NEPOOL Participants Committee Report

April 2019

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 $409M, up $44M from February 2019 and up $39M from March 2018
    - March natural gas prices were 3.5% lower than February values
    - Average RT Hub Locational Marginal Prices ($36.92/MWh) over the period were unchanged from February averages
    - Average March 2019 natural gas prices and RT Hub LMPs during the month were up 1.2% and up 12.3%, respectively, from March 2018 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.5% during March, up from 98% during February*
    - The minimum value for the month was 95% on March 25

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

Underlying natural gas data furnished by:

ICE Global markets in clear view

Highlights, cont.

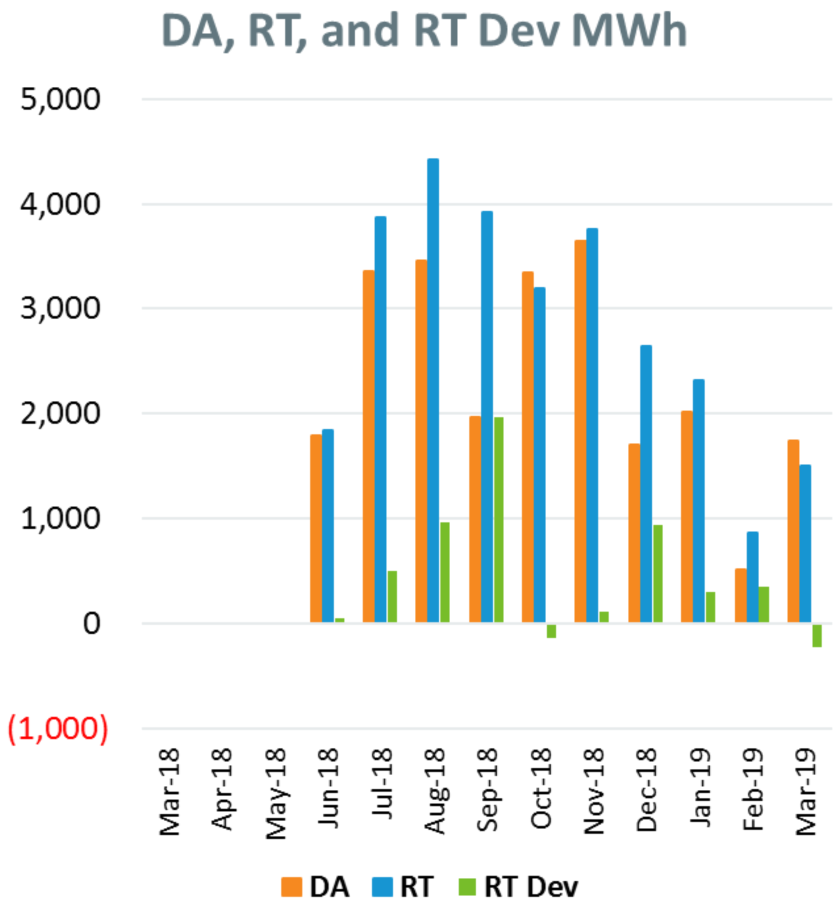
- Daily Net Commitment Period Compensation (NCPC)
  - March NCPC payments totaled $2.3M over the period, up $421K from February 2019 and down $1.6M from March 2018
    - First Contingency* payments totaled $2.2M, up $0.5M from February
      - $2.2M paid to internal resources, up $461K from February
        - » $759K charged to DALO, $573K to RT Deviations, $876K to RTLO
      - $9K paid to resources at external locations, down $1K from February
        - » $8K charged to RT Deviations
    - Voltage payments totaled $69K, up $56K from February
    - Second Contingency and Distribution payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 0.6%

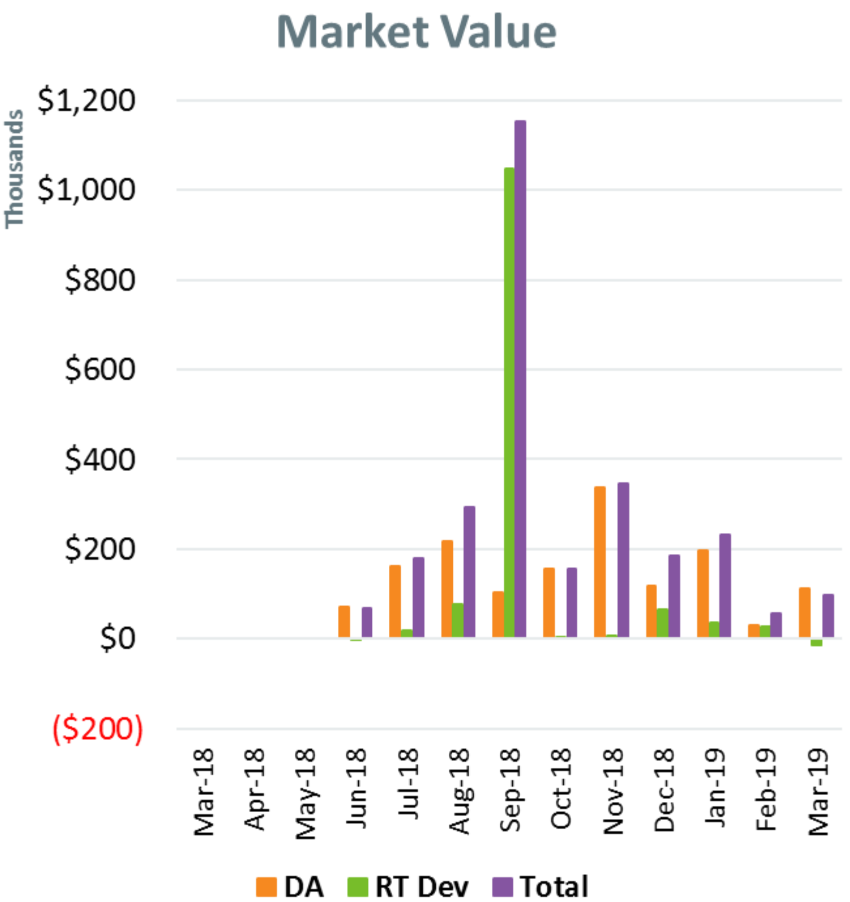
*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $228K; Rapid Response Pricing (RRP) Opportunity Cost - $278K; Posturing - $0K; Generator Performance Auditing (GPA) - $370K;**

Highlights, cont. – NCPC Outlook in NEMA/Boston

- In addition to previously scheduled outages in the NEMA/Boston area, recent events have required the following additional unplanned outages
  - An unexpected fault and subsequent long-term outage at Wakefield Junction
  - Shorter duration outages to improve the Short Circuit performance of the NEMA/Boston area prior to June 2019
- As a result, there is a high probability for the need to commit units in the NEMA/Boston area for Second Contingency Protection
- The ISO currently anticipates the need for such commitment on most days between April 15 through May 15
- The ISO and the transmission owners are working diligently to minimize the need and number of days for such commitment
  - As a reminder, commitment needs will also depend upon loads, adverse weather conditions and resource availability (both transmission and generation)
- The outage logistics are still being finalized, and the ISO will issue an update if there are any further changes

Price Responsive Demand (PRD) Energy Market Activity by Month





Note: DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.

Highlights

- PAC "Grid Transformation Day" is scheduled for May 23
- Show-of-Interest window for Capacity Commitment Period 2023-2024 will be open from April 12 – April 26
- The annual Capacity, Energy, Load, and Transmission (CELT) Report is scheduled to be posted to the ISO website by May 1
- All 20 Qualified Transmission Project Sponsors (QTPSs) met the 2019 annual certification requirements
  - One additional company is moving through the QTPS process
- Three economic study requests were received by the April 1 deadline
  - These requests will be reviewed at the April 25 PAC meeting

Forward Capacity Market (FCM) Highlights

- CCP 9 (2018-2019)
  - Late, new resources are being monitored closely
- CCP 10 (2019-2020)
  - Third reconfiguration auction was March 1-5 and results were posted on March 19
    - No bids were denied for reliability

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 11 (2020-2021)
  - Second reconfiguration auction will be August 1-5, and results to be posted by September 3
- CCP 12 (2021-2022)
  - First reconfiguration auction will be June 3-5
- CCP 13 (2022-2023)
  - Auction results were filed with FERC on February 28, and we are awaiting a FERC Order
    - Summary of the results was presented to the RC at their March meeting

FCM Highlights, cont.

- CCP 14 (2023-2024)
  - Qualification is ongoing
    - Summary of retirement and permanent delist bids is available at: https://www.iso-ne.com/static-assets/documents/2019/03/exit-de-list-bids-for-fca2023-2024-load-zone.pdf
    - Show of Interest window is April 12 – April 26
  - This will be the first FCA where nested capacity zones will be modeled
    - See March RC presentation at: https://www.iso-ne.com/static-assets/documents/2019/03/a7_fca_14_transmission_transfer_capabilities_and_capacity_zone_development.pdf
  - ICR & related values development to commence in May
    - Discussions to be held with the Power Supply Planning Committee
    - ICR & related values development webinar is proposed for mid-May

FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

FERC Order 1000

- Intraregional Planning
  - 20 companies have achieved Qualified Transmission Project Sponsor (QTPS) status
  - 2019 Annual QTPS Certification
    - All 20 QTPSs were notified on March 6, 2019 that they met the 2019 annual QTPS certification requirements
  - One company is currently moving through the QTPS application process

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning March 2, 2019.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 11, 2019.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (0.8°F) Max: 70°F, Min: 15°F Precipitation: 2.95" – Below Normal Normal: 4.32" Snow: 13.5"	Hartford	Temperature: Below Normal (1.2°F) Max: 70°F, Min: 5°F Precipitation: 3.07" - Below Normal Normal: 3.62" Snow: 10.3"

Peak Load:	17,752 MW	March 6, 2019	19:00 (ending)

Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
No Events in March			

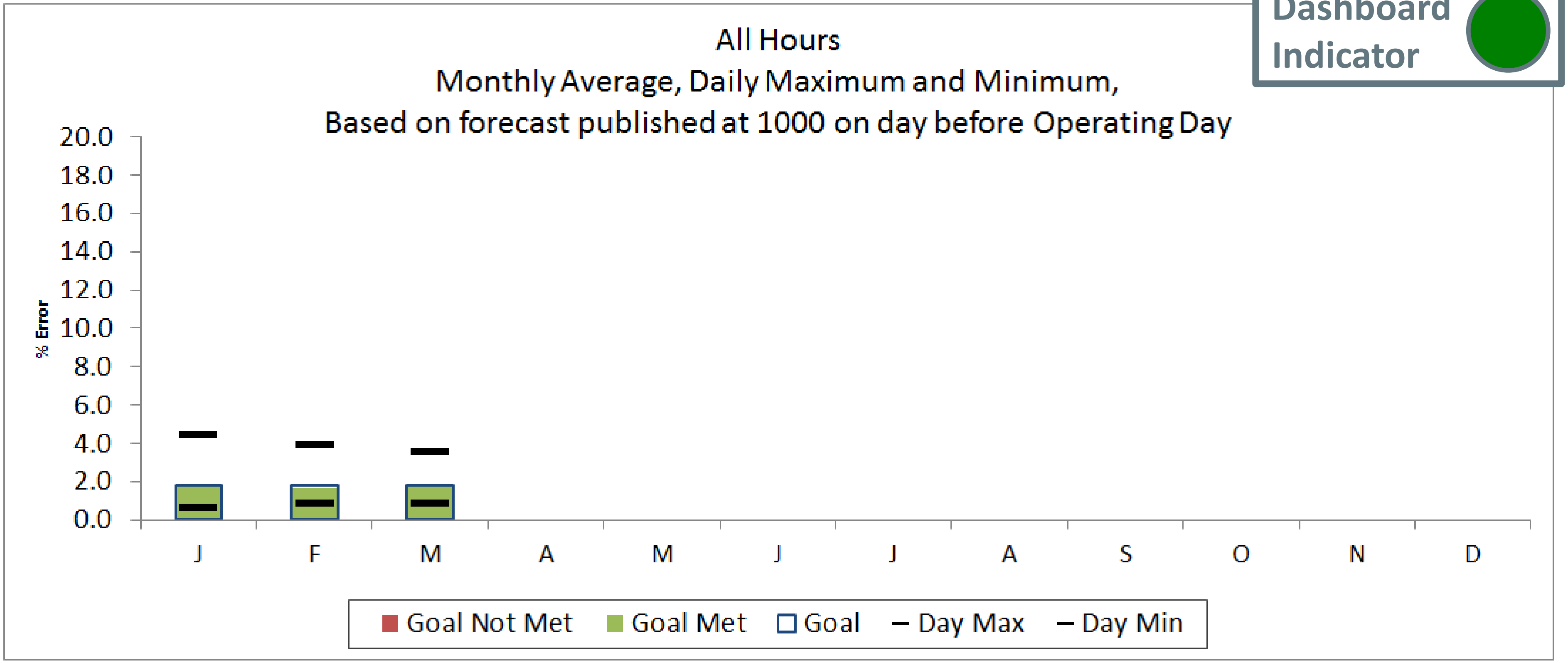
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
3/10/2019	NYISO	650
3/12/2019	ISO-NE	540
3/15/2019	NYISO	1000
3/24/2019	NYISO	945
3/25/2019	IESO	525
3/29/2019	NBPSO	750

2019 System Operations - Load Forecast Accuracy

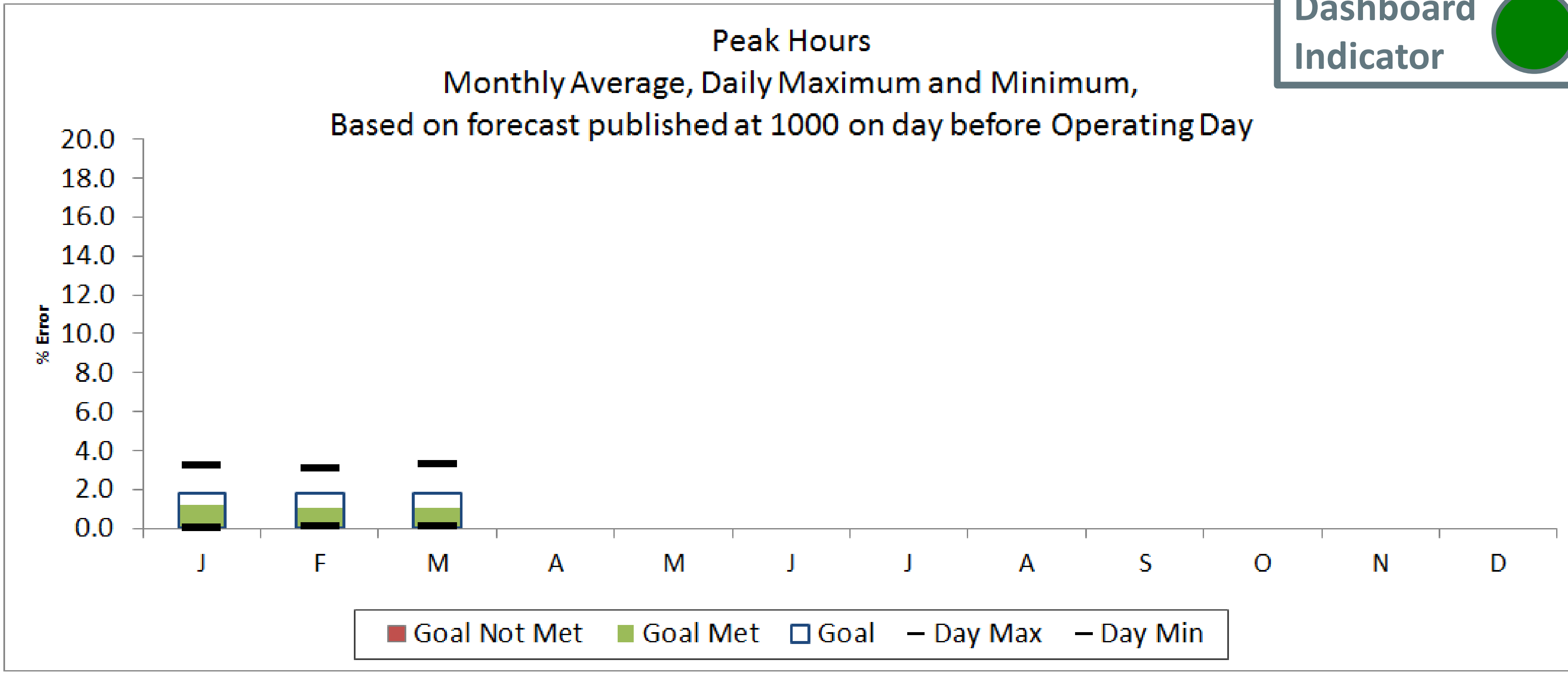
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.36	3.87	3.47										4.36
Day Min	0.60	0.77	0.81										0.60
MAPE	1.76	1.68	1.72										1.72
Goal	1.80	1.80	1.80										

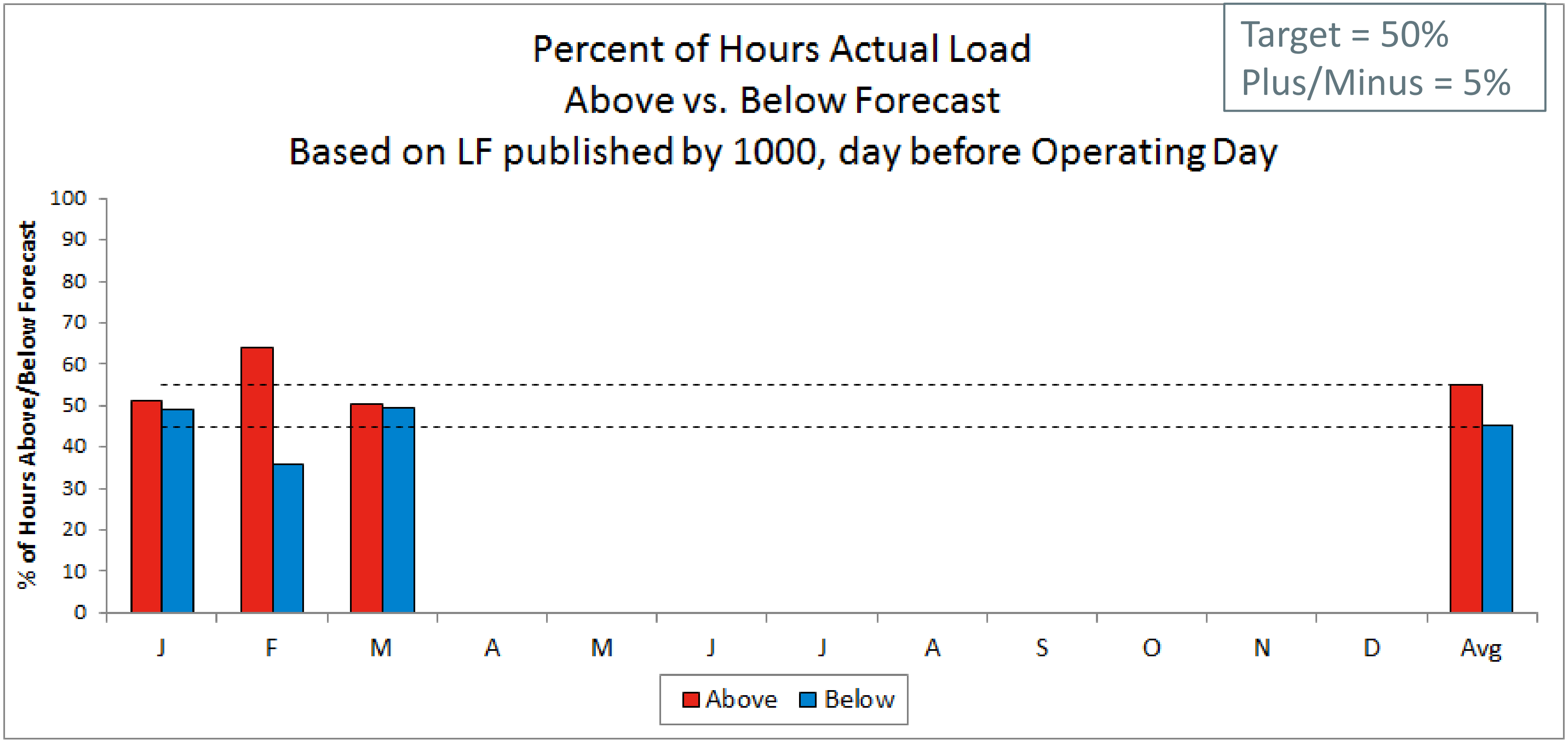
2019 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



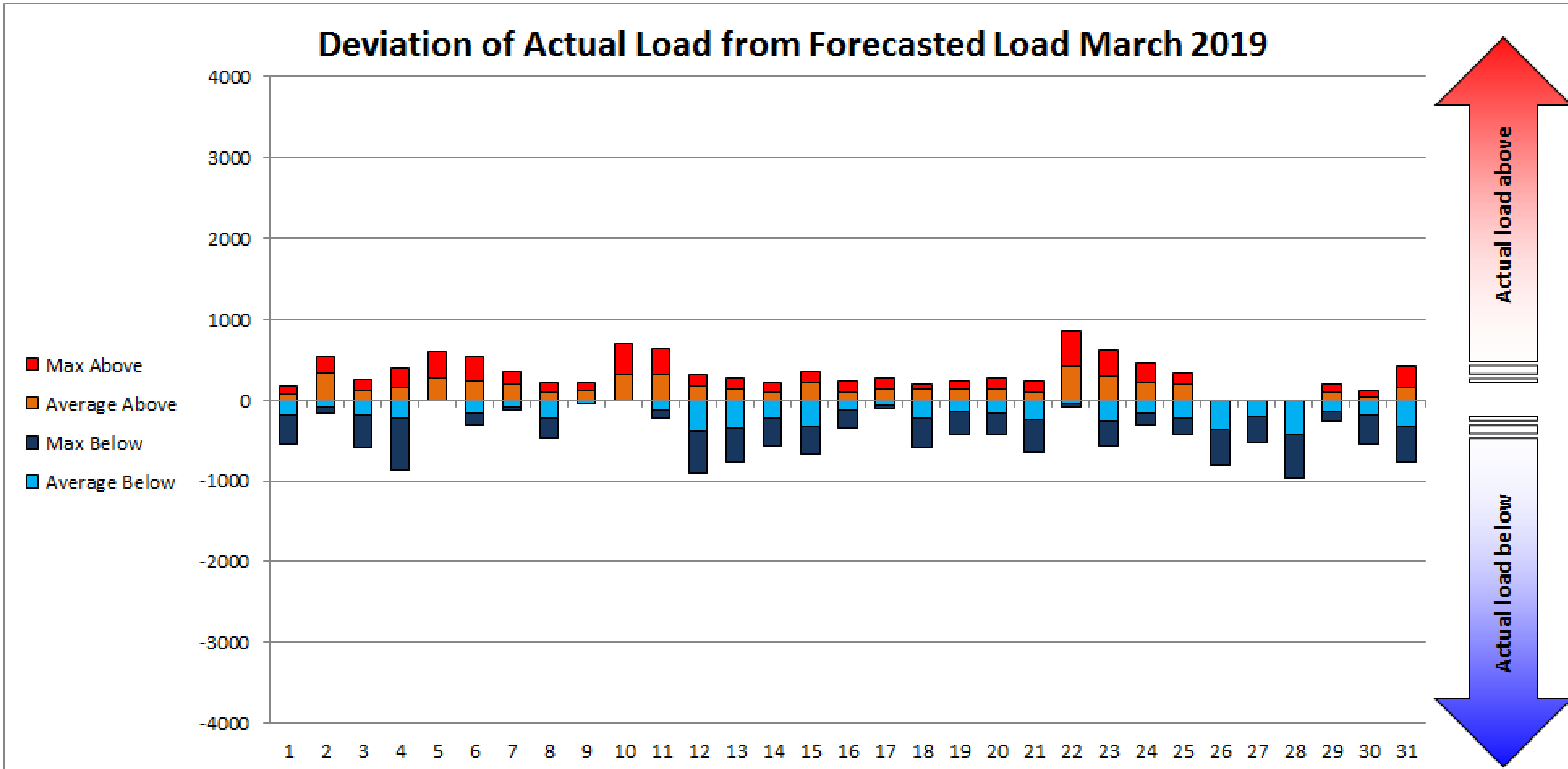
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.17	3.03	3.23										3.23
Day Min	0.02	0.06	0.06										0.02
MAPE	1.22	1.04	1.06										1.11
Goal	1.80	1.80	1.80										

2019 System Operations - Load Forecast Accuracy cont.

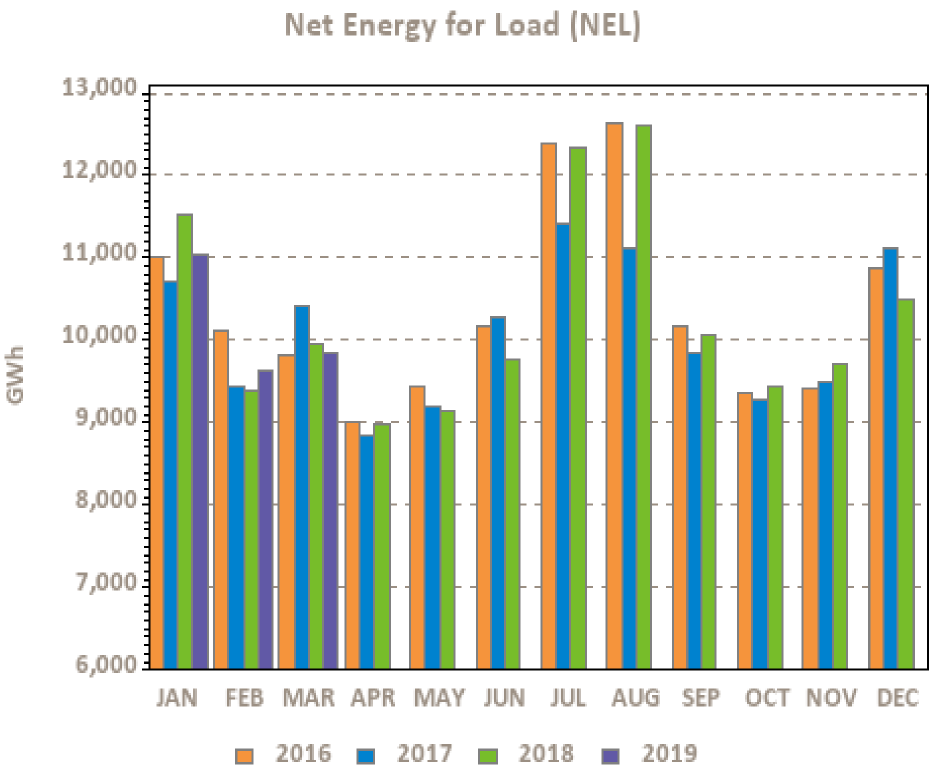


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	51.1	64	50.5										55
Below %	48.9	36	49.5										45
Avg Above	211.7	224.2	162.1										224
Avg Below	-183.0	-174.3	-192.4										-192
Avg All	30	88	-12										34

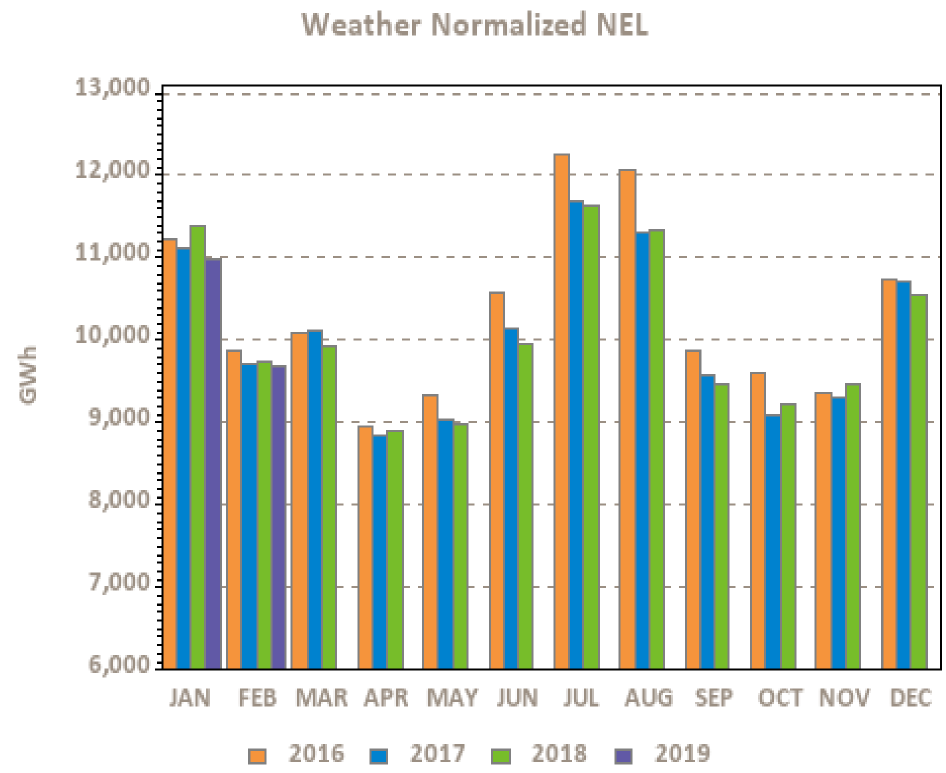
2019 System Operations - Load Forecast Accuracy cont.



