NEPOOL Participants Committee Report

January 2024

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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: November 2023 Energy Market value totaled $399M
  - December 2023 Energy market value was $415M, up $16M from November and down $923M from December of last year
    - December 2023 natural gas prices over the period were 6.7% lower than November average values
    - Average RT Hub Locational Marginal Prices ($37.15/MWh) over the period were 0.4% higher than November averages
      - Avg. DA Hub: $38.14/MWh
    - Average December 2023 natural gas prices and RT Hub LMPs over the period were down 77% and 69%, respectively, from December 2022 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 102% during December, up from 100.6% during November*
    - The minimum value for the month was 95.5% on Monday, December 18th

Underlying natural gas data furnished by:

ice Global markets in clear view

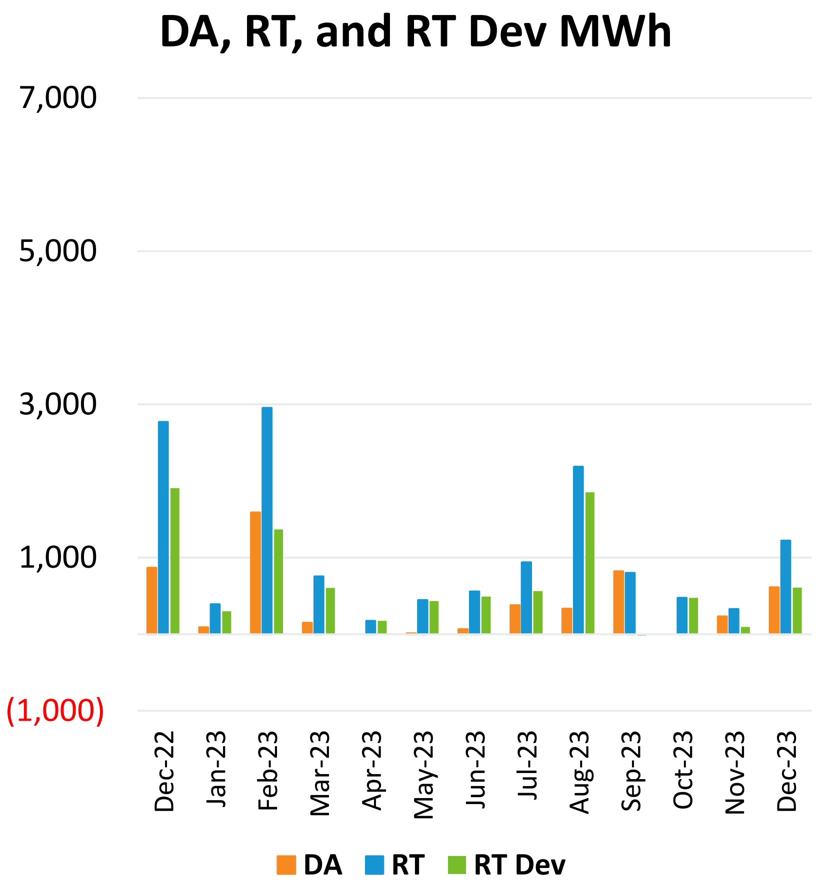
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

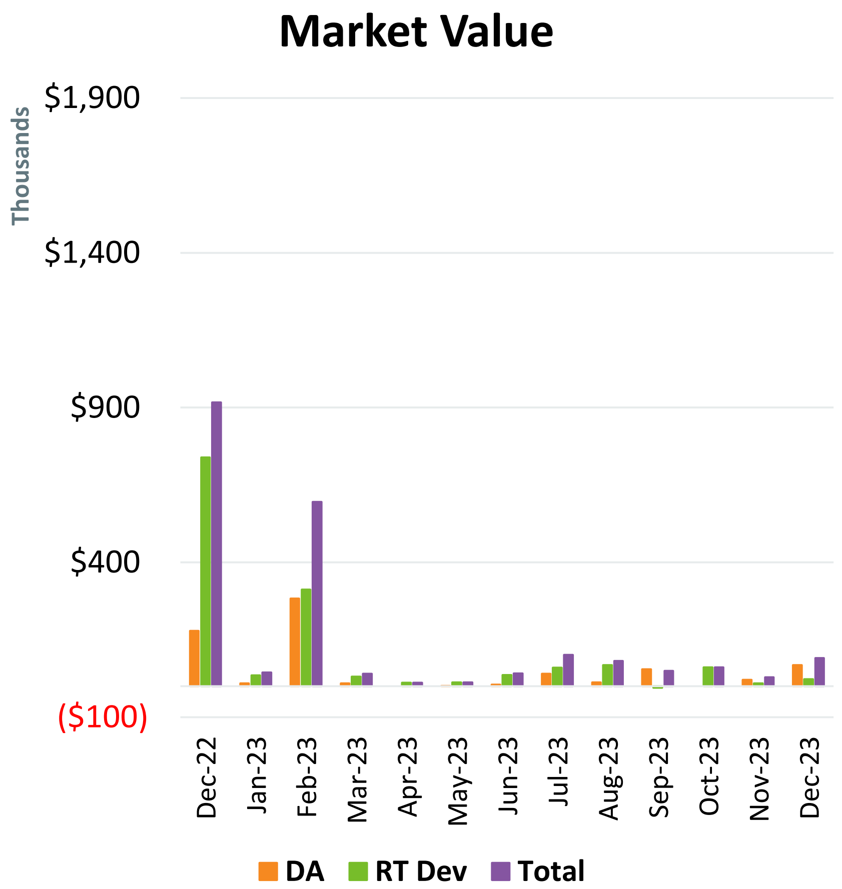
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - December 2023 NCPC payments totaled $4.7M over the period, down $0.4M from November and down $1.9M from December 2022
    - First Contingency payments totaled $4.7M, down $0.4M from November
      - $4.6M paid to internal resources, down $0.3M from November
        - » $0.5M charged to DALO, $3.1M to RT Deviations, $1M to RTLO*
      - $111K paid to resources at external locations, down $33K from November
        - » $17K charged to DALO at external locations, $94K to RT Deviations
    - Second Contingency, Voltage and Distribution payments were all zero
  - NCPC payments over the period as percent of Energy Market value were 1.1%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $324K; Rapid Response Pricing (RRP) Opportunity Cost - $543K; Posturing - $63K; Generator Performance Auditing (GPA) - $52K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Forward Capacity Market (FCM) Highlights

- CCP 15 (2024-2025)
  - The second annual reconfiguration auction (ARA2) was held on August 1-3, 2023 and results were posted on August 24, 2023
  - The third annual reconfiguration auction (ARA3) will be held in March 2024
- CCP 16 (2025-2026)
  - The first annual reconfiguration auction (ARA1) was held on June 1-5, 2023 and results were posted on July 3, 2023
  - ARA2 will be held in August 2024
- CCP 17 (2026-2027)
  - Forward Capacity Auction results were filed with FERC on March 21, 2023 and, on July 18, 2023, FERC issued an order accepting the results effective July 19, 2023
  - ARA1 will be held in June 2024
  - ICR and related values for the ARAs to be conducted in 2024 were presented and approved at the October 24 RC and November 2 PC meetings and were filed with FERC on November 30

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - FCA 18 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - The ISO issued qualification determination notifications on October 12, 2023
  - ICR and related values were approved at the September 19, 2023 RC and October 5, 2023 PC meetings and filed with FERC on November 7, 2023
  - The ISO submitted the FCA 18 informational filing to FERC on November 22, 2023

Load Forecast

- Exploring improvements to the long-term load forecast methodology to better support the evolving grid
- The next LFC meeting will be held on January 12
- EPCET Policy scenario results were presented at the December PAC

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 13, 2024.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (5.1°F) Max: 64°F, Min: 21°F Precipitation: 5.98" – Above Normal Normal: 4.30" Snow: 0.2"	Hartford	Temperature: Above Normal (6.5°F) Max: 64°F, Min: 17°F Precipitation: 8.04" – Above Normal Normal: 4.08" Snow: 0"

Peak Load:	17,576 MW	December 7, 2023	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

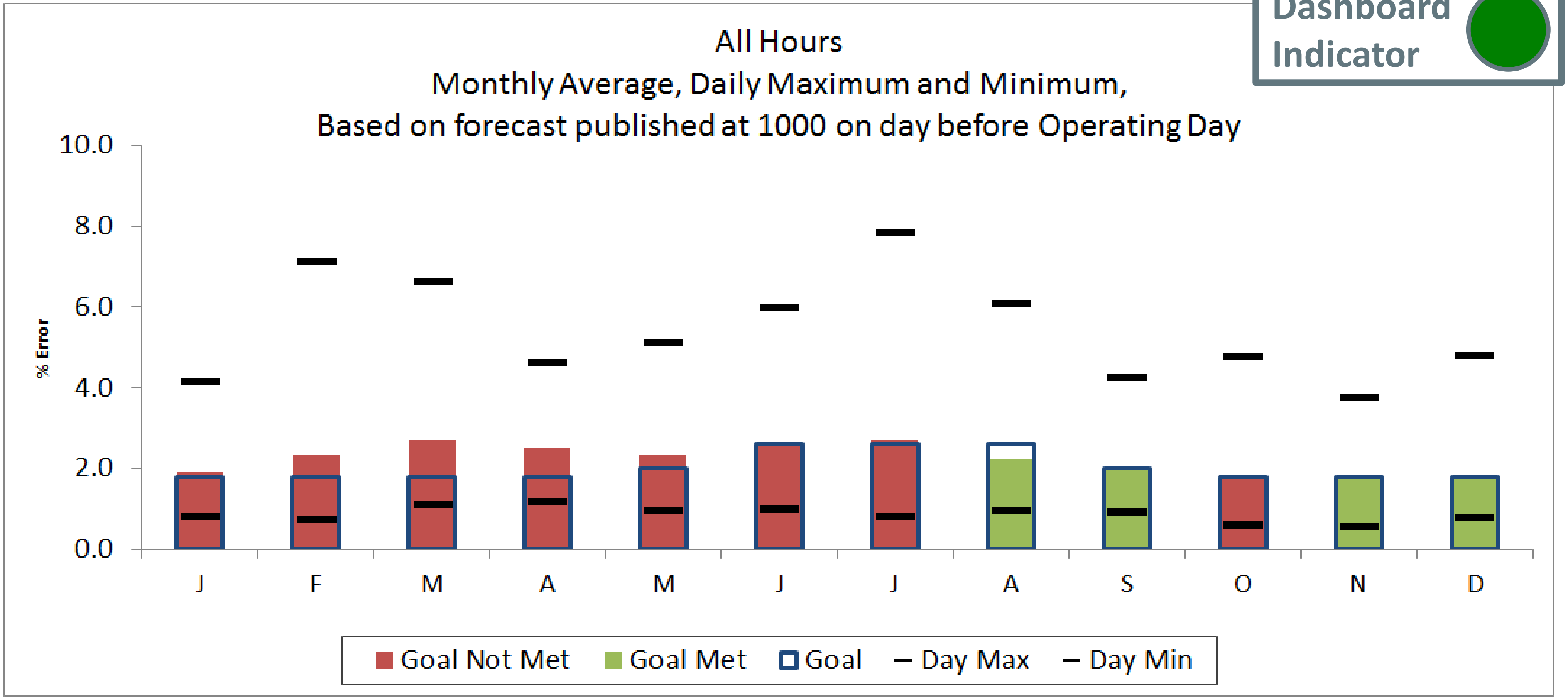
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
12/19/2023	PJM	1,200

2023 System Operations - Load Forecast Accuracy

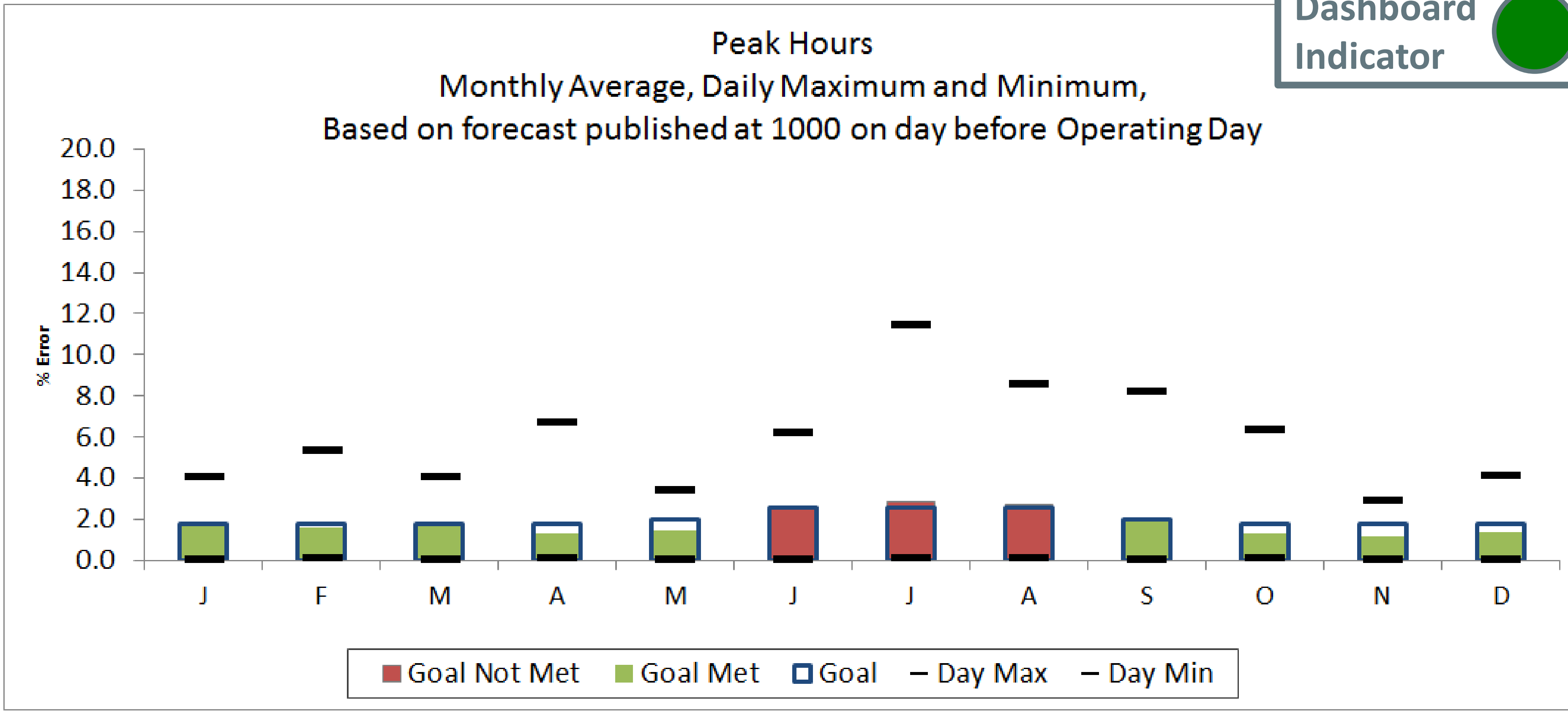
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.14	7.12	6.59	4.61	5.10	5.97	7.82	6.06	4.24	4.73	3.73	4.78	7.82
Day Min	0.80	0.74	1.08	1.17	0.96	0.97	0.79	0.95	0.91	0.59	0.54	0.76	0.54
MAPE	1.91	2.34	2.70	2.52	2.36	2.63	2.70	2.23	1.94	1.84	1.79	1.75	2.22
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

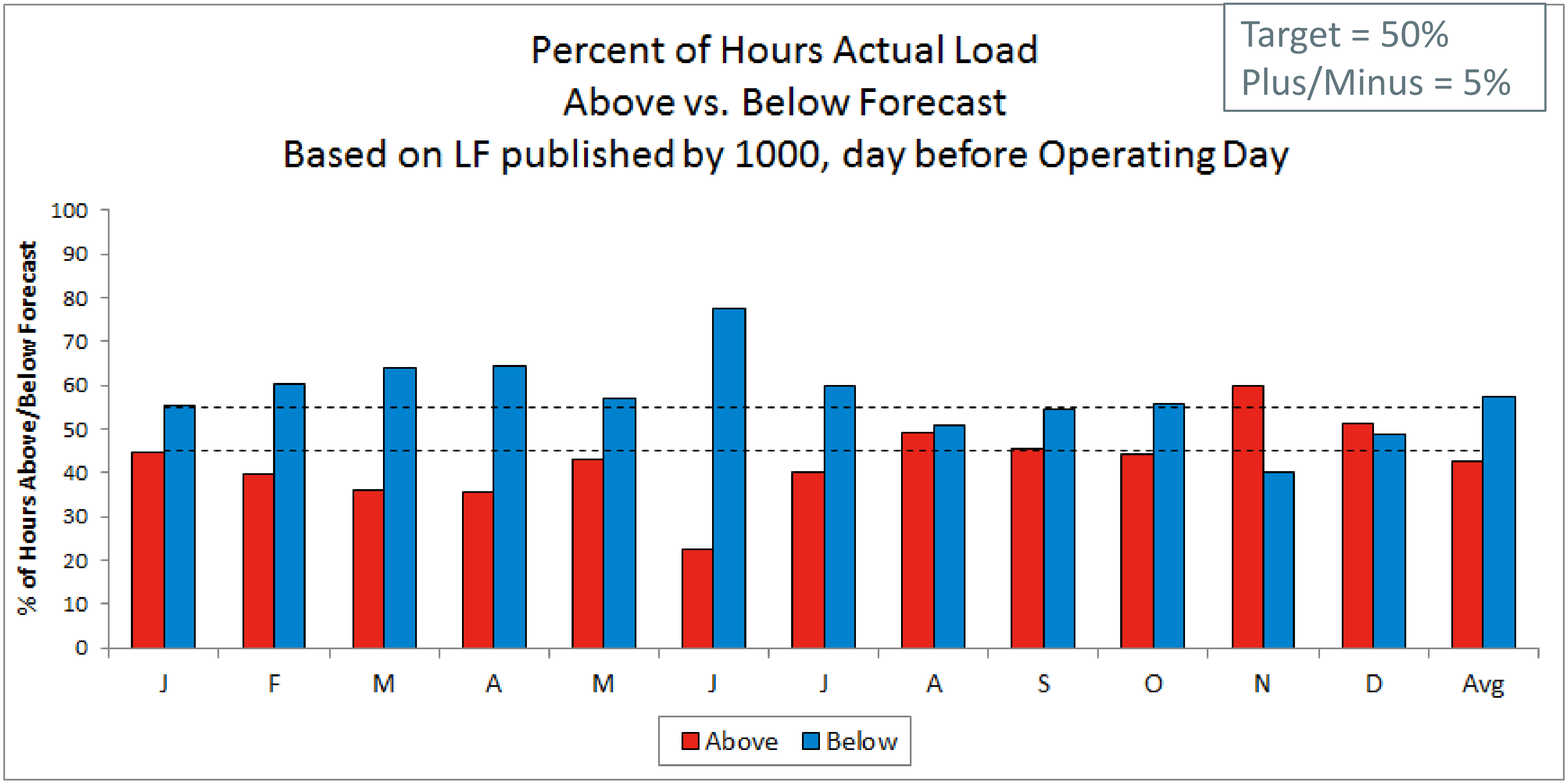
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



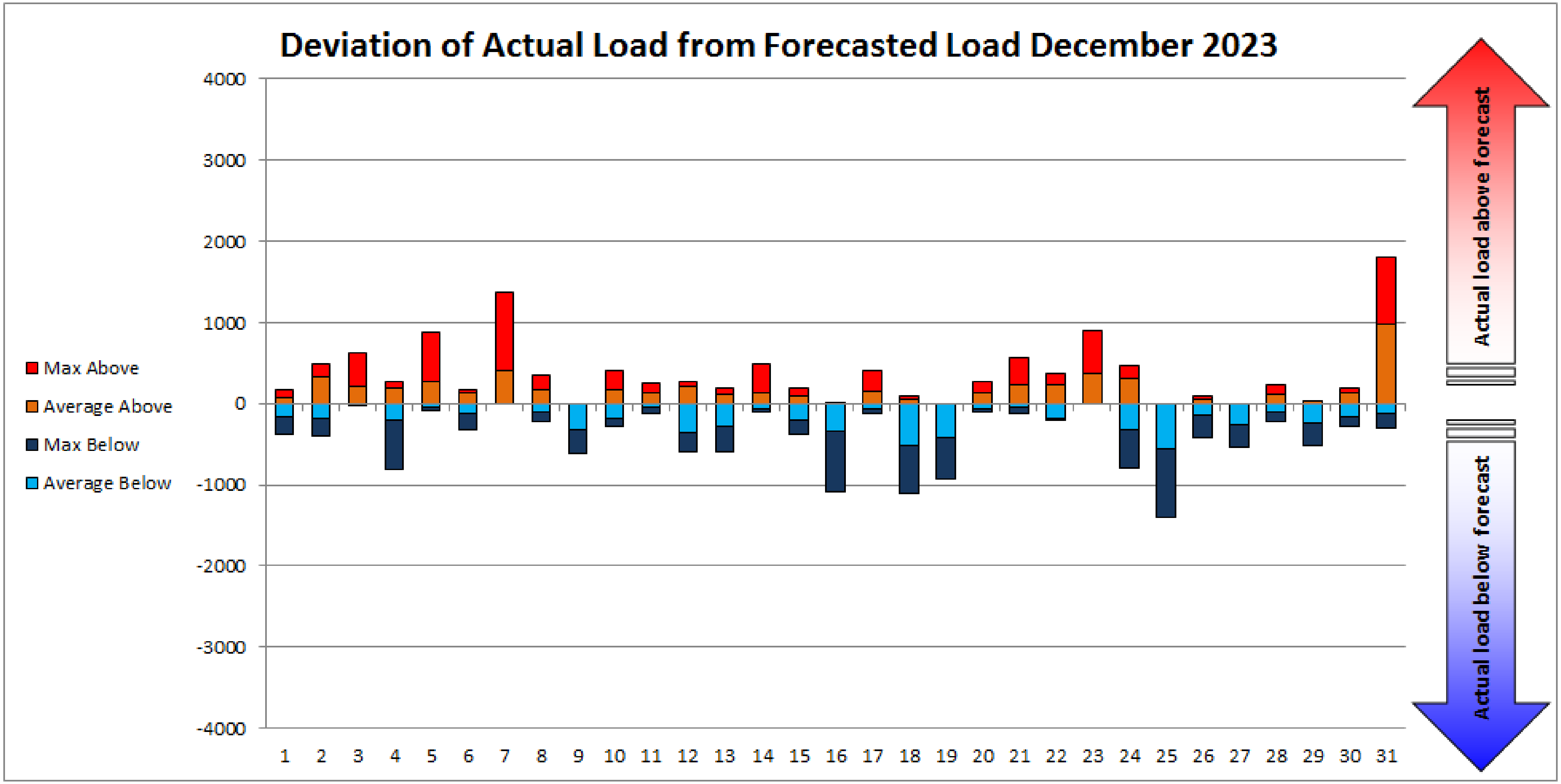
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06	6.68	3.43	6.21	11.40	8.59	8.17	6.31	2.88	4.11	11.40
Day Min	0.01	0.08	0.06	0.11	0.03	0.04	0.08	0.14	0.01	0.10	0.02	0.03	0.01
MAPE	1.70	1.64	1.72	1.33	1.47	2.65	2.87	2.72	1.97	1.34	1.18	1.43	1.84
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

2023 System Operations - Load Forecast Accuracy cont.

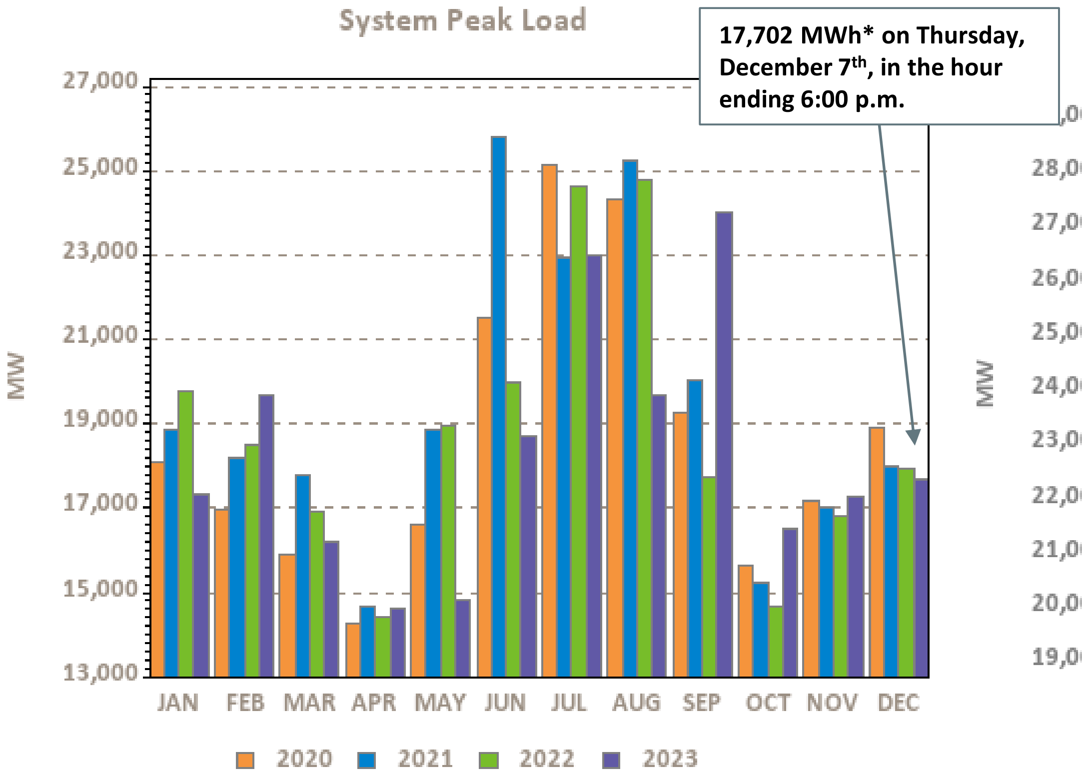


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2	35.7	43	22.6	40.2	49.2	45.6	44.4	59.7	51.3	43
Below %	55.4	60.3	63.8	64.3	57	77.4	59.8	50.8	54.4	55.6	40.3	48.7	57
Avg Above	235.7	228	172.9	194.5	183.5	120	194.8	228.5	226	171.4	166.8	172.7	236
Avg Below	-197.3	-248.9	-328.3	-245.0	-200.1	-350.3	-388.6	-215.1	-169.7	-163.7	-139.1	-159.9	-389
Avg All	-10	-28	-142	-74	-17	-236	-170	-6	20	-16	39	7	-53

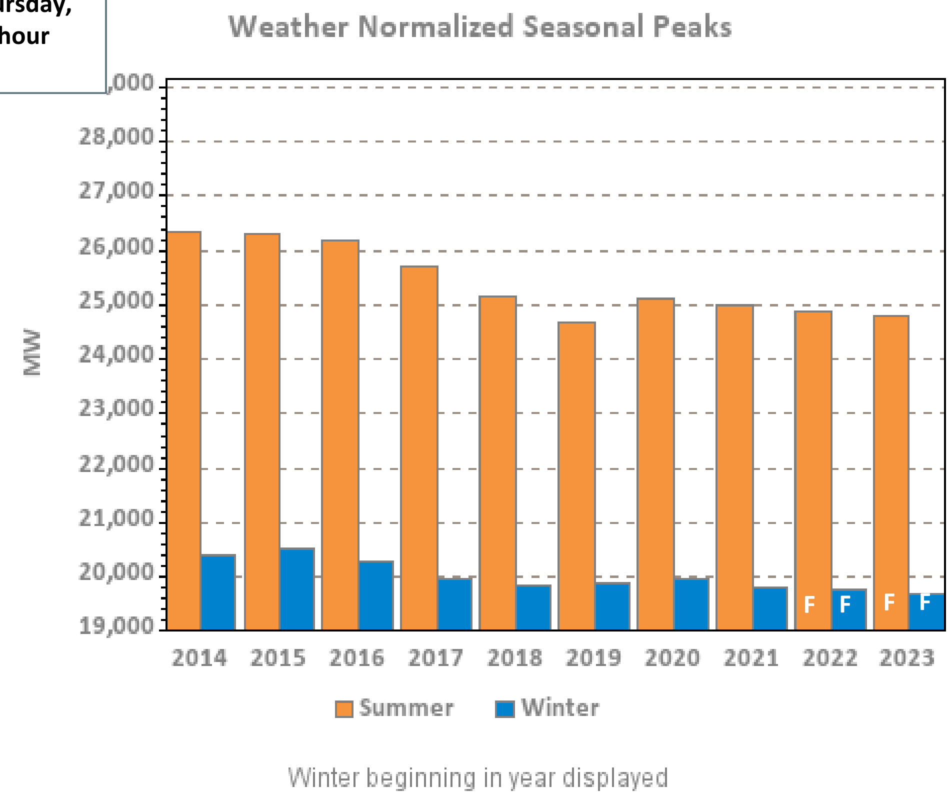
2023 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History

