NEPOOL Participants Committee Report

June 2020

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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

ISO Operations During COVID-19 Outbreak

- Effective March 14, ~95% of ISO workforce is working remotely
- All reliability, market and planning functions are being operated in accordance with all applicable standards
- ISO remote deployment posture extended until June 15, when it expects to start its re-entry plan
- The ISO re-entry plan conforms to national, state, and local guidelines, is phased over four months, and based on business needs and priorities
- The ISO will continue to monitor the situation and take all necessary steps to reliably operate the bulk power system

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - April 2020 Energy market value totaled $159M, the lowest total monthly result since 2003 Standard Market Design implementation
  - May 2020 Energy market value was $120M over the period, down $39M from April and down $107M from May 2019
    - May 2020 natural gas prices over the period were 16% lower than April average values
    - Average RT Hub Locational Marginal Prices ($16.39/MWh) over the period were 9.4% lower than April averages
      - DA Hub: $16/MWh
    - Average May 2020 natural gas prices and RT Hub LMPs over the period were down 41% and 28%, respectively, from May 2019 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 97.9% during May
    - The minimum value for the month was 92% on Wednesday, May 13th

DATA THROUGH May 27, EXCEPT WHERE NOTED.

Underlying natural gas data furnished by:

ICE Global markets in clear view

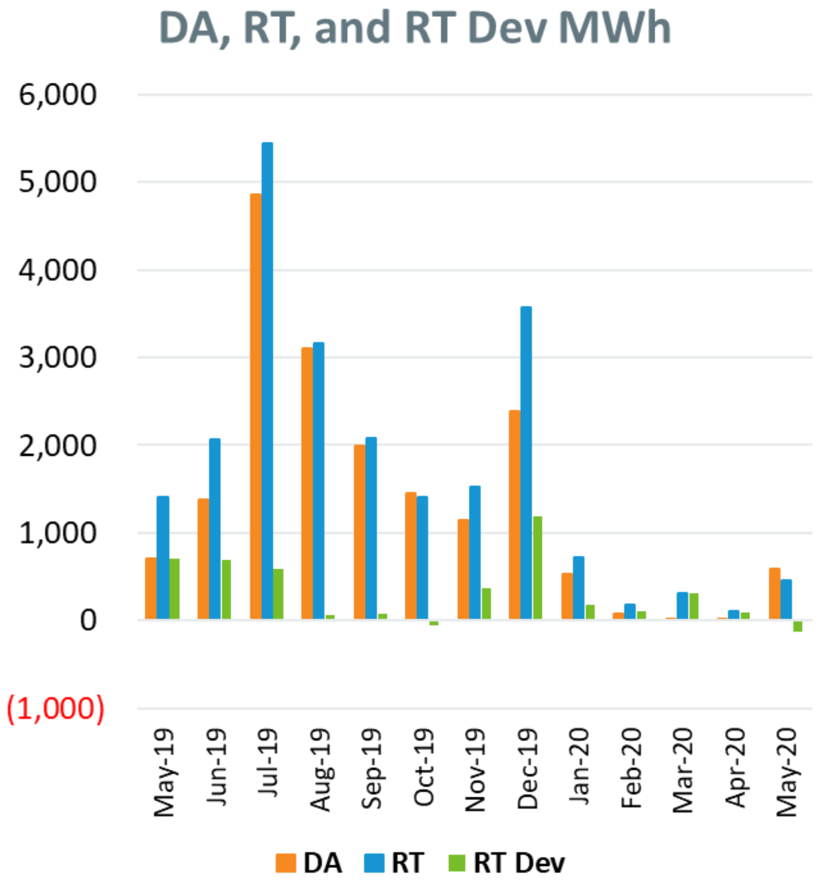
***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**

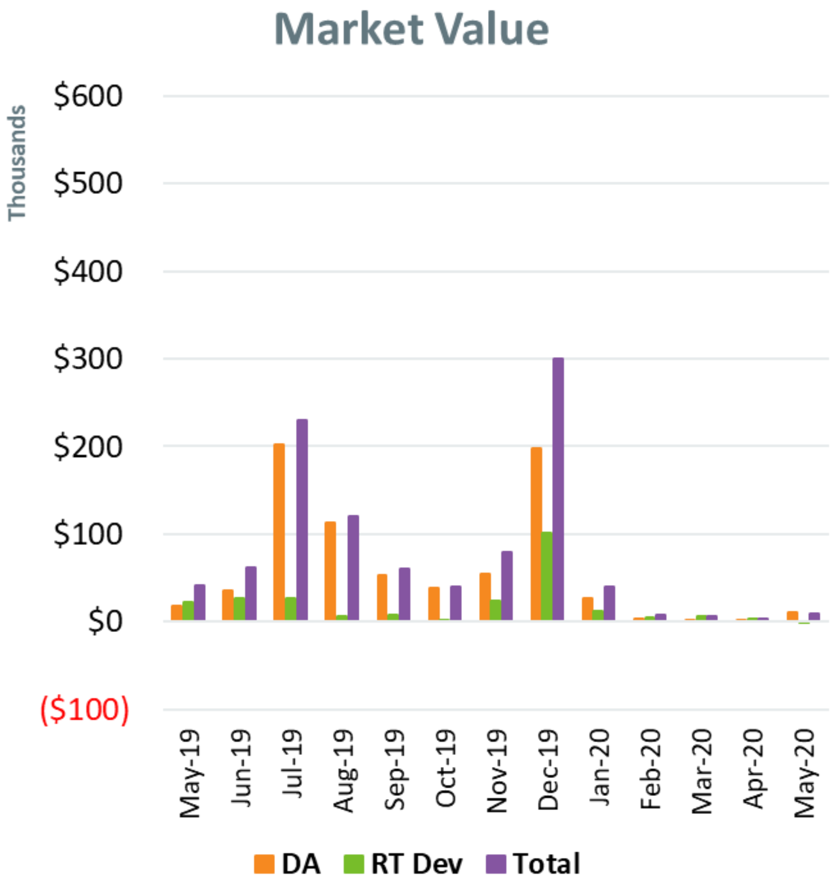
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - May 2020 NCPC payments totaled $1.7M over the period, up $0.2M from April 2020 and down $0.4M from May 2019
  - First Contingency* payments totaled $1.7M, up $0.3M from April
    - $1.4M paid to internal resources, up $0.1M from April 2020
      - » $424K charged to DALO, $547K to RT Deviations, $399K to RTLO
    - $282K paid to resources at external locations, up $165K from April
      - » Charged to RT Deviations
  - Second Contingency payments were negligible ($11K), down $33K from April
  - NCPC payments over the period as percent of Energy Market value were 1.4%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $167K; Rapid Response Pricing (RRP) Opportunity Cost - $146K; Posturing - $0K; Generator Performance Auditing (GPA) - $85K

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

- In response to the Boston 2028 RFP, 36 Phase One Proposals were received from 8 QTPSs
  - The ISO will discuss the draft list of qualifying Phase One Proposals at the June PAC meeting
- It was confirmed at the May 28 PSPC meeting that FCA 15 will model the same zones as FCA 14
- Final 2019 Northeast Coordinated System Plan was posted on May 4
- Final 2018 Electric Generator Air Emissions Report was posted on May 14
- 2020 Public Policy Transmission Upgrade Process will be discussed at the June PAC meeting
- EE Reconstitution Project is underway, and tariff redlines will be presented to the RC in June
- 2019 Economic Studies are nearing completion
  - NESCOE report is on target for July 1
- 2020 Economic Study work has commenced

Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - Third and final annual reconfiguration auction (ARA3) was held March 2-4 and results were posted on April 1
- CCP 12 (2021-2022)
  - Second reconfiguration auction (ARA2) will be August 3-5 and results to be posted by September 2

CCP – Capacity Commitment Period

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - First reconfiguration auction (ARA1) was held June 1-3, and results to be posted by July 1
- CCP 14 (2023-2024)
  - Auction results were filed with FERC on February 18 and FERC accepted the filing on April 10

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - It was confirmed at the May 28 PSPC meeting that FCA 15 will model the same zones as FCA 14
    - Export-constrained zones: Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England
  - Existing capacity values were posted on March 6
  - Summary of retirement and permanent delist bids was posted on March 18 and summary of substitution auction demand bids was posted on May 1
  - Show of Interest window closed on April 24
  - ICR and related values development are underway, with assumption discussions held at the May 28 PSPC meeting

FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- EE Reconstitution project is underway
  - RC was introduced to the issue at their April 22 meeting, and discussions with NEPOOL will continue into early summer
  - Changes will impact the 2021 forecast used for FCA 16 Installed Capacity Requirement development

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
- The Public Policy Process was initiated on 1/14/2020
  - Stakeholder input on federal, state, and local Public Policy Requirements (PPRs) was required to be submitted by 2/28/2020
  - Two PPR submittals were received
  - NESCOE submitted a communication to the ISO regarding PPRs on 5/1/2020
  - No stakeholder input was received on NESCOE's communication regarding federal Public Policy Requirements
  - The ISO will provide an update at the 6/17/20 PAC meeting

Boston 2028 Request for Proposal (RFP)

- The ISO issued the Boston 2028 RFP on 12/20/2019, which is its first RFP for a competitively-selected transmission solution
  - Phase One Proposals were required to be submitted by 11:00 p.m. on 3/4/2020
  - 36 Phase One Proposals were received from 8 QTPSs
    - Installed cost estimates ranged from $49M to $745M
    - In-service dates range from March 2023 to December 2026
  - The ISO will discuss the draft list of qualifying Phase One Proposals at the June PAC meeting

Highlights

- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning June 6, 2020

JUNE 4, 2020

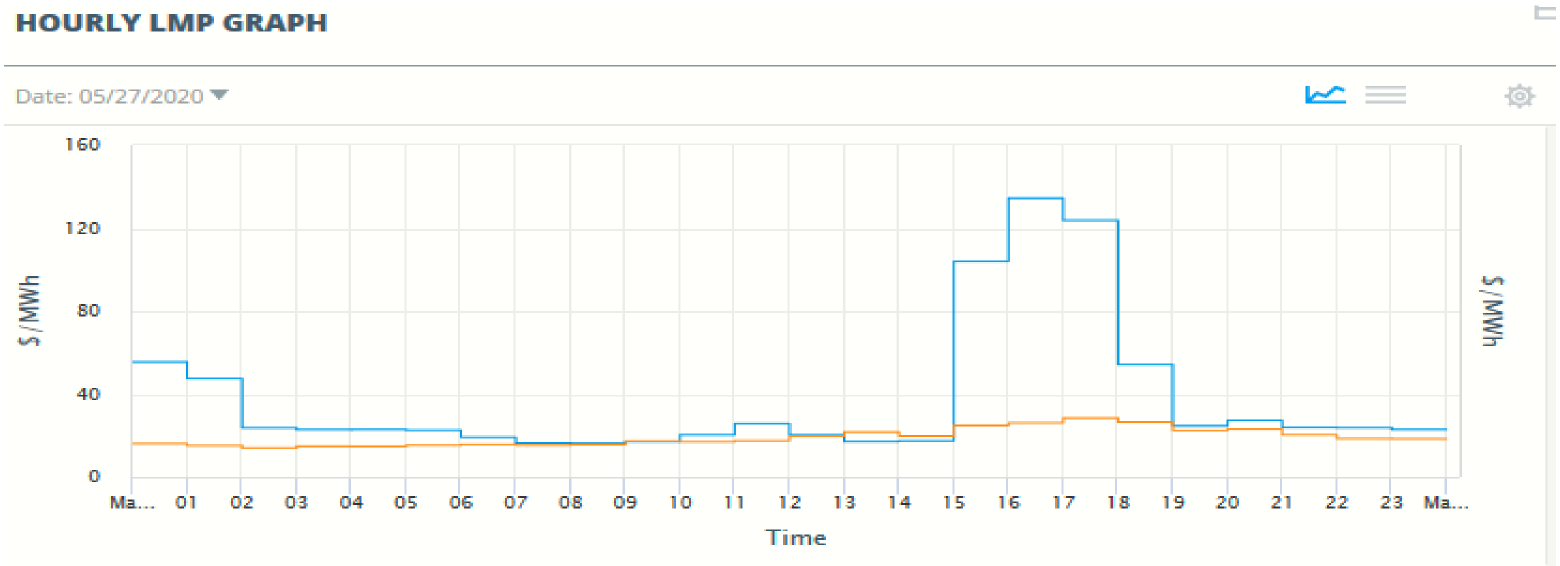
System Events on 5/27 and 5/29

May Operational Events

- There were two operational events that occurred in May
- 5/27 Event
  - Loss of a Phase II at 14:48 on 5/27 due to a lightning strike
  - At the time of the disturbance, Phase II was operating at approximately 1,980 MW
- 5/29 Event
  - Loss of a major generation facility at 14:04 on 5/29 resulted in the loss of 1,250 MW
  - Loss of one pole of Phase II at 20:23 on 5/29 and the second pole at 20:34 due to equipment failure resulted in the loss of 1,340 MW

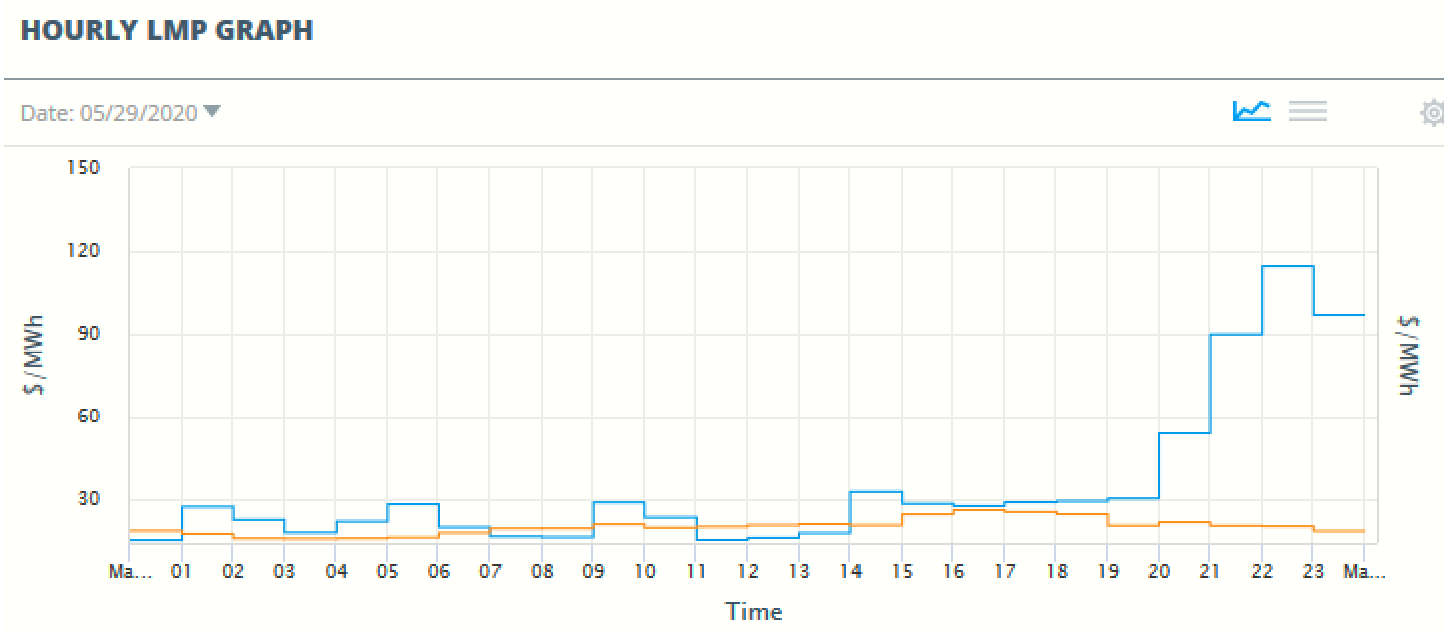
5/27 Loss of a major transmission intertie facility (Phase II)

- On 5/27 at 14:48 the system experienced the loss of Phase II due to a lightning strike which resulted in the loss of 1,980 MW
- All transmission and disturbance control standard criteria were met and maintained during and after the event
  - Recovery times for the Disturbance Control Standard were met within approximately 10 minutes
  - All reserve criteria were met during and following the event
  - The following chart displays Real-Time vs Day-Ahead prices for the day
  - Phase II was returned to commercial service after inspection and testing at 18:00 on 5/27



5/29 Loss of a major Generator

- On 5/29 at 14:04 the system experienced the loss of a major generation facility resulting in the loss of approximately 1,250 MW
- All transmission and disturbance control standard criteria were met and maintained during and after the event
  - Recovery times for the Disturbance Control Standard were met within criteria in approximately 8 minutes
  - All reserve criteria were met during and following the event
  - The following chart displays Real-Time vs Day-Ahead prices for the day (this also reflects the loss of the major transmission facility later in the day)



5/29 Loss of a major transmission intertie facility (Phase II)

- On 5/29 at 20:23, one pole of Phase II tripped and at 20:34, the second pole was tripped
- The cause was due to equipment failure and resulted in the loss of 1,340 MW
- All transmission and disturbance control standard criteria were met and maintained during and after the event
  - Recovery times for the Disturbance Control Standard were met within criteria in approximately 6 minutes each for the two separate events
  - All reserve criteria were met during and following the event
  - Half of the facility was returned to service on 5/30 after repairs, inspection and testing and the other half remains out of service for repairs

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (1.2°F) Max: 83°F, Min: 34°F Precipitation: 2.21” – Below Normal Normal: 3.49”	Hartford	Temperature: Below Normal (1.1°F) Max: 83°F, Min: 31°F Precipitation: 1.62” - Below Normal Normal: 4.35”

Peak Load:	16,294 MW	May, 29, 2020	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for May, 2020			

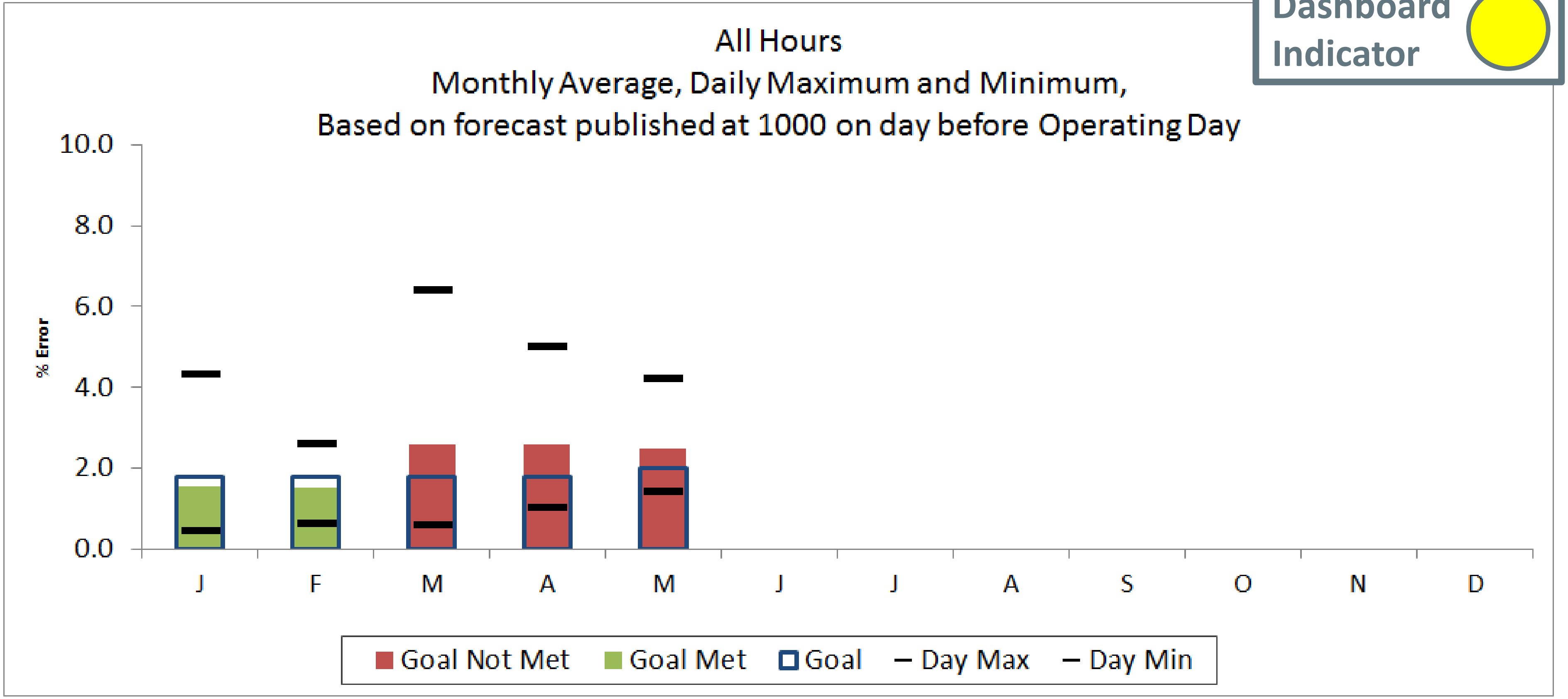
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
5/3	NYISO	580
5/8	IESO	850
5/27	ISO-NE	1980
5/29	ISO-NE	1250
5/29	ISO-NE	670
5/29	ISO-NE	670

2020 System Operations - Load Forecast Accuracy

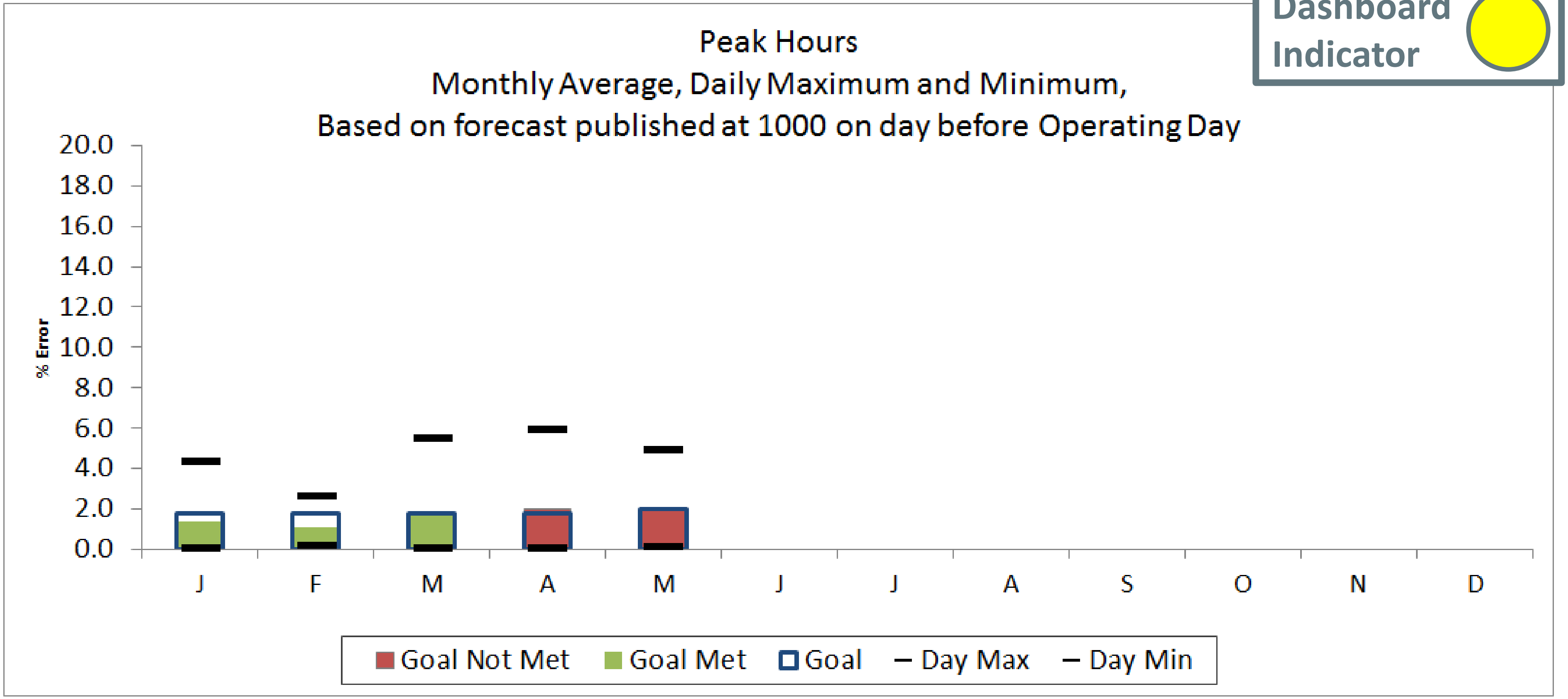
Dashboard Indicator 🟡



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	2.59	6.40	5.00	4.22								6.40
Day Min	0.46	0.61	0.58	1.03	1.42								0.46
MAPE	1.57	1.54	2.60	2.58	2.49								2.16
Goal	1.80	1.80	1.80	1.80	2.00								

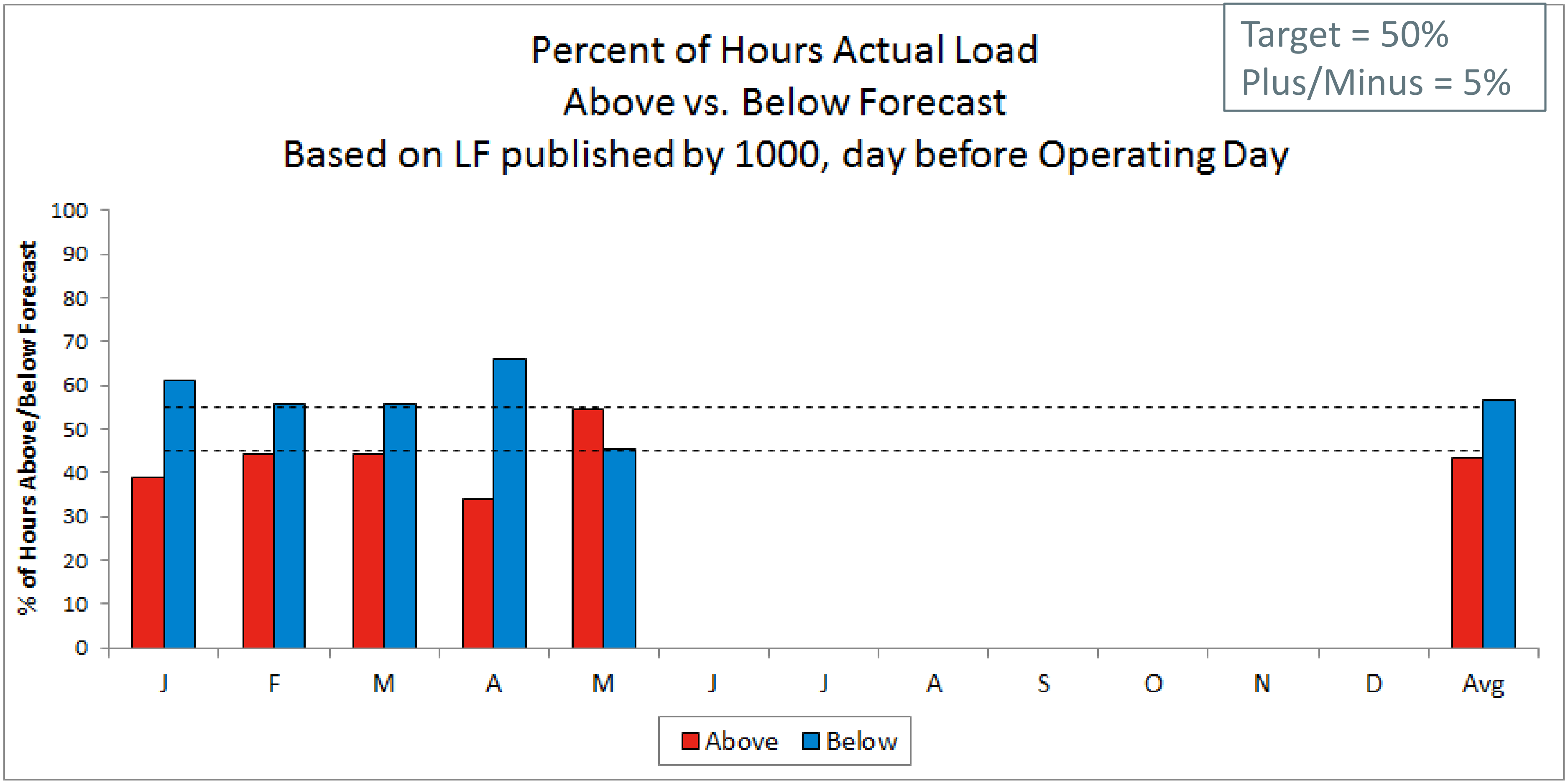
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator 🟡



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59	5.48	5.93	4.94								5.93
Day Min	0.07	0.19	0.01	0.00	0.13								0.00
MAPE	1.41	1.12	1.72	1.97	2.11								1.67
Goal	1.80	1.80	1.80	1.80	2.00								

