NEPOOL Participants Committee Report

September 2022

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Data is through August 24th unless otherwise noted.

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: July 2022 Energy Market value totaled $1.3B
  - August Energy market value was $1.1B, down $184M from July 2022 and up $418M from August 2021
    - August 2022 natural gas prices over the period were 17% higher than July 2022 average values
    - Average RT Hub Locational Marginal Prices ($97.33/MWh) over the period were 7.3% higher than July 2022 averages
      - DA Hub: $101.02/MWh
    - Average August 2022 natural gas prices and RT Hub LMPs over the period were up 109% and 99%, respectively, from August 2021 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 102.8% during August, up from 99.1% during July*
    - The minimum value for the month was 97.7% on Saturday, August 6th

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

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

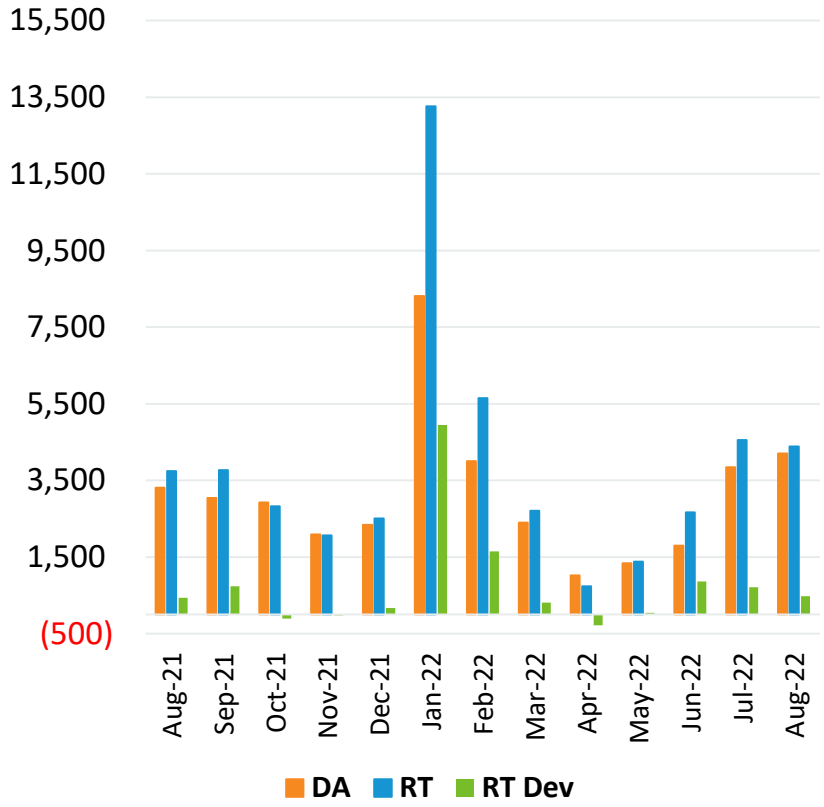
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - August 2022 NCPC payments totaled $5.4M over the period, down $3.7M from July 2022 and up $2M from August 2021
    - First Contingency payments totaled $4.9M, down $3.3M from July
      - $4.8M paid to internal resources, down $3M from July
        - » $1.5M charged to DALO, $2.2M to RT Deviations, $1.1M to RTLO*
      - $180K paid to resources at external locations, down $378K from July
        - » $167K charged to DALO at external locations, $13K to RT Deviations
    - Distribution payments totaled $402K, down $192K from July
  - NCPC payments over the period as percent of Energy Market value were 0.5%

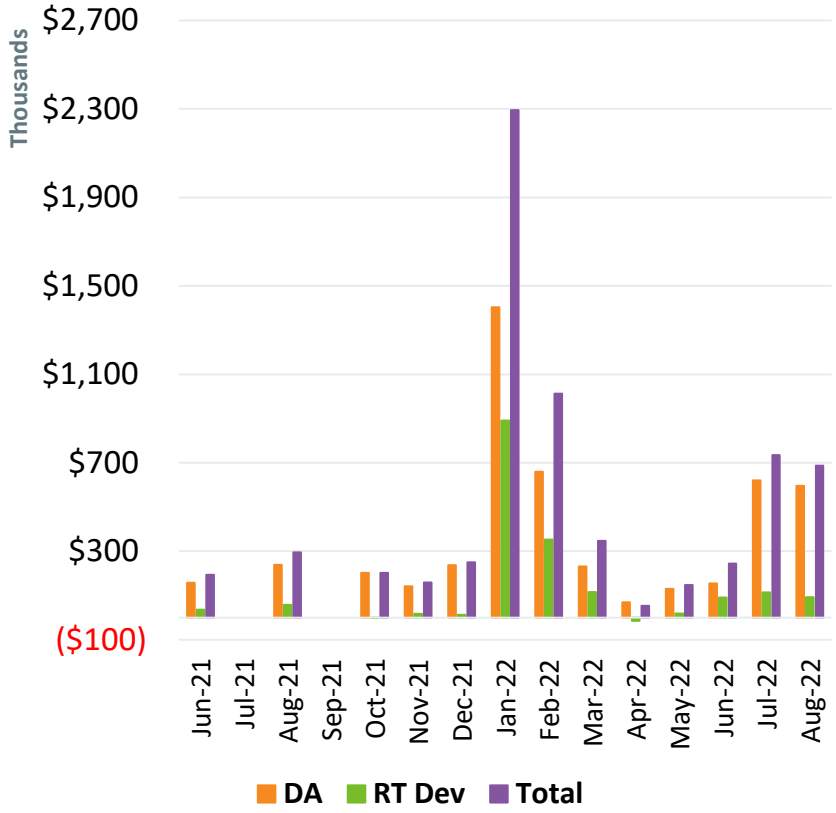
*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $515K; Rapid Response Pricing (RRP) Opportunity Cost - $616K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

Price Responsive Demand (PRD) Energy Market Activity by Month

DA, RT, and RT Dev MWh



Market Value



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

Highlights

- Discussions on the second phase of the 2050 Transmission Study are expected to begin at the NEPOOL committees in late 2022/early 2023
- 2021 Economic Study (FGRS Phase 1) final report expected to be posted by mid-August
- The Installed Capacity Requirement (ICR) related values for the 2022 Annual Reconfiguration Auctions (ARAs) were incorrect
  - The ISO reported the errors to FERC Office of Enforcement and discussed them with the Reliability Committee
  - After studying and presenting the feasible options to stakeholders, the ISO conducted ARA 2 in August, as scheduled, with the FERC-accepted values

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 14 (2023-2024)
  - Second annual reconfiguration auction (ARA2) was held on August 1-3, and results will be posted no later than August 31
- CCP 15 (2024-2025)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted on June 28
- CCP 16 (2025-2026)
  - Auction results were filed with FERC on March 21 and on July 18, FERC issued an order accepting the results effective July 19

CCP – Capacity Commitment Period

Summary of Operations, August 4th – 9th, 2022

Highlights

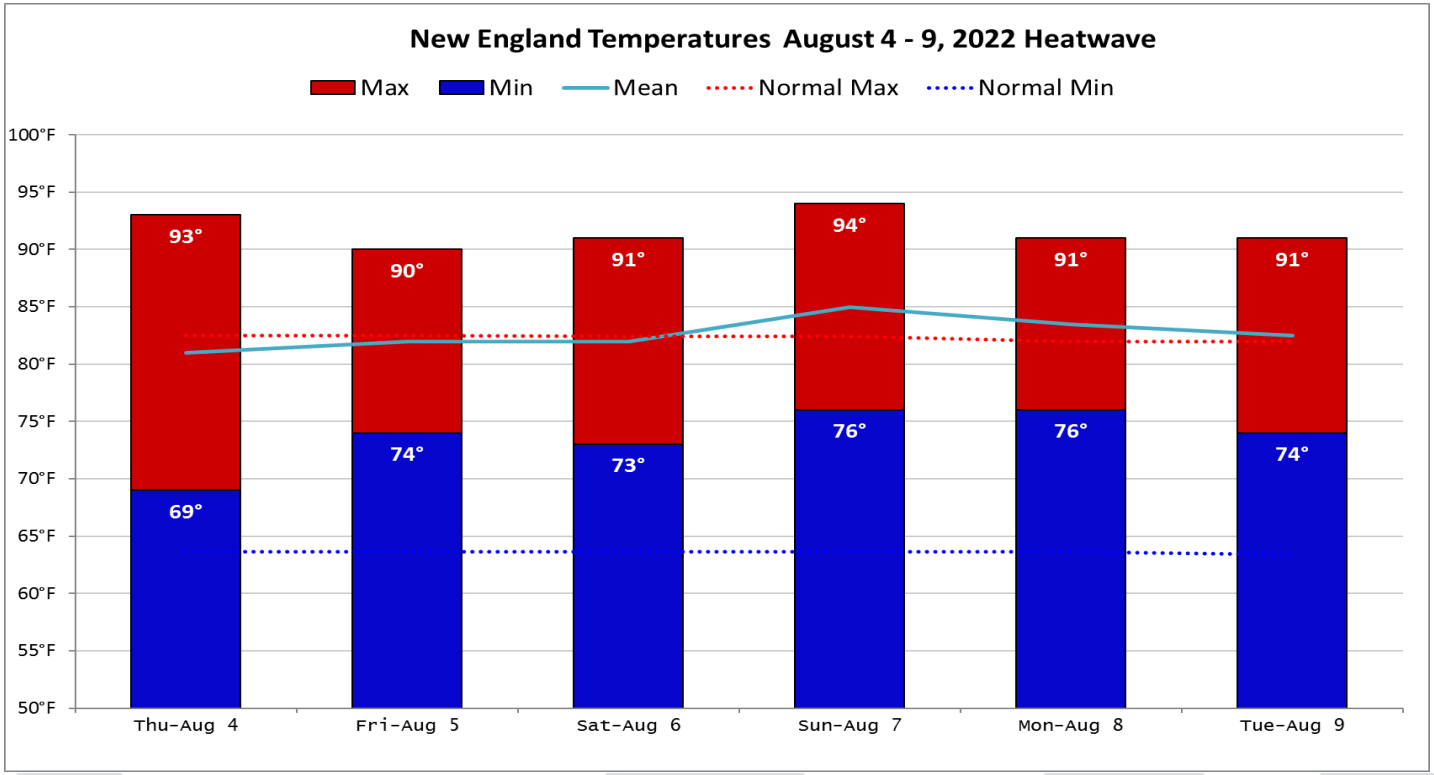
- The August 4 – 9 heat wave was very similar to the July 19 – 24 heat wave in terms of regional weather, loads, and energy demand; one key difference was that fewer unplanned outages of generating resources occurred during this most recent heat wave
- On average, temperatures in the region were well above normal during the six-day heat wave
- Once again during this heat wave, weather and load forecasts were highly accurate
- Significantly less fuel oil was utilized during this heat wave as compared to the July heat wave; this was primarily due to increased energy supplied by natural gas-fired resources
- Despite some unplanned outages, New England's transmission system and resource fleet performed well
- System energy and reserve pricing properly reflected system conditions during the heat wave

Preparation Activities

- Beginning on Wednesday, 8/3, and periodically throughout the week, ISO Operations staff held conference calls and meetings with neighboring NPCC area and Local Control Center management staff
- Due to the forecasted system conditions and expectations for reduced capacity, ISO declared M/LCC-2, Abnormal Conditions Alert, on 8/4 from 1600 – 2200 and on 8/8 from 0930 – 2200

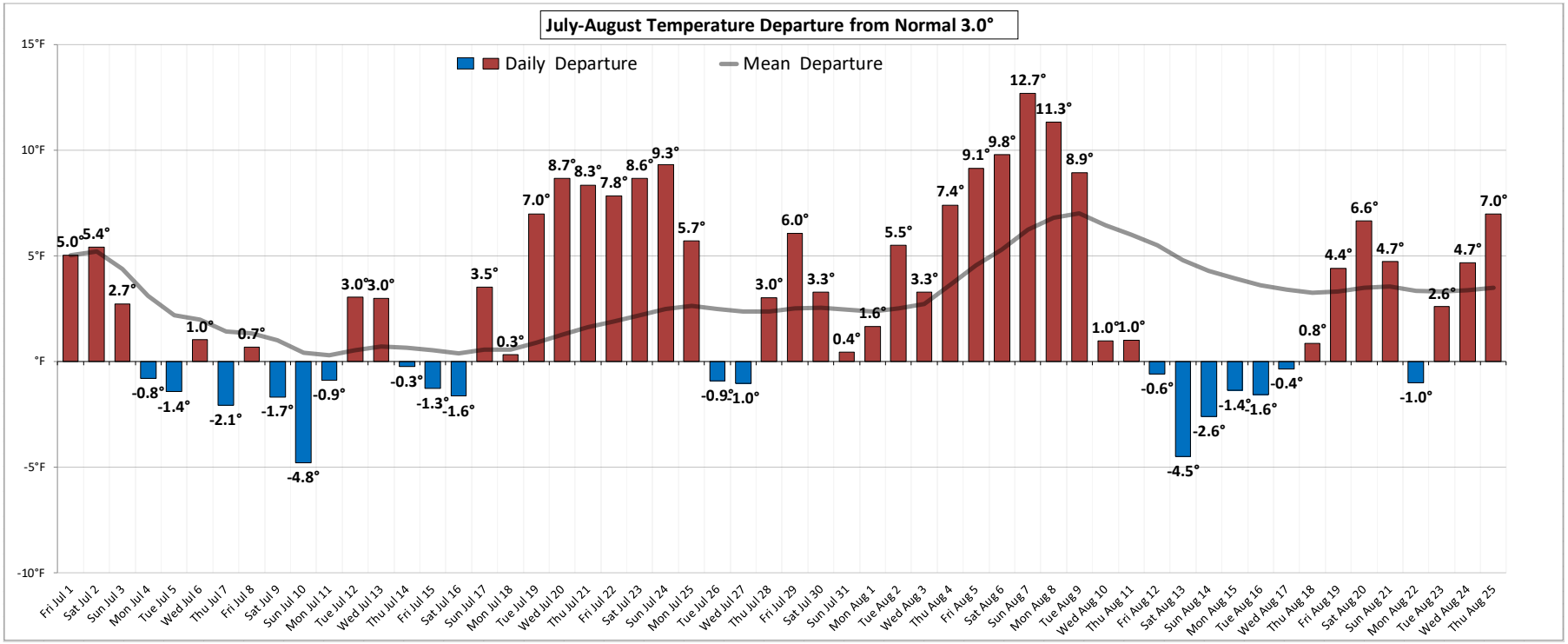
For the Second Time This Summer, New England Temps Reached 90°F For Six Consecutive Days

- The 8-city weighted-avg. high temperature reached 93.8°F, slightly higher than the 92.9°F avg. during the July heat wave; the highest single day 8-city weighted-avg. temperature of 94°F occurred on Sunday, 8/7
- Boston's week-long high temps ranked 6th all-time, reaching a high of 98°F on 4 days during the heat wave (8/4 and 8/7 through 8/9)



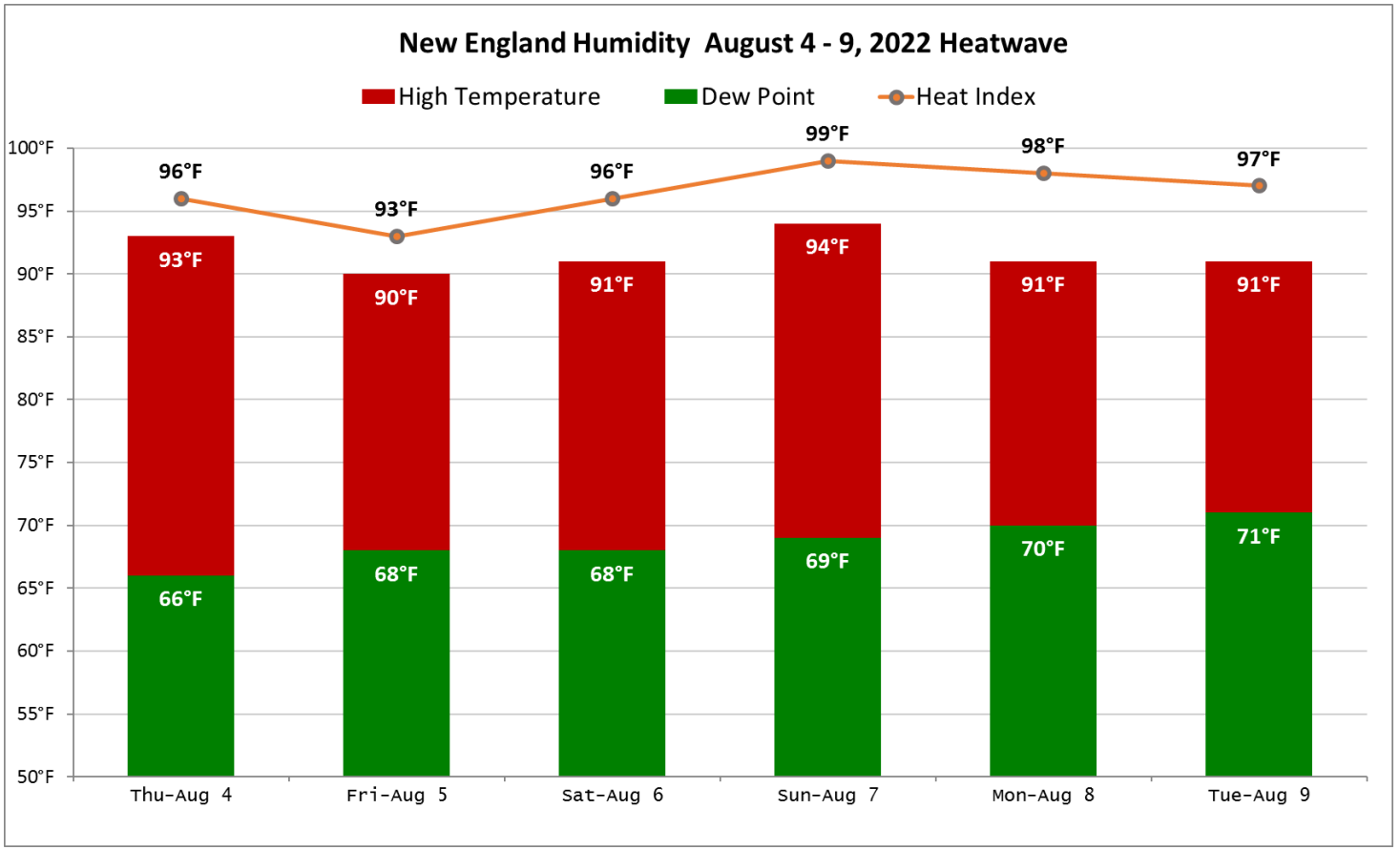
Average Temperatures Continue to Trend Significantly Above Normal

- Since mid-July temperatures have mostly been above normal; during the August heat wave temperatures were well above normal



New England Dew Points Were Not Excessive

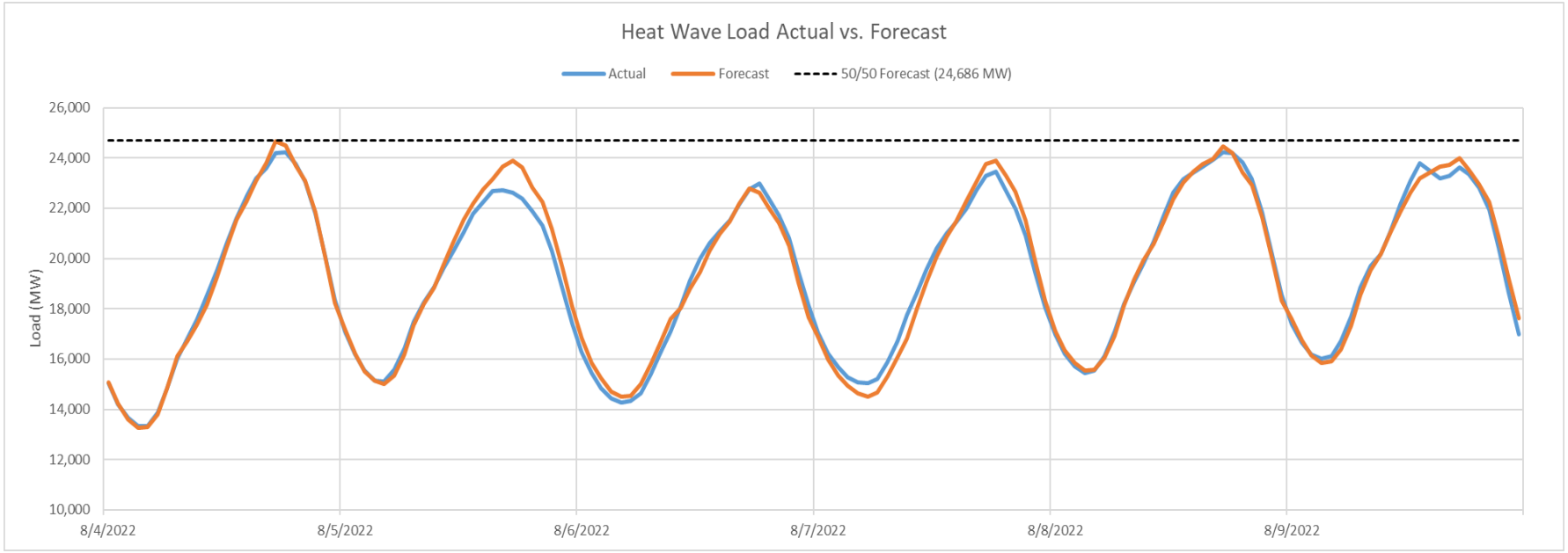
- Similar to the July heat wave, regional dew points were not excessive, resulting in a heat index below 100°F throughout the heat wave



Regional Load and Energy Demand Were Similar to the July Heat Wave

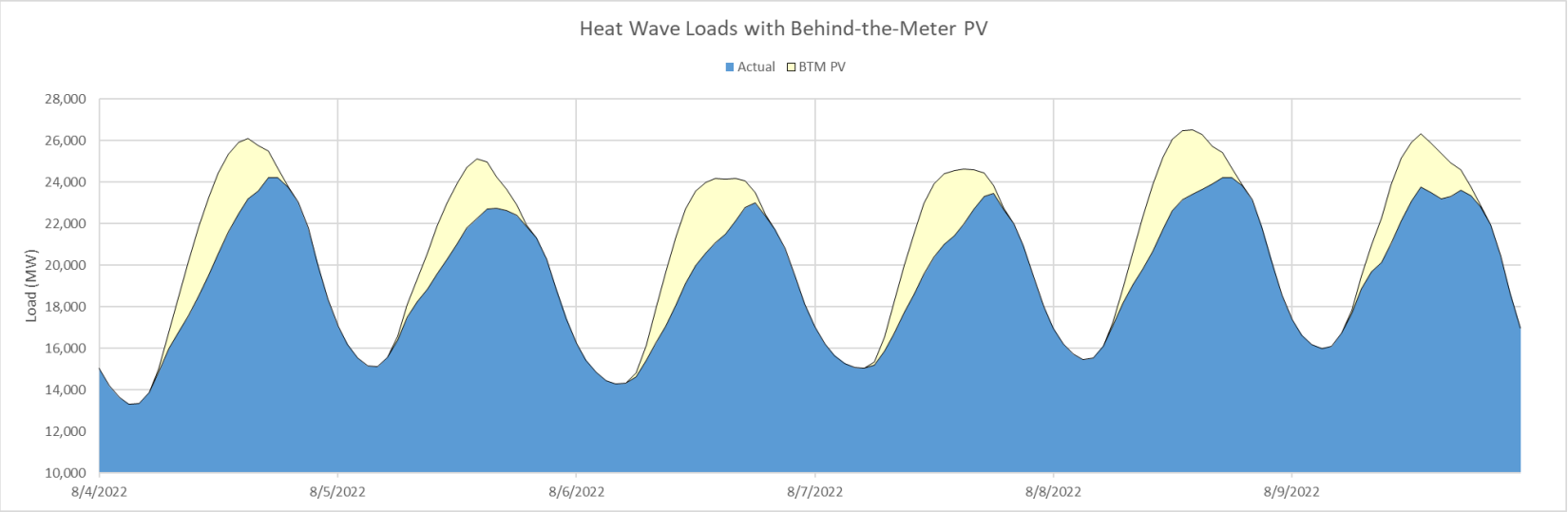
Weather Forecasts and ISO's Load Forecast Were Accurate

- Peak integrated load of 24,226 MW occurred on Thursday, 8/4; peak hourly integrated load, including load served by settlement only generators, was 24,775 MW
- Total energy demand over the 6 days was approximately 2,780 GWh; avg. ~ 465 GWh/day
- Weather forecasts used by ISO to forecast load averaged less than 1.2°F error over all hours



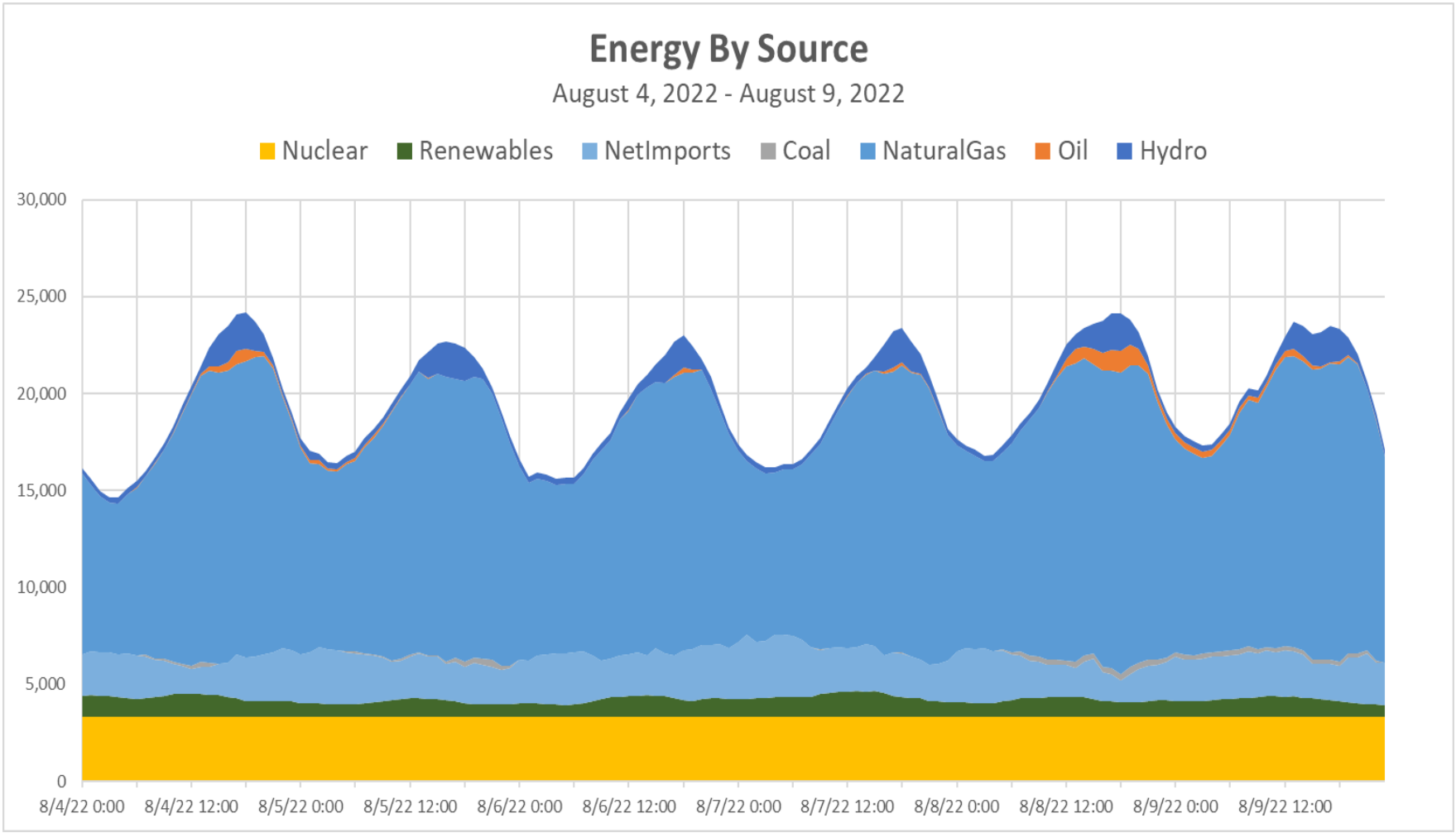
Energy Contributions From Behind-the-Meter PV Was Significant

- The peak contribution from behind-the-meter (BTM) PV during the six-day heat wave was approx. 3,950 MW on 8/4; BTM PV contributions were significantly lower during peak hours



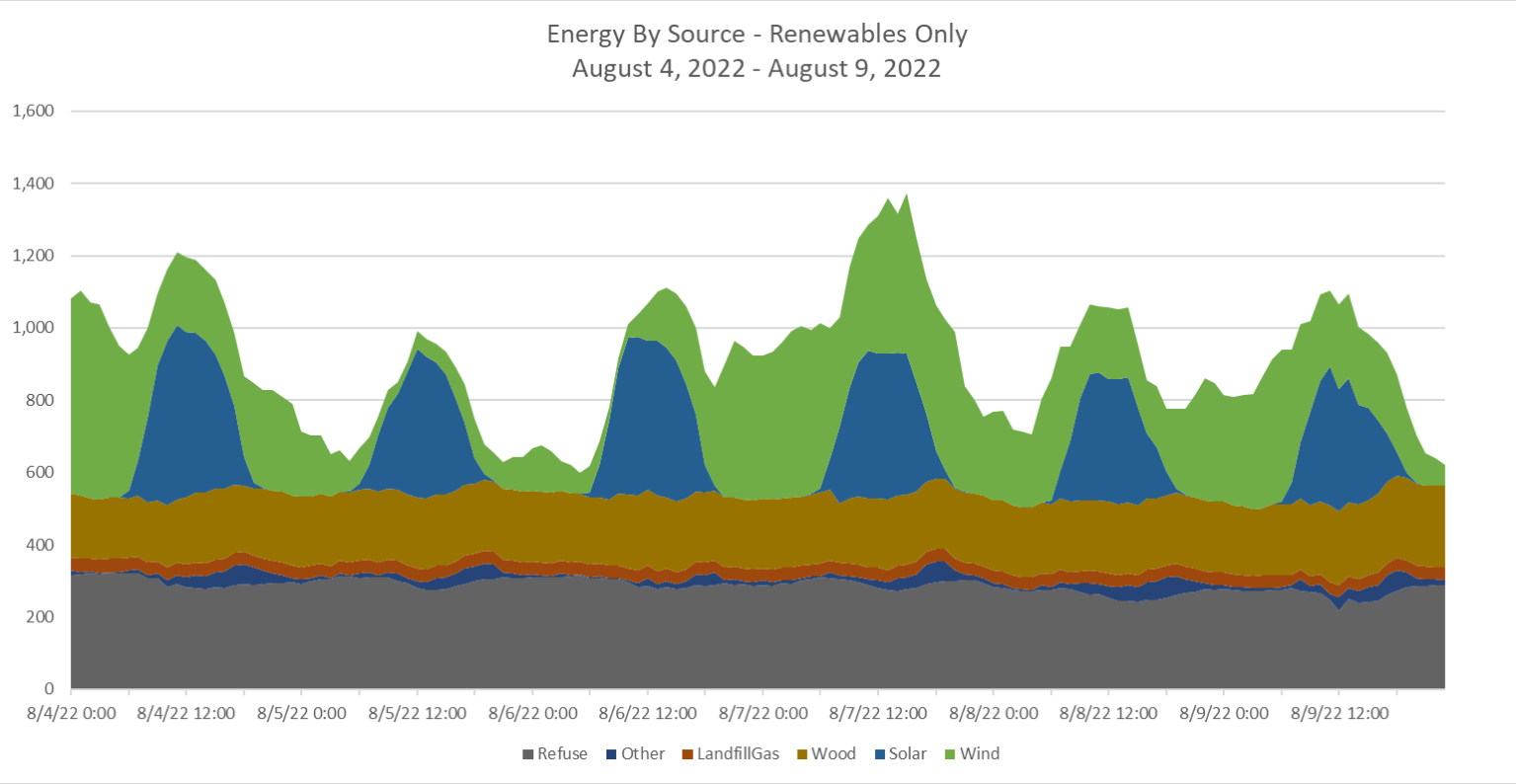
In the figure above, load served behind-the-meter is added to load served by the power grid to show total New England demand during the heat wave