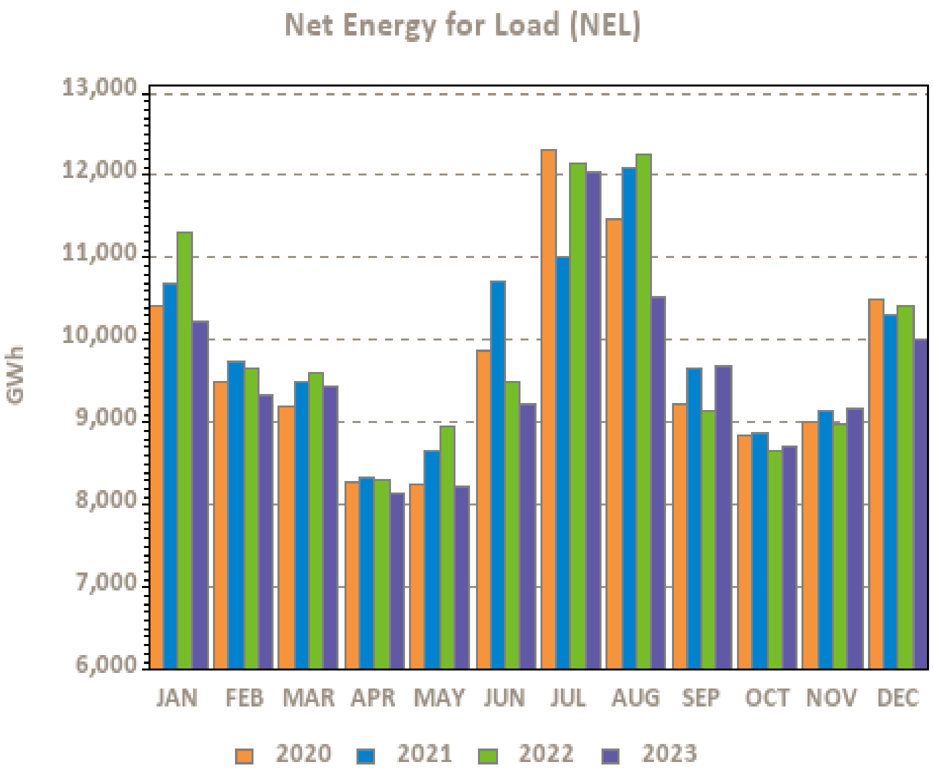


*Revenue quality metered value

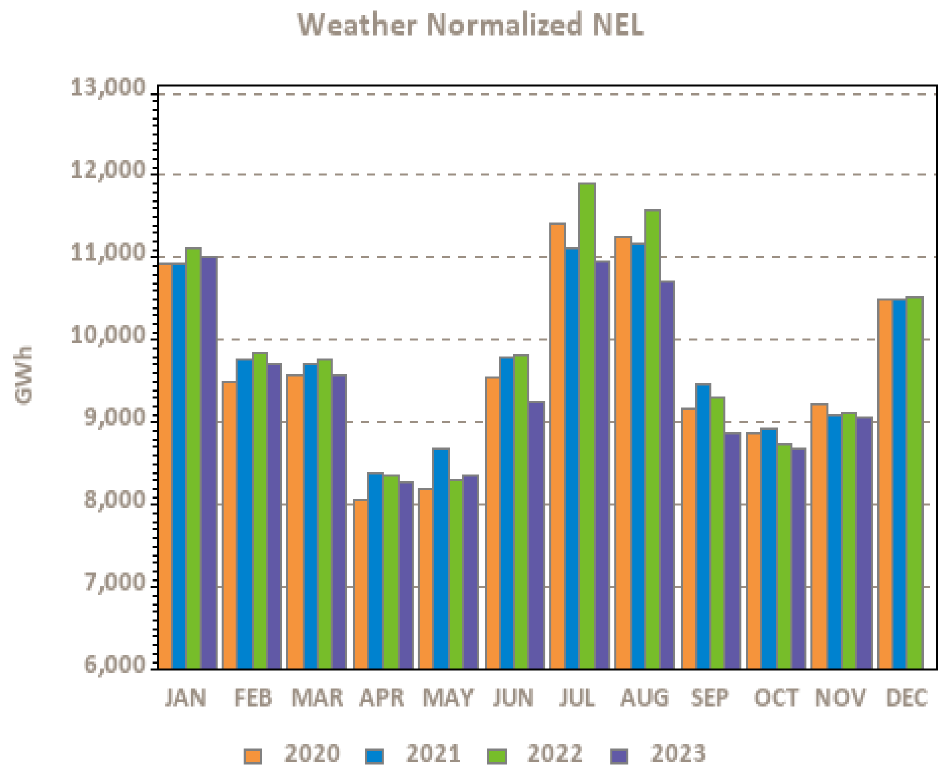


F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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



Ann Tot (TWh): 116.9 118.8 118.9 114.7

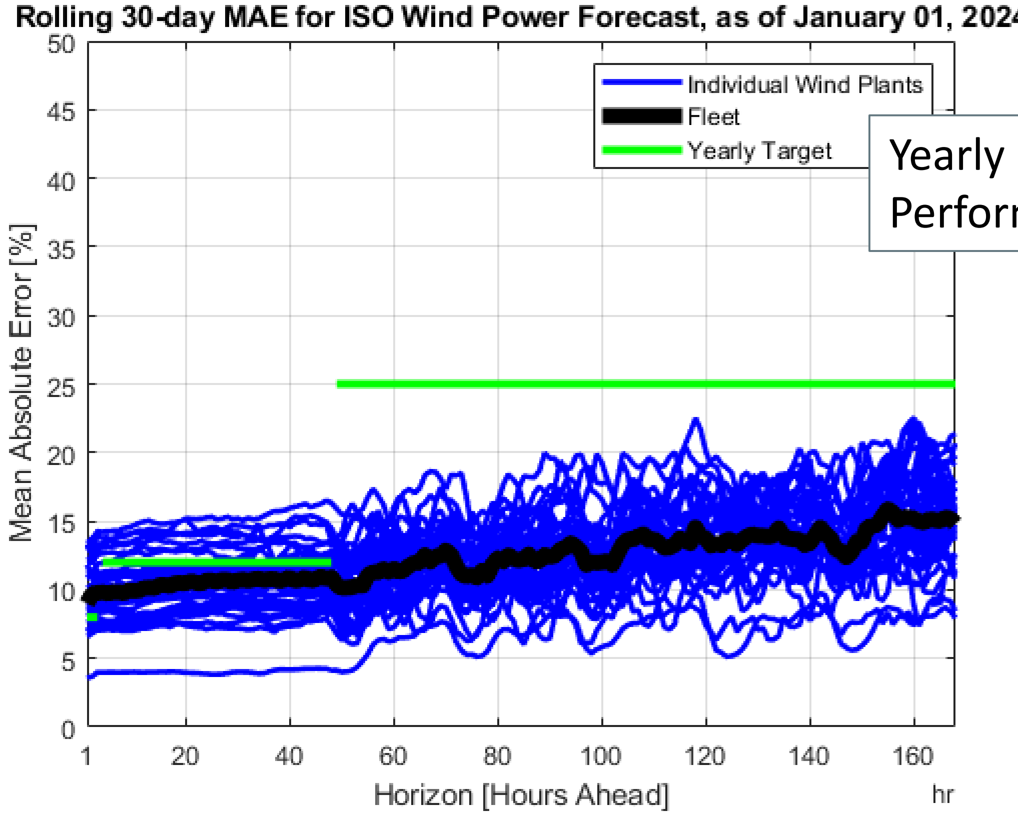


Ann Tot (TWh): 116.3 117.6 118.4 104.5

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

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

Dashboard Indicator

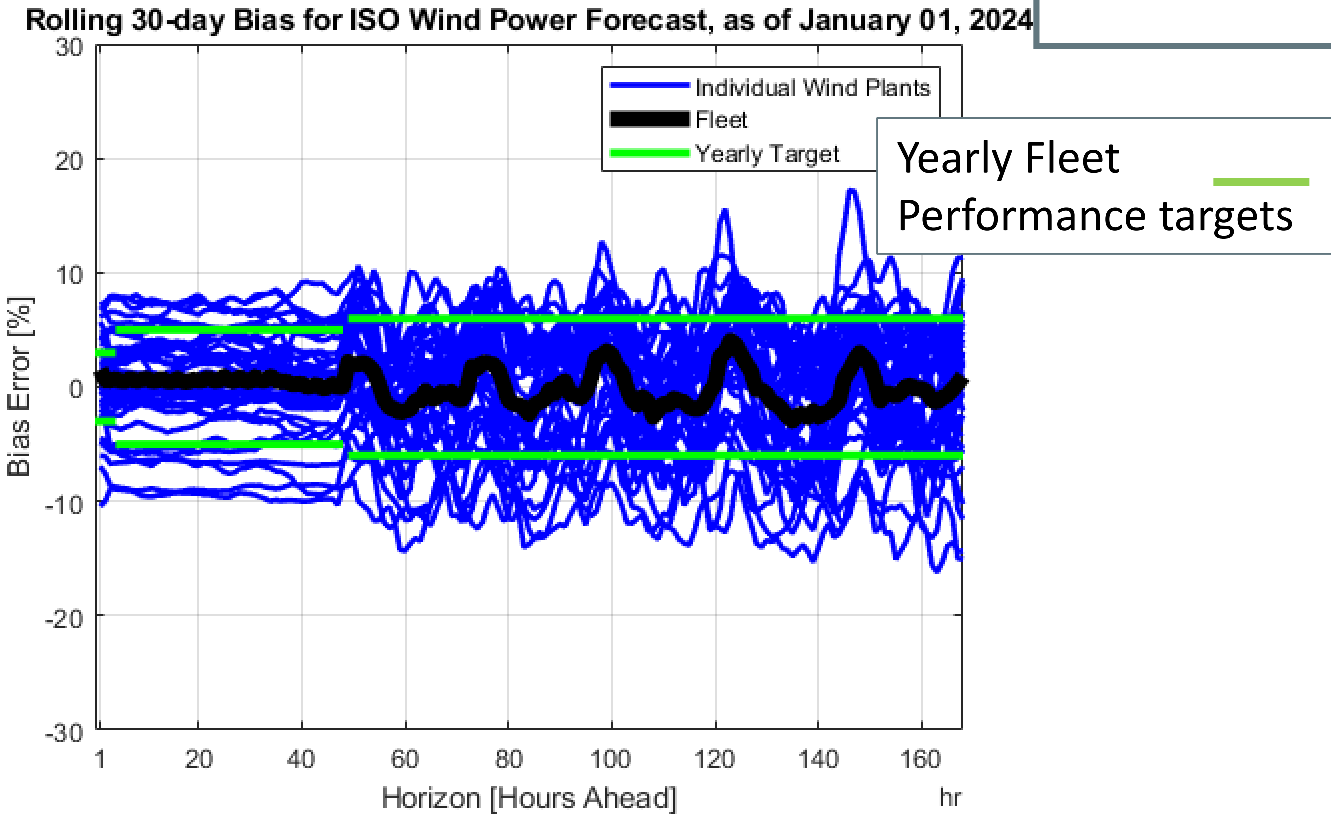


Yearly Fleet Performance targets

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. Monthly MAE is outside of yearly performance targets for 1 hour look-ahead.

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

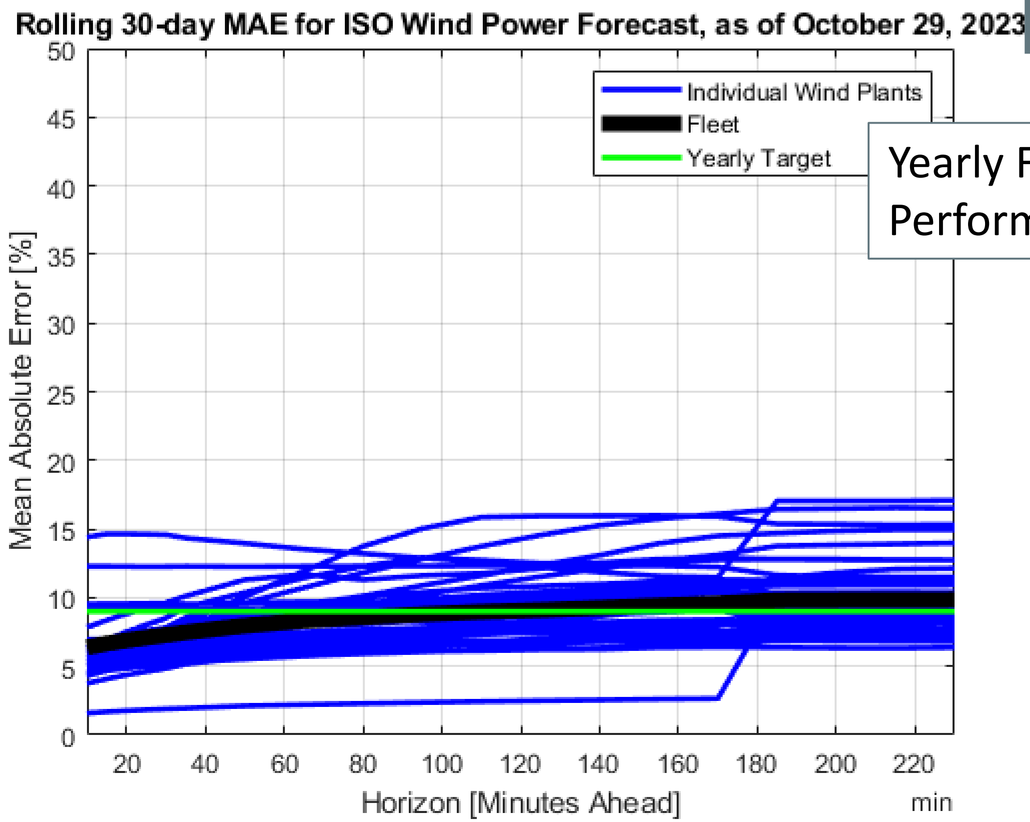
Dashboard Indicator



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

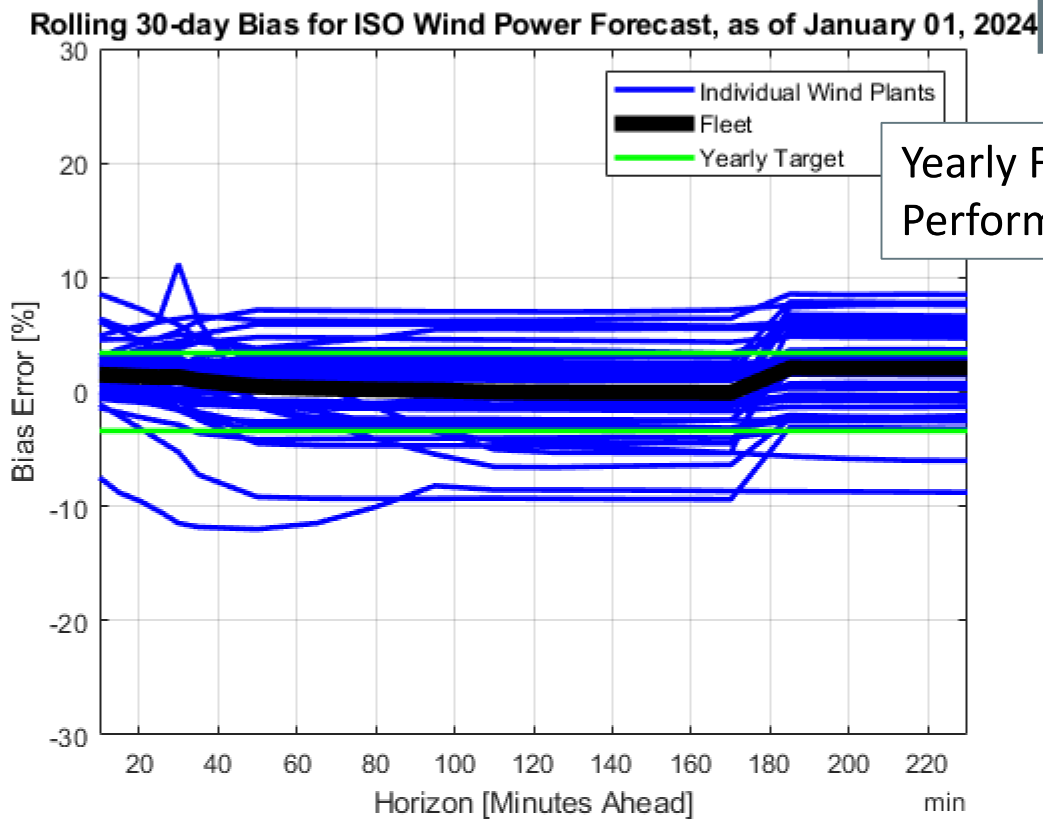


Yearly Fleet Performance targets

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 forecast compares well with industry standards, but monthly MAE is outside of yearly performance targets at greater than140 minutes look-ahead.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

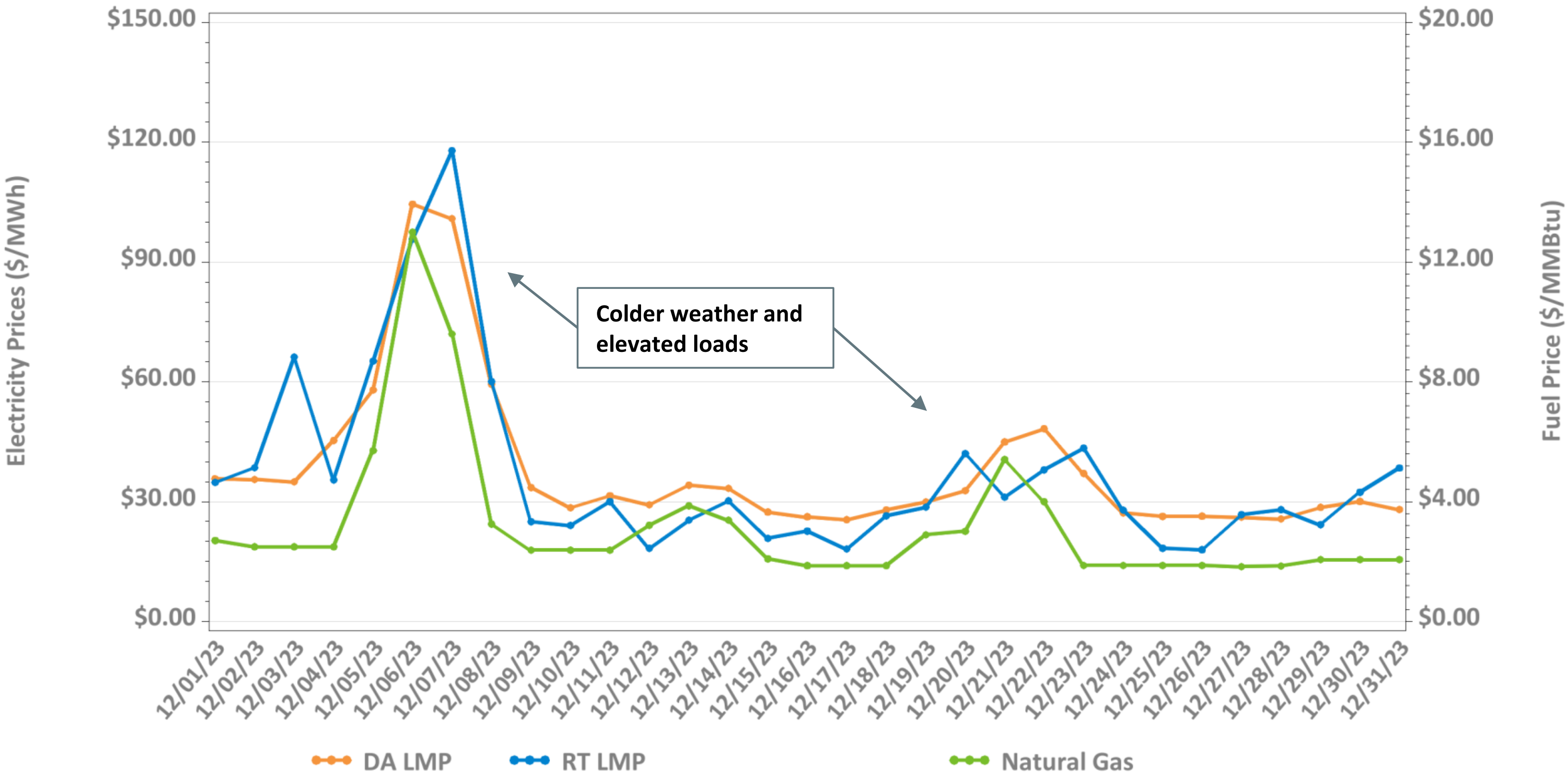


Yearly Fleet Performance targets

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: December 1-31, 2023

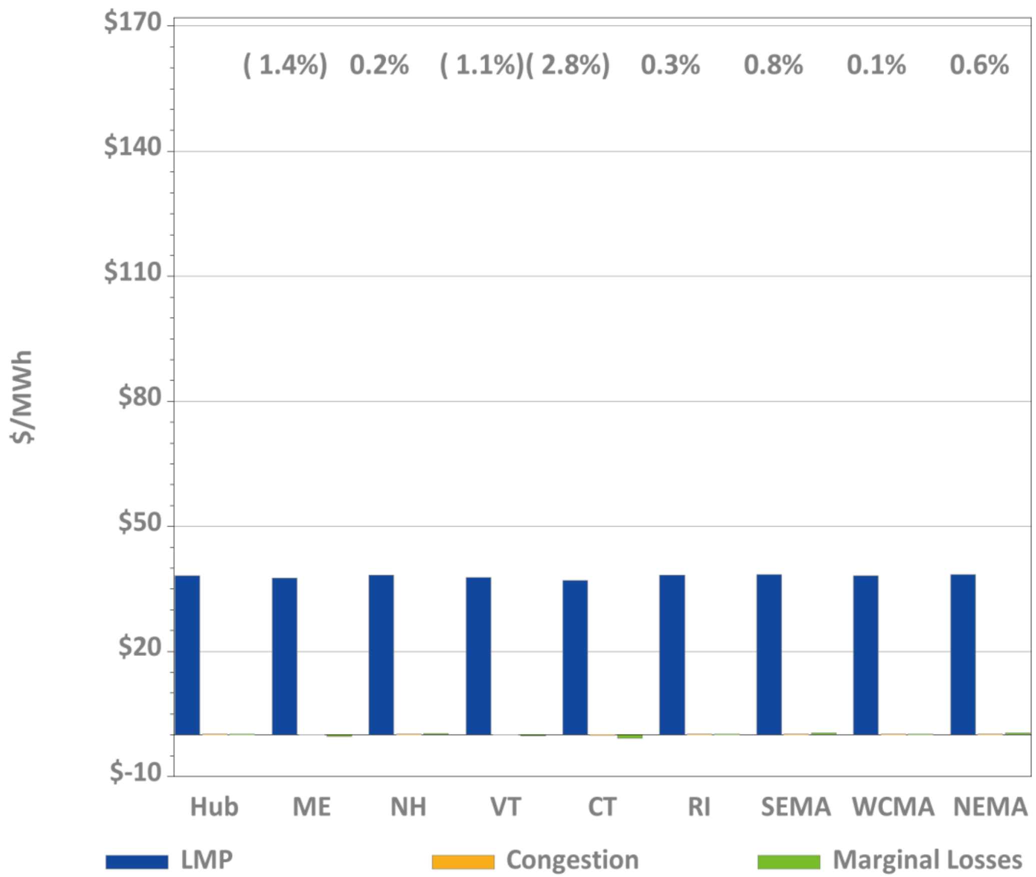


Underlying natural gas data furnished by:

ICE Global markets in clear view

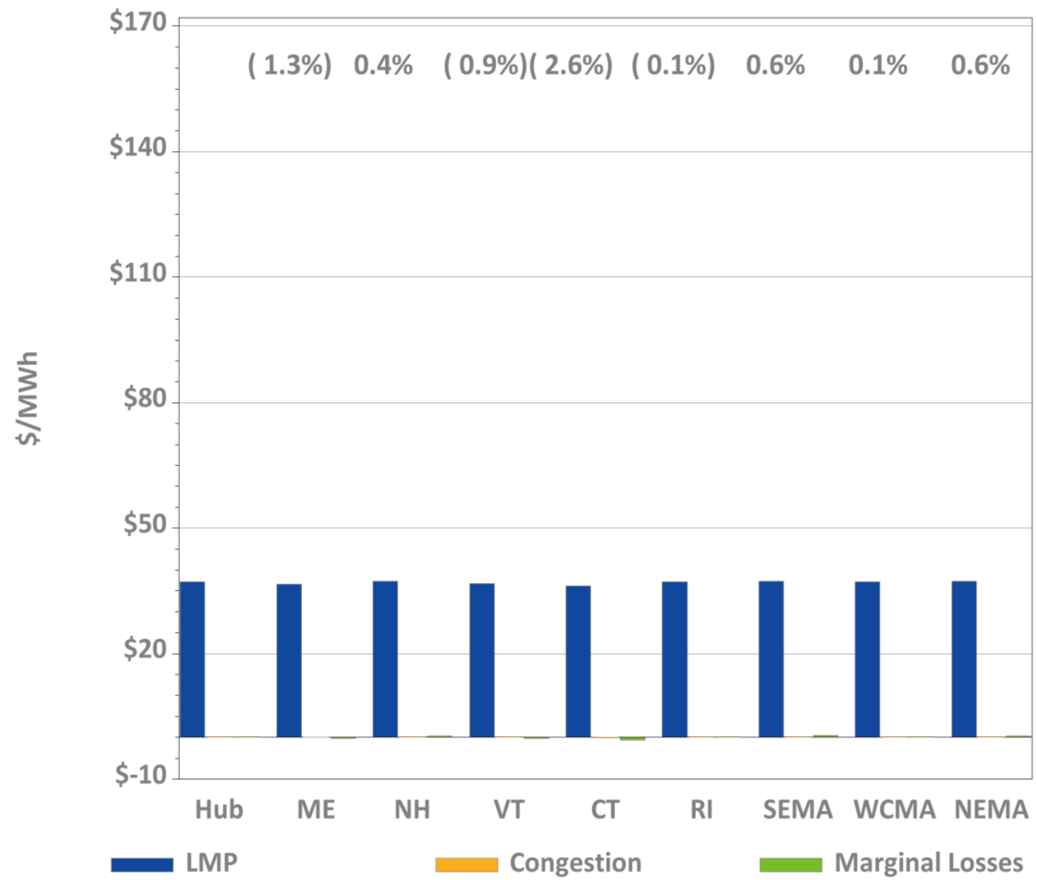
Average price difference over this period (DA-RT): $0.99
Average price difference over this period ABS(DA-RT): $6.87
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, December 2023



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

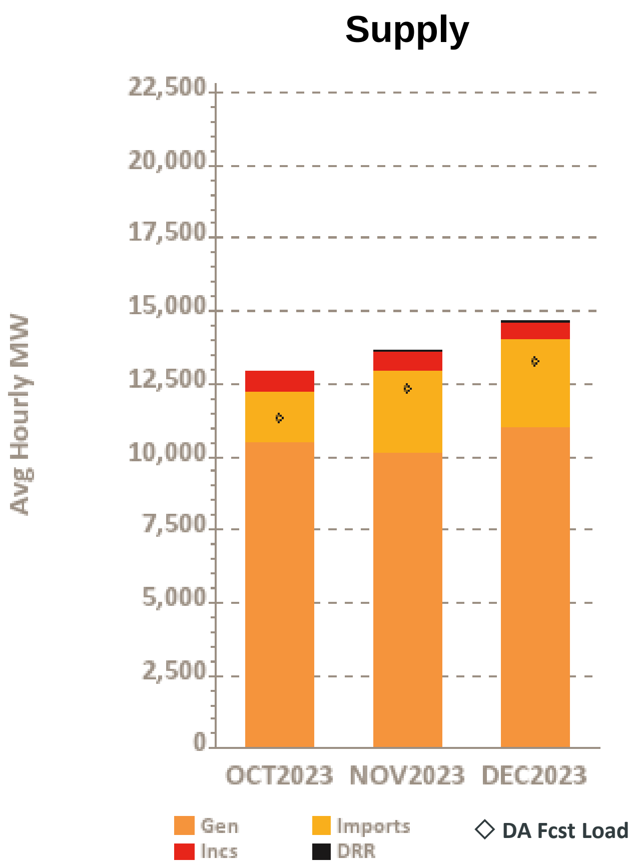
RT LMPs Average by Zone & Hub, December 2023