2020 System Operations - Load Forecast Accuracy cont.

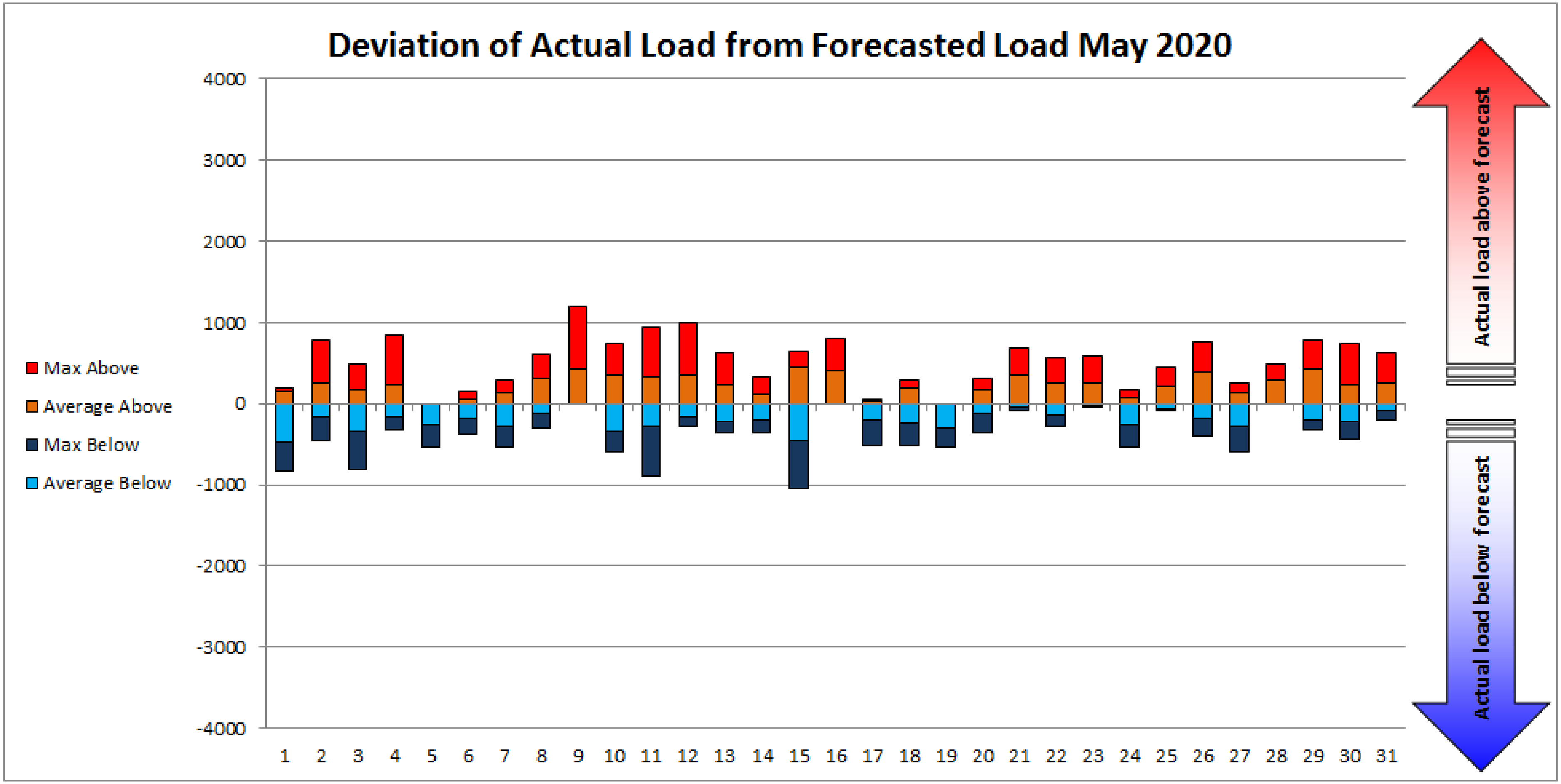


Target = 50%
Plus/Minus = 5%

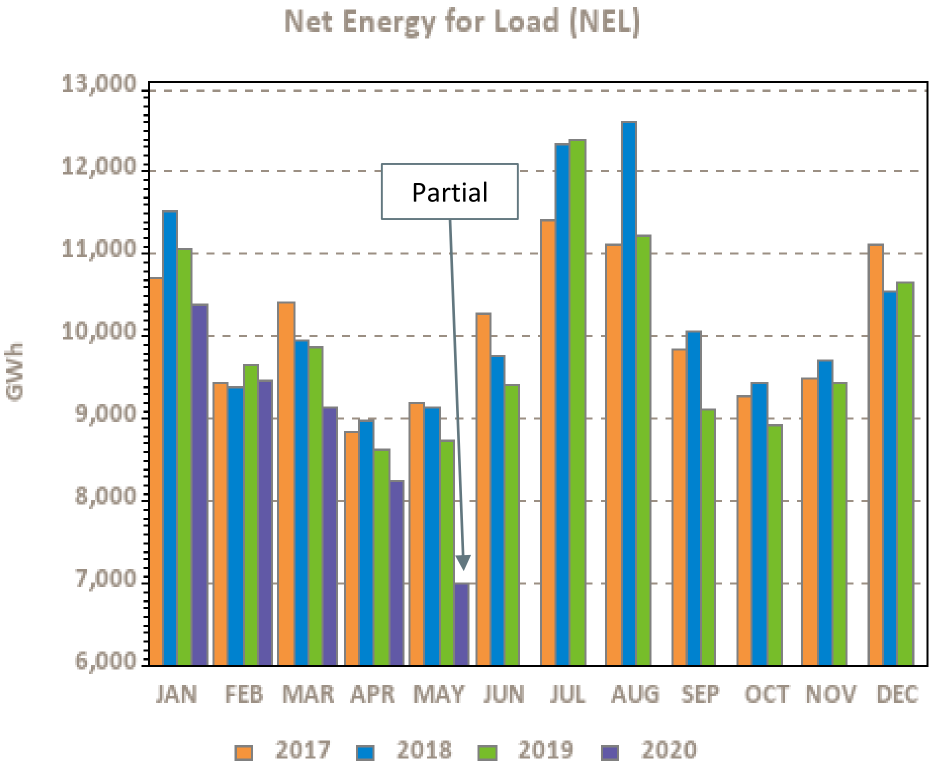
Percent of Hours Actual Load
Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day

	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3	44.4	33.9	54.4								43
Below %	61	55.7	55.6	66.1	45.6								57
Avg Above	136.2	169.9	207	178.9	231.9								232
Avg Below	-192.4	-157.6	-263.9	-265.3	-196.3								-265
Avg All	-65	-13	-56	-106	38								-40

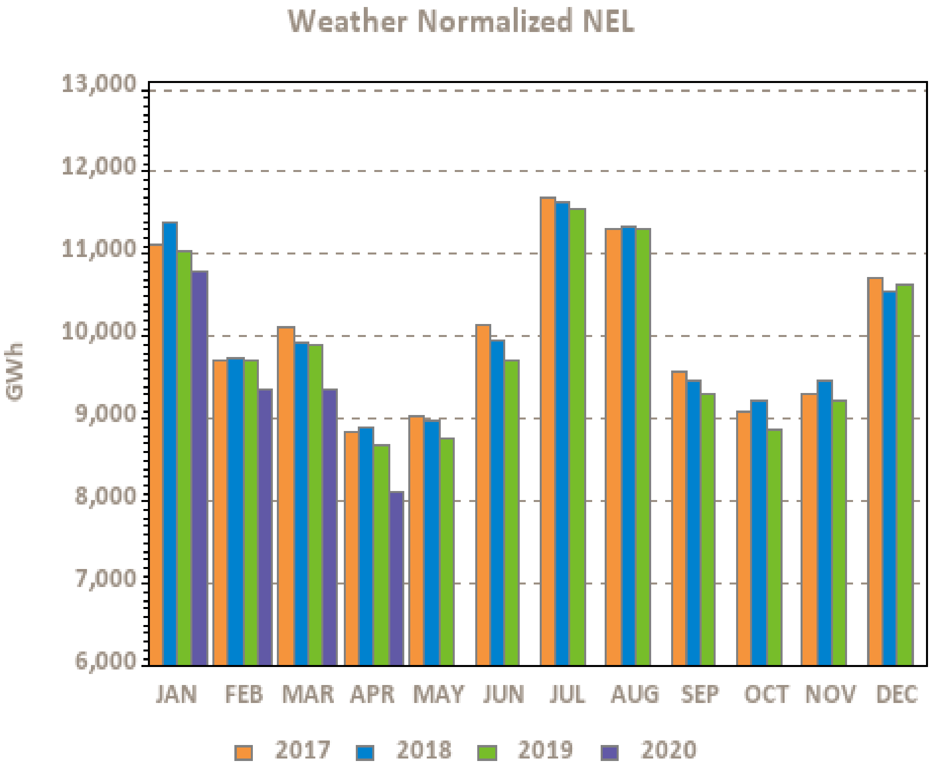
2020 System Operations - Load Forecast Accuracy cont.



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



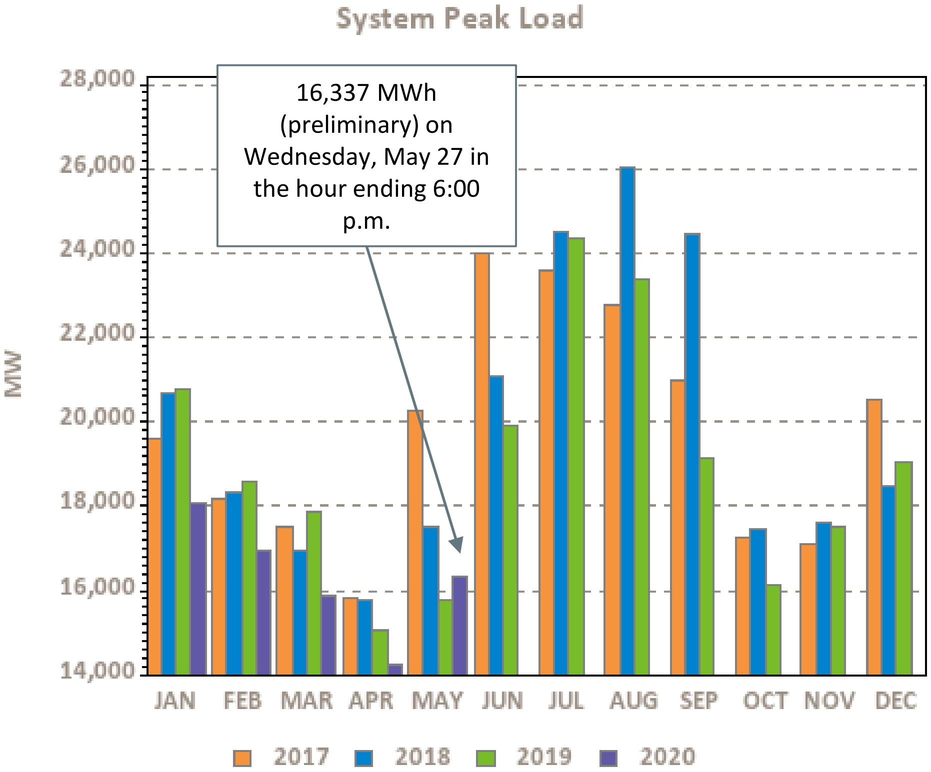
Ann Tot (TWh): 121.2 123.5 119.2 44.3



Ann Tot (TWh): 120.7 120.6 118.7 37.7

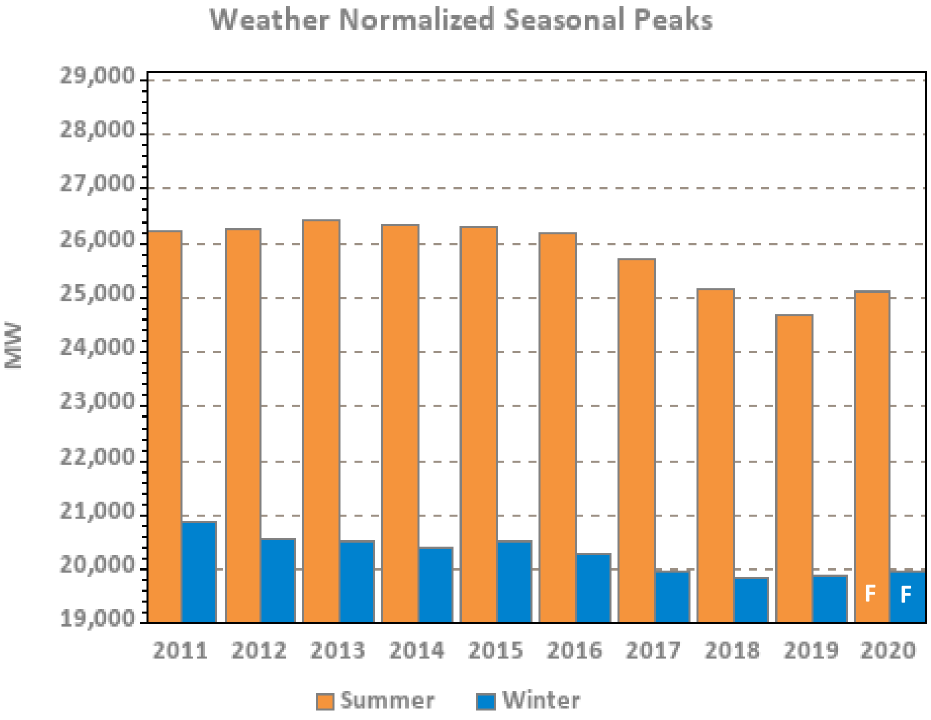
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL may be reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



16,337 MWh (preliminary) on Wednesday, May 27 in the hour ending 6:00 p.m.

Revenue quality metered value

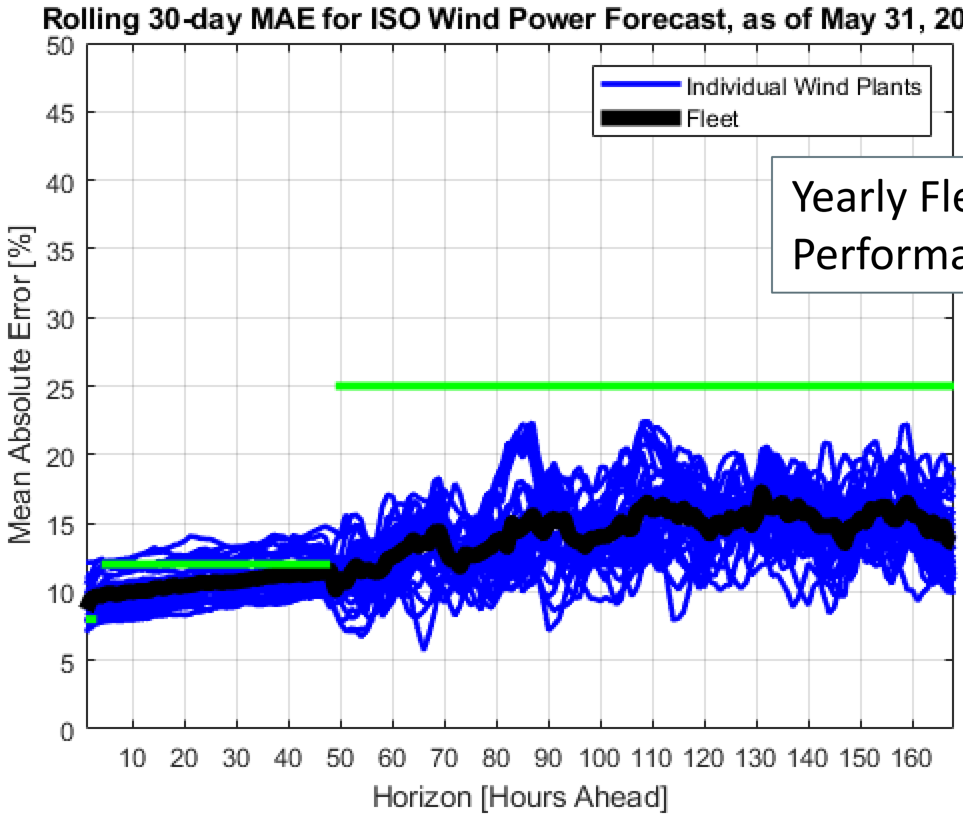


Winter beginning in year displayed

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

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

Dashboard Indicator ●

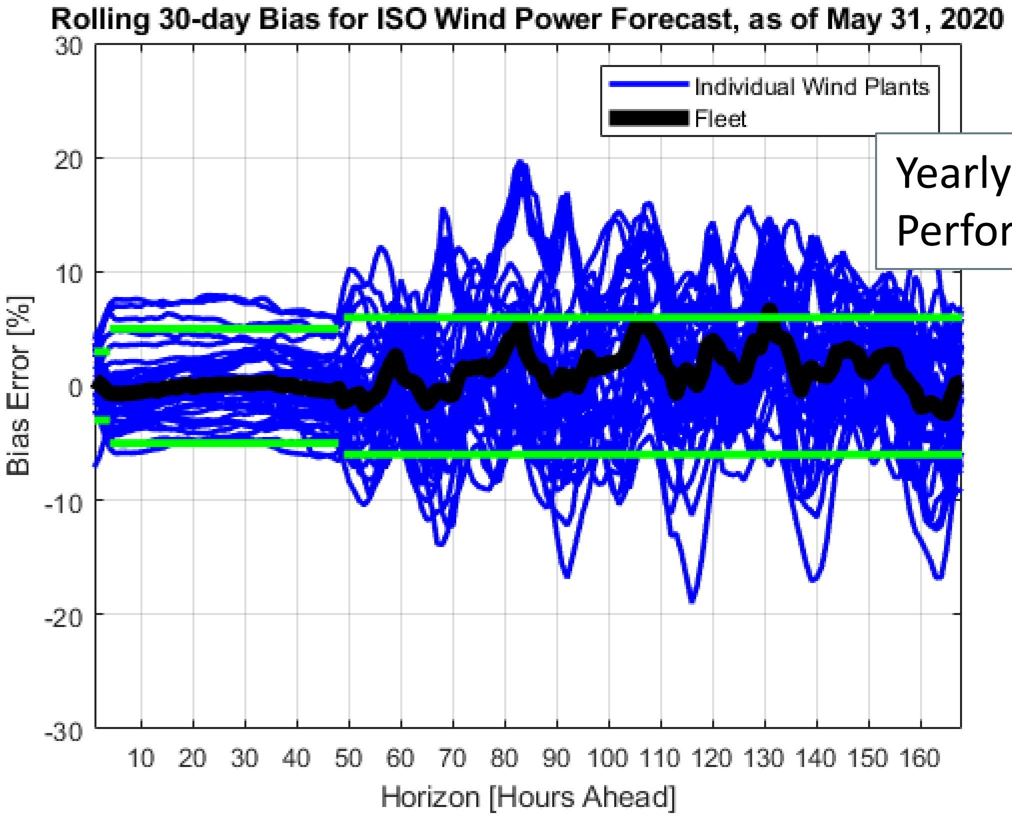


Yearly Fleet Performance targets

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

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

Dashboard Indicator ●

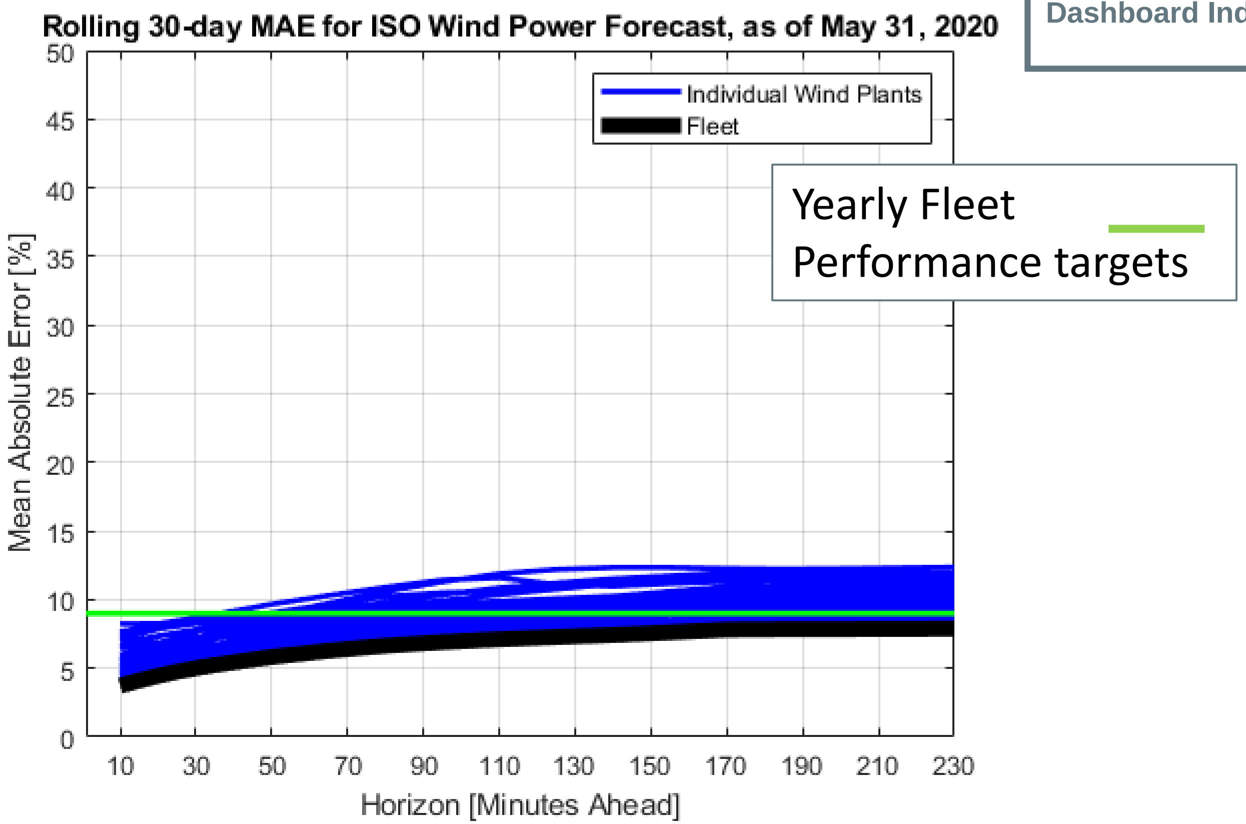


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

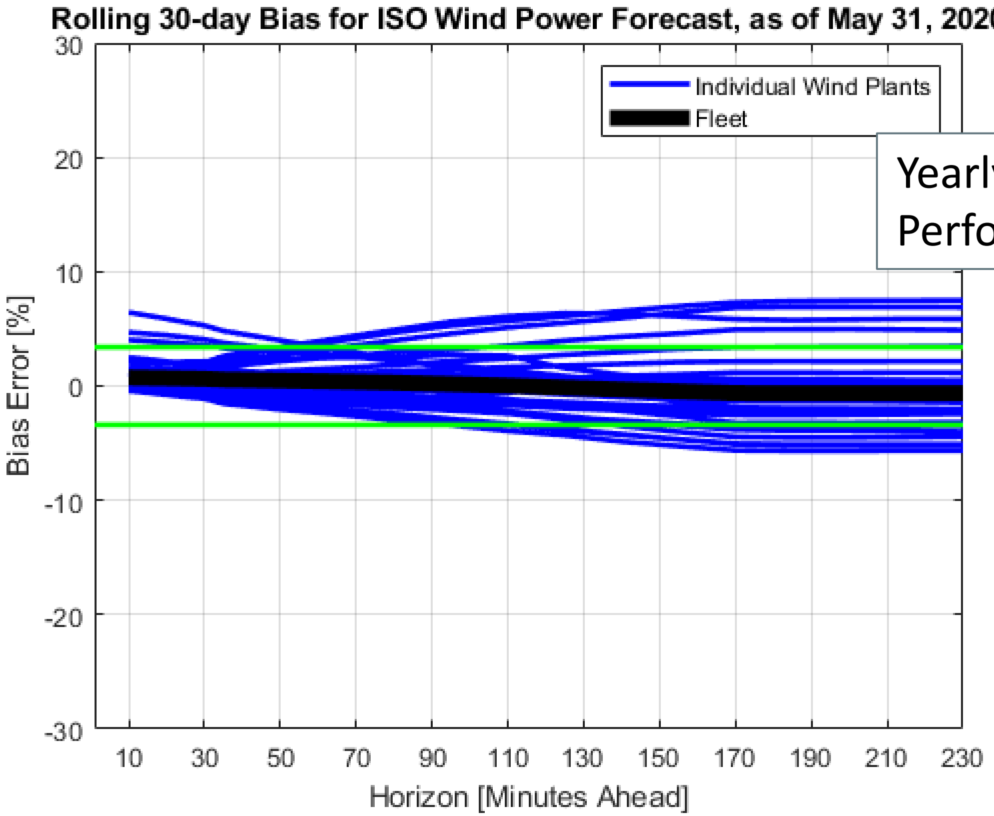
Dashboard Indicator ●



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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator ●

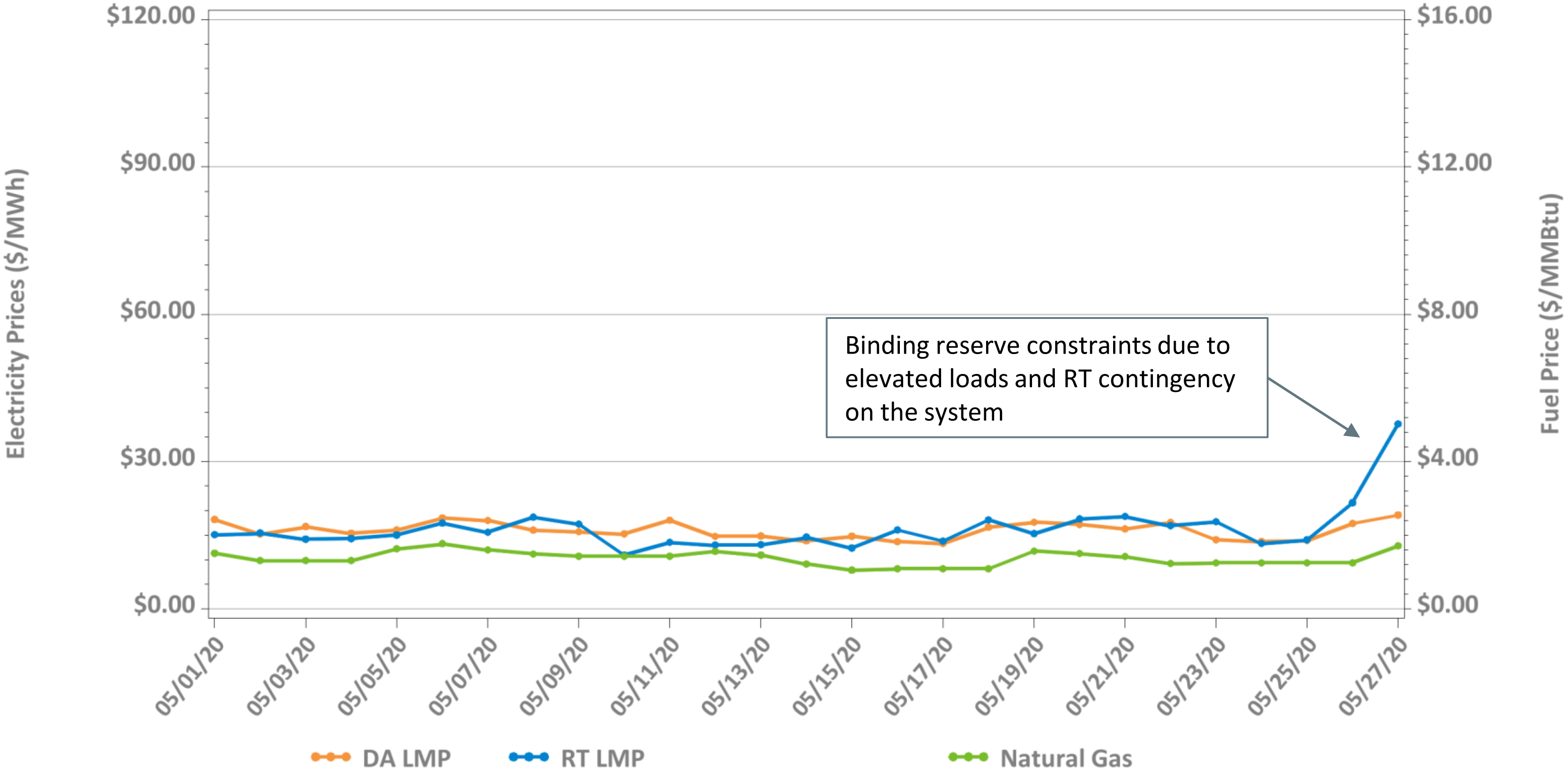

Rolling 30-day Bias for ISO Wind Power Forecast, as of May 31, 2020

Yearly Fleet Performance targets

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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: May 1-27, 2020



Binding reserve constraints due to elevated loads and RT contingency on the system

Underlying natural gas data furnished by:

ICE Global markets in clear view

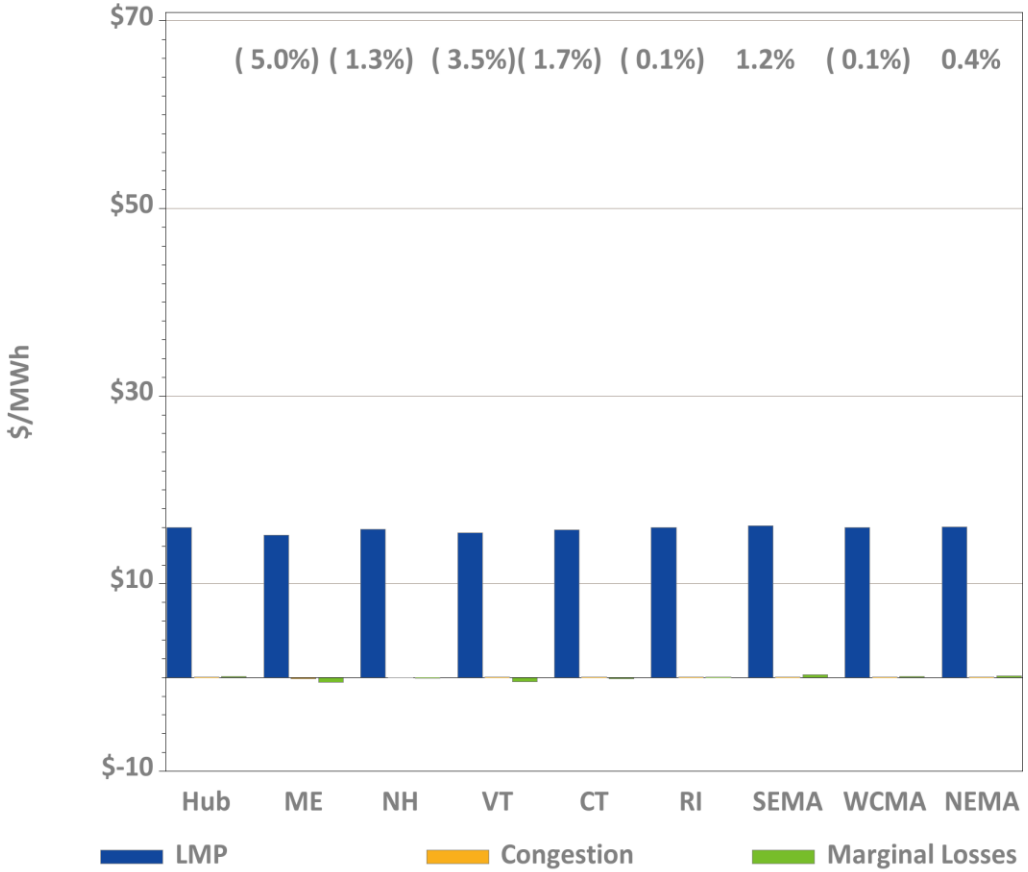
Average price difference over this period (DA-RT): $-0.39

