2023	Total MW	% of Total[1]
Demand Response - Passive	330	196	212	422	0	0	0	1,160	8.7
Demand Response - Active	-37	-433	-270	42	0	0	0	-697	-5.2
Wind & Other Renewables	358	583	2,731	1,216	800	0	800	6,488	48.5
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	75	1,519	904	1,757	0	0	0	4,255	31.8
Natural Gas	808	210	1,154	0	0	0	0	2,172	16.2
Totals	**1,534**	**2,075**	**4,732**	**3,438**	**800**	**0**	**800**	**13,378**	**100.0**

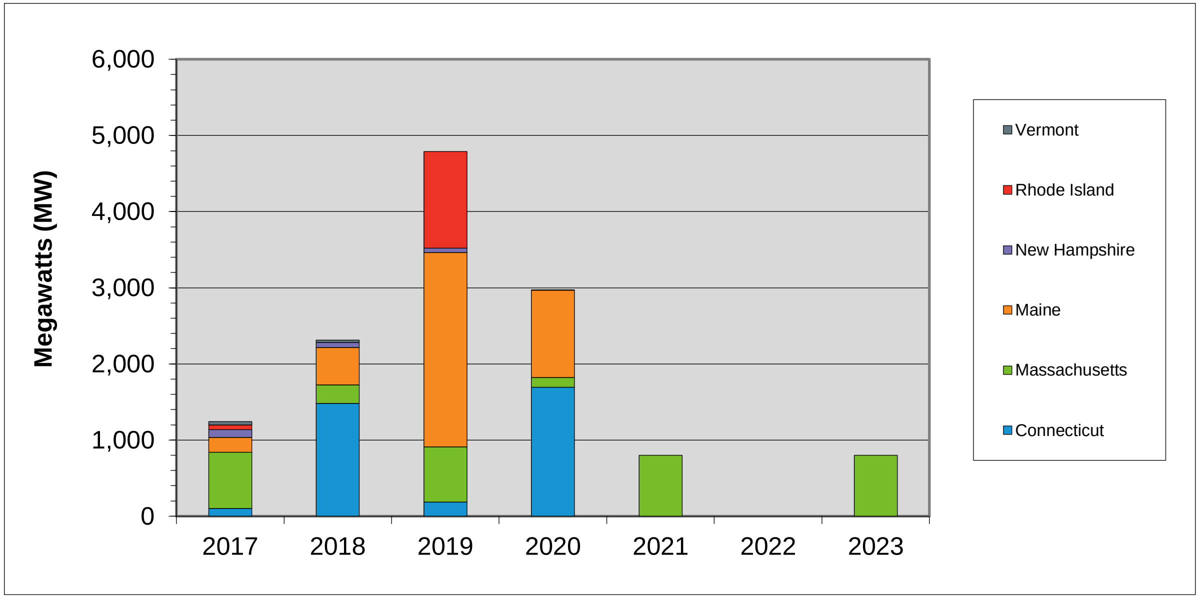
[1] **Sum may not equal 100% due to rounding**

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

- 2017 values include the 16 MW of generation that has gone commercial in 2017
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2017	2018	2019	2020	2021	2022	2023	Total MW	% of Total[1]
Vermont	42	30	0	0	0	0	0	72	0.6
Rhode Island	61	0	1,268	0	0	0	0	1,329	10.3
New Hampshire	102	65	58	5	0	0	0	230	1.8
Maine	195	491	2,553	1,145	0	0	0	4,384	33.9
Massachusetts	741	245	725	128	800	0	800	3,439	26.6
Connecticut	100	1,481	185	1,695	0	0	0	3,461	26.8
Totals	**1,241**	**2,312**	**4,789**	**2,973**	**800**	**0**	**800**	**12,915**	**100.0**

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

- 2017 values reflect the 16 MW of generation that has gone commercial in 2017

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	1	37	0	0	1	37
Hydro	4	101	0	0	4	101
Landfill Gas	1	2	0	0	1	2
Natural Gas	13	2,235	1	100	12	2,135
Natural Gas/Oil	12	4,255	2	1,009	10	3,246
Oil	0	0	0	0	0	0
Solar	15	795	0	0	15	795
Wind	28	5,397	1	23	27	5,374
Battery Storage	2	77	0	0	2	77
Total	76	12,899	4	1,132	72	11,767

- 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	4	107	0	0	4	107
Intermediate	18	5,421	1	801	17	4,620
Peaker	26	1,974	2	308	24	1,666
Wind Turbine	28	5,397	1	23	27	5,374
Total	76	12,899	4	1,132	72	11,767

- 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	1	37	1	37	0	0	0	0	0	0
Hydro	4	101	1	5	2	30	1	66	0	0
Landfill Gas	1	2	1	2	0	0	0	0	0	0
Natural Gas	13	2,235	1	63	9	1,991	3	181	0	0
Natural Gas/Oil	12	4,255	0	0	7	3,400	5	855	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	15	795	0	0	0	0	15	795	0	0
Wind	28	5,397	0	0	0	0	0	0	28	5,397
Battery Storage	2	77	0	0	0	0	2	77	0	0
Total	76	12,899	4	107	18	5,421	26	1,974	28	5,397

- 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	601.852	-170.5	400.487	-201.365	381.941	-18.546
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211	2025.383	68.72	2,036.906	11.523	2,112.758	75.852	2,308.73	195.972
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,848.267**	**1.9**	**2,797.735**	**-50.532**	**2,638.758**	**-158.977**	**2,513.245**	**-125.513**	2,690.671	177.426
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,666.87	143.074	28,658.35	-8.52	28,863.752	205.402	28,888.84	25.092	28,833.605	-55.235
	Intermittent	876.925	898.955	22.03	922.173	23.218	918.782	-3.391	920.037	1.255	916.51	-3.527	823.162	-93.348
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**	**29,577.132**	**-11.911**	**29,783.789**	**206.657**	**29,805.35**	**21.565**	29,656.767	-148.583
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**	**1,375.53**	**0**	**1314.43**	**-61.1**	**1,394.43**	**80**	1,345.998	-48.432
*****Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,812.84**	**306.688**	**33,750.397**	**-62.443**	**33,736.977**	**-13.417**	**33,713.03**	**-23.948**	33,693.436	-19.594
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	**0**	**33,442**	**-619**	**33,442**	**0**	**33,138**	**-304**	33,138	**0**

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

** Change columns contain the changes in CSO amount resulting from, but not limited to, 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. The Grand Total for FCA 8 does not reflect a Supplemental Information filing in March of 2014.

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, but not limited to, 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*	30,520.433												
	Intermittent	850.143												
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, but not limited to, 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 11

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*	419.928												
	Passive Demand	2,791.019												
Demand Total		**3,210.947**												
Generator	*Non-Intermittent*	30,494.8												
	Intermittent	894.217												
Generator Total		**31,389.02**												
Import Total		**1,235.4**												
*****Grand Total**		**35,835.368**												
Net ICR (NICR)		**34,075**												

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

** Change columns contain the changes in CSO amount resulting from, but not limited to, 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
2020-21	Active	334.634	85.294	419.928
	Passive	2236.727	554.292	2791.019
	Grand Total	2571.361	639.586	3210.947

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

What are Daily NCPC Payments?

- Payments made to resources whose 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 during 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
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

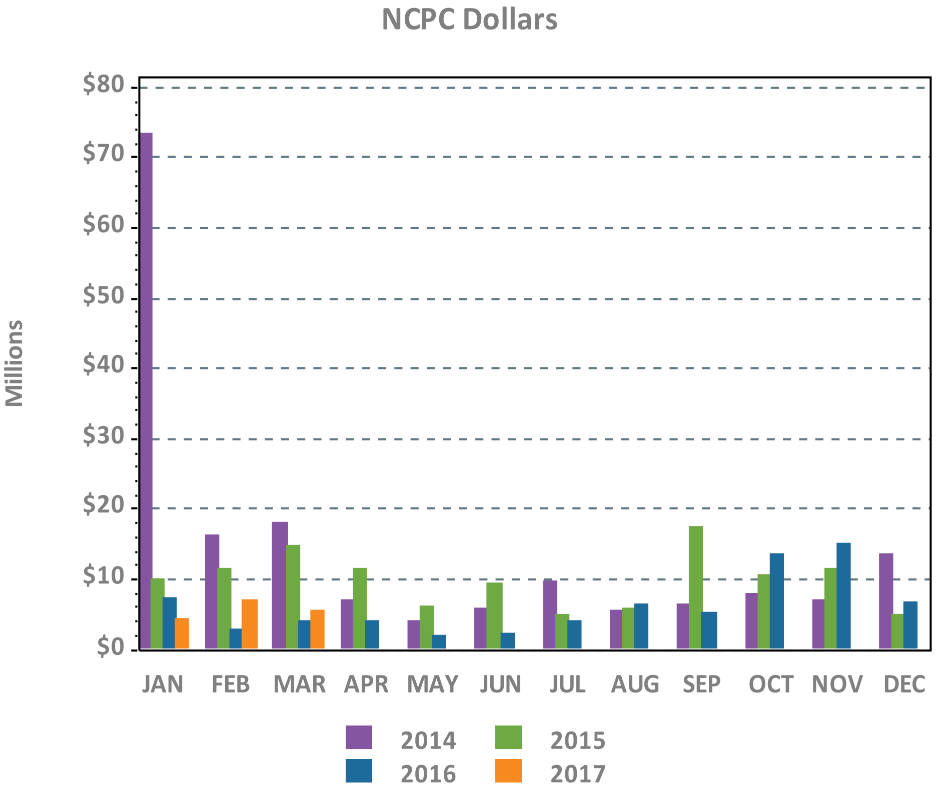
Definitions

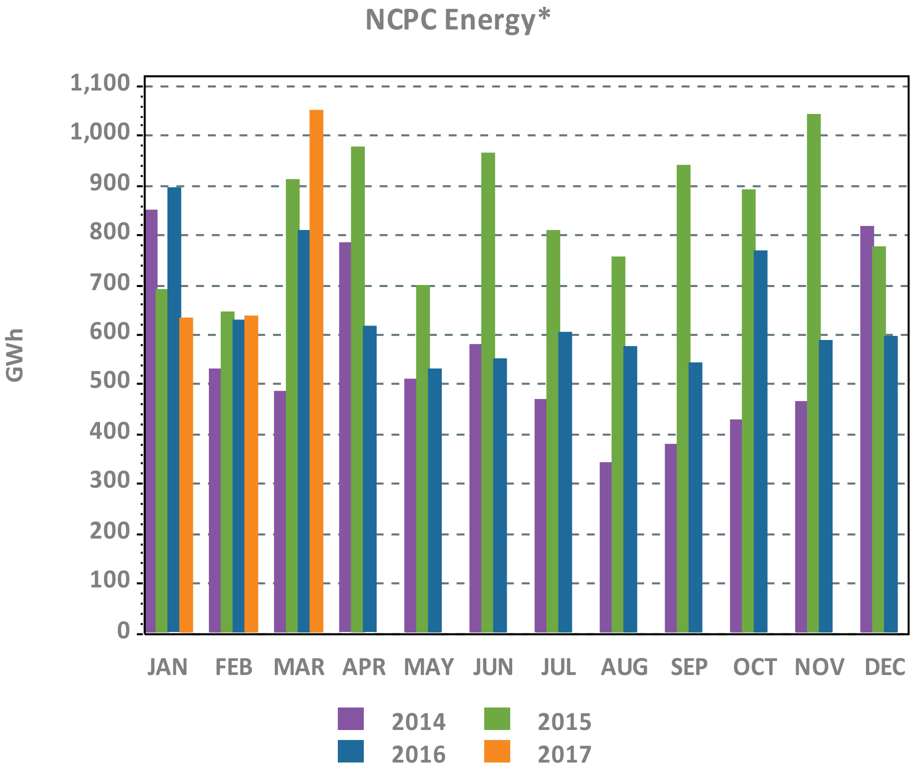
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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
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, Economic Generator/DARD Posturing, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost NCPC (allocated to RTLO); and Min Generation Emergency NCPC (allocated to RTGO).

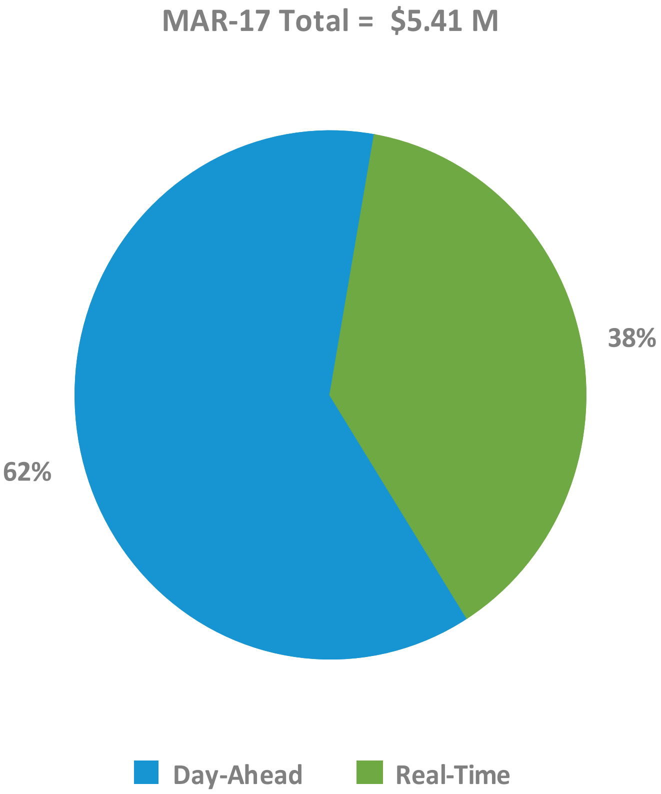
Year-Over-Year Total NCPC Dollars and Energy

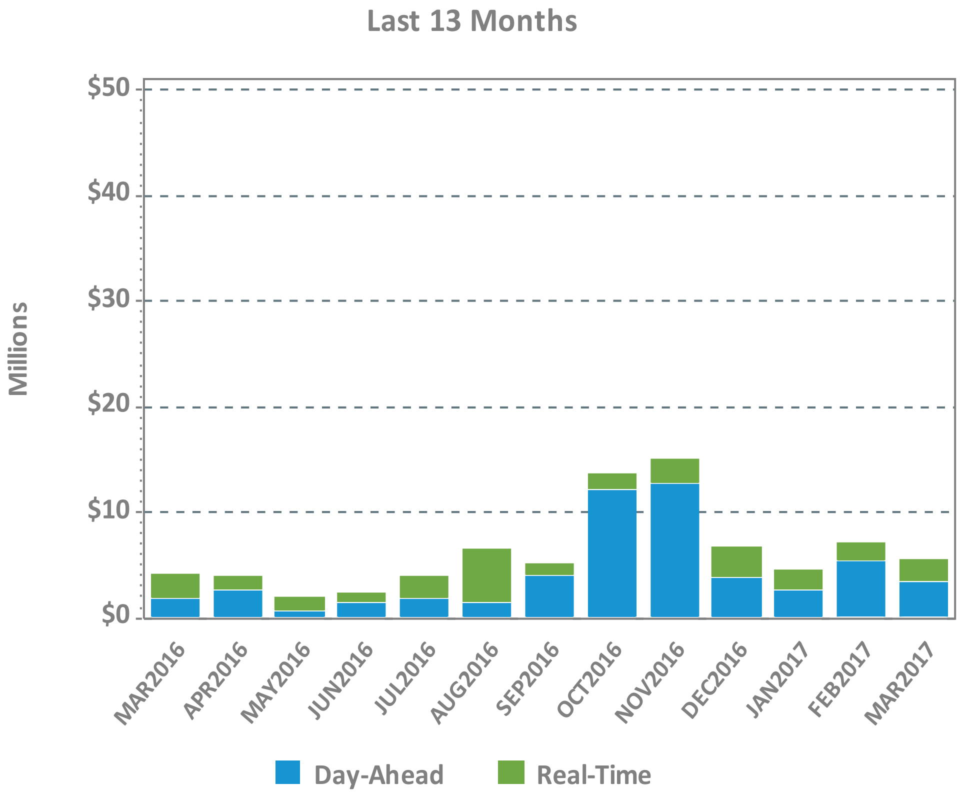




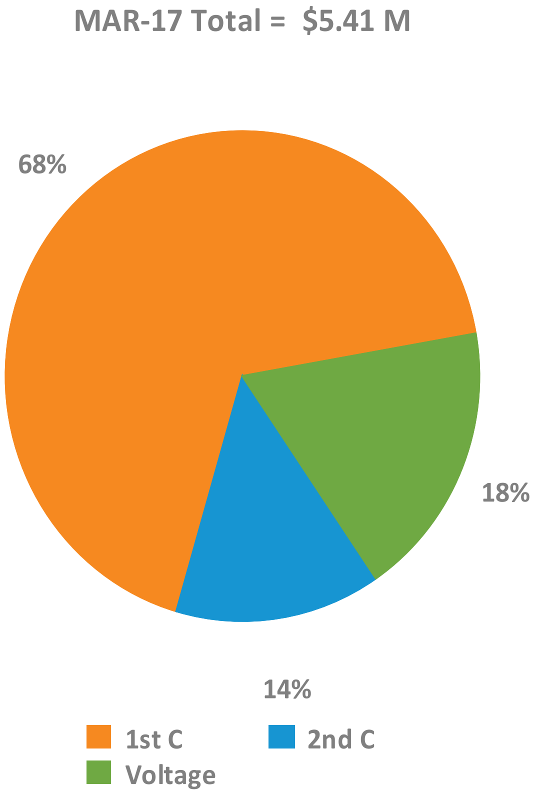
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

