NEPOOL Participants Committee Report

October 2021

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: August 2021 Energy Market value totaled $685M
  - September 2021 Energy market value was $497M, down $188M from August 2021 and up $290M from September 2020
  - September 2021 natural gas prices over the period were 12% higher than for August
    - Average RT Hub Locational Marginal Prices ($46.48/MWh) over the period were 5% lower than August averages
      - DA Hub: $48.01/MWh
    - Average September 2021 natural gas prices and RT Hub LMPs over the period were up 206% and up 134%, respectively, from September 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.9% during September, down from 100.5% during August*
    - The minimum value for the month was 92.7% on Wednesday, September 1st

All data through September 29th

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

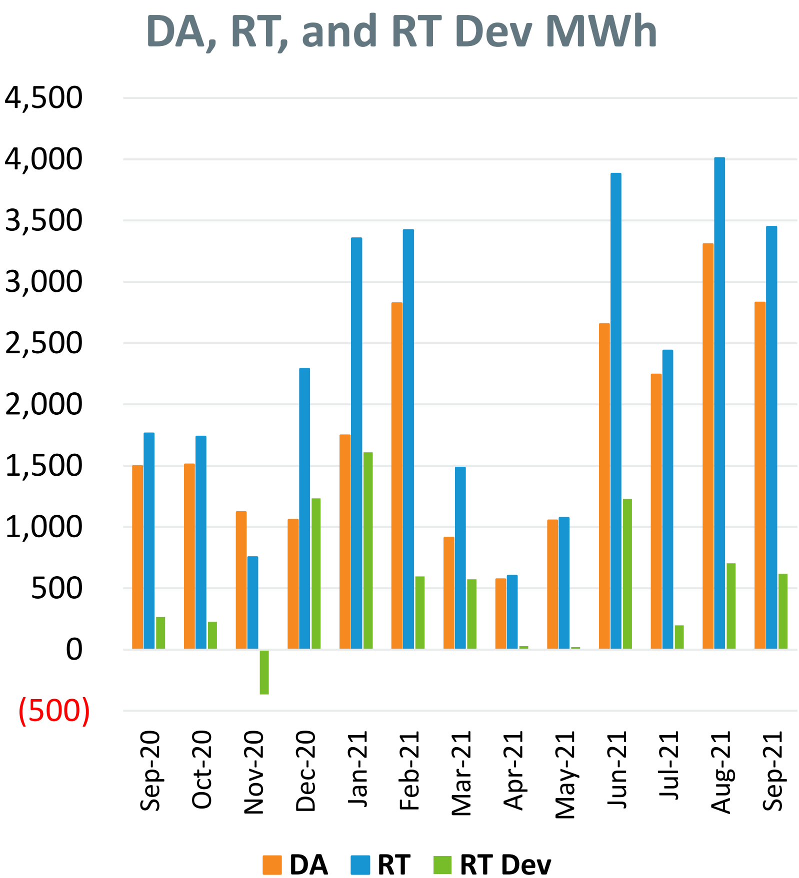
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

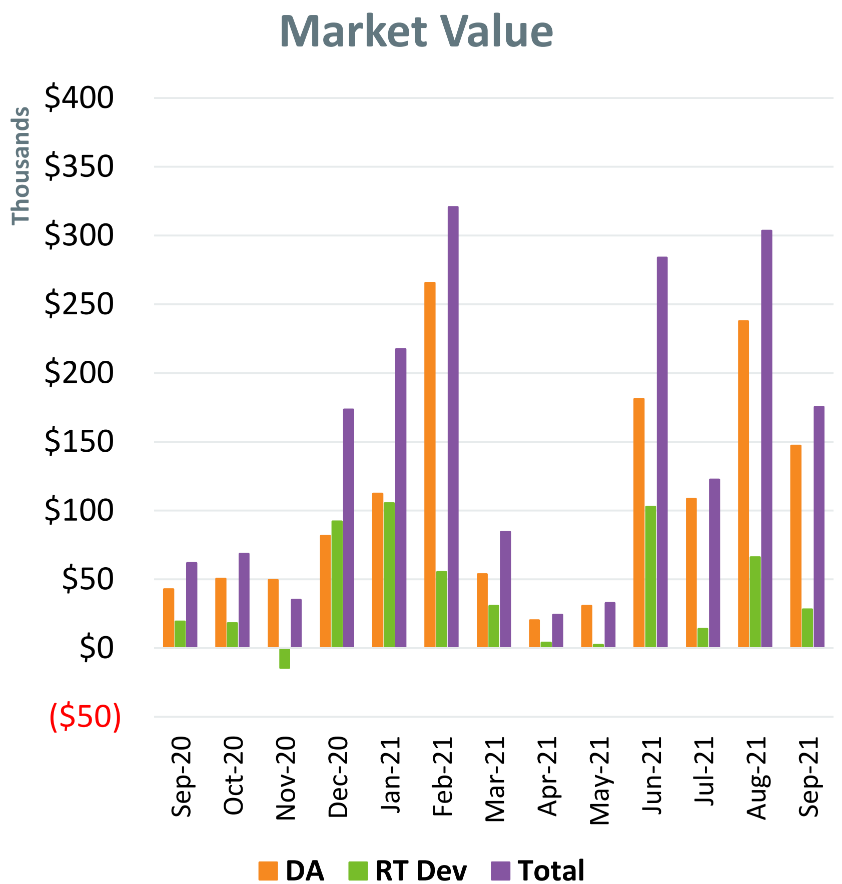
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - September 2021 NCPC payments totaled $1.3M over the period, down $2M from August 2021 and down $1.1M from September 2020
    - First Contingency payments totaled $1.3M, down $1.5M from August
      - $1.3M paid to internal resources, down $1.5M from August
        - » $350K charged to DALO, $491K to RT Deviations, $445K to RTLO*
      - $42K paid to resources at external locations, down $1K from August
        - » $38K charged to DALO at external locations, $1K to RT Deviations
    - Second Contingency payments totaled $5K, down $93K from August
    - Voltage and Distribution payments were negligible ($3K combined)
  - NCPC payments over the period as percent of Energy Market value were 0.3%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $263K; Rapid Response Pricing (RRP) Opportunity Cost - $170K; Posturing - $12K; Generator Performance Auditing (GPA) - $0K

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Highlights

- Production cost preliminary results for the 2021 Economic Study (Future Grid Reliability Study) were discussed at a special September 17 PAC meeting and joint MC/RC meetings
  - The ISO is working on refining the scenario matrix and will present to the MC/RC for approval before completing the final runs
- RC voted in favor of the FCA 16 ICR and Related Values at their September 21 meeting; FERC filing to be made by November 9
- 2022 ARA assumption discussions continue at the PSPC
- Regional System Plan Public Meeting will be held virtually on October 6
- Four Attachment K revisions are in various stages of development

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 29
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) was held on August 2-4, and results were posted on August 31
  - Development of ICR-Related Values continues with discussions at the PSPC; FERC filing to be made by November 30
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted June 30
  - Development of ICR-Related Values continues with discussions at the PSPC; FERC filing to be made by November 30
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26 and FERC approved on June 24
  - Development of ICR-Related Values continues with discussions at the PSPC; FERC filing to be made by November 30

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - FCA 16 will model the same zones as FCA 15
    - Export-constrained zones: Northern New England, and Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England
  - A summary of permanent and retirement de-list bids was posted on March 17, and a summary of substitution auction demand bids was posted on April 30
    - These summaries were reposted on June 11 to reflect de-list bid withdrawals made after the Internal Market Monitor reissued its determinations based on the FERC-accepted CONE, Net CONE and Capacity Performance Payment Rate for FCA 16
      - The bid withdrawal Tariff provision that FERC accepted was for FCA 16 only
    - New Capacity Qualification is ongoing
  - ICR and Related Values to be filed no later than November 9, 2021

CONE – Cost of New Entry

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- Efforts to expand/improve the transportation electrification forecast for CELT 2022 have commenced
  - Initial discussion related to these efforts was at the September 24 Load Forecast Committee meeting

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
- Competitive Solution Process: Order 1000/Boston 2028 Request for Proposal Lessons Learned
  - The ISO held discussions on the associated Tariff changes at the 7/14/21, 8/24/21, and 9/28/21 TC meetings
  - The first discussion at the RC occurred on 9/21/21; next discussion is scheduled for 10/19/21

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning October 16, 2021.
- The lowest 50/50 and 90/10 Preliminary Winter Operable Capacity Margins are projected for week beginning January 8, 2022.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (4.0°F) Max: 86°F, Min: 52°F Precipitation: 7.47" – Above Normal Normal: 3.56"	Hartford	Temperature: Above Normal (1.3°F) Max: 86°F, Min: 44°F Precipitation: 6.81" - Above Normal Normal: 4.39"

Peak Load:	19,707 MW	September 15, 2021	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None in September, 2021			

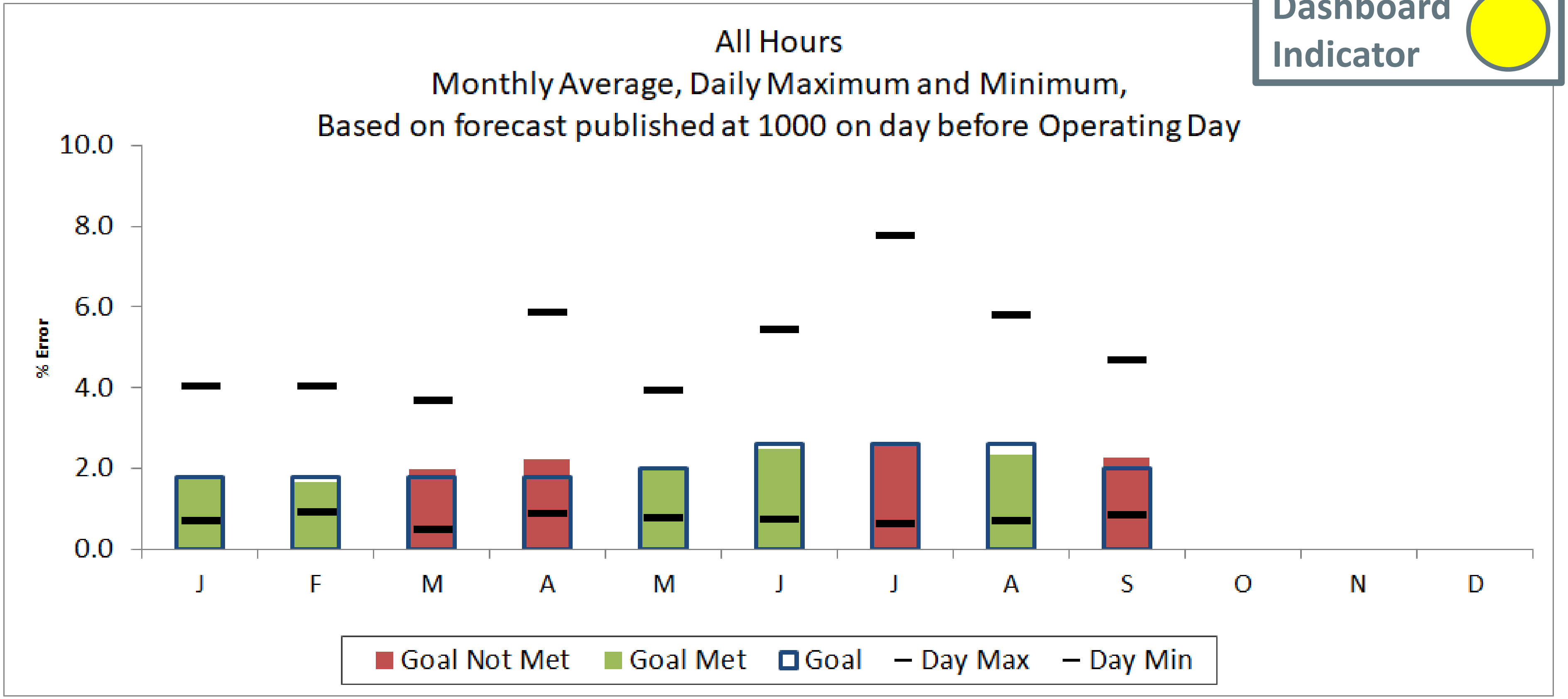
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
9/27/2021	PJM	750
9/30/2021	IESO	530

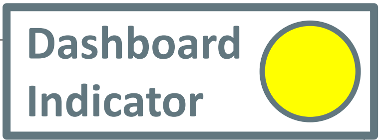
2021 System Operations - Load Forecast Accuracy

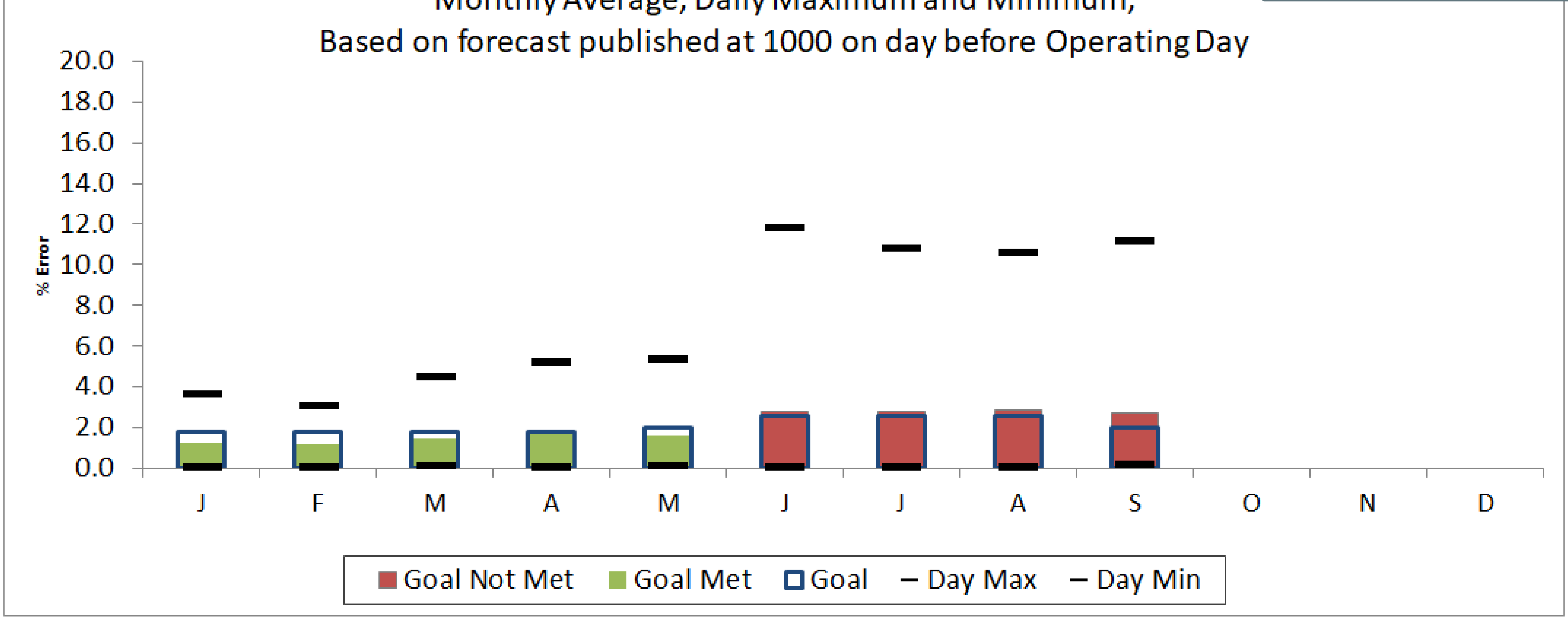
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03	3.67	5.85	3.92	5.41	7.75	5.77	4.68				7.75
Day Min	0.70	0.92	0.49	0.88	0.77	0.73	0.63	0.71	0.86				0.49
MAPE	1.72	1.66	1.97	2.24	1.95	2.50	2.61	2.33	2.28				2.14
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

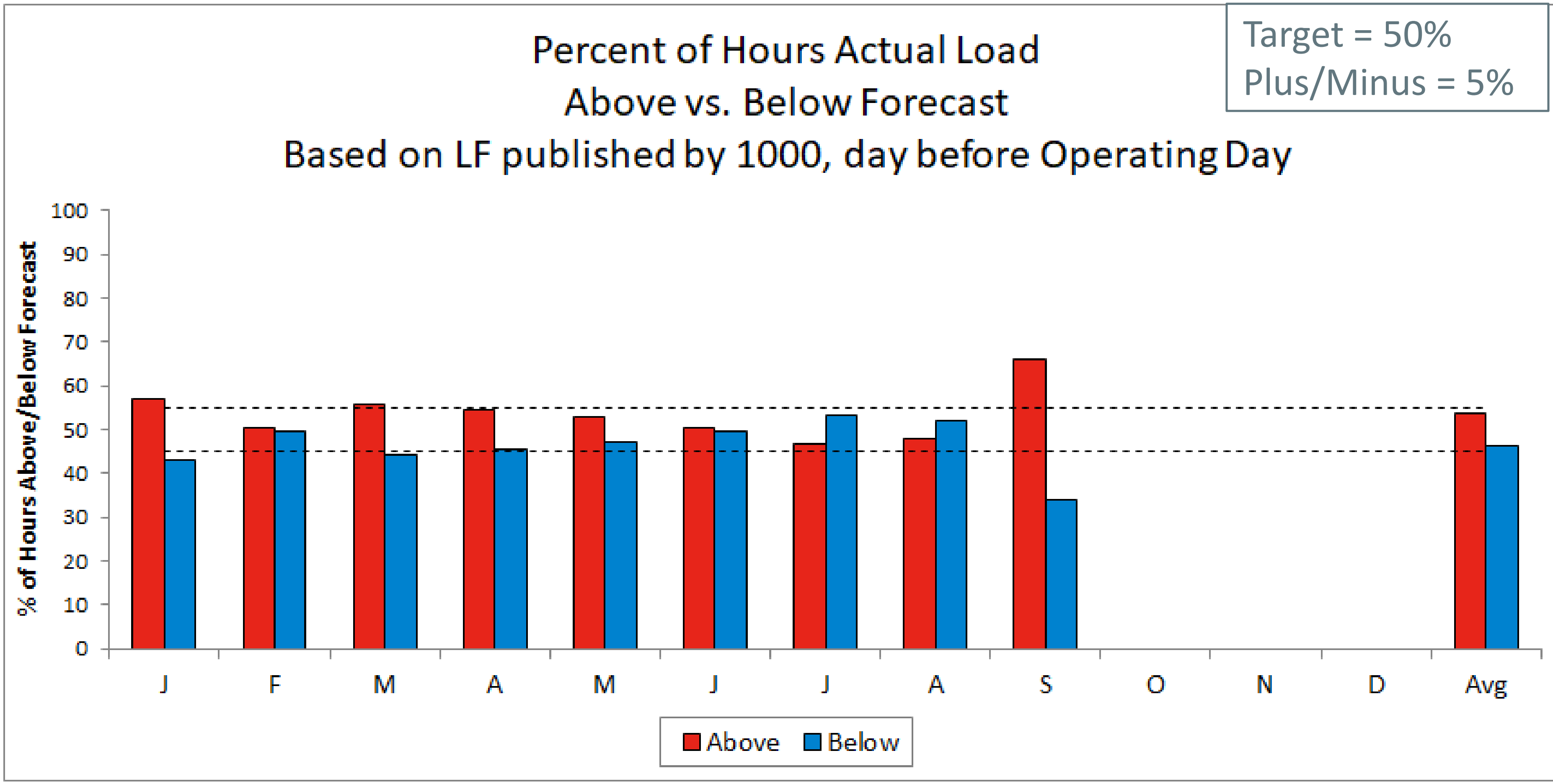
2021 System Operations - Load Forecast Accuracy cont.





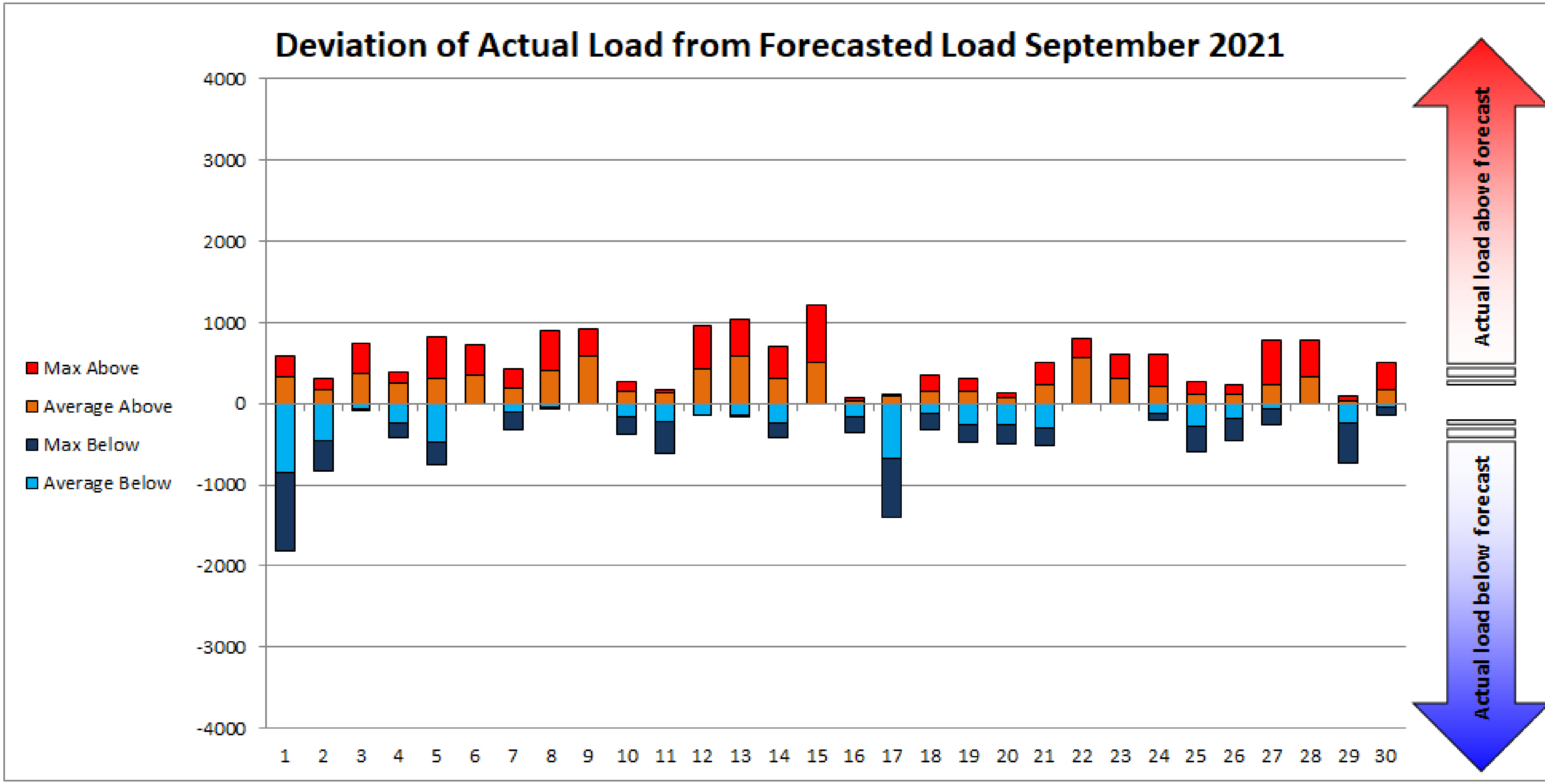
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03	4.47	5.19	5.31	11.76	10.75	10.54	11.13				11.76
Day Min	0.02	0.06	0.08	0.03	0.11	0.04	0.05	0.01	0.17				0.01
MAPE	1.26	1.18	1.48	1.66	1.60	2.79	2.78	2.86	2.73				2.04
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

2021 System Operations - Load Forecast Accuracy cont.

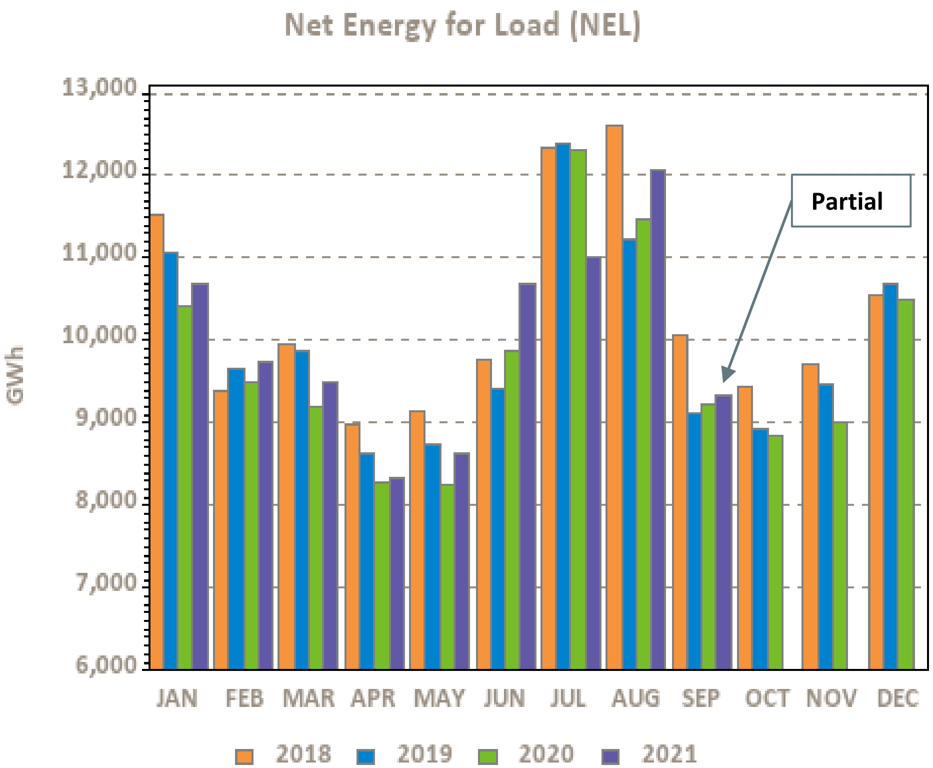


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4	55.6	54.4	52.8	50.3	46.9	47.8	66.2				53
Below %	42.9	49.6	44.4	45.6	47.2	49.7	53.1	52.2	33.8				47
Avg Above	209.5	166.7	185.4	206.1	227.4	233.1	214.5	227	263.1				263
Avg Below	-147.6	-216.4	-188.0	-167.9	-146.8	-309.1	-348.1	-307.5	-195.6				-348
Avg All	60	-25	30	40	61	-48	-122	-79	105				3

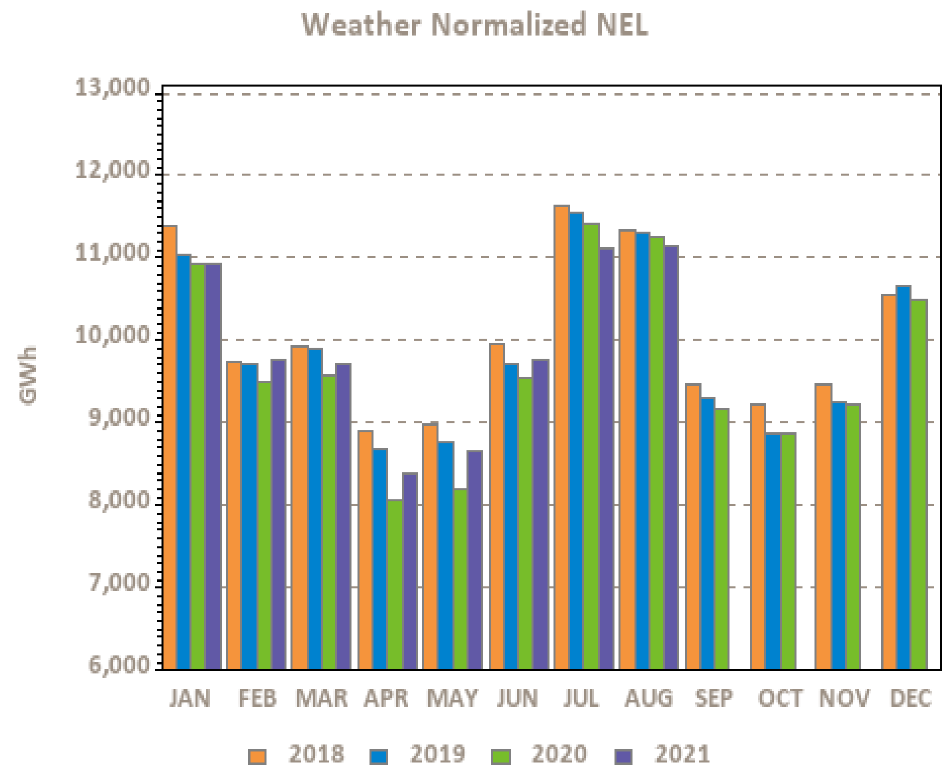
2021 System Operations - Load Forecast Accuracy cont.



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



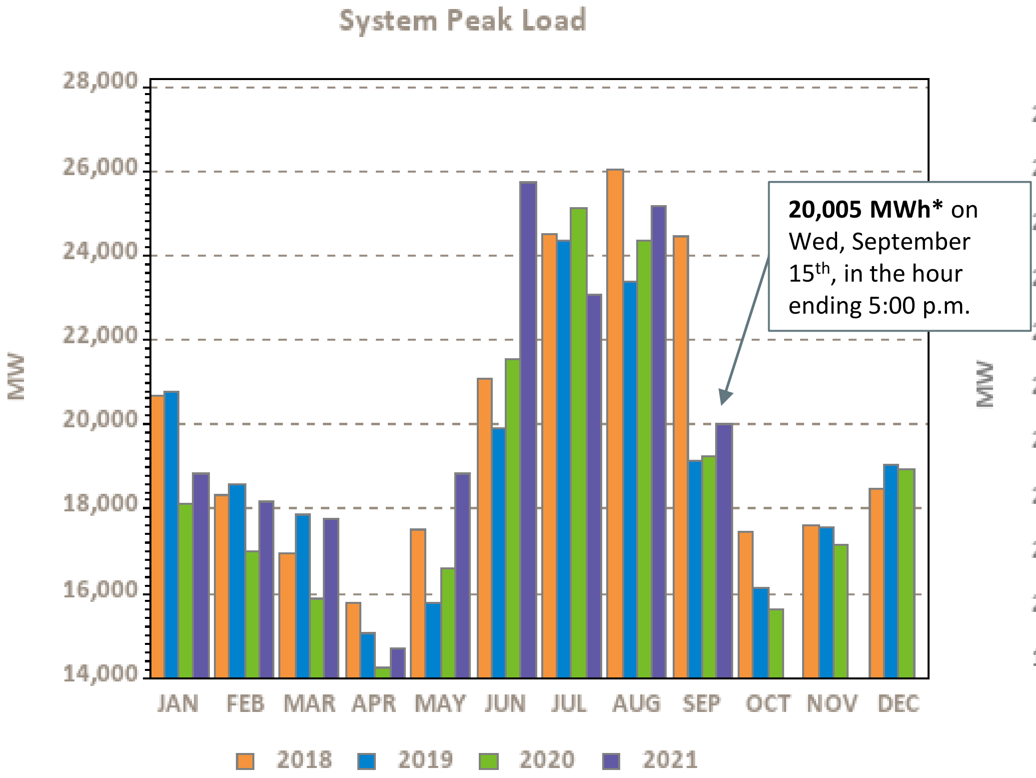
Ann Tot (TWh): 123.5 119.2 116.9 90.0



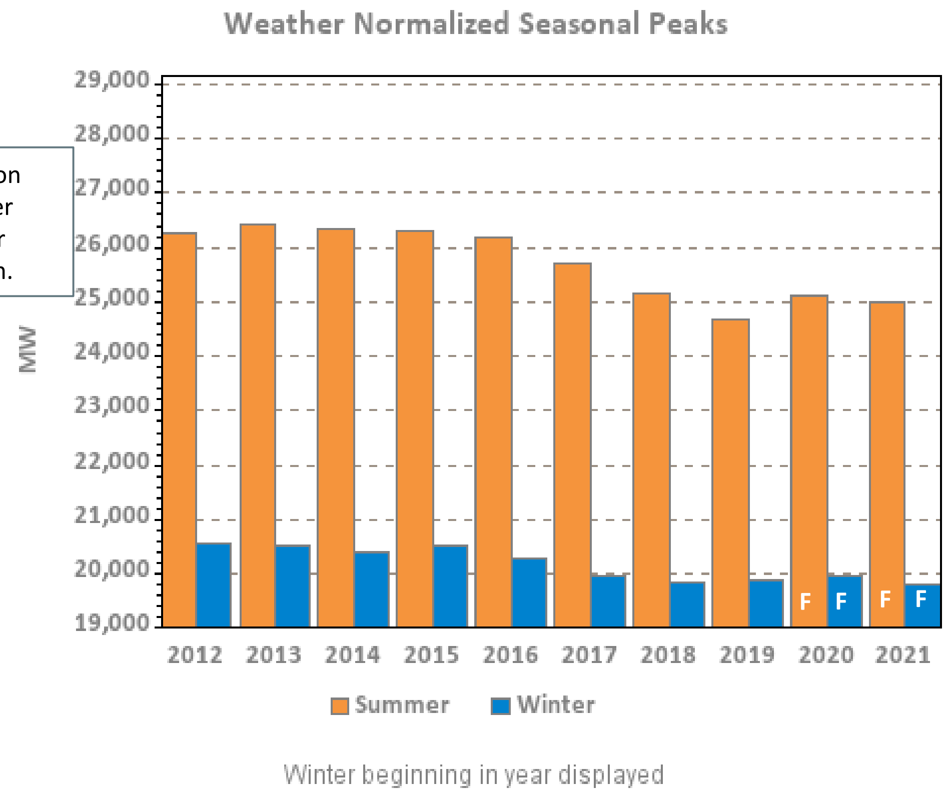
Ann Tot (TWh): 120.6 118.8 116.3 79.5

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 is typically reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

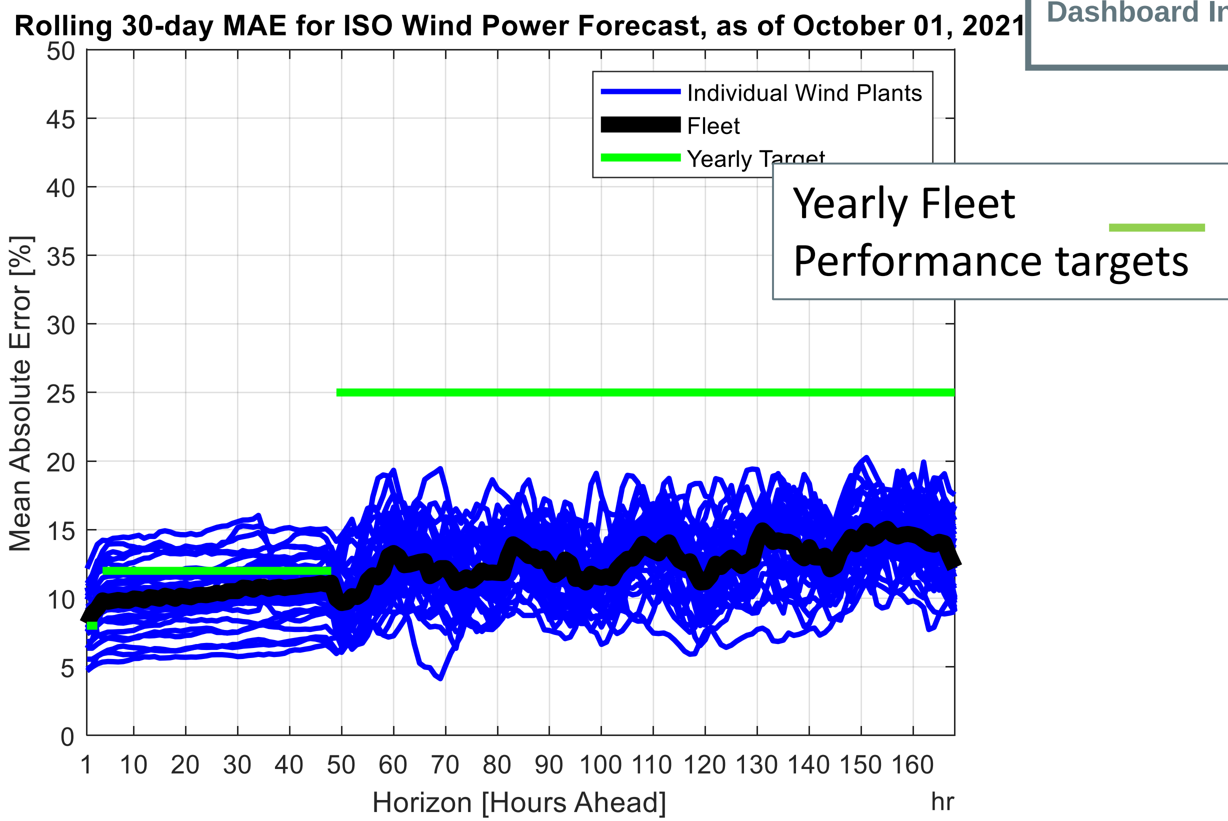


Winter beginning in year displayed

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

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

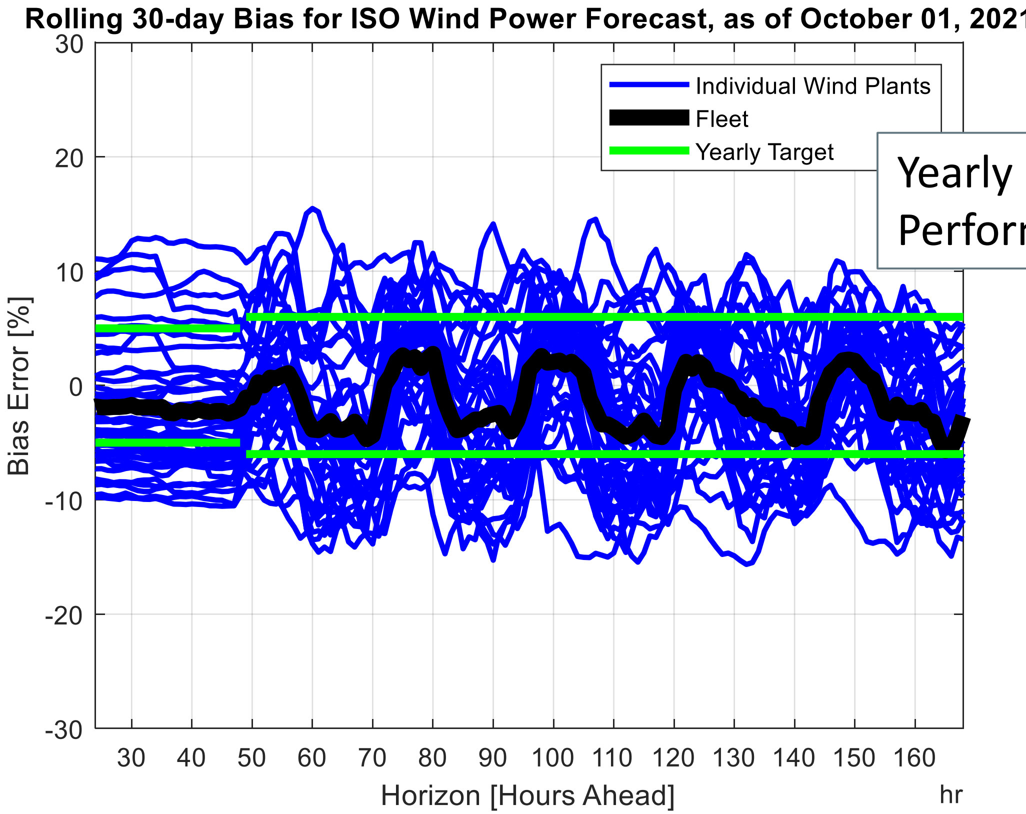
Dashboard Indicator



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

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

Dashboard Indicator

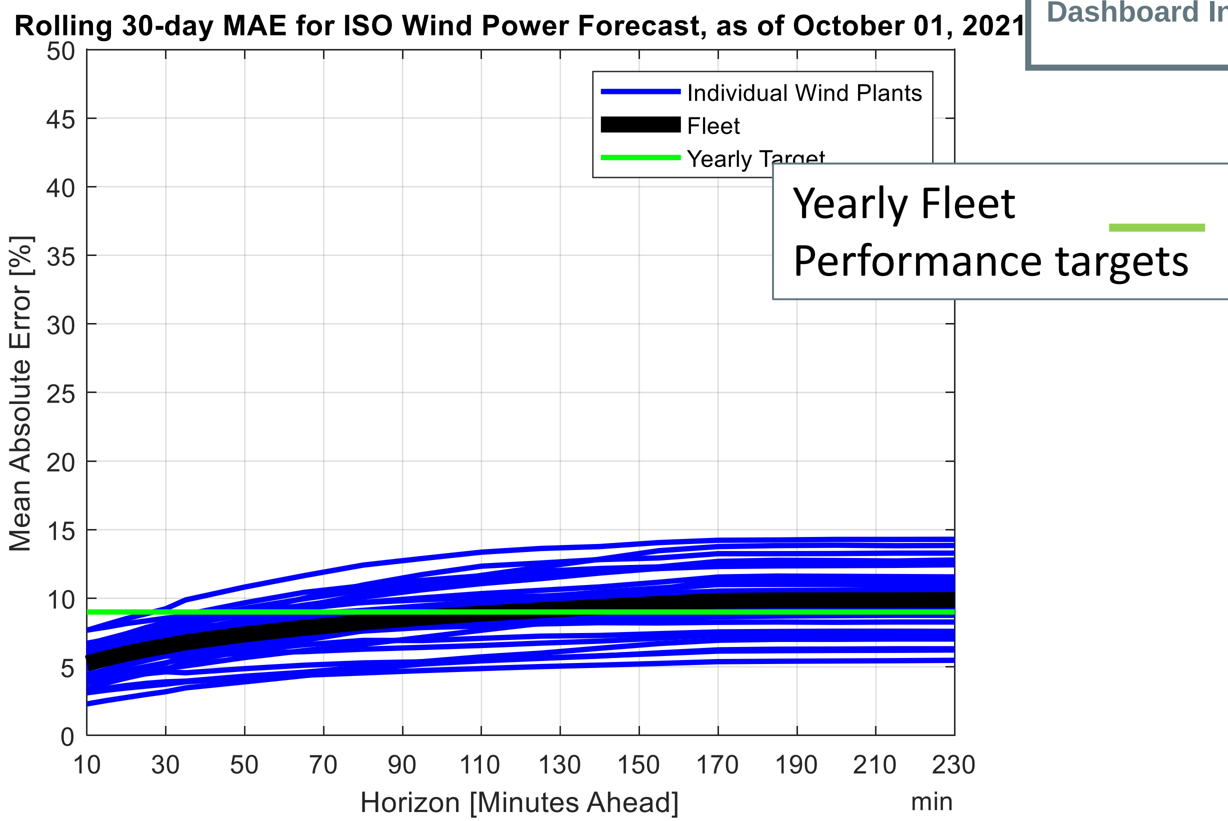


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

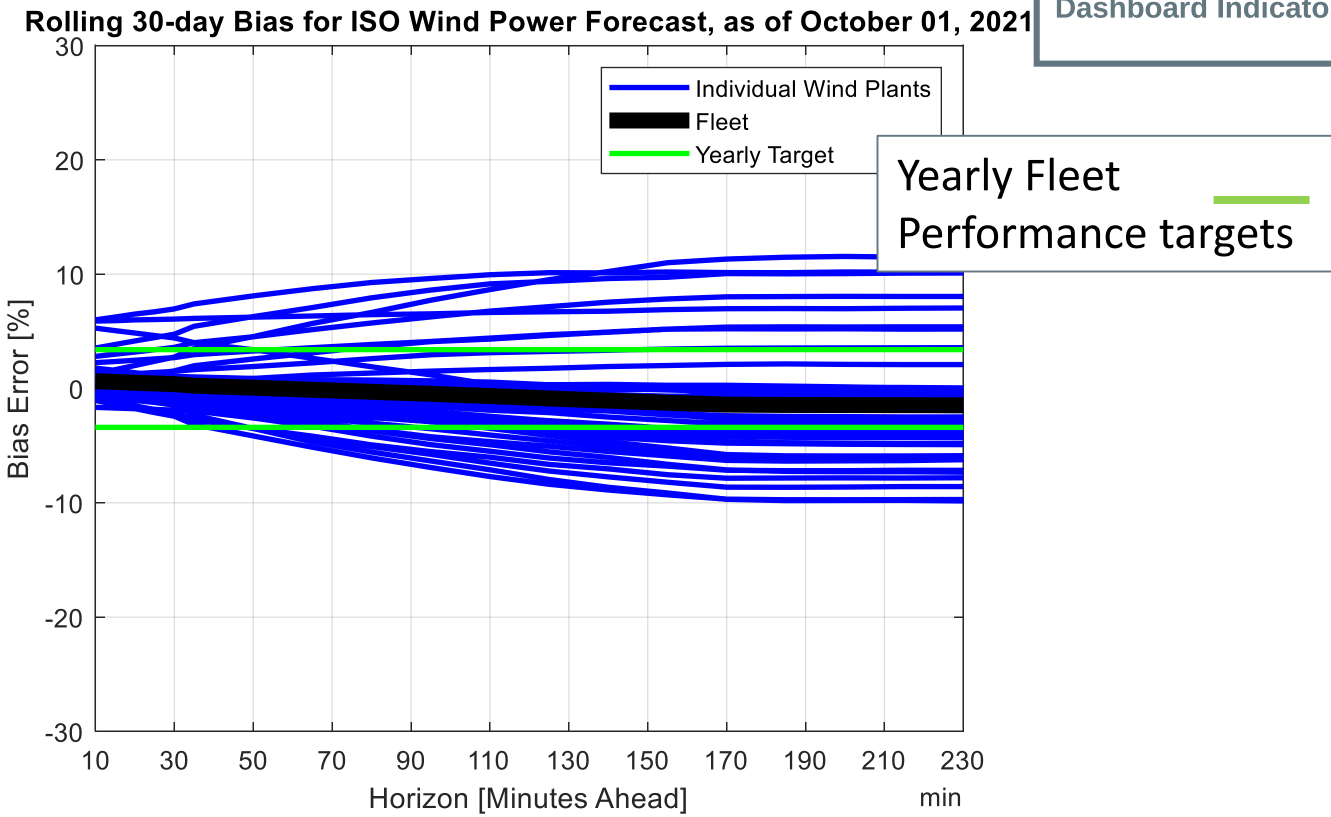
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets up to 130 minutes ahead.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

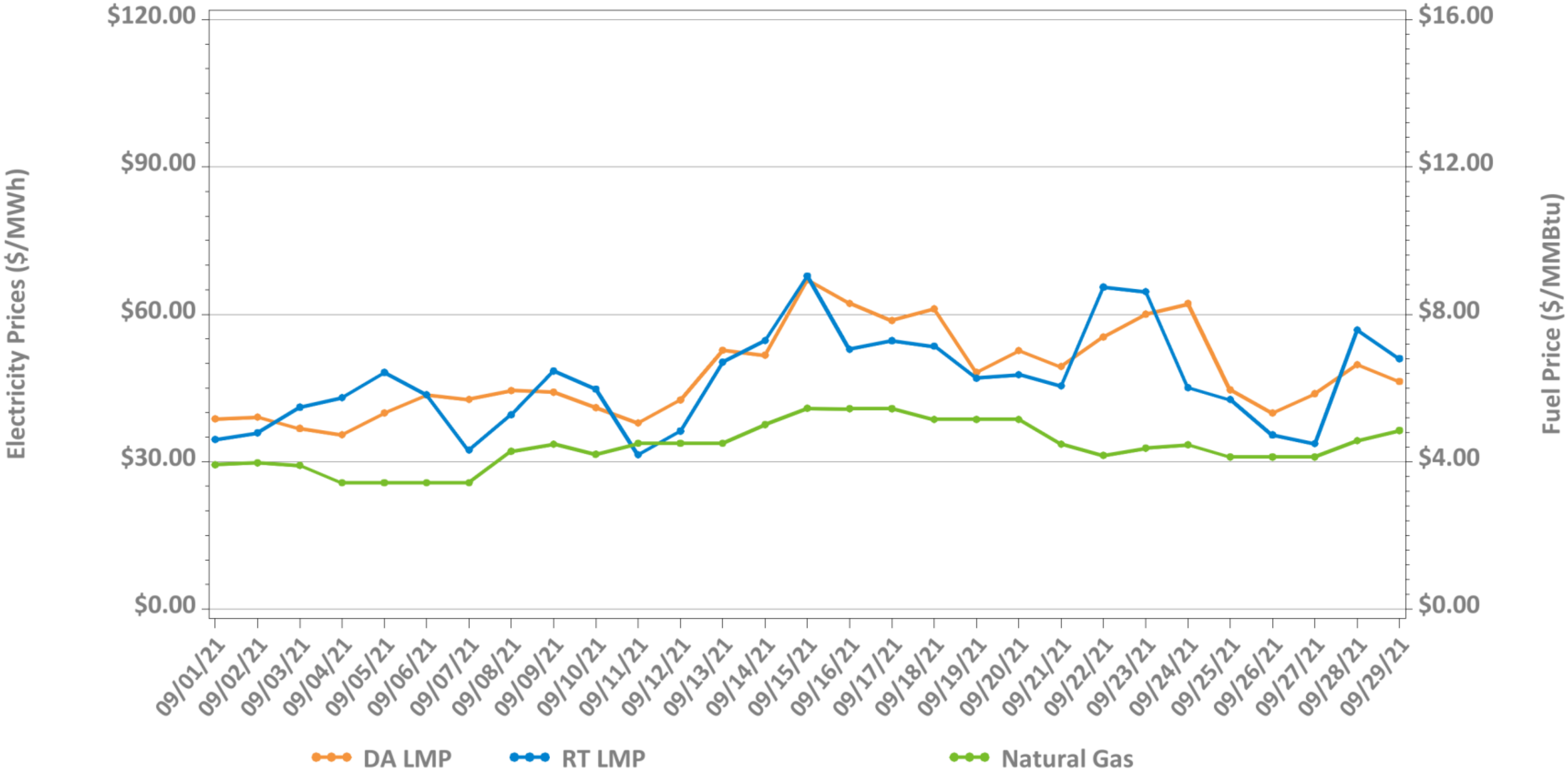
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV 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 1-29, 2021

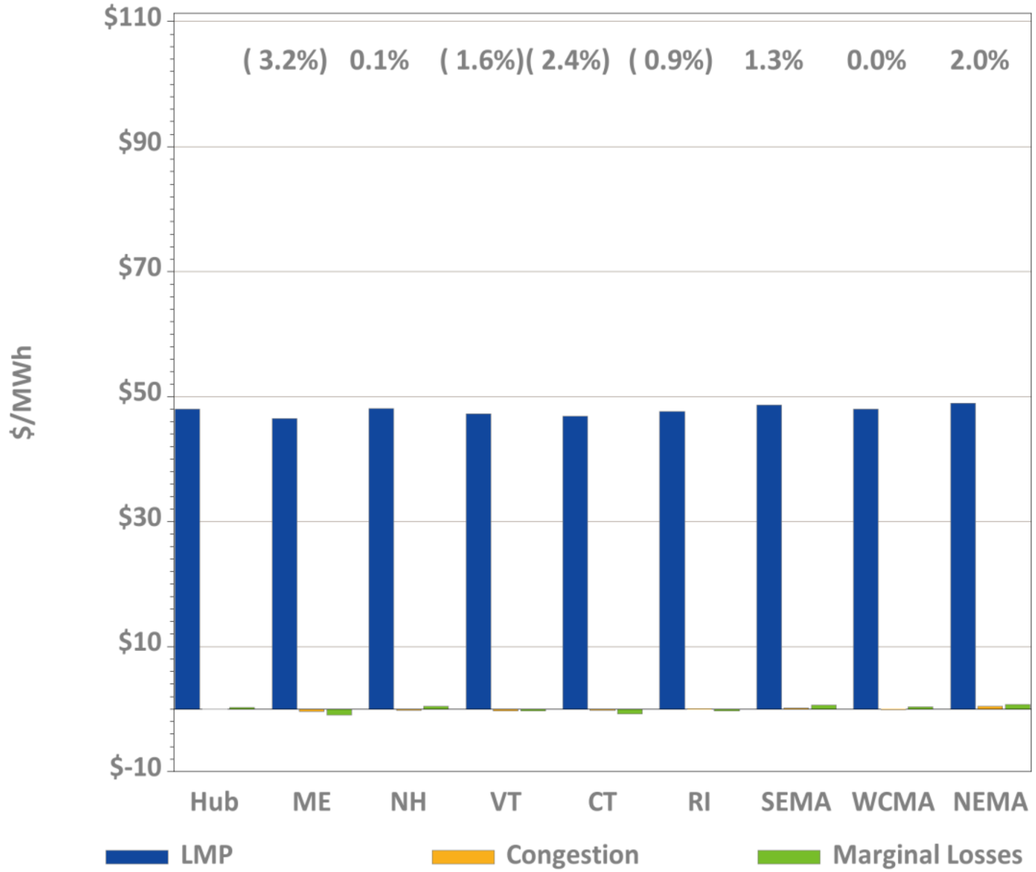


Underlying natural gas data furnished by:

ICE Global markets in clear view

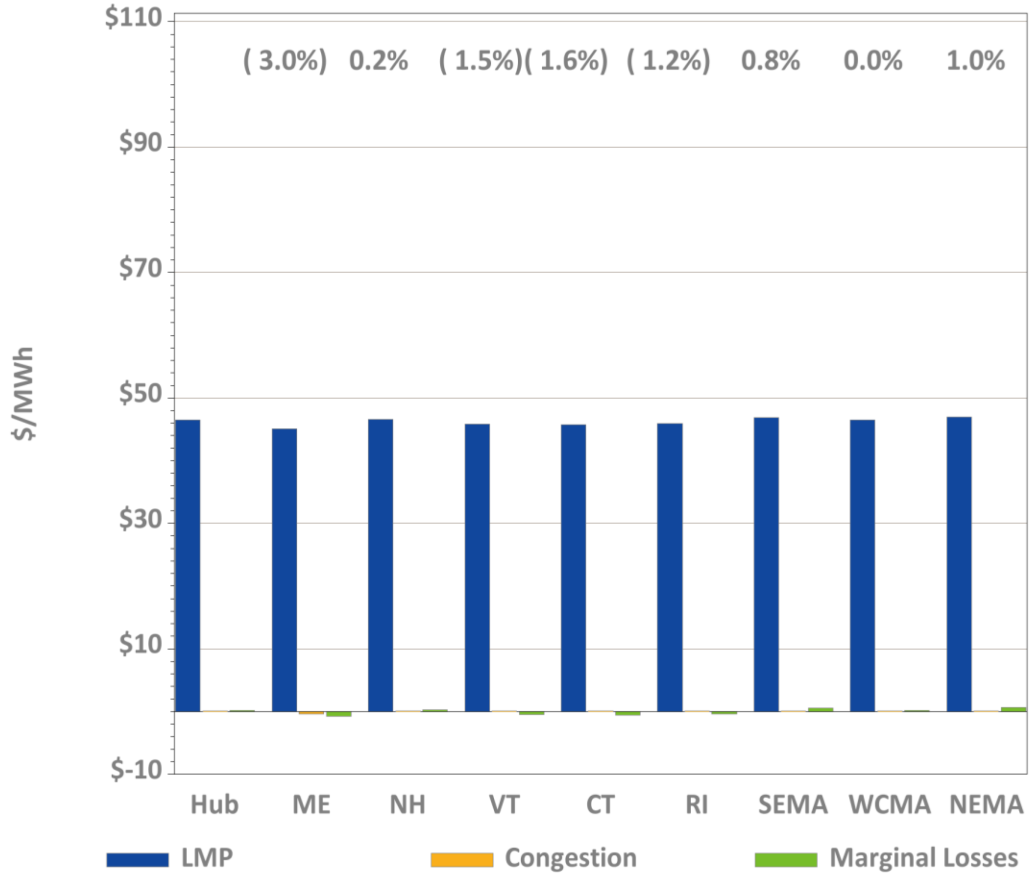
Average price difference over this period (DA-RT): $1.53
Average price difference over this period ABS(DA-RT): $5.55
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 12%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, September 2021



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

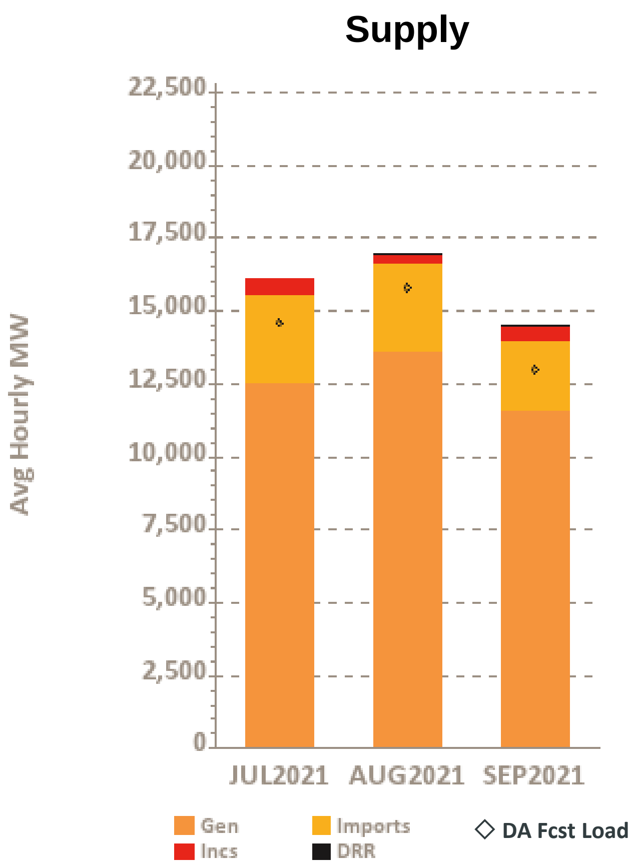
RT LMPs Average by Zone & Hub, September 2021

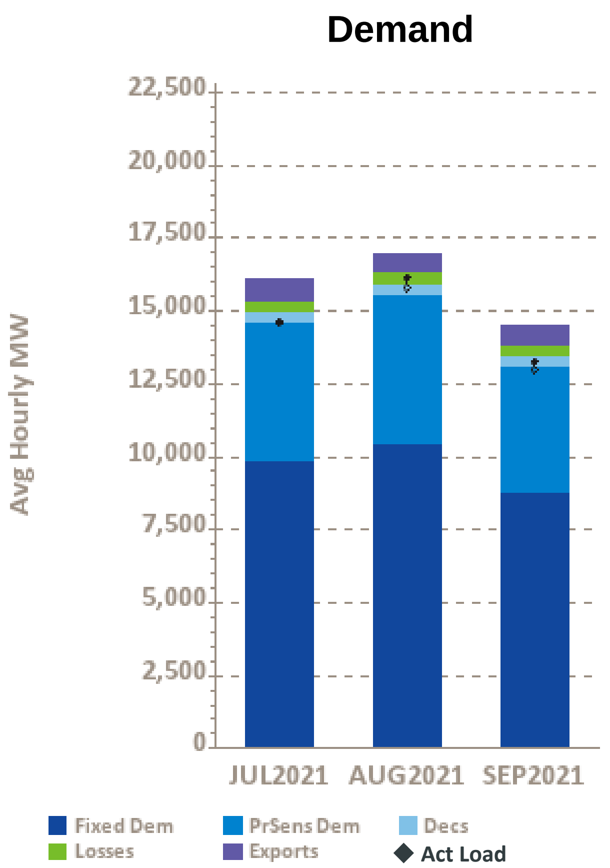


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

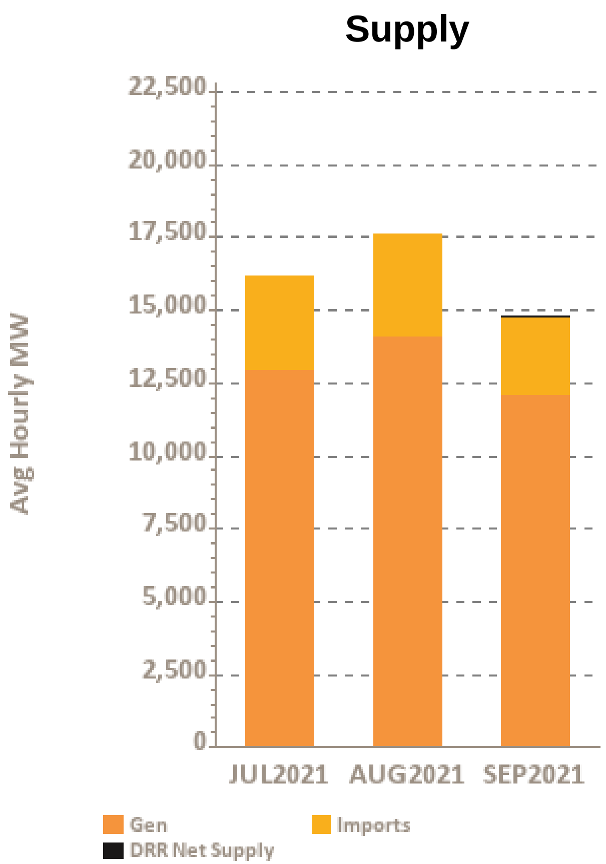


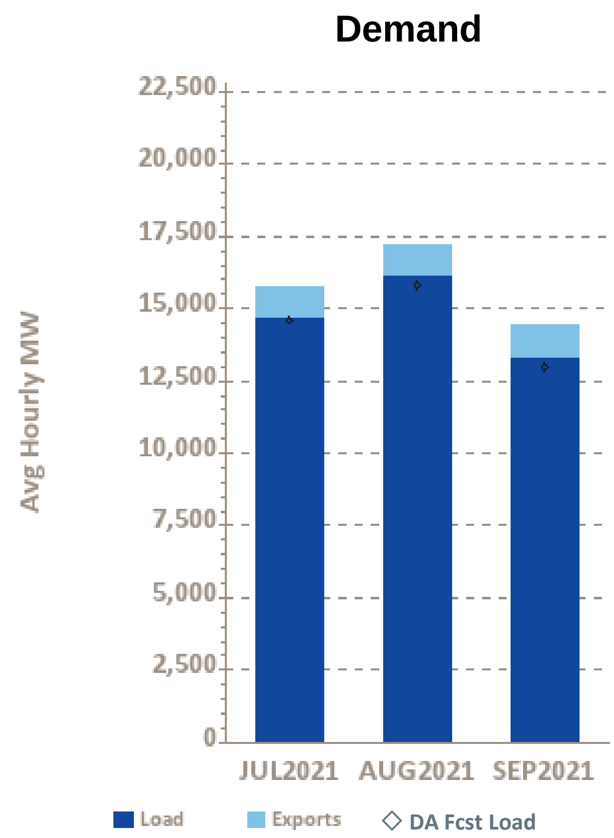


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

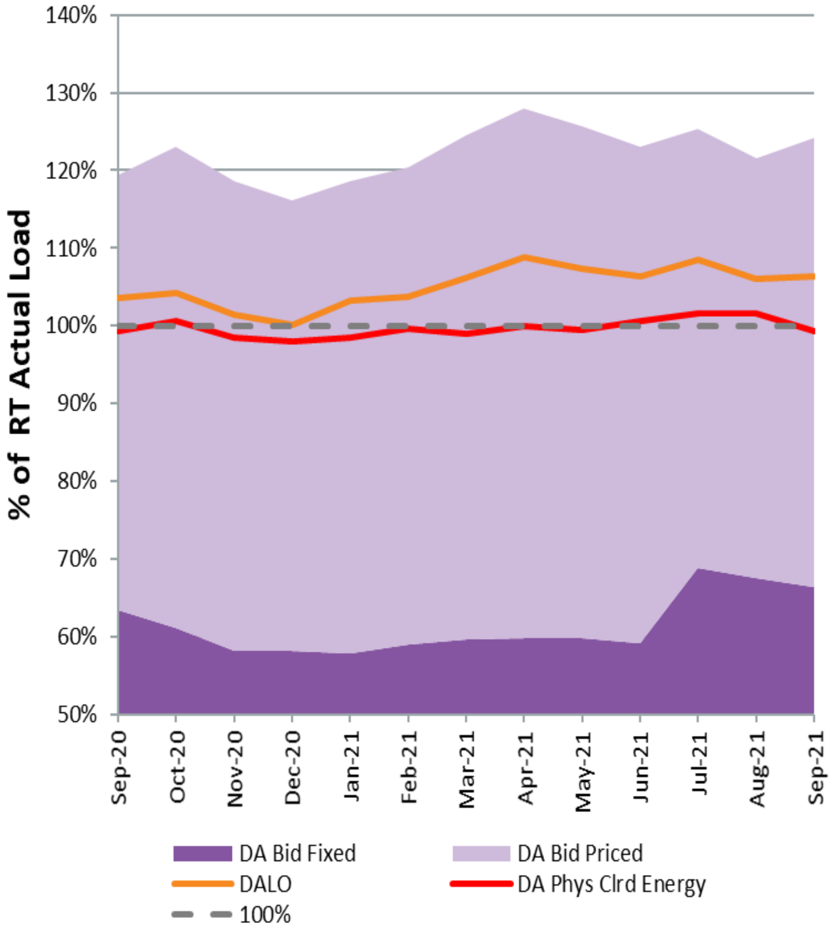
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

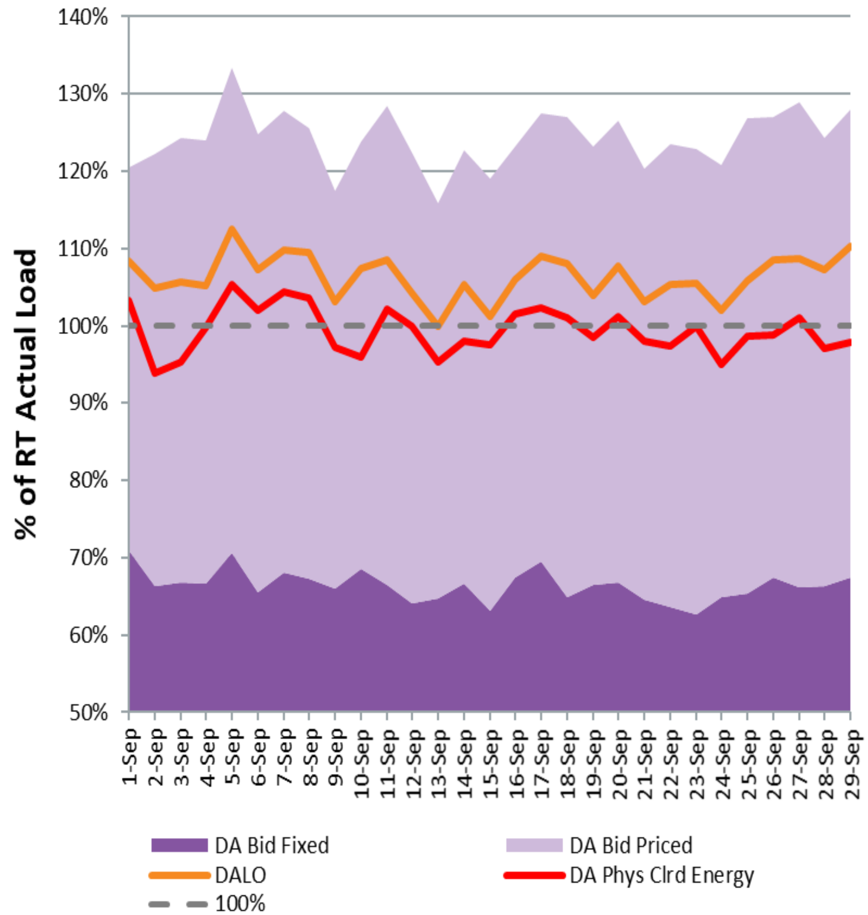
Components of RT Supply and Demand – Last Three Months





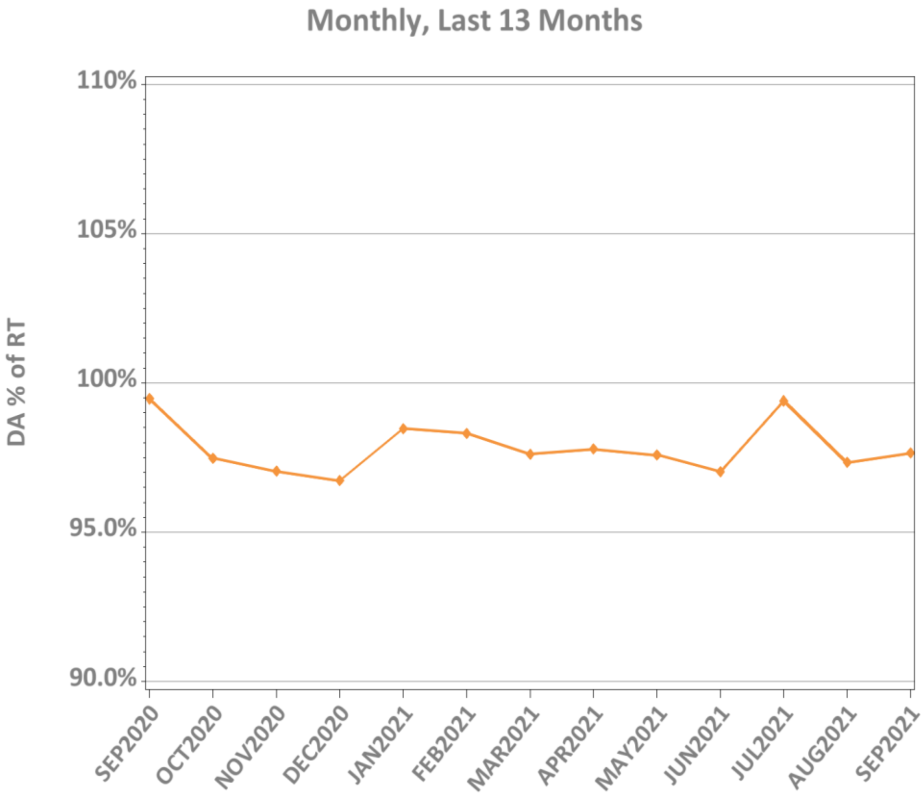
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

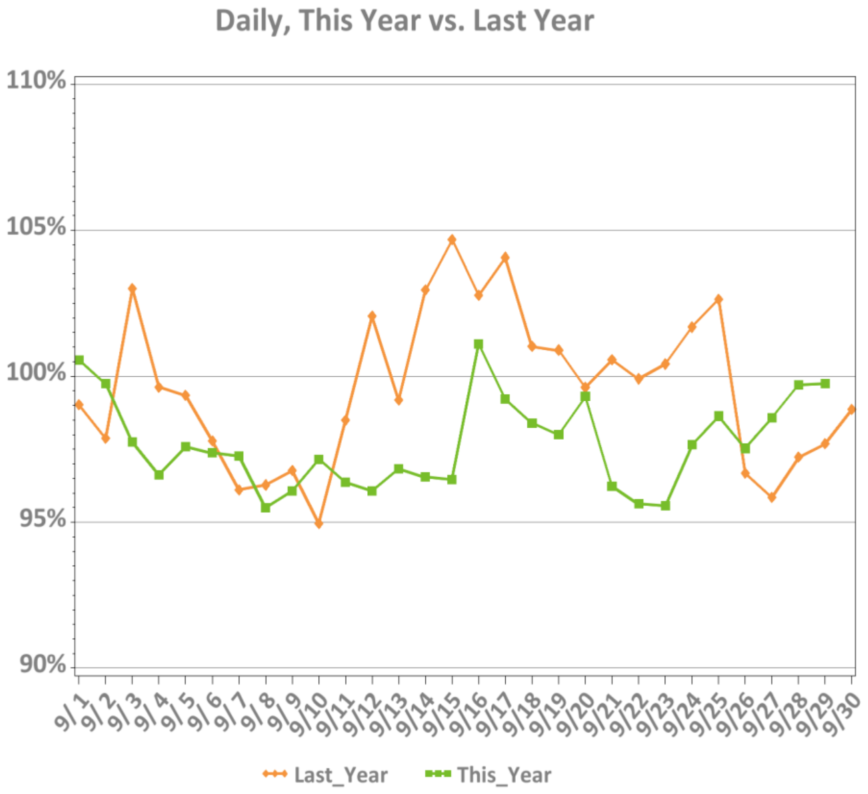




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

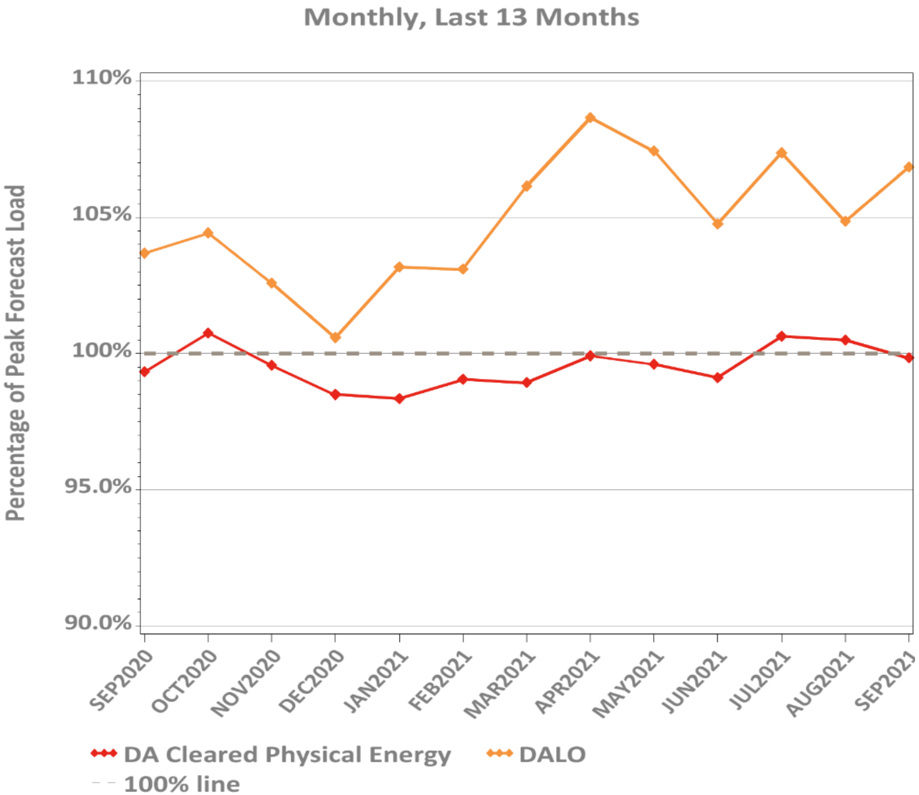
DA vs. RT Load Obligation: September, This Year vs. Last Year

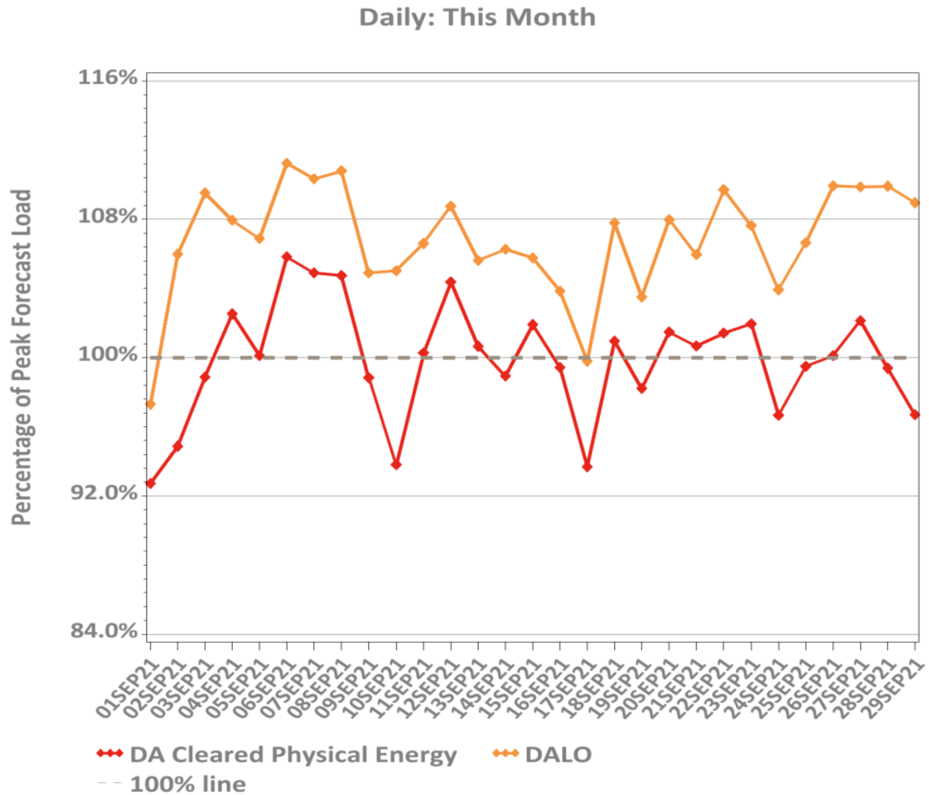




*Hourly average values

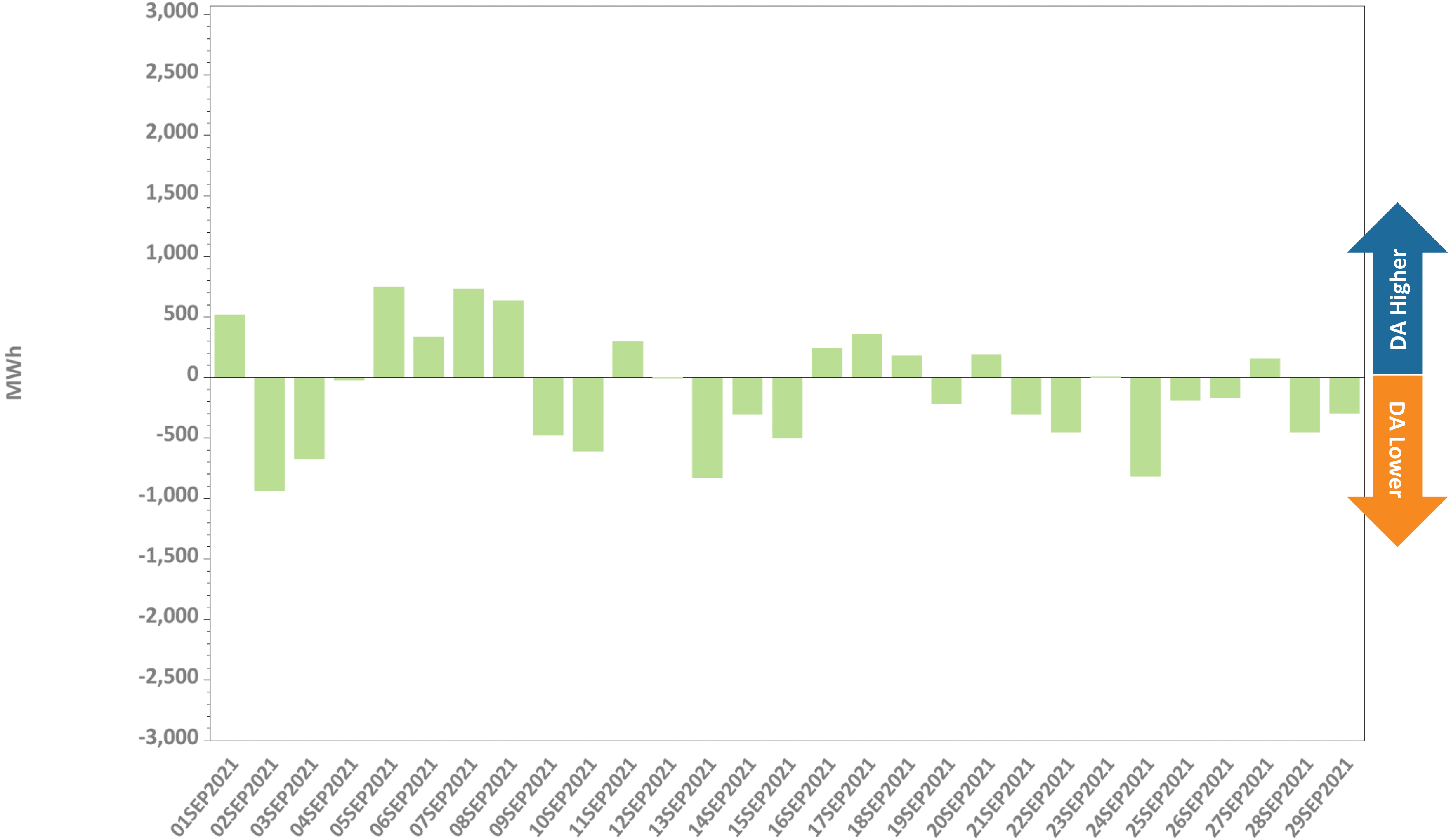
DA Volumes as % of Forecast in Peak Hour





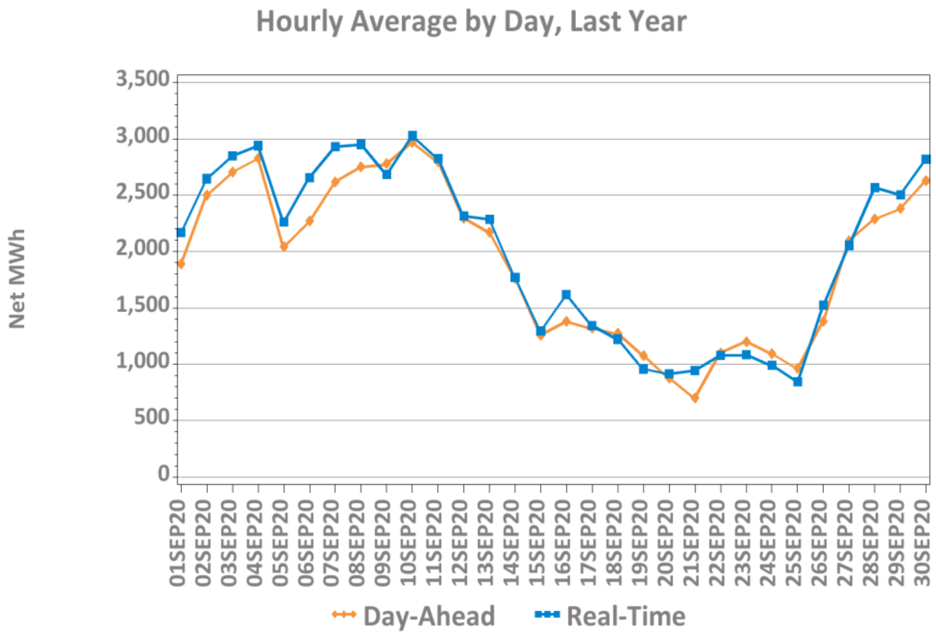
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during the month.

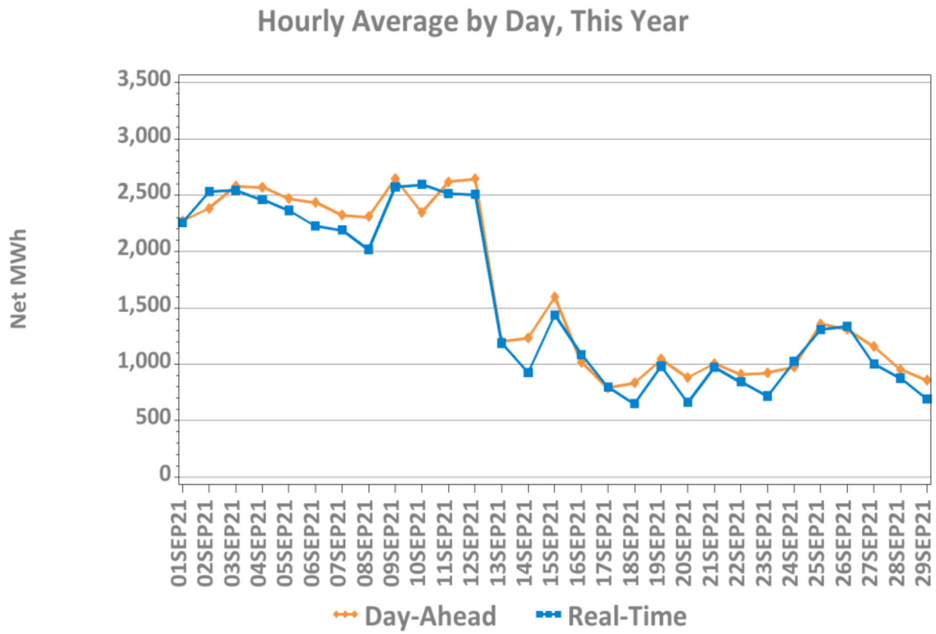
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

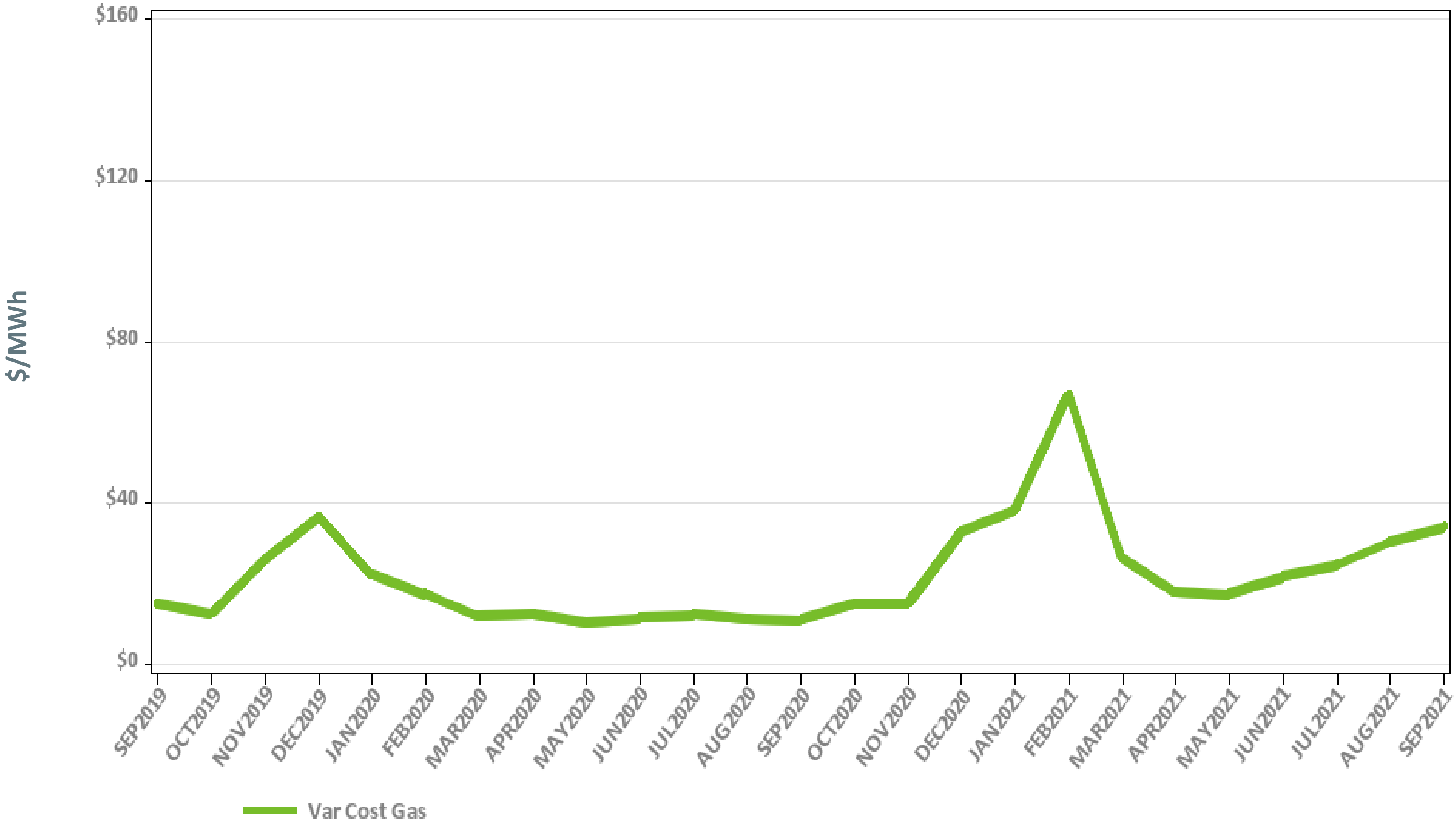
DA vs. RT Net Interchange September 2020 vs. September 2021





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

Variable Production Cost of Natural Gas: Monthly

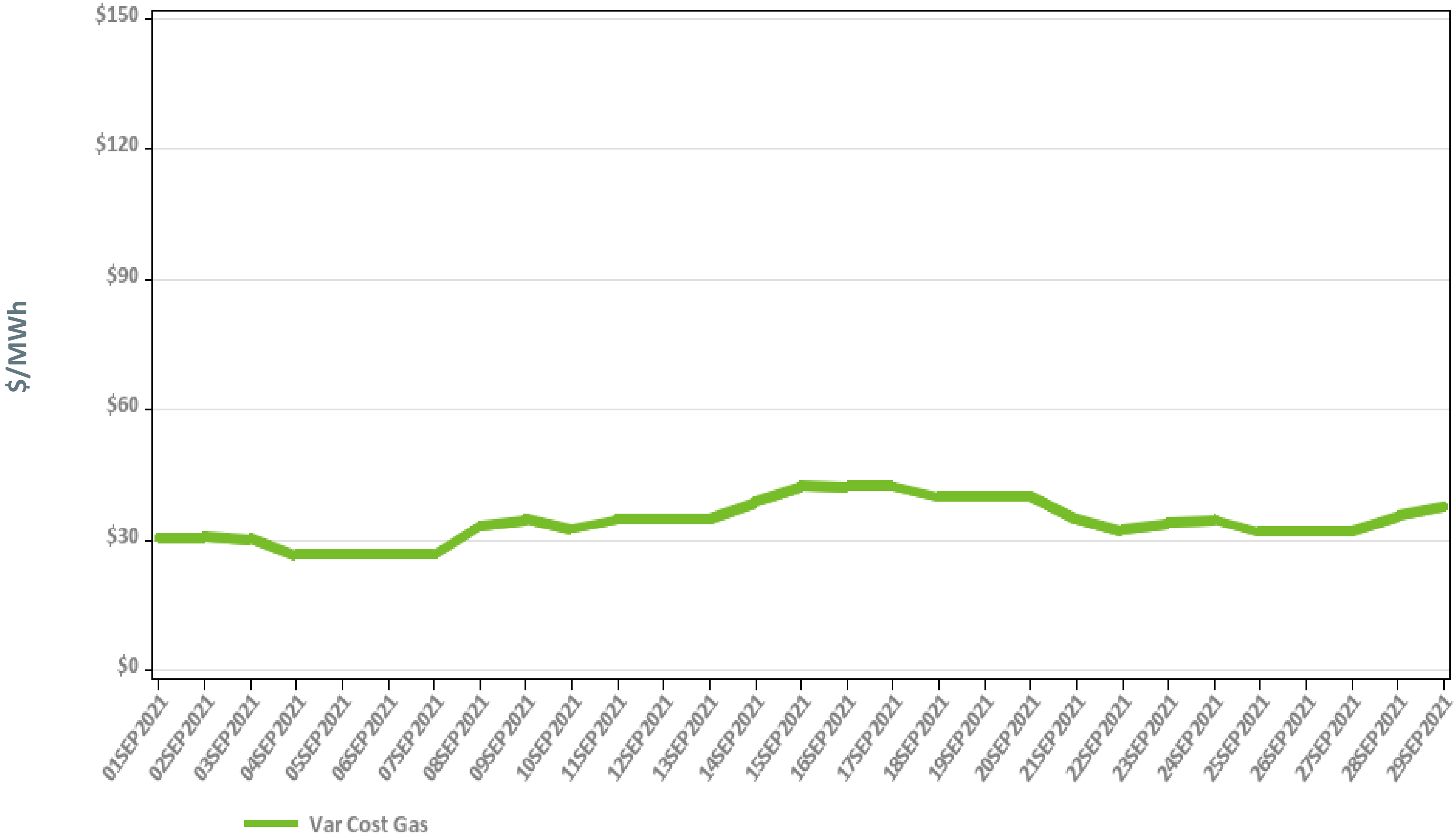


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

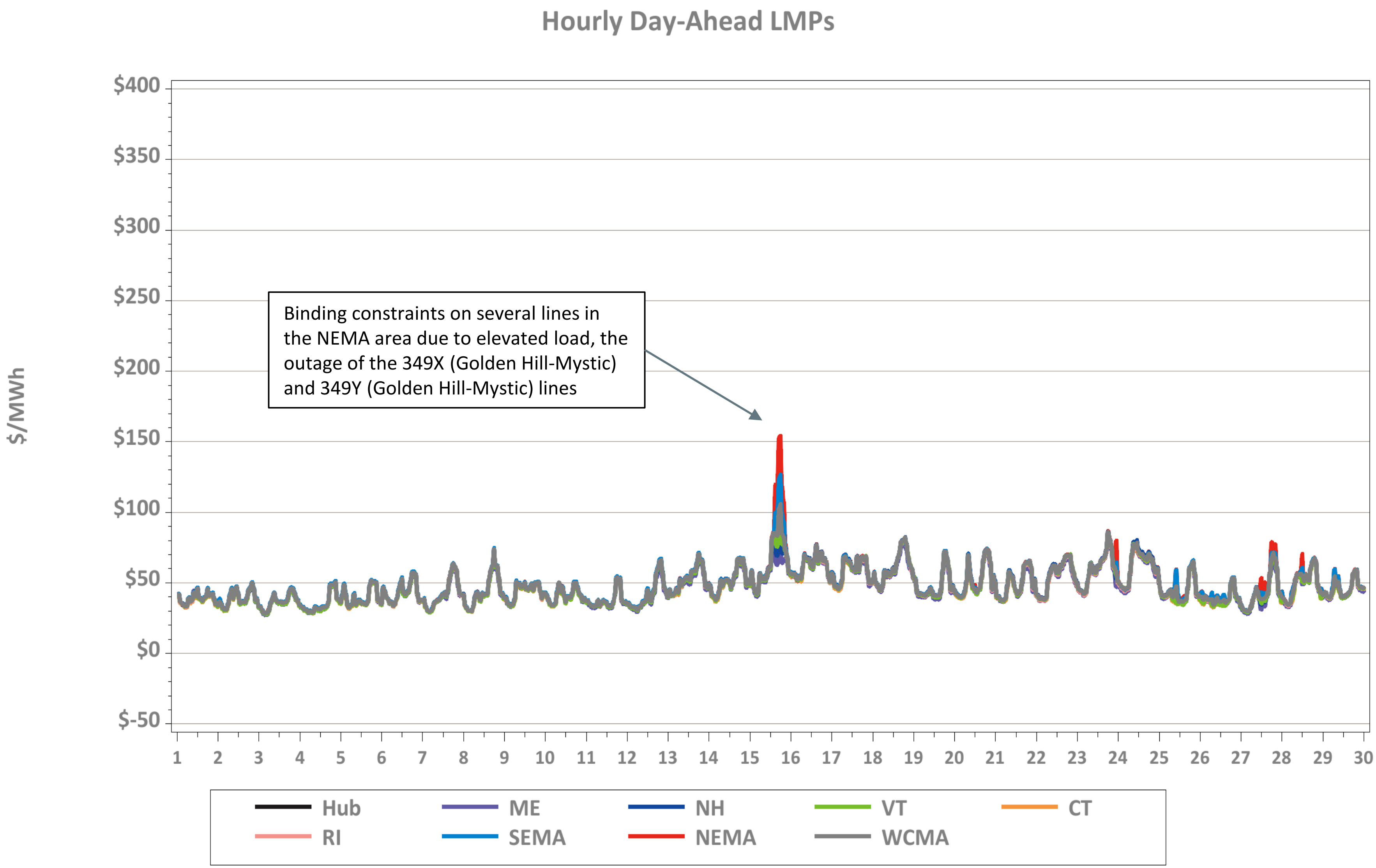


Underlying natural gas data furnished by:

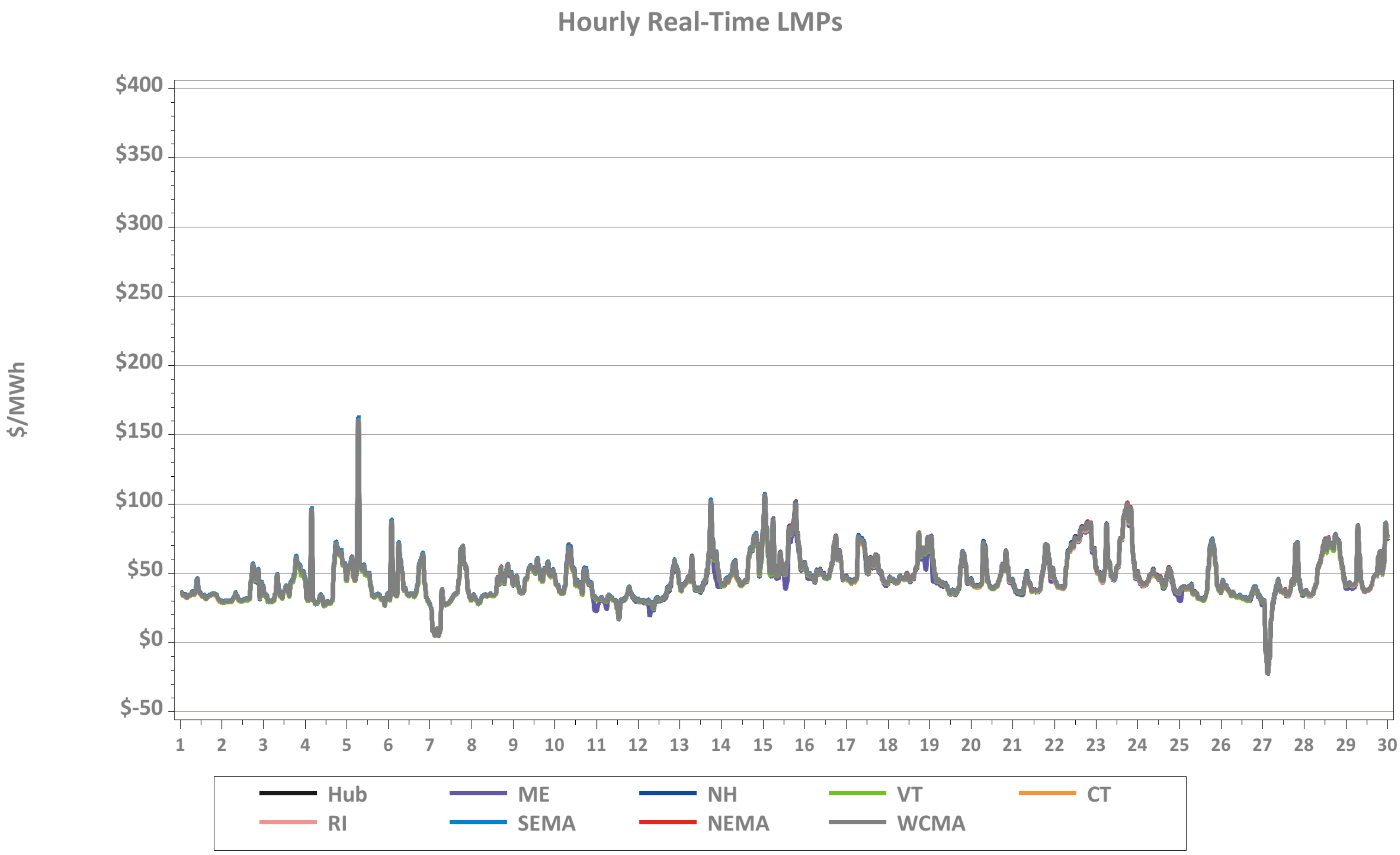
ICE Global markets in clear view

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

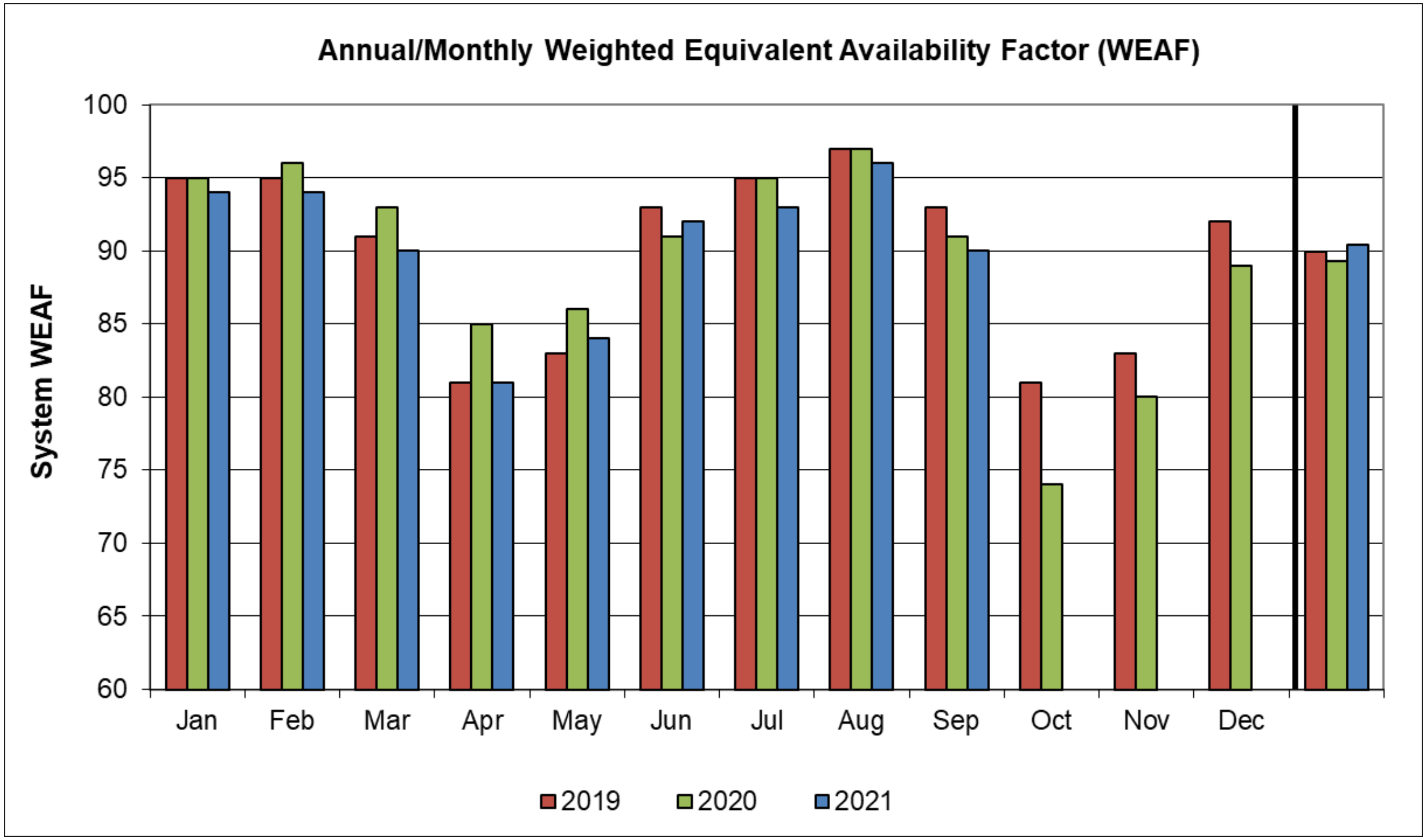
Hourly DA LMPs, September 1-29, 2021



Hourly RT LMPs, September 1-29, 2021



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2021	94	94	90	81	84	92	93	96	90				90
2020	95	96	93	85	86	91	95	97	91	74	80	89	89
2019	95	95	91	81	83	93	95	97	93	81	83	92	90

Data as of 9/28/2021

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for October 2021

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	85.4	202.5	0.0	287.9
NH	40.3	147.6	0.0	187.9
VT	38.1	125.6	0.0	163.7
CT	139.3	120.1	614.8	874.3
RI	39.2	323.4	0.0	362.6
SEMA	44.3	506.9	0.0	551.2
WCMA	84.1	539.3	39.6	663.0
NEMA	60.7	860.7	0.0	921.4
Total	**531.4**	**2,826.0**	**654.4**	**4,011.8**

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

NEW GENERATION

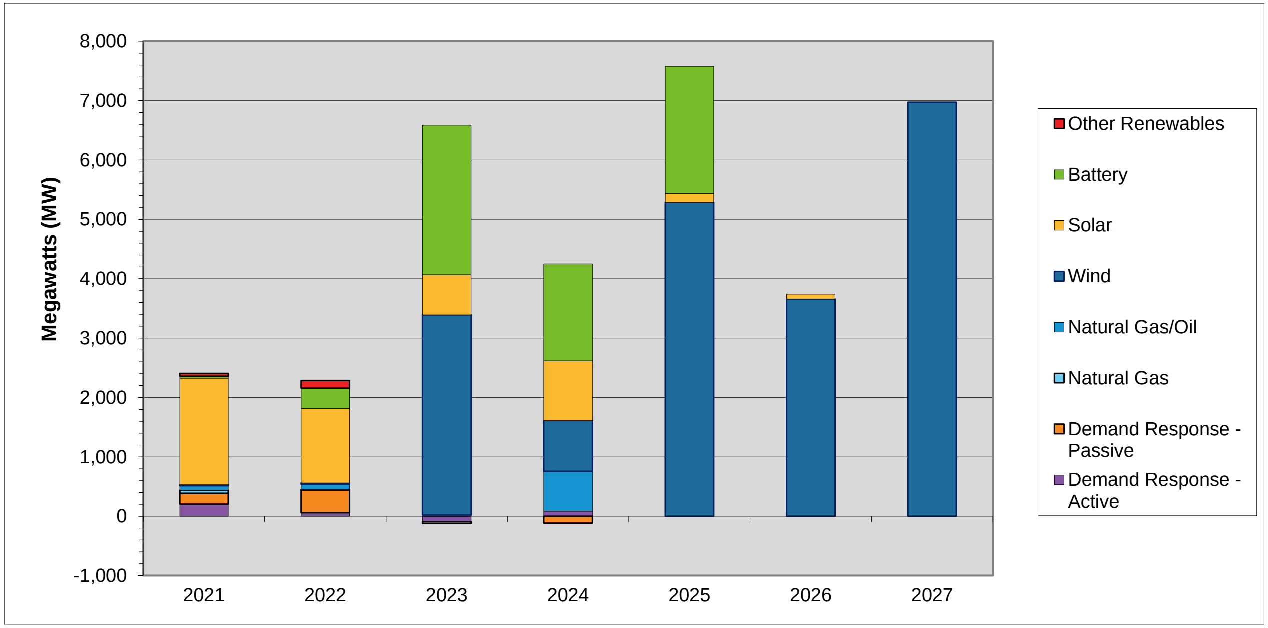
New Generation Update

Based on Queue as of 10/01/21

- Four new projects totaling 325 MW applied for interconnection study since the last update
  - They consist of one battery and three solar with battery projects with in-service dates ranging from 2022 to 2023
- One project went commercial and five projects were withdrawn
- In total, 294 generation projects are currently being tracked by the ISO, totaling approximately 32,907 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



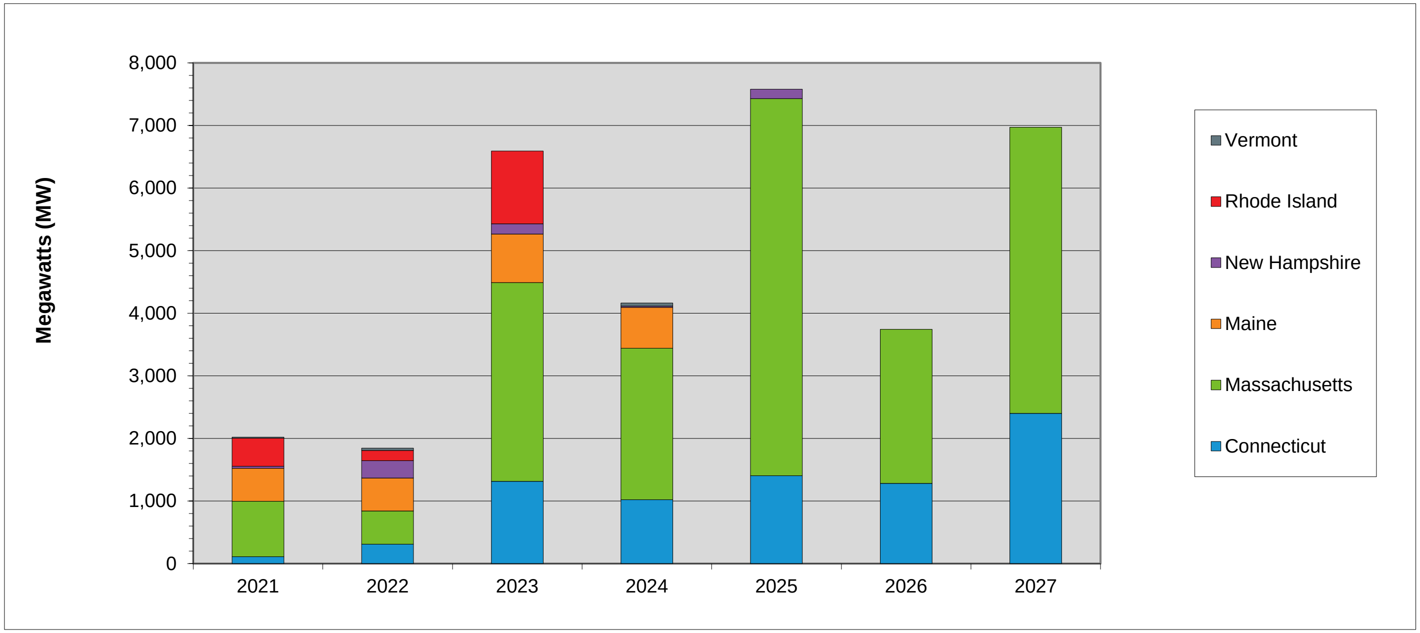
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	48	128	0	0	0	0	0	176	0.5
Battery	34	347	2,524	1,630	2,140	0	0	6,675	19.9
Solar[2]	1,792	1,251	675	1,010	150	83	0	4,961	14.8
Wind	19	20	3,367	852	5,287	3,658	6,972	20,175	60.1
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	2.6
Natural Gas	49	11	0	0	0	0	0	60	0.2
Demand Response - Passive	184	380	-28	-114	0	0	0	422	1.3
Demand Response - Active	204	62	-94	86	0	0	0	258	0.8
Totals	**2,406**	**2,288**	**6,467**	**4,136**	**7,577**	**3,741**	**6,972**	**33,587**	**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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.3
Rhode Island	450	160	1,161	0	0	0	0	1,771	5.4
New Hampshire	30	281	164	20	150	0	0	645	2.0
Maine	526	523	774	652	0	0	0	2,475	7.5
Massachusetts	888	532	3,178	2,421	6,022	2,458	4,572	20,071	61.0
Connecticut	109	310	1,312	1,021	1,405	1,283	2,400	7,840	23.8
Totals	**2,018**	**1,846**	**6,589**	**4,164**	**7,577**	**3,741**	**6,972**	**32,907**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	37	6,675	0	0	37	6,675
Fuel Cell	3	40	1	10	2	30
Hydro	3	99	2	71	1	28
Natural Gas	6	60	0	0	6	60
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	207	4,961	19	316	188	4,645
Wind	30	20,175	1	15	29	20,160
Total	294	32,907	24	426	270	32,481

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	110	2	15	4	95
Intermediate	8	818	1	14	7	804
Peaker	250	11,804	20	382	230	11,422
Wind Turbine	30	20,175	1	15	29	20,160
Total	294	32,907	24	426	270	32,481

- 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	0	0	0	0	0	0	0	0	0	0
Battery Storage	37	6,675	0	0	0	0	37	6,675	0	0
Fuel Cell	3	40	3	40	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	6	60	0	0	3	43	3	17	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	207	4,961	0	0	0	0	207	4,961	0	0
Wind	30	20,175	0	0	0	0	0	0	30	20,175
Total	294	32,907	6	110	8	818	250	11,804	30	20,175

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation (CSO) FCA 12

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445	659.137	34.692	603.776	-55.361	587.270	-16.506
	Passive Demand	2,975.36	3,045.073	69.713	3,123.232	78.159	3,322.722	199.490
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**3,727.008**	**22.798**	**3,909.992**	**182.984**
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159	28,941.276	321.031
	Intermittent	880.317	806.609	-73.708	660.932	-145.677	663.179	2.247
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**	**29,604.455**	**323.278**
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**	**1207.78**	**-99.807**
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**	**34,722.227**	**406.455**
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,230**	**-1,320**	**32,925**	**695**

* 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.

ARA – Annual Reconfiguration Auction
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

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	658.659	-24.457		
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392		
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**		
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07		
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387		
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**		
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**		
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**		
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**		

* 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	688.07	96.027				
	Passive Demand	3,327.071	3,327.932	0.861				
Demand Total		**3,919.114**	**4,016.002**	**96.888**				
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241				
	Intermittent	1,160.916	1,128.446	-32.47				
Generator Total		**28,977.818**	**29,403.589**	**425.771**				
Import Total		**1,058.72**	**1,058.72**	**0**				
Grand Total*		**33,955.652**	**34,478.311**	**522.661**				
Net ICR (NICR)		**32,490**	**32,980**	**490**				

* 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 15

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*	677.673						
	Passive Demand	3,212.865						
Demand Total		**3,890.538**						
Generator	*Non-Intermittent*	28,154.203						
	Intermittent	1,089.265						
Generator Total		**29,243.468**						
Import Total		**1,487.059**						
Grand Total*		**34,621.065**						
Net ICR (NICR)		**33,270**						

* 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**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**

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

What are Daily NCPC Payments?

- Payments made to resources whose commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output during the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

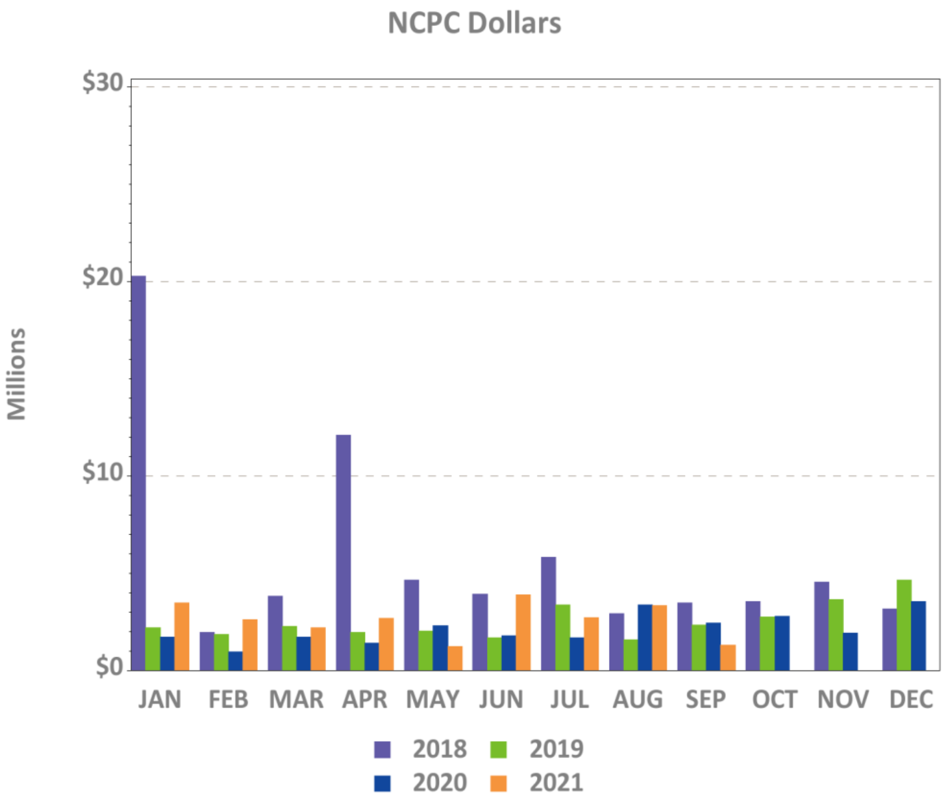
Definitions

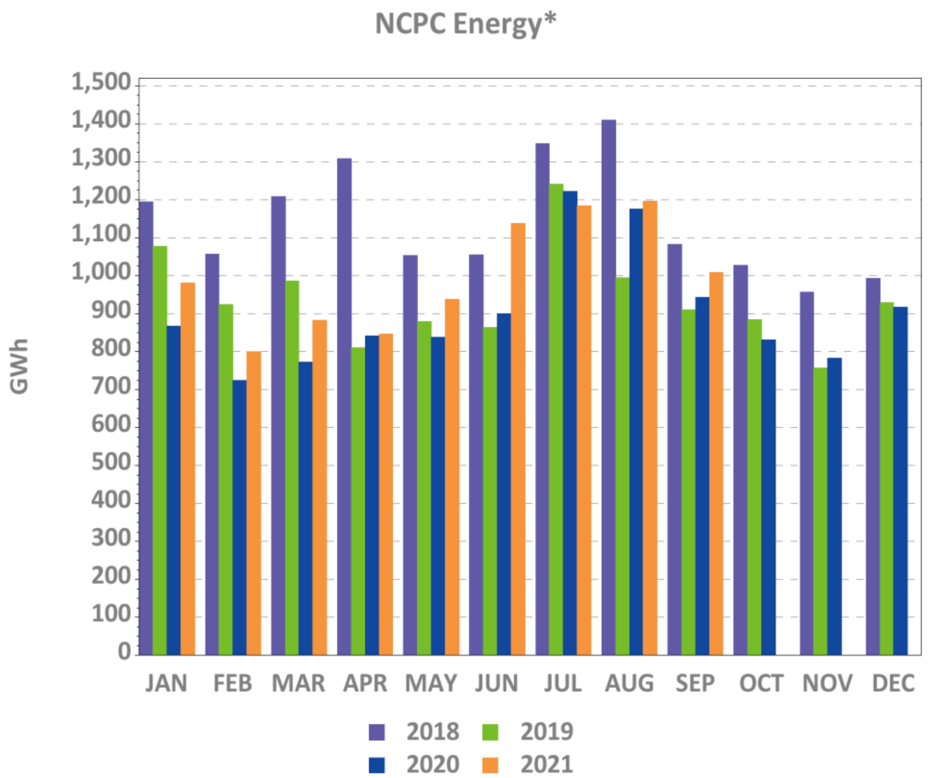
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
OATT	Open Access Transmission Tariff

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Economic Generator/DARD Posturing, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost NCPC (allocated to RTLO); and Min Generation Emergency NCPC (allocated to RTGO).

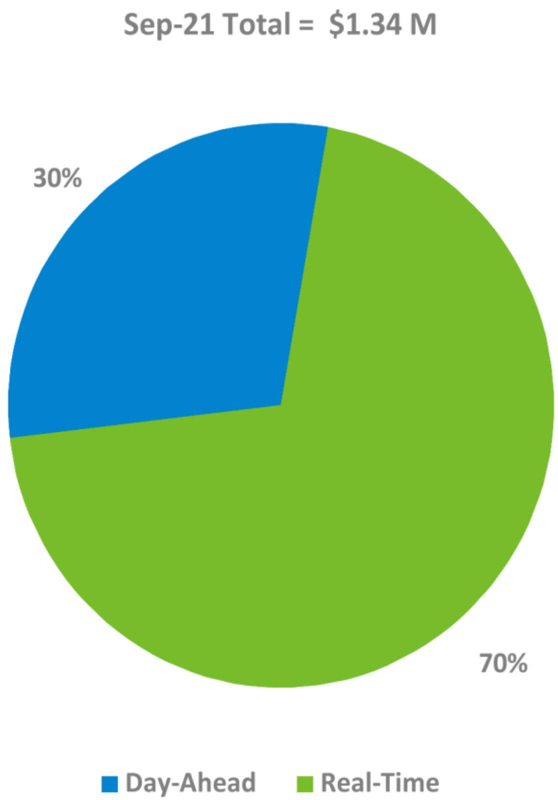
Year-Over-Year Total NCPC Dollars and Energy

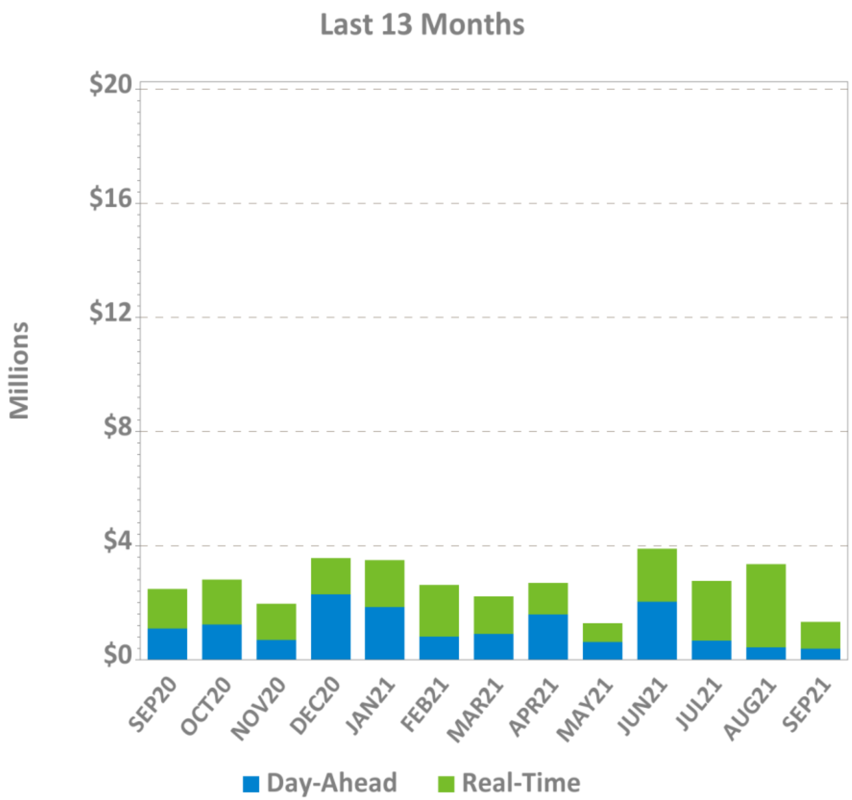




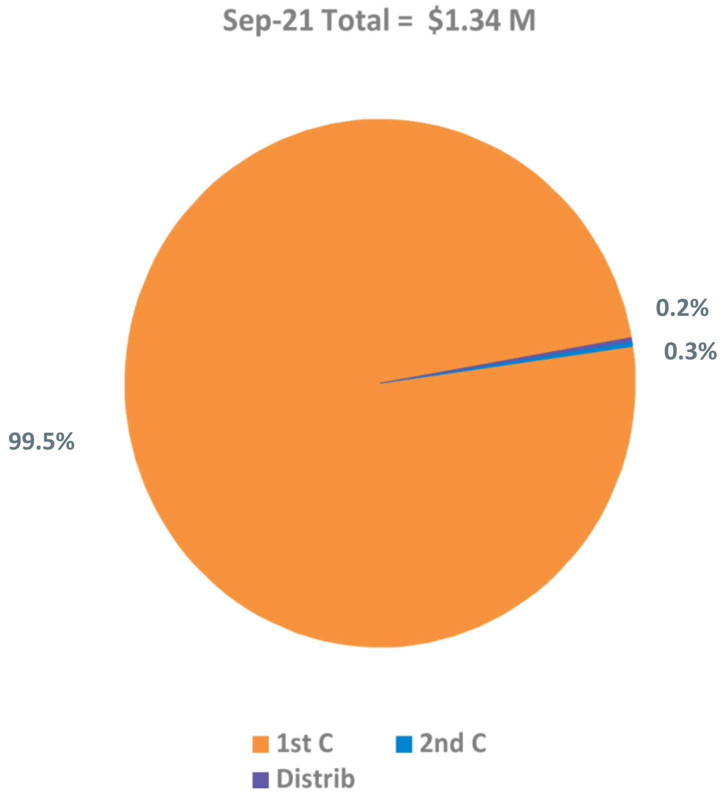
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

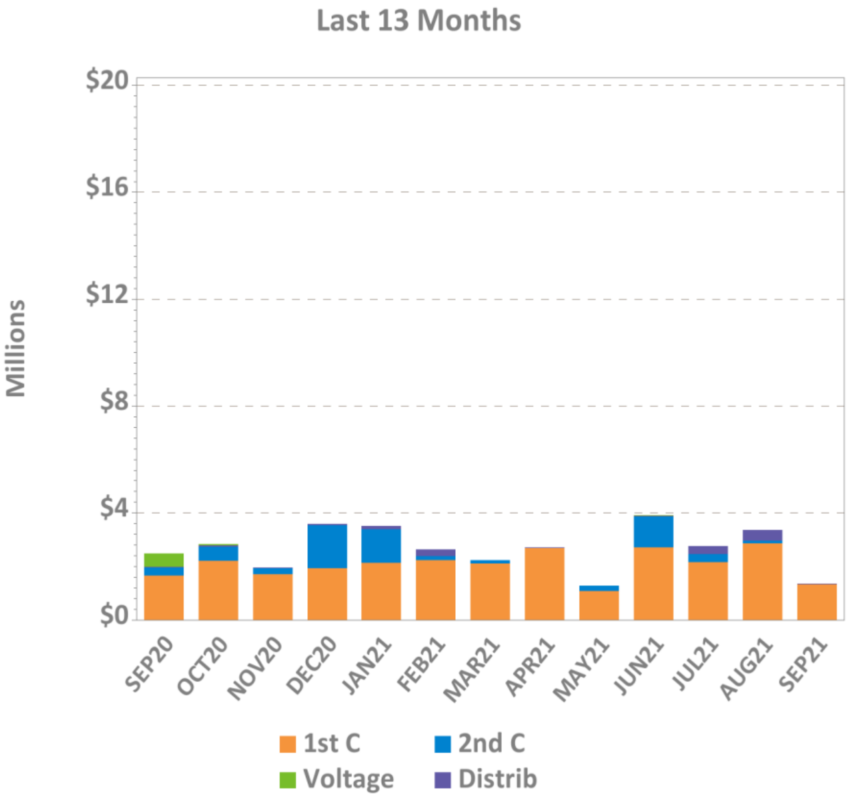
DA and RT NCPC Charges





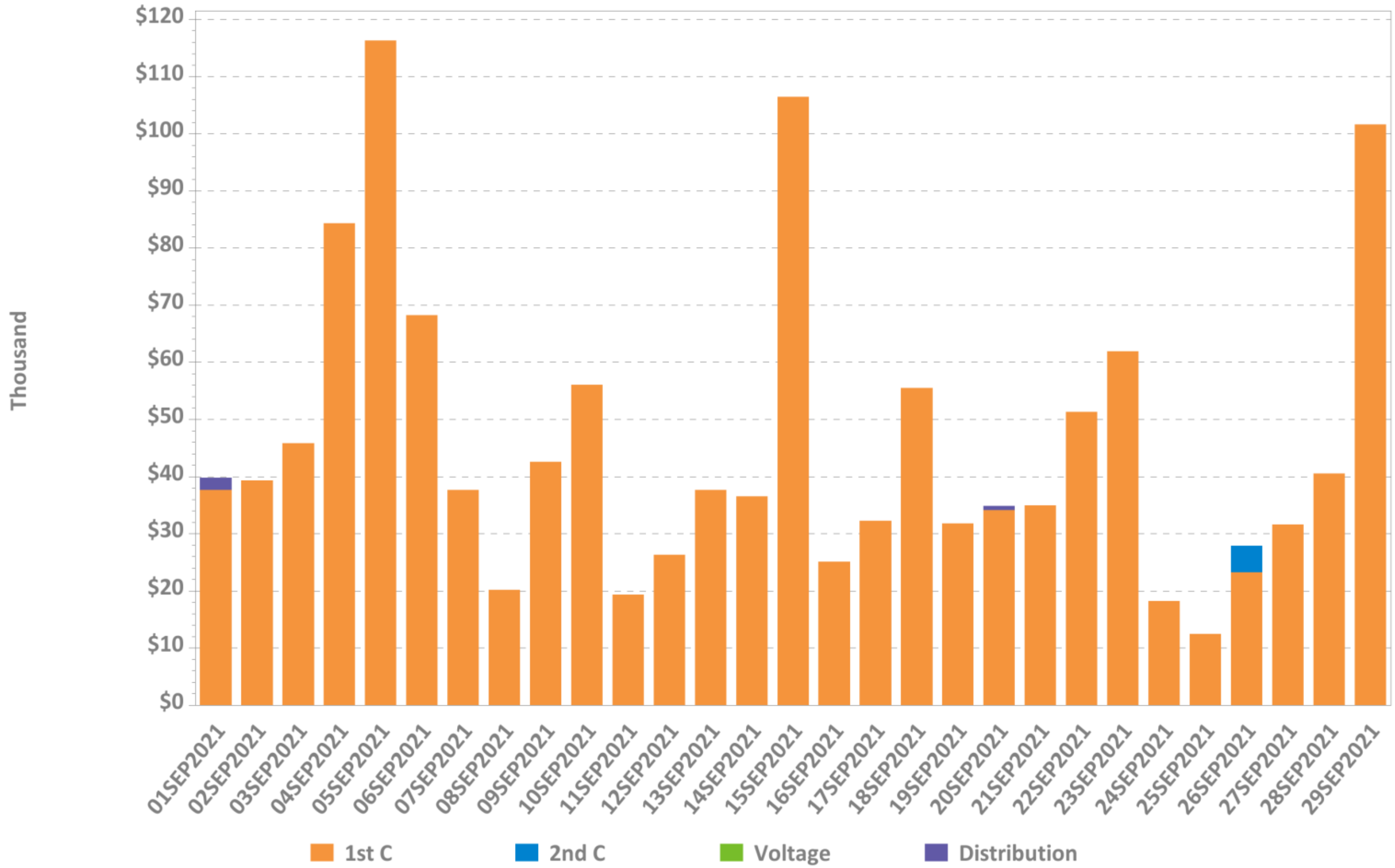
NCPC Charges by Type



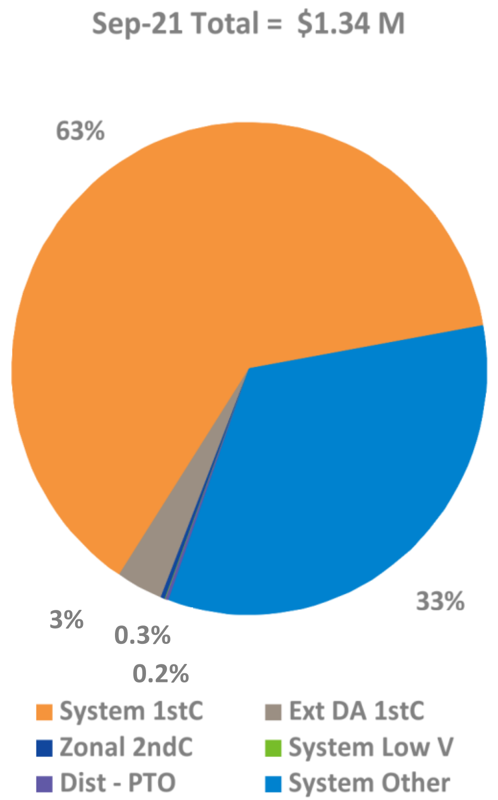


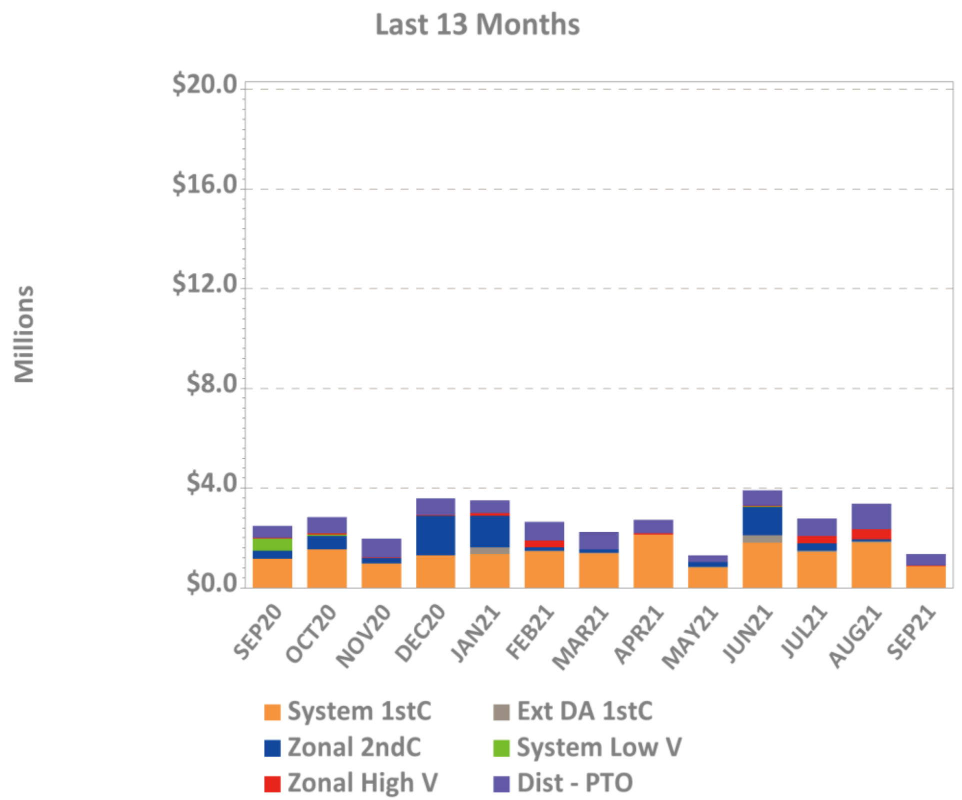
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



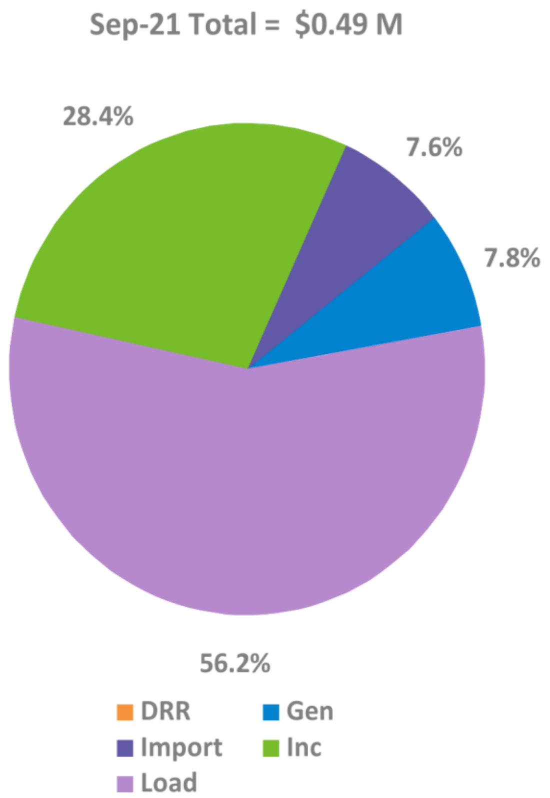
NCPC Charges by Allocation

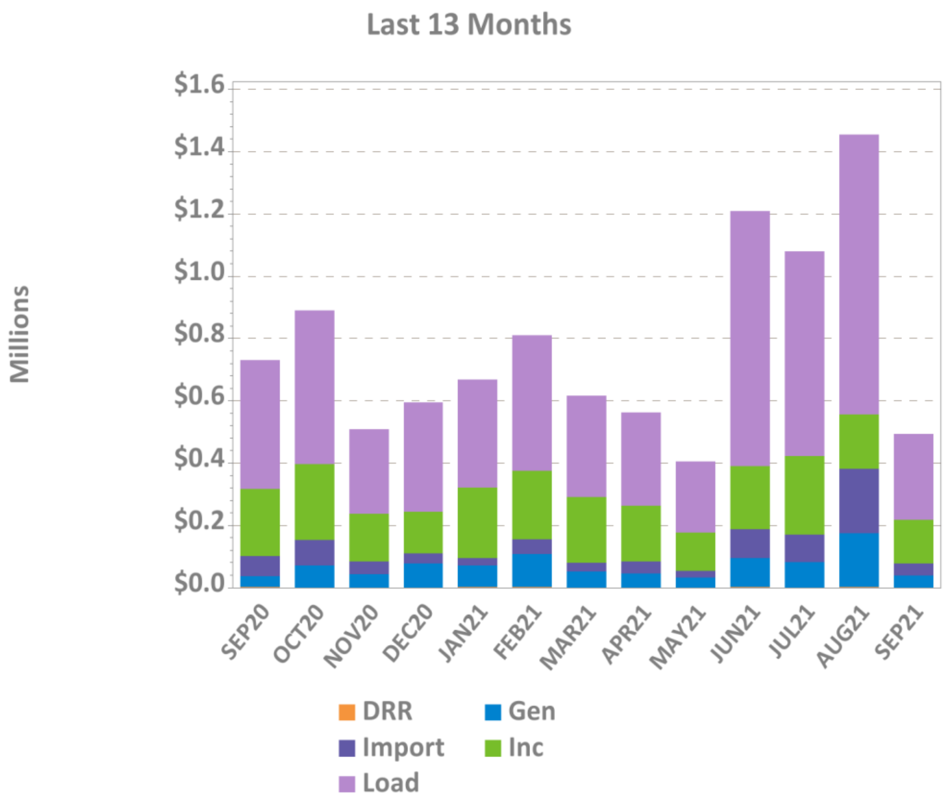




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

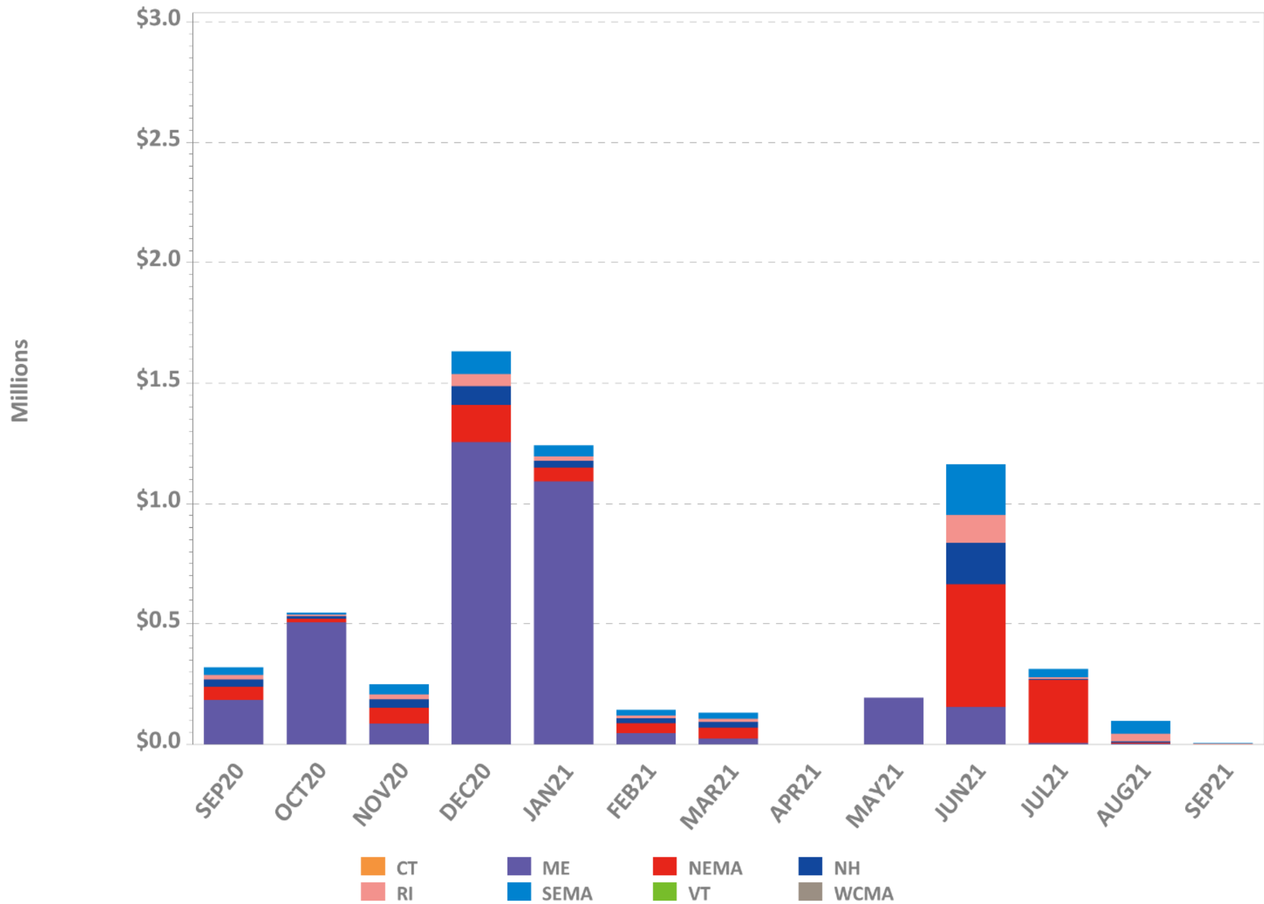
RT First Contingency Charges by Deviation Type





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

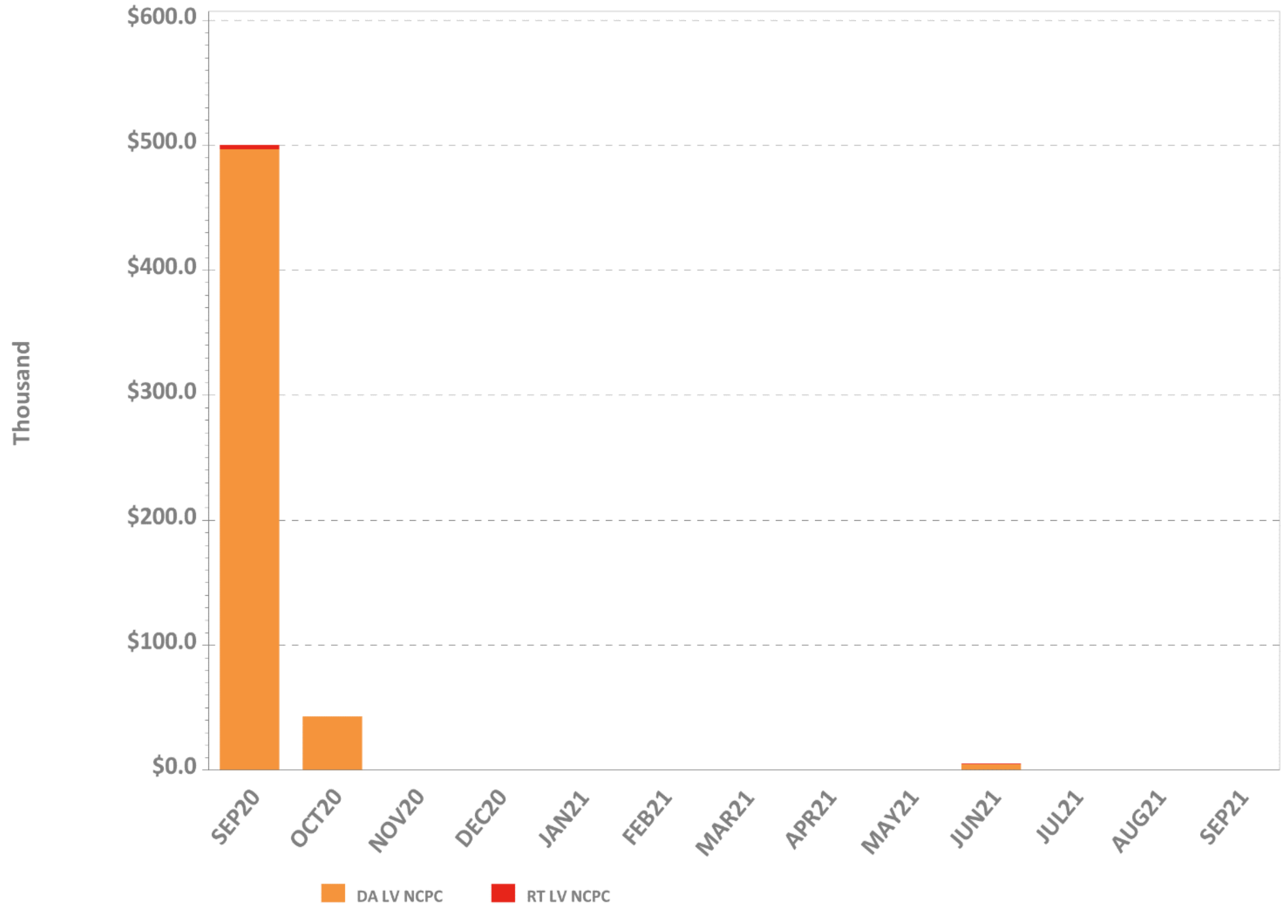
LSCPR Charges by Reliability Region



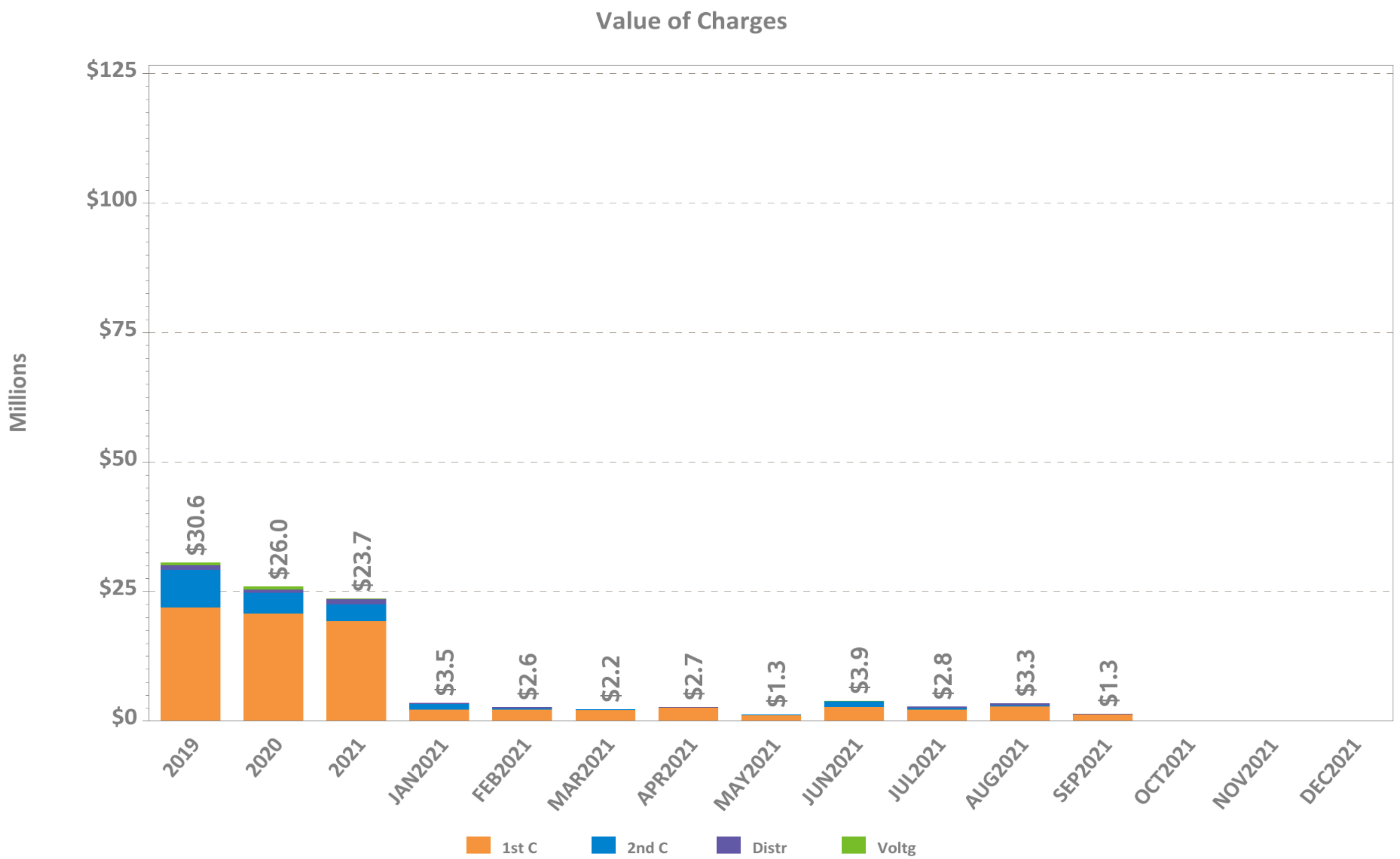
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

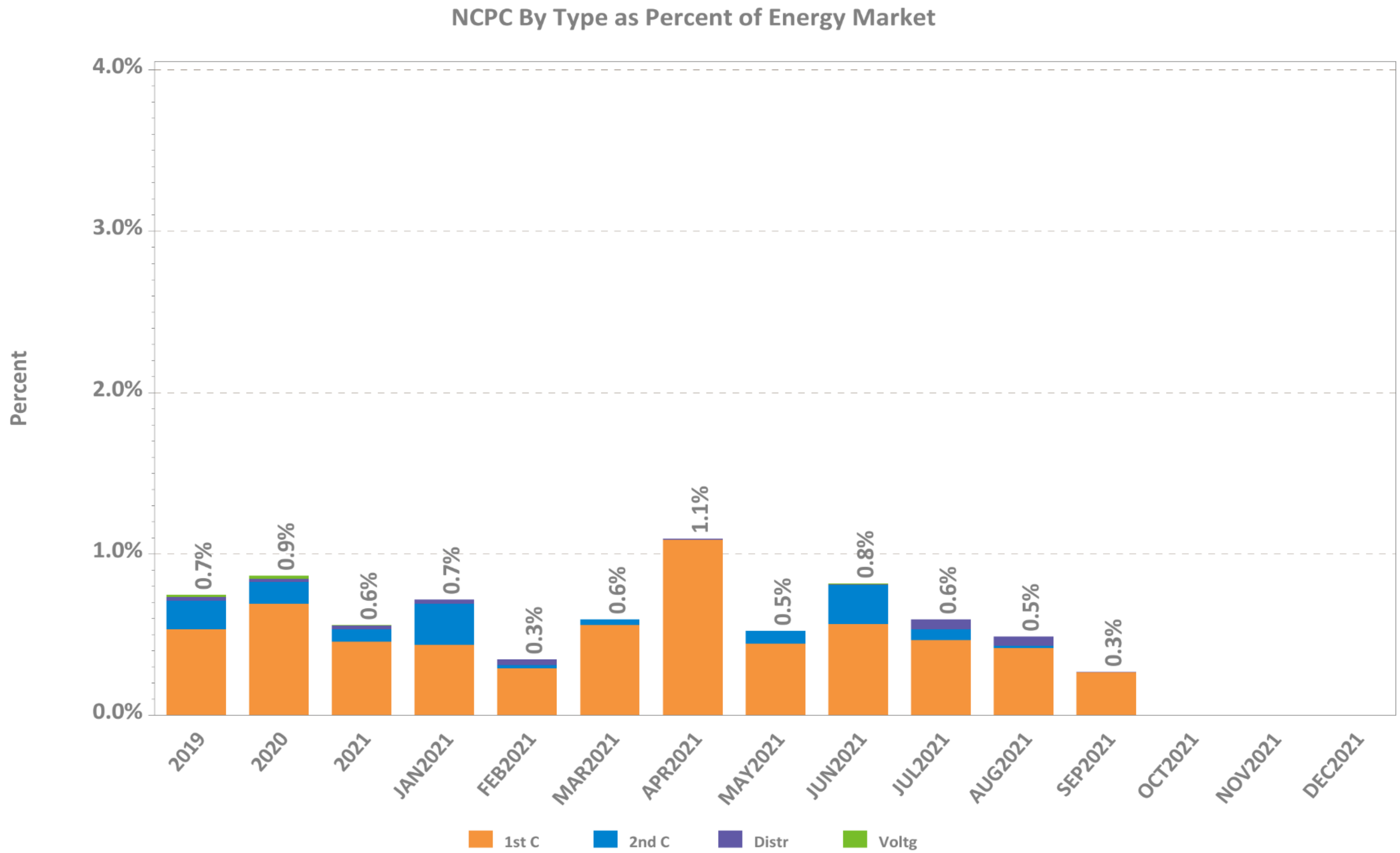
NCPC Charges for Voltage Support and High Voltage Control



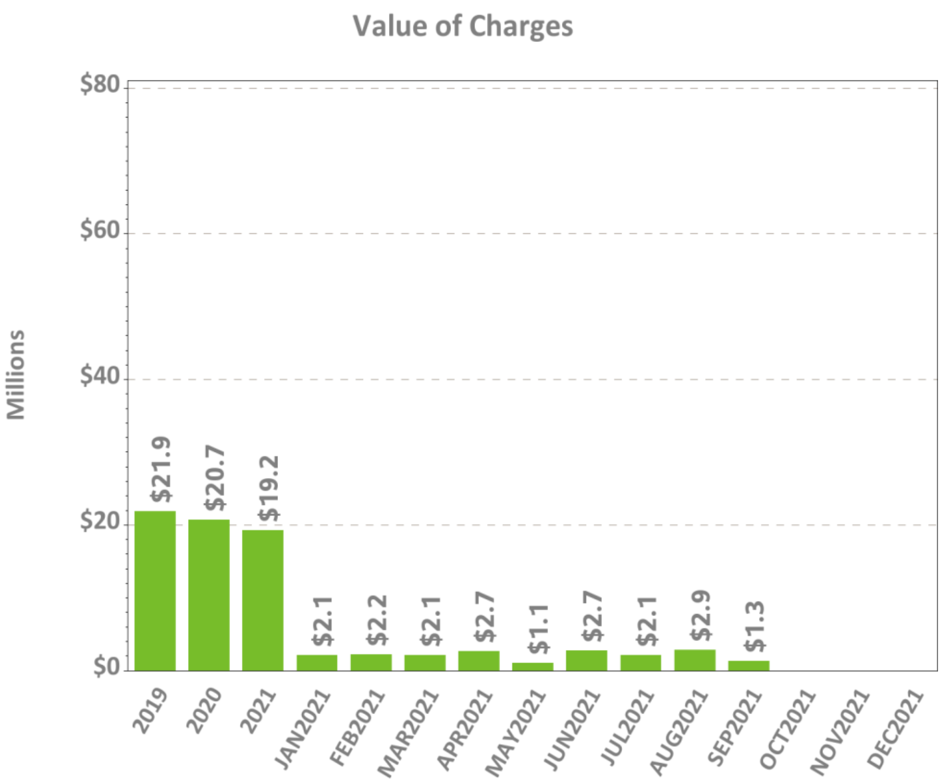
NCPC Charges by Type

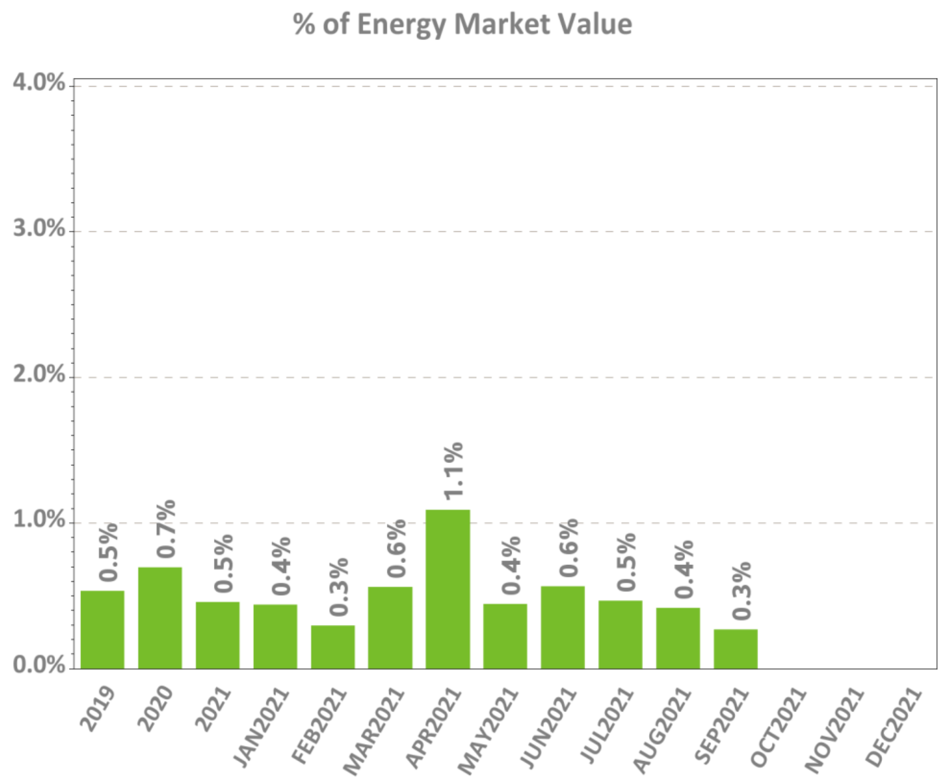


NCPC Charges as Percent of Energy Market



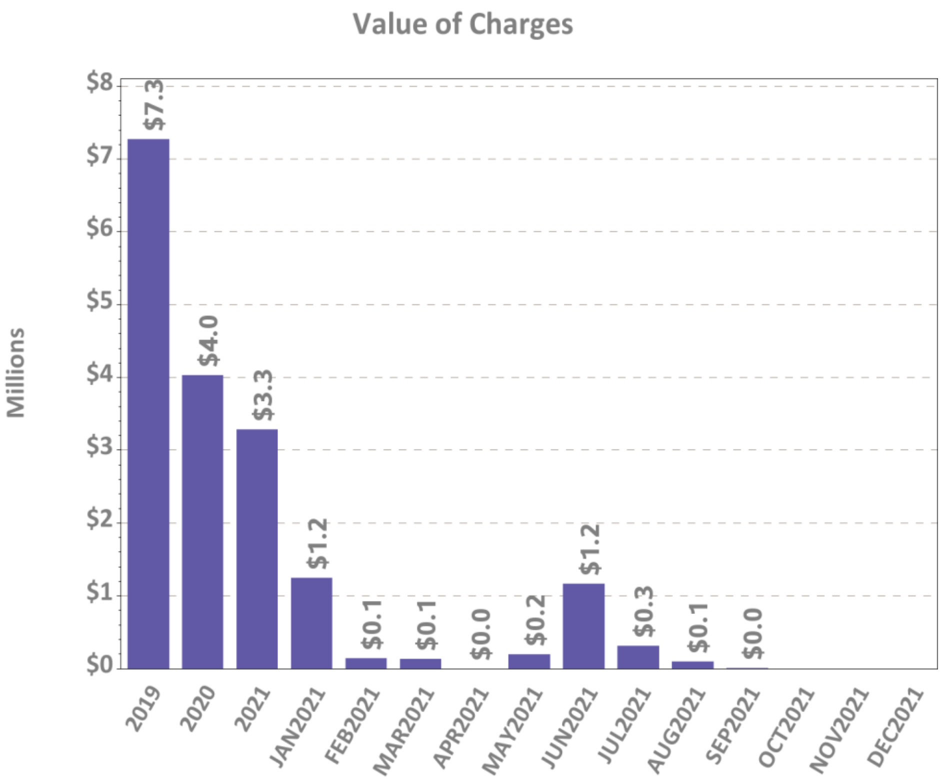
First Contingency NCPC Charges

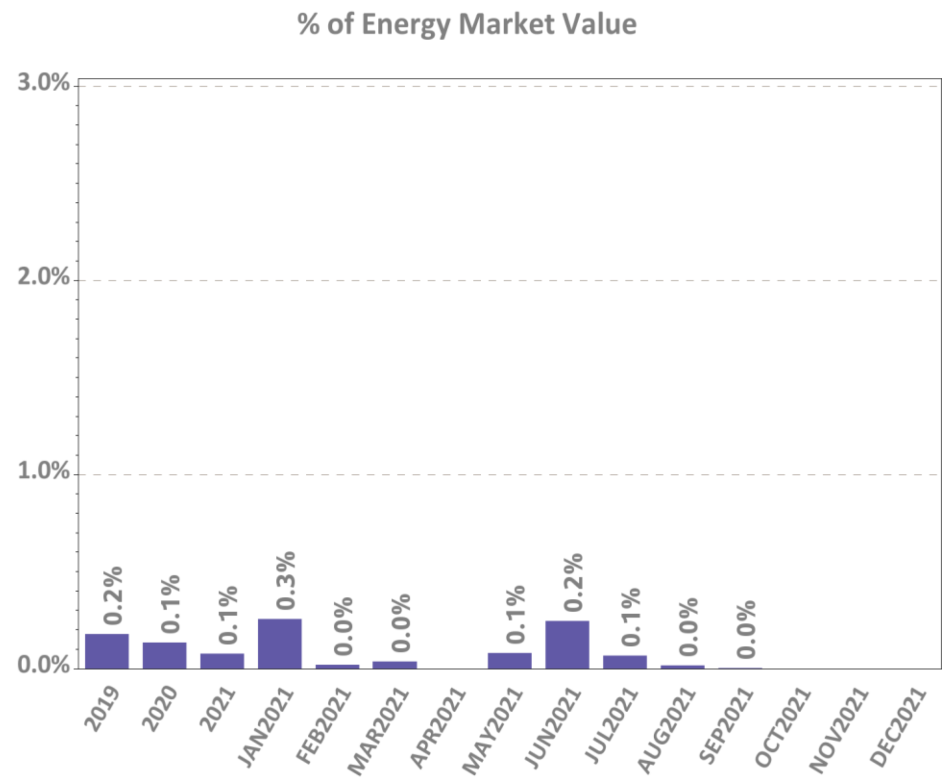




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

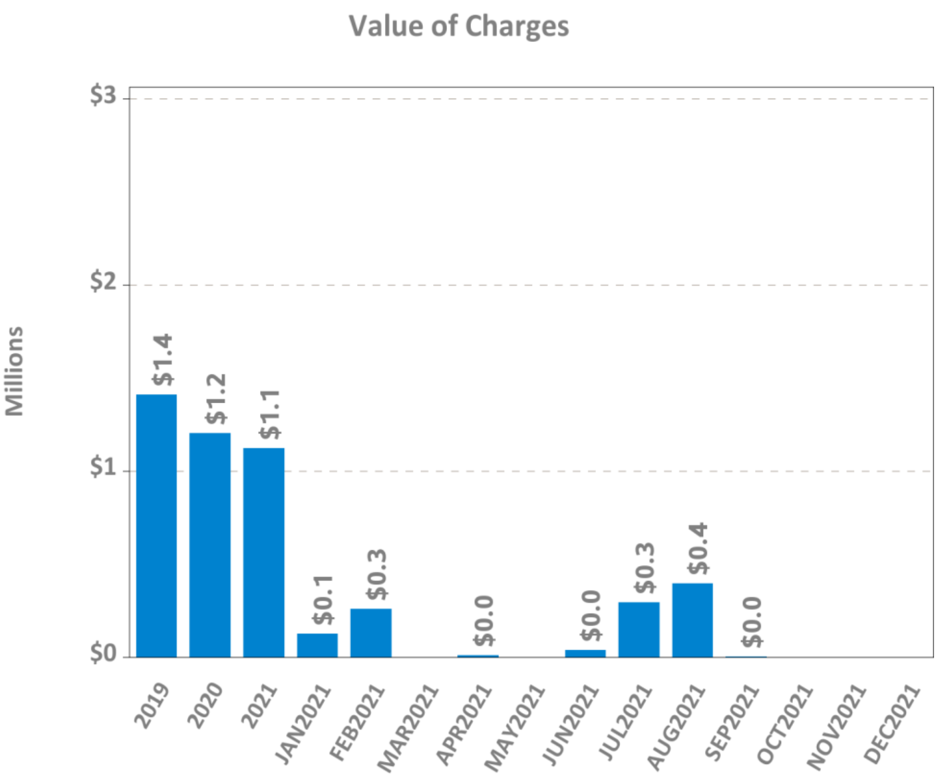
Second Contingency NCPC Charges

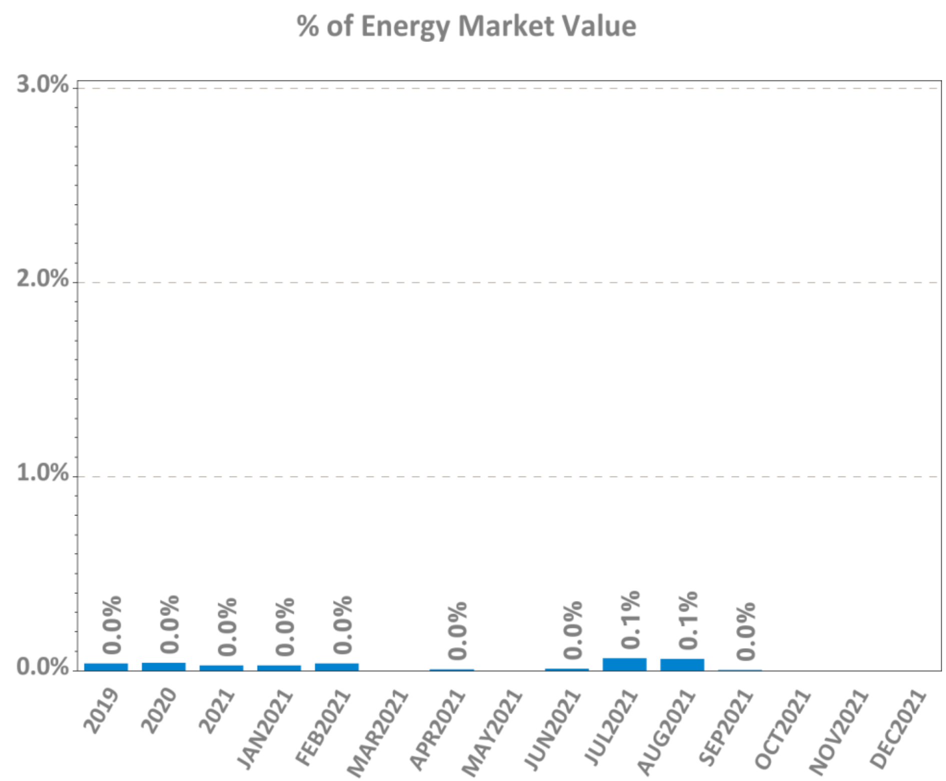




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

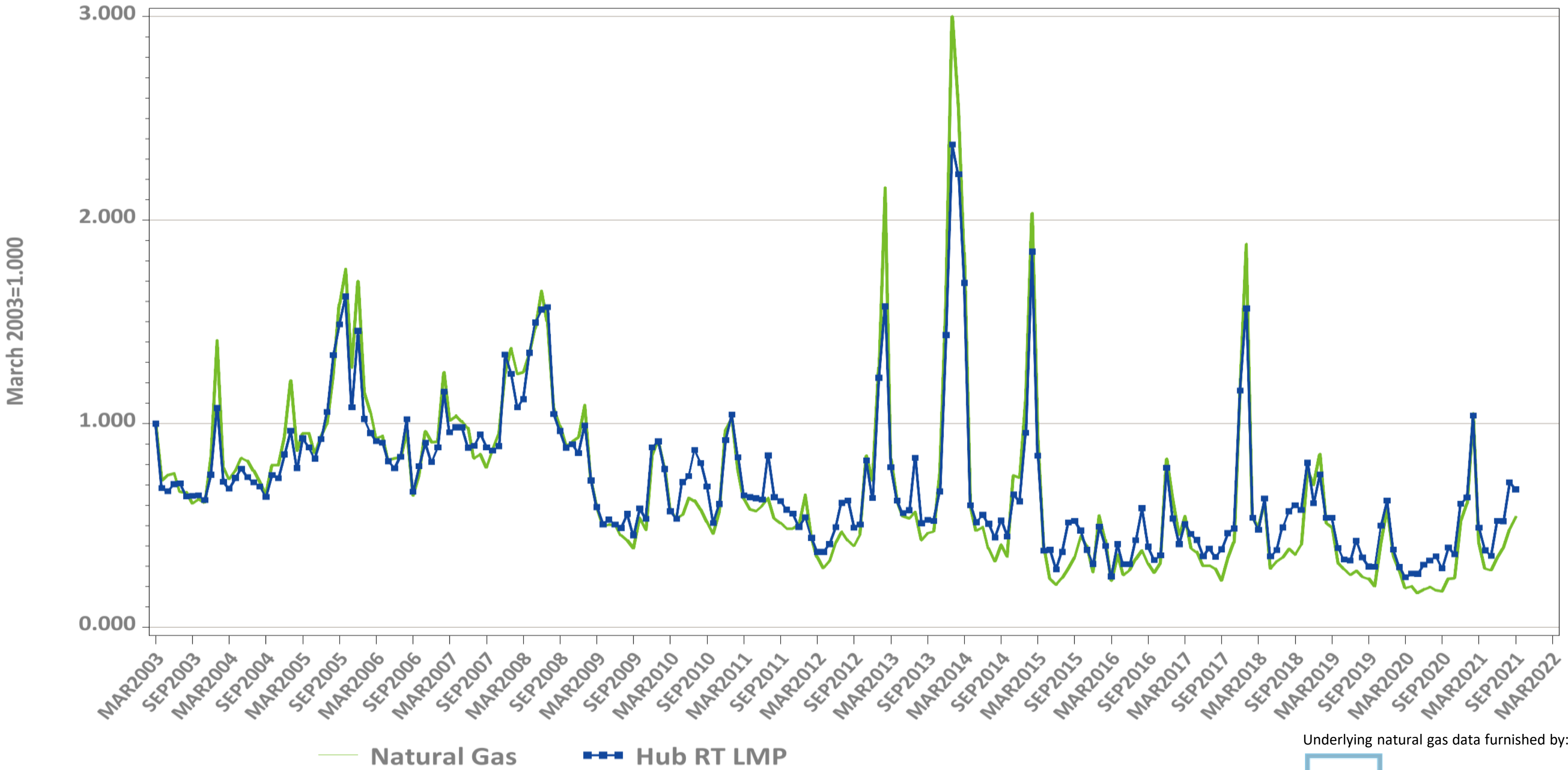
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 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%
Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%

September-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$21.07	$19.41	$21.14	$21.00	$19.80	$20.51	$20.84	$20.43	$20.46
Real-Time	$20.17	$19.41	$20.59	$20.25	$19.68	$19.64	$19.93	$19.88	$19.88
RT Delta %	-4.3%	0.0%	-2.6%	-3.6%	-0.6%	-4.3%	-4.4%	-2.7%	-2.9%
September-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$48.96	$46.85	$46.45	$48.05	$47.23	$47.58	$48.61	$48.02	$48.01
Real-Time	$46.94	$45.74	$45.07	$46.60	$45.81	$45.94	$46.85	$46.50	$46.48
RT Delta %	-4.1%	-2.4%	-3.0%	-3.0%	-3.0%	-3.4%	-3.6%	-3.2%	-3.2%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	132.4%	141.5%	119.7%	128.8%	138.5%	131.9%	133.2%	135.0%	134.6%
Yr over Yr RT	132.8%	135.7%	118.9%	130.1%	132.7%	133.9%	135.1%	133.9%	133.8%

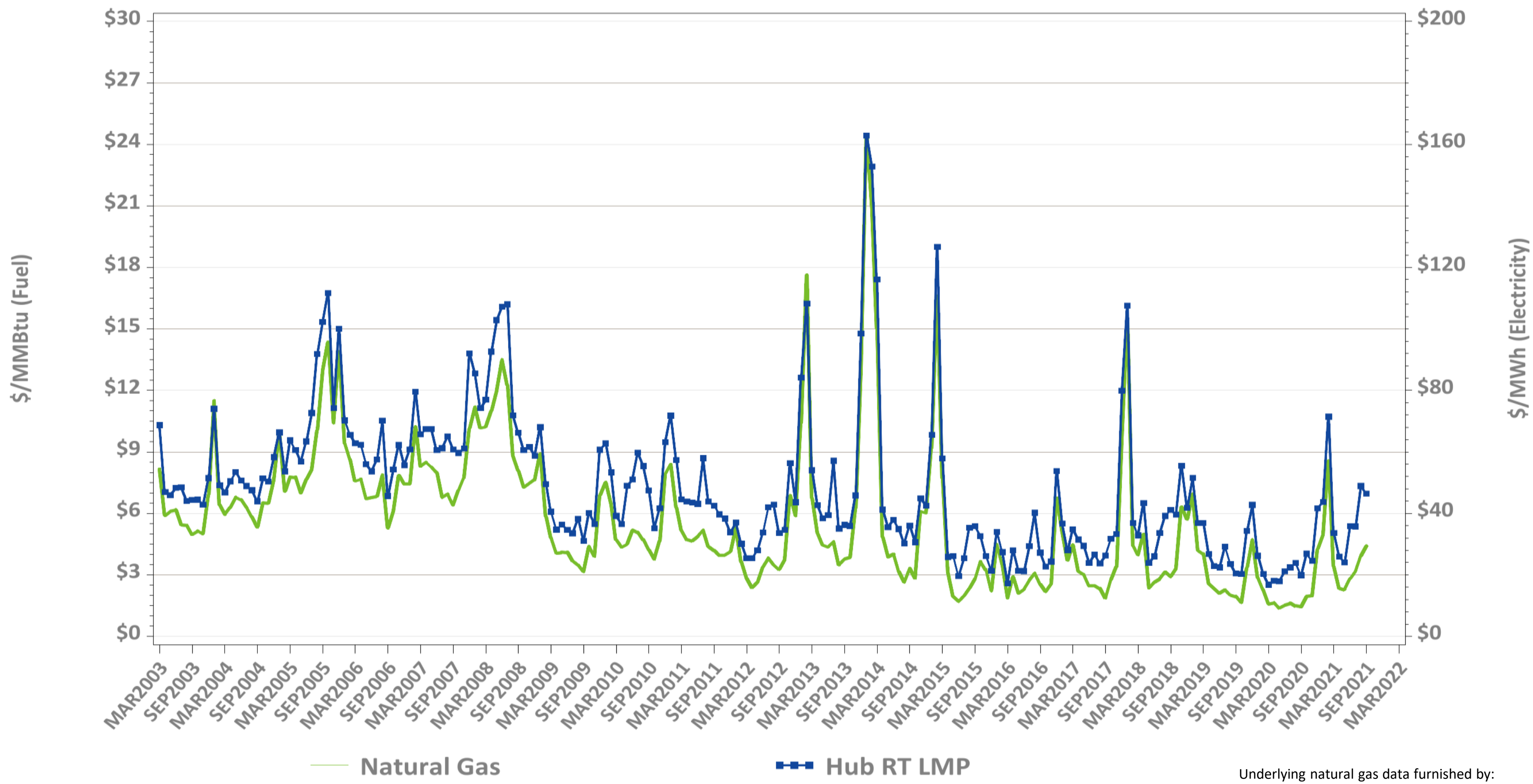
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

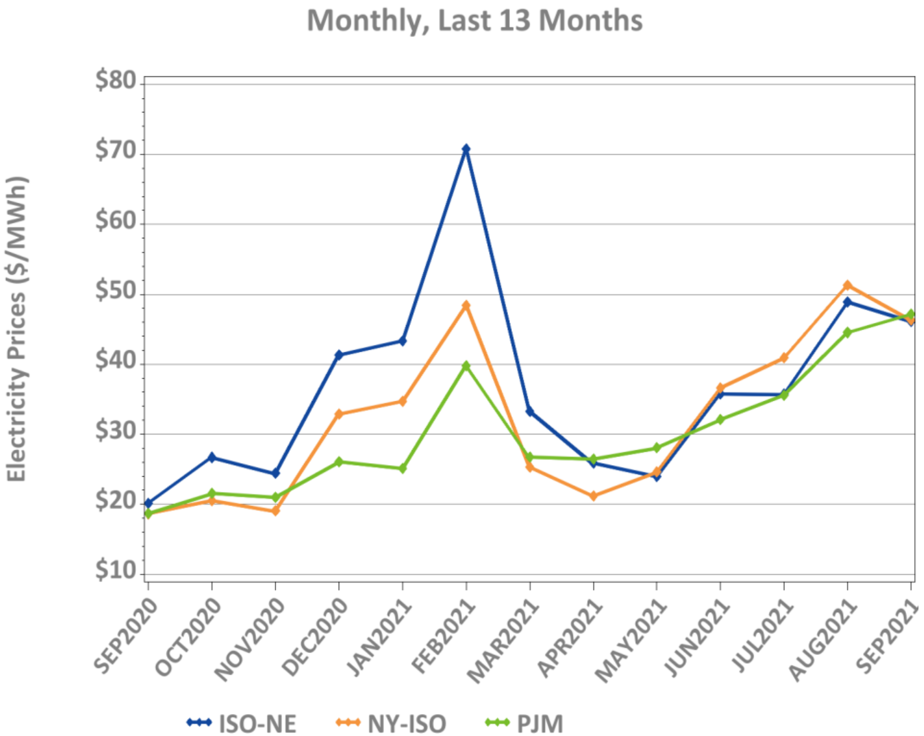
ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

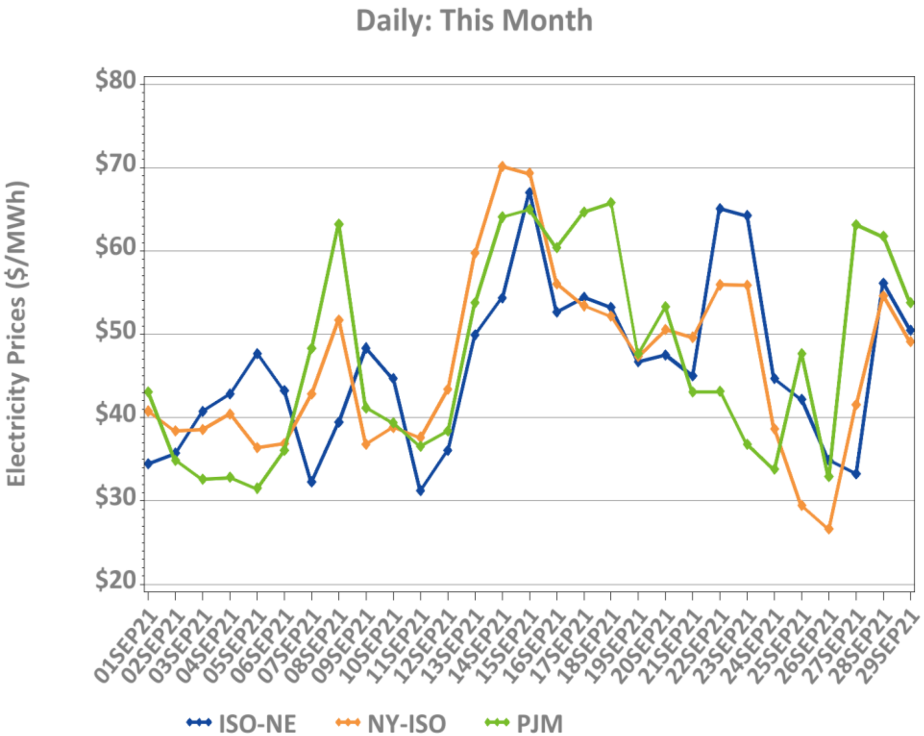


Underlying natural gas data furnished by: ICE Global markets in clear view

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

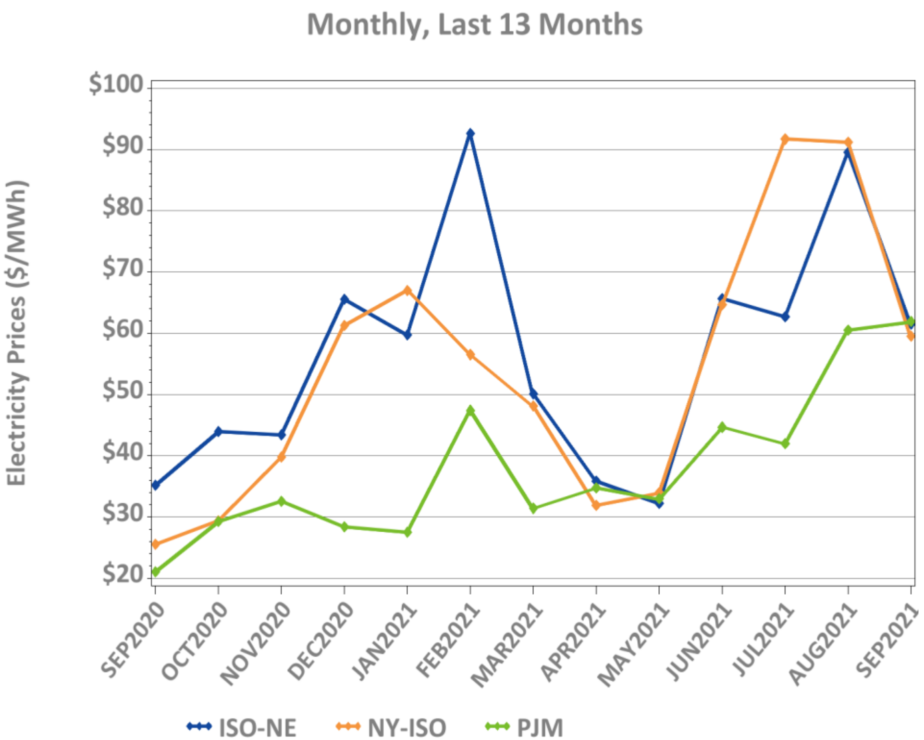


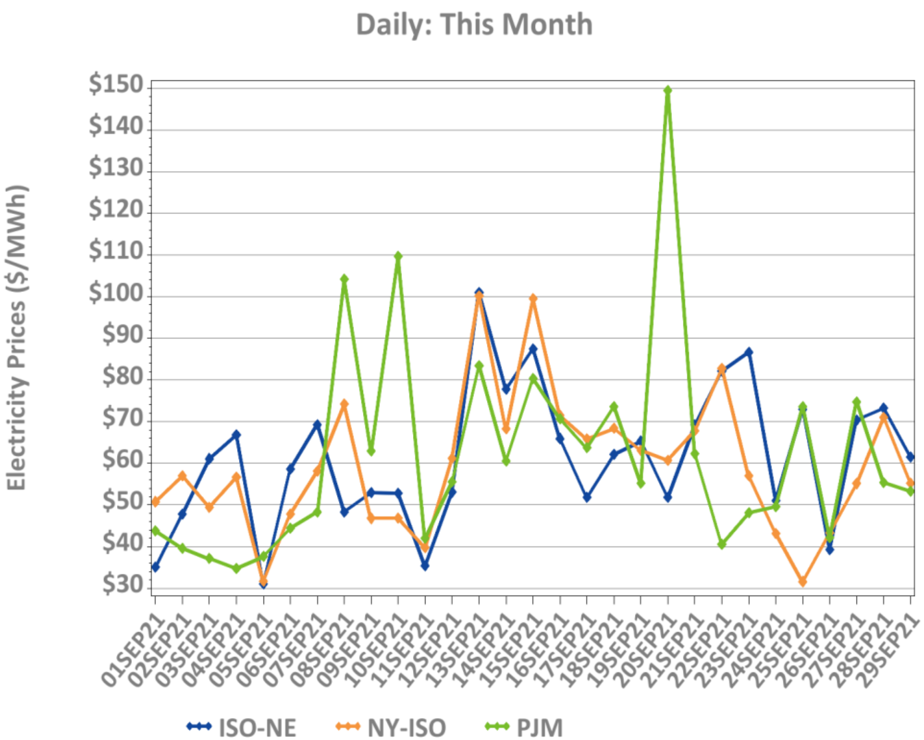
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





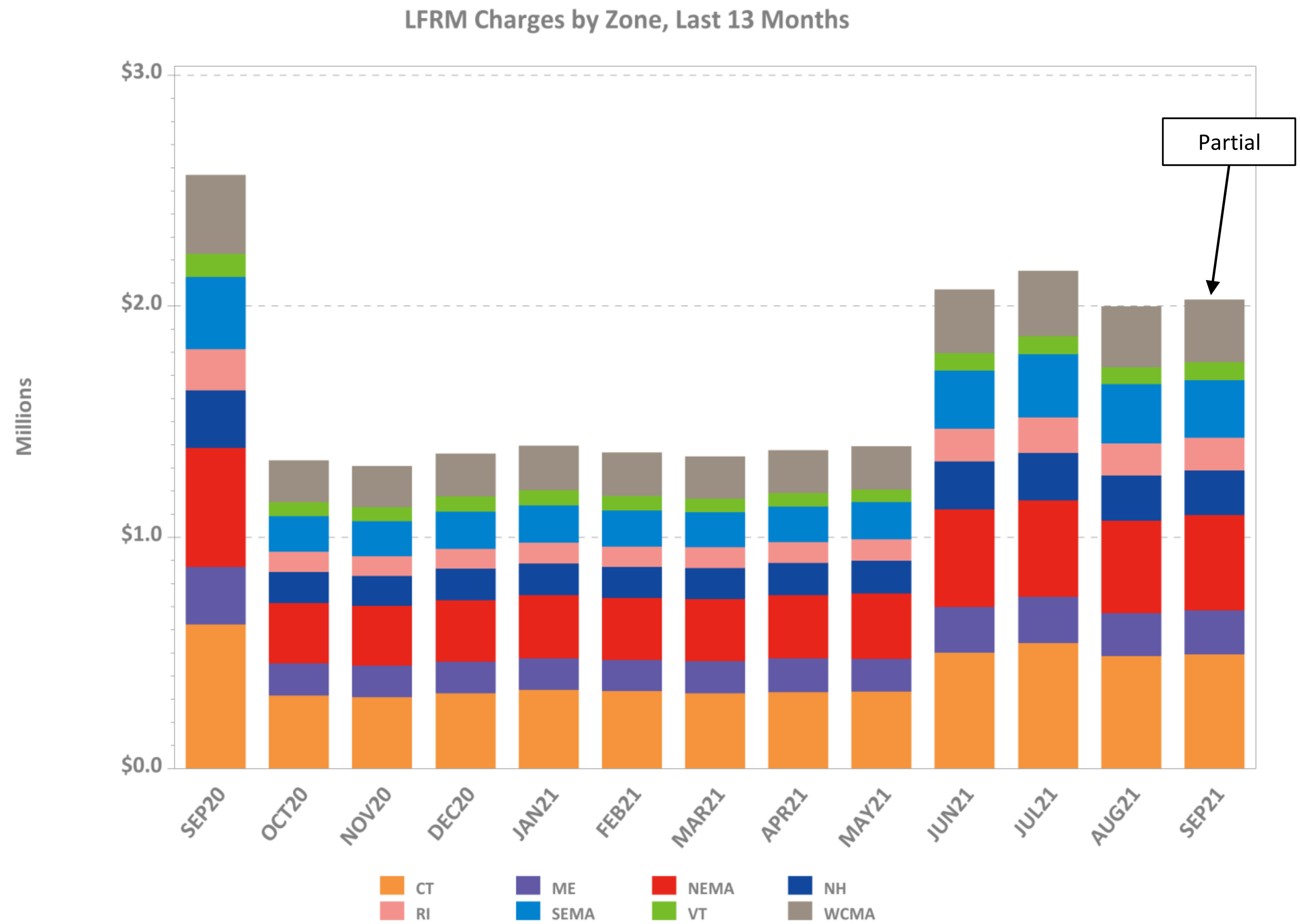
*Forecasted New England daily peak hours reflected

Reserve Market Results – September 2021

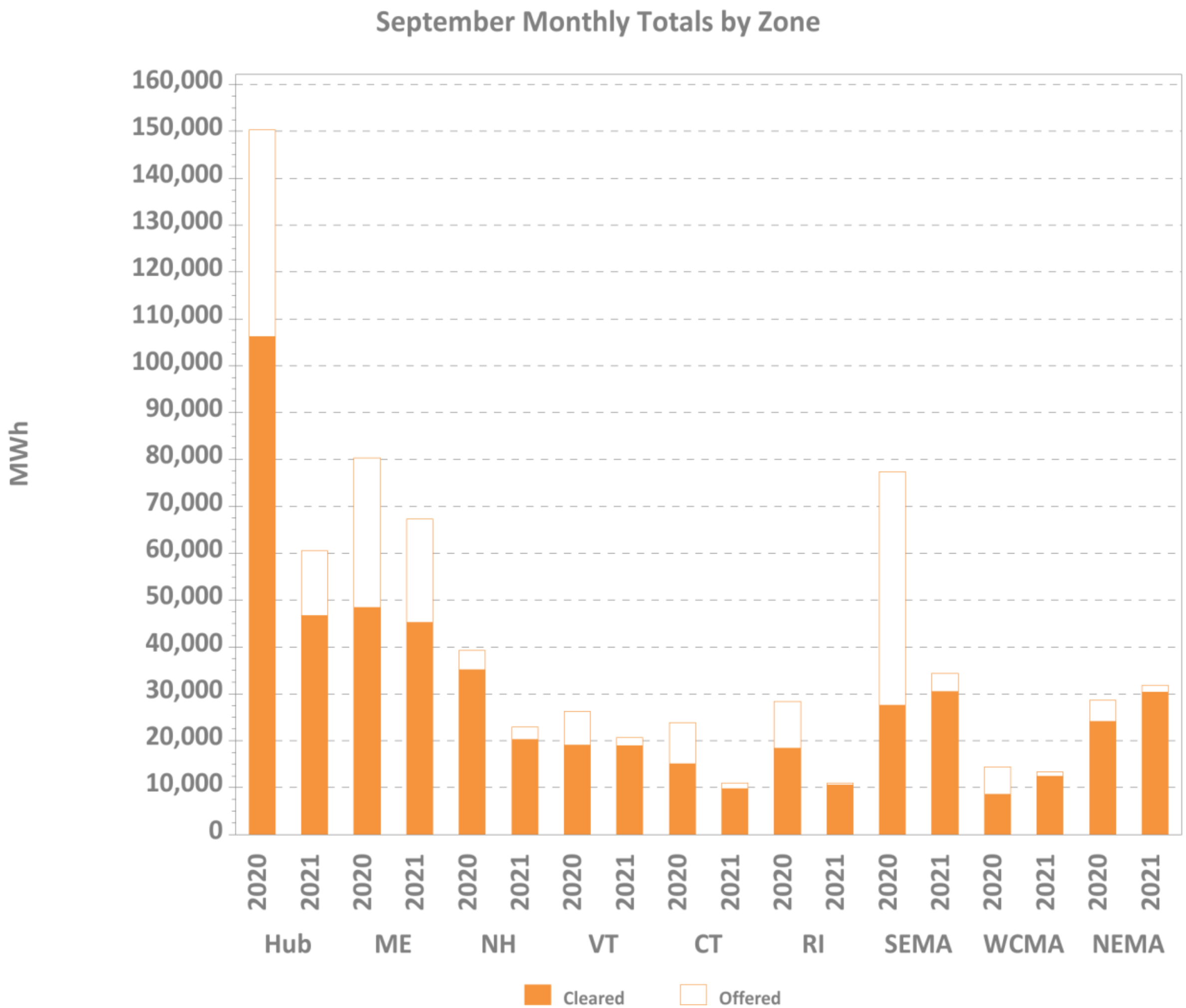
- Maximum potential Forward Reserve Market payments of $2.2M were reduced by credit reductions of $53K, failure-to-reserve penalties of $80K and no failure-to-activate penalties, resulting in a net payout of $2M or 95% of maximum
  - Rest of System: $1.56M/1.69M (92%)
  - Southwest Connecticut: $0.05M/0.05M (99%)
  - Connecticut: $0.4M/0.41M (99%)
  - NEMA: $0M/0M (100%)
- $361K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $361K in Real-Time Reserve payments
  - Rest of System: 199 hours, $262K
  - Southwest Connecticut: 199 hours, $37K
  - Connecticut: 199 hours, $41K
  - NEMA: 199 hours, $21K

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.

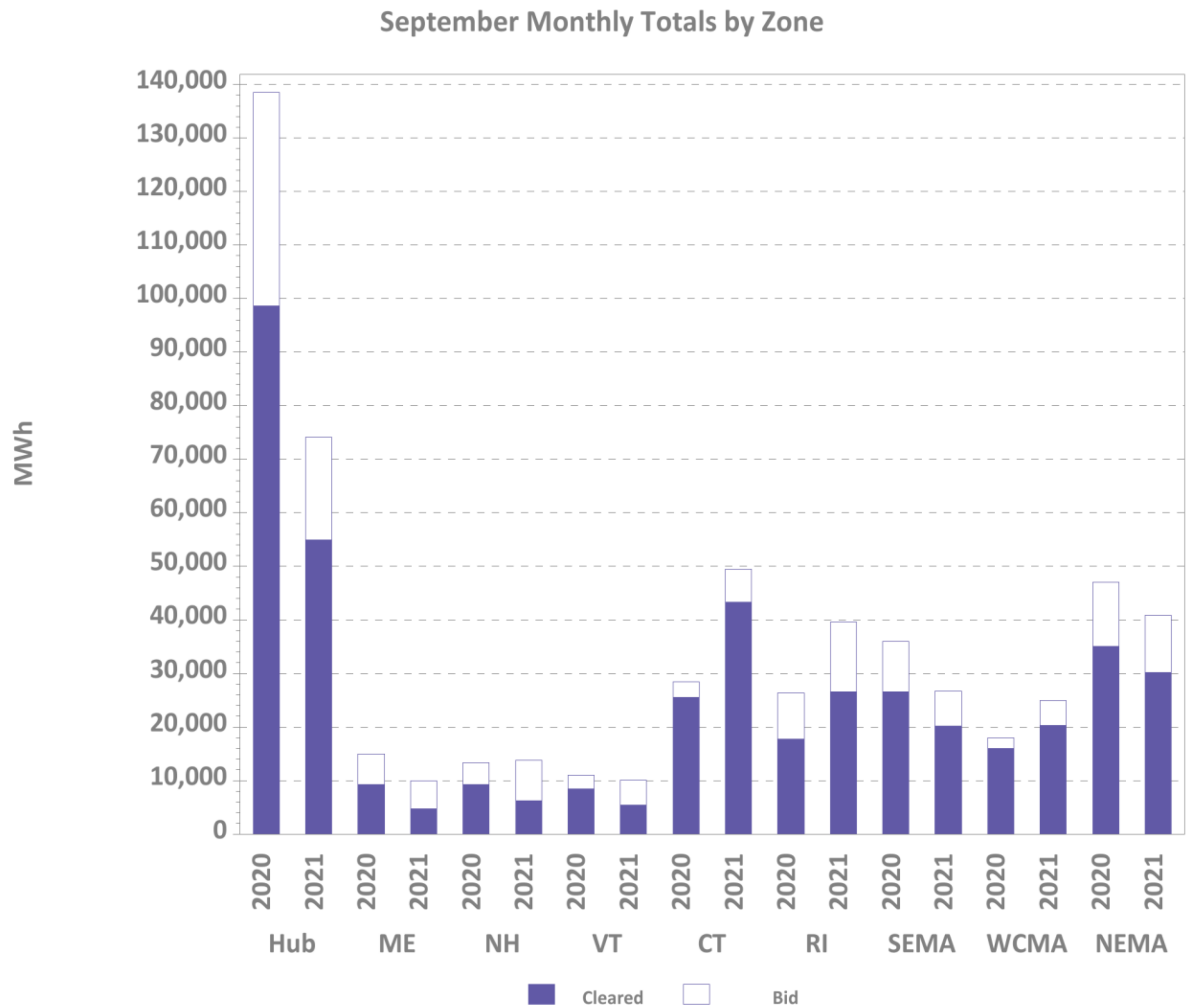
LFRM Charges to Load by Load Zone ($)



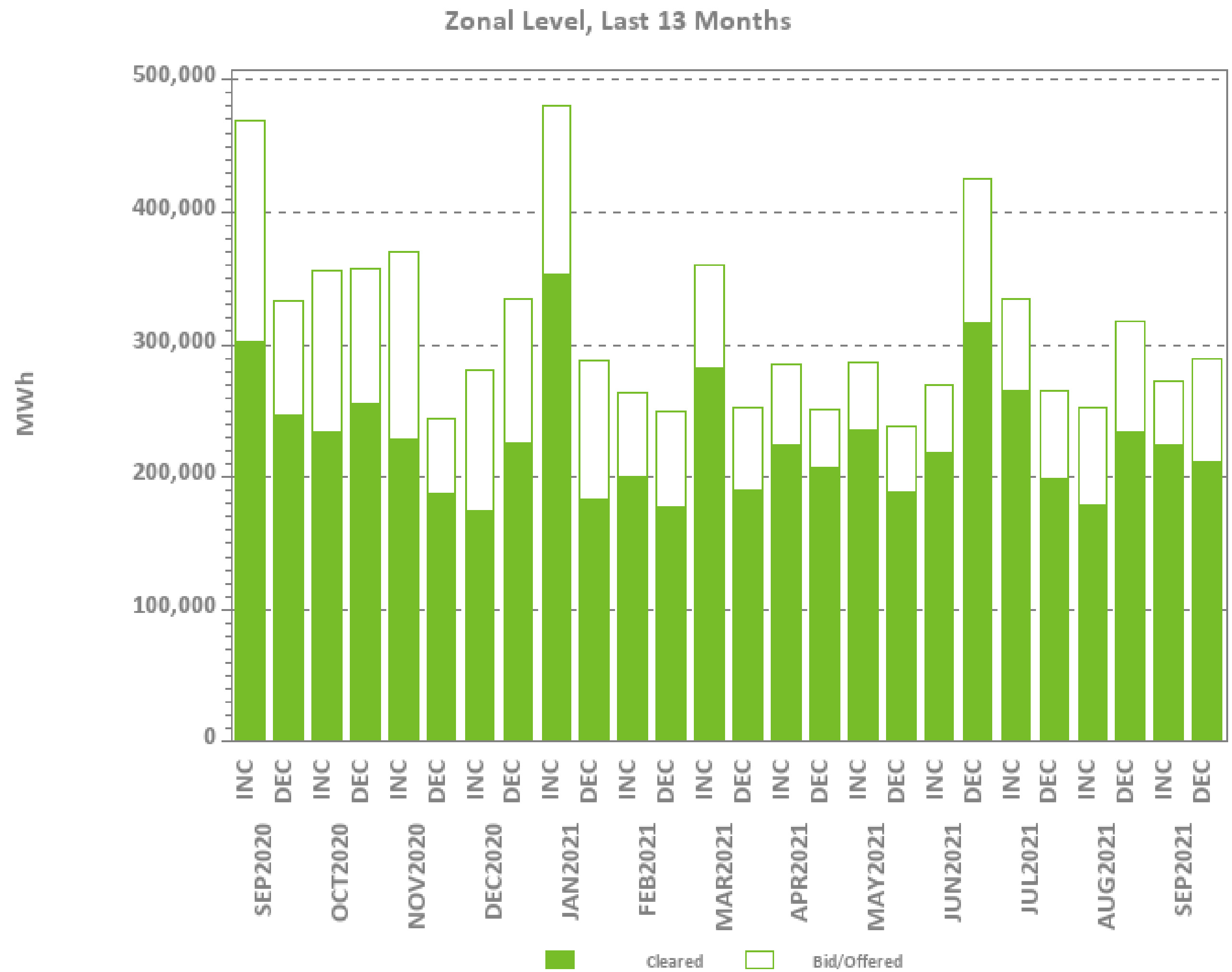
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

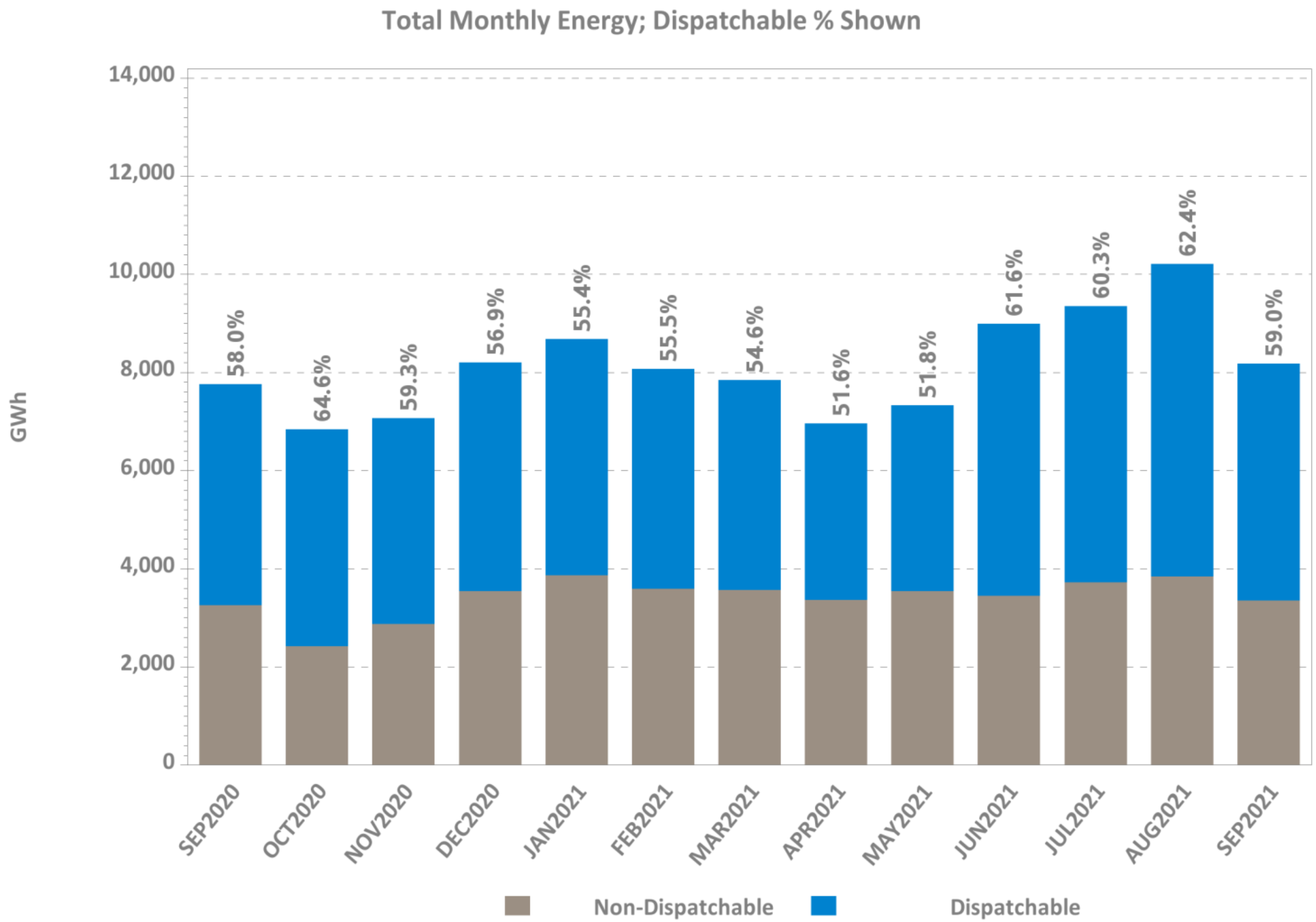


Total Increment Offers and Decrement Bids



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)

Regional System Plan (RSP)

- The near-final draft of RSP21 was posted with the October 6 Public Meeting materials

Planning Advisory Committee (PAC)

- October 20 PAC Meeting Agenda Topics*
  - 2021 Economic Study: Future Grid Reliability Study Phase 1 - Ancillary Services Preliminary Results - Part 2
  - 2021 Economic Study: Future Grid Reliability Study Phase 1 - High Level Transmission Analysis - Preliminary Results
  - Updated Transmission Planning Technical Guide
  - SEMA/RI 2030 Minimum Load Needs Assessment Results
  - Transmission Owners Planning Advisory Committee (TOPAC) - Updated Local System Plans
    - New Hampshire Transmission
    - VELCO
    - Versant Power
    - UI/AVANGRID
    - National Grid
    - Eversource Energy

* 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 9/24/20 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
- A follow-up presentation at the 11/19/20 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published draft revisions to the Transmission Planning Technical Guide reflecting these changes on 9/15/21
- Future testing will focus on transient stability modeling and performance criteria

Economic Studies

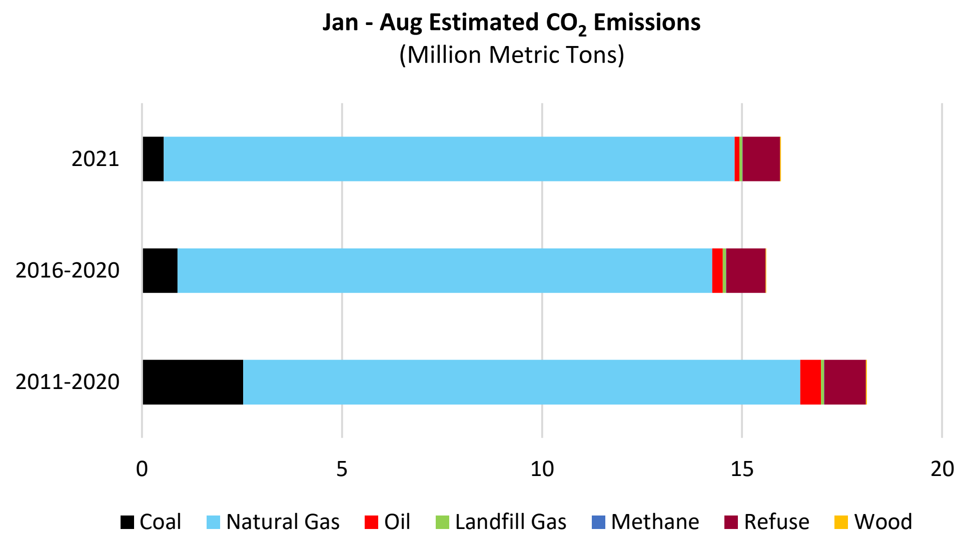
- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Draft report to be completed by the end of 2021
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
    - Preliminary production cost results were discussed at the special September 17 PAC meeting and joint MC/RC meetings
      - The ISO is working on refining the scenario matrix and will present to the MC/RC for approval before finishing the final runs
    - Preliminary ancillary services analyses results were presented at the September 22 PAC meeting and, after confirmation of scenario adjustments at the MC/RC meeting, the remaining preliminary ancillary services analyses results will be presented at the October 20 PAC meeting

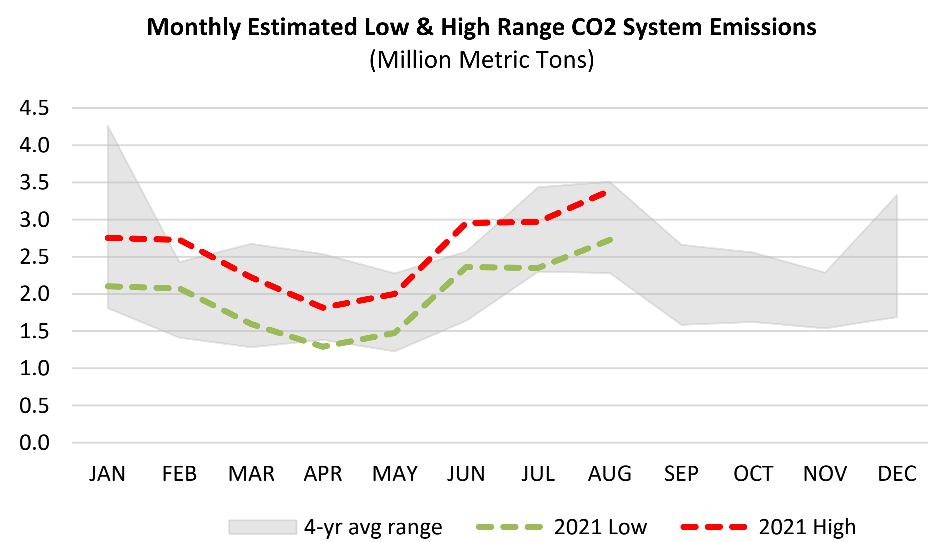
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - Phase 1 work was submitted as the only 2021 economic study
  - Production Cost Simulations preliminary results were presented at the special September 17 PAC meeting
  - Ancillary Services Simulation initial results were presented at the September 22 PAC meeting and remaining results will be presented at the October PAC meeting
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined
  - Studies likely to be performed by a consultant
  - Embellishment of the study scope continues at the MC/RC

Environmental Matters – Shift in Power System Emission Trends

- 2021 estimated CO_2 emissions running 102% of 5-year averages and 88% of 10-year averages for the same period (January - August)
  - Natural-gas CO_2 emissions 107% of 5-year averages and 102% of 10-year averages
  - CO_2 emissions from all other emitting fuel categories declined compared to 5- and 10-year averages
- January - August 2021 estimated system CO_2 emissions range between 15.9 and 20.8 million metric tons (MMT)
- January - August 4-year average (2017-2020) CO_2 emissions range between 13.3 and 23.6 MMT



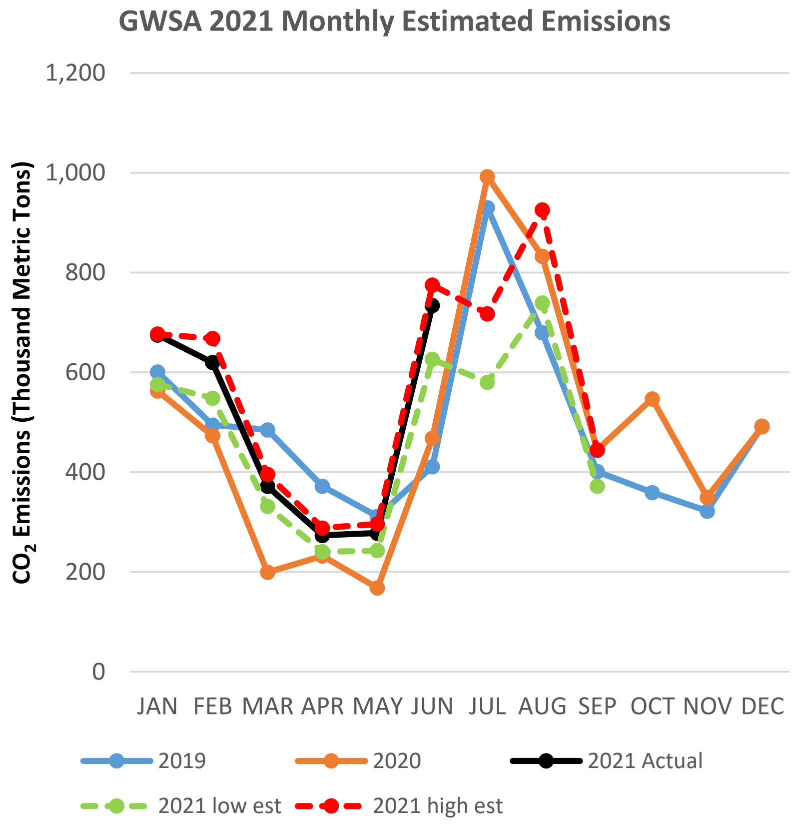


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 GWSA Emissions Trending Lower

- As of 9/26/21, estimated GWSA CO_2 emissions range between 4.25 and 5.18 MMT:
  - 51% to 63% of the 8.23 MMT 2021 cap
- 9/15/21 GWSA auction cleared at $10 per metric ton. Using latest clearing price, IMM estimated compliance costs by fuel type (based average GWSA emission/heat rates):
  - No. 2 fuel oil - $8.54/MWh
  - No. 6 fuel oil - $8.29/MWh
  - Natural gas - $2.39/MWh
- Affected generators have access to banked allowances in excess of expected 2021 emissions

2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



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 Boston Projects

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	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*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	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 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	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
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	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	Mar-21	4

Greater Boston Projects, cont.

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	May-22	3
1357	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
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1520	Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
1643	Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
1341, 1645	Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
1646	Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
1647	Install a 115 kV breaker in series with the 5 breaker at Framingham	Mar-17	4
1554	Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

SEMA/RI Reliability Projects

Status as of 9/27/2021

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

RSP Project List 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	4
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
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	4
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 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	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	May-25	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-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-23	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 9/27/2021

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

RSP Project List 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	3
1727	Retire the Barnstable SPS	Dec-21	3
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 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	3
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	3
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	Aug-20	4

* 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 9/27/2021

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

RSP Project List 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	Jun-22	2
1724	Replace the Kent County 345/115 kV transformer	Mar-22	2
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
1851	Upgrade Card 115 kV to BPS standards	Mar-23	2
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	1

Eastern CT Reliability Projects, cont.

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	1
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	1
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	1
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-21	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	1
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Mar-22	2

Eastern CT Reliability Projects, cont.

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	June-22	2
1862	Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	1
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	1
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	1

Boston Area Optimized Solution Projects

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Jun-23	3
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Jan-23	2
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	2

New Hampshire Solution Projects

Status as of 9/27/2021

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +50/-25 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Aug-23	2
1879	Install a +50/-25 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Aug-23	2
1880	Install a +100/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec-23	1
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Nov-23	1

Upper Maine Solution Projects

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland – Coopers Mills 115 kV line	Dec-27	1
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-27	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-27	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-27	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Dec-25	1

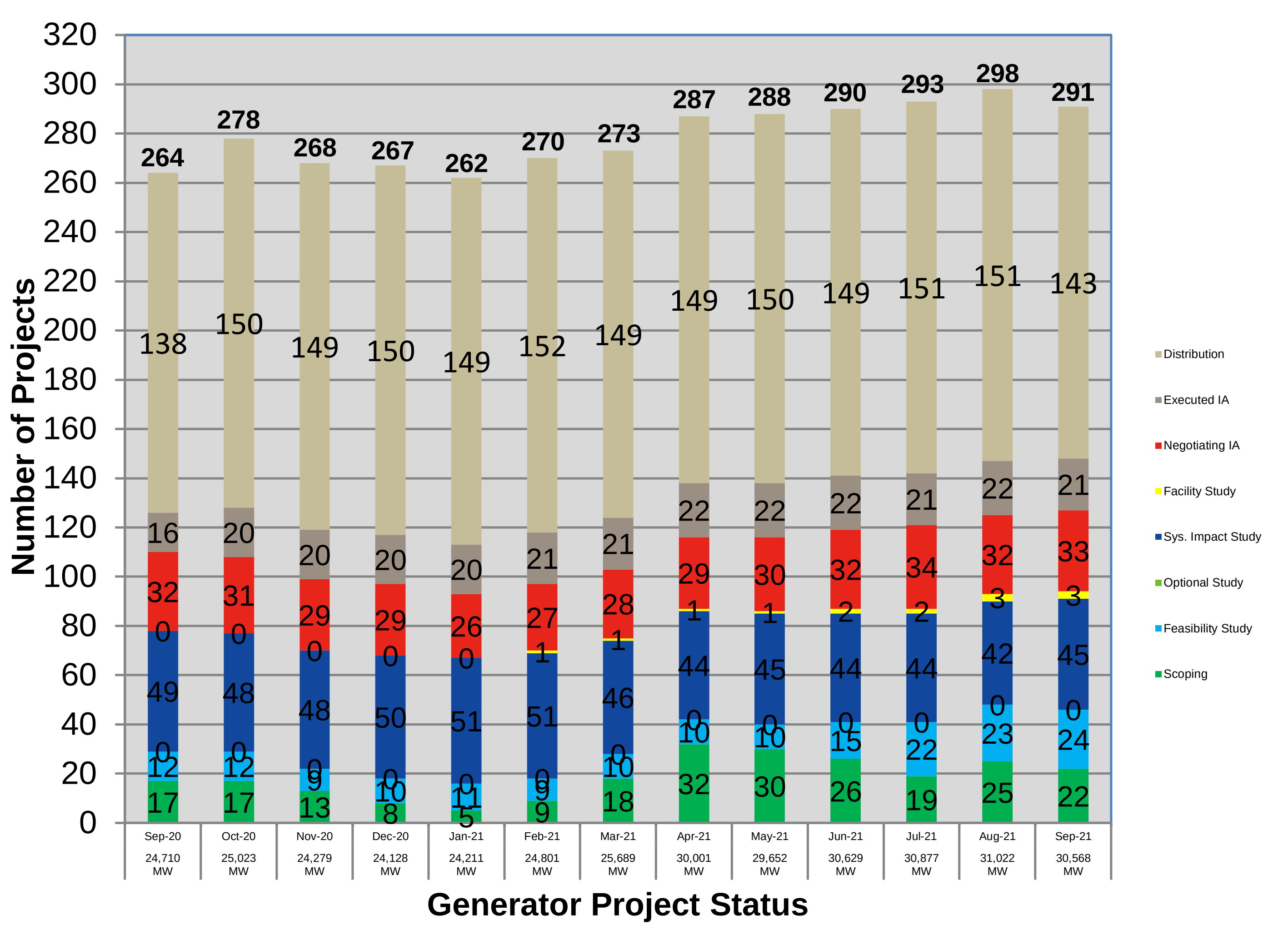
Upper Maine Solution Projects, cont.

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Dec-25	1
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Dec-23	1
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	1

Status of Tariff Studies



Note: September 2021 is based on partial data.

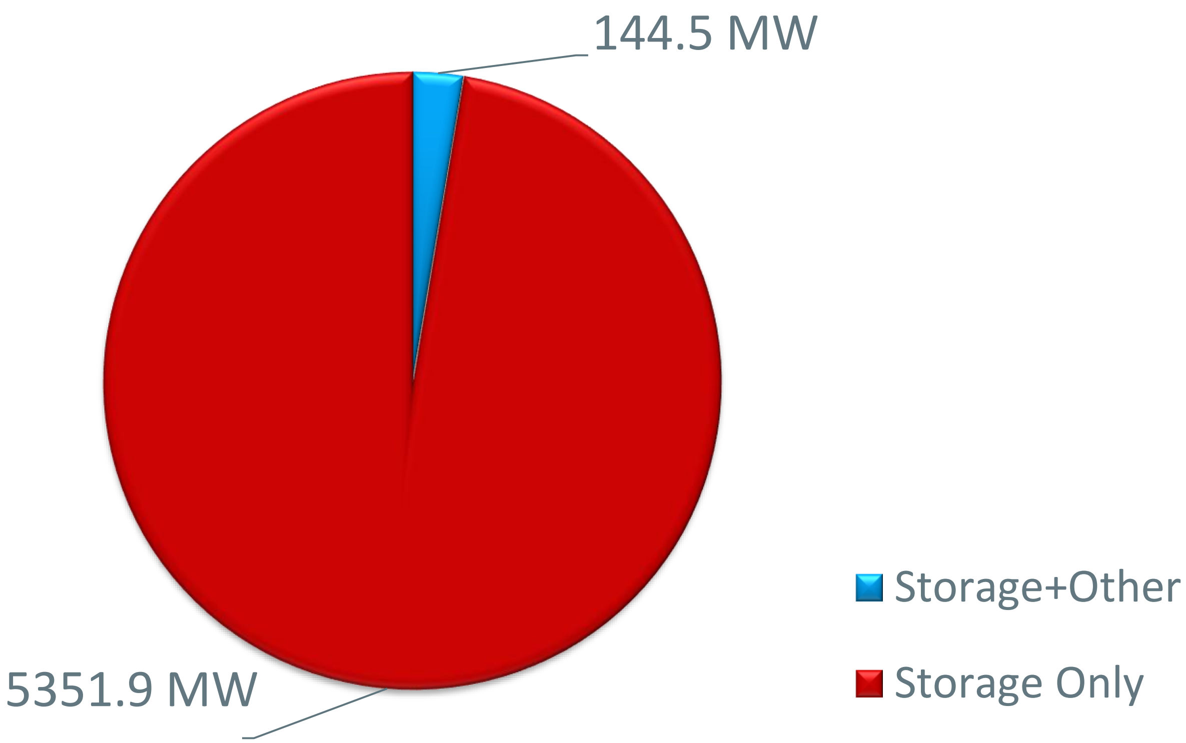
As of September 2021: 3 ETUs in Scoping, 0 in FS, 2 in SIS, 0 in OIS, 1 in FAC, 0 Negotiating IA, and 2 with Executed IA

Transmission Service Requests needing study: 1 in Scoping

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

What is in the Queue (as of September 28, 2021)

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



OPERABLE CAPACITY ANALYSIS

Fall 2021 Analysis

Fall 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Oct. - 2021[2] CSO (MW)	Oct. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,714	32,069
Active Demand Capacity Resource (+) [5]	492	398
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,068	1,068
Non Commercial Capacity (+)	42	42
Non Gas-fired Planned Outage MW (-)	4,865	5,455
Gas Generator Outages MW (-)	4,236	4,850
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)	19,415	20,473
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	15,749	15,749
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,054	18,054
Operable Capacity Margin	1,362	2,419

[1]Operable Capacity is based on data as of **September 28, 2021** 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, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **October 16, 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.

Fall 2021 Operable Capacity Analysis

90/10 Load Forecast	Oct. - 2021[2] CSO (MW)	Oct. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,714	32,069
Active Demand Capacity Resource (+) [5]	492	398
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,068	1,068
Non Commercial Capacity (+)	42	42
Non Gas-fired Planned Outage MW (-)	4,865	5,455
Gas Generator Outages MW (-)	4,236	4,850
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)	19,415	20,473
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	16,279	16,279
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,584	18,584
Operable Capacity Margin	832	1,889

[1]Operable Capacity is based on data as of **September 28, 2021** 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, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **October 16, 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.

Fall 2021 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 28, 2021 - 50-50 FORECAST using CSO MW

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.

Report created: 9/28/2021

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
10/16/2021	**29714**	**492**	**1068**	**42**	**4865**	**4236**	**2800**	**0**	**19415**	**15749**	**2305**	**18054**	**1362**	**Y**	**Fall 2021**
10/23/2021	29714	492	1011	42	4601	2779	2800	0	21079	16113	2305	18418	2662	N	Fall 2021
10/30/2021	29750	540	1135	50	5091	1349	3600	0	21435	16320	2305	18625	2810	N	Fall 2021
11/6/2021	29750	540	1135	50	2480	1322	3600	0	24073	16435	2305	18740	5334	N	Fall 2021
11/13/2021	29750	540	1135	50	1723	1434	3600	0	24718	16780	2305	19085	5633	N	Fall 2021
11/20/2021	29750	540	1135	50	1088	8	3600	1362	25417	17517	2305	19822	5596	N	Fall 2021

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: 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 particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All 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.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Fall 2021 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 28, 2021 - 90/10 FORECAST using CSO MW

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 December, January, February, March and April.

Report created: 9/28/2021

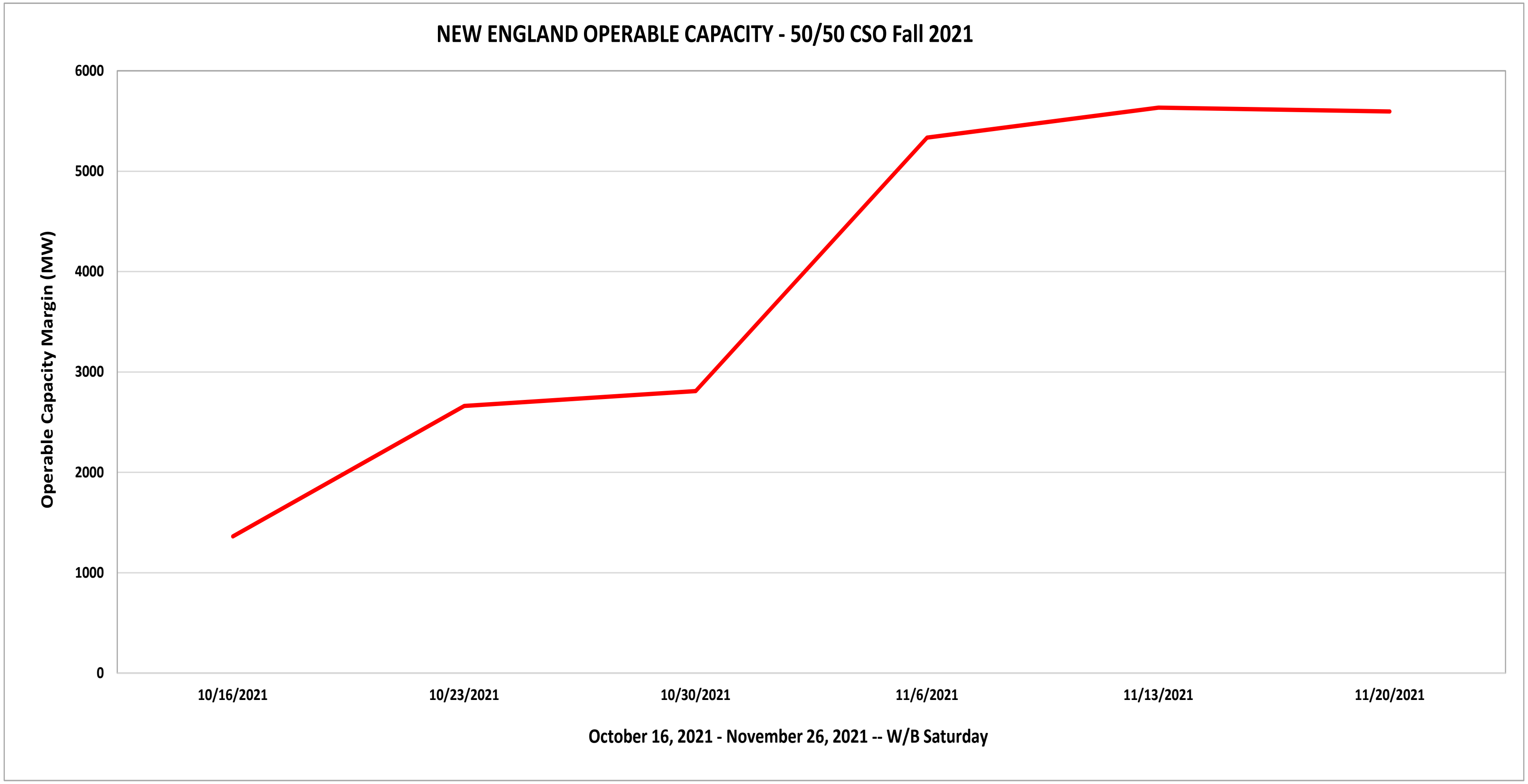
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
10/16/2021	**29714**	**492**	**1068**	**42**	**4865**	**4236**	**2800**	**0**	**19415**	**16279**	**2305**	**18584**	**832**	**Y**	**Fall 2021**
10/23/2021	29714	492	1011	42	4601	2779	2800	0	21079	16654	2305	18959	2121	N	Fall 2021
10/30/2021	29750	540	1135	50	5091	1349	3600	0	21435	16866	2305	19171	2264	N	Fall 2021
11/6/2021	29750	540	1135	50	2480	1322	3600	0	24073	16985	2305	19290	4784	N	Fall 2021
11/13/2021	29750	540	1135	50	1723	1434	3600	101	24617	17339	2305	19644	4973	N	Fall 2021
11/20/2021	29750	540	1135	50	1088	8	3600	2297	24482	18098	2305	20403	4080	N	Fall 2021

Column Definitions

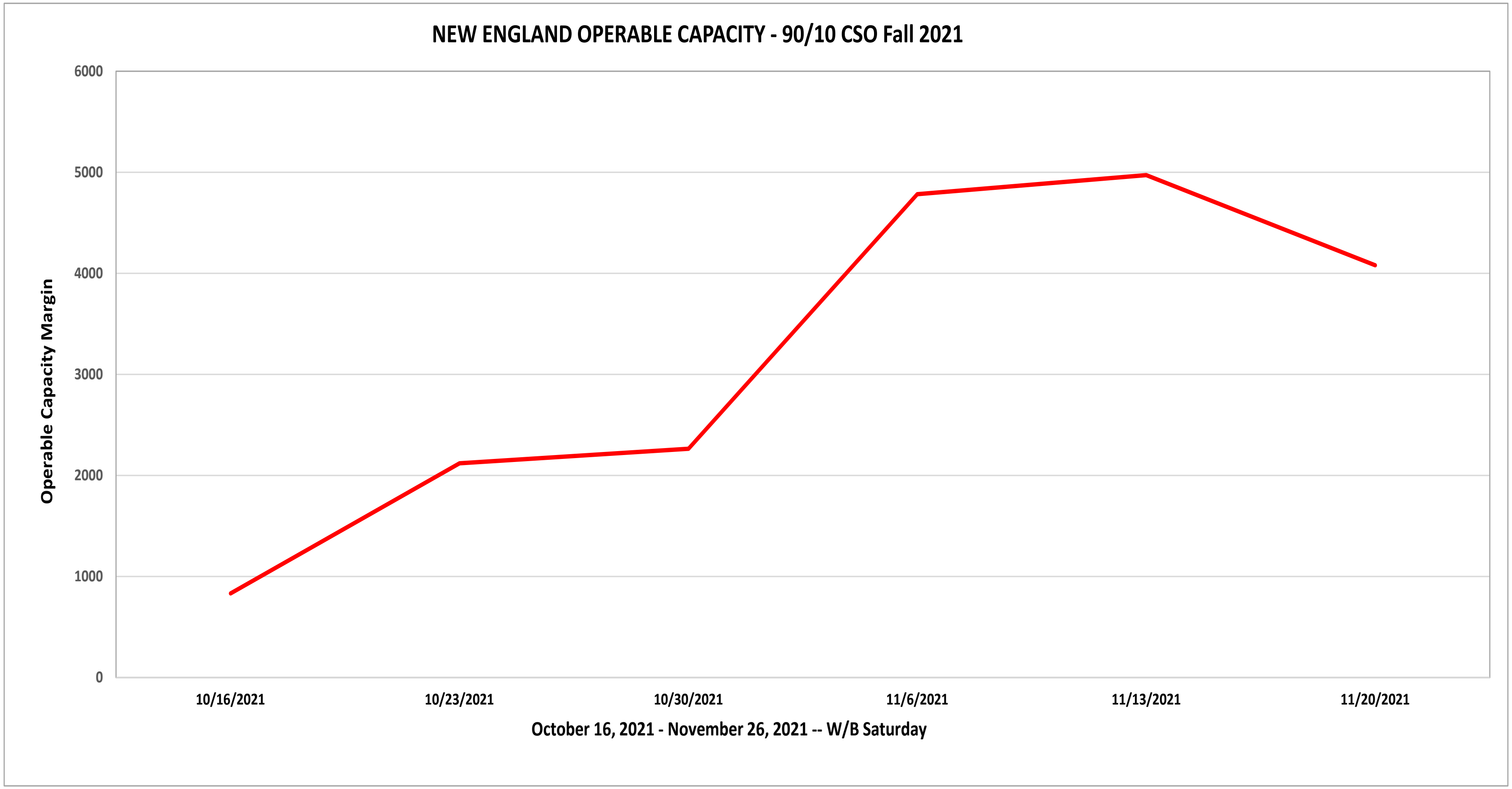
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All 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.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Fall 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Fall 2021 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2021/22 Analysis

Preliminary Winter 2021/22 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,774	32,069
Active Demand Capacity Resource (+) [5]	541	398
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	296	401
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,735	4,287
Net Capacity (NET OPCAP SUPPLY MW)	24,669	26,164
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,710	19,710
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,015	22,015
Operable Capacity Margin	2,654	4,149

[1] Operable Capacity is based on data as of **September 28, 2021** 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, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 8, 2022.**

[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 2021/22 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,774	32,069
Active Demand Capacity Resource (+) [5]	541	398
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	296	401
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,546	5,217
Net Capacity (NET OPCAP SUPPLY MW)	23,858	25,234
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,349	20,349
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,654	22,654
Operable Capacity Margin	1,204	2,580

[1]Operable Capacity is based on data as of **September 28, 2021** 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, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 8, 2022.**

[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 2021/22 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 28, 2021 - 50-50 FORECAST using CSO MW

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.

Report created: 9/28/2021

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/27/2021	29750	540	1135	50	1123	8	3600	1950	24794	18237	2305	20542	4253	N	Winter 2021/2022
12/4/2021	29774	541	1135	50	387	272	3200	2110	25531	18611	2305	20916	4615	N	Winter 2021/2022
12/11/2021	29774	541	1135	50	358	270	3200	2311	25361	18900	2305	21205	4156	N	Winter 2021/2022
12/18/2021	29774	541	1135	50	303	0	3200	2794	25203	18911	2305	21216	3987	N	Winter 2021/2022
12/25/2021	29774	541	1135	50	303	0	3200	3141	24856	18973	2305	21278	3578	N	Winter 2021/2022
1/1/2022	29774	541	1135	50	307	0	2800	3740	24653	19246	2305	21551	3102	N	Winter 2021/2022
1/8/2022	**29774**	**541**	**1135**	**50**	**296**	**0**	**2800**	**3735**	**24669**	**19710**	**2305**	**22015**	**2654**	**Y**	**Winter 2021/2022**
1/15/2022	29774	541	1135	50	296	0	2800	3590	24814	19710	2305	22015	2799	N	Winter 2021/2022
1/22/2022	29774	541	1135	50	296	0	2800	3141	25263	19710	2305	22015	3248	N	Winter 2021/2022
1/29/2022	29774	541	1135	50	296	0	3100	2842	25262	19488	2305	21793	3469	N	Winter 2021/2022
2/5/2022	29774	541	1135	50	296	0	3100	2543	25561	19222	2305	21527	4034	N	Winter 2021/2022
2/12/2022	29774	541	1135	50	289	0	3100	2244	25867	19193	2305	21498	4369	N	Winter 2021/2022
2/19/2022	29774	541	1135	50	291	18	3100	1777	26314	18931	2305	21236	5078	N	Winter 2021/2022
2/26/2022	29774	541	1135	50	346	18	3100	1478	26558	17944	2305	20249	6309	N	Winter 2021/2022
3/5/2022	29774	541	1135	50	350	270	2200	927	27753	17596	2305	19901	7852	N	Winter 2021/2022
3/12/2022	29774	541	1135	50	634	718	2200	0	27949	17400	2305	19705	8244	N	Winter 2021/2022
3/19/2022	29774	541	1135	50	1058	1120	2200	0	27122	17036	2305	19341	7781	N	Winter 2021/2022
3/26/2022	29750	540	1135	50	1698	757	2700	0	26320	16472	2305	18777	7544	N	Winter 2021/2022

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: 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 particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All 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.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Preliminary Winter 2021/22 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 28, 2021 - 90/10 FORECAST using CSO MW

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 December, January, February, March and April.

Report created: 9/28/2021

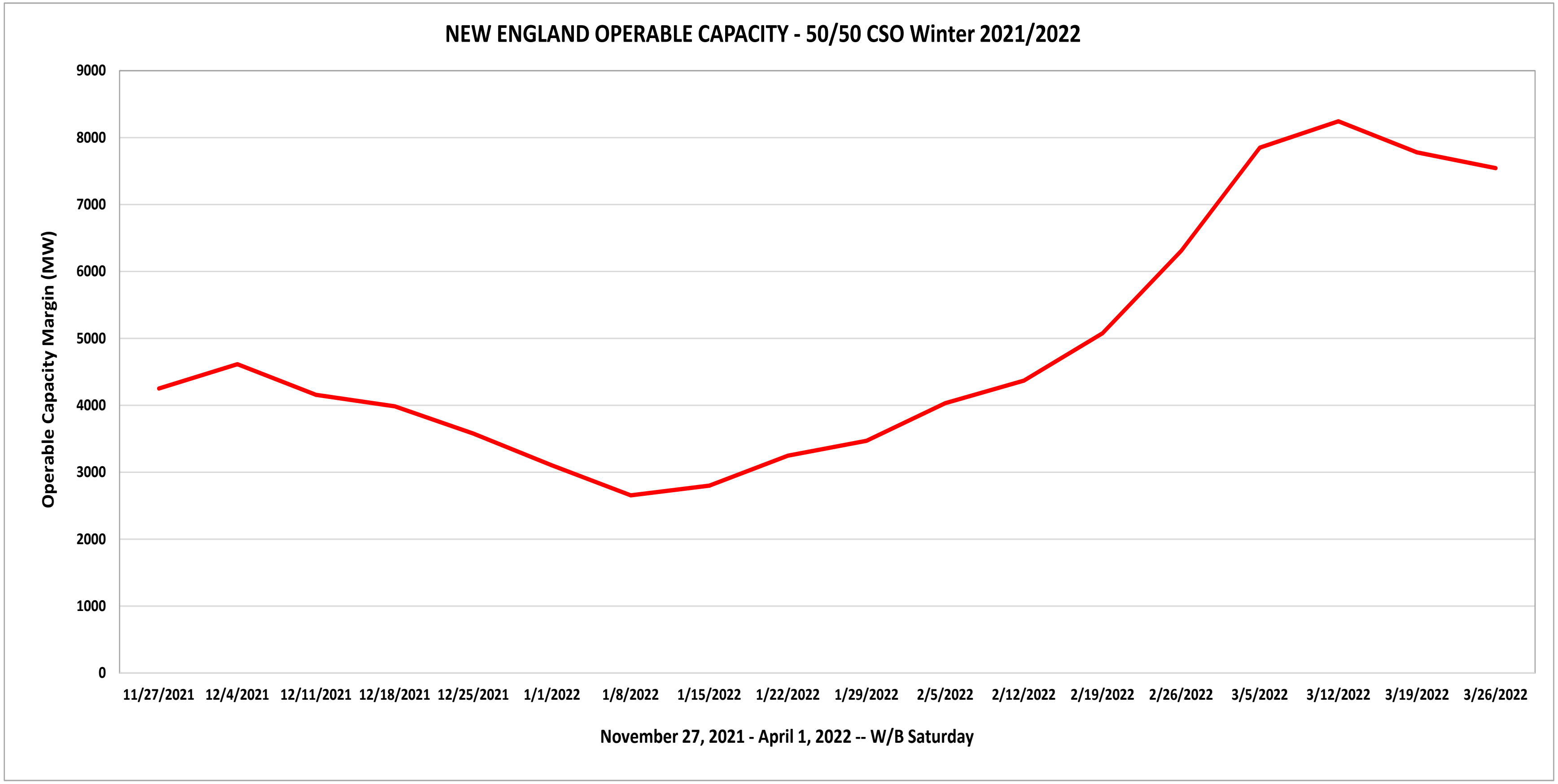
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/27/2021	29750	540	1135	50	1123	8	3600	2864	23880	18838	2305	21143	2738	N	Winter 2021/2022
12/4/2021	29774	541	1135	50	387	272	3200	3098	24543	19218	2305	21523	3020	N	Winter 2021/2022
12/11/2021	29774	541	1135	50	358	270	3200	3298	24374	19515	2305	21820	2554	N	Winter 2021/2022
12/18/2021	29774	541	1135	50	303	0	3200	3913	24084	19527	2305	21832	2252	N	Winter 2021/2022
12/25/2021	29774	541	1135	50	303	0	3200	4287	23710	19591	2305	21896	1814	N	Winter 2021/2022
1/1/2022	29774	541	1135	50	307	0	2800	4415	23978	19872	2305	22177	1801	N	Winter 2021/2022
1/8/2022	**29774**	**541**	**1135**	**50**	**296**	**0**	**2800**	**4546**	**23858**	**20349**	**2305**	**22654**	**1204**	**Y**	**Winter 2021/2022**
1/15/2022	29774	541	1135	50	296	0	2800	4338	24066	20349	2305	22654	1412	N	Winter 2021/2022
1/22/2022	29774	541	1135	50	296	0	2800	4039	24365	20349	2305	22654	1711	N	Winter 2021/2022
1/29/2022	29774	541	1135	50	296	0	3100	4039	24065	20121	2305	22426	1639	N	Winter 2021/2022
2/5/2022	29774	541	1135	50	296	0	3100	3590	24514	19847	2305	22152	2362	N	Winter 2021/2022
2/12/2022	29774	541	1135	50	289	0	3100	3291	24820	19817	2305	22122	2698	N	Winter 2021/2022
2/19/2022	29774	541	1135	50	291	18	3100	2675	25416	19547	2305	21852	3564	N	Winter 2021/2022
2/26/2022	29774	541	1135	50	346	18	3100	2226	25810	18533	2305	20838	4972	N	Winter 2021/2022
3/5/2022	29774	541	1135	50	350	270	2200	1824	26856	18174	2305	20479	6377	N	Winter 2021/2022
3/12/2022	29774	541	1135	50	634	718	2200	778	27170	17973	2305	20278	6892	N	Winter 2021/2022
3/19/2022	29774	541	1135	50	1058	1120	2200	0	27122	17598	2305	19903	7219	N	Winter 2021/2022
3/26/2022	29750	540	1135	50	1698	757	2700	0	26320	17017	2305	19322	6999	N	Winter 2021/2022

Column Definitions

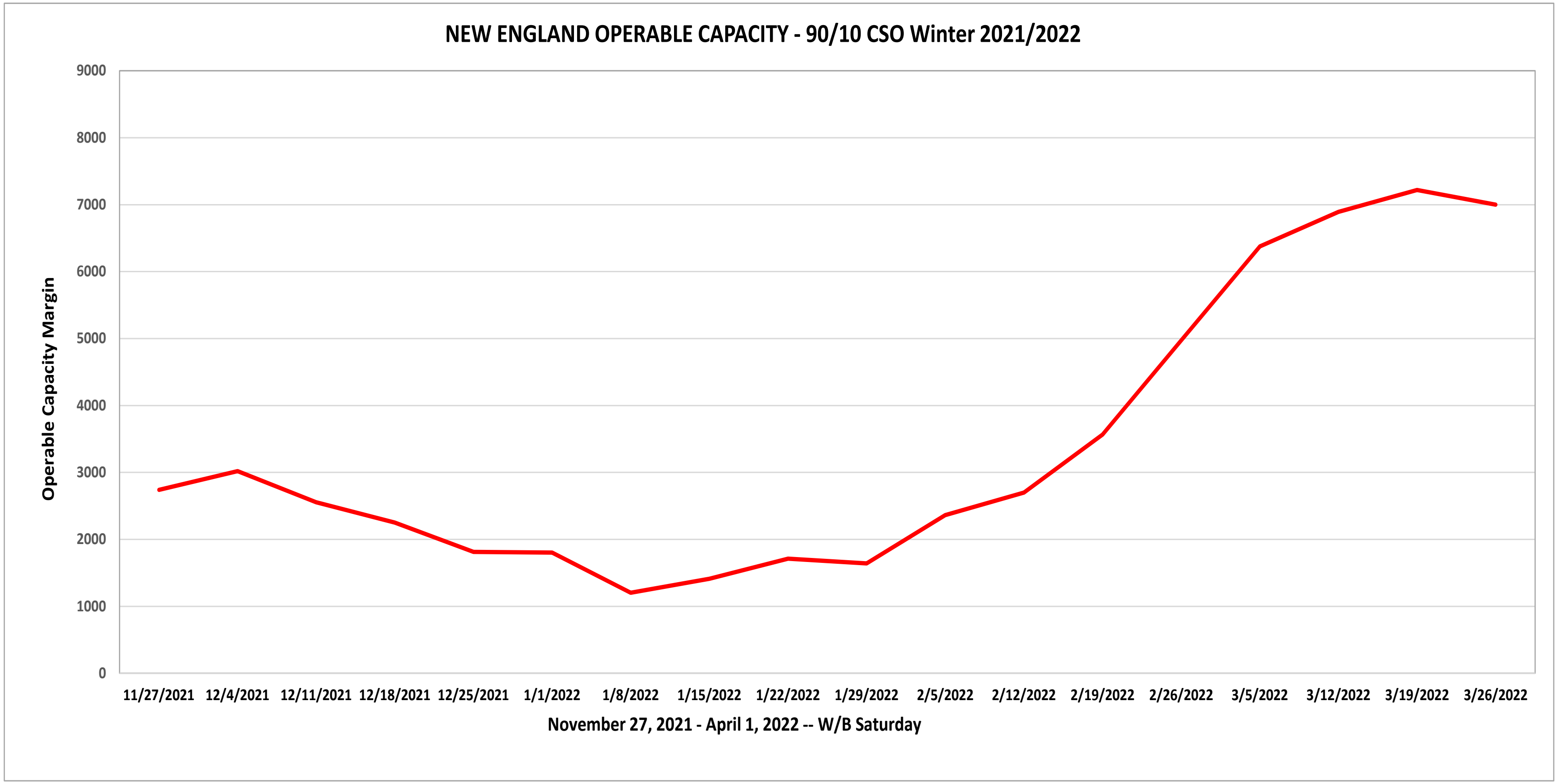
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All 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.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Preliminary Winter 2021/22 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Winter 2021/22 Operable Capacity Analysis
90/10 Forecast



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