Average price difference over this period ABS(DA-RT): $2.56

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 16%

Gas price is average of Massachusetts delivery points

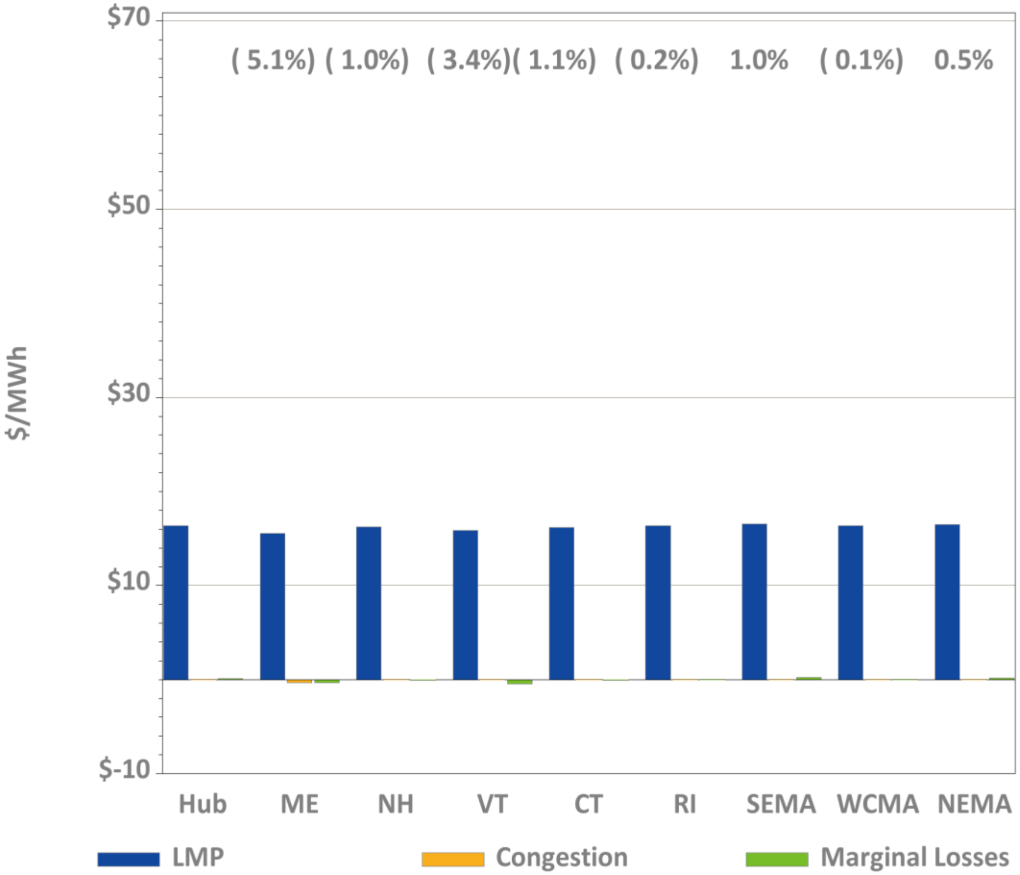
DA LMPs Average by Zone & Hub, May 2020



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

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

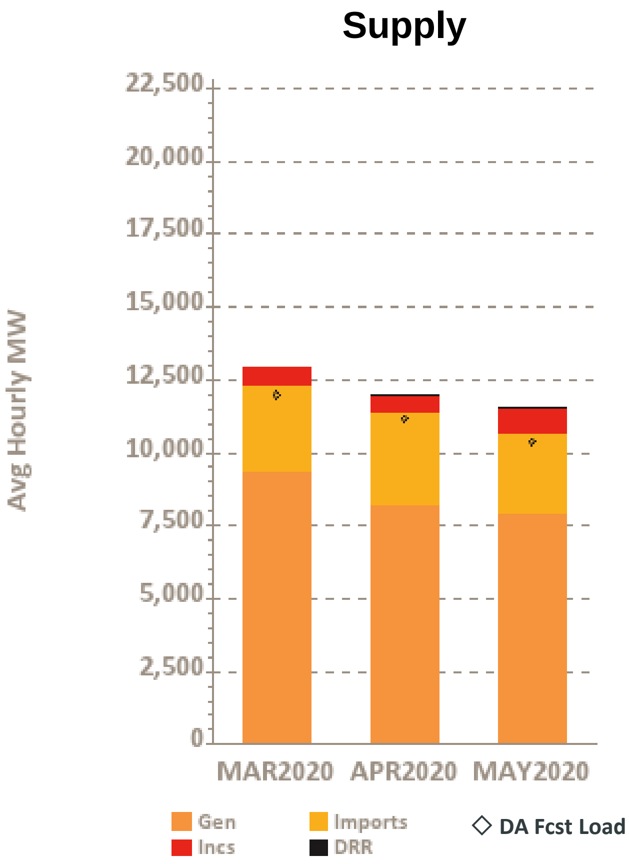
RT LMPs Average by Zone & Hub, May 2020

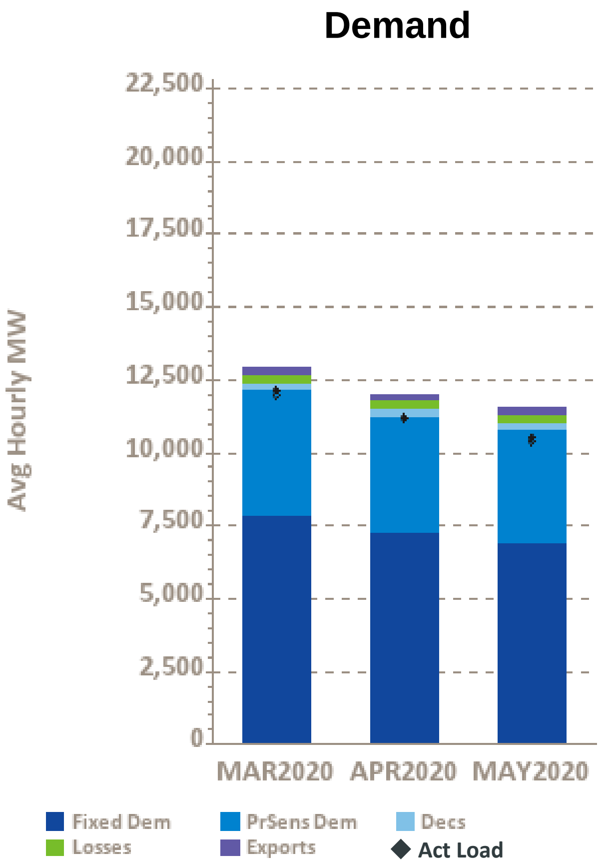


Definitions

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

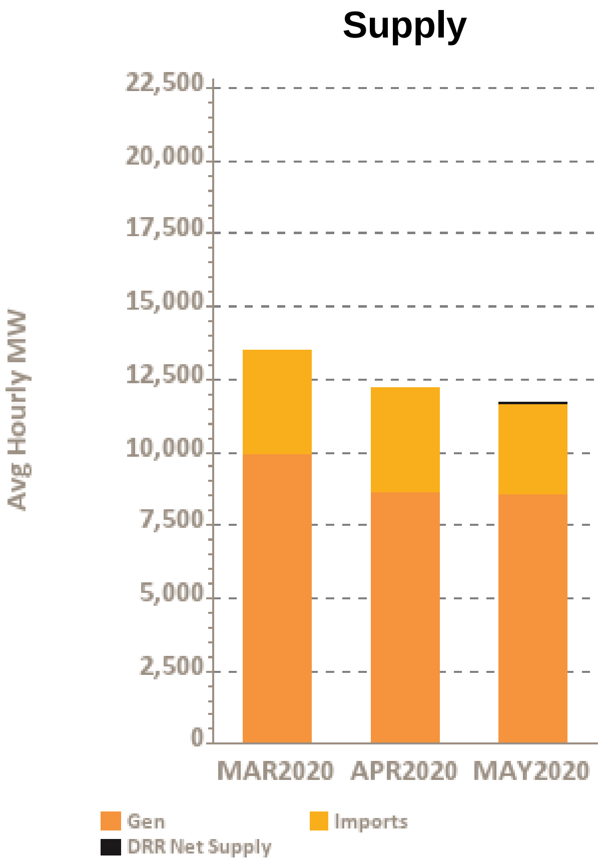


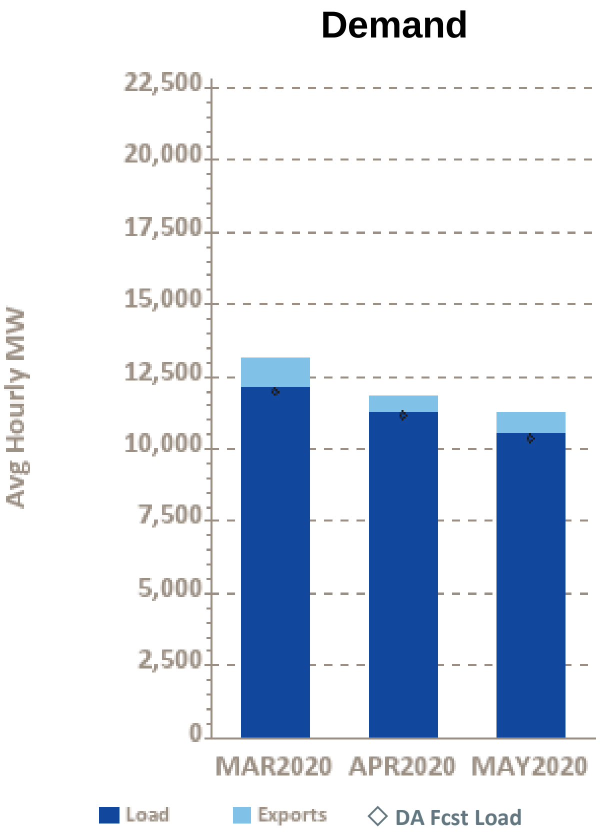


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

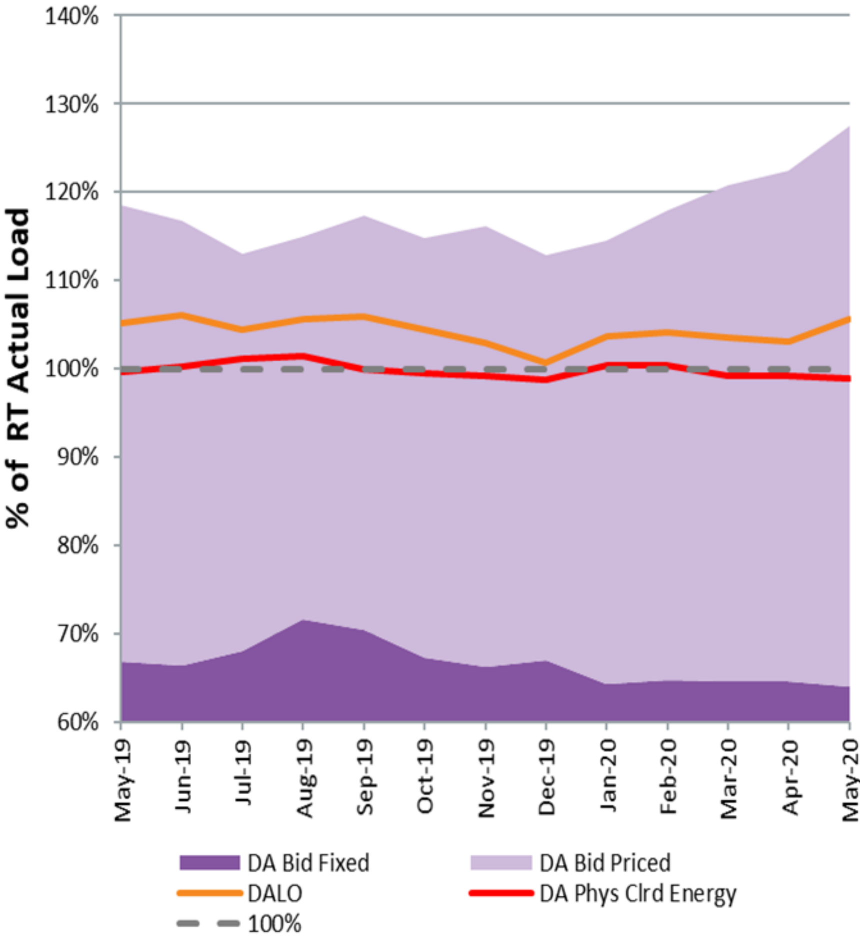
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

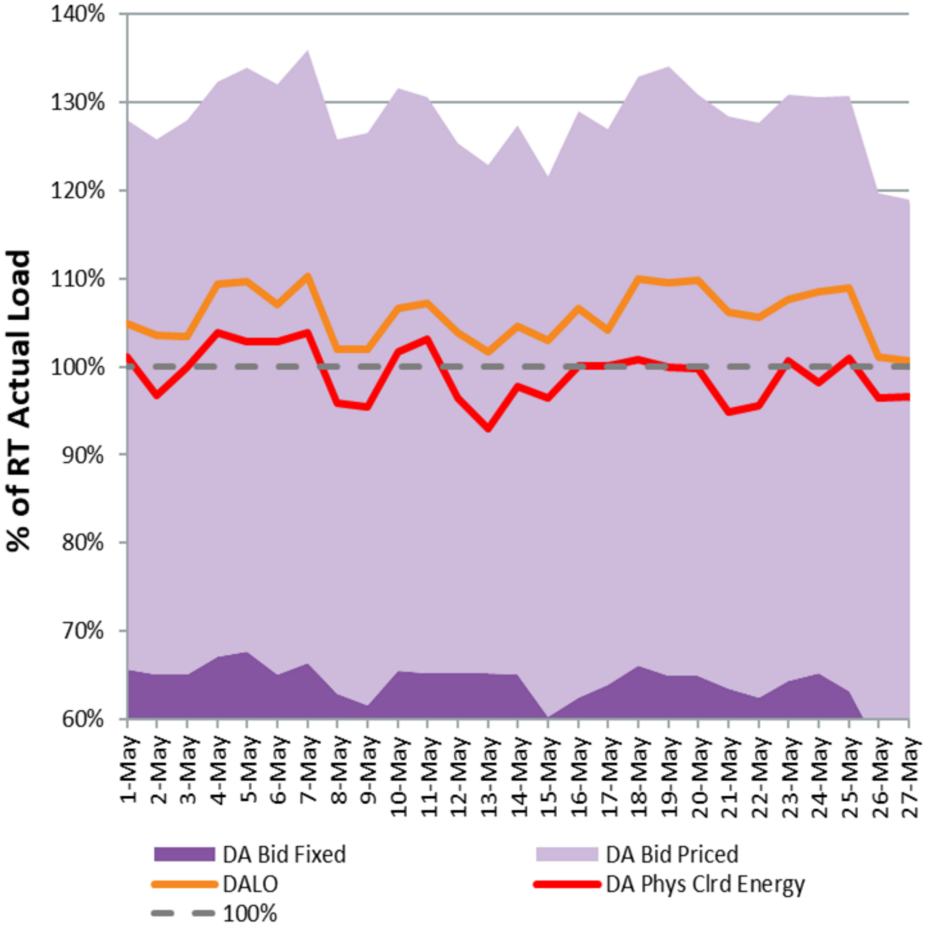
Components of RT Supply and Demand – Last Three Months





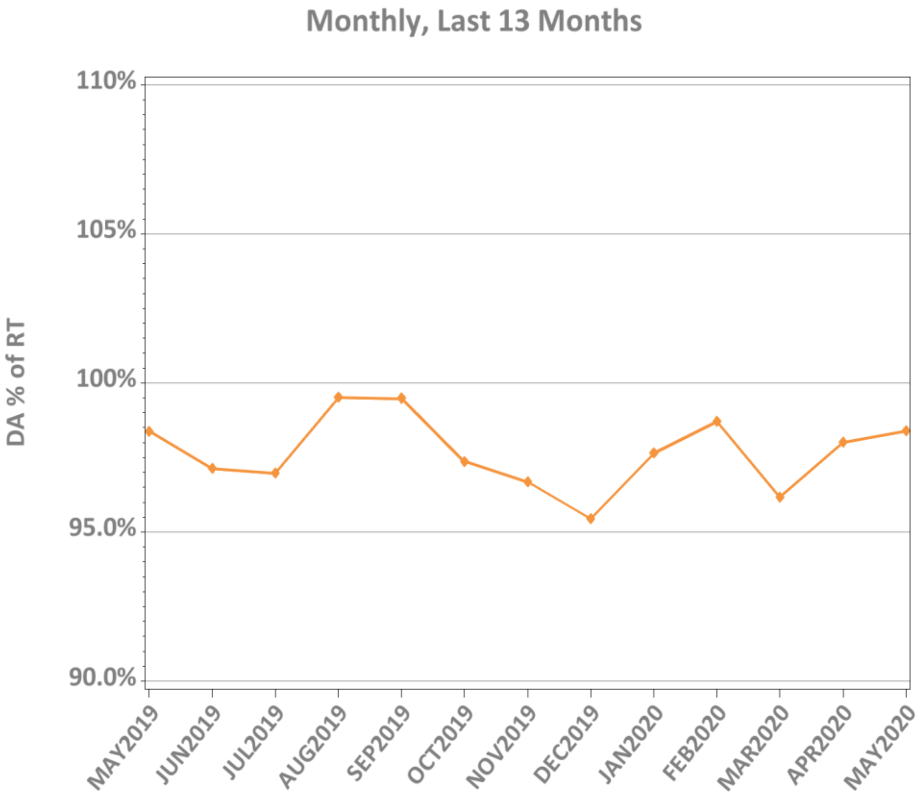
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

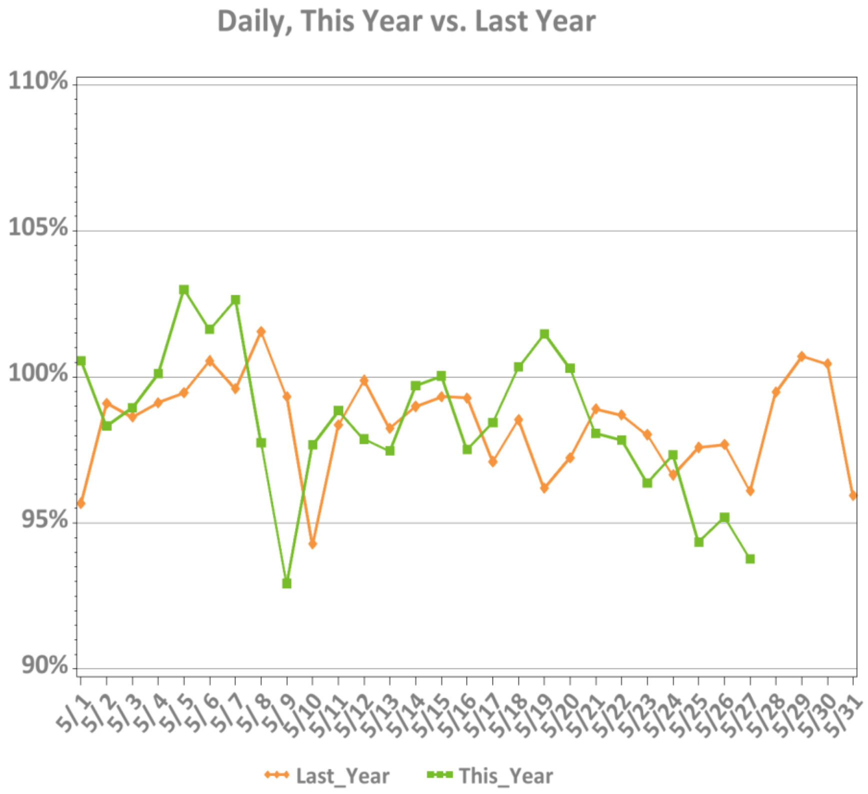




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

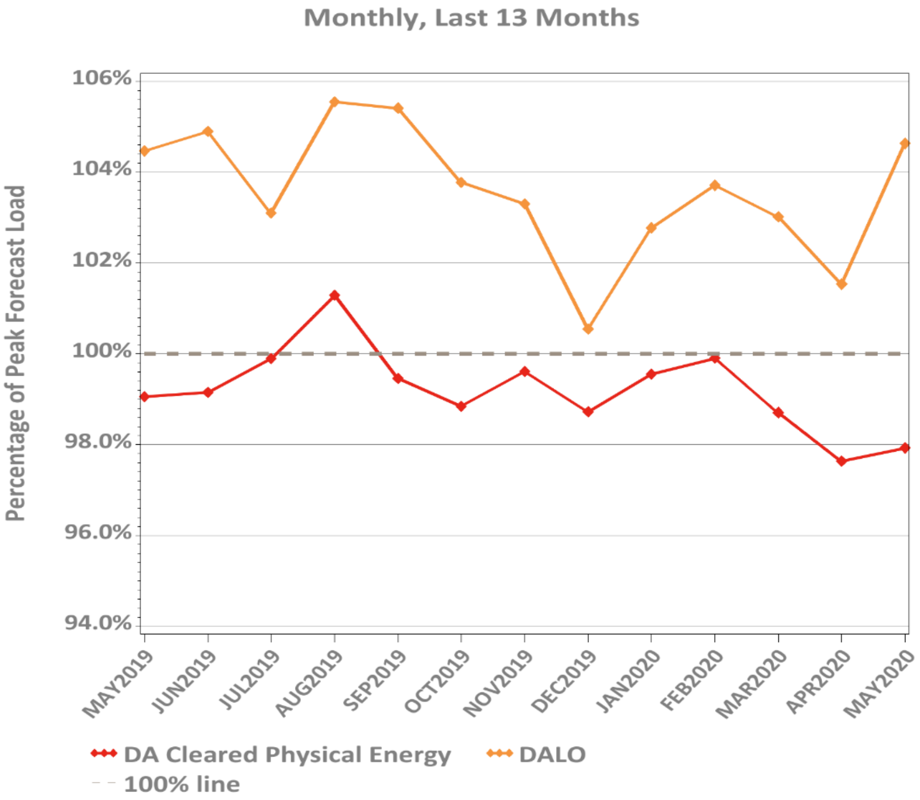
DA vs. RT Load Obligation: May, This Year vs. Last Year

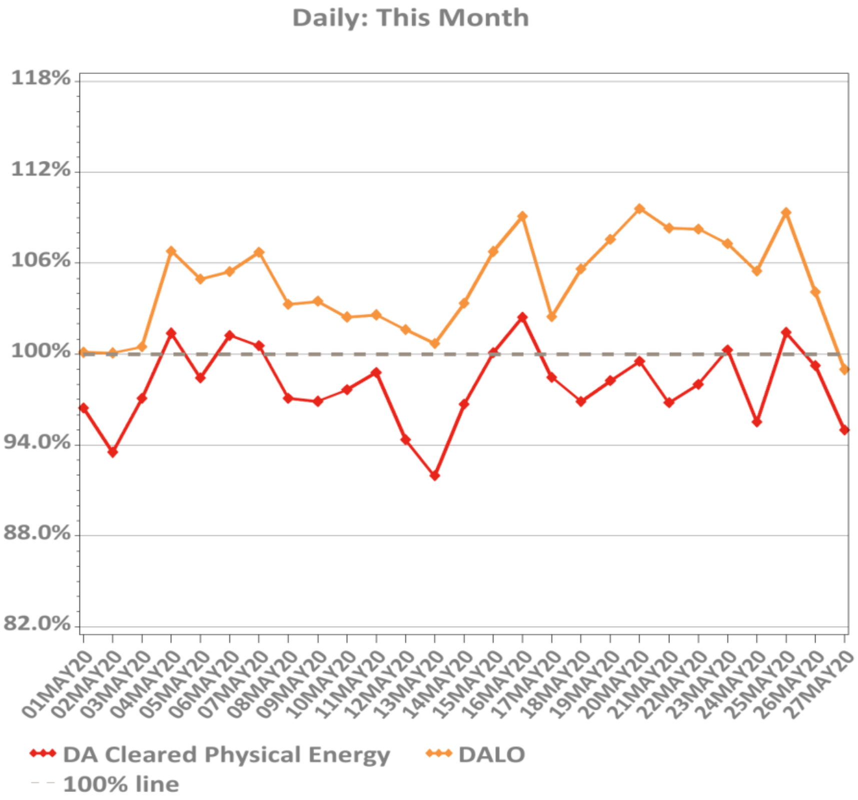




*Hourly average values

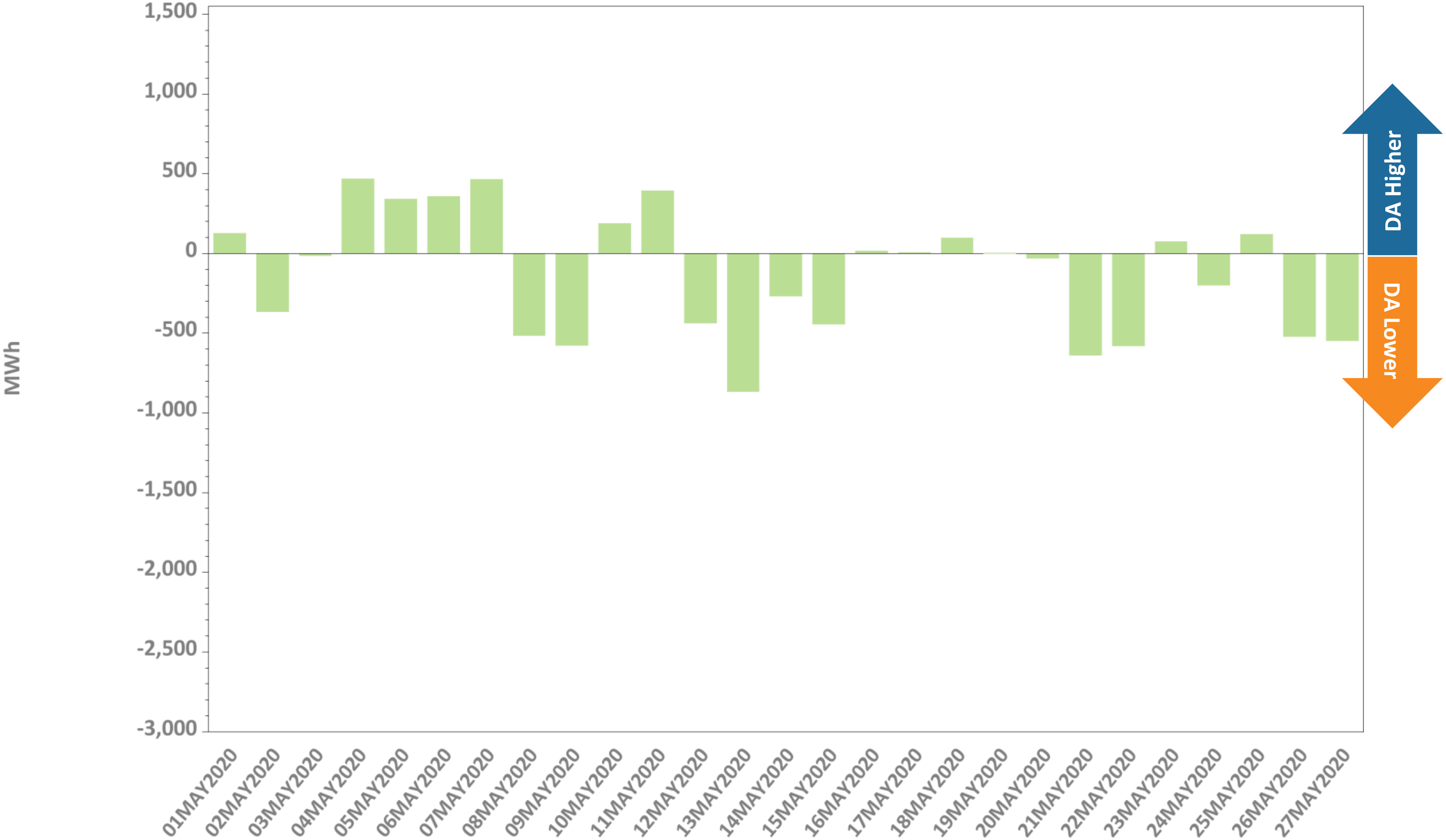
DA Volumes as % of Forecast in Peak Hour


Monthly, Last 13 Months


Daily: This Month

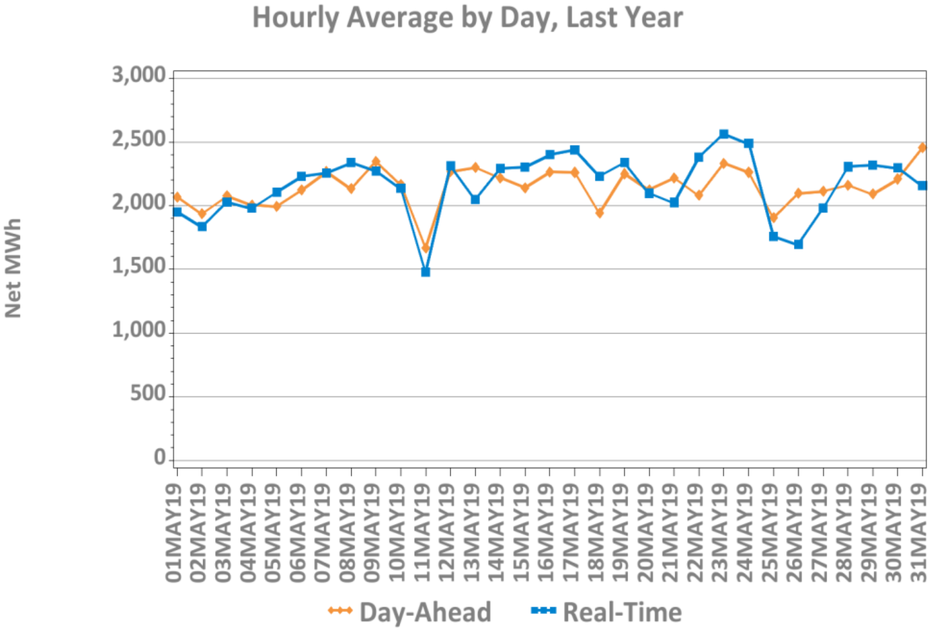
* There were *no* system-level supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during May.