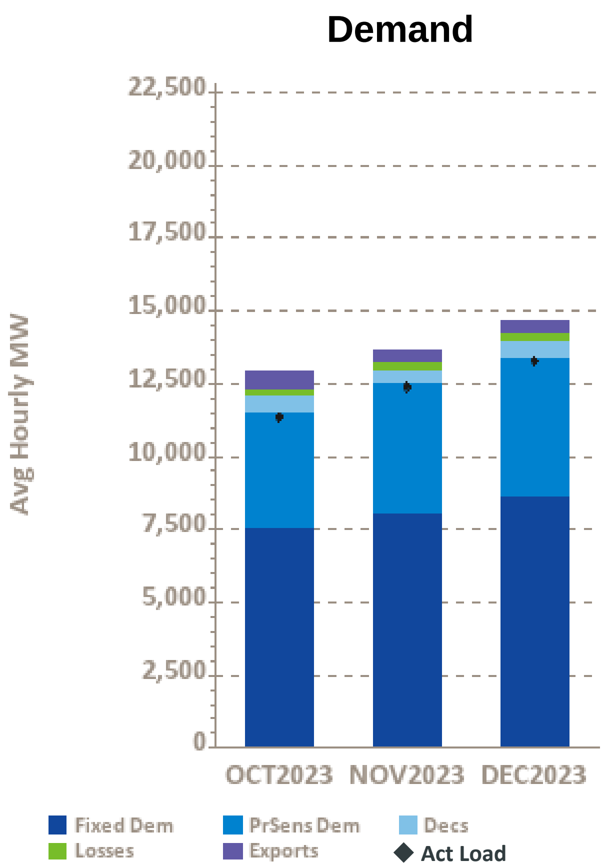


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

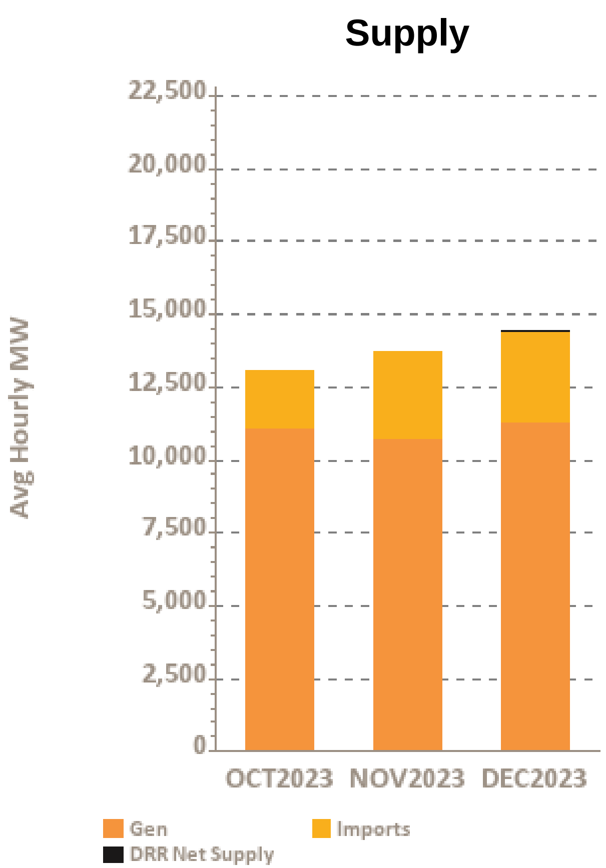


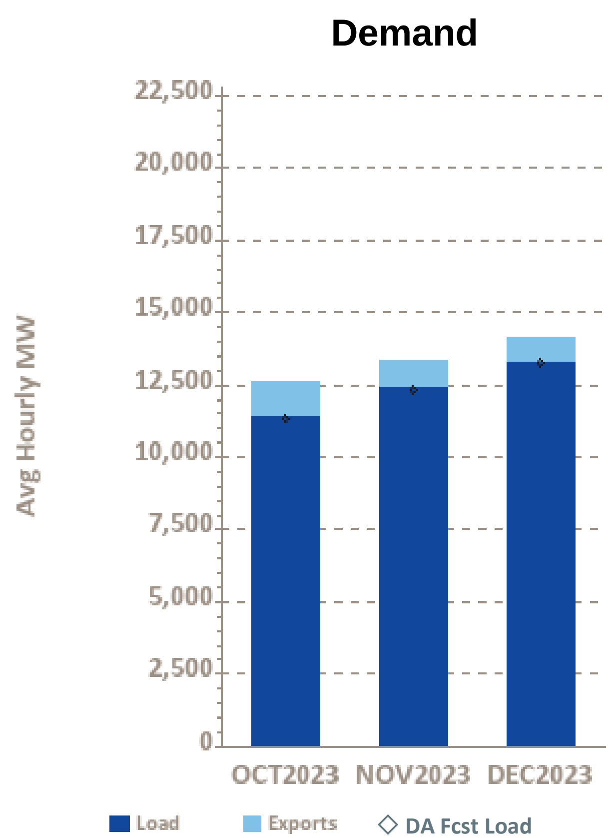


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

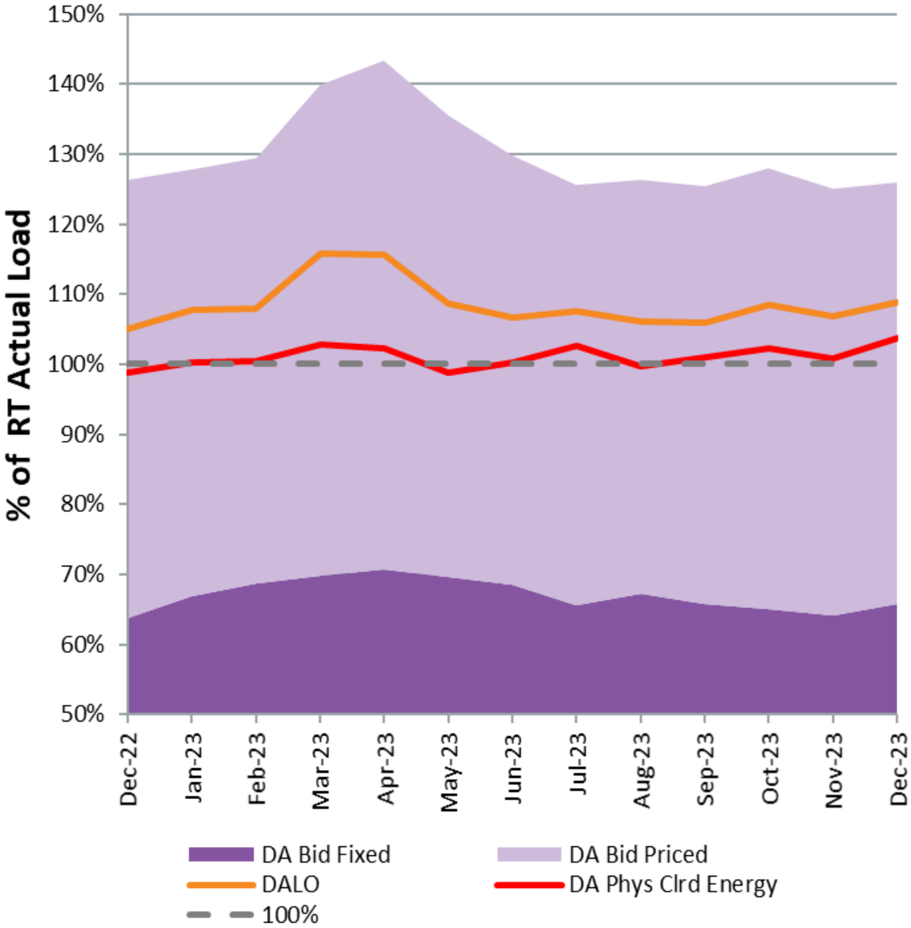
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

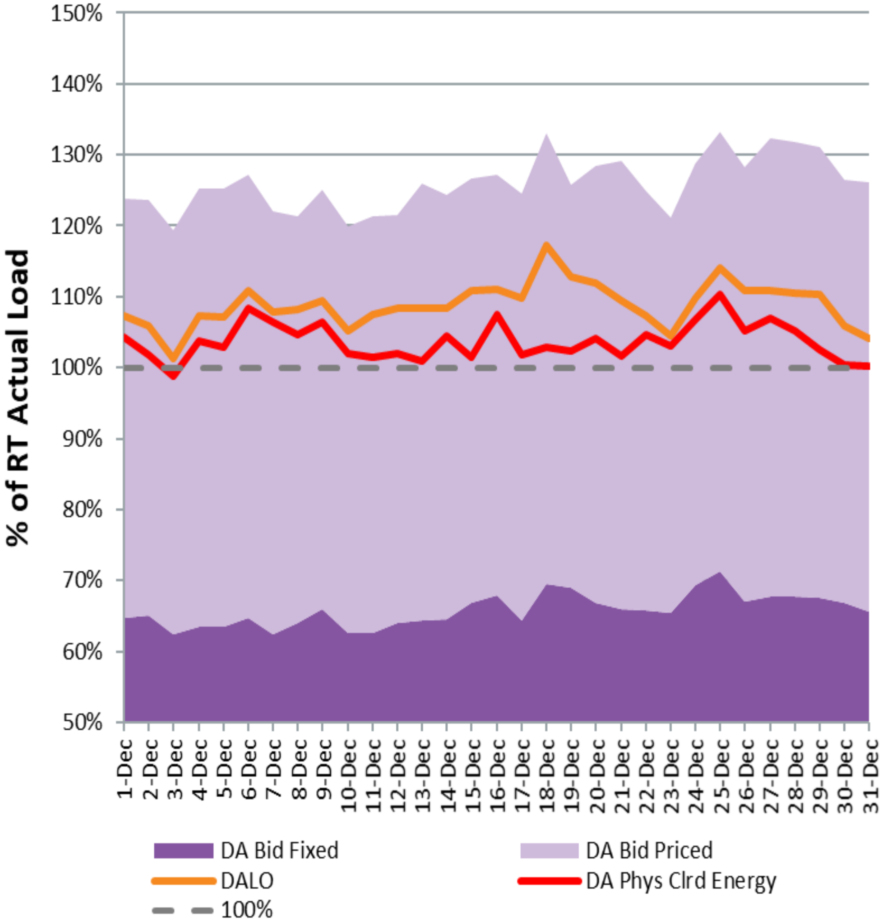
Components of RT Supply and Demand – Last Three Months





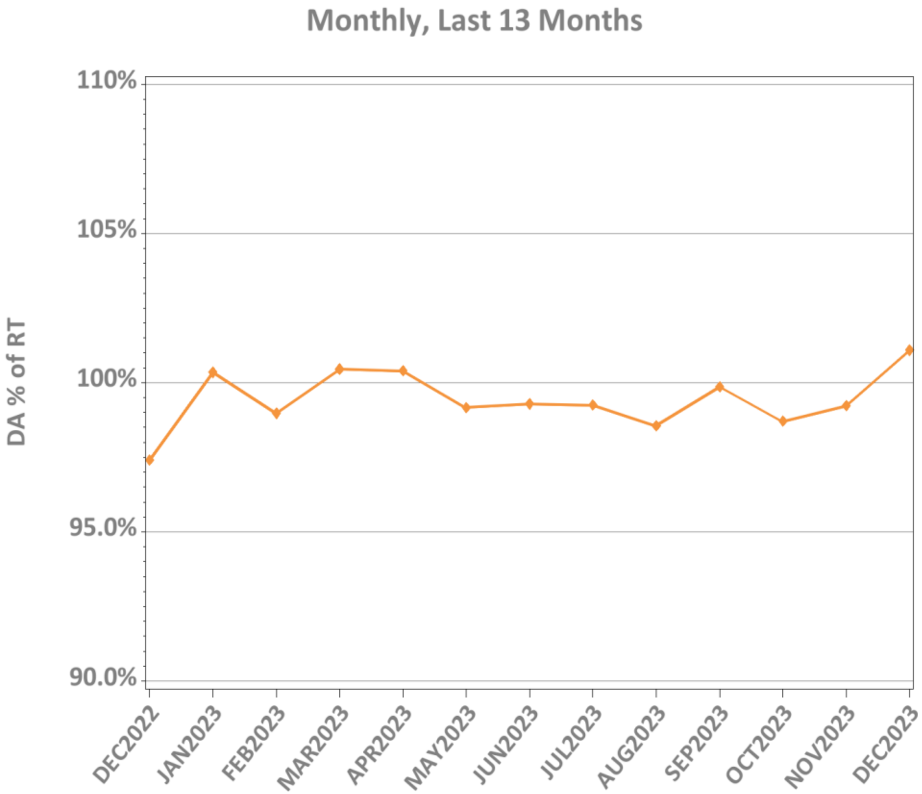
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

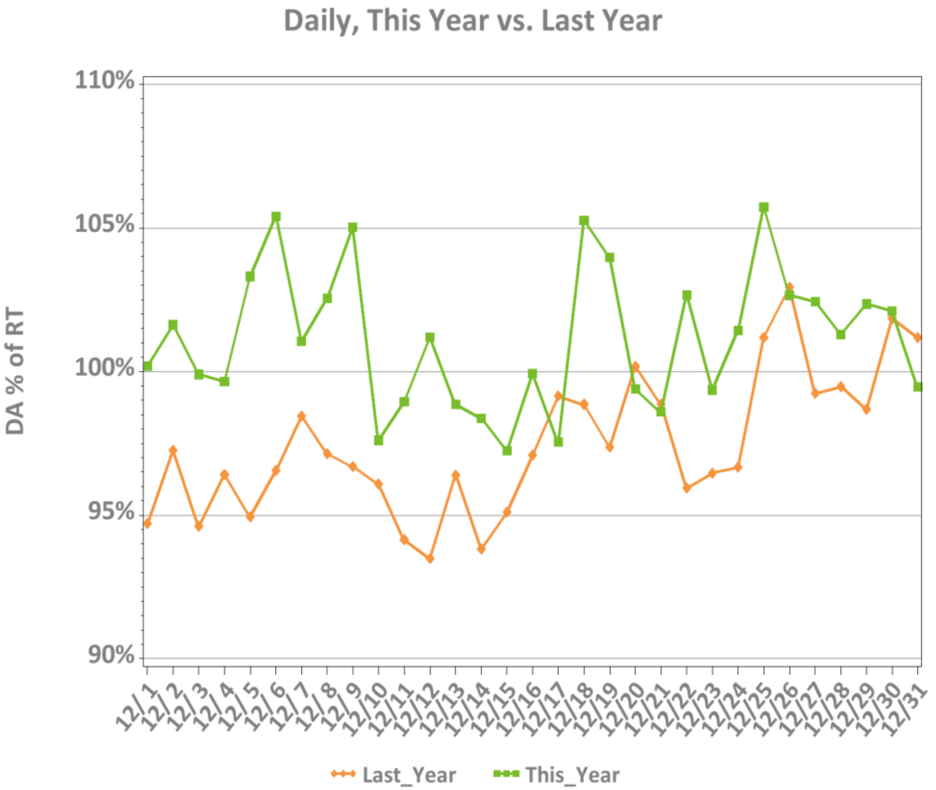




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

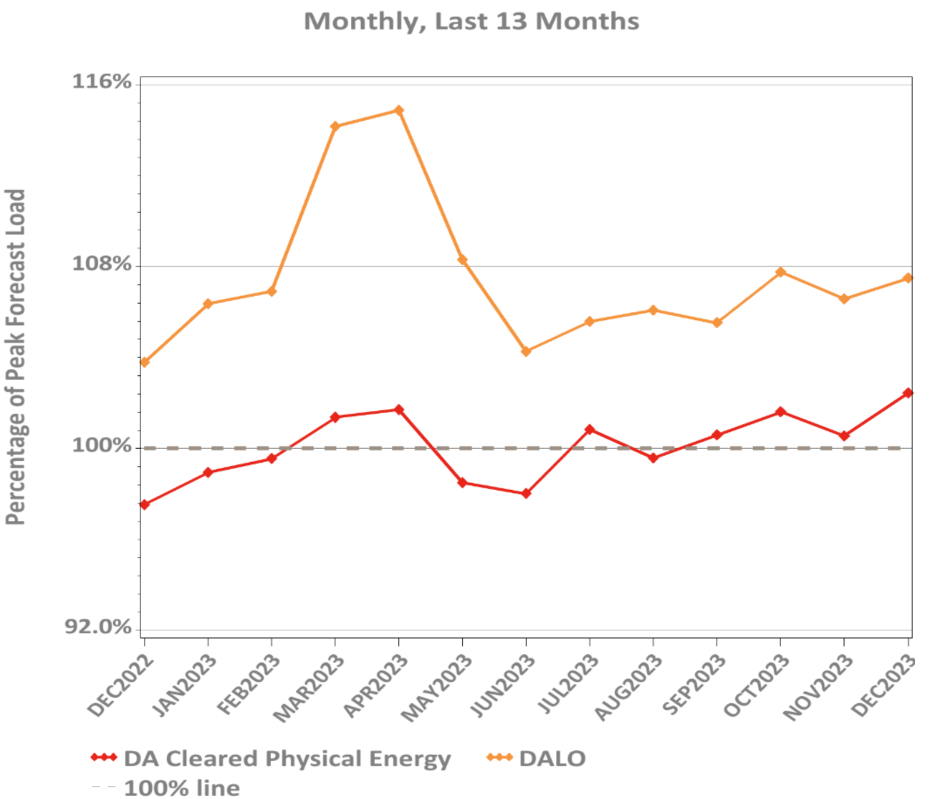
DA vs. RT Load Obligation: December, This Year vs. Last Year

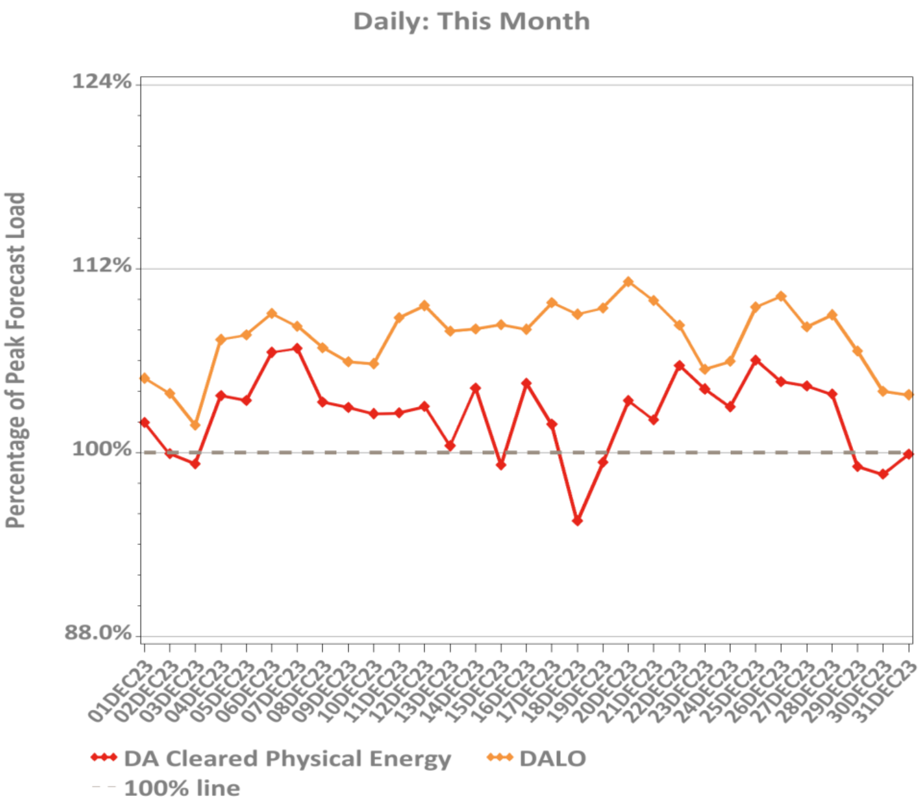




*Hourly average values

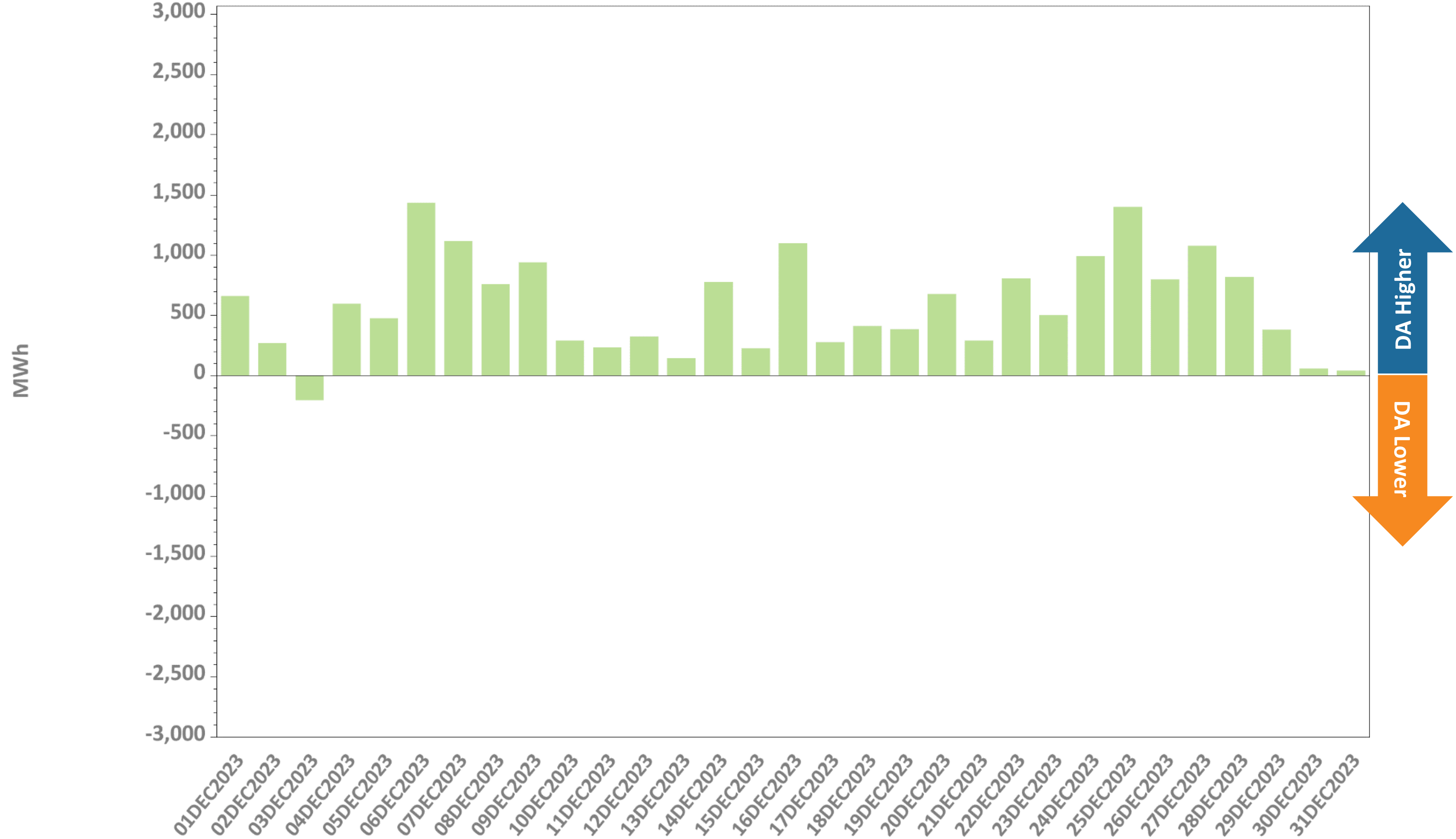
DA Volumes as % of Forecast in Peak Hour





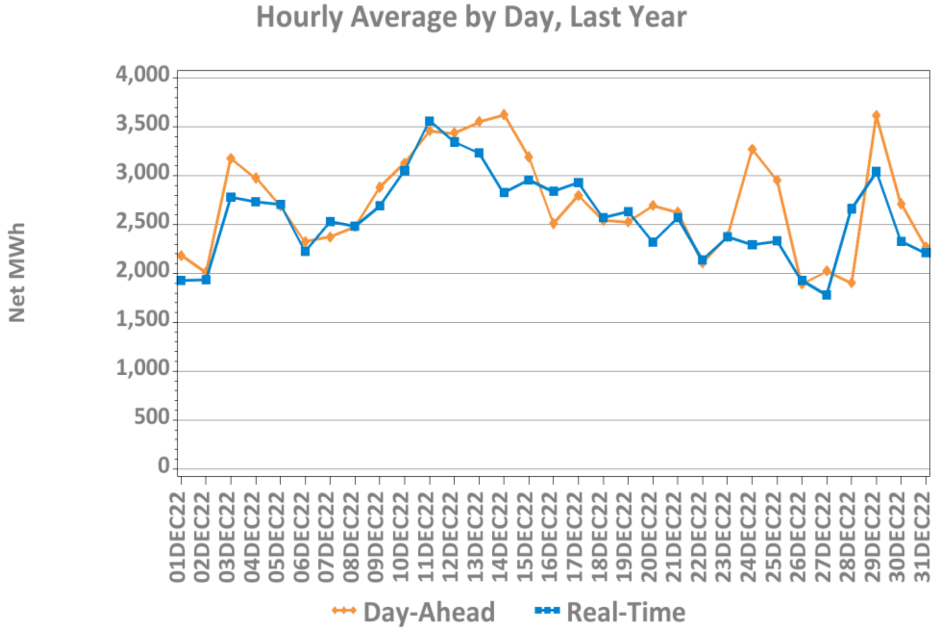
Note: The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

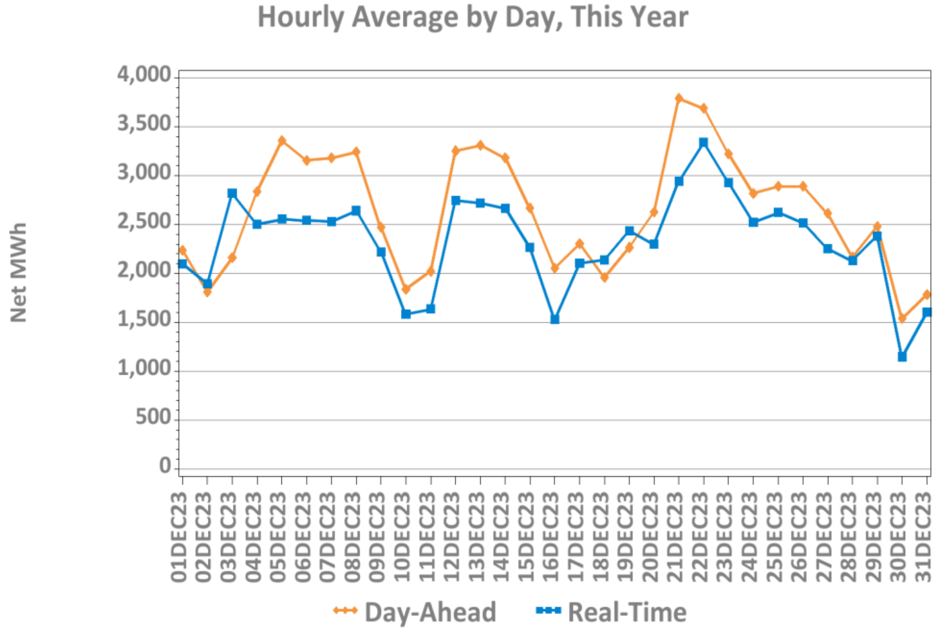
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