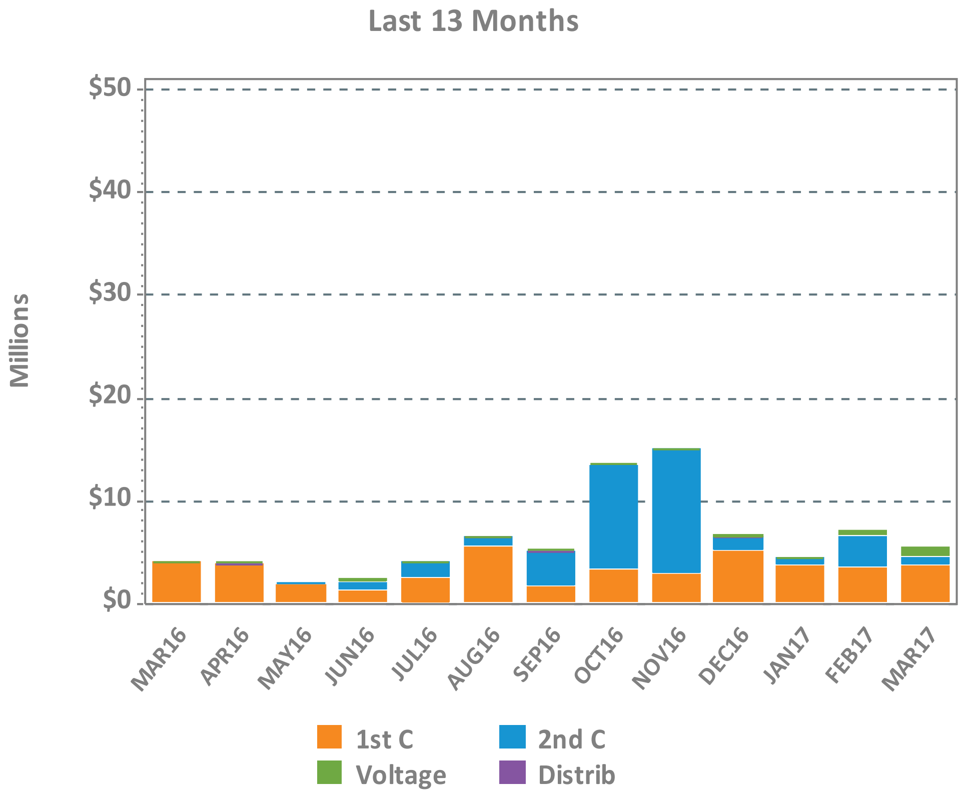
DA and RT NCPC Charges





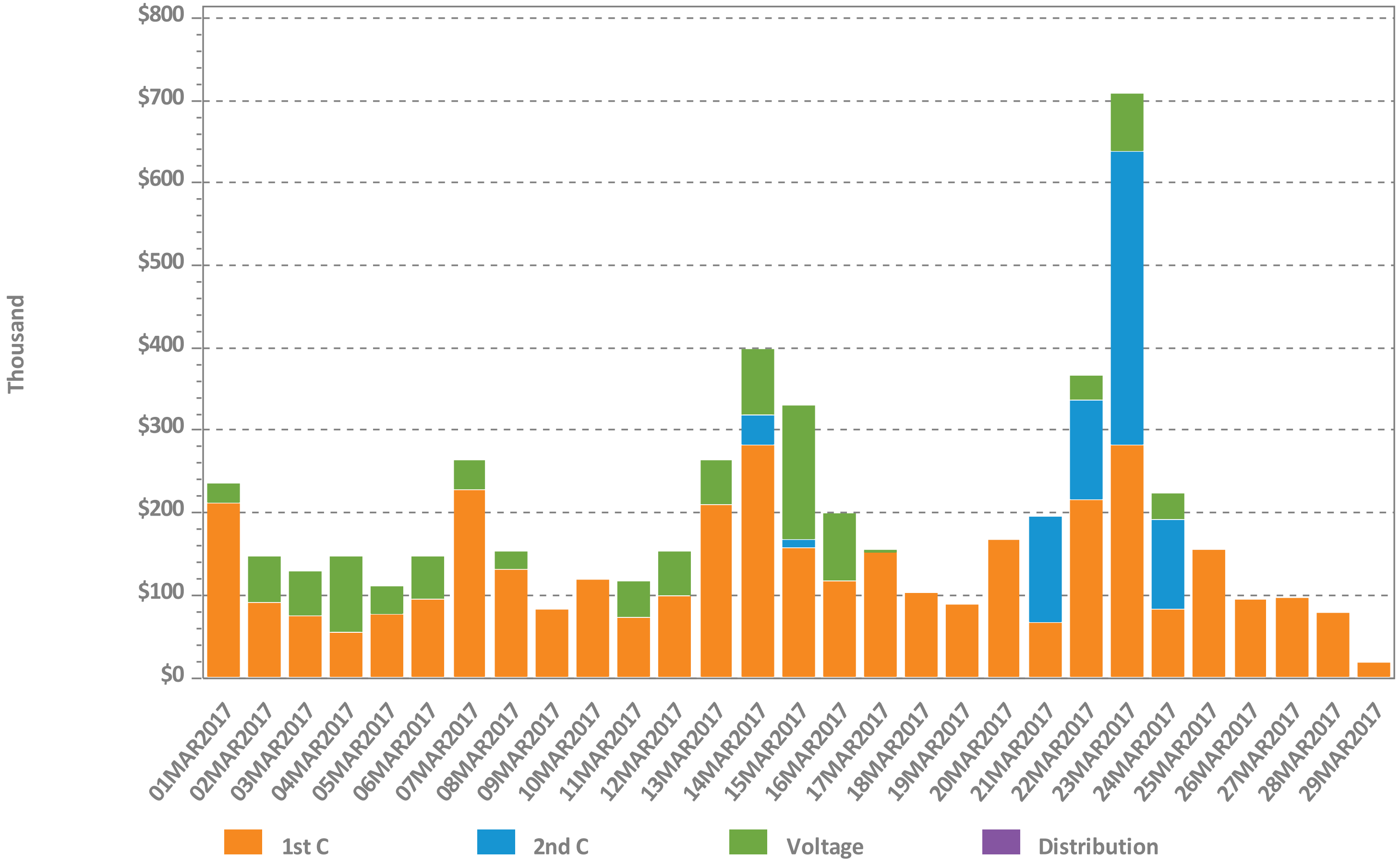
NCPC Charges by Type



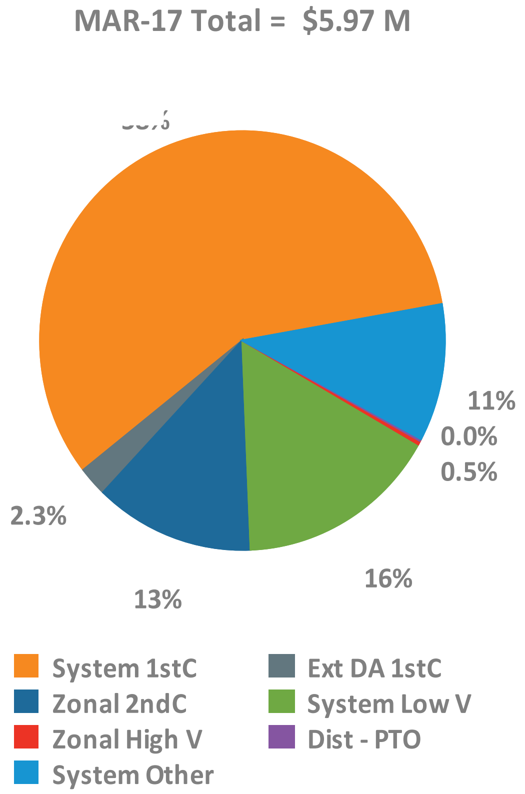


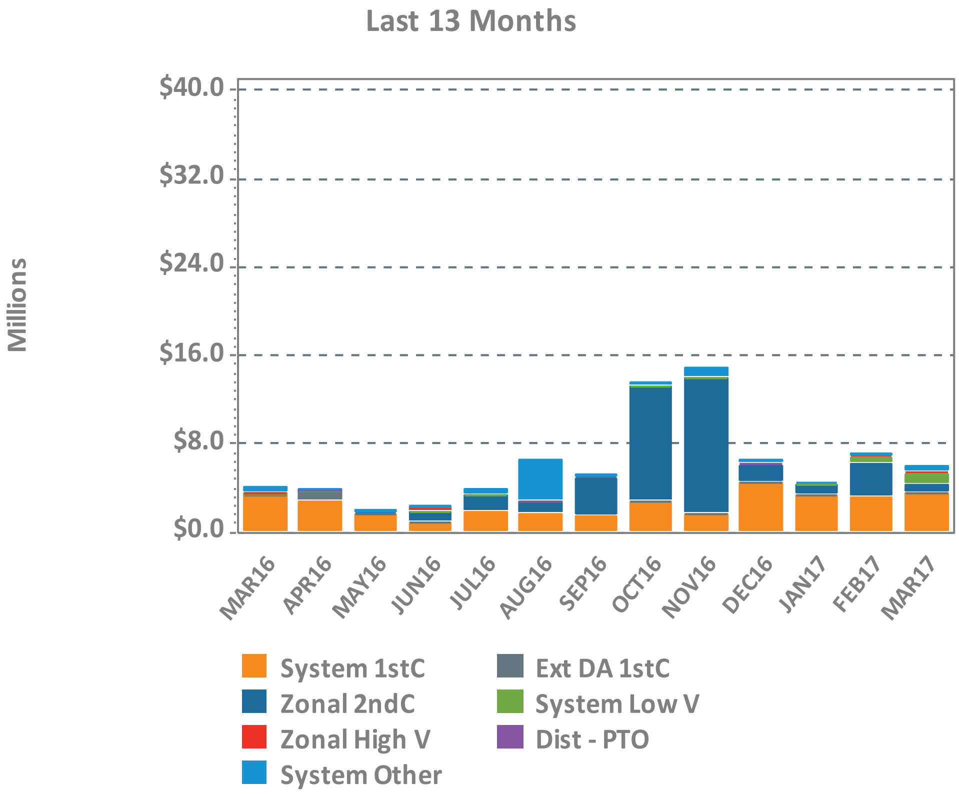
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