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



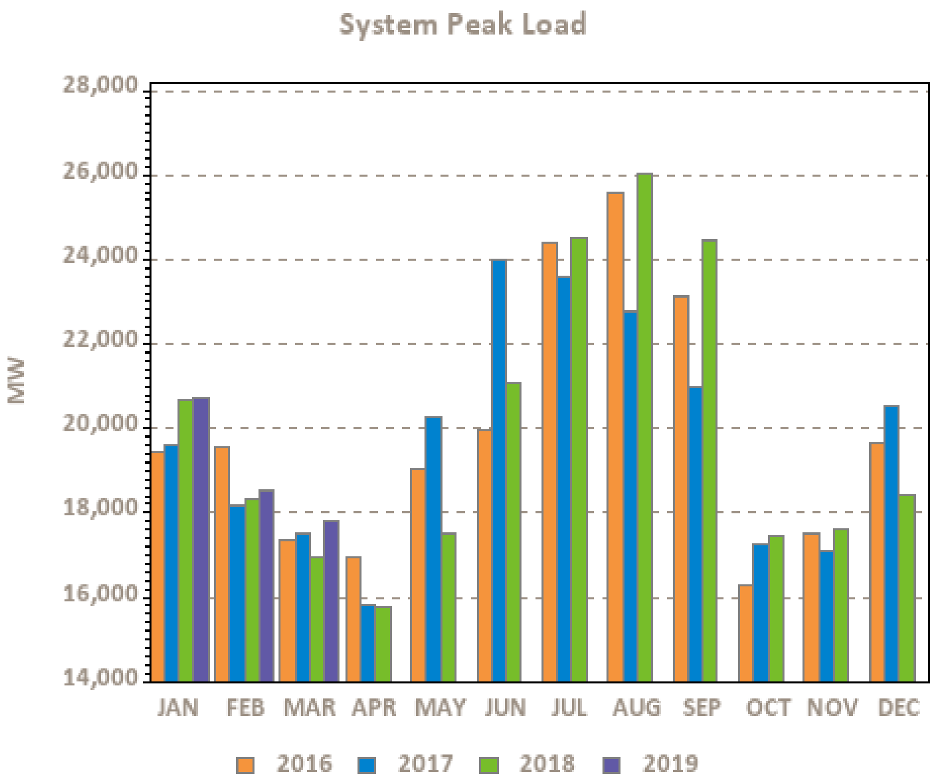
Ann Tot (TWh): 124.4 121.2 123.3 30.5



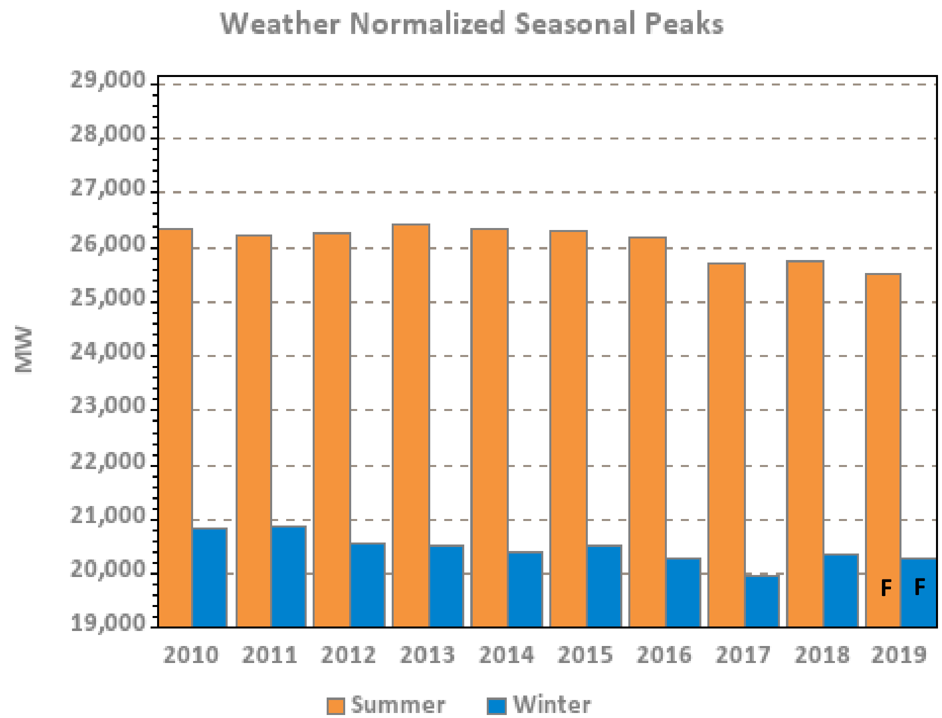
Ann Tot (TWh): 124.0 120.7 120.6 20.7

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

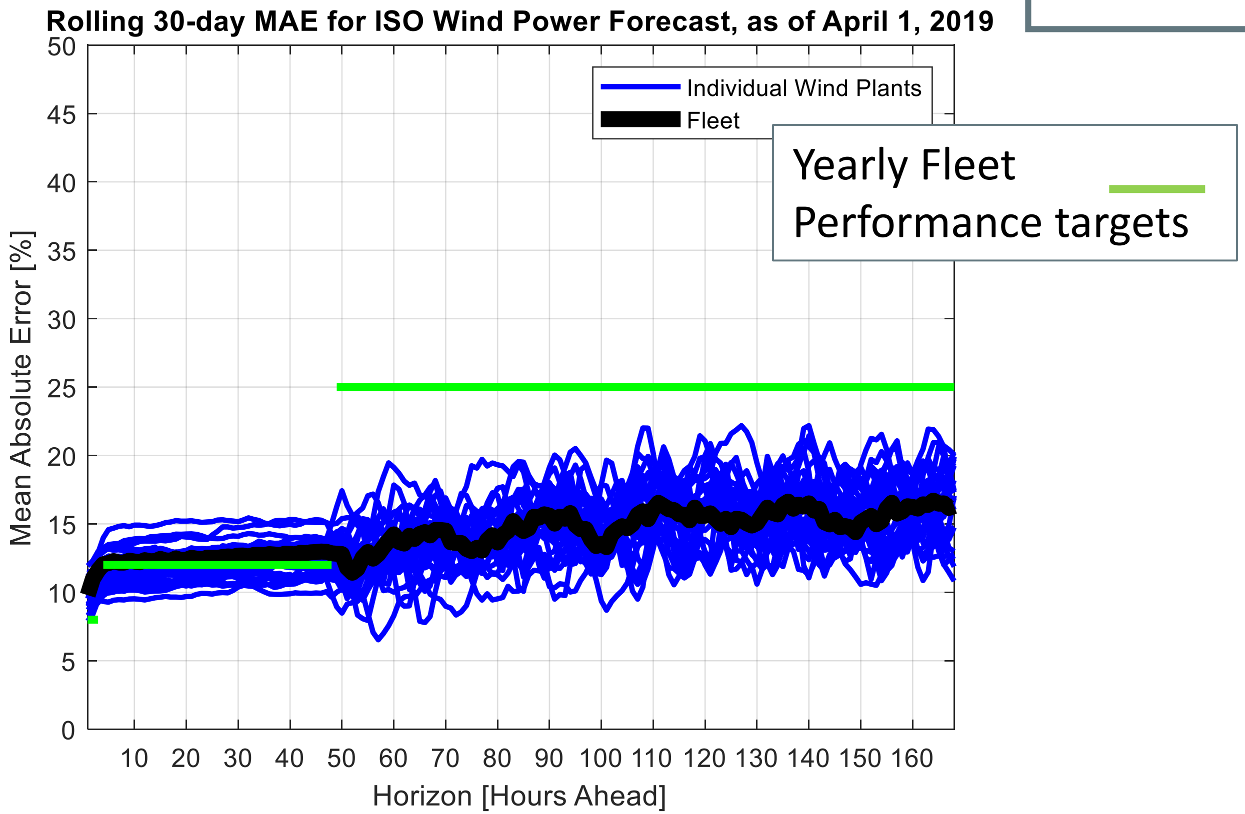


Winter beginning in year displayed

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

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

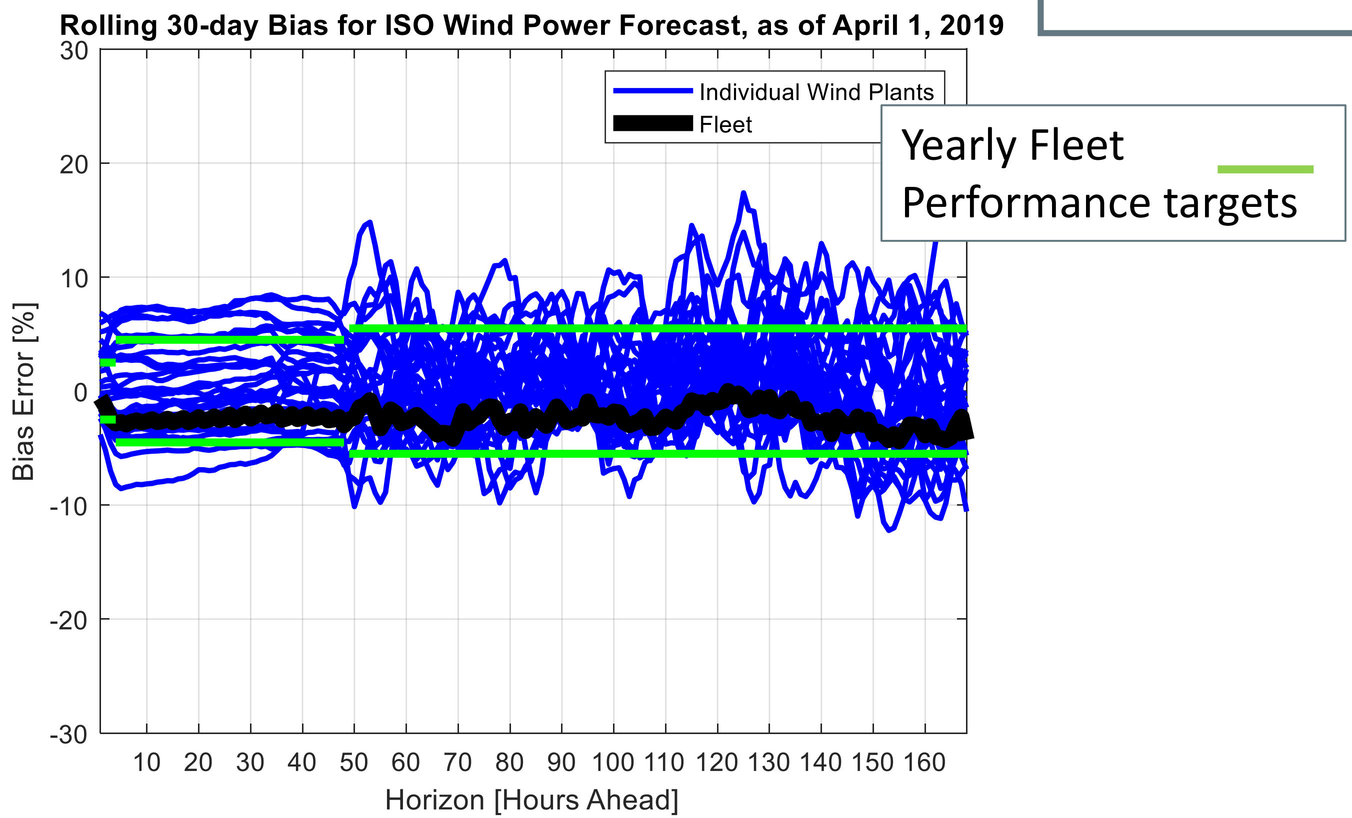
Dashboard Indicator



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

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

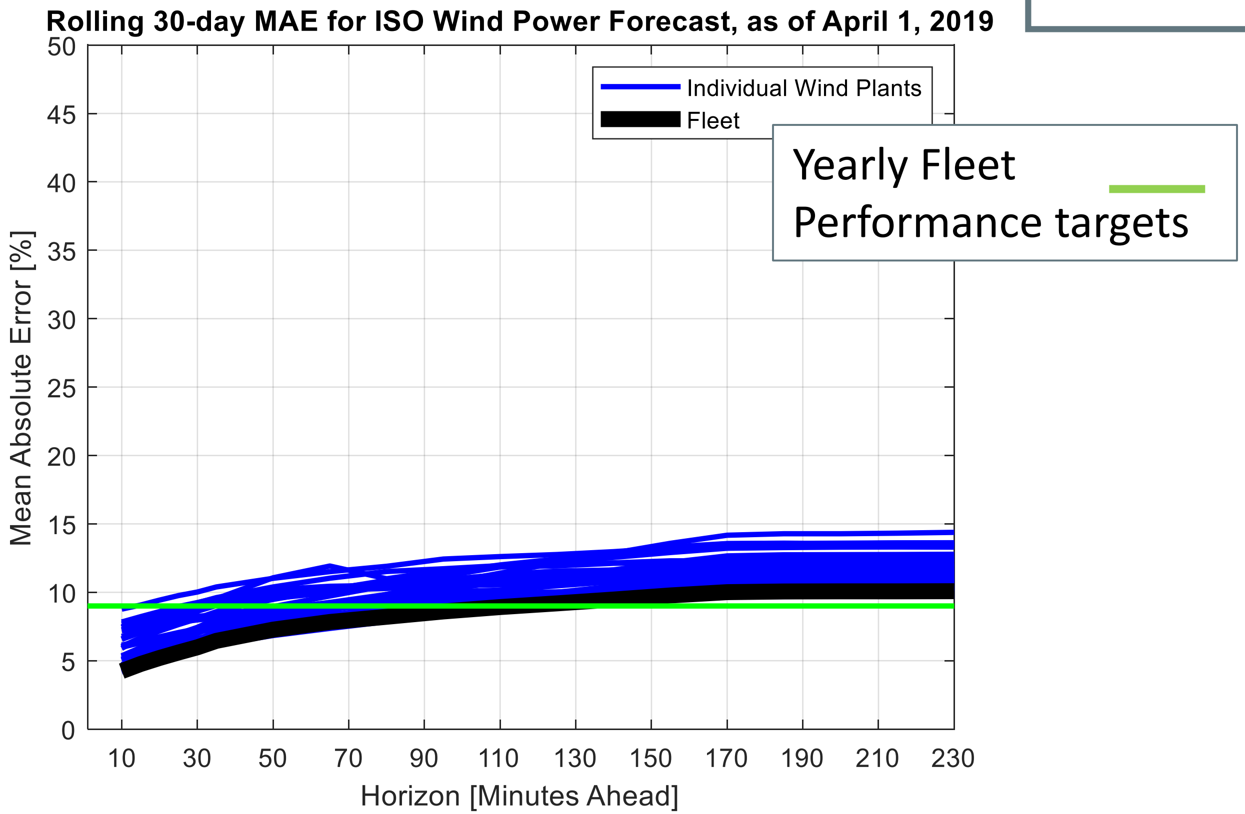
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

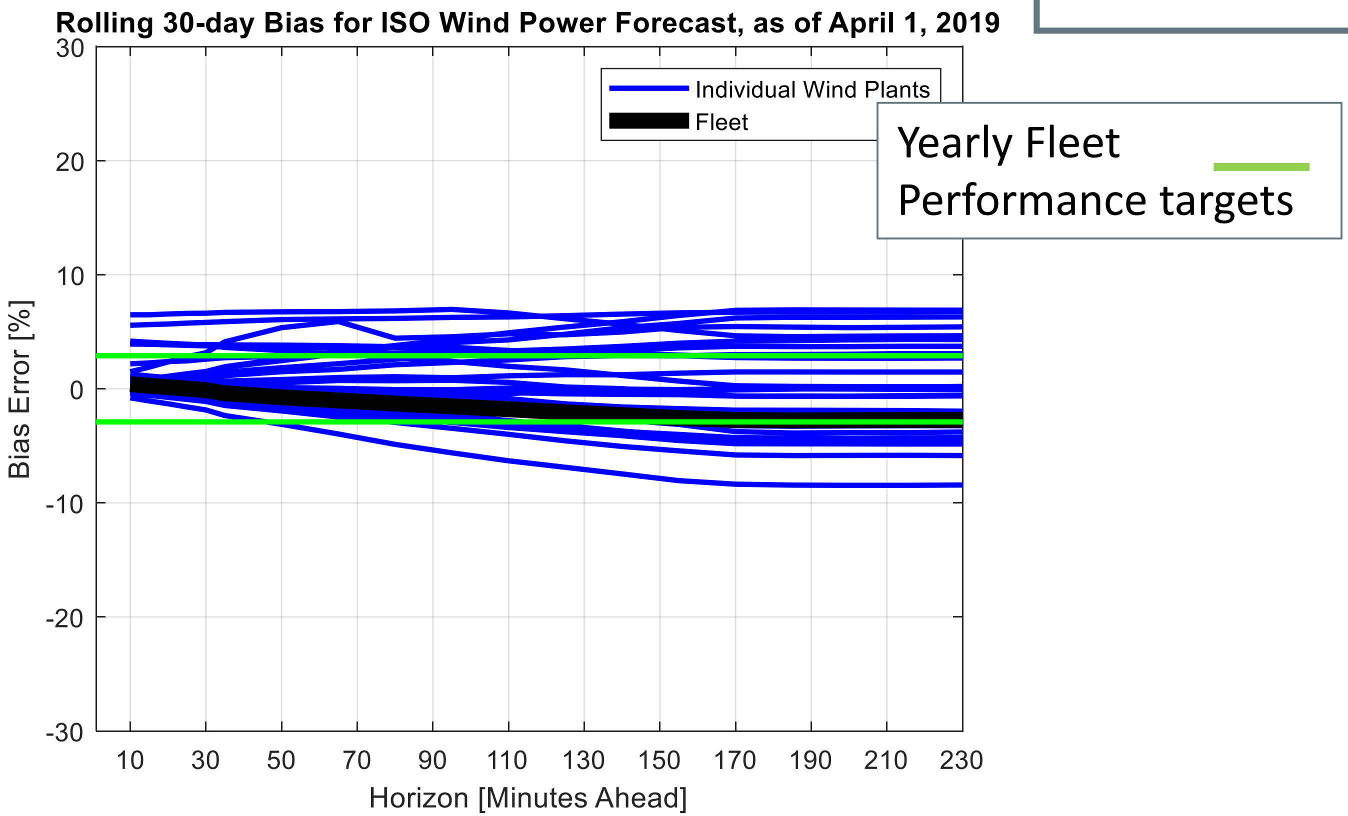
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets during the first 2 hours.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

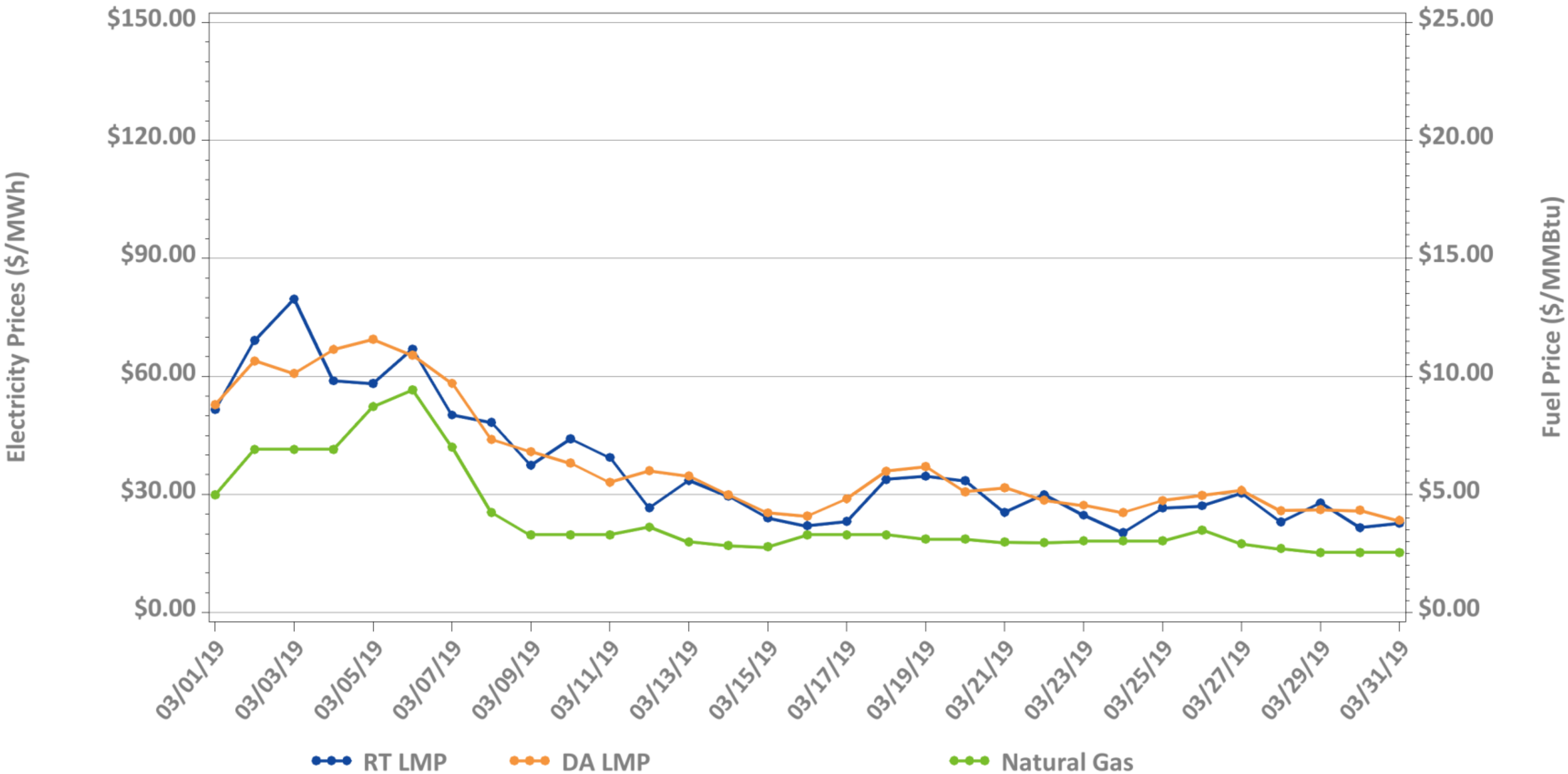
Dashboard Indicator



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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: March 1-31, 2019



Underlying natural gas data furnished by:

ICE Global markets in clear view

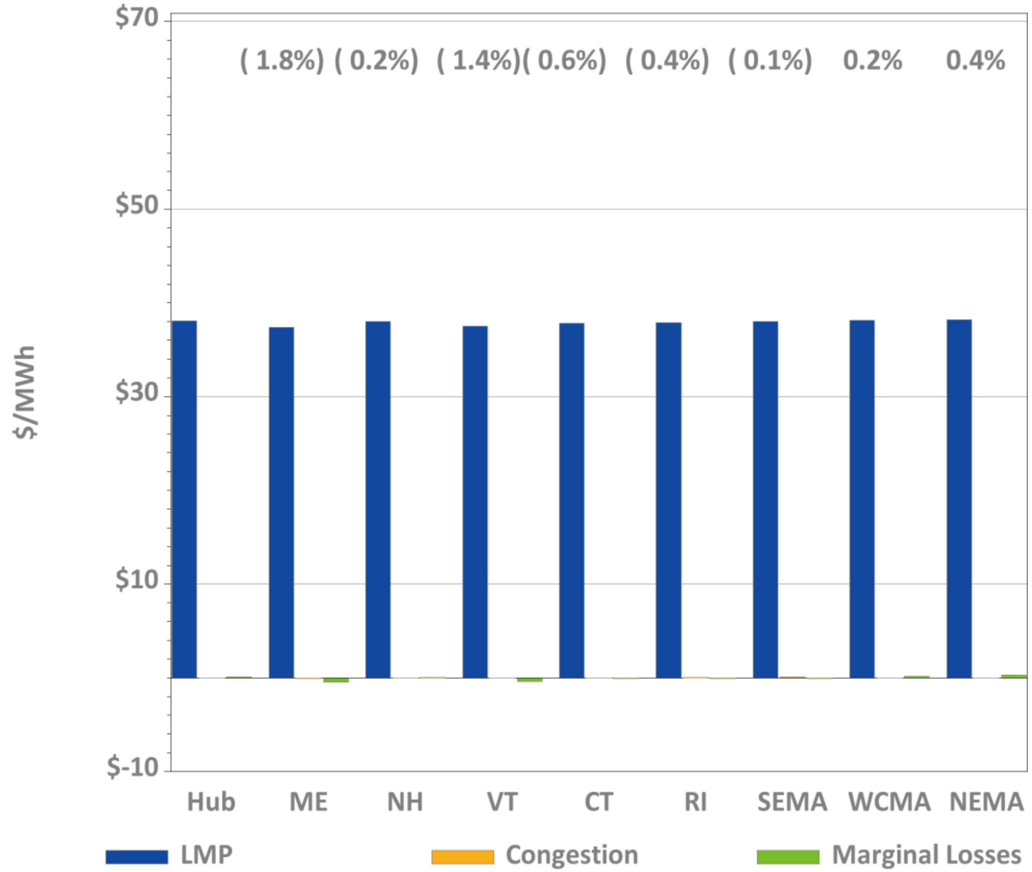
Average price difference over this period (DA-RT): $1.14

Average price difference over this period ABS(DA-RT): $4.27

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 12%

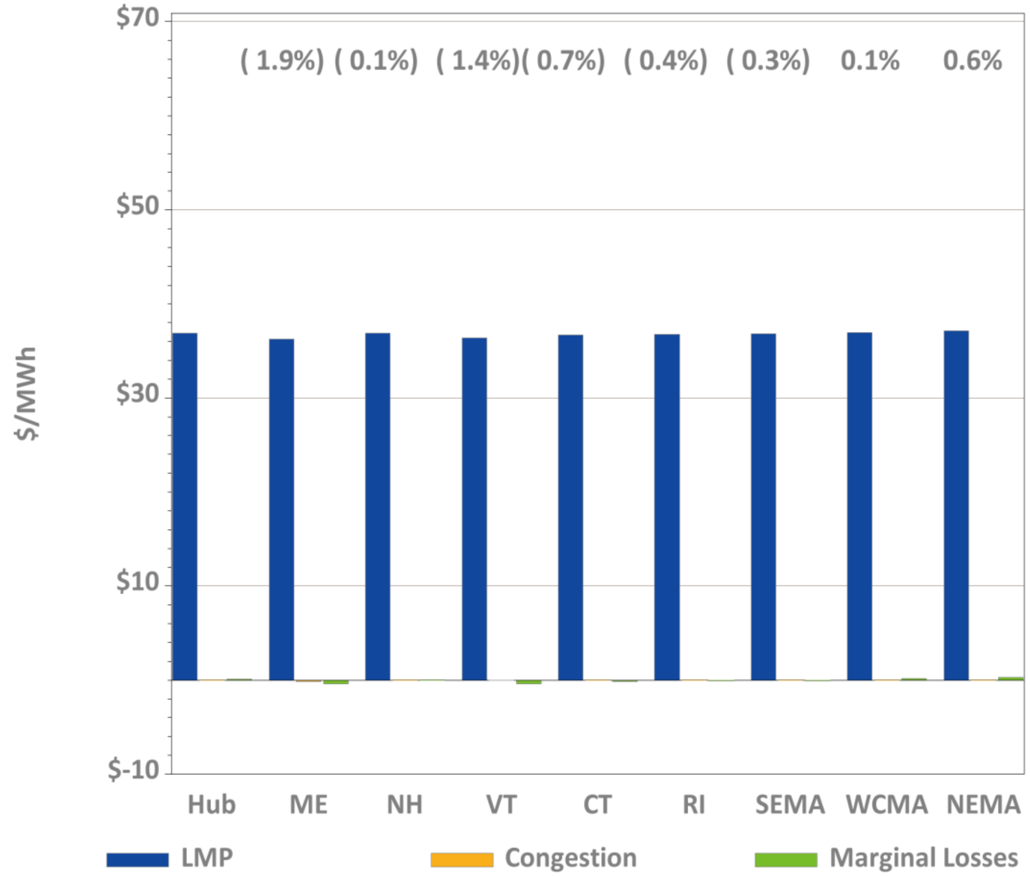
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, March 2019



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

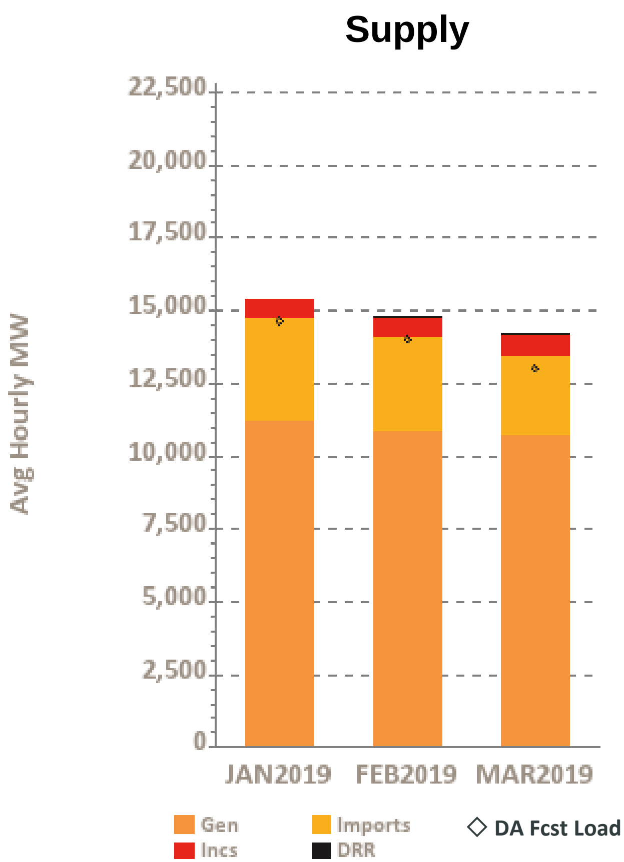
RT LMPs Average by Zone & Hub, March 2019

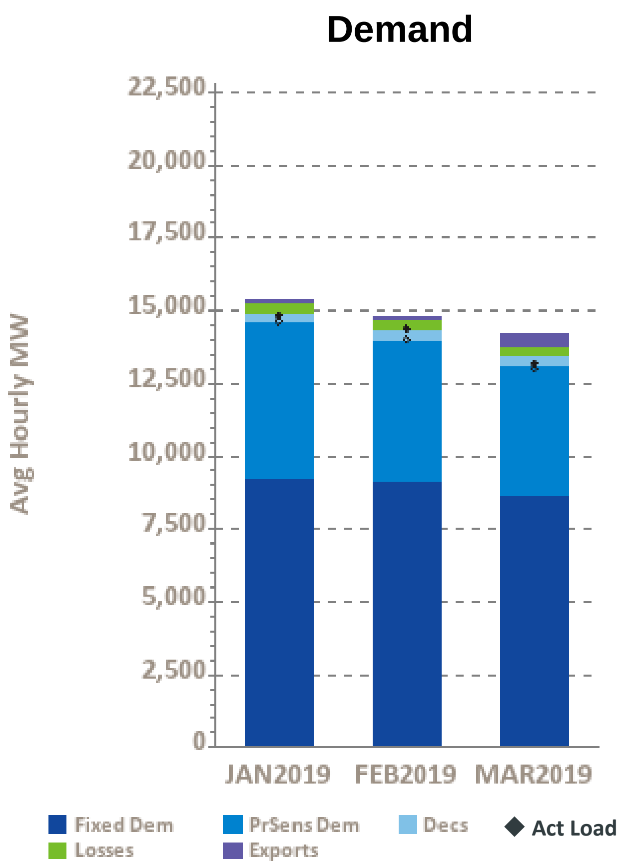


Definitions

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

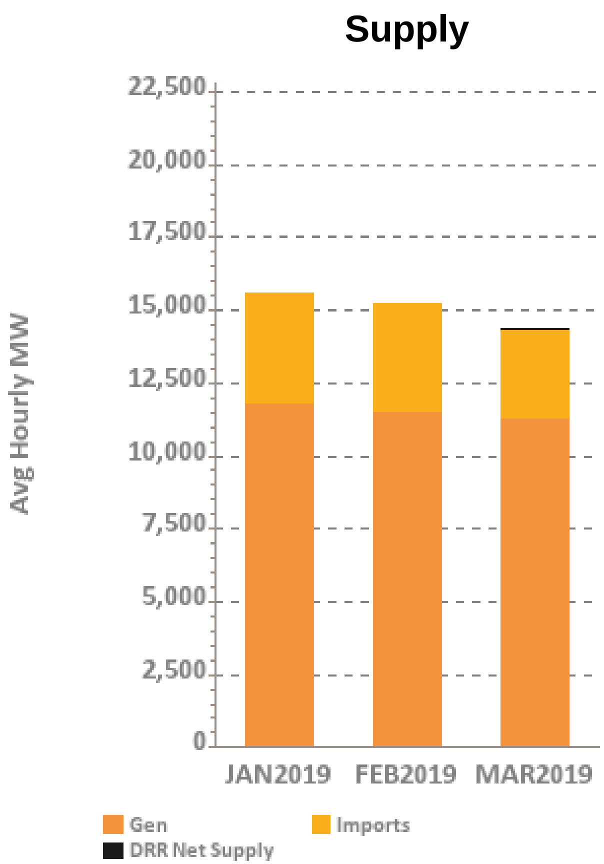


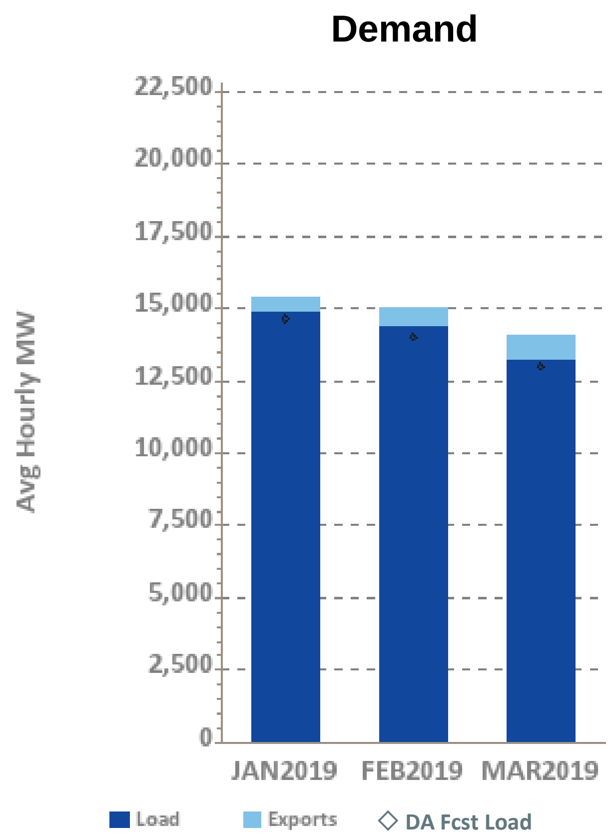


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

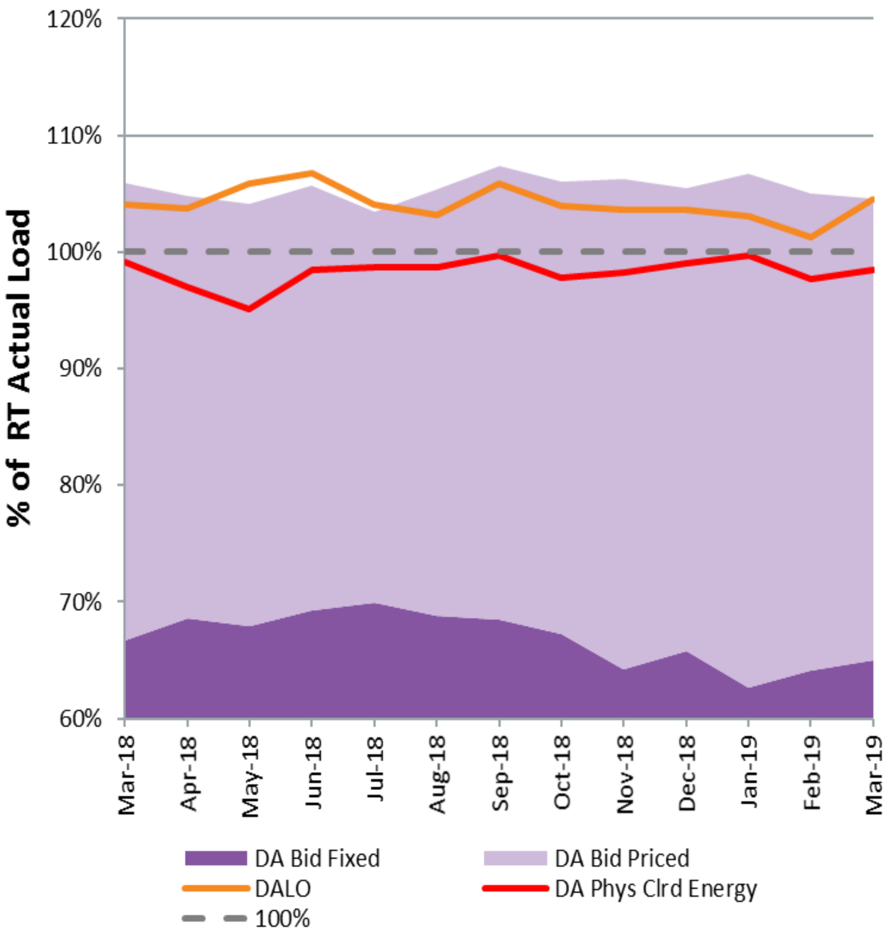
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