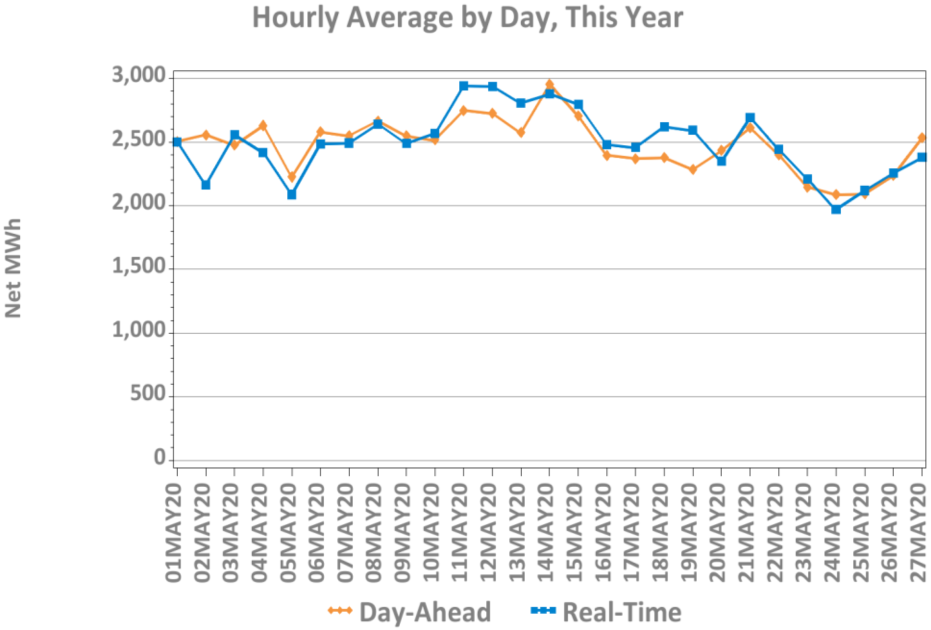
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

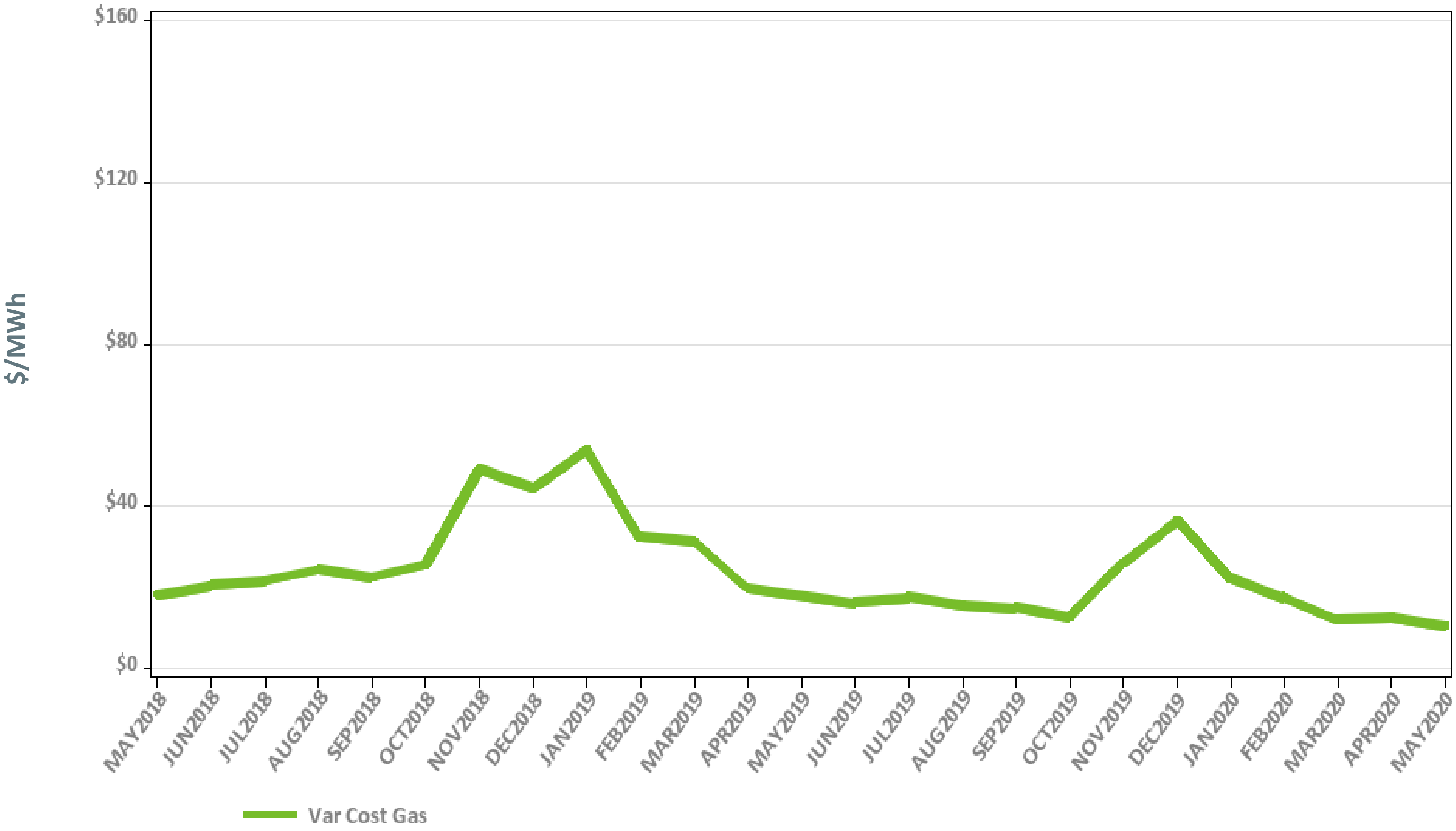
DA vs. RT Net Interchange
May 2019 vs. May 2020





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

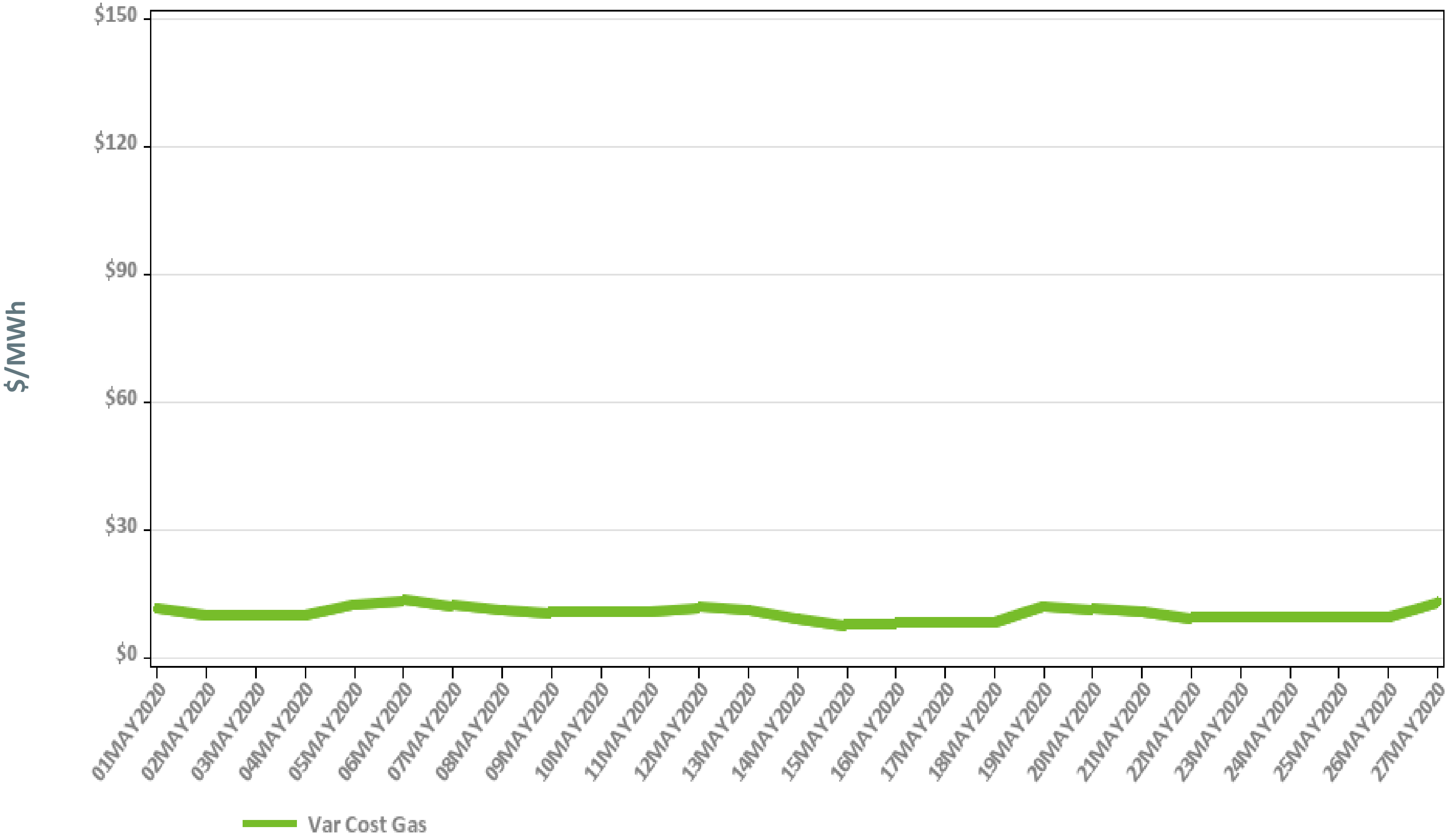


Underlying natural gas data furnished by:

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

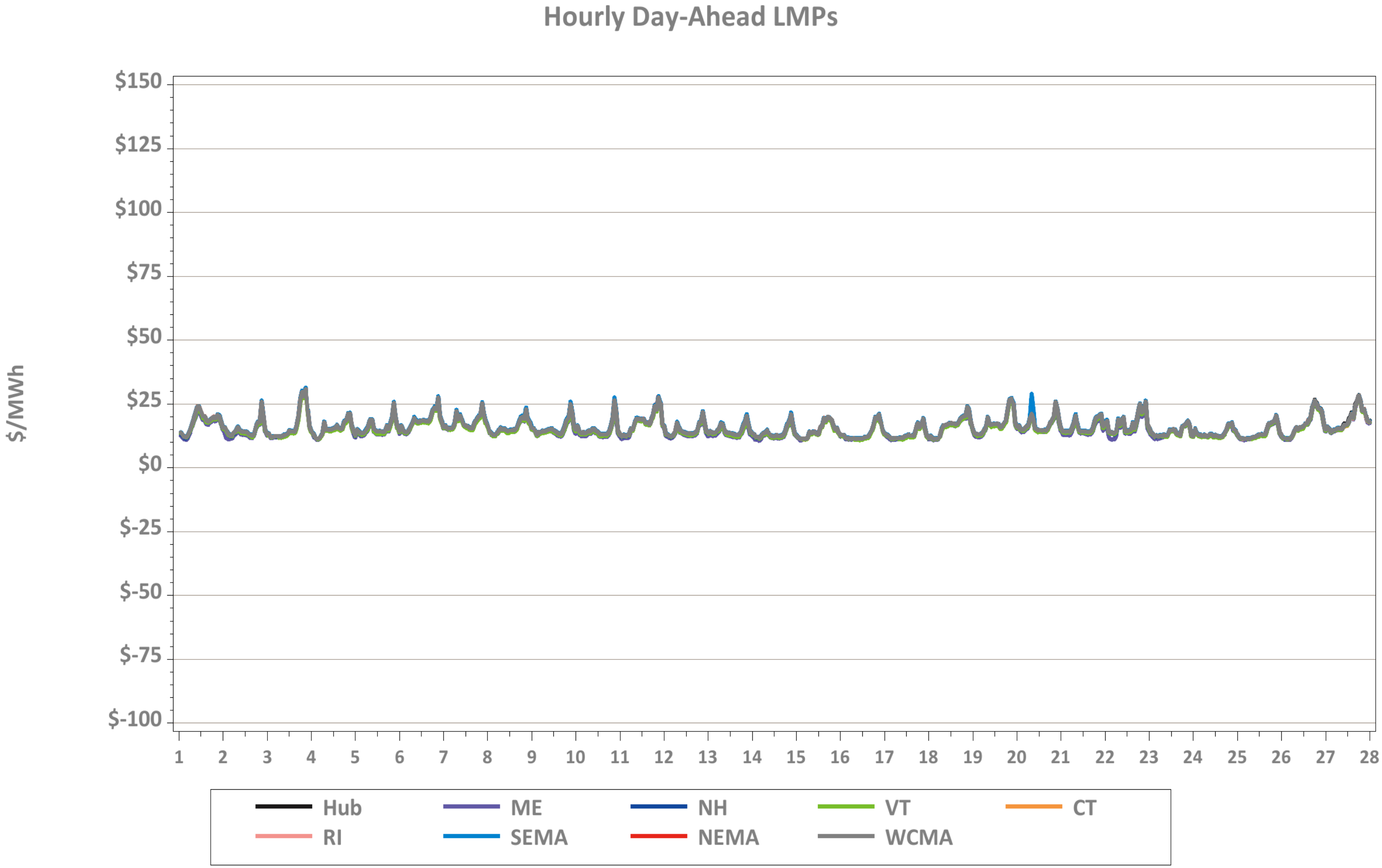


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

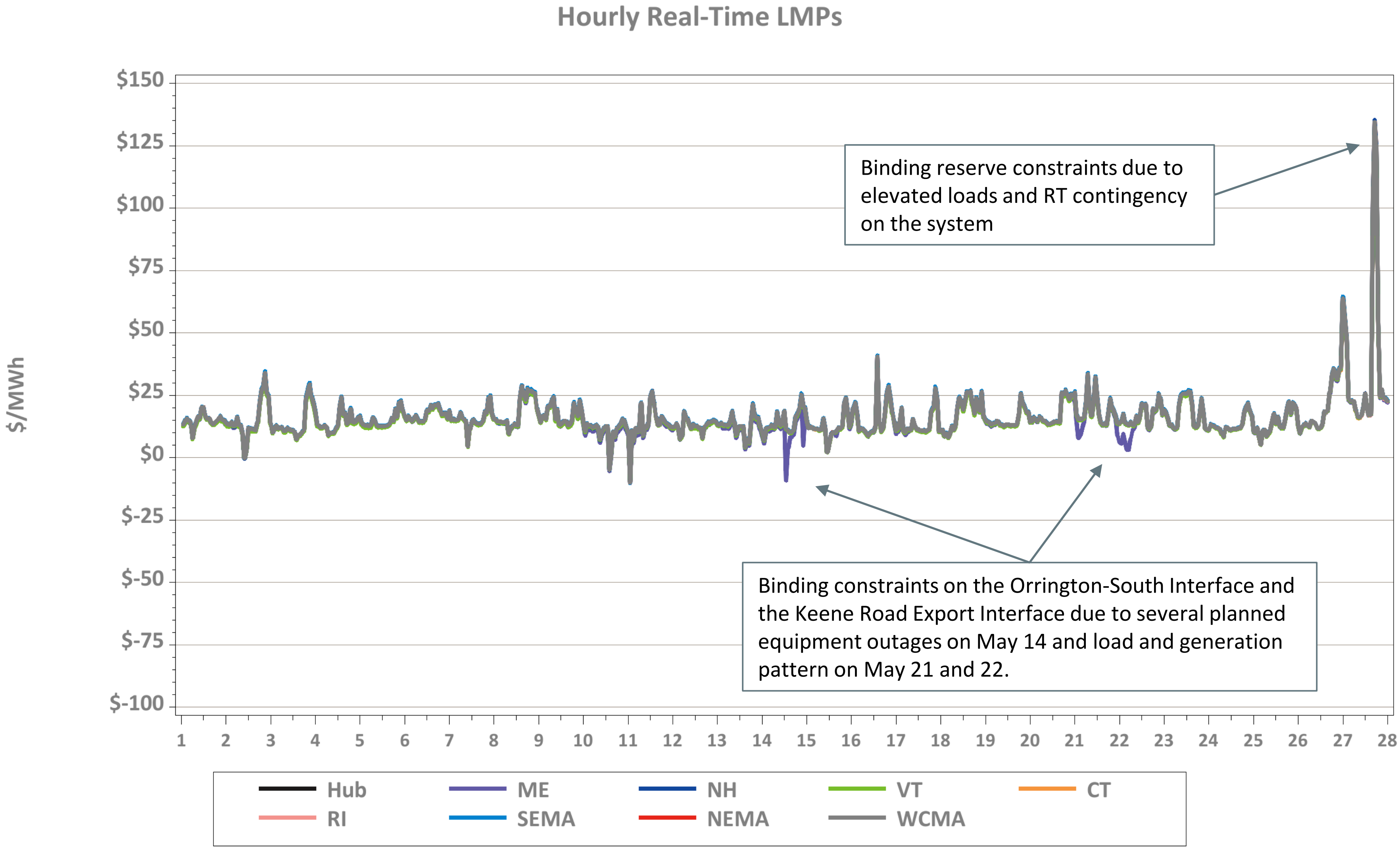
Underlying natural gas data furnished by:

ice Global markets in clear view

Hourly DA LMPs, May 1-27, 2020



Hourly RT LMPs, May 1-27, 2020

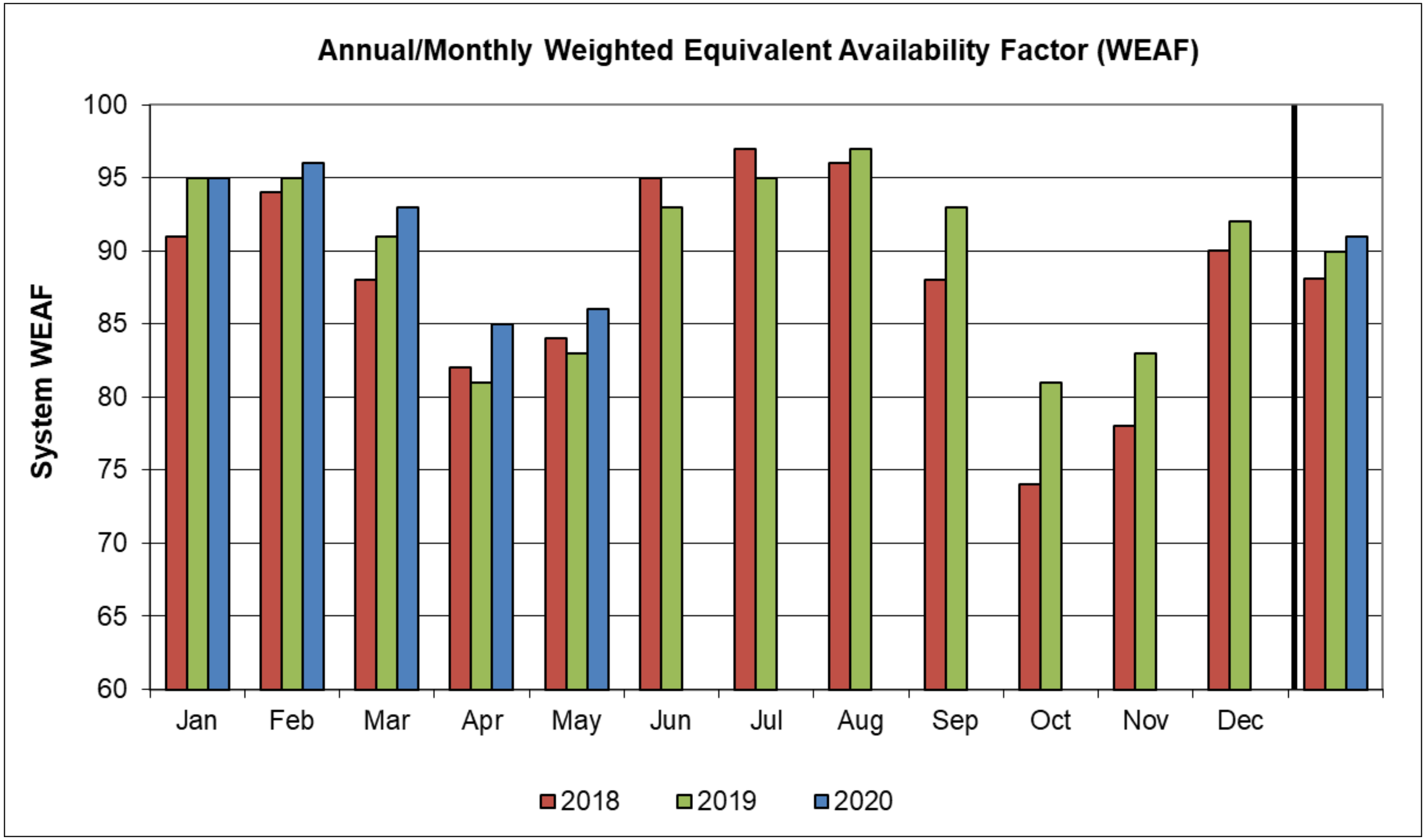


Binding reserve constraints due to elevated loads and RT contingency on the system

Binding constraints on the Orrington-South Interface and the Keene Road Export Interface due to several planned equipment outages on May 14 and load and generation pattern on May 21 and 22.

- No Minimum Generation Emergencies were declared during May.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95	96	93	85	86								91
2019	95	95	91	81	83	93	95	97	93	81	83	92	90
2018	91	94	88	82	84	95	97	96	88	74	78	90	88

Data as of 5/26/2020

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for June 2020

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	59.4	184.1	0.0	243.5
NH	31.8	147.3	0.0	179.1
VT	22.9	100.6	0.0	123.5
CT	93.2	154.2	549.2	796.7
RI	34.4	268.2	0.0	302.6
SEMA	38.0	443.0	0.0	481.0
WCMA	67.0	463.6	45.3	575.9
NEMA	48.9	811.3	0.0	860.2
Total	**395.6**	**2,572.3**	**594.5**	**3,562.4**

*** Active Demand Capacity Resources**

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

NEW GENERATION

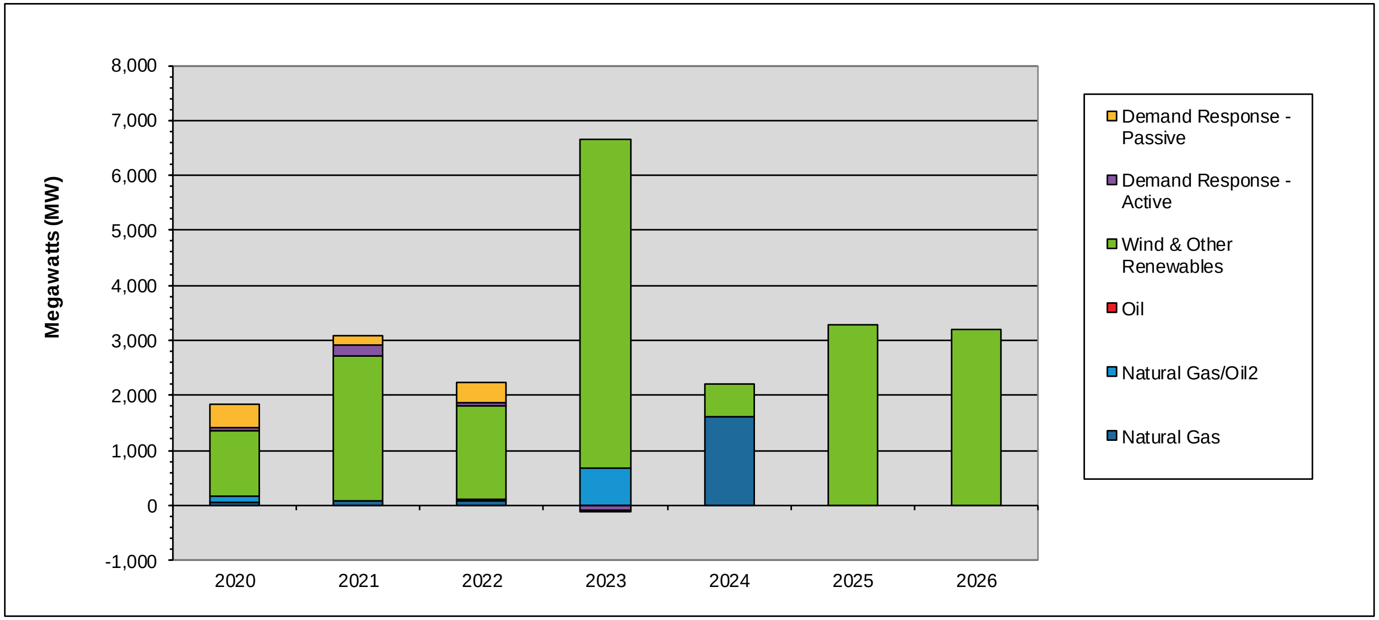
New Generation Update

Based on Queue as of 5/29/20

- Four projects totaling 273 MW applied for interconnection study since the last update
- No projects went commercial or withdrew, resulting in a net increase in new generation projects of 273 MW
- In total, 236 generation projects are currently being tracked by the ISO, totaling approximately 21,146 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Demand Response - Passive	422	184	380	-28	0	0	0	958	4.3
Demand Response - Active	42	204	62	-94	0	0	0	214	1.0
Wind & Other Renewables	1,201	2,627	1,685	5,990	607	3,276	3,200	18,586	83.0
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	121	0	39	672	0	0	0	832	3.7
Natural Gas	43	76	73	0	1,600	0	0	1,792	8.0
Totals	**1,830**	**3,091**	**2,239**	**6,540**	**2,207**	**3,276**	**3,200**	**22,383**	**100.0**

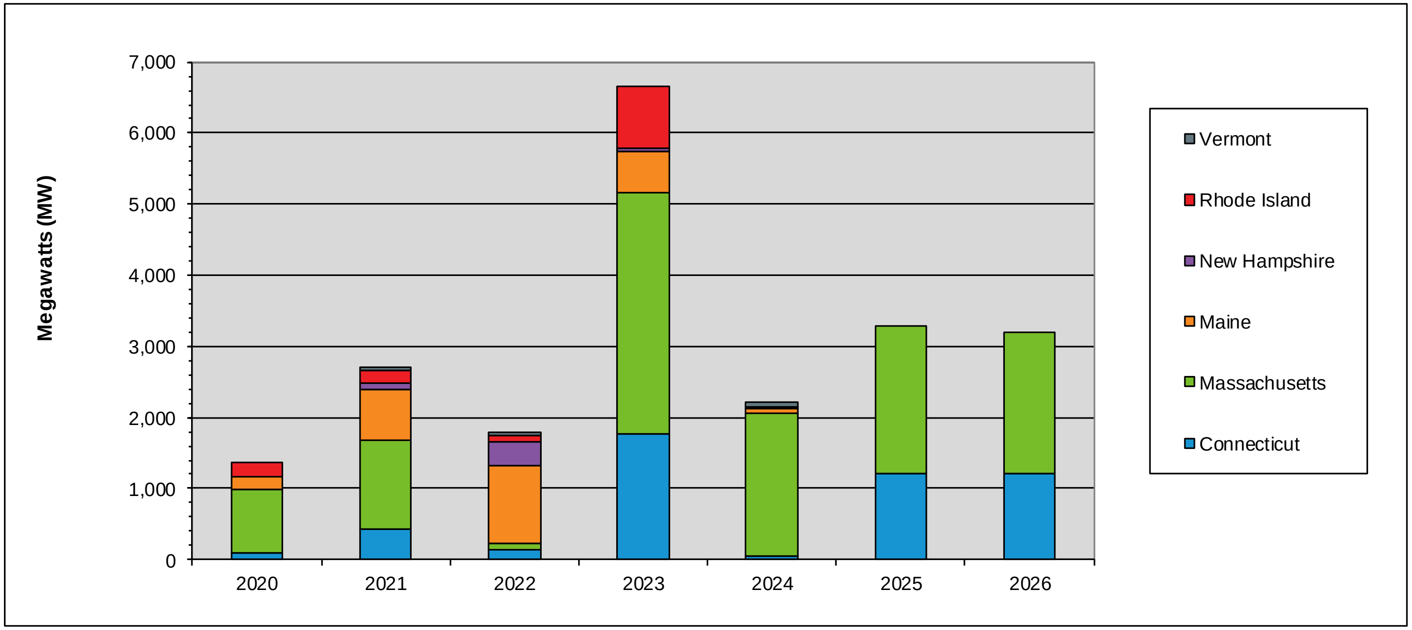
[1] Sum may not equal 100% due to rounding

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

- 2020 values include the 64 MW of generation that has gone commercial in 2020
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Vermont	0	35	60	0	50	0	0	145	0.7
Rhode Island	206	196	73	880	0	0	0	1,355	6.4
New Hampshire	0	83	352	50	20	0	0	505	2.4
Maine	161	717	1,090	571	81	0	0	2,620	12.4
Massachusetts	896	1,232	87	3,384	2,016	2,076	2,000	11,691	55.1
Connecticut	102	440	135	1,777	40	1,200	1,200	4,894	23.1
Totals	**1,365**	**2,703**	**1,797**	**6,662**	**2,207**	**3,276**	**3,200**	**21,210**	**100.0**

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

- 2020 values include the 64 MW of generation that has gone commercial in 2020

New Generation Projection

By Fuel Type

Fuel Type	**Total**		**Green**		**Yellow**	
	No. of Projects	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	1	8	0	0	1	8
Battery Storage	15	2,079	0	0	15	2,079
Hydro	3	99	1	66	2	33
Landfill Gas	0	0	0	0	0	0
Natural Gas	13	1,792	0	0	13	1,792
Natural Gas/Oil	6	787	1	14	5	773
Nuclear	1	37	0	0	1	37
Oil	0	0	0	0	0	0
Solar	175	3,860	7	171	168	3,689
Wind	22	12,484	0	0	22	12,484
Total	236	21,146	9	251	227	20,895

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	133	0	0	8	133
Intermediate	12	2,433	1	14	11	2,419
Peaker	194	6,037	8	237	186	5,800
Wind Turbine	22	12,543	0	0	22	12,543
Total	236	21,146	9	251	227	20,895

- 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	1	8	1	8	0	0	0	0	0	0
Battery Storage	15	2,079	0	0	0	0	15	2,079	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	13	1,792	4	55	8	1,731	1	6	0	0
Natural Gas/Oil	6	787	0	0	4	702	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	175	3,860	0	0	0	0	174	3,740	1	120
Wind	22	12,484	0	0	0	0	1	61	21	12,423
Total	236	21,146	8	133	12	2,433	194	6,037	22	12,543

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

FORWARD CAPACITY MARKET

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	594.551	153.33	584.35	-10.201
	Passive Demand	2,791.02	2,835.354	44.334	2,883.767	48.413	2,964.695	80.928
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**	**3,549.045**	70.727
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661	2,9678.995	-480.896
	Intermittent	894.217	823.796	-70.421	809.571	-14.225	689.524	-120.047
Generator Total		**31,389.02**	**30,888.027**	**-500.993**	**30,969.462**	**81.435**	**30,368.519**	**-600.943**
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**	**1,124.6**	**-485.244**
****Grand Total**		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**	**35,042.164**	**-1015.46**
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**	**32,205**	**-1,315**

* 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	659.137	34.692				
	Passive Demand	2,975.36	3,045.073	69.713				
Demand Total		**3,599.81**	**3,704.21**	**104.4**				
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654				
	Intermittent	880.317	806.609	-73.708				
Generator Total		**30,011.07**	**30,051.013**	**39.943**				
Import Total		**1,217**	**1,305.487**	**88.487**				
****Grand Total**		**34,827.88**	**35,060.710**	**232.83**				
Net ICR (NICR)		**33,725**	**33,550**	**-175**				

* 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.

