

NEPOOL Participants Committee Report

October 2020



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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



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Regular Operations Report - Highlights



Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
 - Update: August 2020 Energy Market value totaled \$305M
 - September Energy market value over the period was \$158M, down \$148M from August 2020 and down \$53M from September 2019
 - September natural gas prices over the period were 1.3% lower than August average values
 - Average RT Hub Locational Marginal Prices (\$20.47/MWh) over the period were 14% lower than August averages
 - DA Hub: \$20.41/MWh
 - Average September 2020 natural gas prices and RT Hub LMPs over the period were down 25% and up 0.1%, respectively, from September 2019 average
 - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.3% during September, down from 101.4% during August*
 - The minimum value for the month was 93.6% on Wednesday, September 16th

Data through September 23rd, except where otherwise noted.

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

Underlying natural gas data furnished by:



Highlights, cont.

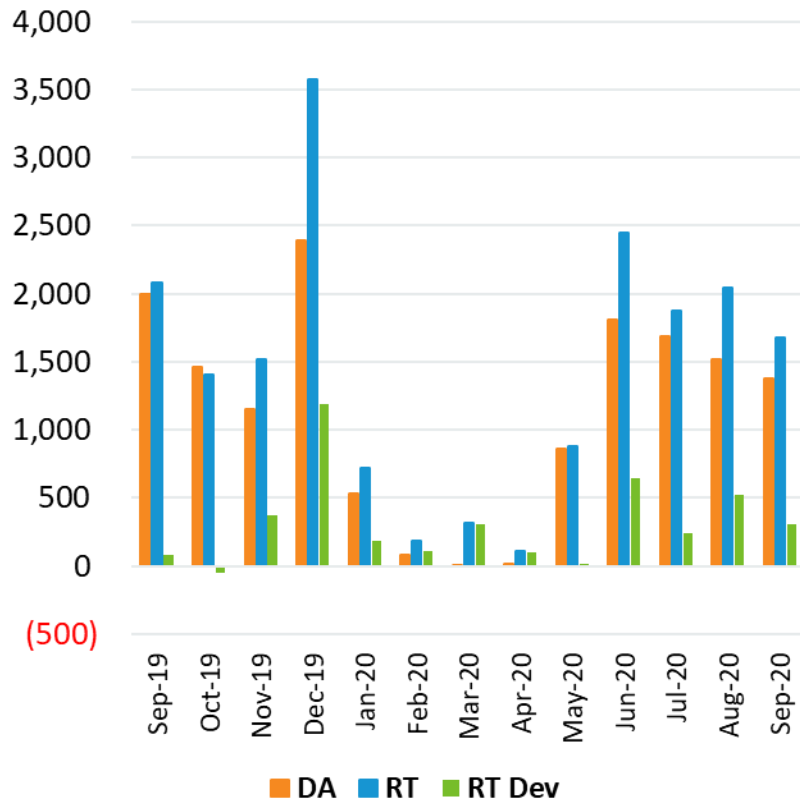
- Daily Net Commitment Period Compensation (NCPC)
 - September NCPC payments totaled \$1.9M over the period, down \$1.5M from August 2020 and down \$0.4M from September 2019
 - First Contingency payments totaled \$1.4M, down \$0.9M from August
 - \$1.4M paid to internal resources, down \$0.8M from August
 - » \$306K charged to DALO, \$582K to RT Deviations, \$467K to RTLO*
 - \$60K paid to resources at external locations, down \$132K from August
 - » Charged to RT Deviations
 - Second Contingency payments totaled \$237K, down \$601K from August
 - Voltage payments totaled \$262K, up \$258K from August
 - Distribution payments totaled \$6K, down \$199K from August
 - NCPC payments over the period as percent of Energy Market value were 1.2%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - \$99K; Rapid Response Pricing (RRP) Opportunity Cost - \$188K; Posturing - \$142K; Generator Performance Auditing (GPA) - \$37K

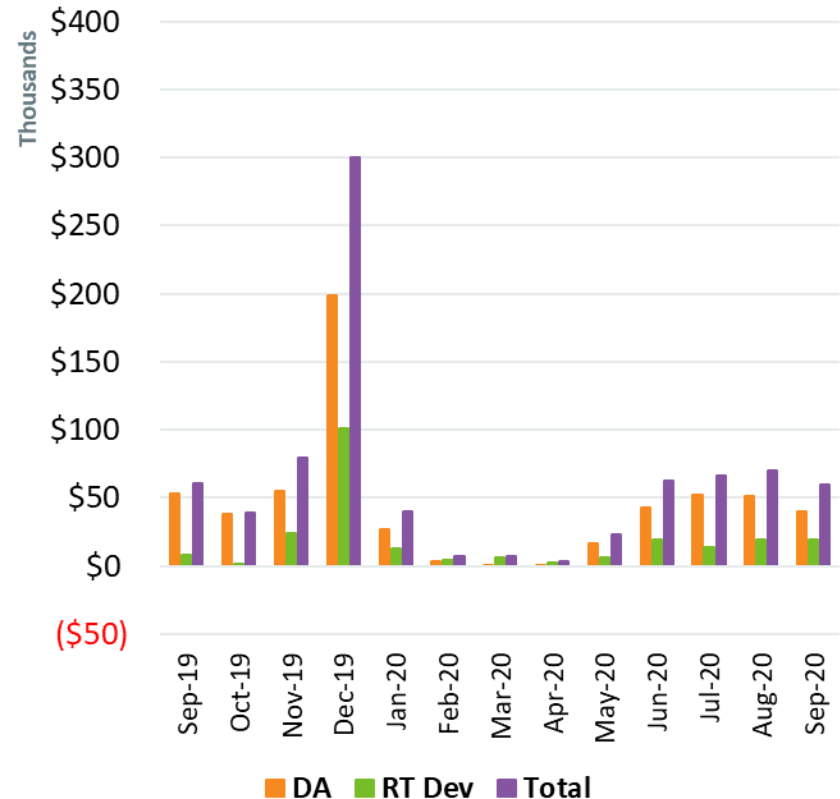


Price Responsive Demand (PRD) Energy Market Activity by Month

DA, RT, and RT Dev MWh



Market Value



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



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)
 - ARA2 was held August 3-5 and results were posted on September 1
 - ICR and related values development for ARA3 continue at the PSPC
 - RC vote anticipated October 20, PC vote expected November 6, and FERC filing to be made by December 1

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

ISO-NE PUBLIC

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
 - ARA1 was held June 1-3, and results were posted on June 25
 - ICR and related values development for ARA2 continue at the PSPC
 - RC vote anticipated October 20, PC vote expected November 6, and FERC filing to be made by December 1
- CCP 14 (2023-2024)
 - Auction results were filed with FERC on February 18 and FERC accepted the filing on April 10
 - ICR and related values development for ARA1 continue at the PSPC
 - RC vote anticipated October 20, PC vote expected November 6, and FERC filing to be made by December 1



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 zone: 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
 - Qualification Determination Notifications are on schedule to be released by October 2
 - ICR and related values to be filed with FERC no later than November 10

Highlights

- On September 24, Transmission Planning initiated discussions with the Planning Advisory Committee regarding appropriate study assumptions to accommodate the changing landscape of the power system
- Qualification Determination Notifications are on schedule to be released by October 2
- RSP21 development will commence in Q1 2021
 - Improvements to streamline the RSP have already begun and include the addition of a new web page for Economic Studies and enhanced Environmental/Emissions information
- ICR and Related Values Development Continues
 - FCA 15 values to be filed with FERC no later than November 10
 - 2021 ARA values to be filed with FERC by December 1
- EE Reconstitution Project
 - Reconstitution methodology changes to MR1, Section 12.8(d) were filed with FERC on September 11 and will impact the 2021 load forecast used for FCA 16 ICR and Related Values development



Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
 - Discussions are ongoing with industry experts regarding emerging technologies/trends and methods of incorporating these into the forecast
- The 2021 load forecast development process has commenced
 - Discussions will continue at the Load Forecast Committee, Energy-Efficiency Forecast Working Group, and Distributed Generation Forecast Working Group through the rest of 2020 and into Q1 2021
 - In the March/April timeframe, PAC will discuss the preliminary ten-year forecast
 - Publication of the final ten-year forecast will be in the May 2021 CELT report



FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
 - 25 companies have achieved QTPS status
- The Boston 2028 RFP process has been completed and the ISO has started the Solutions Study process
 - The Preliminary Preferred Solution was discussed at the 8/27/20 PAC meeting
 - The draft Solutions Study was issued on 9/8/20 and stakeholder comments were due on 9/23/20
 - No stakeholder comments were received
 - The final Solutions Study was issued on 9/24/20

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning October 17, 2020.
- The lowest 50/50 and 90/10 Preliminary Winter Operable Capacity Margins are projected for week beginning January 2, 2021.



SYSTEM OPERATIONS



System Operations

<u>Weather Patterns</u>	Boston	Temperature: Below Normal (-0.4°F) Max: 85°F, Min: 44°F Precipitation: 0.46" – Below Normal Normal: 3.06"	Hartford	Temperature: Below Normal (-0.1°F) Max: 86°F, Min: 33°F Precipitation: 0.97" - Below Normal Normal: 3.42"
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<u>Peak Load:</u>	19,134 MW	Sep 10, 2020	18:00 (ending)
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Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
None in September			



System Operations

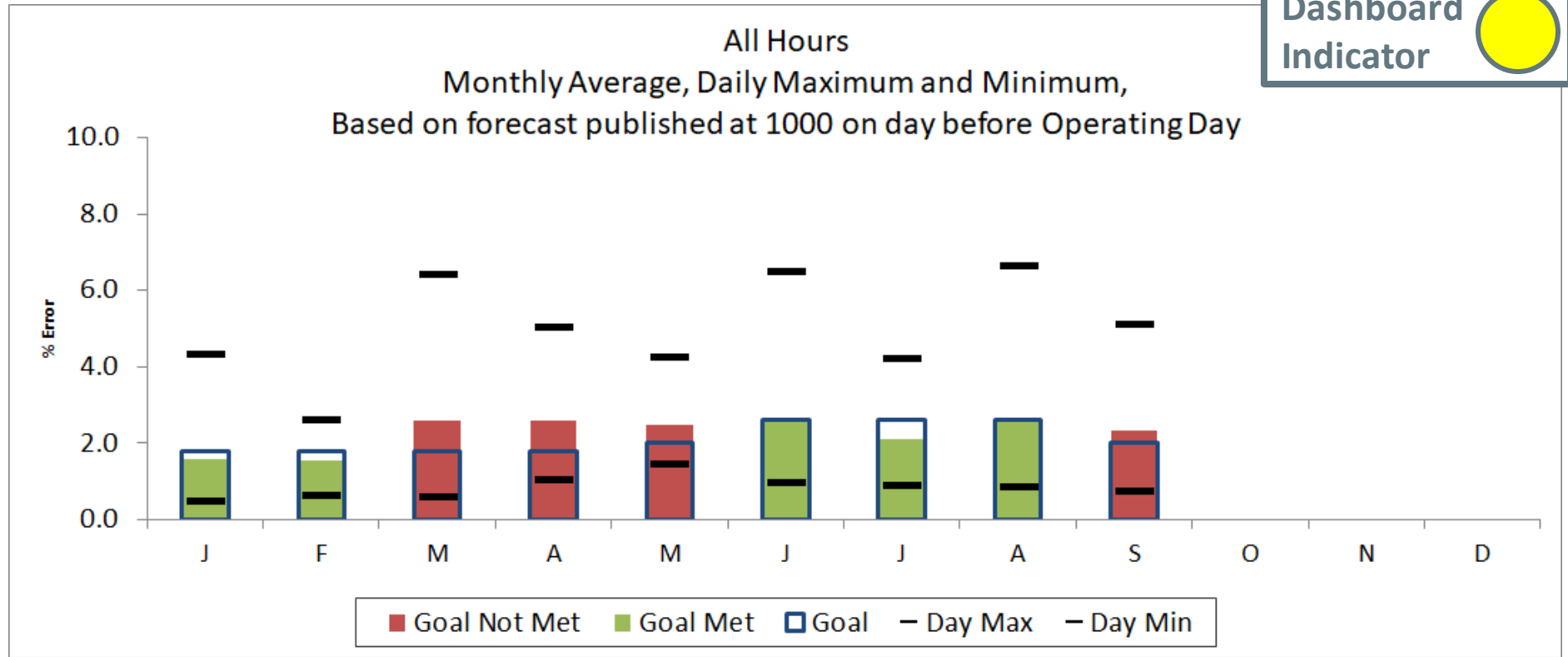
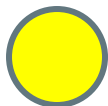
NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
9/6	IESO	520
9/8	NBPSO	350



2020 System Operations - Load Forecast Accuracy

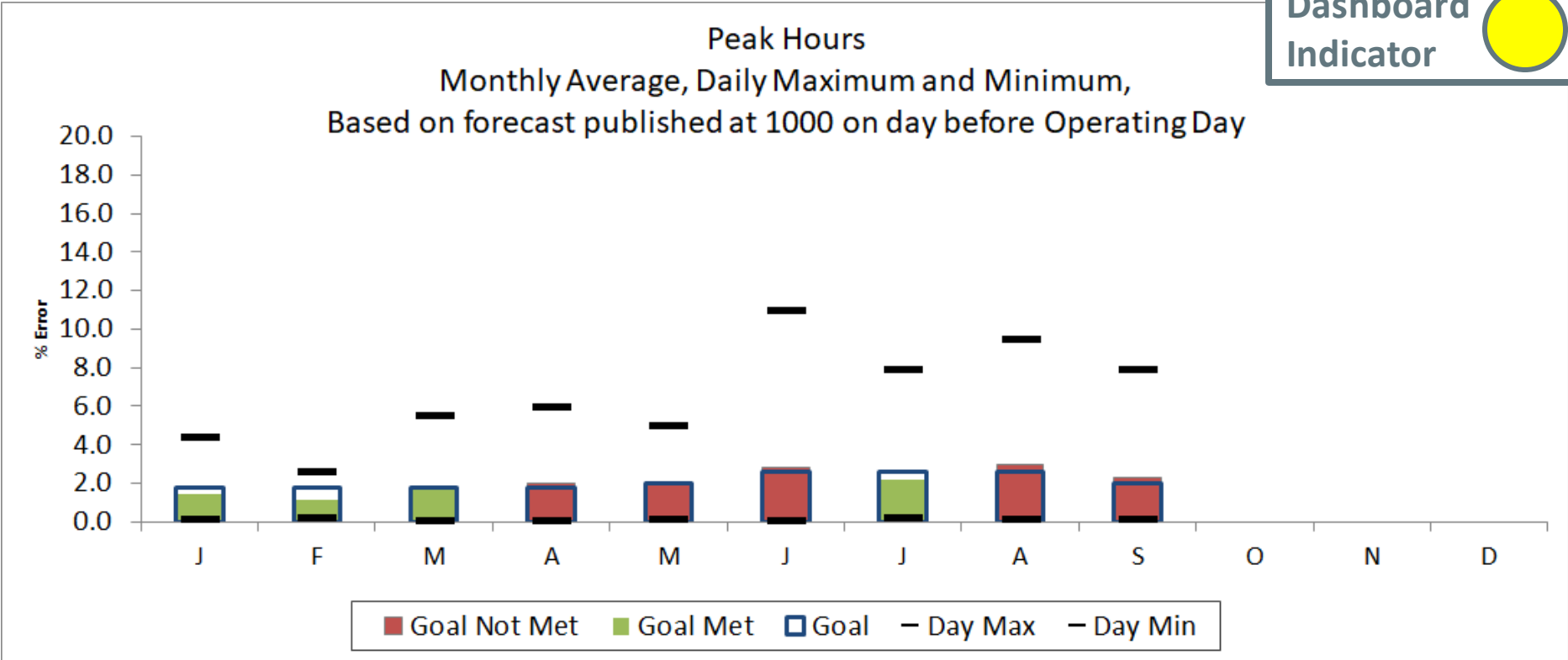
Dashboard
Indicator



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	6.47	4.18	6.63	5.09				6.63
Day Min	0.46	0.61	0.58	1.03	1.42	0.96	0.88	0.84	0.72				0.46
MAPE	1.57	1.54	2.60	2.58	2.49	2.58	2.10	2.56	2.31				2.26
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

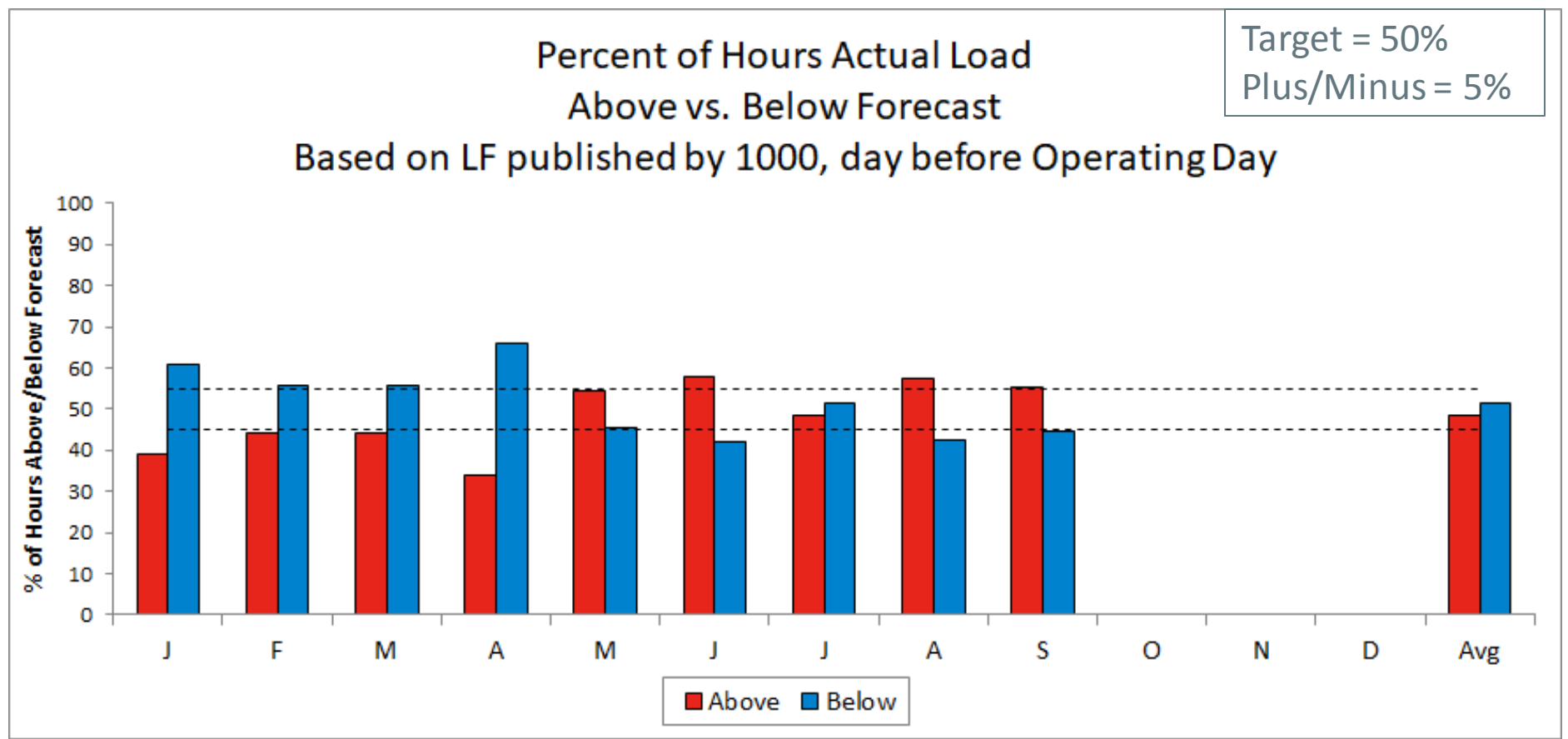
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



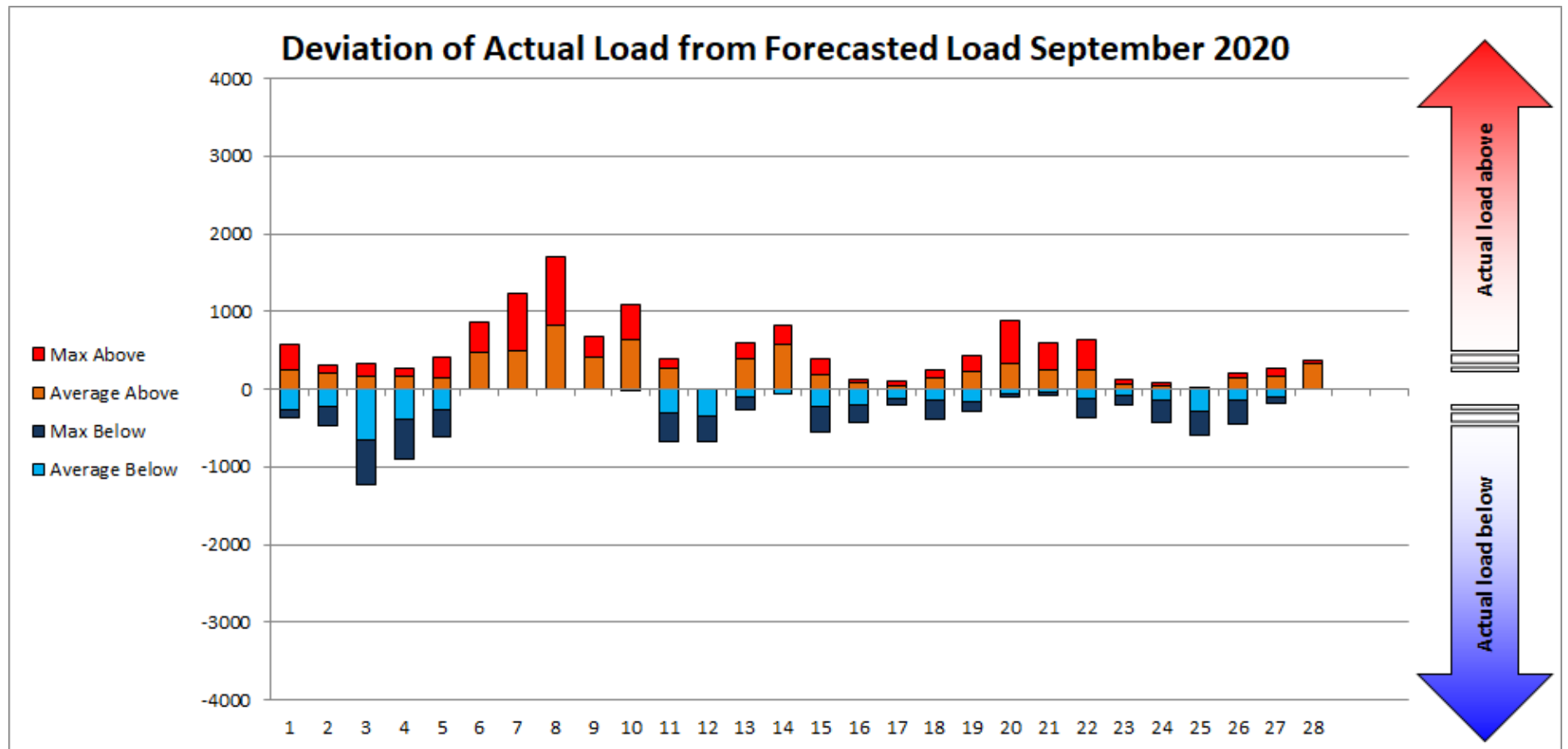
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59	5.48	5.93	4.94	10.93	7.84	9.44	7.88				10.93
Day Min	0.07	0.19	0.01	0.00	0.13	0.05	0.14	0.07	0.10				0.00
MAPE	1.41	1.12	1.72	1.97	2.11	2.83	2.18	2.97	2.29				2.07
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

2020 System Operations - Load Forecast Accuracy cont.



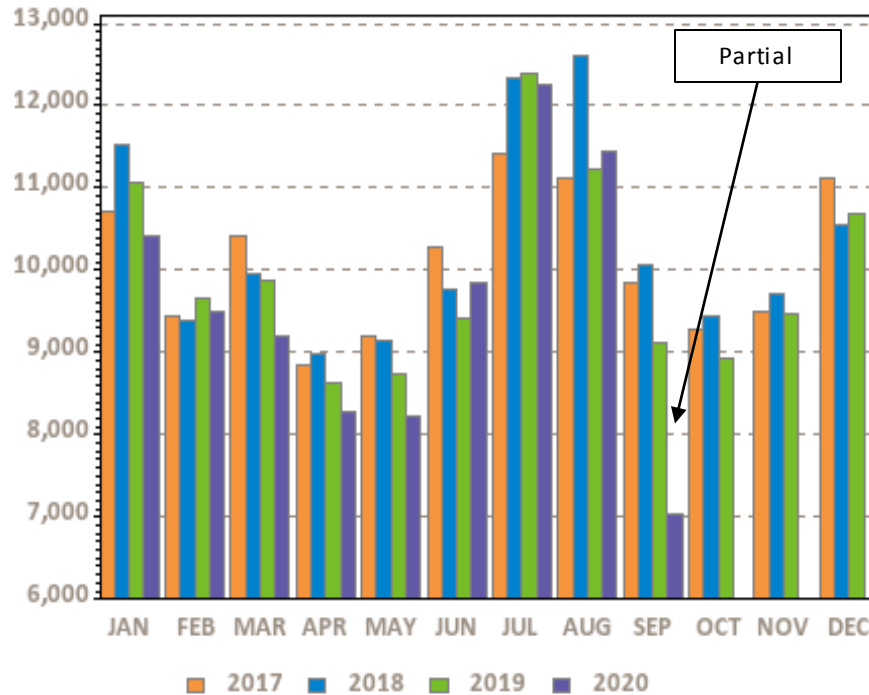
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3	44.4	33.9	54.4	57.9	48.4	57.6	55.4				48
Below %	61	55.7	55.6	66.1	45.6	42.1	51.6	42.4	44.6				52
Avg Above	136.2	169.9	207	178.9	231.9	257.5	248.3	287.2	242.5				287
Avg Below	-192.4	-157.6	-263.9	-265.3	-196.3	-243.5	-281.7	-245.5	-148.3				-282
Avg All	-65	-13	-56	-106	38	22	-26	73	96				-4

2020 System Operations - Load Forecast Accuracy cont.



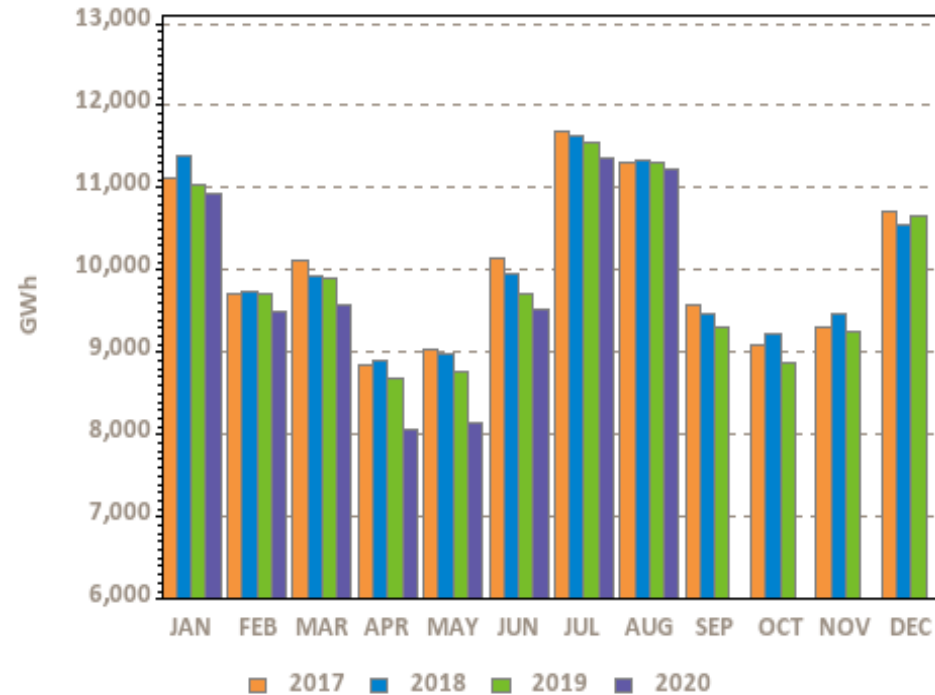
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

Net Energy for Load (NEL)



Ann Tot (TWh): 121.2 123.5 119.2 86.2

Weather Normalized NEL

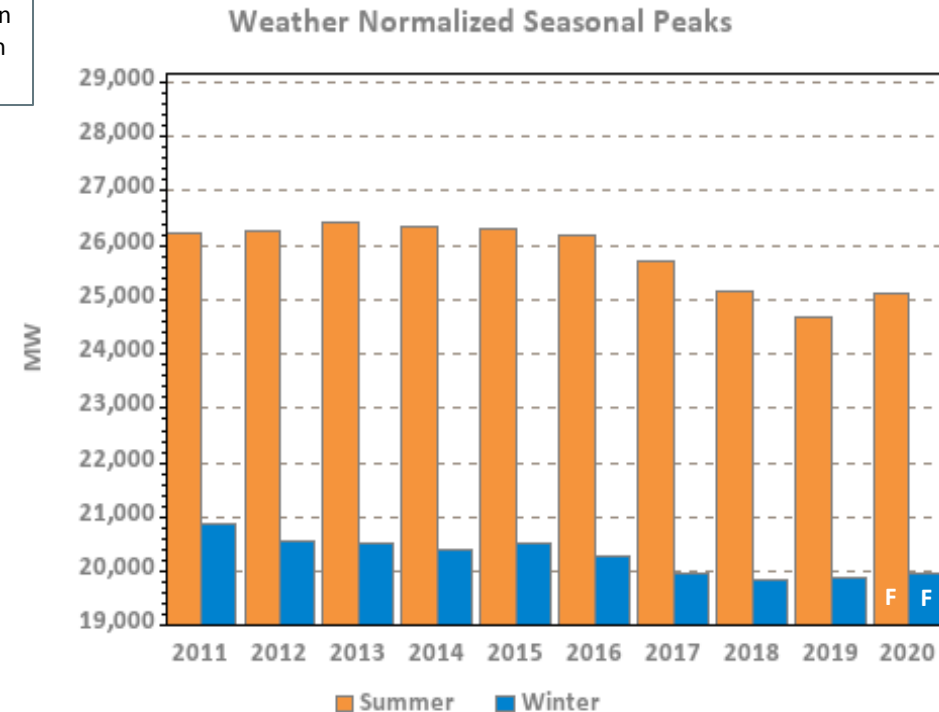
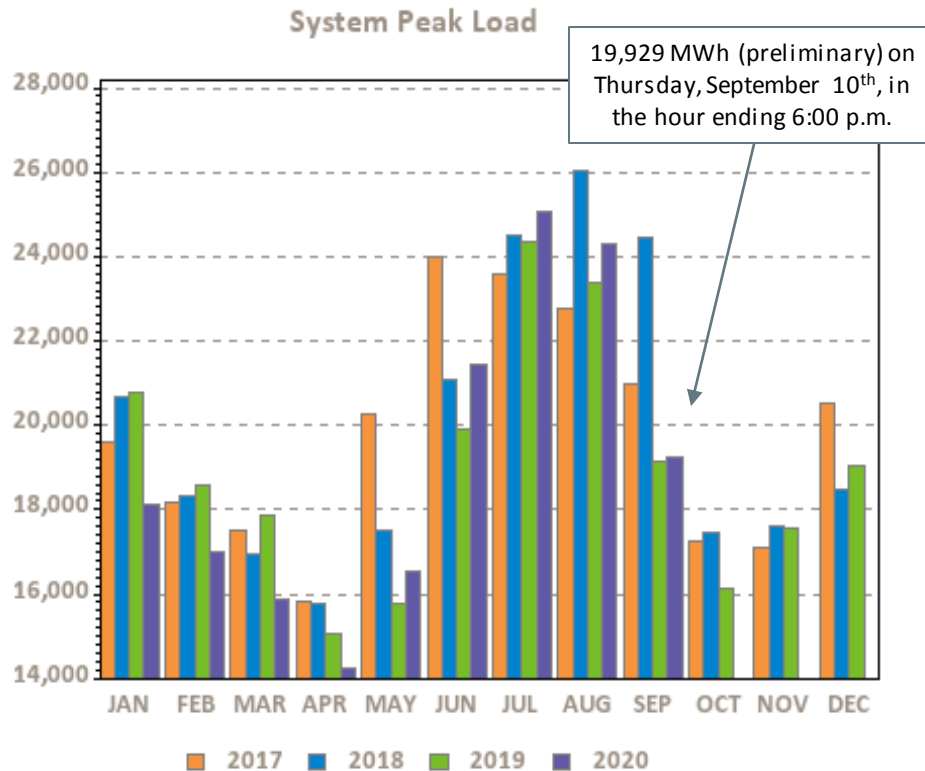


Ann Tot (TWh): 120.7 120.6 118.7 78.4

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.