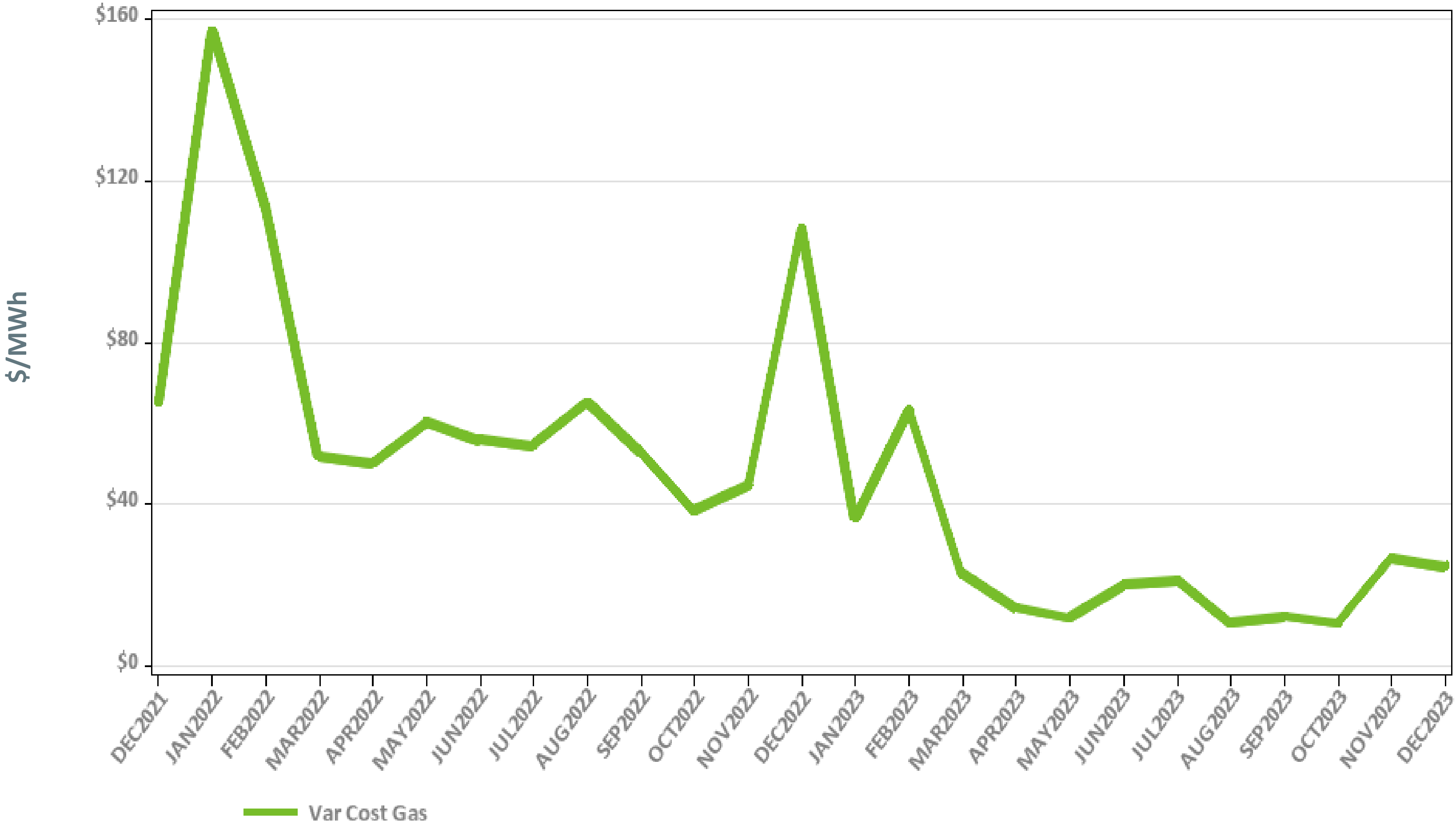
DA vs. RT Net Interchange December 2023 vs. December 2022





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

Variable Production Cost of Natural Gas: Monthly

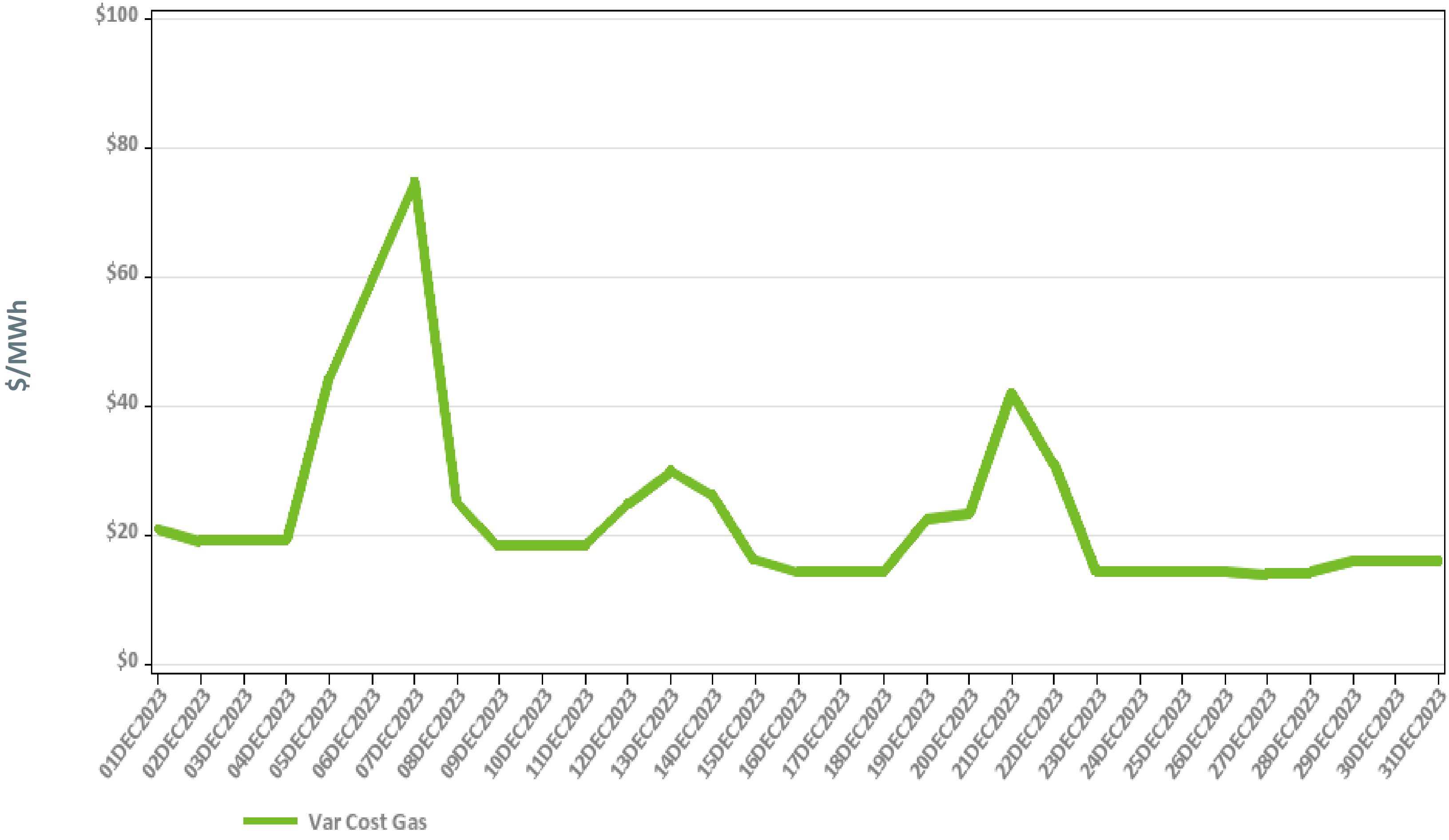


Underlying natural gas data furnished by:

ice Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

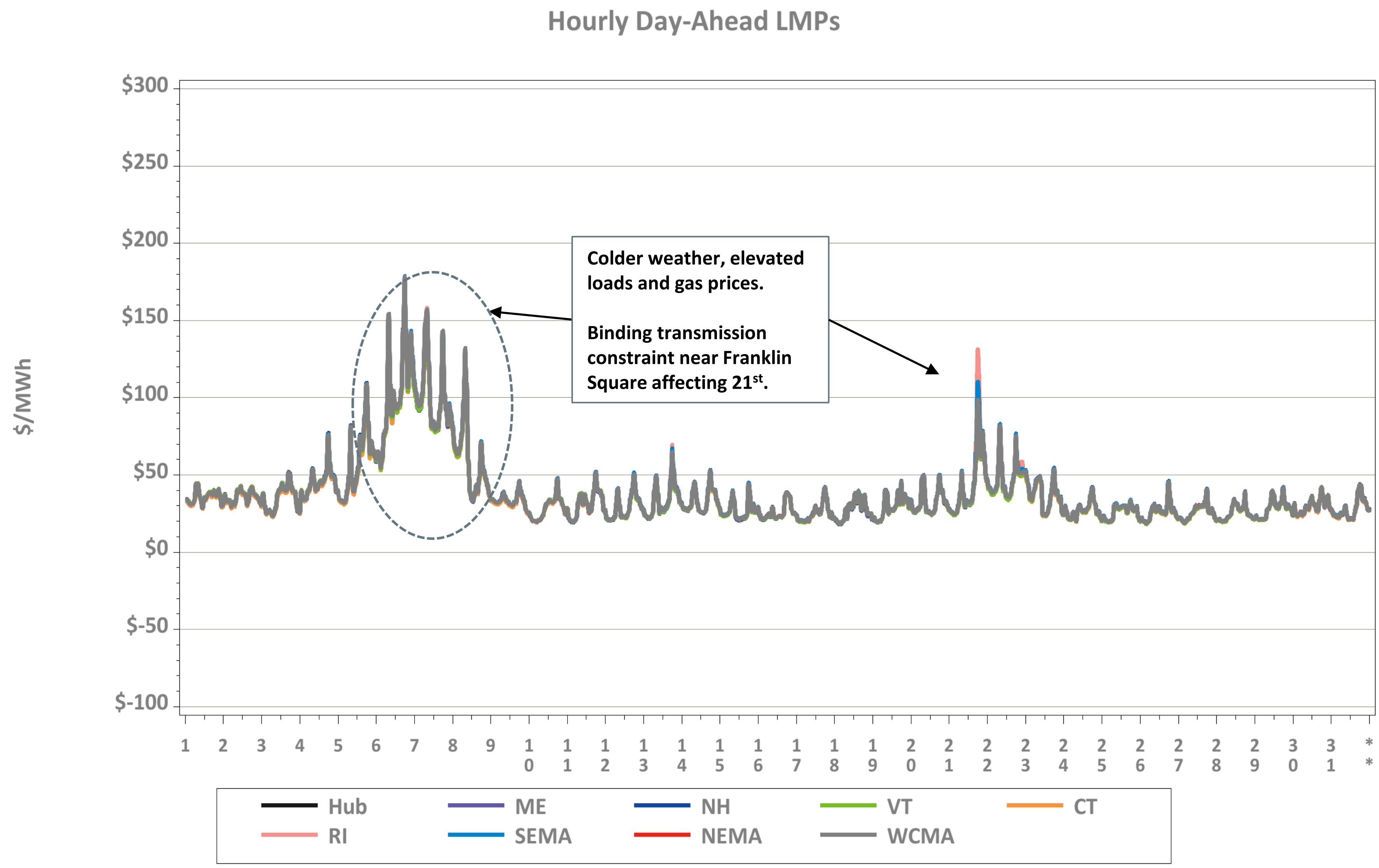


Underlying natural gas data furnished by:

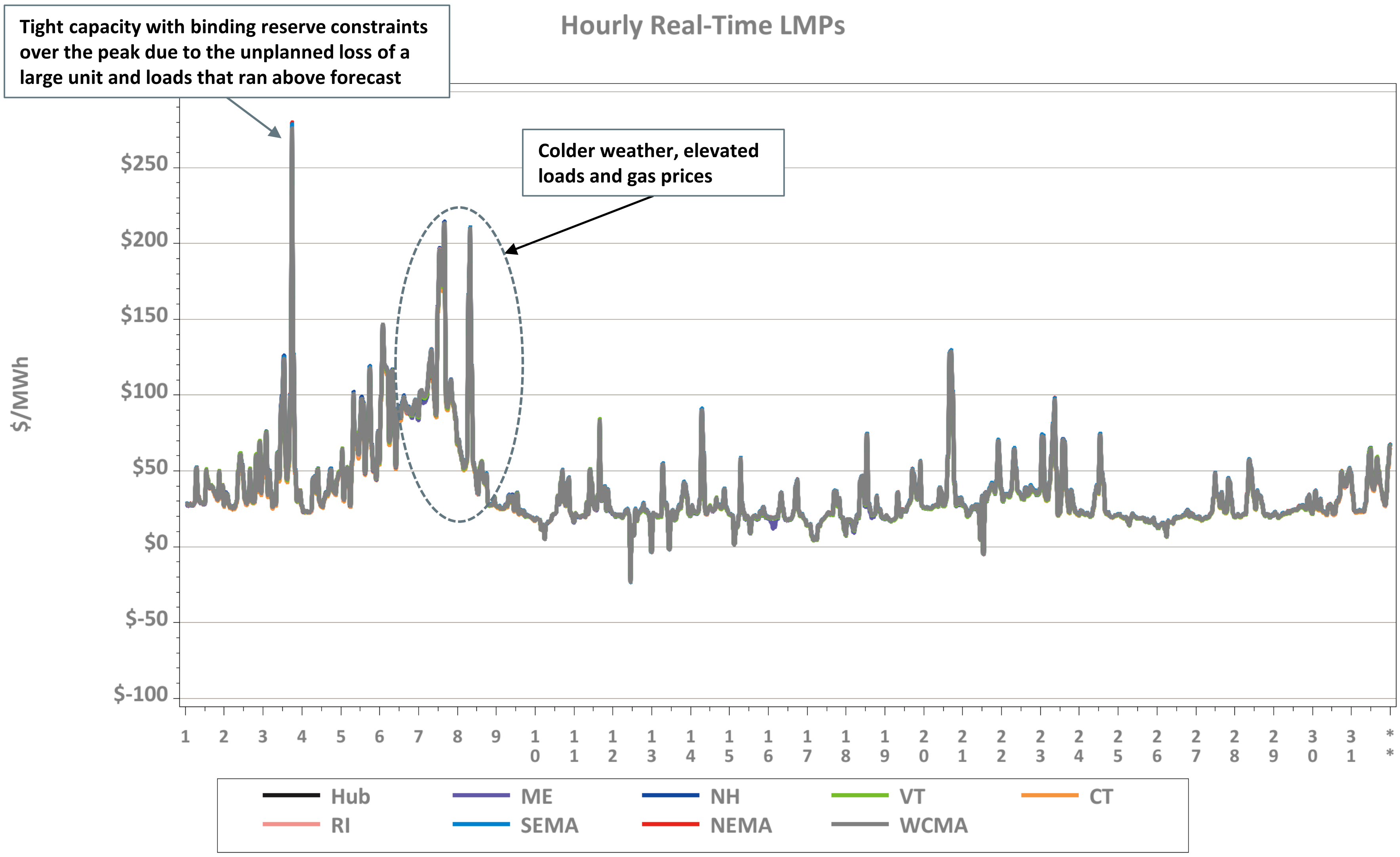
ICE Global markets in clear view

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

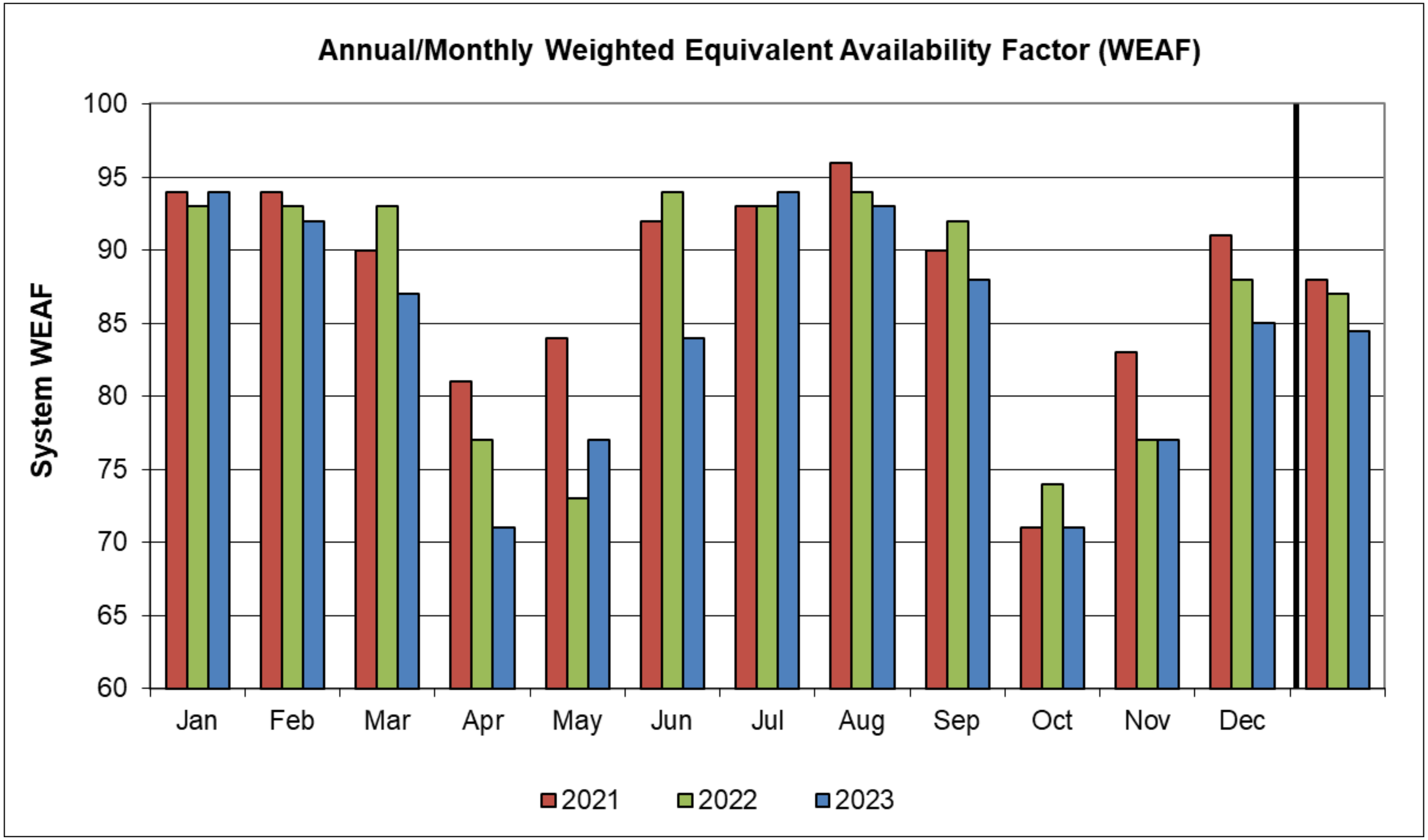
Hourly DA LMPs, December 1-31 2023



Hourly RT LMPs, December 1-31, 2023



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94	92	87	71	77	84	94	93	88	71	77	85	84
2022	93	93	93	77	73	94	93	94	92	74	77	88	87
2021	94	94	90	81	84	92	93	96	90	71	83	91	88

Data as of 12/15/2023

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for January 2024

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	55.0	174.1	0.0	229.2
NH	31.9	147.2	0.0	179.1
VT	38.2	169.4	0.0	207.5
CT	71.9	72.5	664.8	809.2
RI	21.8	319.2	0.0	341.0
SEMA	33.5	466.7	0.0	500.2
WCMA	60.4	517.7	8.4	586.4
NEMA	60.0	757.7	0.0	817.8
Total	**372.8**	**2,624.5**	**673.2**	**3,670.4**

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

NEW GENERATION

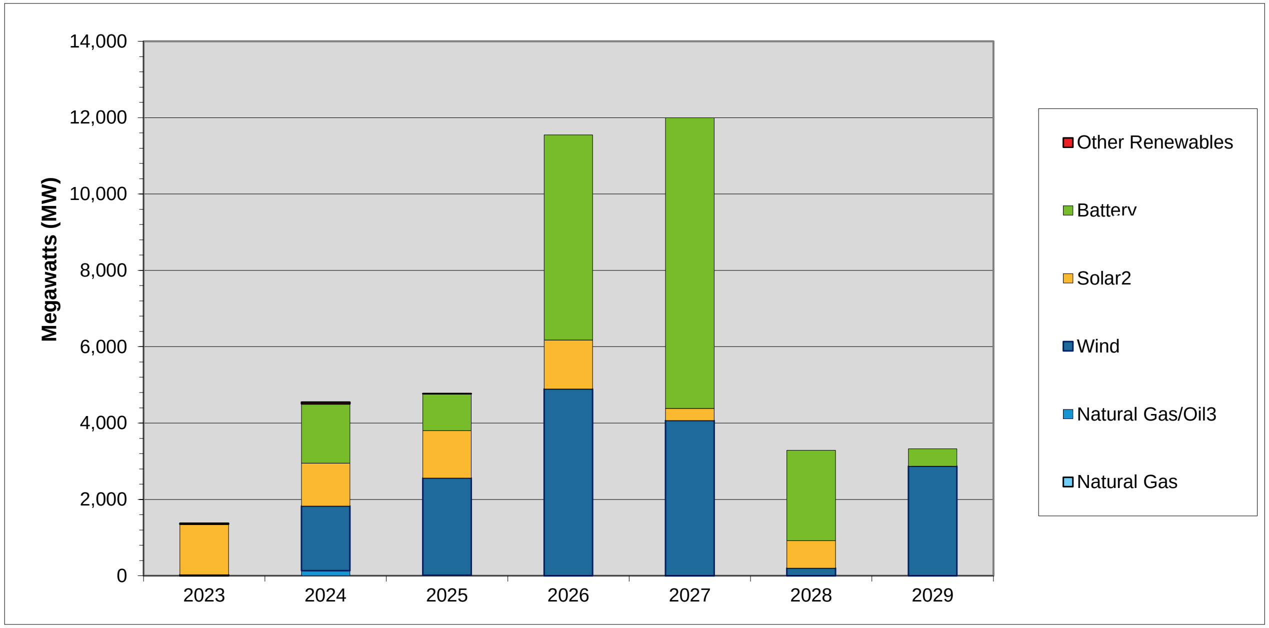
New Generation Update

Based on Queue as of 12/31/23

- Twenty projects totaling 1,178 MW were added to the interconnection queue since the last update
  - Solar, solar with battery and battery storage projects with in-service dates between 2025 and 2028
- In total, 403 generation projects are currently being tracked by the ISO, totaling approximately 42,195 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total[1]
Other Renewables	28	44	2	0	0	0	0	74	0.2
Battery	5	1,555	965	5,378	7,617	2,362	454	18,336	44.9
Solar[2]	1,314	1,122	1,242	1,280	314	725	0	5,997	14.7
Wind	0	1,693	2,545	4,893	4,064	197	2,870	16,262	39.8
Natural Gas/Oil[3]	0	135	16	0	0	0	0	151	0.4
Natural Gas	26	0	0	0	4	0	0	30	0.1
Totals	**1,373**	**4,549**	**4,770**	**11,551**	**11,999**	**3,284**	**3,324**	**40,850**	**100.0**

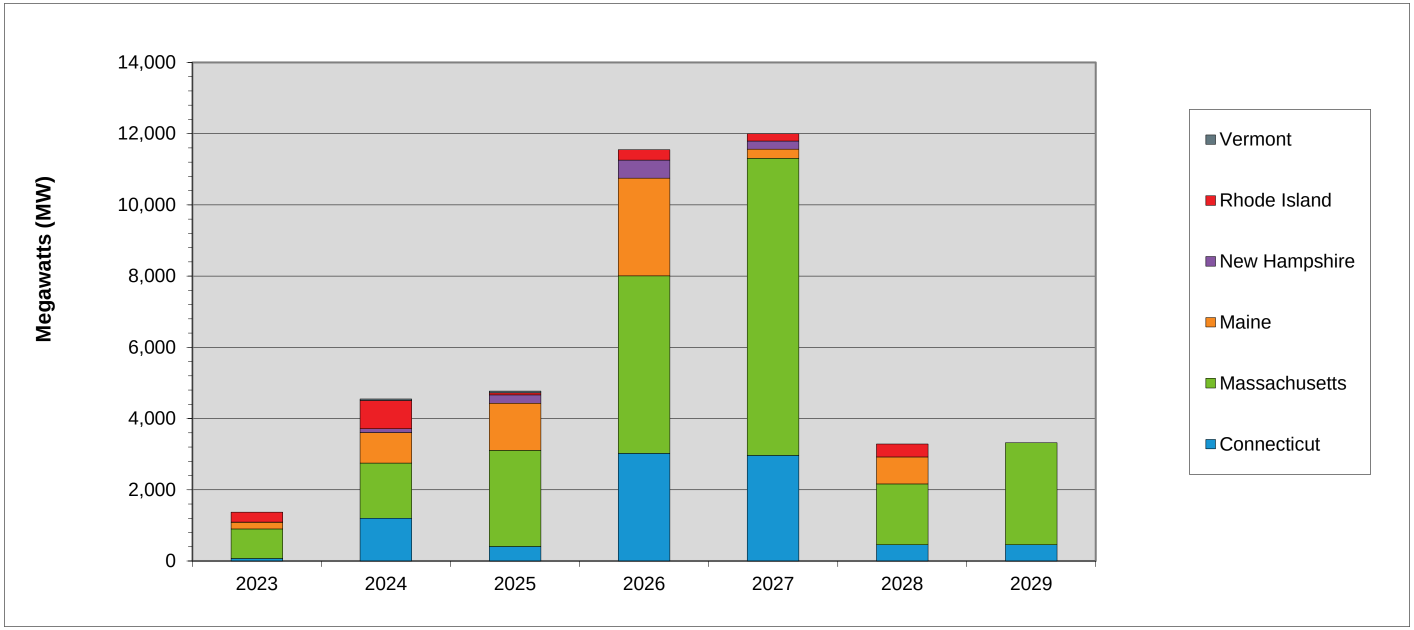
[1] Sum may not equal 100% due to rounding

[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

Actual and Projected Annual Generator Capacity Additions

By State



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total[1]
Vermont	0	40	50	0	0	0	0	90	0.2
Rhode Island	281	794	54	295	210	360	0	1,994	4.9
New Hampshire	5	109	239	504	226	0	0	1,083	2.7
Maine	185	854	1,323	2,743	254	764	0	6,123	15.0
Massachusetts	834	1,550	2,696	4,985	8,348	1,705	2,870	22,988	56.3
Connecticut	68	1,202	408	3,024	2,961	455	454	8,572	21.0
Totals	**1,373**	**4,549**	**4,770**	**11,551**	**11,999**	**3,284**	**3,324**	**40,850**	**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	119	18,336	0	0	119	18,336
Fuel Cell	4	46	0	0	4	46
Hydro	1	28	0	0	1	28
Natural Gas	4	30	0	0	4	30
Natural Gas/Oil	3	151	1	62	2	89
Nuclear	0	0	0	0	0	0
Solar	244	5,997	15	343	229	5,654
Wind	28	17,571	1	800	27	16,771
Total	403	42,159	17	1,205	386	40,954

- 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 within the next 12 months
- 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	7	87	0	0	7	87
Intermediate	2	89	0	0	2	89
Peaker	366	24,412	16	405	350	24,007
Wind Turbine	28	17,571	1	800	27	16,771
Total	403	42,159	17	1,205	386	40,954

- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	119	18,336	0	0	0	0	119	18,336	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	1	28	1	28	0	0	0	0	0	0
Natural Gas	4	30	2	13	0	0	2	17	0	0
Natural Gas/Oil	3	151	0	0	2	89	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	244	5,997	0	0	0	0	244	5,997	0	0
Wind	28	17,571	0	0	0	0	0	0	28	17,571
Total	403	42,159	7	87	2	89	366	24,412	28	17,571

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

FORWARD CAPACITY MARKET

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	659.671	-28.399	564.371	-95.3
	Passive Demand		3,327.071	3,327.932	0.861	3,315.207	-12.725	3,253.179	-62.028
Demand Total			**3,919.114**	**4,016.002**	**96.888**	**3,974.878**	**-41.124**	**3,817.550**	**-157.328**
Generator		*Non-Intermittent*	27,816.902	28,275.143	458.241	27,697.714	-577.429	27,684.252	-13.462
		Intermittent	1,160.916	1,128.446	-32.47	925.942	-202.504	893.444	-32.498
Generator Total			**28,977.818**	**29,403.589**	**425.771**	**28,623.656**	**-779.933**	**28,577.696**	**-45.96**
Import Total			**1,058.72**	**1,058.72**	**0**	**1,029.800**	**-28.92**	**958.380**	**-71.42**
Grand Total*			**33,955.652**	**34,478.311**	**522.661**	**33,628.334**	**-849.977**	**33,353.626**	**-274.708**
Net ICR (NICR)			**32,490**	**32,980**	**490**	**31,480**	**-1,500**	**31,690**	**210**

* 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 reconfiguration auctions 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 2015-2023 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	579.692	-93.709		
	Passive Demand	3,212.865	3,211.403	-1.462	3,134.652	-76.751		
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**		
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125		
	Intermittent	1,089.265	1,073.794	-15.471	1,056.601	-17.193		
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**		
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**		
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**		
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**		

* 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 and reconfiguration auctions 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 2015-2023 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	589.882	-175.468				
	Passive Demand		2,557.256	2,579.120	21.864				
Demand Total			**3,322.606**	**3,169.002**	**-153.604**				
Generator		*Non-Intermittent*	26,805.003	26,643.379	-161.624				
		Intermittent	1,178.933	1,146.783	-32.15				
Generator Total			**27,983.936**	**27,790.162**	**-193.774**				
Import Total			**1,503.842**	**1,247.601**	**-256.241**				
Grand Total*			**32,810.384**	**32,206.765**	**-603.619**				
Net ICR (NICR)			**31,645**	**30,585**	**-1,060**				