Capacity Supply Obligation FCA 14

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*	**592.043**						
	Passive Demand	**3,327.071**						
Demand Total		**3,919.114**						
Generator	*Non-Intermittent*	**27,816.902**						
	Intermittent	**1,160.916**						
Generator Total		**28,977.818**						
Import Total		**1,058.72**						
****Grand Total**		**33,955.652**						
Net ICR (NICR)		**32,490**						

* 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**
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	2,375.422	370.734	2,746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2,571.361	639.586	3,210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3,085.734	514.072	3,599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3,386.703	653.541	4,040.244
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	3,596.056	323.058	3,919.114

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

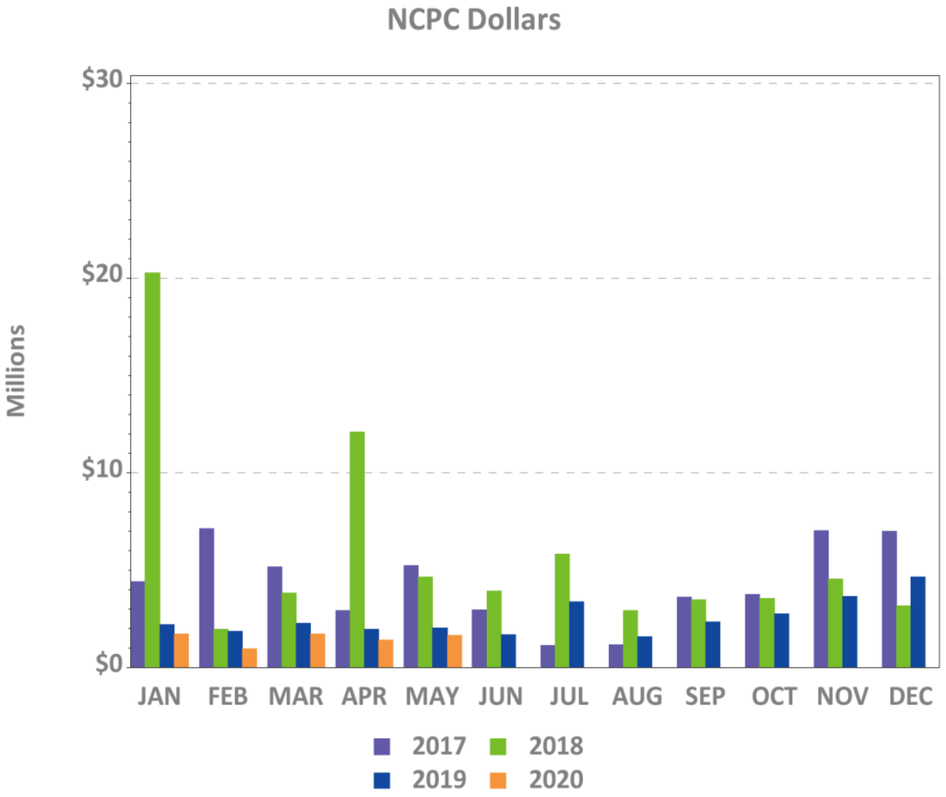
Definitions

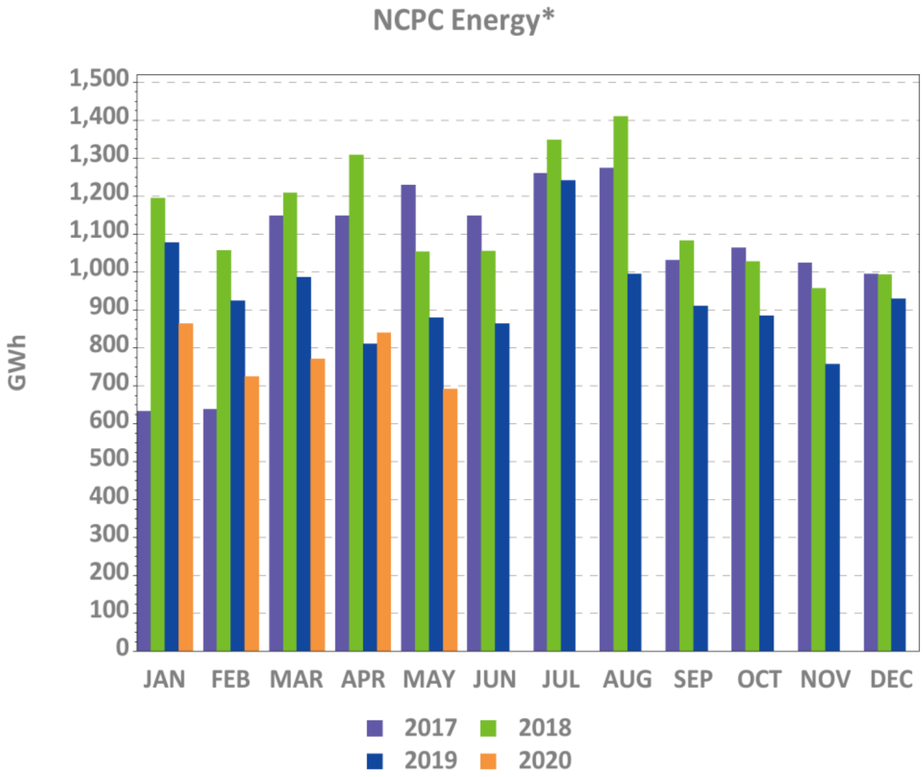
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

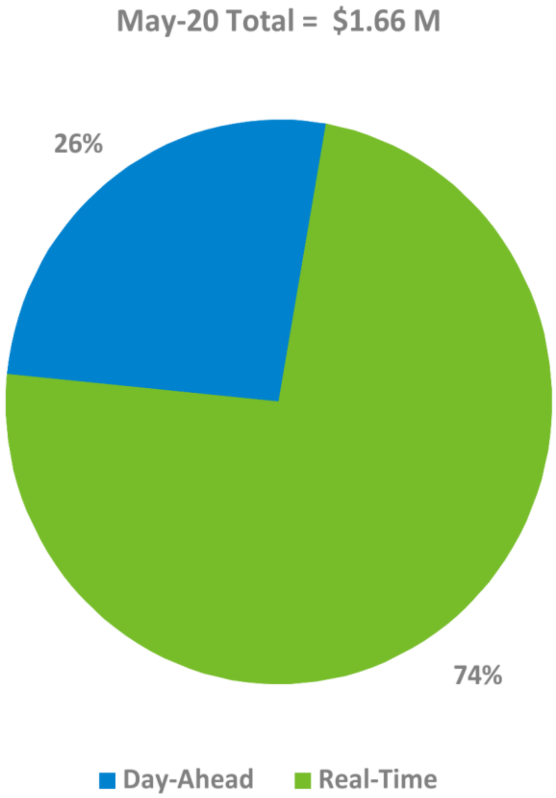
Year-Over-Year Total NCPC Dollars and Energy



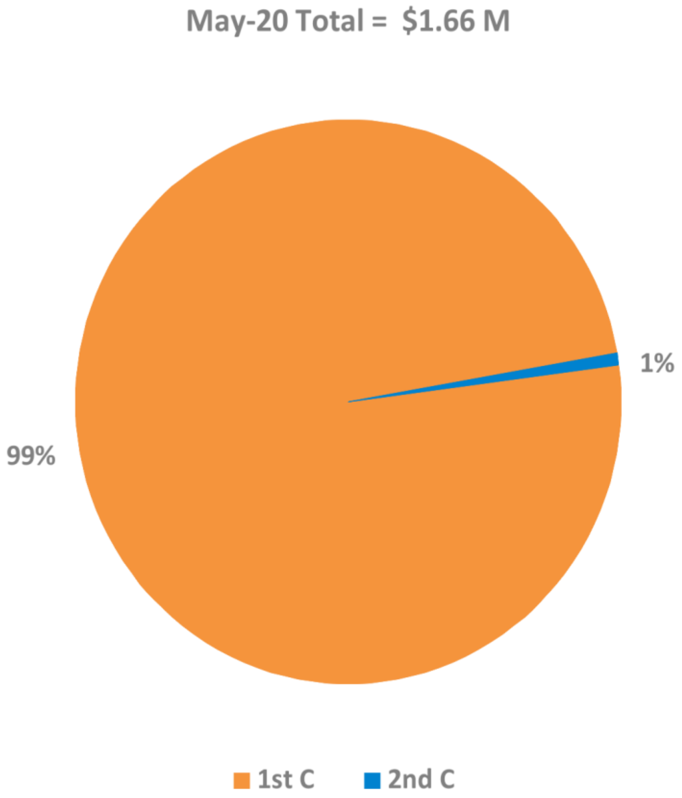


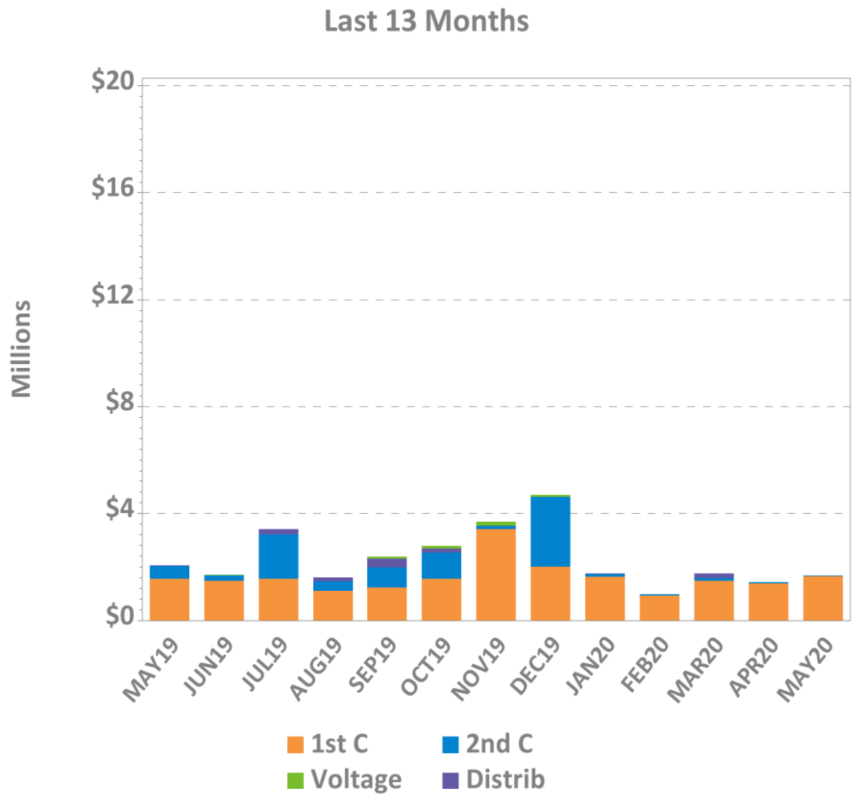
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



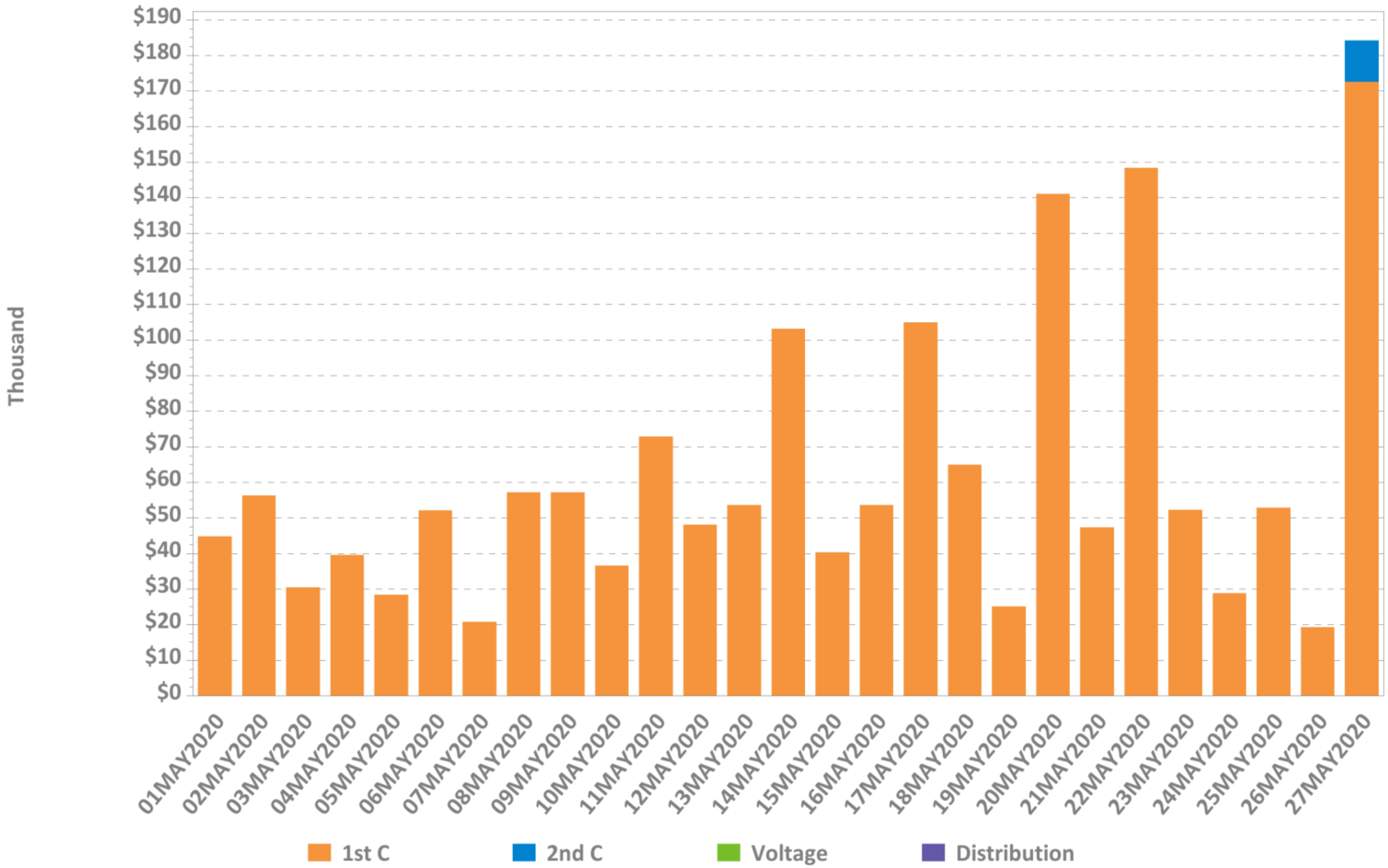
NCPC Charges by Type



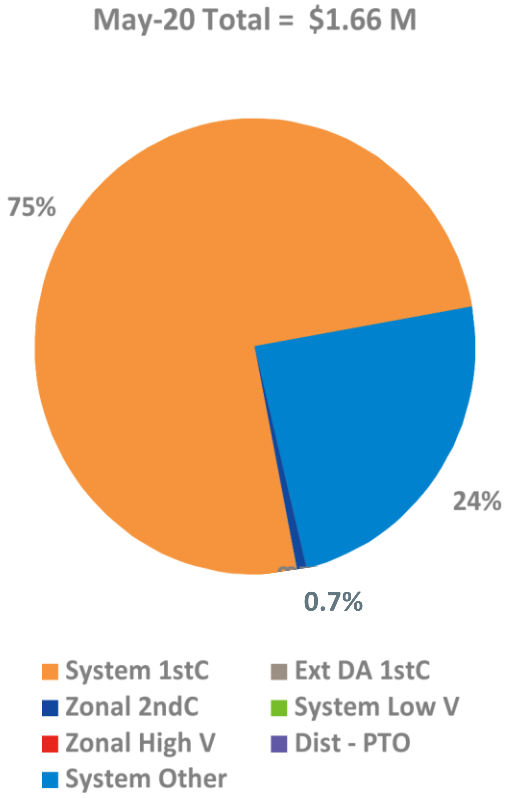


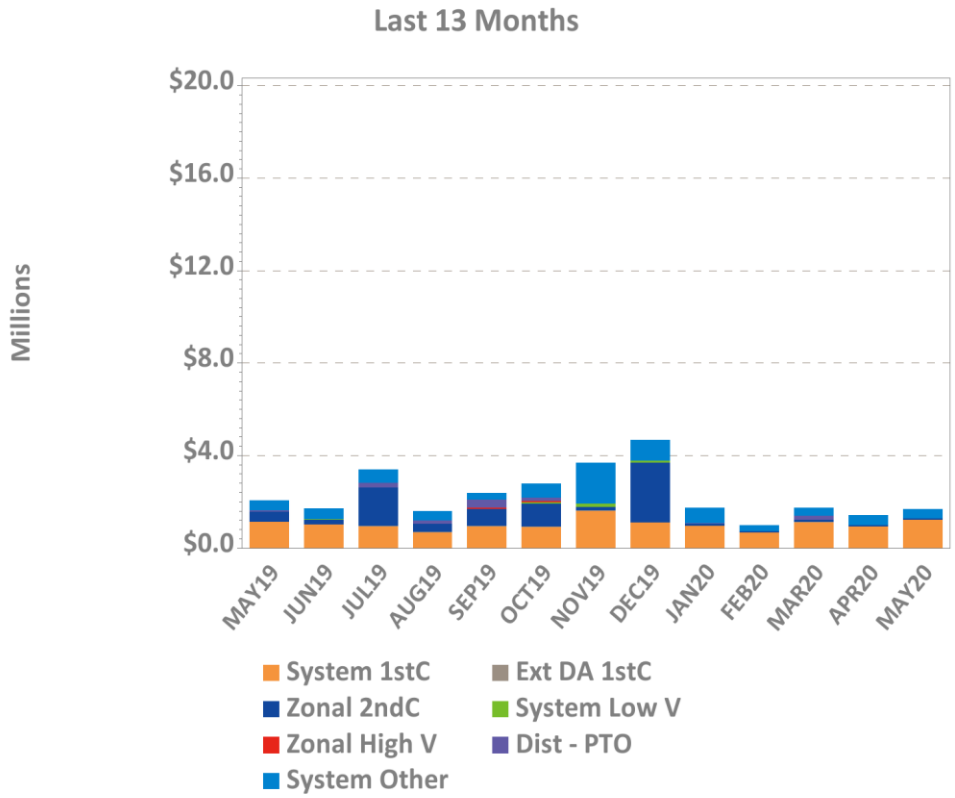
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



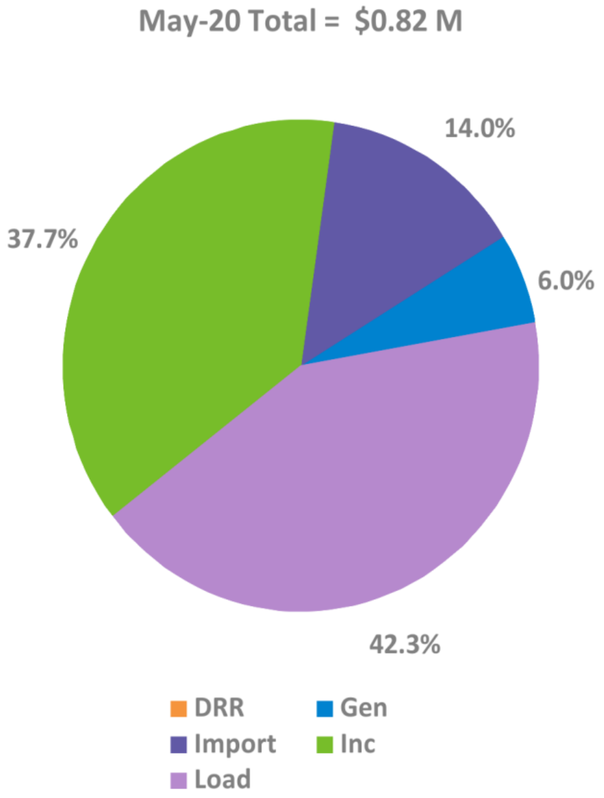
NCPC Charges by Allocation

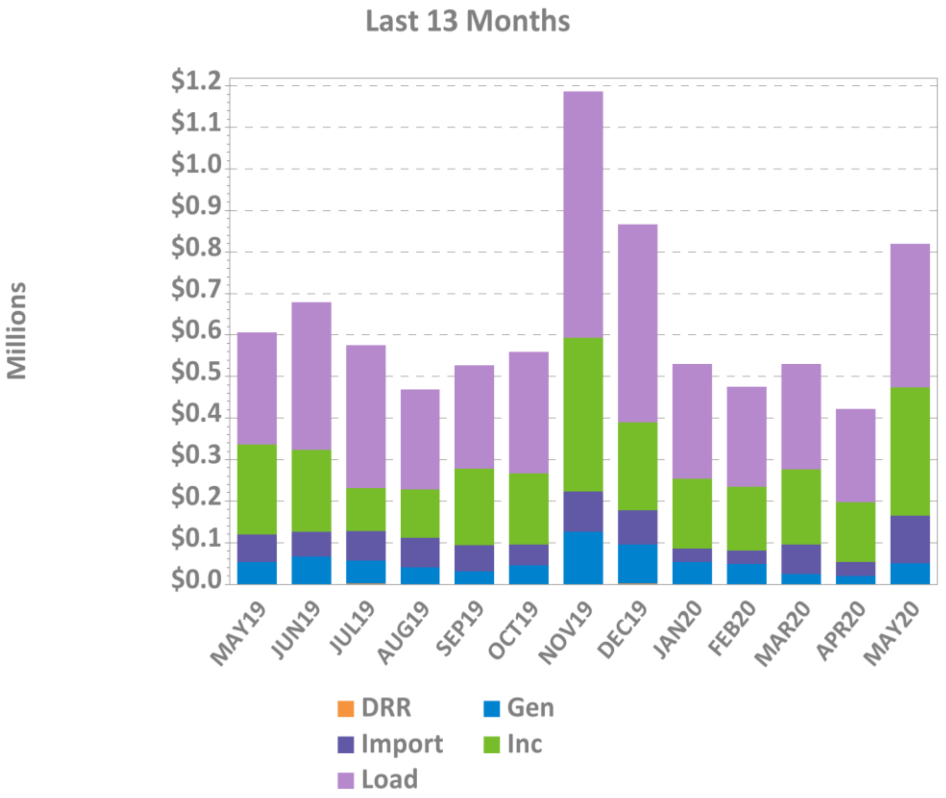




Note: ‘System Other’ includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

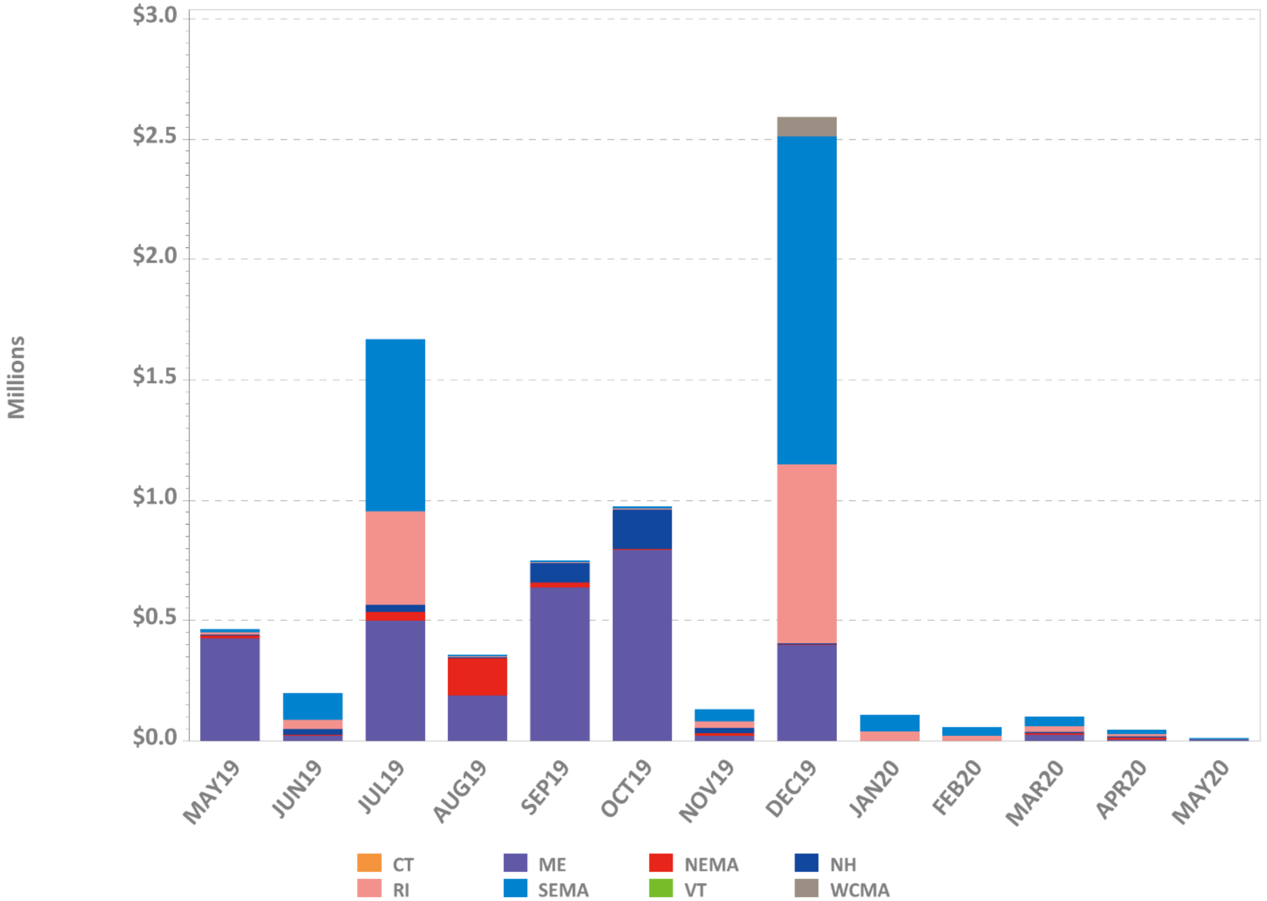
RT First Contingency Charges by Deviation Type