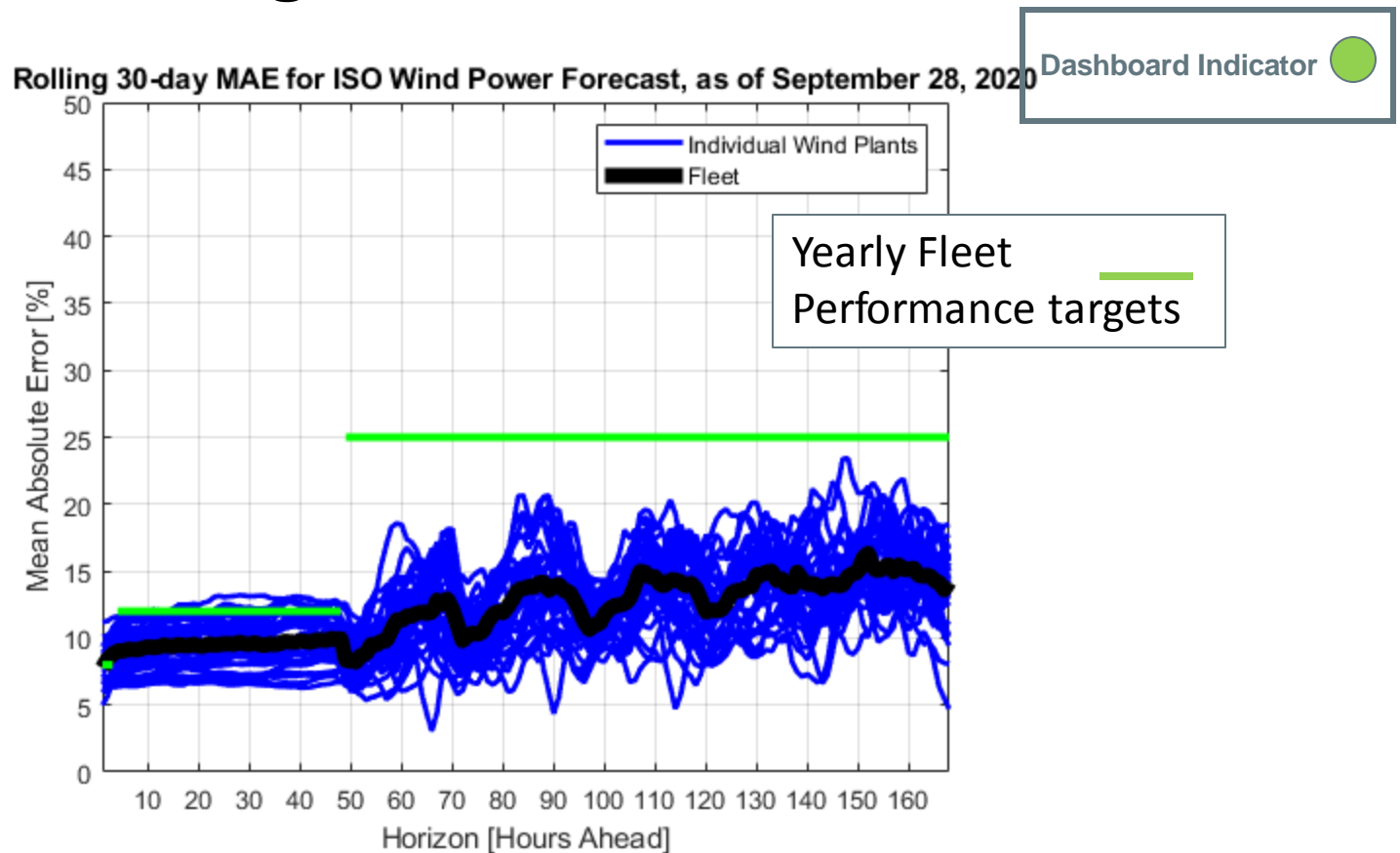
Monthly Peak Loads and Weather Normalized Seasonal Peak History



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

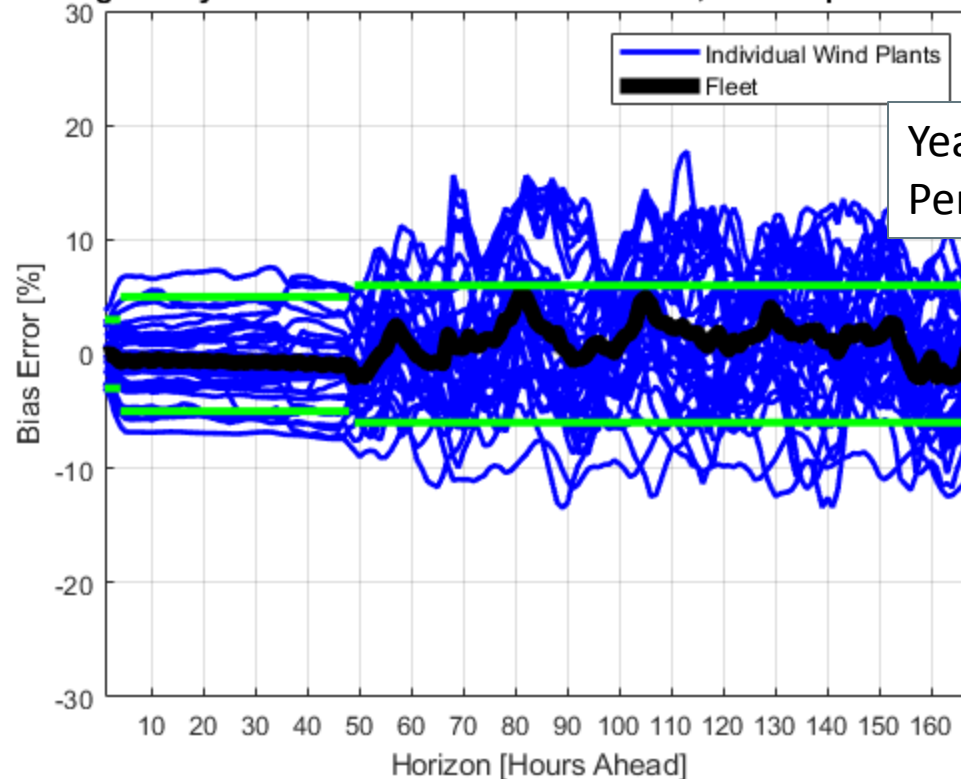


Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV-GL forecast is very good compared to industry standards, and monthly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

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

Rolling 30-day Bias for ISO Wind Power Forecast, as of September 28, 2020

Dashboard Indicator 

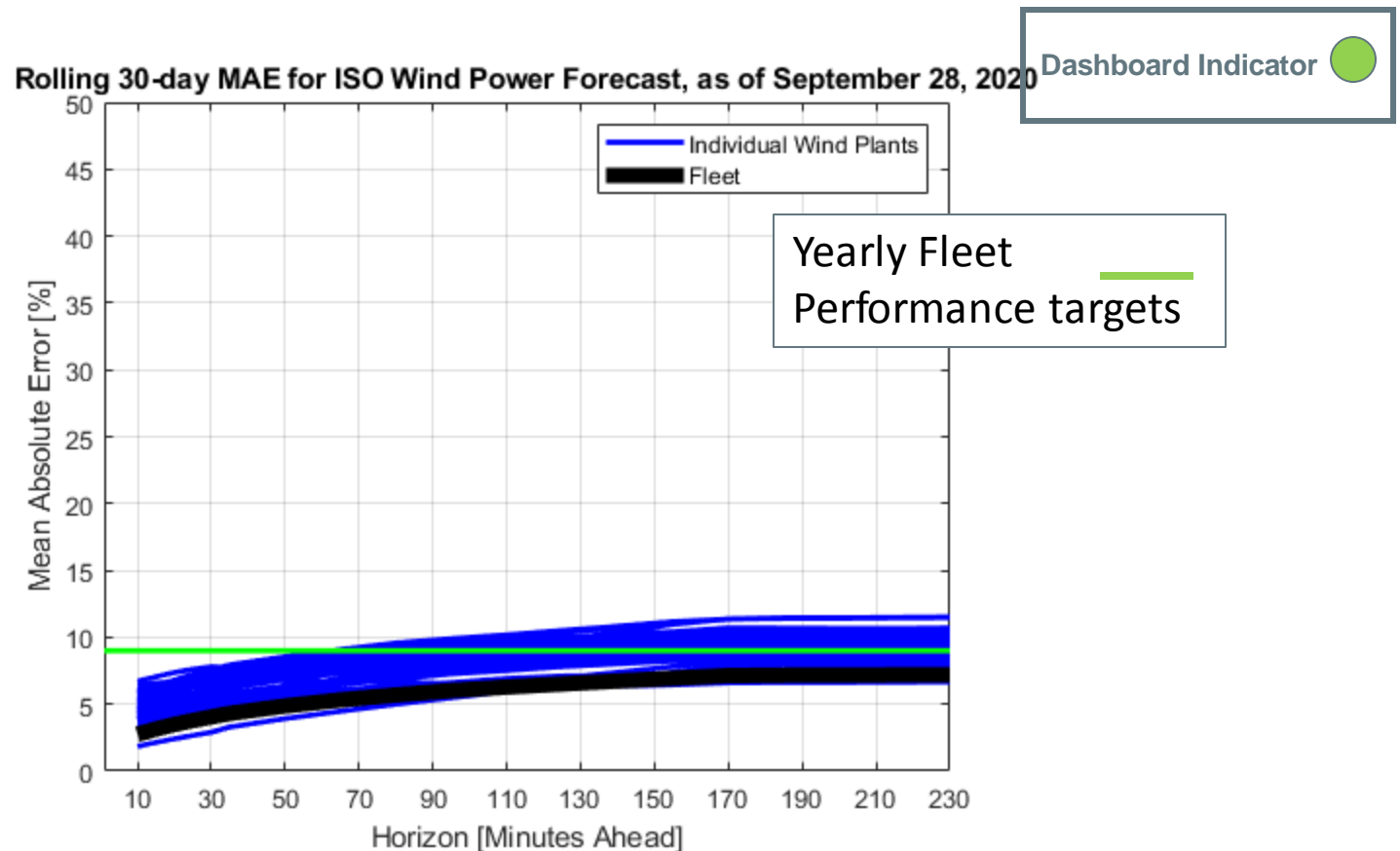


Yearly Fleet
Performance targets

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 within yearly performance targets.

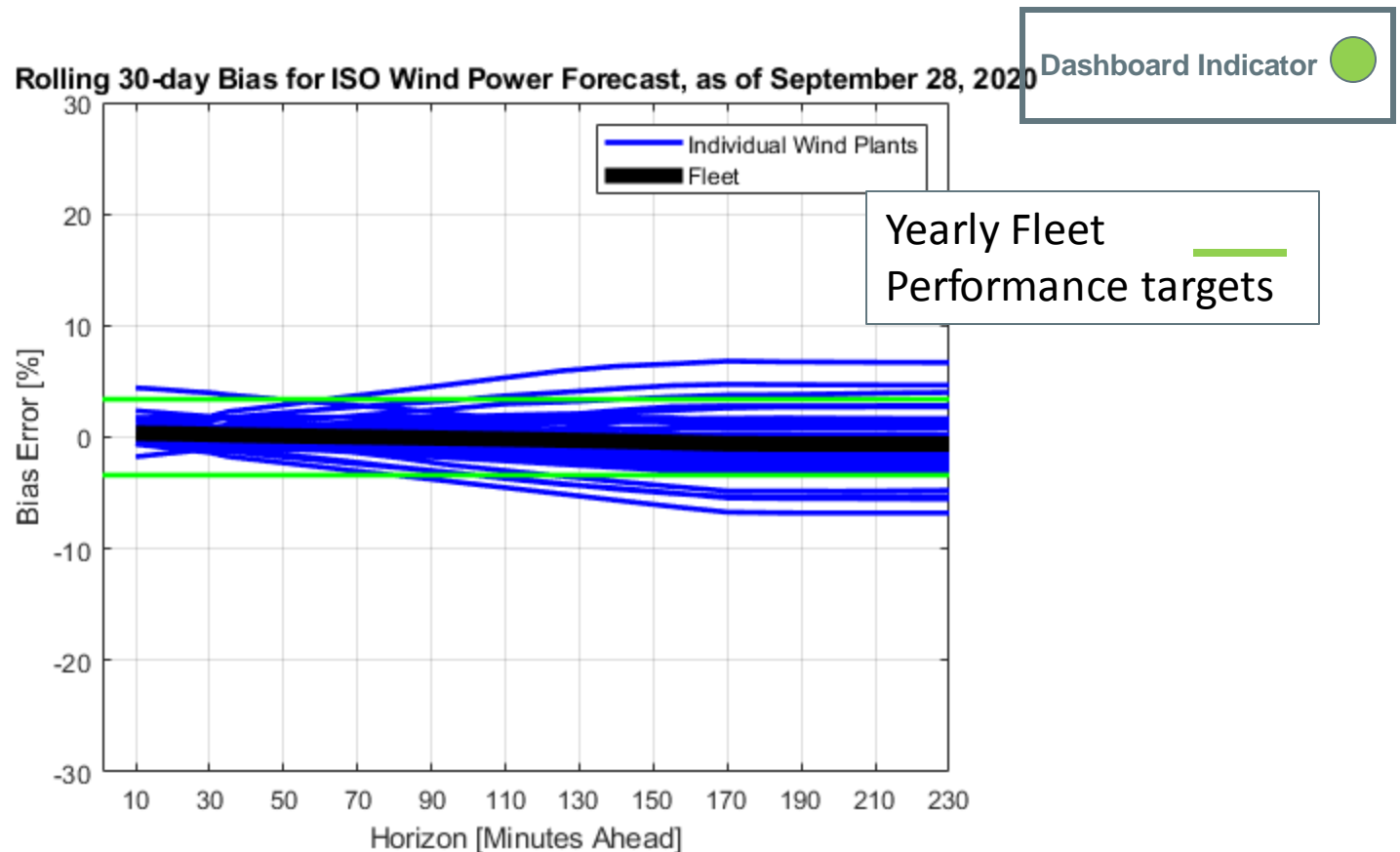
Wind Power Forecast Error Statistics:

Short Term Forecast MAE



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

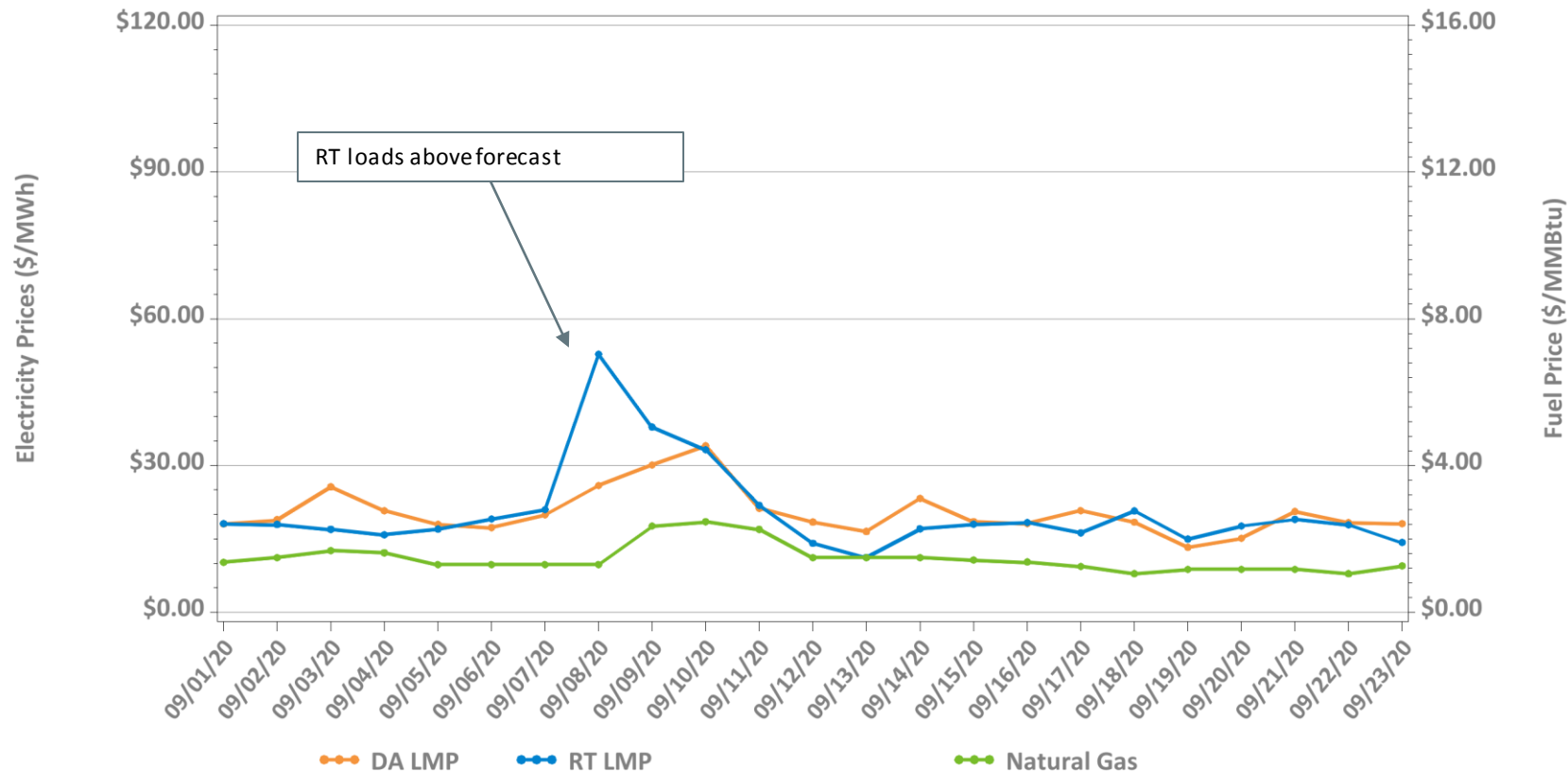


Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards,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

MARKET OPERATIONS



Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: September 1-23, 2020

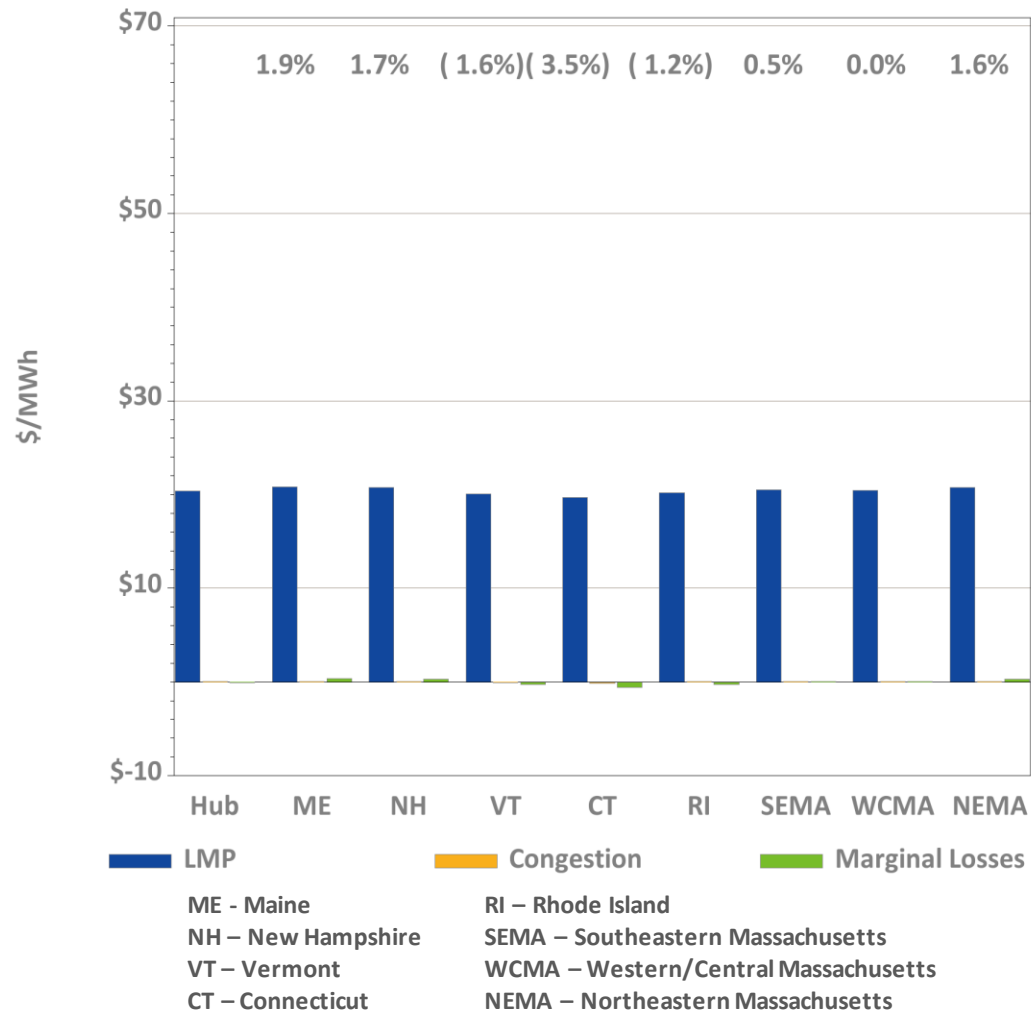


Underlying natural gas data furnished by:

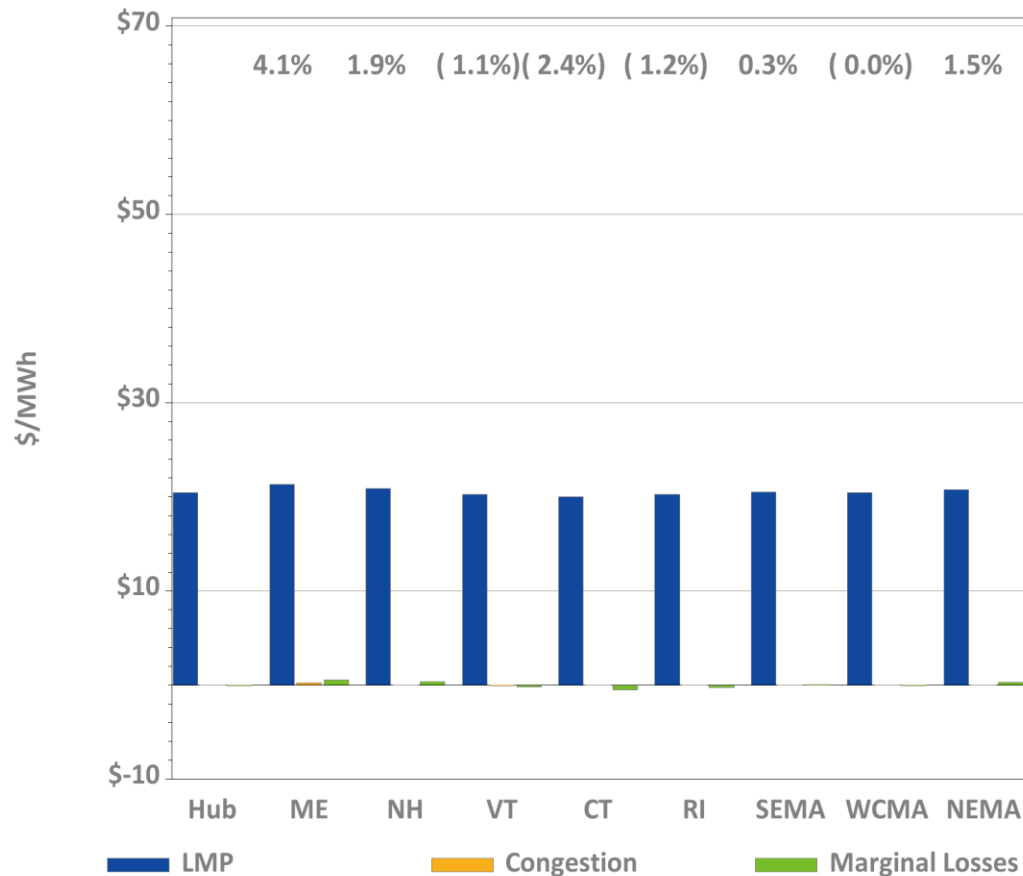


Average price difference over this period (DA-RT): \$-0.07
 Average price difference over this period ABS(DA-RT): \$3.81
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
 Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, September 2020



RT LMPs Average by Zone & Hub, September 2020



Definitions

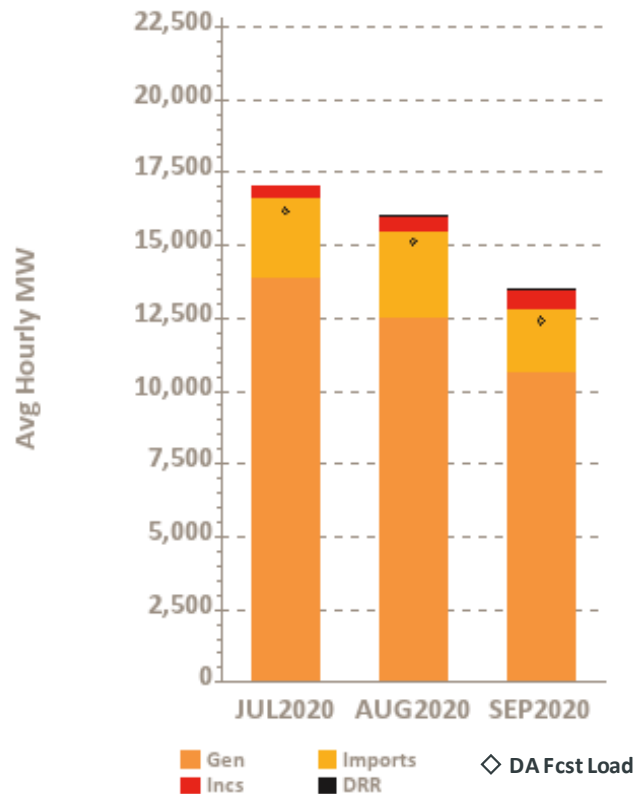
Day-Ahead Concept	Definition
Day-Ahead Load Obligation (DALO)	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports



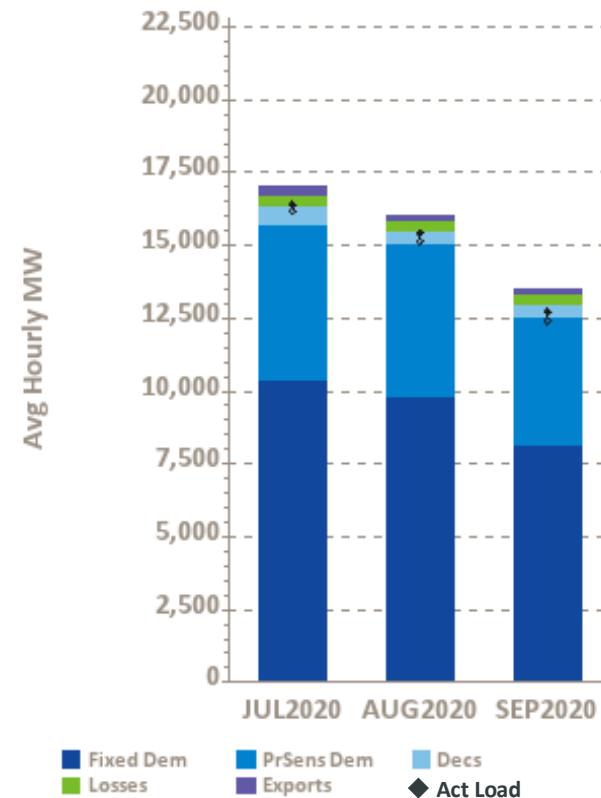
Components of Cleared DA Supply and Demand

– Last Three Months

Supply



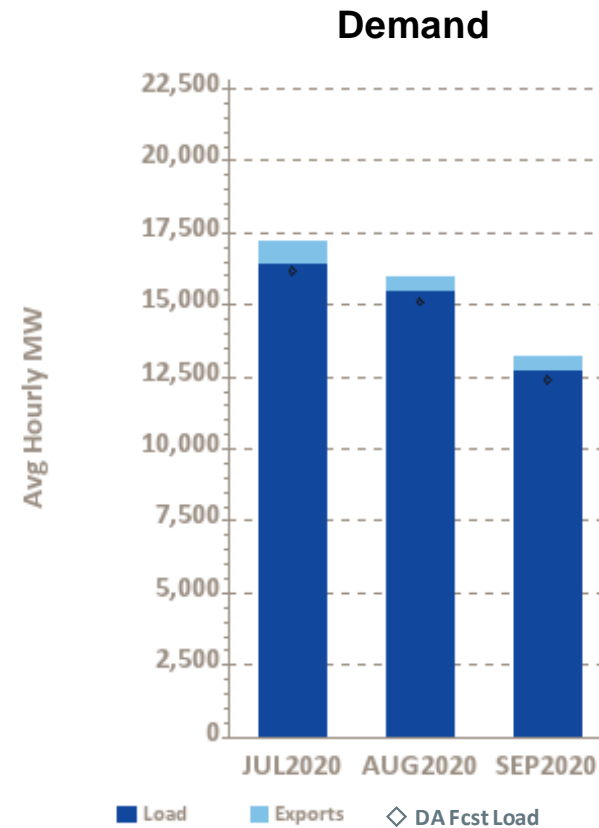
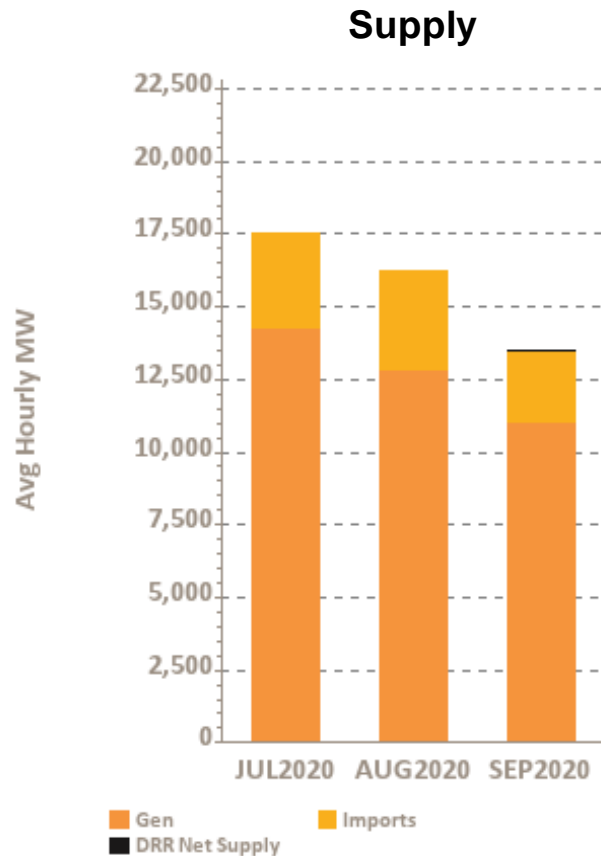
Demand



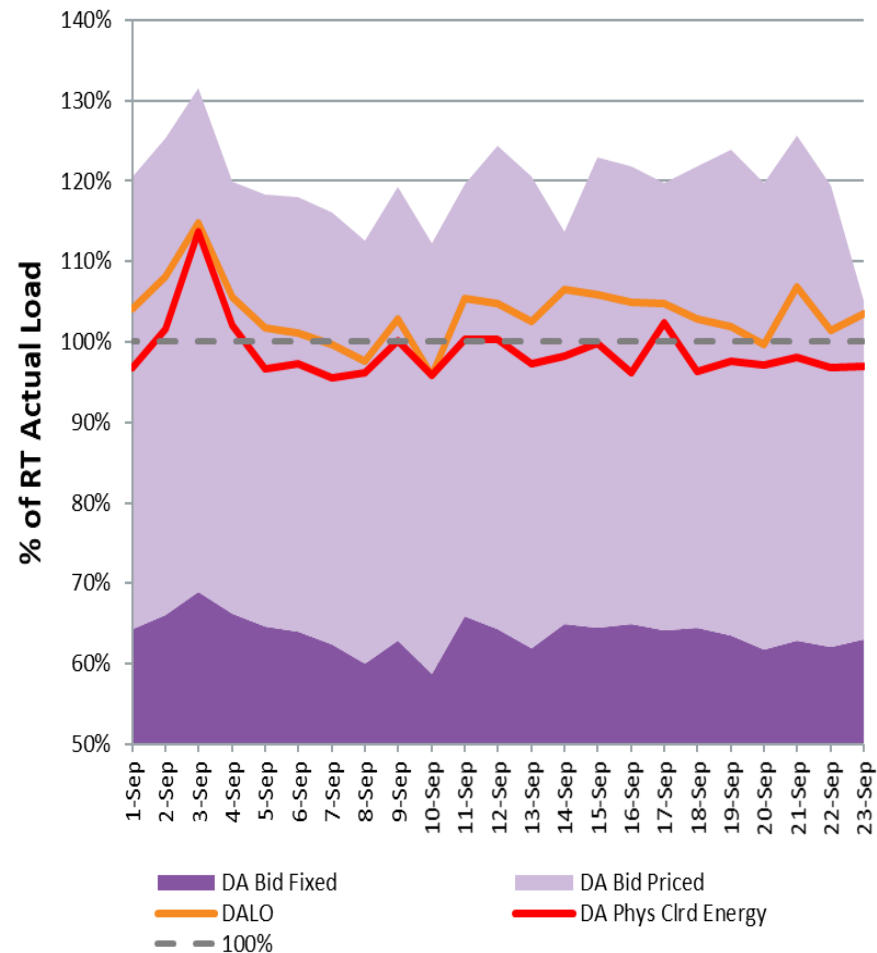
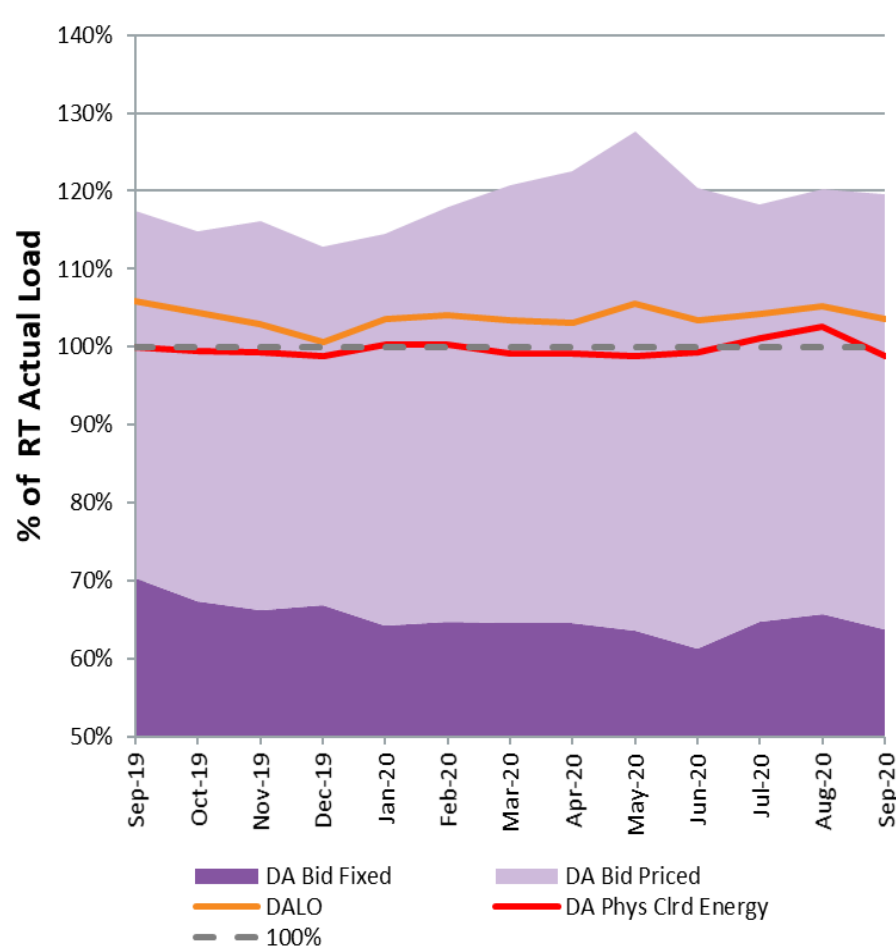
Gen – Generation
 Incs – Increment Offers
 DA Fcst Load – Day-Ahead Forecast Load
 DRR – Demand Response Resource

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



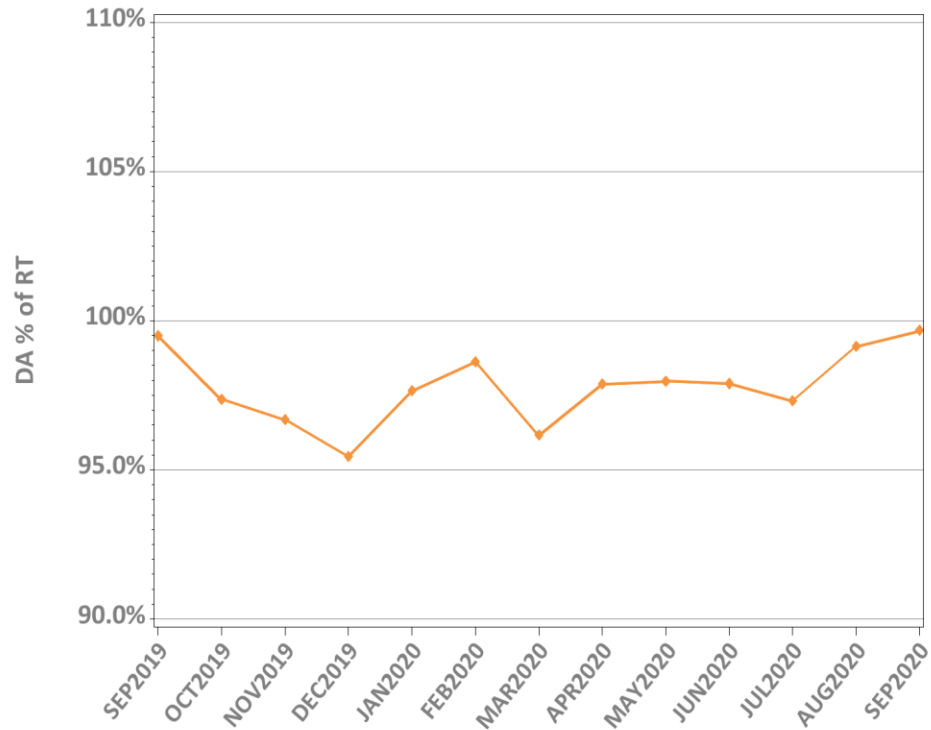
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)



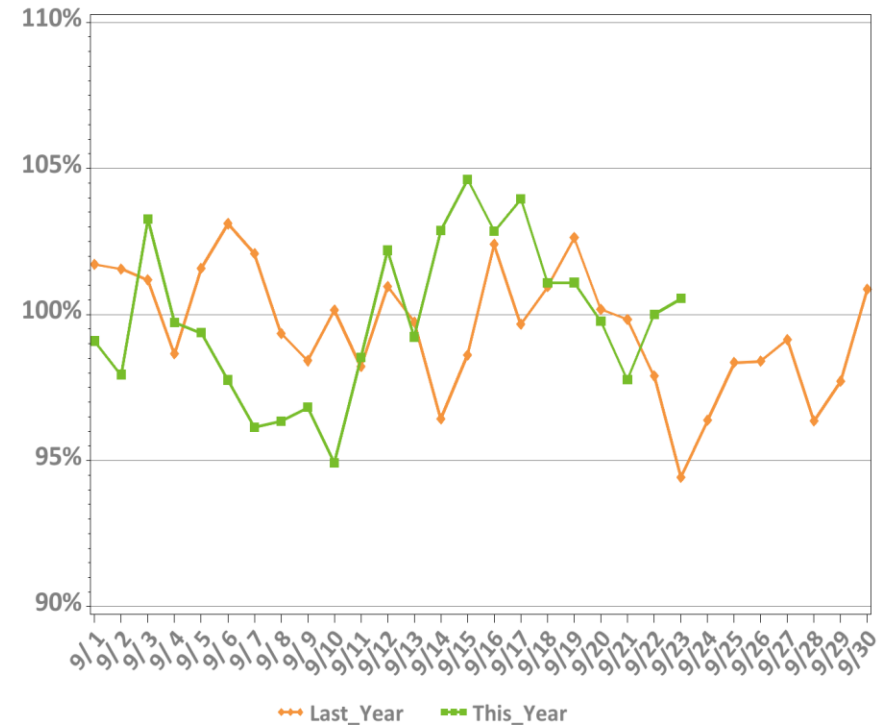
Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

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

Monthly, Last 13 Months



Daily, This Year vs. Last Year

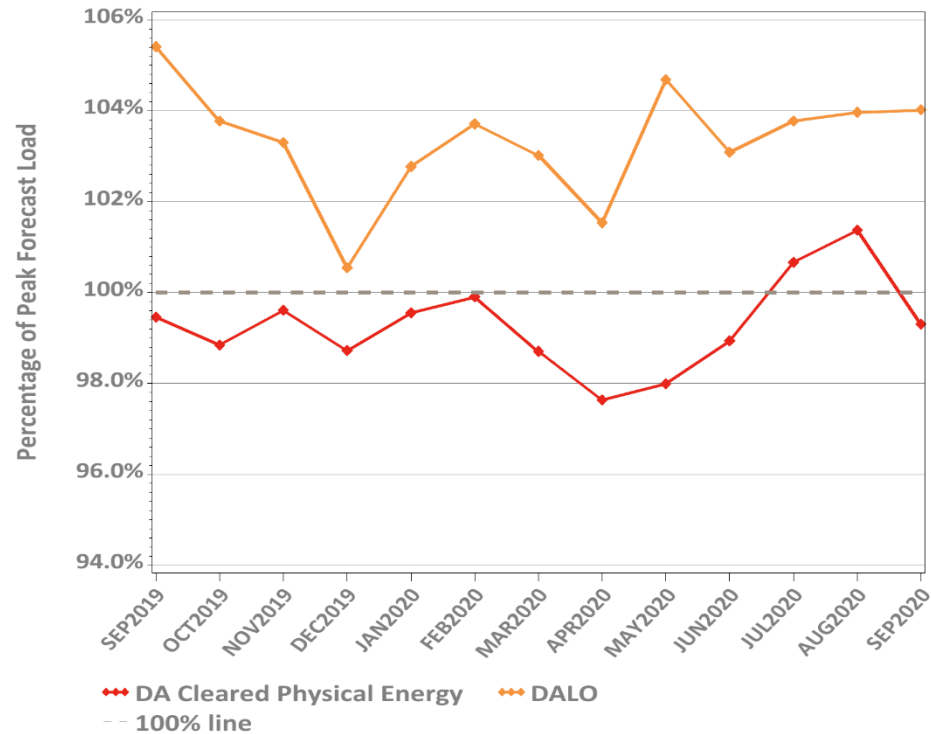


*Hourly average values

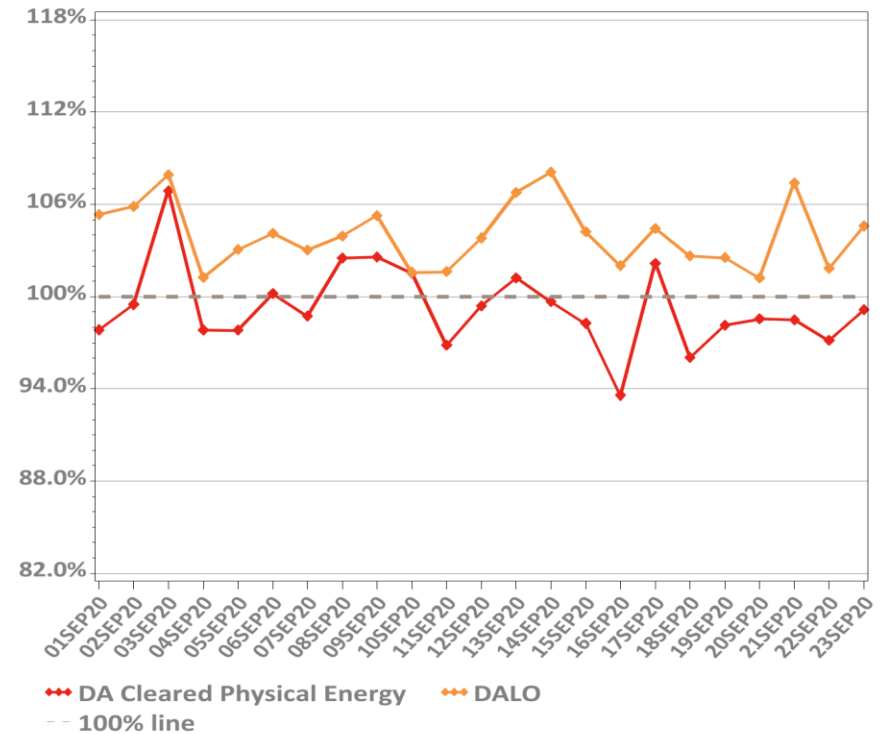


DA Volumes as % of Forecast in Peak Hour

Monthly, Last 13 Months

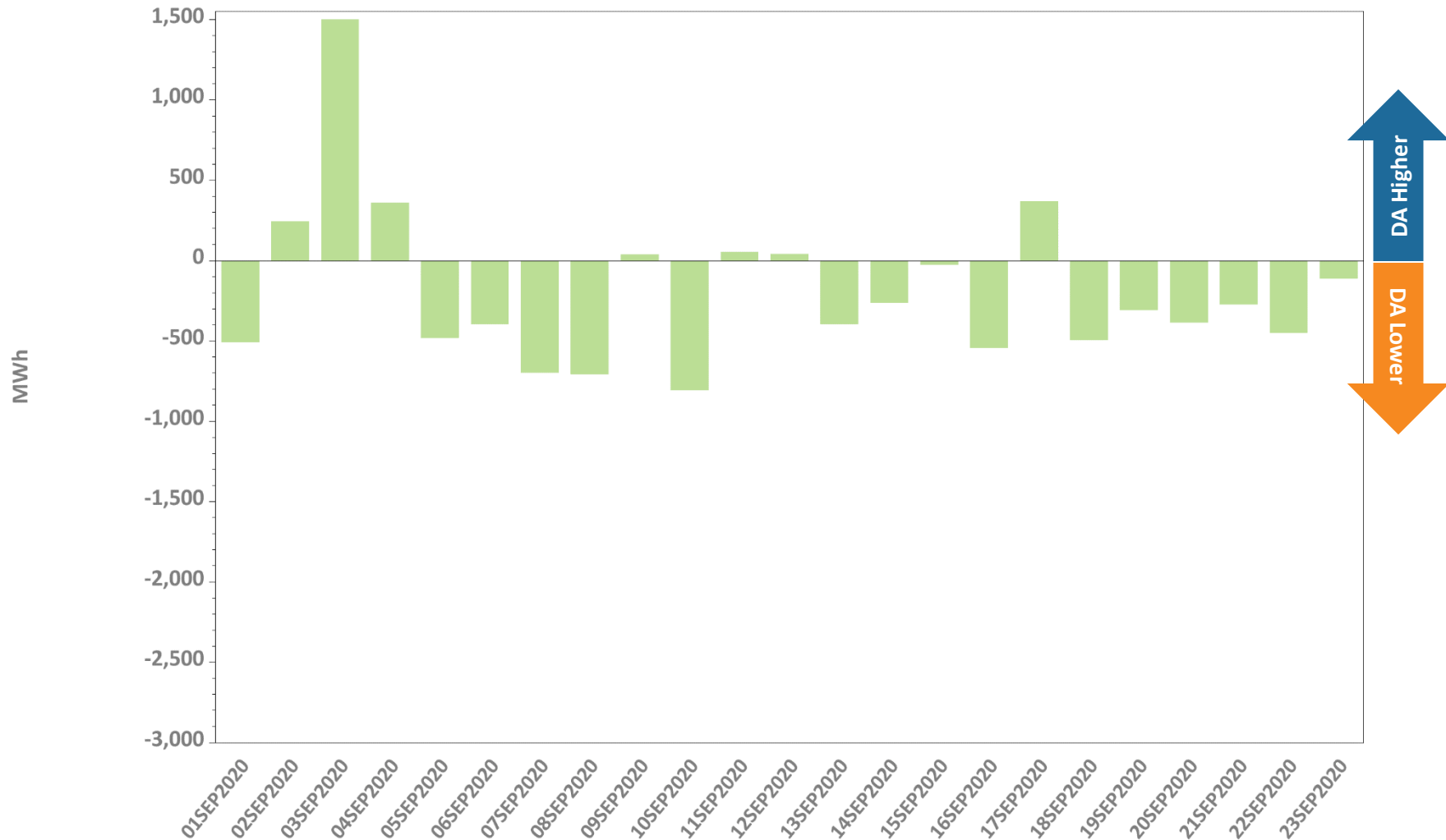


Daily: This Month



Note: There were **no** instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during September.

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



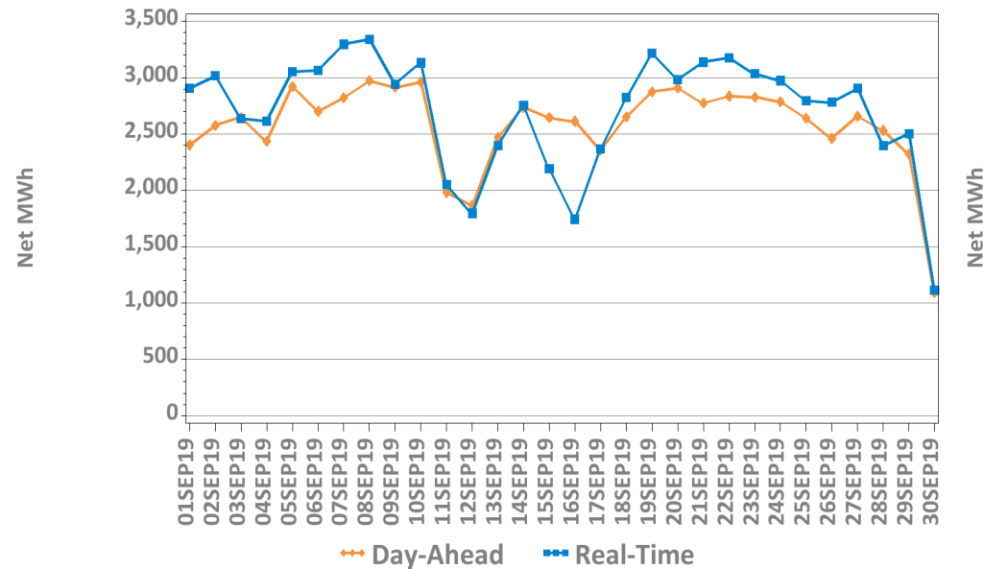
*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.