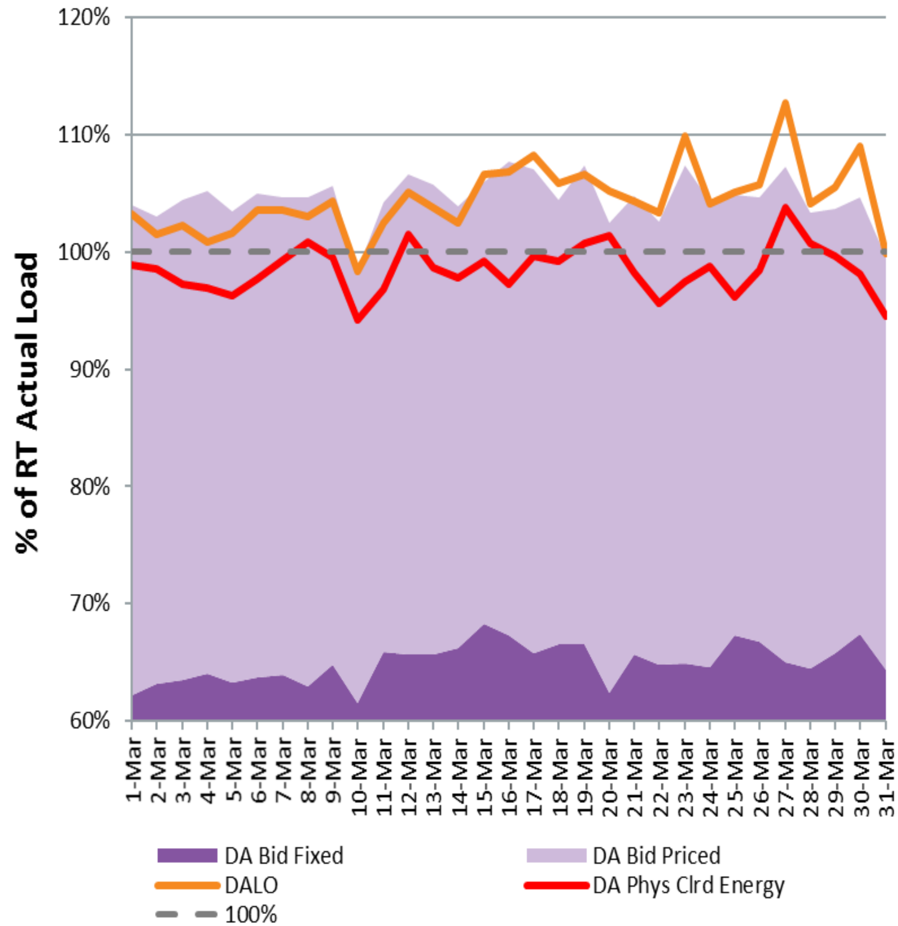
Components of RT Supply and Demand – Last Three Months





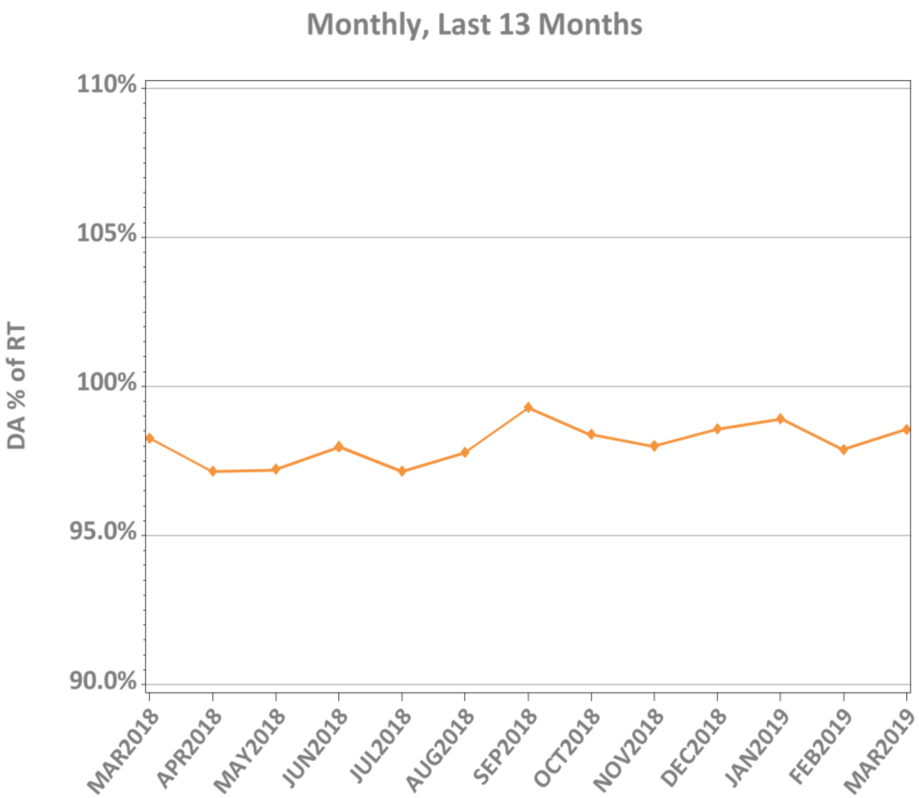
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

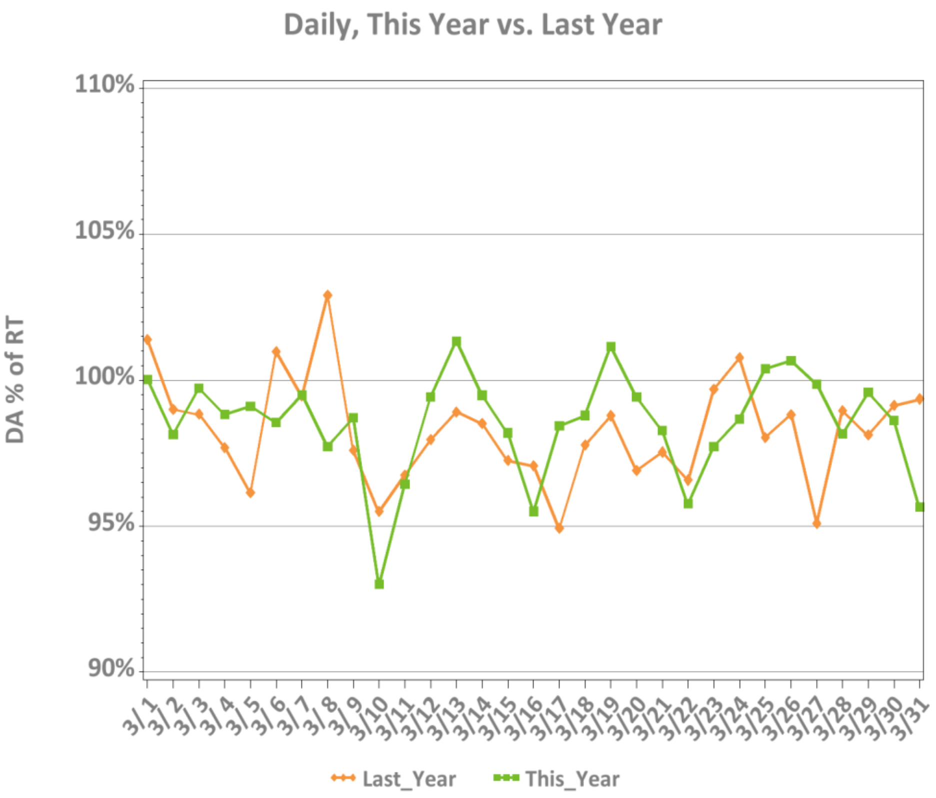




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

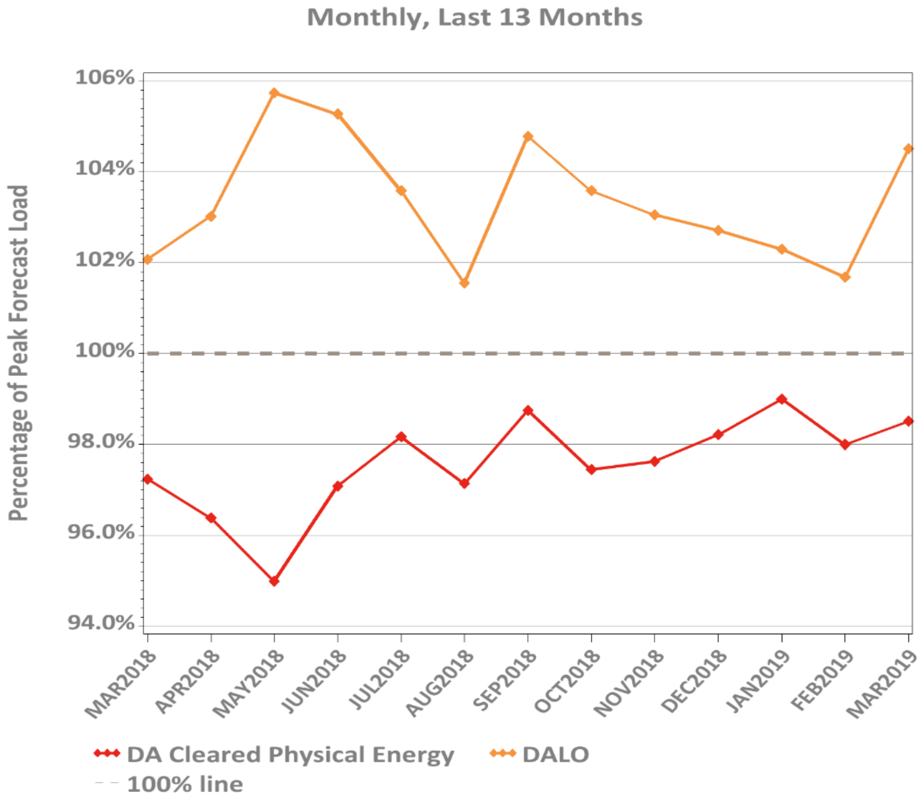
DA vs. RT Load Obligation: March, This Year vs. Last Year

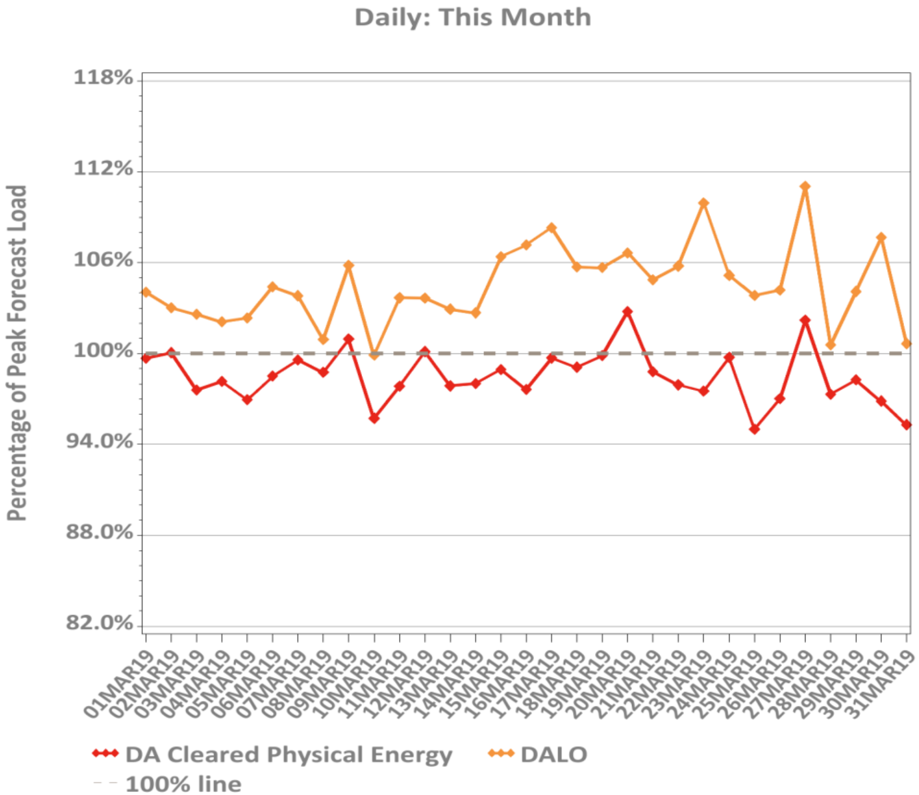




*Hourly average values

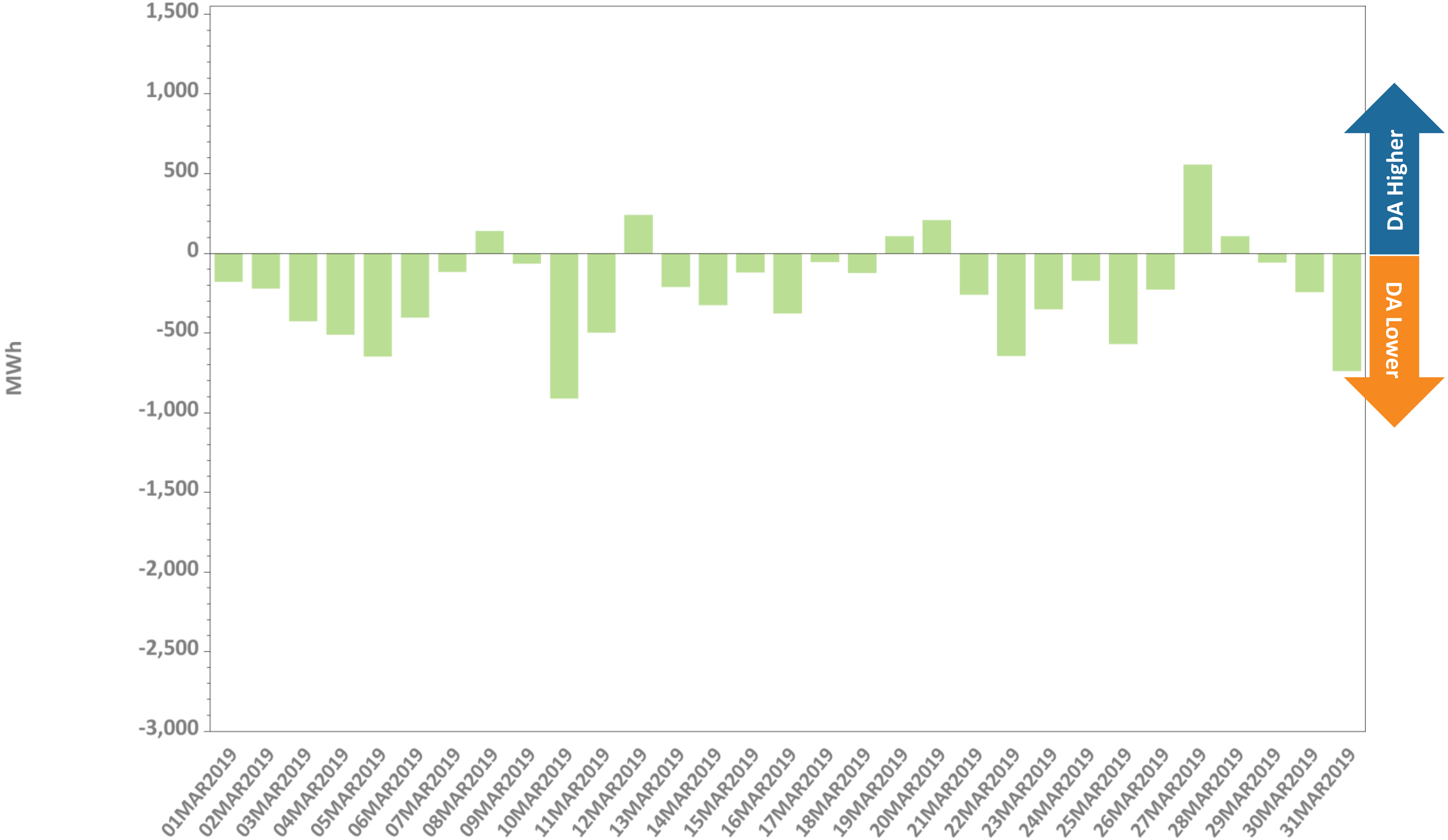
DA Volumes as % of Forecast in Peak Hour





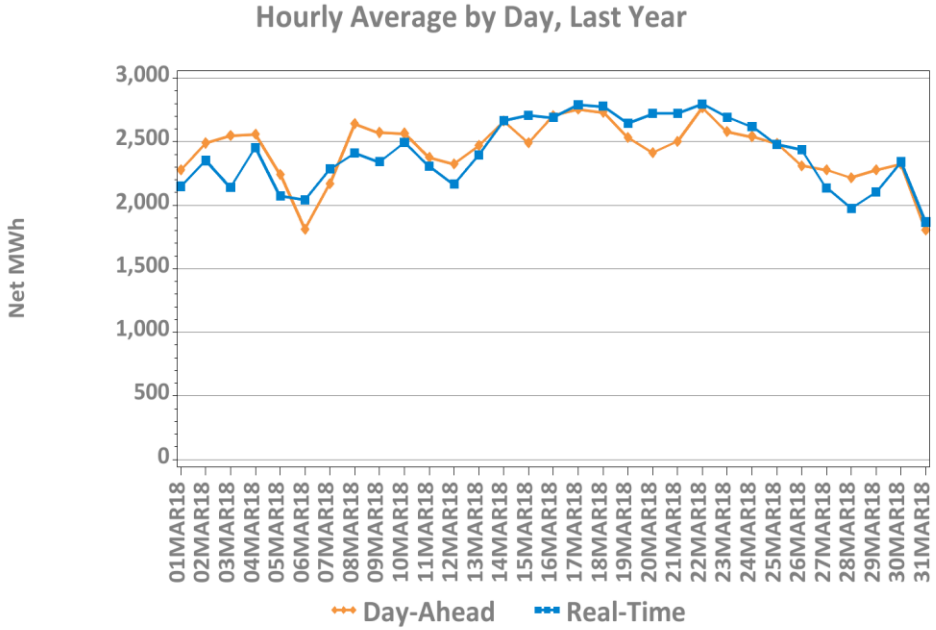
* There were no supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) during March.

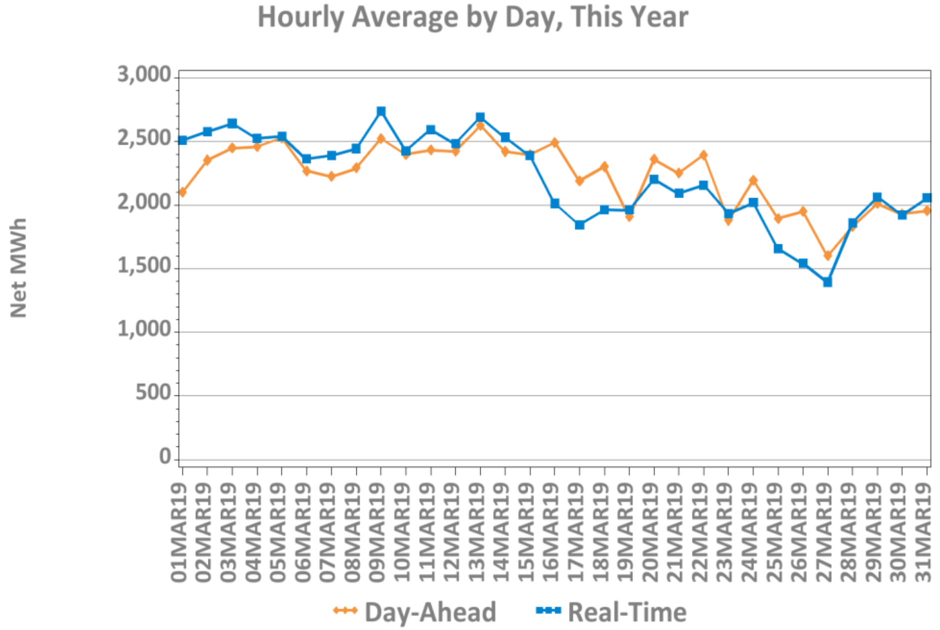
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

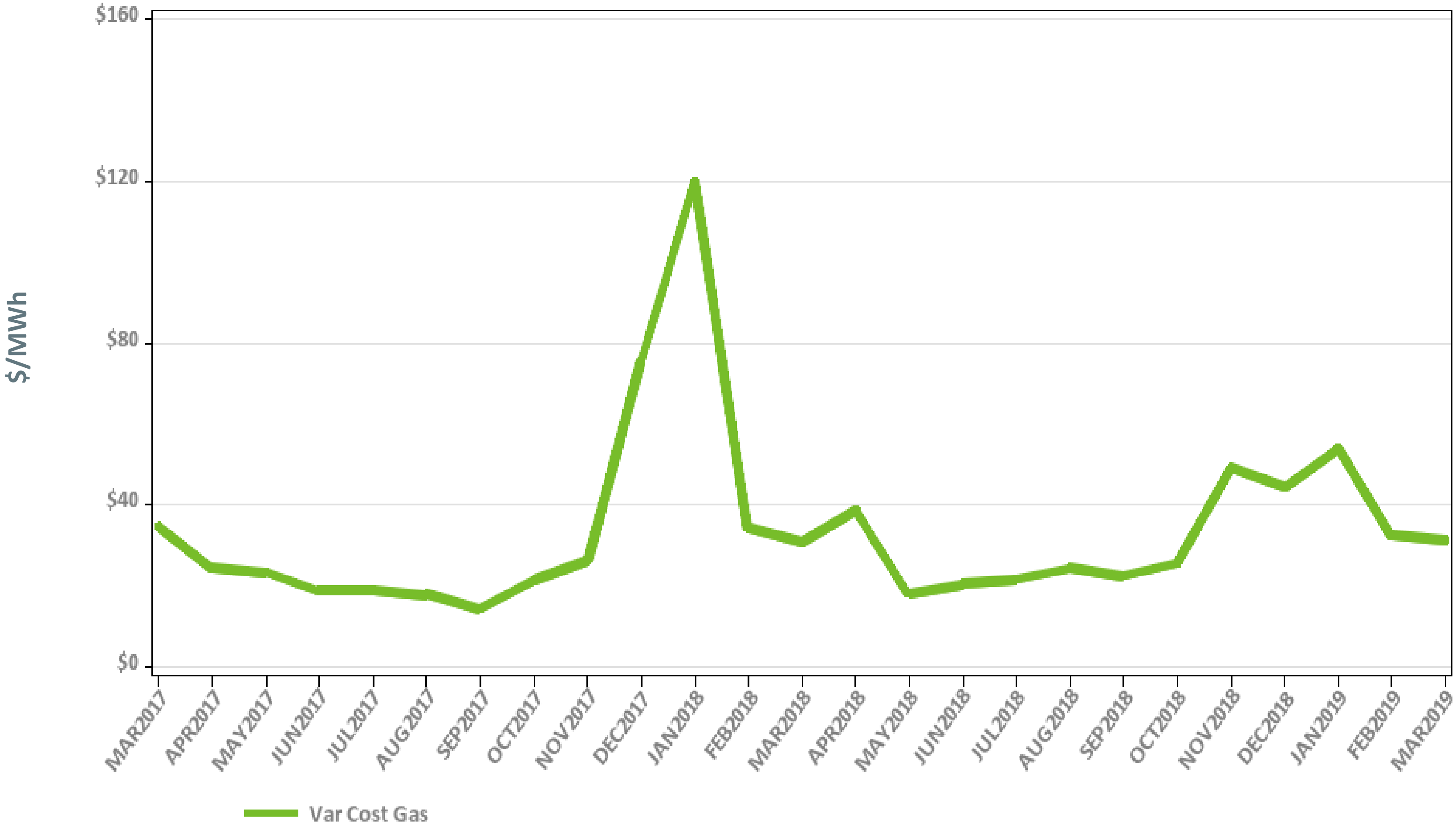
DA vs. RT Net Interchange March 2019 vs. March 2018





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

Variable Production Cost of Natural Gas: Monthly

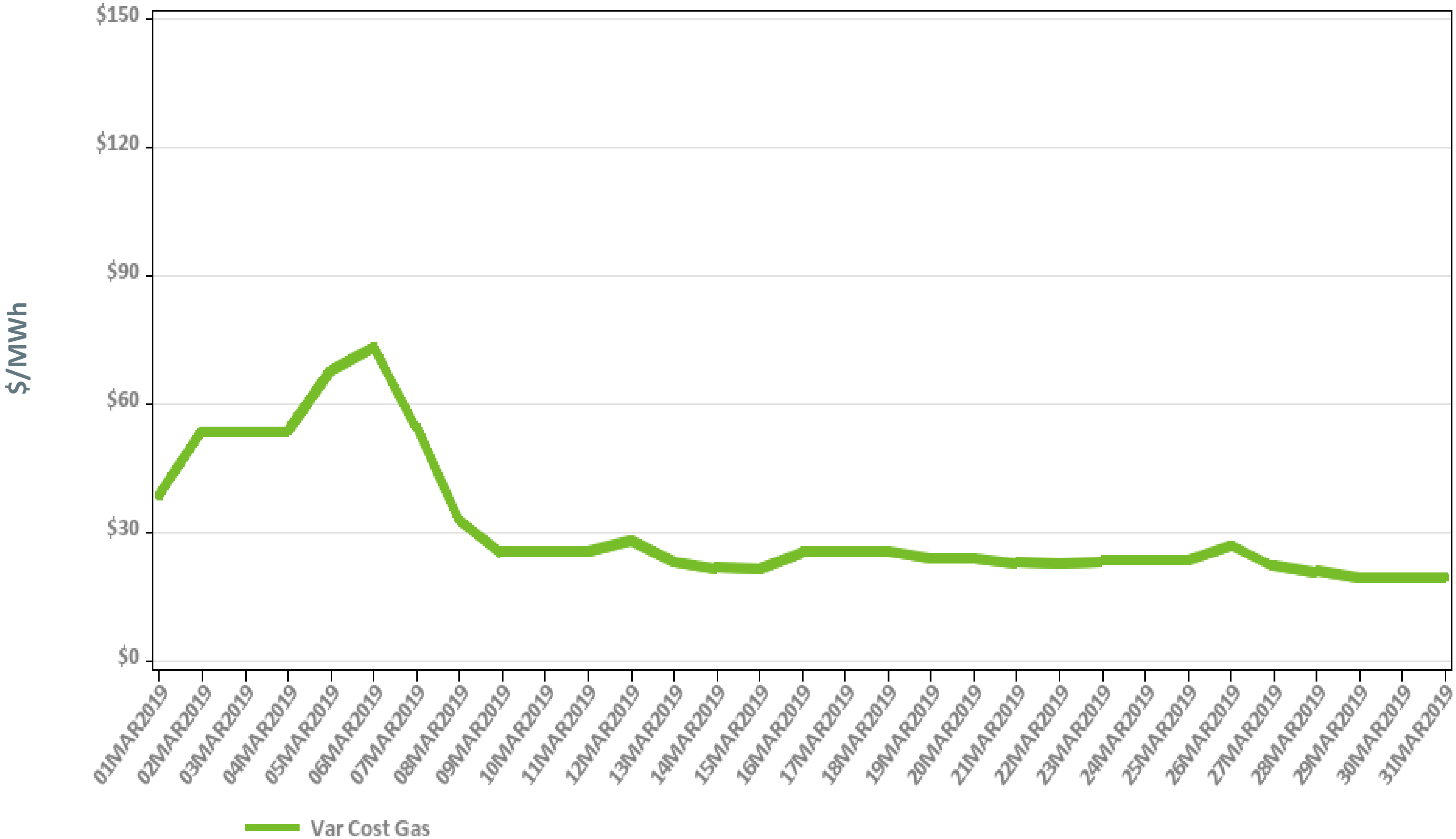


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

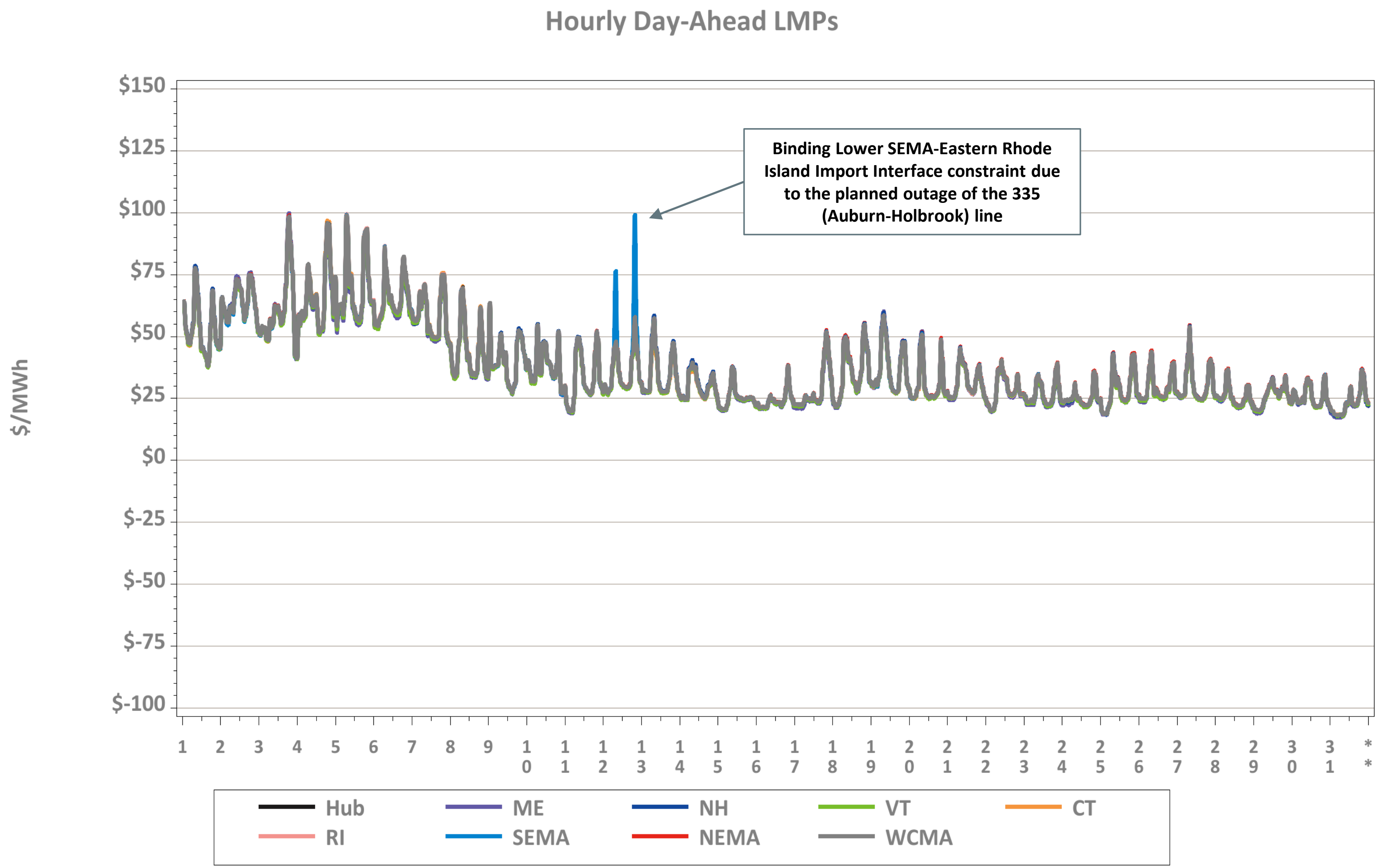


Underlying natural gas data furnished by:

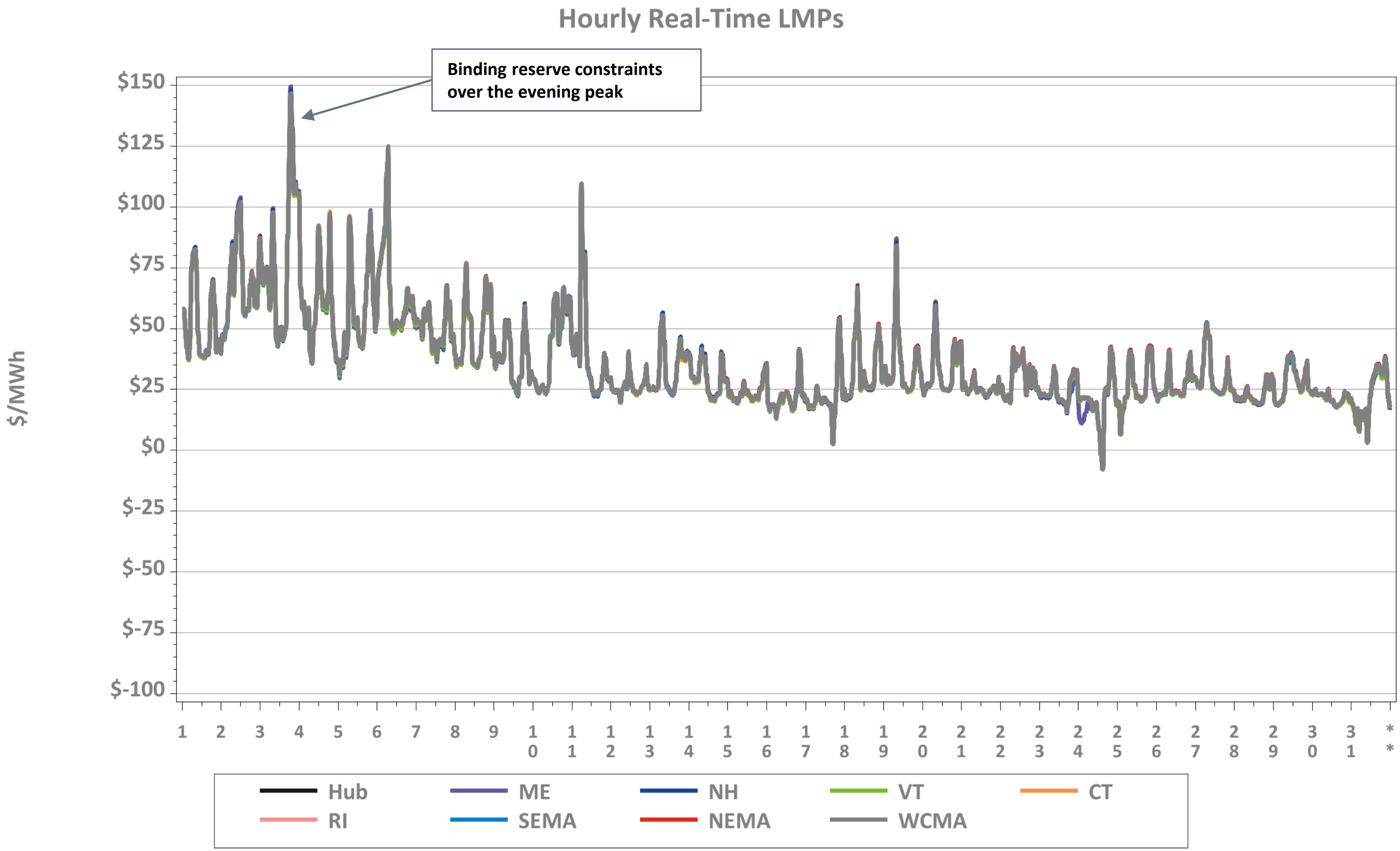
ICE Global markets in clear view

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

Hourly DA LMPs, March 1-31, 2019

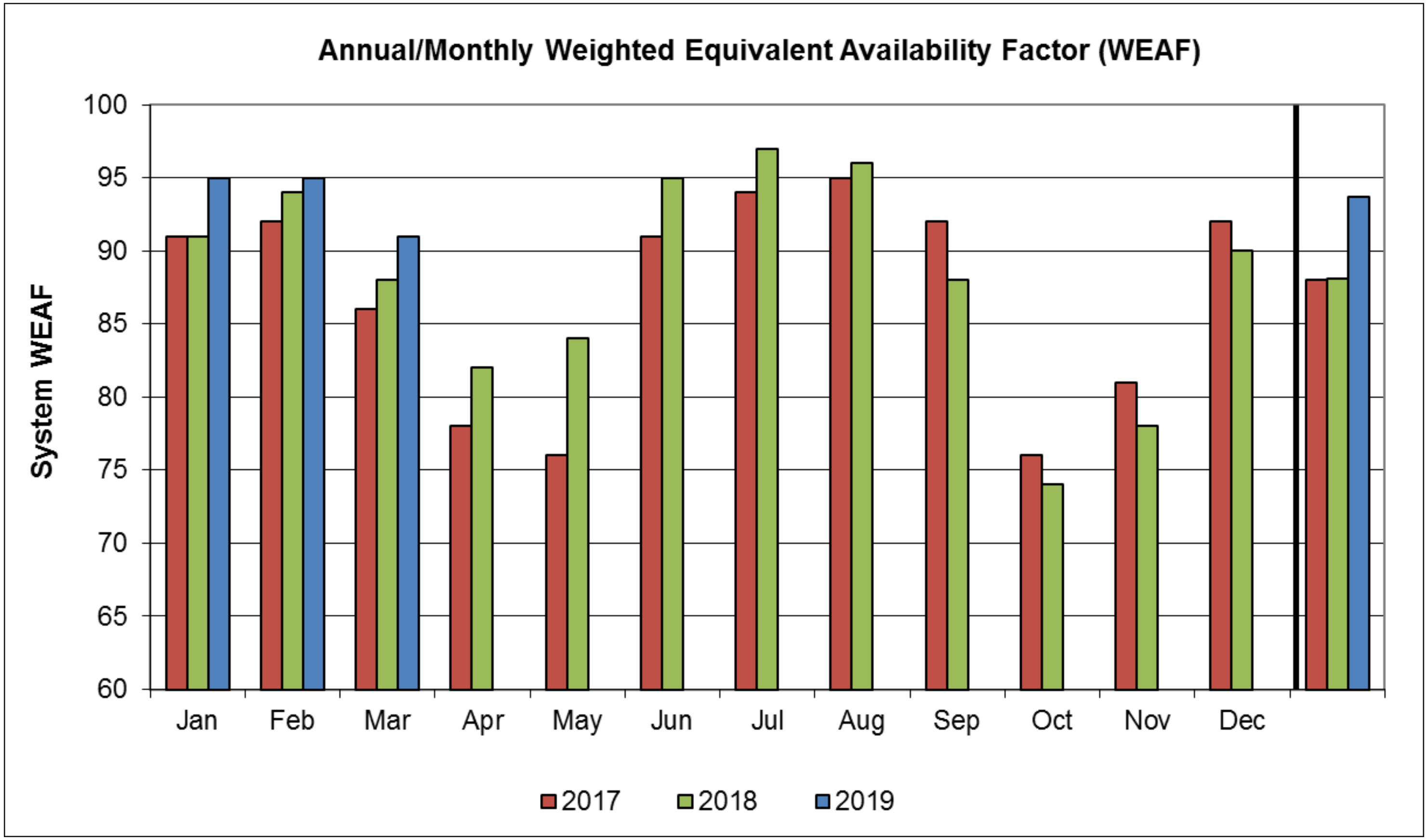


Hourly RT LMPs, March 1-31, 2019



- No Minimum Generation Emergencies were declared during March.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2019	95	95	91										94
2018	91	94	88	82	84	95	97	96	88	74	78	90	88
2017	91	92	86	78	76	91	94	95	92	76	81	92	88

Data as of 4/1/19

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for April 2019

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	100.2	169.7	0.0	269.9
NH	19.7	95.7	0.0	115.4
VT	25.2	119.7	0.0	144.9
CT	95.8	87.5	448.4	631.7
RI	16.7	237.8	0.0	254.5
SEMA	22.1	381.1	0.0	403.2
WCMA	40.3	358.9	53.0	452.2
NEMA	36.0	667.8	0.0	703.8
Total	**356.0**	**2,118.3**	**501.3**	**2,975.6**

*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

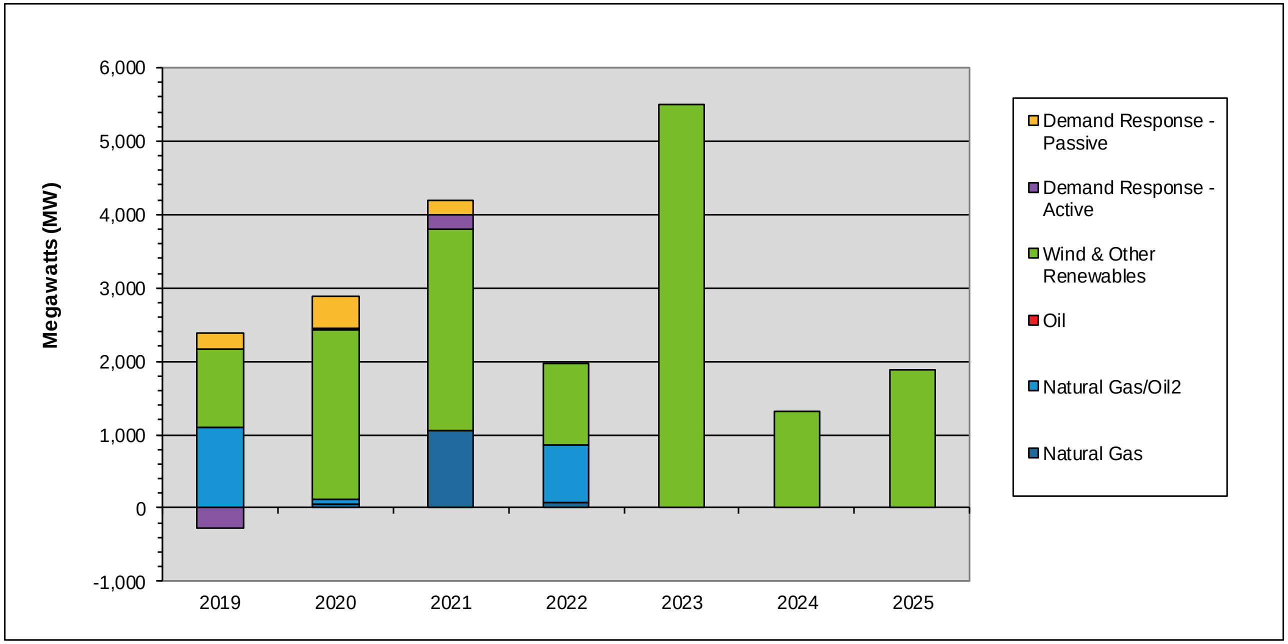
NEW GENERATION

New Generation Update
Based on Queue as of 4/1/19

- 30 projects totaling 1,149 MW applied for interconnection study since the last update
  - The projects consist of 27 new solar projects, two battery storage projects, and one wind project, with in-service dates ranging from 2019 to 2023
- Five projects withdrew and none went commercial, resulting in a net increase in new generation projects of 942 MW
- In total, 177 generation projects are currently being tracked by the ISO, totaling approximately 19,000 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total[1]
Demand Response - Passive	212	422	184	0	0	0	0	819	4.1
Demand Response - Active	-270	42	204	0	0	0	0	-23	-0.1
Wind & Other Renewables	1,079	2,306	2,750	1,116	5,496	1,312	1,884	15,943	80.3
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	1,097	62	0	778	0	0	0	1,937	9.8
Natural Gas	0	49	1,045	73	0	0	0	1,167	5.9
Totals	**2,119**	**2,882**	**4,183**	**1,967**	**5,496**	**1,312**	**1,884**	**19,843**	**100.0**

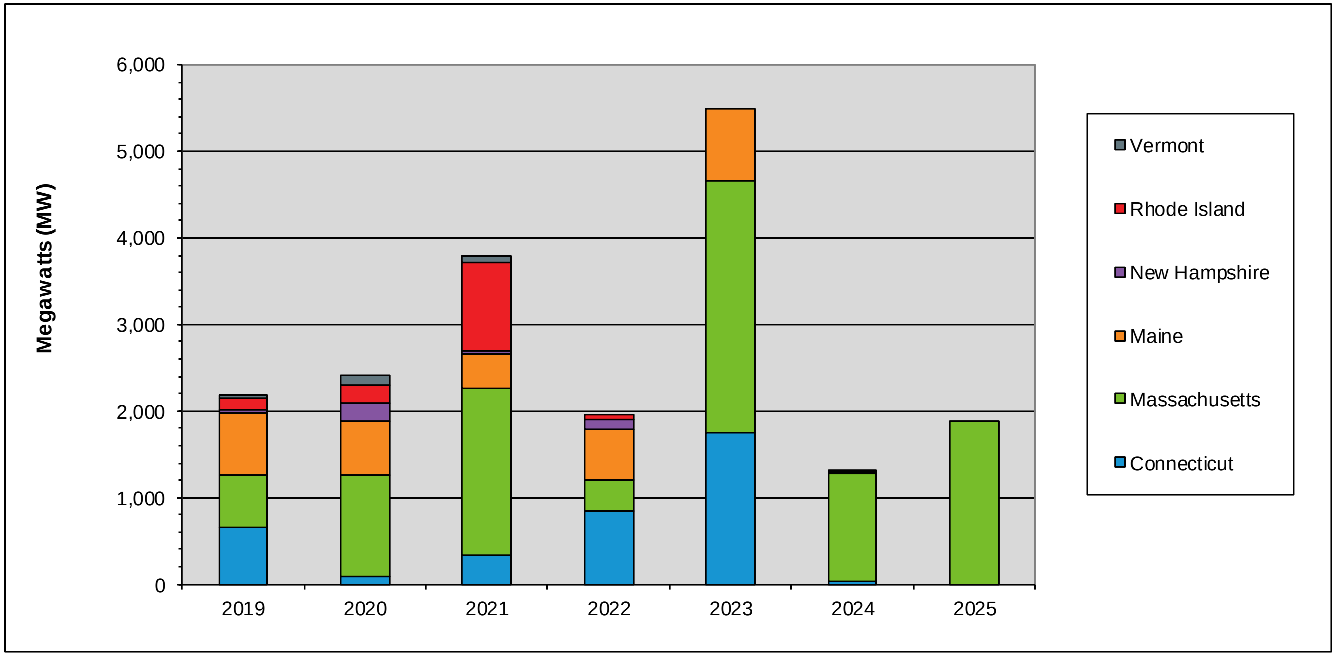
[1] **Sum may not equal 100% due to rounding**

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

- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total[1]
Vermont	33	127	70	0	0	0	0	230	1.2
Rhode Island	130	202	1,030	73	0	0	0	1,435	7.5
New Hampshire	28	210	28	105	0	20	0	391	2.1
Maine	730	612	415	595	828	20	0	3,200	16.8
Massachusetts	609	1,186	1,920	353	2,908	1,232	1,884	10,092	53.0
Connecticut	646	80	332	841	1,760	40	0	3,699	19.4
Totals	**2,176**	**2,417**	**3,795**	**1,967**	**5,496**	**1,312**	**1,884**	**19,047**	**100.0**

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

ISO-NE PUBLIC

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	2	39	0	0	2	39
Hydro	3	74	0	0	3	74
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	1,230	0	0	7	1,230
Natural Gas/Oil	8	1,937	3	1,051	5	886
Oil	0	0	0	0	0	0
Solar	118	3,319	2	51	116	3,268
Wind	26	11,239	2	35	24	11,204
Battery storage	13	1,209	0	0	13	1,209
Total	177	19,047	7	1,137	170	17,910

- 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	5	123	0	0	5	123
Intermediate	5	1,657	1	510	4	1,147
Peaker	141	6,028	4	592	137	5,436
Wind Turbine	26	11,239	2	35	24	11,204
Total	177	19,047	7	1,137	170	17,910

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

New Generation Projection

By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/wood waste	2	39	1	37	0	0	1	2	0	0
Hydro	3	74	2	8	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	7	1,230	2	78	3	1,146	2	6	0	0
Natural Gas/Oil	8	1,937	0	0	2	511	6	1,426	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	118	3,319	0	0	0	0	118	3,319	0	0
Wind	26	11,239	0	0	0	0	0	0	26	11,239
Battery storage	13	1,209	0	0	0	0	13	1,209	0	0
Total	177	19,047	5	123	5	1,657	141	6,028	26	11,239

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

FORWARD CAPACITY MARKET

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	367.227	-10.298	464.715	97.488	460.55	-4.165	459.928	-0.622	457.966	-1.962	493.5	35.534
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834	2,363.789	-0.16	2,527.244	163.46	2,529.014	1.77	2594.08	65.066
Demand Total		**2,746.156**	**2,734.01**	**-12.146**	**2,828.664**	**94.654**	**2,824.339**	**-4.325**	**2,987.172**	**162.83**	**2,986.98**	**-0.192**	**3,087.58**	**100.6**
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272	30,103.684	55.286	30,093.142	-10.54	30,081.64	-11.502	30,146.76	65.115
	Intermittent	850.143	893.189	43.046	904.311	11.122	831.251	-73.06	798.958	-32.293	800.387	1.429	733.668	-66.719
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**	**30,934.935**	**-17.774**	**30,892.1**	**-42.84**	**30,882.027**	**-10.073**	**30,880.42**	**-1.604**
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**	**1,451**	**0**	**1,451**	**0**	**1,459**	**8**	1,428	-31
****Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**	**35,210.274**	**-22.099**	**35,330.272**	**120.00**	**35,328.007**	**-2.265**	**35,396**	**67.996**
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**	**33,407**	**-348**	**33,407**	**0**	**33,390**	**-17**	33,390	0

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 11

Resource Type	Resource Type		FCA	ARA 1		ARA 2		ARA 3	
			*CSO	CSO	Change	CSO	Change	CSO	Change
			MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*		419.928	441.221	21.293				
	Passive Demand		2,791.02	2,835.354	44.334				
Demand Total			**3,210.95**	**3,276.575**	**65.625**				
Generator		*Non-Intermittent*	30,494.80	30,064.23	-430.569				
		Intermittent	894.217	823.796	-70.421				
Generator Total			**31,389.02**	**30,888.03**	**-500.993**				
Import Total			**1,235.40**	**1,622.037**	**386.637**				
****Grand Total**			**35,835.37**	**35,786.64**	**-48.731**				
Net ICR (NICR)			**34,075**	**33,660**	**-415**				

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 12

Resource Type	Resource Type		FCA	ARA 1		ARA 2		ARA 3	
			*CSO	CSO	Change	CSO	Change	CSO	Change
			MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*		624.445						
	Passive Demand		2,975.36						
Demand Total			**3,599.81**						
Generator		*Non-Intermittent*	29,130.75						
		Intermittent	880.317						
Generator Total			**30,011.07**						
Import Total			**1217**						
****Grand Total**			**34,827.88**						
Net ICR (NICR)			**33,725**						

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 13

Resource Type	Resource Type		FCA	ARA 1		ARA 2		ARA 3	
			*CSO	CSO	Change	CSO	Change	CSO	Change
			MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*		685.554						
	Passive Demand		3,354.69						
Demand Total			**4,040.244**						
Generator		*Non-Intermittent*	28,586.498						
		Intermittent	1,024.792						
Generator Total			**2,9611.29**						
Import Total			**1,187.69**						
****Grand Total**			**34,839.224**						
Net ICR (NICR)			**33,750**						

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1,246.40	603.675	1,850.07
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1,768.39	184.99	1,953.38
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1,726.55	98.227	1,824.78
	Passive	861.602	211.261	1,072.86
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1,794.20	257.341	2,051.54
	Passive	1,040.11	257.793	1,297.91
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2,062.20	41.945	2,104.14
	Passive	1,264.64	221.072	1,485.71
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1,935.41	66.104	2,001.51
	Passive	1,395.89	247.449	1,643.33
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1,116.47	0.23	1,116.70
	Passive	1,386.56	244.775	1,631.34
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1,066.59	13.486	1,080.08
	Passive	1,619.15	341.37	1,960.52
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1,870.55	285.602	2,156.15
	Grand Total	2436.415	366.996	2803.411
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	2375.422	370.734	2746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2571.361	639.586	3210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3085.734	514.072	3599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3386.703	653.541	4040.244

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

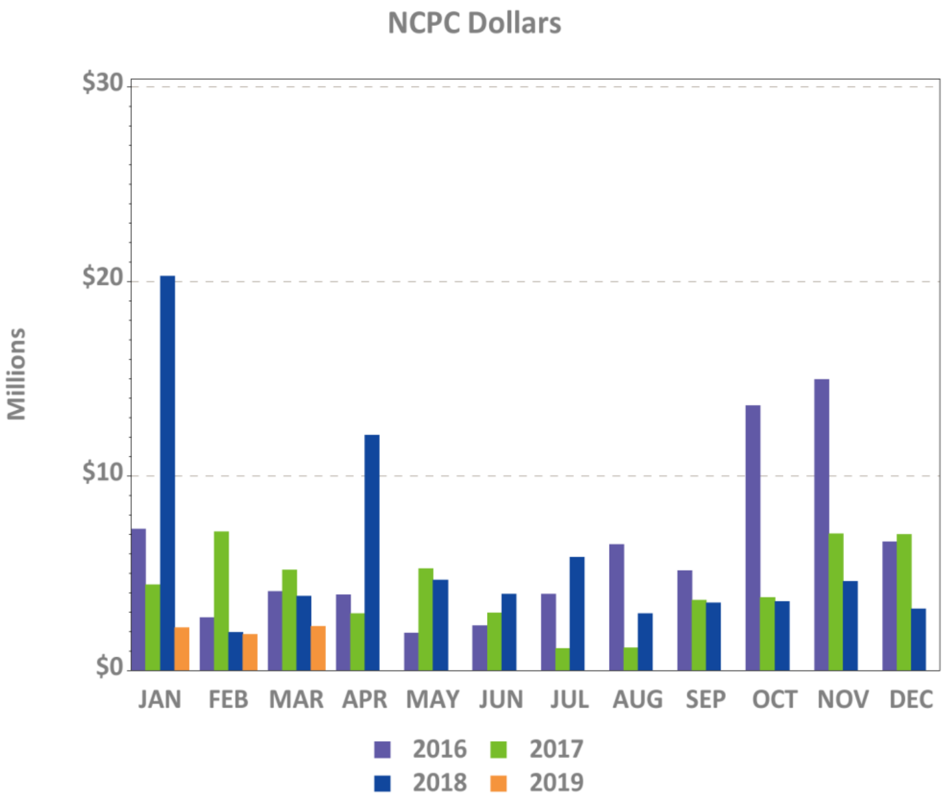
Definitions

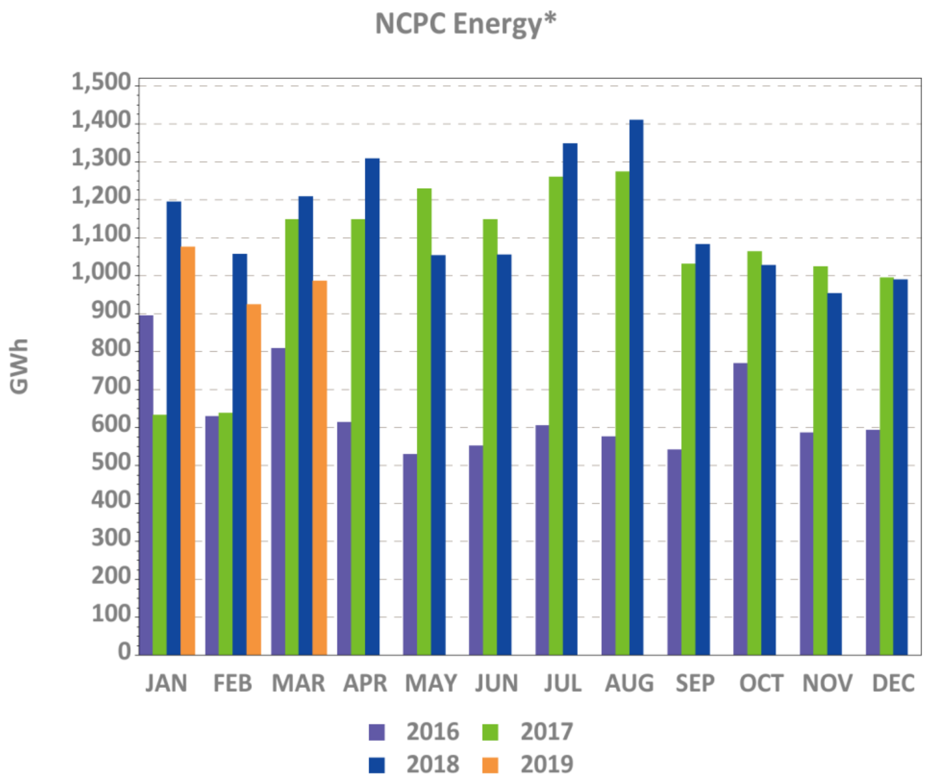
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

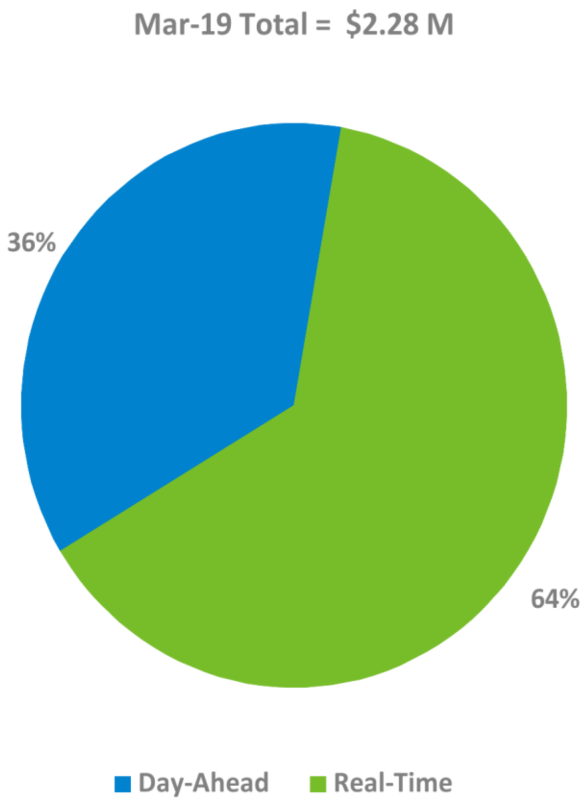
Year-Over-Year Total NCPC Dollars and Energy

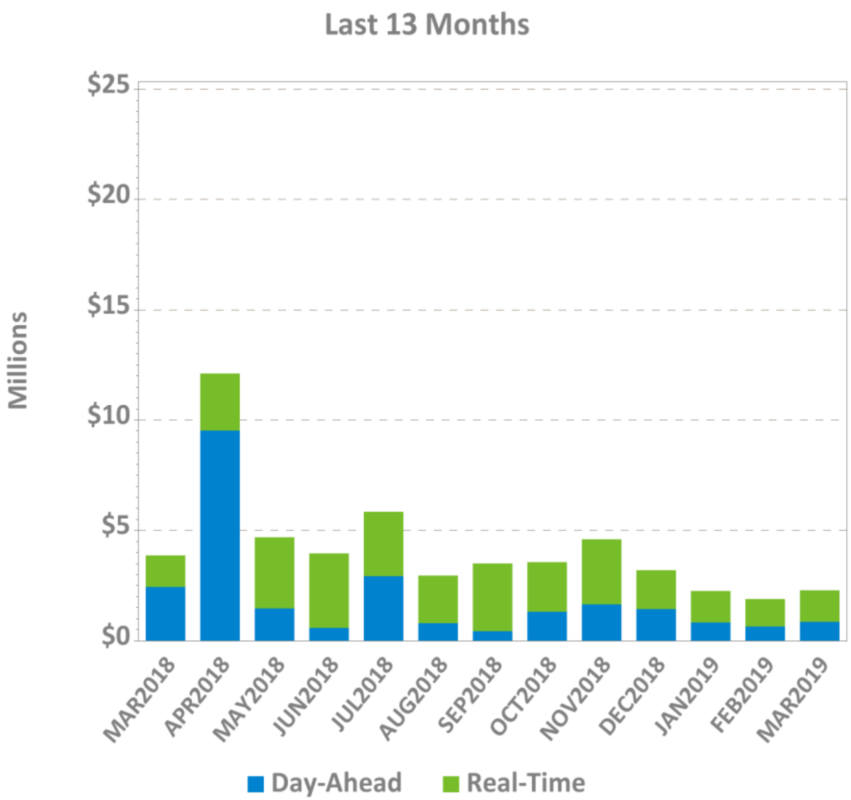




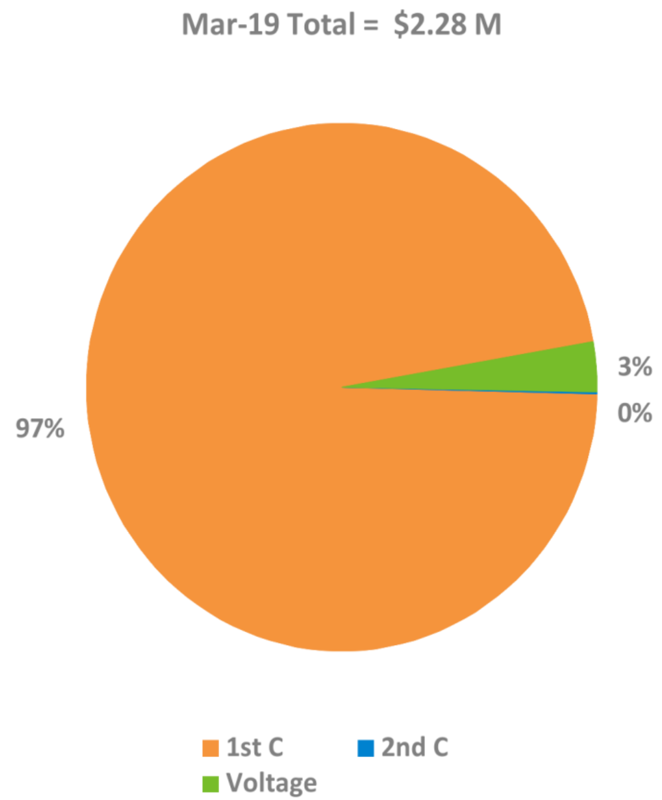
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