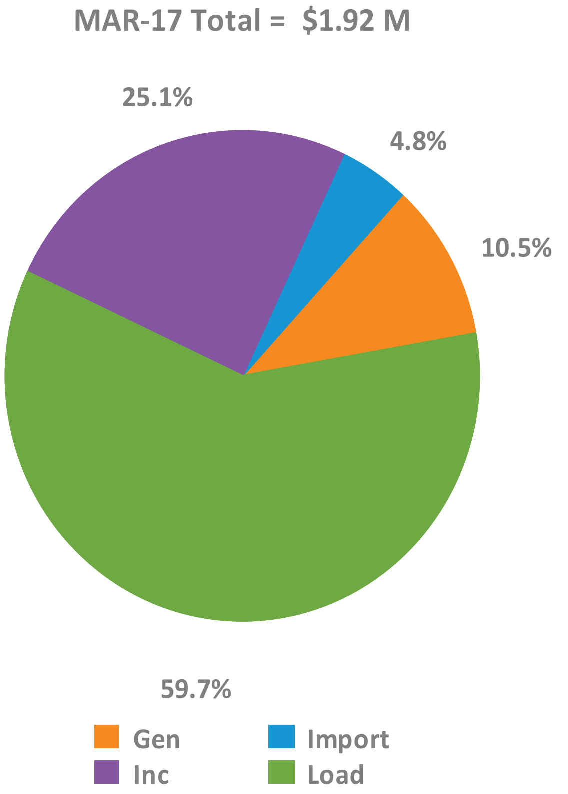
NCPC Charges by Allocation

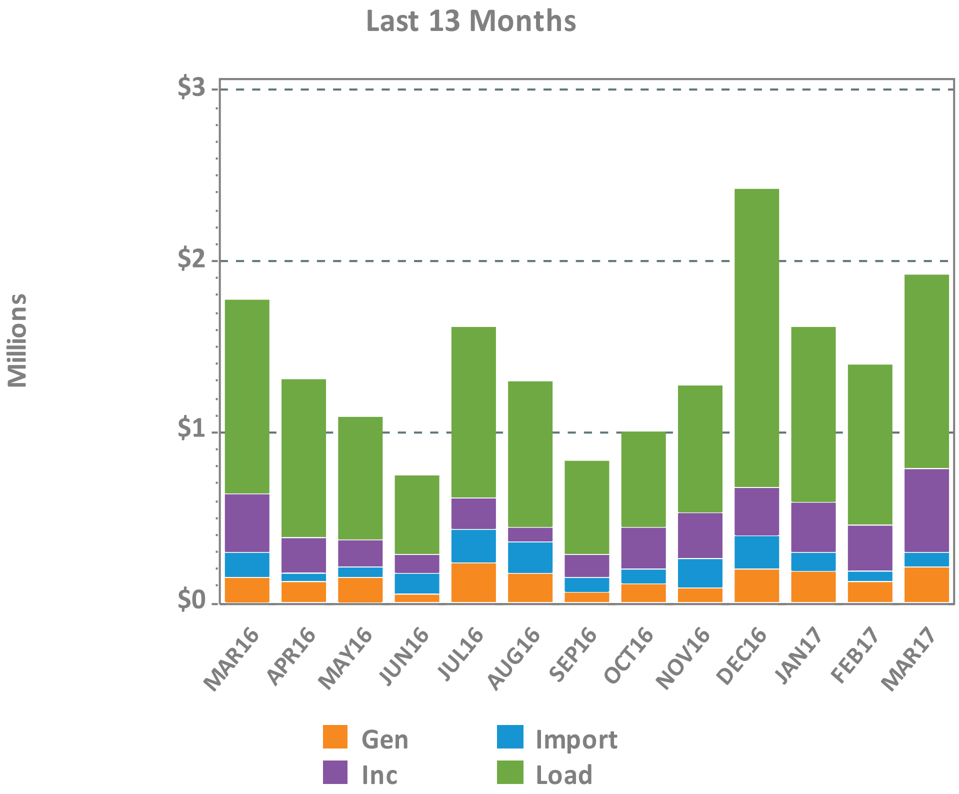




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

RT First Contingency Charges by Deviation Type





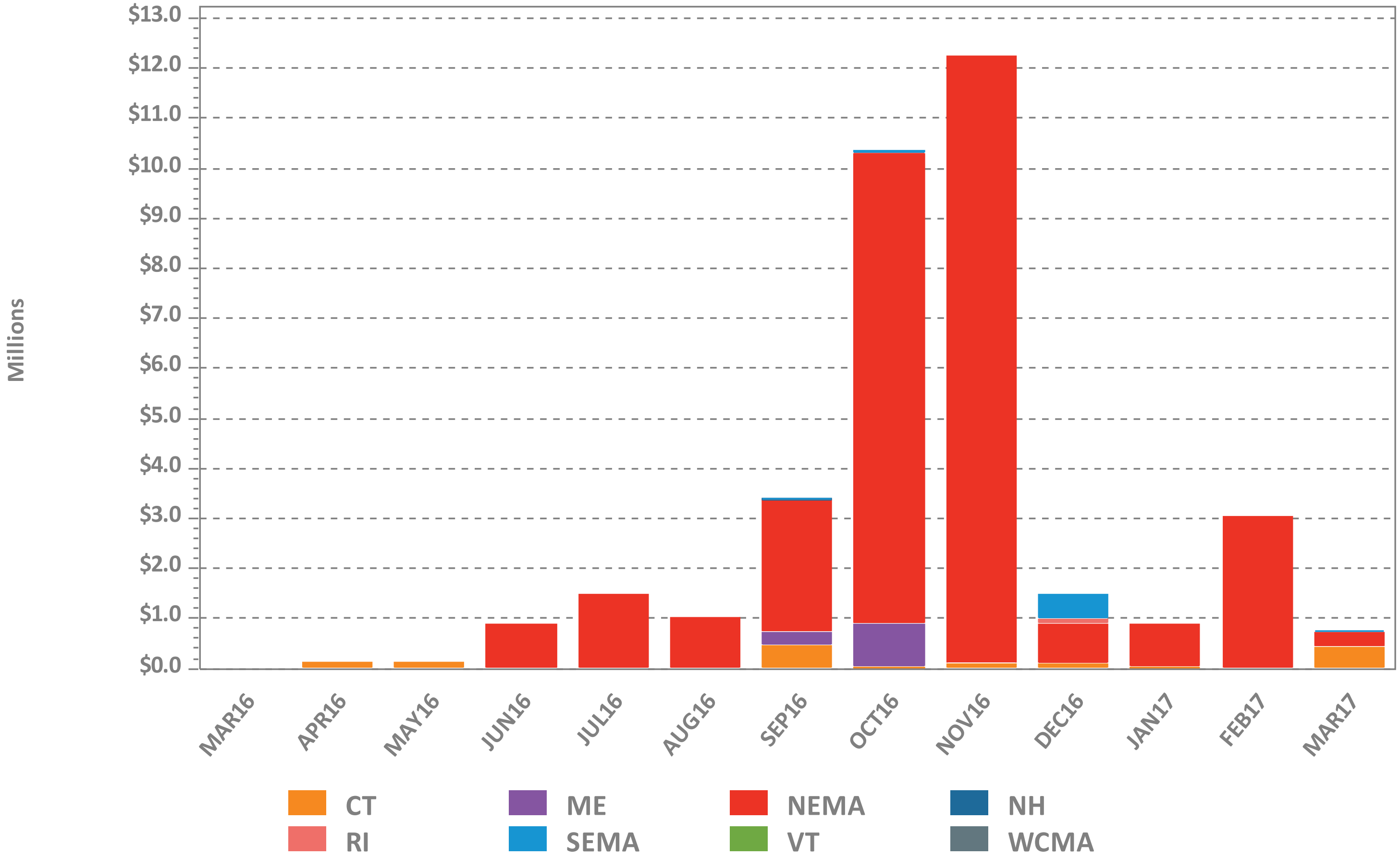
Gen – Generator deviations

Inc – Increment Offer deviations

Imp – Import deviations

Load – Load obligation deviations

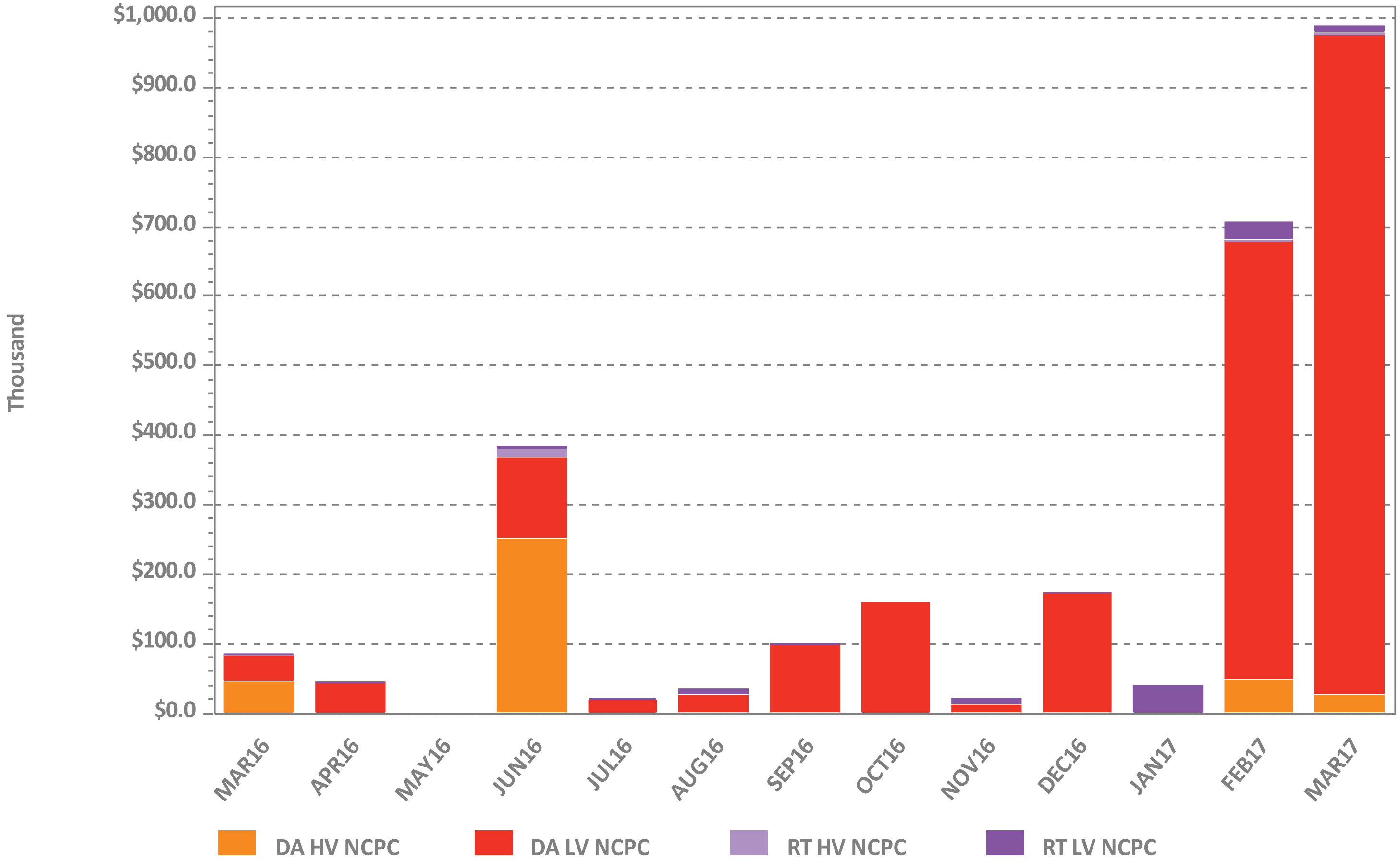
LSCPR Charges by Reliability Region



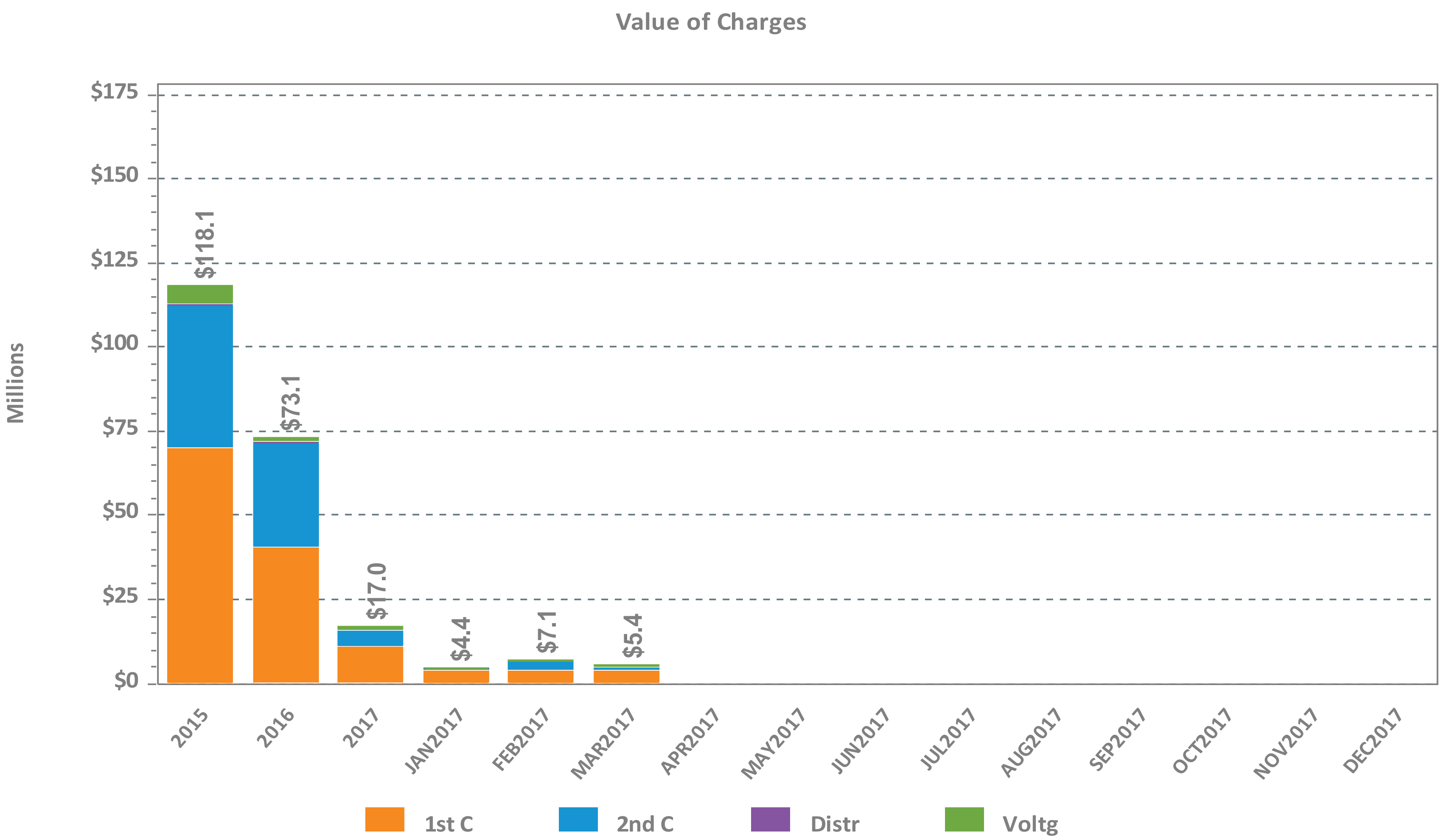
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

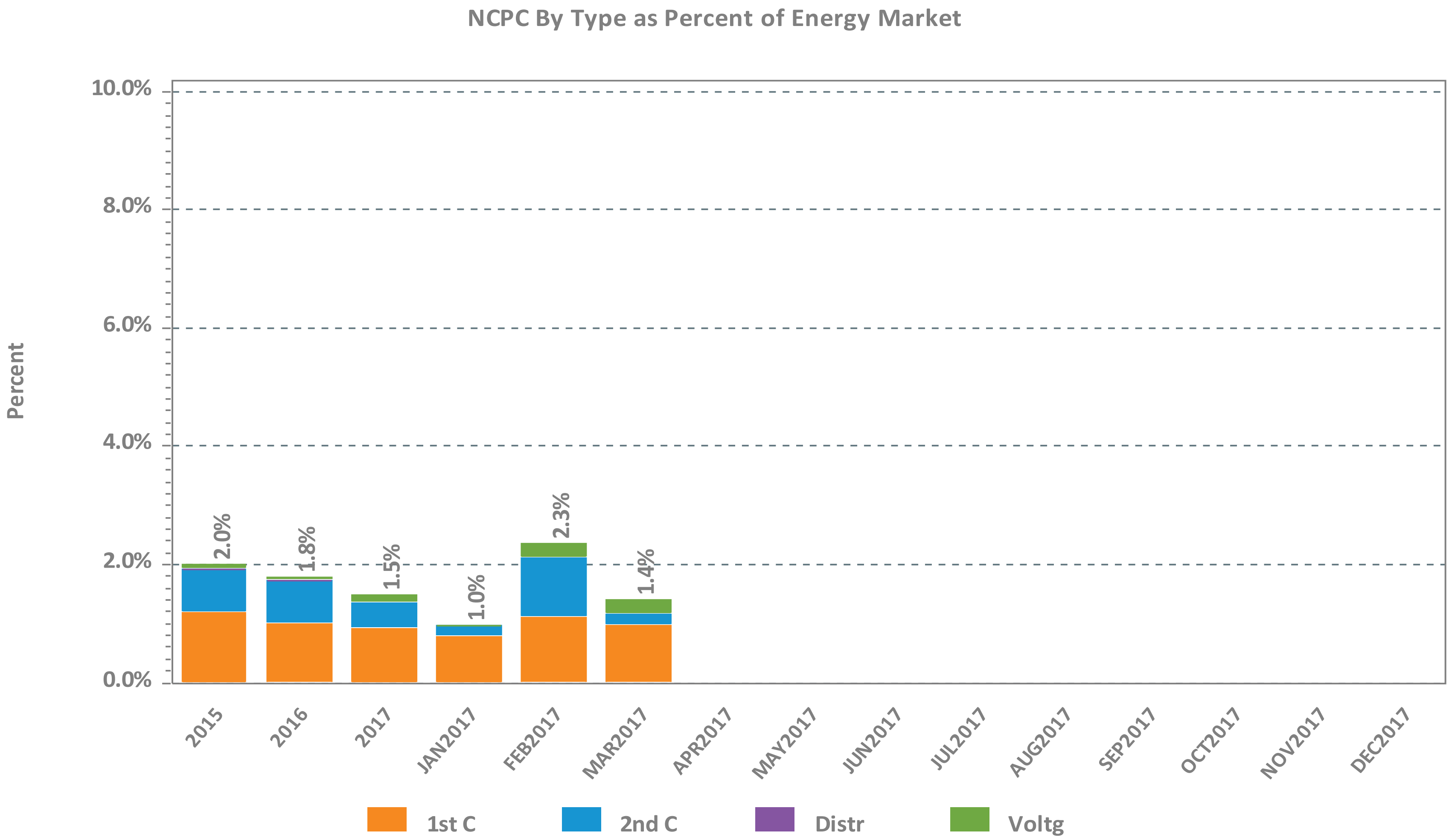
NCPC Charges for Voltage Support and High Voltage Control



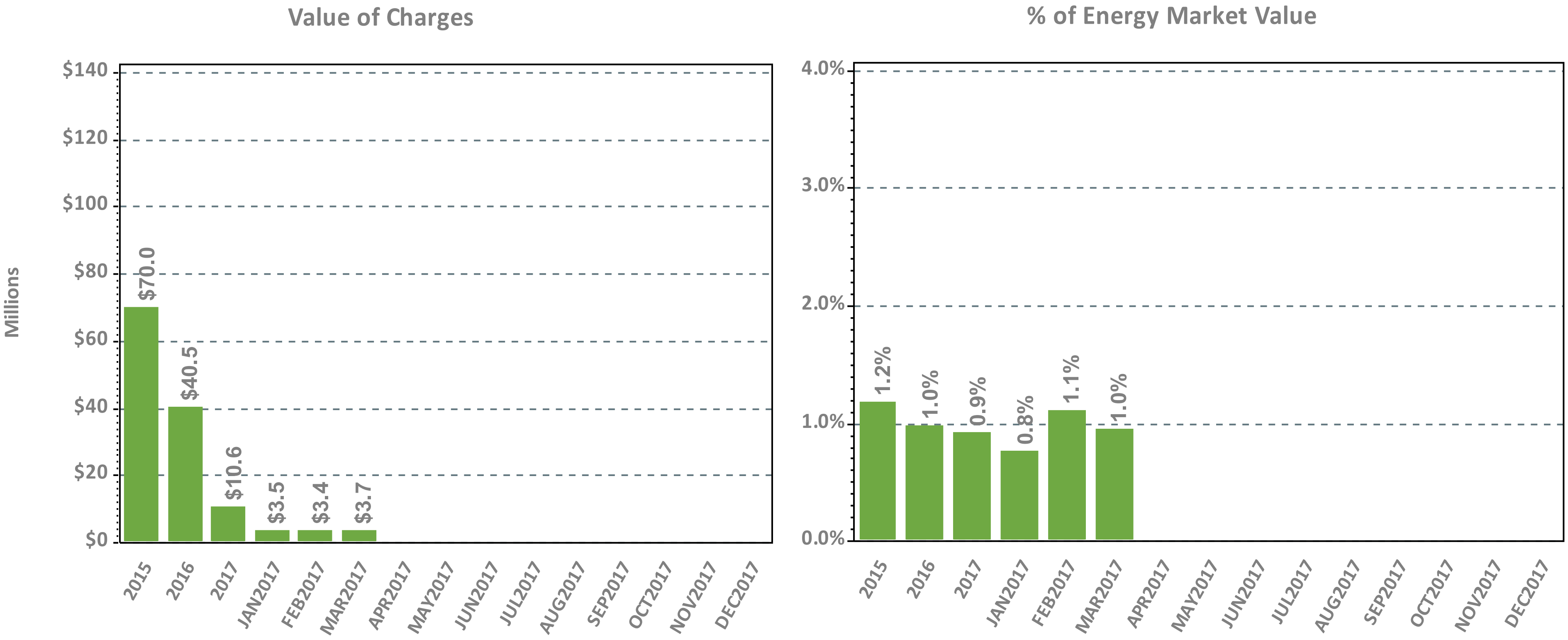
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