* 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 reconfiguration auctions 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 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

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*		622.854						
	Passive Demand		2,316.815						
Demand Total			**2,939.669**						
Generator		*Non-Intermittent*	26,507.420						
		Intermittent	1,356.084						
Generator Total			**27,863.504**						
Import Total			**566.998**						
Grand Total*			**31,370.171**						
Net ICR (NICR)			**30,305**						

* 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 reconfiguration auctions 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 2015-2023 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

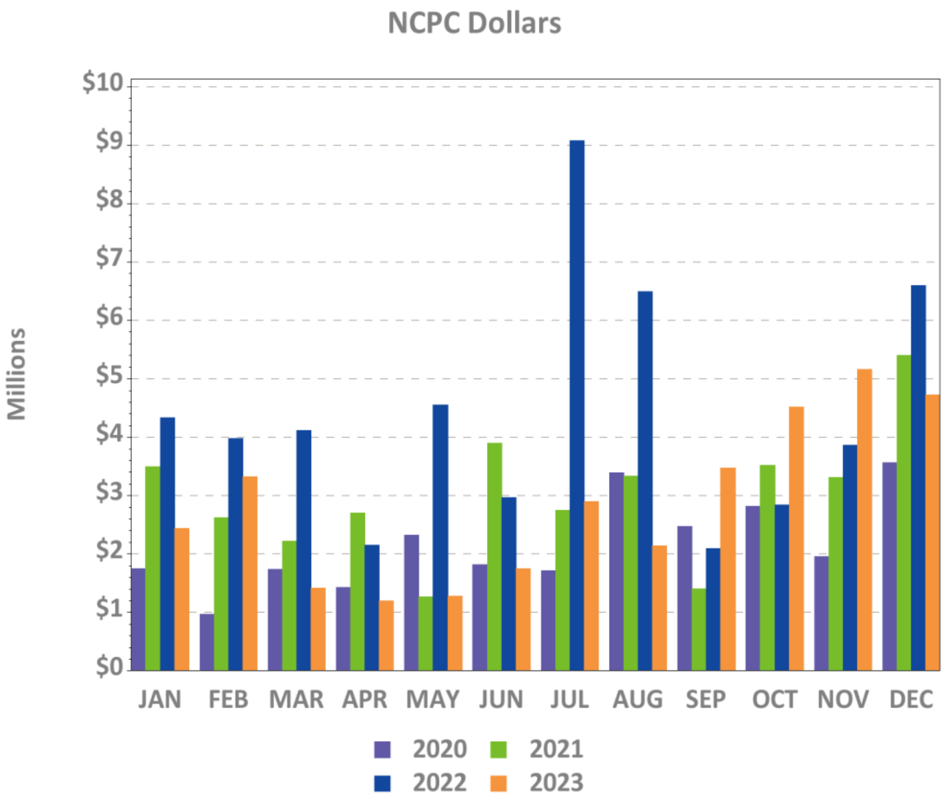
Definitions

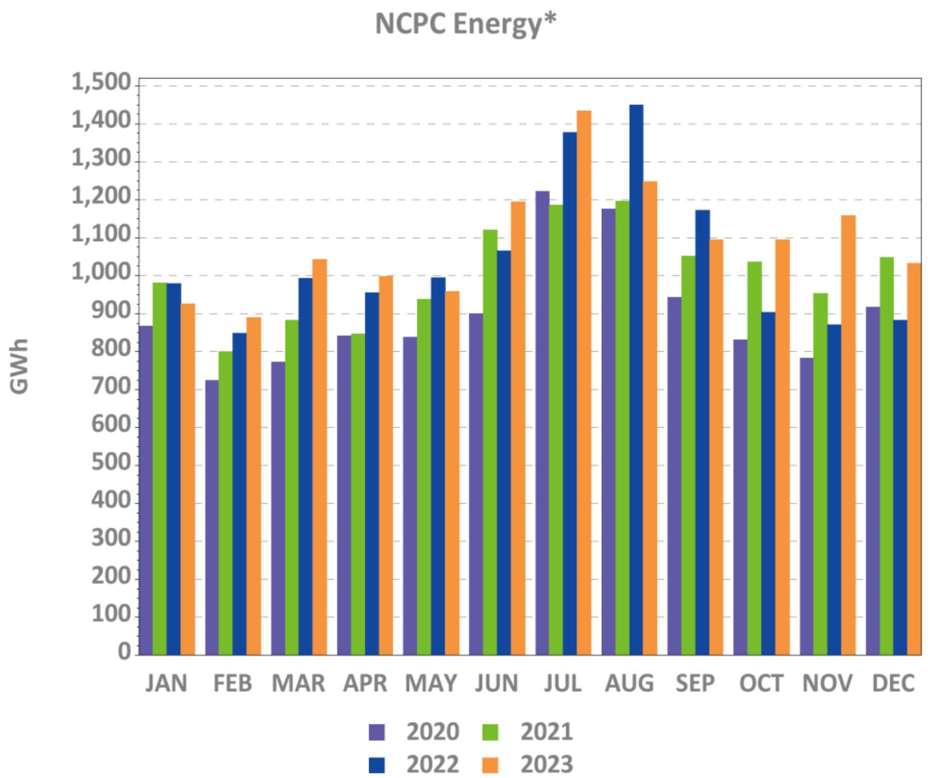
1^{st} Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2^{nd} Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 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).

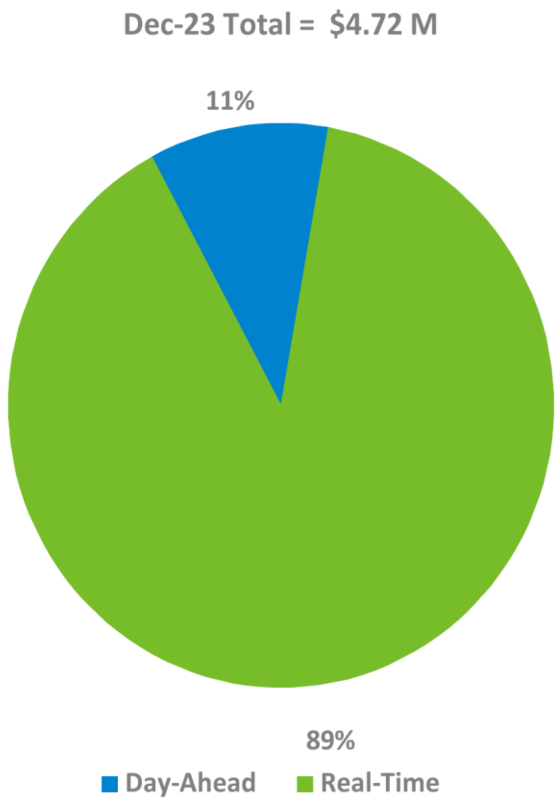
Year-Over-Year Total NCPC Dollars and Energy



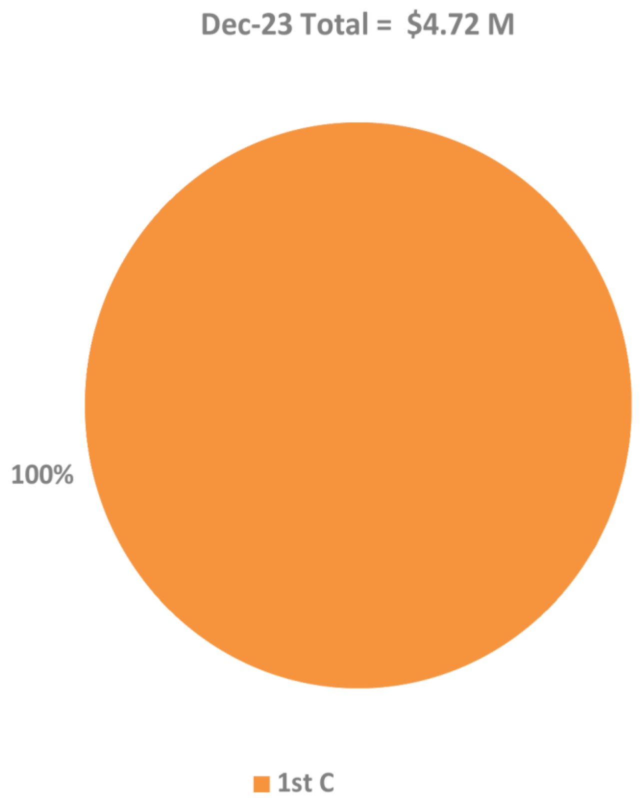


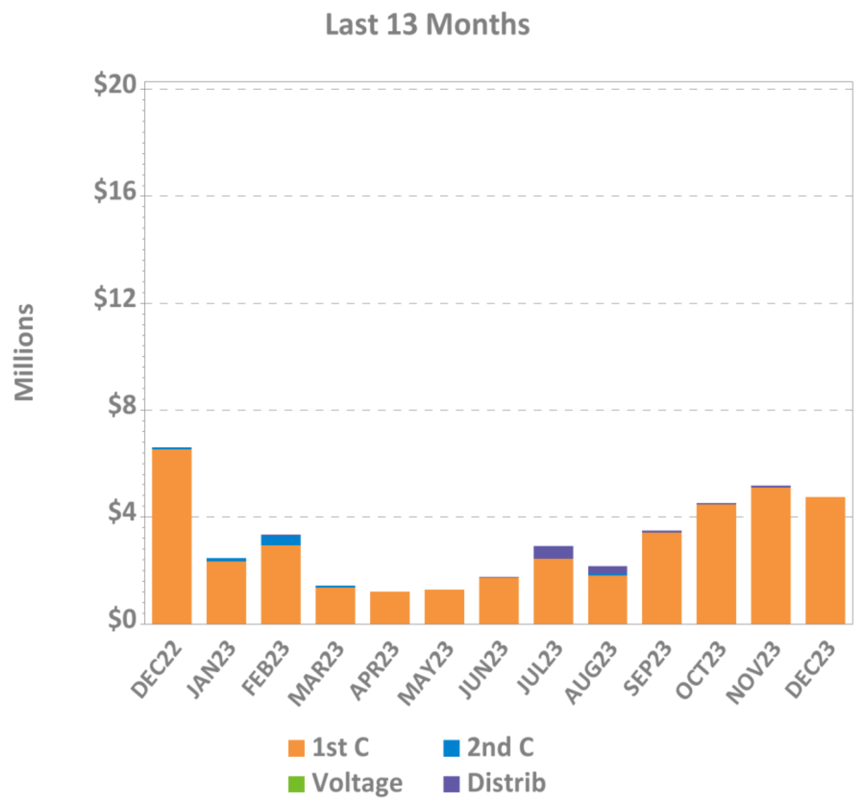
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



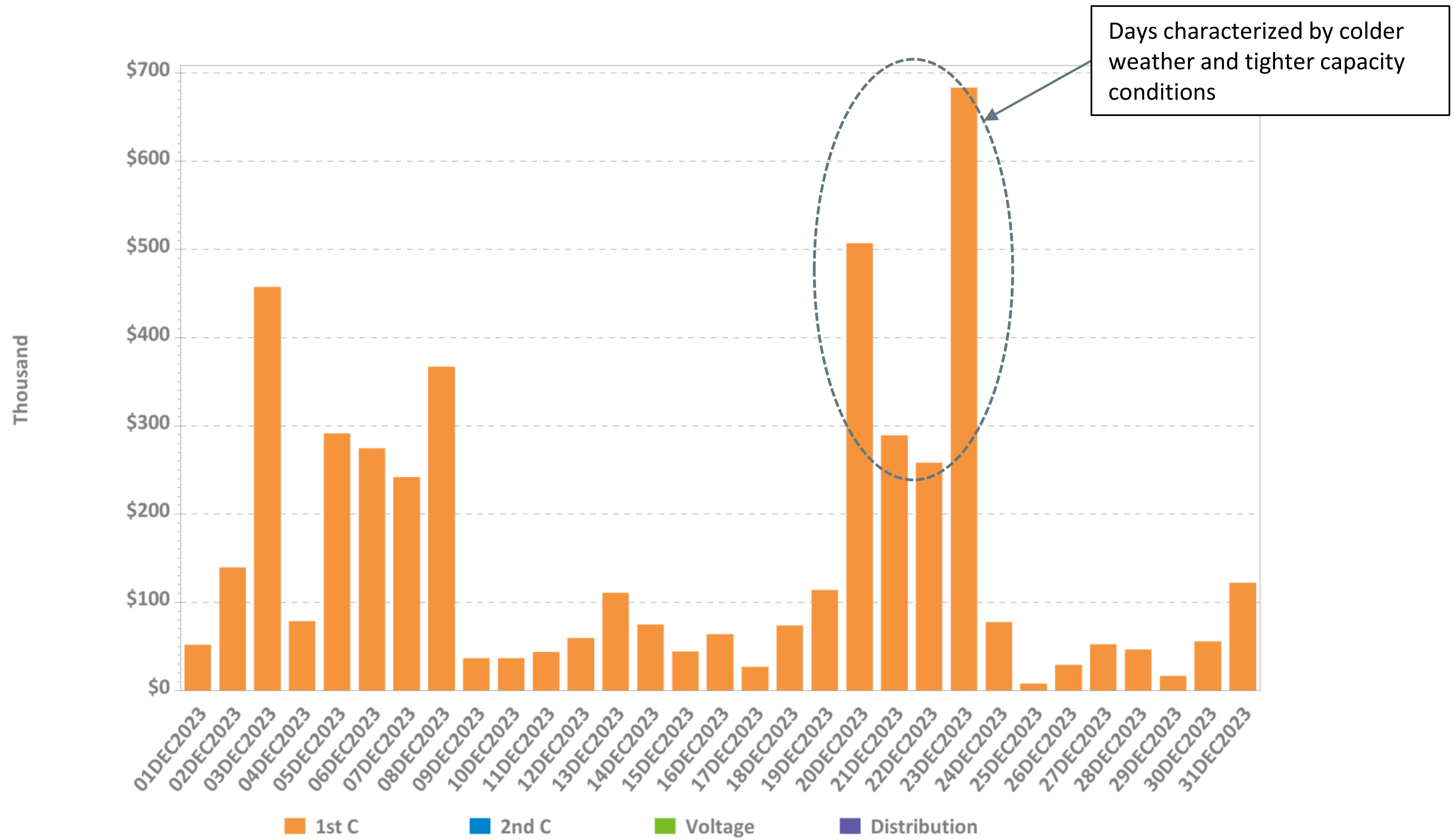
NCPC Charges by Type



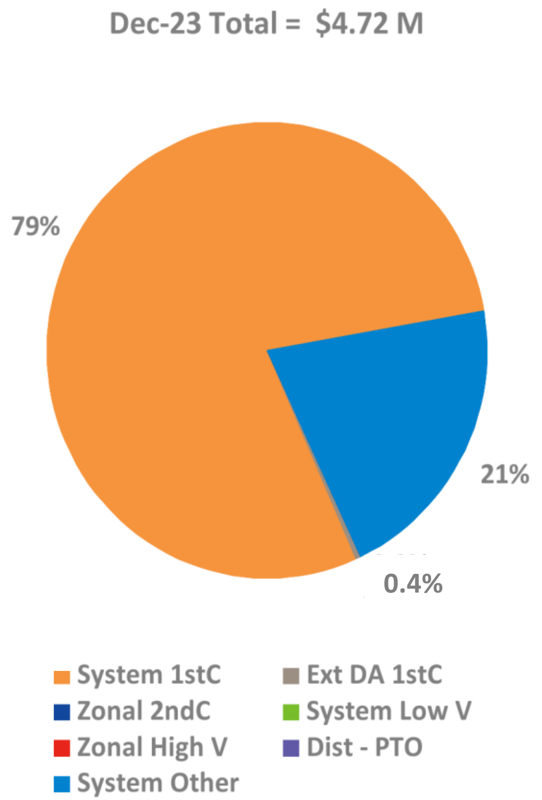


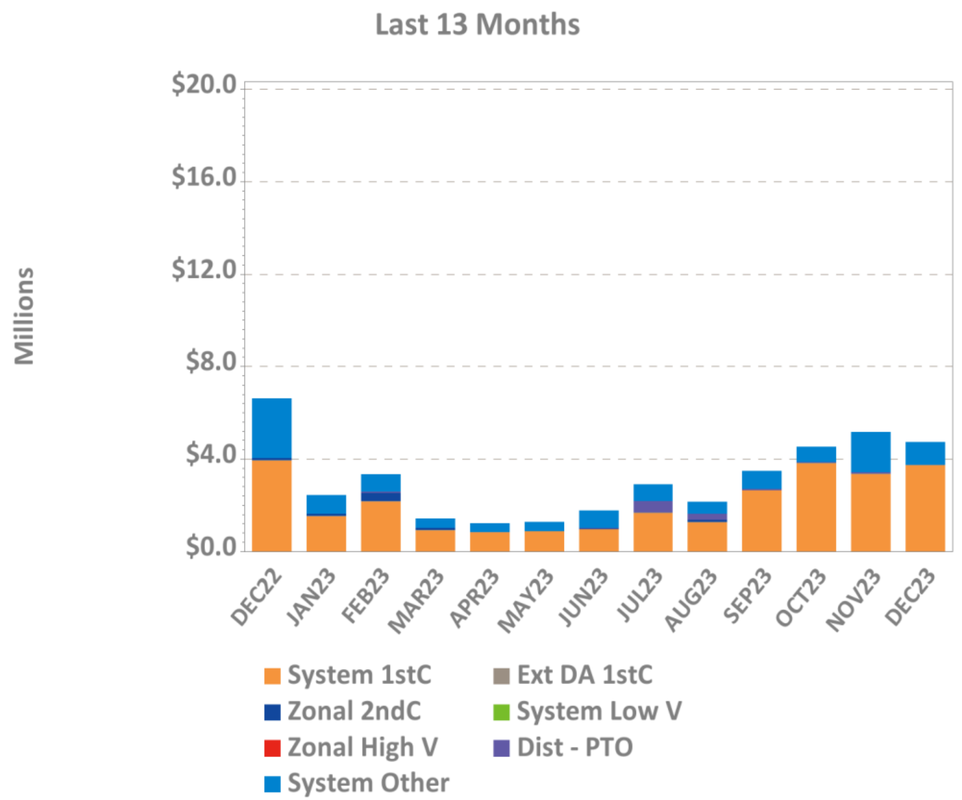
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



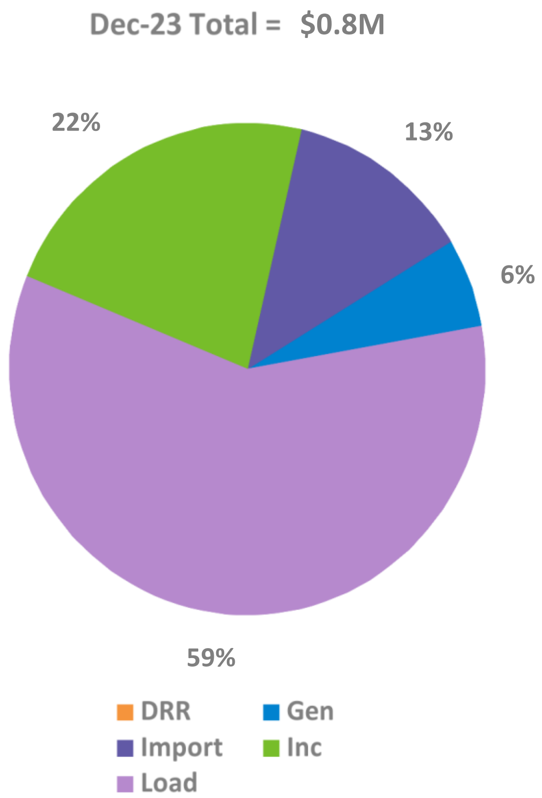
NCPC Charges by Allocation

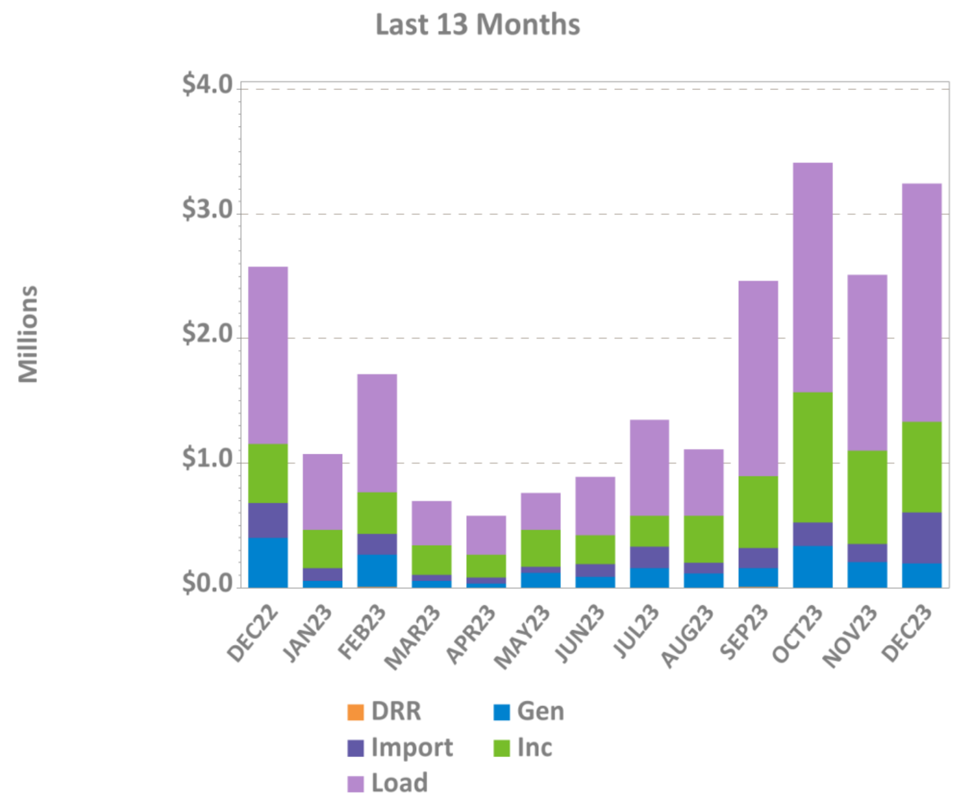




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

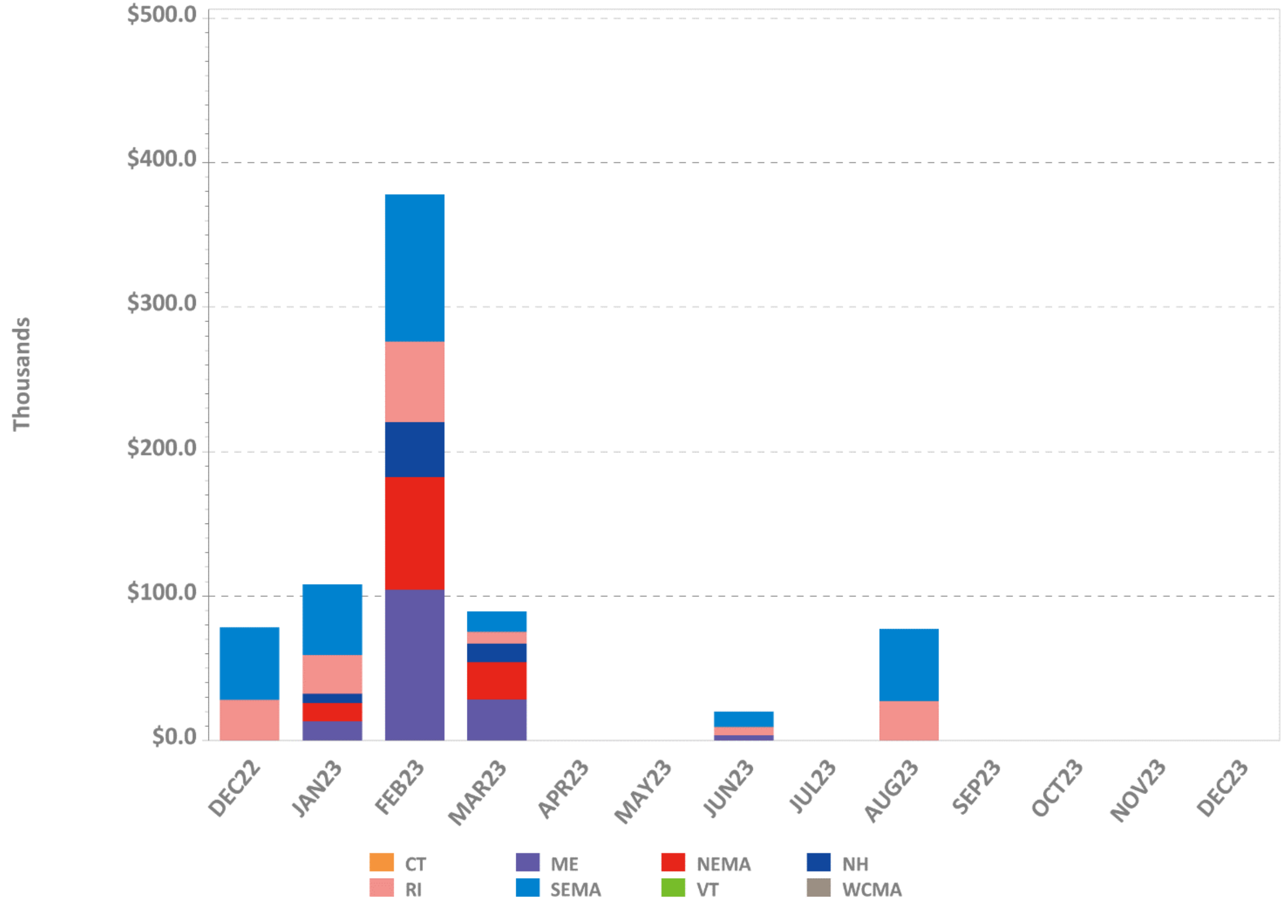
RT First Contingency Charges by Deviation Type