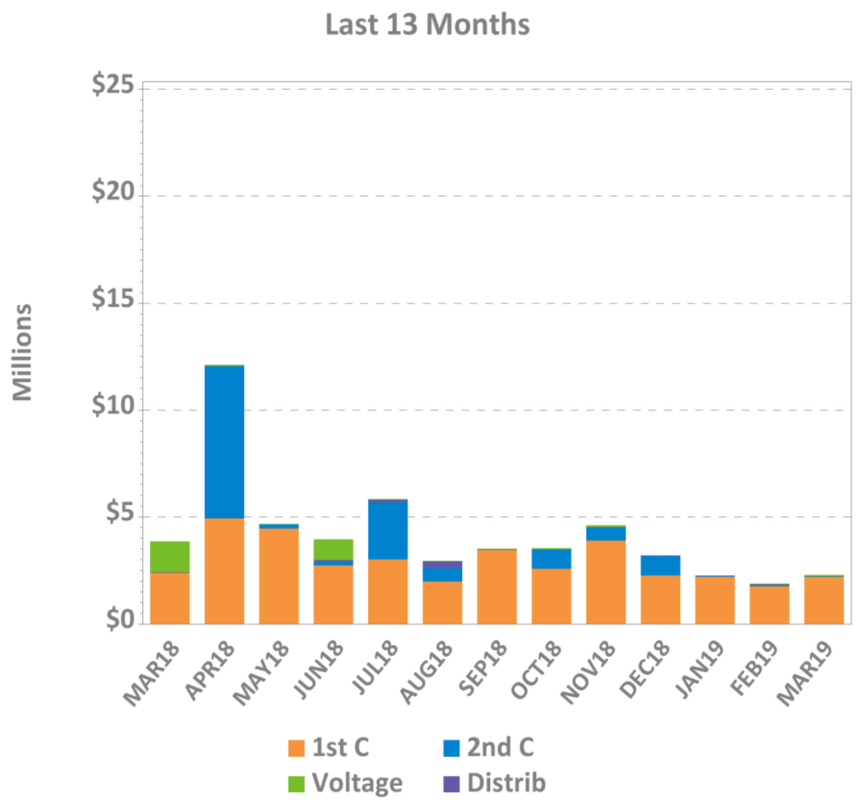
DA and RT NCPC Charges





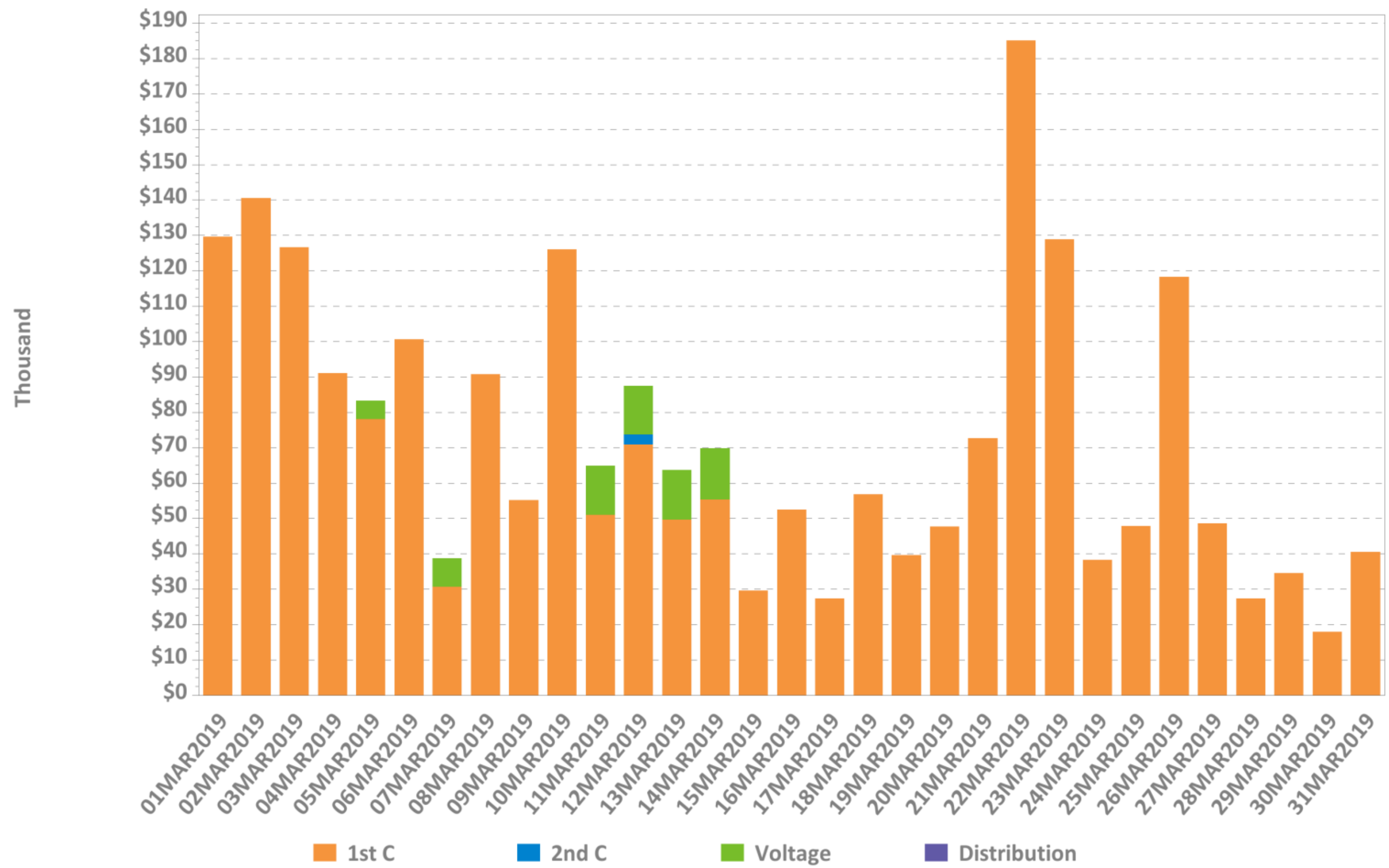
NCPC Charges by Type



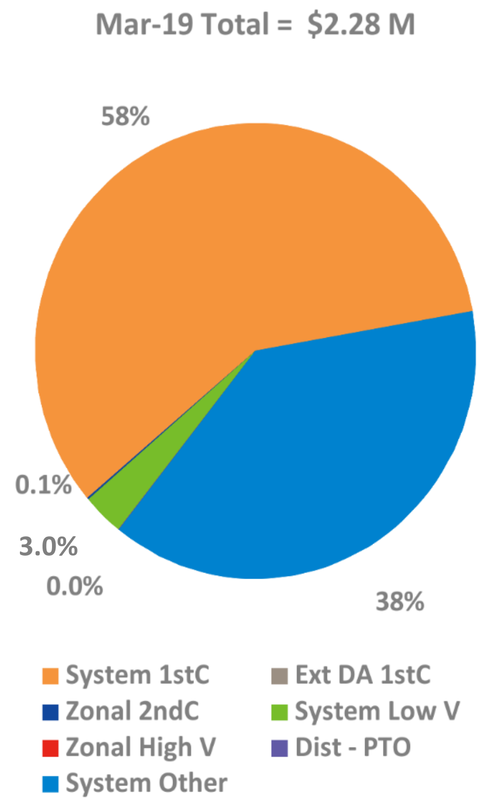


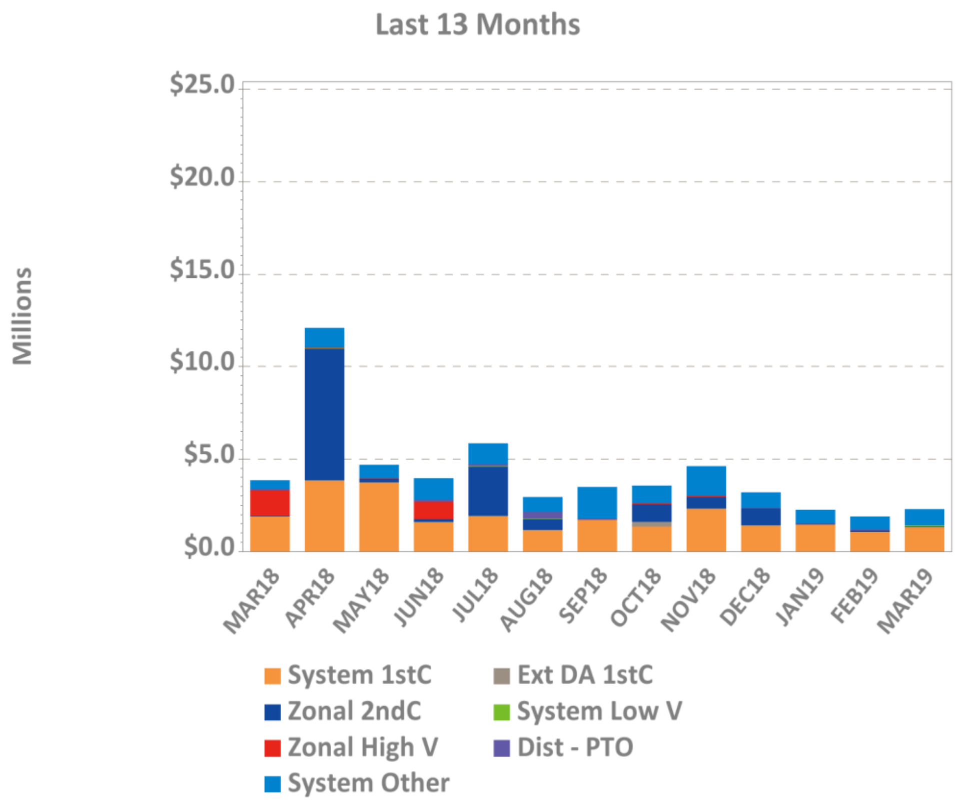
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



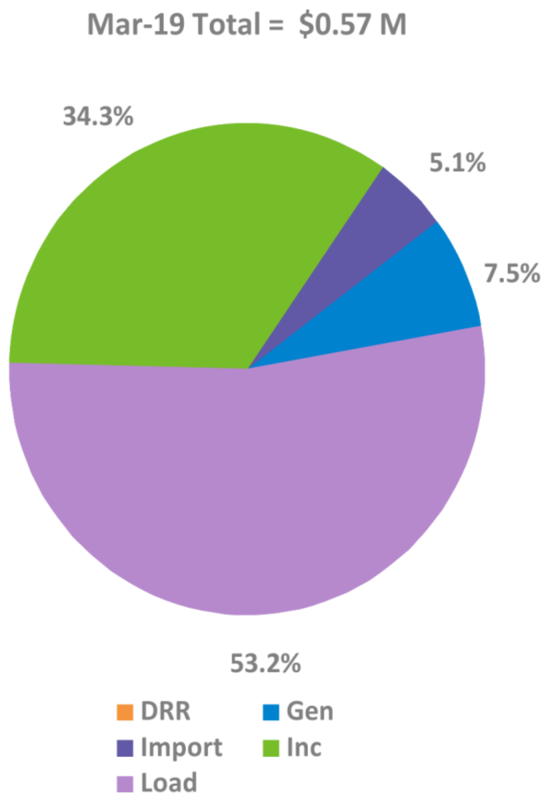
NCPC Charges by Allocation

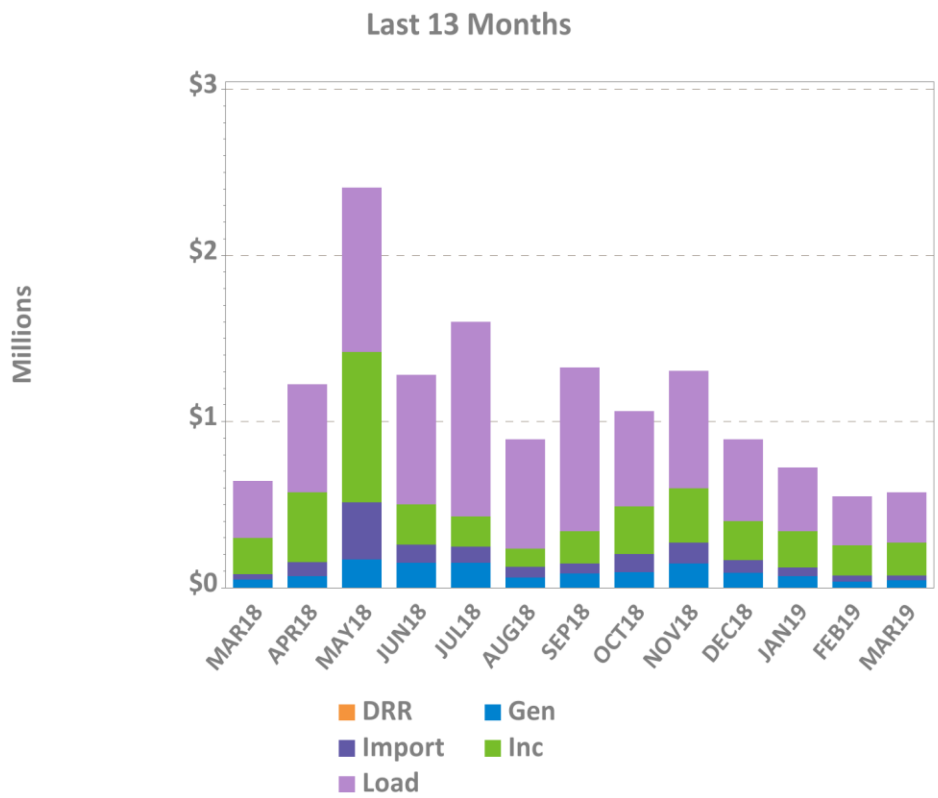




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

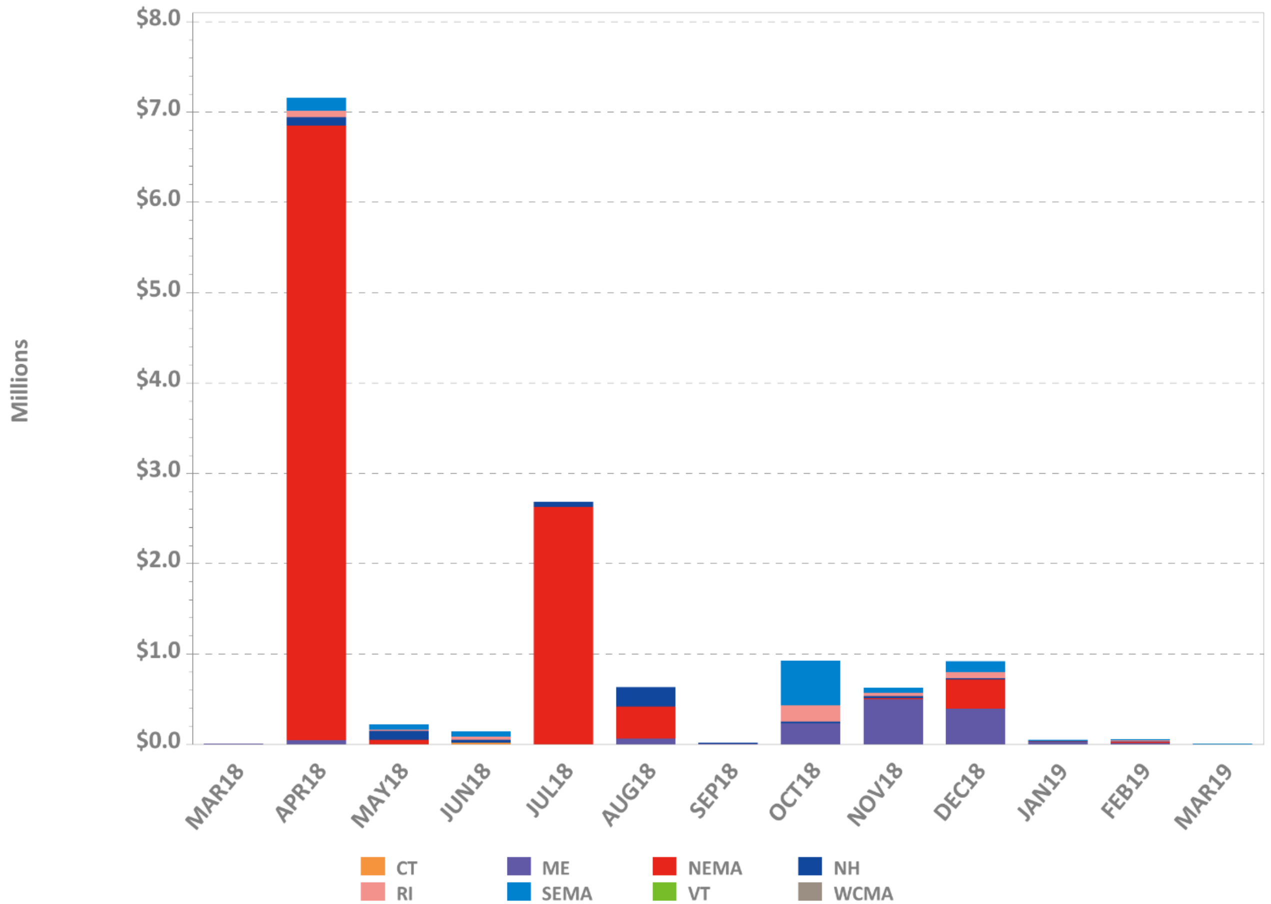
RT First Contingency Charges by Deviation Type





DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

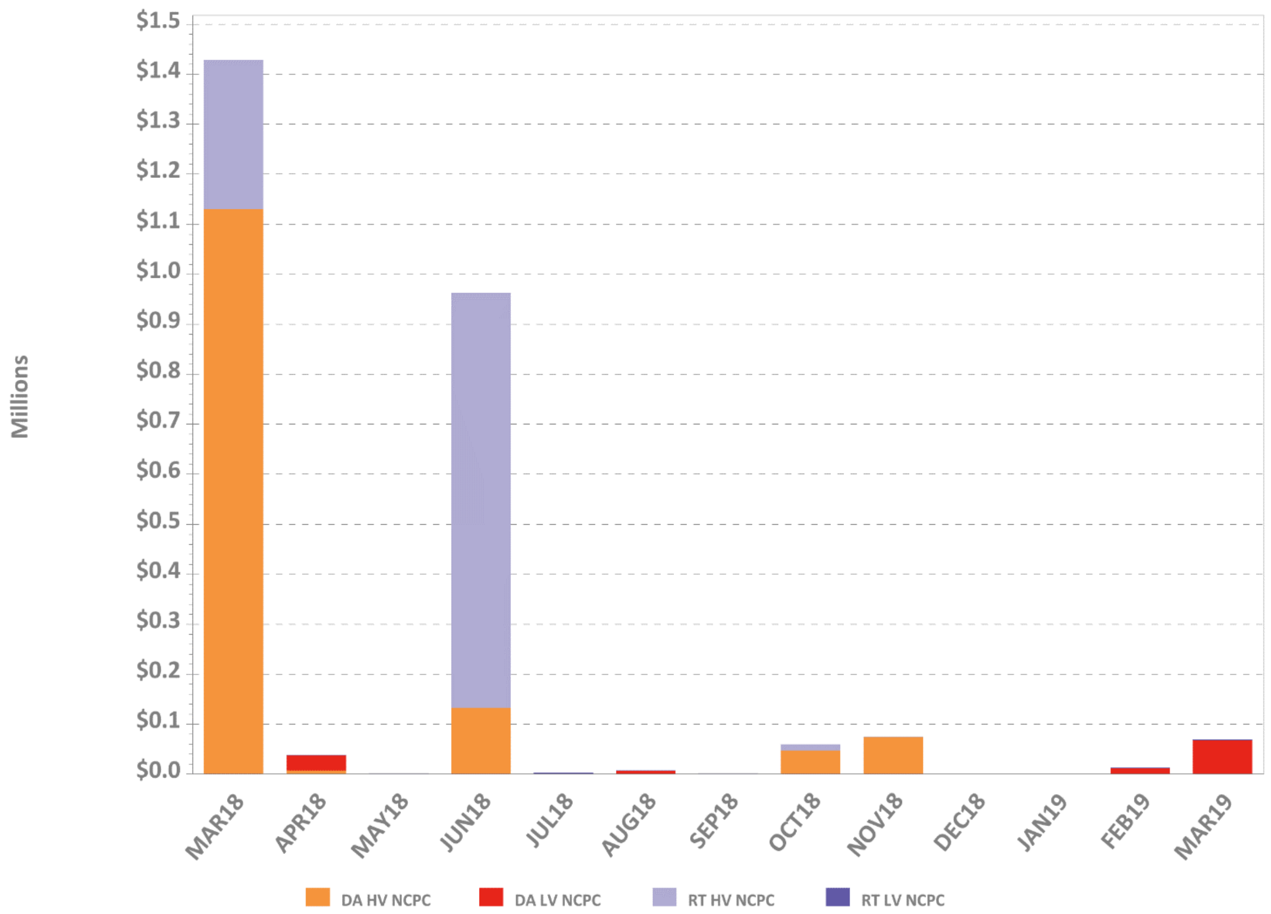
LSCPR Charges by Reliability Region



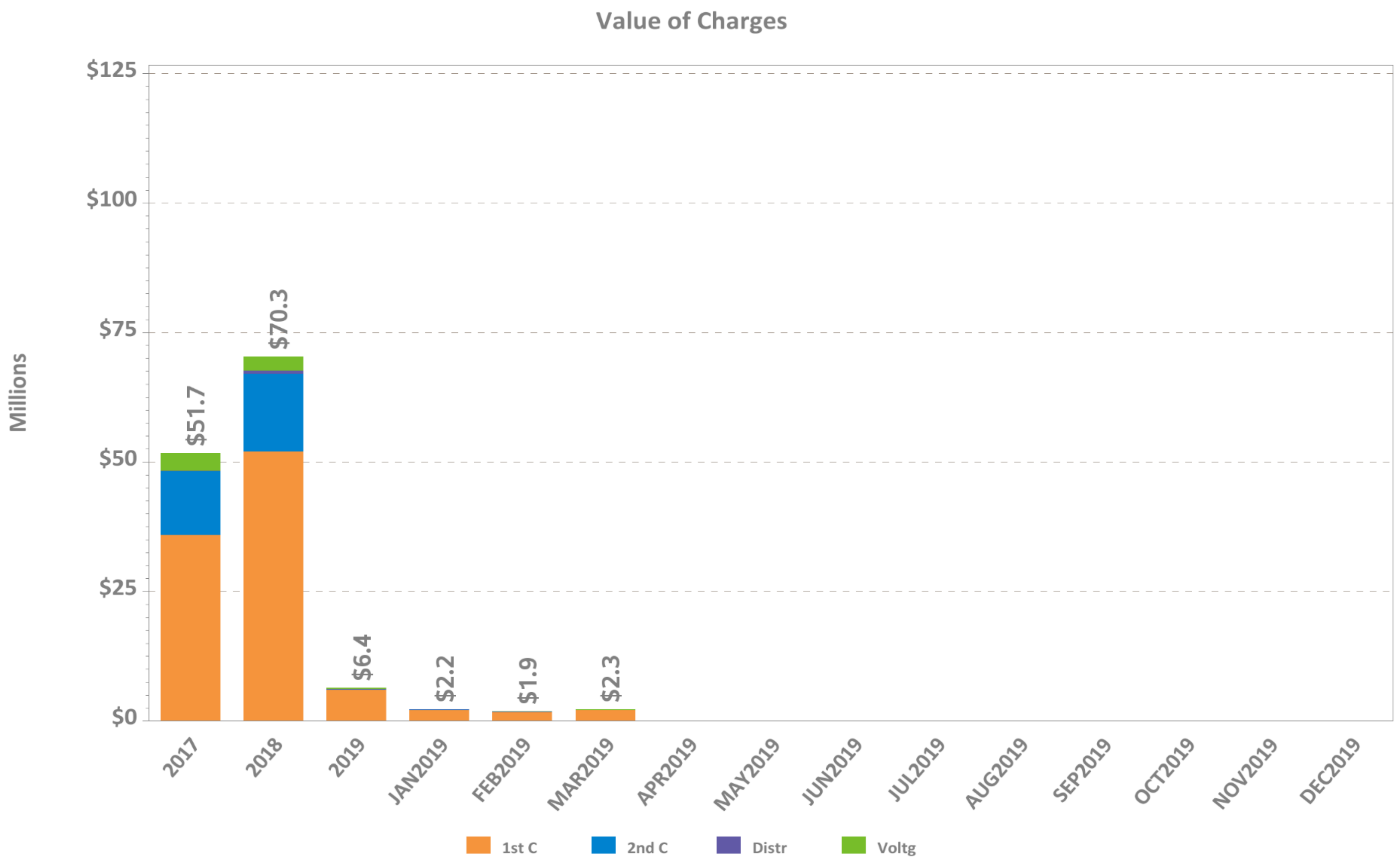
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

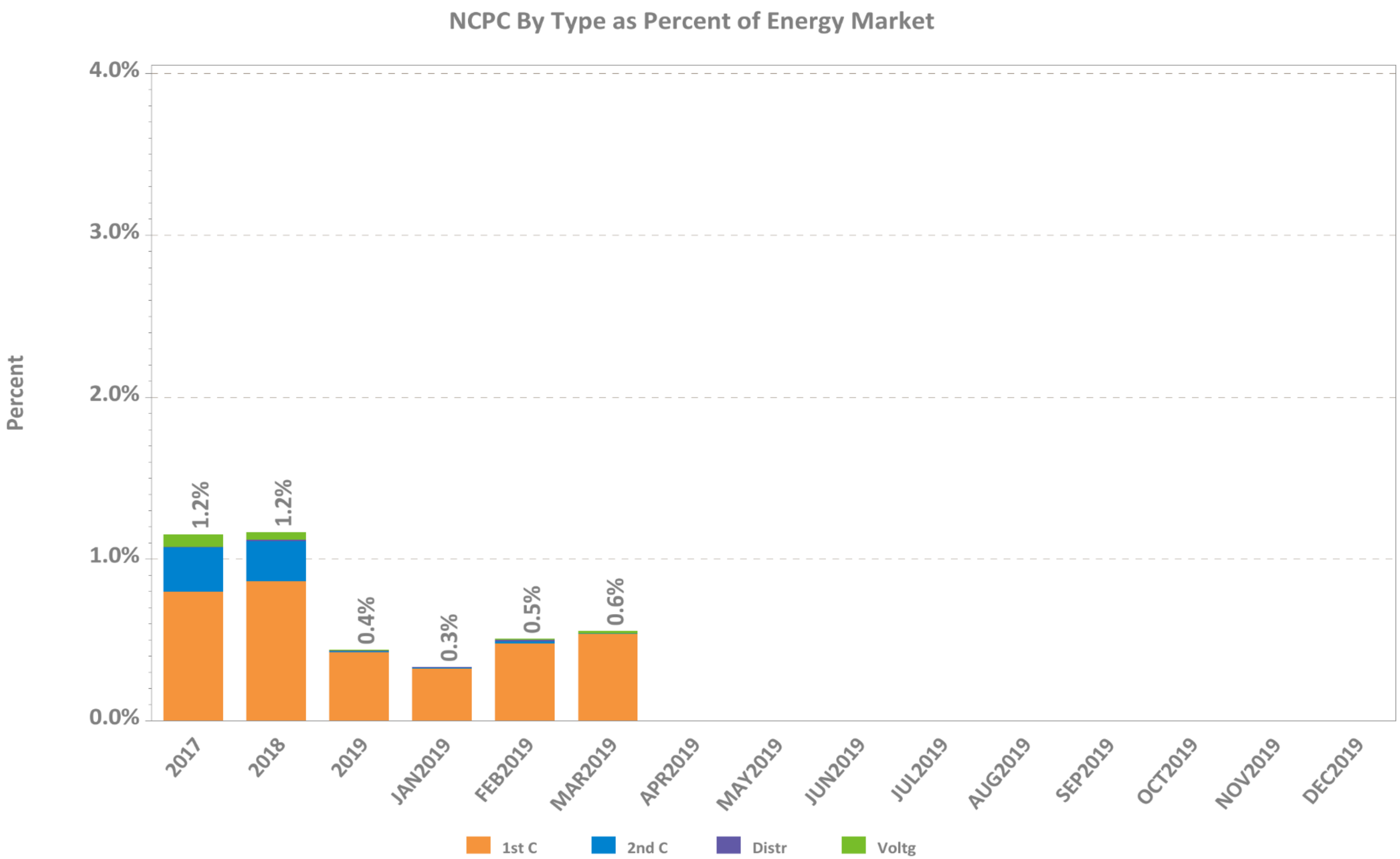
NCPC Charges for Voltage Support and High Voltage Control