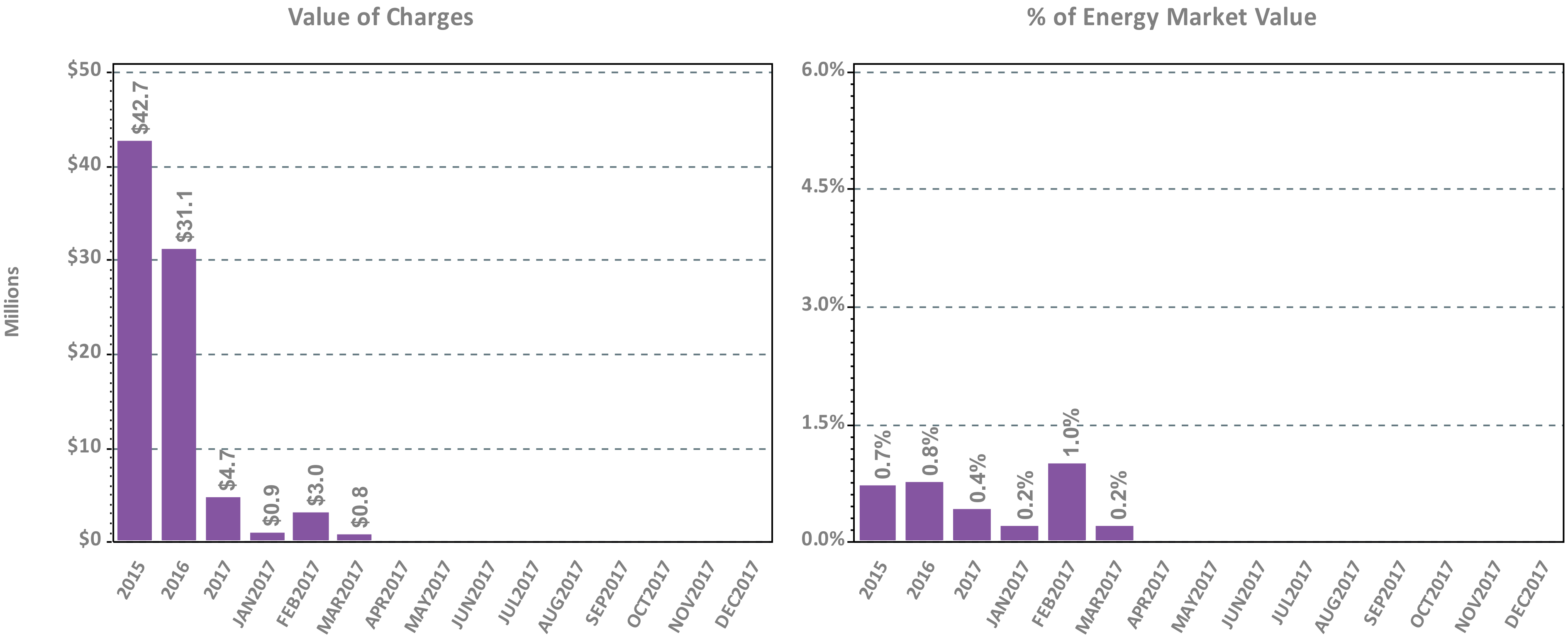


First Contingency NCPC Charges



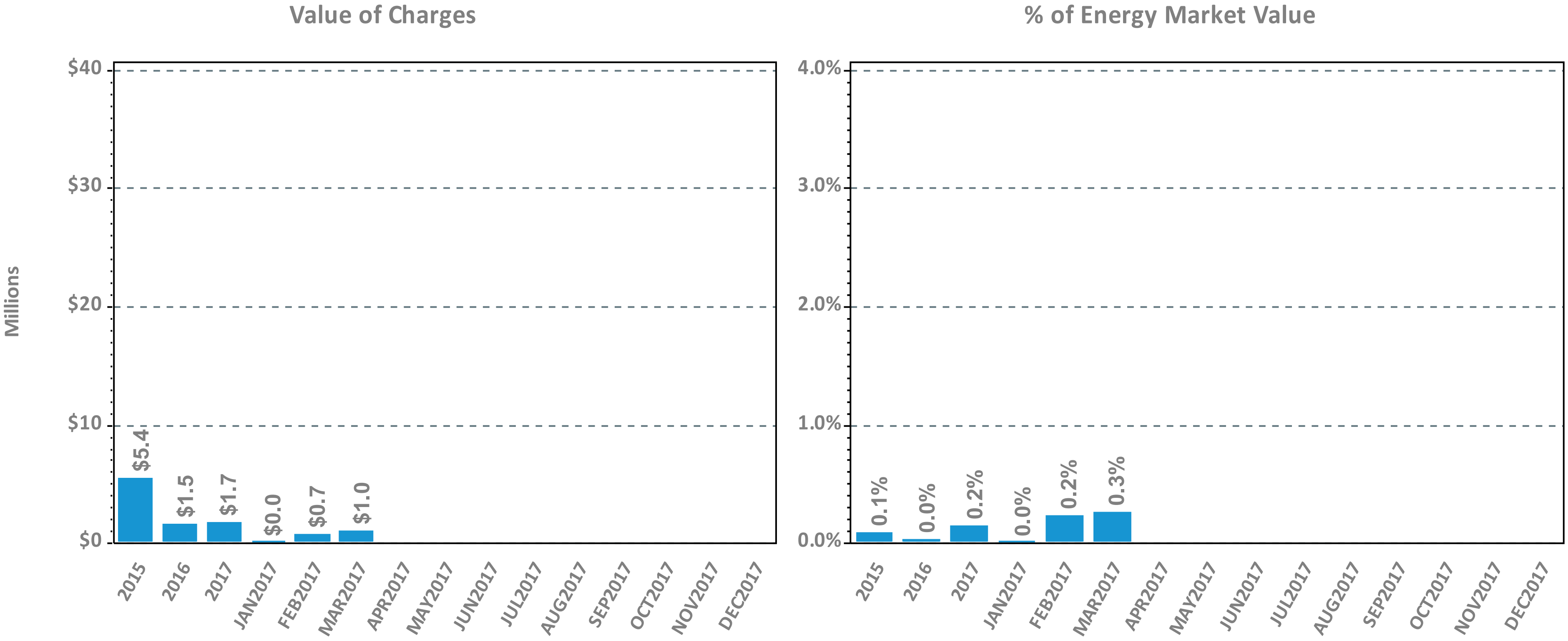
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

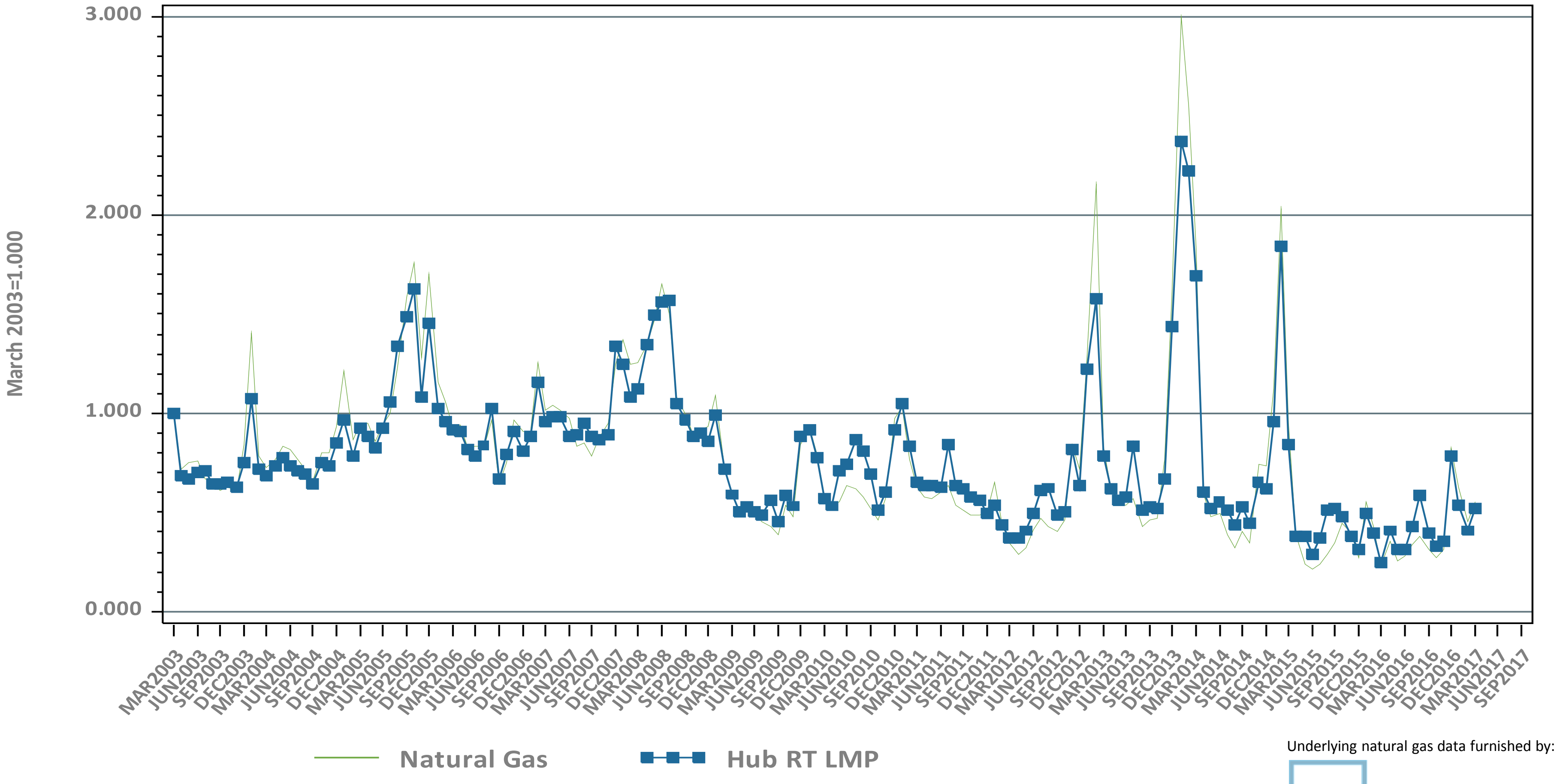
The following slides outline:

- 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)

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%
Year 2016	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$30.66	$29.77	$29.07	$29.64	$29.66	$29.66	$29.88	$29.85	$29.78
Real-Time	$29.74	$29.00	$27.81	$28.60	$28.49	$28.87	$29.01	$28.98	$28.94
RT Delta %	-3.0%	-2.6%	-4.3%	-3.5%	-3.9%	-2.7%	-2.9%	-2.9%	-2.8%
March-16	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$20.70	$20.58	$19.98	$20.53	$20.54	$20.54	$20.74	$20.67	$20.63
Real-Time	$17.34	$17.21	$16.63	$17.03	$16.86	$17.18	$17.34	$17.21	$17.20
RT Delta %	-16.2%	-16.4%	-16.7%	-17.1%	-17.9%	-16.4%	-16.4%	-16.8%	-16.6%
March-17	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$35.71	$36.15	$34.69	$35.45	$35.36	$35.67	$35.71	$36.02	$35.91
Real-Time	$35.36	$35.72	$32.51	$34.66	$34.40	$35.19	$35.31	$35.49	$35.43
RT Delta %	-1.0%	-1.2%	-6.3%	-2.2%	-2.7%	-1.3%	-1.1%	-1.5%	-1.3%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	72.5%	75.7%	73.6%	72.7%	72.1%	73.7%	72.2%	74.2%	74.1%
Yr over Yr RT	103.9%	107.6%	95.5%	103.6%	104.1%	104.9%	103.6%	106.2%	106.0%

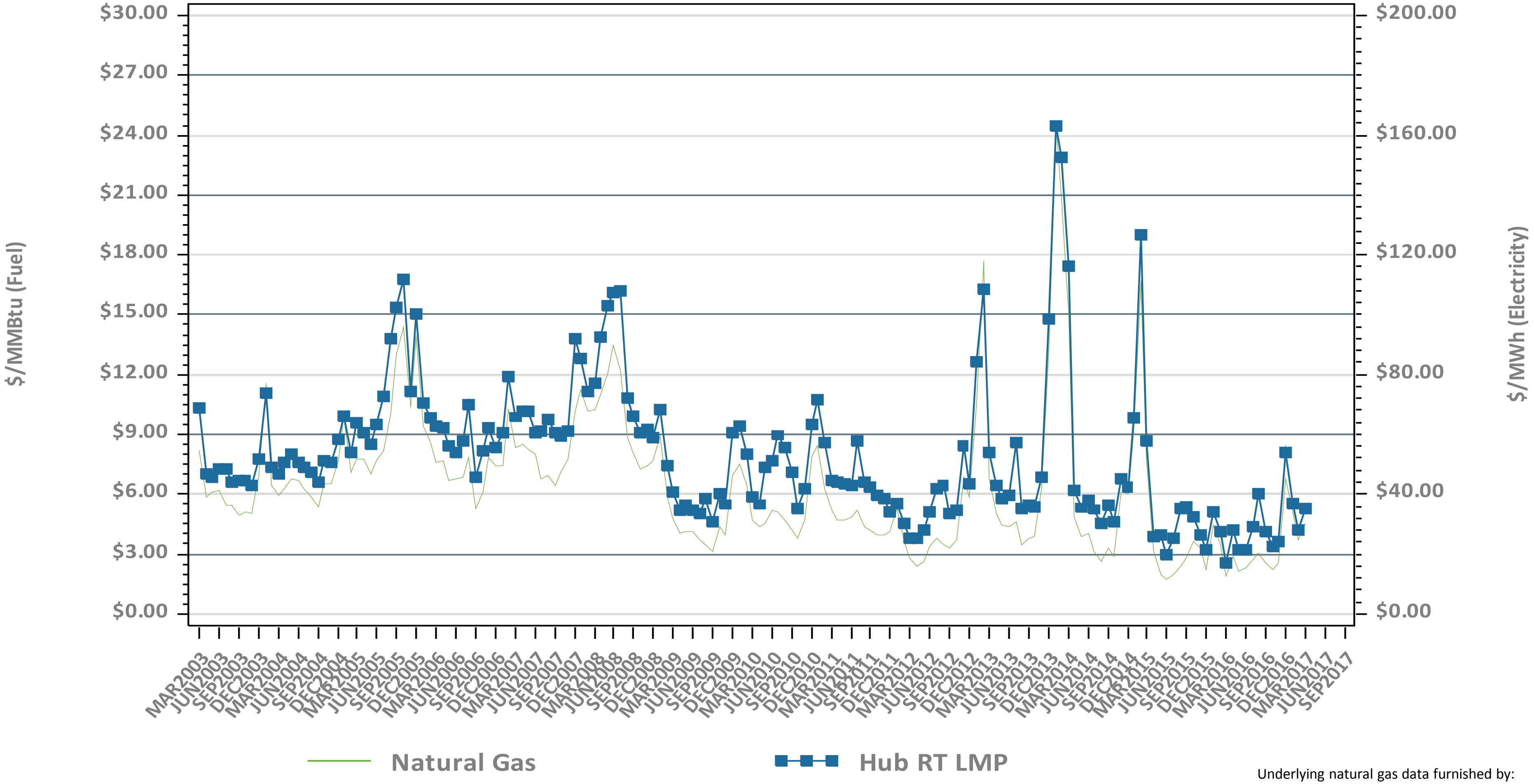
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

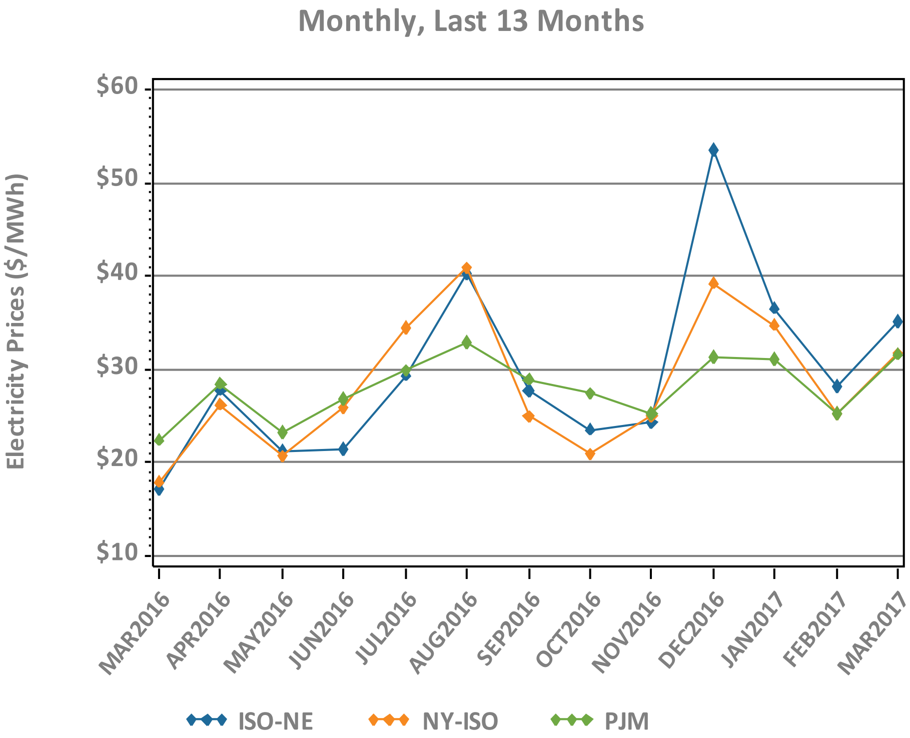
ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