Energy Sources During the Heat Wave

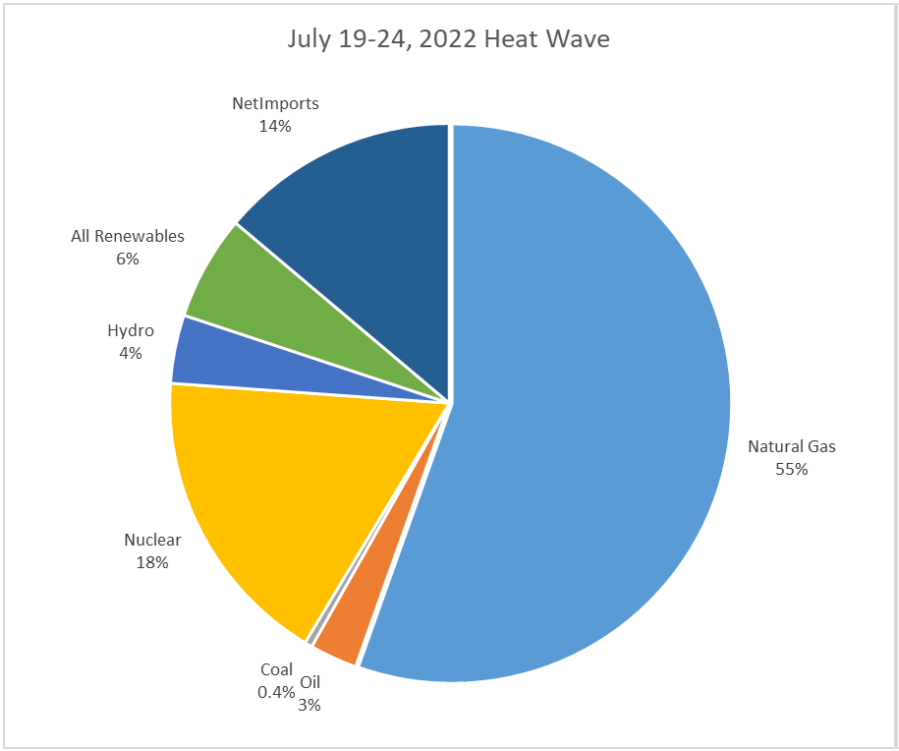


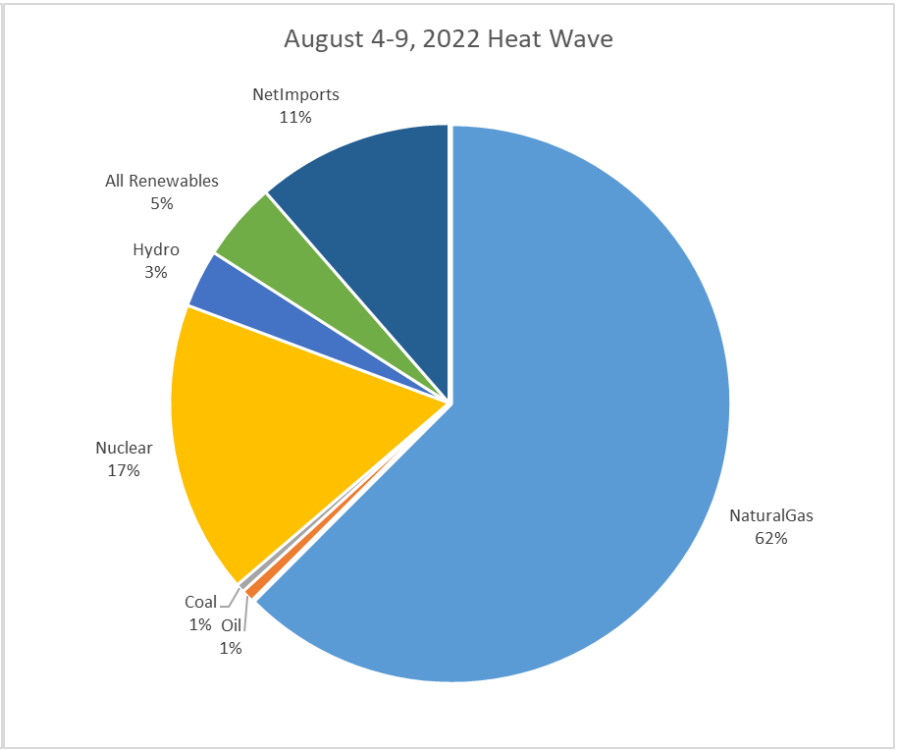
Energy Sources During the Heat Wave – Renewables Only

- Aggregate contributions from wind energy peaked in HE02 on 8/4, and averaged ~240MW/hr during the six-day period which was down from ~450MW/hr in the July heat wave



Energy Sources – Comparison of August and July 2022 Heat Waves





Stored Fuel Usage During the Heat Wave

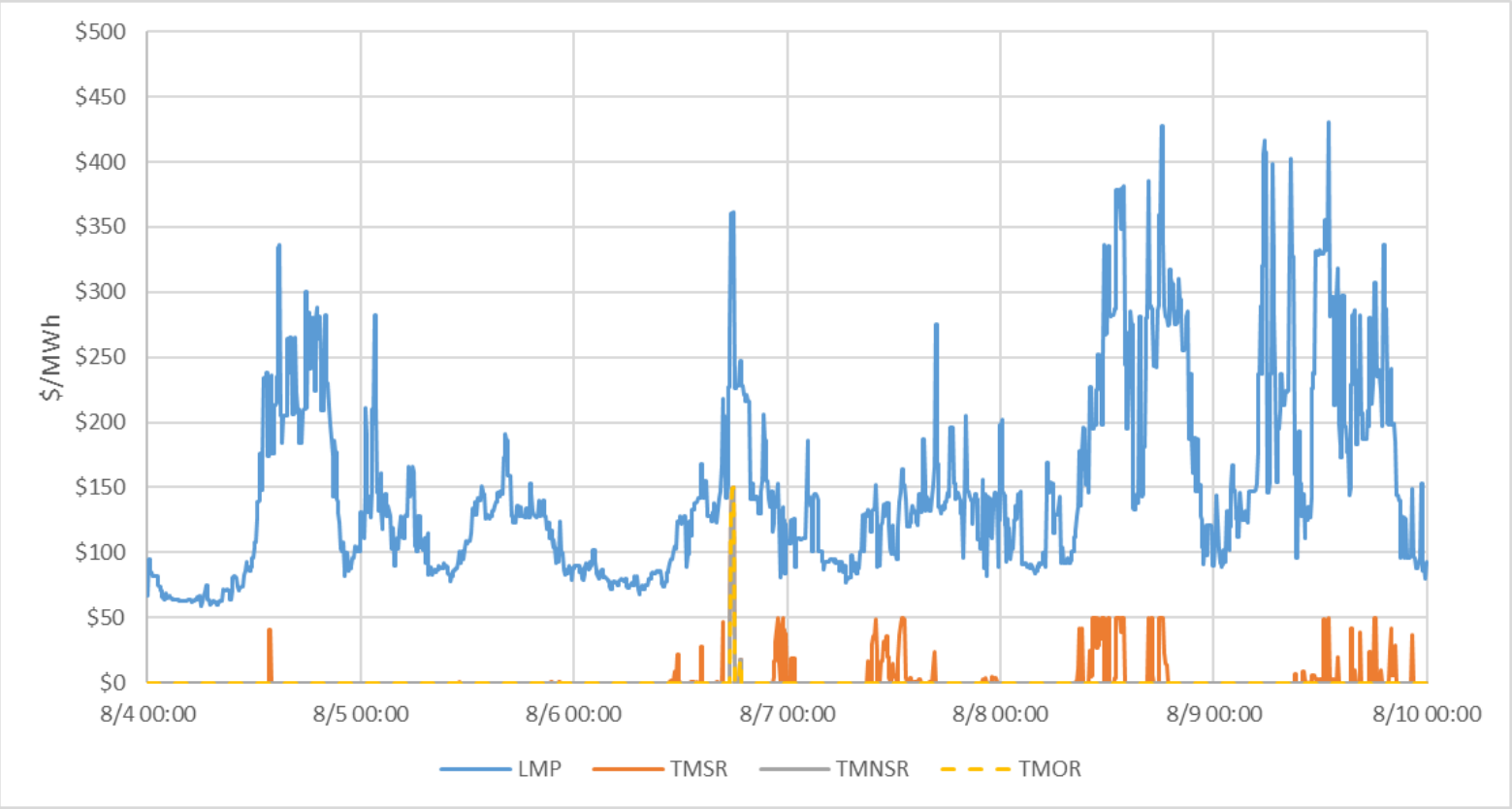
- Injection of LNG to pipelines for use by generators was minimal
- Fuel-oil usage was lower than the amount used during the July heat wave (~6M gallons); according to generator survey responses, during the two-week span of 7/27 to 8/9;
  - Approx. 1.5M gallons of fuel-oil was consumed by generators; a majority of fuel-oil consumption occurred during the six-day heat wave
  - Some replenishment has already occurred and additional replenishment of distillate fuel oil (DFO) and residual fuel oil (RFO) is expected prior to this winter

New England's Transmission System and Resource Fleet Performed Well

- Unplanned transmission outages were minimal
- Unplanned resource outages and reductions occurred at times throughout the heat wave, averaging ~750 MW/day; this was a reduction from ~1,500 MW/day of outages and reductions during the July heat wave
  - Unplanned outages and reductions occurring on the peak load day of 8/4, totaled ~1,050 MW
- Supplemental commitment of resources occurred on each day of the heat wave, averaging ~700 MW/day

System Energy and Reserve Pricing

- System LMPs averaged ~ $148/MWh during the six-day heat wave; non-zero system reserve prices occurred periodically, with TMOR and TMNSR pricing occurring only on 8/6



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.5°F) Max: 98°F, Min: 63°F Precipitation: 1.14" – Below Normal Normal: 2.94"	Hartford	Temperature: Above Normal (3.9°F) Max: 96°F, Min: 54°F Precipitation: 4.69" - Above Normal Normal: 3.86"

Peak Load:	24,226 MW	August 4, 2022	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	8/4 16:00	8/4 22:00	Capacity
M/LCC 2	8/8 09:30	8/8 22:00	Capacity

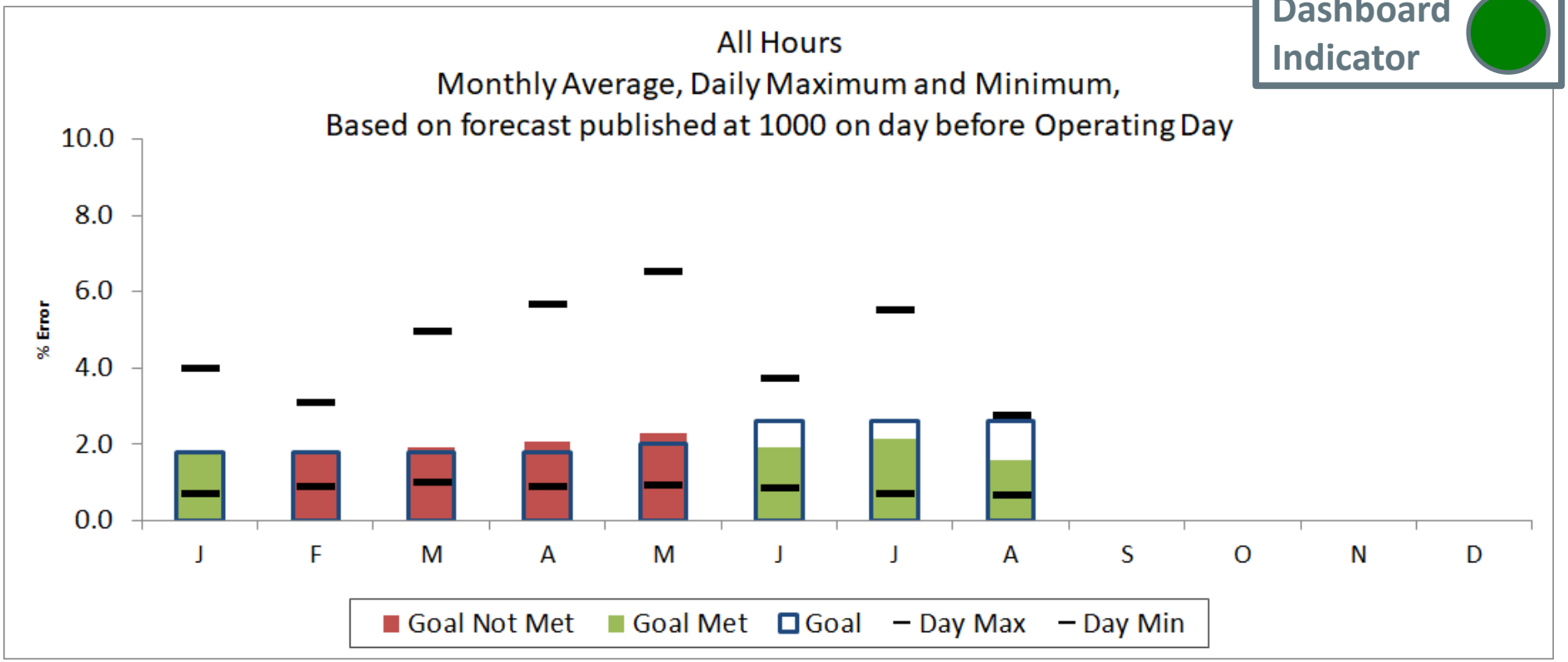
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
8/2/2022	NBPSO	617
8/4/2022	NYISO	1100
8/8/2022	NYISO	550
8/8/2022	NYISO	750

2022 System Operations - Load Forecast Accuracy

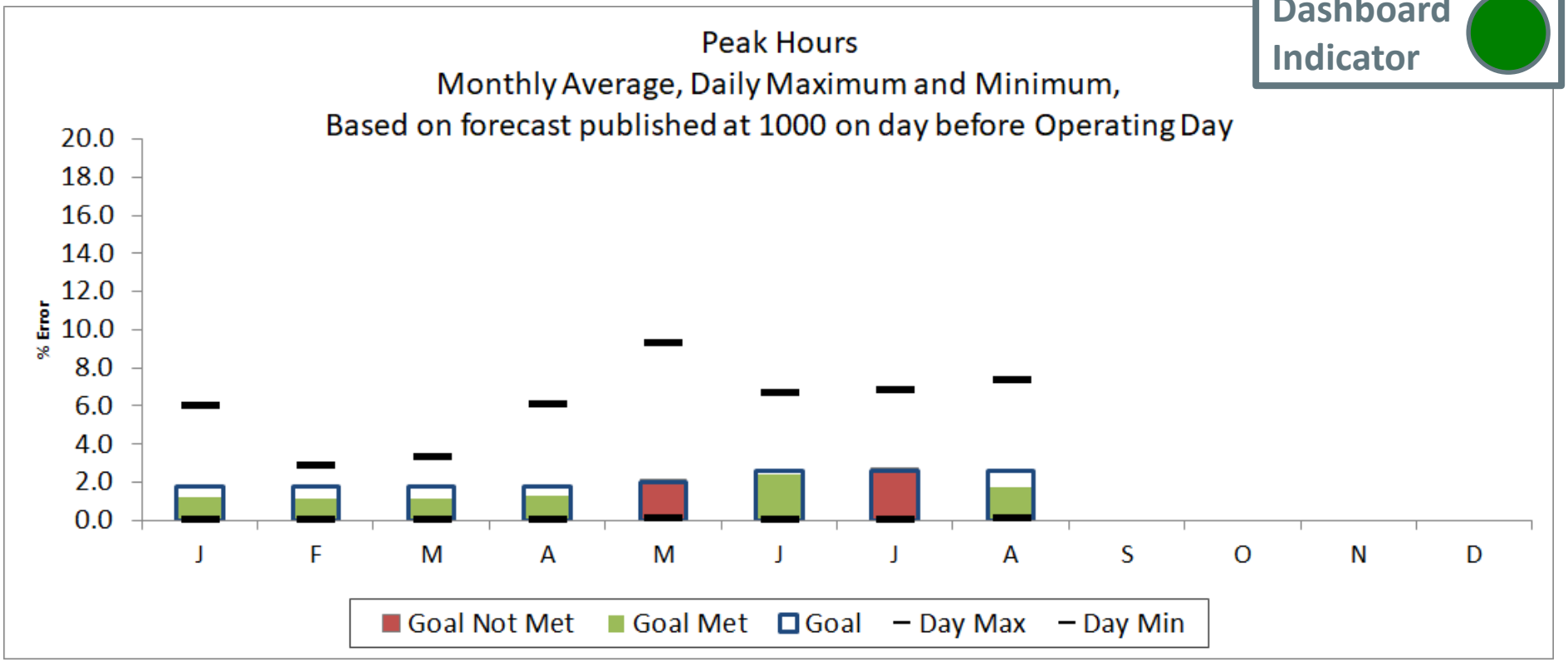
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.97	3.07	4.92	5.66	6.52	3.71	5.48	2.74					6.52
Day Min	0.69	0.87	0.97	0.85	0.91	0.83	0.69	0.66					0.66
MAPE	1.79	1.81	1.93	2.05	2.30	1.92	2.13	1.59					1.94
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

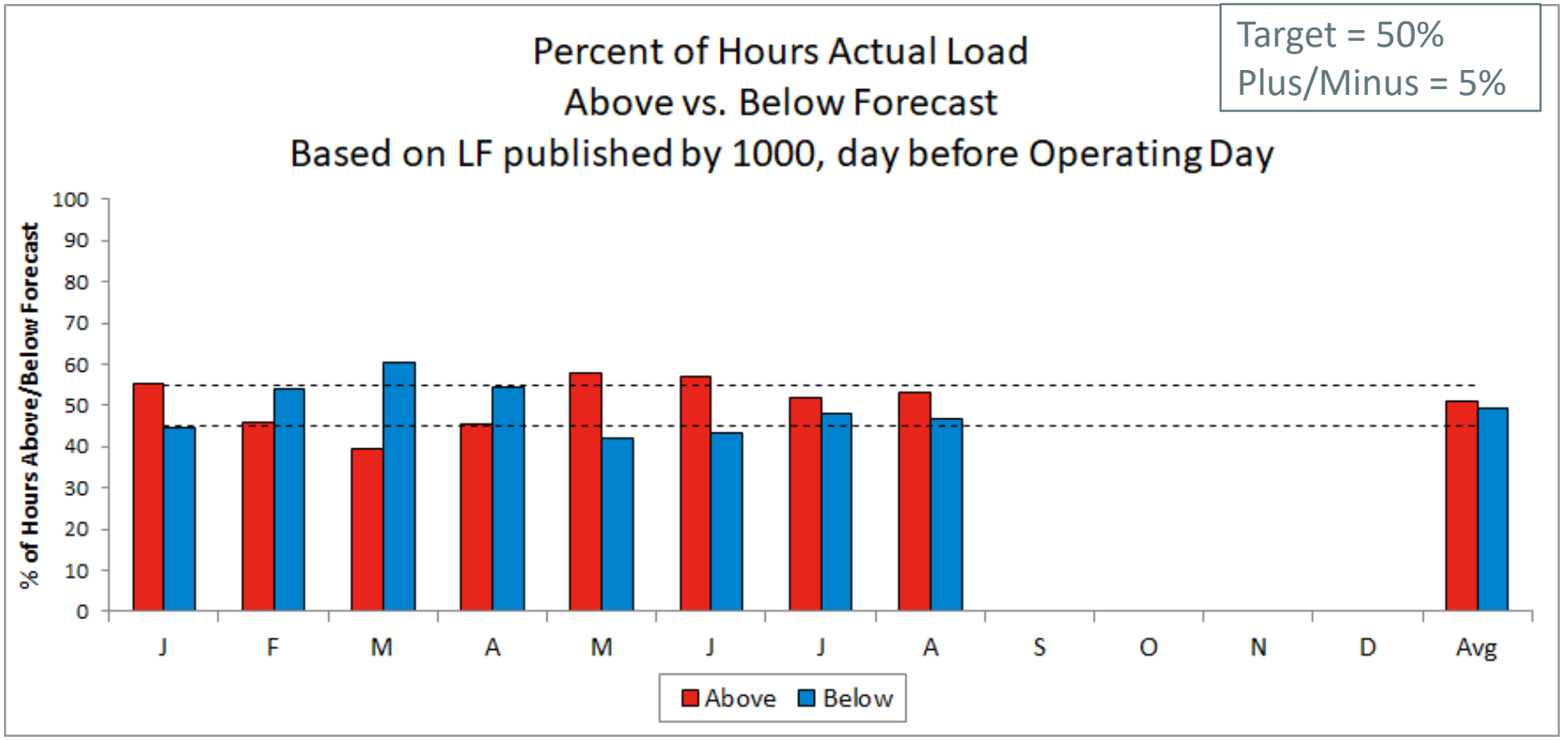
2022 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



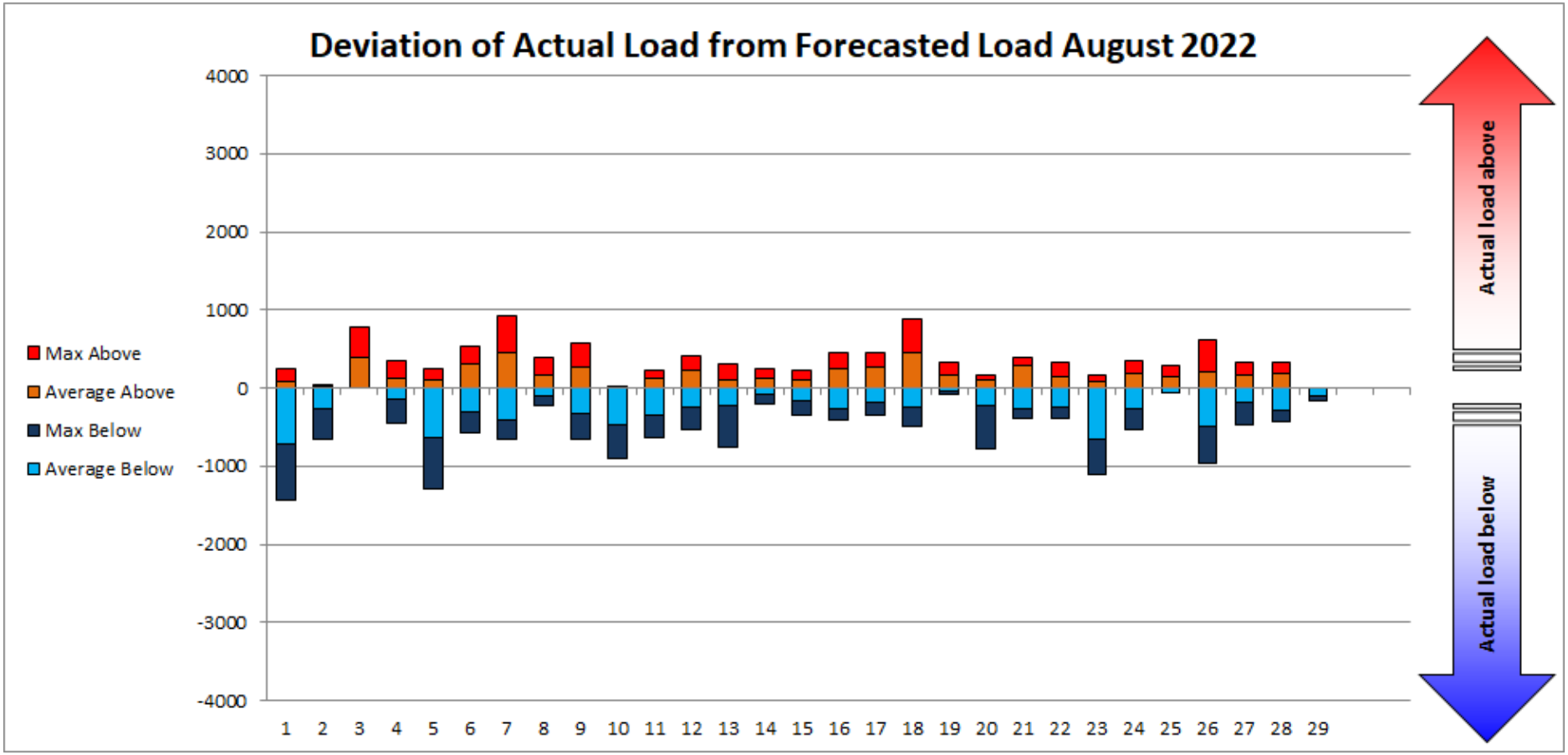
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.01	2.85	3.32	6.08	9.27	6.70	6.85	7.31					9.27
Day Min	0.02	0.03	0.04	0.00	0.06	0.01	0.02	0.08					0.00
MAPE	1.25	1.11	1.13	1.29	2.14	2.43	2.73	1.77					1.74
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

2022 System Operations - Load Forecast Accuracy cont.

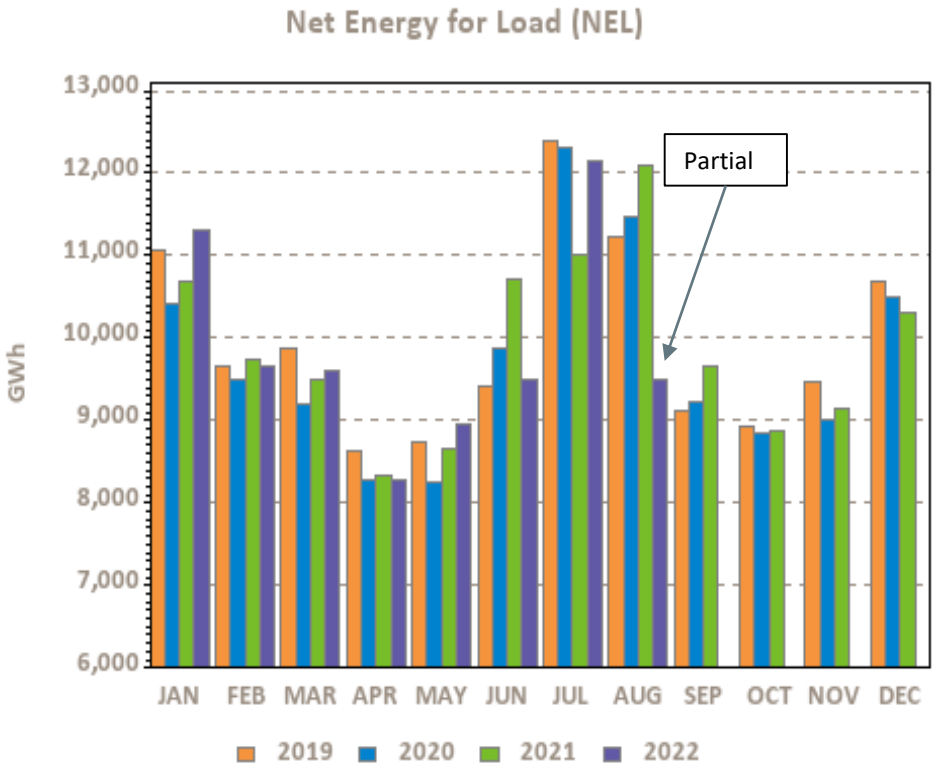


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	55.2	46	39.7	45.6	57.8	56.8	51.9	53.1					51
Below %	44.8	54	60.3	54.4	42.2	43.2	48.1	46.9					49
Avg Above	219.5	245.7	175.9	180	217.2	209.6	268.3	170.3					268
Avg Below	-223.1	-207.6	-240.0	-191.5	-192.2	-215.9	-295.8	-256.9					-296
Avg All	22	6	-78	-18	30	23	5	-37					-6

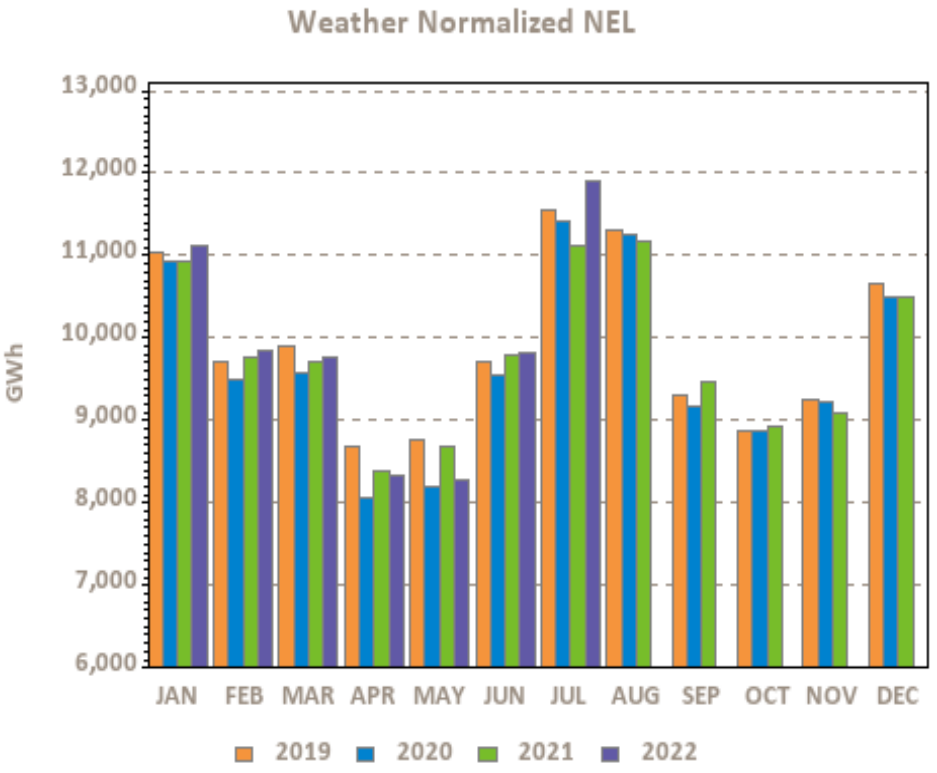
2022 System Operations - Load Forecast Accuracy cont.