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

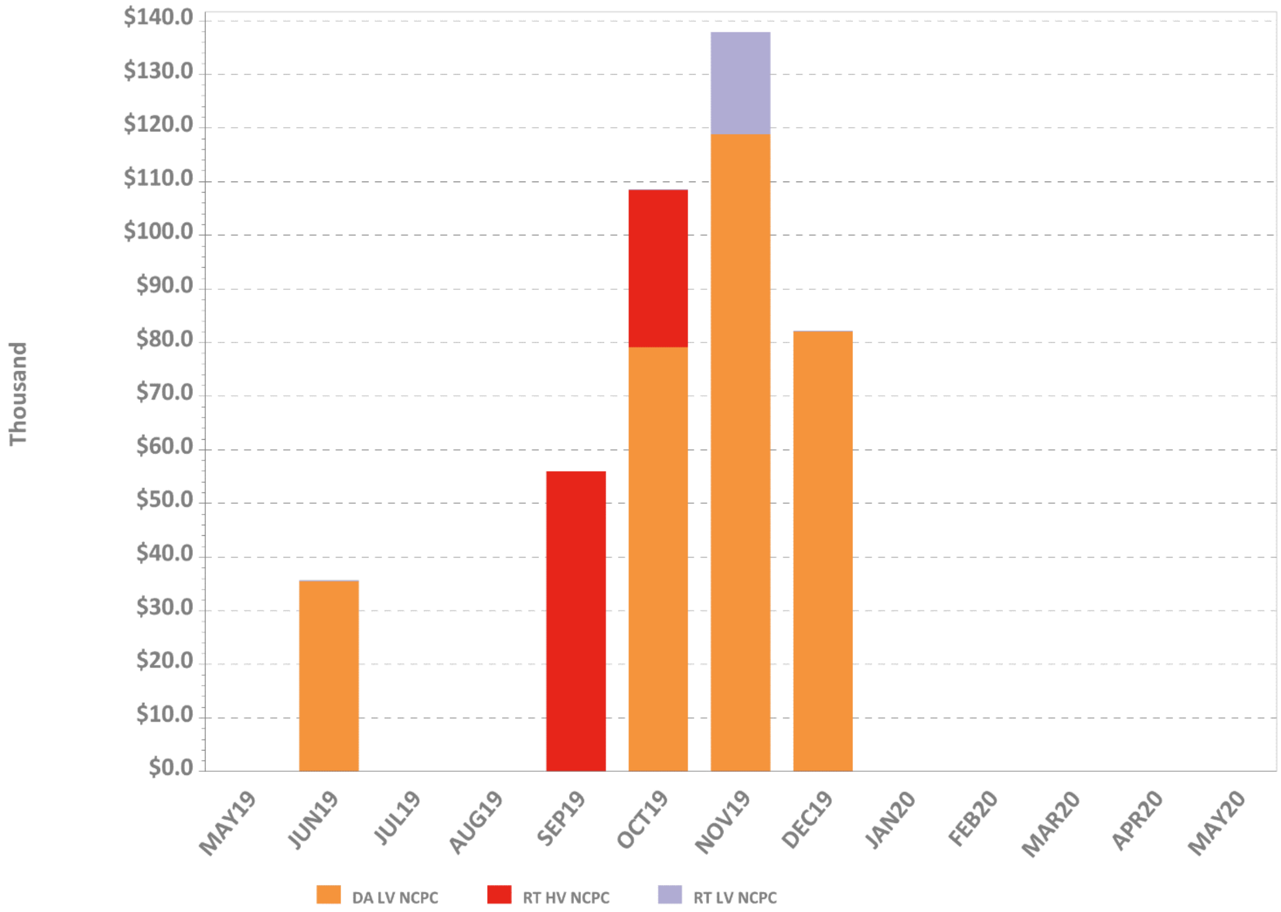
LSCPR Charges by Reliability Region



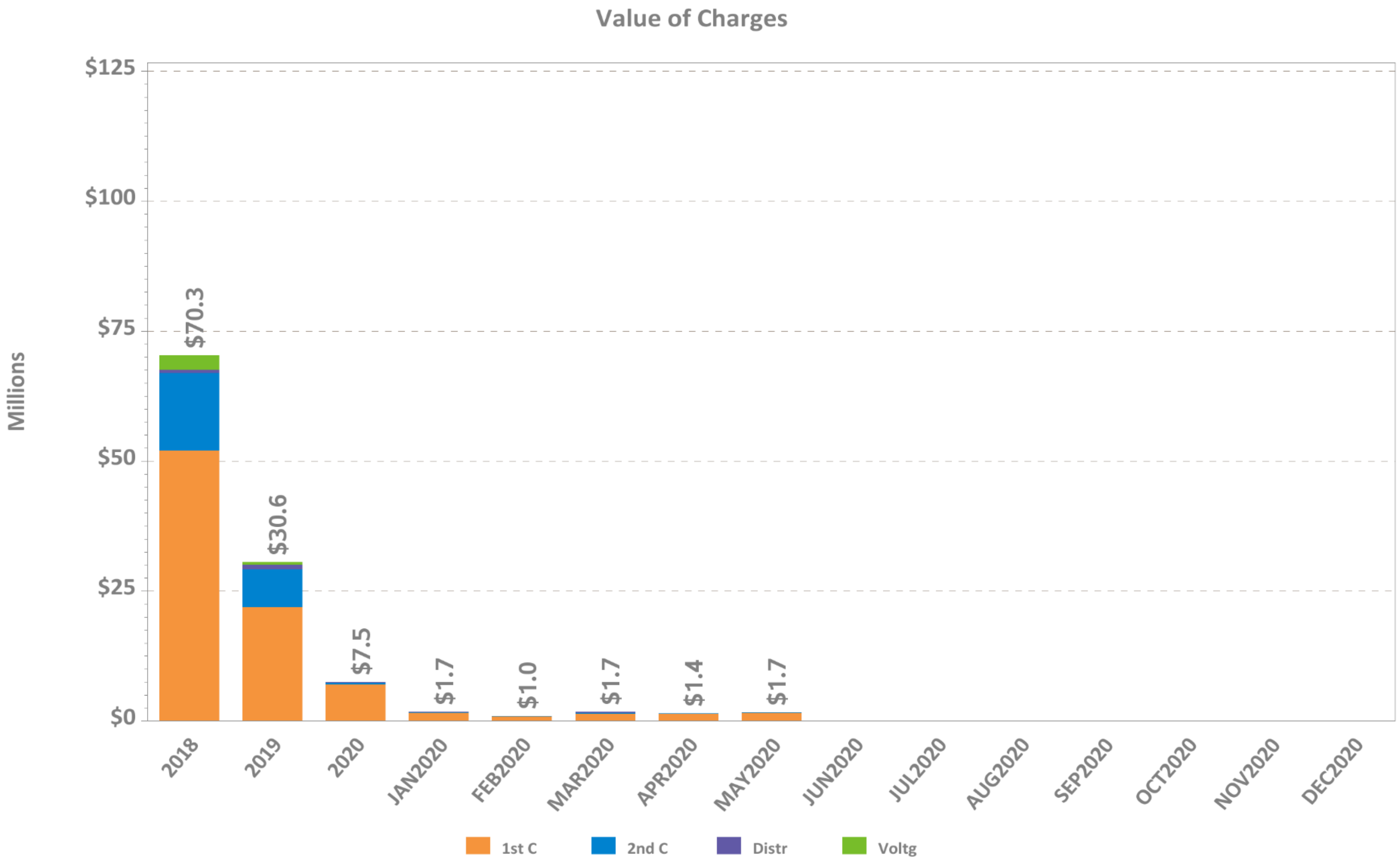
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

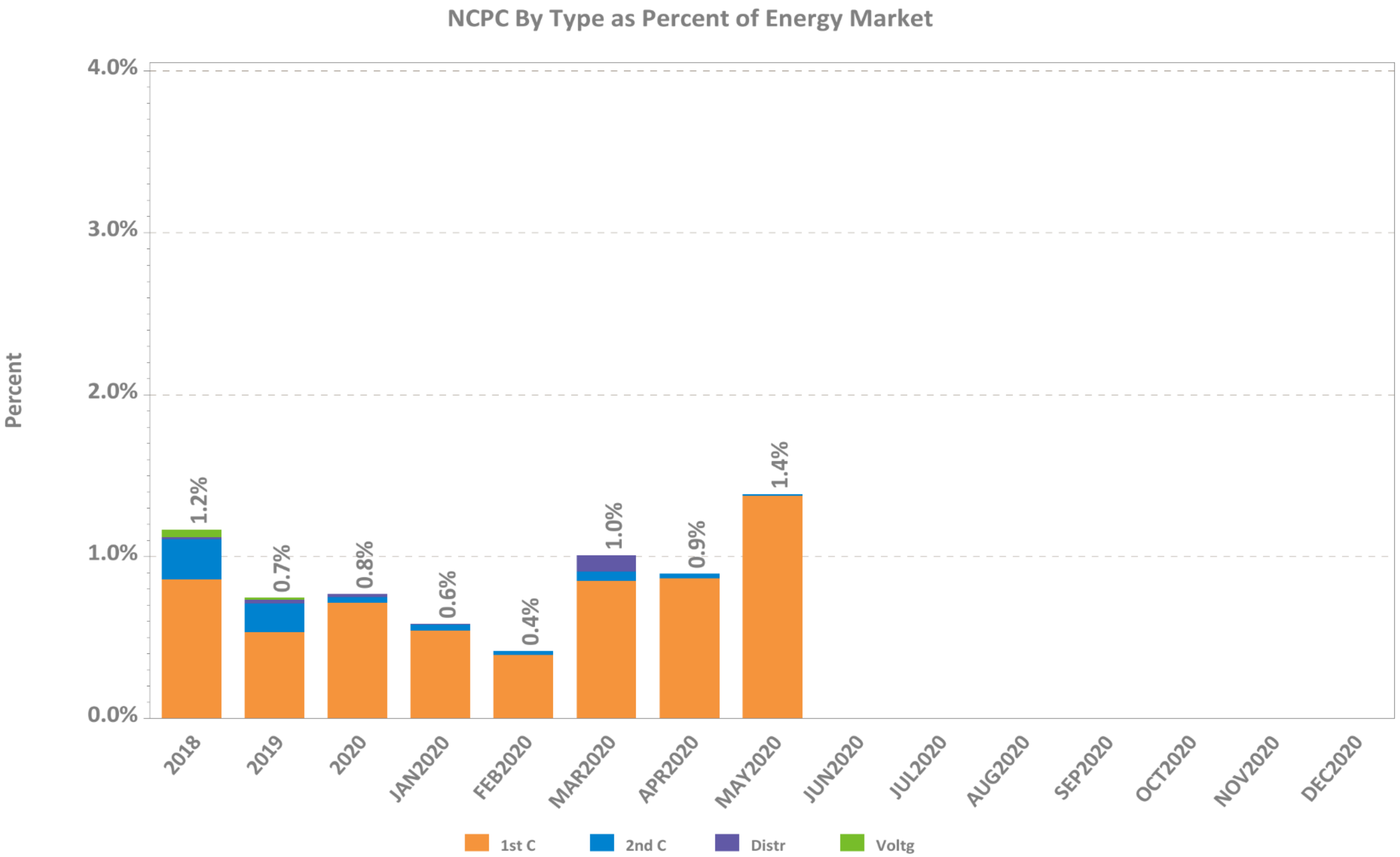
NCPC Charges for Voltage Support and High Voltage Control



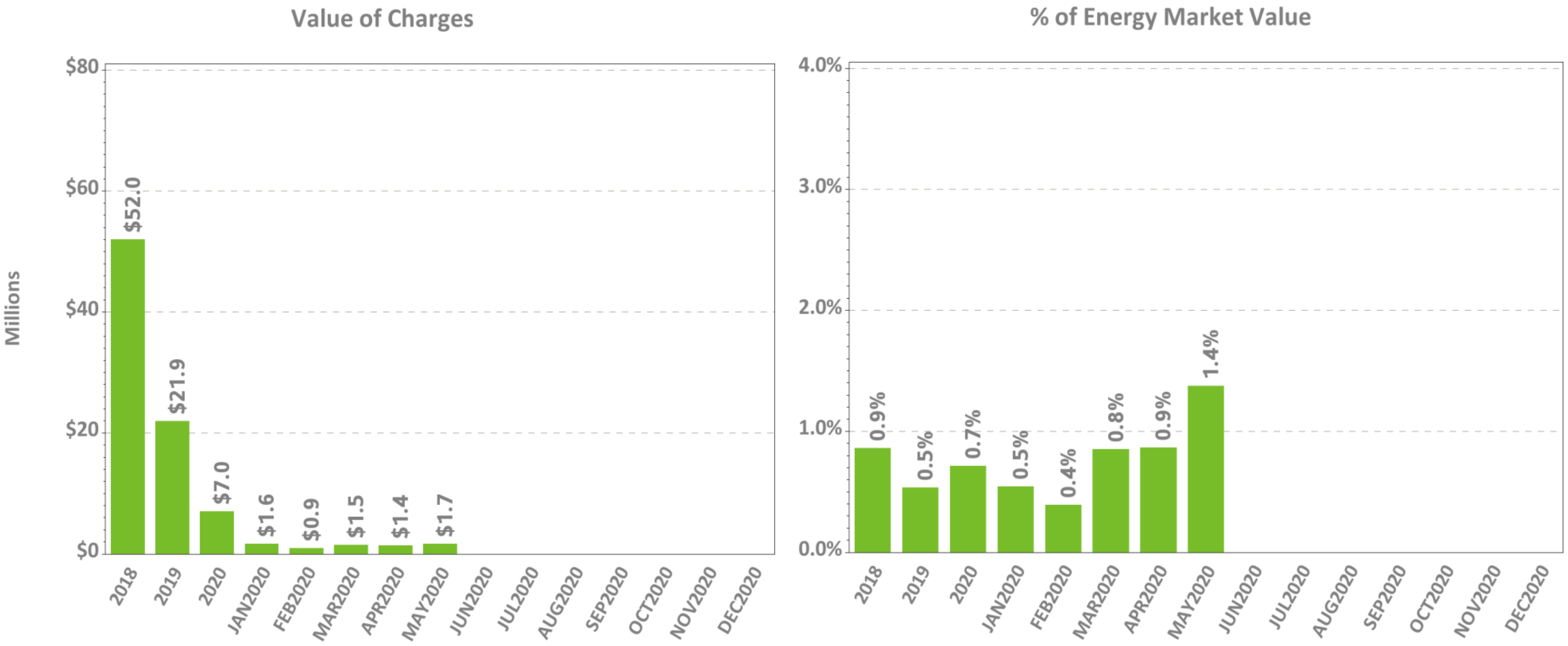
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

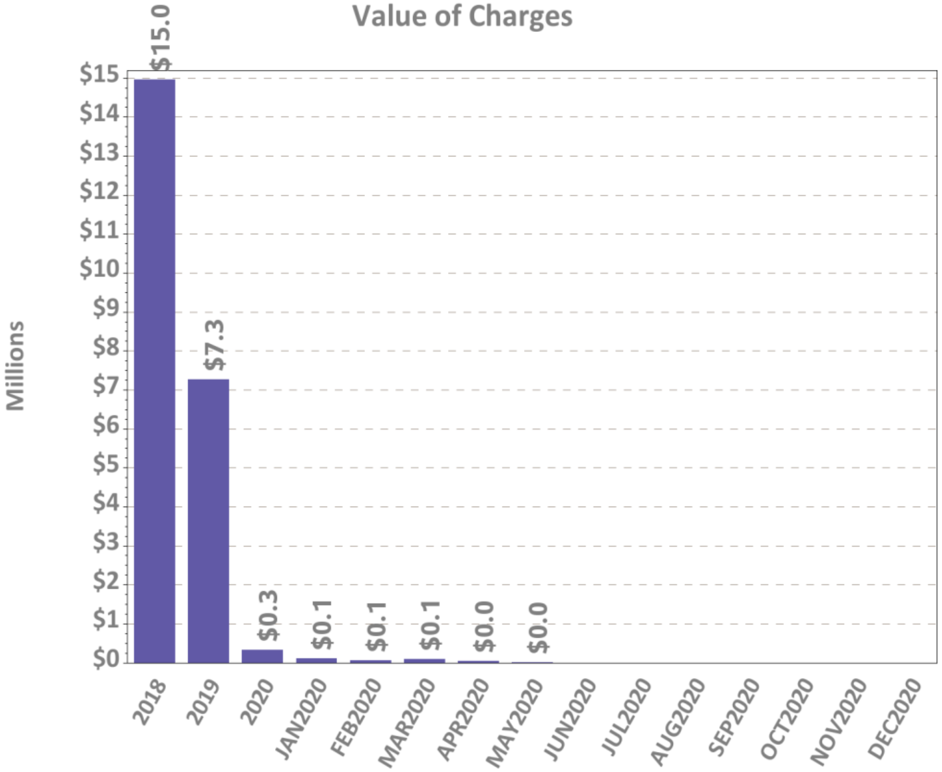


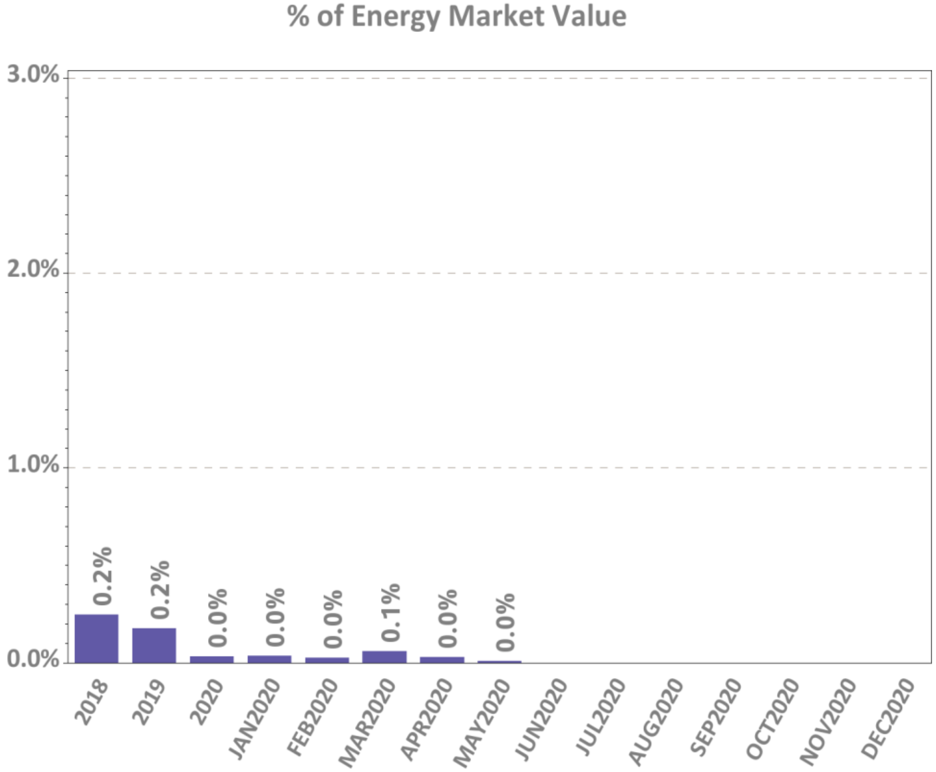
First Contingency NCPC Charges



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

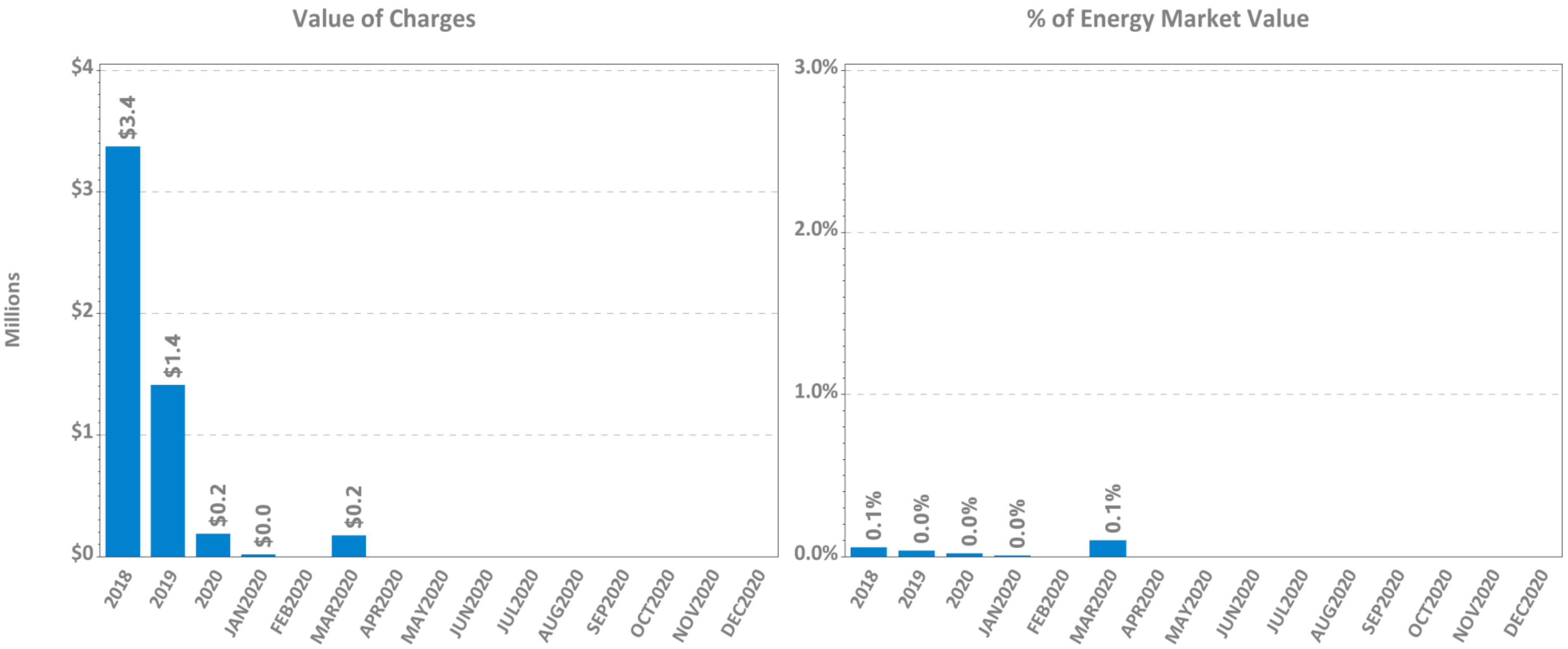
Second Contingency NCPC Charges





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

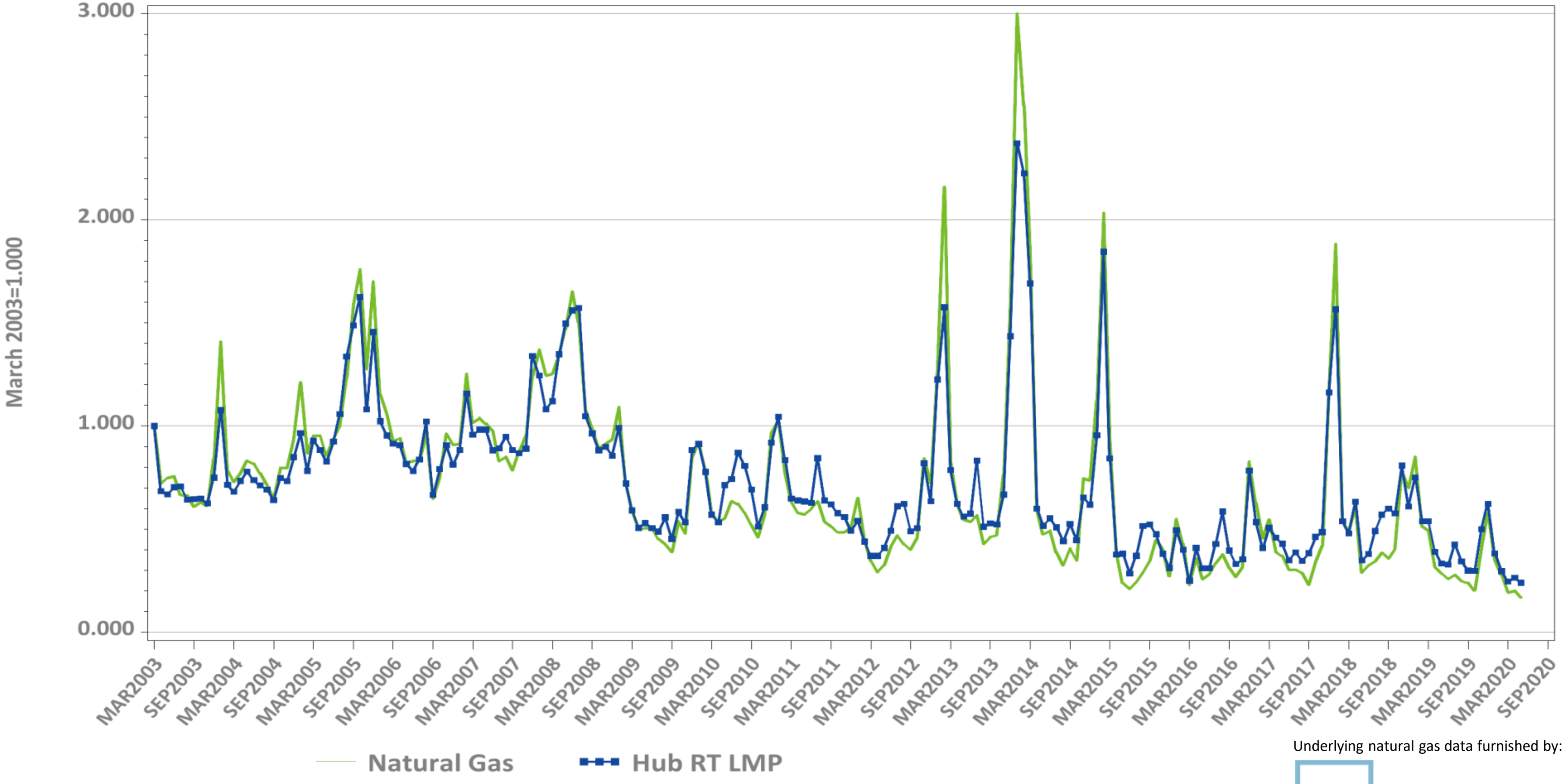
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 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%
Year 2019	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%

May-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$24.43	$23.92	$23.83	$24.23	$23.65	$24.18	$24.77	$24.27	$24.21
Real-Time	$23.09	$22.76	$22.67	$22.90	$22.25	$22.75	$22.89	$22.93	$22.89
RT Delta %	-5.5%	-4.9%	-4.9%	-5.5%	-5.9%	-5.9%	-7.6%	-5.5%	-5.5%
May-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$16.06	$15.73	$15.20	$15.79	$15.43	$15.99	$16.19	$15.97	$16.00
Real-Time	$16.47	$16.20	$15.54	$16.23	$15.83	$16.35	$16.55	$16.36	$16.39
RT Delta %	2.5%	3.0%	2.3%	2.8%	2.6%	2.3%	2.2%	2.4%	2.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-34.3%	-34.2%	-36.2%	-34.9%	-34.8%	-33.9%	-34.6%	-34.2%	-33.9%
Yr over Yr RT	-28.7%	-28.8%	-31.4%	-29.1%	-28.9%	-28.1%	-27.7%	-28.6%	-28.4%

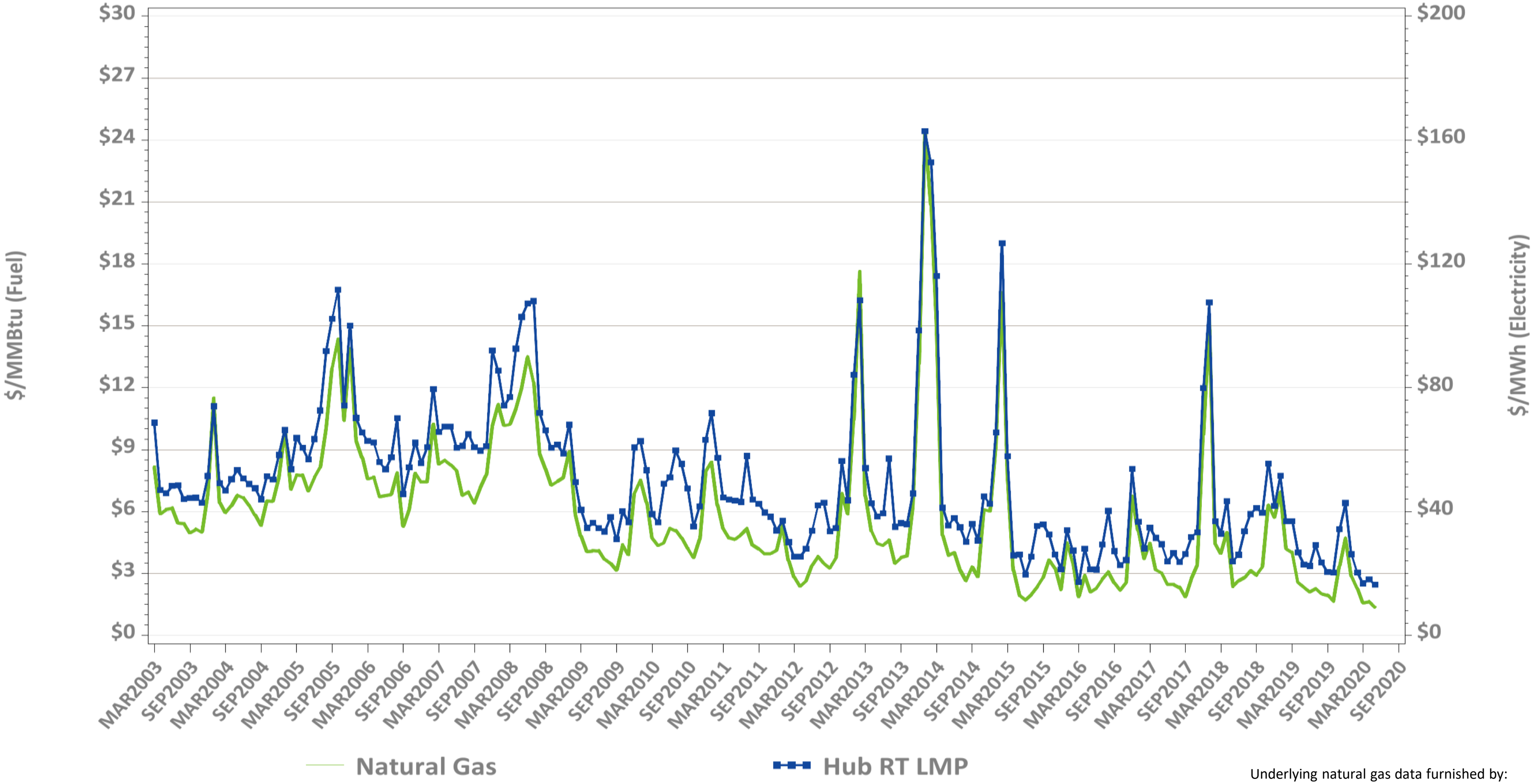
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