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

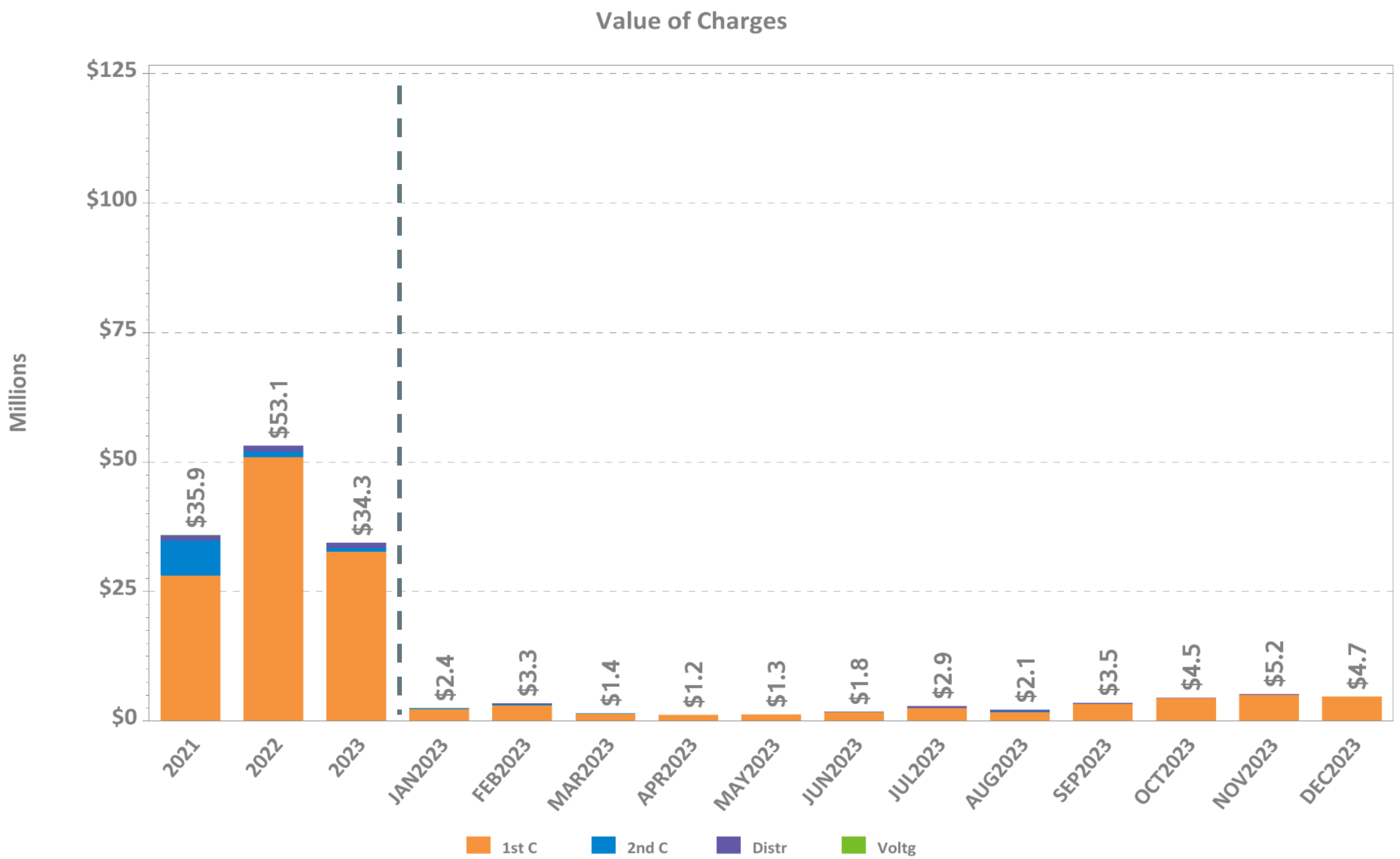
LSCPR Charges by Reliability Region



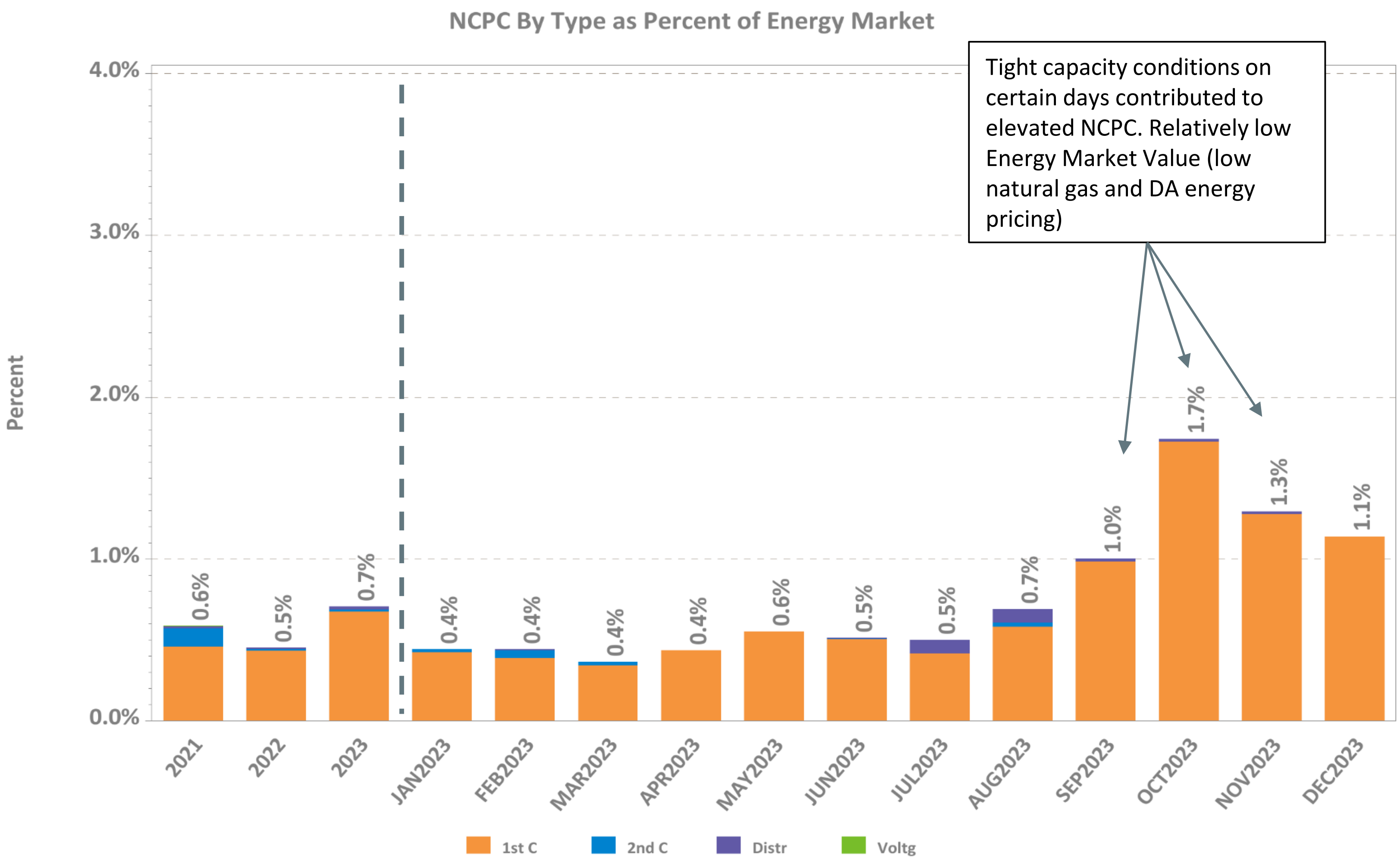
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

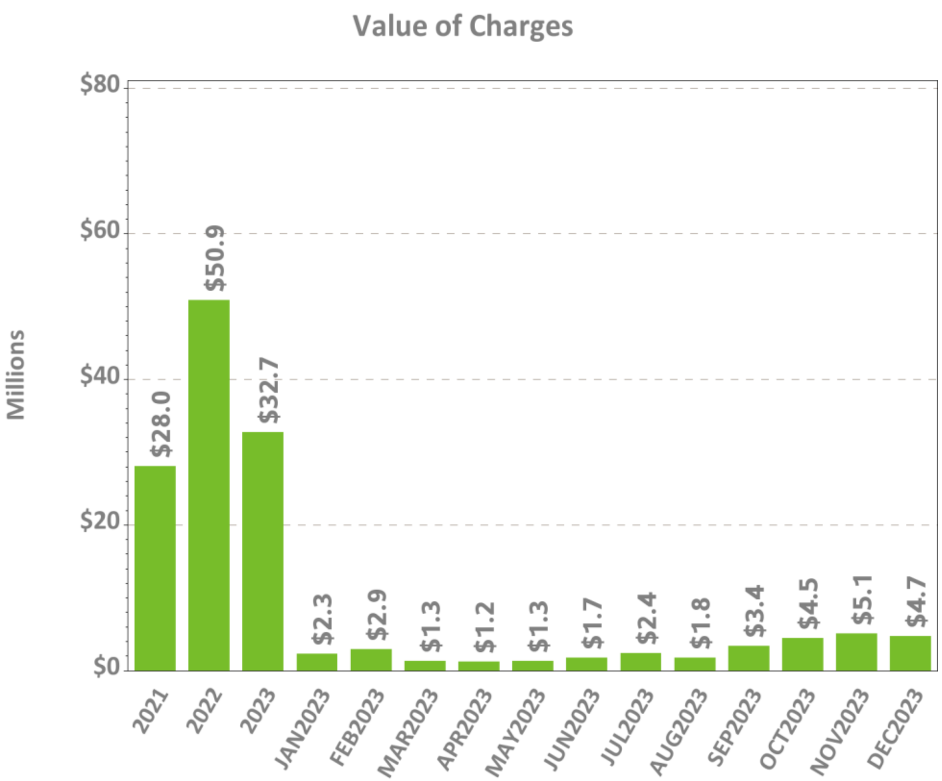
NCPC Charges by Type

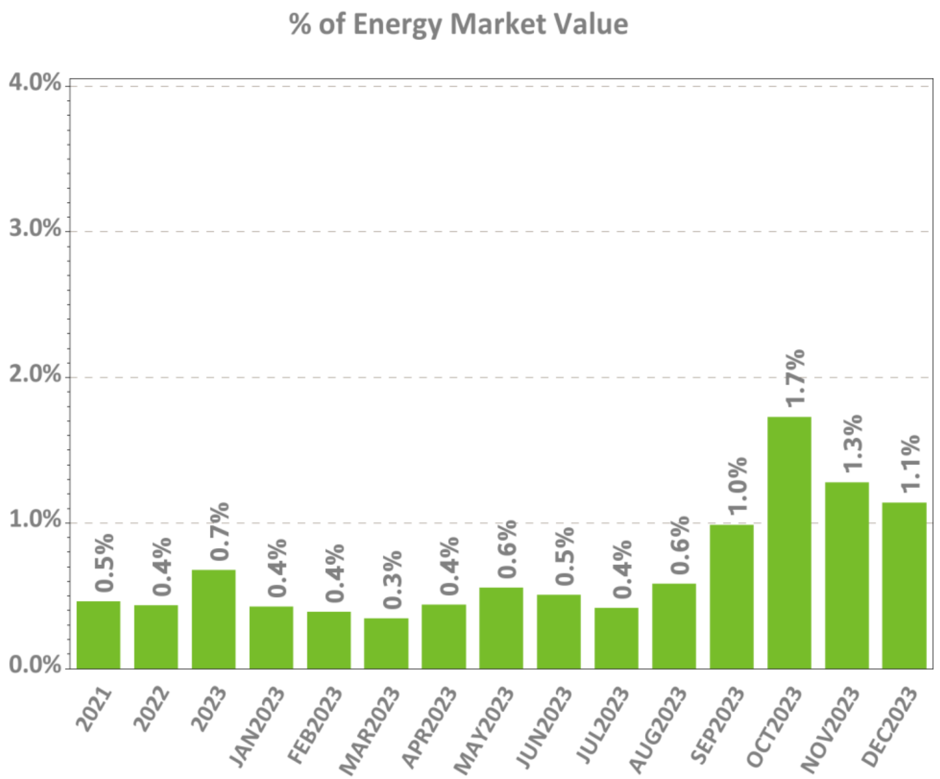


NCPC Charges as Percent of Energy Market



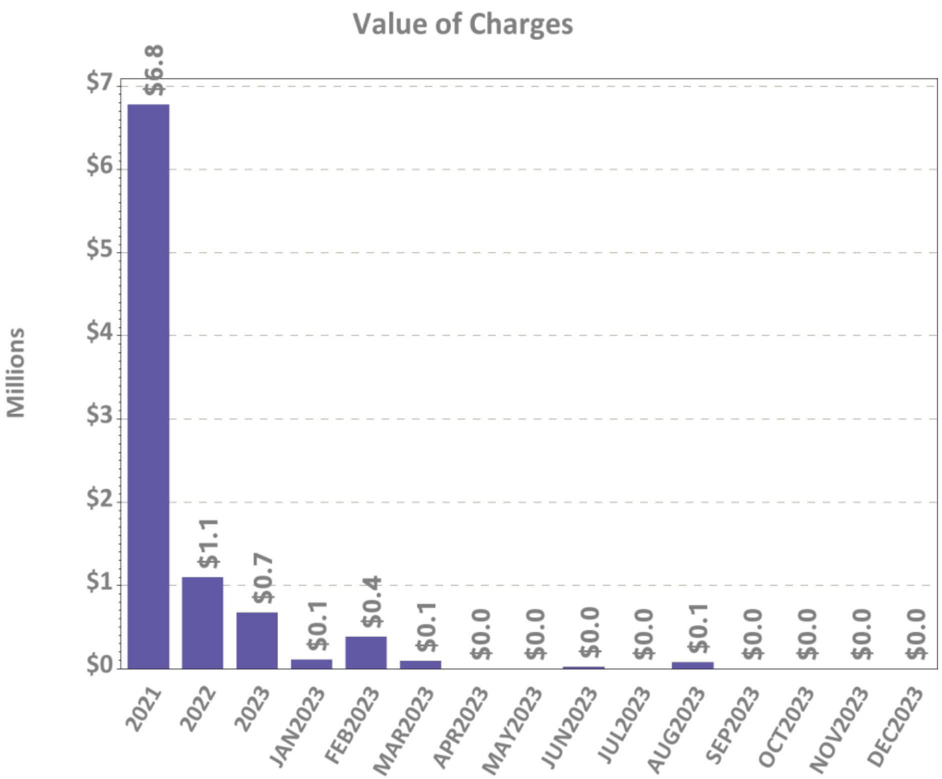
First Contingency NCPC Charges

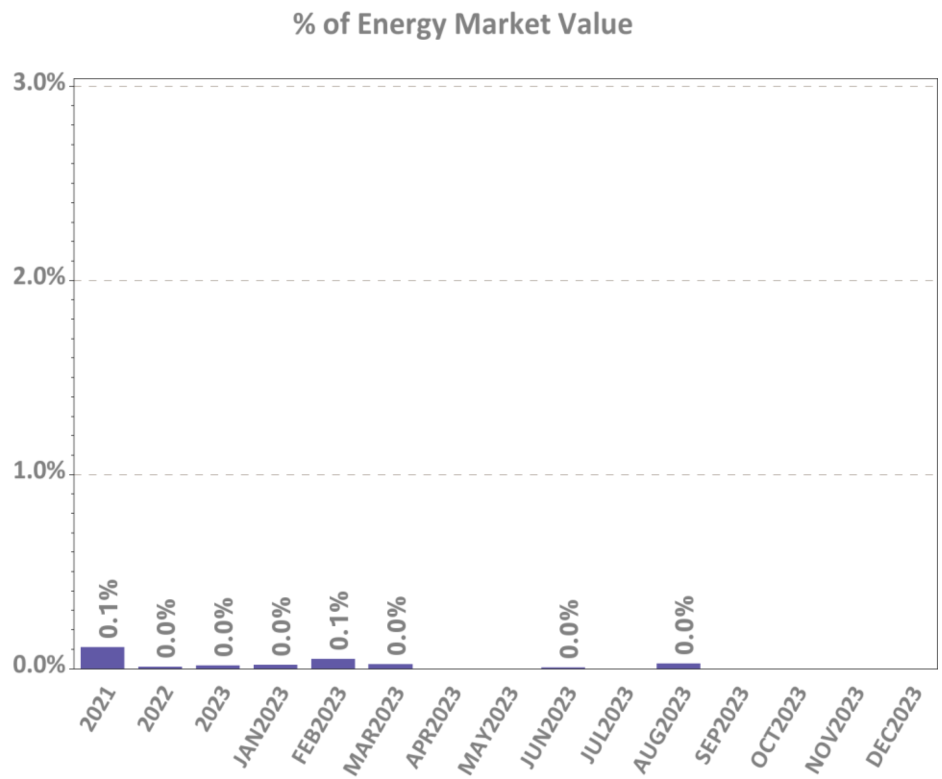




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

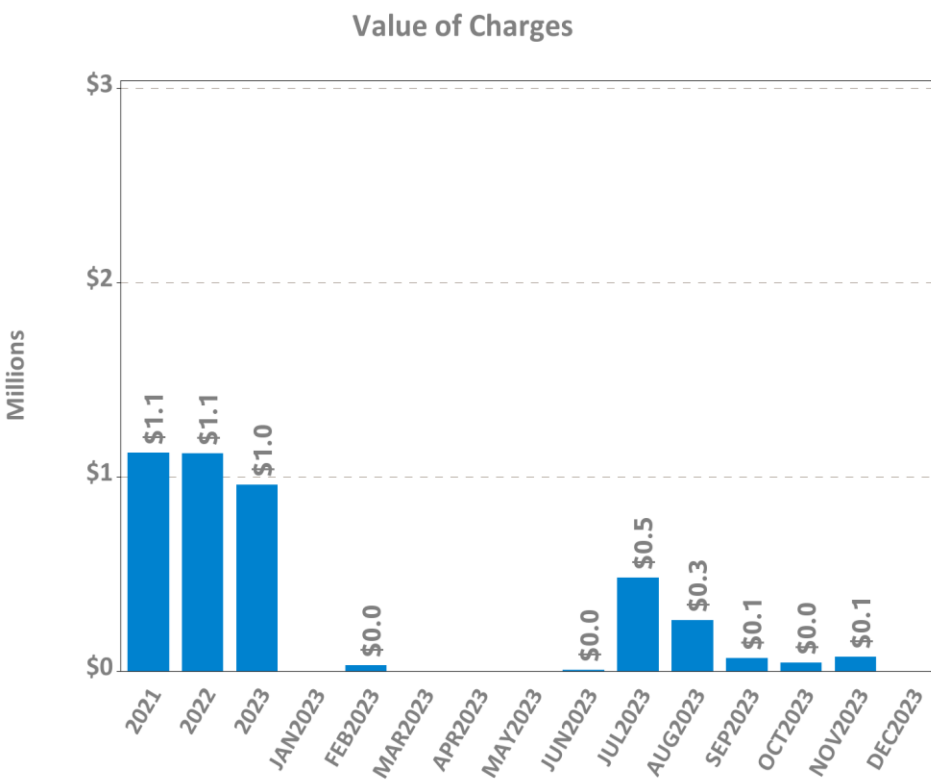
Second Contingency NCPC Charges

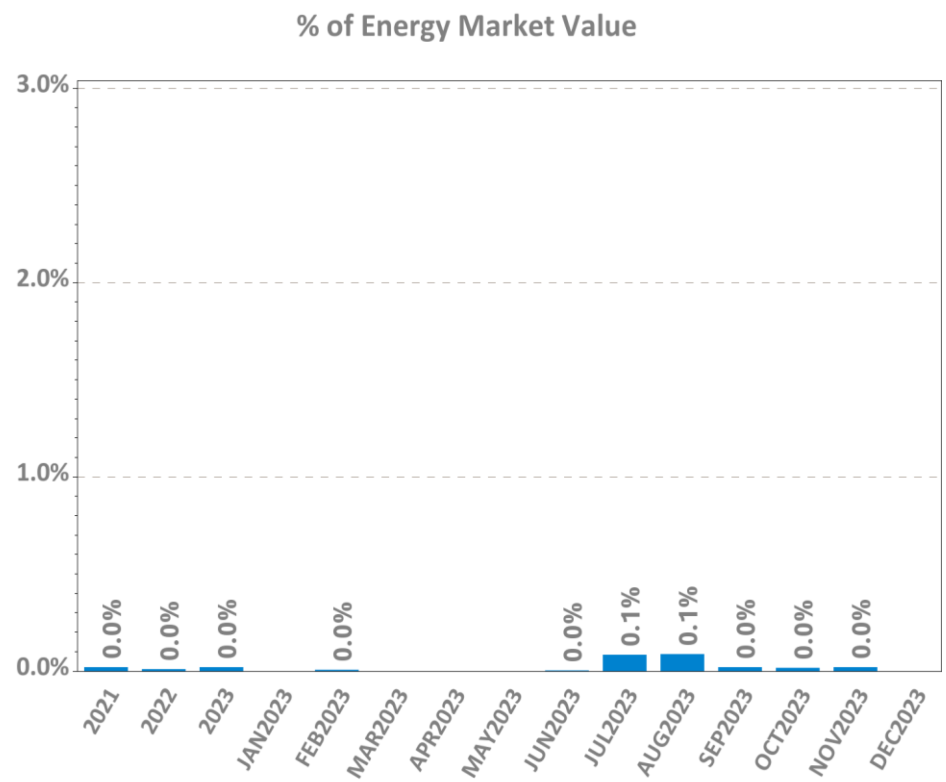




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

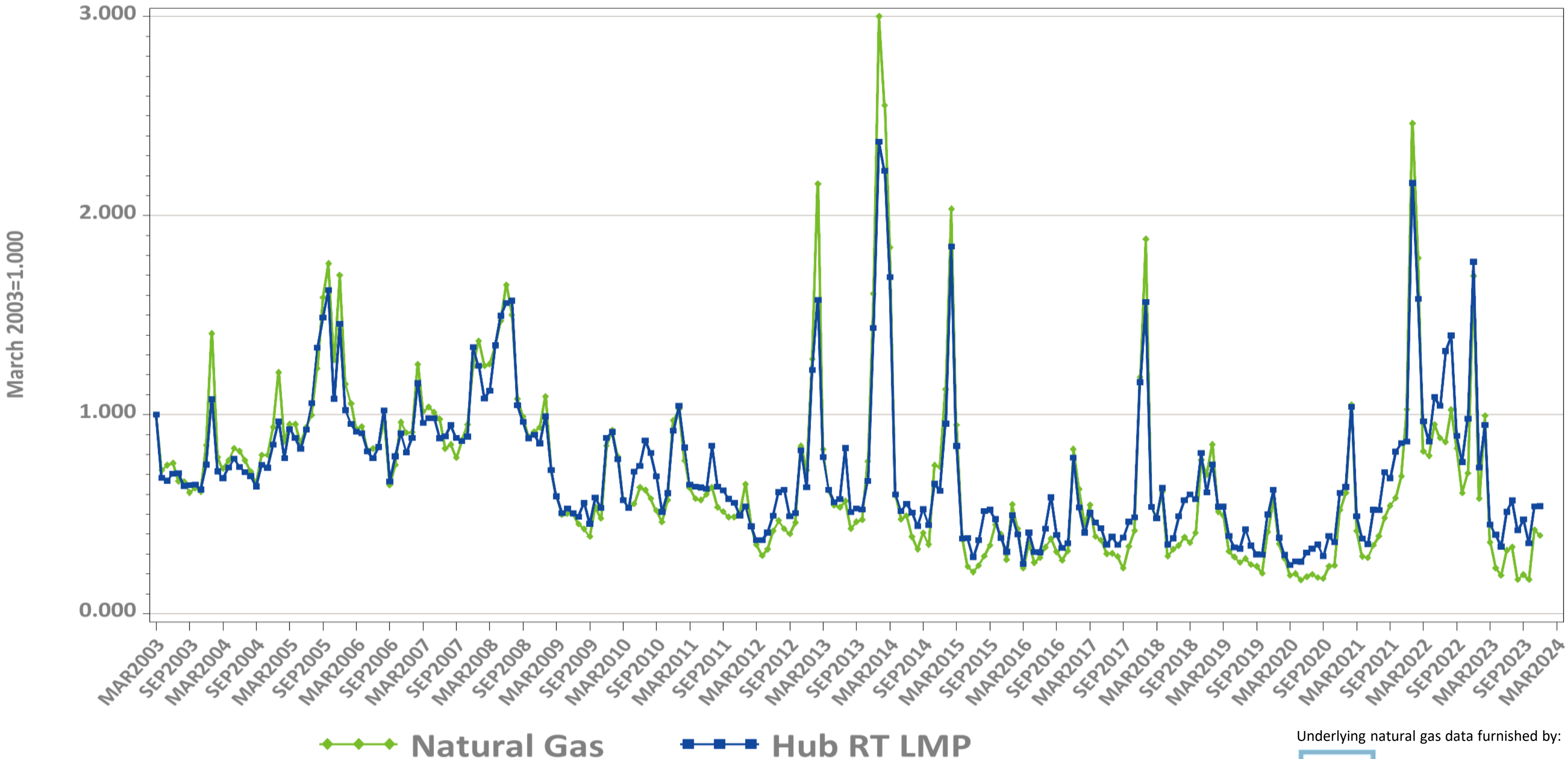
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.54	$44.60	$45.52	$46.27	$45.05	$45.88	$46.38	$45.91	$45.92
Real-Time	$45.25	$43.97	$44.28	$45.10	$44.15	$44.61	$45.09	$44.85	$44.84
RT Delta %	-2.8%	-1.4%	-2.7%	-2.5%	-2.0%	-2.8%	-2.8%	-2.3%	-2.3%
Year 2022	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$86.07	$84.05	$84.15	$85.73	$84.46	$85.35	$86.01	$85.66	$85.55
Real-Time	$85.42	$83.83	$83.06	$85.07	$83.67	$84.71	$85.37	$85.00	$84.92
RT Delta %	-0.8%	-0.3%	-1.3%	-0.8%	-0.9%	-0.7%	-0.7%	-0.8%	-0.7%

December-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$115.47	$113.51	$111.80	$115.27	$113.63	$115.54	$115.95	$115.59	$115.50
Real-Time	$121.70	$119.88	$116.21	$121.38	$119.05	$121.80	$122.21	$121.46	$121.47
RT Delta %	5.4%	5.6%	3.9%	5.3%	4.8%	5.4%	5.4%	5.1%	5.2%
December-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$38.37	$37.07	$37.59	$38.23	$37.73	$38.27	$38.44	$38.17	$38.14
Real-Time	$37.37	$36.18	$36.65	$37.28	$36.80	$37.13	$37.38	$37.17	$37.15
RT Delta %	-2.6%	-2.4%	-2.5%	-2.5%	-2.5%	-3.0%	-2.8%	-2.6%	-2.6%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-66.8%	-67.3%	-66.4%	-66.8%	-66.8%	-66.9%	-66.8%	-67.0%	-67.0%
Yr over Yr RT	-69.3%	-69.8%	-68.5%	-69.3%	-69.1%	-69.5%	-69.4%	-69.4%	-69.4%

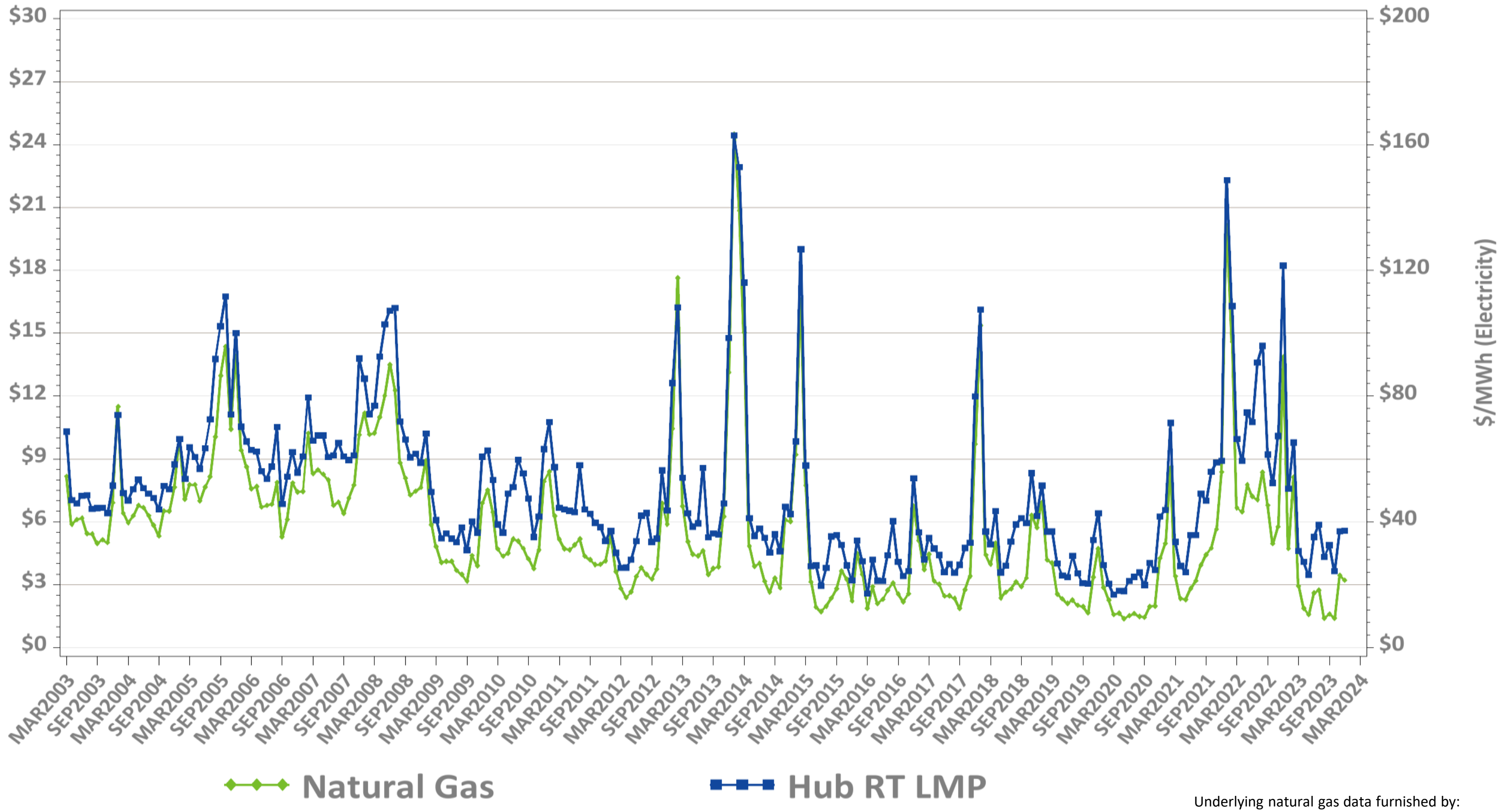
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