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



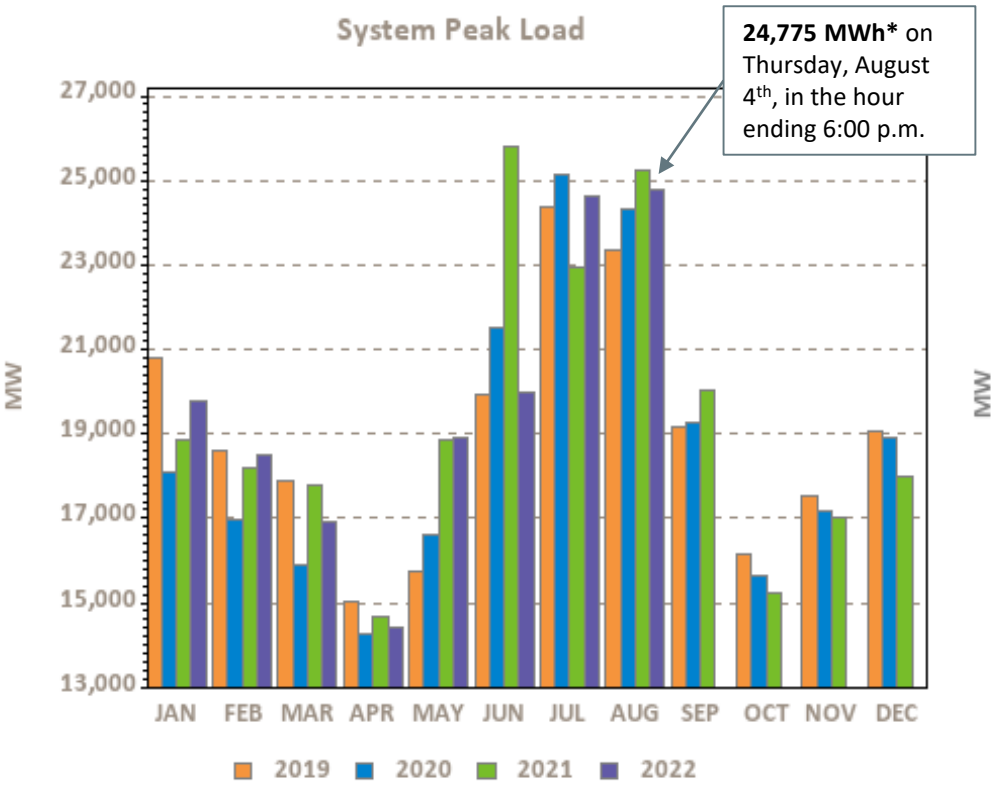
Ann Tot (TWh): 119.2 116.9 118.8 78.9



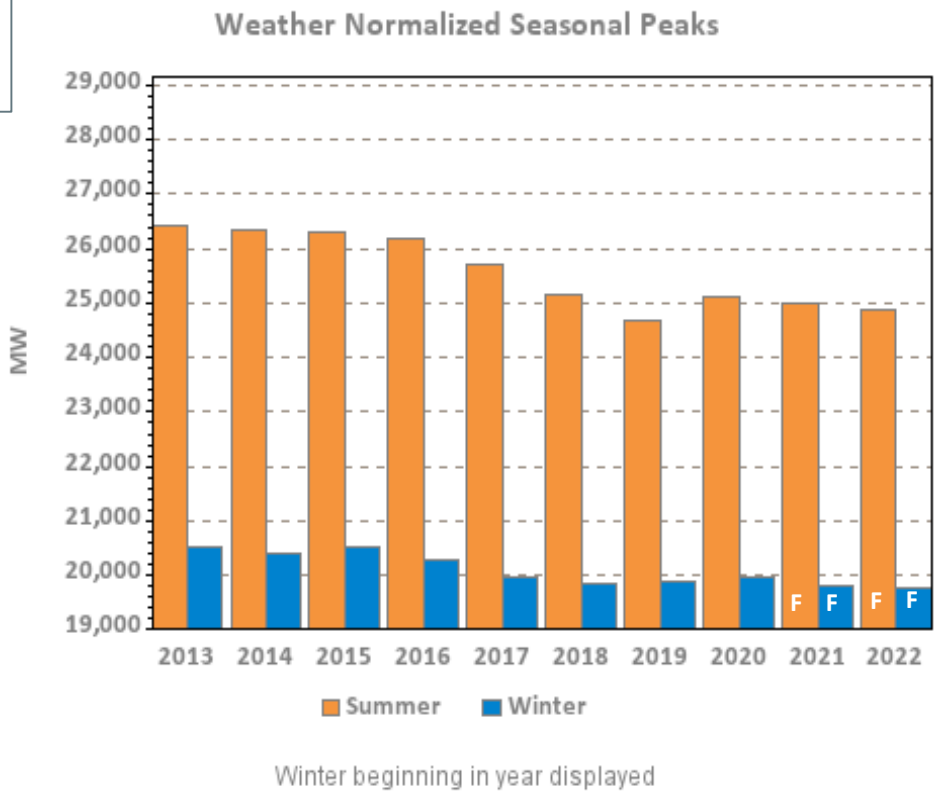
Ann Tot (TWh): 118.8 116.3 117.6 69.1

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



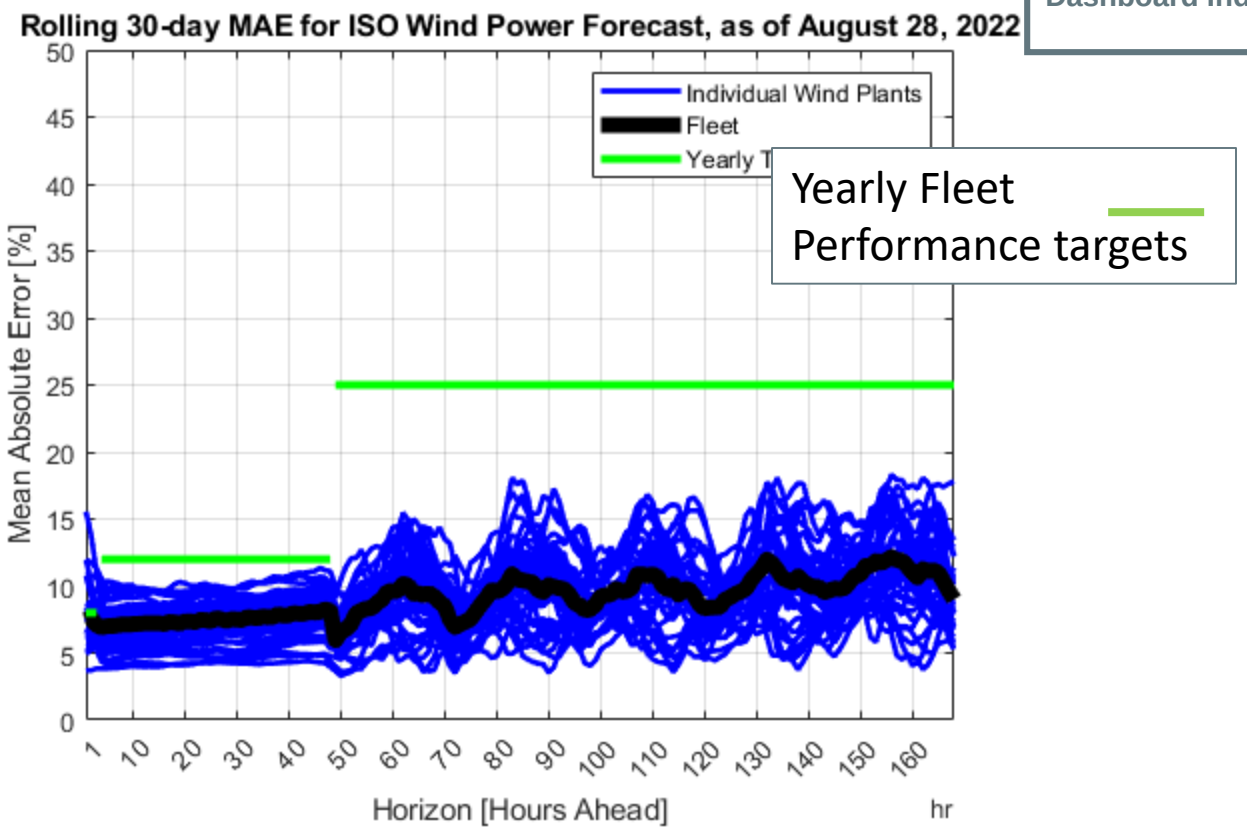
*Revenue quality metered value



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

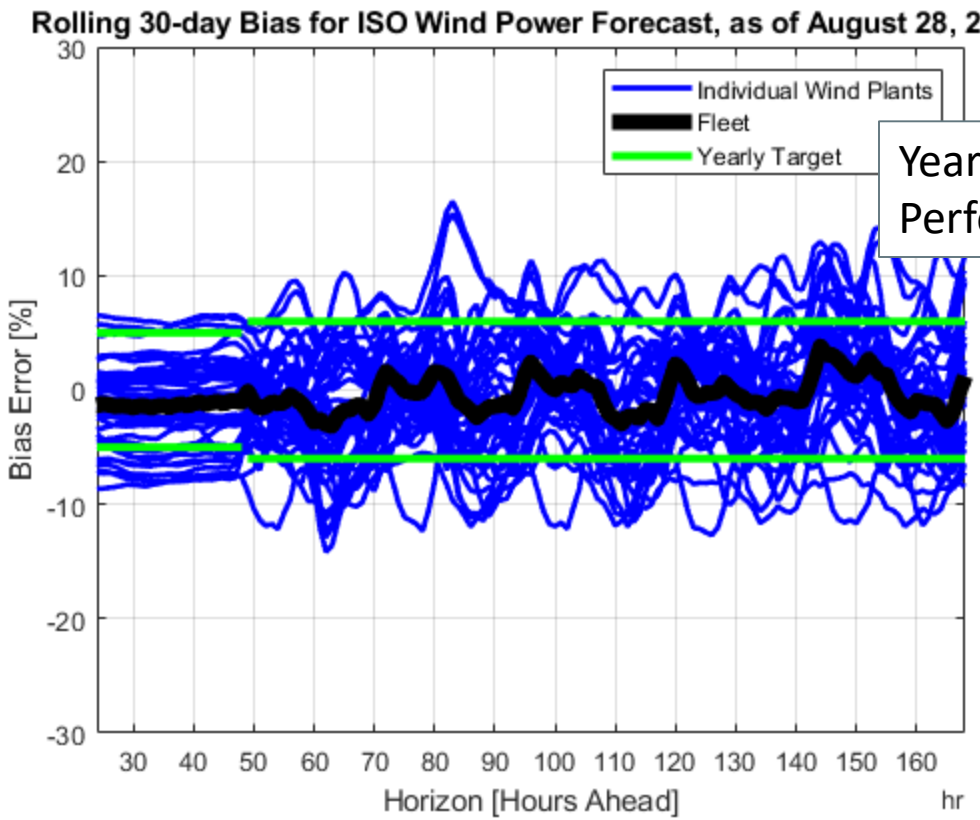


Yearly Fleet Performance targets

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

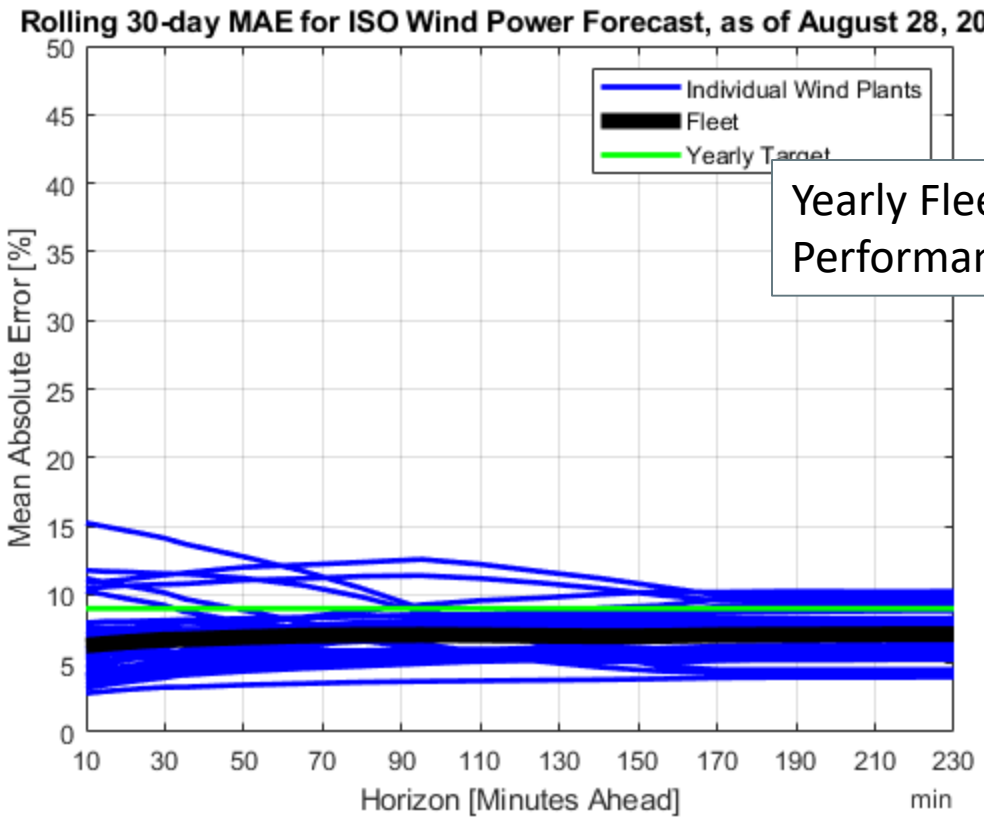


Yearly Fleet Performance targets

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

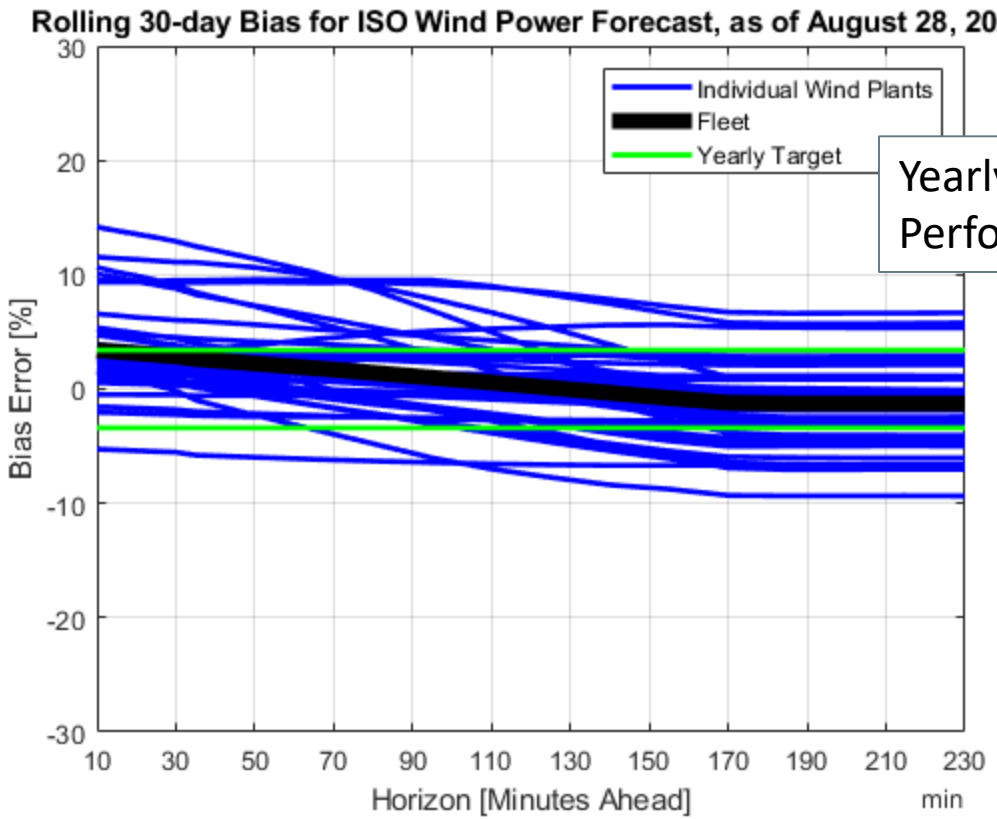


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

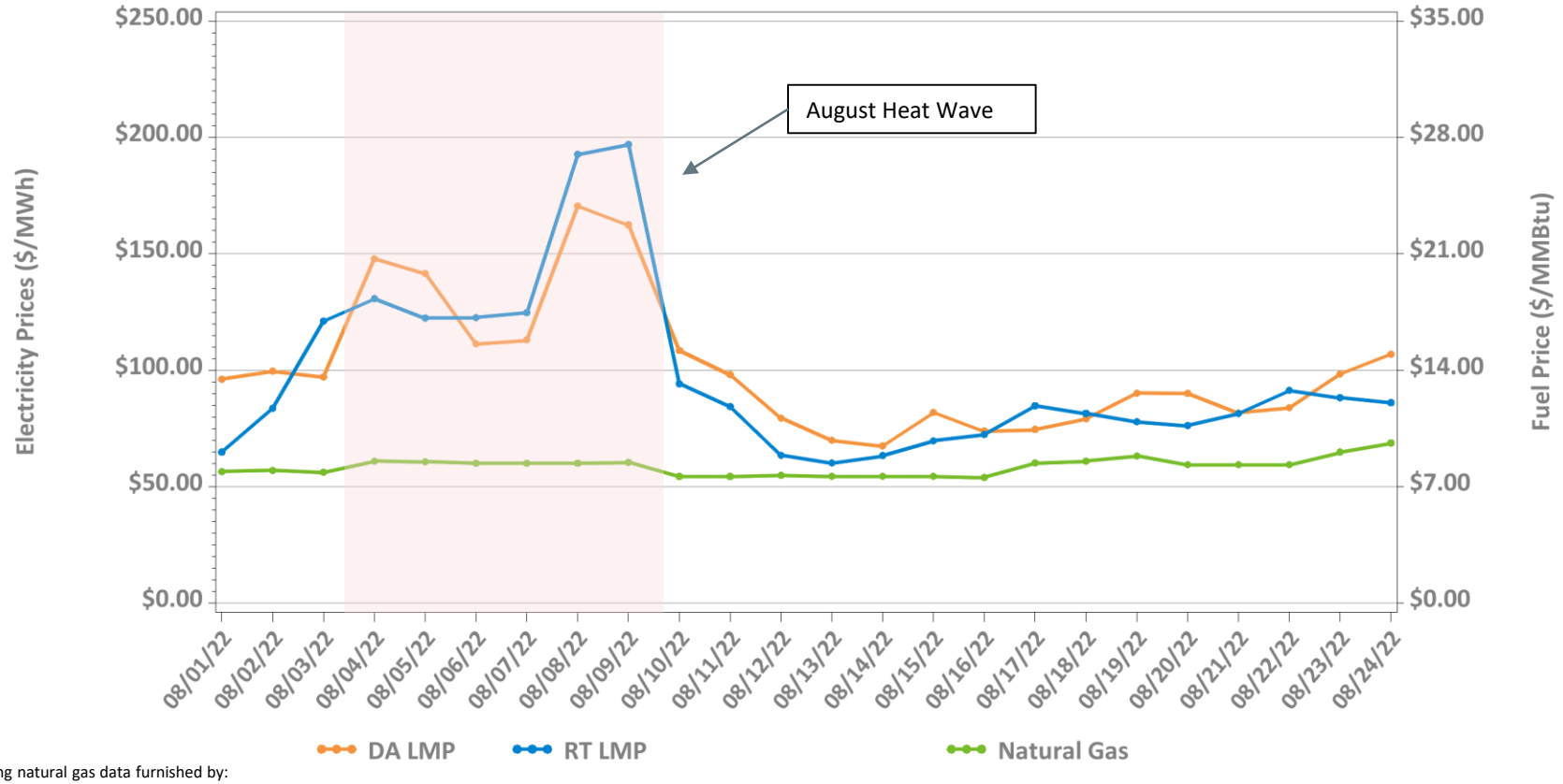


Yearly Fleet Performance targets

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.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: August 1-24, 2022

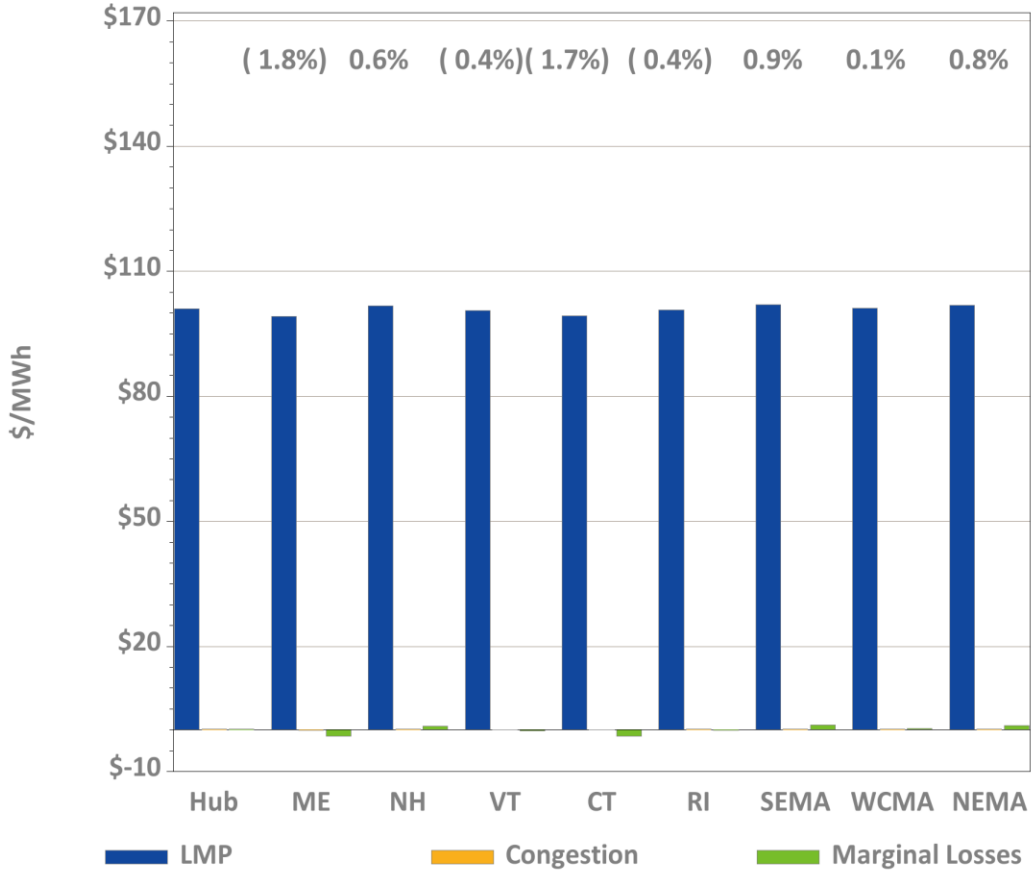


Underlying natural gas data furnished by:

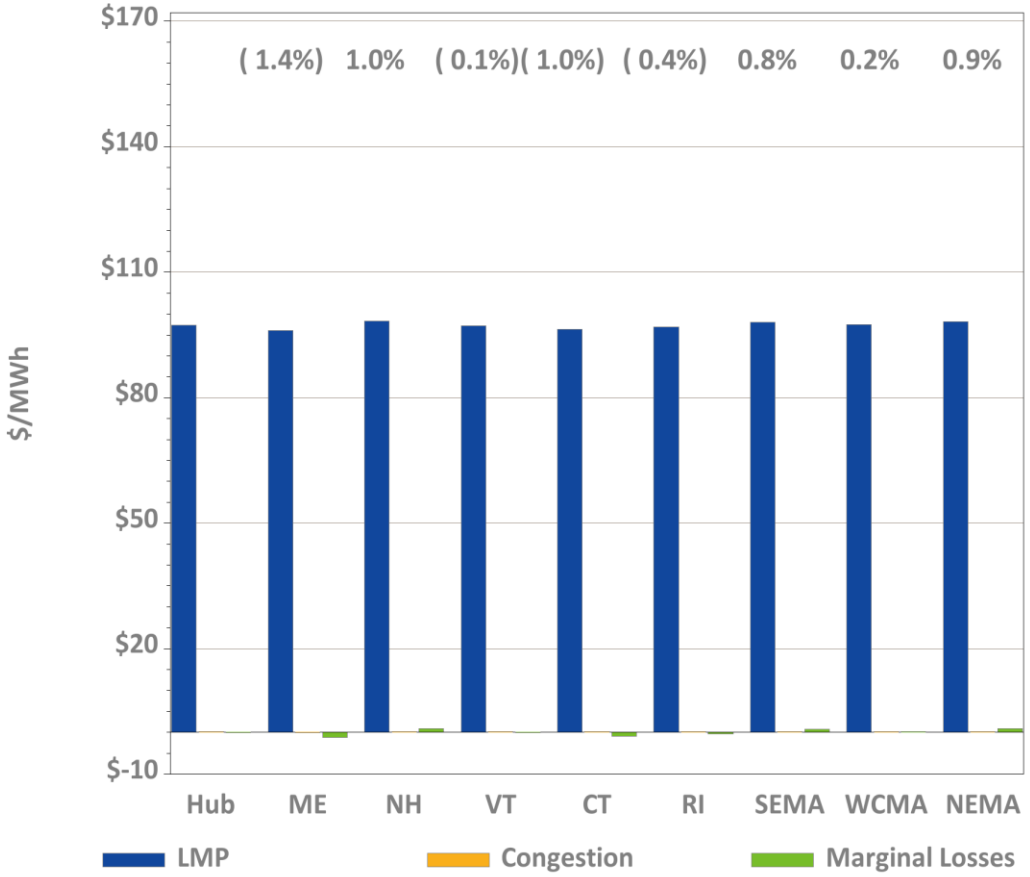
ICE Global markets in clear view

Average price difference over this period (DA-RT): $3.70
Average price difference over this period ABS(DA-RT): $14.01
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 14%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, August 2022



RT LMPs Average by Zone & Hub, August 2022

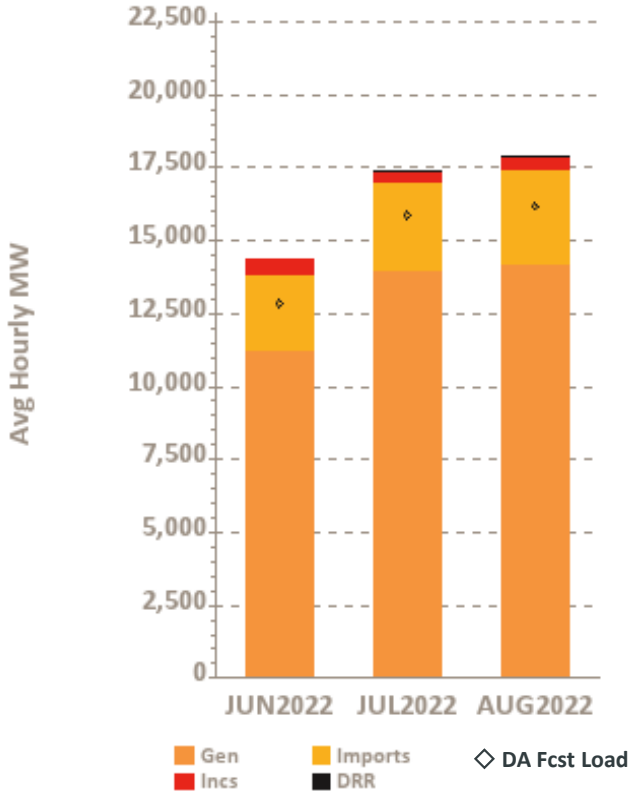


Definitions

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

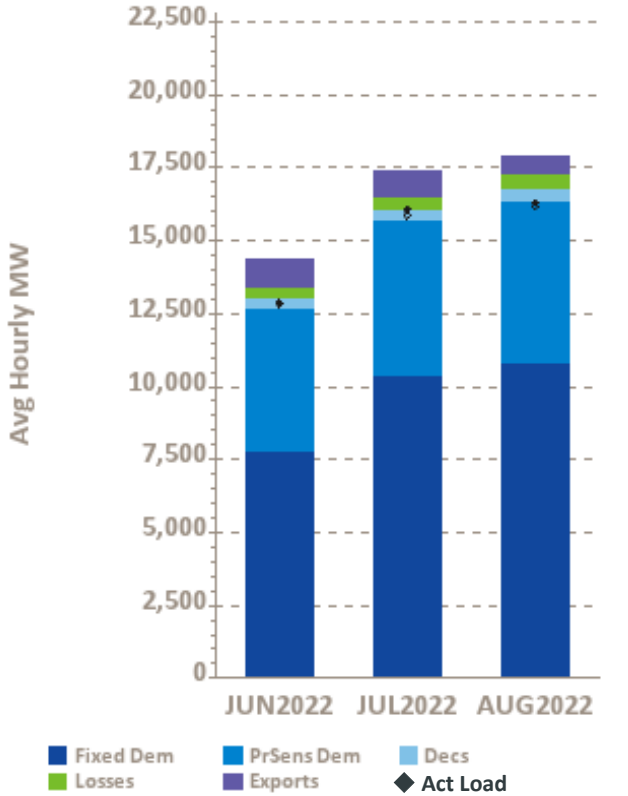
Components of Cleared DA Supply and Demand – Last Three Months

Supply



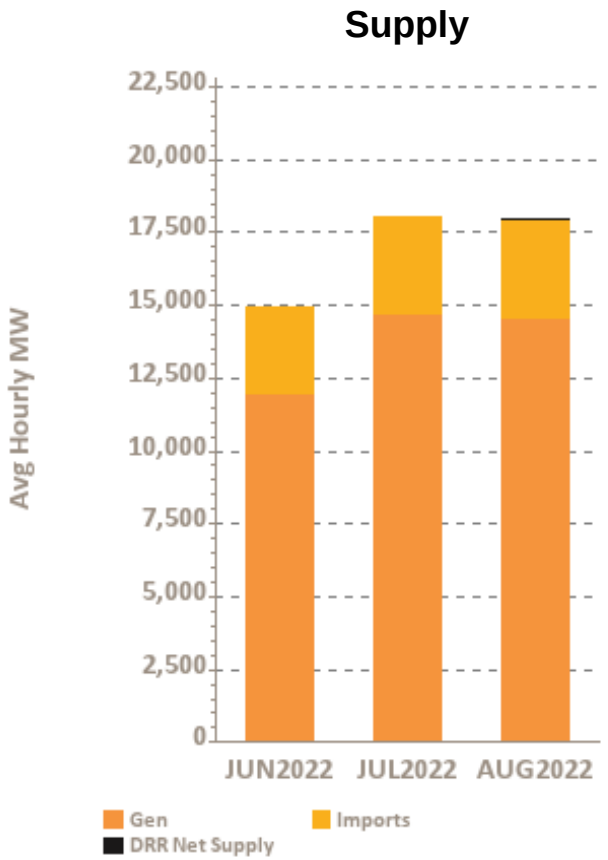
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

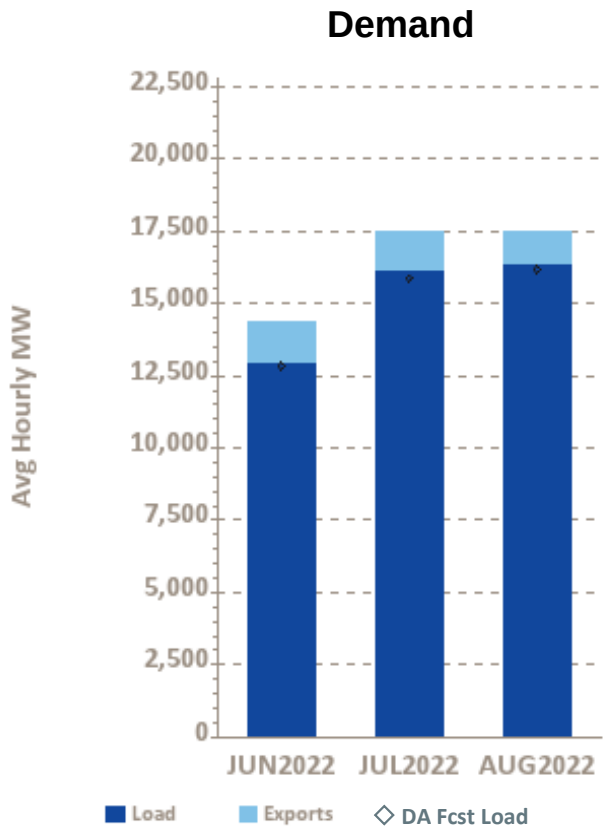
Demand



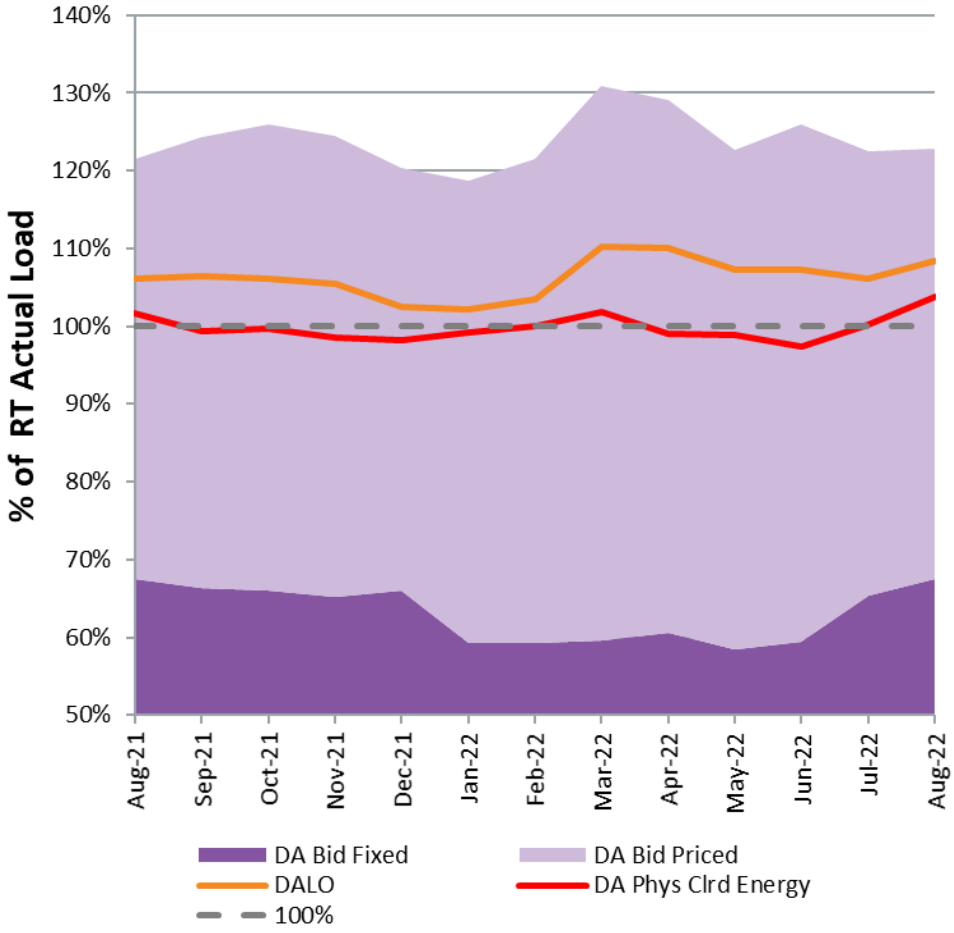
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

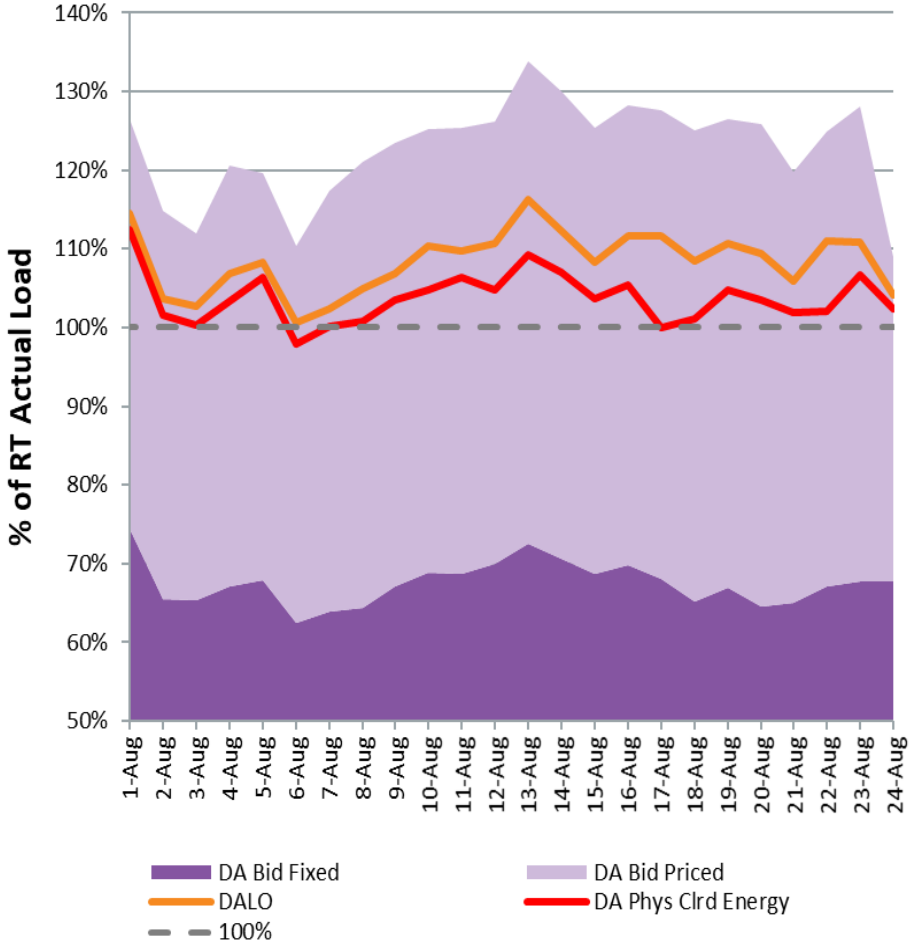
Components of RT Supply and Demand – Last Three Months





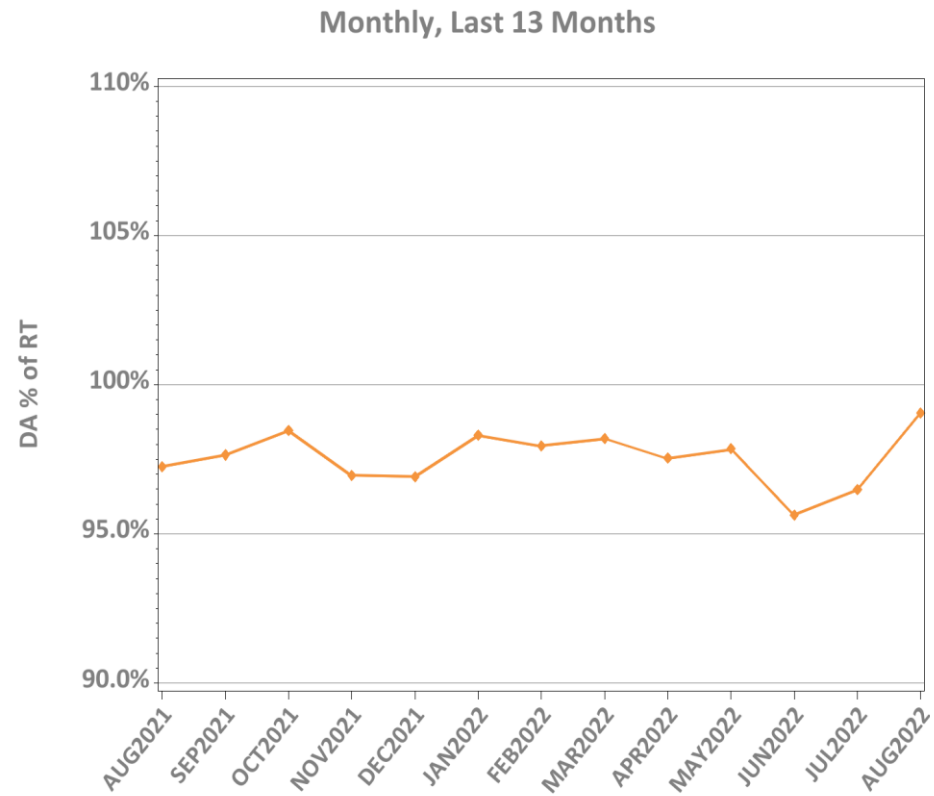
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