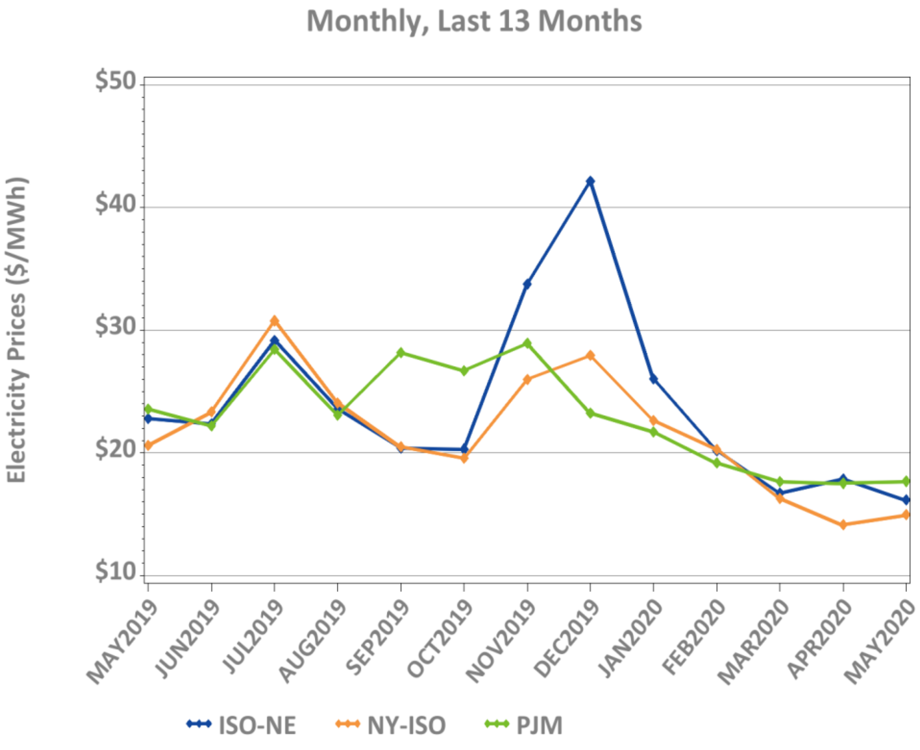
Monthly Average Fuel Price and RT Hub LMP



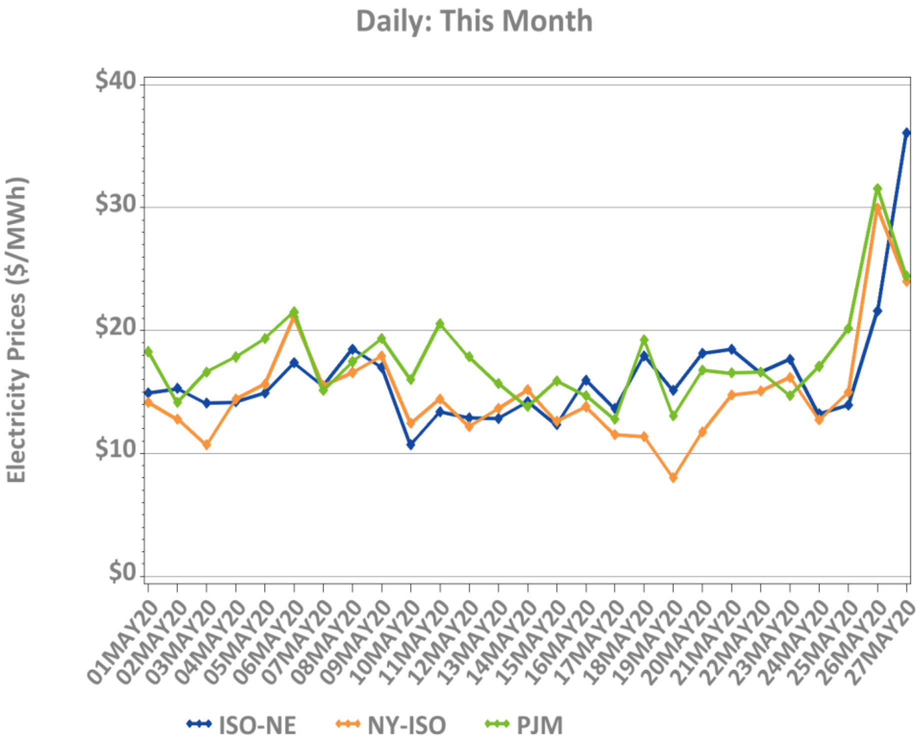
Underlying natural gas data furnished by:

ice Global markets in clear view

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

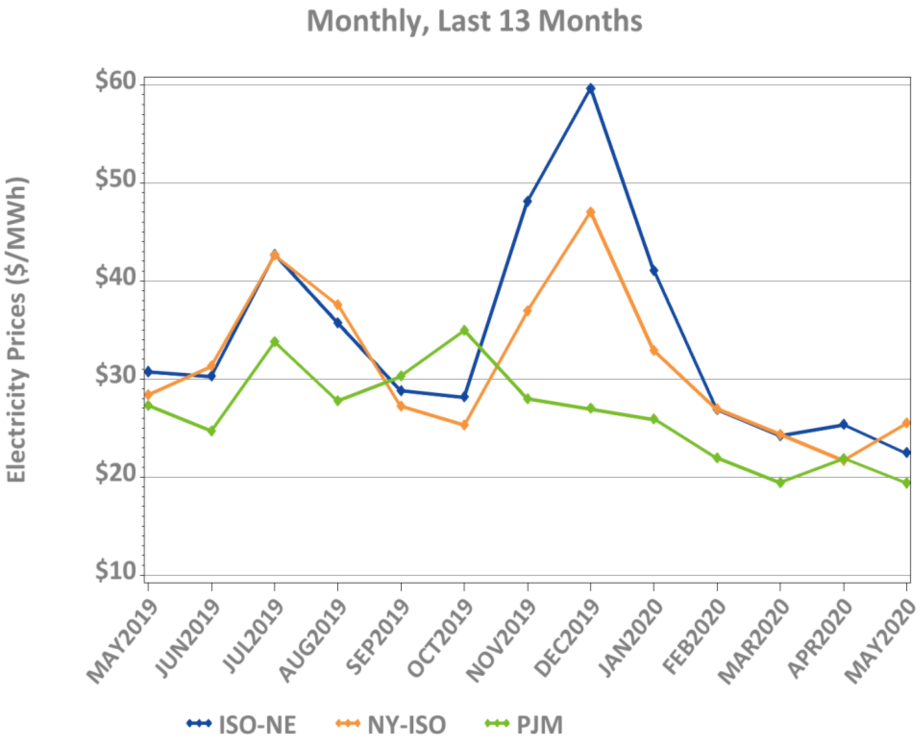


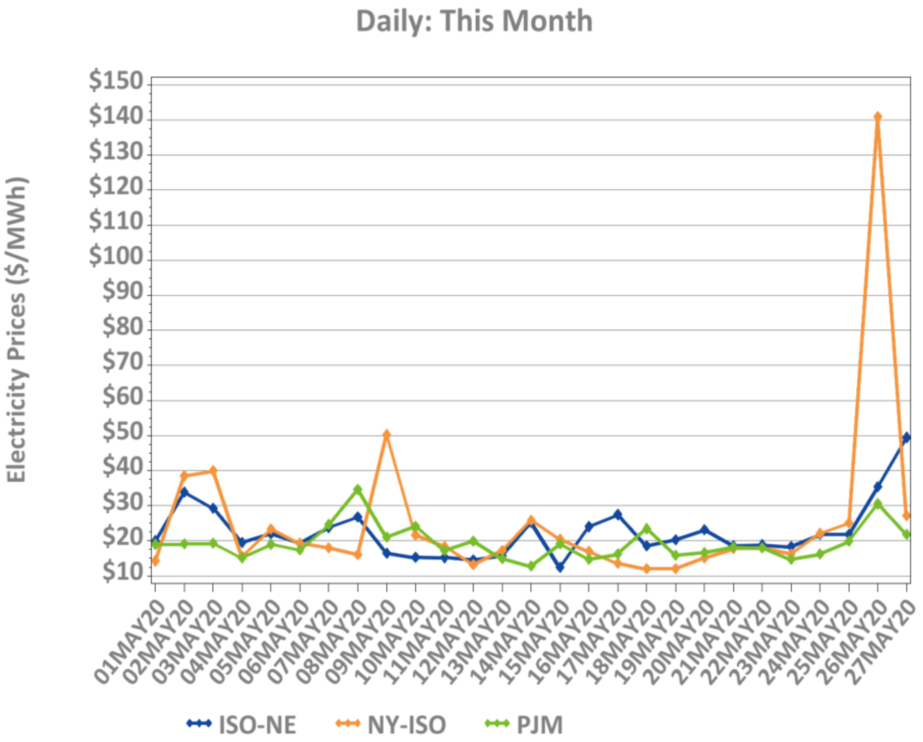
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





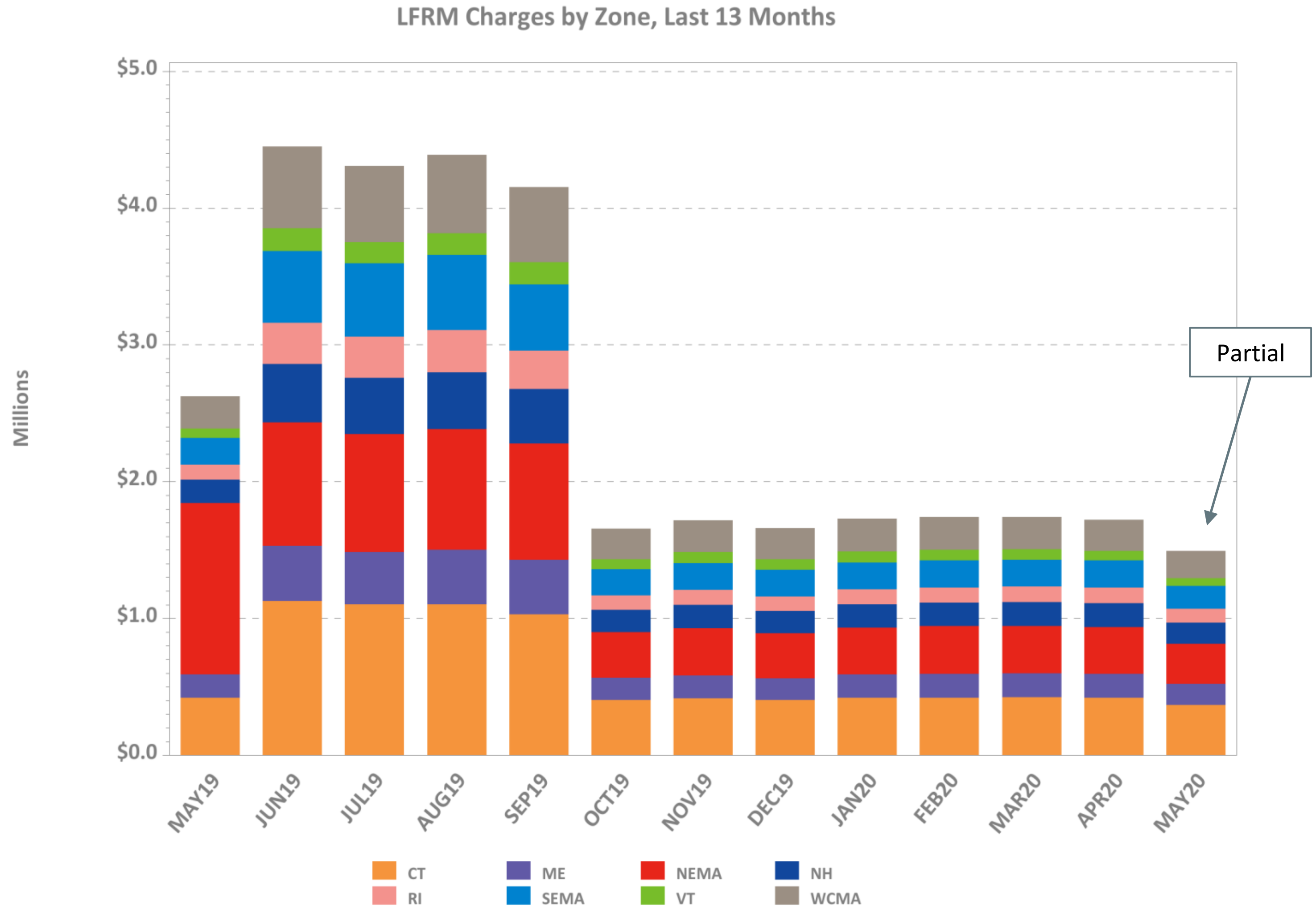
***Forecasted New England daily peak hours reflected**

Reserve Market Results – May 2020

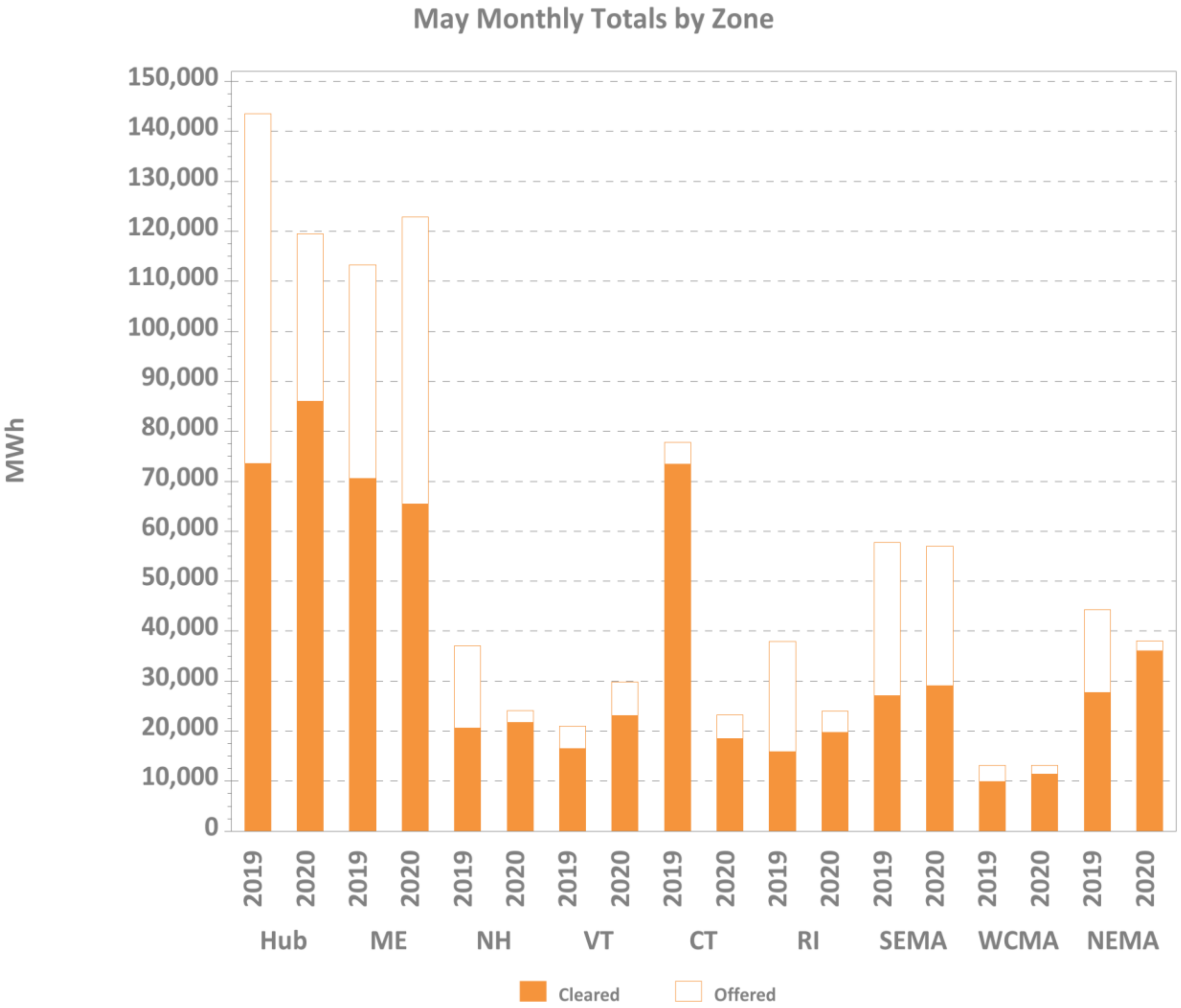
- Maximum potential Forward Reserve Market payments of $1.6M were reduced by credit reductions of $16K, failure-to-reserve penalties of $46K and failure-to-activate penalties of $20K, resulting in a net payout of $1.5M or 95% of maximum
  - Rest of System: $1.14M/1.2M (95%)
  - Southwest Connecticut: $0.05M/0.05M (92%)
  - Connecticut: $0.31M/0.33M (96%)
- $939K total Real-Time credits were reduced by $115K in Forward Reserve Energy Obligation Charges for a net of $824K in Real-Time Reserve payments
  - Rest of System: 313 hours, $516K
  - Southwest Connecticut: 313 hours, $190K
  - Connecticut: 313 hours, $89K
  - NEMA: 313 hours, $28K

Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

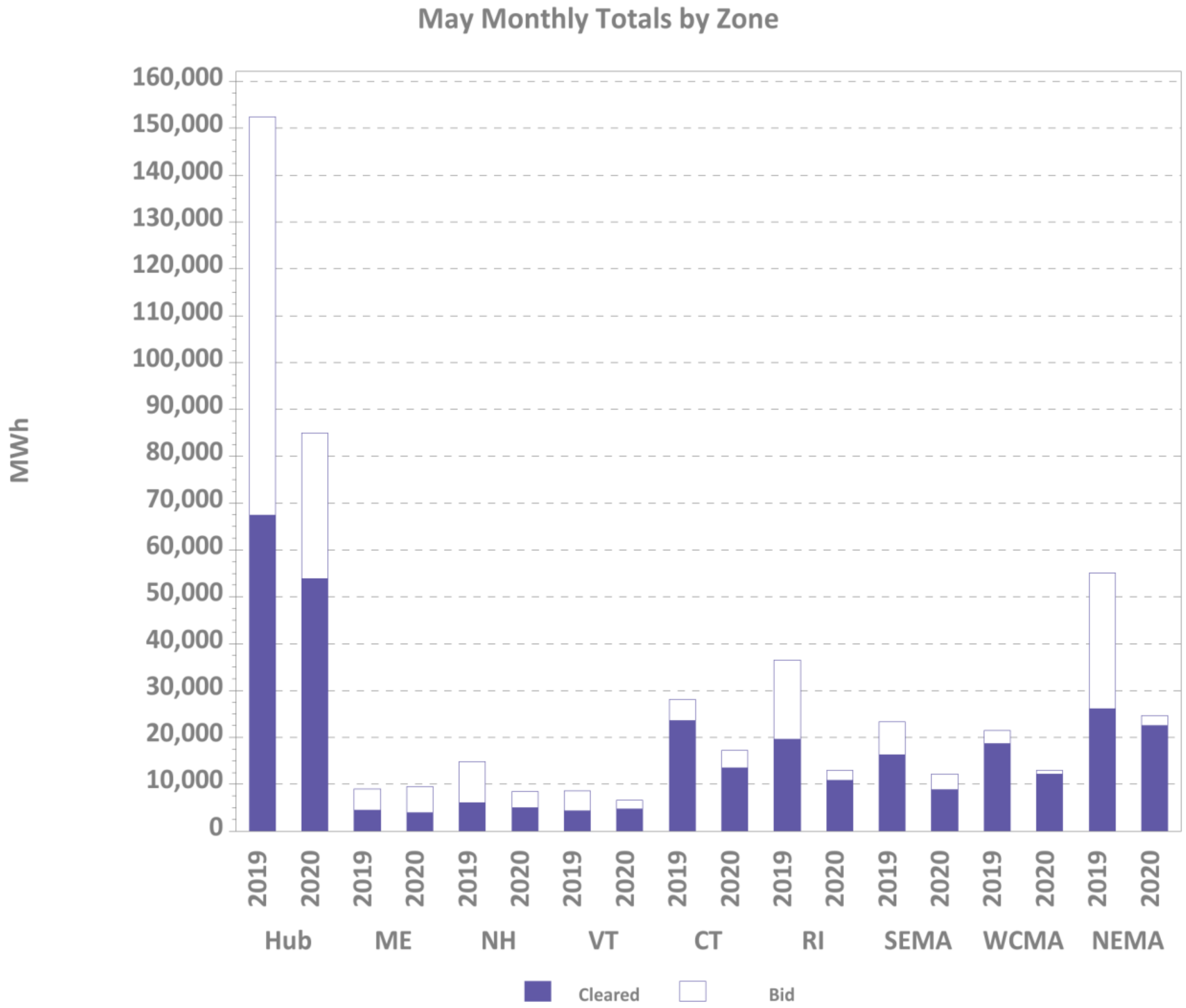
LFRM Charges to Load by Load Zone ($)



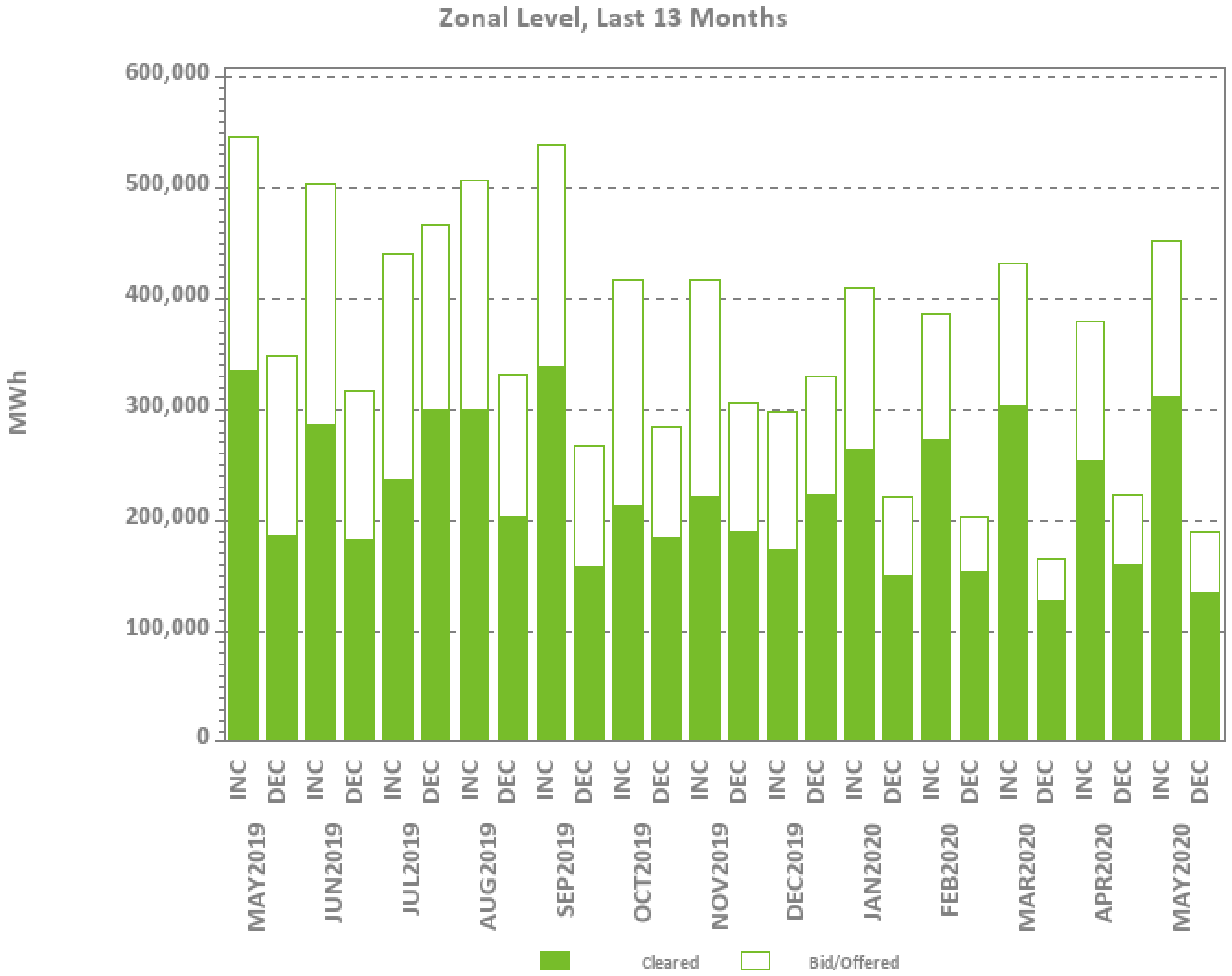
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

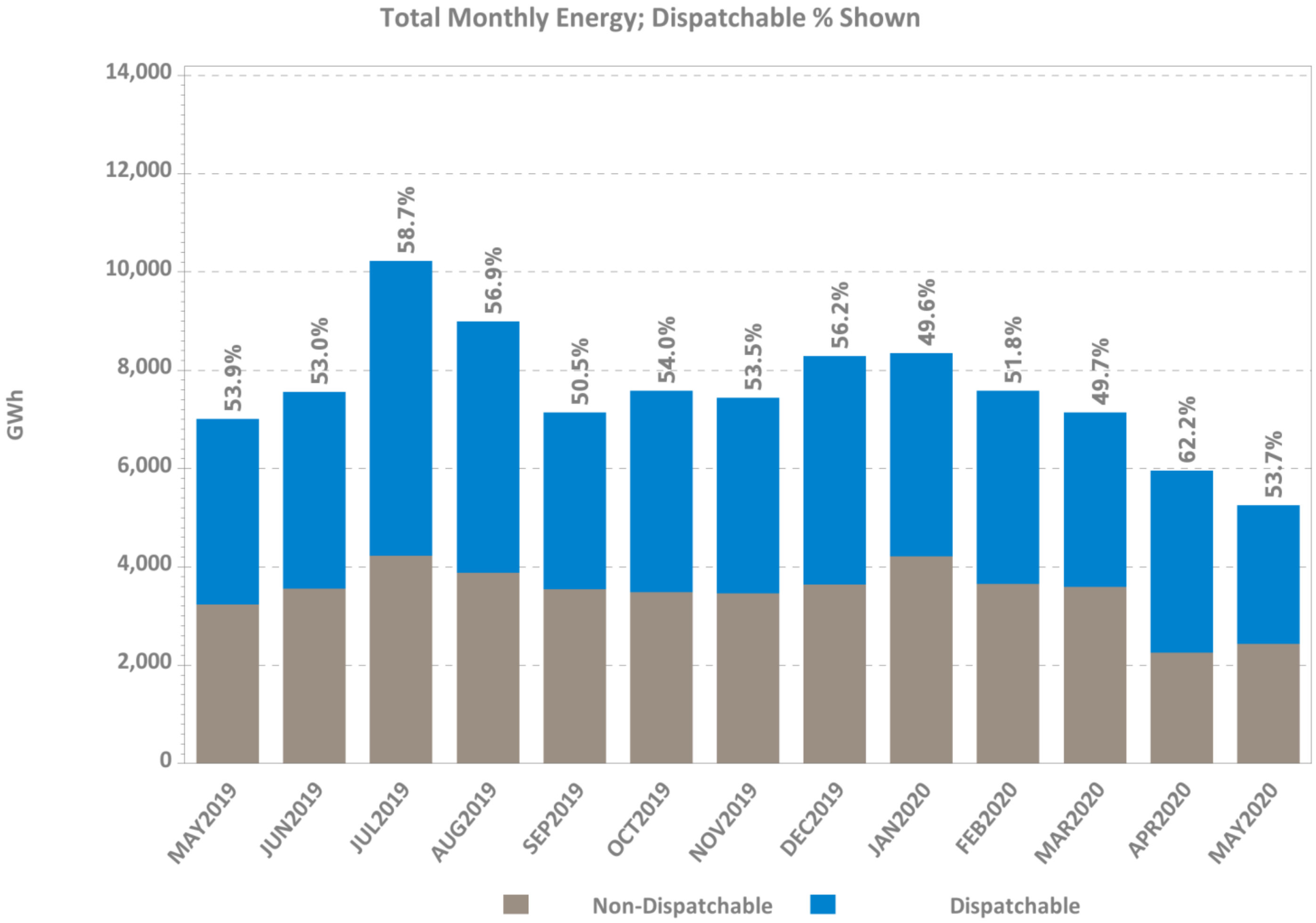


Total Increment Offers and Decrement Bids



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 (‘must run’) by the customer.**

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- June 17 PAC Meeting Agenda Topics*
  - Regional System Plan Transmission Projects and Asset Condition June 2020 Update
  - Representative Future Locational Reserve Needs for Current Reserve Zones
  - New Hampshire Solutions Study Alternatives
  - 2020 Public Policy Transmission Upgrade Process
  - 2020 Economic Study Update
  - 2019 Economic Study Offshore Wind Transmission Interconnection Analysis
  - Boston 2028 RFP – Review of Phase One Proposals

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

Interregional Planning

- Final 2019 Northeastern Coordinated System Plan (NCSP19) was posted on May 4
- Inter-Area Planning Stakeholder Advisory Committee (IPSAC) meeting was held on May 15 and included discussions of:
  - Regional Planning Needs and Solutions for PJM, ISO-NE, and NYISO
  - Interconnection Coordination - Interconnection Queue and Long-Term Firm Transmission Requests for NYISO, ISO-NE, and PJM
  - Review of Final NCSP19
  - Stakeholder Input and Outline Next Steps

Economic Studies

- Three 2019 study requests were received (NESCOE, Anbaric, and RENEW)
  - RENEW scenarios modeled varying degrees of increases in Orrington-South transfer limit
  - NESCOE and Anbaric scenarios modeled different transmission and resource expansion options
- Anbaric and RENEW studies are complete and efforts are now focused on report writing to be completed in July
- NESCOE ancillary services and transmission interconnection results were presented to PAC on May 20
  - In addition, as a late request, a marginal emissions analysis was also performed
  - A concise report has been requested by NESCOE, and the final report is targeted to be completed by July
- NGRID submitted a 2020 economic study request
  - Assumptions are under development and presentation was made to PAC in May, with additional presentation scheduled for June
  - Goal is to complete study work by Q4 2020 and publish the report in Q1 2021

2018 Generator Emissions Report

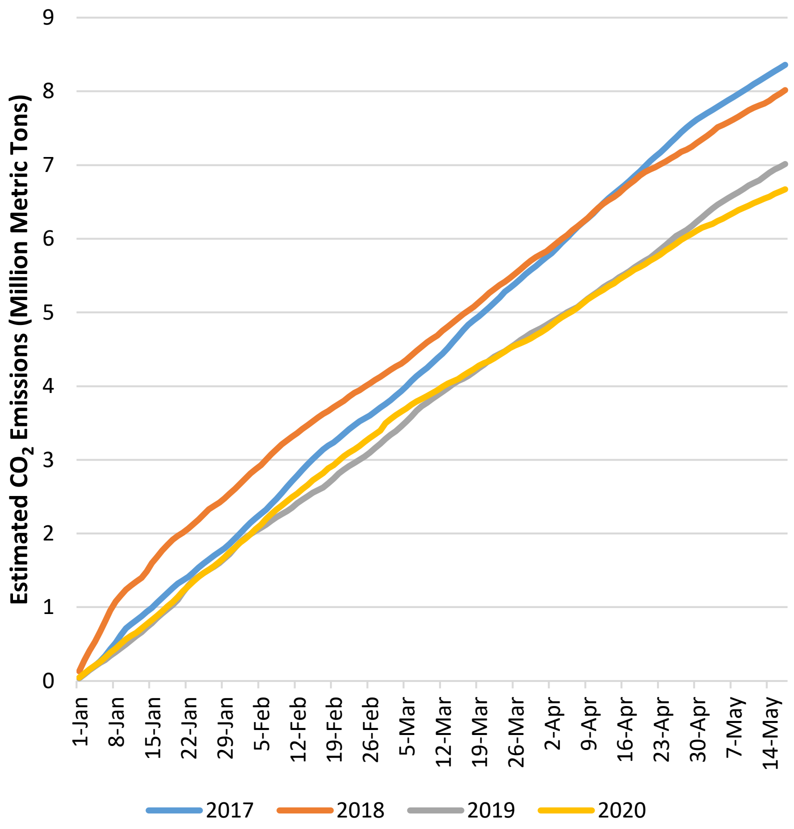
- Final 2018 ISO New England Electric Generator Air Emissions Report was posted on May 14
- At the April EAG meeting, stakeholders discussed obstacles to reporting emissions from imports, and what actions could be taken to overcome the lack of publically available information
  - Comments on the options presented by the ISO will be addressed at the next EAG meeting in June

Environmental Matters – Carbon Dioxide (CO_2) Emissions from Native Generation (1/1 - 5/17)

Air Emissions Lower, Reflect Mix of Milder Weather, COVID-19

- Estimated 2020 year-to-date CO_2 system emissions declined 5% compared to same period in 2019 (1/1 - 5/17):
  - Native emitting generation declined -4% in 2020 YTD (17,511 GWh) compared to 2019 YTD (18,159 GWh)
  - Natural gas generation increased 28%; coal (-78%) and oil (-27%) declined
- EPA issued various guidances responding to COVID-19 pandemic, temporarily waiving compliance and reporting requirements for regulated entities, including power plants for air emissions and water discharges but:
  - Limited in scope, conditional, discretionary for EPA, not binding on states, tribes, or localities, and temporary

Cumulative CO_2 System Emissions (Million Metric Tons)

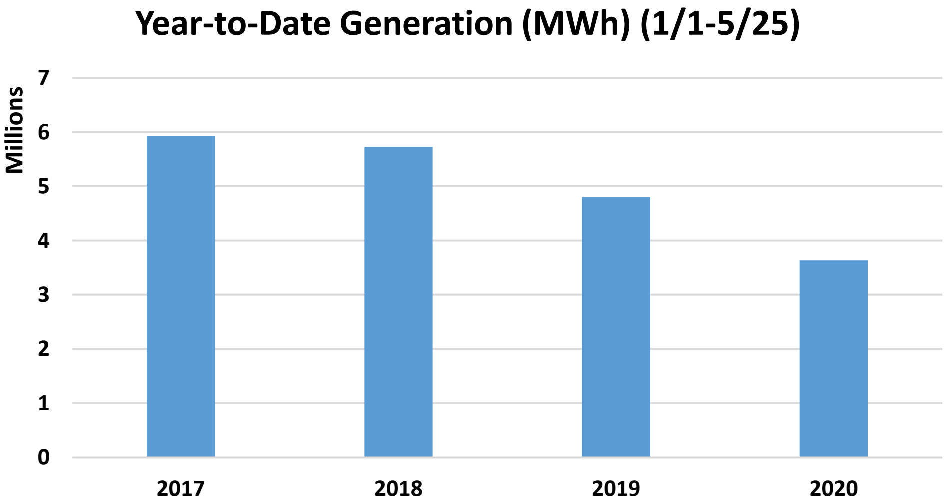


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2020 YTD Emissions Declined 25%, Generation Declined 29% vs. 2019

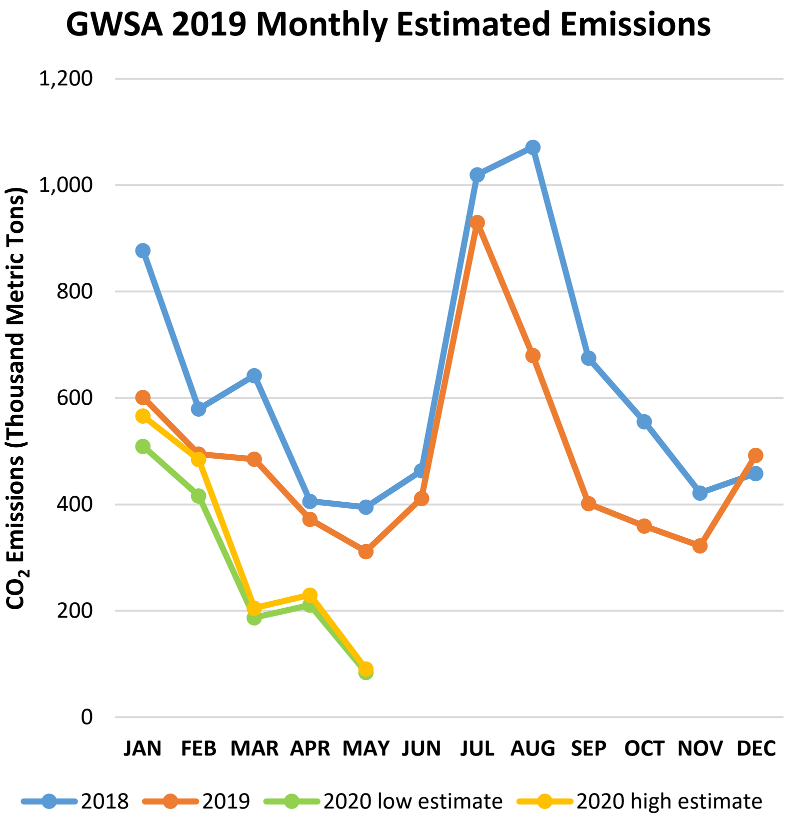
2020 CO_2 Estimated Emissions Below 2019 Trend lines

- Year-to-date generation from affected generators declined 25%, while estimated emissions declined 29% compared to same period in 2019



GWSA - Global Warming Solutions Act

2020 Estimated, Past Monthly Emissions (Thousand Metric 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 5/22/20

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	May-20	3
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 5/22/20

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 5/22/20

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 5/22/20

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 5/22/20

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	Nov-20	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)	Mar-20	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/22/20

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)	Nov-20	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	4
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 5/22/20

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 5/22/20

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 5/22/20

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-20	3
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 5/22/20

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)	Dec-19	4
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	4

Southwest Connecticut Projects, cont.

Status as of 5/22/20

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)	Jun-21	3

Southwest Connecticut Projects, cont.

Status as of 5/22/20

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 5/22/20

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	4
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	Dec-21	3*
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	4

* Substation portion of the project is a Present Stage status 4

Greater Boston Projects, cont.

Status as of 5/22/20

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	Oct-20	3
Install third 115 kV line from West Walpole to Holbrook	Oct-20	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-23	2

Greater Boston Projects, cont.

Status as of 5/22/20

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	4
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	4
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-21	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-20	3

Greater Boston Projects, cont.

Status as of 5/22/20

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-21	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	4
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 5/22/20

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	Dec-19	4
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 5/22/20

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 5/22/20

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 5/22/20

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	3

SEMA/RI Reliability Projects

Status as of 5/22/20

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	Sep-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	Oct-20	3
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
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	4

SEMA/RI Reliability Projects, cont.

Status as of 5/22/20

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	Dec-20	3
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*

* The ISO is reevaluating this project with updated data and assumptions.

SEMA/RI Reliability Projects, cont.

Status as of 5/22/20

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-23	1*
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	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-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-21	1

* The ISO is reevaluating this project with updated data and assumptions.

SEMA/RI Reliability Projects, cont.

Status as of 5/22/20

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	Jan-23	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-20	3

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

** The ISO is reevaluating this project with updated data and assumptions.

SEMA/RI Reliability Projects, cont.

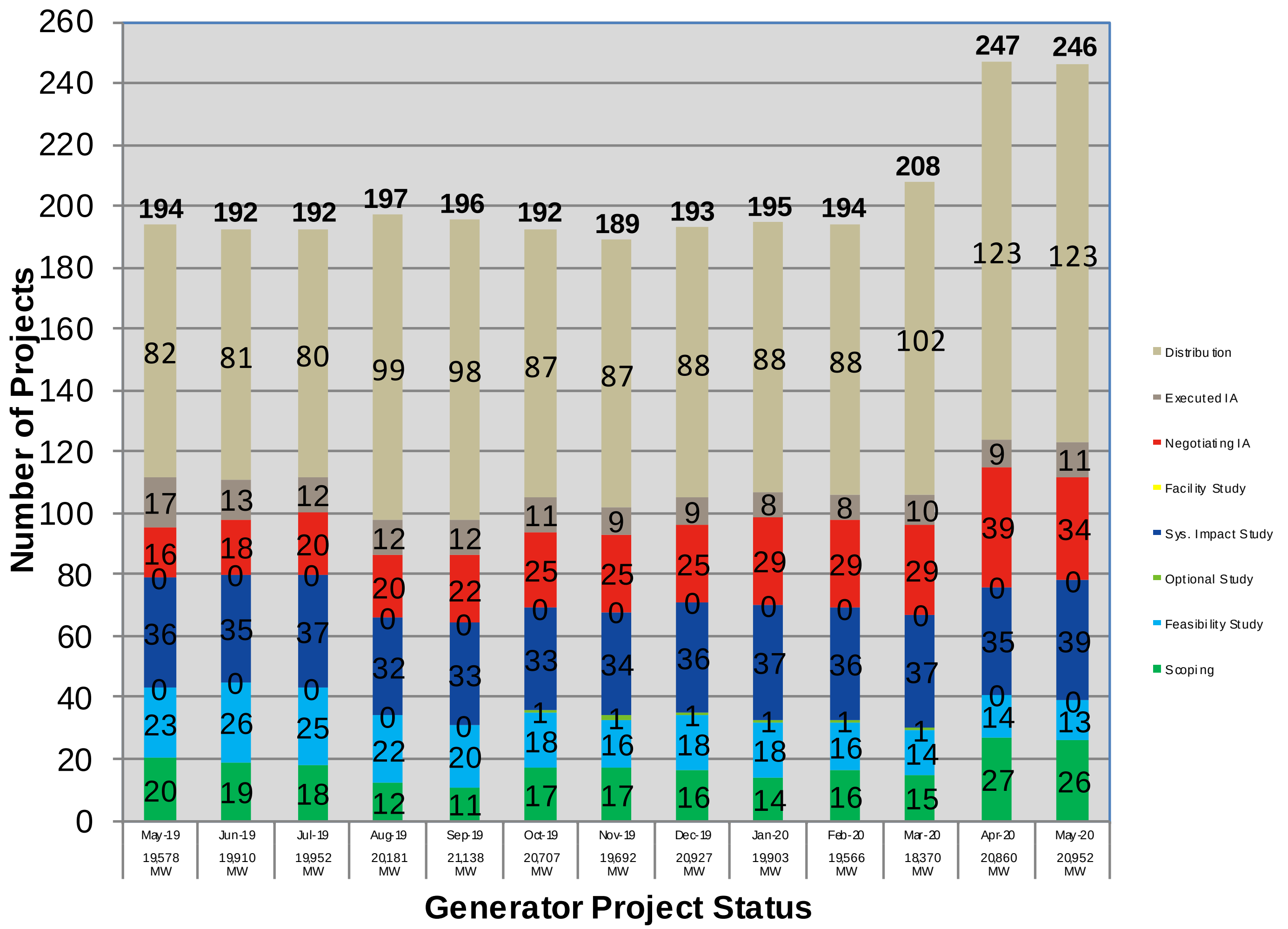
Status as of 5/22/20

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	4
1782	Reconductor the J16S line	Dec-21	2*
1724	Replace the Kent County 345/115 kV transformer	Feb-21	2*
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	3
1790	Medway 115 kV circuit breaker replacements	Dec-21	3

* The ISO is reevaluating this project with updated data and assumptions.

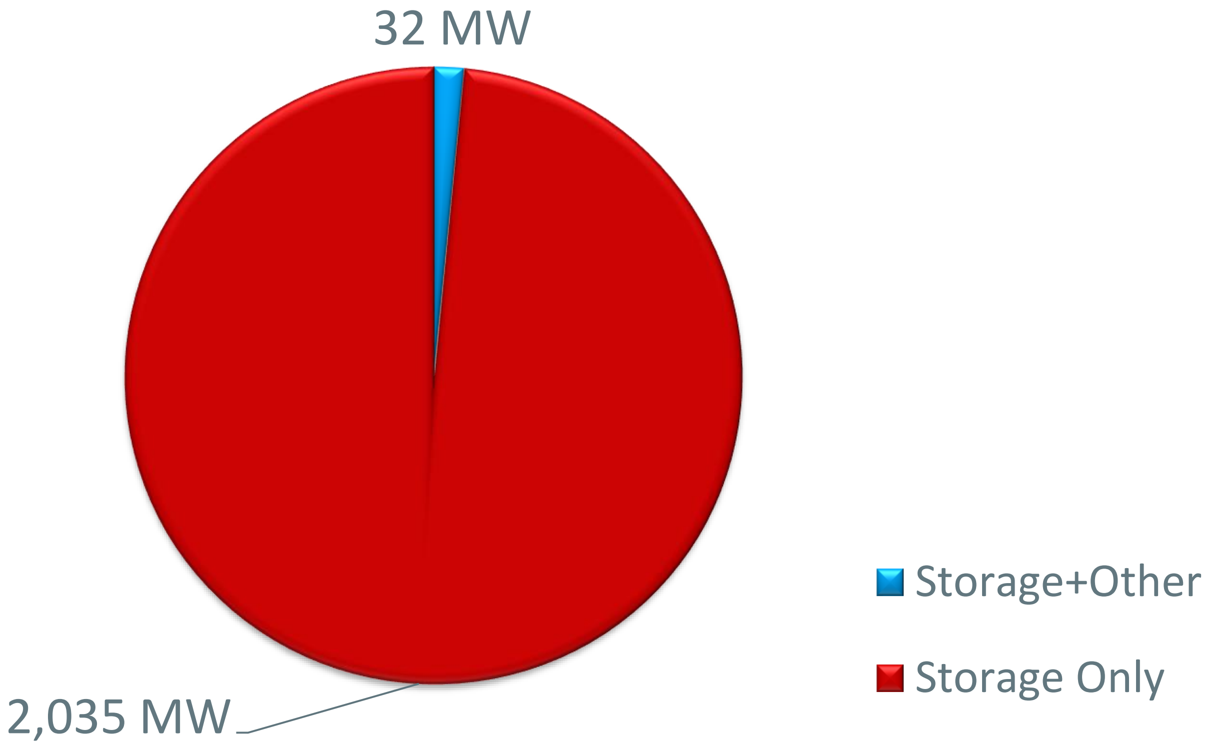
Status of Tariff Studies



Note: May 2020 is based on partial data.
As of May 2020, there are 4 ETU's in Scoping, 4 in FS, 4 in SIS, 0 in FAC, 0 Negotiating IA, and 1 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of May 27, 2020)

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



OPERABLE CAPACITY ANALYSIS

Summer 2020 Analysis

Summer 2020 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2020[2] CSO (MW)	June - 2020[2] SCC (MW)
Operable Capacity MW [1]	29,897	31,079
Active Demand Capacity Resource (+) [5]	366	452
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,101	1,101
Non Commercial Capacity (+)	5	5
Non Gas-fired Planned Outage MW (-)	1,196	1,234
Gas Generator Outages MW (-)	719	723
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)	26,654	27,880
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,125	25,125
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,430	27,430
Operable Capacity Margin	-776	450

[1] Operable Capacity is based on data as of **May 25, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **May 25, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 6, 2020.**

[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.

Summer 2020 Operable Capacity Analysis

90/10 **Load Forecast** (Extreme)	**June - 2020[2] CSO (MW)**	**June - 2020[2] SCC (MW)**
Operable Capacity MW [1]	29,897	31,079
Active Demand Capacity Resource (+) [5]	366	452
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,101	1,101
Non Commercial Capacity (+)	5	5
Non Gas-fired Planned Outage MW (-)	1,196	1,234
Gas Generator Outages MW (-)	719	723
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)	26,654	27,880
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	27,084	27,084
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,389	29,389
Operable Capacity Margin	-2,735	-1,509

[1] Operable Capacity is based on data as of **May 25, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **May 25, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 6, 2020.**

[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.

Summer 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

May 29, 2020 - 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, 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]
6/6/2020	**29897**	**366**	**1101**	**5**	**1196**	**719**	**2800**	**0**	**26654**	**25125**	**2305**	**27430**	**-776**
6/13/2020	29897	366	1101	5	738	479	2800	0	27352	25125	2305	27430	-78
6/20/2020	29897	366	1101	5	93	0	2800	0	28476	25125	2305	27430	1046
6/27/2020	29897	366	1101	5	40	0	2800	0	28529	25125	2305	27430	1099
7/4/2020	30156	537	1025	7	652	0	2100	0	28973	25125	2305	27430	1543
7/11/2020	30156	537	1025	7	445	0	2100	0	29180	25125	2305	27430	1750
7/18/2020	30156	537	1025	7	274	0	2100	0	29351	25125	2305	27430	1921
7/25/2020	30156	537	1025	7	310	0	2100	0	29315	25125	2305	27430	1885
8/1/2020	30156	537	1025	7	354	0	2100	0	29271	25125	2305	27430	1841
8/8/2020	30156	537	1025	7	899	0	2100	0	28726	25125	2305	27430	1296
8/15/2020	30156	537	1025	7	912	0	2100	0	28713	25125	2305	27430	1283
8/22/2020	30156	537	1025	7	357	0	2100	0	29268	25125	2305	27430	1838
8/29/2020	30156	537	1025	7	461	0	2100	0	29164	25125	2305	27430	1734
9/5/2020	30156	537	1025	7	1049	0	2100	0	28576	25125	2305	27430	1146
9/12/2020	30156	537	584	7	2438	66	2100	0	26680	25125	2305	27430	-750

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 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 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)

Summer 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

May 29, 2020 - 90-10 FORECAST using CSO

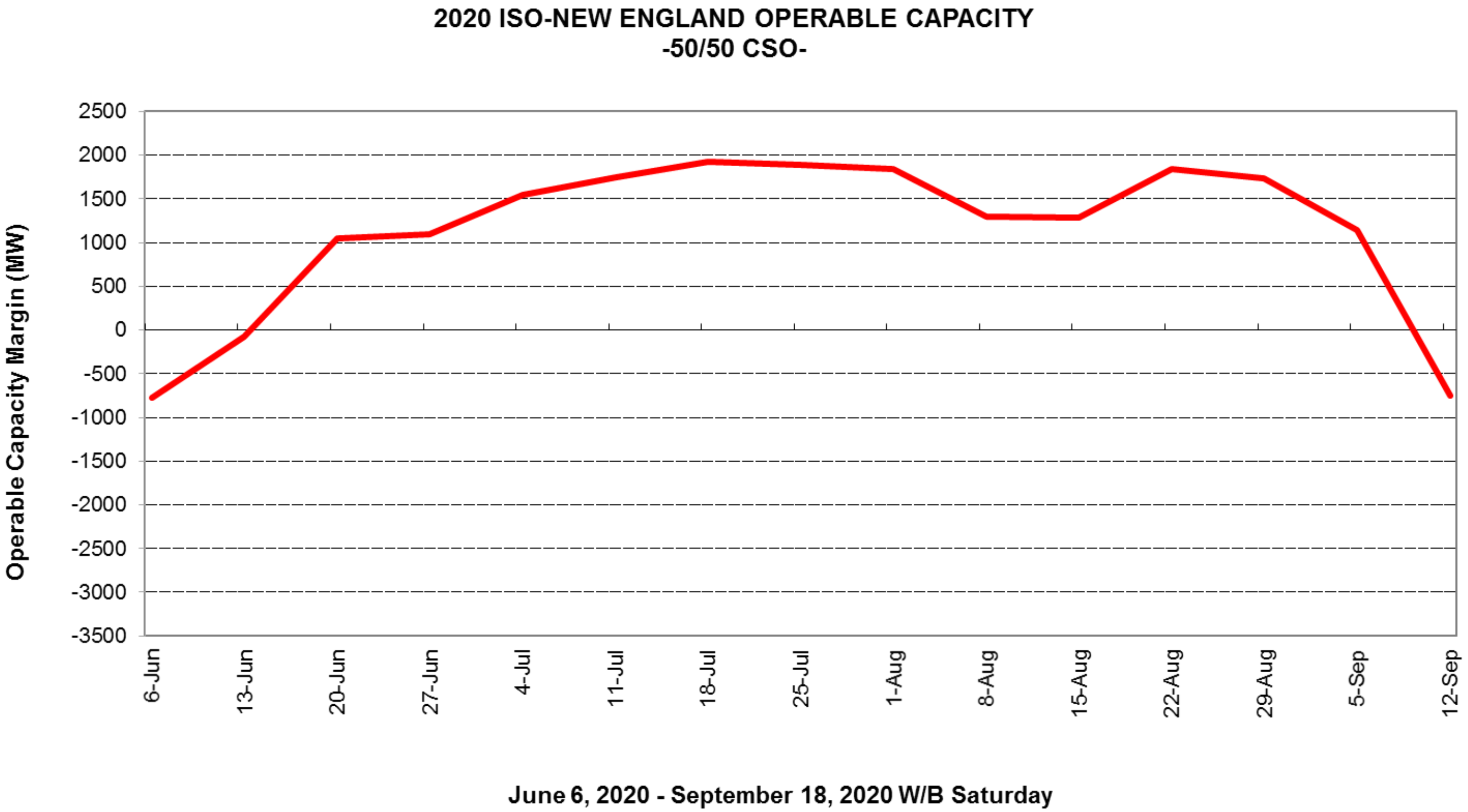
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

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]
6/6/2020	**29897**	**366**	**1101**	**5**	**1196**	**719**	**2800**	**0**	**26654**	**27084**	**2305**	**29389**	**-2735**
6/13/2020	29897	366	1101	5	738	479	2800	0	27352	27084	2305	29389	-2037
6/20/2020	29897	366	1101	5	93	0	2800	0	28476	27084	2305	29389	-913
6/27/2020	29897	366	1101	5	40	0	2800	0	28529	27084	2305	29389	-860
7/4/2020	30156	537	1025	7	652	0	2100	0	28973	27084	2305	29389	-416
7/11/2020	30156	537	1025	7	445	0	2100	0	29180	27084	2305	29389	-209
7/18/2020	30156	537	1025	7	274	0	2100	0	29351	27084	2305	29389	-38
7/25/2020	30156	537	1025	7	310	0	2100	0	29315	27084	2305	29389	-74
8/1/2020	30156	537	1025	7	354	0	2100	0	29271	27084	2305	29389	-118
8/8/2020	30156	537	1025	7	899	0	2100	0	28726	27084	2305	29389	-663
8/15/2020	30156	537	1025	7	912	0	2100	0	28713	27084	2305	29389	-676
8/22/2020	30156	537	1025	7	357	0	2100	0	29268	27084	2305	29389	-121
8/29/2020	30156	537	1025	7	461	0	2100	0	29164	27084	2305	29389	-225
9/5/2020	30156	537	1025	7	1049	0	2100	0	28576	27084	2305	29389	-813
9/12/2020	30156	537	584	7	2438	66	2100	0	26680	27084	2305	29389	-2709

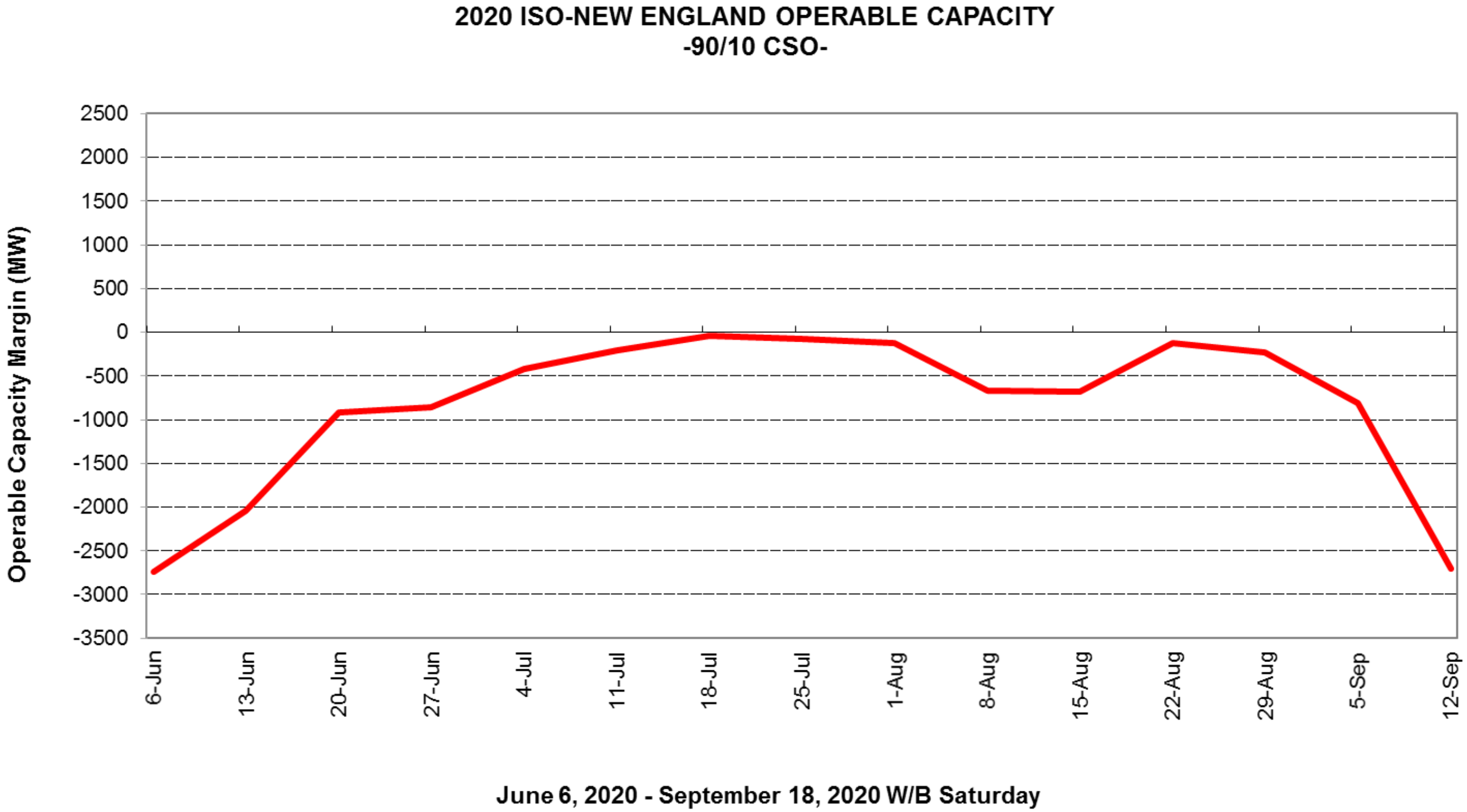
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 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)

***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Summer 2020 Operable Capacity Analysis
50/50 Forecast (Reference)



Summer 2020 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	125 [3]

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <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 25,000 MW system load 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	250 [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		**2,520**

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <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 25,000 MW system load 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