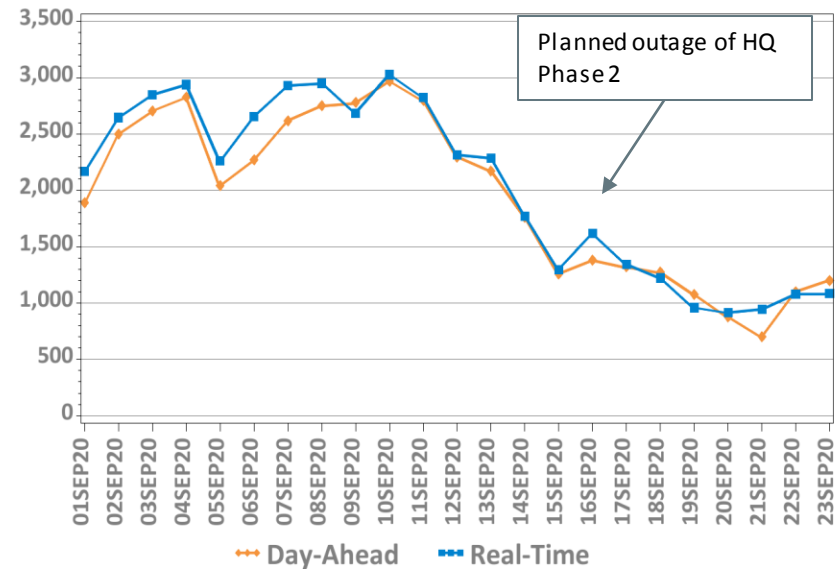
DA vs. RT Net Interchange

September 2019 vs. September 2020

Hourly Average by Day, Last Year



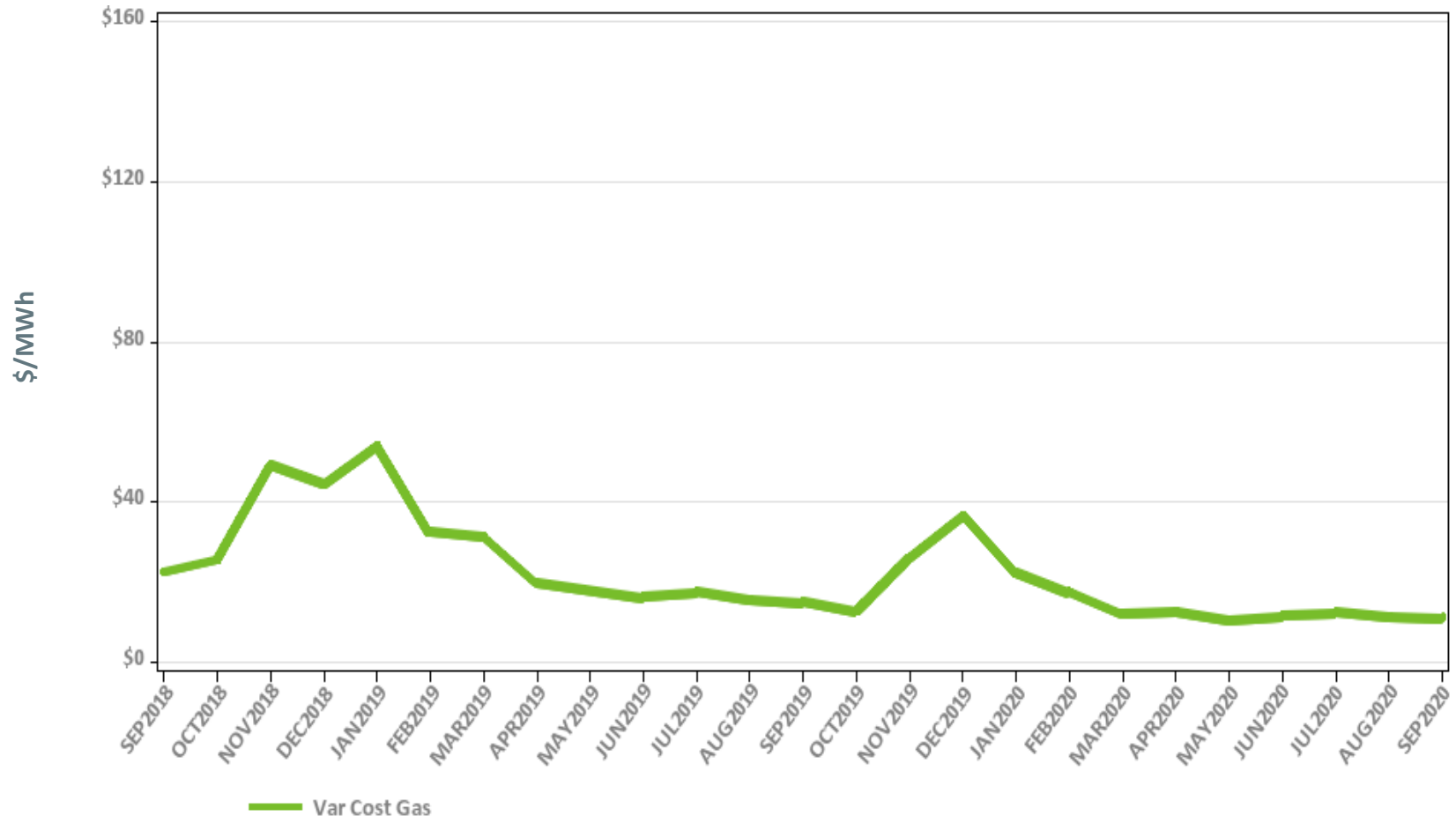
Hourly Average by Day, This Year



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



Variable Production Cost of Natural Gas: Monthly

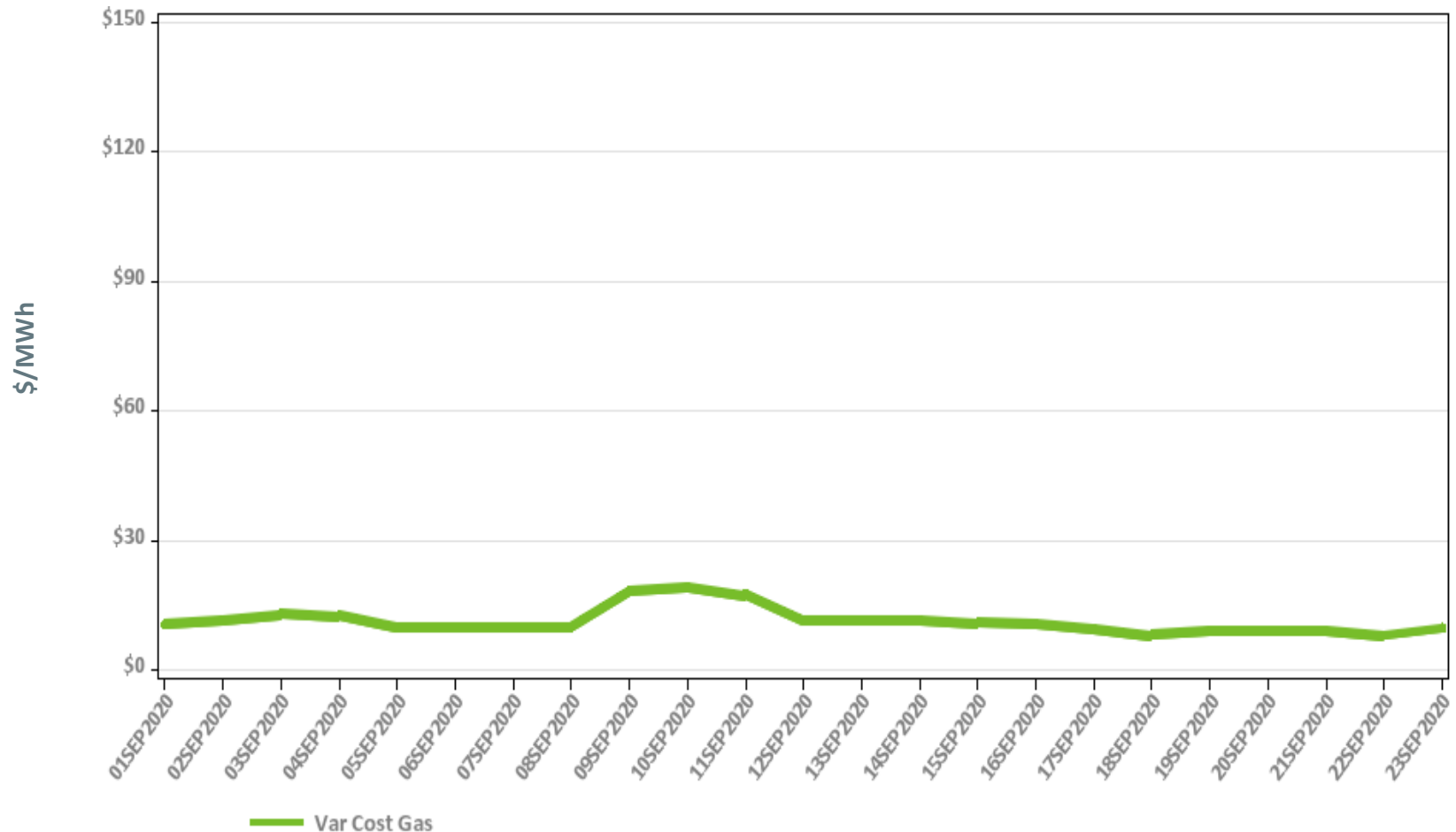


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



Variable Production Cost of Natural Gas: Daily



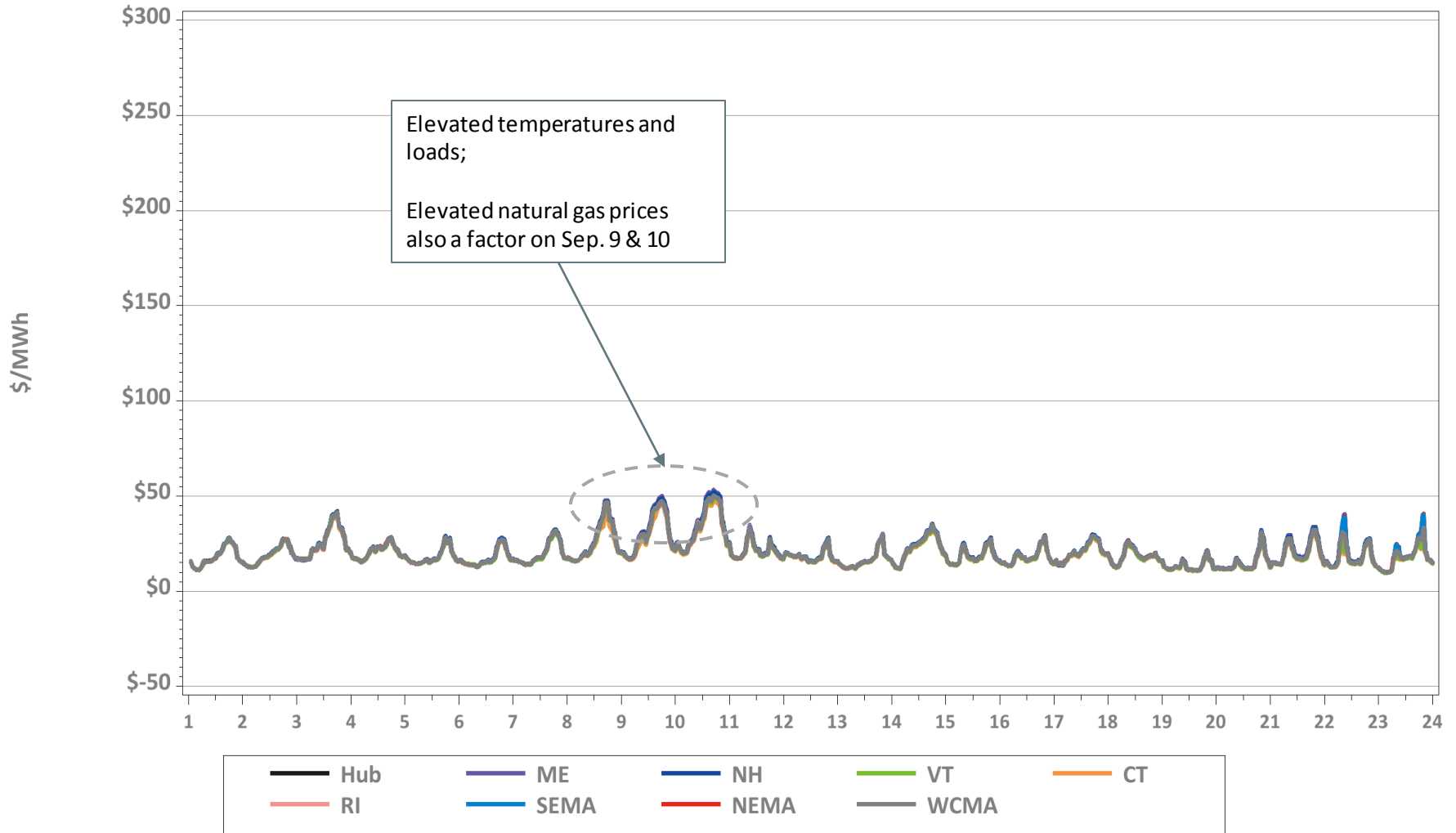
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



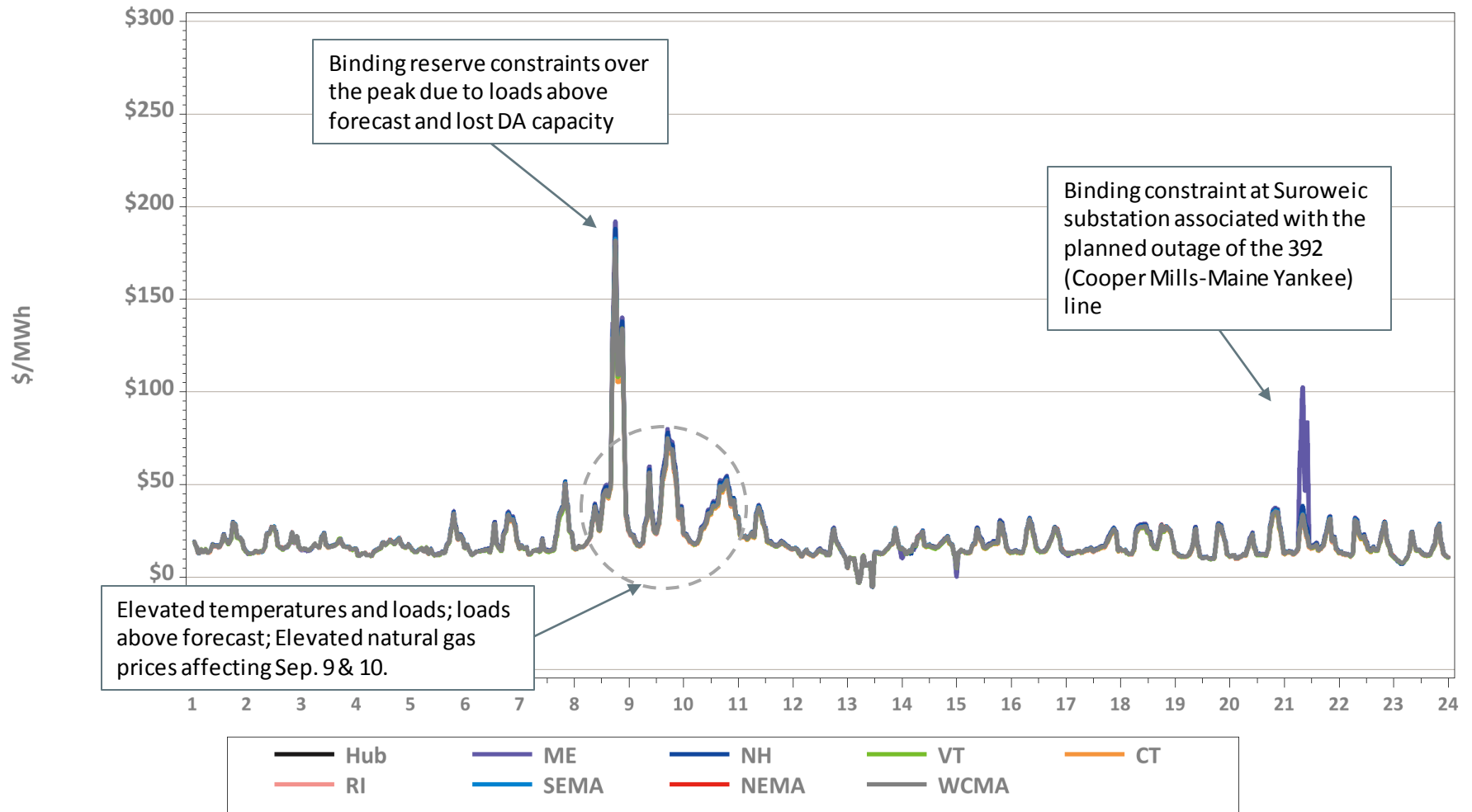
Hourly DA LMPs, September 1-23, 2020

Hourly Day-Ahead LMPs



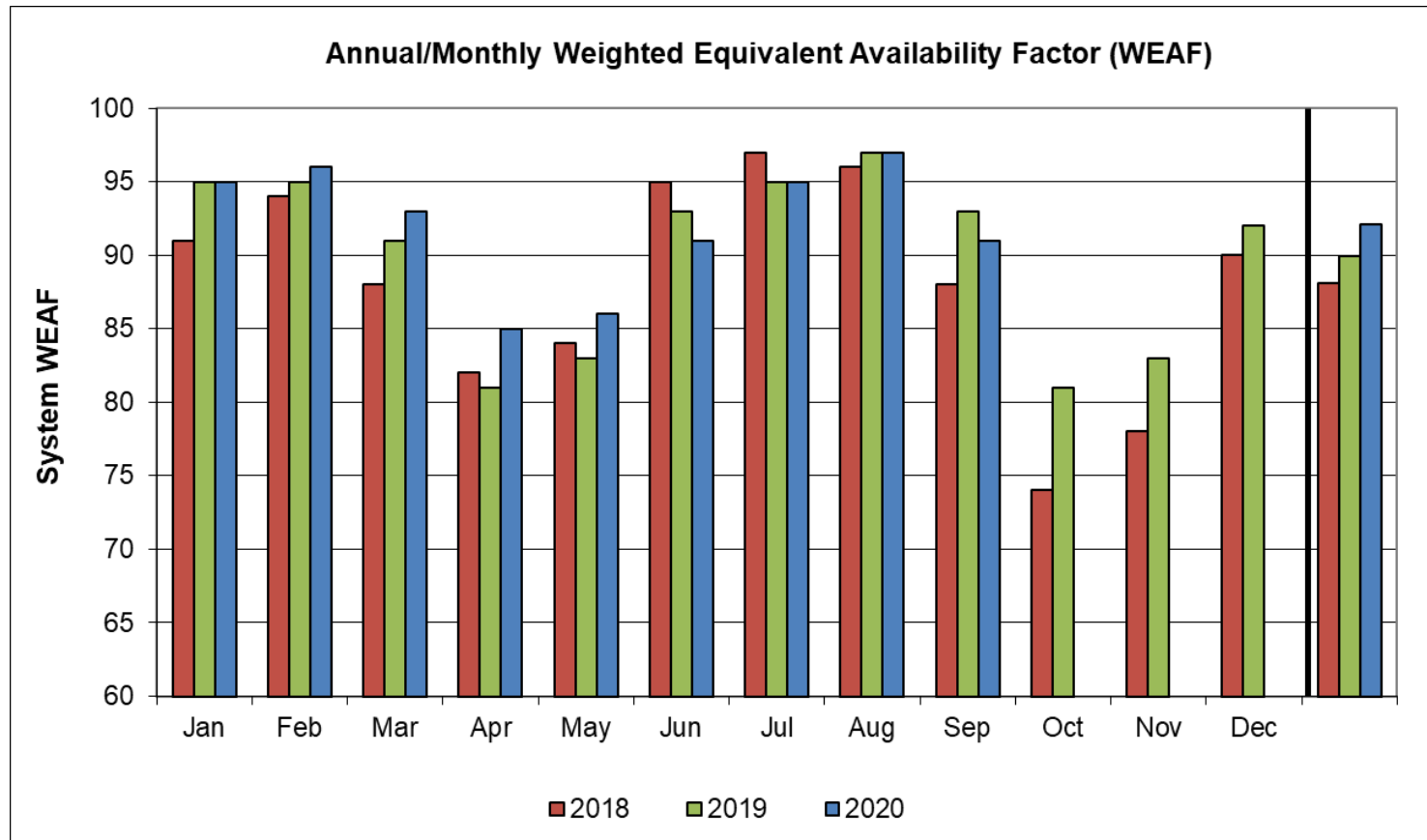
Hourly RT LMPs, September 1-23, 2020

Hourly Real-Time LMPs



• No Minimum Generation Emergencies were declared during September.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95	96	93	85	86	91	95	97	91				92
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 9/22/2020

BACK-UP DETAIL



DEMAND RESPONSE



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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	50.1	167.3	0.0	217.4
NH	31.9	149.0	0.0	180.9
VT	31.9	103.4	0.0	135.3
CT	106.1	165.3	549.2	820.6
RI	40.1	270.5	0.0	310.6
SEMA	45.0	446.6	0.0	491.6
WCMA	77.2	469.3	45.3	591.8
NEMA	61.3	812.2	0.0	873.6
Total	443.6	2,583.7	594.5	3,621.7

* Active Demand Capacity Resources

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

NEW GENERATION

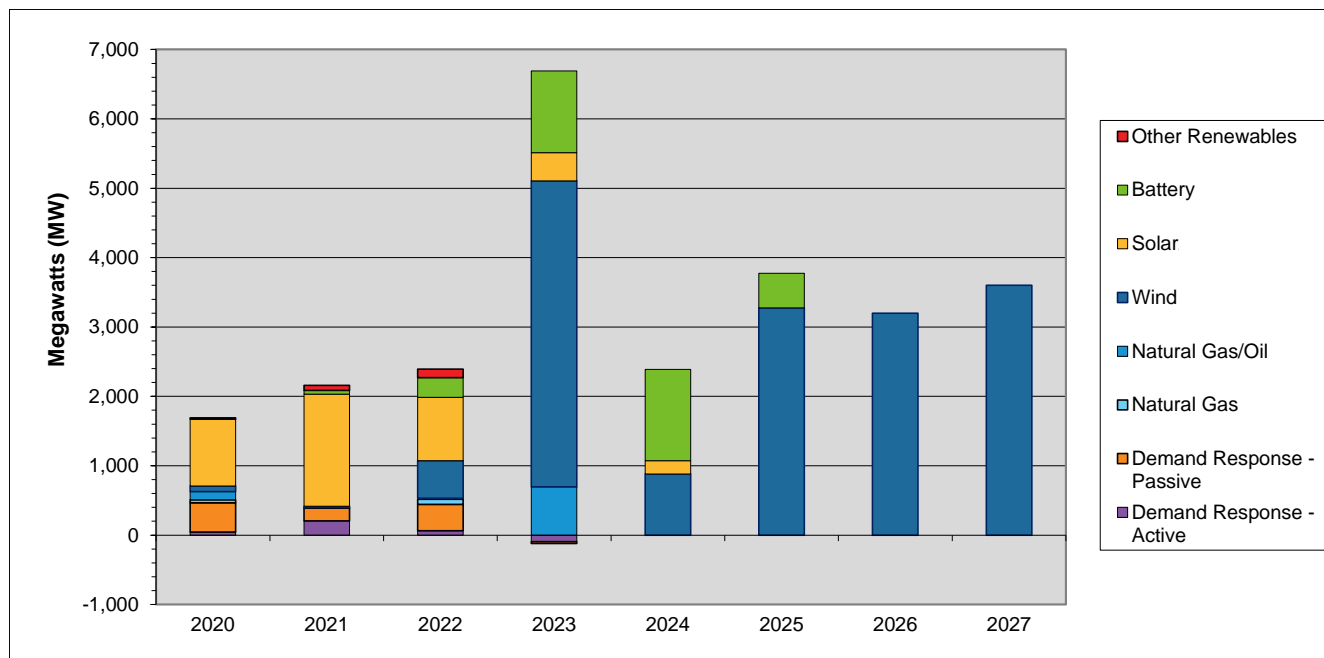
New Generation Update

Based on Queue as of 9/25/20

- Seven new projects totaling 4,252 MW applied for interconnection study since the last update
 - They consist of three new solar projects, three wind facilities, and one battery project, with in-service dates ranging from 2020 to 2027
- No projects went commercial and three were withdrawn, resulting in a net increase in new generation projects of 4,127 MW
- In total, 250 generation projects are currently being tracked by the ISO, totaling approximately 24,500 MW



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



	2020	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total ¹
Other Renewables	18	73	122	0	0	0	0	0	213	0.8
Battery	0	54	284	1,175	1,316	500	0	0	3,329	12.9
Solar ²	964	1,614	914	408	191	0	0	0	4,091	15.9
Wind	78	19	540	4,411	881	3,276	3,200	3,600	16,005	62.1
Natural Gas/Oil ³	121	0	16	695	0	0	0	0	832	3.2
Natural Gas	43	10	73	0	0	0	0	0	126	0.5
Demand Response - Passive	422	184	380	-28	0	0	0	0	958	3.7
Demand Response - Active	42	204	62	-94	0	0	0	0	214	0.8
Totals	1,689	2,158	2,391	6,567	2,388	3,776	3,200	3,600	25,769	100.0

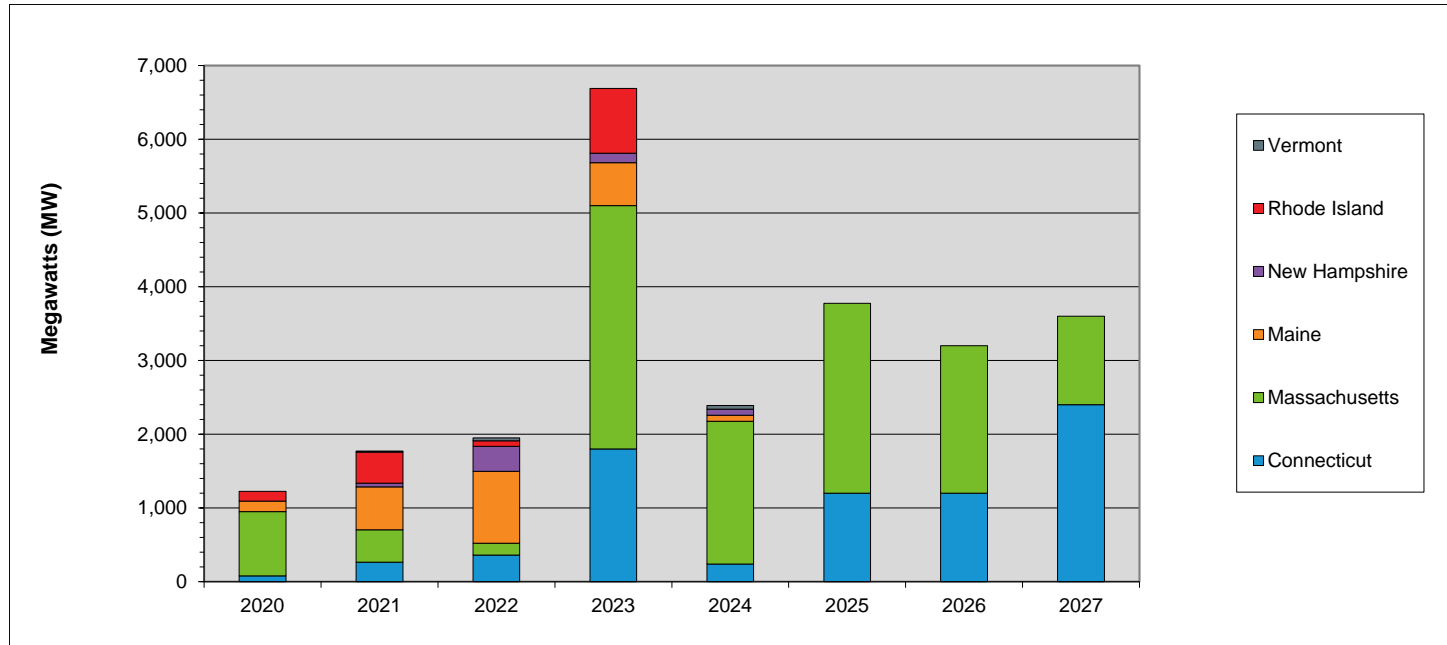
¹ Sum may not equal 100% due to rounding

² This category includes both solar-only, and co-located solar and battery projects

³ The projects in this category are dual fuel, with either gas or oil as the primary fuel

- 2020 values include the 83 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	2027	Total MW	% of Total ¹
Vermont	0	15	40	0	50	0	0	0	105	0.4
Rhode Island	133	421	73	880	0	0	0	0	1,507	6.1
New Hampshire	0	50	340	126	81	0	0	0	597	2.4
Maine	141	579	975	583	81	0	0	0	2,359	9.6
Massachusetts	873	440	159	3,300	1,936	2,576	2,000	1,200	12,484	50.8
Connecticut	77	265	362	1,800	240	1,200	1,200	2,400	7,544	30.7
Totals	1,224	1,770	1,949	6,689	2,388	3,776	3,200	3,600	24,596	100.0

¹ Sum may not equal 100% due to rounding

- 2020 values include the 83 MW of generation that has gone commercial in 2020



New Generation Projection

By Fuel Type

Unit 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	18	3,329	0	0	18	3,329
Fuel Cell	5	69	1	10	4	59
Hydro	3	99	1	66	2	33
Natural Gas	7	126	0	0	7	126
Natural Gas/Oil	5	787	1	14	4	773
Nuclear	1	37	0	0	1	37
Solar	185	4,058	9	175	176	3,883
Wind	25	16,000	2	88	23	15,912
Total	250	24,513	14	353	236	24,160

- 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	9	147	1	10	8	137
Intermediate	9	822	1	14	8	808
Peaker	207	7,544	10	241	197	7,303
Wind Turbine	25	16,000	2	88	23	15,912
Total	250	24,513	14	353	236	24,160

- 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

Unit 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	18	3,329	0	0	0	0	18	3,329	0	0
Fuel Cell	5	69	5	69	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	126	0	0	6	120	1	6	0	0
Natural Gas/Oil	5	787	0	0	3	702	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	185	4,058	0	0	0	0	185	4,058	0	0
Wind	25	16,000	0	0	0	0	0	0	25	16,000
Total	250	24,513	9	147	9	822	207	7,544	25	16,000

- 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				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	603.776	-55.361			
	Passive Demand	2,975.36	3,045.073	69.713	31,23.232	78.159			
Demand Total		3,599.81	3,704.21	104.4	37,27.008	22.798			
Generator		Non-Intermittent	29,130.75	29,244.404	113.654	28,620.245	-624.159		
		Intermittent	880.317	806.609	-73.708	660.932	-145.677		
Generator Total		30,011.07	30,051.013	39.943	29,281.177	-769.836			
Import Total		1,217	1,305.487	88.487	1,307.587	2.10			
**Grand Total		34,827.88	35,060.710	232.83	34,315.772	-744.94			
Net ICR (NICR)		33,725	33,550	-175	32,320	-230			

* 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	683.116	-2.438				
	Passive Demand	3,354.69	3,407.507	52.817				
Demand Total		4,040.244	4,090.623	50.38				
Generator	Non-Intermittent	28,586.498	27,868.341	-718.157				
	Intermittent	1,024.792	901.672	-123.12				
Generator Total		2,961.129	28,770.013	-841.28				
Import Total		1,187.69	1,292.41	104.72				
**Grand Total		34,839.224	34,153.046	-686.18				
Net ICR (NICR)		33,750	32,465	-1,285				

* 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	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
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	3596.056	323.058	3919.114

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

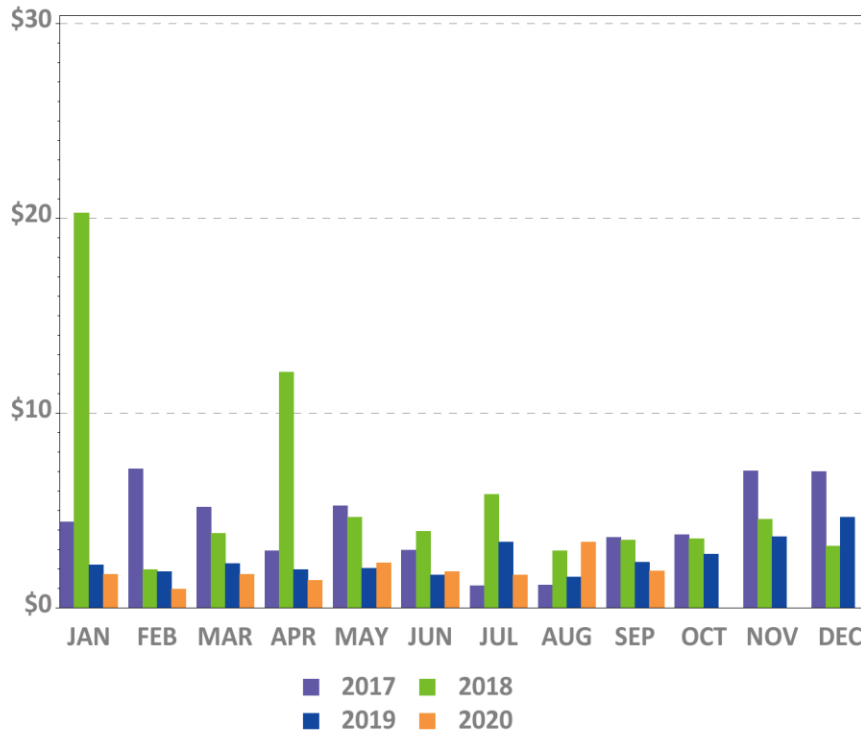
1 st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2 nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2 nd 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

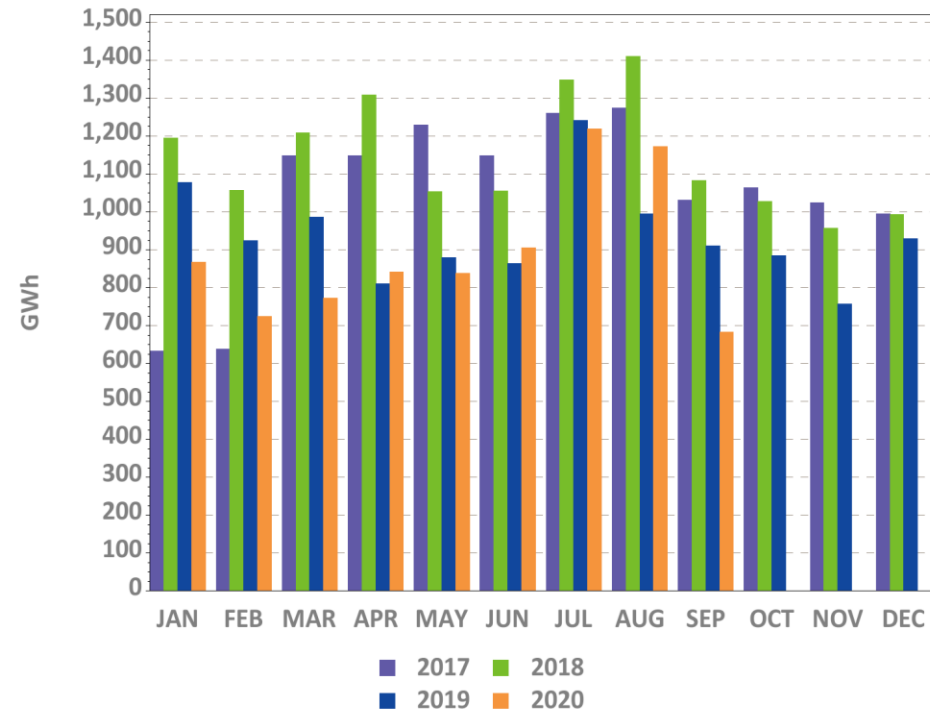
Allocation Category	Market / OATT	Allocation
System 1 st Contingency	Market	DA 1 st C (excluding at external nodes) is allocated to system DALO. RT 1 st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1 st Contingency	Market	DA 1 st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2 nd Contingency	Market	DA and RT 2 nd 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 Dollars



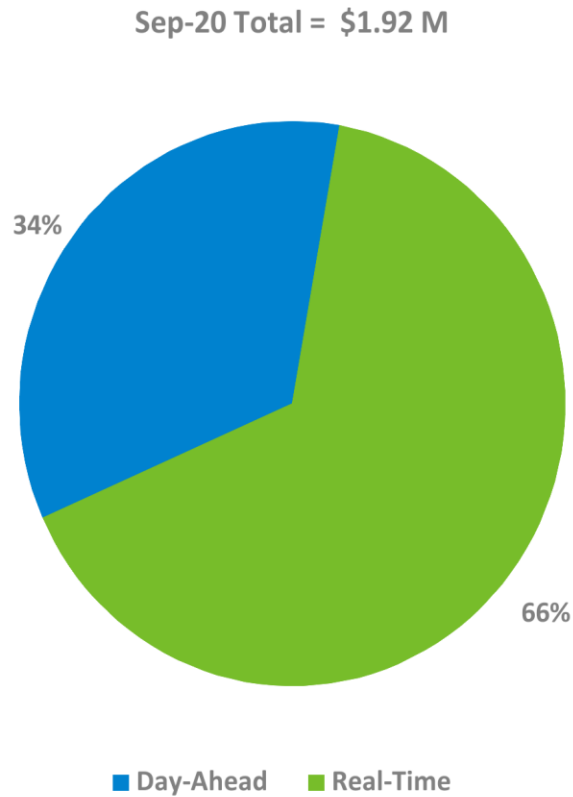
NCPC Energy*



* 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.