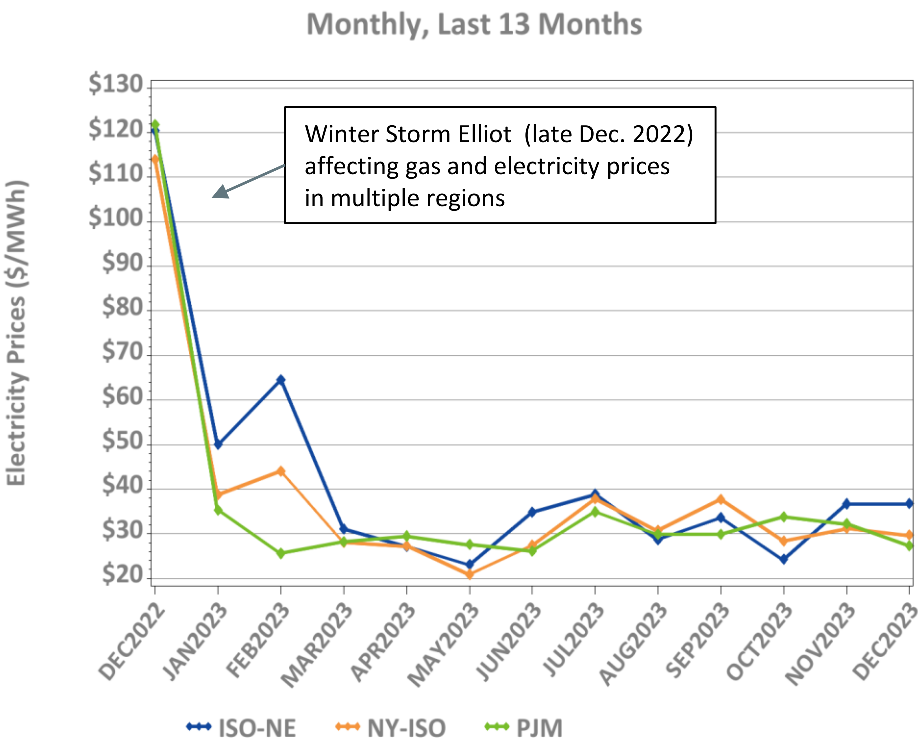
Monthly Average Fuel Price and RT Hub LMP



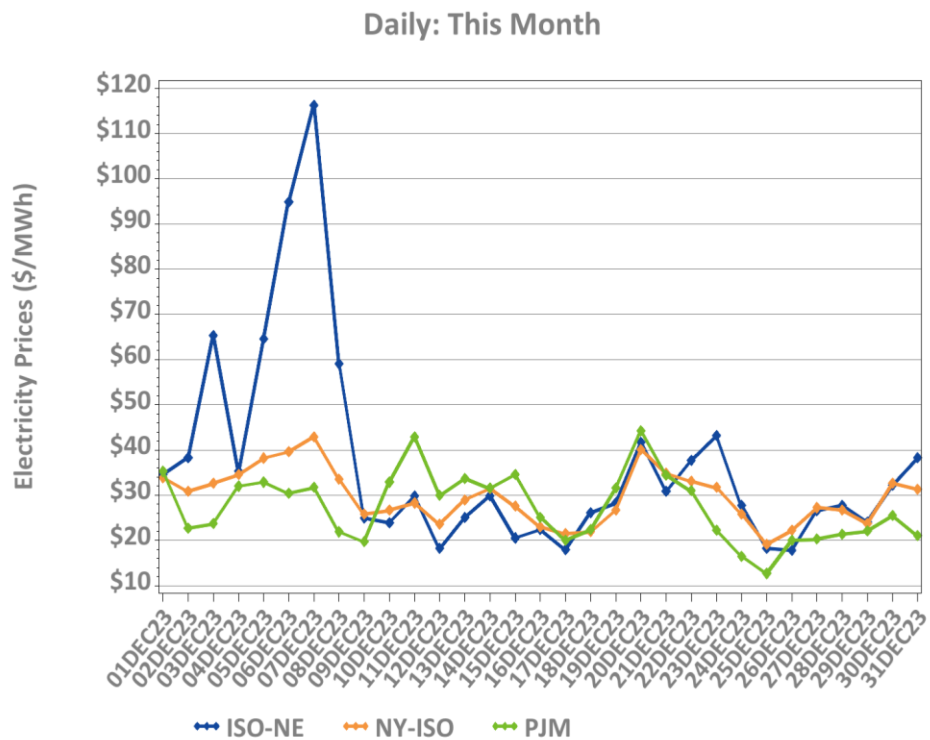
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

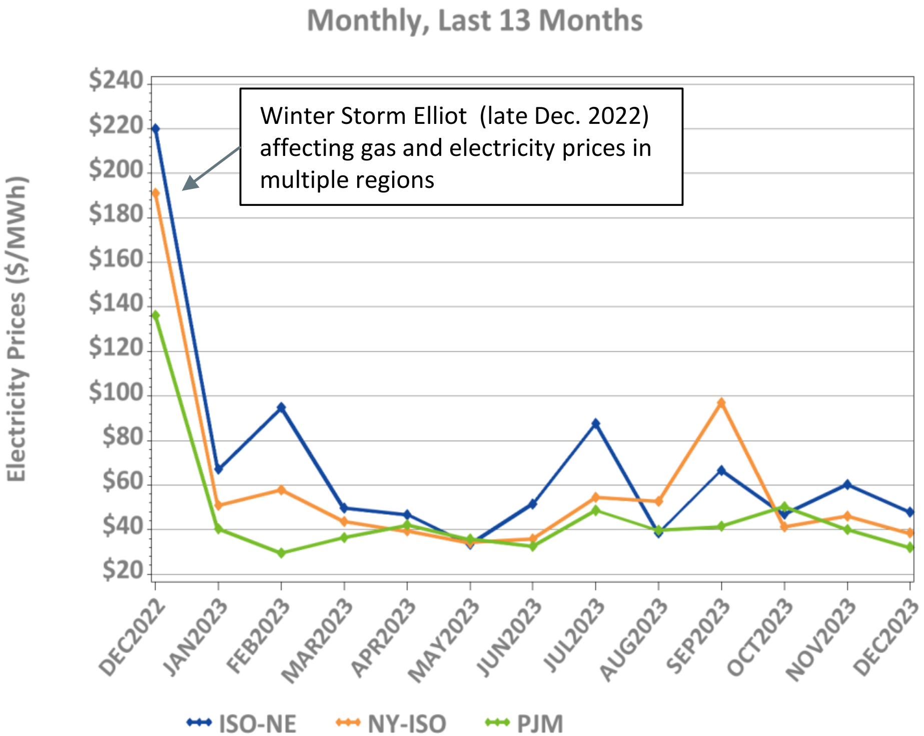


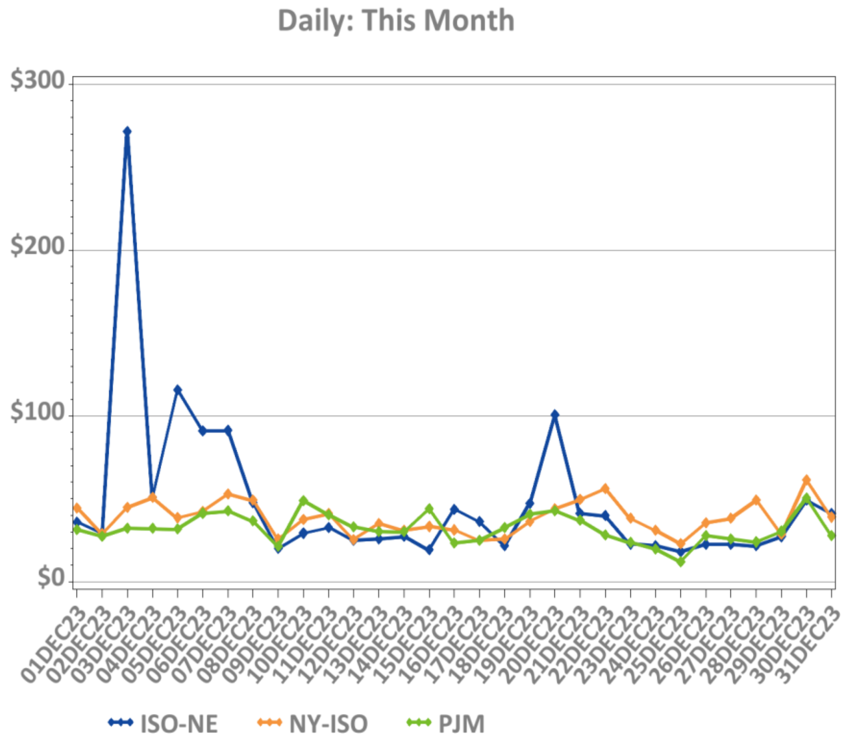
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





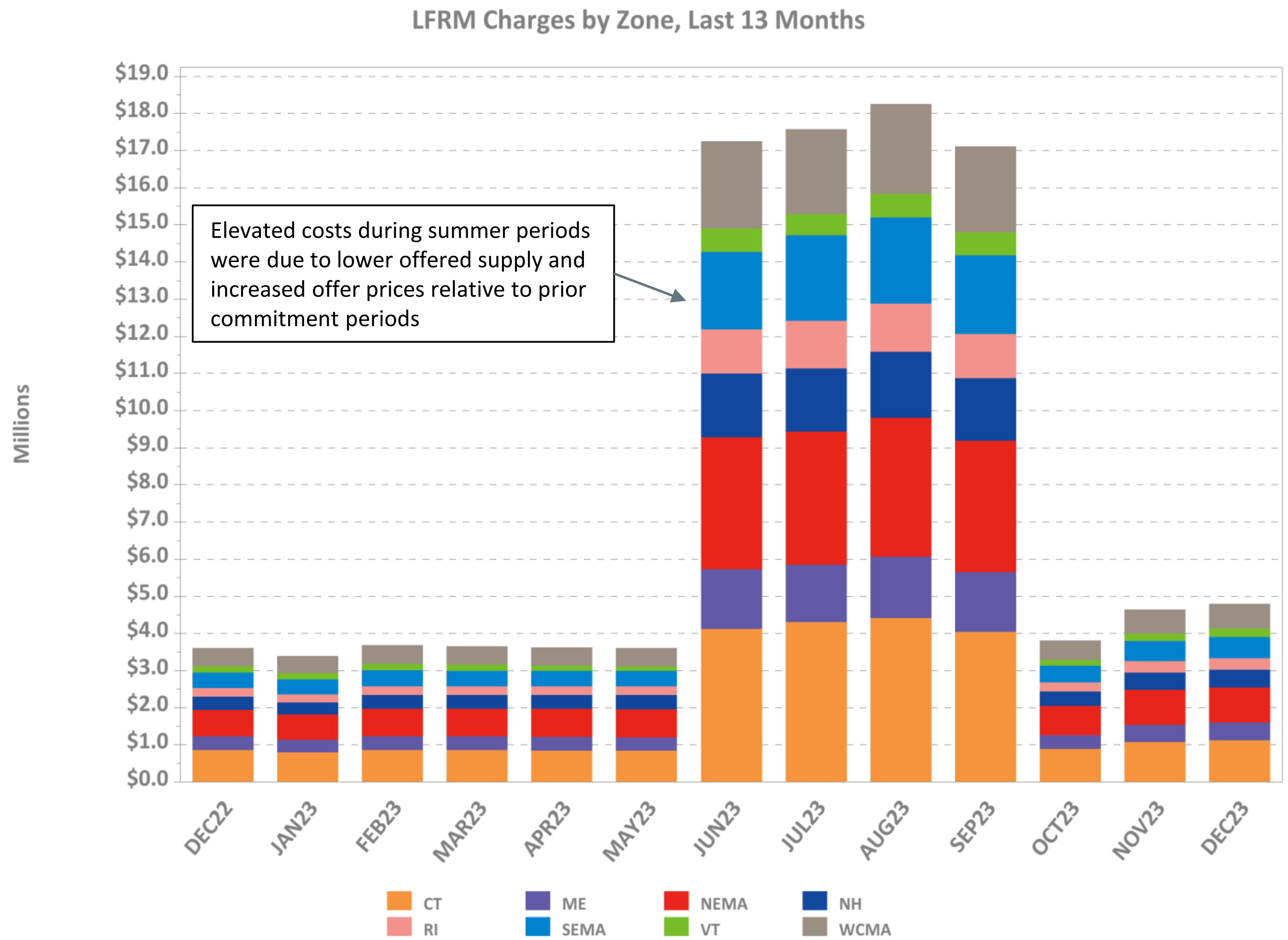
***Forecasted New England daily peak hours reflected**

Reserve Market Results – December 2023

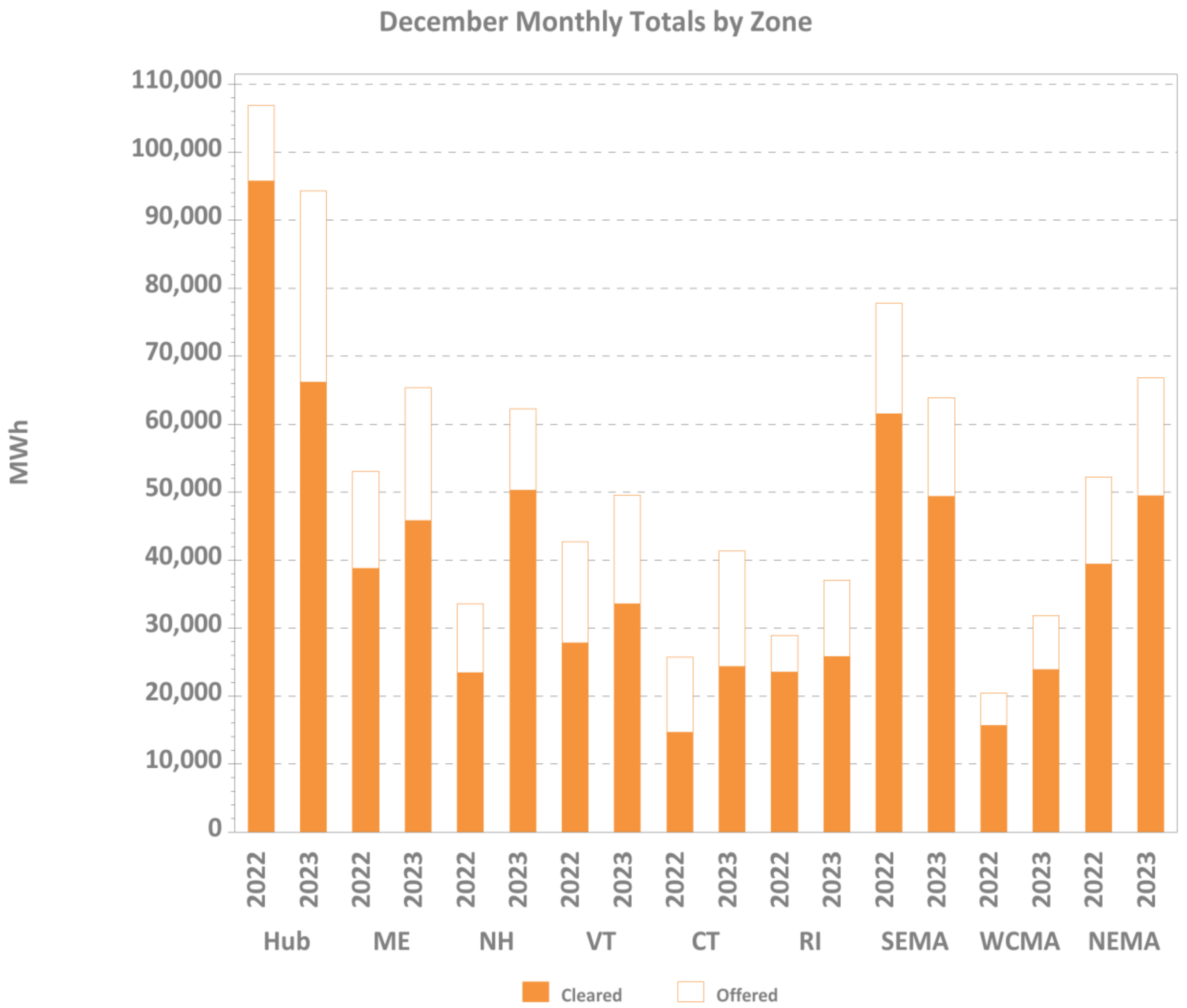
- Maximum potential Forward Reserve Market payments of $5.4M were reduced by credit reductions of $0.2M, failure-to-reserve penalties of $0.4M and failure-to-activate penalties of $1K, resulting in a net payout of $4.8M or 89% of maximum
  - Rest of System: $3.71M/4.02M (92%)
  - Southwest Connecticut: $0.04M/0.04M (99%)
  - Connecticut: $0.98M/1.26M (78%)
  - NEMA: $0.1M/0.1M (100%)
- $2.1M total Real-Time credits were reduced by $149K in Forward Reserve Energy Obligation Charges for a net of $1.9M in Real-Time Reserve payments
  - Rest of System: 161 hours, $970K
  - Southwest Connecticut: 161 hours, $540K
  - Connecticut: 161 hours, $310K
  - NEMA: 161 hours, $85K

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.

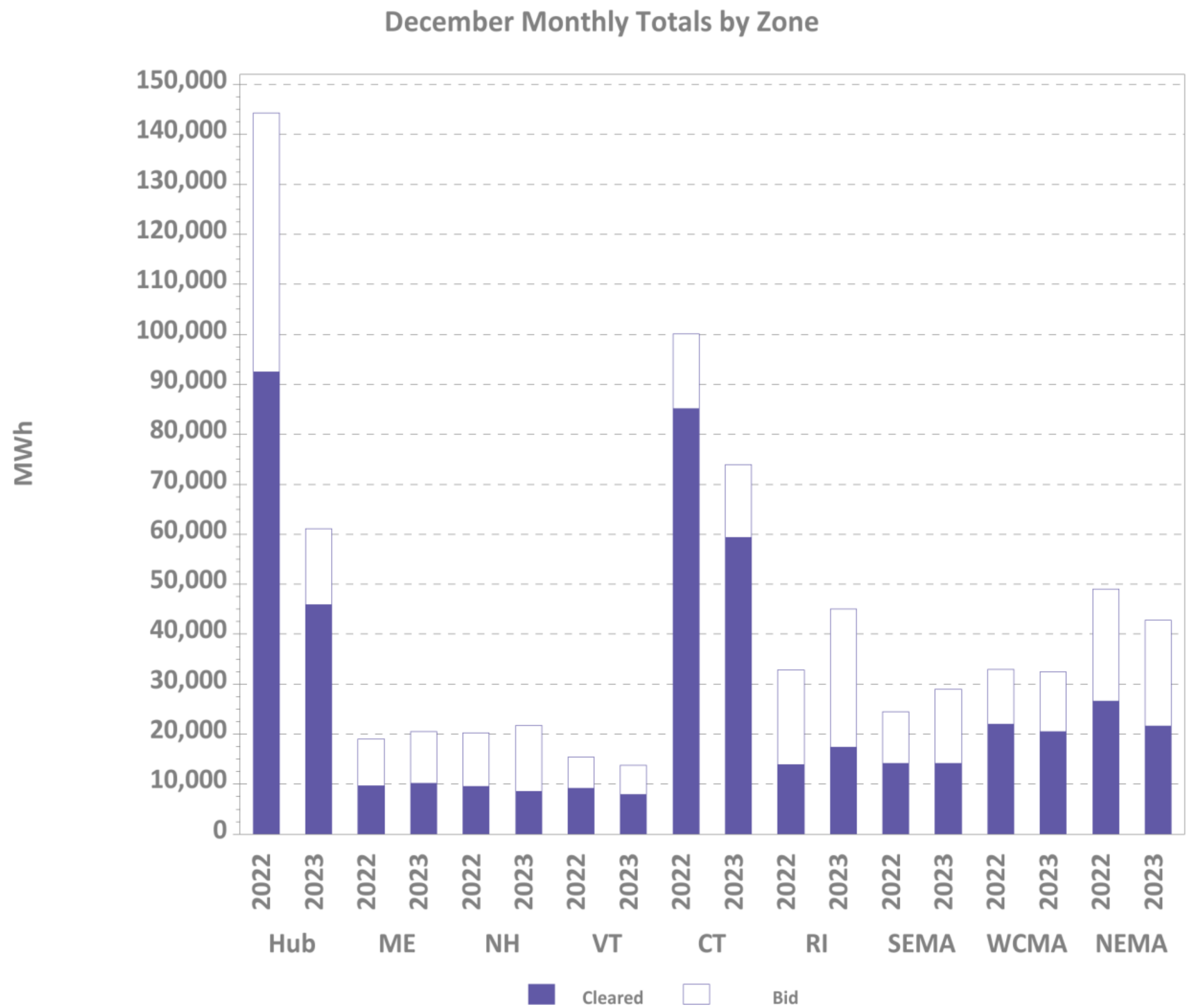
LFRM Charges to Load by Load Zone ($)



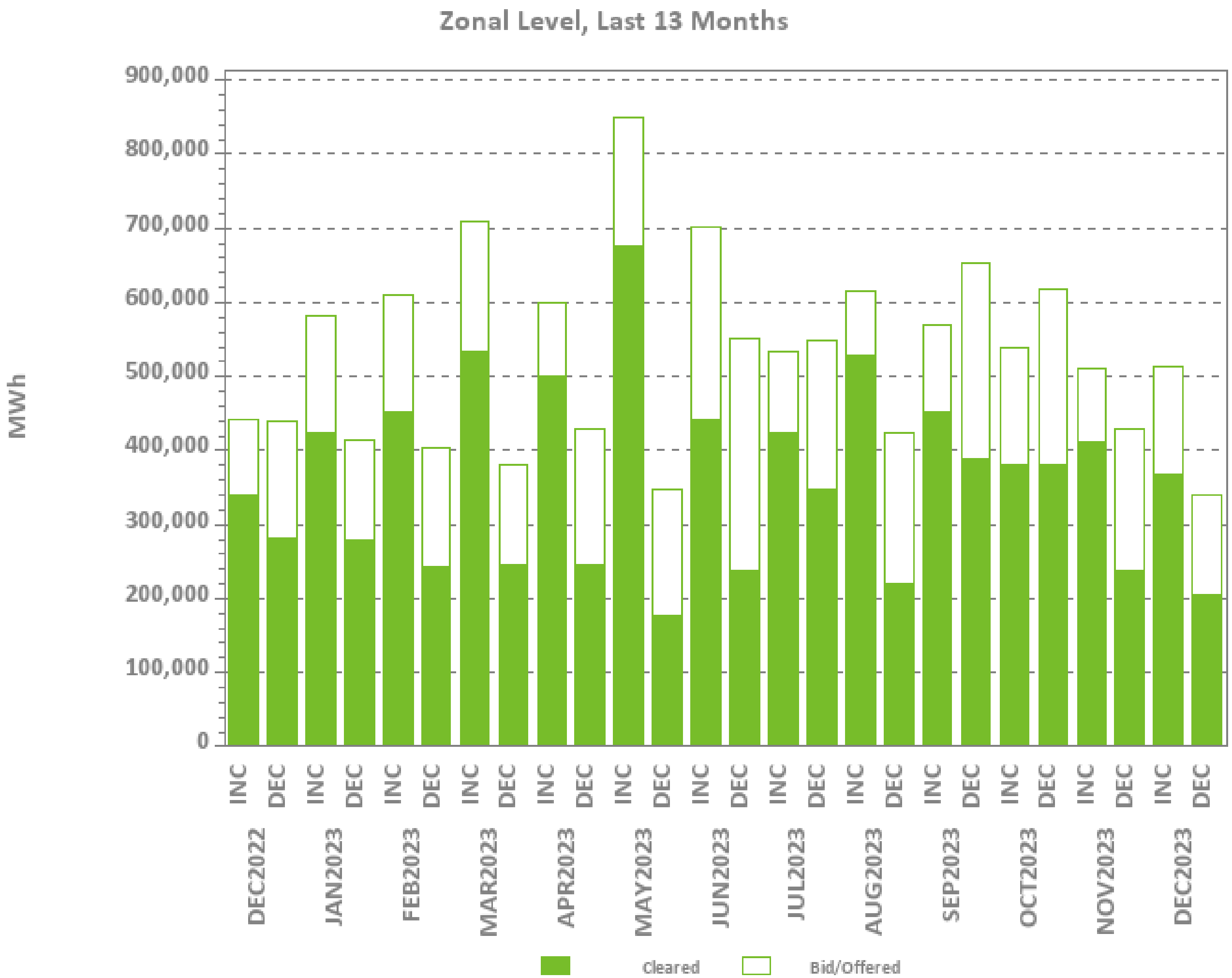
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

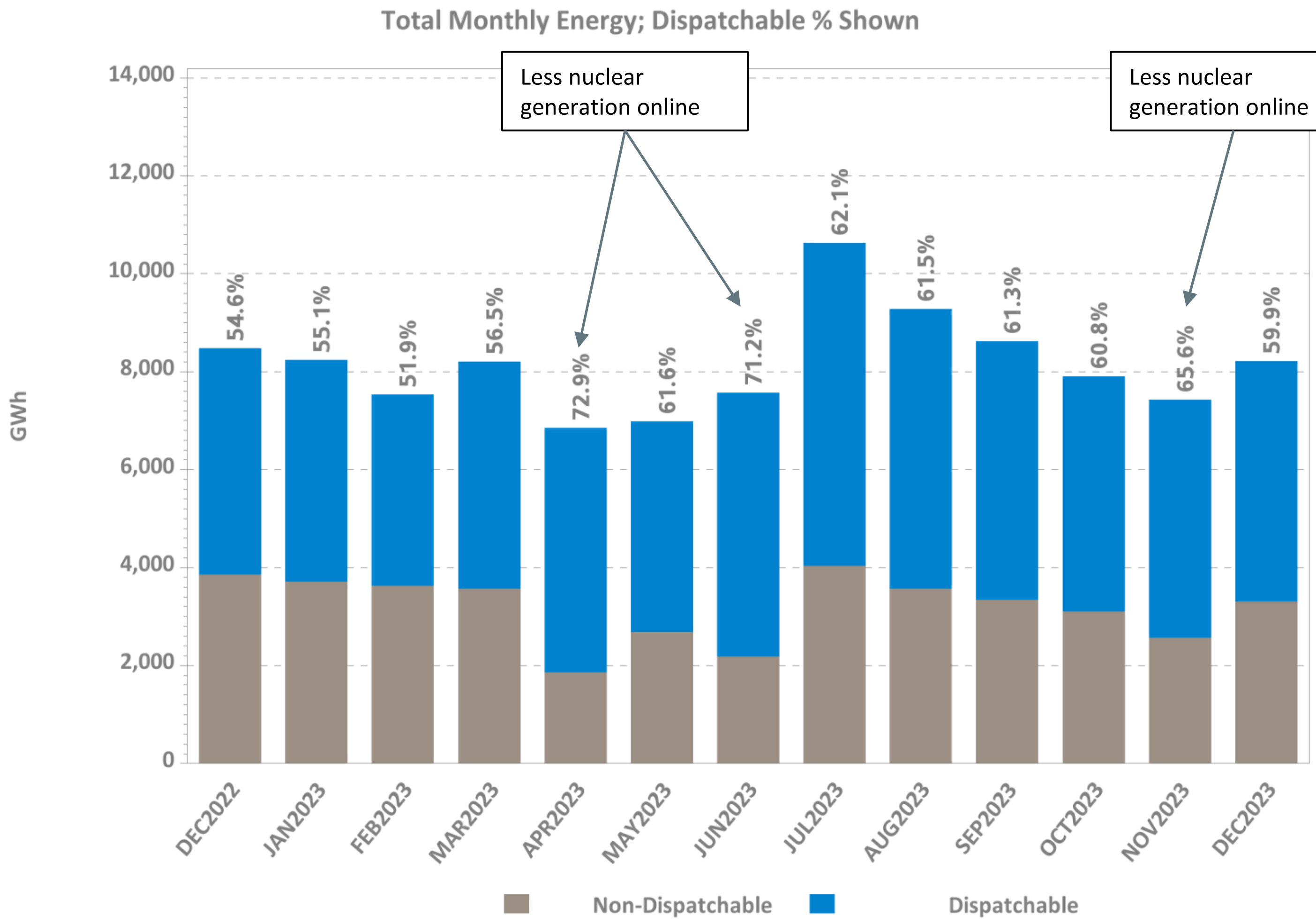


Total Increment Offers and Decrement Bids



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)

- January 18 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Scobie Pond Relay Replacement Projects - Eversource
    - Hurd State Park Corridor Rebuild - Eversource
    - NPCC Directory 1 Implementation Plan Phase 4 Update - Rhode Island Energy
    - A201/B202 230 kV Line Asset Condition Project - National Grid
  - Maine Short Circuit Solutions Study
  - Economic Studies Technical Guide - Introduction
  - 2024 Economic Study

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

2050 Transmission Study

- 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
- ISO began initial discussions on solution development and lessons learned at the 12/13/22 PAC meeting
- Additional discussion on solution development occurred at the 4/20/23 and 7/25/23 PAC meetings
- Development of transmission solutions and associated costs, including work by Electrical Consultants Inc. (ECI) on cost estimates, is now complete
- ISO presented solutions and associated costs at the 10/18/23 PAC meeting
- Draft report was posted on 11/1/23; ISO has received stakeholder comments and is preparing a written response
- Draft technical appendix was posted on 12/4/23, and stakeholder comments are requested by 1/4/24