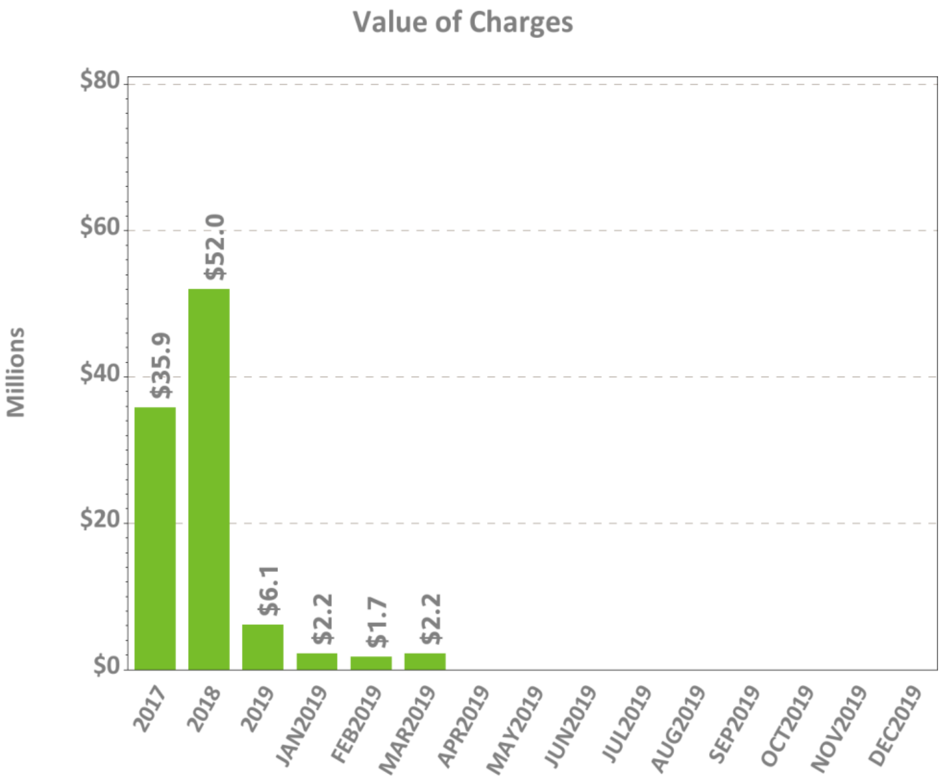
NCPC Charges by Type

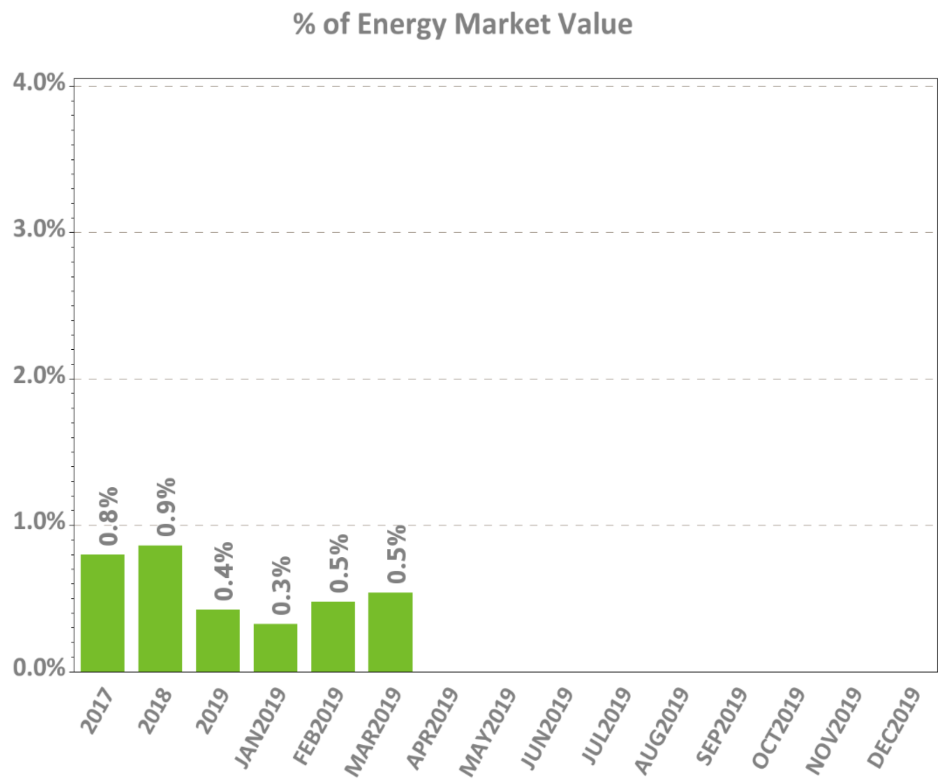


NCPC Charges as Percent of Energy Market



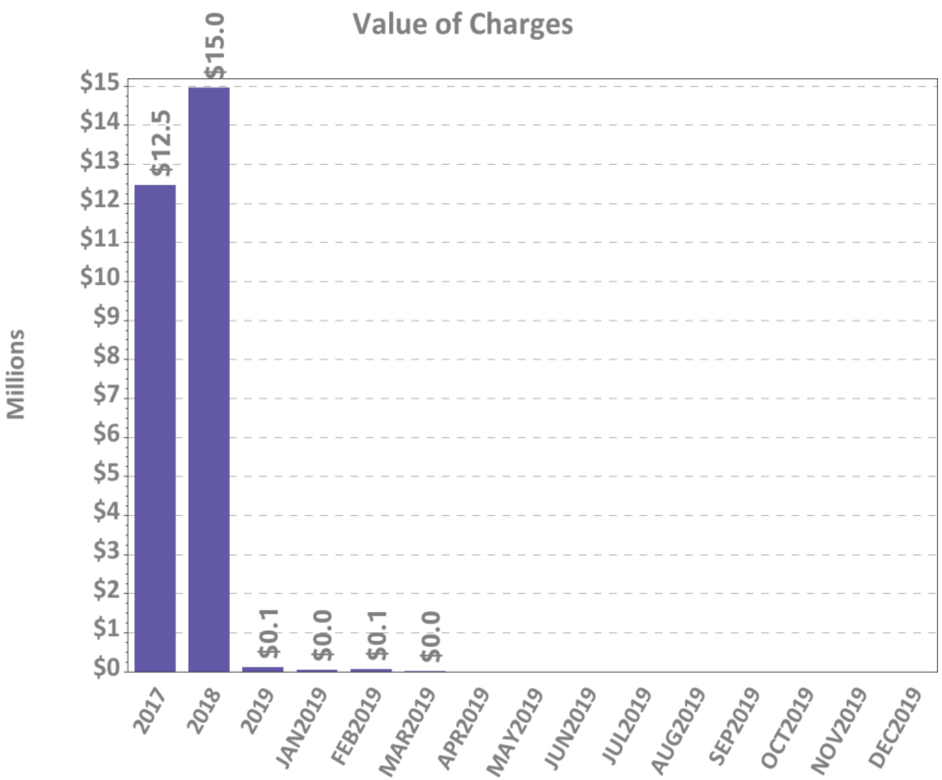
First Contingency NCPC Charges

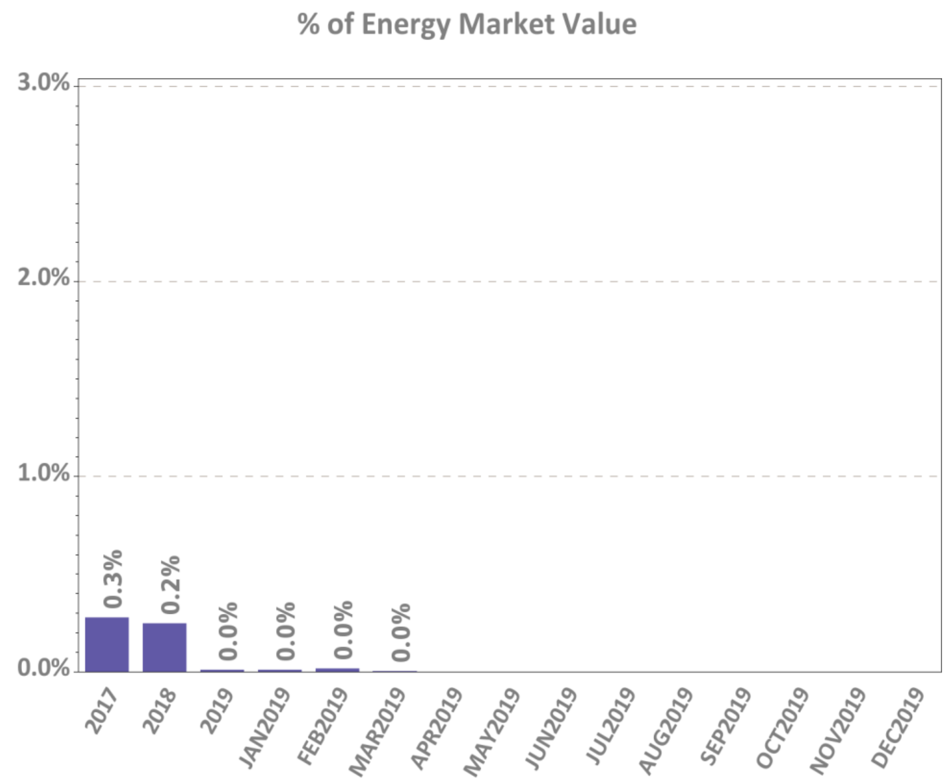




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

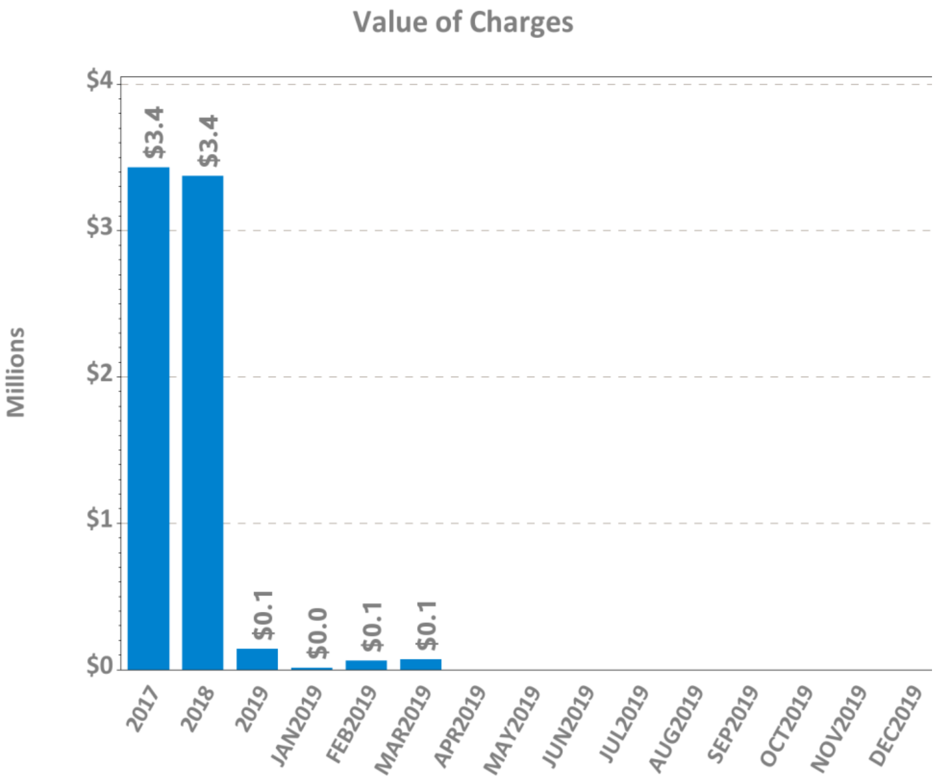
Second Contingency NCPC Charges

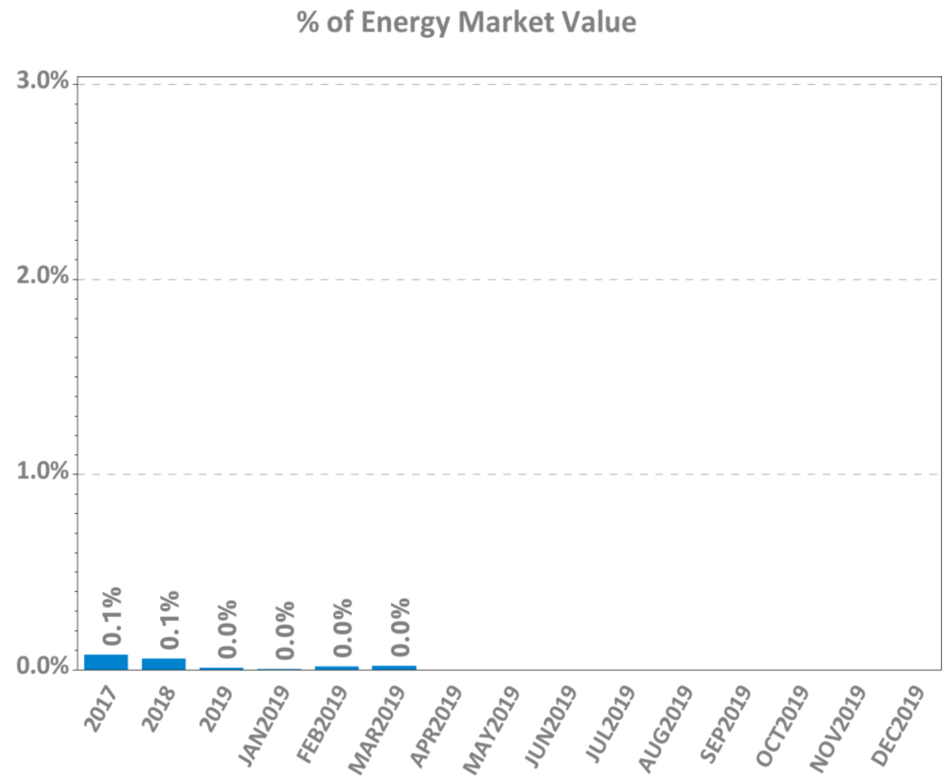




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

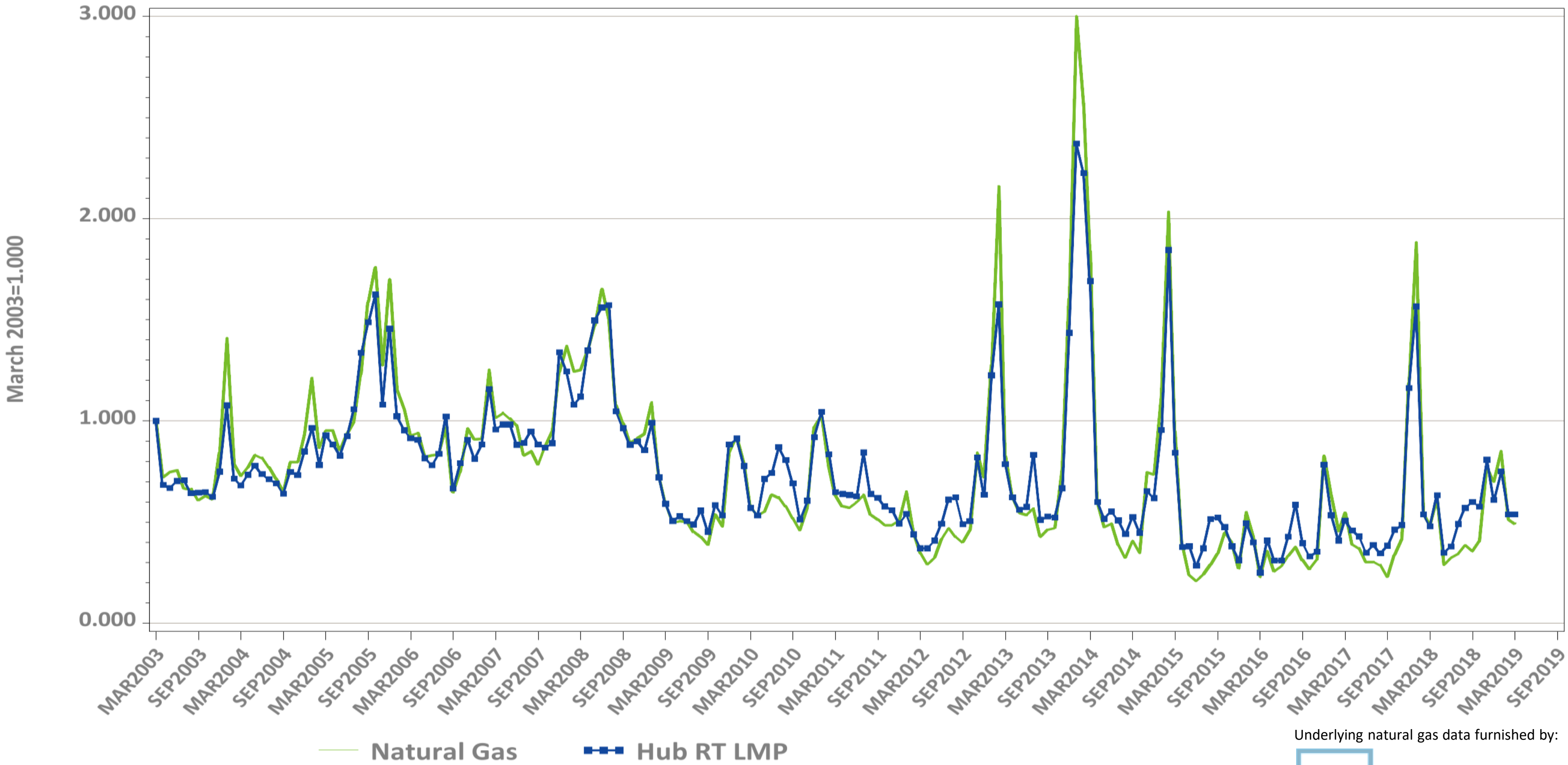
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2017	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$33.46	$33.35	$32.50	$33.13	$33.05	$33.13	$33.27	$33.43	$33.35
Real-Time	$34.76	$33.93	$31.39	$32.78	$33.02	$33.78	$33.98	$33.97	$33.94
RT Delta %	3.9%	1.7%	-3.4%	-1.0%	-0.1%	2.0%	2.1%	1.6%	1.7%
Year 2018	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$44.45	$43.60	$42.63	$44.04	$43.71	$44.11	$44.62	$44.19	$44.13
Real-Time	$43.87	$43.13	$41.03	$43.17	$42.83	$43.37	$43.68	$43.58	$43.54
RT Delta %	-1.3%	-1.1%	-3.8%	-2.0%	-2.0%	-1.7%	-2.1%	-1.4%	-1.3%

March-18	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$35.42	$35.22	$33.89	$35.20	$35.02	$35.38	$35.64	$35.44	$35.38
Real-Time	$33.19	$32.62	$30.22	$32.26	$32.23	$32.91	$33.17	$32.92	$32.87
RT Delta %	-6.3%	-7.4%	-10.8%	-8.4%	-8.0%	-7.0%	-6.9%	-7.1%	-7.1%
March-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$38.22	$37.82	$37.39	$37.99	$37.53	$37.91	$38.04	$38.14	$38.07
Real-Time	$37.13	$36.67	$36.23	$36.88	$36.41	$36.77	$36.80	$36.97	$36.92
RT Delta %	-2.9%	-3.0%	-3.1%	-2.9%	-3.0%	-3.0%	-3.2%	-3.0%	-3.0%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	7.9%	7.4%	10.3%	7.9%	7.2%	7.1%	6.7%	7.6%	7.6%
Yr over Yr RT	11.9%	12.4%	19.9%	14.3%	12.9%	11.7%	11.0%	12.3%	12.3%

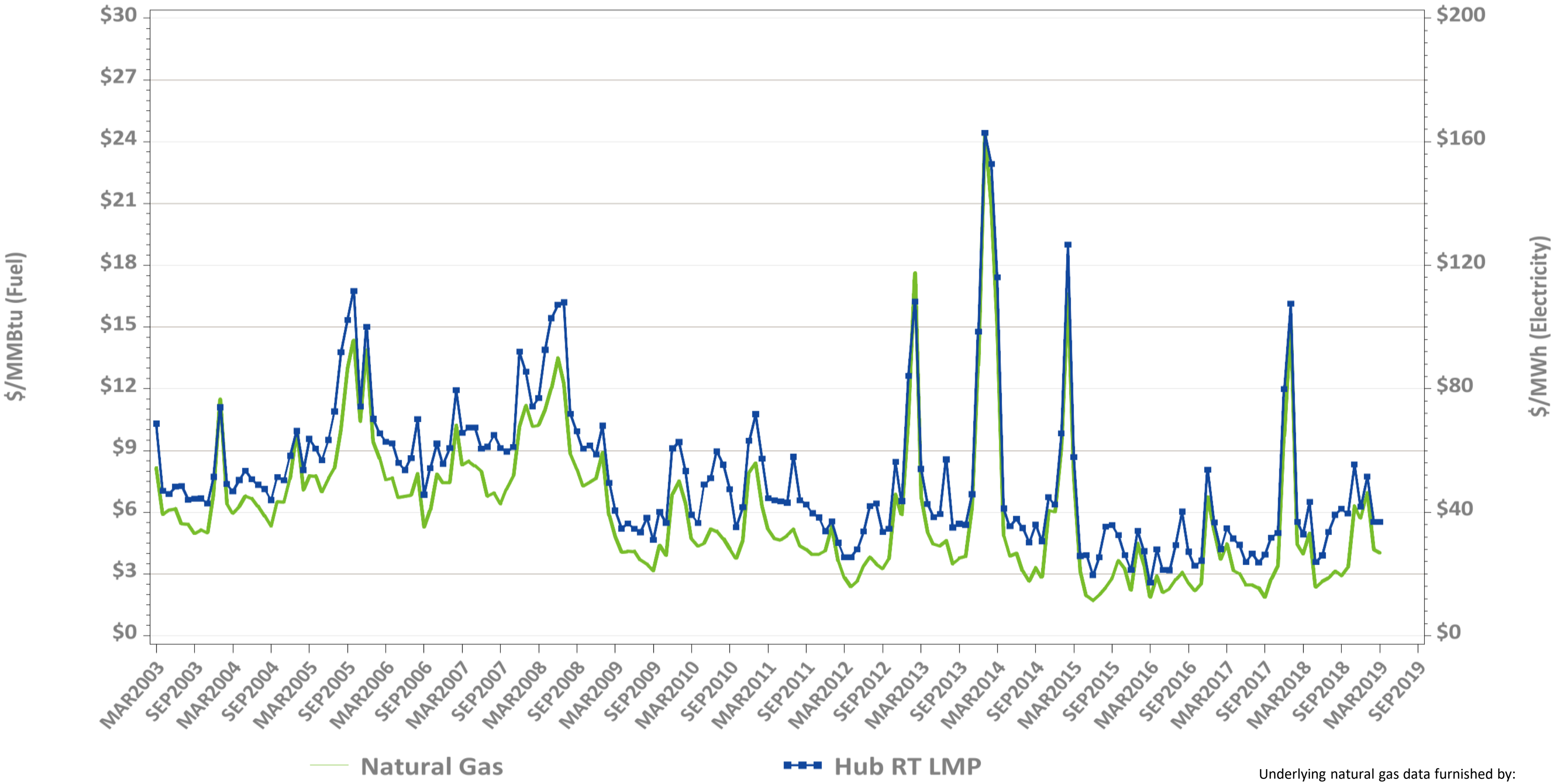
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

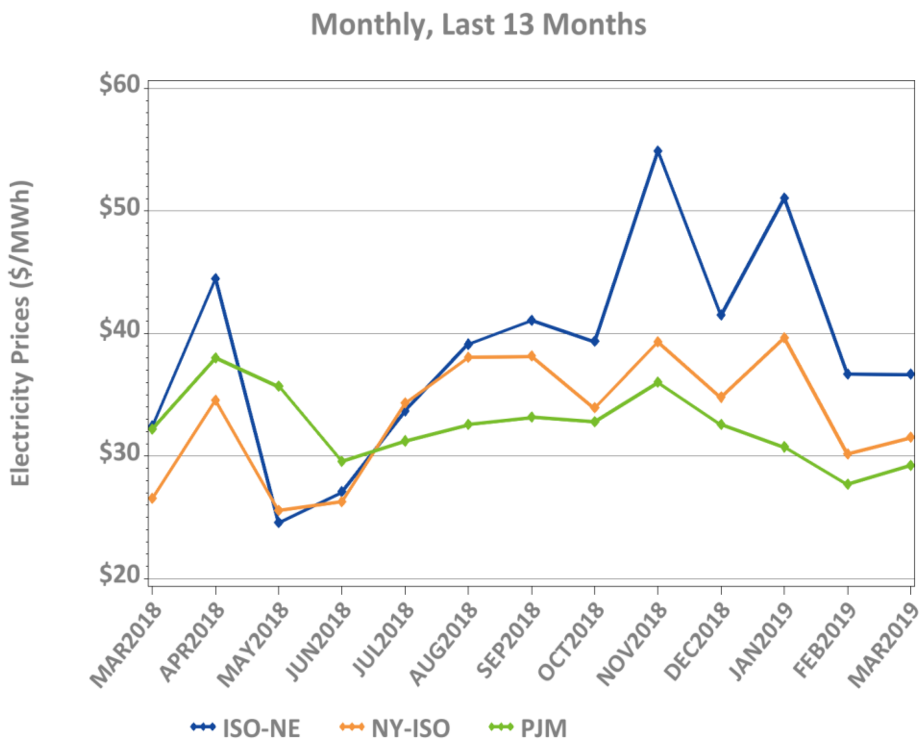
Monthly Average Fuel Price and RT Hub LMP



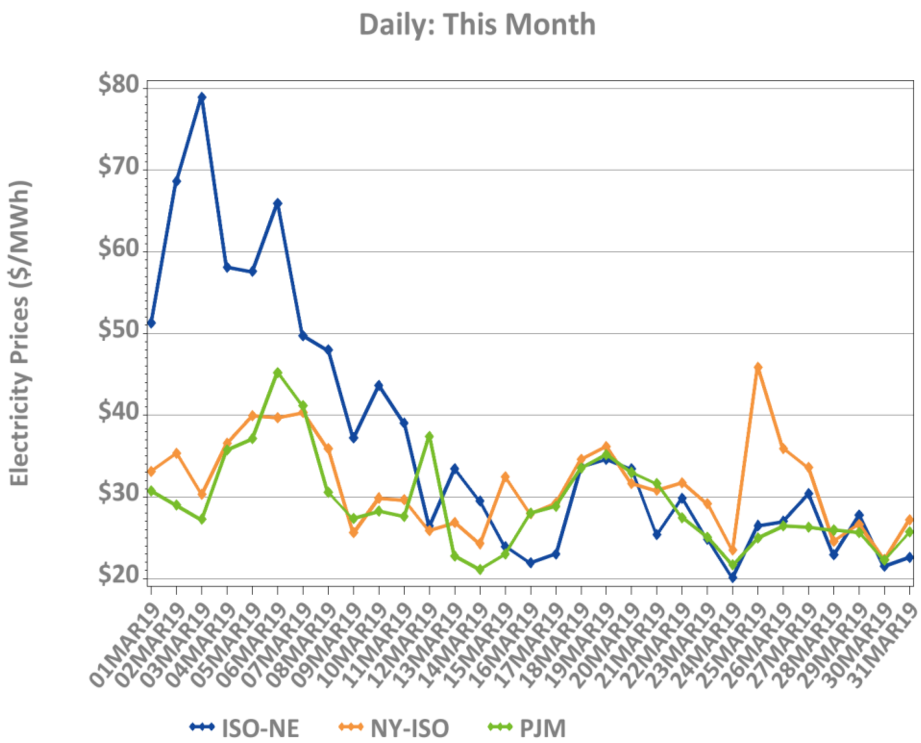
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

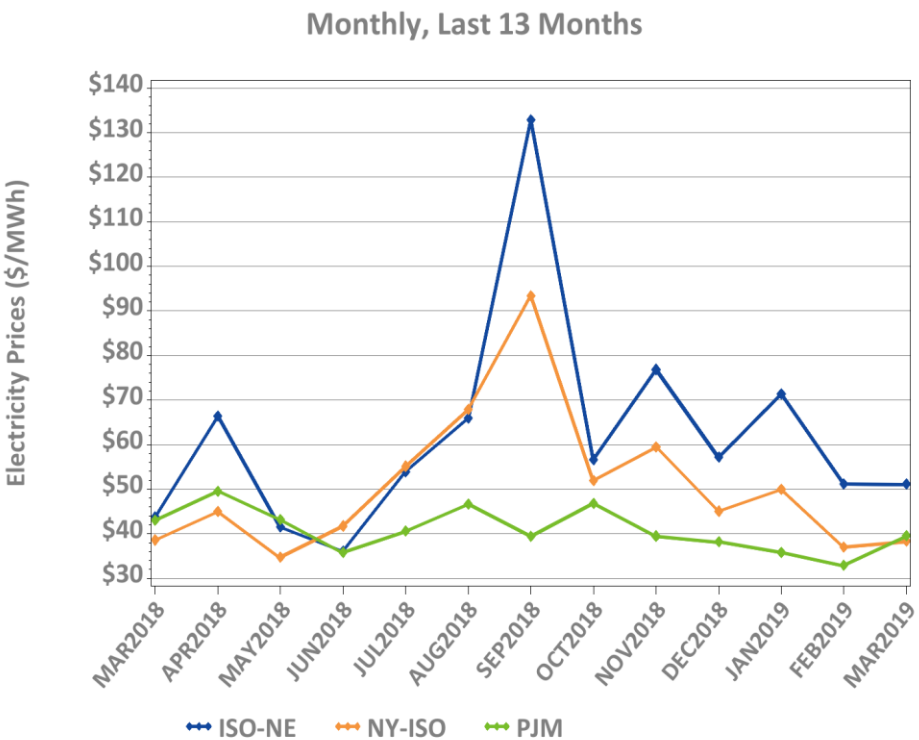


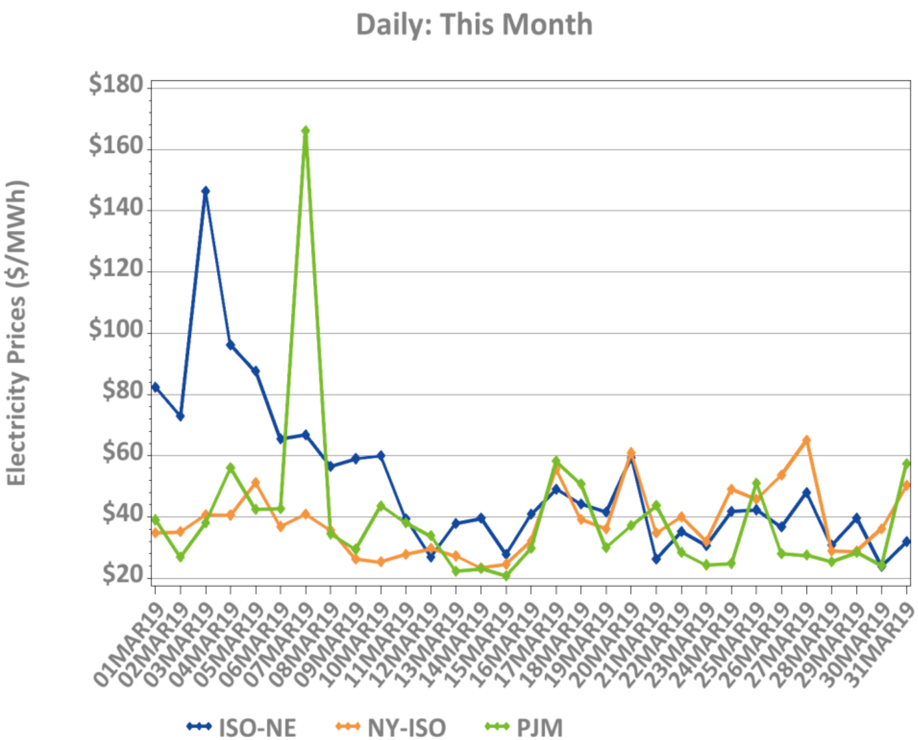
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





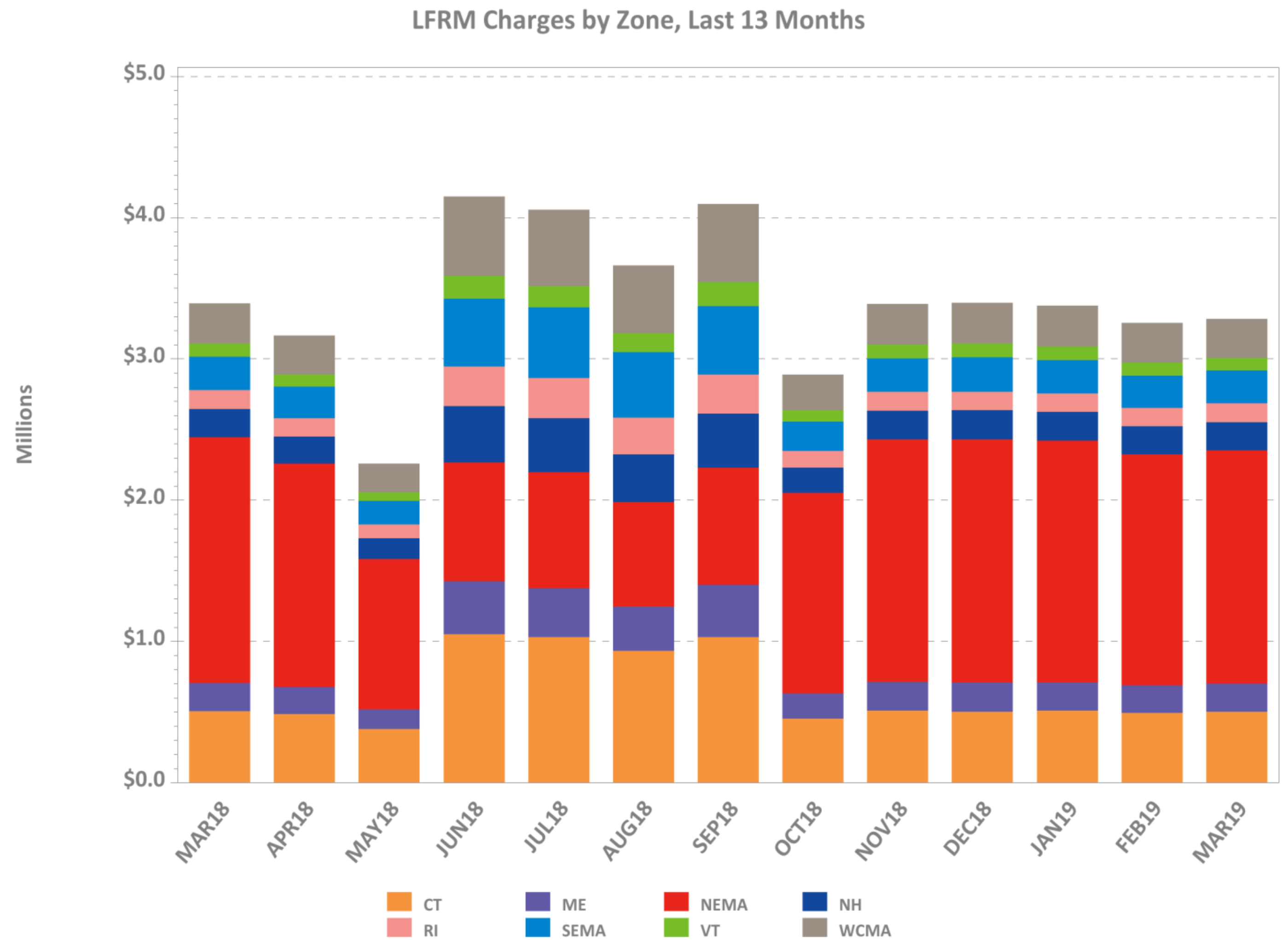
***Forecasted New England daily peak hours reflected**