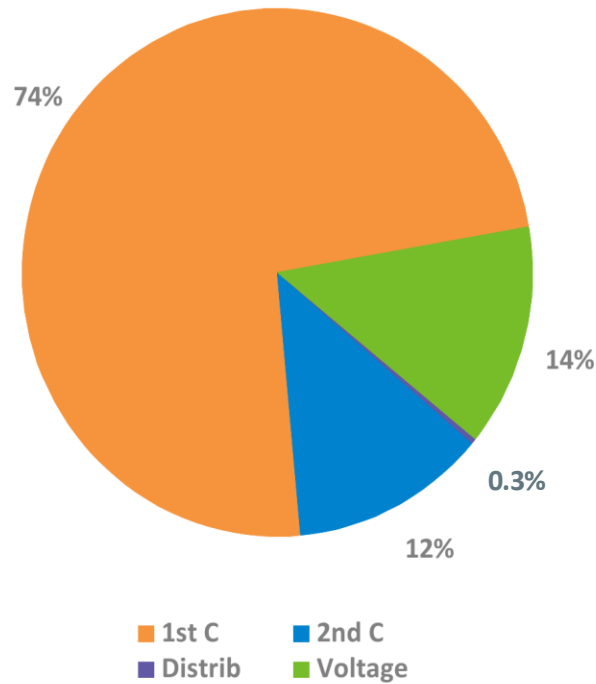


DA and RT NCPC Charges



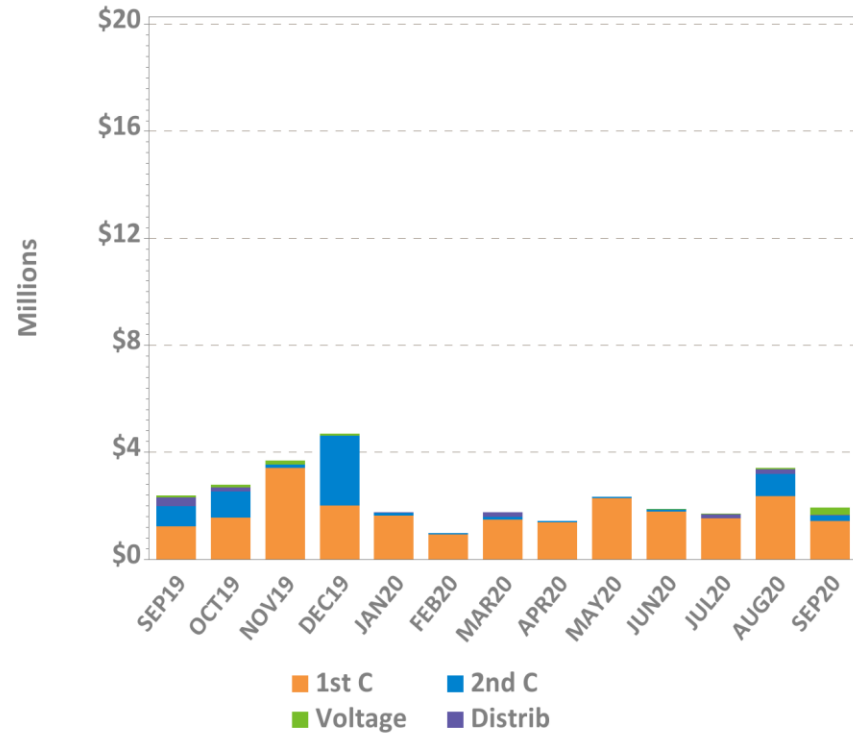
NCPC Charges by Type

Sep-20 Total = \$1.92 M

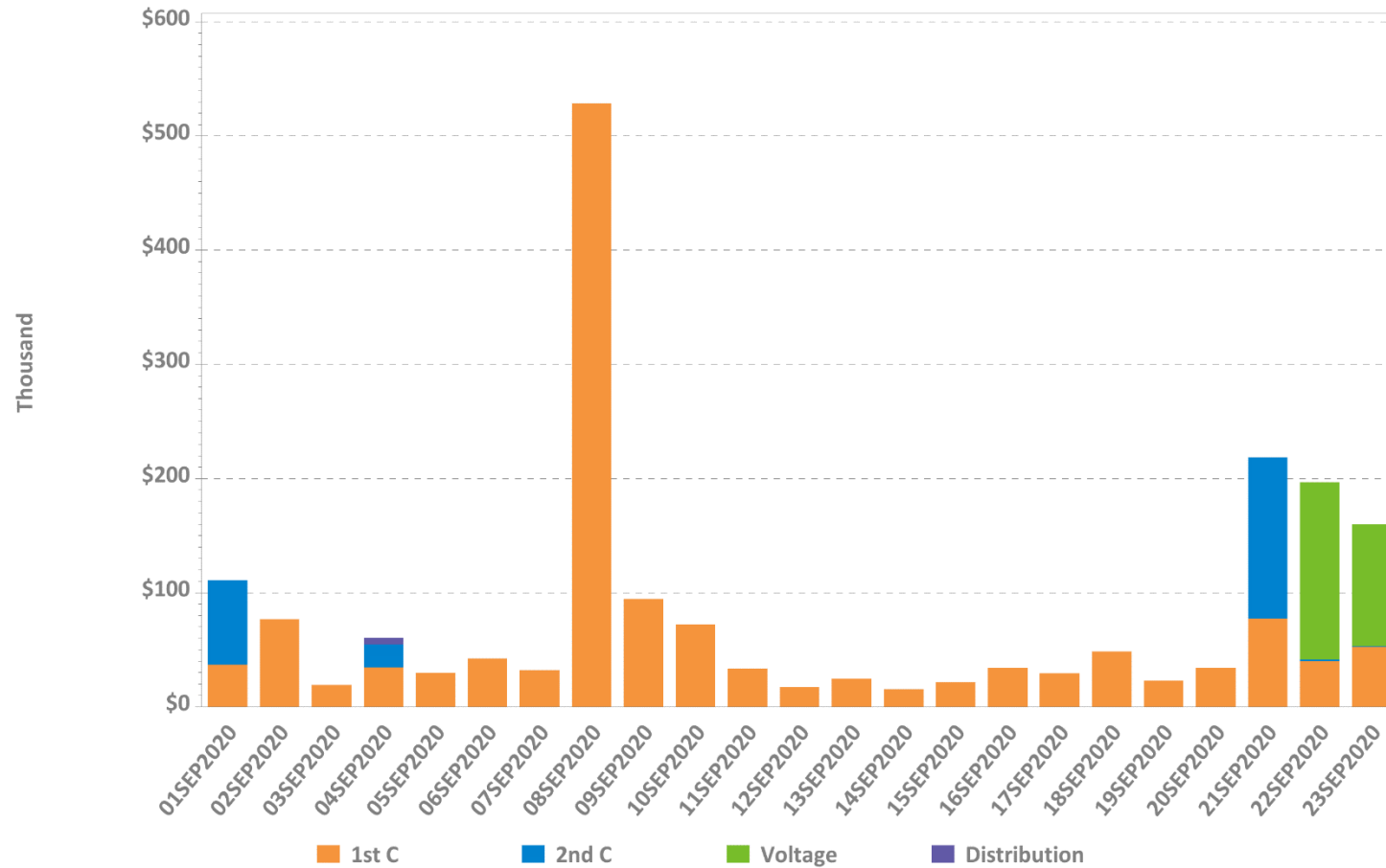


1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Last 13 Months

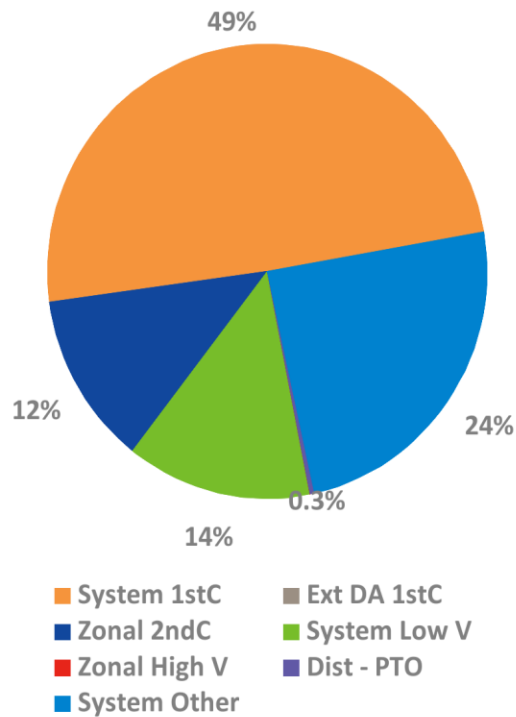


Daily NCPC Charges by Type

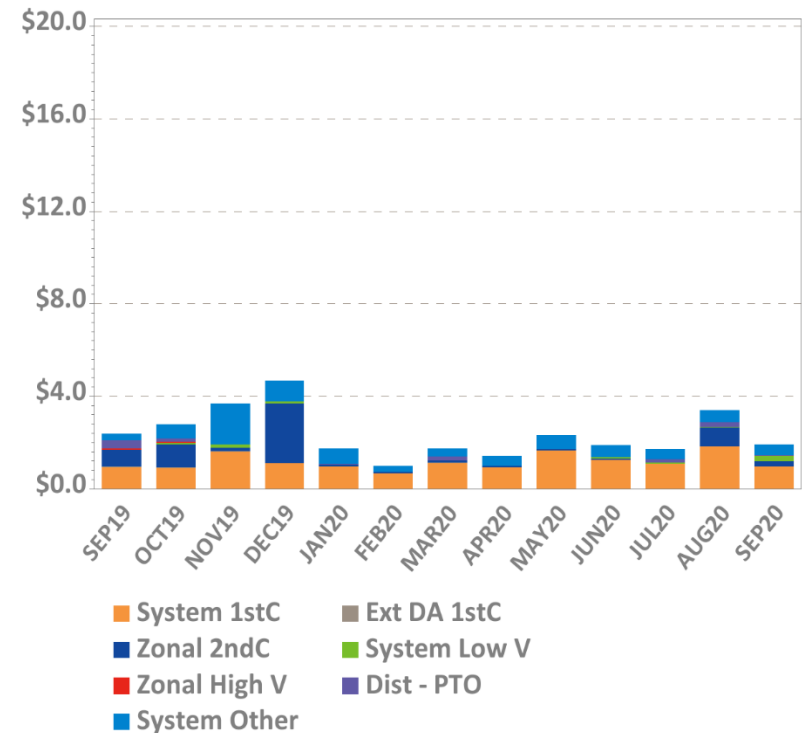


NCPC Charges by Allocation

Sep-20 Total = \$1.92 M

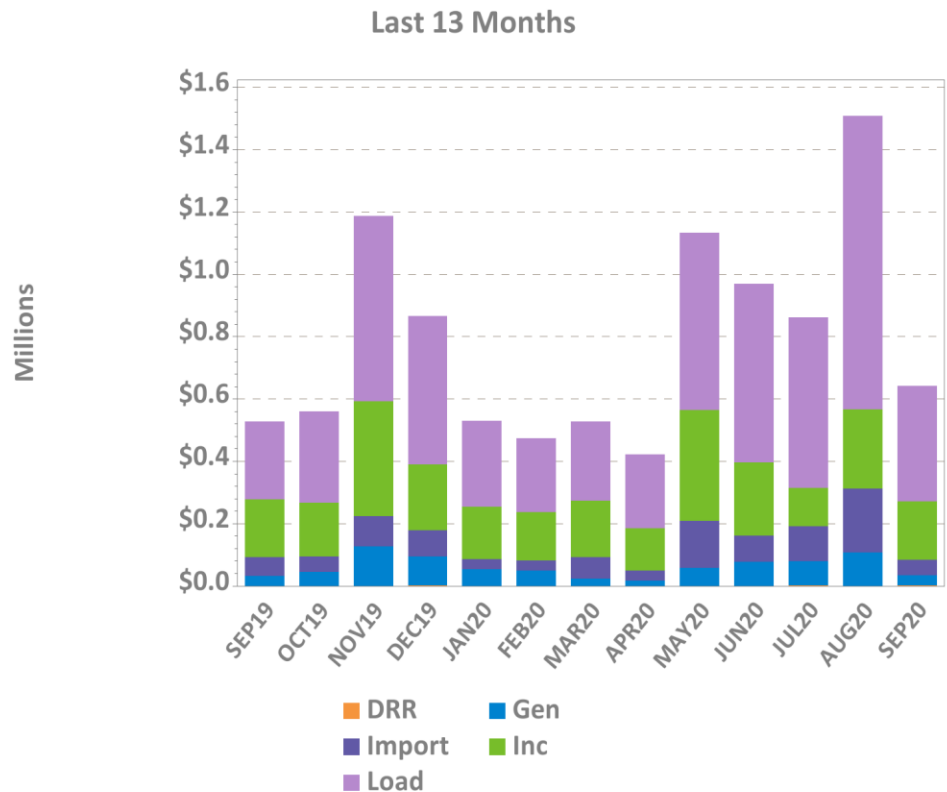
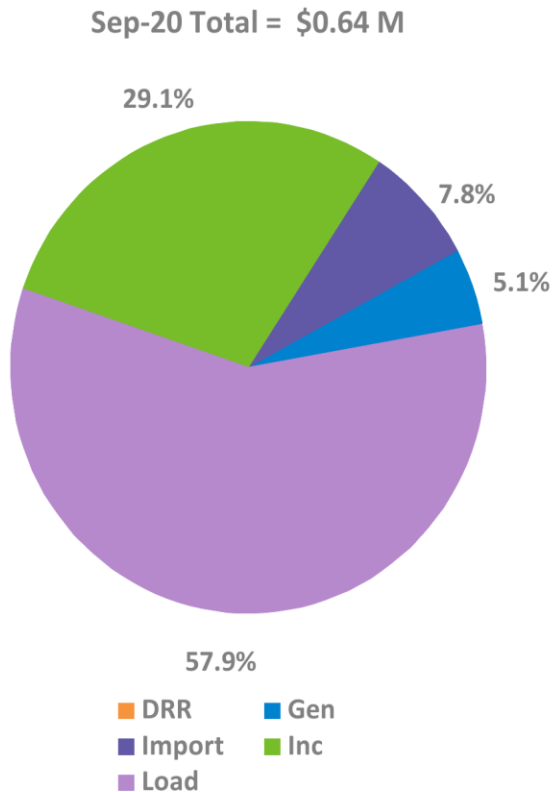


Last 13 Months



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

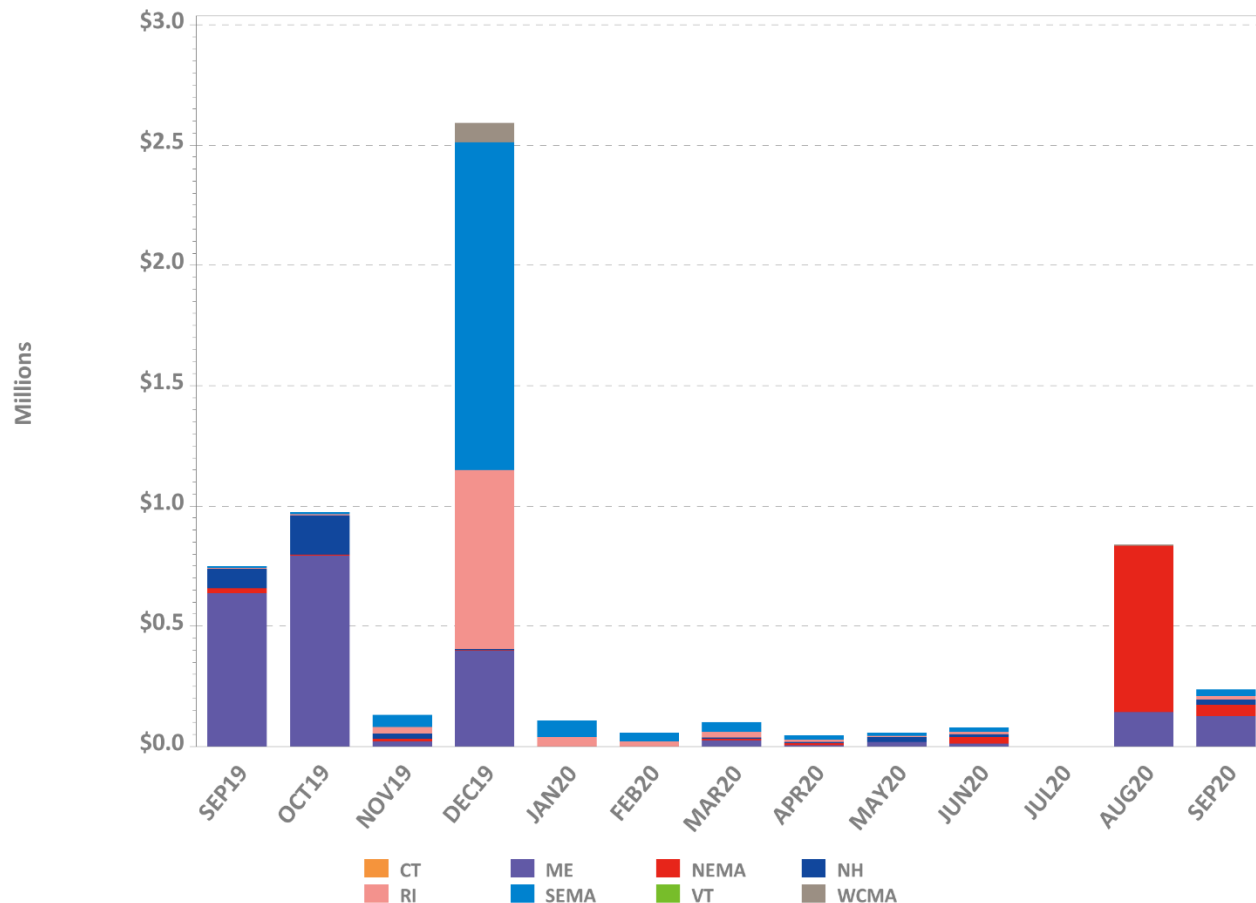
Inc – Increment Offer deviations

Import – Import deviations

Load – Load obligation deviations



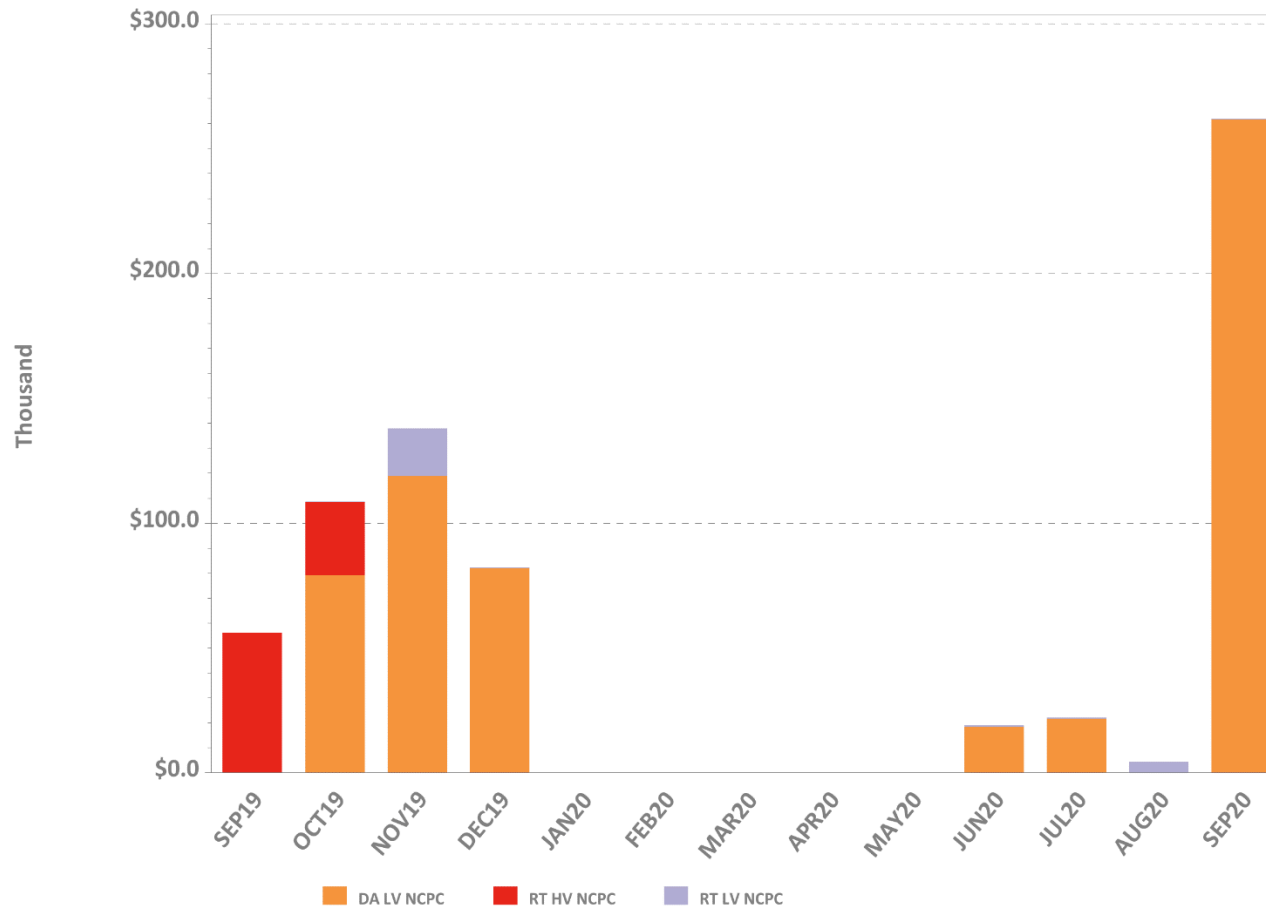
LSCPR Charges by Reliability Region



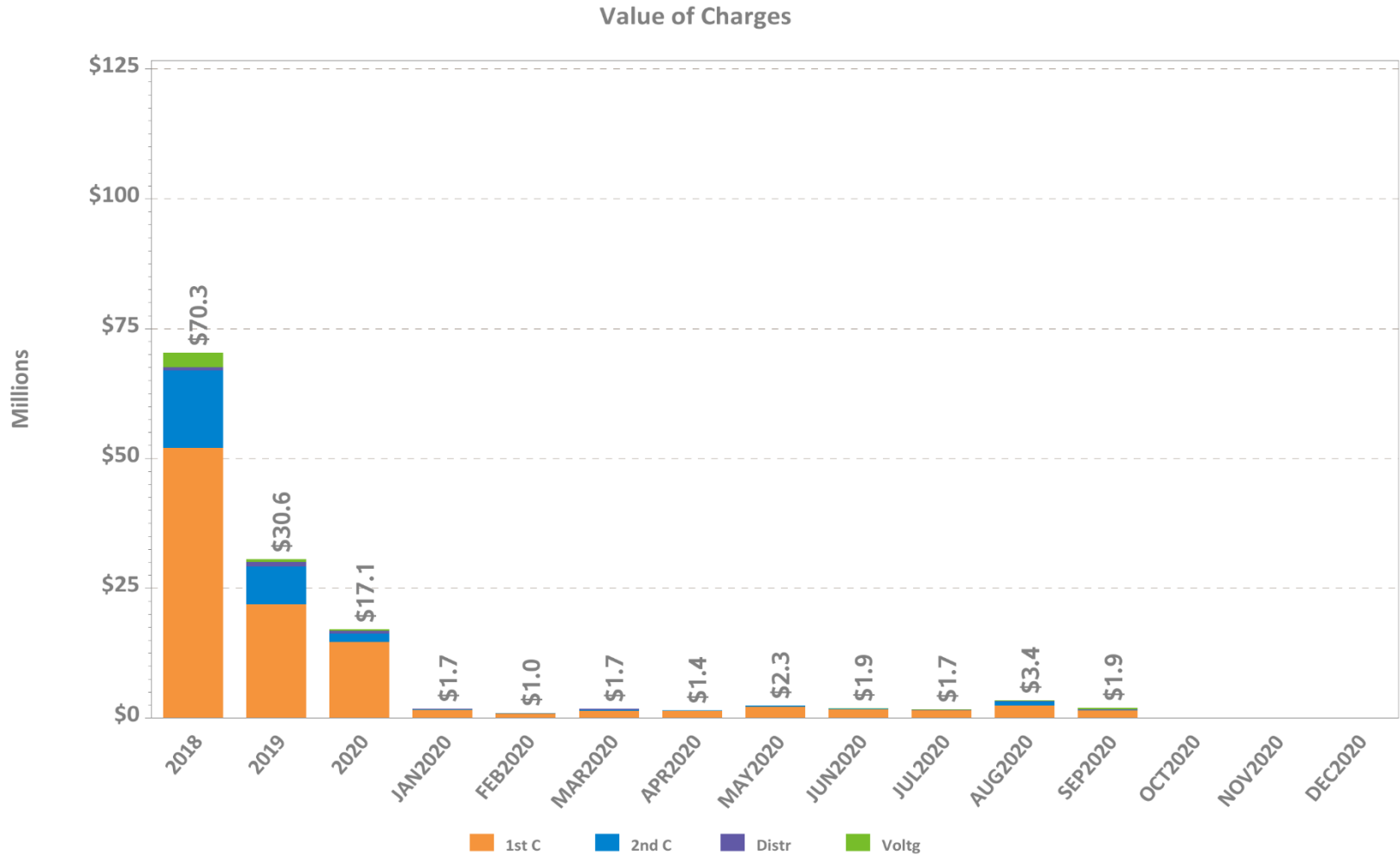
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