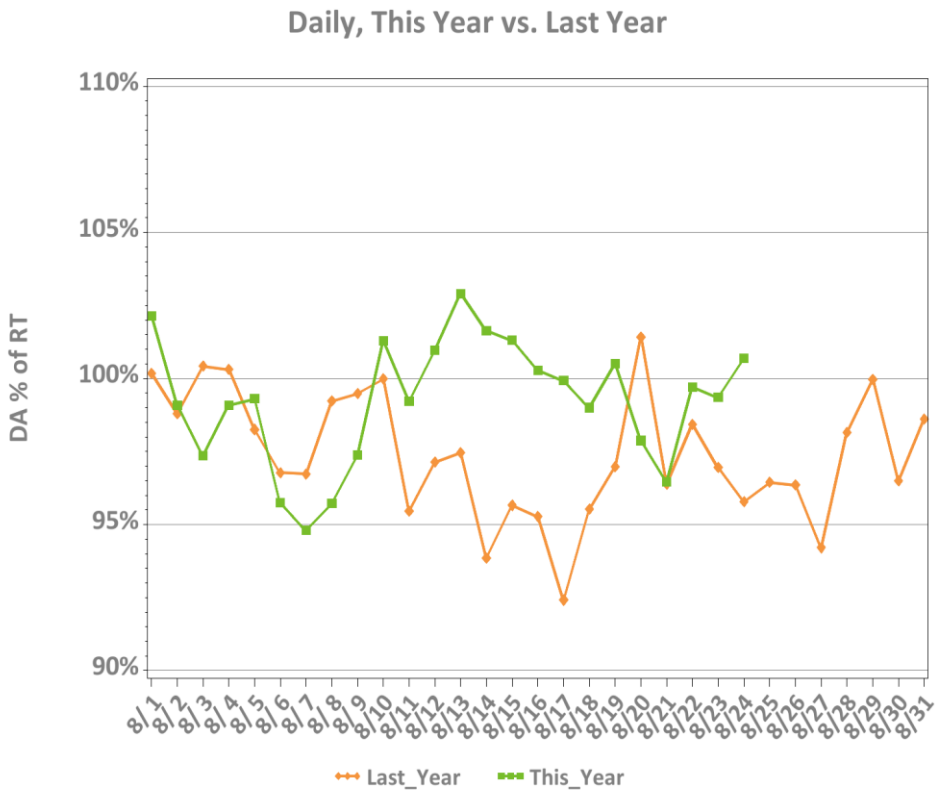




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

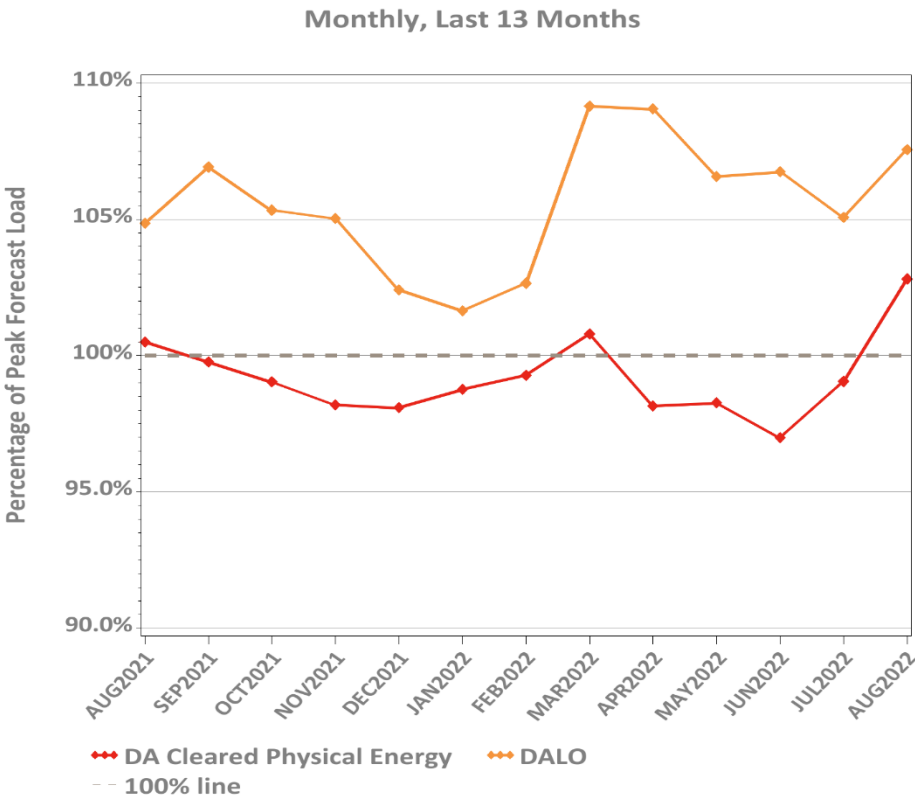
DA vs. RT Load Obligation: August, This Year vs. Last Year

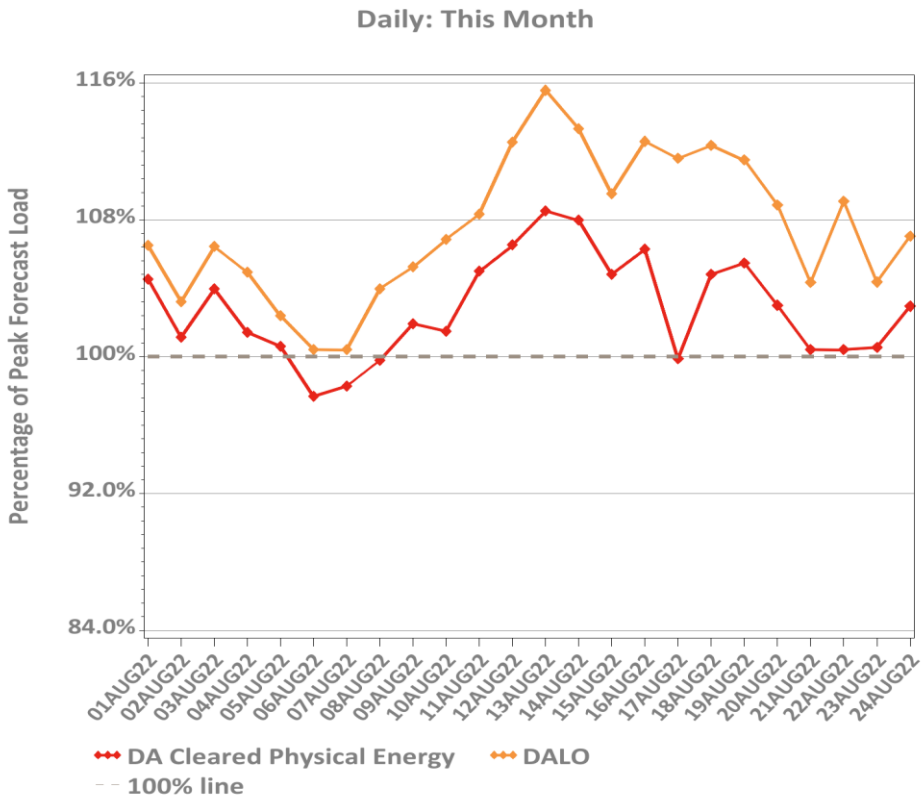




*Hourly average values

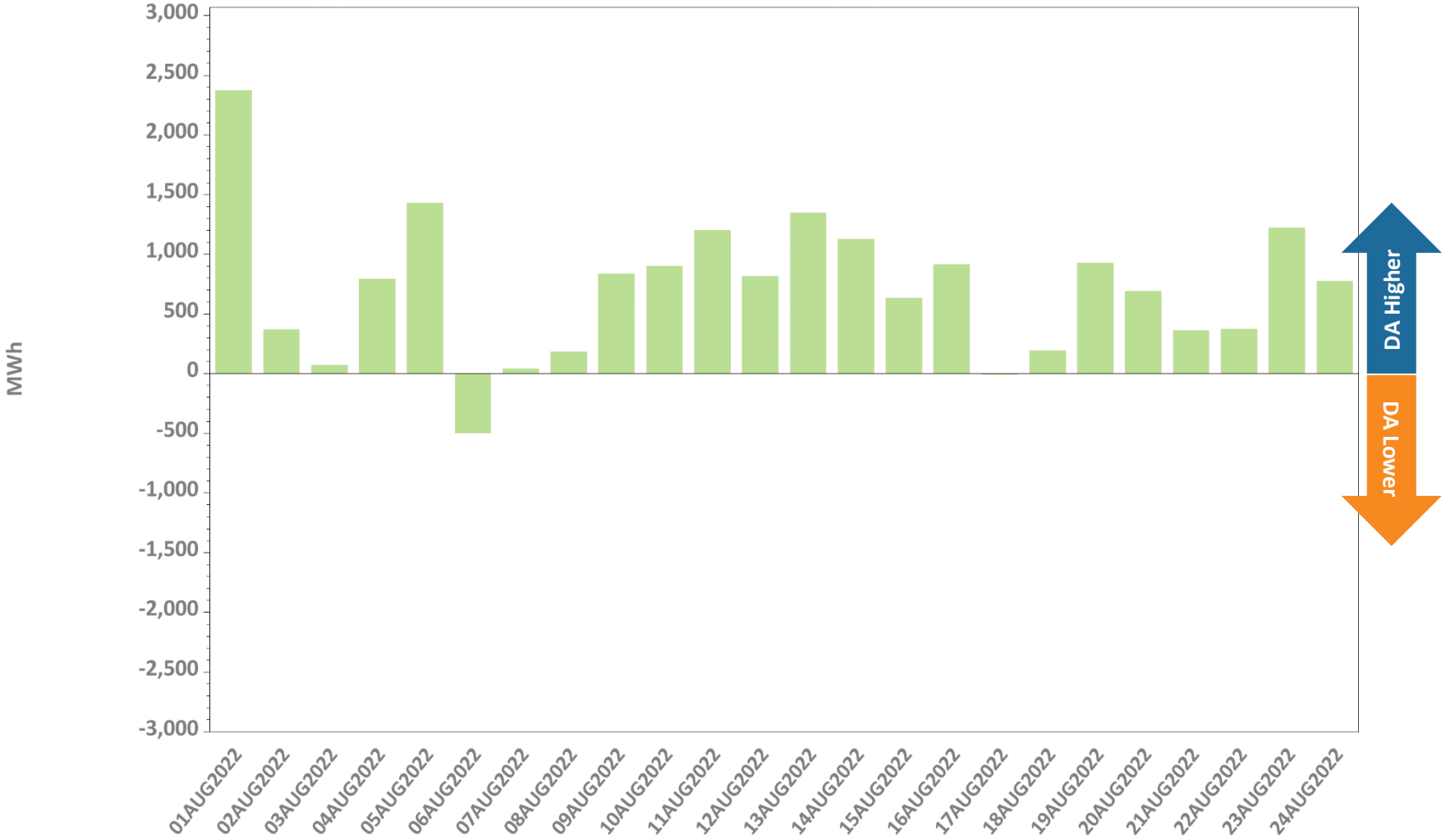
DA Volumes as % of Forecast in Peak Hour





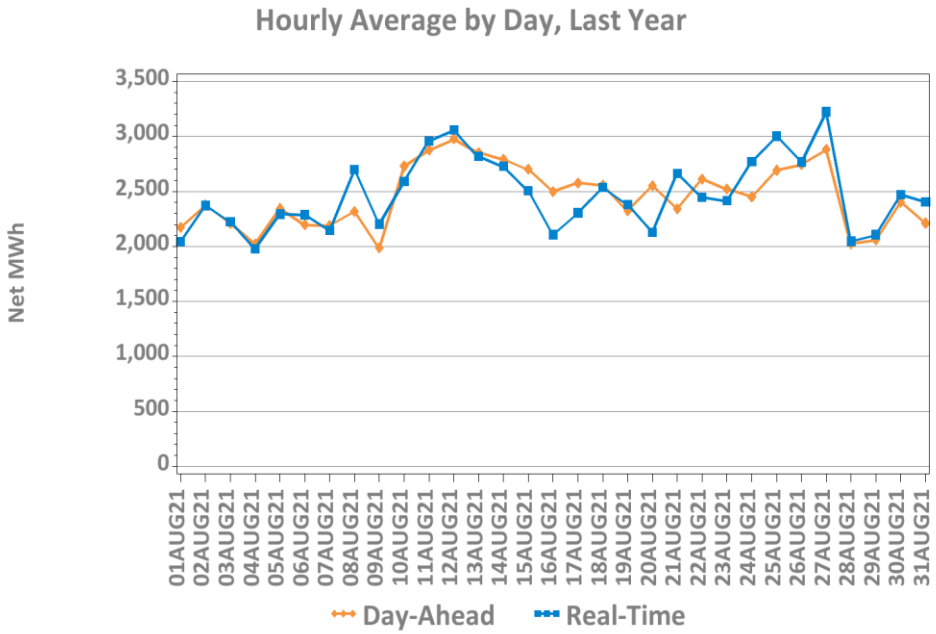
Note: There were three system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month. These occurred on August 6th, 7th and 8th

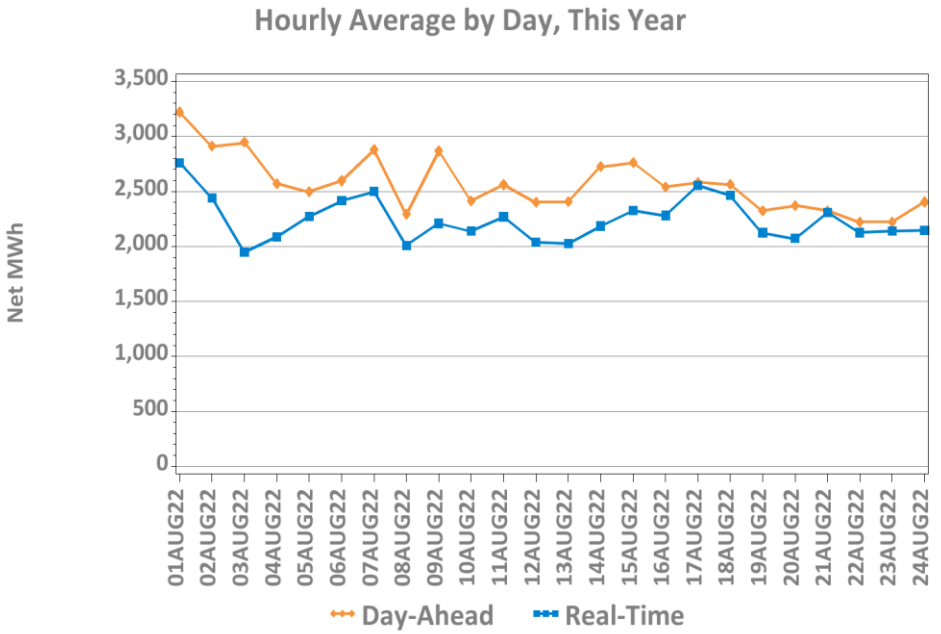
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

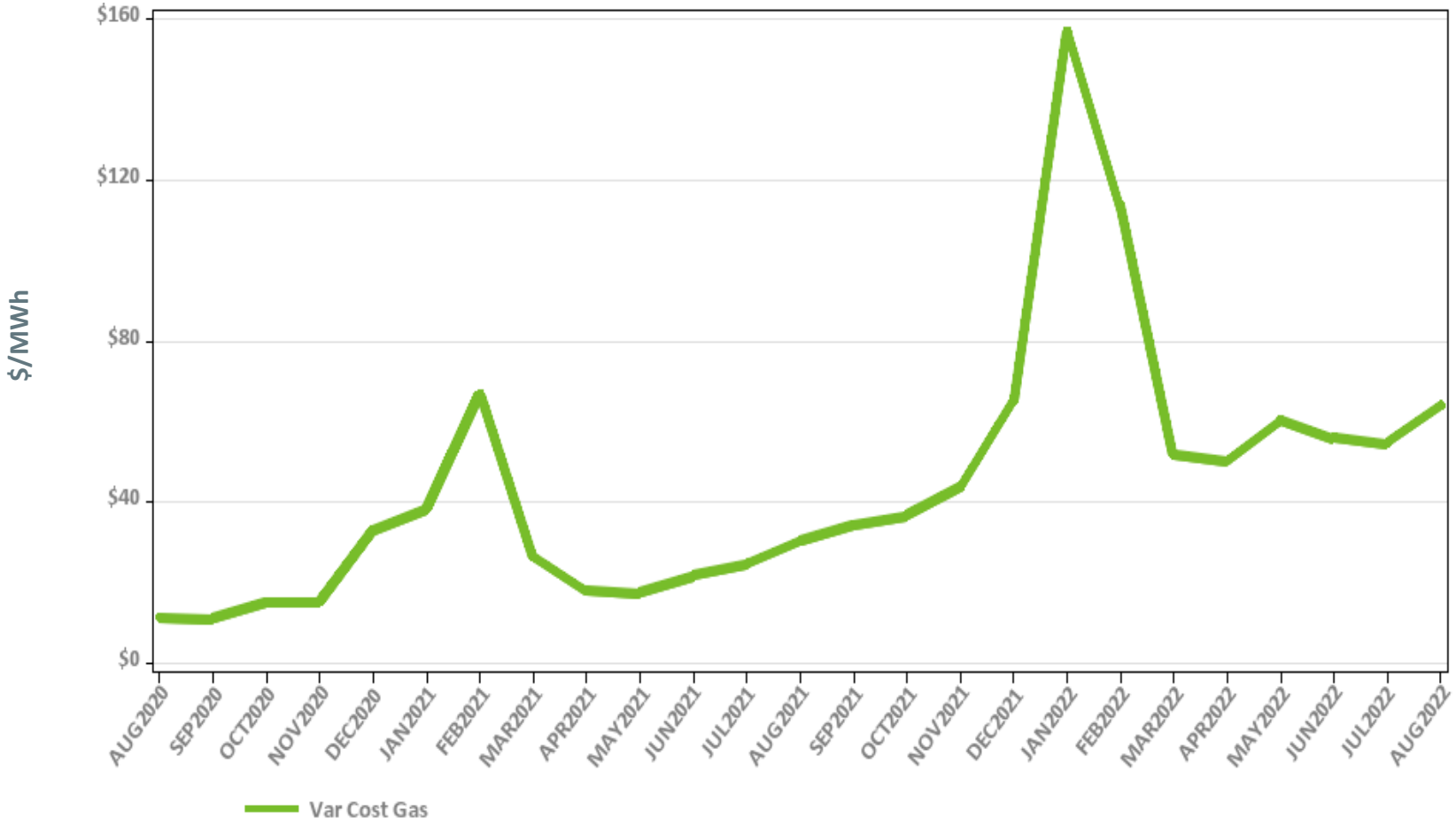
DA vs. RT Net Interchange
August 2021 vs. August 2022





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

Variable Production Cost of Natural Gas: Monthly

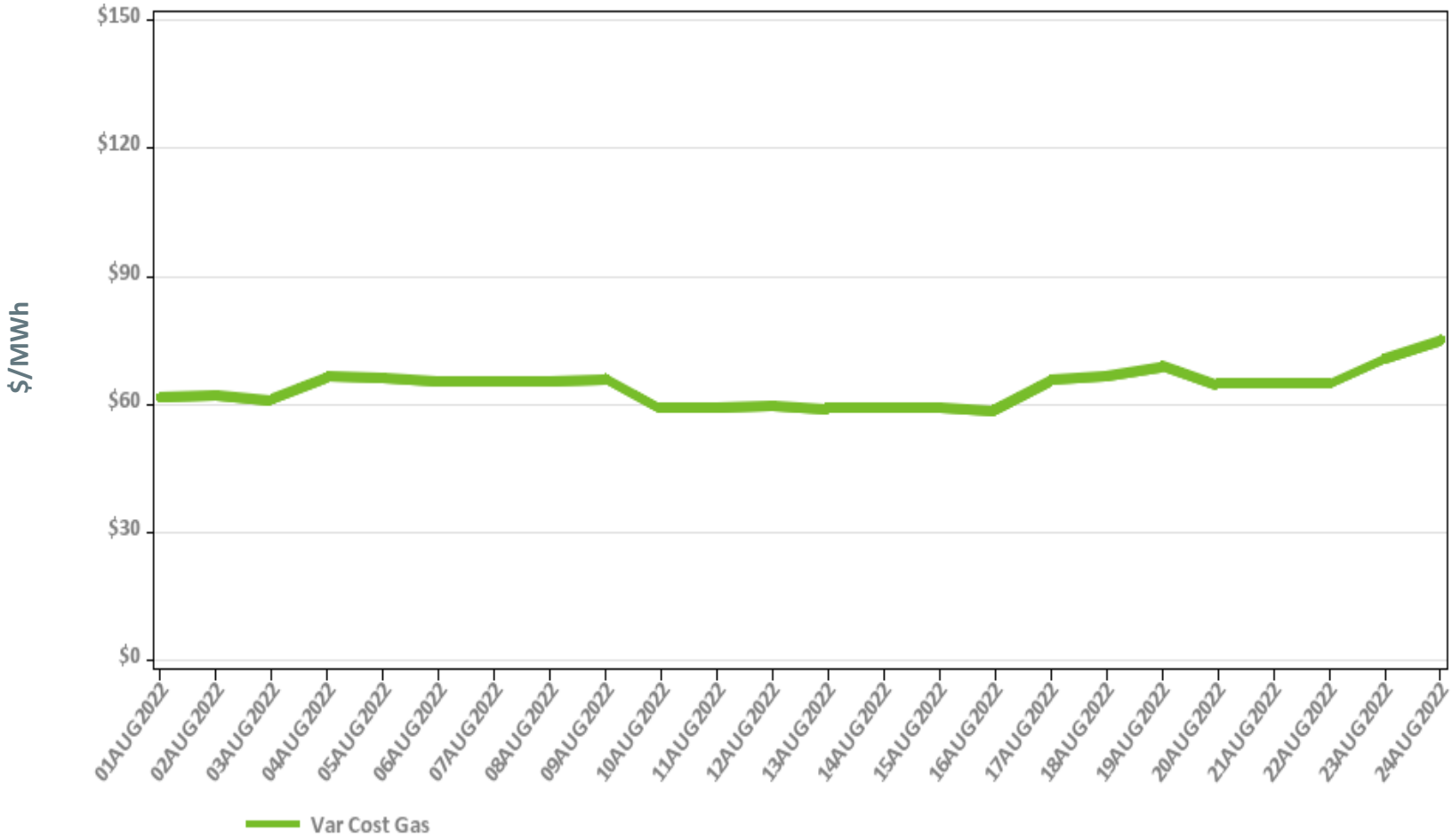


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

ICE Global markets in clear view

Variable Production Cost of Natural Gas: Daily

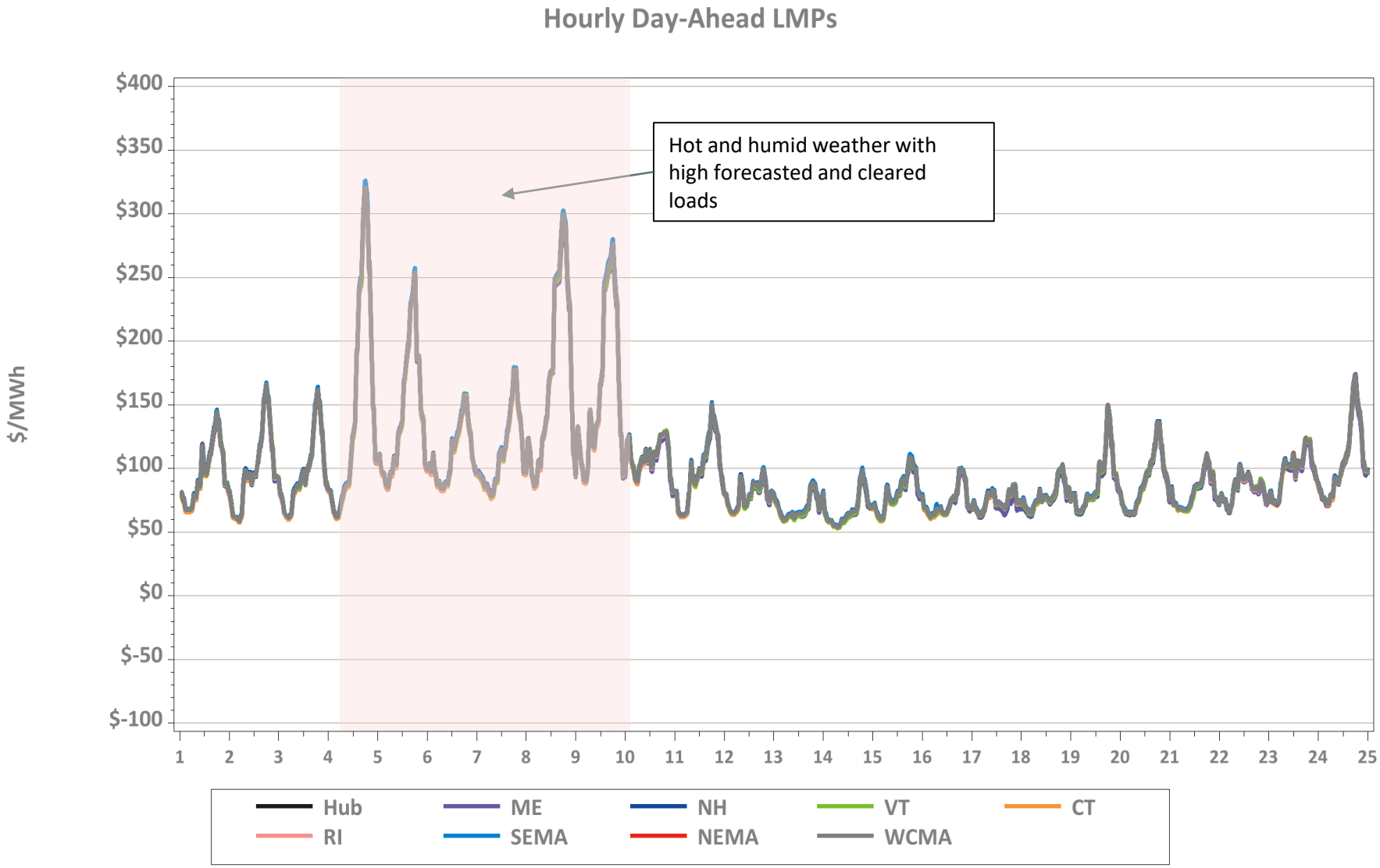


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

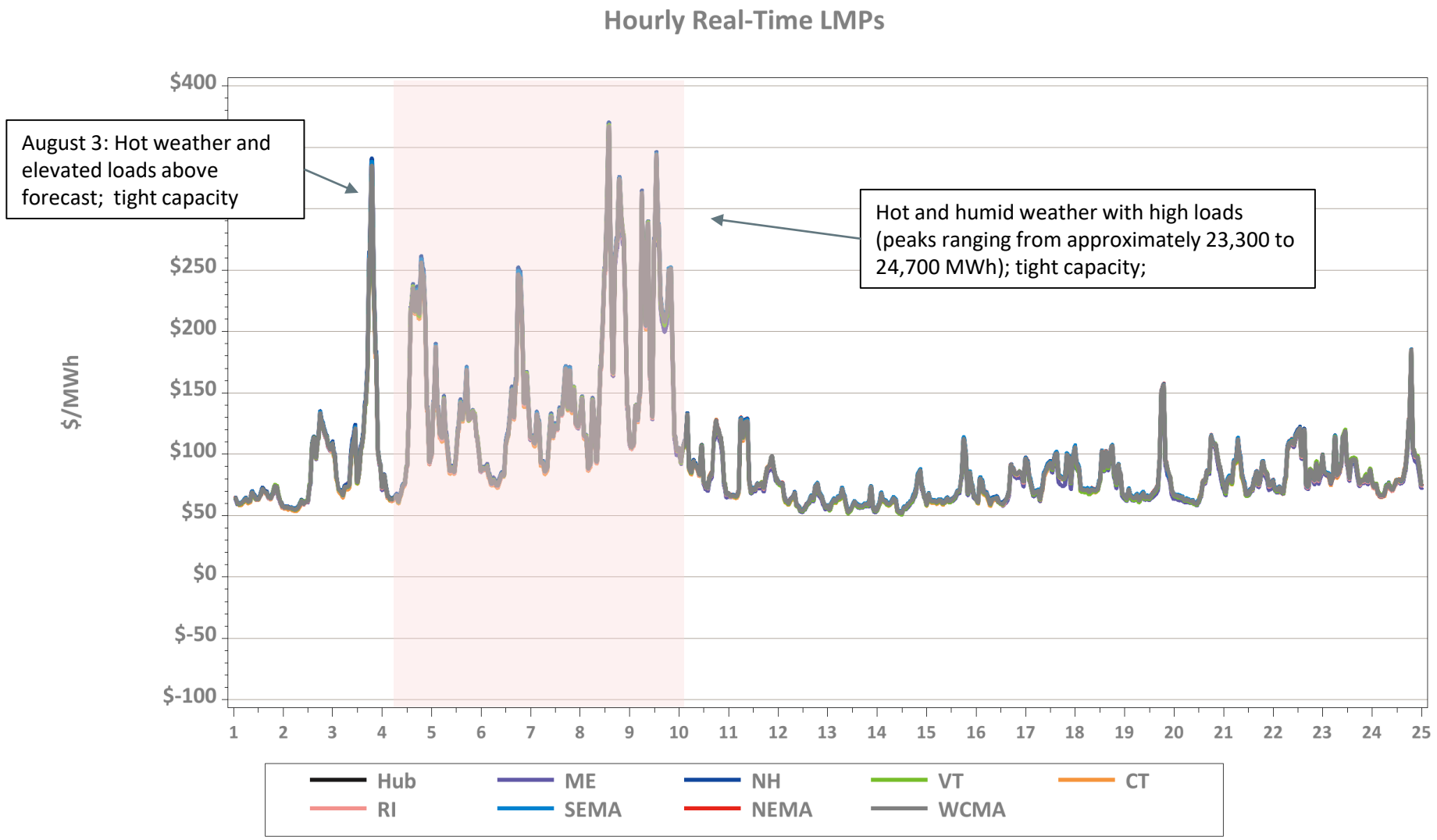
Underlying natural gas data furnished by:

ICE Global markets in clear view

Hourly DA LMPs, August 1-24, 2022

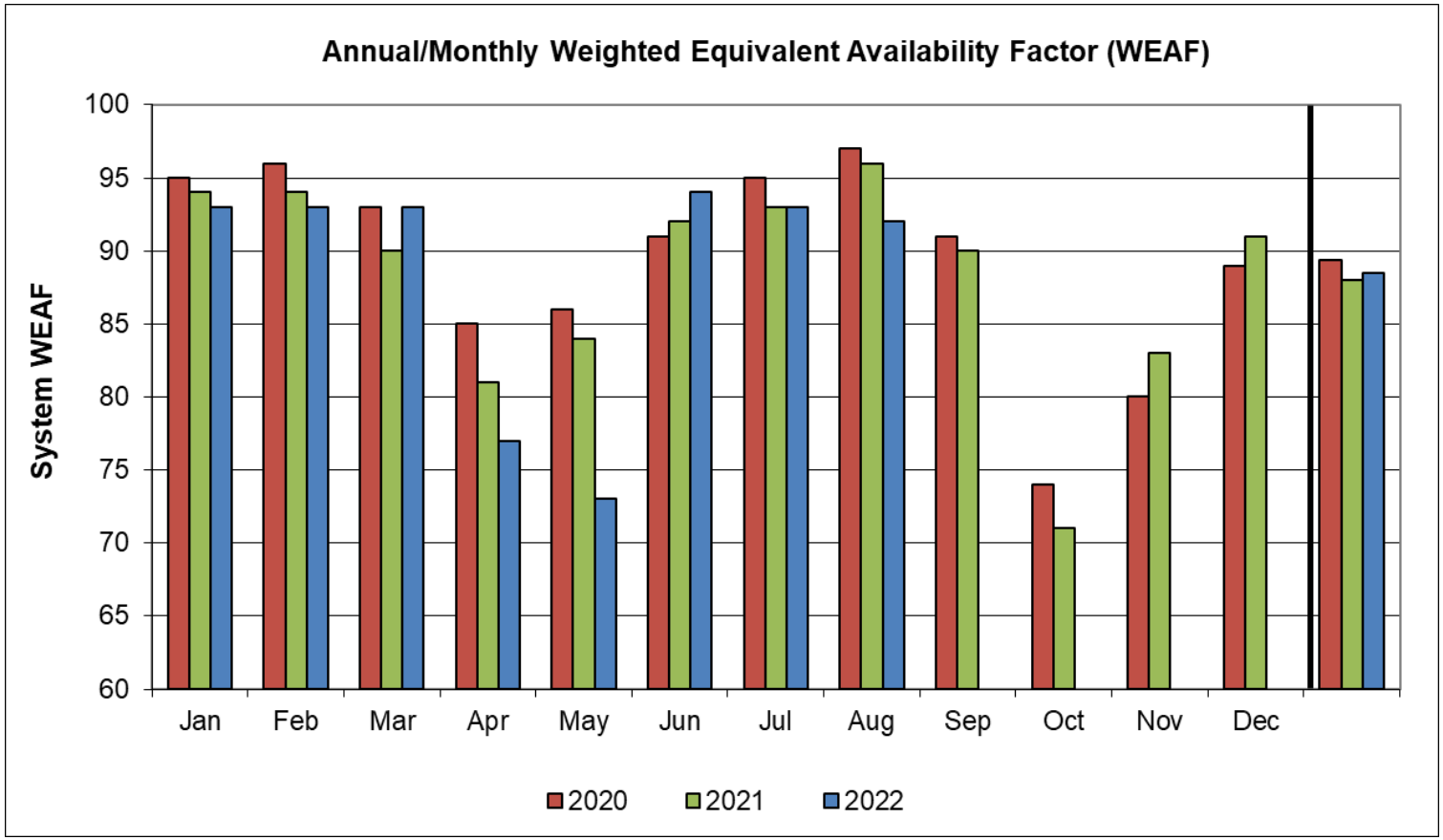


Hourly RT LMPs, August 1-24, 2022



* Revenue quality metered values reflected

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2022	93	93	93	77	73	94	93	92					89
2021	94	94	90	81	84	92	93	96	90	71	83	91	88
2020	95	96	93	85	86	91	95	97	91	74	80	89	89

Data as of 8/24/2022

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for September 2022

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	91.1	213.0	0.0	304.0
NH	42.7	169.4	0.0	212.1
VT	41.7	133.7	0.0	175.4
CT	138.4	232.3	630.2	1,000.9
RI	40.4	346.2	0.0	386.5
SEMA	40.9	532.5	0.0	573.4
WCMA	86.5	558.5	35.2	680.1
NEMA	73.0	879.5	0.0	952.5
Total	**554.5**	**3,065.0**	**665.4**	**4,285.0**

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

NEW GENERATION

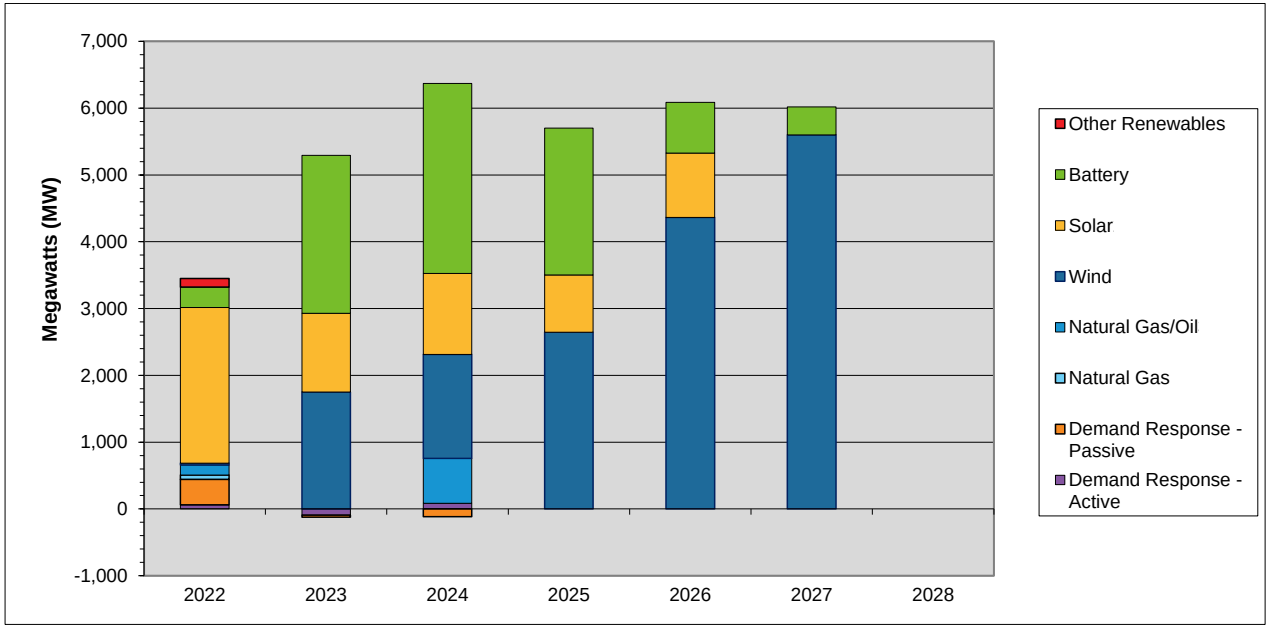
New Generation Update

Based on Queue as of 08/26/22

- Six projects totaling 1,842 MW were added to the interconnection queue since the last update
  - Two solar projects, two battery projects, one solar with battery project and one wind project with in-service dates of 2025 to 2029
- Seven projects were withdrawn
- In total, 353 generation projects are currently being tracked by the ISO, totaling approximately 34,789 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



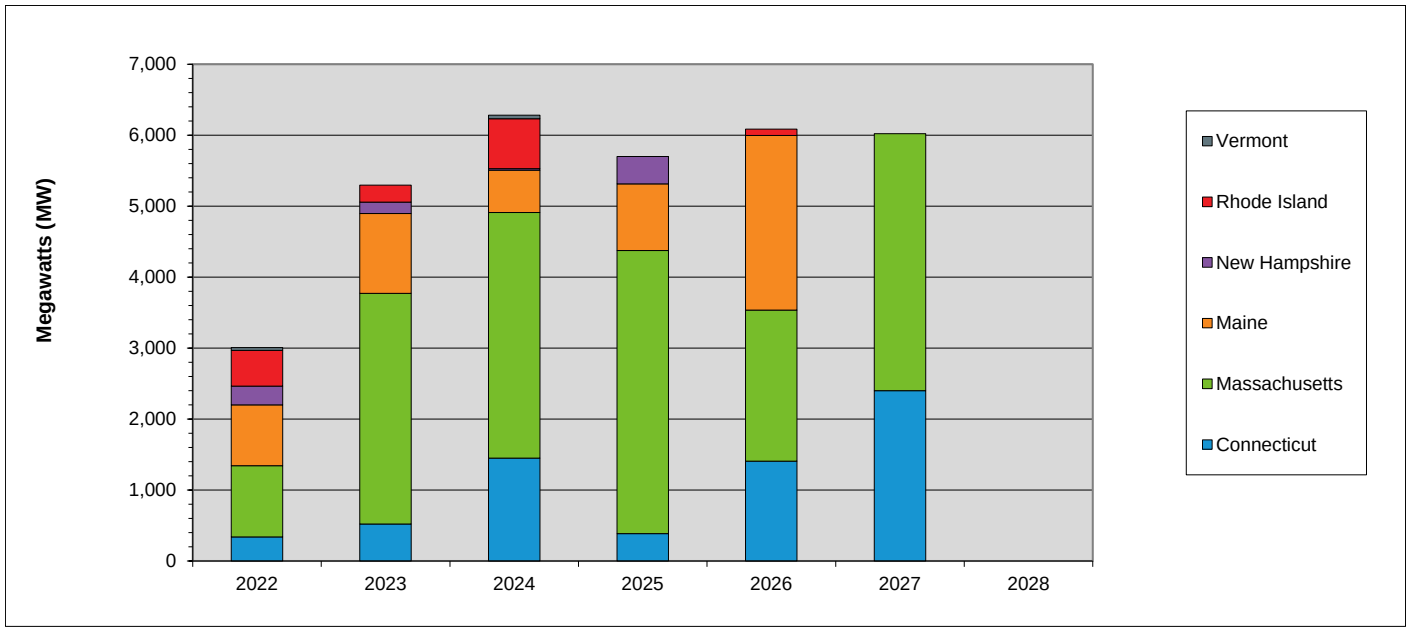
	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	129	0	0	0	0	0	0	129	0.4
Battery	305	2,367	2,841	2,196	759	421	0	8,889	27.2
Solar[2]	2,331	1,175	1,213	859	964	0	0	6,542	20.0
Wind	24	1,752	1,556	2,645	4,363	5,599	0	15,939	48.8
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.5
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.7
Demand Response - Active	62	-94	86	0	0	0	0	54	0.2
Totals	3,449	5,172	6,254	5,700	6,086	6,020	0	32,681	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



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Vermont	40	0	50	0	0	0	0	90	0.3
Rhode Island	502	236	704	0	91	0	0	1,533	4.7
New Hampshire	266	164	20	385	0	0	0	835	2.6
Maine	858	1,123	597	942	2,461	0	0	5,981	18.5
Massachusetts	1,001	3,251	3,462	3,989	2,126	3,620	0	17,449	53.9
Connecticut	340	520	1,449	384	1,408	2,400	0	6,501	20.1
Totals	**3,007**	**5,294**	**6,282**	**5,700**	**6,086**	**6,020**	**0**	**32,389**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	58	8,889	0	0	58	8,889
Fuel Cell	2	30	0	0	2	30
Hydro	3	99	2	71	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	1	62	4	761
Nuclear	0	0	0	0	0	0
Solar	251	6,542	23	242	228	6,300
Wind	27	18,339	1	20	26	18,319
Total	353	34,789	27	395	326	34,394

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	70	1	5	4	65
Intermediate	7	804	0	0	7	804
Peaker	315	16,776	25	370	290	16,406
Wind Turbine	26	17,139	1	20	25	17,119
Total	353	34,789	27	395	326	34,394

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	58	8,889	0	0	0	0	58	8,889	0	0
Fuel Cell	2	30	2	30	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	251	6,542	0	0	0	0	251	6,542	0	0
Wind	27	18,339	0	0	0	0	1	1,200	26	17,139
Total	353	34,789	5	70	7	804	315	16,776	26	17,139

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

FORWARD CAPACITY MARKET

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	609.826	-48.833
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392	3,512.604	61.705
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**	**4,122.43**	**12.872**
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07	27,426.242	-679.169
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387	778.962	-117.323
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**	**28,205.204**	**-796.492**
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**	**1,115.22**	**-177.19**
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**	**33,442.854**	**-960.81**
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**	**31,590**	**-1,175**

* 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
CSO – Capacity Supply Obligation
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

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	673.401	-4.272				
	Passive Demand	3,212.865	3,211.403	-1.462				
Demand Total		**3,890.538**	**3,884.804**	**-5.734**				
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425				
	Intermittent	1,089.265	1,073.794	-15.471				
Generator Total		**29,243.468**	**28,788.572**	**-454.896**				
Import Total		**1,487.059**	**1297.132**	**-189.927**				
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**				
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**				

* 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 16

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*	765.35						
	Passive Demand	2,557.256						
Demand Total		**3,322.606**						
Generator	*Non-Intermittent*	26,805.003						
	Intermittent	1,178.933						
Generator Total		**27,983.936**						
Import Total		**1,503.842**						
Grand Total*		**32,810.384**						
Net ICR (NICR)		**31,645**						

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	**2,375.422**	**370.734**	**2,746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2,571.361**	**639.586**	**3,210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3,596.056**	**323.058**	**3,919.114**
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**
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	**3,092.648**	**229.958**	**3,322.606**

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

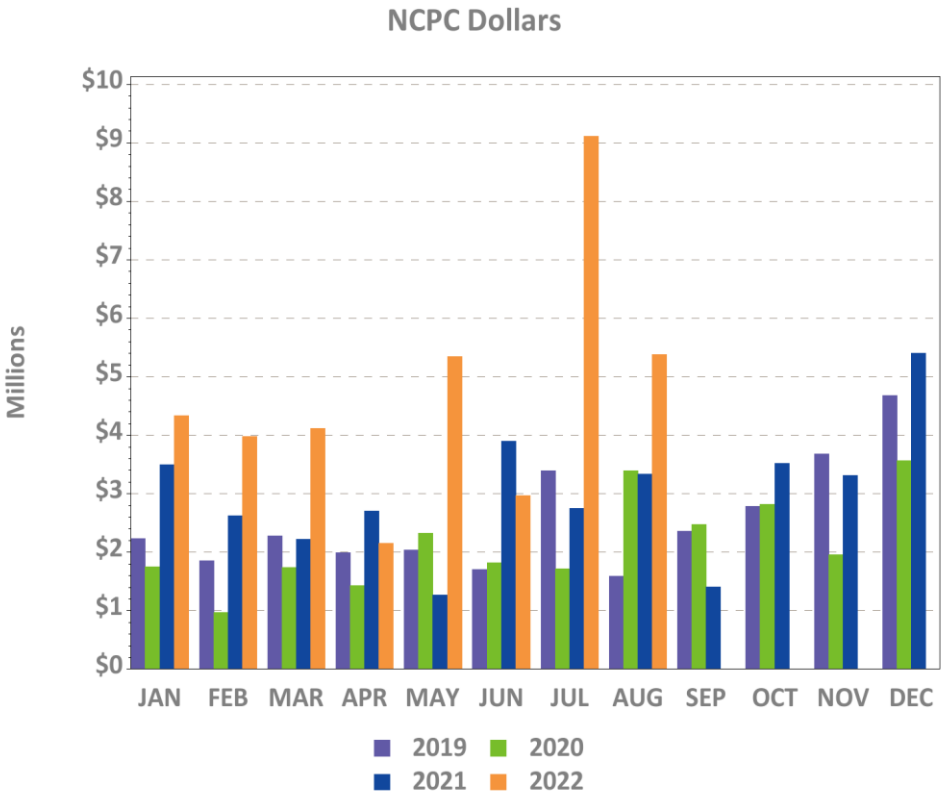
Definitions

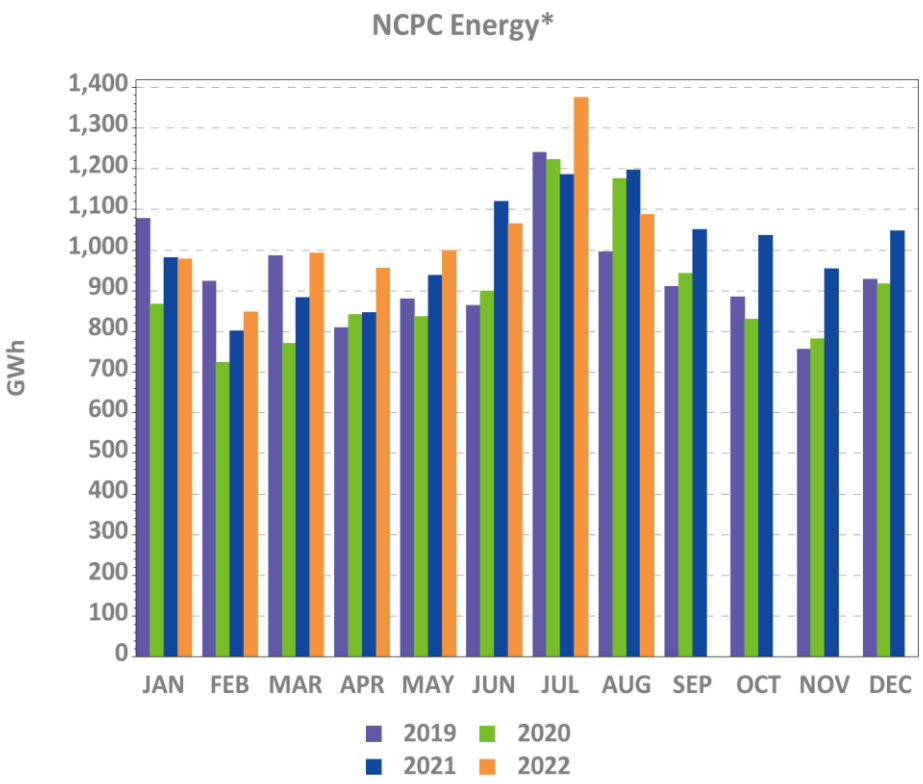
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

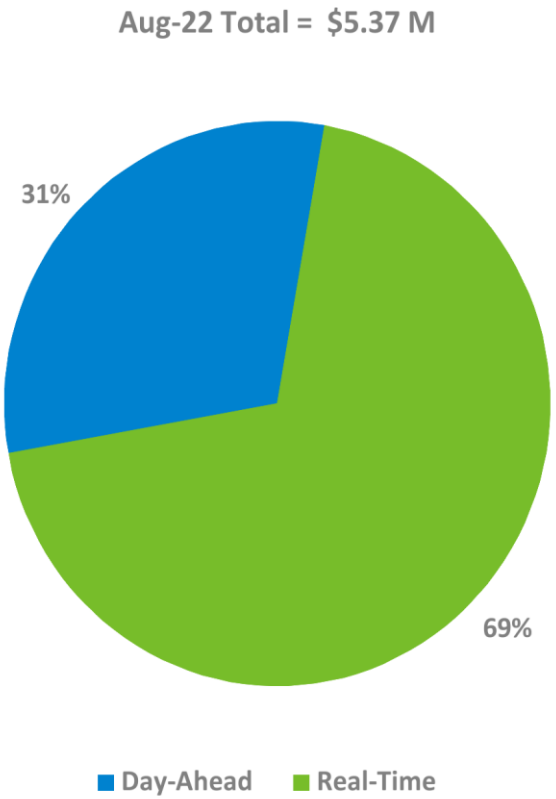
Year-Over-Year Total NCPC Dollars and Energy

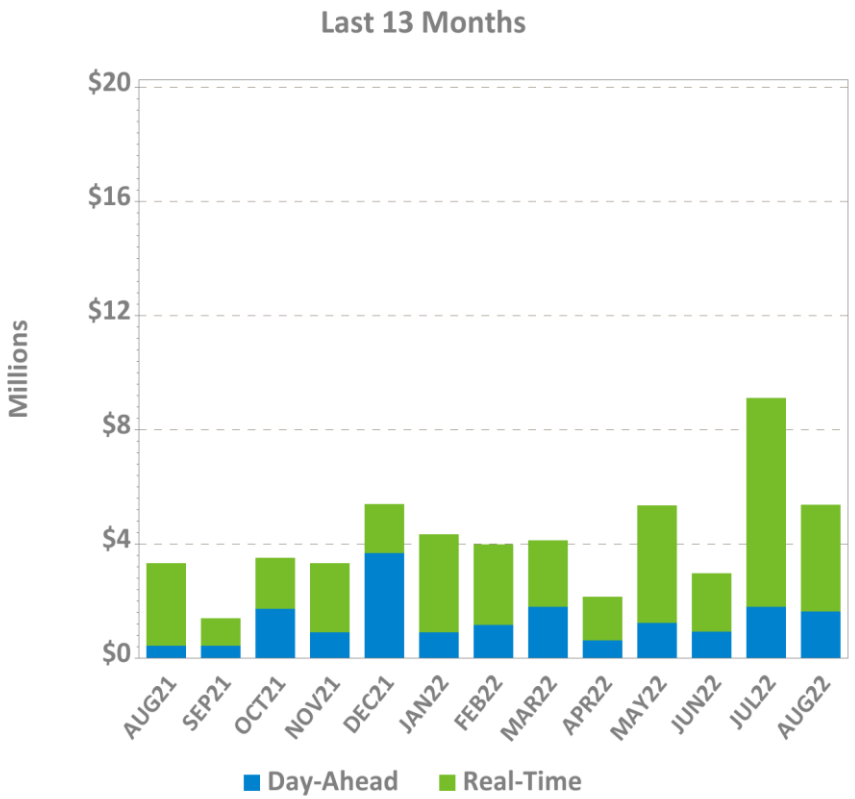




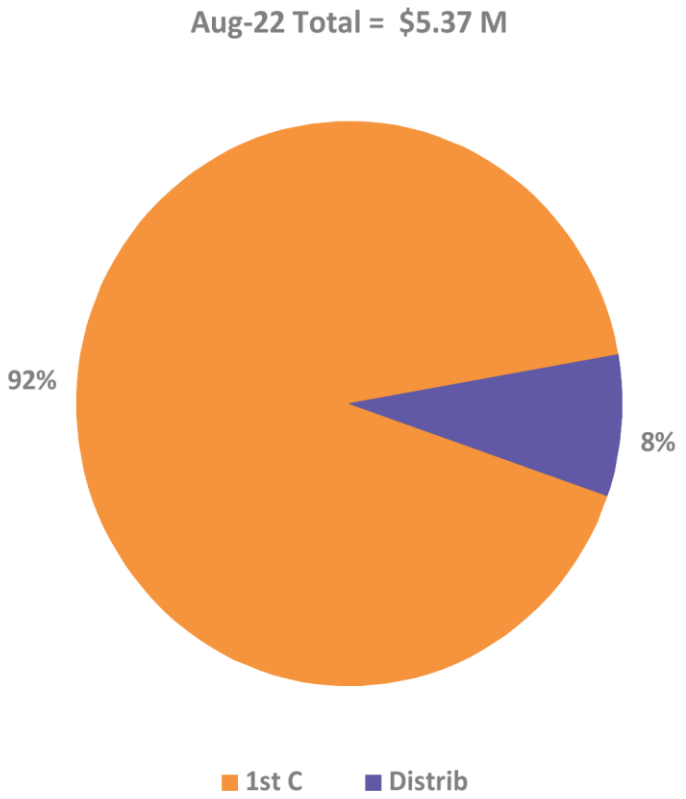
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

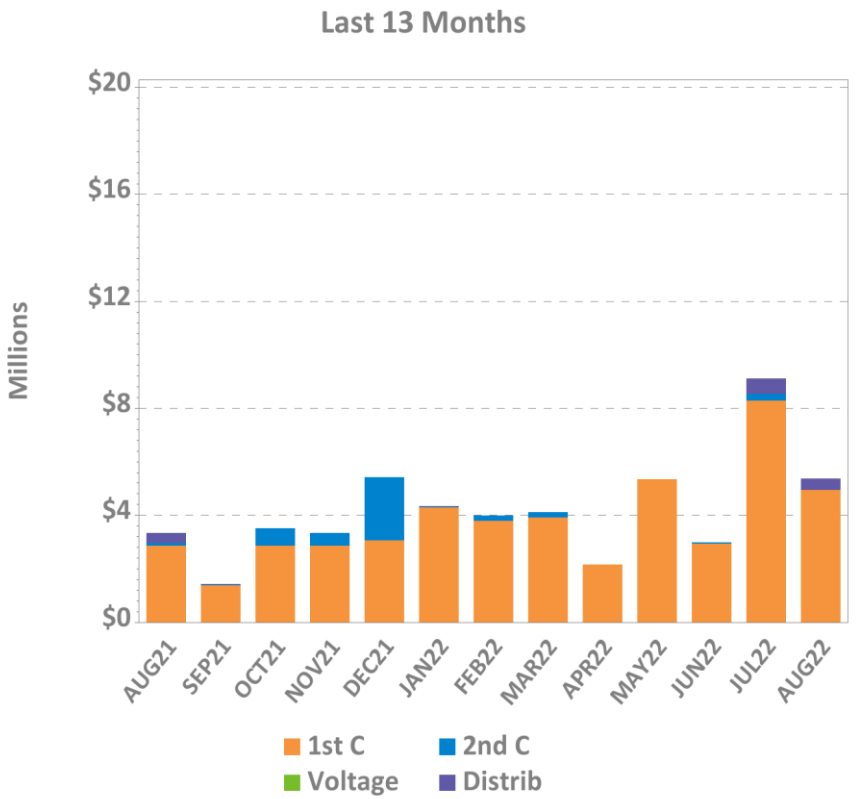
DA and RT NCPC Charges





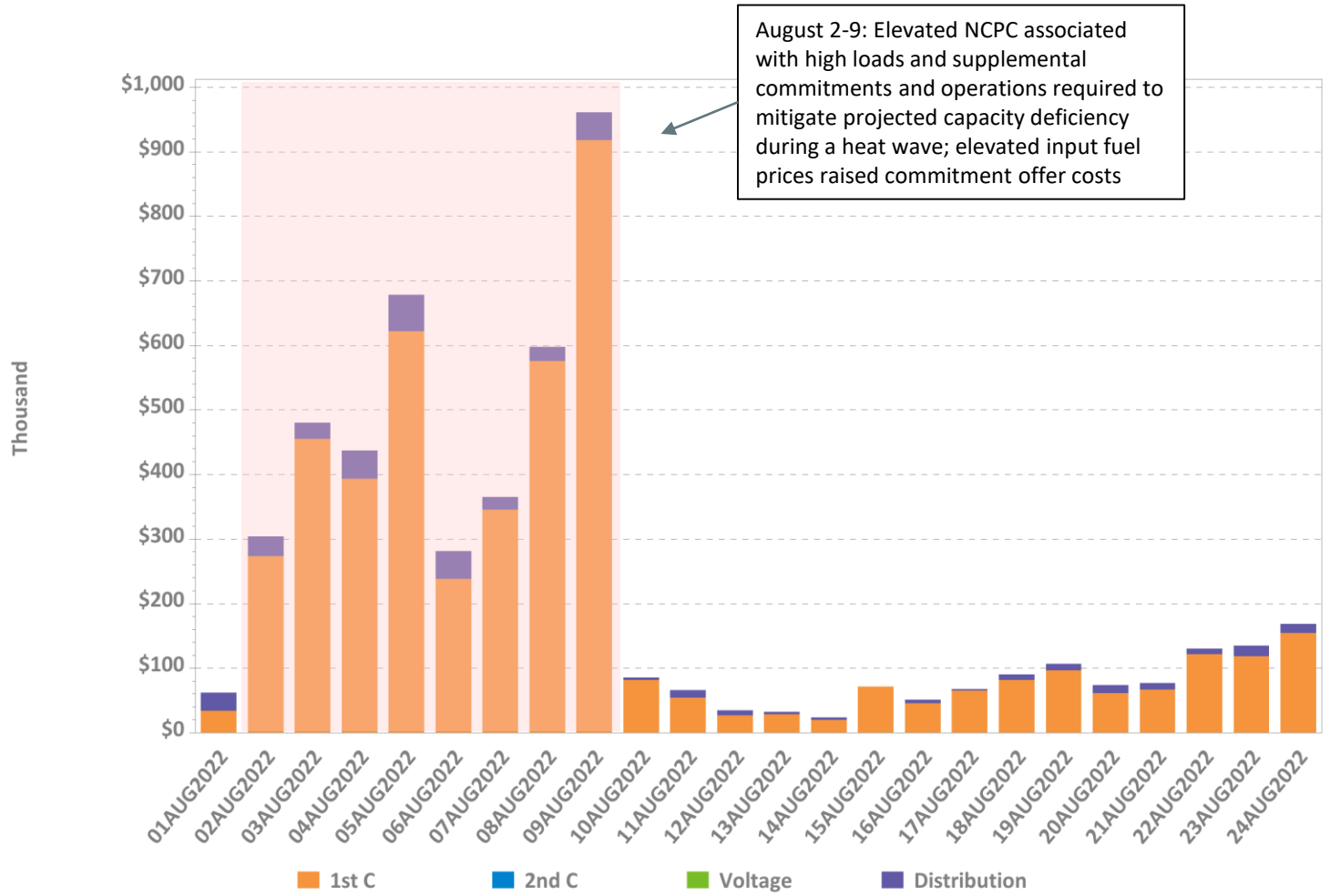
NCPC Charges by Type



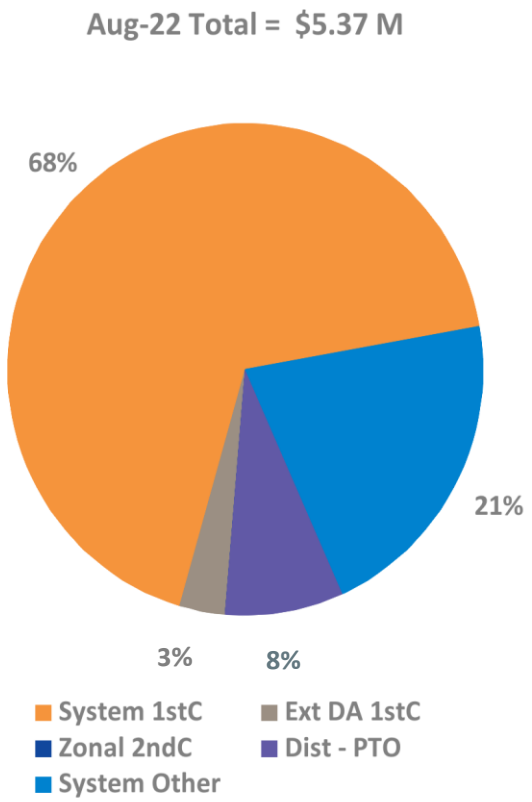


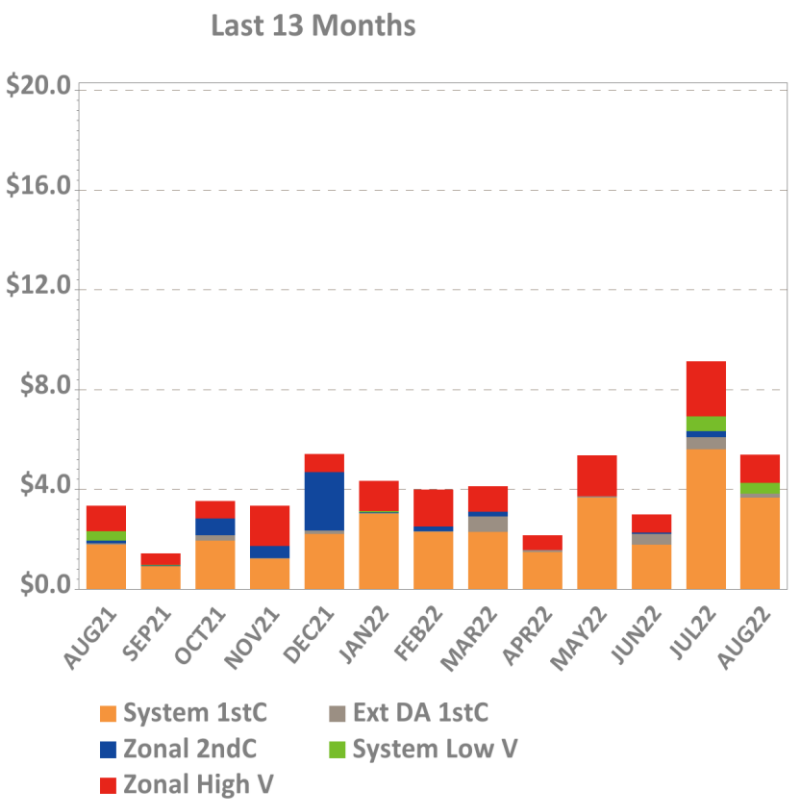
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



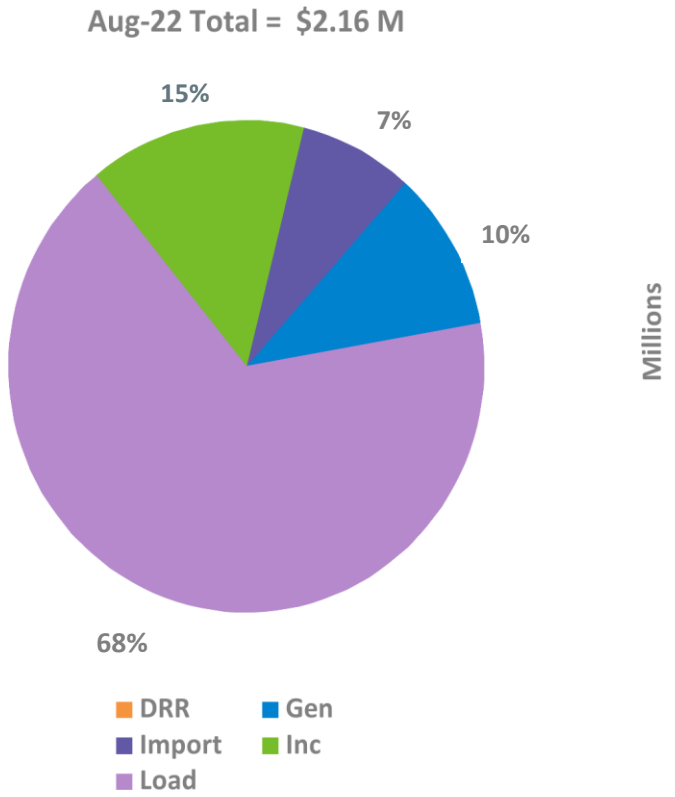
NCPC Charges by Allocation

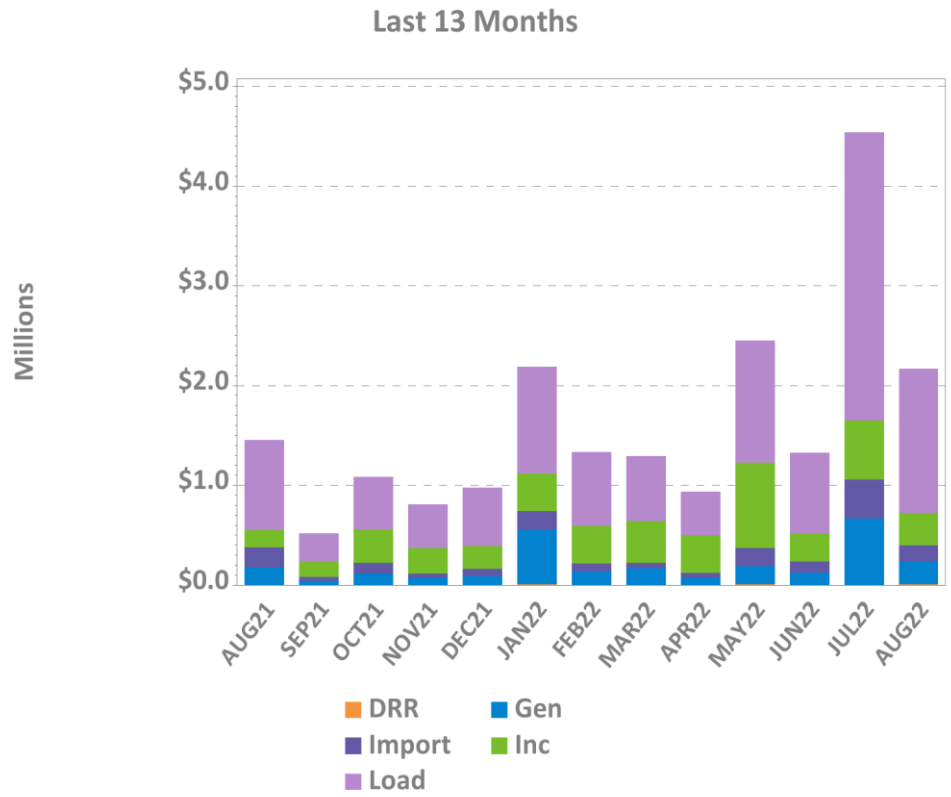




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

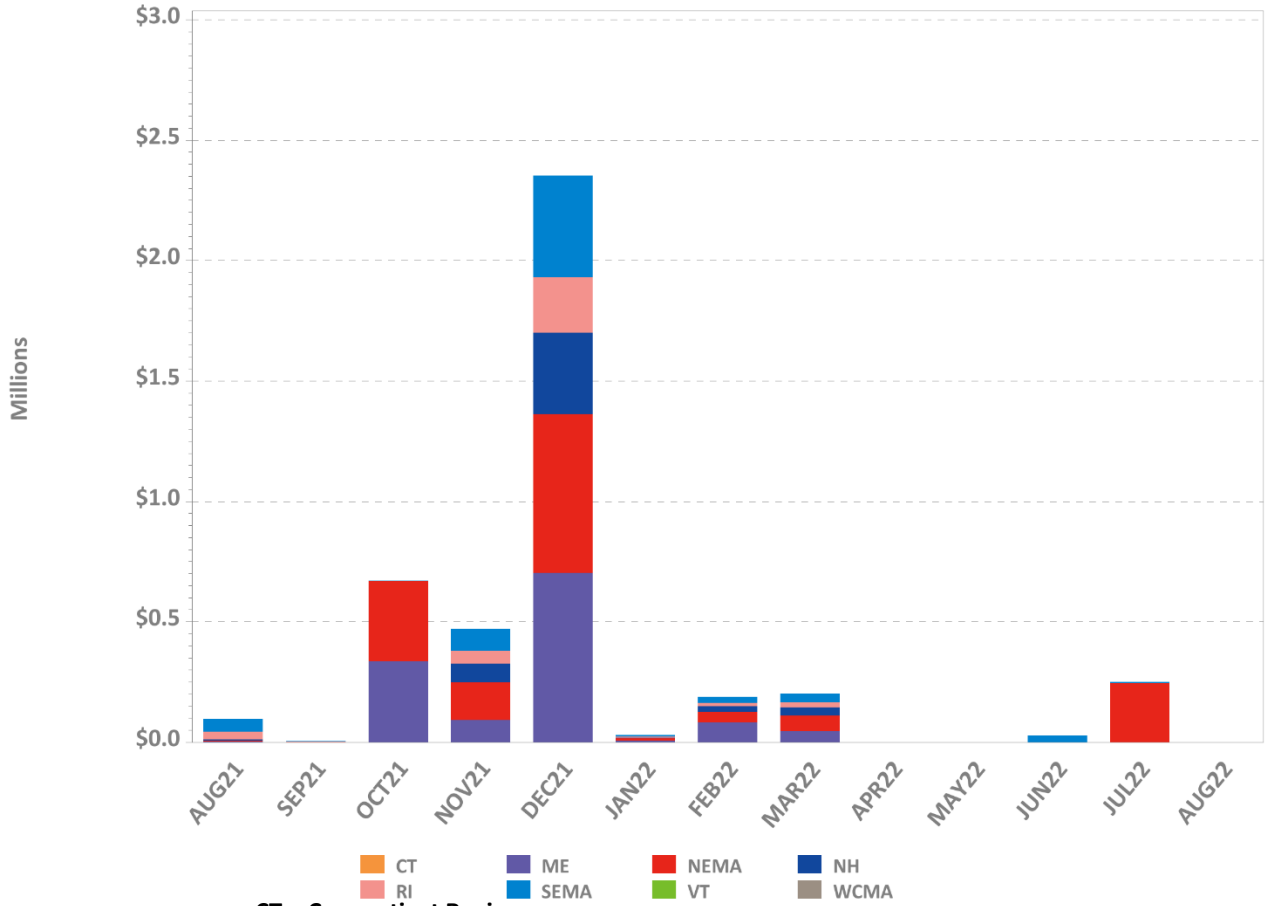
RT First Contingency Charges by Deviation Type





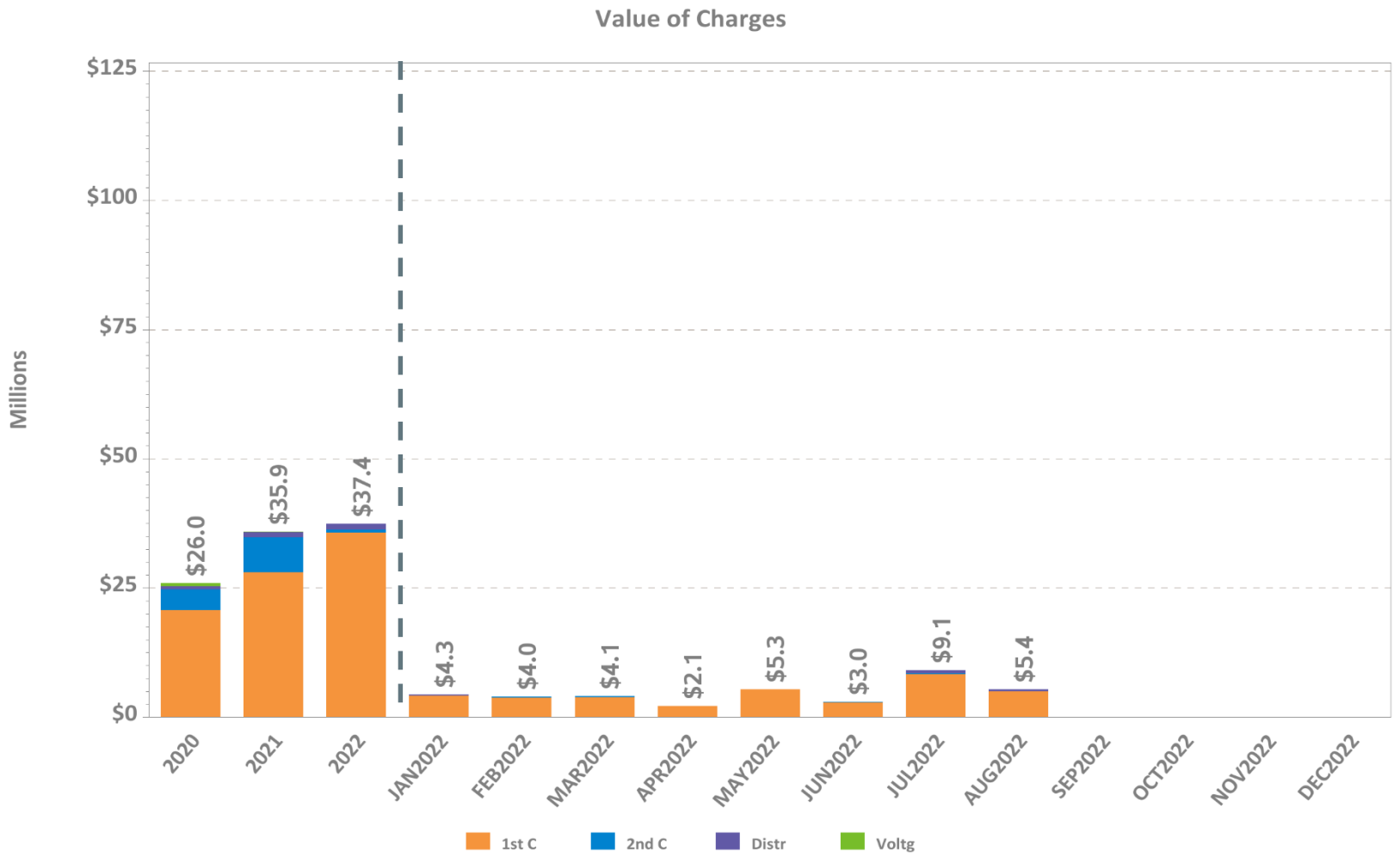
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

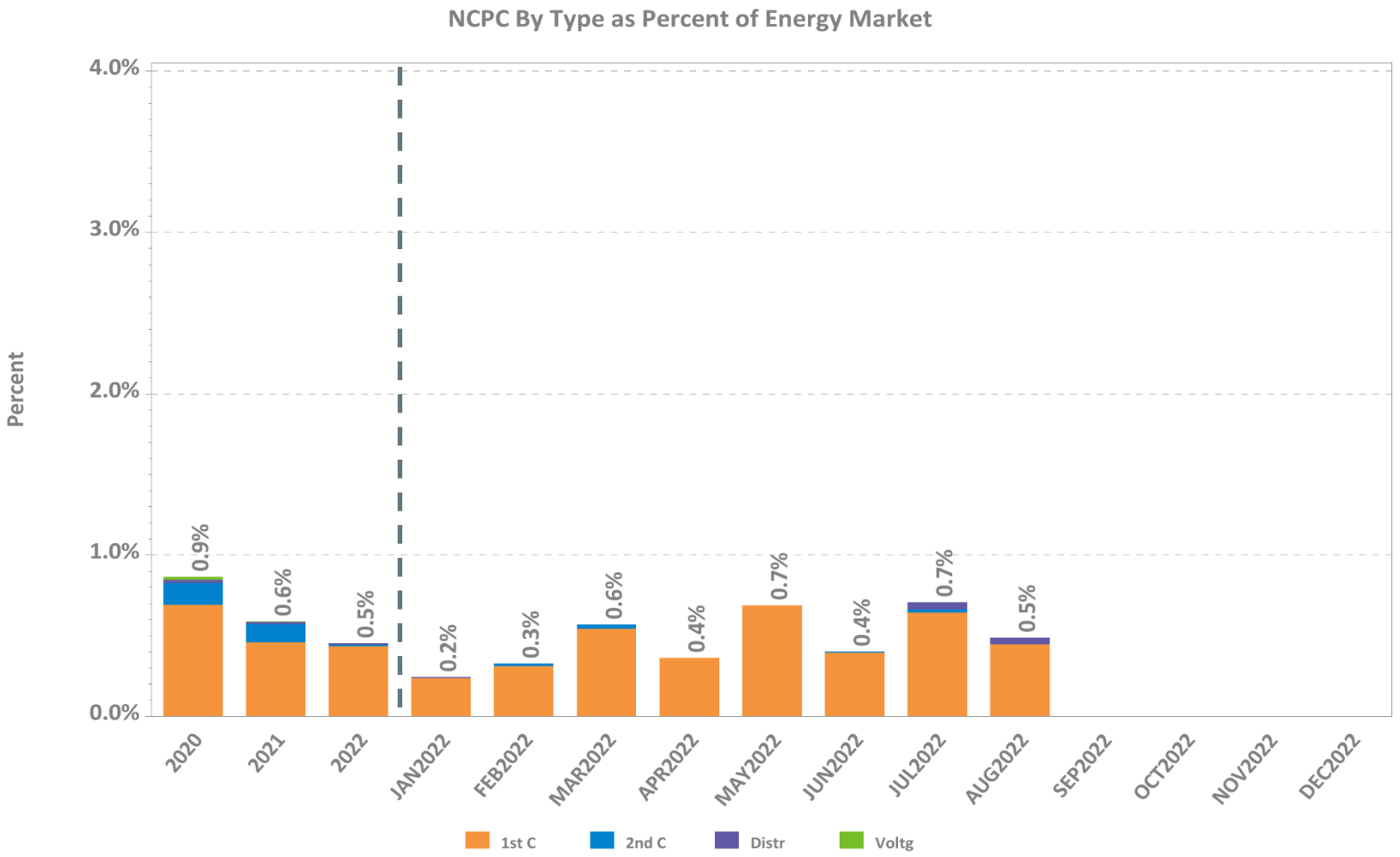


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

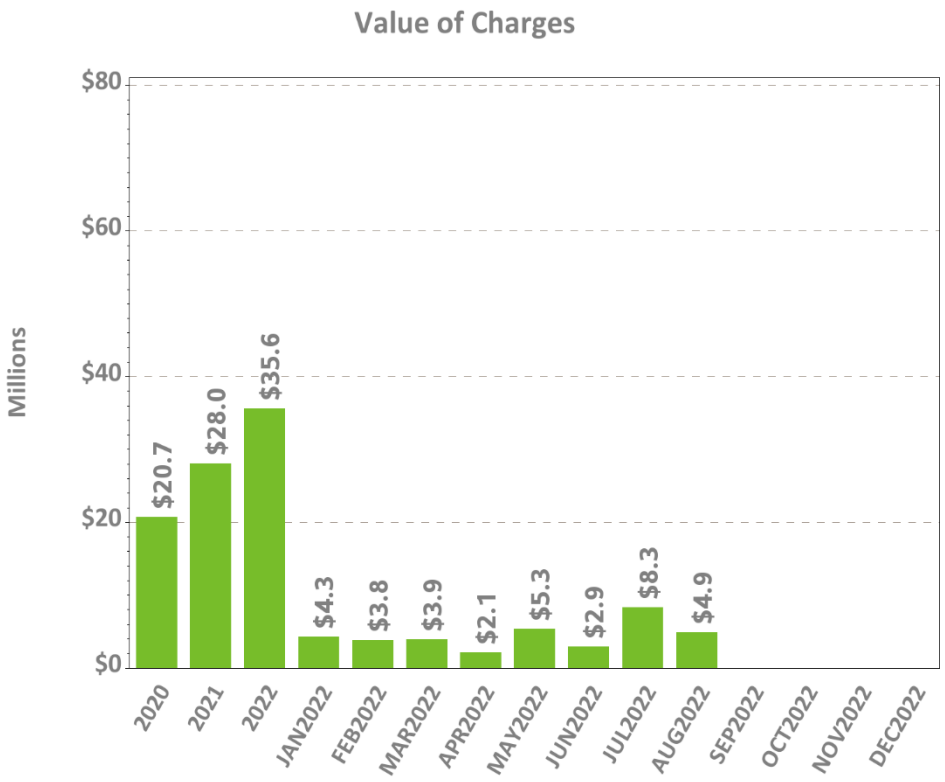
NCPC Charges by Type

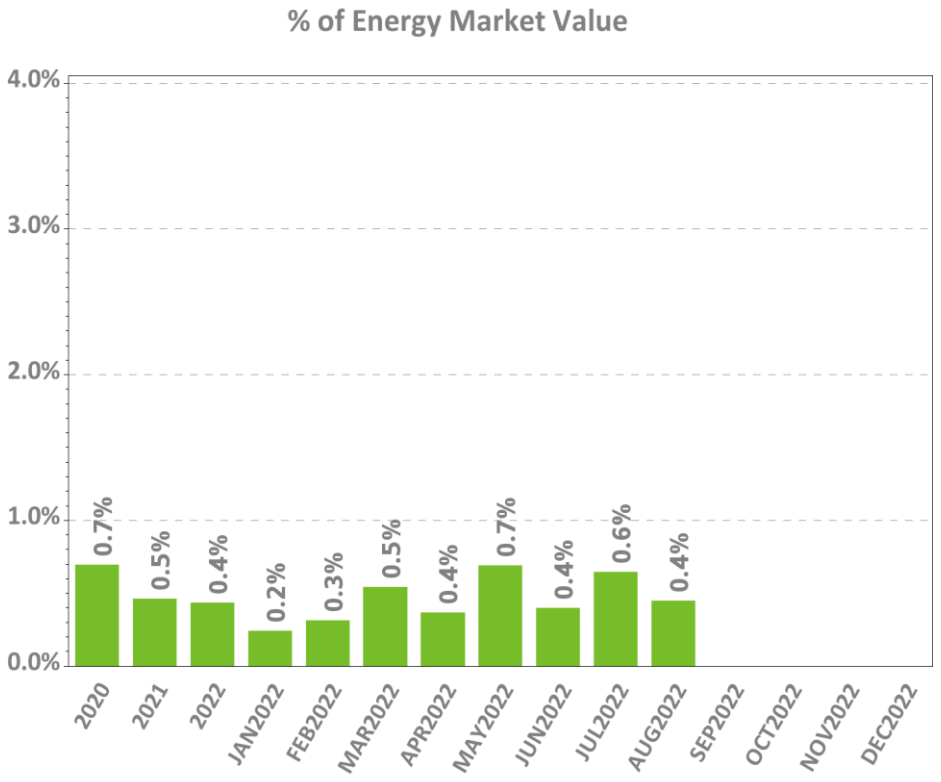


NCPC Charges as Percent of Energy Market



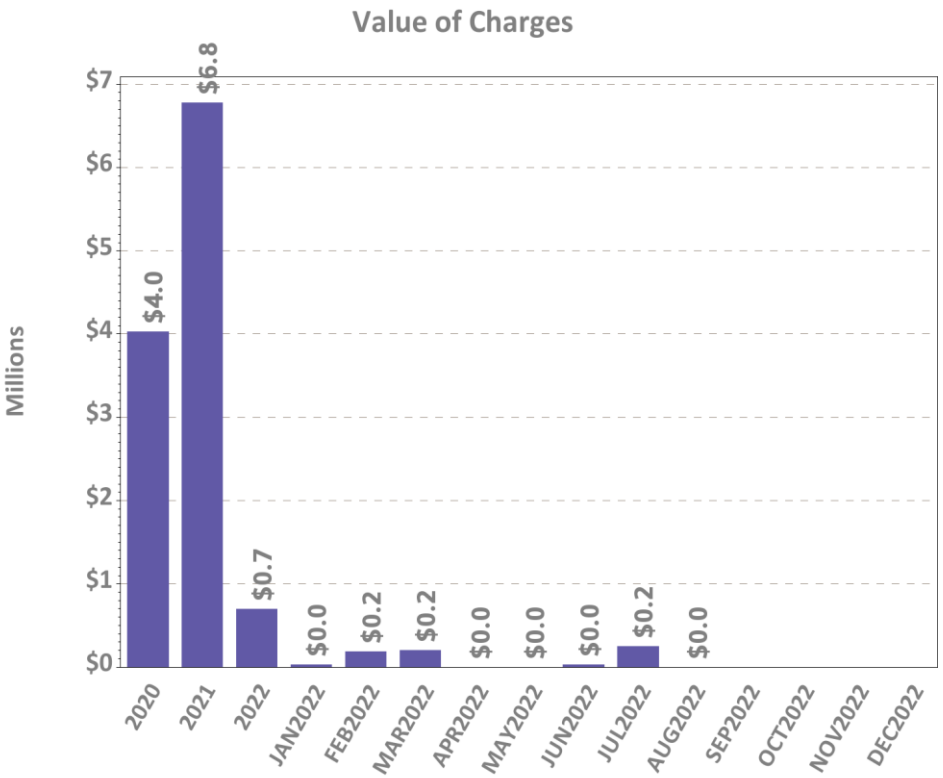
First Contingency NCPC Charges

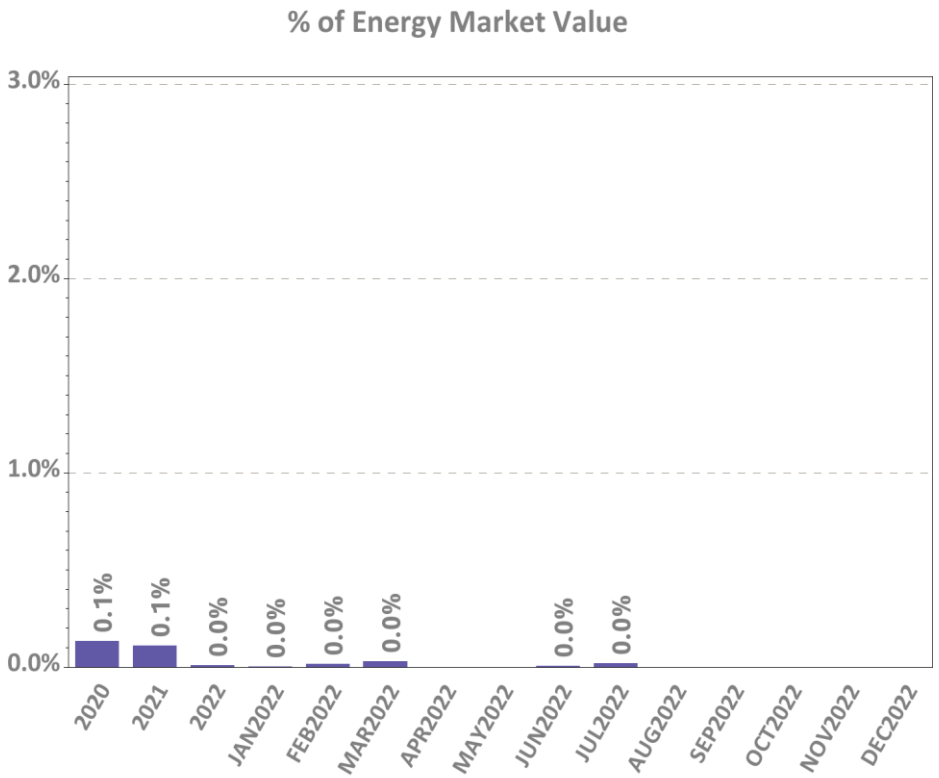




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

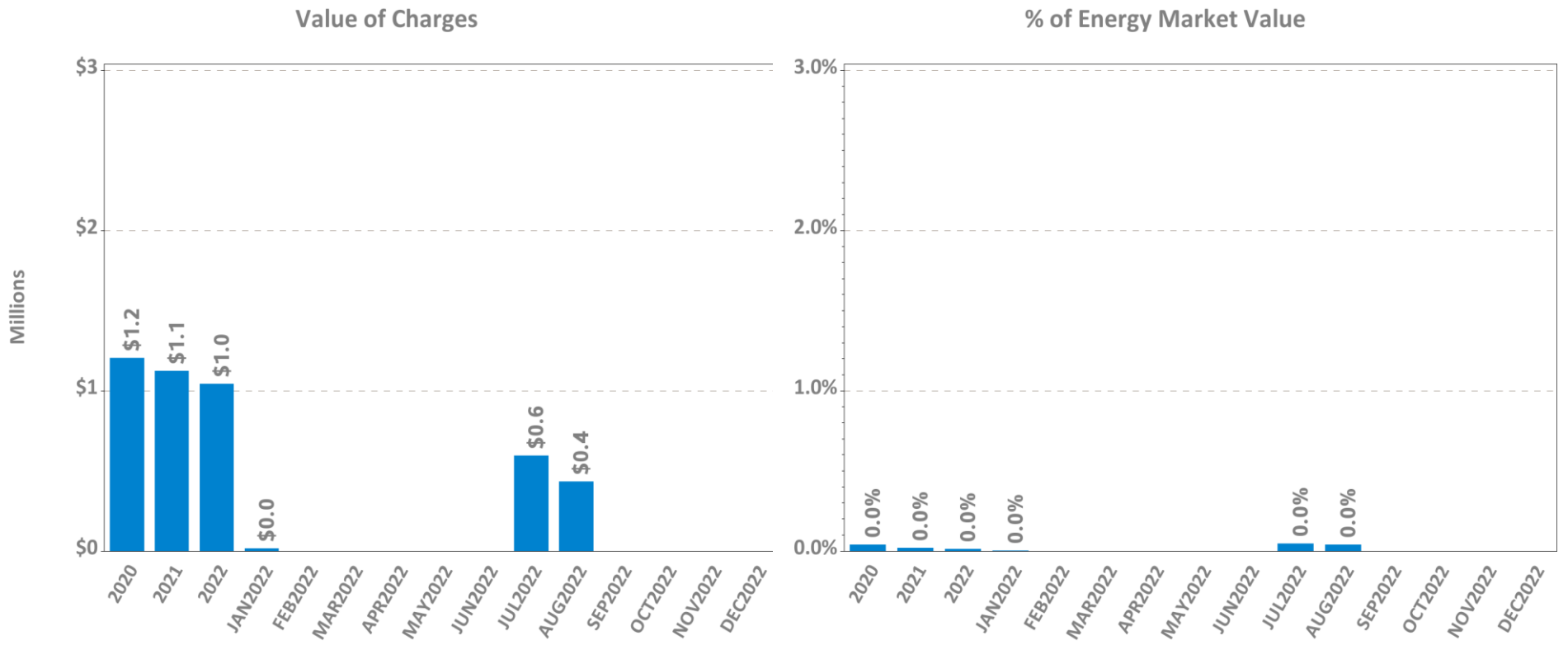
Second Contingency NCPC Charges





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

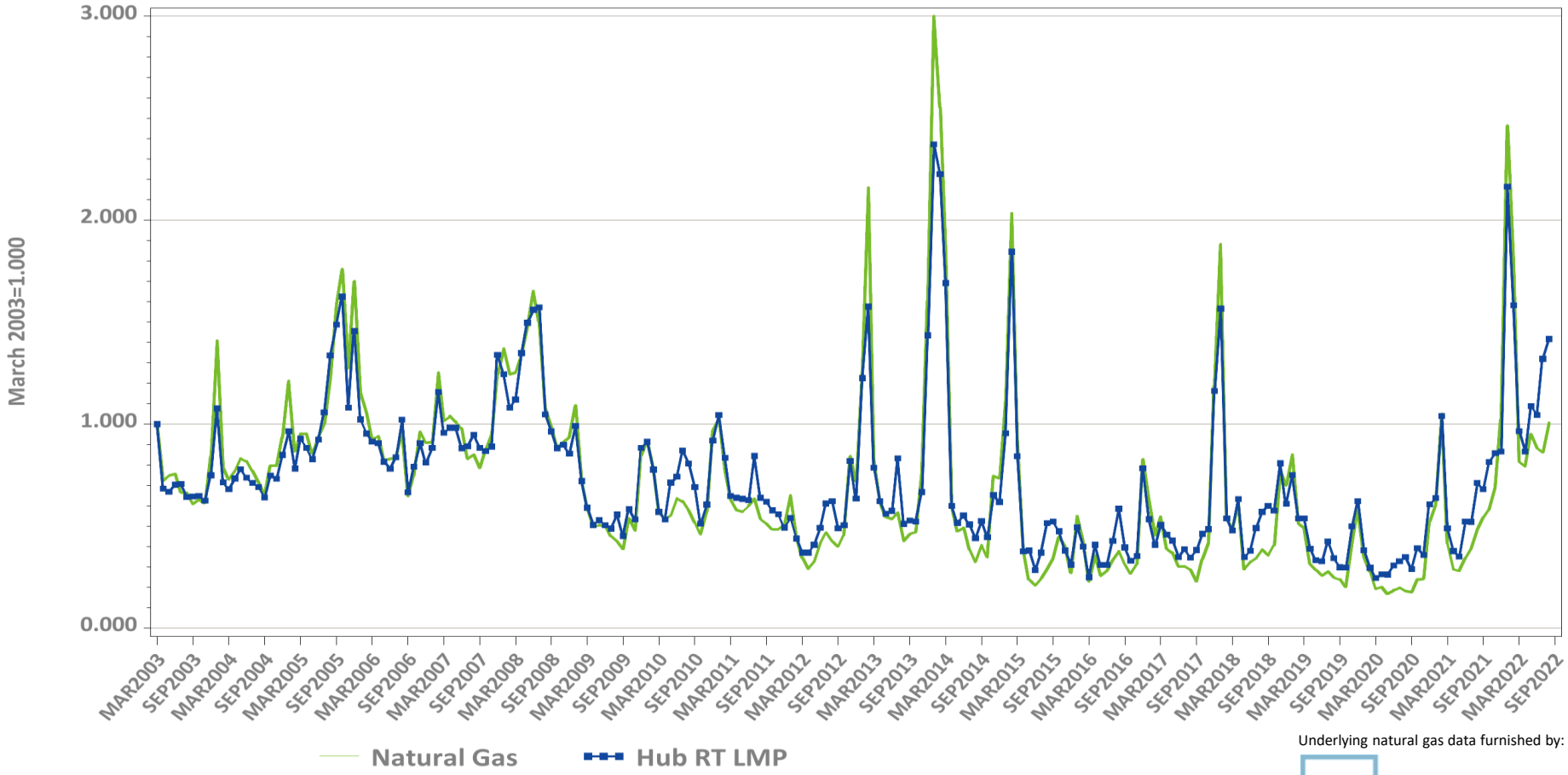
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$56.58	$53.52	$55.13	$56.17	$54.29	$55.36	$56.22	$55.40	$55.44
Real-Time	$54.58	$52.88	$53.26	$54.45	$53.22	$53.48	$54.30	$53.99	$53.99
RT Delta %	-3.5%	-1.2%	-3.4%	-3.1%	-2.0%	-3.4%	-3.4%	-2.5%	-2.6%
Year 2022	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$91.64	$89.42	$89.71	$91.16	$89.76	$90.84	$91.51	$91.11	$91.00
Real-Time	$90.01	$88.40	$87.68	$89.57	$88.07	$89.25	$89.91	$89.53	$89.43
RT Delta %	-1.8%	-1.1%	-2.3%	-1.7%	-1.9%	-1.8%	-1.7%	-1.7%	-1.7%

August-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$50.06	$48.44	$49.56	$50.11	$49.32	$49.19	$49.81	$49.52	$49.47
Real-Time	$49.61	$48.22	$49.12	$49.59	$48.67	$48.63	$49.29	$48.98	$48.92
RT Delta %	-0.9%	-0.5%	-0.9%	-1.0%	-1.3%	-1.1%	-1.0%	-1.1%	-1.1%
August-22	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$101.79	$99.31	$99.21	$101.64	$100.60	$100.66	$101.97	$101.16	$101.02
Real-Time	$98.20	$96.33	$96.00	$98.30	$97.23	$96.89	$98.06	$97.53	$97.33
RT Delta %	-3.5%	-3.0%	-3.2%	-3.3%	-3.4%	-3.7%	-3.8%	-3.6%	-3.7%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	103.4%	105.0%	100.2%	102.8%	104.0%	104.6%	104.7%	104.3%	104.2%
Yr over Yr RT	97.9%	99.8%	95.4%	98.2%	99.8%	99.2%	99.0%	99.1%	98.9%

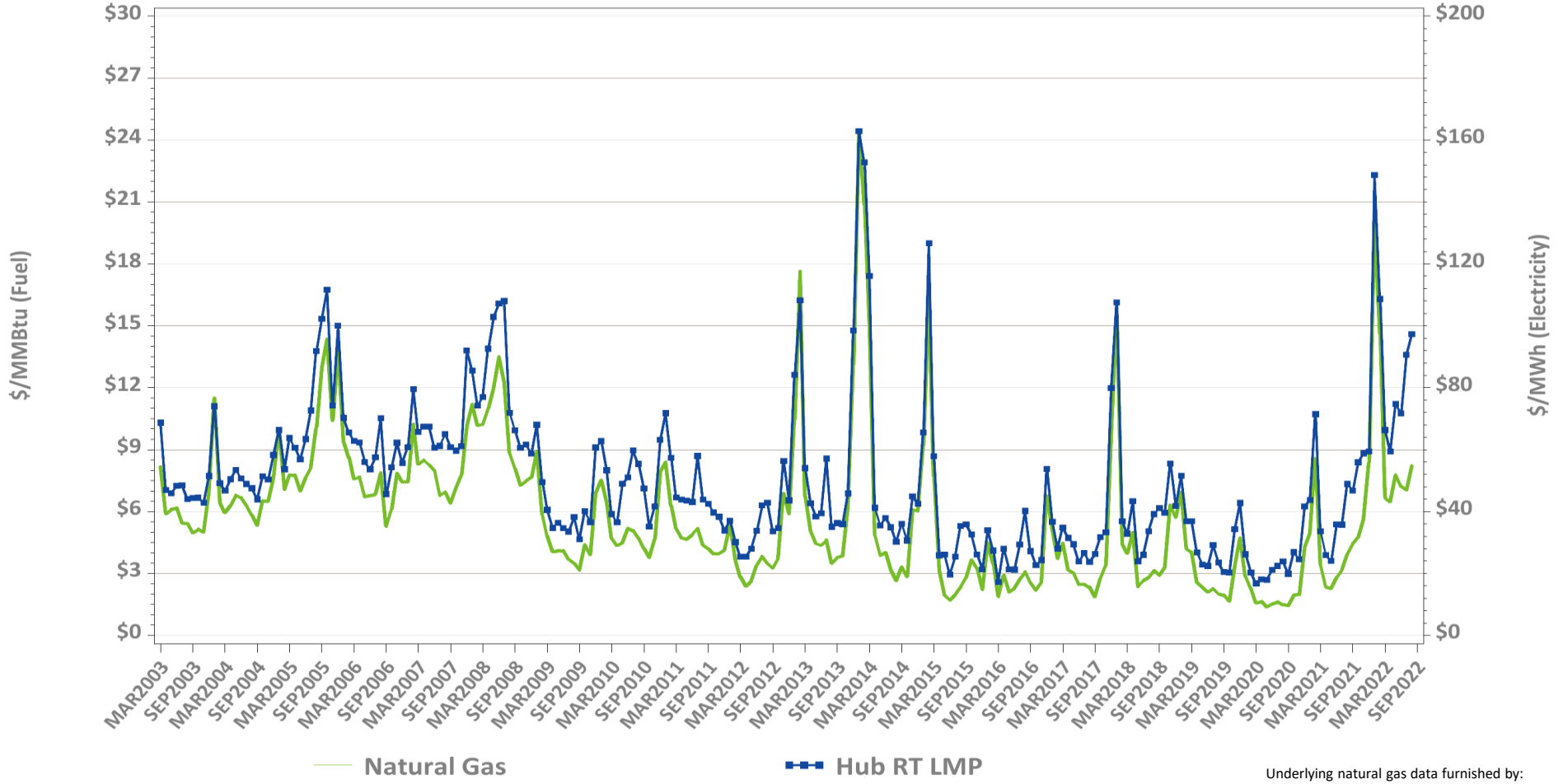
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

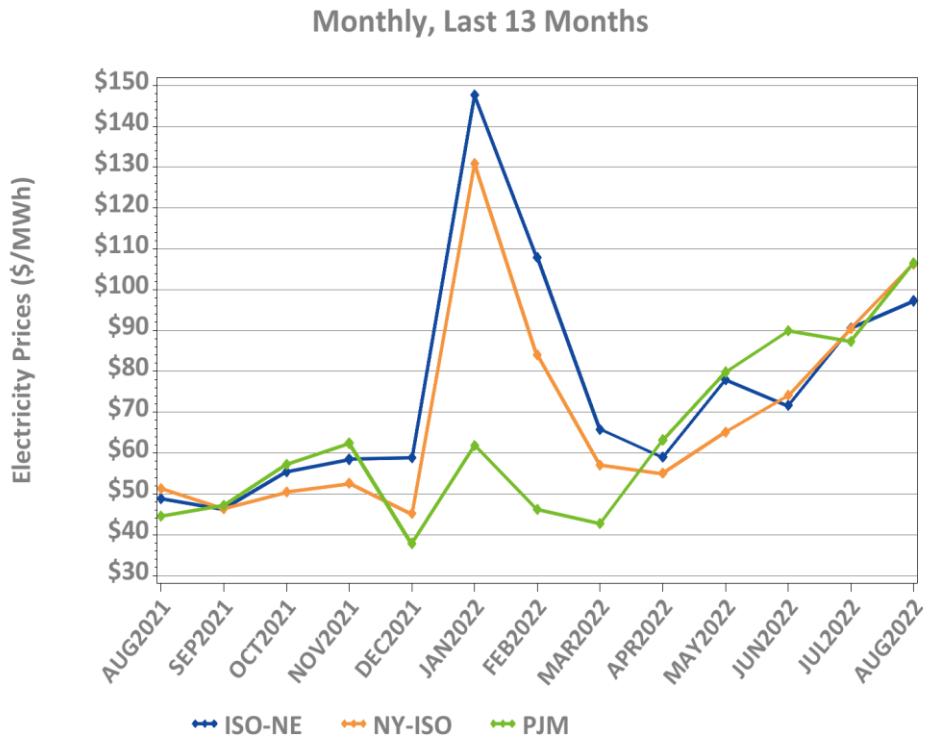
Monthly Average Fuel Price and RT Hub LMP



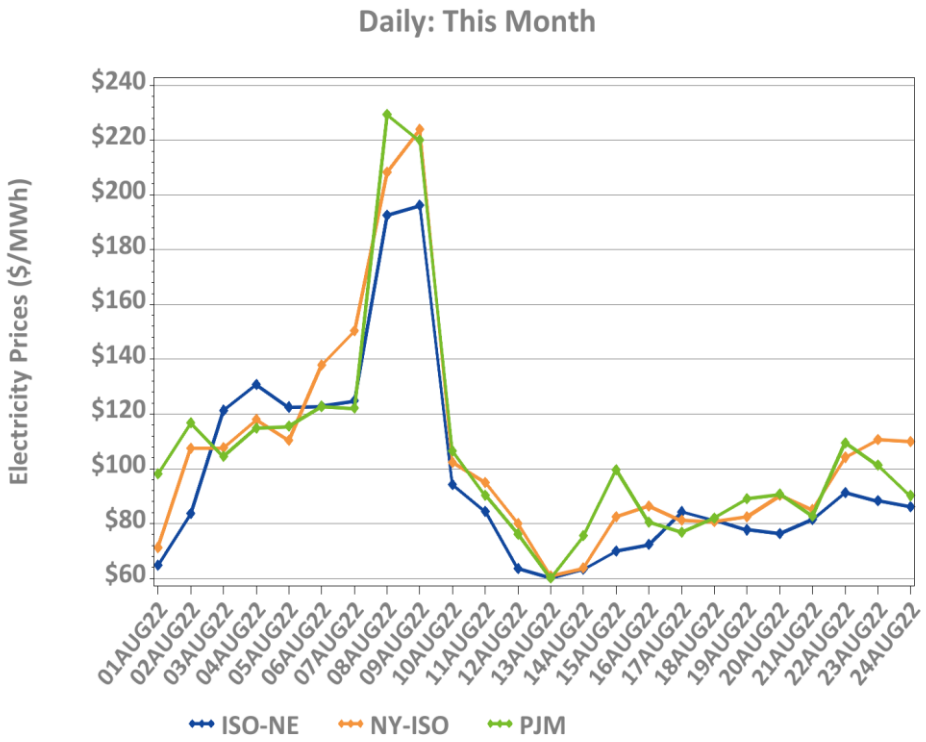
Underlying natural gas data furnished by:

ice Global markets in clear view

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

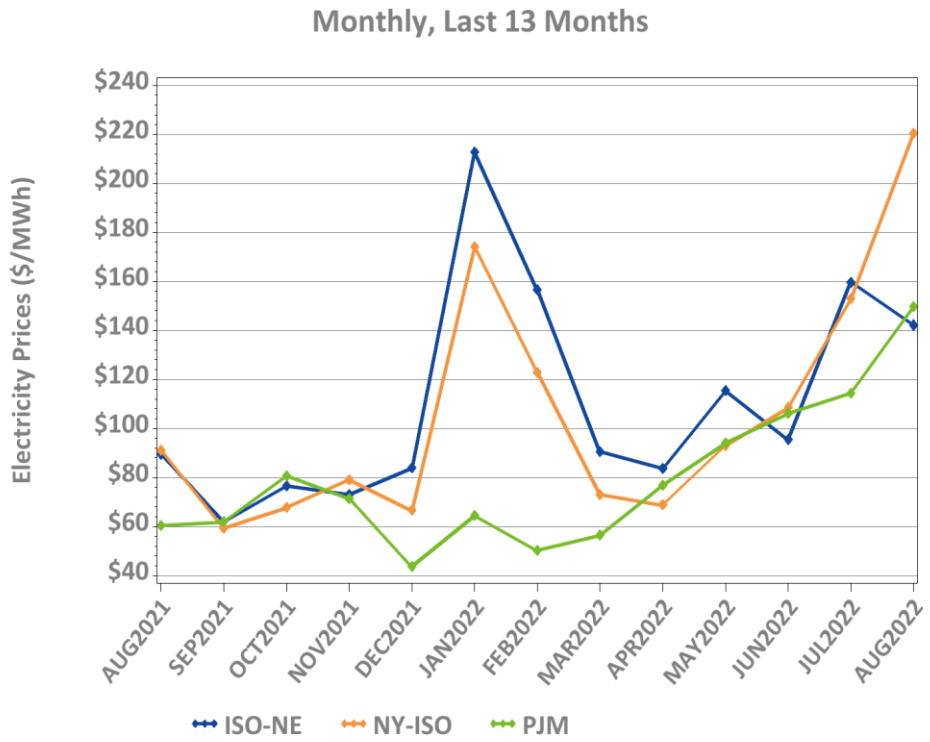


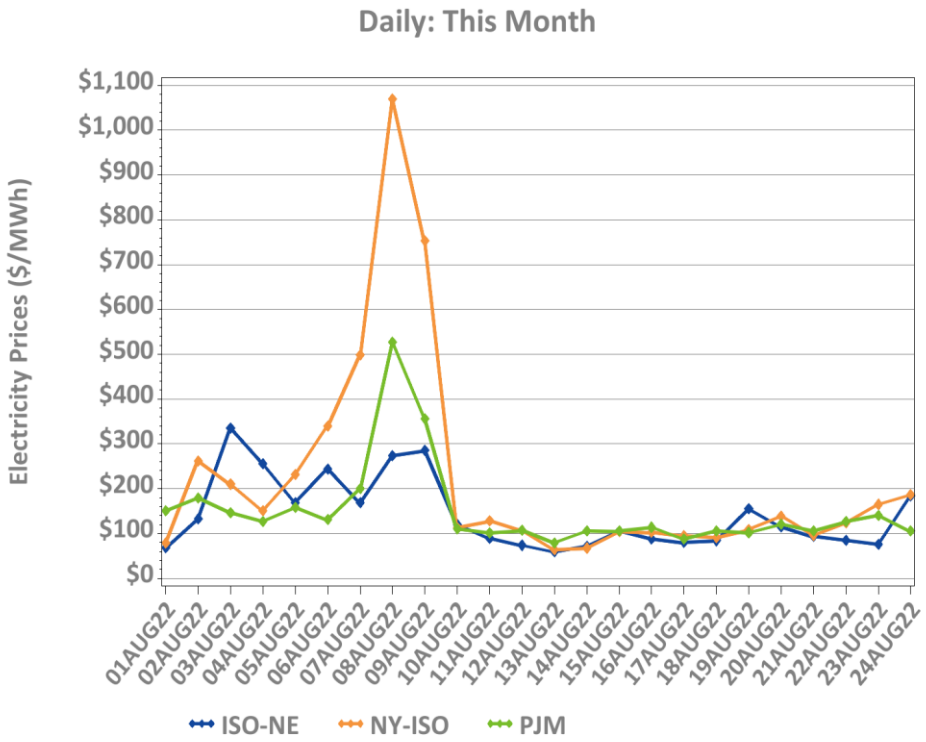
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





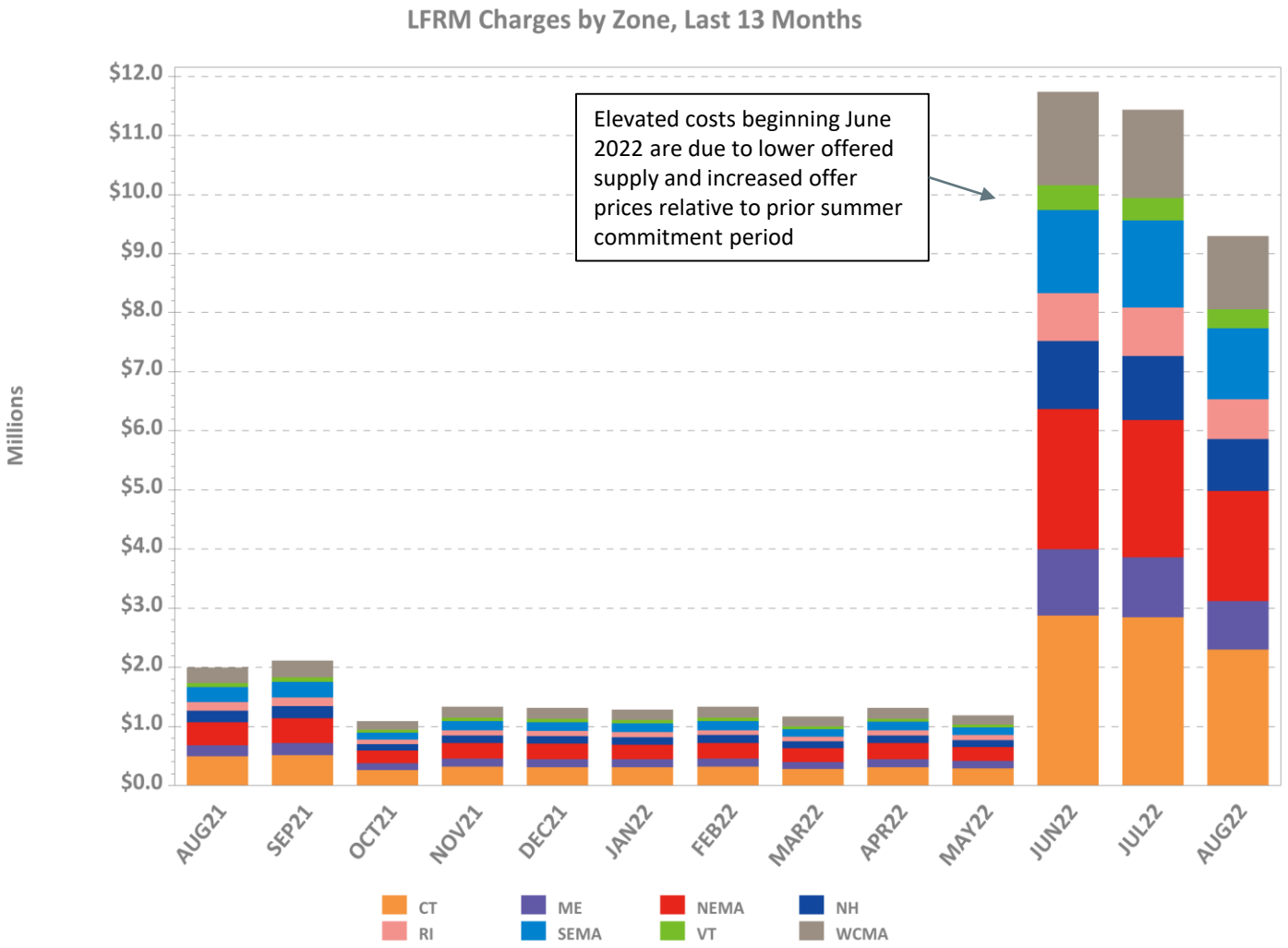
***Forecasted New England daily peak hours reflected**

Reserve Market Results – August 2022

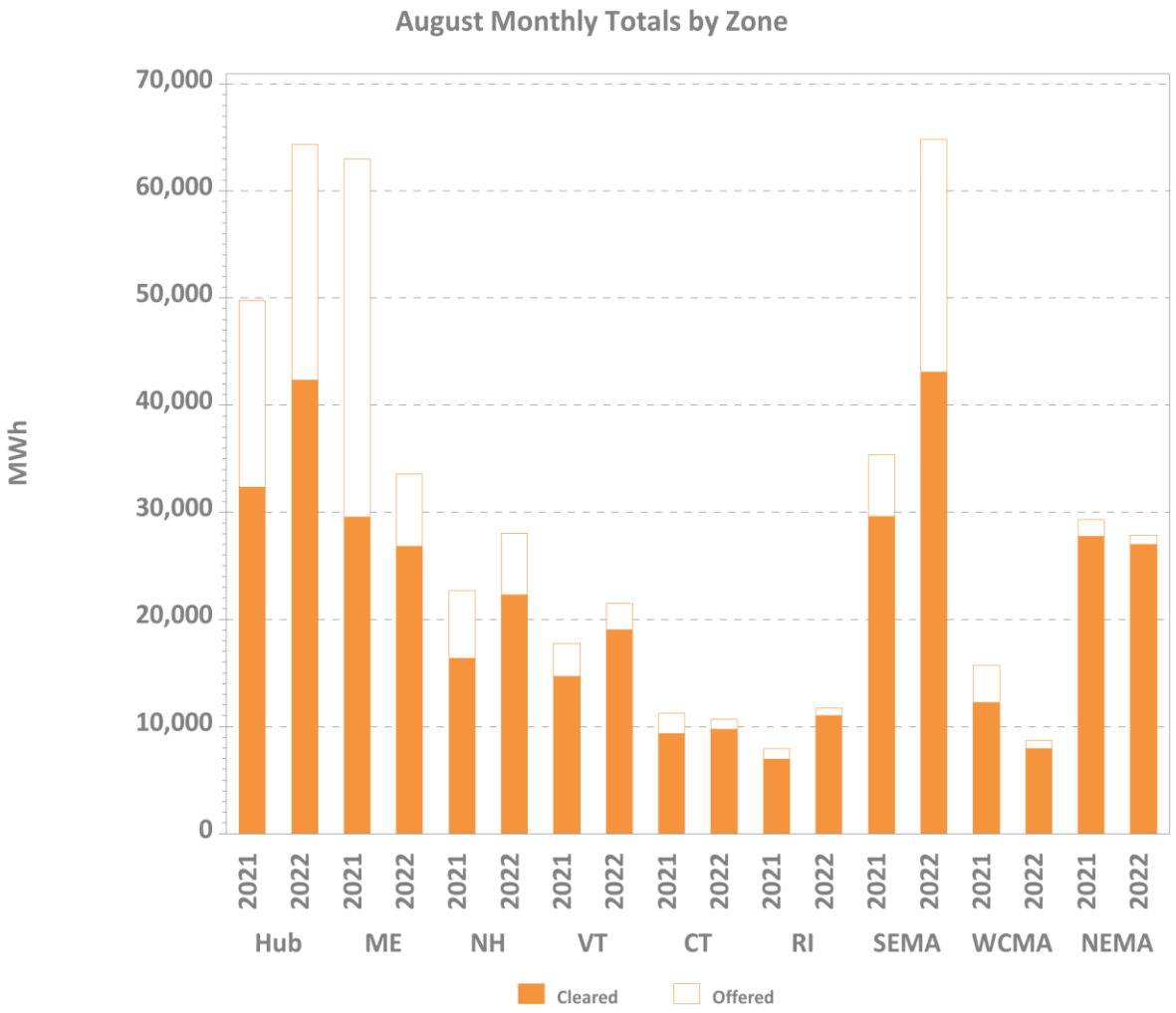
- Maximum potential Forward Reserve Market payments of $9.4M were reduced by credit reductions of $23K, failure-to-reserve penalties of $35K and failure-to-activate penalties of $3K, resulting in a net payout of $9.3M or 99% of maximum
  - Rest of System: $6.04M/6.08M (99%)
  - Southwest Connecticut: $0.03M/0.03M (93%)
  - Connecticut: $2.1M/2.12M (99%)
  - NEMA: $0.1M/0.1M (100%)
- $954K total Real-Time credits were reduced by $183K in Forward Reserve Energy Obligation Charges for a net of $771K in Real-Time Reserve payments
  - Rest of System: 168 hours, $472K
  - Southwest Connecticut: 168 hours, $116K
  - Connecticut: 168 hours, $119K
  - NEMA: 168 hours, $63K

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

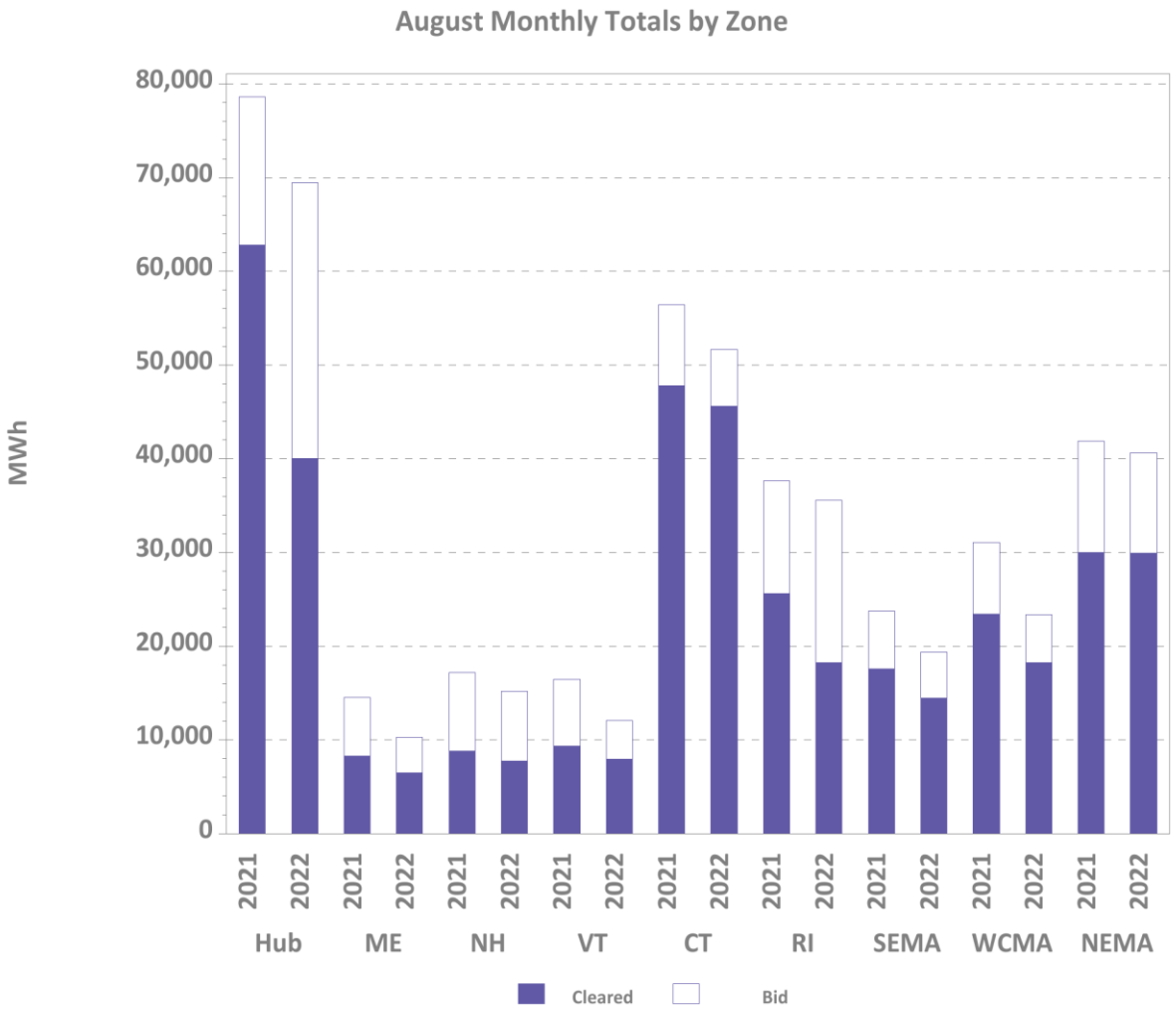
LFRM Charges to Load by Load Zone ($)



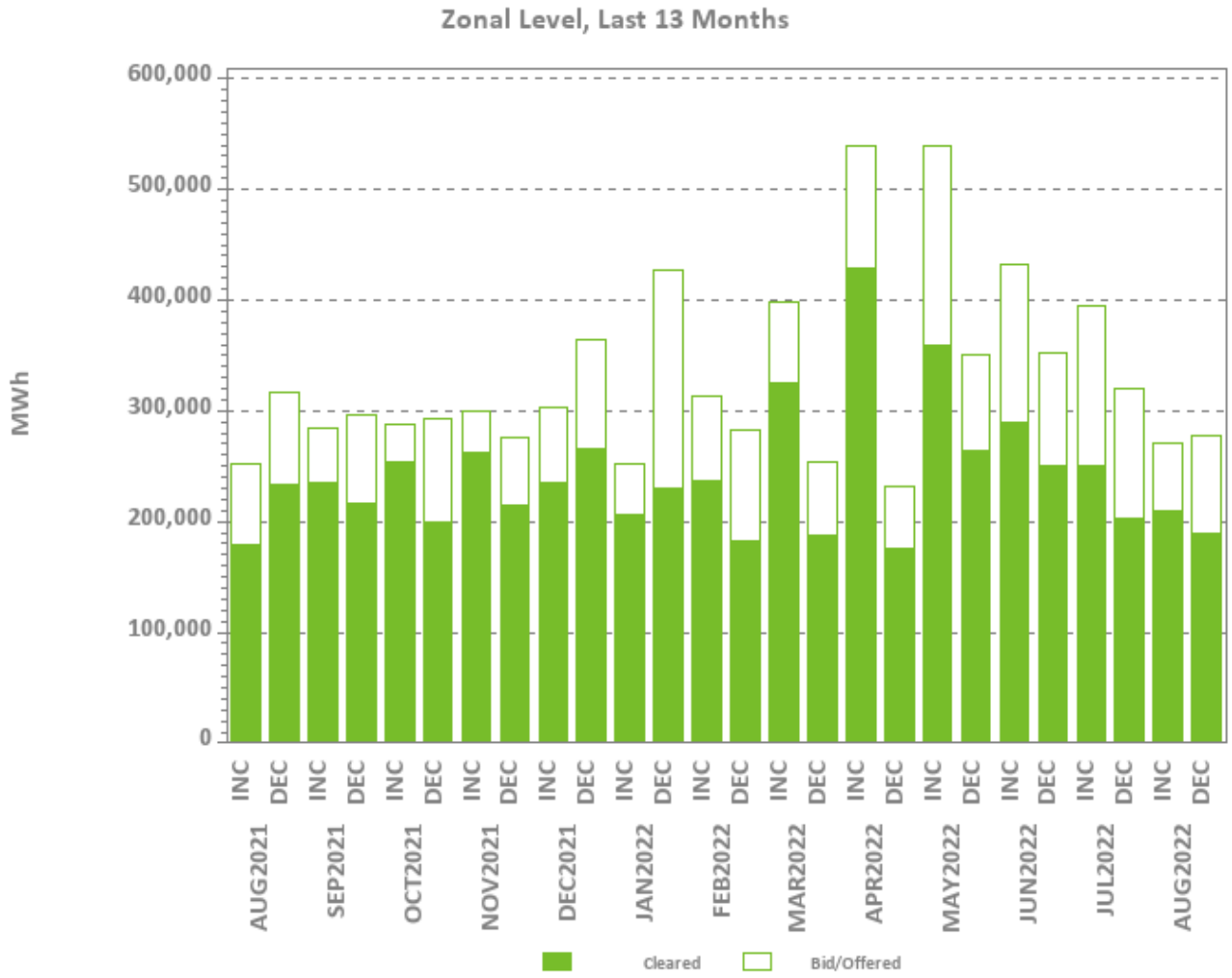
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

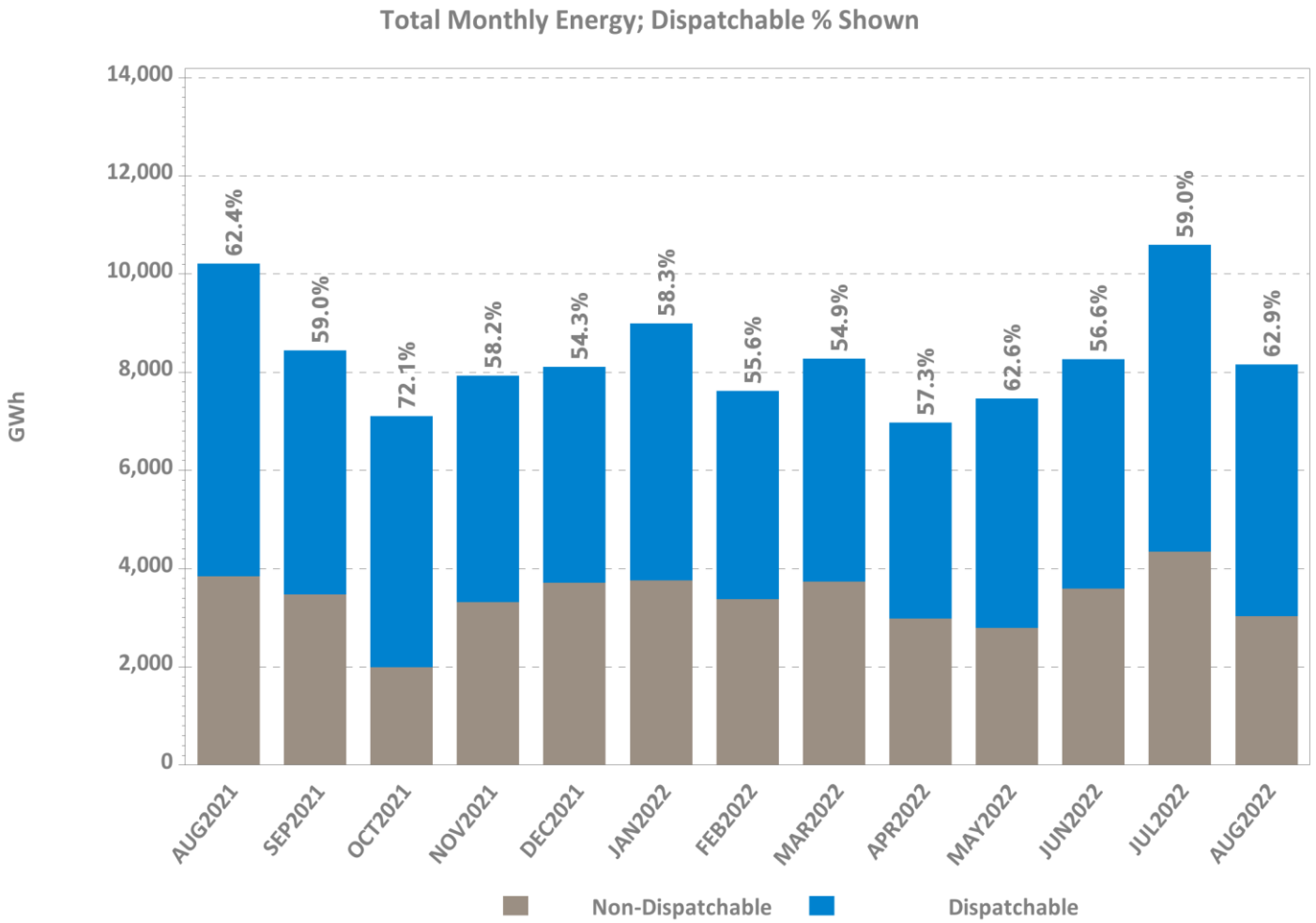


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



*** Dispatchable MWh here are defined to be all generation output that is not self-committed ('must run') by the customer.**

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- September 21 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Greggs Substation Rebuild (Eversource)
    - Connecticut River Crossing and Structure Replacement/Separation of 348 & 1772 Lines (Eversource)
    - 115 kV Structure Replacements & Optical Ground Wire Installation (CT Line 1783 & NH Lines P106, Q171 (Eversource)
  - NPCC Bulk Power System Classification
  - Second Cape Cod Resource Integration Study Update

* 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 (TPCET)

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to transmission planning 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, 12/16/20, and 1/21/21 PAC meetings 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
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published final revisions to the Transmission Planning Technical Guide reflecting these changes on 9/30/21
- CEII supplement to the PAC presentations was released on 10/5/21
- The final TPCET Pilot Study Report was posted to the PAC website on 1/14/22
- Status updates on ongoing transient stability modeling and performance criteria were discussed at the 4/28/22, 5/18/22, 6/15/22, and 8/24/22 PAC meetings

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting

Economic Studies

- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Final report was posted on July 29
  - Draft technical appendices expected to be posted late Q3/early Q4
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
  - Initial scope of work presented at the April PAC meeting and new modeling features and initial benchmark scenario results were presented at the August PAC meeting

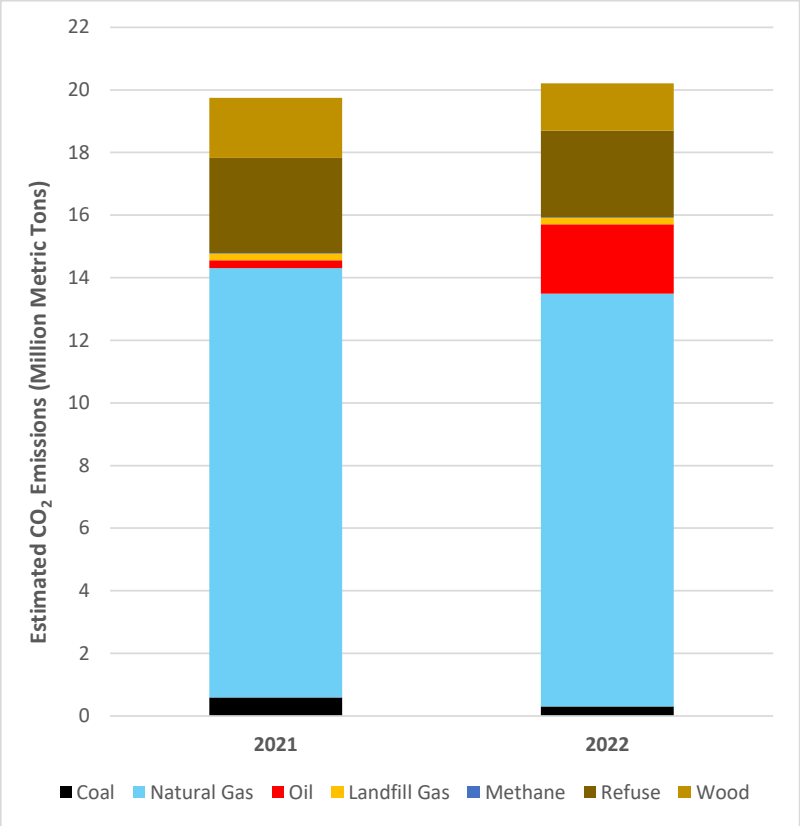
Future Grid Reliability Study (FGRS)

- 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 completed as the 2021 Economic Study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are performed
  - Scope expected to be shared with stakeholders in the 2nd half of 2022

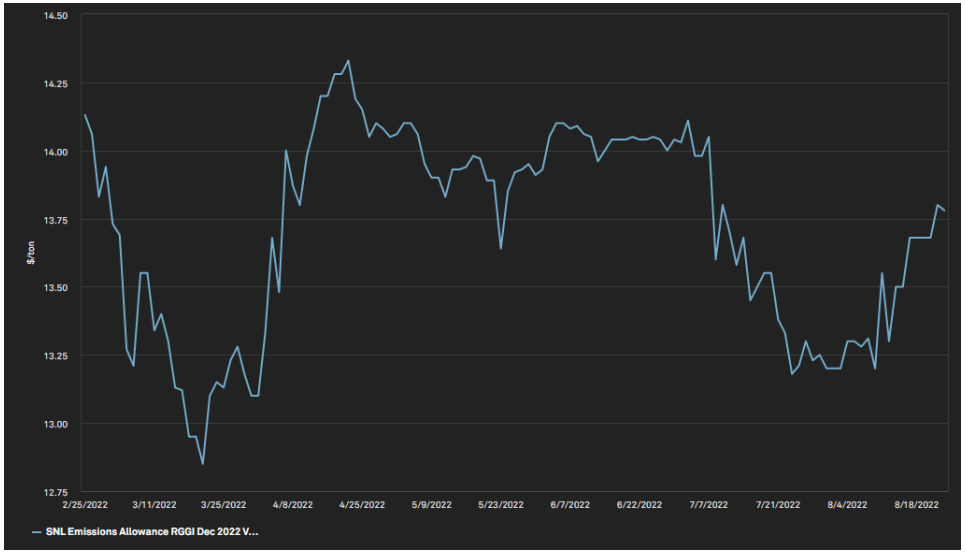
New England Power System Carbon Emissions

CO_2 emissions Up 2% year to year, reflects January oil-fired generation spike

2021 vs. 2022 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



RGGI Allowance Prices Affected by Factors External to New England



- 8/24/22: RGGI allowance spot price - $13.78 per allowance (1 allowance = 1 short ton CO_2)
- 6/1/22 56th RGGI auction cleared at $13.90
  - 97 million allowances will be auctioned in 2022
  - 192 million allowances already in circulation

Data as of 8/21/22

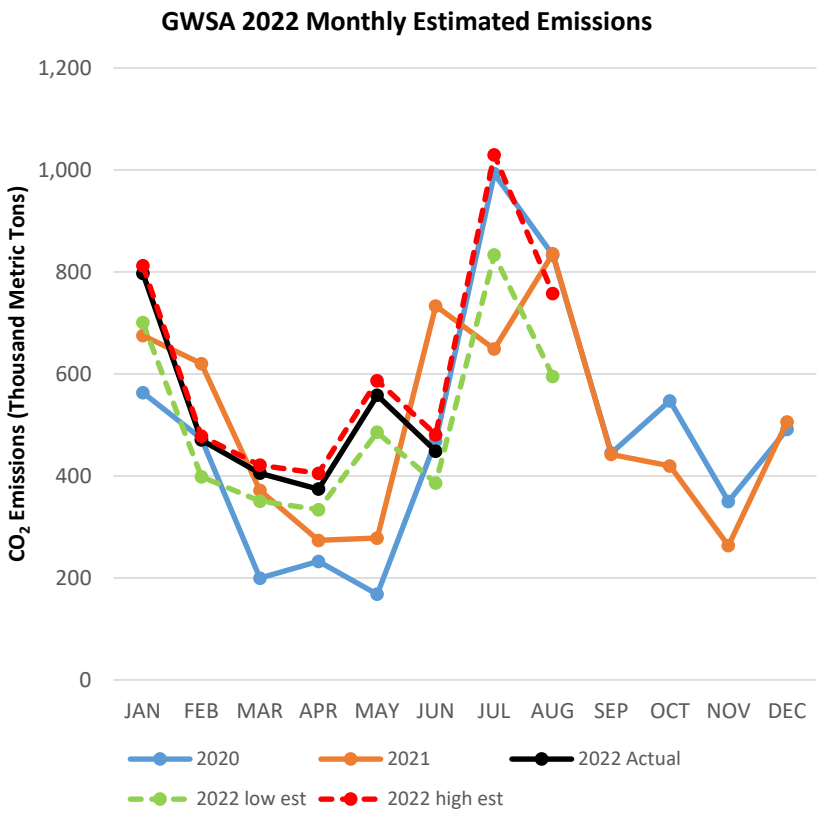
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

Uptick in 2022 Estimated Emissions Under CO_2 Cap

- 8/21/22: 2022 estimated GWSA CO_2 emissions range between 4.1 and 5.0 MMT
  - 41% to 50% of the 8.06 MMT 2022 cap
- 6/10/22 GWSA auction cleared at $9.75; 1.20 million 2022 vintage allowances sold
  - 2022 RGGI allowance spot price at $14.05 per metric ton
  - 0.39 million 2023 vintage GWSA allowances were also offered, clearing at $4.0
- 2022 YTD estimated GWSA emissions were between 3% lower and 17% higher than YTD 2021 emissions

2020-2022 Estimated Monthly Emissions (Thousand Metric tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Sources: ISO-NE (estimated emissions); EPA (actual emissions)

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 8/23/2022

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-23	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 8/23/2022

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 8/23/2022

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 8/23/2022

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	Dec-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 8/23/2022

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 8/23/2022

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 8/23/2022

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	4
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-24	1
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 8/23/2022

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	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Jun-23	3
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Jun-23	2
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-24	1

SEMA/RI Reliability Projects, cont.

Status as of 8/23/2022

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	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-25	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 8/23/2022

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	May 22	4
1724	Replace the Kent County 345/115 kV transformer	Mar-22	4
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 8/23/2022

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	3
1851	Upgrade Card 115 kV to BPS standards	Mar-23	3
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	3
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	3
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	3

Eastern CT Reliability Projects, cont.

Status as of 8/23/2022

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	3
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	3
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	3
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-22	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	3
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 8/23/2022

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	Nov-21	4
1862	Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	3
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Mar-22	4
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	3

Boston Area Optimized Solution Projects

Status as of 8/23/2022

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	Dec-21	4
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Apr-22	4
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	3

New Hampshire Solution Projects

Status as of 8/23/2022

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	3
1879	Install a +50/-25 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Aug-23	3
1880	Install a +100/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec-23	2
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	2

Upper Maine Solution Projects

Status as of 8/23/2022

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-24	2
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	Jun-24	2

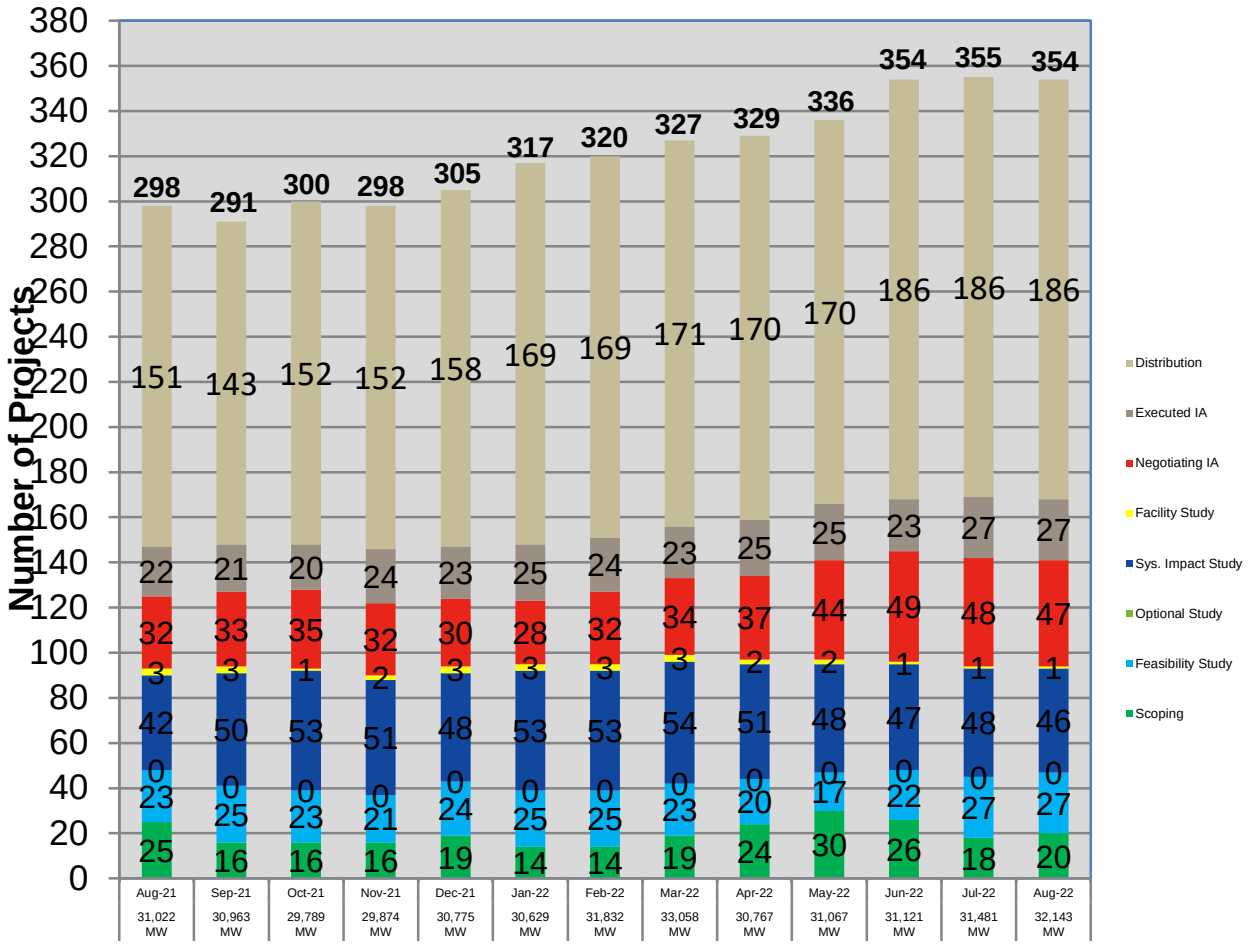
Upper Maine Solution Projects, cont.

Status as of 8/23/2022

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	Jun-24	2
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	2
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	2

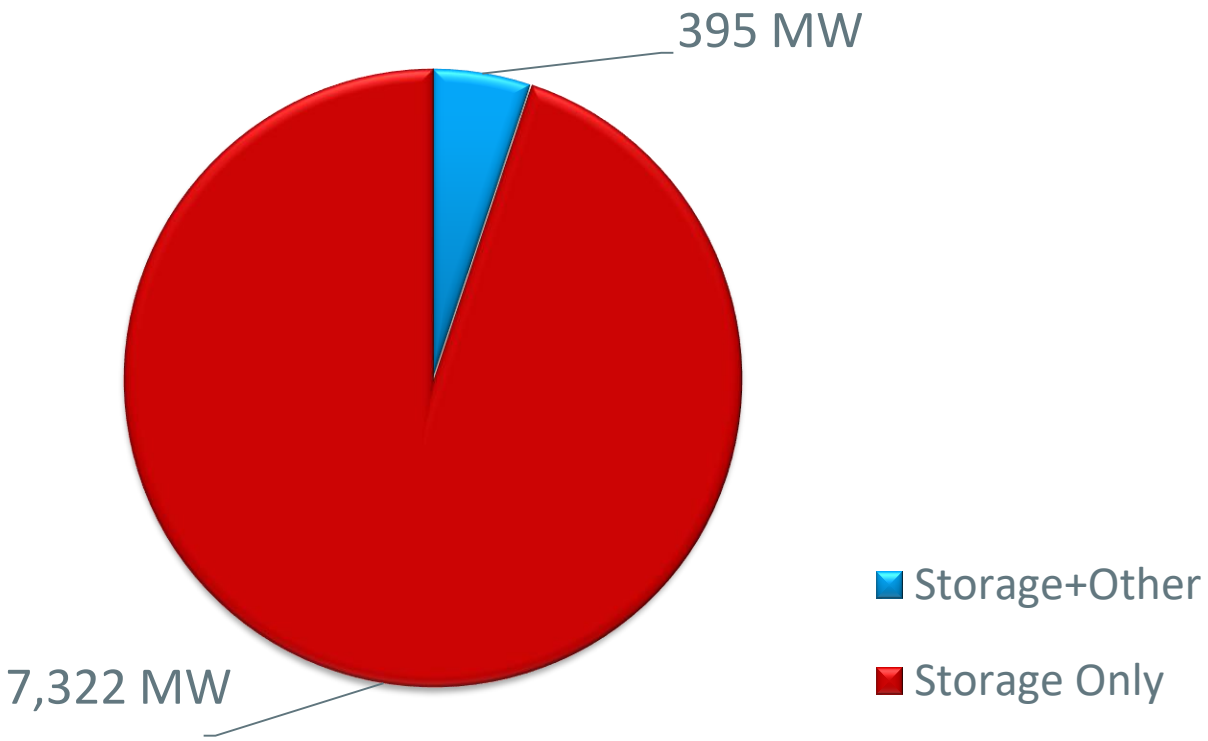
Status of Tariff Studies as of August 19, 2022



Note: August 2022 is based on partial data.
6 ETUs in Scoping, 2 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 3 Negotiating IA, and 2 with Executed IA
Transmission Service Requests needing study: 1 in Scoping and 1 in SIS
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of August 19, 2022)

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



OPERABLE CAPACITY ANALYSIS

Fall 2022 Analysis

Fall 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Sep. - 2022[2] CSO (MW)	Sep. - 2022[2] SCC (MW)
Operable Capacity MW [1]	27,767	29,610
Active Demand Capacity Resource (+) [5]	510	453
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	660	660
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	2,311	2,702
Gas Generator Outages MW (-)	974	1,046
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,584	24,907
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,619	20,619
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,924	22,924
Operable Capacity Margin	660	1,983

[1]Operable Capacity is based on data as of **August 23, 2022** 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 **August 23, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 24, 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.

Fall 2022 Operable Capacity Analysis

90/10 Load Forecast	Sep. - 2022[2] CSO (MW)	Sep. - 2022[2] SCC (MW)
Operable Capacity MW [1]	27,767	29,610
Active Demand Capacity Resource (+) [5]	510	453
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	660	660
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	2,311	2,702
Gas Generator Outages MW (-)	974	1,046
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,584	24,907
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,095	22,095
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,400	24,400
Operable Capacity Margin	-816	507

[1]Operable Capacity is based on data as of **August 23, 2022** 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 **August 23, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 24, 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.

Fall 2022 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 23, 2022 - 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 September, October & November.

Report created: 8/23/2022

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
9/17/2022	27767	510	660	32	1499	272	2100	0	25098	20711	2305	23016	2082	N	Fall 2022
9/24/2022	**27767**	**510**	**660**	**32**	**2311**	**974**	**2100**	**0**	**23584**	**20619**	**2305**	**22924**	**660**	**Y**	**Fall 2022**
10/1/2022	28158	559	1070	70	3672	2822	2800	0	20563	15169	2305	17474	3089	N	Fall 2022
10/8/2022	28158	559	1070	70	3957	4157	2800	0	18943	15205	2305	17510	1433	N	Fall 2022
10/15/2022	28158	559	1070	70	3540	2319	2800	0	21198	16121	2305	18426	2772	N	Fall 2022
10/22/2022	28158	559	1070	70	1886	2499	2800	0	22672	16482	2305	18787	3885	N	Fall 2022
10/29/2022	28158	559	1070	70	2344	3250	3600	0	20663	16687	2305	18992	1671	N	Fall 2022
11/5/2022	28158	559	1070	70	2366	2249	3600	0	21642	16802	2305	19107	2535	N	Fall 2022
11/12/2022	28158	559	1070	70	1918	938	3600	0	23401	17143	2305	19448	3953	N	Fall 2022
11/19/2022	28158	559	1070	70	1156	305	3600	1065	23731	17875	2305	20180	3551	N	Fall 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 2022 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 2022 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 23, 2022 - 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 September, October & November.

Report created: 8/23/2022

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
9/17/2022	27767	510	660	32	1499	272	2100	0	25098	22192	2305	24497	601	N	Fall 2022
9/24/2022	**27767**	**510**	**660**	**32**	**2311**	**974**	**2100**	**0**	**23584**	**22095**	**2305**	**24400**	**-816**	**Y**	**Fall 2022**
10/1/2022	28158	559	1070	70	3672	2822	2800	0	20563	15709	2305	18014	2549	N	Fall 2022
10/8/2022	28158	559	1070	70	3957	4157	2800	0	18943	15745	2305	18050	893	N	Fall 2022
10/15/2022	28158	559	1070	70	3540	2319	2800	0	21198	16690	2305	18995	2203	N	Fall 2022
10/22/2022	28158	559	1070	70	1886	2499	2800	0	22672	17063	2305	19368	3304	N	Fall 2022
10/29/2022	28158	559	1070	70	2344	3250	3600	0	20663	17274	2305	19579	1084	N	Fall 2022
11/5/2022	28158	559	1070	70	2366	2249	3600	0	21642	17392	2305	19697	1945	N	Fall 2022
11/12/2022	28158	559	1070	70	1918	938	3600	597	22804	17744	2305	20049	2755	N	Fall 2022
11/19/2022	28158	559	1070	70	1156	305	3600	2000	22796	18498	2305	20803	1993	N	Fall 2022

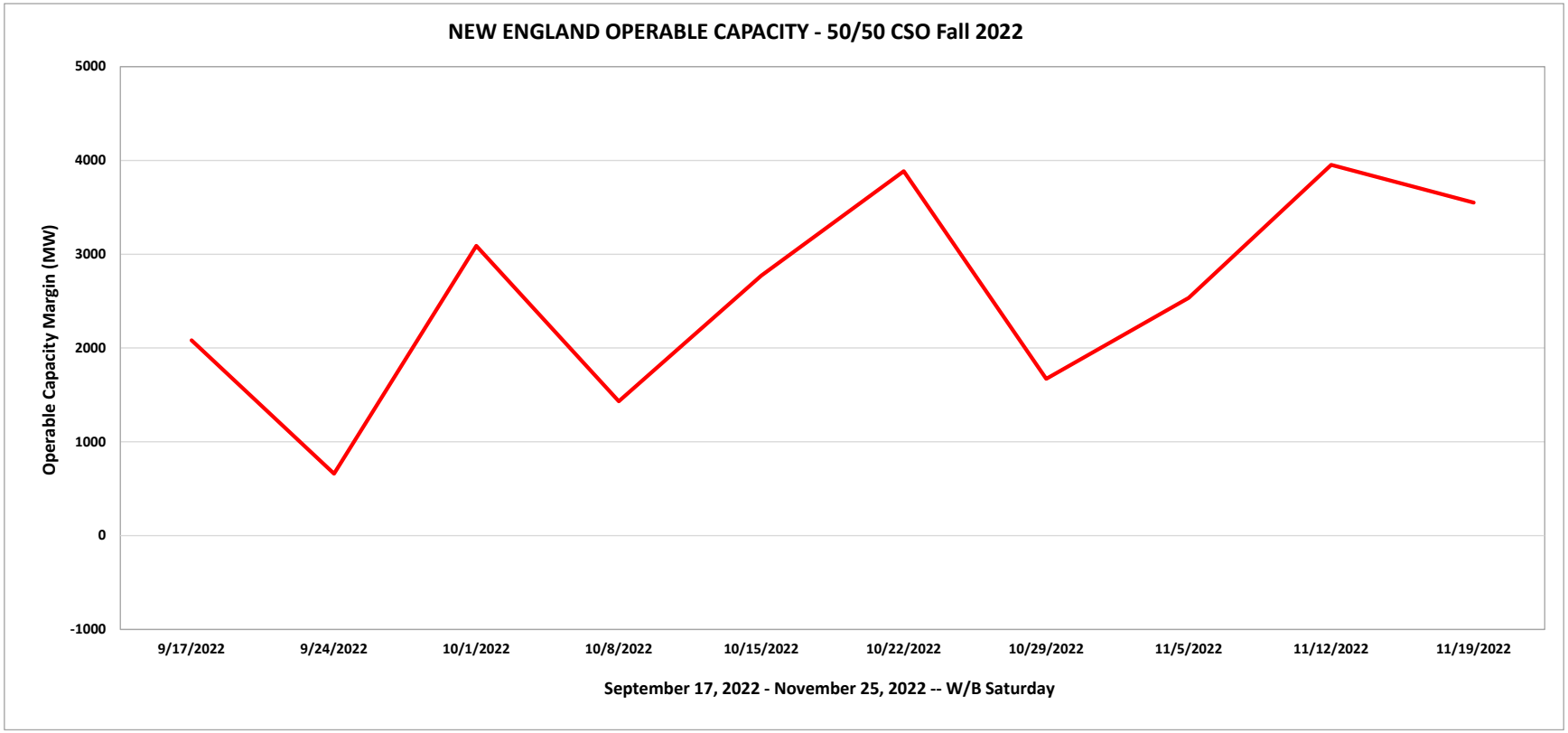
Column Definitions

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 2022 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**

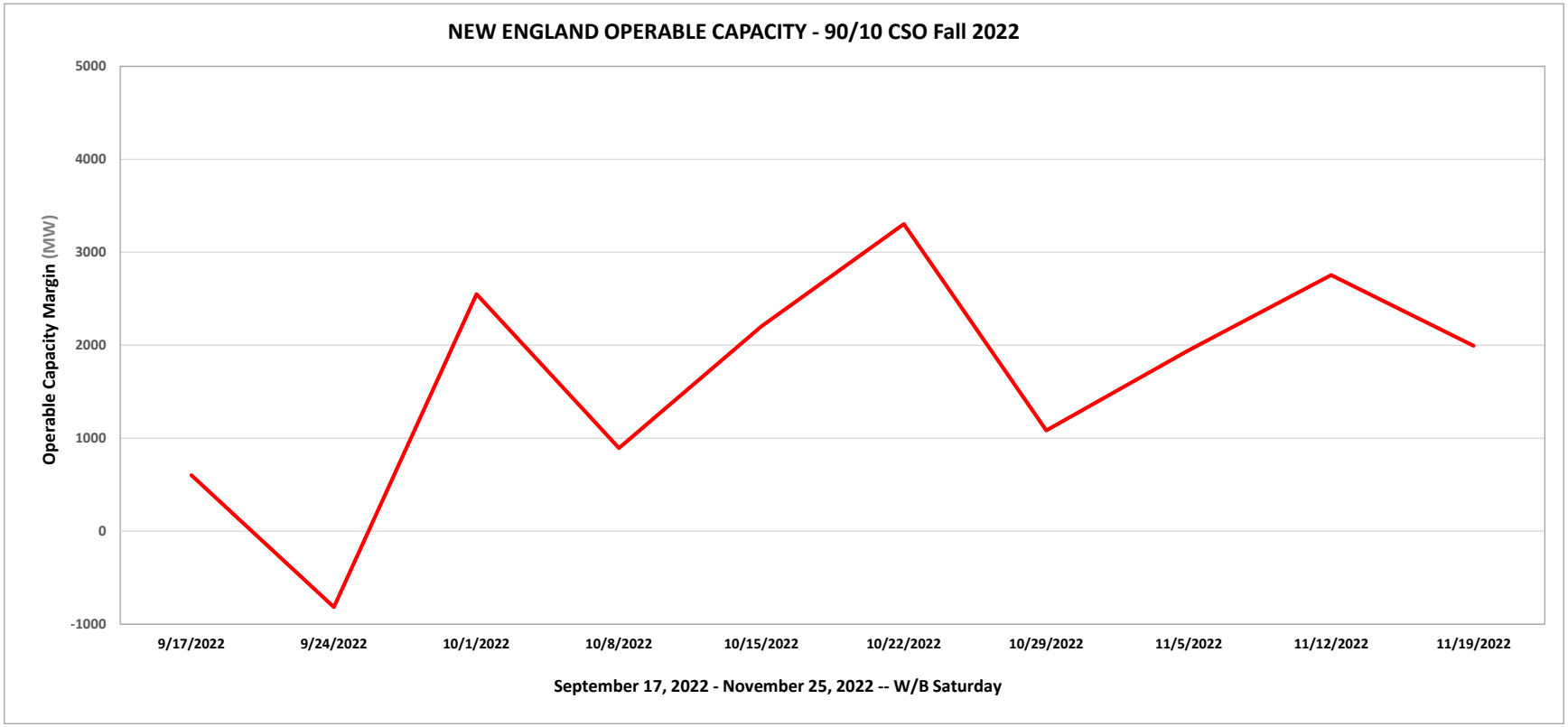
Fall 2022 Operable Capacity Analysis

50/50 Forecast (Reference)



Fall 2022 Operable Capacity Analysis

90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2022/23 Analysis

Preliminary Winter 2022/23 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,239	32,065
Active Demand Capacity Resource (+) [5]	560	413
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,070	1,070
Non Commercial Capacity (+)	70	70
Non Gas-fired Planned Outage MW (-)	75	139
Gas Generator Outages MW (-)	7	156
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,728	4,131
Net Capacity (NET OPCAP SUPPLY MW)	23,329	26,392
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,009	20,009
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,314	22,314
Operable Capacity Margin	1,015	4,078

[1]Operable Capacity is based on data as of **August 23, 2022** 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 **August 23, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 2023.**

[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 2022/23 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,239	32,065
Active Demand Capacity Resource (+) [5]	560	413
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,070	1,070
Non Commercial Capacity (+)	70	70
Non Gas-fired Planned Outage MW (-)	75	139
Gas Generator Outages MW (-)	7	156
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,539	5,061
Net Capacity (NET OPCAP SUPPLY MW)	22,518	25,462
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,695	20,695
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,000	23,000
Operable Capacity Margin	-482	2,462

[1]Operable Capacity is based on data as of **August 23, 2022** 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 **August 23, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 2023.**

[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 2022/23 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 23, 2022 - 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 from November through March.

Report created: 8/23/2022

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
11/26/2022	28158	559	1070	70	545	296	3600	1662	23754	18588	2305	20893	2861	N	Winter 2022/2023
12/3/2022	28239	560	1070	70	377	578	3200	1804	23980	18919	2305	21224	2756	N	Winter 2022/2023
12/10/2022	28239	560	1070	70	357	49	3200	2532	23801	19205	2305	21510	2291	N	Winter 2022/2023
12/17/2022	28239	560	1070	70	349	49	3200	2745	23596	19216	2305	21521	2075	N	Winter 2022/2023
12/24/2022	28239	560	1070	70	19	7	3200	3134	23579	19278	2305	21583	1996	N	Winter 2022/2023
12/31/2022	28239	560	1070	70	93	7	2800	3733	23306	19549	2305	21854	1452	N	Winter 2022/2023
1/7/2023	**28239**	**560**	**1070**	**70**	**75**	**7**	**2800**	**3728**	**23329**	**20009**	**2305**	**22314**	**1015**	**Y**	**Winter 2022/2023**
1/14/2023	28239	560	1070	70	75	7	2800	3583	23474	20009	2305	22314	1160	N	Winter 2022/2023
1/21/2023	28239	560	1070	70	75	7	2800	3134	23923	20009	2305	22314	1609	N	Winter 2022/2023
1/28/2023	28239	560	1070	70	47	7	3100	2835	23950	19789	2305	22094	1856	N	Winter 2022/2023
2/4/2023	28239	560	1070	70	47	7	3100	2536	24249	19524	2305	21829	2420	N	Winter 2022/2023
2/11/2023	28239	560	1070	70	47	7	3100	2237	24548	19496	2305	21801	2747	N	Winter 2022/2023
2/18/2023	28239	560	1070	70	20	7	3100	1788	25024	19236	2305	21541	3483	N	Winter 2022/2023
2/25/2023	28239	560	1070	70	123	7	3100	1489	25220	18258	2305	20563	4657	N	Winter 2022/2023
3/4/2023	28239	560	1070	70	90	783	2200	414	26452	17912	2305	20217	6235	N	Winter 2022/2023
3/11/2023	28239	560	1070	70	90	290	2200	308	27051	17718	2305	20023	7028	N	Winter 2022/2023
3/18/2023	28239	560	1070	70	780	447	2200	0	26512	17357	2305	19662	6850	N	Winter 2022/2023
3/25/2023	28239	560	1070	70	739	1670	2200	0	25330	16797	2305	19102	6228	N	Winter 2022/2023

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 2022 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 2022/23 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 23, 2022 - 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 from November through March.

Report created: 8/23/2022

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
11/26/2022	28158	559	1070	70	545	296	3600	2576	22840	19234	2305	21539	1301	N	Winter 2022/2023
12/3/2022	28239	560	1070	70	377	578	3200	2792	22992	19571	2305	21876	1116	N	Winter 2022/2023
12/10/2022	28239	560	1070	70	357	49	3200	3519	22814	19866	2305	22171	643	N	Winter 2022/2023
12/17/2022	28239	560	1070	70	349	49	3200	3864	22477	19877	2305	22182	295	N	Winter 2022/2023
12/24/2022	28239	560	1070	70	19	7	3200	4280	22433	19941	2305	22246	187	N	Winter 2022/2023
12/31/2022	28239	560	1070	70	93	7	2800	4408	22631	20220	2305	22525	106	N	Winter 2022/2023
1/7/2023	**28239**	**560**	**1070**	**70**	**75**	**7**	**2800**	**4539**	**22518**	**20695**	**2305**	**23000**	**-482**	**Y**	**Winter 2022/2023**
1/14/2023	28239	560	1070	70	75	7	2800	4331	22726	20695	2305	23000	-274	N	Winter 2022/2023
1/21/2023	28239	560	1070	70	75	7	2800	4032	23025	20695	2305	23000	25	N	Winter 2022/2023
1/28/2023	28239	560	1070	70	47	7	3100	4032	22753	20468	2305	22773	-20	N	Winter 2022/2023
2/4/2023	28239	560	1070	70	47	7	3100	3583	23202	20195	2305	22500	702	N	Winter 2022/2023
2/11/2023	28239	560	1070	70	47	7	3100	3284	23501	20166	2305	22471	1030	N	Winter 2022/2023
2/18/2023	28239	560	1070	70	20	7	3100	2686	24126	19898	2305	22203	1923	N	Winter 2022/2023
2/25/2023	28239	560	1070	70	123	7	3100	2237	24472	18889	2305	21194	3278	N	Winter 2022/2023
3/4/2023	28239	560	1070	70	90	783	2200	1311	25555	18533	2305	20838	4717	N	Winter 2022/2023
3/11/2023	28239	560	1070	70	90	290	2200	1206	26153	18333	2305	20638	5515	N	Winter 2022/2023
3/18/2023	28239	560	1070	70	780	447	2200	600	25912	17960	2305	20265	5647	N	Winter 2022/2023
3/25/2023	28239	560	1070	70	739	1670	2200	0	25330	17383	2305	19688	5642	N	Winter 2022/2023

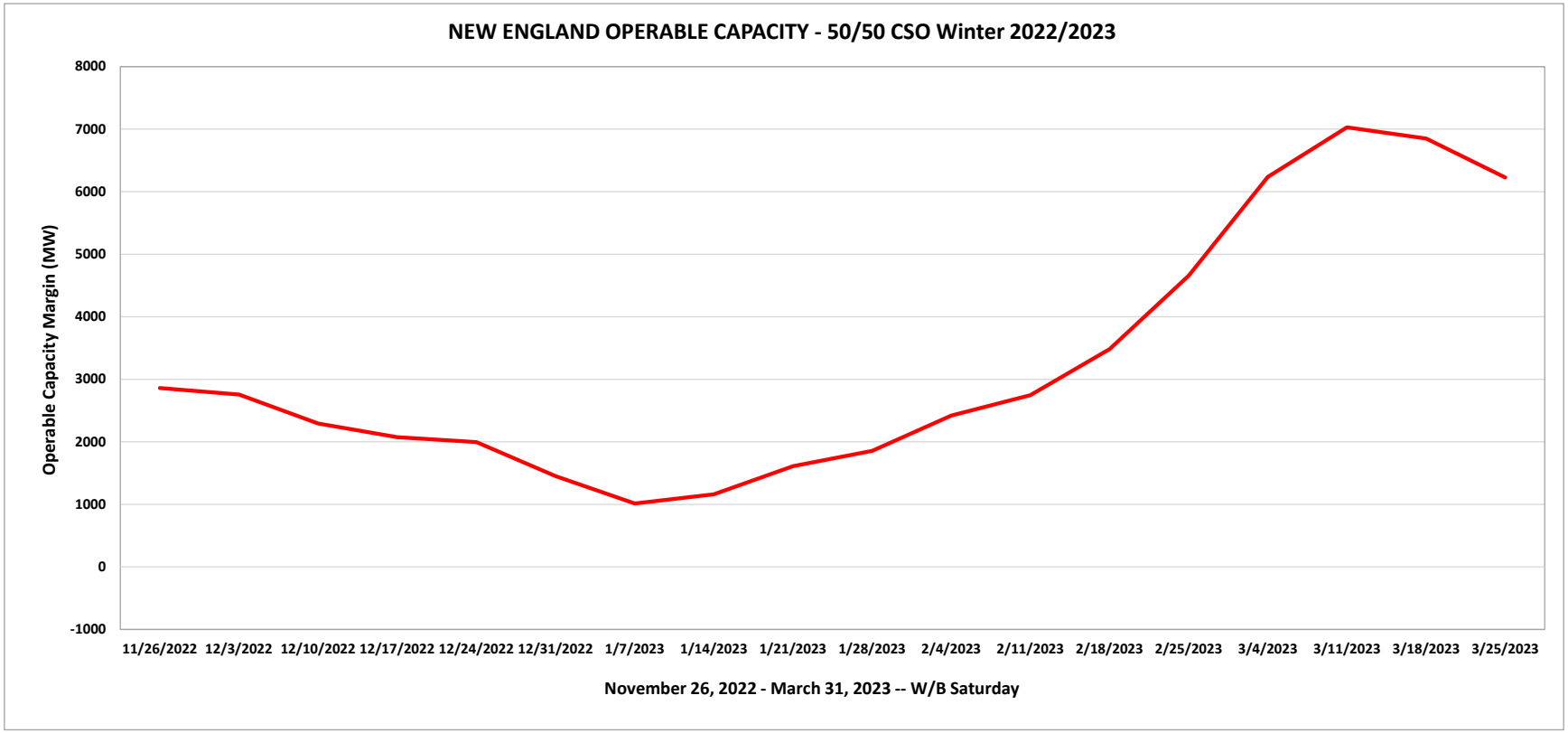
Column Definitions

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 2022 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

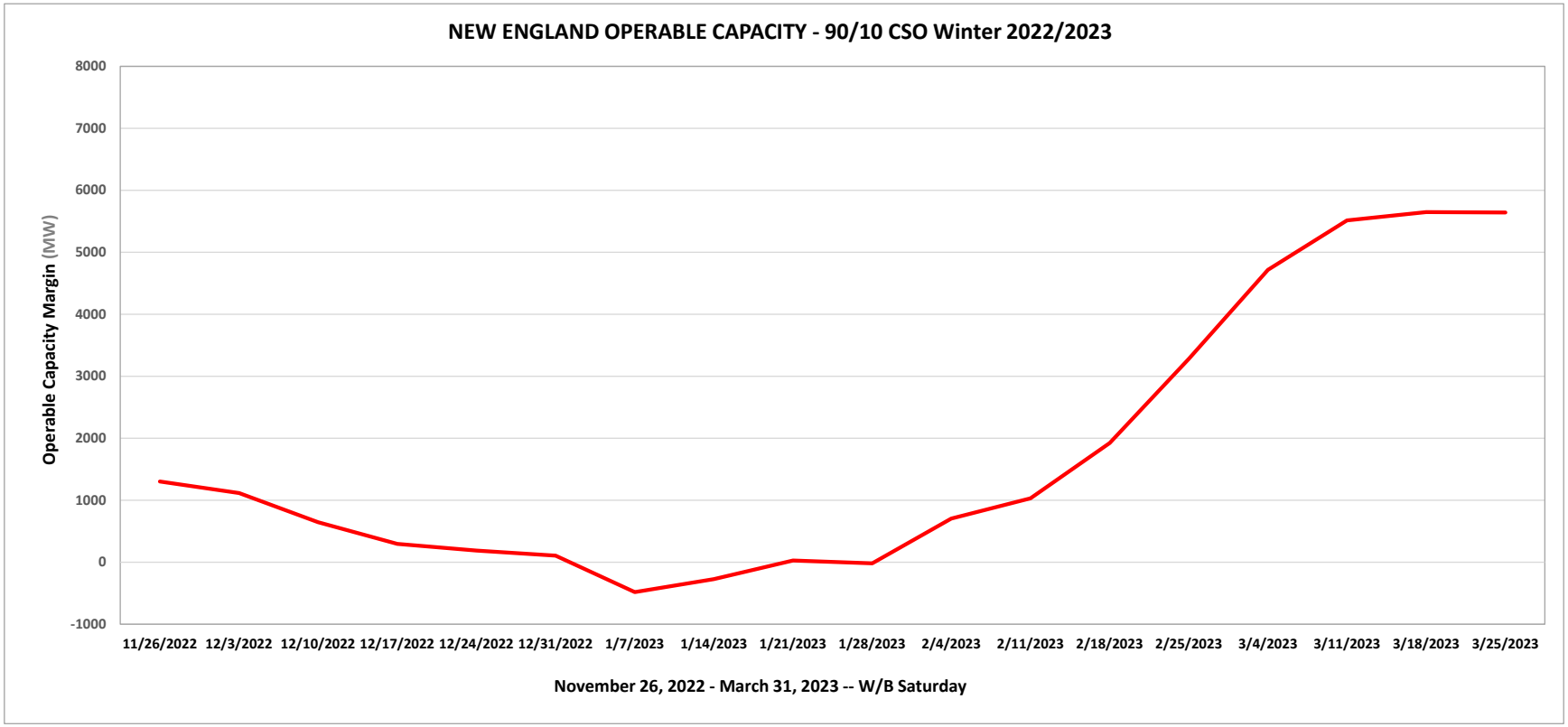
Preliminary Winter 2022/23 Operable Capacity Analysis

50/50 Forecast (Reference)



Preliminary Winter 2022/23 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