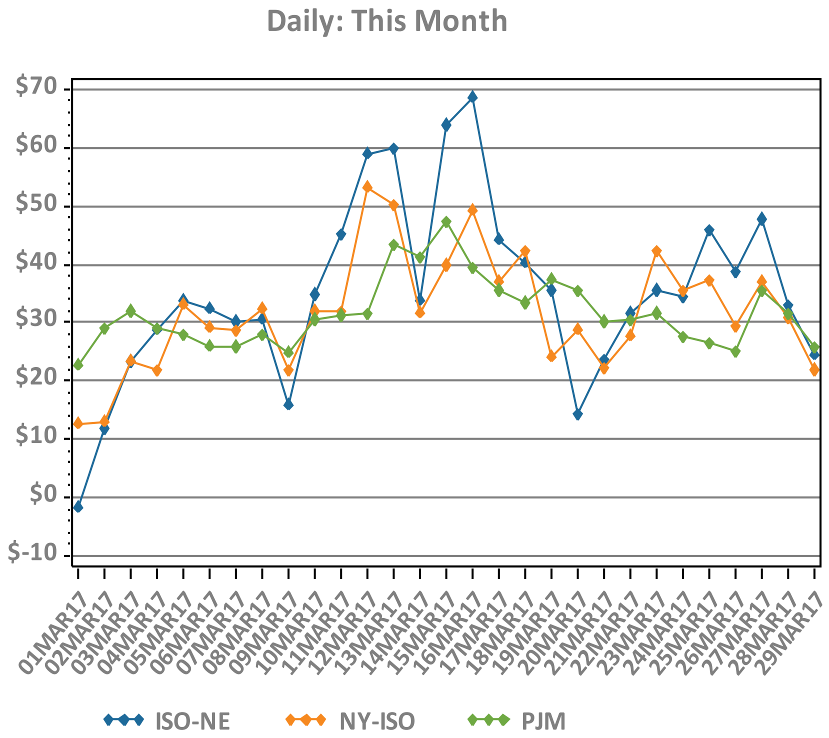


Underlying natural gas data furnished by: ICE Global markets in clear view

New England, NY, and PJM Hourly Average Real Time Prices by Month

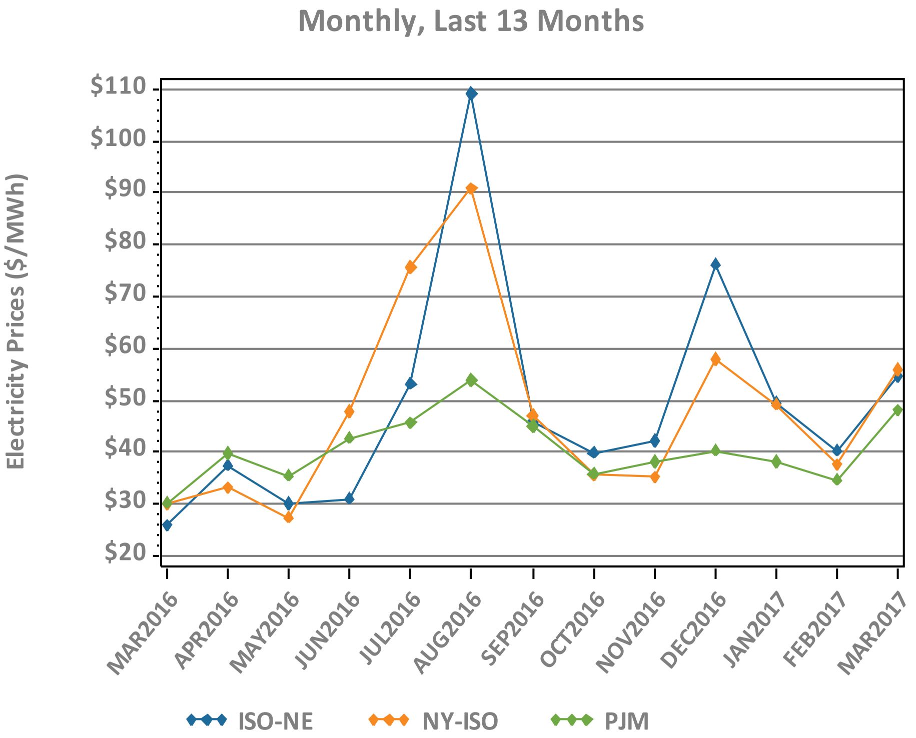


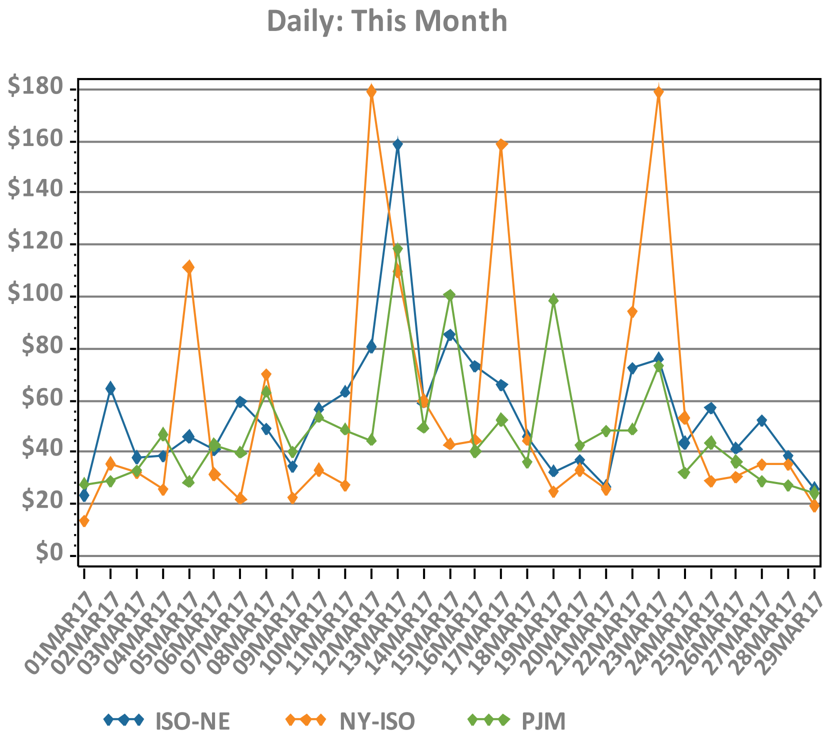
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Average Peak Hour Real Time Prices





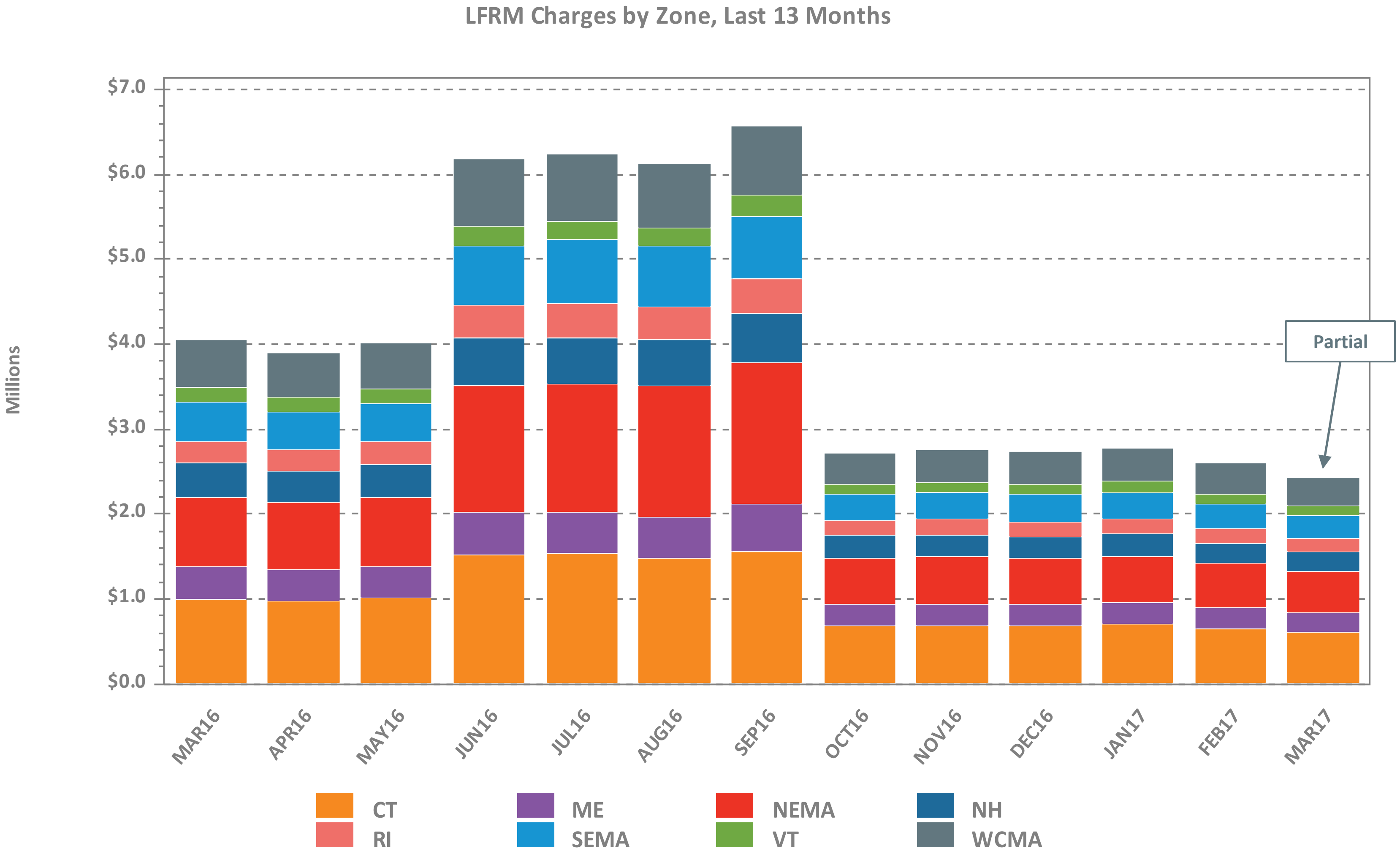
***Forecasted New England daily peak hours reflected**

Reserve Market Results – March 2017

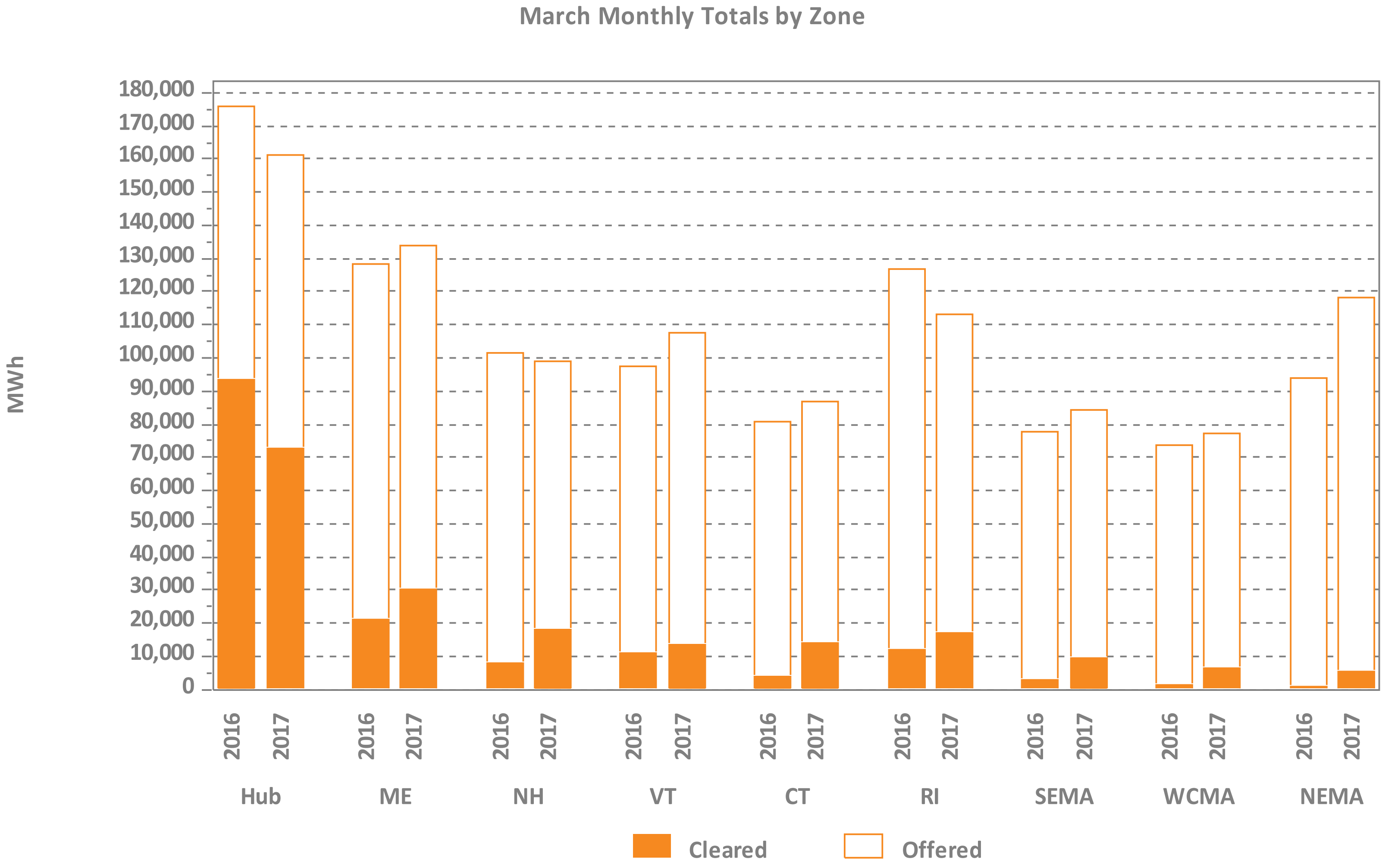
- Maximum potential Forward Reserve Market payments of $2.6M were reduced by credit reductions of $65K, failure-to-reserve penalties of $98K and no failure-to-activate penalties, resulting in a net payout of $2.4M or 94% of maximum
  - Rest of System: $1.42M/1.5M (95)%
  - Southwest Connecticut: $0.22M/0.25M (88)%
  - Connecticut: $0.77M/0.83M (93)%
- $1.1M total Real-Time credits were not reduced for any Forward Reserve Energy Obligation Charges for a net of $1.1M in Real-Time Reserve payments
  - Rest of System: 243 hours, $874K
  - Southwest Connecticut: 243 hours, $50K
  - Connecticut: 243 hours, $55K
  - NEMA: 244 hours, $95K

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

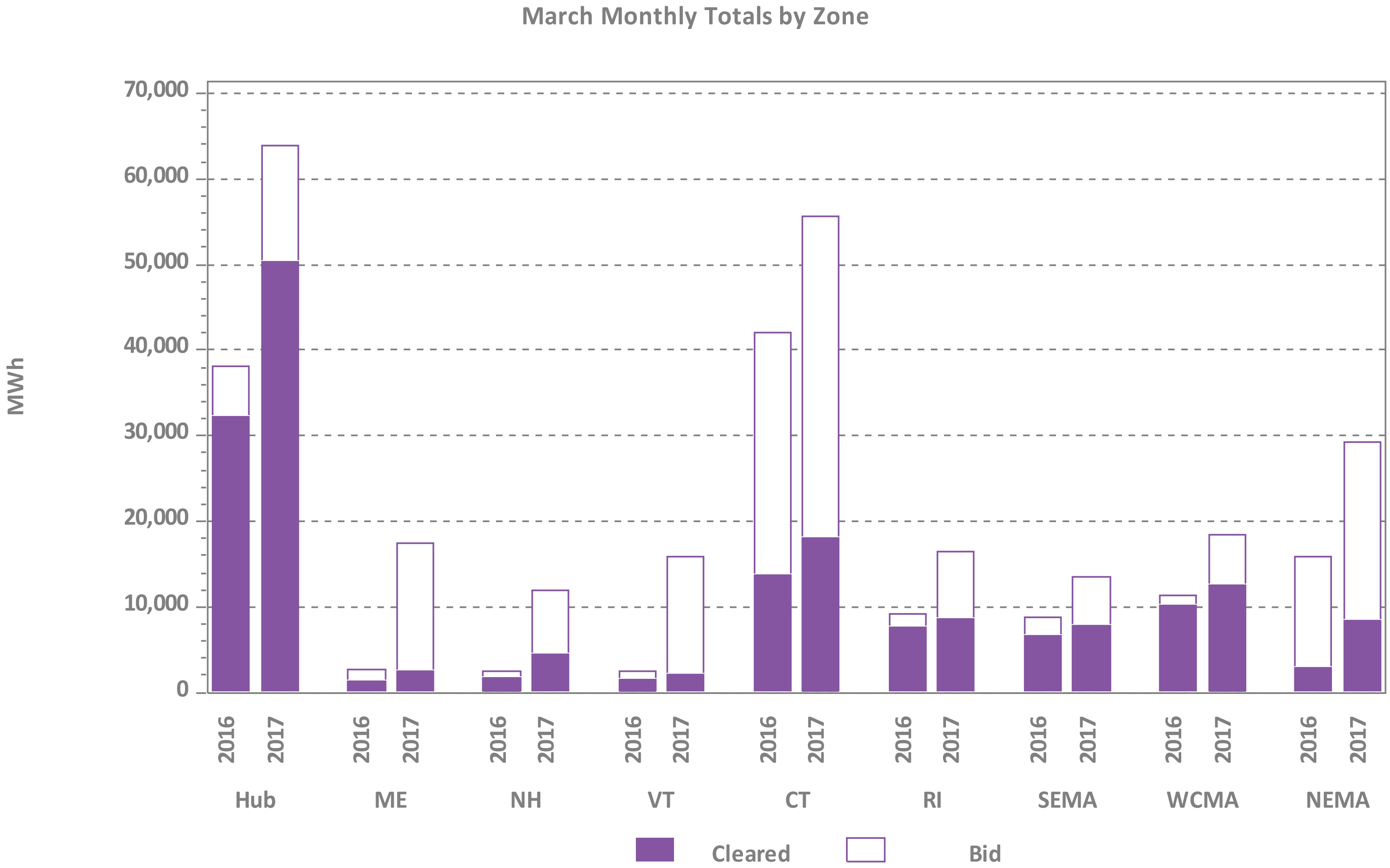
LFRM Charges to Load by Load Zone ($)



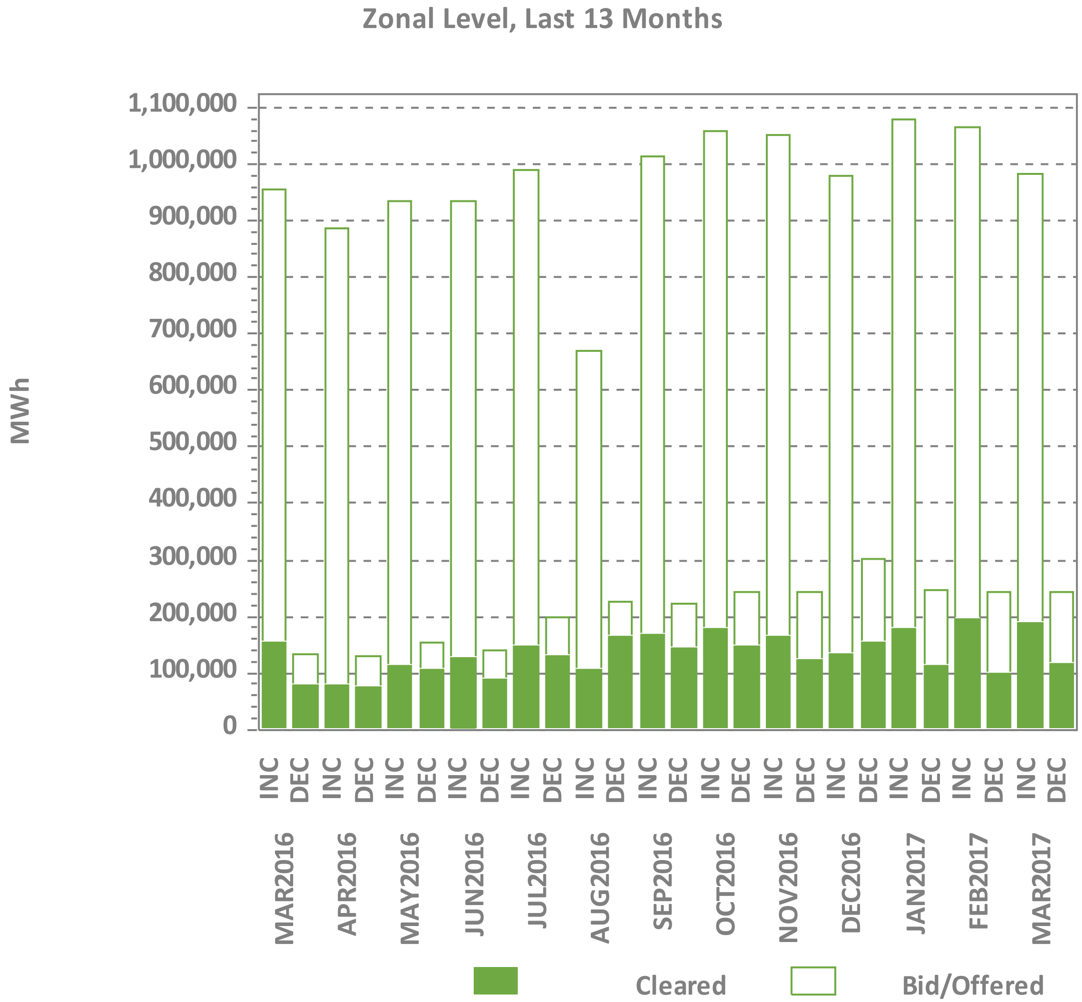
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

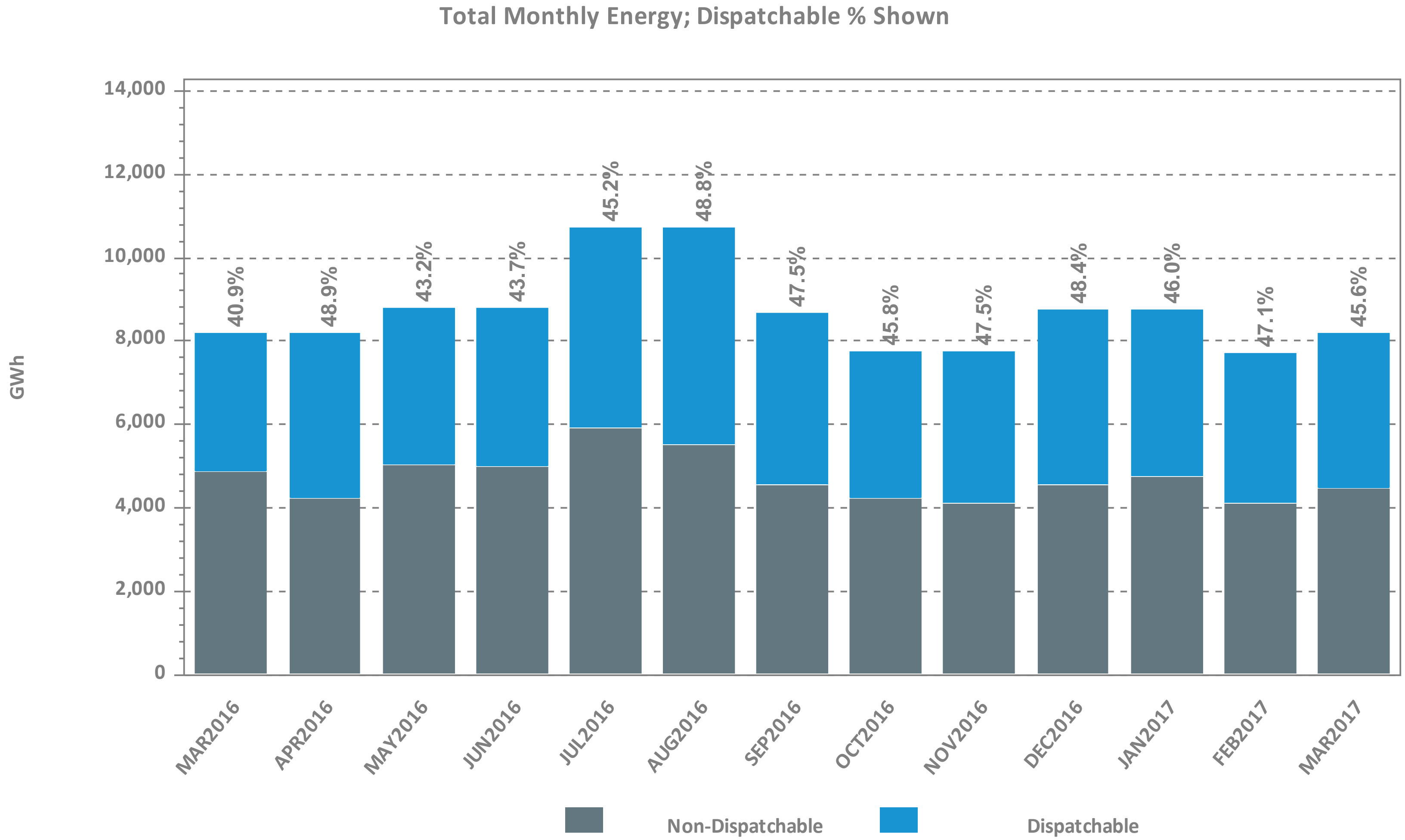


Total Increment Offers and Decrement Bids



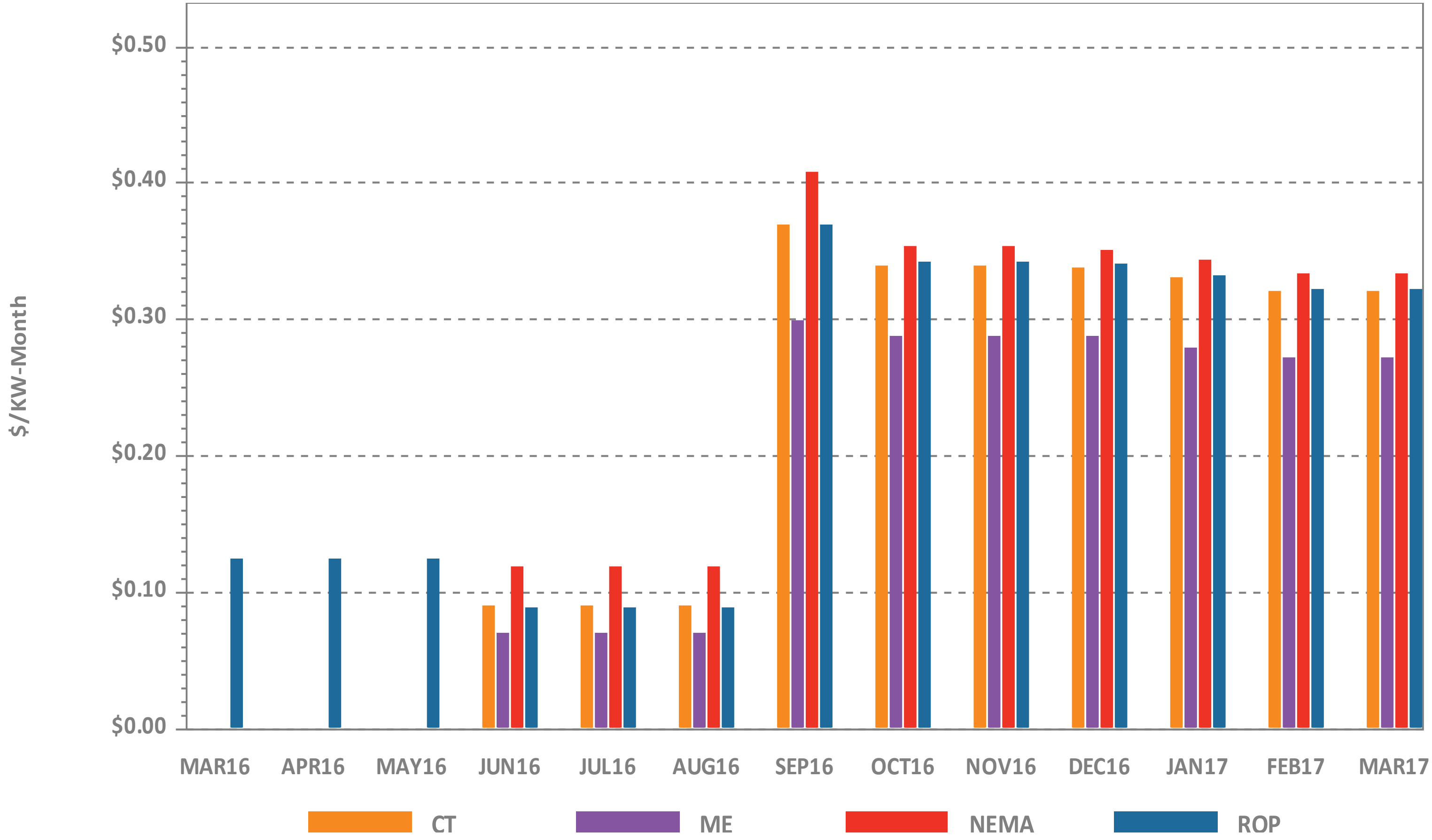
Data excludes nodal offers and bids

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).**

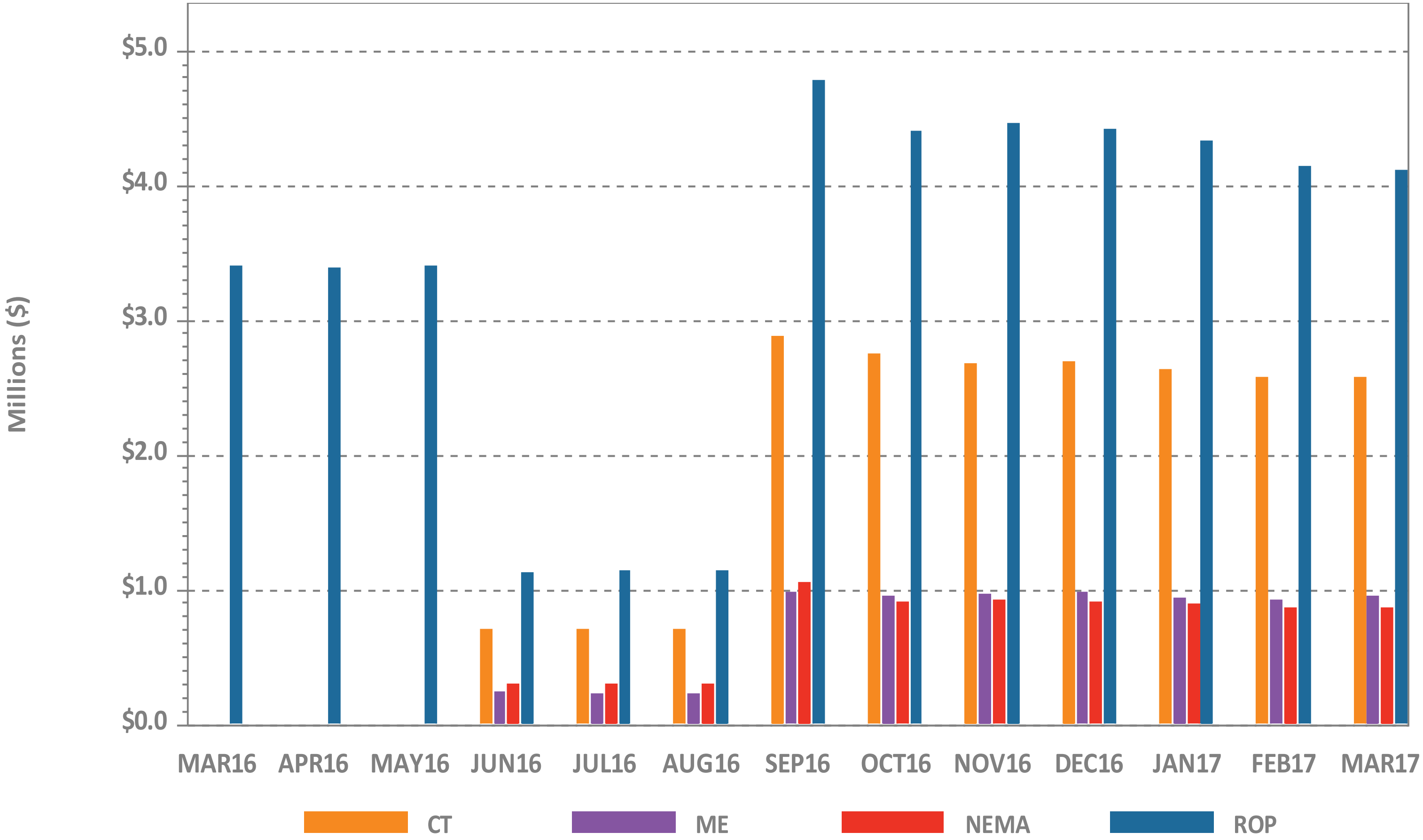
Rolling Average Peak Energy Rent (PER)



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)

- RSP17 work is proceeding
- April 19 PAC Meeting Agenda*
  - Post Winter 2016/2017 Gas Review
  - Northeast Gas Association Gas Update
  - 2017 CELT ISO-NE Annual Energy and Summer Peak Forecast Update
  - 2017 Economic Study Stakeholder Presentations**
  - 2016 Interface Flow and Other System Performance Summaries
  - Mt. Tom Station Update
  - 2016 Economic Study Phase 2 - Scenario Analysis Natural Gas System Analysis Results
  - 2016 Economic Study Phase 2 - Emission Cost Sensitivity
  - Devon 7R Control House Modifications
- The second PAC meeting scheduled for April 20 has been canceled

* Agenda items are subject to change. Visit https://www.iso-ne.com/committees/planning/planning-advisory for the latest PAC agendas.

** The presentation is dependent on economic study requests received from stakeholders.

Load, Energy Efficiency, and Photovoltaic Forecast

- Load Forecast
  - Development of the ten-year load forecast is nearly complete and compared to the 2016 CELT forecast:
    - Gross annual energy forecast is about 1.0% lower in 2025
    - Net annual energy forecast is about 3.9% lower in 2025
    - Net summer 90/10 forecast is about 2.7% lower in 2025
  - Next Load Forecast Committee is April 4 to discuss the final forecast which will be published as part of the 2017 CELT Report on or about May 1
- Energy-Efficiency (EE) Forecast
  - Comments received from the EE working group members have been addressed and/or considered
  - The 2017 forecast is nearly complete and compared to the 2016 CELT, the EE forecast is approximately 11% higher in 2025. Final forecast to be published on or about May 1.

Load, Energy Efficiency, and Photovoltaic Forecast, cont.

- Photovoltaic (PV) Forecast
  - Comments received from DGFWG members have been considered
    - Concerns that the forecast is too conservative and underestimating the amount of Behind-the-Meter (BTM) PV installed
  - Next DGFWG meeting will be held on April 14 where both the comments received and the finalized 2017 forecast will be discussed
  - As compared to the 2016 CELT forecast, the total 2017 nameplate PV forecast is approximately 33% higher in 2025, and the BTM PV portion of the forecast is approximately 15% higher in 2025
  - The PV forecast will be published as part of the 2017 CELT Report on or about May 1

Environmental Matters

- February 23 environmental update to PAC discussed the following matters:
  - Environmental performance of the generation system in 2016
    - Air emissions, water usage
  - Update on federal environmental regulatory actions
    - Regional MATS implementation, 2015 Ozone Standard developments
    - Other relevant federal regulatory activity
  - 2016-2017 Regional Greenhouse Gas Initiative Program Review Update
  - Massachusetts Global Warmings Solutions Act Generator Emissions Cap Update
- Environmental Advisory Group is scheduled to meet on April 14

Economic Studies and Keene Road Market Efficiency Transmission Upgrade Needs Assessment

- 2016 Economic Study - NEPOOL Scenario Analysis Phase I draft report remains on schedule for the second quarter
  - Phase I observations and key messages and results for requests for additional metrics and sensitivities were discussed with the PAC for the six base scenarios
  - Work is proceeding on the Phase II scopes of work discussed at the December 14 PAC meeting and are scheduled for completion during 2017
    - Natural gas pipeline results
    - Scope of work for FCA auction results
    - Scope of work for regulation, ramping, and reserves

Economic Studies and Keene Road Market Efficiency Transmission Upgrade Needs Assessment, cont.

- 2017 Economic Study requests are due to the ISO by close of business on April 3
  - The ISO will contact requestors by April 6 to discuss draft PAC presentations
  - Discussions of the requests are scheduled for the May PAC meeting
- Keene Road Market Efficiency Transmission Upgrade needs assessment final results were posted on the PAC website
  - At the March PAC meeting, the ISO concluded that a Market Efficiency Transmission Upgrade will not be pursued for the Keene Road Area

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 4/3/17

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	Oct-17	3
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	May-18	3
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	Dec-16	4
Chelsea Station - Rebuild to a three-breaker ring bus	Dec-17	3

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 4/3/17

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4*
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	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Nov-15	4*
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-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 4/3/17

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 4/3/17

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 4/3/17

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)	Feb-17	4**
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	4**
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
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	4

* Replaces the NEEWS Central Connecticut Reliability Project

** Placed in-service ahead of schedule

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 4/3/17

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	3
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-17	3
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 4/3/17

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	3
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	3
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	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 4/3/17

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	3
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	3
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
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 4/3/17

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-18	2
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	3
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	4
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	Jun-18	2
Loop the 1570 line in and out the Pootatuck substation	Jun-18	2
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

* Placed in-service ahead of schedule

** Project to be cancelled

Southwest Connecticut Projects, cont.

Status as of 4/3/17

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	2
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	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-17	2
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-18	2
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-18	2
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	2

Southwest Connecticut Projects, cont.

Status as of 4/3/17

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	3
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	May-17	3
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	2

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 4/3/17

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	3
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	3
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-20	2

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 4/3/17

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	4
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-16	4
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-16	4
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	4
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Nov-16	4
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

* Project to be cancelled

Greater Boston Projects

Status as of 4/3/17

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	3
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Sep-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-18	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	May-19	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	Jul-18	2

* Eversource portion of the project is complete

Greater Boston Projects, cont.

Status as of 4/3/17

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	4*
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	Dec-19	1

* Eversource portion of the project is complete

Greater Boston Projects, cont.

Status as of 4/3/17

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	May-19	3
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	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	4
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	May-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	May-19	2

Greater Boston Projects, cont.

Status as of 4/3/17

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	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	Jun-18	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Jun-18	2
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 4/3/17

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	Nov-17	3
Install a 200 MVAR STATCOM at Coopers Mills	Sep-18	2
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	3
Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-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	Apr-17	3

Pittsfield/Greenfield Projects

Status as of 4/3/17

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	4
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Nov-17	3
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Jun-17	3
Build a new 115 kV three-breaker switching station (Erving) ring bus	Mar-17	4
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Jun-17	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 4/3/17

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

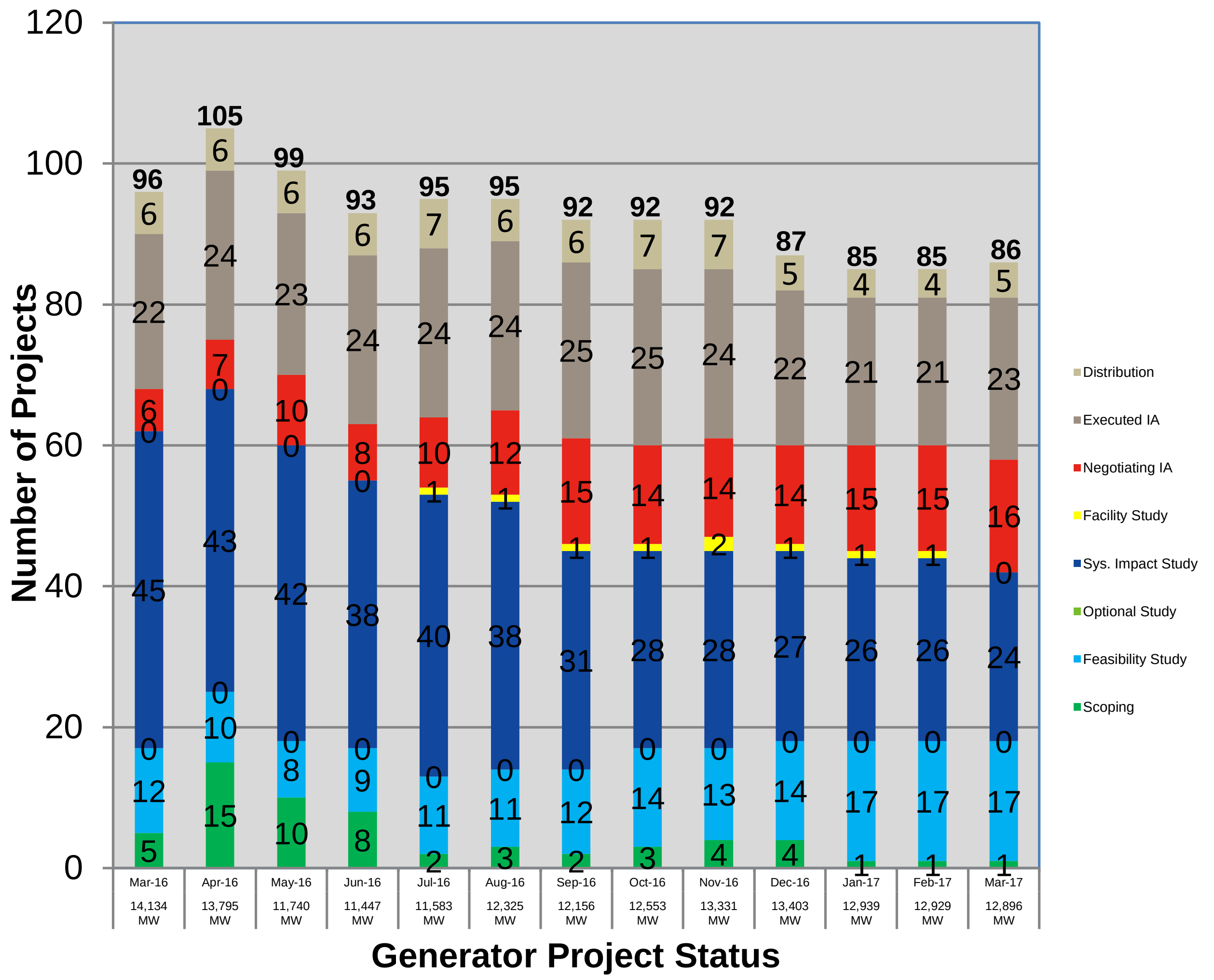
Pittsfield/Greenfield Projects, cont.

Status as of 4/3/17

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	2
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	2
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	2
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 March 2017, there are 8 ETU's in SIS, 1 in OSIS, 3 in FS, and 3 in Neg. IA

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

OPERABLE CAPACITY ANALYSIS

Spring 2017

Spring 2017 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2017 CSO	May - 2017 SCC
Operable Capacity MW [1]	30,241	32,828
OP CAP From OP-4 RTDR (+)	253	253
OP CAP From OP-4 RTEG (+)	13	13
Operable Capacity with OP-4 DR and RTEG	30,507	33,094
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	994	994
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	1,463	3,896
Gas Generator Outages/Reductions MW (-)	3,255	1,960
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,383	24,832
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,632	20,632
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,937	22,937
Operable Capacity Margin [3]	446	1,895

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **March 30, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 13, 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.

Spring 2017 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2017 CSO	May - 2017 SCC
Operable Capacity MW [1]	30,241	32,828
OP CAP From OP-4 RTDR (+)	253	253
OP CAP From OP-4 RTEG (+)	13	13
Operable Capacity with OP-4 DR and RTEG	30,507	33,094
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	994	994
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	1,463	3,896
Gas Generator Outages/Reductions MW (-)	3,255	1,960
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,383	24,832
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,516	22,516
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,821	24,821
Operable Capacity Margin [3]	-1,438	11

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **March 30, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 13, 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.

Spring 2017 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

April 7, 2017 - 50/50 FORECAST using CSO values with RTDR and RTEG

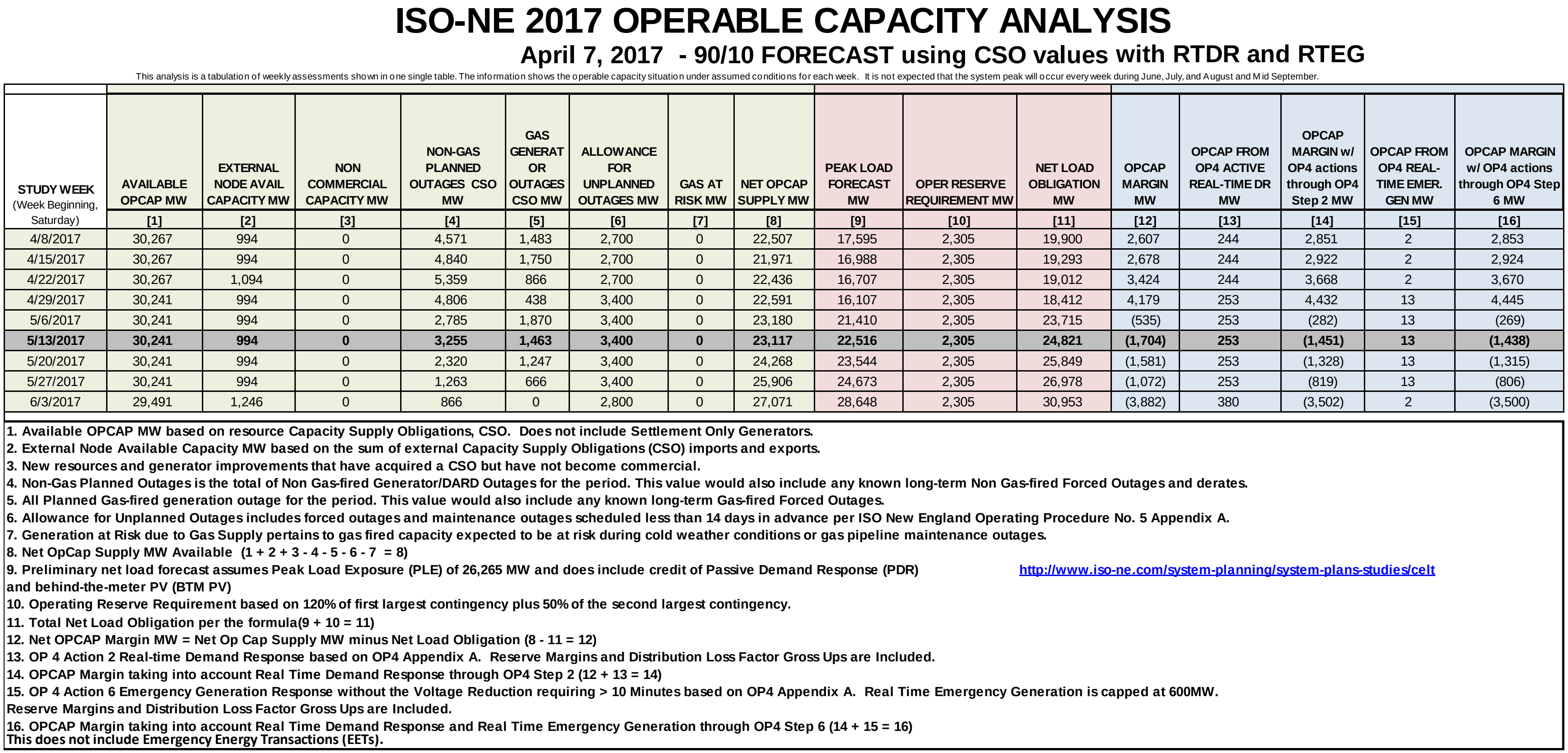
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September

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]
4/8/2017	30,267	994	0	4,571	1,483	2,700	0	22,507	17,031	2,305	19,336	3,171	244	3,415	2	3,417
4/15/2017	30,267	994	0	4,840	1,750	2,700	0	21,971	16,431	2,305	18,736	3,235	244	3,479	2	3,481
4/22/2017	30,267	1,094	0	5,359	866	2,700	0	22,436	16,158	2,305	18,463	3,973	244	4,217	2	4,219
4/29/2017	30,241	994	0	4,806	438	3,400	0	22,591	15,559	2,305	17,864	4,727	253	4,980	13	4,993
5/6/2017	30,241	994	0	2,785	1,870	3,400	0	23,180	19,609	2,305	21,914	1,266	253	1,519	13	1,532
5/13/2017	**30,241**	**994**	**0**	**3,255**	**1,463**	**3,400**	**0**	**23,117**	**20,632**	**2,305**	**22,937**	**180**	**253**	**433**	**13**	**446**
5/20/2017	30,241	994	0	2,320	1,247	3,400	0	24,268	21,583	2,305	23,888	380	253	633	13	646
5/27/2017	30,241	994	0	1,263	666	3,400	0	25,906	22,626	2,305	24,931	975	253	1,228	13	1,241

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 and derates.
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. Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt
and behind-the-meter PV (BTM PV)
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).

Spring 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)



ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

April 7, 2017 - 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]
4/8/2017	30,267	994	0	4,571	1,483	2,700	0	22,507	17,595	2,305	19,900	2,607	244	2,851	2	2,853
4/15/2017	30,267	994	0	4,840	1,750	2,700	0	21,971	16,988	2,305	19,293	2,678	244	2,922	2	2,924
4/22/2017	30,267	1,094	0	5,359	866	2,700	0	22,436	16,707	2,305	19,012	3,424	244	3,668	2	3,670
4/29/2017	30,241	994	0	4,806	438	3,400	0	22,591	16,107	2,305	18,412	4,179	253	4,432	13	4,445
5/6/2017	30,241	994	0	2,785	1,870	3,400	0	23,180	21,410	2,305	23,715	(535)	253	(282)	13	(269)
5/13/2017	**30,241**	**994**	**0**	**3,255**	**1,463**	**3,400**	**0**	**23,117**	**22,516**	**2,305**	**24,821**	**(1,704)**	**253**	**(1,451)**	**13**	**(1,438)**
5/20/2017	30,241	994	0	2,320	1,247	3,400	0	24,268	23,544	2,305	25,849	(1,581)	253	(1,328)	13	(1,315)
5/27/2017	30,241	994	0	1,263	666	3,400	0	25,906	24,673	2,305	26,978	(1,072)	253	(819)	13	(806)
6/3/2017	29,491	1,246	0	866	0	2,800	0	27,071	28,648	2,305	30,953	(3,882)	380	(3,502)	2	(3,500)

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 and derates.
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. Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt and behind-the-meter PV (BTM PV)
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)
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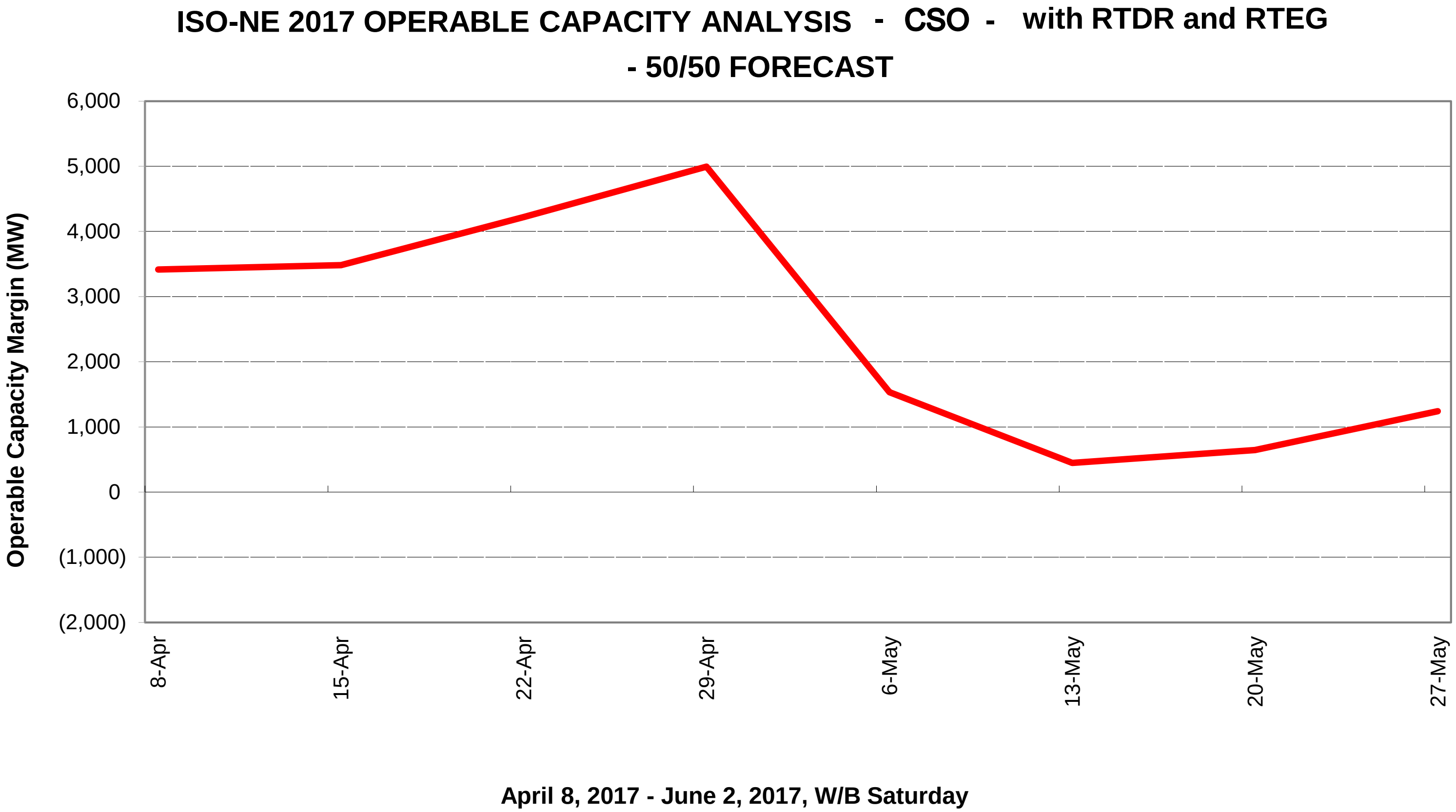
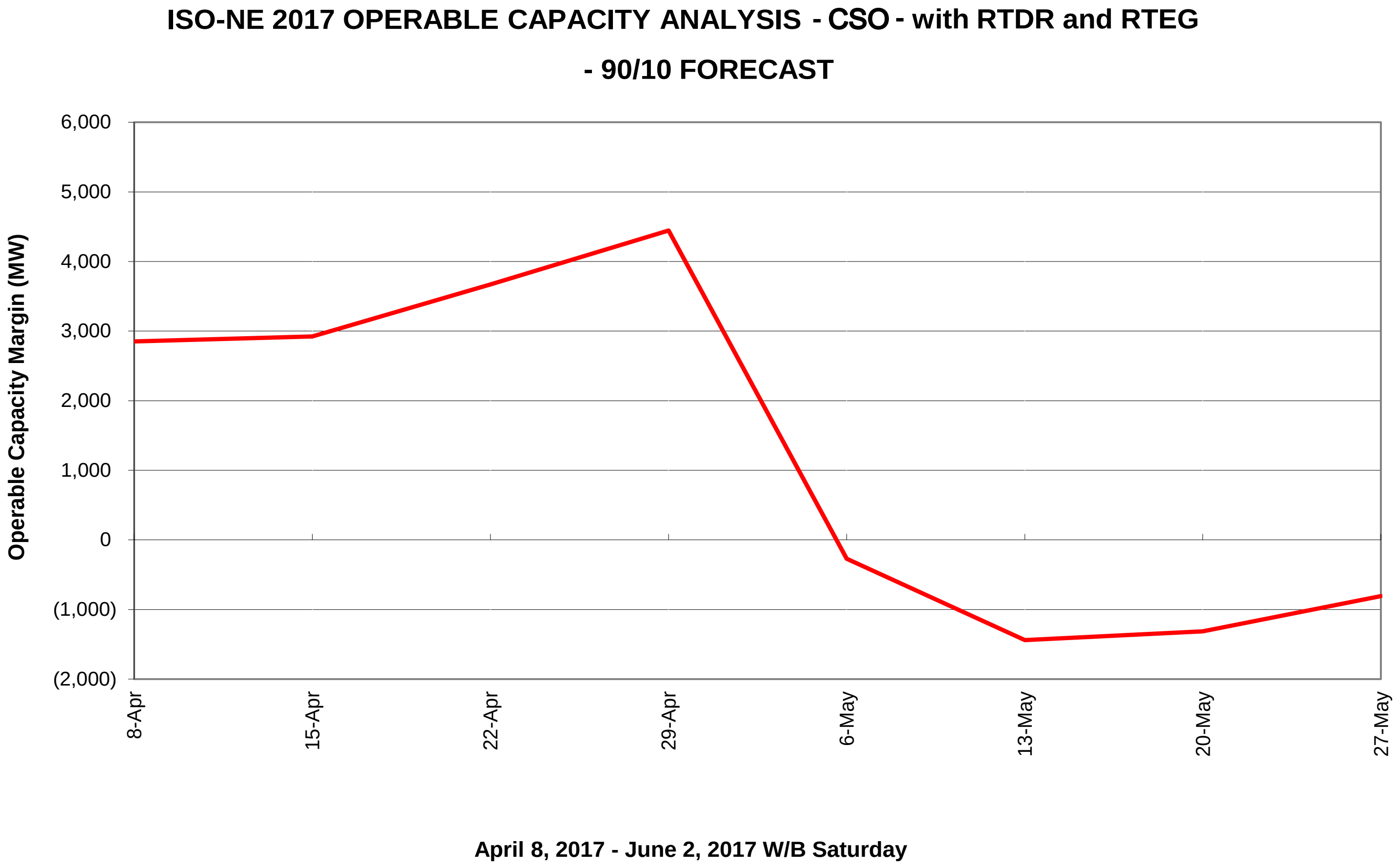
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16) This does not include Emergency Energy Transactions (EETs).