NCPC Charges for Voltage Support and High Voltage Control

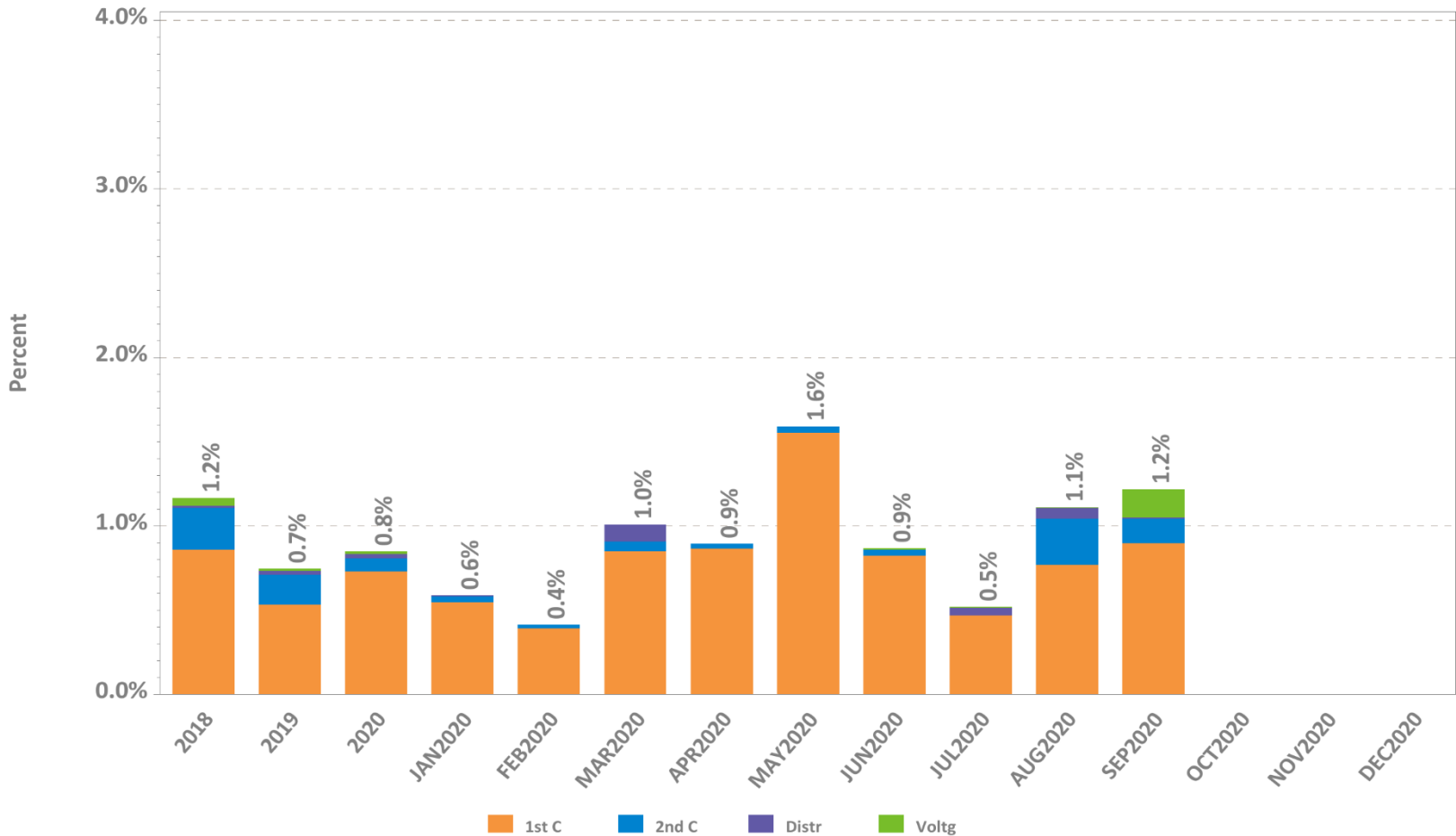


NCPC Charges by Type

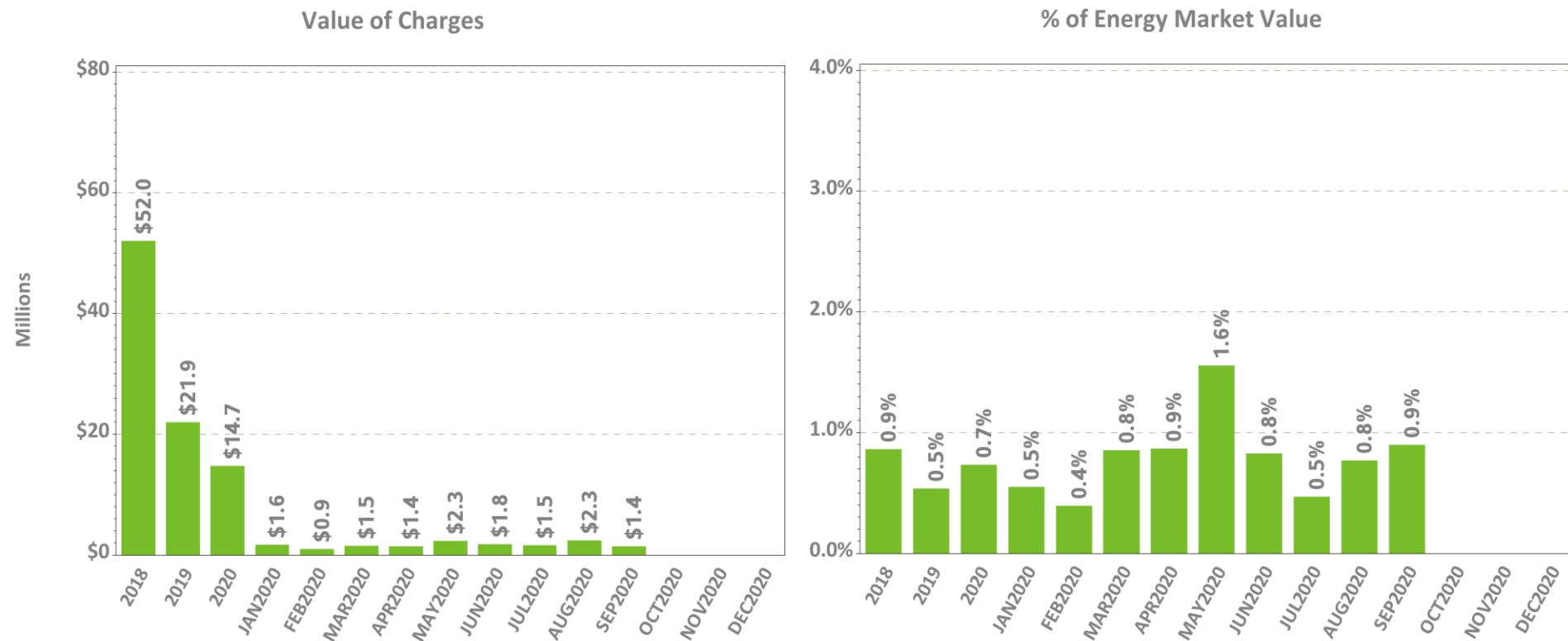


NCPC Charges as Percent of Energy Market

NCPC By Type as Percent of Energy Market

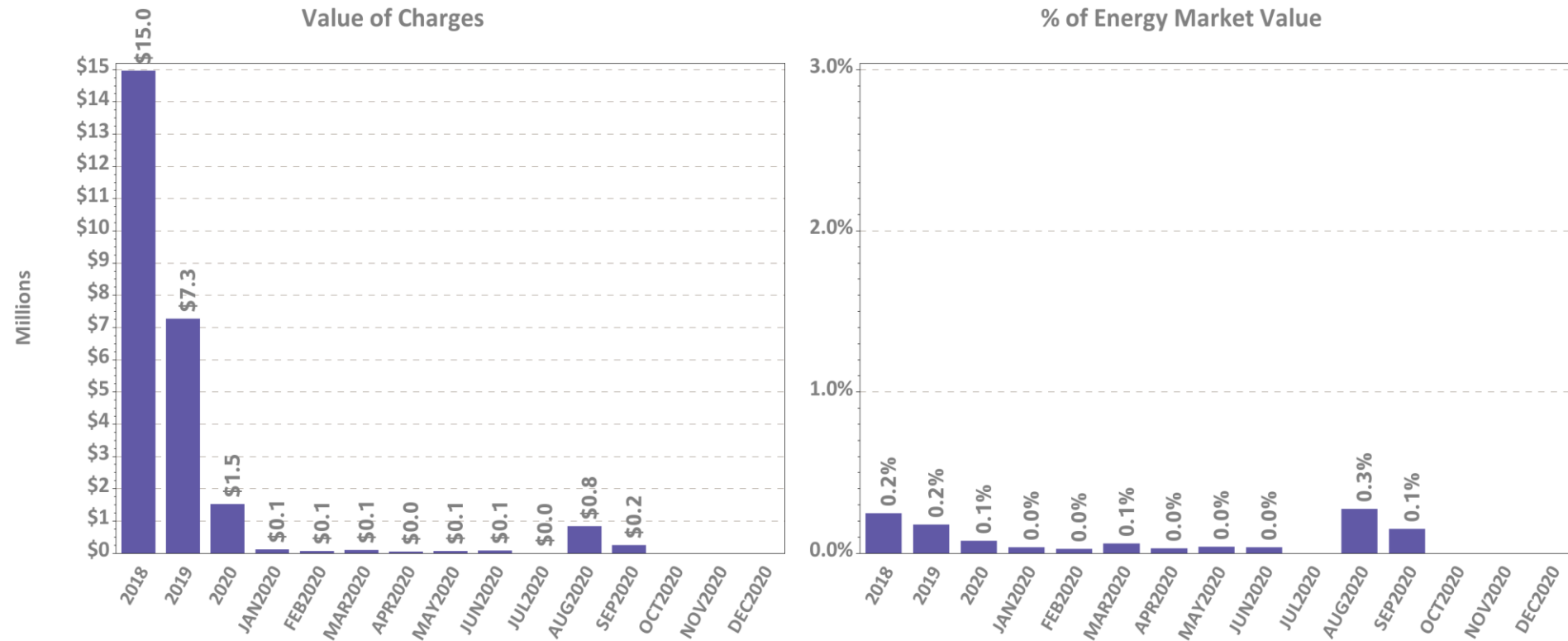


First Contingency NCPC Charges



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

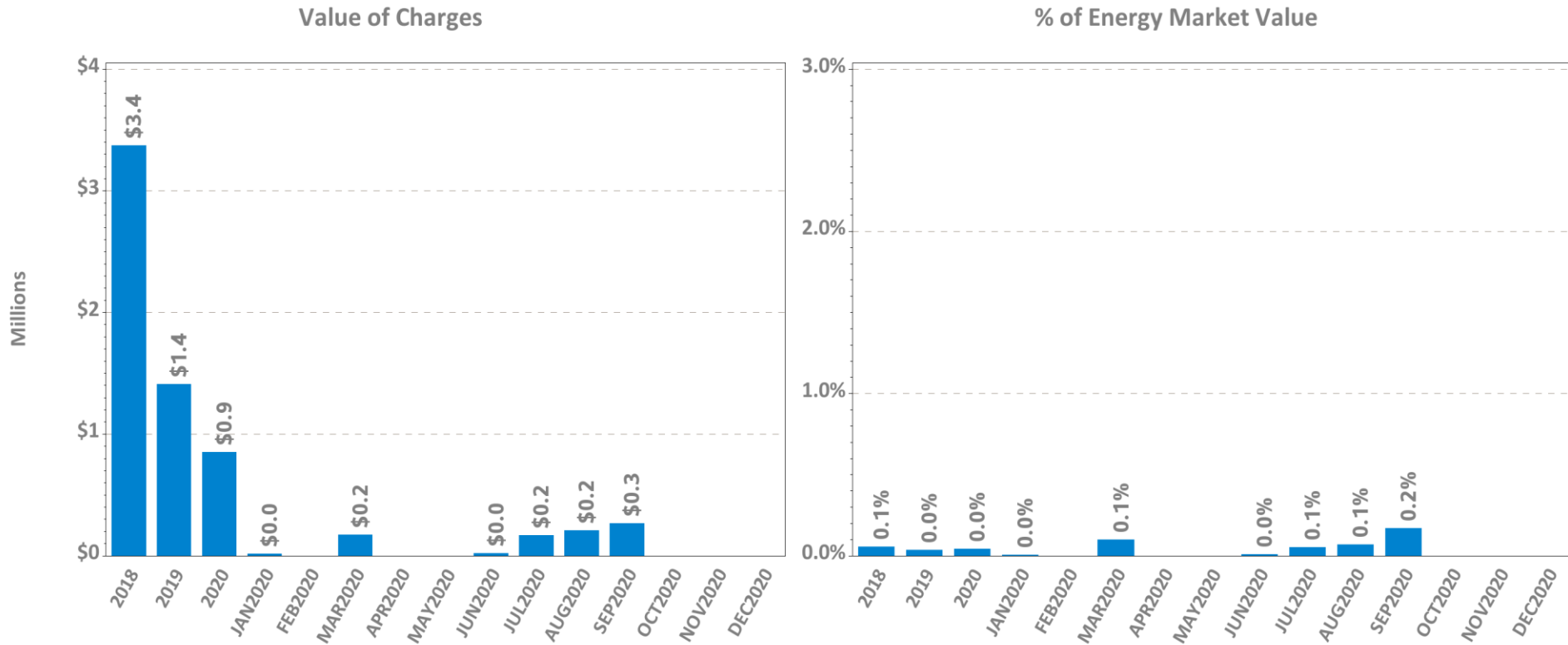
Second Contingency NCPC Charges



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



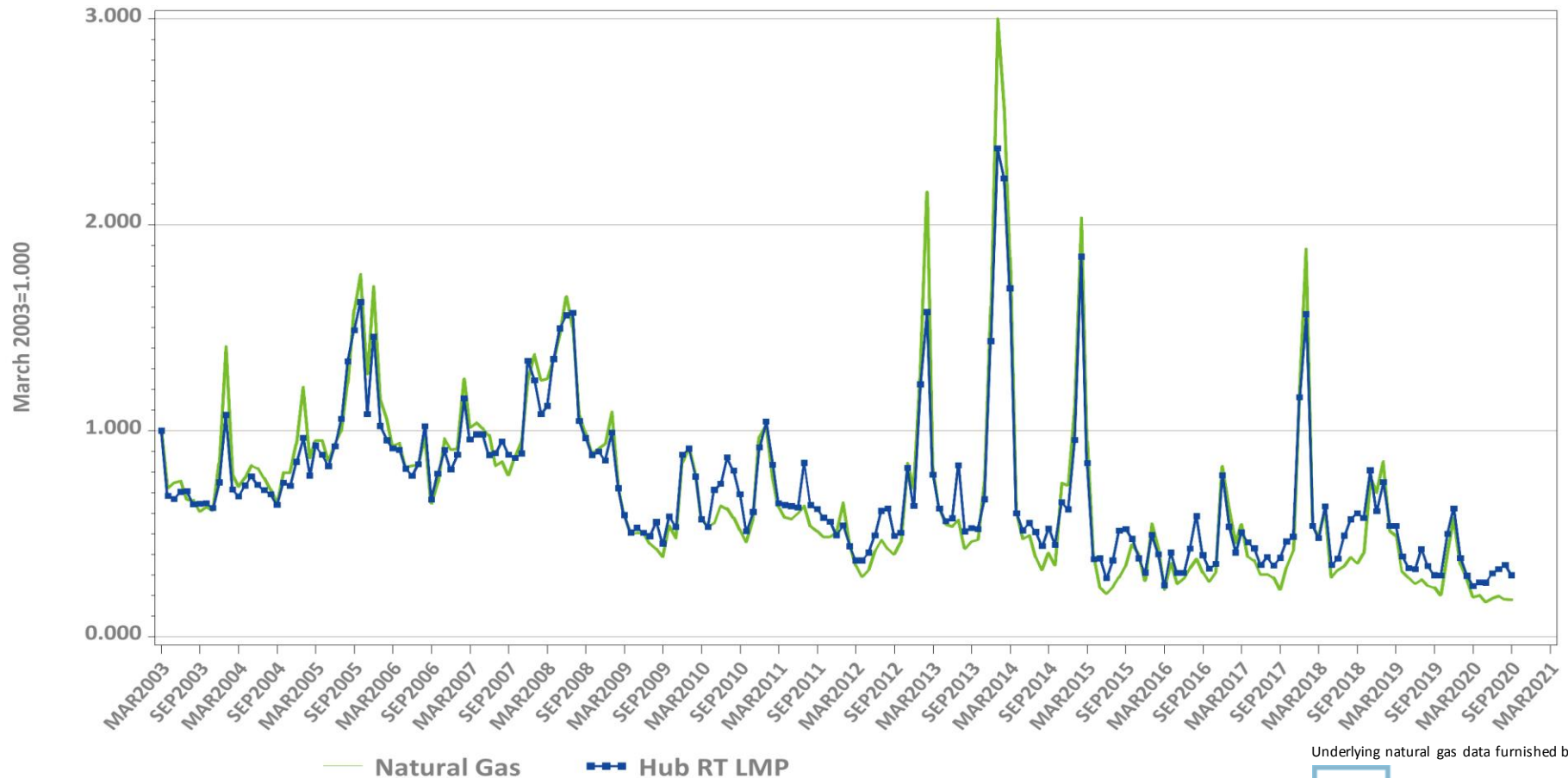
DA vs. RT LMPs (\$/MWh)

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%

September-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$21.35	\$20.75	\$20.97	\$21.29	\$20.94	\$21.07	\$21.35	\$21.15	\$21.14
Real-Time	\$20.67	\$20.21	\$20.27	\$20.59	\$20.26	\$20.37	\$20.60	\$20.45	\$20.45
RT Delta %	-3.2%	-2.6%	-3.3%	-3.3%	-3.2%	-3.3%	-3.5%	-3.3%	-3.3%
September-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$20.73	\$19.69	\$20.79	\$20.75	\$20.08	\$20.17	\$20.51	\$20.41	\$20.41
Real-Time	\$20.78	\$19.98	\$21.30	\$20.86	\$20.25	\$20.23	\$20.53	\$20.47	\$20.47
RT Delta %	0.2%	1.5%	2.5%	0.5%	0.9%	0.3%	0.1%	0.3%	0.3%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-2.9%	-5.1%	-0.9%	-2.5%	-4.1%	-4.2%	-3.9%	-3.5%	-3.5%
Yr over Yr RT	0.5%	-1.1%	5.1%	1.3%	0.0%	-0.7%	-0.3%	0.1%	0.1%

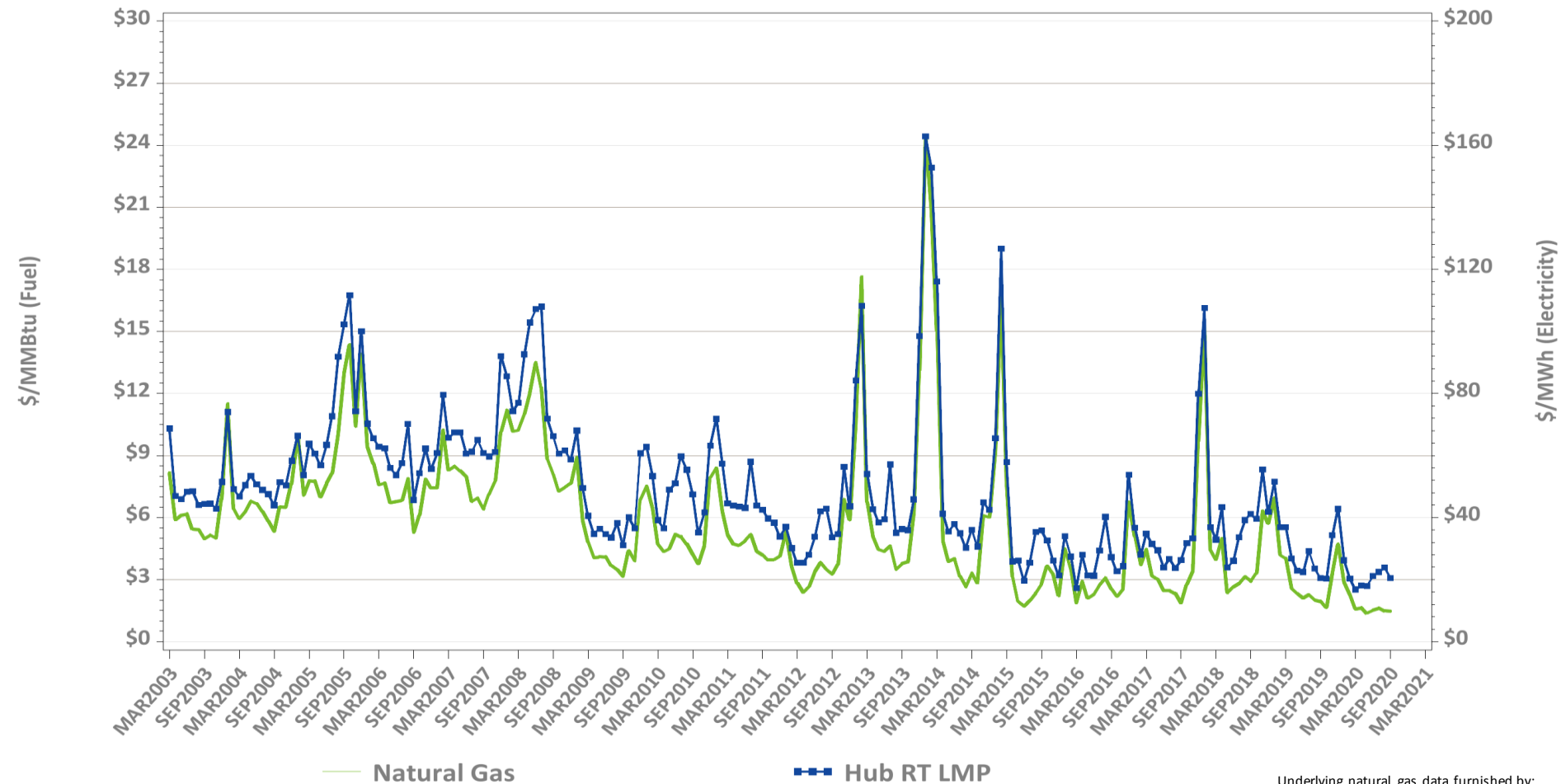
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



Monthly Average Fuel Price and RT Hub LMP

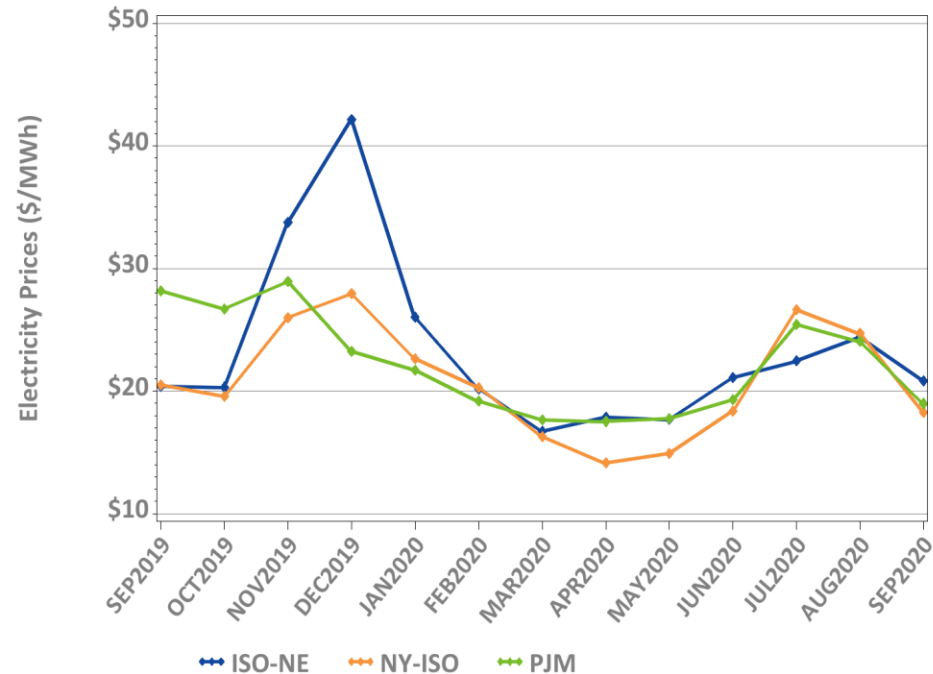


Underlying natural gas data furnished by:



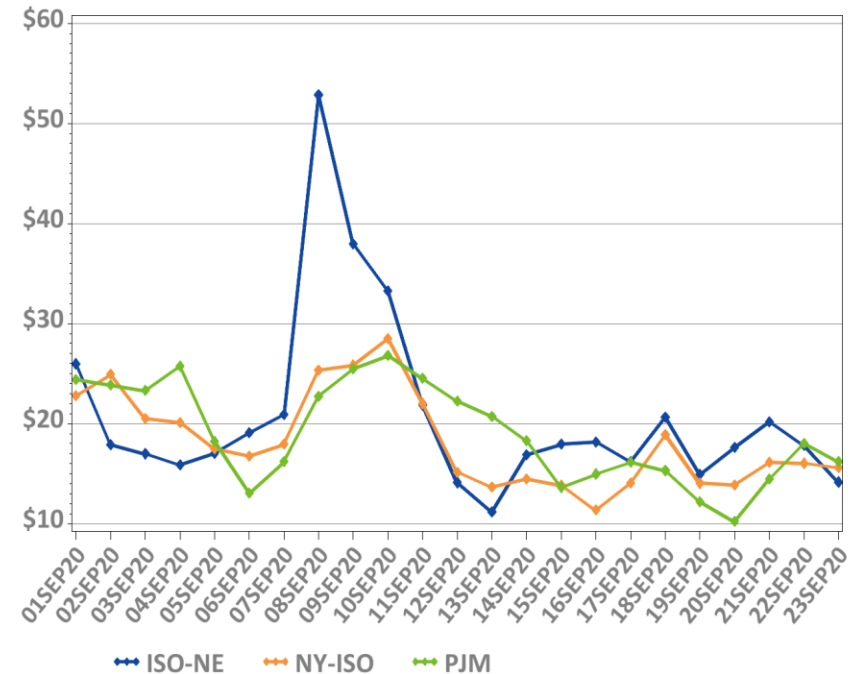
New England, NY, and PJM Hourly Average Real Time Prices by Month

Monthly, Last 13 Months



*Note: Hourly average prices are shown.

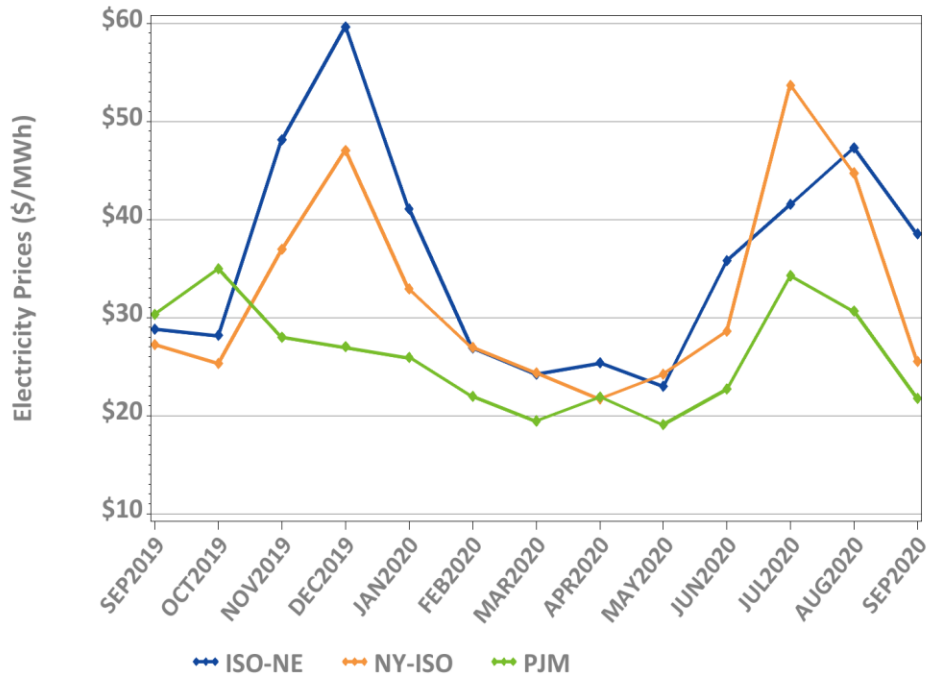
Daily: This Month



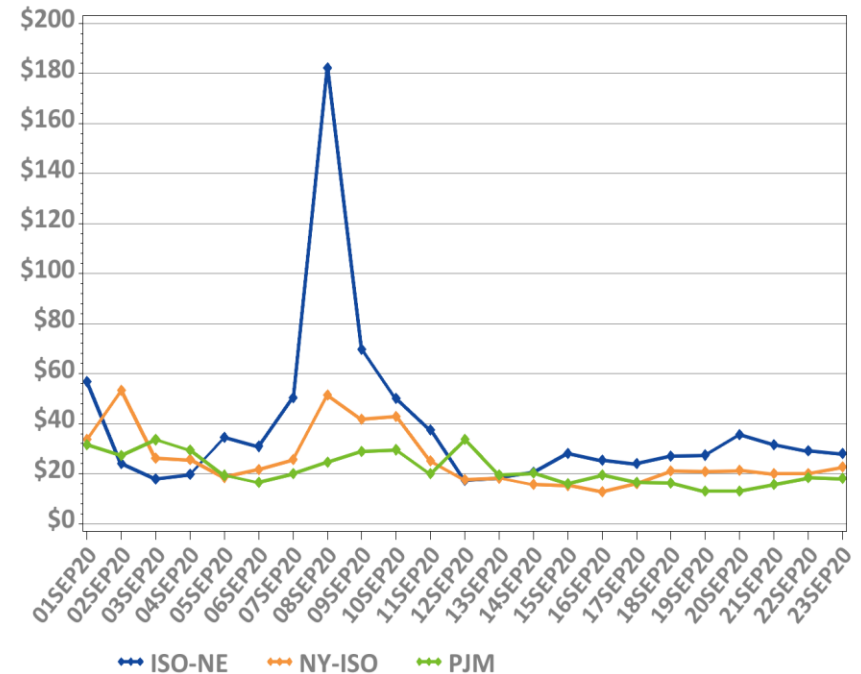
*Note: Hourly average prices are shown.

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

Monthly, Last 13 Months



Daily: This Month



*Forecasted New England daily peak hours reflected



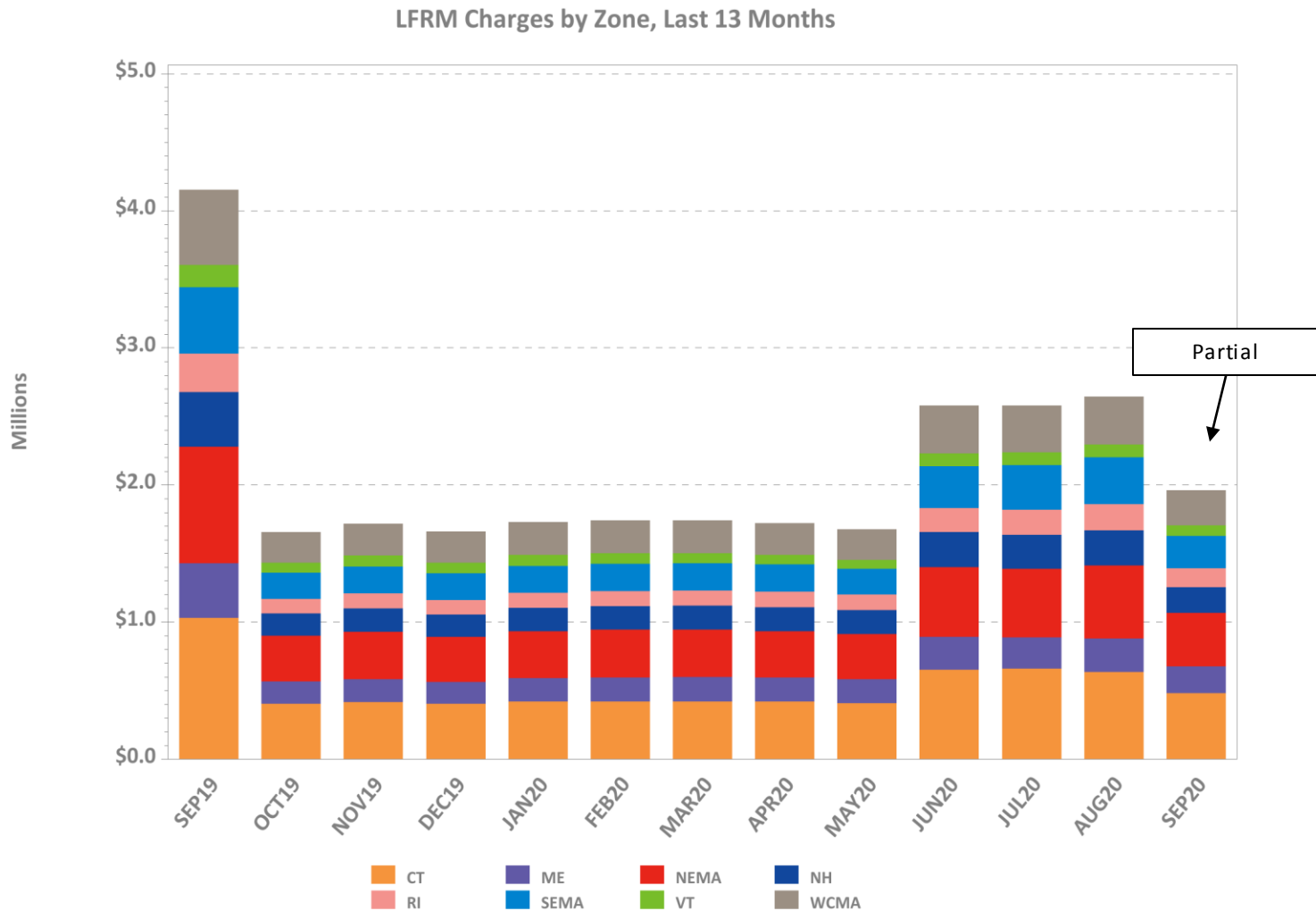
Reserve Market Results – September 2020

- Maximum potential Forward Reserve Market payments of \$2.1M were reduced by credit reductions of \$39K, failure-to-reserve penalties of \$61K and failure-to-activate penalties of \$4K, resulting in a net payout of \$2M or 95% of maximum
 - Rest of System: \$1.55M/1.65M (94%)
 - Southwest Connecticut: \$0.06M/0.06M (99%)
 - Connecticut: \$0.35M/0.36M (98%)
- \$942K total Real-Time credits were reduced by \$276K in Forward Reserve Energy Obligation Charges for a net of \$666K in Real-Time Reserve payments
 - Rest of System: 200 hours, \$402K
 - Southwest Connecticut: 200 hours, \$150K
 - Connecticut: 200 hours, \$74K
 - NEMA: 200 hours, \$41K

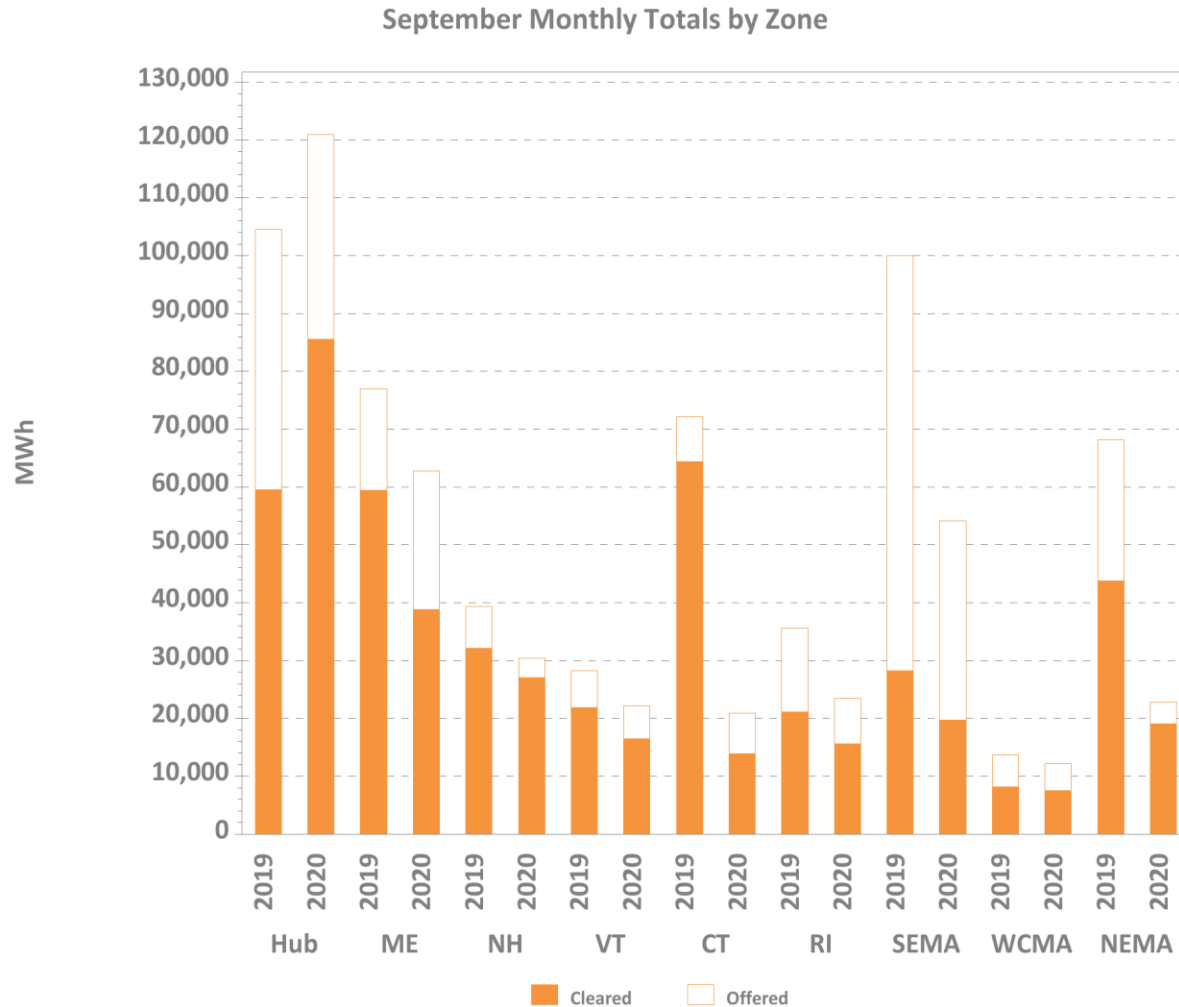
Note: “Failure to reserve” results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.



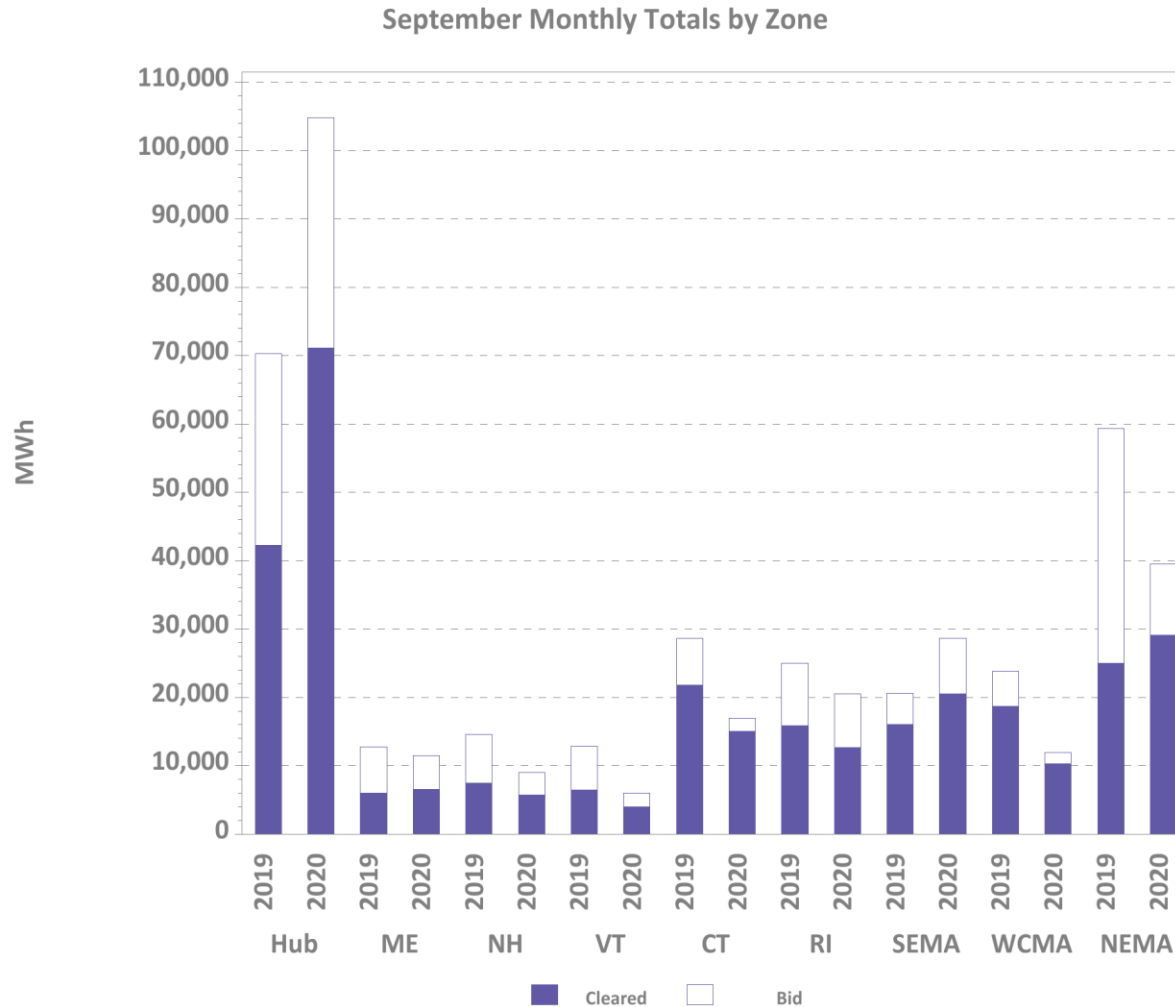
LFRM Charges to Load by Load Zone (\$)



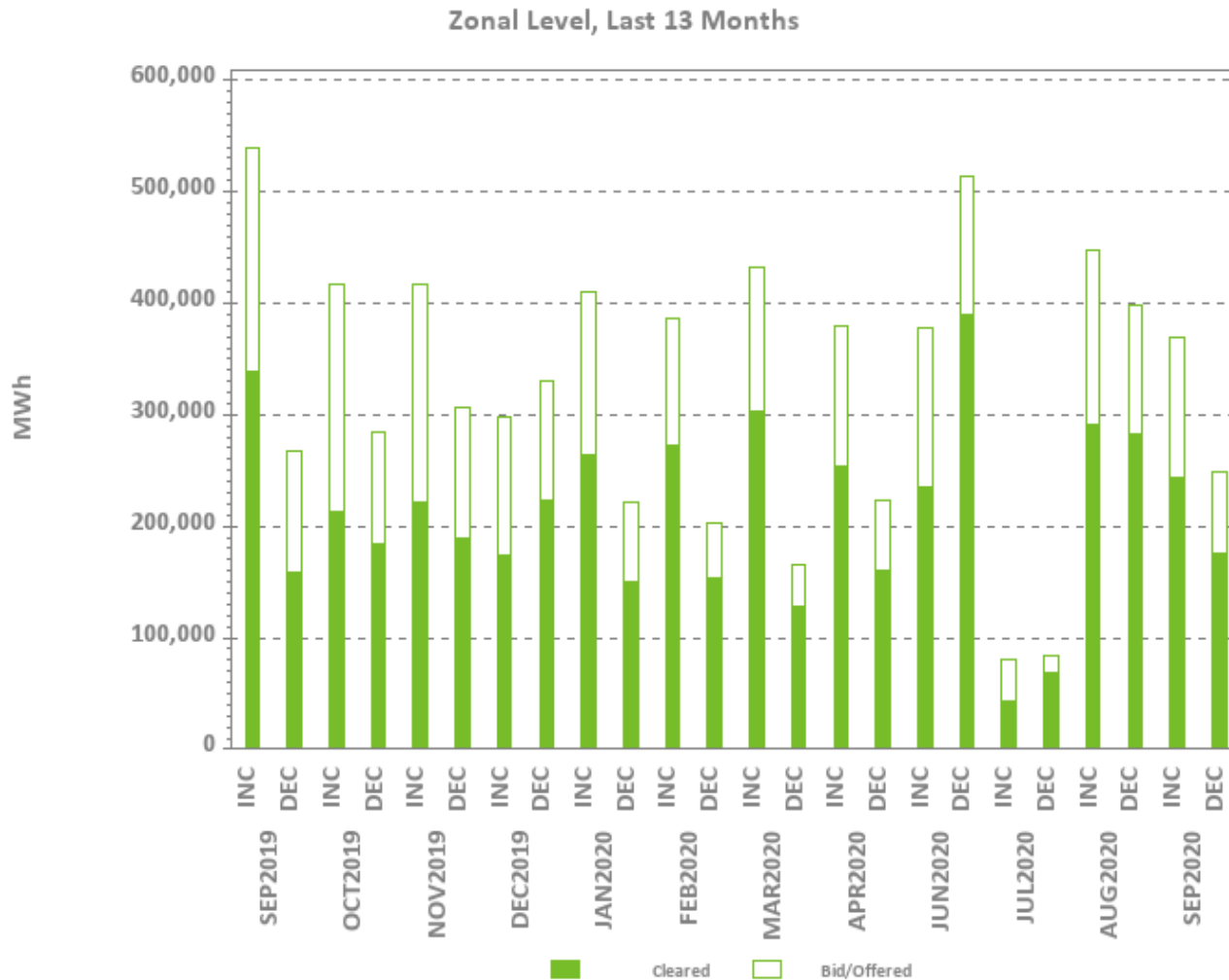
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

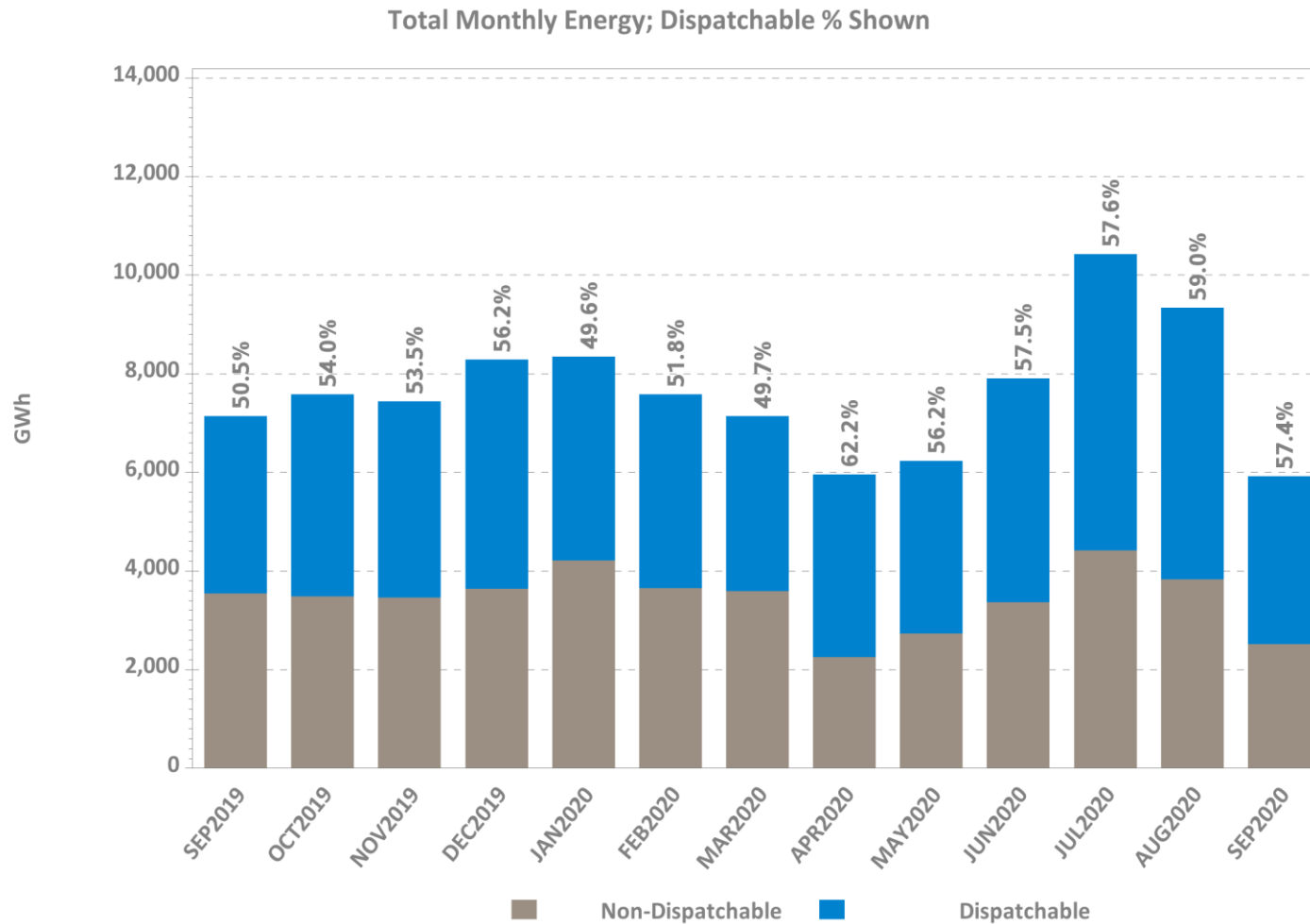


Total Increment Offers and Decrement Bids



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)

- October 21 PAC Meeting Agenda Topics*
 - RSP Transmission Projects and Asset Condition - October 2020 Update
 - Transmission Owners' Local System Plan Presentations

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



Transmission Planning for the Clean-Energy Transition

- On September 24, the ISO [initiated discussions with the PAC](#) about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- Initial topics being discussed include:
 - New study conditions based on time of day/time of year
 - Load level assumptions
 - Onshore and offshore wind output assumptions
 - Photovoltaic output assumptions
 - The need for more detailed distributed energy resource information



Economic Studies

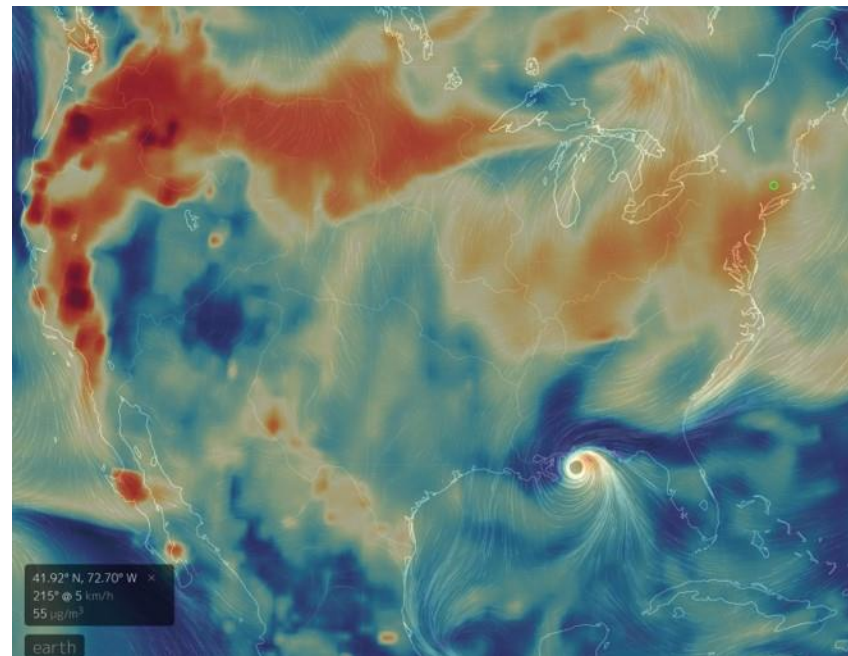
- Three 2019 study requests were received (NESCOE, Anbaric, and RENEW)
 - Study work is complete and results have been presented to PAC
 - NESCOE report was posted to the ISO website on June 30
 - Anbaric report expected to be published by October 1
 - RENEW report expected to be published in late October
- NGRID submitted a 2020 economic study request
 - Assumptions have been agreed upon and were presented to PAC in May, June and July
 - Preliminary production cost results are anticipated to be shared at the November PAC, and the goal is to complete all study work by Q1 2021
- ISO-NE website enhancement project is ongoing
 - All reports are now accessible from a single point on the website
 - Additional modifications related to study metrics are expected in Q4



Environmental Issues

- Preliminary monitoring data indicates a moderate ground level ozone smog season across New England over the summer
- Smoke from West Coast wildfires reached New England and contributed to regional haze and a decline in solar production in the region
- Next Environmental Advisory Group (EAG) meeting is scheduled for October 6
- Various updates are being made to the EAG web page and quarterly reports are being introduced to improve user access to relevant environmental performance data and regulatory developments



Wildfire Smoke Crossing U.S. Mid-September 2020



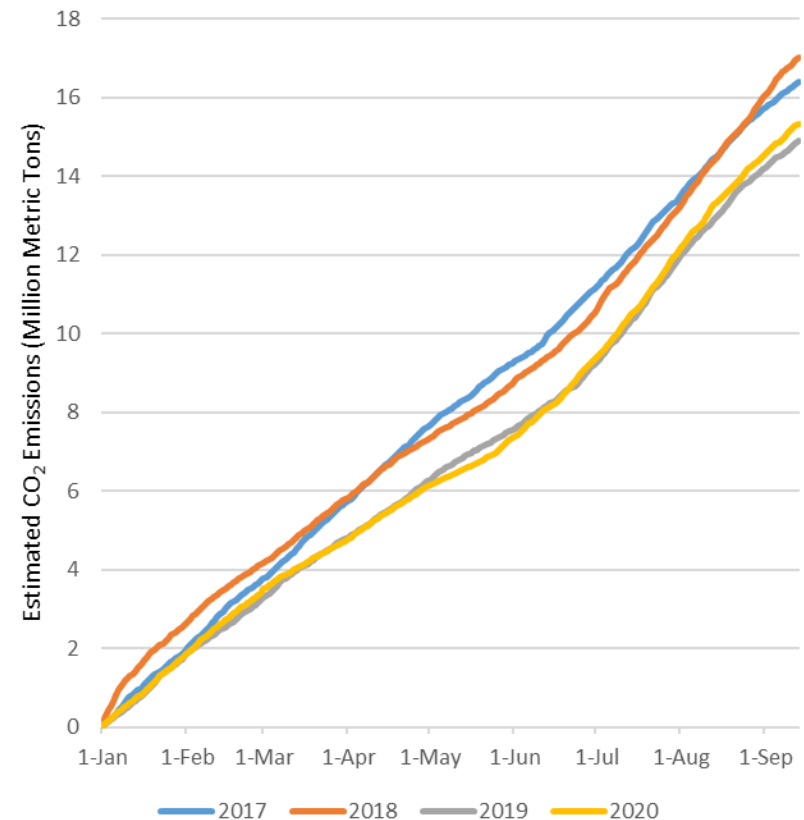
Wind and particle matter pollution (blue to dark red) estimated surface concentrations from various satellite measurements on 9/16/2020

Environmental Matters – Carbon Dioxide (CO₂) Emissions from Native Generation (1/1 - 9/14)

Estimated Emissions Increasing 2020 vs. 2019

- Estimated 2020 YTD CO₂ system emissions increased 3% compared to same period in 2019 (1/1 - 9/16):
 - Coal -81% 
 - Oil -8.5%
 - Natural Gas 5.5% 
- 2020 YTD (40,071 GWh) native emitting generation exceeded 2019 YTD (38,622 GWh) by 3.8%
 - Increases in natural gas generation (4.8%) and net imports (2.5%), offset decline in nuclear generation (-15.8%)

Cumulative CO₂ System Emissions (Million Metric Tons)

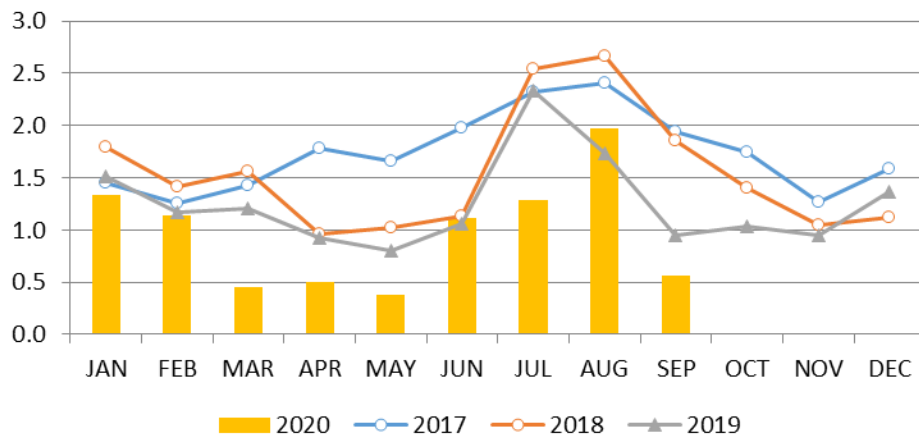


Environmental Matters – Massachusetts CO₂ Generator Emissions Cap

2020 CO₂ Estimated Emissions Remain Lower Than 2019

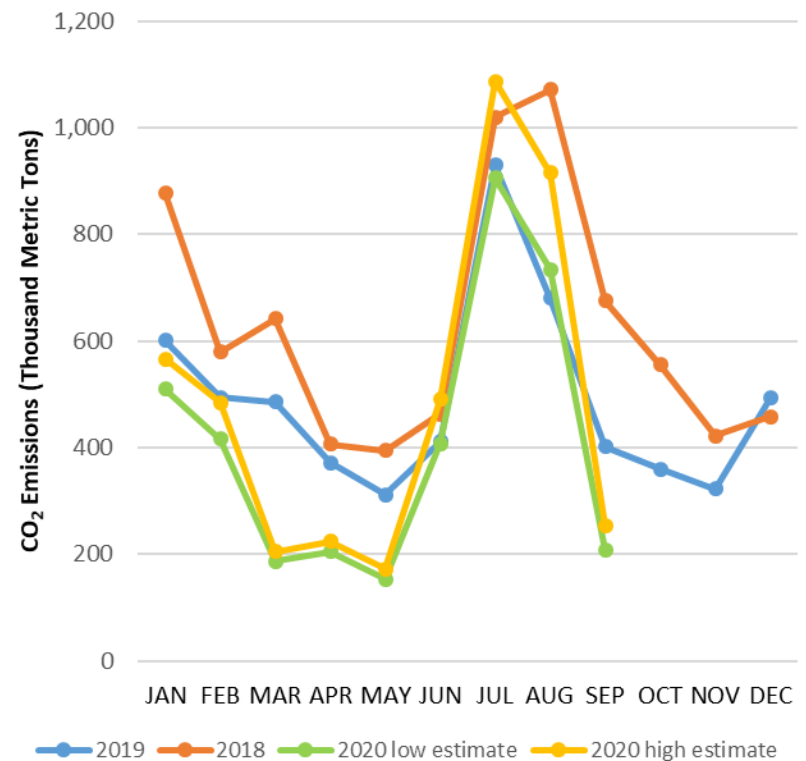
- YTD CO₂ emissions estimated between 80% - 94% of same period in 2019
- YTD generation 25% compared to same period in 2019

Year-to-Date Massachusetts Generation (Million MWh)
(1/1-9/14)



2020 Estimated Past Monthly Emissions (Thousand Metric tons)

GWSA 2020 Monthly Estimated Emissions



GWSA - Global Warming Solutions Act

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.



Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 9/21/20

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 9/21/20

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 9/21/20

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)	Jul-20	4
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 9/21/20

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 9/21/20

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 9/21/20

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 9/21/20

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 9/21/20

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 9/21/20

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 9/21/20

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*	May-22	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 9/21/20

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 9/21/20

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 9/21/20

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	May-22	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 position	Dec-16	4



Greater Boston Projects, cont.

Status as of 9/21/20

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



SEMA/RI Reliability Projects

Status as of 9/21/20

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	Oct-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 9/21/20

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-21	3
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
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	Cancelled*	N/A

*Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 9/21/20

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-23	1



SEMA/RI Reliability Projects, cont.

Status as of 9/21/20

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	2
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	Cancelled**	N/A
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

** Cancelled per ISO-NE PAC presentation on August 27, 2020



SEMA/RI Reliability Projects, cont.

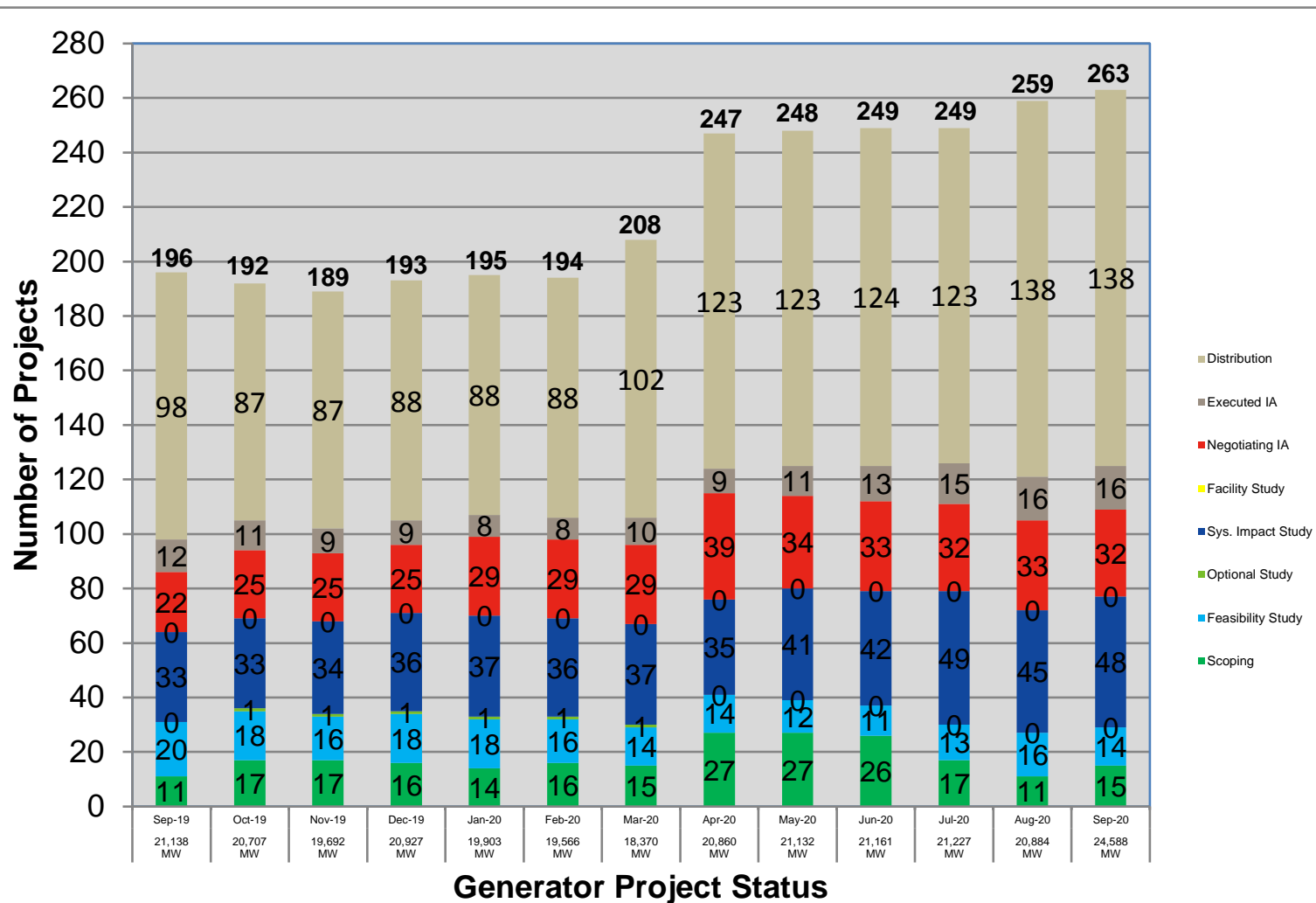
Status as of 9/21/20

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	Mar-22	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	3
1790	Medway 115 kV circuit breaker replacements	Dec-21	3



Status of Tariff Studies



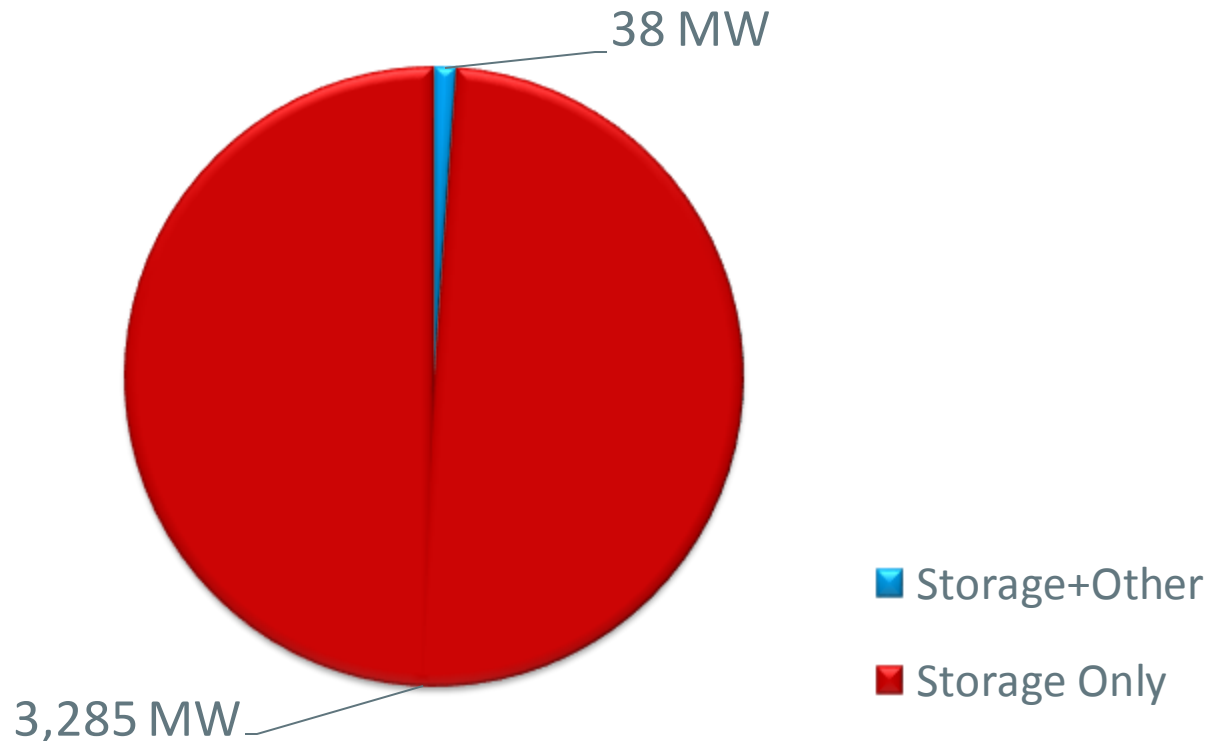
Note: September 2020 is based on partial data.

As of September 2020, there are 4 ETU's in Scoping, 1 in FS, 3 in SIS, 0 in FAC, 1 Negotiating IA, and 1 with Executed IA.

<https://irrt.iso-ne.com/external.aspx>

What is in the Queue (as of September 16, 2020)

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



OPERABLE CAPACITY ANALYSIS

Fall 2020 Analysis

Fall 2020 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Oct. - 2020 ² CSO (MW)	Oct. - 2020 ² SCC (MW)
Operable Capacity MW ¹	30,401	30,837
Active Demand Capacity Resource (+) ⁵	411	425
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,096	1,096
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	6,317	7,100
Gas Generator Outages MW (-)	1,606	1,843
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)	21,204	20,634
Peak Load Forecast MW(adjusted for Other Demand Resources) ²	16,459	16,459
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,764	18,764
Operable Capacity Margin	2,440	1,870

¹ Operable Capacity is based on data as of **September 28, 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 **September 28, 2020**.

² Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **October 17, 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.

Fall 2020 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	Oct.- 2020 ² CSO (MW)	Oct. - 2020 ² SCC (MW)
Operable Capacity MW ¹	30,401	30,837
Active Demand Capacity Resource (+) ⁵	411	425
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,096	1,096
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	6,317	7,100
Gas Generator Outages MW (-)	1,606	1,843
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)	21,204	20,634
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	17,001	17,001
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,306	19,306
Operable Capacity Margin	1,898	1,328

¹ Operable Capacity is based on data as of **September 28, 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 **September 28, 2020**.

² Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **October 17, 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.

Fall 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 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
10/10/2020	30401	411	1096	19	6317	1382	2800	0	21428	16076	2305	18381	3047
10/17/2020	30401	411	1096	19	6317	1606	2800	0	21204	16459	2305	18764	2440
10/24/2020	30401	411	996	19	5866	815	2800	0	22346	16677	2305	18982	3364
10/31/2020	30476	510	1025	19	4209	1459	3600	0	22762	16798	2305	19103	3659
11/7/2020	30476	510	1025	19	2761	1292	3600	0	24377	17160	2305	19465	4912
11/14/2020	30476	510	1025	19	2770	1469	3600	0	24191	17936	2305	20241	3950
11/21/2020	30476	510	1025	19	1822	1544	3600	0	25064	18694	2305	20999	4065

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 $(9 - 12 = 13)$

Fall 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 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]
10/10/2020	30401	411	1096	19	6317	1382	2800	0	21428	16607	2305	18912	2516
10/17/2020	30401	411	1096	19	6317	1606	2800	0	21204	17001	2305	19306	1898
10/24/2020	30401	411	996	19	5866	815	2800	0	22346	17224	2305	19529	2817
10/31/2020	30476	510	1025	19	4209	1459	3600	0	22762	17349	2305	19654	3108
11/7/2020	30476	510	1025	19	2761	1292	3600	0	24377	17721	2305	20026	4351
11/14/2020	30476	510	1025	19	2770	1469	3600	129	24062	18518	2305	20823	3239
11/21/2020	30476	510	1025	19	1822	1544	3600	855	24209	19296	2305	21601	2608

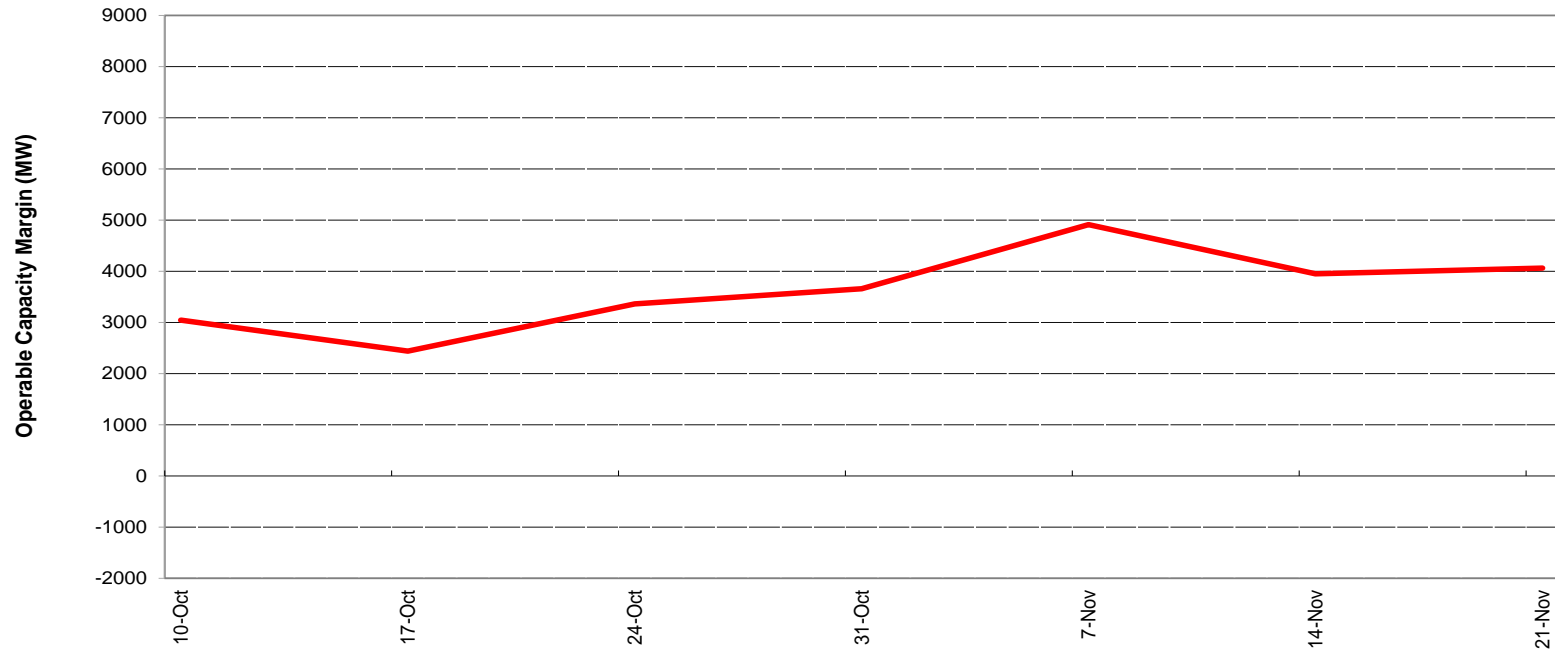
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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.
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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 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

Fall 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

2020 ISO-NEW ENGLAND OPERABLE CAPACITY
-50/50 CSO-



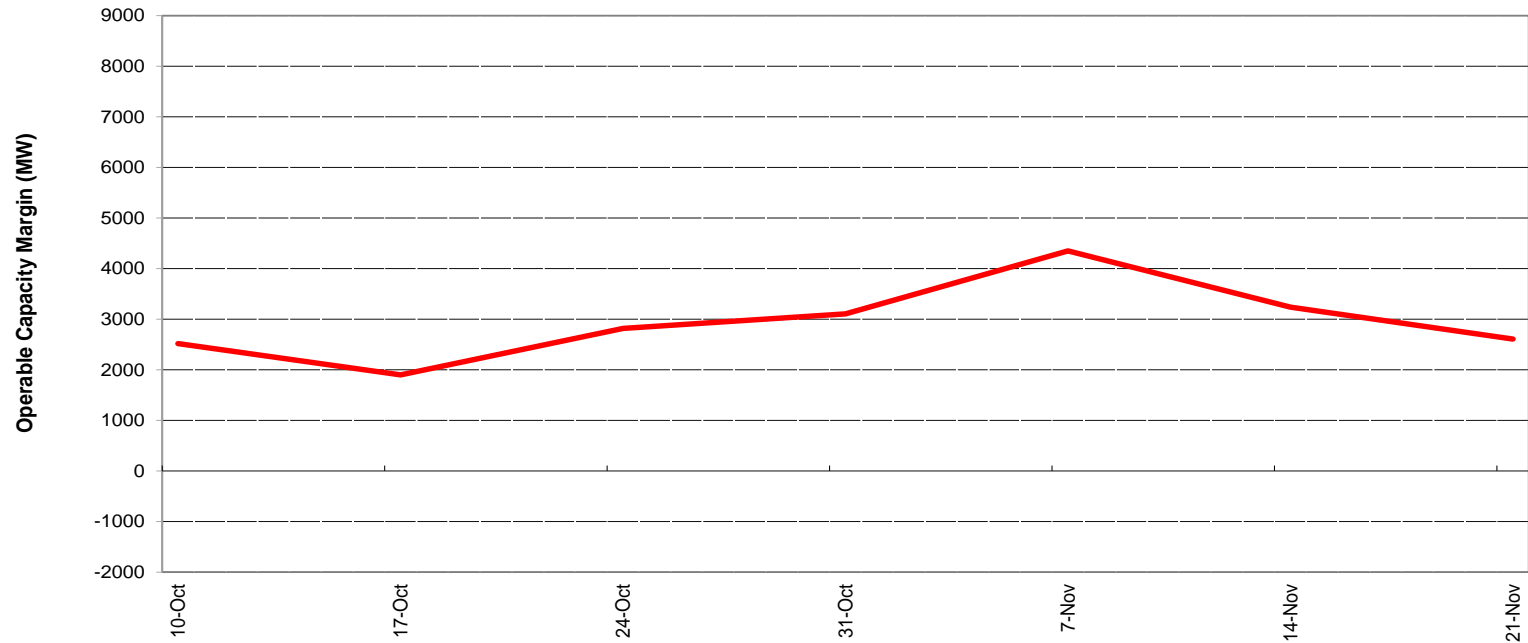
October 10, 2020 - November 27, 2020, W/B Saturday



Fall 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)

2020 ISO-NEW ENGLAND OPERABLE CAPACITY
-90/10 CSO-



October 10, 2020 - November 27, 2020, W/B Saturday



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2020/21 Analysis



Preliminary Winter 2020/21 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2020 ² CSO (MW)	Jan. - 2020 ² SCC (MW)
Operable Capacity MW ¹	30,459	33,692
Active Demand Capacity Resource (+) ⁵	533	381
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	298	301
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) ⁴	2,800	2,800
Generation at Risk Due to Gas Supply (-) ³	3,893	4,301
Net Capacity (NET OPCAP SUPPLY MW)	25,045	27,715
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	20,166	20,166
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,471	22,471
Operable Capacity Margin	2,574	5,244

¹ Operable Capacity is based on data as of **September 28, 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 **September 28, 2020**.

² Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 2, 2021**.

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 Winter 2020/21 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	Jan. - 2020 ² CSO (MW)	Jan. - 2020 ² SCC (MW)
Operable Capacity MW ¹	30,459	33,692
Active Demand Capacity Resource (+) ⁵	533	381
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	298	301
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) ⁴	2,800	2,800
Generation at Risk Due to Gas Supply (-) ³	4,595	5,077
Net Capacity (NET OPCAP SUPPLY MW)	24,343	26,939
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	20,806	20,806
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,111	23,111
Operable Capacity Margin	1,232	3,828

¹ Operable Capacity is based on data as of **September 28, 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 **September 28, 2020**.

² Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 2, 2021**.

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 Winter 2020/21 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 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]
11/28/2020	30476	510	1025	19	1536	0	3600	2038	24856	19009	2305	21314	3542
12/5/2020	30459	533	1025	19	339	264	3200	2215	26018	19313	2305	21618	4400
12/12/2020	30459	533	1025	19	350	267	3200	2419	25800	19325	2305	21630	4170
12/19/2020	30459	533	1025	19	309	0	3200	2909	25618	19390	2305	21695	3923
12/26/2020	30459	533	1025	19	298	0	3200	3270	25268	19390	2305	21695	3573
1/2/2021	30459	533	1025	19	298	0	2800	3893	25045	20166	2305	22471	2574
1/9/2021	30459	533	1025	19	298	0	2800	3888	25050	20166	2305	22471	2579
1/16/2021	30459	533	1025	19	368	0	2800	3737	25131	20166	2305	22471	2660
1/23/2021	30459	533	1025	19	293	0	2800	3270	25673	19933	2305	22238	3435
1/30/2021	30459	533	1025	19	293	0	3100	2958	25685	19933	2305	22238	3447
2/6/2021	30459	533	1025	19	293	0	3100	2647	25996	19652	2305	21957	4039
2/13/2021	30459	533	1025	19	753	0	3100	2336	25847	19622	2305	21927	3920
2/20/2021	30459	533	1025	19	764	0	3100	1869	26303	19346	2305	21651	4652
2/27/2021	30459	533	1025	19	1068	0	2200	1557	27211	18308	2305	20613	6598
3/6/2021	30459	533	1025	19	1074	0	2200	1246	27516	17941	2305	20246	7270
3/13/2021	30459	533	1025	19	1080	0	2200	623	28133	17736	2305	20041	8092
3/20/2021	30459	533	1025	19	1339	508	2200	0	27989	17352	2305	19657	8332
3/27/2021	30446	537	1025	19	864	239	2700	0	28224	16759	2305	19064	9160

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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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 $(9 - 12 = 13)$

Preliminary Winter 2020/21 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 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

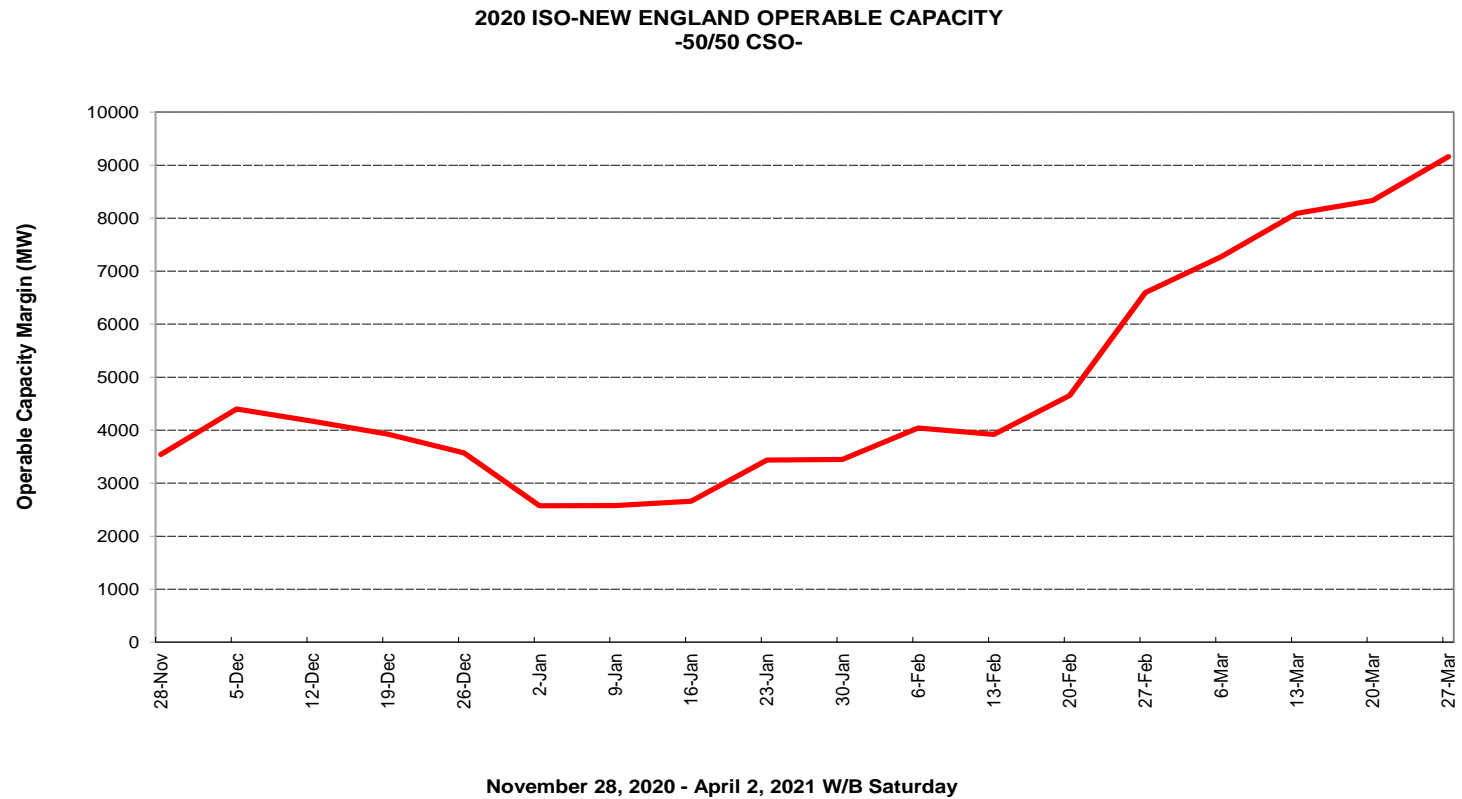
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	
11/28/2020	30476	510	1025	19	1536	0	3600	2990	23904	19618	2305	21923	1981
12/5/2020	30459	533	1025	19	339	264	3200	3244	24989	19930	2305	22235	2754
12/12/2020	30459	533	1025	19	350	267	3200	3447	24772	19942	2305	22247	2525
12/19/2020	30459	533	1025	19	309	0	3200	4073	24454	20009	2305	22314	2140
12/26/2020	30459	533	1025	19	298	0	3200	4463	24075	20009	2305	22314	1761
1/2/2021	30459	533	1025	19	298	0	2800	4595	24343	20806	2305	23111	1232
1/9/2021	30459	533	1025	19	298	0	2800	4732	24206	20806	2305	23111	1095
1/16/2021	30459	533	1025	19	368	0	2800	4516	24352	20806	2305	23111	1241
1/23/2021	30459	533	1025	19	293	0	2800	4204	24739	20566	2305	22871	1868
1/30/2021	30459	533	1025	19	293	0	3100	4204	24439	20566	2305	22871	1568
2/6/2021	30459	533	1025	19	293	0	3100	3737	24906	20278	2305	22583	2323
2/13/2021	30459	533	1025	19	753	0	3100	3426	24757	20247	2305	22552	2205
2/20/2021	30459	533	1025	19	764	0	3100	2803	25369	19963	2305	22268	3101
2/27/2021	30459	533	1025	19	1068	0	2200	2336	26432	18897	2305	21202	5230
3/6/2021	30459	533	1025	19	1074	0	2200	2180	26582	18520	2305	20825	5757
3/13/2021	30459	533	1025	19	1080	0	2200	1557	27199	18309	2305	20614	6585
3/20/2021	30459	533	1025	19	1339	508	2200	582	27407	17915	2305	20220	7187
3/27/2021	30446	537	1025	19	864	239	2700	384	27840	17305	2305	19610	8230

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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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.
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9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
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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

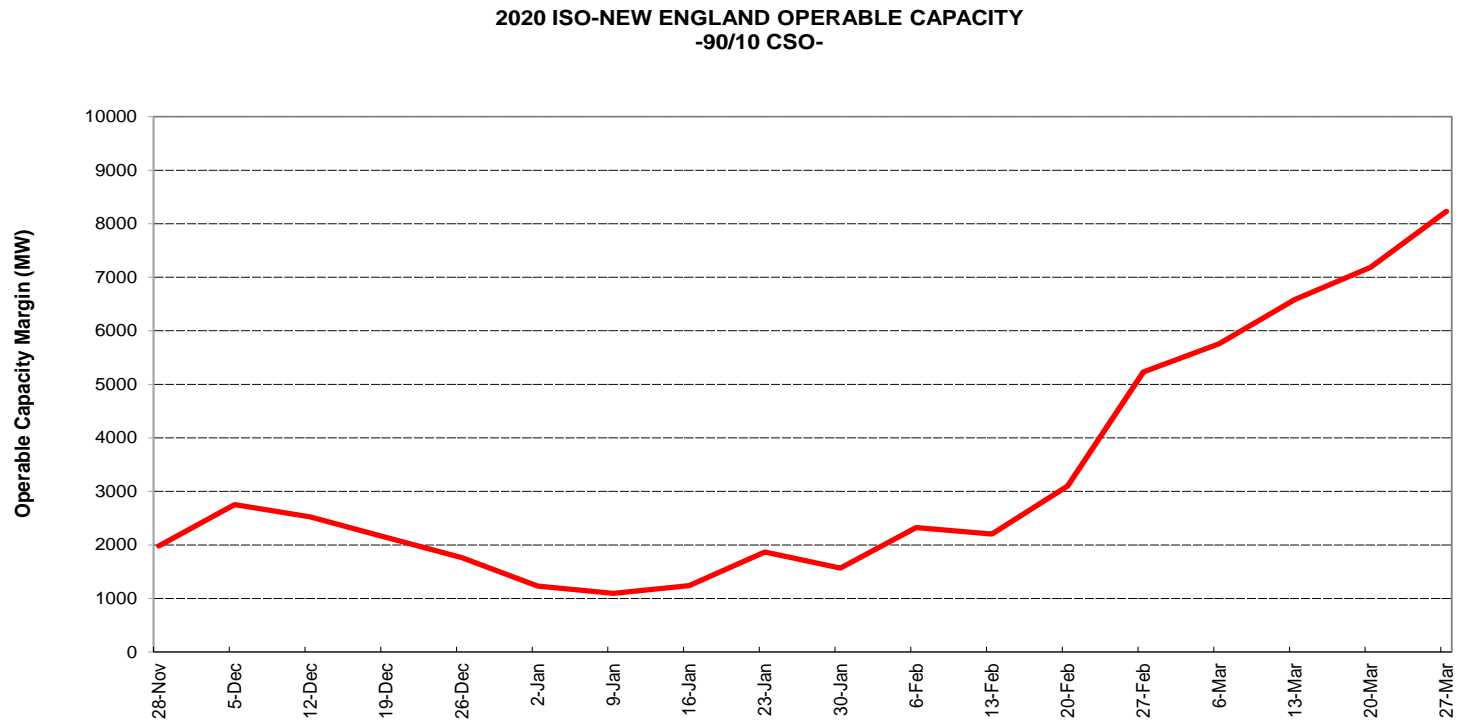
Preliminary Winter 2020/21 Operable Capacity Analysis

50/50 Forecast (Reference)



Preliminary Winter 2020/21 Operable Capacity Analysis

90/10 Forecast (Extreme)



November 28, 2020 - April 2, 2021 W/B Saturday

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