Reserve Market Results – March 2019

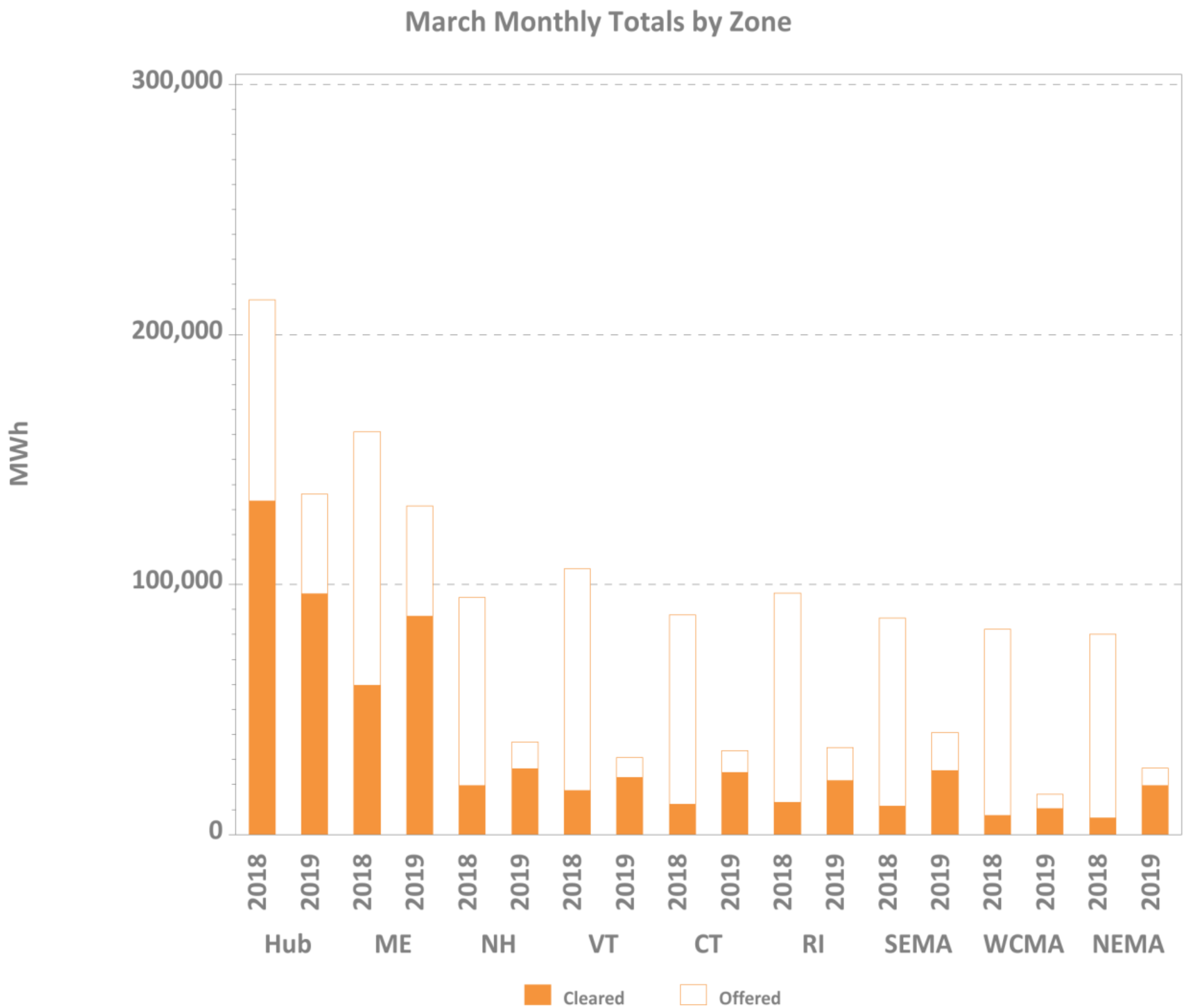
- Maximum potential Forward Reserve Market payments of $3.5M were reduced by credit reductions of $73K, failure-to-reserve penalties of $110K and no failure-to-activate penalties, resulting in a net payout of $3.3M or 95% of maximum
  - Rest of System: $1.13M/1.13M (100%)
  - Southwest Connecticut: $0.13M/0.15M (84%)
  - Connecticut: $0.3M/0.3M (99%)
  - NEMA: $1.7M/1.9M (92%)
- $998K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $998K in Real-Time Reserve payments
  - Rest of System: 280 hours, $751K
  - Southwest Connecticut: 280 hours, $157K
  - Connecticut: 280 hours, $68K
  - NEMA: 280 hours, $22K

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

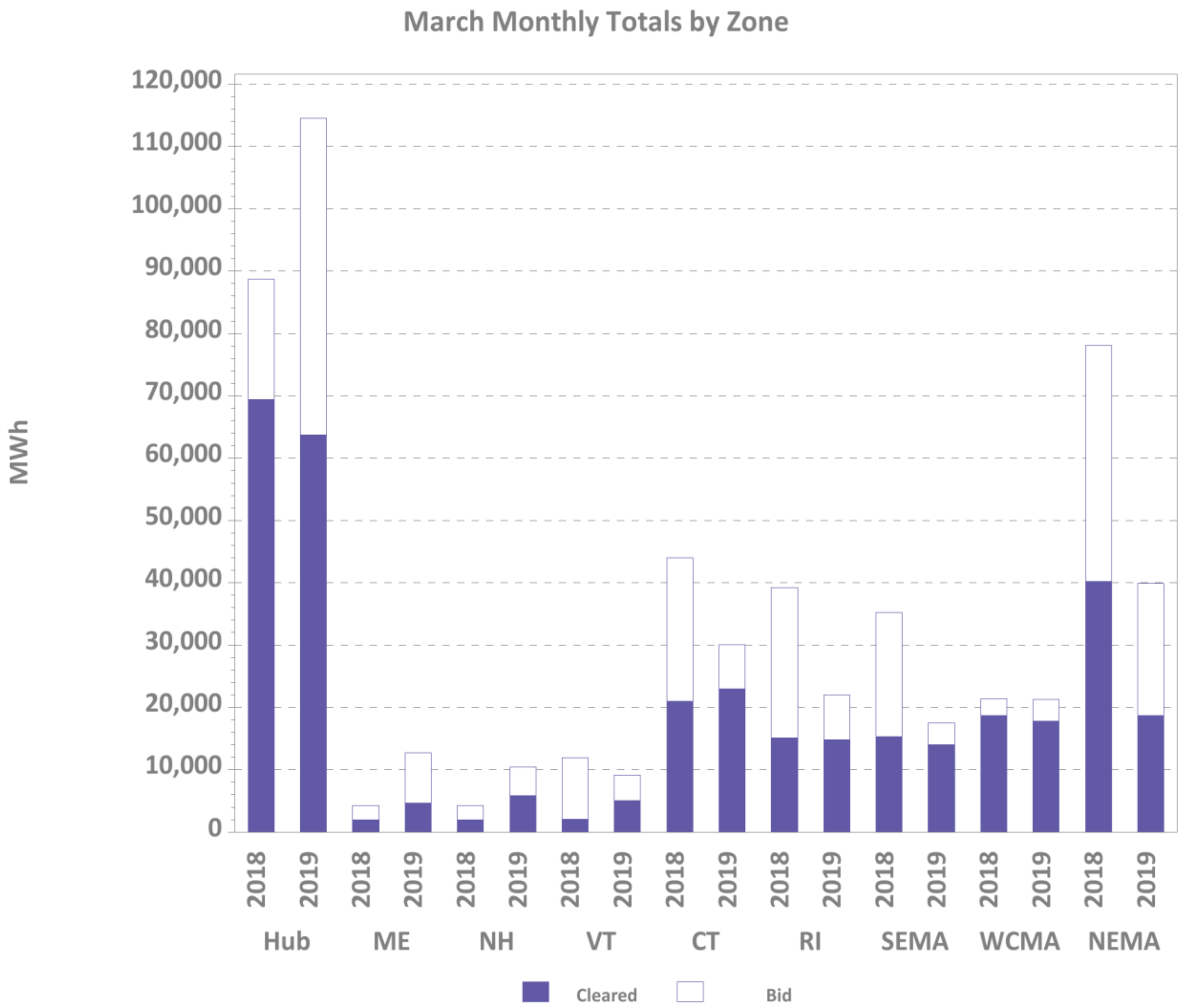
LFRM Charges to Load by Load Zone ($)



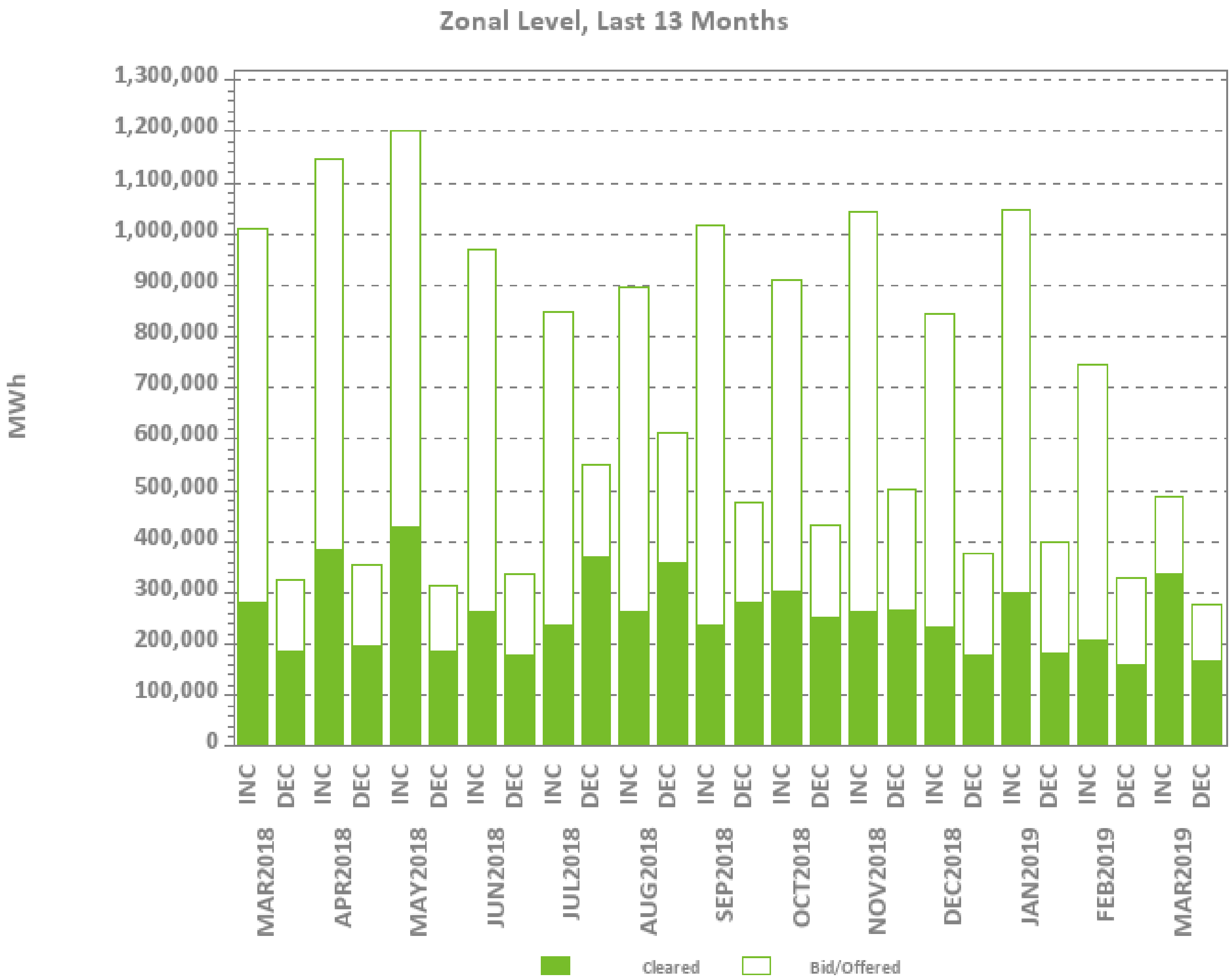
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

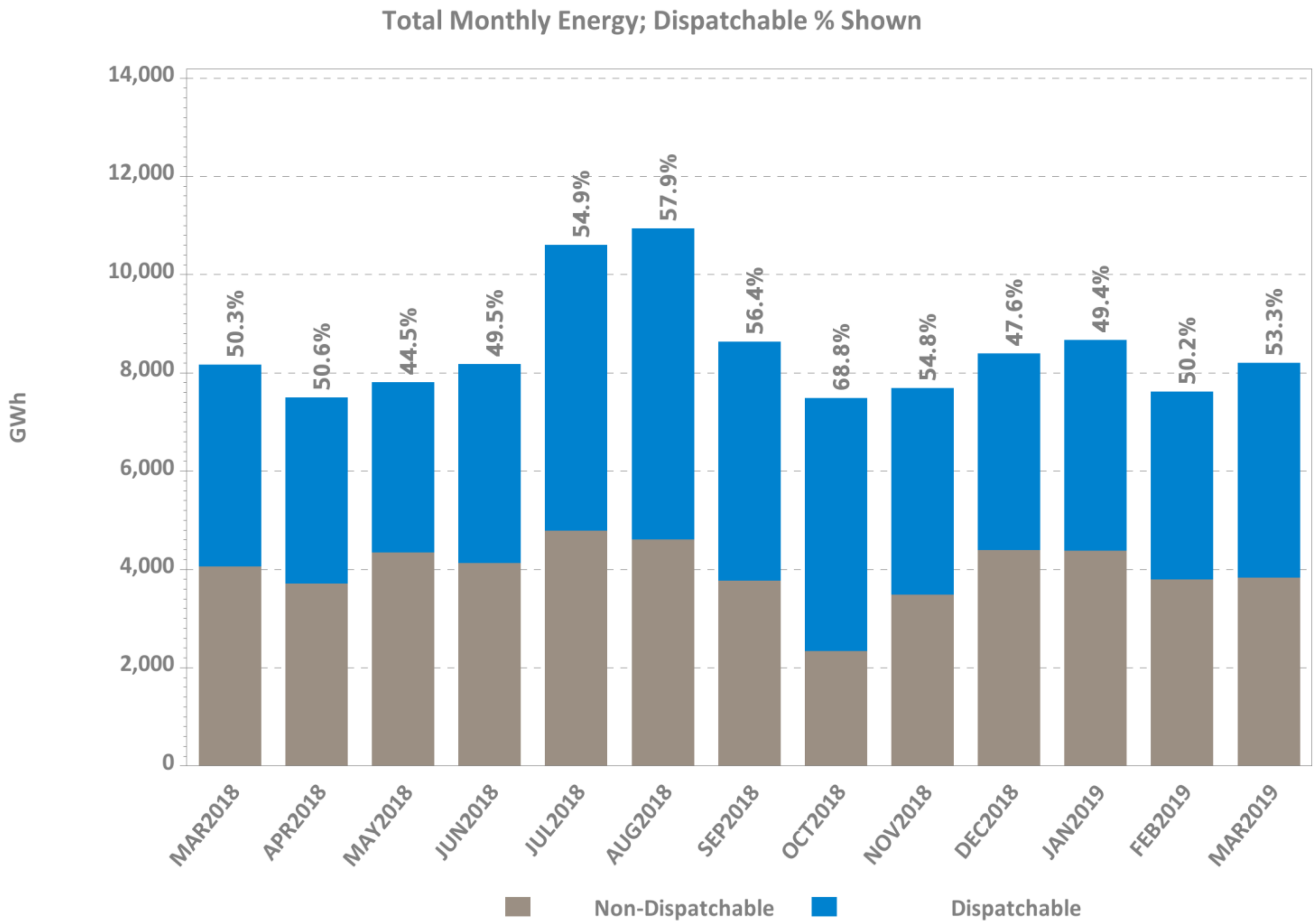


Total Increment Offers and Decrement Bids



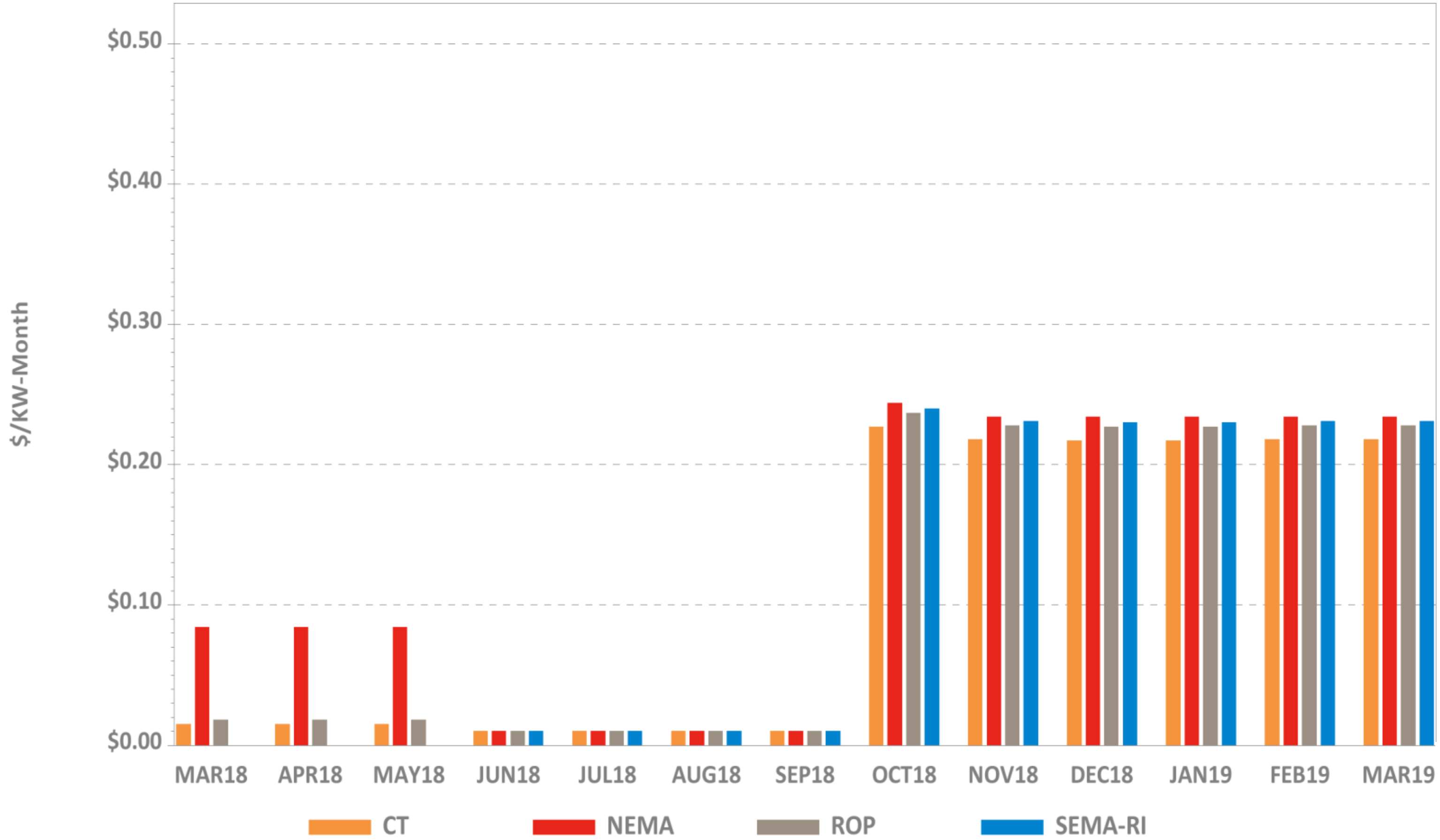
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



* Dispatchable MWh here are defined to be all generation output that is not self-committed (a.k.a, offered as ‘must run’) by the customer.

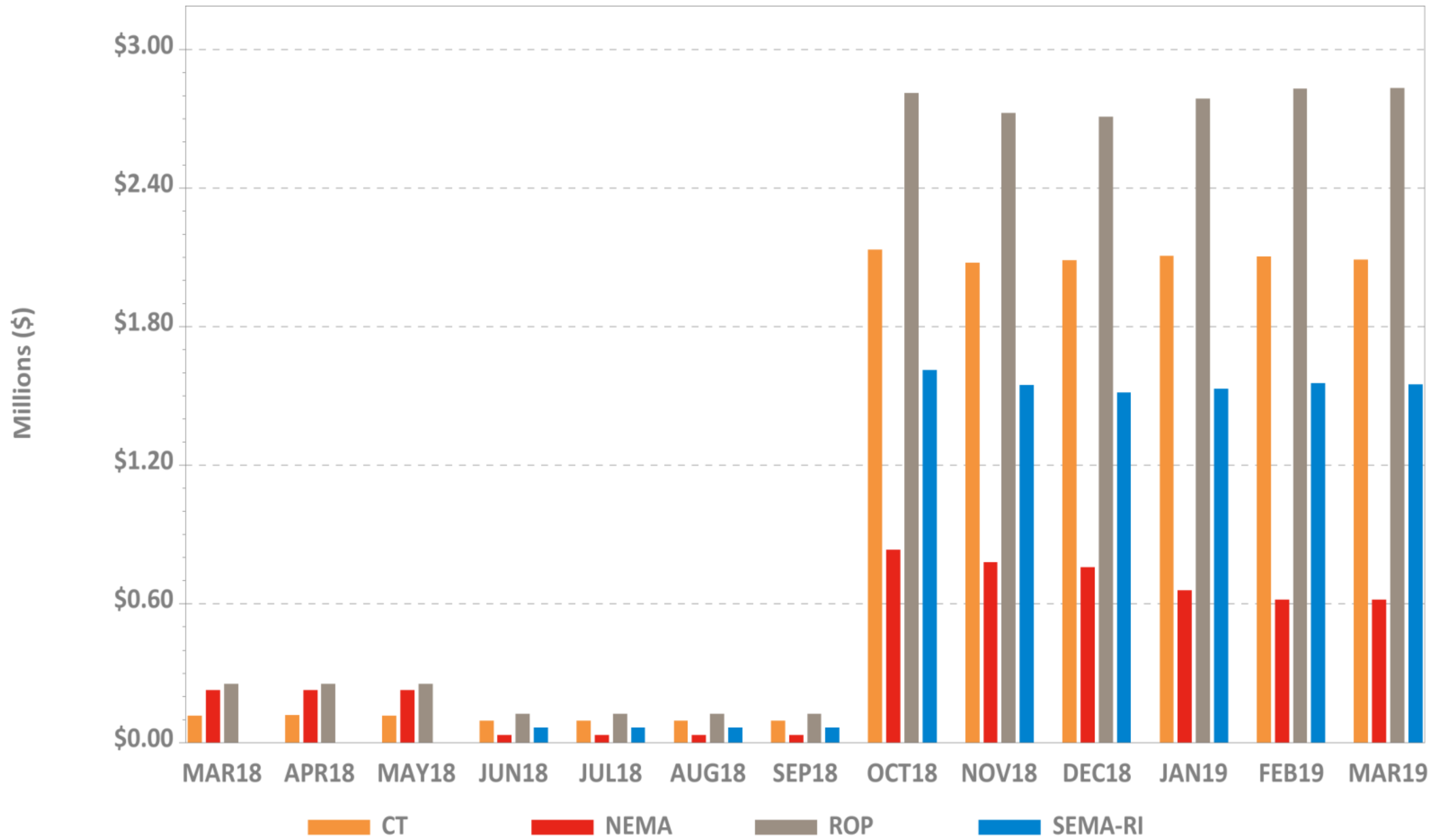
Rolling Average Peak Energy Rent (PER) by Capacity Zone



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: <u>Home > Markets > Other Markets Data > Forward Capacity Market > Reports</u> 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)

- April 25 PAC Meeting Agenda Topics*
  - Economic Study Request Presentations
  - Final 2019 Load Forecast: Winter Peak Demand and Sub-regional Forecasts
  - ECT 2029 Needs Assessment Scope Details
  - Boston 2028 Needs Assessment Results
  - Avangrid 1130/1430 Line OPGW Replacement
  - Eversource 345 kV Structure Replacements
  - Qualified Transmission Project Sponsor Application Reminder
  - Revision to Typical Review Periods

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

PAC "Grid Transformation Day" – May 23

- The large-scale development of wind generation facilities, distributed energy resources (especially PV), storage (batteries and other types), demand response, and HVDC/FACTS are transforming the electric power system
- Discussions will include physical and technical challenges, potential solutions, implementation experience in New England, and regulatory and business models
- Registration is open at:
  - https://www.iso-ne.com/event-details?eventId=137649

Economic Studies

- Three economic study requests were received for discussion at the April 25 PAC meeting

Load, Energy Efficiency, and Photovoltaic Forecast

- The 2019 ten-year load forecast development process is underway
  - Enhancements will be implemented, such as including cooling degree days in the demand models and the development of monthly energy models
  - Staff continues to investigate ways to better capture expiring measures in the energy-efficiency forecast
  - Draft forecast was discussed with the PAC in March and additional details of the ten-year forecast will be discussed in April
  - Forecast to be finalized and posted as part of the CELT report by May 1
- Discussions with industry and counterparts at other ISOs/utilities continue regarding potential impacts of future emerging technologies/trends and methods of incorporating these into the forecast

Interregional Planning

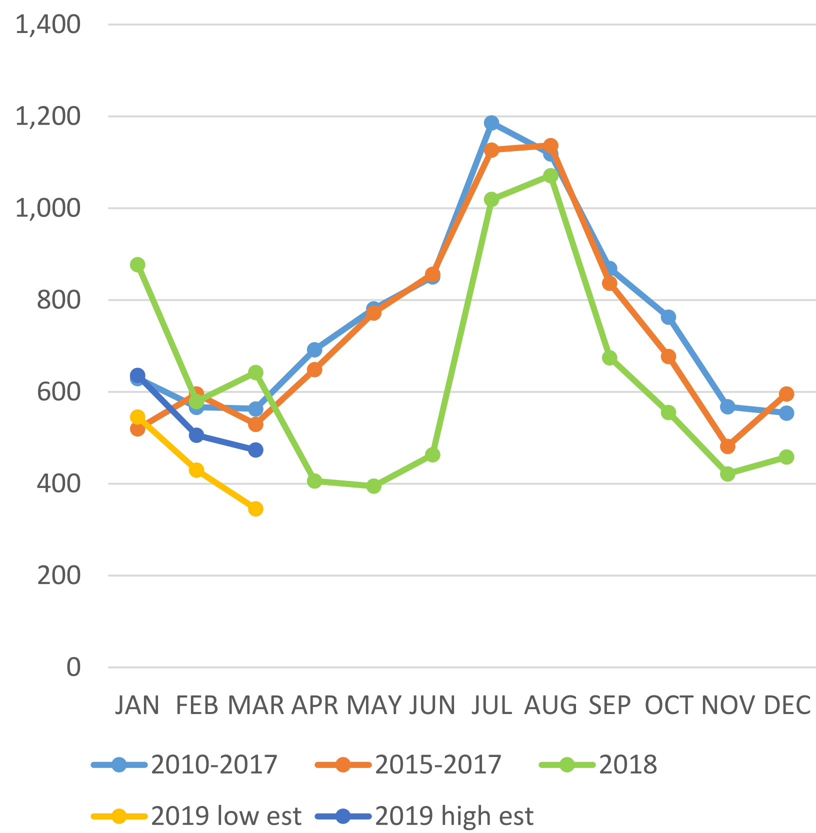
- The next Inter-Area Planning Stakeholder Advisory Committee (IPSAC) meeting is scheduled for May 13 from 2:00pm - 4:30pm
  – Draft agenda items include:
    - Regional Planning Needs and Solutions
      – PJM
      – ISO-NE
      – NYISO
    - Interconnection Coordination - Interconnection Queue and Long-Term Firm Transmission Requests
      – NYISO
      – ISO-NE
      – PJM
    - Receive Stakeholder Input and Outline Next Steps

Environmental Matters – MA CO_2 Generator Emissions Cap Update (310 CMR 7.74)

Estimated 2019 Monthly Emissions Trend Lower under GWSA CO_2 Cap

- 2019 cap set at 8.73 million metric tons (MMT)
  - 2018 reported emissions were 7.56 MMT
- Estimated 2019 monthly emissions range (metric tons)
  - Jan 2019: 545,228 – 635,949
  - Feb 2019: 429,523 – 505,696
  - Mar 2019: 345,470 – 473,633
- All affected generators complied with the 2018 GWSA cap obligations by the March 2019 deadline according to the MA DEP

GWSA Monthly CO_2 Emissions (Thousand Metric Tons)

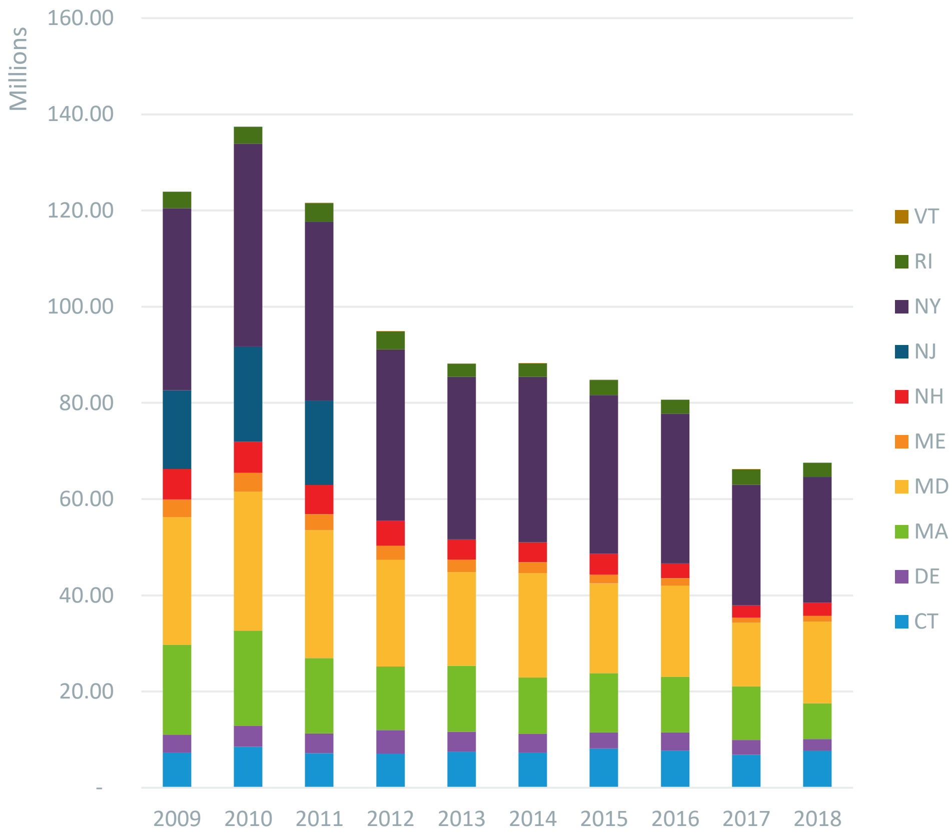


Environmental Matters – Regional Greenhouse Gas Initiative Update

First Year-to-Year Increase Ever in RGGI Emissions

- RGGI emissions (73.3 million short tons (MT) in 2018) increased for only the 2nd time in the 9-year history of the program compared to 2017 emissions (66.1), a 7.18 MT increase:
  - ↑ CT 1.91 million
  - ↓ DE 0.486 million
  - ↓ MA 2.81 million
  - ↑ MD 5.16 million
  - ↑ ME 0.113 million
  - ↑ NH 0.267 million
  - ↑ NY 1.0 million
  - ↓ RI 0.325 million
  - ↓ VT 0.002 million
- New England RGGI emissions overall declined by 194,497 short tons between 2017 (24.7 MT) and 2018 (24.5 MT)

RGGI Annual CO_2 Emissions (Million Short Tons)



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

Note: The listings in this section focus on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades

Status as of 3/25/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual 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	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-19	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 3/25/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual 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	Dec-14	4
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 3/25/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Dec-14	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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 3/25/19

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/ Actual 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	Apr-17	4
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	Jun-18	4
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	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	Mar-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

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 3/25/19

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/ Actual 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 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Dec-19	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-19	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 3/25/19

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/ Actual 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	4
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	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-19	3
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-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	3
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 3/25/19

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/ Actual In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-18	4
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	4
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	Jun-18	4
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-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 3/25/19

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

Southwest Connecticut Projects, cont.

Status as of 3/25/19

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/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-19	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 3/25/19

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/ Actual 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	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-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	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Nov-19	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Nov-19	2

Southwest Connecticut Projects, cont.

Status as of 3/25/19

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

Southwest Connecticut Projects, cont.