Spring 2017 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Spring 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Summer 2017

Summer 2017 Operable Capacity Analysis

50/50 Load Forecast (Reference)	July - 2017 CSO	July - 2017 SCC
Operable Capacity MW [1]	29,491	29,412
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	29,873	29,794
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,246	1,246
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	674	674
Gas Generator Outages/Reductions MW (-)	0	0
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]	28,345	28,266
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,265	26,265
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,570	28,570
Operable Capacity Margin [3]	-225	-304

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **March 30, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and represents the peak demand of week beginning **July 15, 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.

Summer 2017 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	**July - 2017 CSO**	**July - 2017 SCC**
Operable Capacity MW [1]	29,491	29,412
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	29,873	29,794
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,246	1,246
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	674	674
Gas Generator Outages/Reductions MW (-)	0	0
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]	28,345	28,266
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	28,648	28,648
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	30,953	30,953
Operable Capacity Margin [3]	-2,608	-2,687

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **March 30, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and represents the peak demand of week beginning **July 15, 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.

Summer 2017 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

April 7, 2017 - 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]
6/3/2017	29,491	1,246	0	866	0	2,800	0	27,071	26,265	2,305	28,570	(1,499)	380	(1,119)	2	(1,117)
6/10/2017	29,491	1,246	0	866	0	2,800	0	27,071	26,265	2,305	28,570	(1,499)	380	(1,119)	2	(1,117)
6/17/2017	29,491	1,246	0	866	0	2,800	0	27,071	26,265	2,305	28,570	(1,499)	380	(1,119)	2	(1,117)
6/24/2017	29,491	1,246	0	674	0	2,800	0	27,263	26,265	2,305	28,570	(1,307)	380	(927)	2	(925)
7/1/2017	29,491	1,246	0	688	0	2,100	0	27,949	26,265	2,305	28,570	(621)	380	(241)	2	(239)
7/8/2017	29,491	1,246	0	688	0	2,100	0	27,949	26,265	2,305	28,570	(621)	380	(241)	2	(239)
7/15/2017	**29,491**	**1,246**	**0**	**674**	**0**	**2,100**	**0**	**27,963**	**26,265**	**2,305**	**28,570**	**(607)**	**380**	**(227)**	**2**	**(225)**
7/22/2017	29,491	1,246	0	674	0	2,100	0	27,963	26,265	2,305	28,570	(607)	380	(227)	2	(225)
7/29/2017	29,491	1,246	0	688	0	2,100	0	27,949	26,265	2,305	28,570	(621)	380	(241)	2	(239)
8/5/2017	29,491	1,246	0	674	0	2,100	0	27,963	26,265	2,305	28,570	(607)	380	(227)	2	(225)
8/12/2017	29,491	1,246	0	764	0	2,100	0	27,873	26,265	2,305	28,570	(697)	380	(317)	2	(315)
8/19/2017	29,491	1,246	0	688	0	2,100	0	27,949	26,265	2,305	28,570	(621)	380	(241)	2	(239)
8/26/2017	29,491	1,246	0	674	0	2,100	0	27,963	26,265	2,305	28,570	(607)	380	(227)	2	(225)
9/2/2017	29,491	1,246	0	678	0	2,100	0	27,959	26,265	2,305	28,570	(611)	380	(231)	2	(229)
9/9/2017	29,491	1,246	0	678	0	2,100	0	27,959	26,265	2,305	28,570	(611)	380	(231)	2	(229)

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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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 and derates.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
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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. Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt and behind-the-meter PV (BTM PV)
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 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

April 7, 2017 - 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]
6/3/2017	29,491	1,246	0	866	0	2,800	0	27,071	28,648	2,305	30,953	(3,882)	380	(3,502)	2	(3,500)
6/10/2017	29,491	1,246	0	866	0	2,800	0	27,071	28,648	2,305	30,953	(3,882)	380	(3,502)	2	(3,500)
6/17/2017	29,491	1,246	0	866	0	2,800	0	27,071	28,648	2,305	30,953	(3,882)	380	(3,502)	2	(3,500)
6/24/2017	29,491	1,246	0	674	0	2,800	0	27,263	28,648	2,305	30,953	(3,690)	380	(3,310)	2	(3,308)
7/1/2017	29,491	1,246	0	688	0	2,100	0	27,949	28,648	2,305	30,953	(3,004)	380	(2,624)	2	(2,622)
7/8/2017	29,491	1,246	0	688	0	2,100	0	27,949	28,648	2,305	30,953	(3,004)	380	(2,624)	2	(2,622)
7/15/2017	**29,491**	**1,246**	**0**	**674**	**0**	**2,100**	**0**	**27,963**	**28,648**	**2,305**	**30,953**	**(2,990)**	**380**	**(2,610)**	**2**	**(2,608)**
7/22/2017	29,491	1,246	0	674	0	2,100	0	27,963	28,648	2,305	30,953	(2,990)	380	(2,610)	2	(2,608)
7/29/2017	29,491	1,246	0	688	0	2,100	0	27,949	28,648	2,305	30,953	(3,004)	380	(2,624)	2	(2,622)
8/5/2017	29,491	1,246	0	674	0	2,100	0	27,963	28,648	2,305	30,953	(2,990)	380	(2,610)	2	(2,608)
8/12/2017	29,491	1,246	0	764	0	2,100	0	27,873	28,648	2,305	30,953	(3,080)	380	(2,700)	2	(2,698)
8/19/2017	29,491	1,246	0	688	0	2,100	0	27,949	28,648	2,305	30,953	(3,004)	380	(2,624)	2	(2,622)
8/26/2017	29,491	1,246	0	674	0	2,100	0	27,963	28,648	2,305	30,953	(2,990)	380	(2,610)	2	(2,608)
9/2/2017	29,491	1,246	0	678	0	2,100	0	27,959	28,648	2,305	30,953	(2,994)	380	(2,614)	2	(2,612)
9/9/2017	29,491	1,246	0	678	0	2,100	0	27,959	28,648	2,305	30,953	(2,994)	380	(2,614)	2	(2,612)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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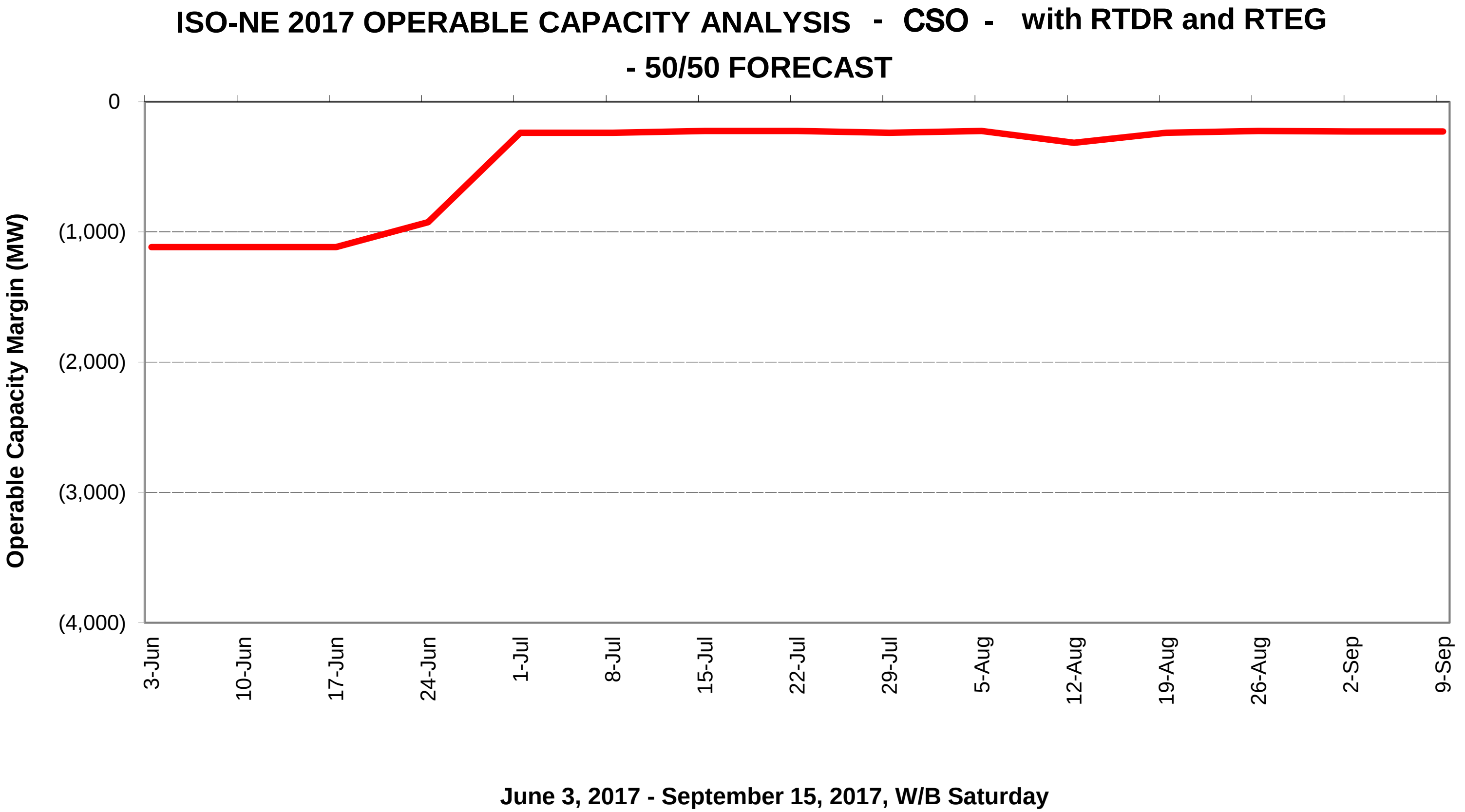
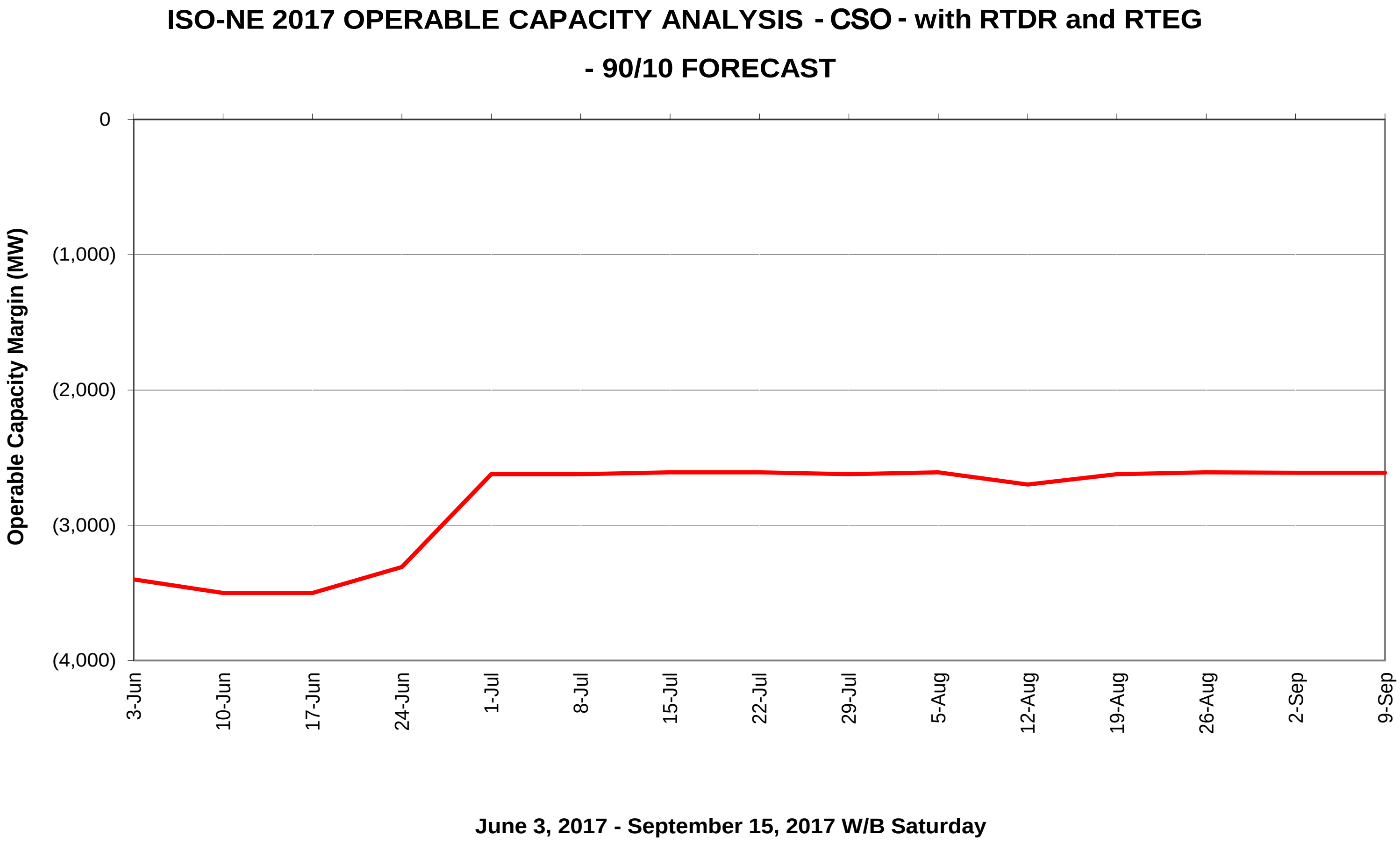
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Summer 2017 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Summer 2017 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.	**April 244** [3] **May 253** [3] **June – September 380** [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] **April 2** [3] **May 13** [3] **June – September 2** [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 March 30, 2017.
4. The MW values are based on a 26,704 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A, cont.

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		**April 2,792 [3]** **May 2,812[3]** **June – September 2,928 [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 March 30, 2017.
4. The MW values are based on a 26,704 MW system load and the most recent voltage reduction test % achieved.