Economic Studies

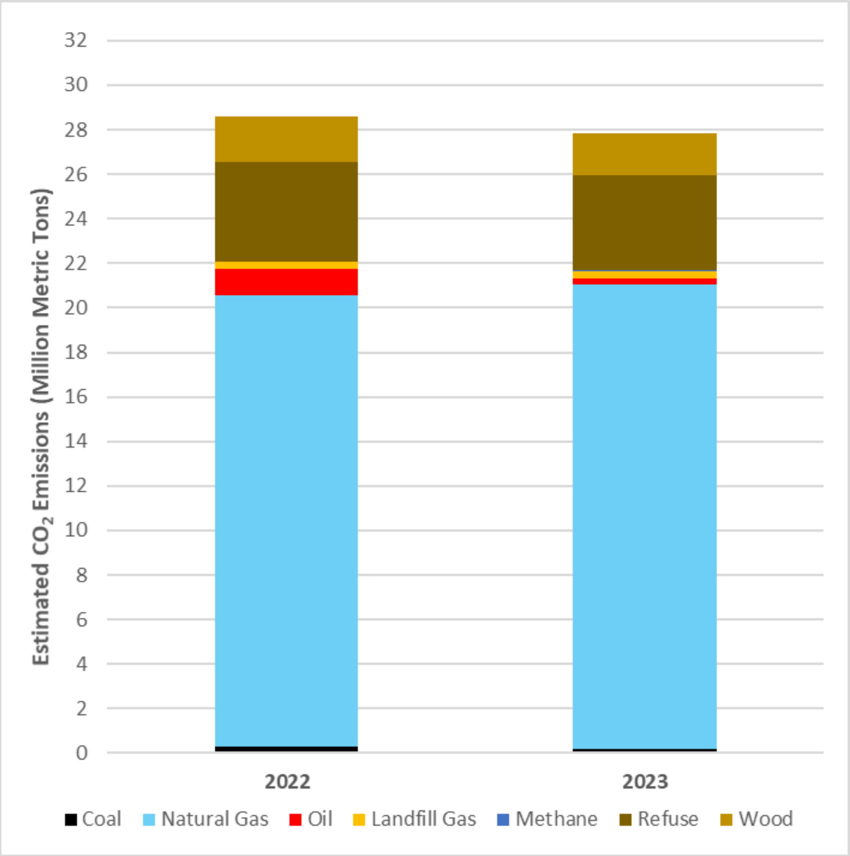
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - An effort to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented results from the Benchmark, Market Efficiency Need, and Policy scenarios.
    - As announced at the October PAC, FGRS Phase 2 will be completed via the EPCET Policy scenario. Results were presented at the December PAC
    - Further sensitivity results will be presented through Q1 2024
    - A report will be issued in Q2 2024

ISO-NE Tie Benefits Evaluation

- The ISO started the tie benefits evaluation at the October 19 PSPC meeting. The first presentation reviewed general topics such as:
  - What are tie benefits?
  - What is probabilistic planning?
  - How do other ISO/RTOs factor in external emergency assistance?
- The scope of the project includes three major components
  - Historical review of external transfers
  - Future outlook for the northeast
  - Modeling assumptions review
- The evaluation will extend into Q3 of 2024
  - Additional PSPC time will be dedicated for this topic; additional meetings have been scheduled for January 15 and March 15

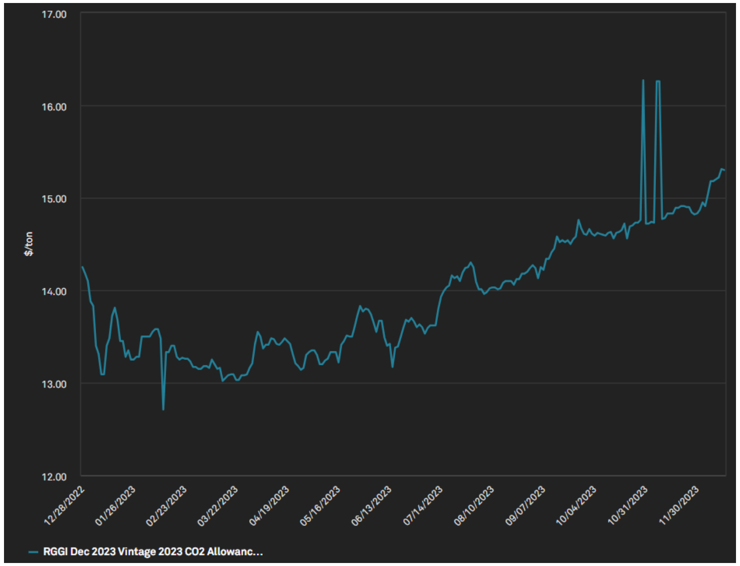
New England Power System Carbon Emissions

2022 vs. 2023 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



Data as of 12/10/2023

RGGI Allowance Prices



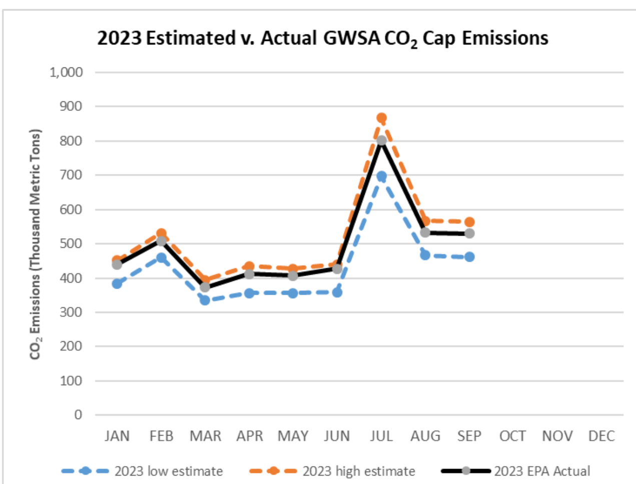
- 12/14/23: RGGI allowance spot price - $15.30
- 12/08/23: 62nd RGGI Auction
  - $411.5 million raised in 2023 for re-investment into state energy programs
  - 27,656,000 CO_2 allowances sold
  - The clearing price of $14.88 triggered the release of 5.6 million cost containment reserve allowances (CCR)

RGGI – Regional Greenhouse Gas Initiative

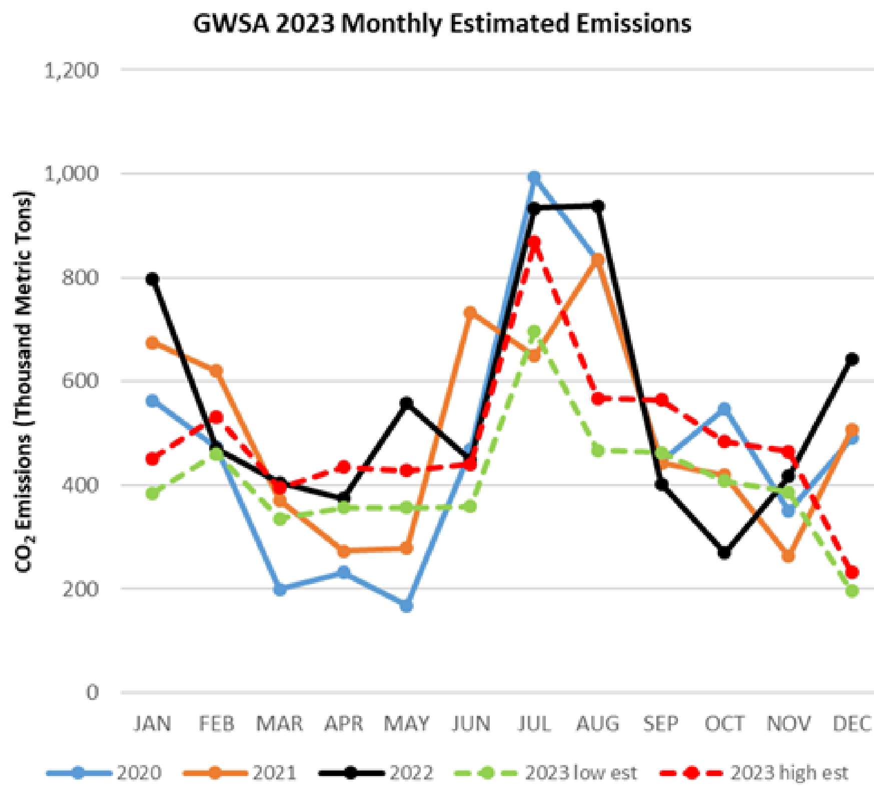
Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 12/11/23, December 2023 estimated GWSA CO_2 emissions range between **196,240** and **232,256** metric tons
  - Year-to-date 2023 estimated emissions range between **62%** and **75%** of the 2023 cap of 7.84 MMT
- According to the EPA CAMPD, the Q1-Q3 (January-September) GWSA CO_2 emissions were **4.43** MMT. The Q1-Q3 emissions were **57%** of the 2023 cap of 7.84 MMT



2020-2023 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Source: ISO-NE (estimated 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 12/18/2023

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*	Apr-24	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 12/18/2023

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	Mar-25	3

Greater Boston Projects, cont.

Status as of 12/18/2023

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 12/18/2023

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	Apr-24	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 12/18/2023

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 12/18/2023

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 12/18/2023

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	Mar-27	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	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-25	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 12/18/2023

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	May-24	3
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	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-25	2

SEMA/RI Reliability Projects, cont.

Status as of 12/18/2023

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 12/18/2023

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 12/18/2023

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	3
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Dec-22	4
1851	Upgrade Card 115 kV to BPS standards	Dec-22	4
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Feb-23	4
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Nov-23	4
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	4

Eastern CT Reliability Projects, cont.

Status as of 12/18/2023

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	Jun-23	4
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Feb-23	4
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Feb-23	4
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Sept-22	4
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Feb-23	4
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 12/18/2023

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 +55/-29 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-23	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)	Feb-23	4
1904	Convert 69 kV equipment at Buddington to 115 kV to facilitate the conversion of the 400-2 line to 115 kV	Dec-23	3

New Hampshire Solution Projects

Status as of 12/18/2023

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Sep-24	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	May-24	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Jun-24	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	4

Upper Maine Solution Projects

Status as of 12/18/2023

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	3
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	Jul-28	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Jul-28	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	3

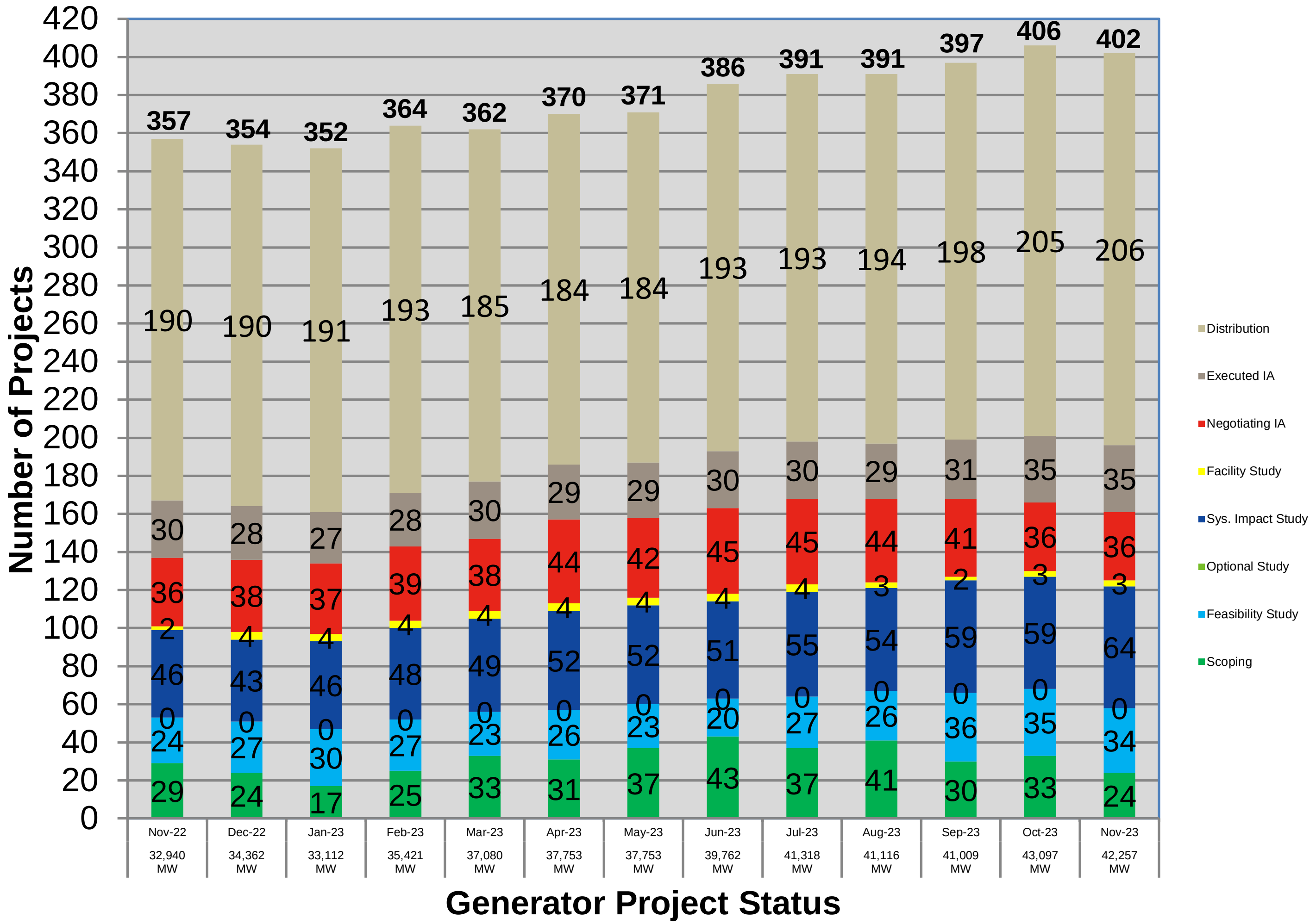
Upper Maine Solution Projects, cont.

Status as of 12/18/2023

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	3
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-24	2

Status of Tariff Studies as of December 1, 2023



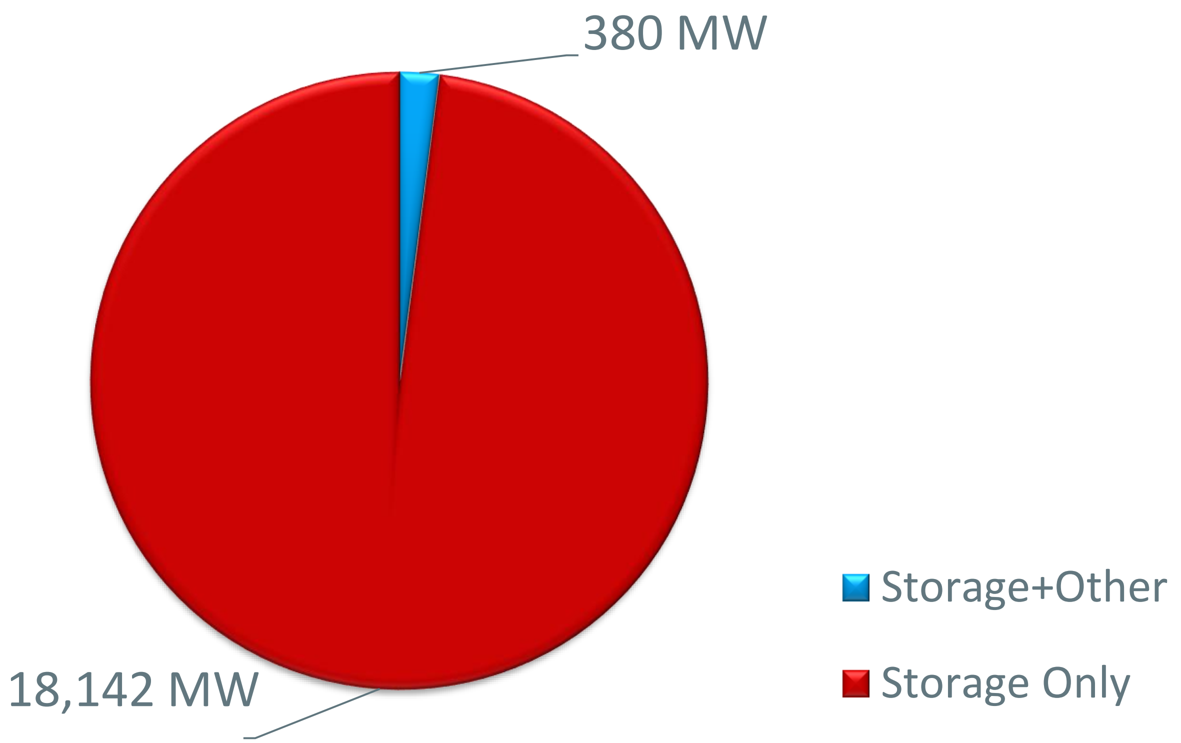
8 ETUs in Scoping, 6 in FS, 1 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 1 in SIS

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

What is in the Queue (as of December 1, 2023)

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



OPERABLE CAPACITY ANALYSIS

Winter 2024 Analysis

Winter 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2024[2] CSO (MW)	Jan. - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,659	31,742
Active Demand Capacity Resource (+) [5]	344	346
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	869	869
Non Commercial Capacity (+)	20	20
Non Gas-fired Planned Outage MW (-)	572	1,192
Gas Generator Outages MW (-)	196	414
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,387	3,555
Net Capacity (NET OPCAP SUPPLY MW)	22,937	25,016
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,269	20,269
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,574	22,574
Operable Capacity Margin	363	2,442

[1]Operable Capacity is based on data as of **December 27, 2023** 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 **December 27, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 13, 2024.**

[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.

Winter 2024 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2024[2] CSO (MW)	Jan. - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,659	31,742
Active Demand Capacity Resource (+) [5]	344	346
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	869	869
Non Commercial Capacity (+)	20	20
Non Gas-fired Planned Outage MW (-)	572	1,192
Gas Generator Outages MW (-)	196	414
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,135	4,414
Net Capacity (NET OPCAP SUPPLY MW)	22,189	24,157
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,032	21,032
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,337	23,337
Operable Capacity Margin	-1,148	820

[1]Operable Capacity is based on data as of **December 27, 2023** 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 **December 27, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 13, 2024.**

[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.

Winter 2024 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

December 27, 2023 - 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 in January through March.

Report created: 12/27/2023

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
1/13/2024	28659	344	869	20	572	196	2800	3387	22937	20269	2305	22574	363	Y	Winter 2023/2024
1/20/2024	28659	344	869	20	238	197	2800	2937	23720	20269	2305	22574	1146	N	Winter 2023/2024
1/27/2024	28649	346	869	20	314	191	3100	2644	23635	20049	2305	22354	1281	N	Winter 2023/2024
2/3/2024	28649	346	869	20	1365	93	3100	2443	22883	19784	2305	22089	794	N	Winter 2023/2024
2/10/2024	28649	346	869	17	1358	48	3100	2189	23186	19755	2305	22060	1126	N	Winter 2023/2024
2/17/2024	28649	346	869	17	157	45	3100	1744	24835	19495	2305	21800	3035	N	Winter 2023/2024
2/24/2024	28649	346	869	17	297	141	3100	1348	24995	18516	2305	20821	4174	N	Winter 2023/2024
3/2/2024	28349	512	958	199	1857	113	2200	301	25547	18170	2305	20475	5072	N	Winter 2023/2024
3/9/2024	28349	512	958	199	1062	660	2200	0	26096	17976	2305	20281	5815	N	Winter 2023/2024
3/16/2024	28349	512	958	199	1081	566	2200	0	26171	17614	2305	19919	6252	N	Winter 2023/2024
3/23/2024	28349	512	958	199	1647	1283	2200	0	24888	17054	2305	19359	5529	N	Winter 2023/2024
3/30/2024	28247	512	958	199	1780	2091	2700	0	23345	16379	2305	18684	4661	N	Winter 2023/2024

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 2023 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.

Winter 2024 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

December 27, 2023 - 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 in January through March.

Report created: 12/27/2023

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
1/13/2024	28659	344	869	20	572	196	2800	4135	22189	21032	2305	23337	-1148	Y	Winter 2023/2024
1/20/2024	28659	344	869	20	238	197	2800	3835	22822	21032	2305	23337	-515	N	Winter 2023/2024
1/27/2024	28649	346	869	20	314	191	3100	3841	22438	20804	2305	23109	-671	N	Winter 2023/2024
2/3/2024	28649	346	869	20	1365	93	3100	3490	21836	20530	2305	22835	-999	N	Winter 2023/2024
2/10/2024	28649	346	869	17	1358	48	3100	3236	22139	20500	2305	22805	-666	N	Winter 2023/2024
2/17/2024	28649	346	869	17	157	45	3100	2642	23937	20231	2305	22536	1401	N	Winter 2023/2024
2/24/2024	28649	346	869	17	297	141	3100	2096	24247	19218	2305	21523	2724	N	Winter 2023/2024
3/2/2024	28349	512	958	199	1857	113	2200	1198	24650	18860	2305	21165	3485	N	Winter 2023/2024
3/9/2024	28349	512	958	199	1062	399	2200	807	25550	18659	2305	20964	4586	N	Winter 2023/2024
3/16/2024	28349	512	958	199	1081	566	2200	0	26171	18285	2305	20590	5581	N	Winter 2023/2024
3/23/2024	28349	512	958	199	1647	1283	2200	0	24888	17705	2305	20010	4878	N	Winter 2023/2024
3/30/2024	28247	512	958	199	1780	2091	2700	0	23345	17014	2305	19319	4026	N	Winter 2023/2024

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).
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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.
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9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
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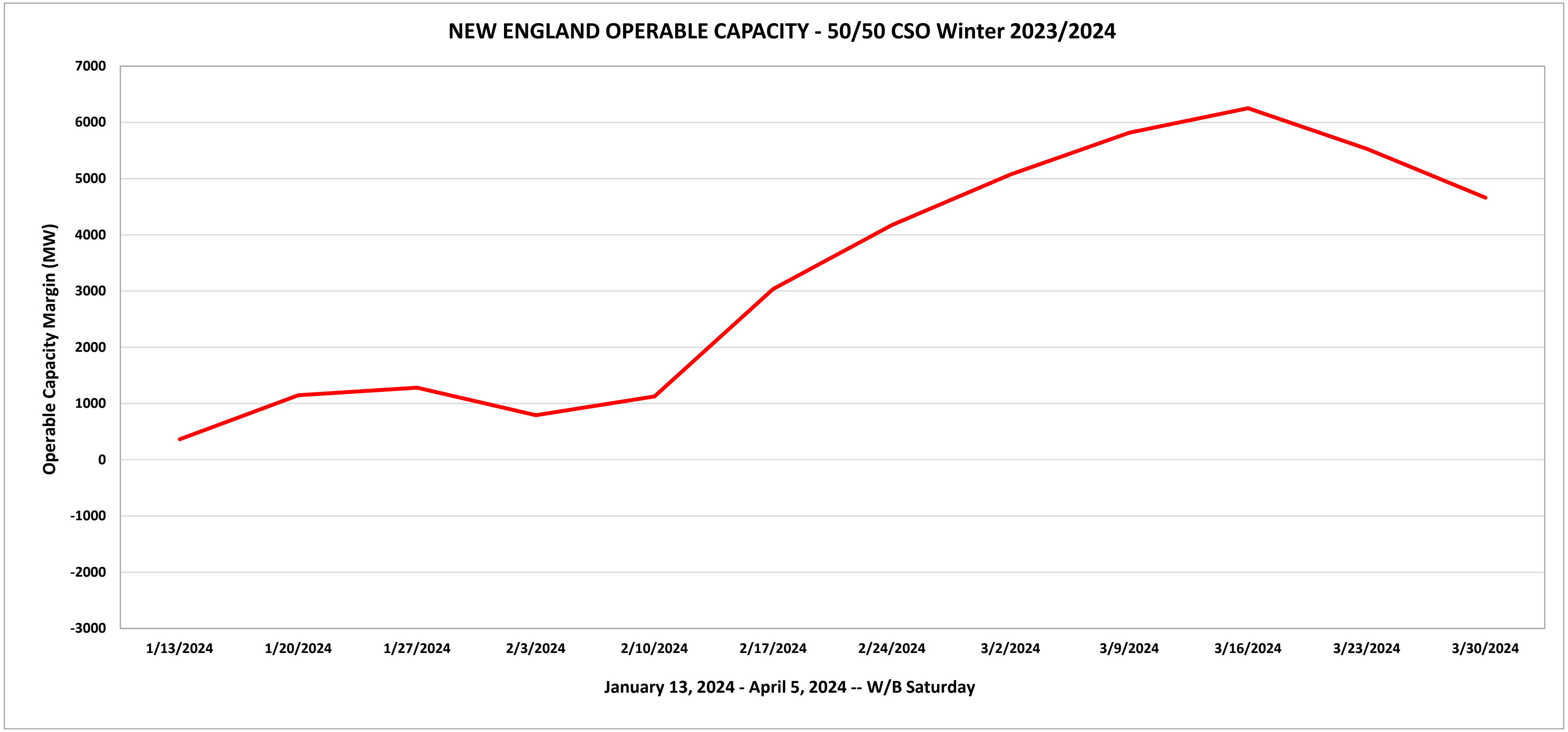
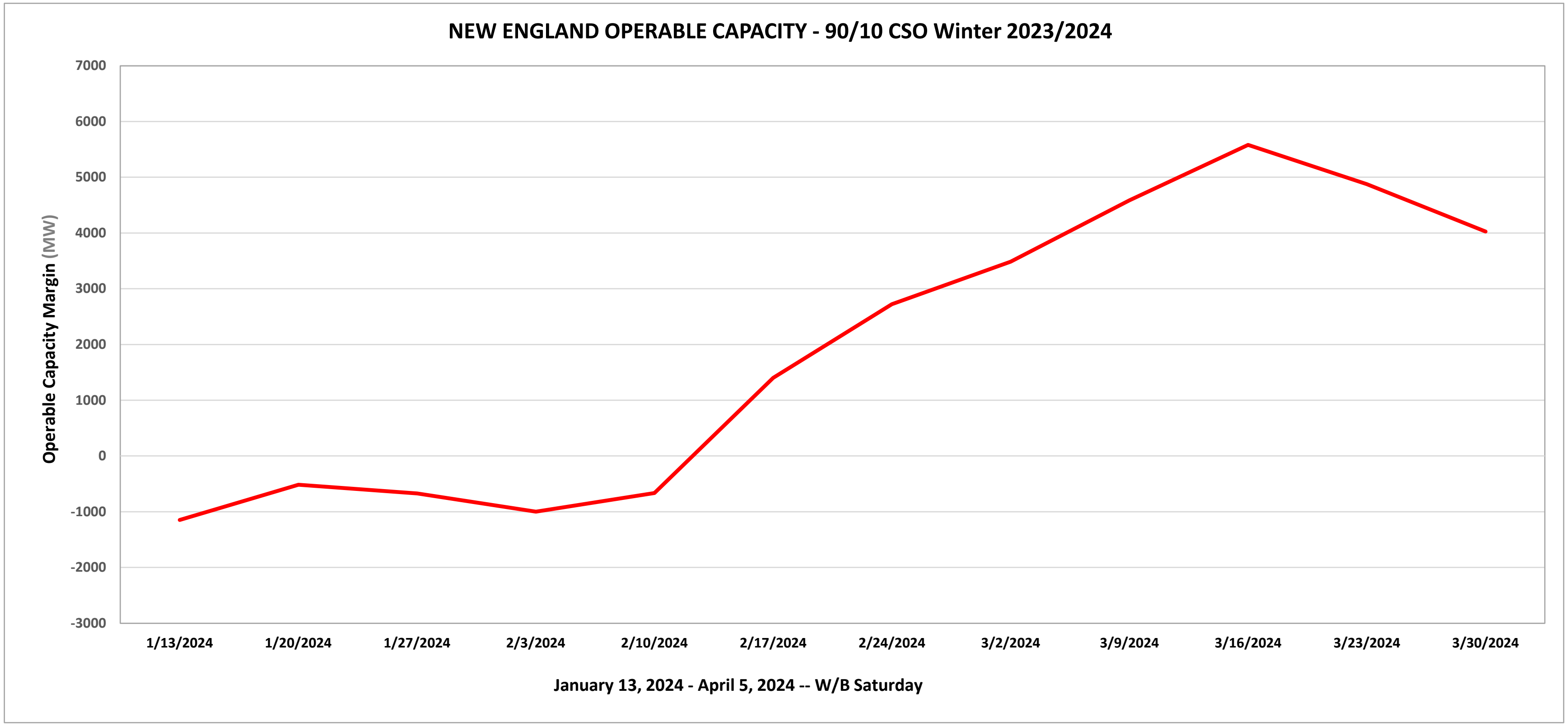
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable 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**

Winter 2024 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2024 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