Status as of 3/25/19

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/ Actual 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
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

Greater Boston Projects

Status as of 3/25/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
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-19	3
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-21	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	Jun-19	3

* Substation portion of the project is a Present Stage status 3

Greater Boston Projects, cont.

Status as of 3/25/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
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	Dec-19	3
Install third 115 kV line from West Walpole to Holbrook	Dec-19	3
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	4
Install a new 115 kV line from Sudbury to Hudson	Dec-20	2

Greater Boston Projects, cont.

Status as of 3/25/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	3
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
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	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	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	Nov-20	3
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-19	3

Greater Boston Projects, cont.

Status as of 3/25/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-20	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	3
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 3/25/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
Install a 345 kV 160 MVAR shunt reactor at K Street	Nov-19	2
Install a 115 kV breaker in series with the 5 breaker at Framingham	Apr-17	4
Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

Pittsfield/Greenfield Projects

Status as of 3/25/19

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

Upgrade	Expected/ Actual 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	4
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Jun-17	4
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	4
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 3/25/19

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

Upgrade	Expected/ Actual 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 3/25/19

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

Upgrade	Expected/ Actual 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.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
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	Jun-20	1

SEMA/RI Reliability Projects

Status as of 3/25/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Nov-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	3
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Jun-20	2
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	3
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	3

SEMA/RI Reliability Projects

Status as of 3/25/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Nov-20	2
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Dec-20	2
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Sep-21	2

SEMA/RI Reliability Projects

Status as of 3/25/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-21	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Nov-20	1
1727	Retire the Barnstable SPS	Dec-21	1
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-21	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-21	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-21	1

SEMA/RI Reliability Projects

Status as of 3/25/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	1
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-21	1
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Dec-21	1
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Dec-21	3

* Does not include the reconductoring work over the Cape Cod canal

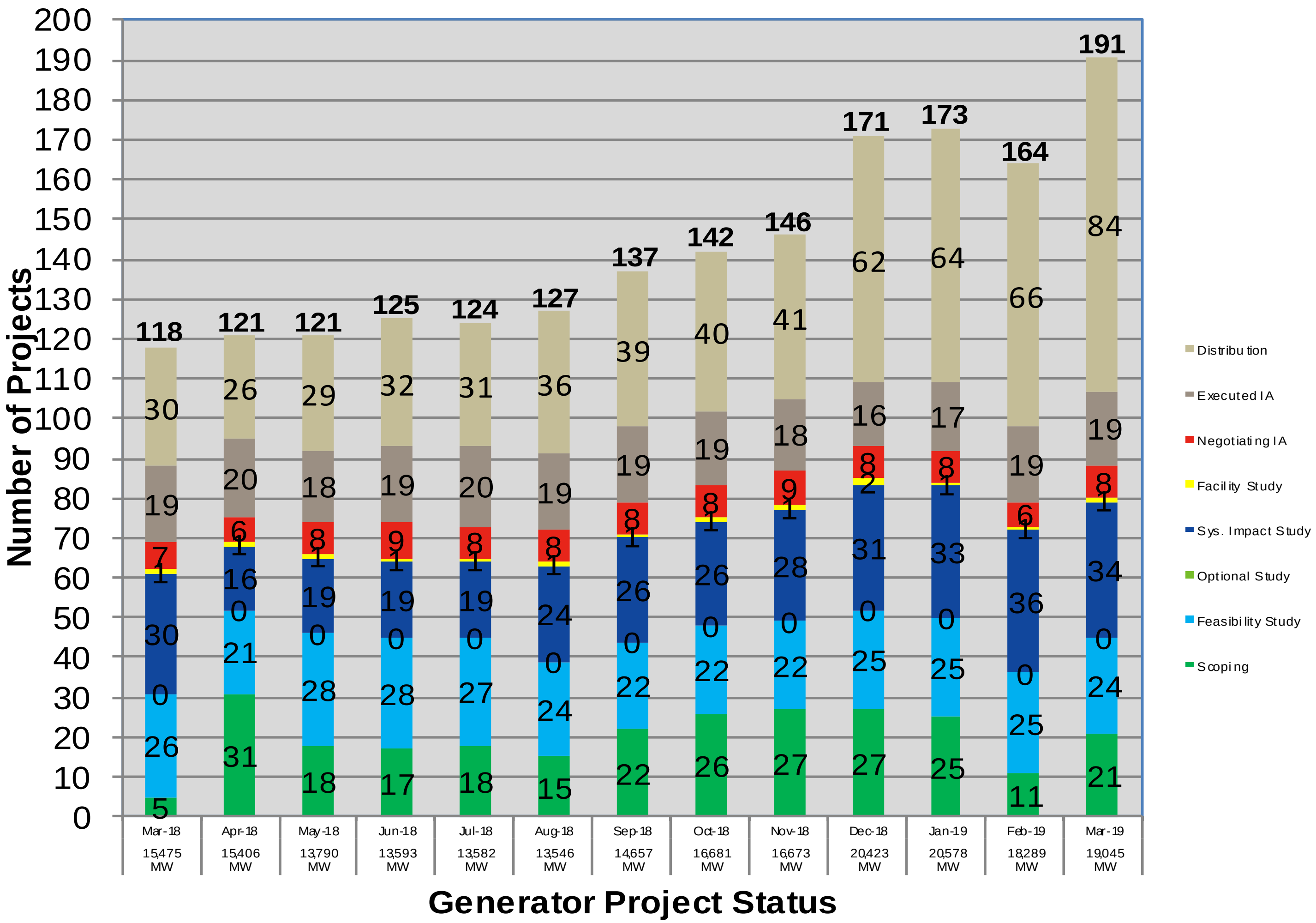
SEMA/RI Reliability Projects

Status as of 3/25/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	3
1782	Reconductor the J16S line	Dec-20	2
1724	Replace the Kent County 345/115 kV transformer	Nov-20	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	2
1790	Medway 115 kV circuit breaker replacements	Dec-21	2

Status of Tariff Studies



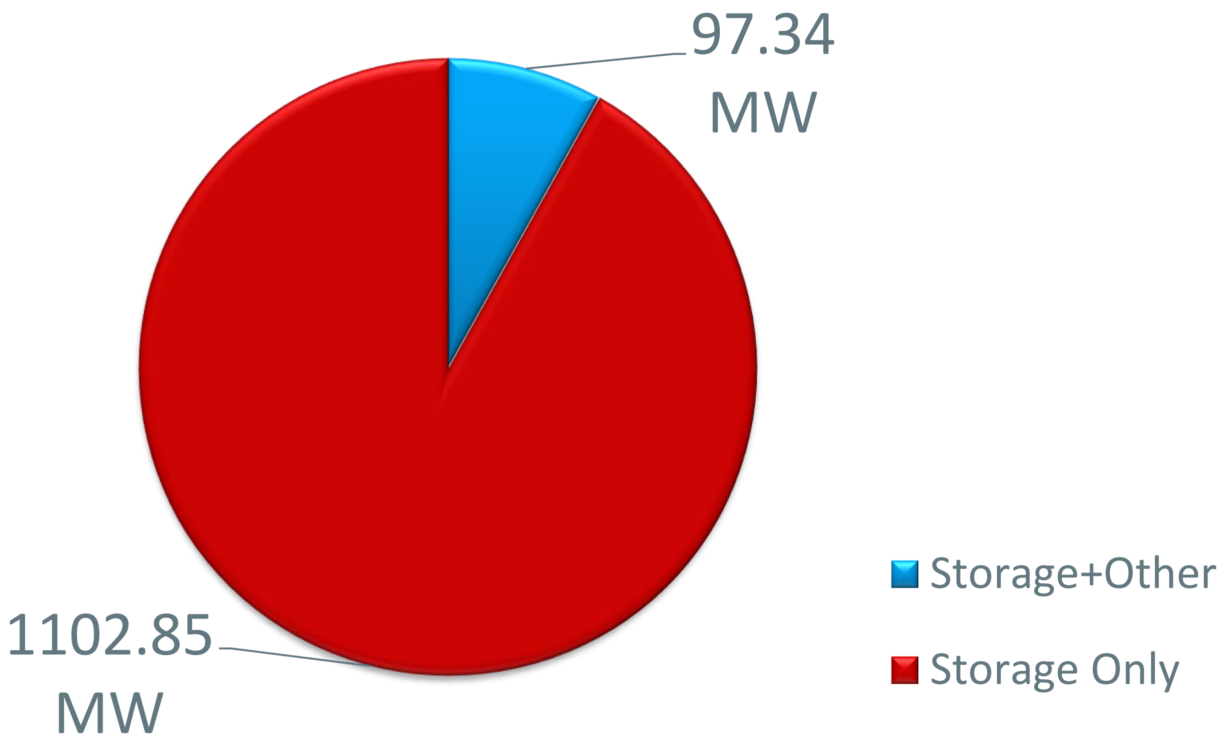
Note: March 2019 based on partial data

As of March 2019, there are 6 ETU's in SIS, 3 in FS, 5 in Scoping, 1 Negotiating IA, and 2 with Executed IA

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

What is in the Queue (as of March 28, 2019)

Storage Projects are proposed as stand-alone storage or as co-located with wind or solar projects



OPERABLE CAPACITY ANALYSIS

Spring 2019 Analysis

Spring 2019 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2019[2] CSO (MW)	May - 2019[2] SCC (MW)
Operable Capacity MW [1]	31,158	33,262
Active Demand Capacity Resource (+) [5]	377	340
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	709	709
Non Commercial Capacity (+)	156	156
Non Gas-fired Planned Outage MW (-)	4,439	4,546
Gas Generator Outages MW (-)	696	763
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,865	25,758
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,216	19,216
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,521	21,521
Operable Capacity Margin	2,344	4,237

[1]Operable Capacity is based on data as of **March 21, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **March 21, 2019.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 11, 2019.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Spring 2019 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2019[2] CSO (MW)	May - 2019[2] SCC (MW)
Operable Capacity MW [1]	31,158	33,262
Active Demand Capacity Resource (+) [5]	377	340
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	709	709
Non Commercial Capacity (+)	156	156
Non Gas-fired Planned Outage MW (-)	4,439	4,546
Gas Generator Outages MW (-)	696	763
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,865	25,758
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,709	20,709
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,014	23,014
Operable Capacity Margin	851	2,744

[1]Operable Capacity is based on data as of **March 21, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **March 21, 2019.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 11, 2019.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Spring 2019 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

April 1, 2019 - 50/50 FORECAST using CSO

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	Active Capacity Demand 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
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
4/6/2019	31085	330	735	156	3367	2319	2700	0	23920	15950	2305	18255	5665
4/13/2019	31085	330	735	156	4192	2541	2700	0	22873	15423	2305	17728	5145
4/20/2019	31085	330	735	156	4110	1045	2700	0	24451	15149	2305	17454	6997
4/27/2019	31158	377	709	156	3988	289	3400	0	24723	14413	2305	16718	8005
5/4/2019	31158	377	809	156	4996	932	3400	0	23172	18200	2305	20505	2667
5/11/2019	**31158**	**377**	**709**	**156**	**4439**	**696**	**3400**	**0**	**23865**	**19216**	**2305**	**21521**	**2344**
5/18/2019	31158	377	709	156	2067	1616	3400	0	25317	20160	2305	22465	2852
5/25/2019	31158	377	709	156	520	941	3400	0	27539	21196	2305	23501	4038

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. 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.
8. 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.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Spring 2019 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

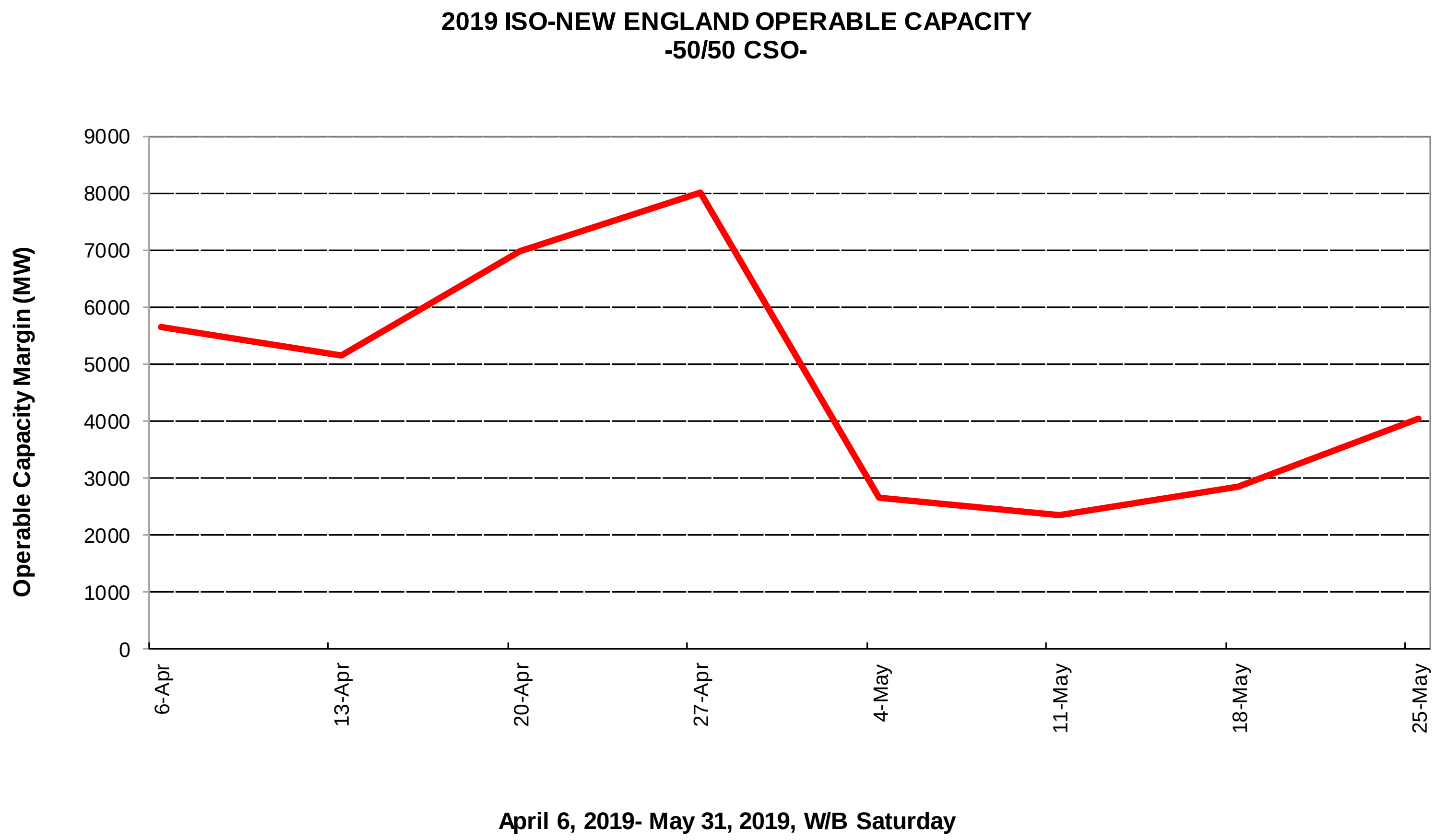
April 1, 2019 - 90/10 FORECAST using CSO

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

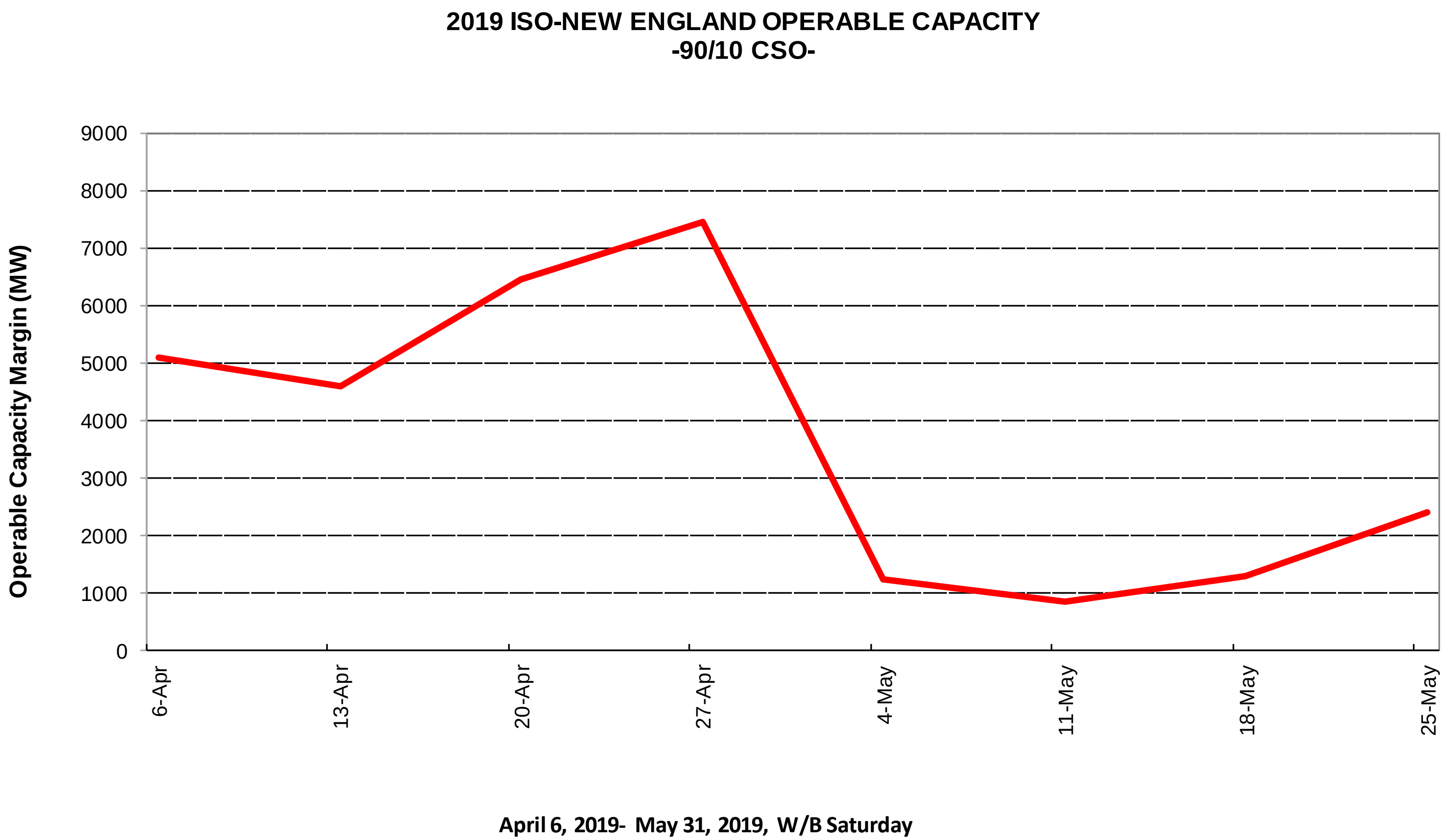
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
4/6/2019	31085	330	735	156	3367	2319	2700	0	23920	16515	2305	18820	5100
4/13/2019	31085	330	735	156	4192	2541	2700	0	22873	15971	2305	18276	4597
4/20/2019	31085	330	735	156	4110	1045	2700	0	24451	15689	2305	17994	6457
4/27/2019	31158	377	709	156	3988	289	3400	0	24723	14953	2305	17258	7465
5/4/2019	31158	377	809	156	4996	932	3400	0	23172	19627	2305	21932	1240
5/11/2019	**31158**	**377**	**709**	**156**	**4439**	**696**	**3400**	**0**	**23865**	**20709**	**2305**	**23014**	**851**
5/18/2019	31158	377	709	156	2067	1616	3400	0	25317	21714	2305	24019	1298
5/25/2019	31158	377	709	156	520	941	3400	0	27539	22818	2305	25123	2416

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. 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.
8. 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.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Spring 2019 Operable Capacity Analysis
50/50 Forecast (Reference)



Spring 2019 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Summer 2019 Analysis

Preliminary Summer 2019 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2019[2] CSO (MW)	June - 2019[2] SCC (MW)
Operable Capacity MW [1]	29,705	30,356
Active Demand Capacity Resource (+) [5]	430	340
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,270	1,270
Non Commercial Capacity (+)	973	973
Non Gas-fired Planned Outage MW (-)	153	154
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	29,425	29,985
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,323	25,323
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,628	27,628
Operable Capacity Margin	1,797	2,357

[1] Operable Capacity is based on data as of **March 21, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **March 21, 2019.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 1, 2019.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Preliminary Summer 2019 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	June - 2019[2] CSO (MW)	June - 2019[2] SCC (MW)
Operable Capacity MW [1]	29,705	33,356
Active Demand Capacity Resource (+) [5]	430	340
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,270	1,270
Non Commercial Capacity (+)	973	973
Non Gas-fired Planned Outage MW (-)	153	154
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	29,425	29,985
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	27,212	27,212
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,517	29,517
Operable Capacity Margin	(92)	468

[1]Operable Capacity is based on data as of **March 21, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **March 21, 2019.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 1, 2019.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Preliminary Summer 2019 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

April 1, 2019 - 50/50 FORECAST using CSO

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	Active Capacity Demand 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
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
6/1/2019	**29705**	**430**	**1270**	**973**	**153**	**0**	**2800**	**0**	**29425**	**25323**	**2305**	**27628**	**1797**
6/8/2019	29705	430	1328	973	166	0	2800	0	29470	25323	2305	27628	1842
6/15/2019	29705	430	1328	973	88	0	2800	0	29548	25323	2305	27628	1920
6/22/2019	29705	430	1328	973	33	0	2800	0	29603	25323	2305	27628	1975
6/29/2019	29705	430	1328	973	30	0	2100	0	30306	25323	2305	27628	2678
7/6/2019	29705	430	1328	973	53	0	2100	0	30283	25323	2305	27628	2655
7/13/2019	29705	430	1328	973	33	0	2100	0	30303	25323	2305	27628	2675
7/20/2019	29705	430	1328	973	18	0	2100	0	30318	25323	2305	27628	2690
7/27/2019	29705	430	1328	973	18	0	2100	0	30318	25323	2305	27628	2690
8/3/2019	29705	430	1328	973	41	0	2100	0	30295	25323	2305	27628	2667
8/10/2019	29705	430	1328	973	27	0	2100	0	30309	25323	2305	27628	2681
8/17/2019	29705	430	1328	973	41	0	2100	0	30295	25323	2305	27628	2667
8/24/2019	29705	430	1328	973	17	0	2100	0	30319	25323	2305	27628	2691
8/31/2019	29705	430	1328	973	310	0	2100	0	30026	25323	2305	27628	2398
9/7/2019	29705	430	1328	973	688	0	2100	0	29648	25323	2305	27628	2020

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. 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.
8. 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.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Preliminary Summer 2019 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS
April 1, 2019 - 90/10 FORECAST using CSO

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	Active Capacity Demand 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
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
6/1/2019	**29705**	**430**	**1270**	**973**	**153**	**0**	**2800**	**0**	**29425**	**27212**	**2305**	**29517**	**-92**
6/8/2019	29705	430	1328	973	166	0	2800	0	29470	27212	2305	29517	-47
6/15/2019	29705	430	1328	973	88	0	2800	0	29548	27212	2305	29517	31
6/22/2019	29705	430	1328	973	33	0	2800	0	29603	27212	2305	29517	86
6/29/2019	29705	430	1328	973	30	0	2100	0	30306	27212	2305	29517	789
7/6/2019	29705	430	1328	973	53	0	2100	0	30283	27212	2305	29517	766
7/13/2019	29705	430	1328	973	33	0	2100	0	30303	27212	2305	29517	786
7/20/2019	29705	430	1328	973	18	0	2100	0	30318	27212	2305	29517	801
7/27/2019	29705	430	1328	973	18	0	2100	0	30318	27212	2305	29517	801
8/3/2019	29705	430	1328	973	41	0	2100	0	30295	27212	2305	29517	778
8/10/2019	29705	430	1328	973	27	0	2100	0	30309	27212	2305	29517	792
8/17/2019	29705	430	1328	973	41	0	2100	0	30295	27212	2305	29517	778
8/24/2019	29705	430	1328	973	17	0	2100	0	30319	27212	2305	29517	802
8/31/2019	29705	430	1328	973	310	0	2100	0	30026	27212	2305	29517	509
9/7/2019	29705	430	1328	973	688	0	2100	0	29648	27212	2305	29517	131

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
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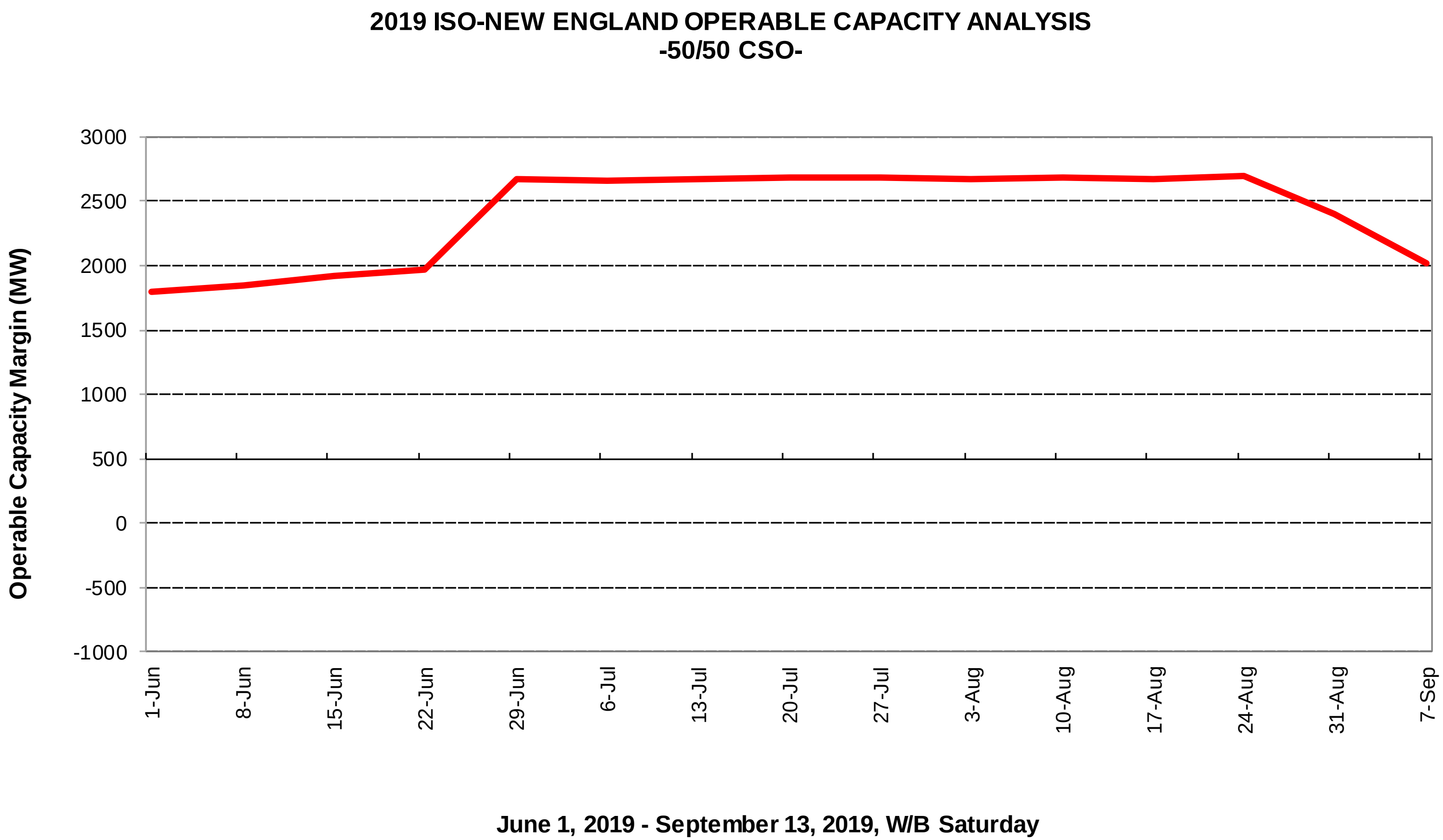
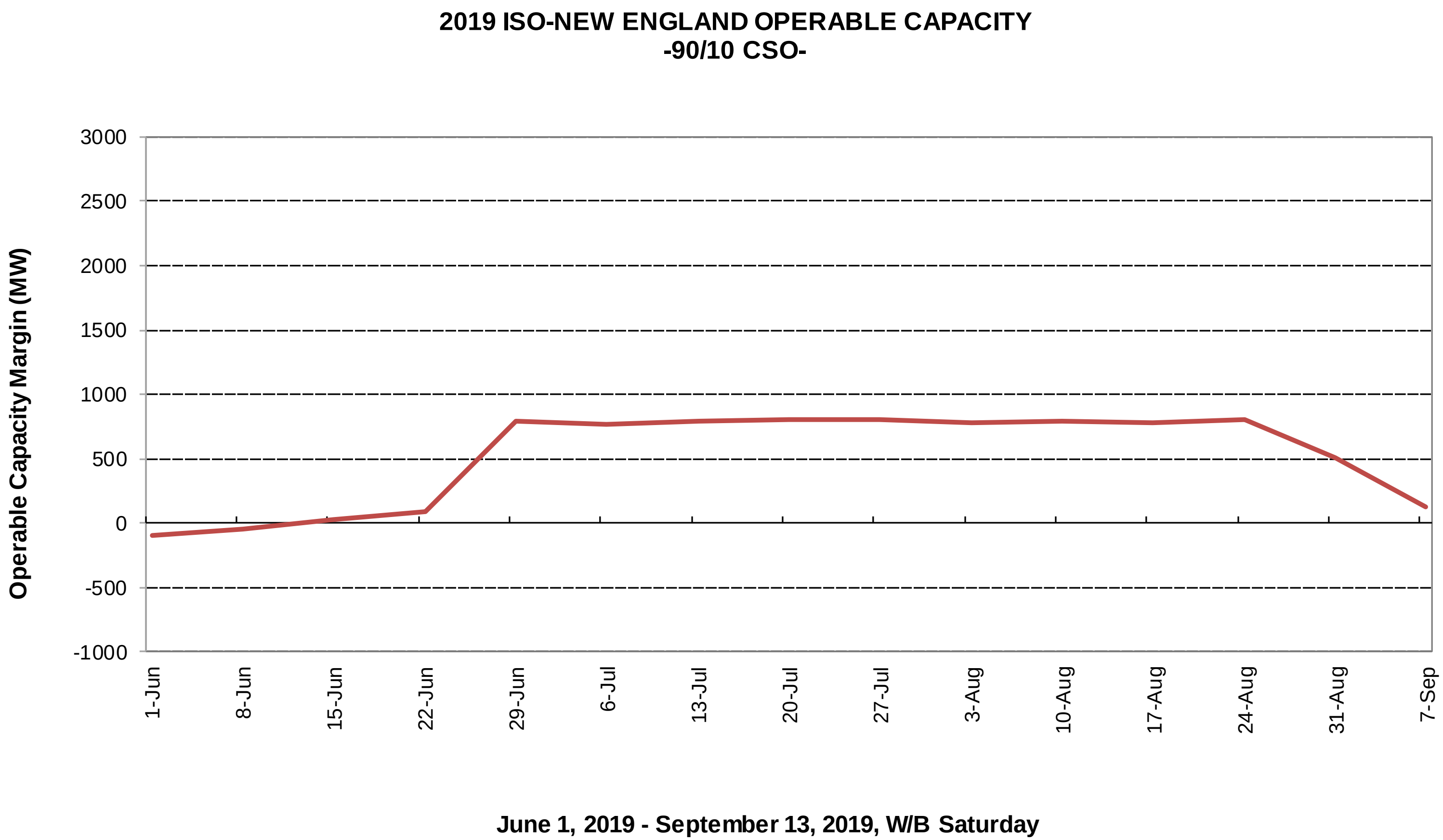
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Preliminary Summer 2019 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Summer 2019 Operable Capacity Analysis
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 the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
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	132 [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 MW values are based on a 26,458 MW system load based on the 2017 CELT Gross 50/50 Forecast minus PV and PDR and verified by the most recent voltage reduction test..
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	265 [3]
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		**2,542**

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 MW values are based on a 26,458 MW system load based on the 2017 CELT Gross 50/50 Forecast minus PV and PDR and verified by the most recent voltage reduction test..
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations