NEPOOL Participants Committee Report

October 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

Highlights

Data is through September 27th, unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: August 2023 Energy Market value totaled $310M
  - September 2023 Energy market value was $324M, up $14M from August 2023 and down $368M from September 2022
  - September natural gas prices over the period were 18% higher than August average values
    - Average RT Hub Locational Marginal Prices ($33.69/MWh) over the period were 17% higher than August averages
      - DA Hub: $30.92/MWh
    - Average September 2023 natural gas prices and RT Hub LMPs over the period were down 76% and 45%, respectively, from September of last year
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.6% during September, up from 99.6% during August
      - The minimum value for the month was 94.9% on Tuesday, September 19th

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

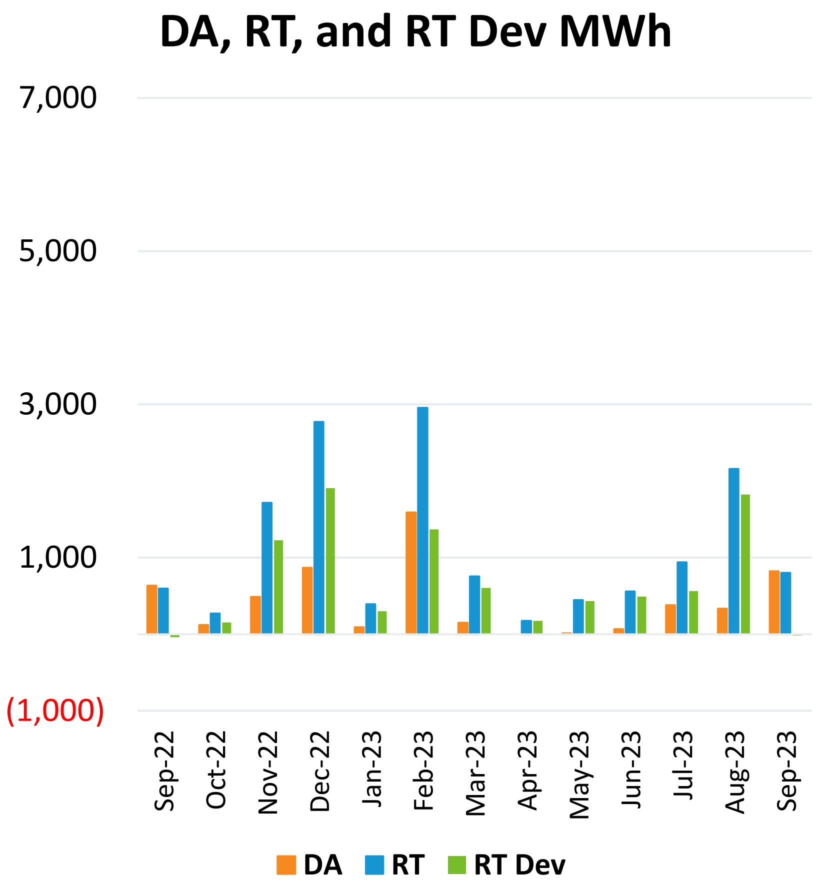
Underlying natural gas data furnished by: ICE Global markets in clear view

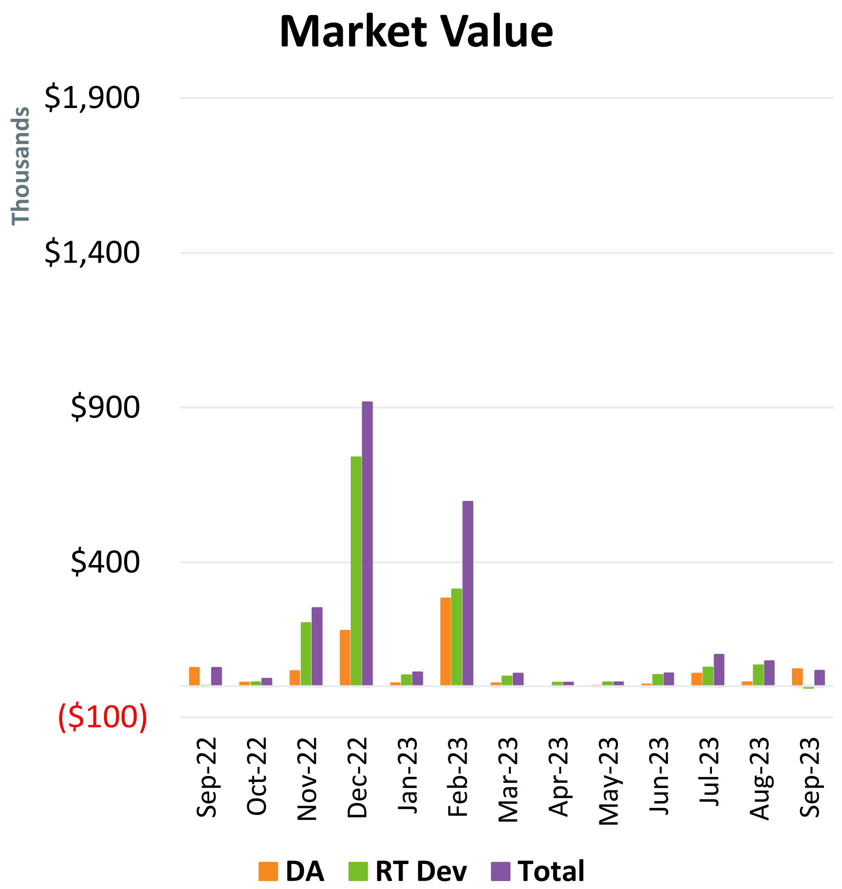
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - September 2023 NCPC payments totaled $3.4M over the period, up $1.2M from August 2023 and up $1.3M from September 2022
    - First Contingency payments totaled $3.3M, up $1.5M from August
      - $3.2M paid to internal resources, up $1.5M from August
        - » $160K charged to DALO, $2.3M to RT Deviations, $751K to RTLO*
      - $82K paid to resources at external locations, down $49K from August
        - » All charged to RT Deviations
    - Distribution payments totaled $67K, down $195K from August
      - Local protection for Martha's Vineyard early in the month
    - Second Contingency and Voltage payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 1.0%
    - Elevated NCPC due to stressed conditions early in the month; Relatively low Energy Market Value (low natural gas and DA energy pricing)

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $300K; Rapid Response Pricing (RRP) Opportunity Cost - $451K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 15 (2024-2025)
  - Second annual reconfiguration auction (ARA2) was held on August 1-3, and results were posted on August 24
  - At the September 21 PSPC meeting, ISO presented results for the CCP 15 ARA 3 tie benefits study
- CCP 16 (2025-2026)
  - First annual reconfiguration auction (ARA1) was held on June 1-5, and results were posted on July 3
- CCP 17 (2026-2027)
  - 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

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
  - New Capacity Qualification Package (NCQP) Submission Window closed on June 28, and review of the NCQPs is ongoing
  - ICR and related values were approved at the September 19 RC meeting

Highlights

- FCA 18 ICR and related values were approved by stakeholders at the September 19 RC meeting
- RSP Public Meeting will be held on November 1 and will be concurrent with the ISO Open Board Meeting
  - Presentation from Debra Lew, Associate Director, Energy Systems Integration Group
- Qualified Transmission Project Sponsor (QTPS)
  - 27 companies have achieved QTPS status
    - PPL Translink, Inc. was recently qualified
- The 2024 forecast cycle was initiated at the September 22 Load Forecast Committee (LFC) meeting
- The next LFC meeting will be held on November 13

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.8°F) Max: 93°F, Min: 49°F Precipitation: 3.75” – Above Normal Normal: 3.56”	Hartford	Temperature: Above Normal (2.1°F) Max: 95°F, Min: 43°F Precipitation: 12.18” - Above Normal Normal: 4.39”

Peak Load:	23,521 MW	September 7, 2023	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	09/06/2023 17:29	09/06/2023 22:00	Projected Capacity Deficiency
M/LCC 2	09/15/2023 11:39	09/17/2023 11:48	Severe Weather

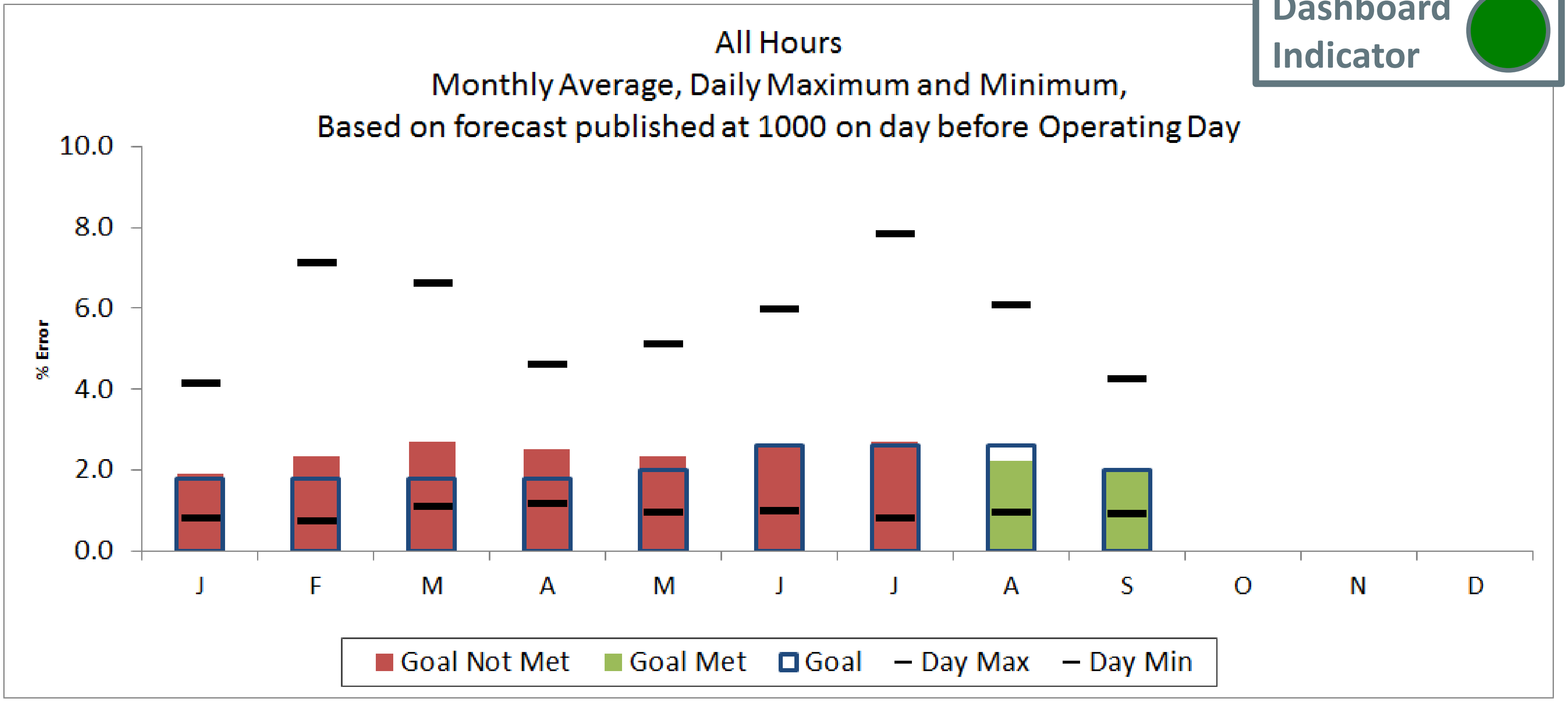
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
09/02/2023	NYISO	1258
09/06/2023	IESO	850
09/07/2023	IESO	900
09/09/2023	NYISO	563

2023 System Operations - Load Forecast Accuracy

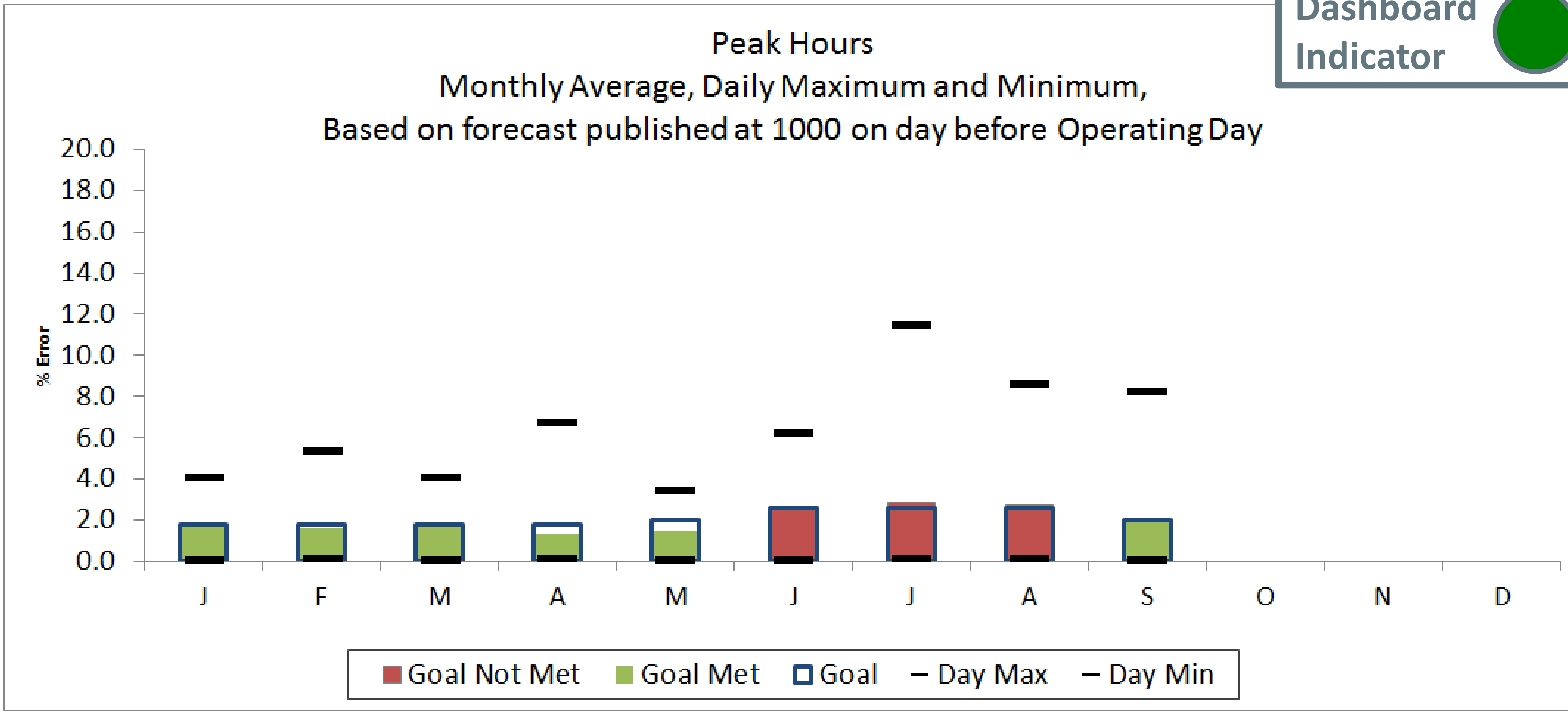
Dashboard Indicator



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				7.82
Day Min	0.80	0.74	1.08	1.17	0.96	0.97	0.79	0.95	0.91				0.74
MAPE	1.91	2.34	2.70	2.52	2.36	2.63	2.70	2.23	1.94				2.37
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

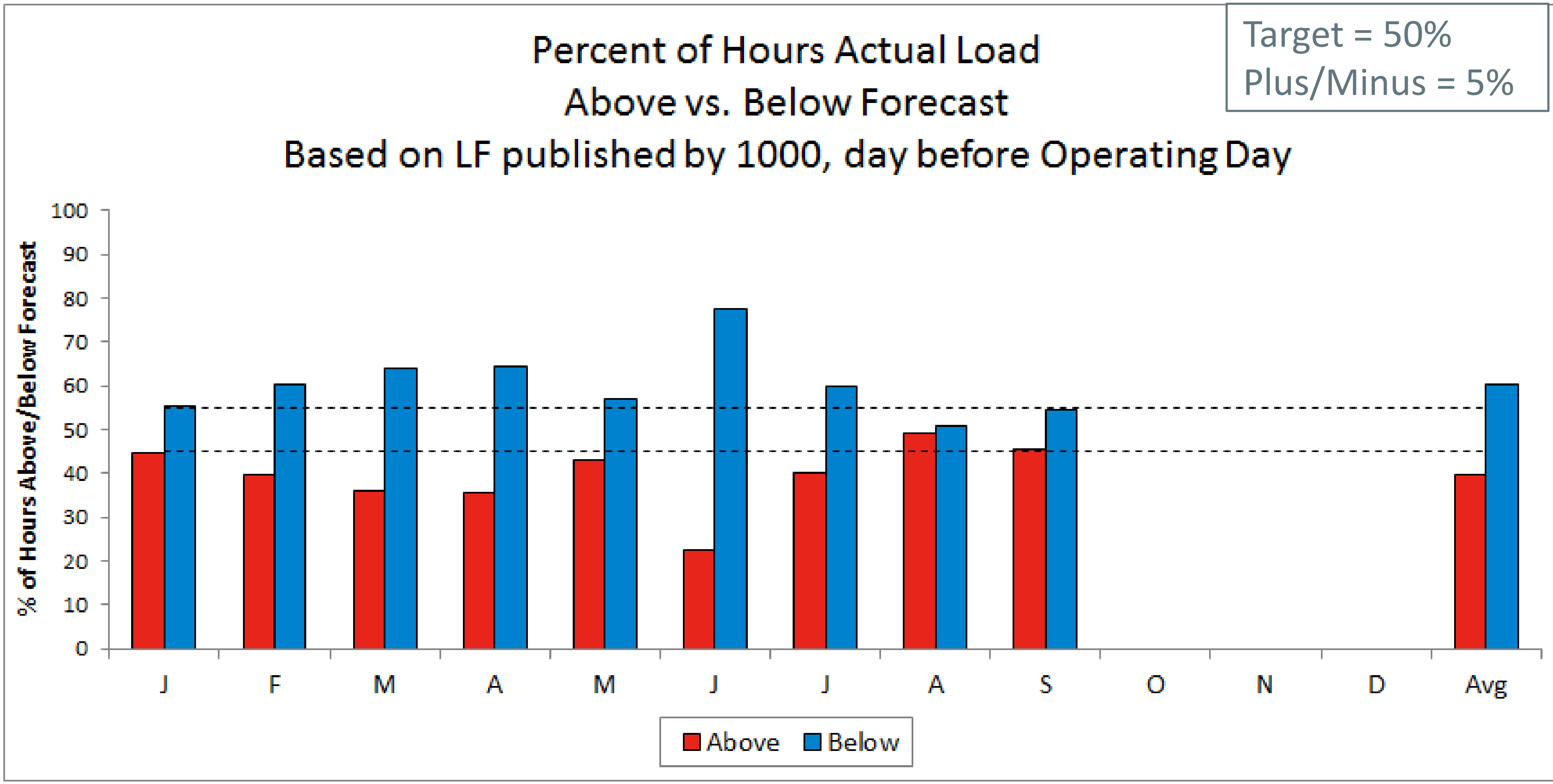
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



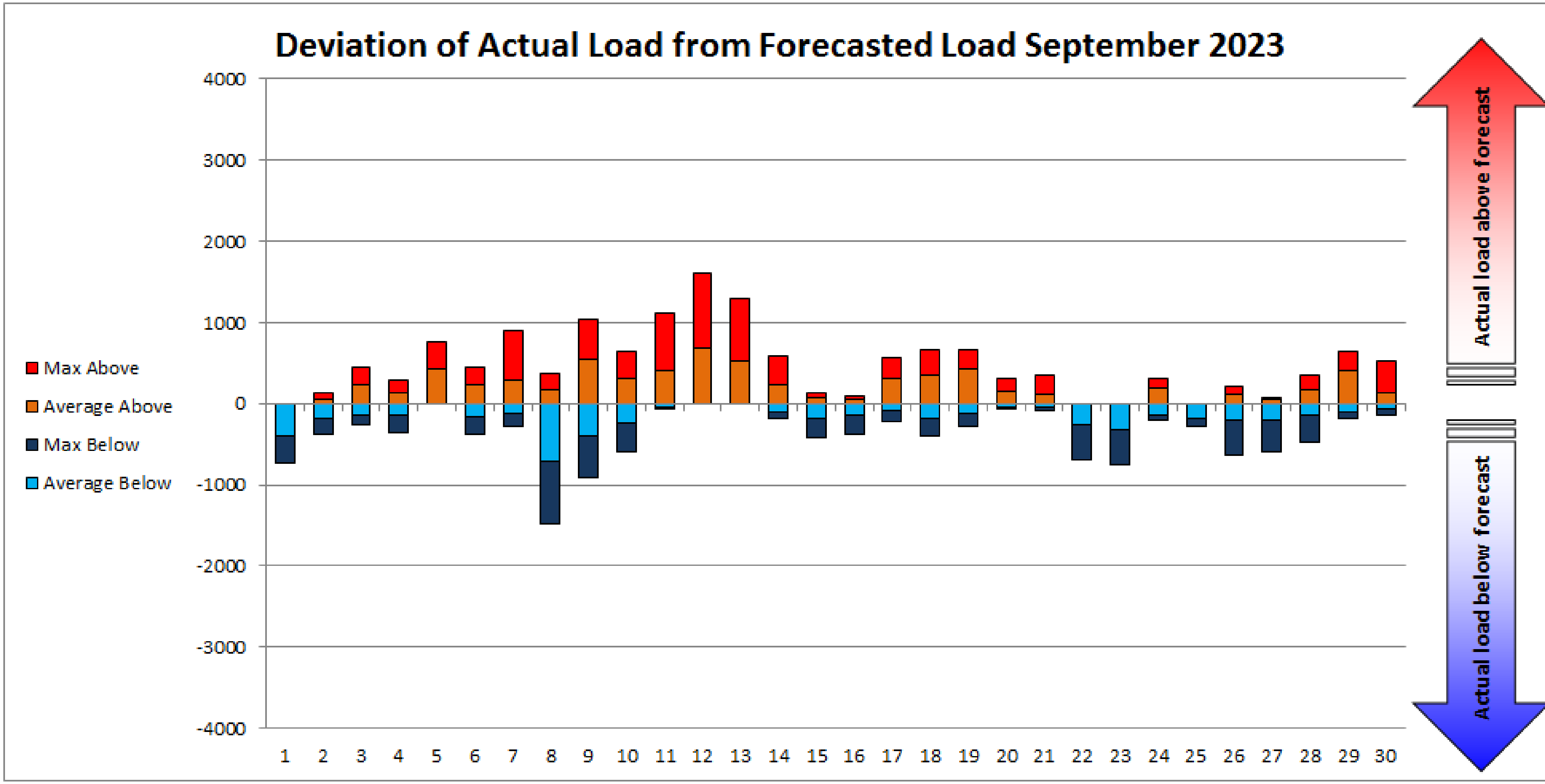
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06	6.68	3.43	6.21	11.40	8.59	8.17				11.40
Day Min	0.01	0.08	0.06	0.11	0.03	0.04	0.08	0.14	0.01				0.01
MAPE	1.70	1.64	1.72	1.33	1.47	2.65	2.87	2.72	1.97				2.01
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

2023 System Operations - Load Forecast Accuracy cont.

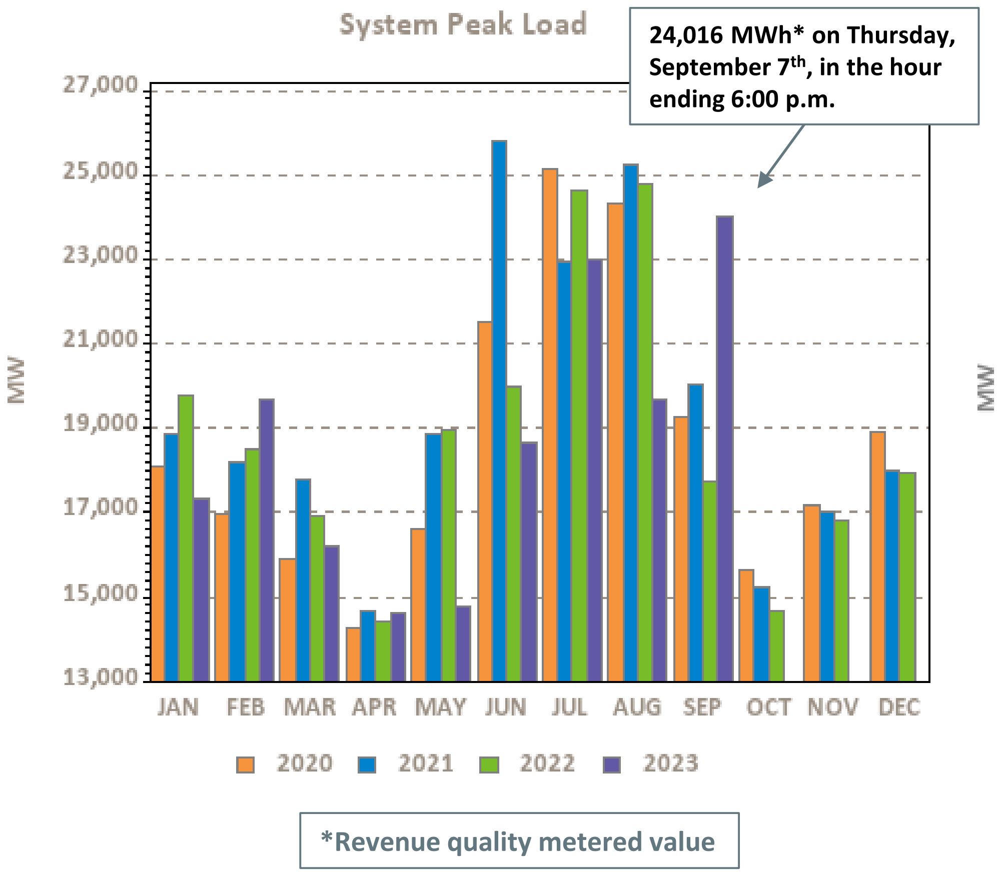


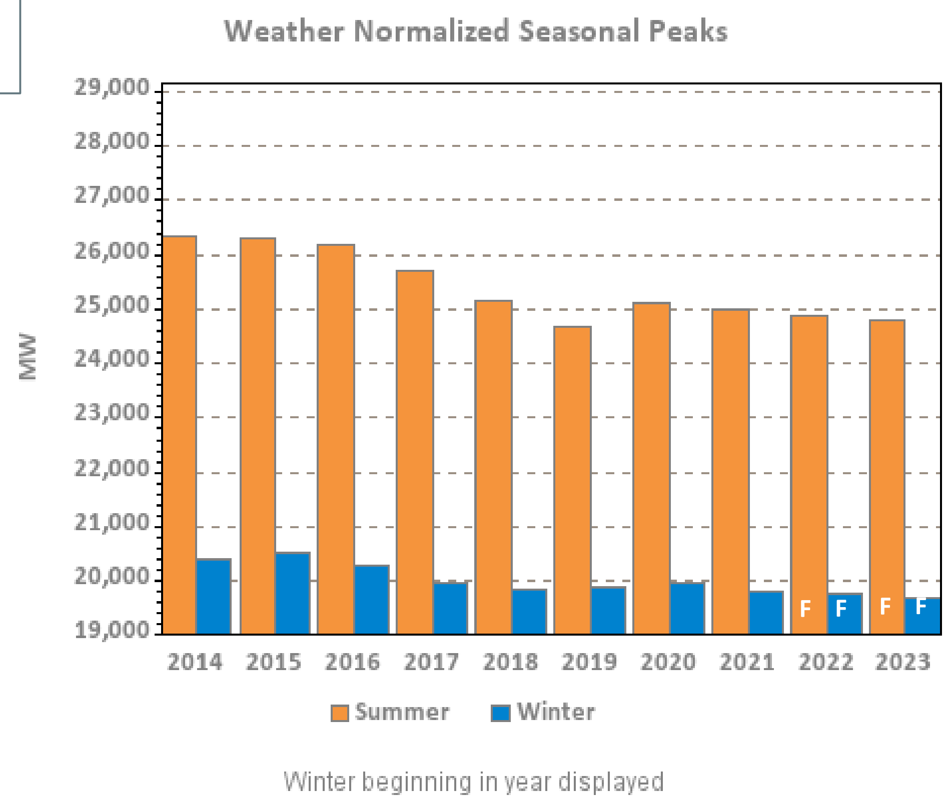
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2	35.7	43	22.6	40.2	49.2	45.6				40
Below %	55.4	60.3	63.8	64.3	57	77.4	59.8	50.8	54.4				60
Avg Above	235.7	228	172.9	194.5	183.5	120	194.8	228.5	226				236
Avg Below	-197.3	-248.9	-328.3	-245.0	-200.1	-350.3	-388.6	-215.1	-169.7				-389
Avg All	-10	-28	-142	-74	-17	-236	-170	-6	20				-74

2023 System Operations - Load Forecast Accuracy cont.



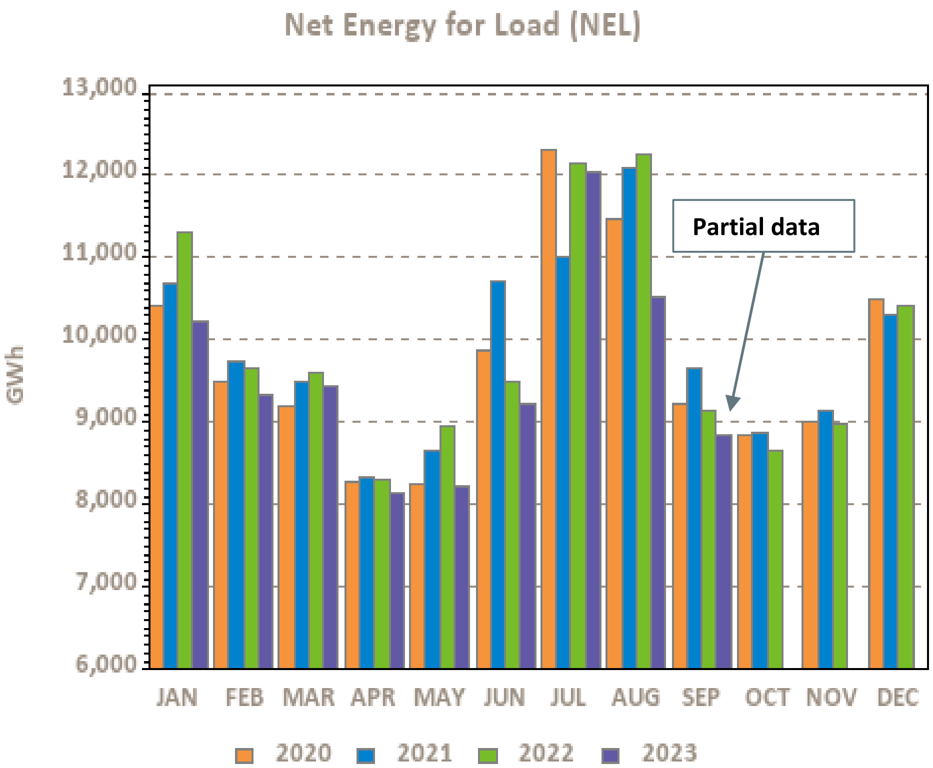
Monthly Peak Loads and Weather Normalized Seasonal Peak History



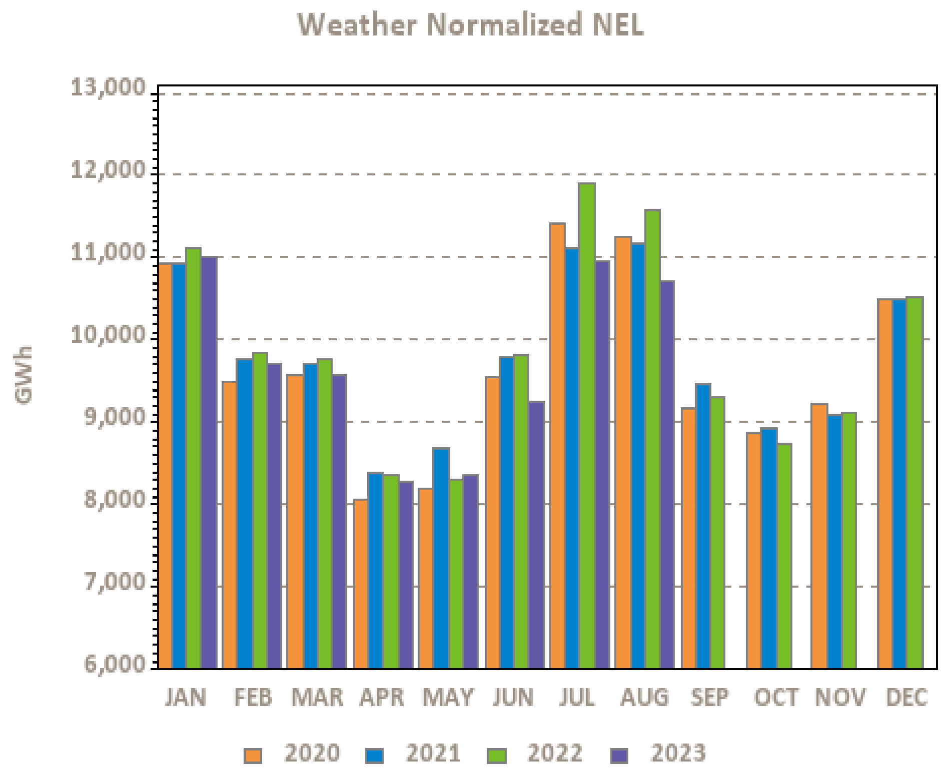


F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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



Ann Tot (TWh): 116.9 118.8 118.9 86.0

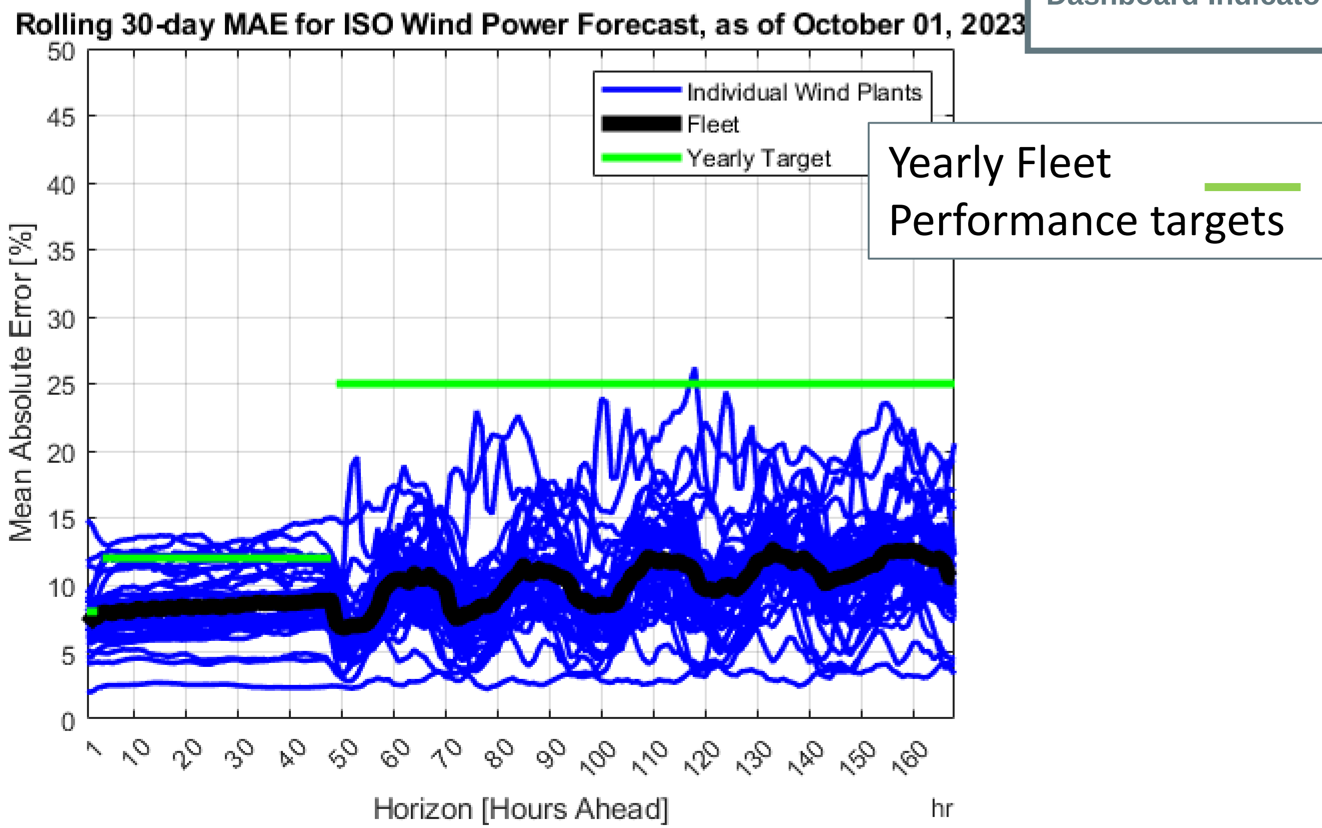


Ann Tot (TWh): 116.3 117.6 118.4 77.8

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

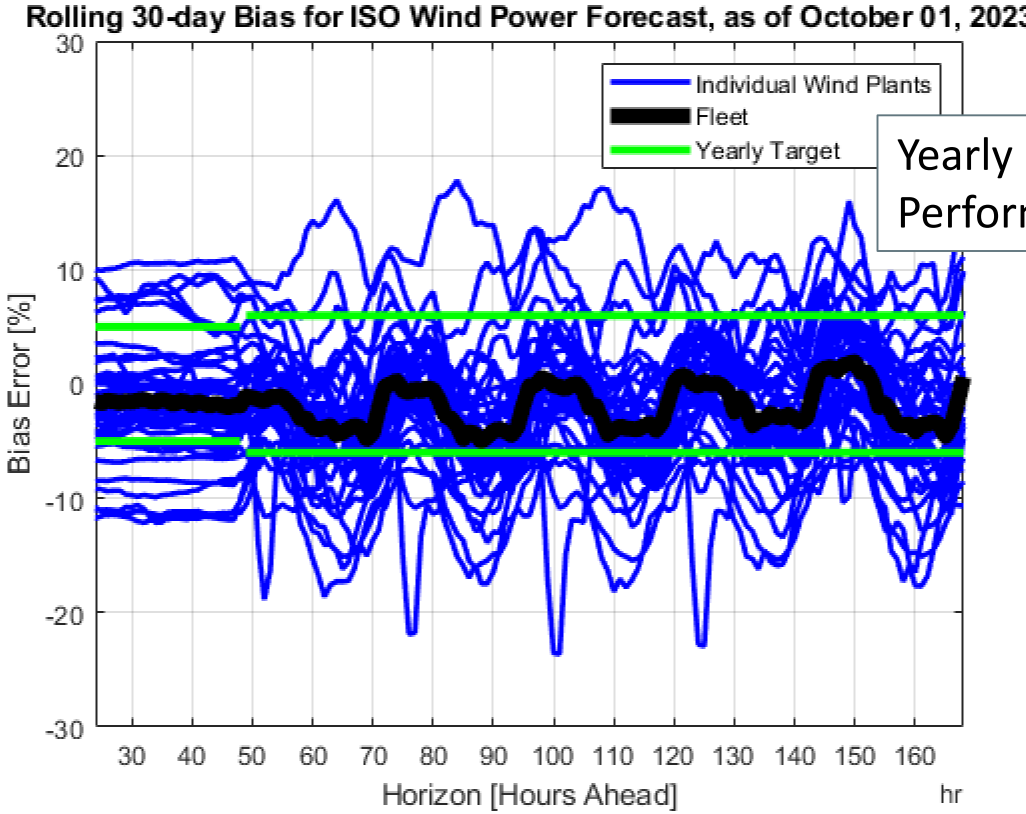
Dashboard Indicator



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

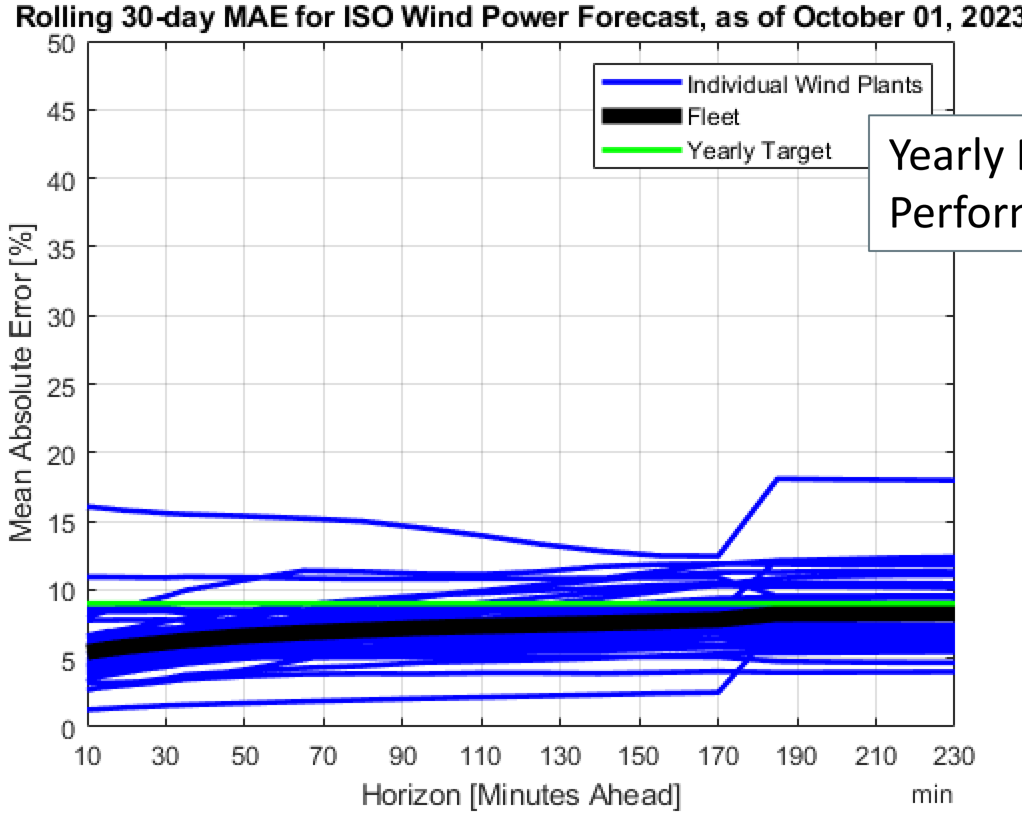


Yearly Fleet Performance targets

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

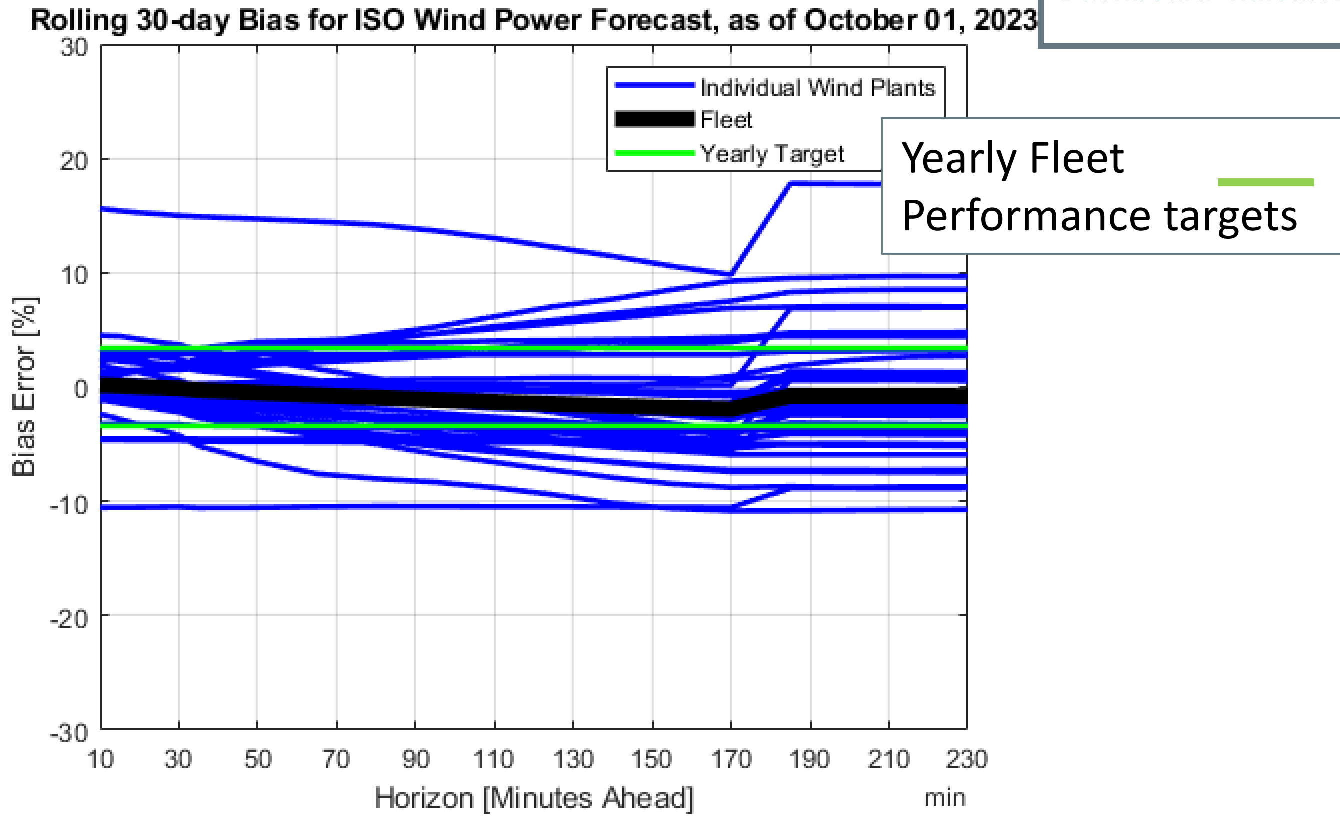


Yearly Fleet Performance targets

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 forecast compares well with industry standards, and monthly MAE is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator



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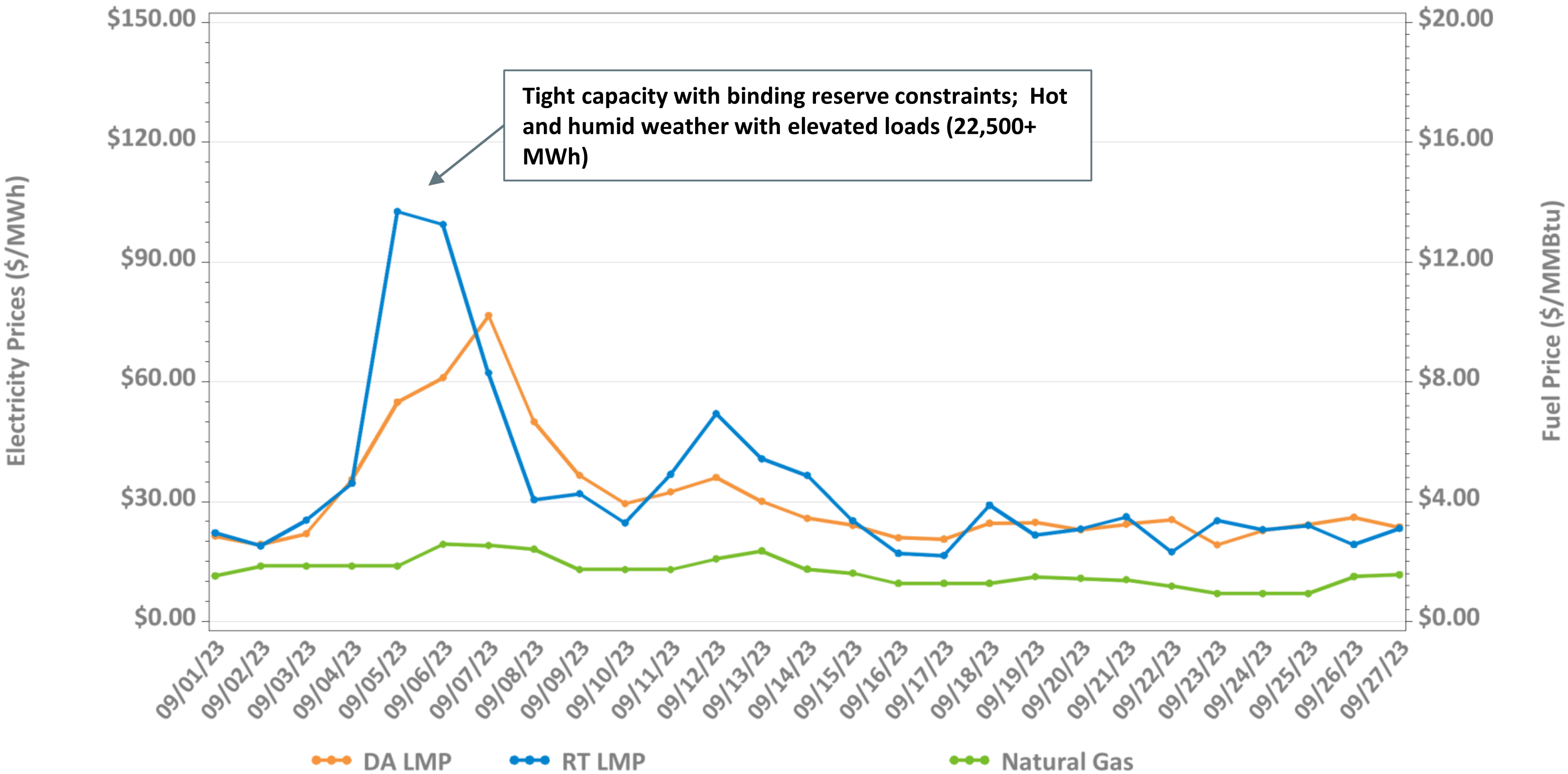
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: September 1-27, 2023



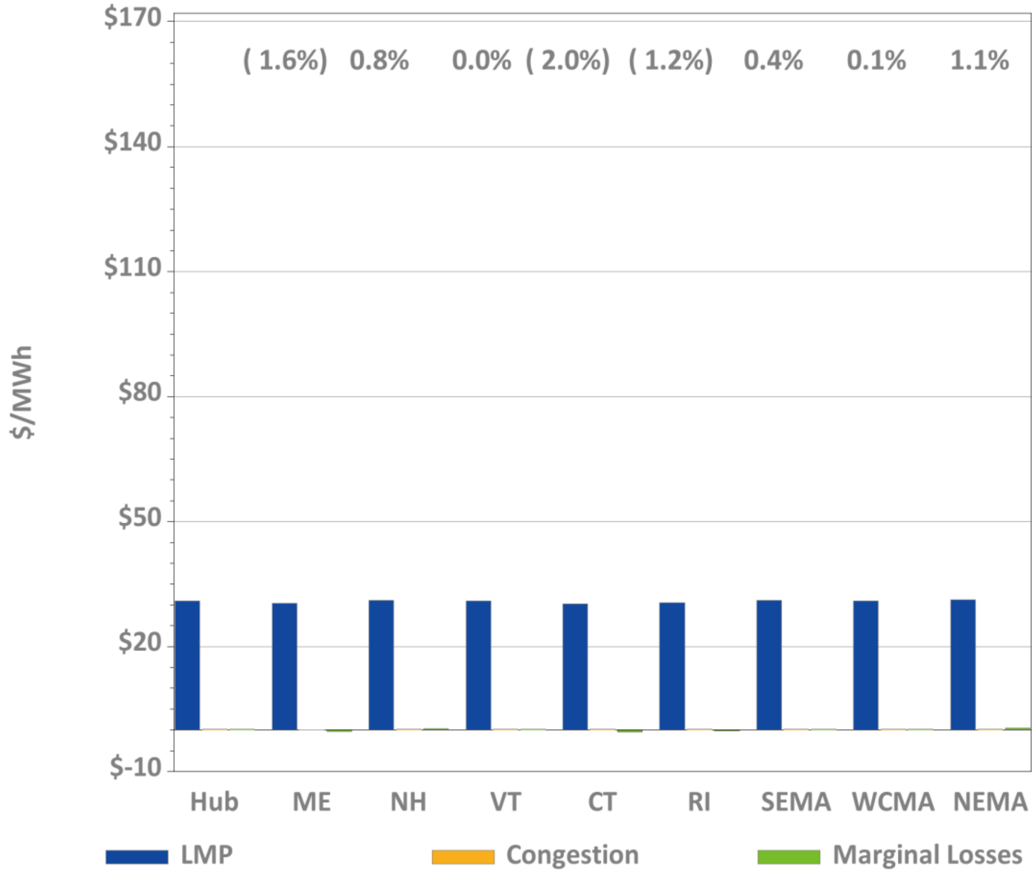
Underlying natural gas data furnished by:

ICE Global markets in clear view

*Revenue quality metered values

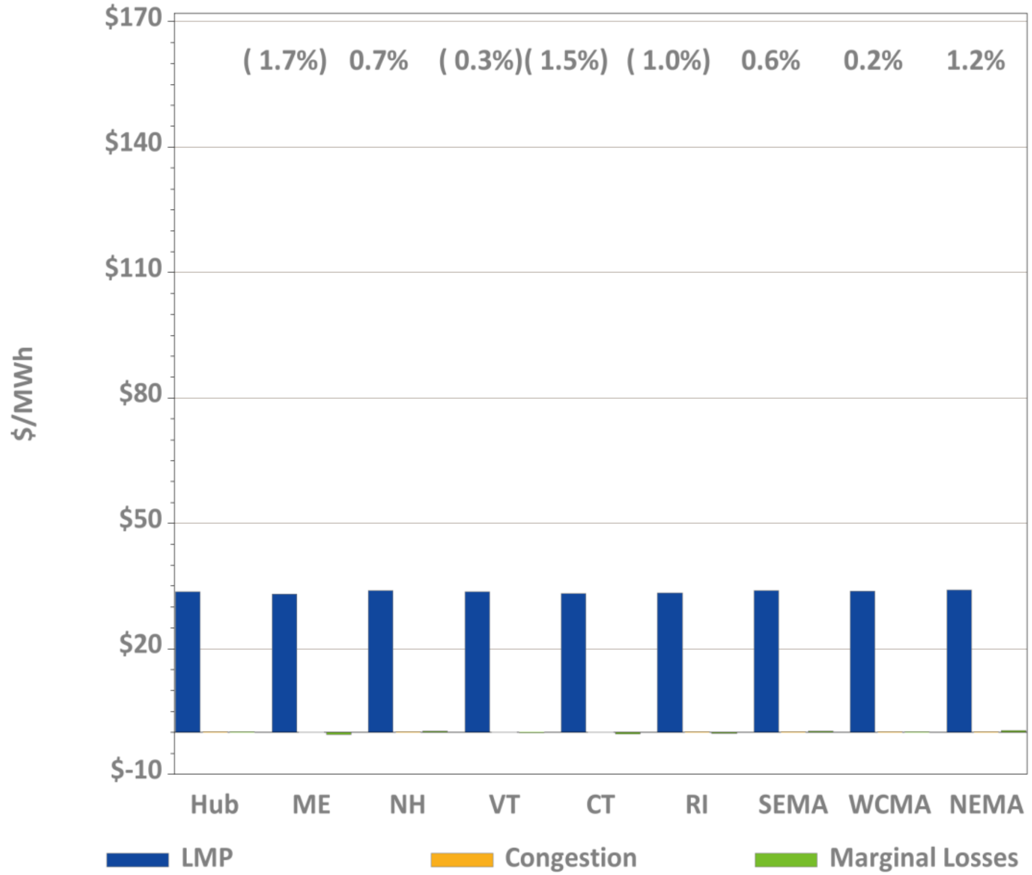
Average price difference over this period (DA-RT): $-2.77
Average price difference over this period ABS(DA-RT): $8.04
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 24%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, September 2023



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

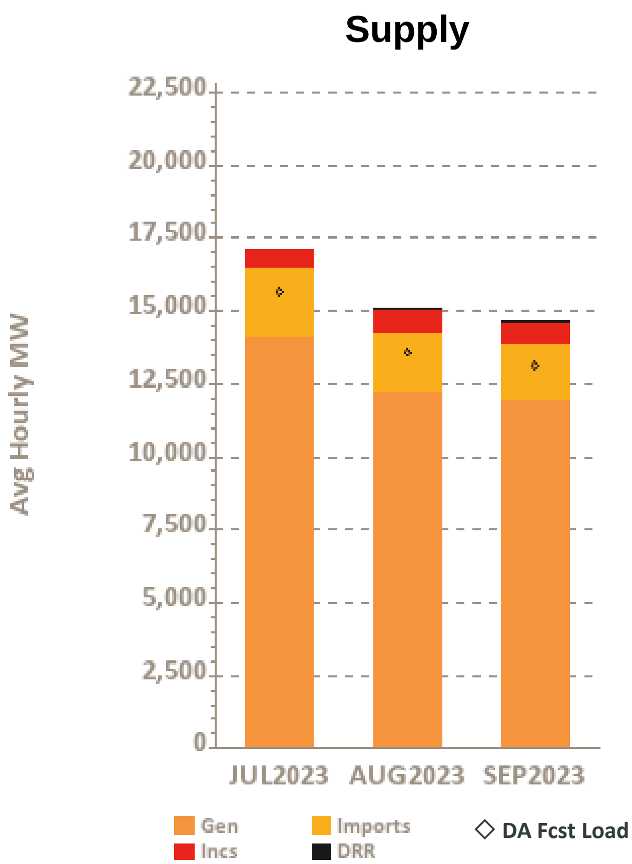
RT LMPs Average by Zone & Hub, September 2023



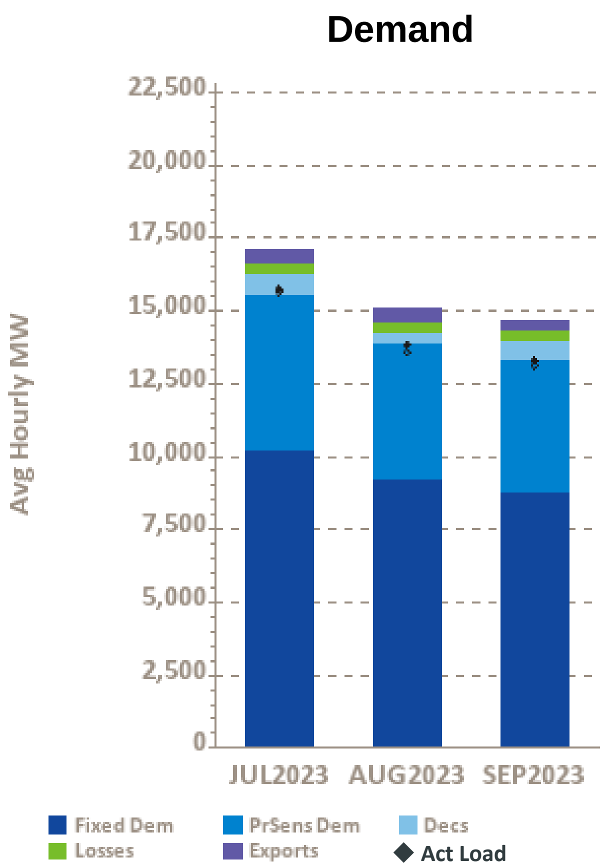
Definitions

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

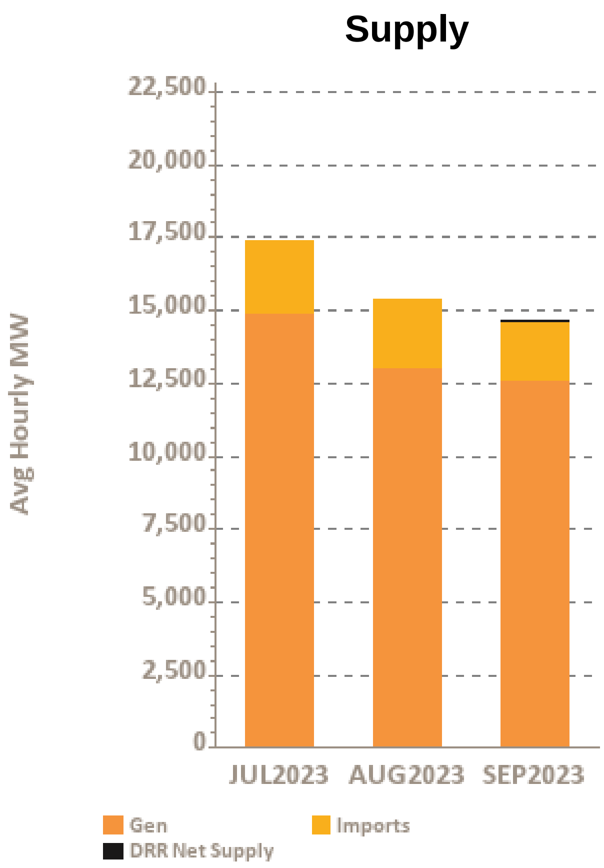


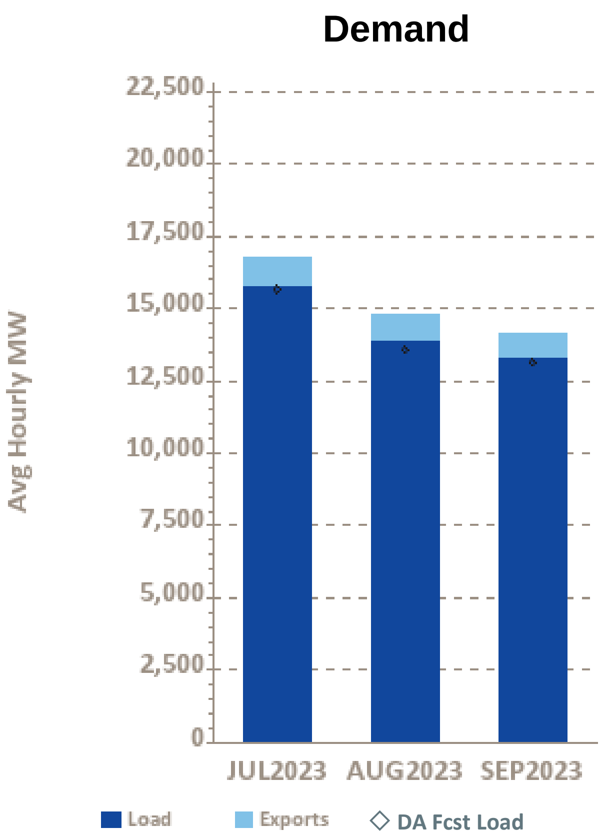
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource



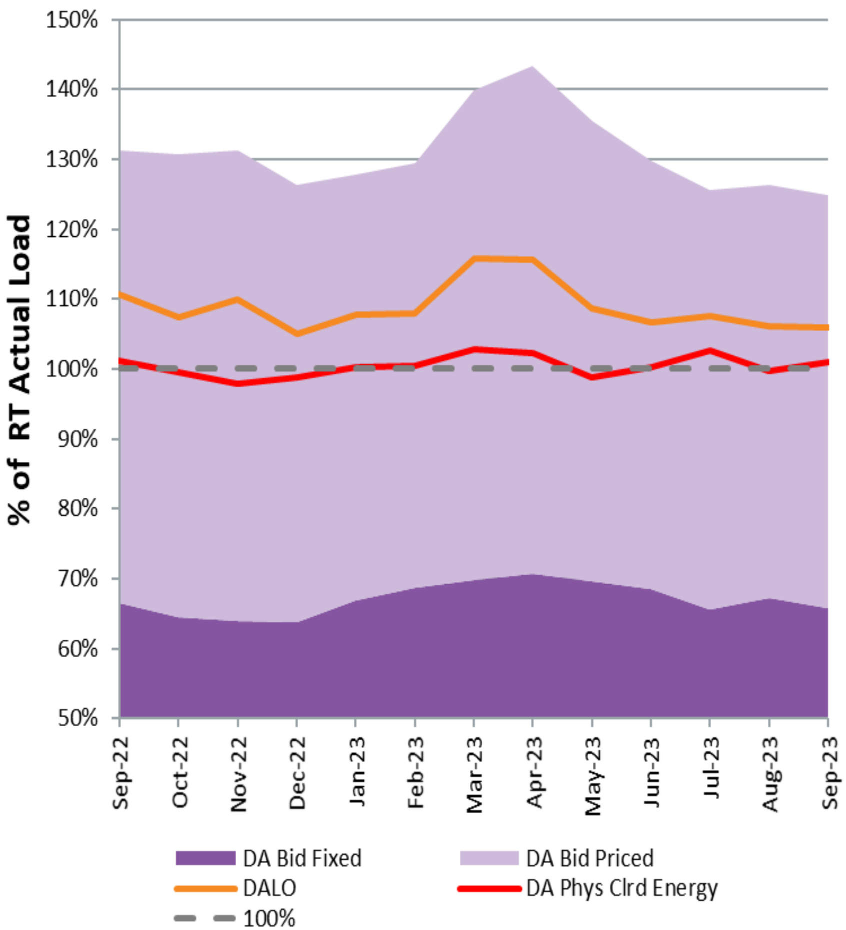
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

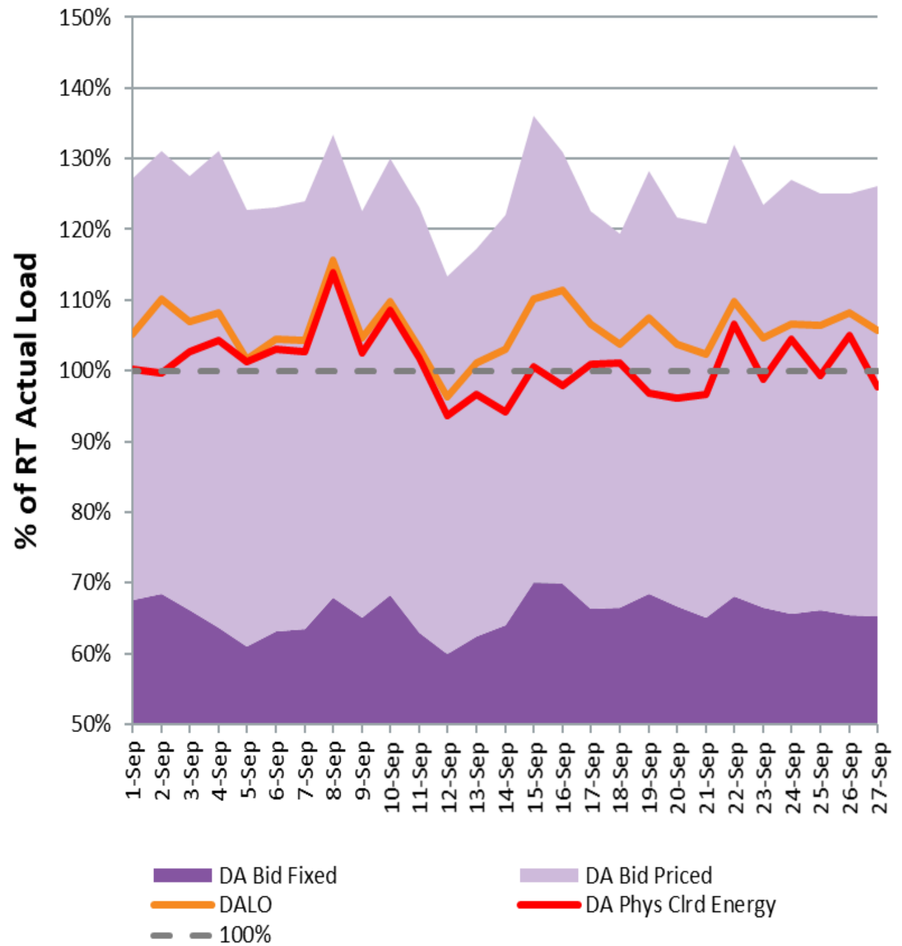
Components of RT Supply and Demand – Last Three Months





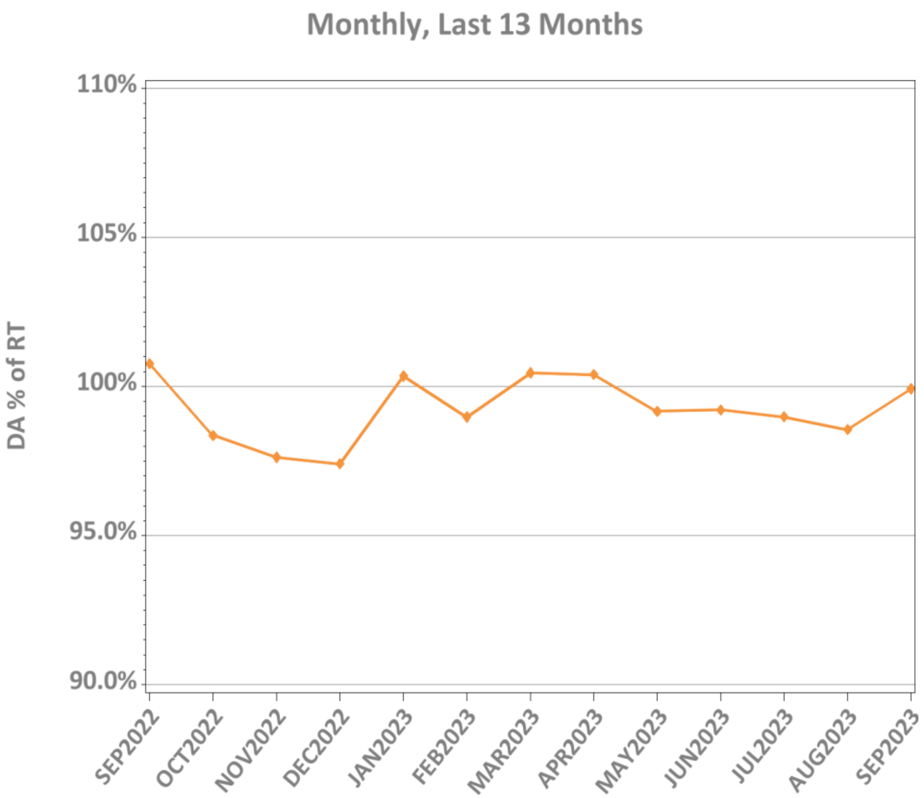
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

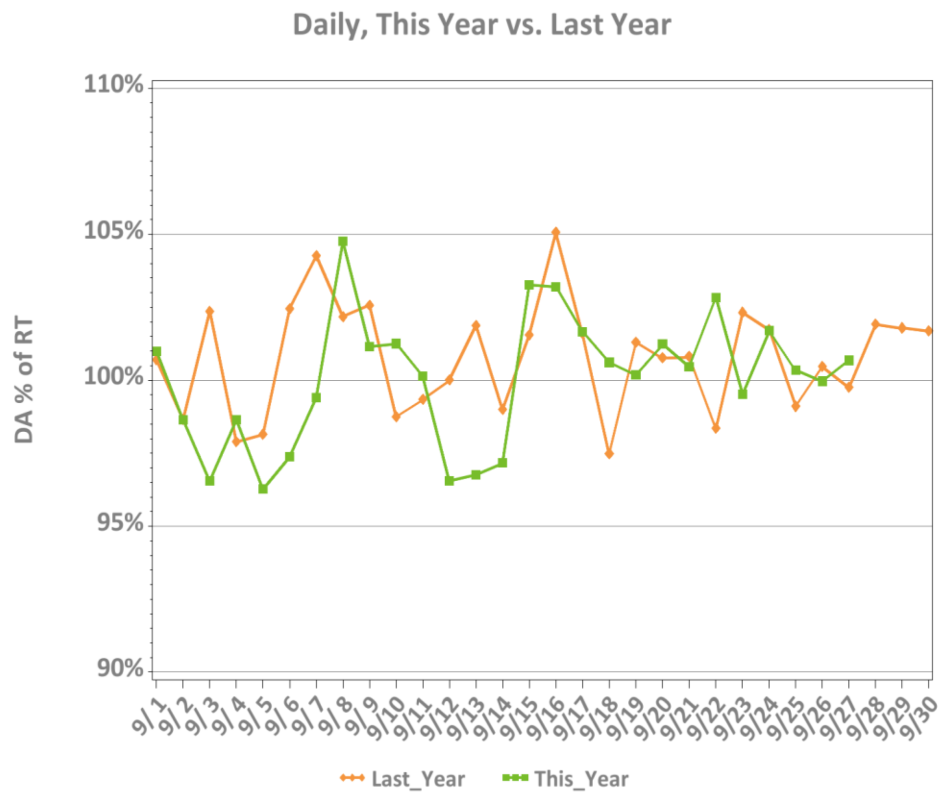




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

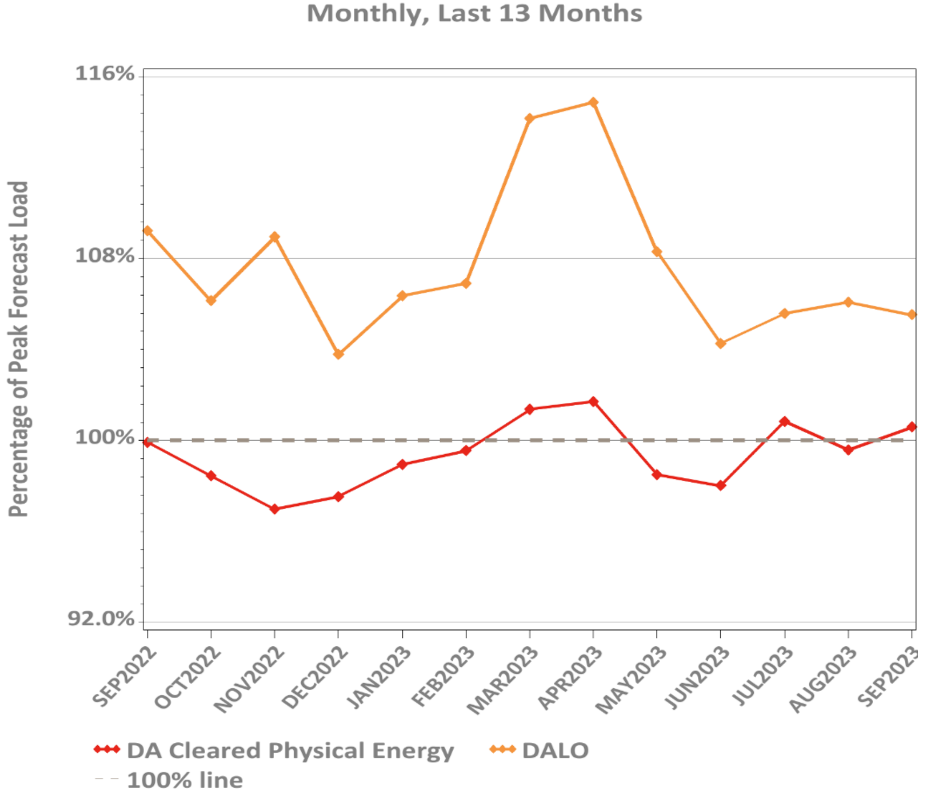
DA vs. RT Load Obligation: September, This Year vs. Last Year

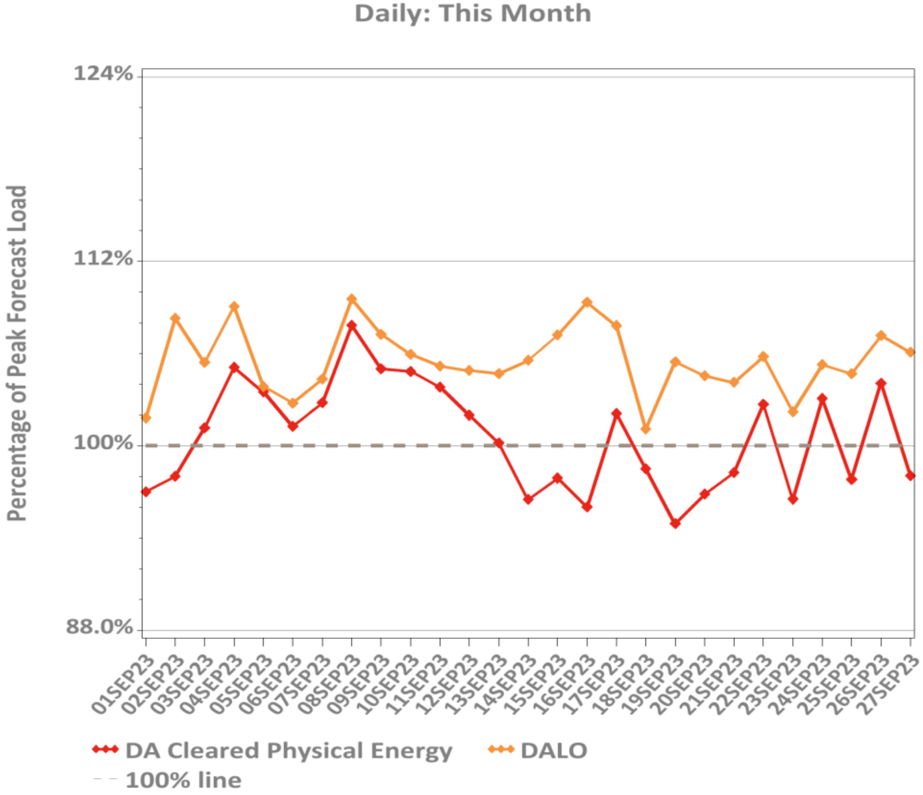




*Hourly average values

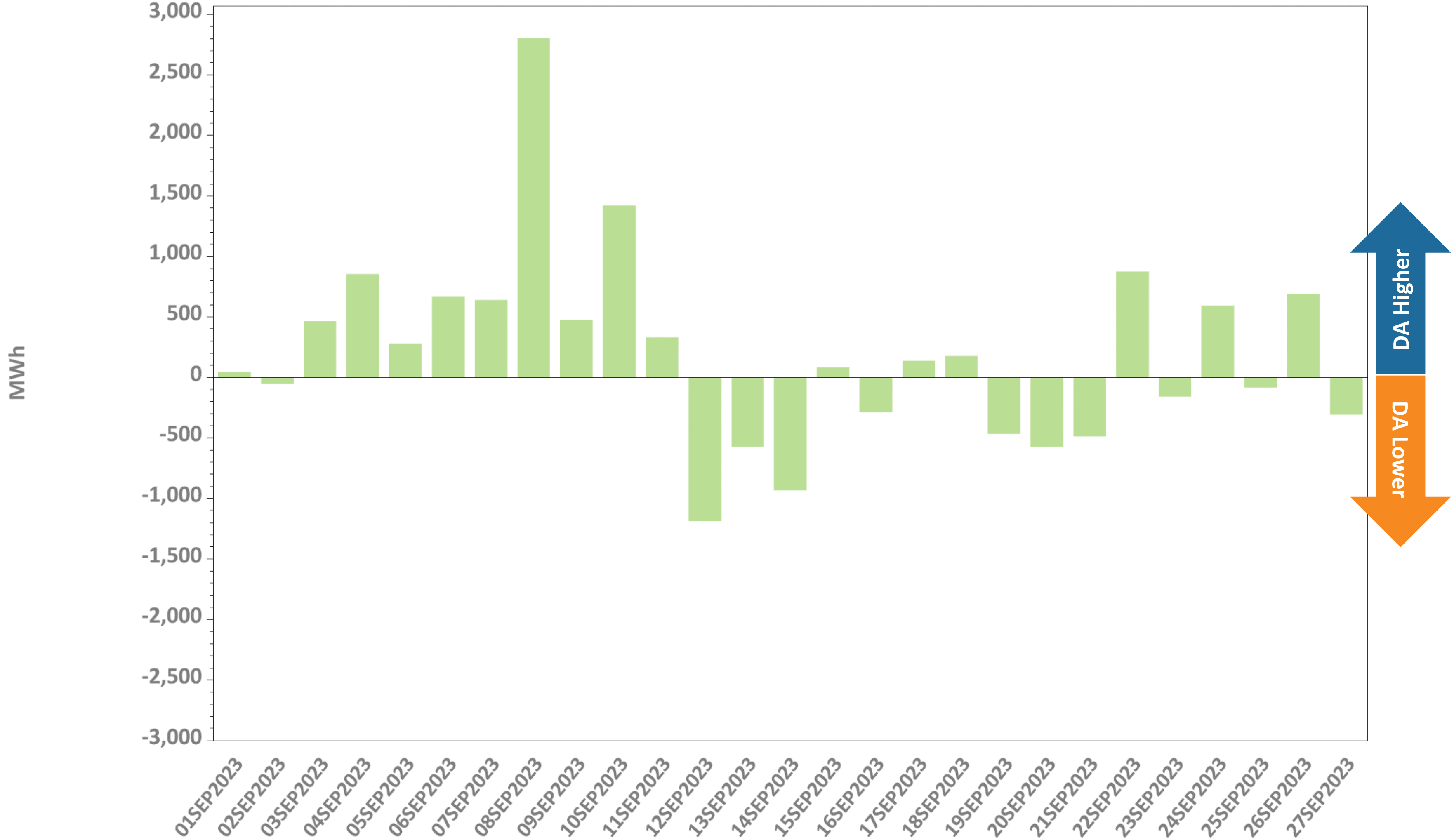
DA Volumes as % of Forecast in Peak Hour





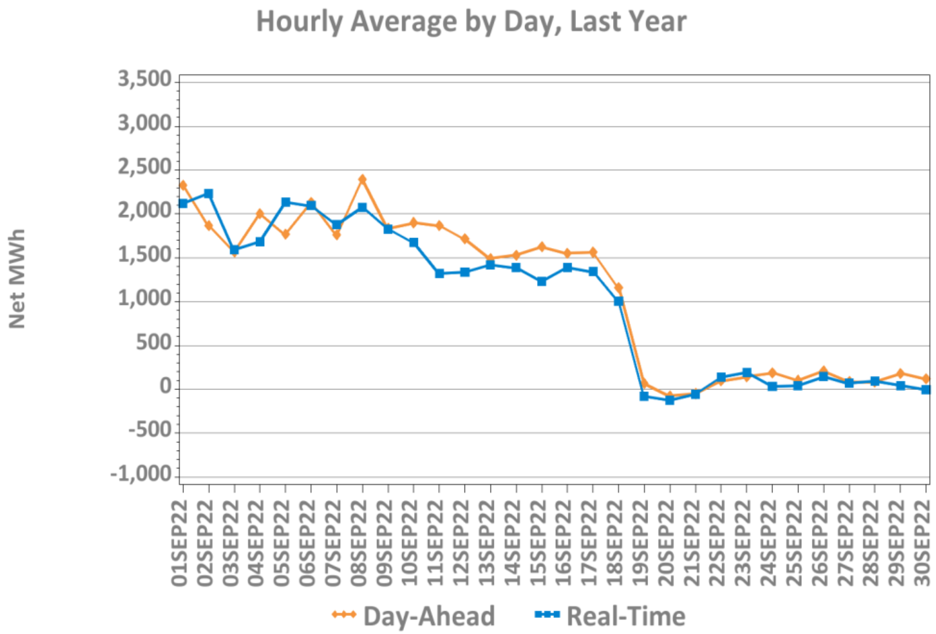
Note: The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

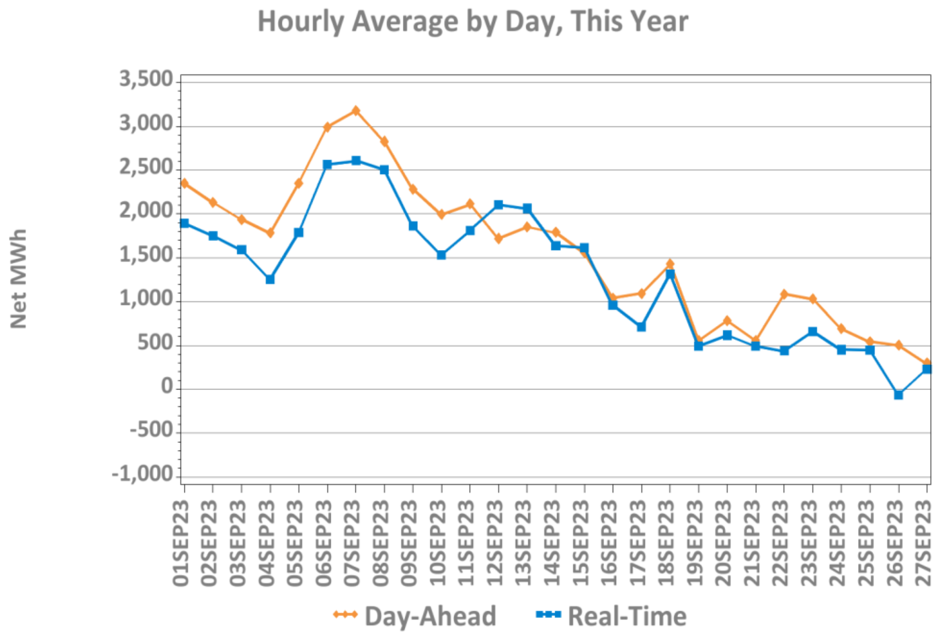
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

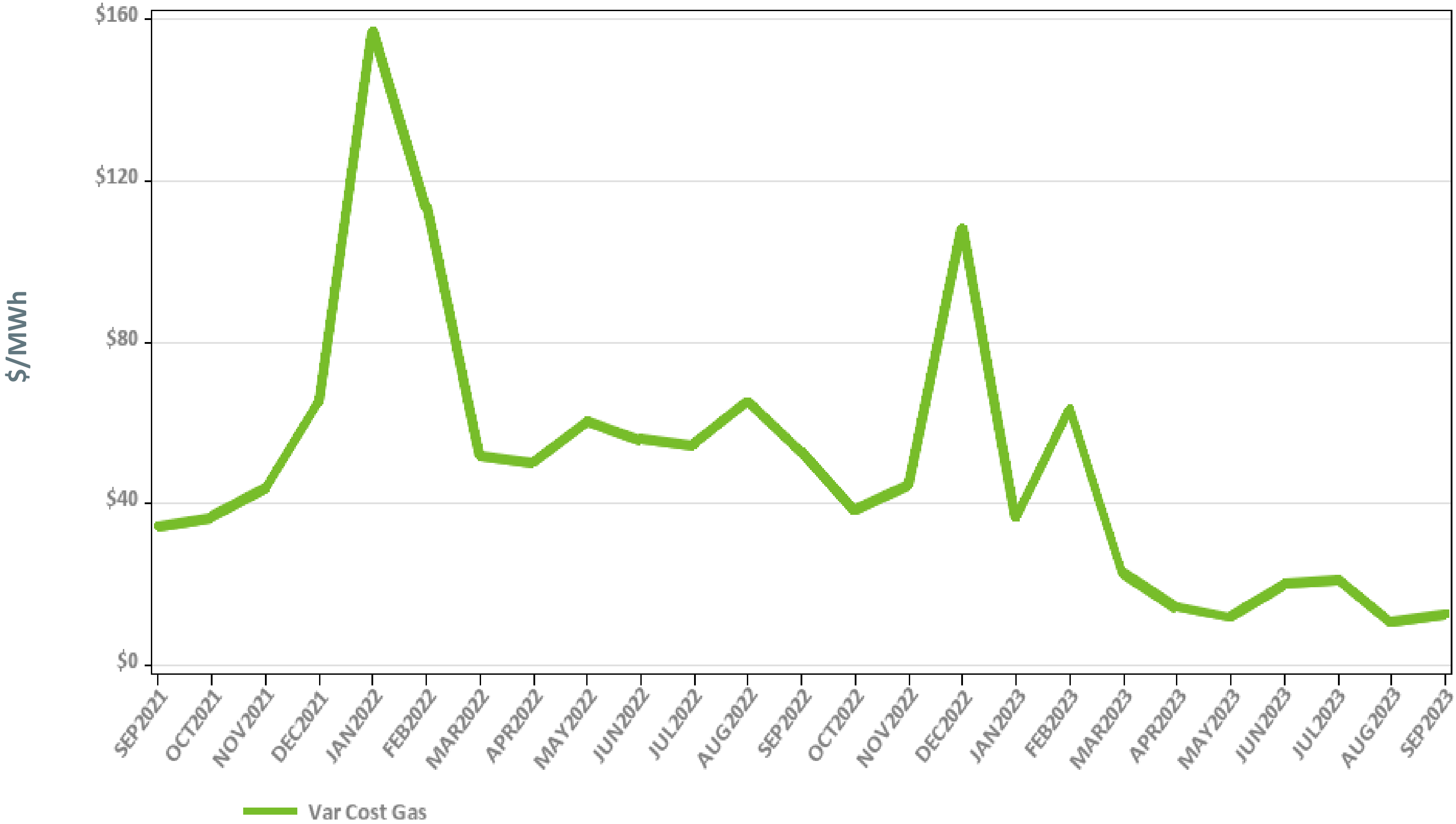
DA vs. RT Net Interchange September 2023 vs. September 2022





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

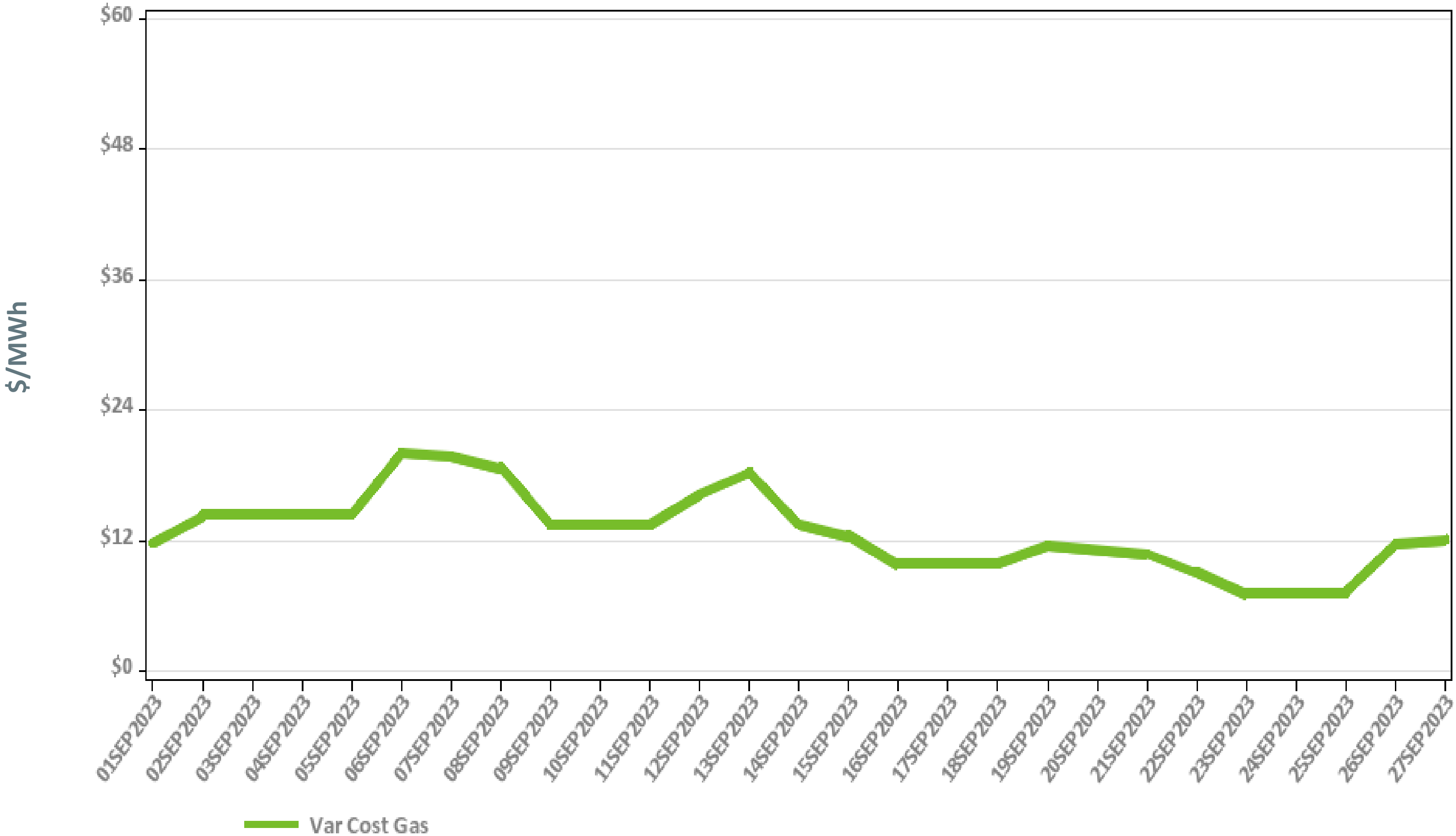


Note: **Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.**

Underlying natural gas data furnished by:

ICE Global markets in clear view

Variable Production Cost of Natural Gas: Daily

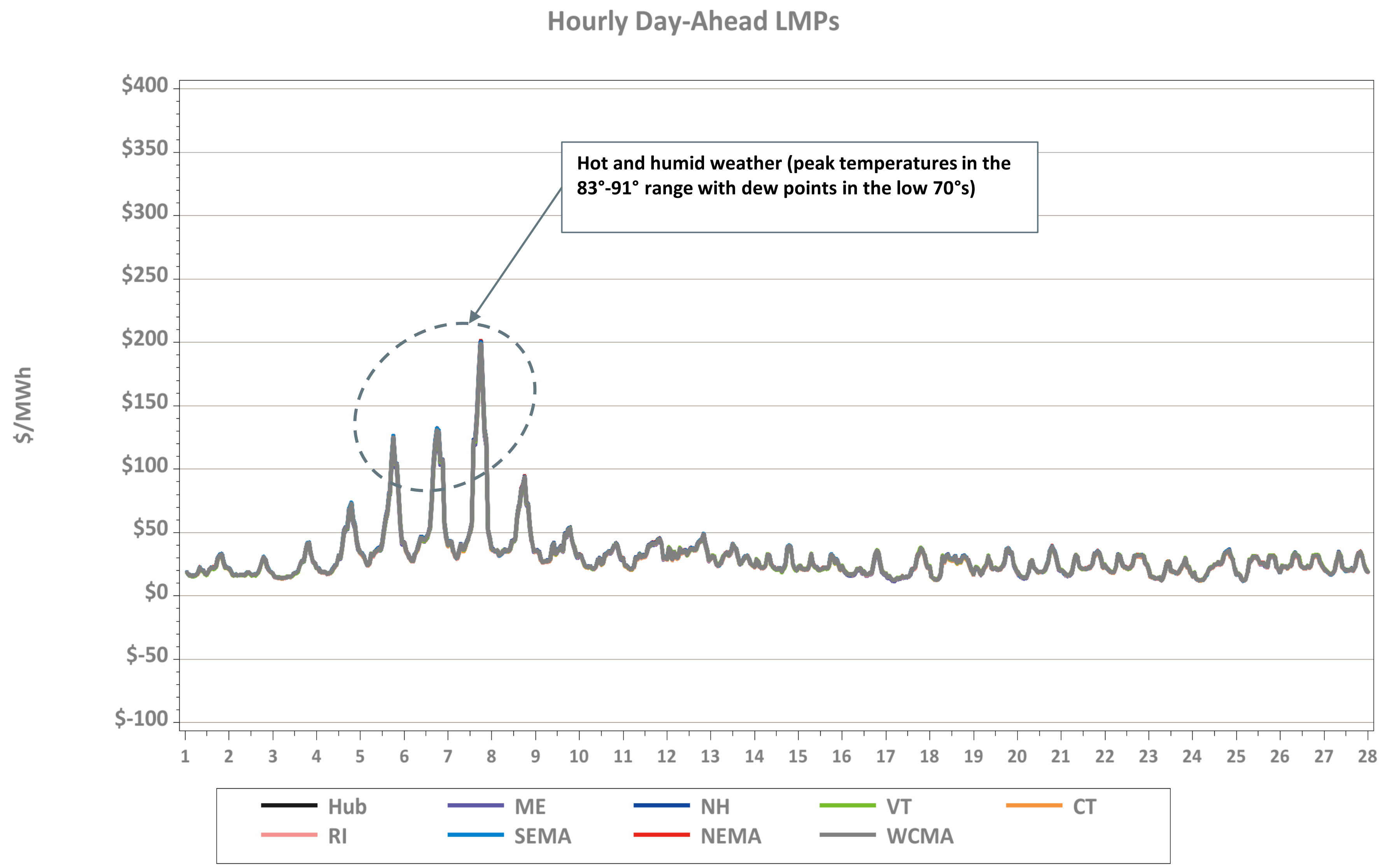


Underlying natural gas data furnished by:

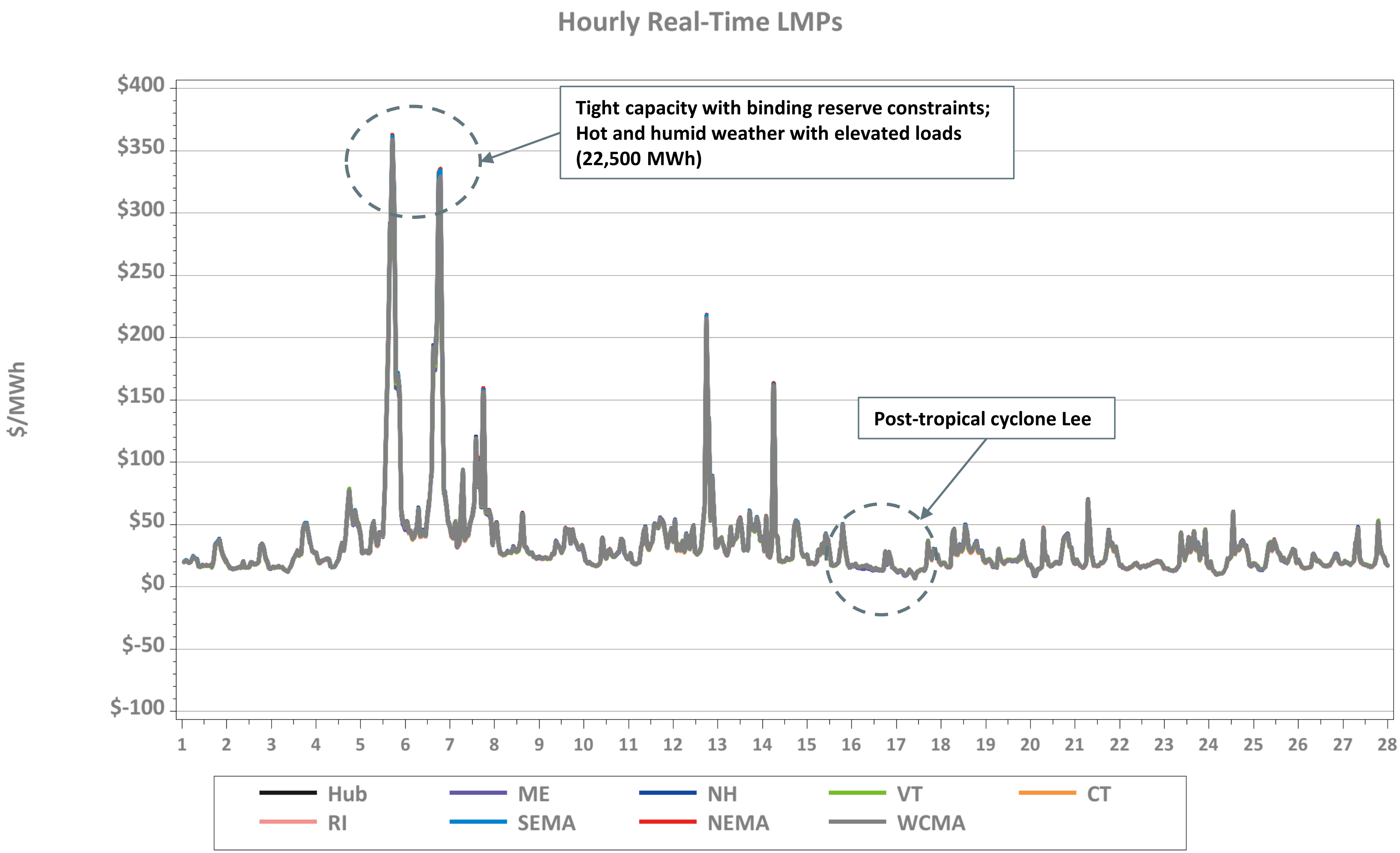
ICE Global markets in clear view

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

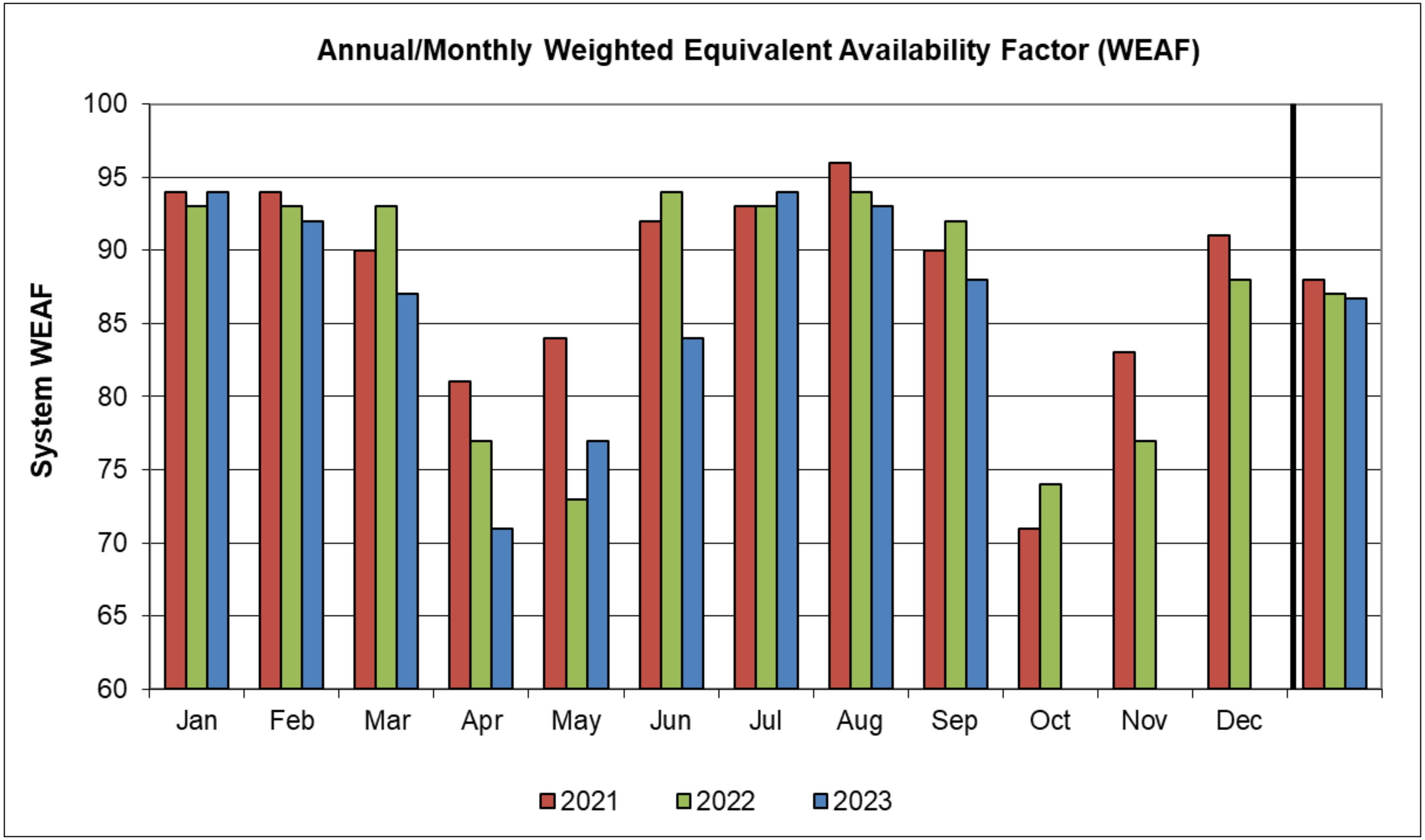
Hourly DA LMPs, September 1-27, 2023



Hourly RT LMPs, September 1-27, 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				87
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 9/25/2023

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for October 2023

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	48.7	201.7	0.0	250.4
NH	38.1	152.0	0.0	190.2
VT	39.5	135.9	0.0	175.4
CT	118.1	170.7	598.6	887.5
RI	22.8	321.7	0.0	344.5
SEMA	36.8	476.8	0.0	513.6
WCMA	77.6	523.4	26.6	627.6
NEMA	71.1	788.8	0.0	859.9
Total	**452.8**	**2,771.1**	**625.3**	**3,849.1**

*** Active Demand Capacity Resources**

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

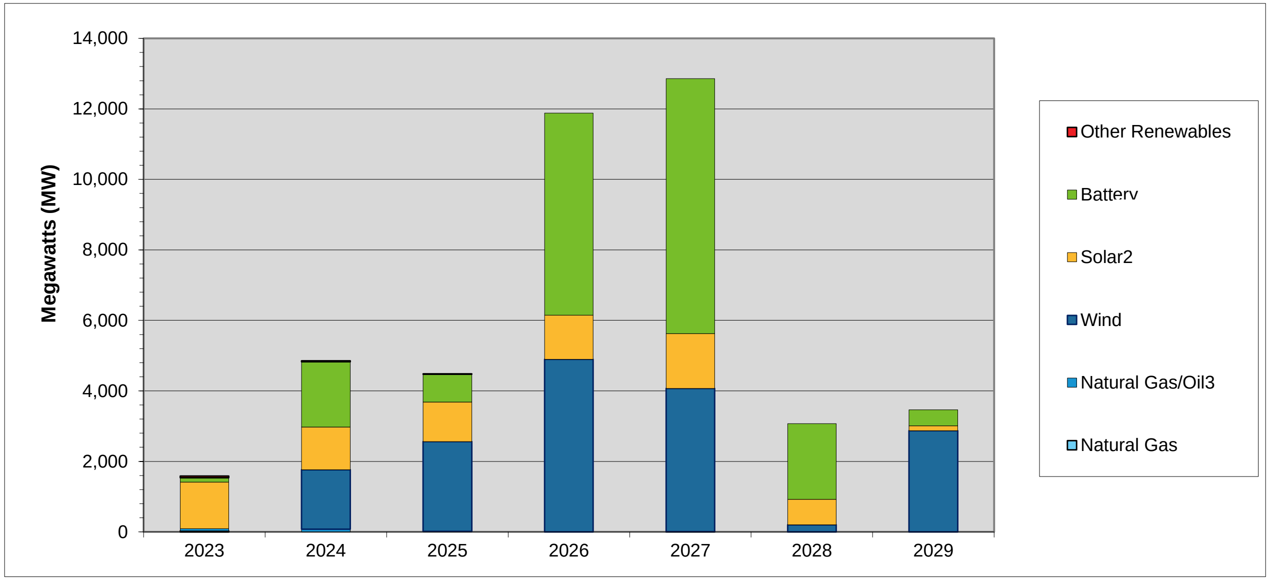
NEW GENERATION

New Generation Update
Based on Queue as of 9/30/23

- Twelve projects totaling 1,143 MW were added to the interconnection queue since the last update
  – Six battery projects and six solar projects with in-service dates of 2024 to 2027
- In total, 390 generation projects are currently being tracked by the ISO, totaling approximately 42,184 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	47	30	2	0	0	0	0	79	0.2
Battery	120	1,850	788	5,734	7,234	2,150	454	18,330	43.5
Solar[2]	1,324	1,207	1,124	1,255	1,558	725	139	7,332	17.4
Wind	0	1,693	2,545	4,893	4,064	197	2,870	16,262	38.6
Natural Gas/Oil[3]	62	73	16	0	0	0	0	151	0.4
Natural Gas	26	0	0	0	4	0	0	30	0.1
Totals	1,579	4,853	4,475	11,882	12,860	3,072	3,463	42,184	100.0

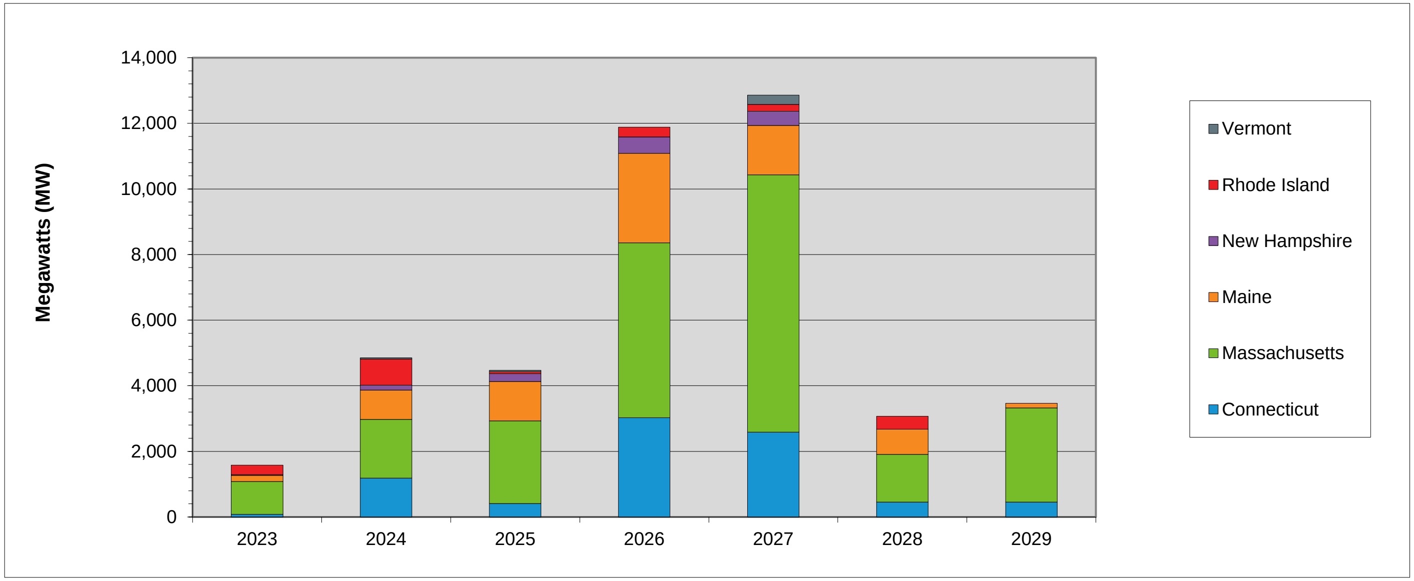
[1] Sum may not equal 100% due to rounding

[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	285	0	0	375	0.9
Rhode Island	291	794	54	295	211	400	0	2,045	4.8
New Hampshire	25	154	238	504	426	0	0	1,347	3.2
Maine	185	894	1,205	2,723	1,506	764	139	7,416	17.6
Massachusetts	996	1,783	2,520	5,336	7,844	1,453	2,870	22,802	54.1
Connecticut	82	1,188	408	3,024	2,588	455	454	8,199	19.4
Totals	**1,579**	**4,853**	**4,475**	**11,882**	**12,860**	**3,072**	**3,463**	**42,184**	**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	118	18,330	1	15	117	18,315
Fuel Cell	4	46	0	0	4	46
Hydro	2	33	1	5	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	232	7,332	15	343	217	6,989
Wind	27	16,262	1	800	26	15,462
Total	390	42,184	19	1,225	371	40,959

- 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	8	92	1	5	7	87
Intermediate	2	89	0	0	2	89
Peaker	353	25,741	17	420	336	25,321
Wind Turbine	27	16,262	1	800	26	15,462
Total	390	42,184	19	1,225	371	40,959

- 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	118	18,330	0	0	0	0	118	18,330	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	2	33	2	33	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	232	7,332	0	0	0	0	232	7,332	0	0
Wind	27	16,262	0	0	0	0	0	0	27	16,262
Total	390	42,184	8	92	2	89	353	25,741	27	16,262

- 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

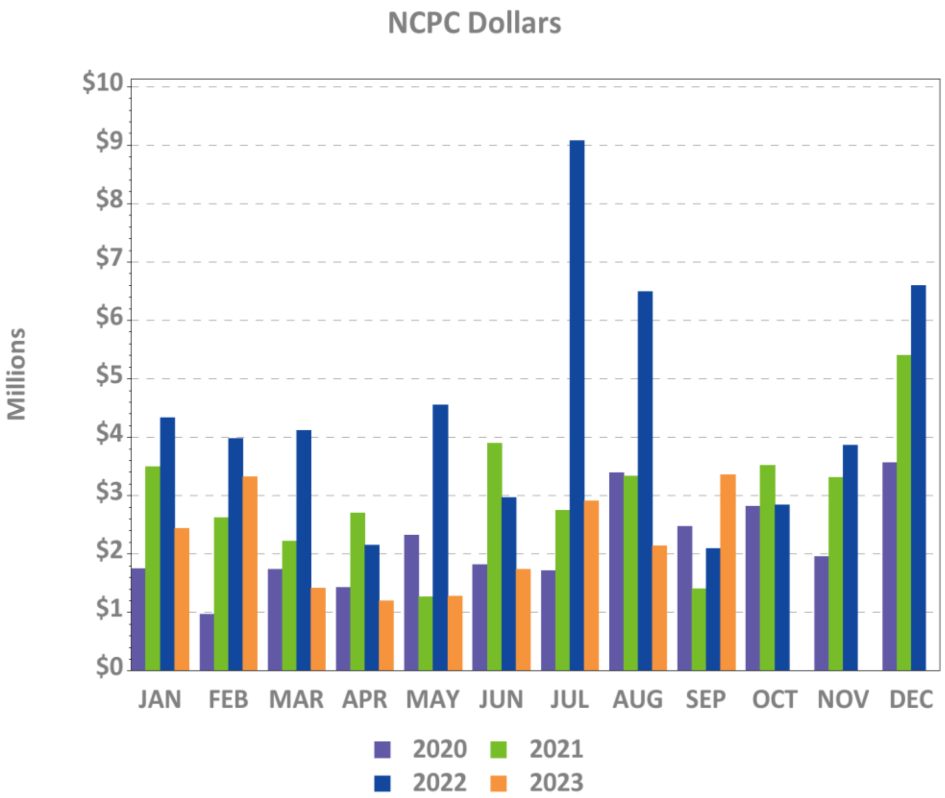
Definitions

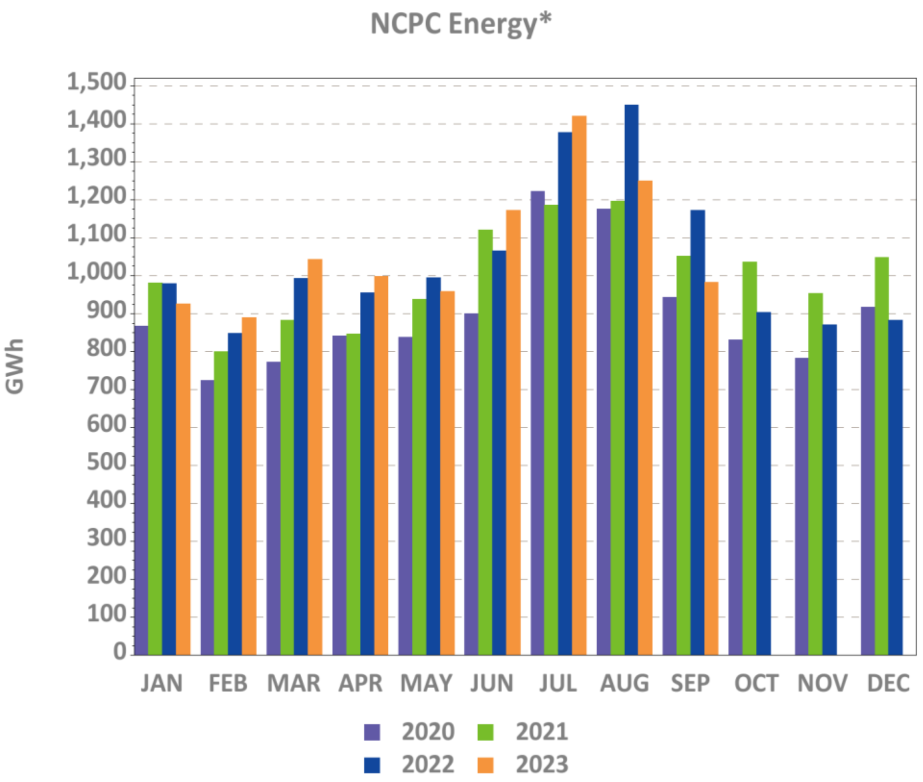
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

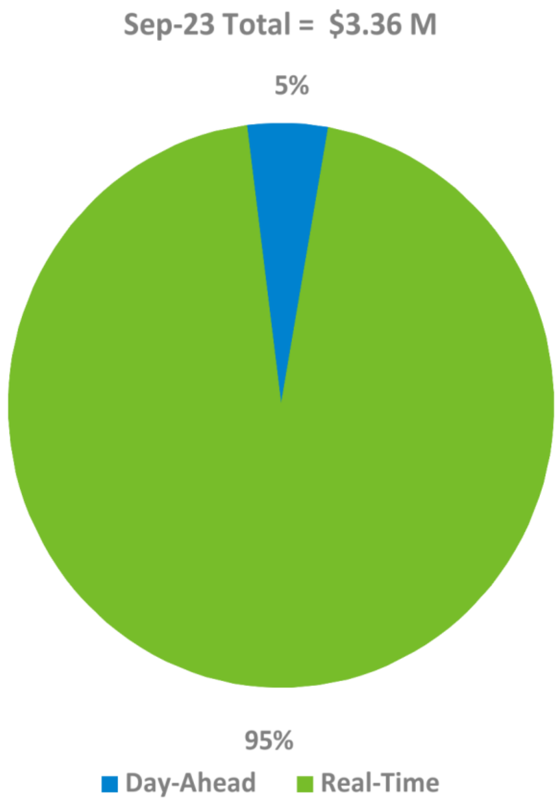
Year-Over-Year Total NCPC Dollars and Energy

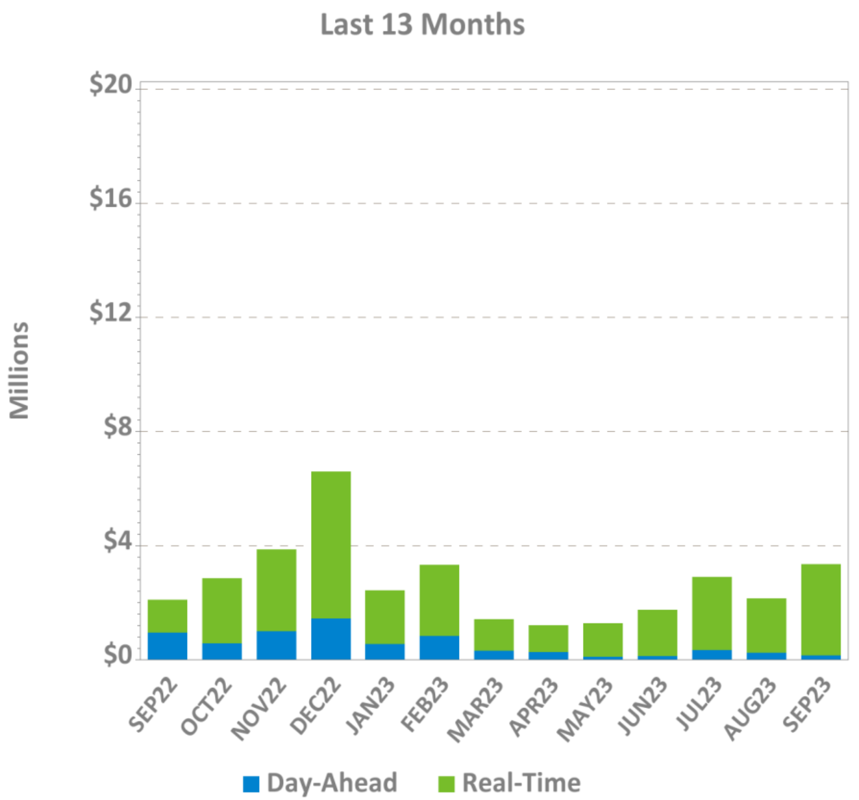




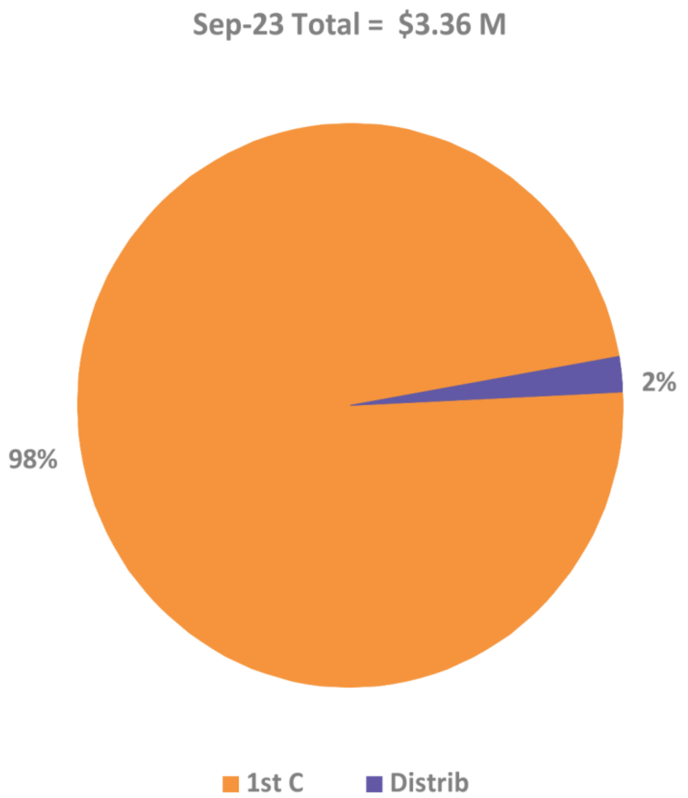
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

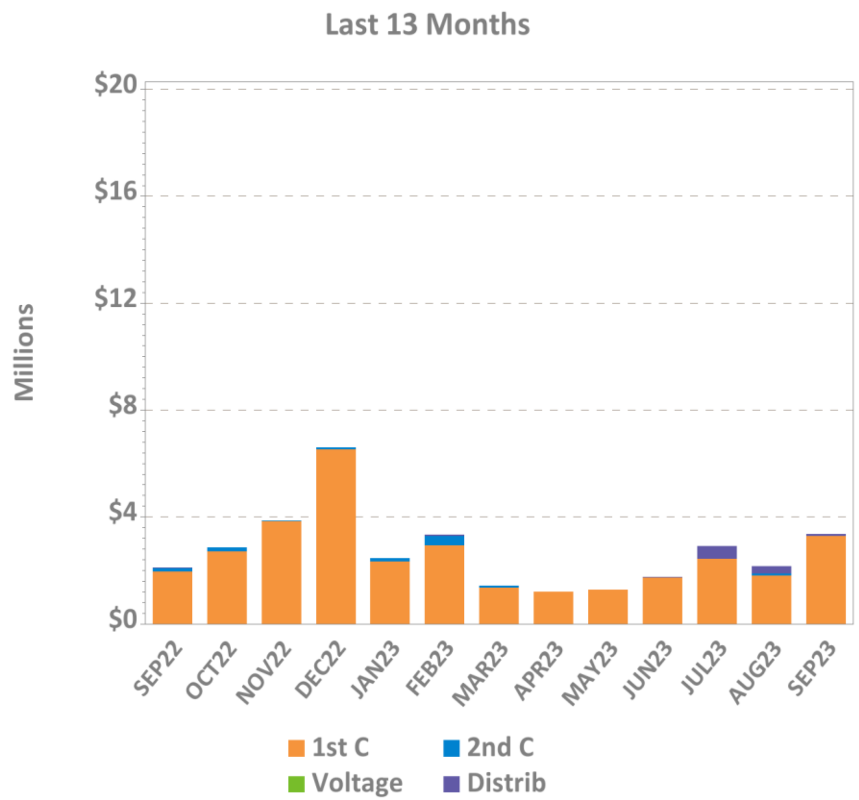
DA and RT NCPC Charges





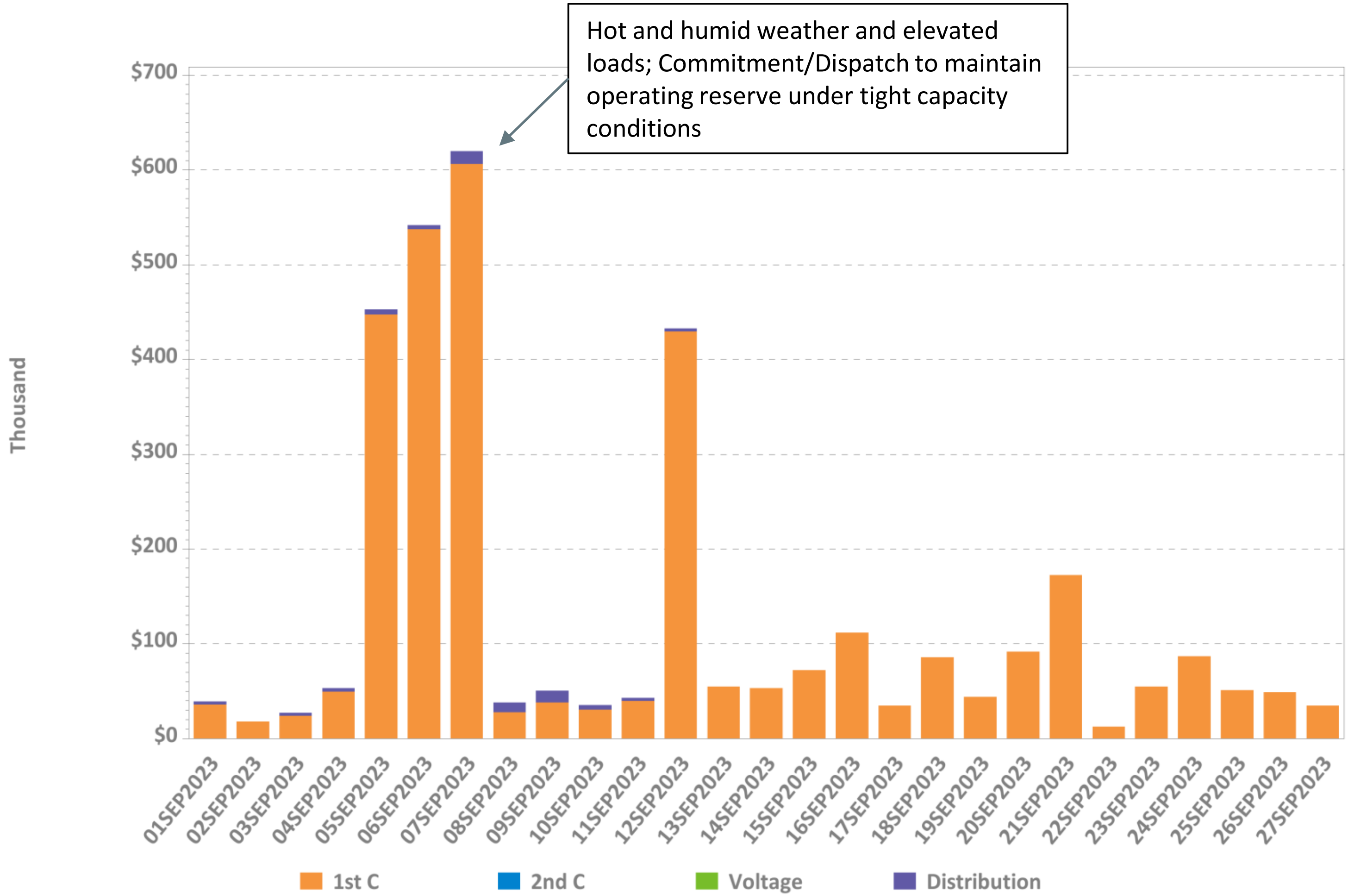
NCPC Charges by Type



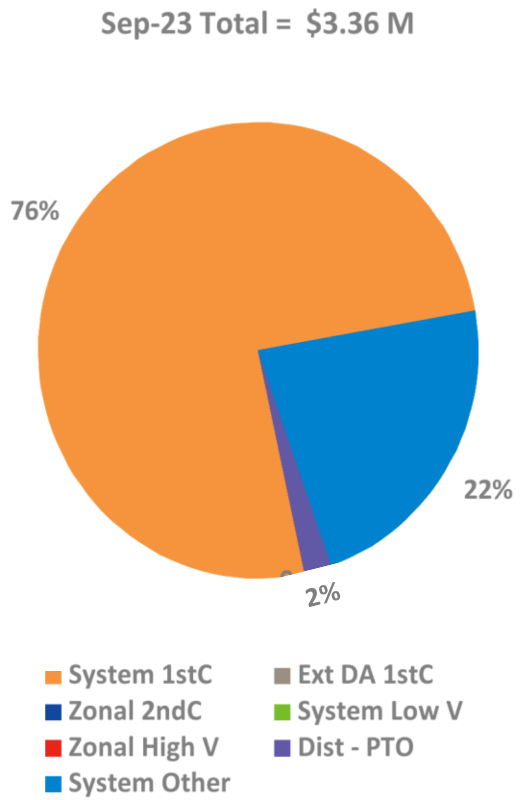


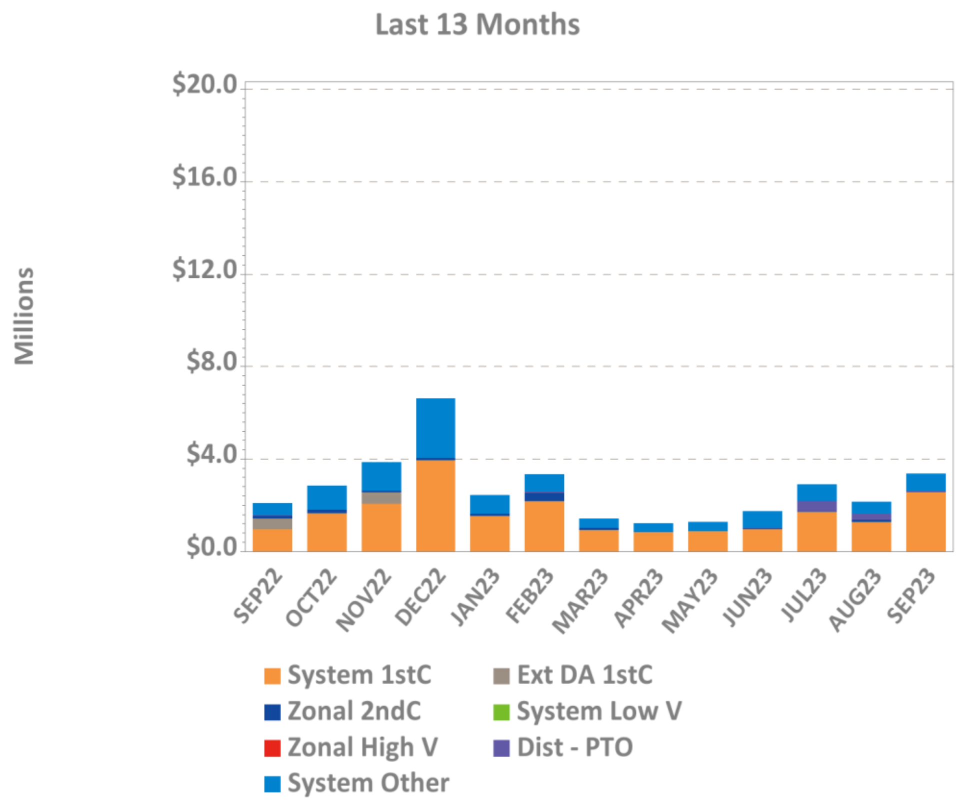
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



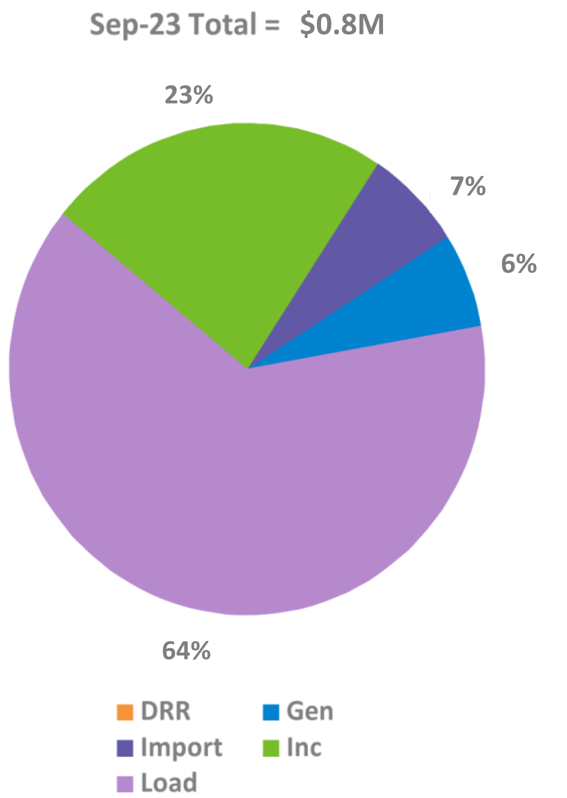
NCPC Charges by Allocation

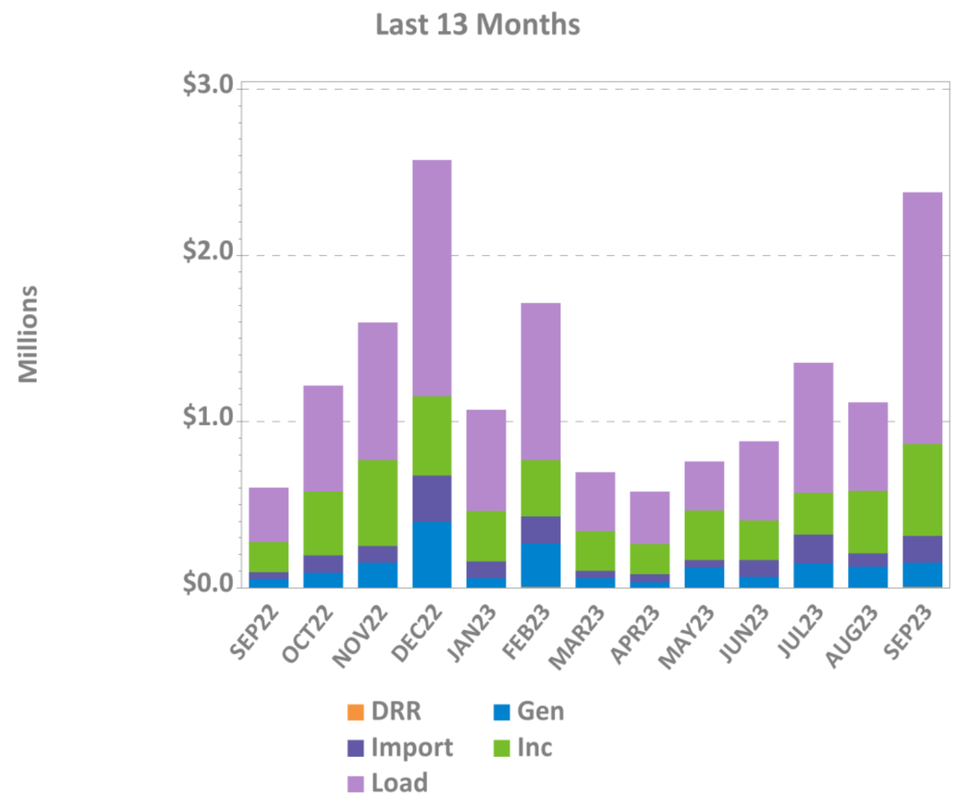




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

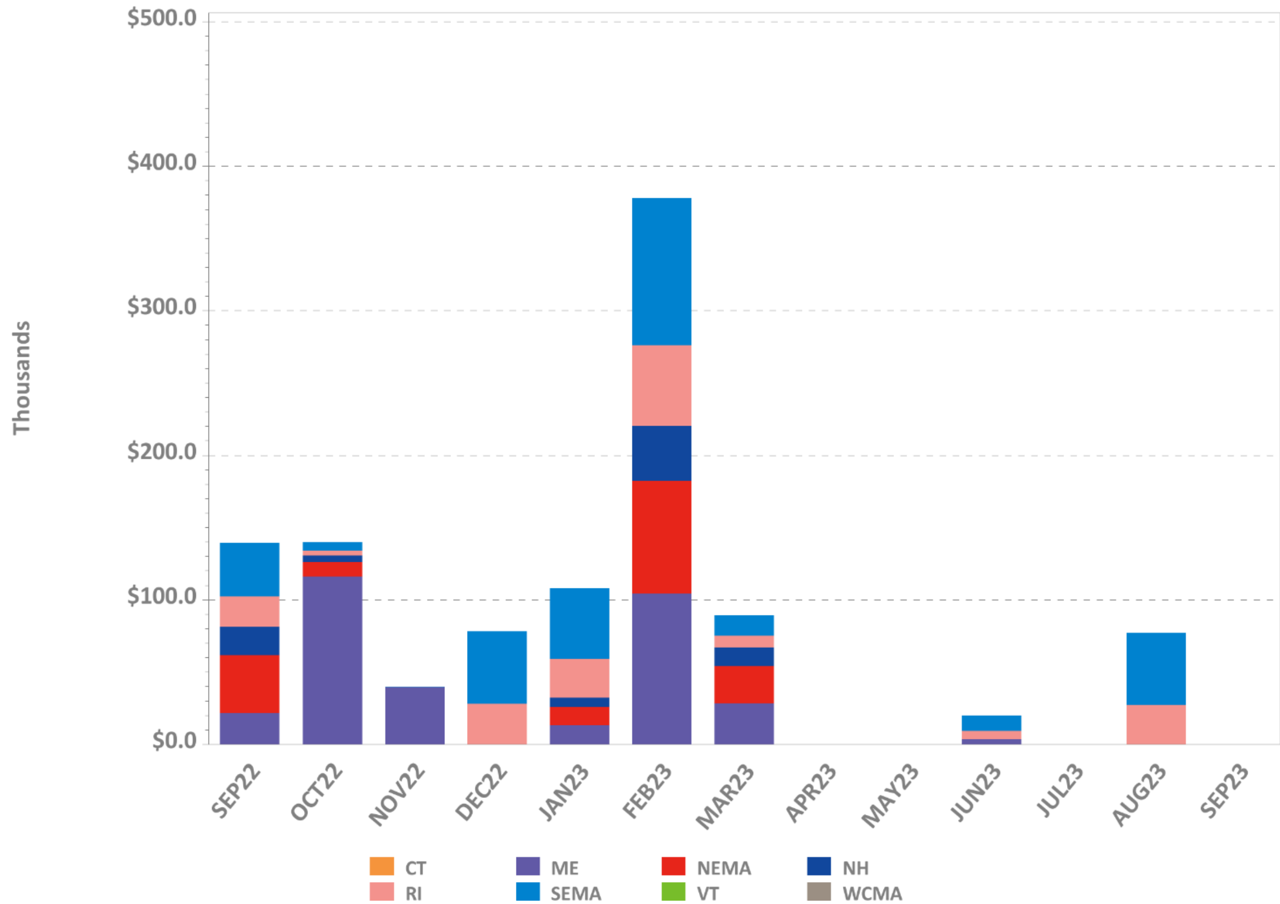
RT First Contingency Charges by Deviation Type





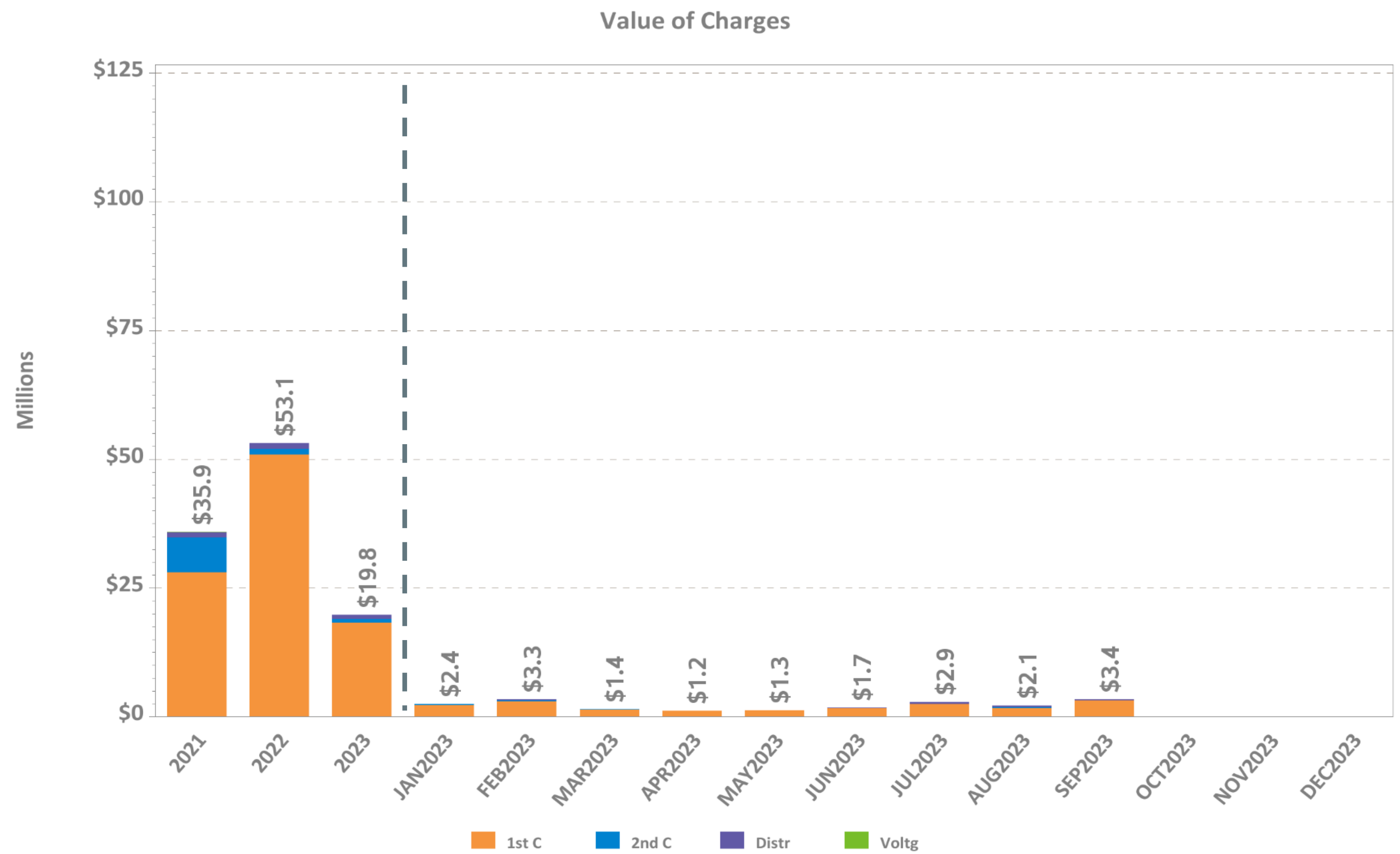
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

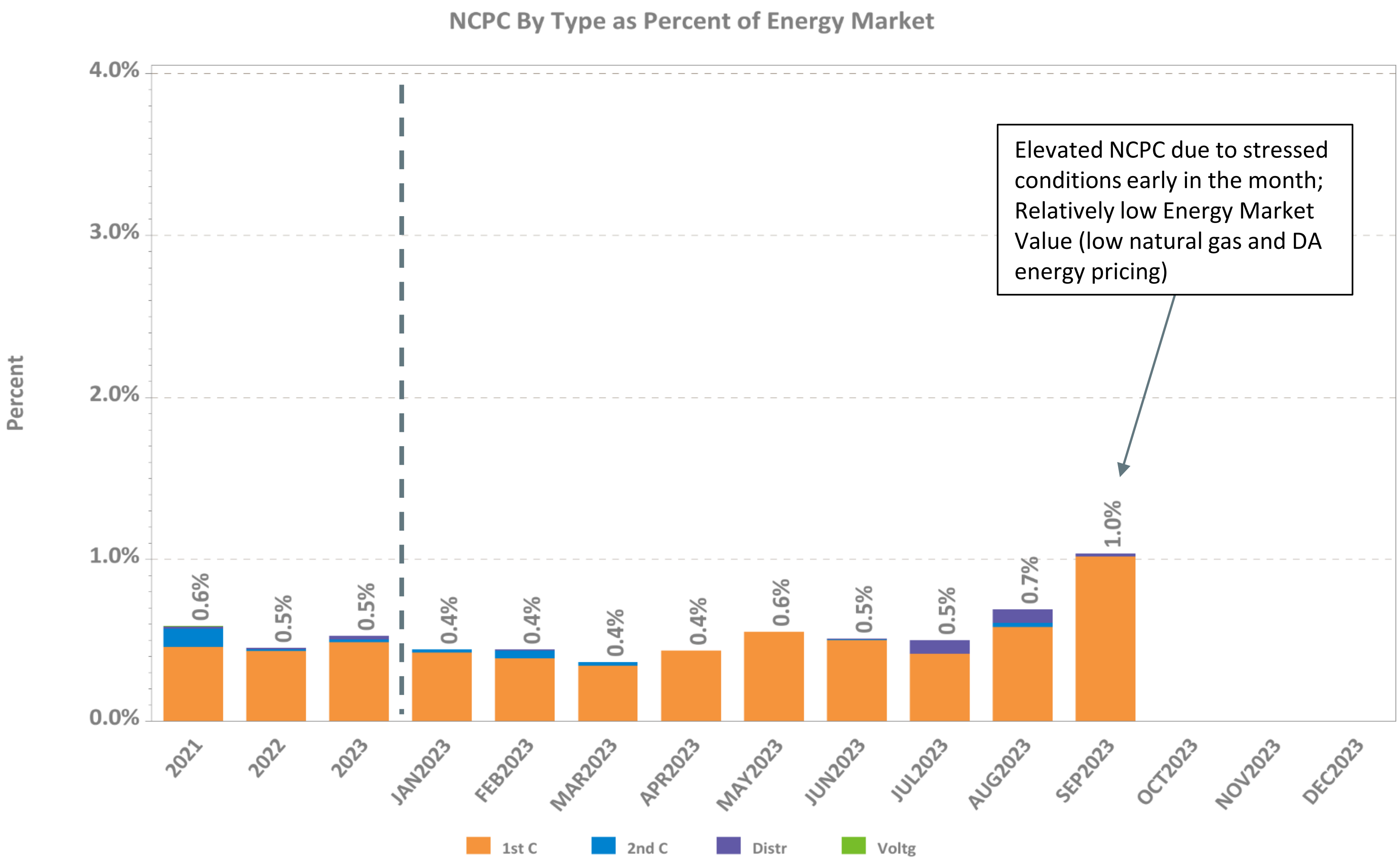


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

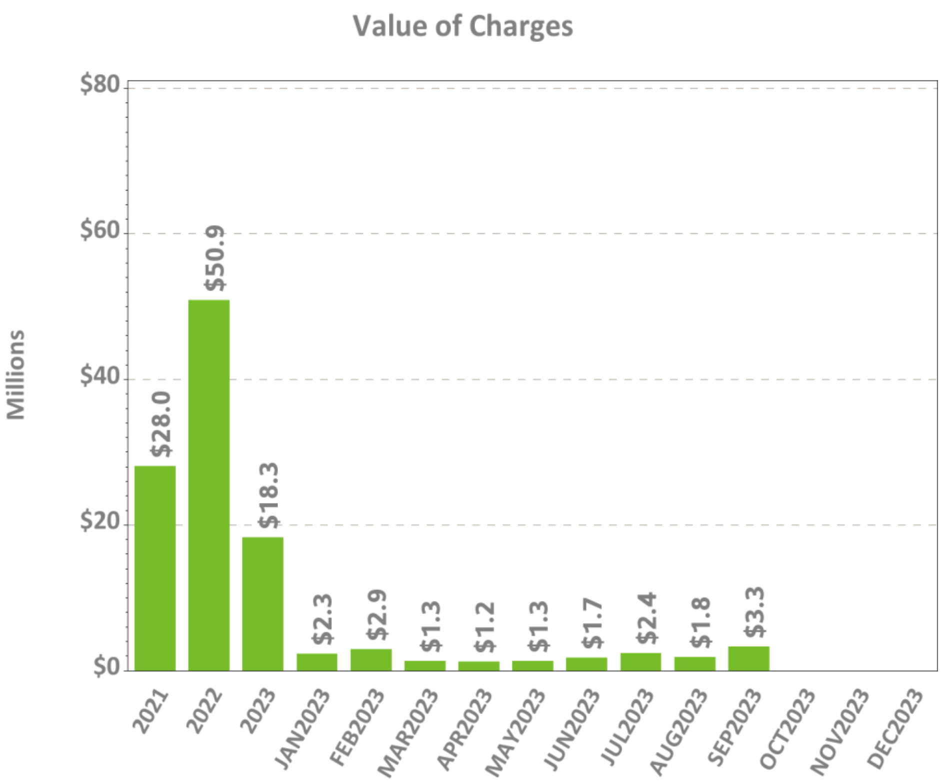
NCPC Charges by Type

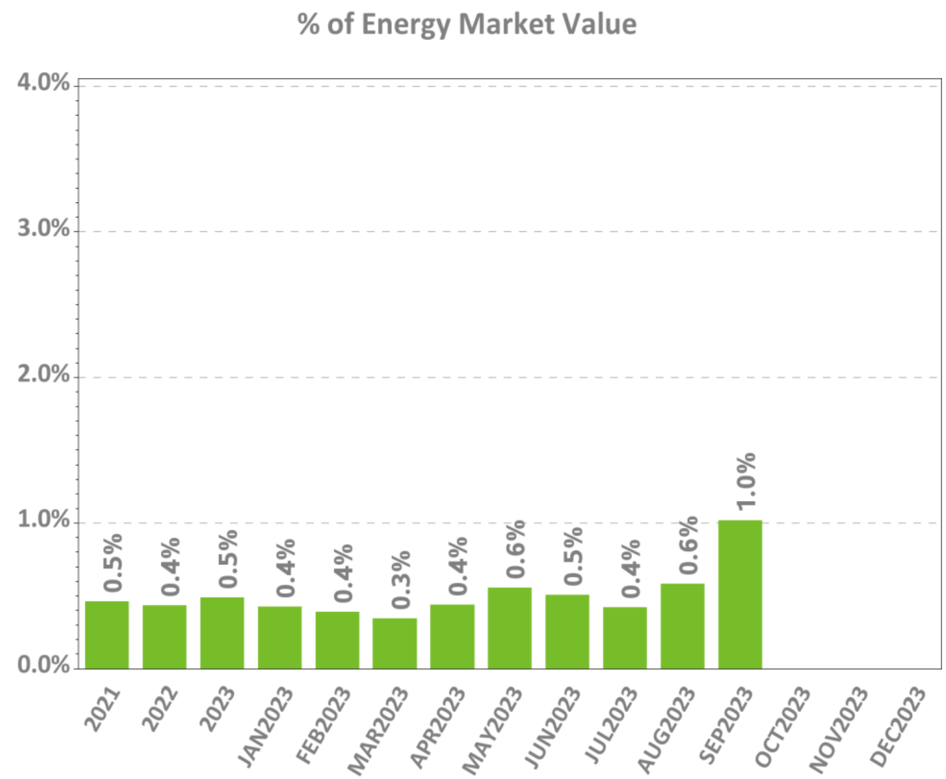


NCPC Charges as Percent of Energy Market



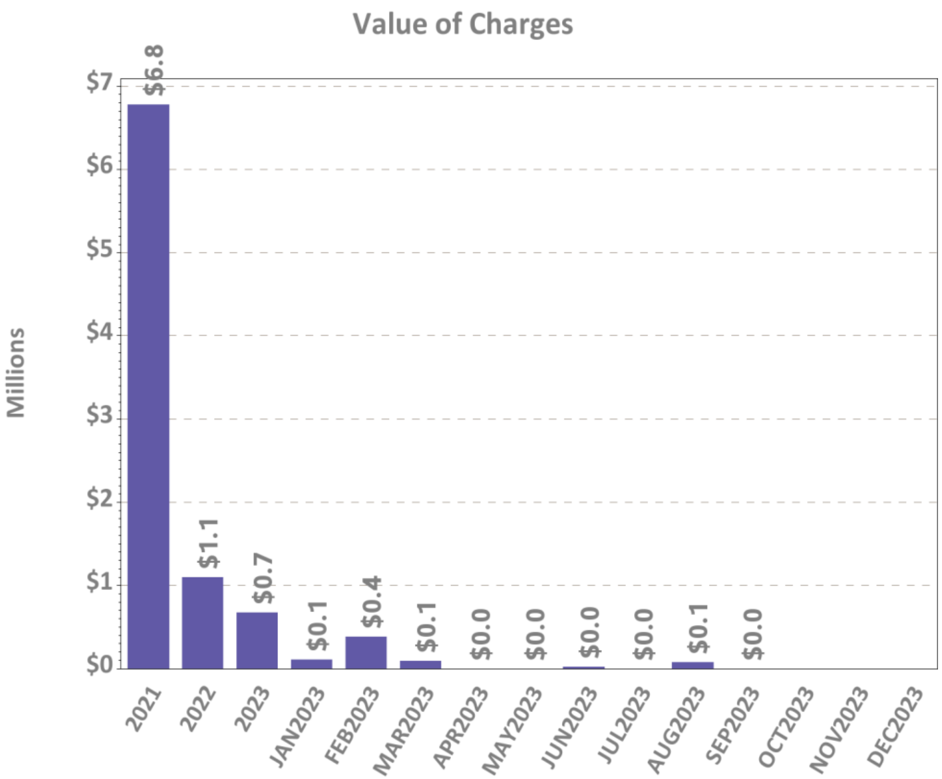
First Contingency NCPC Charges

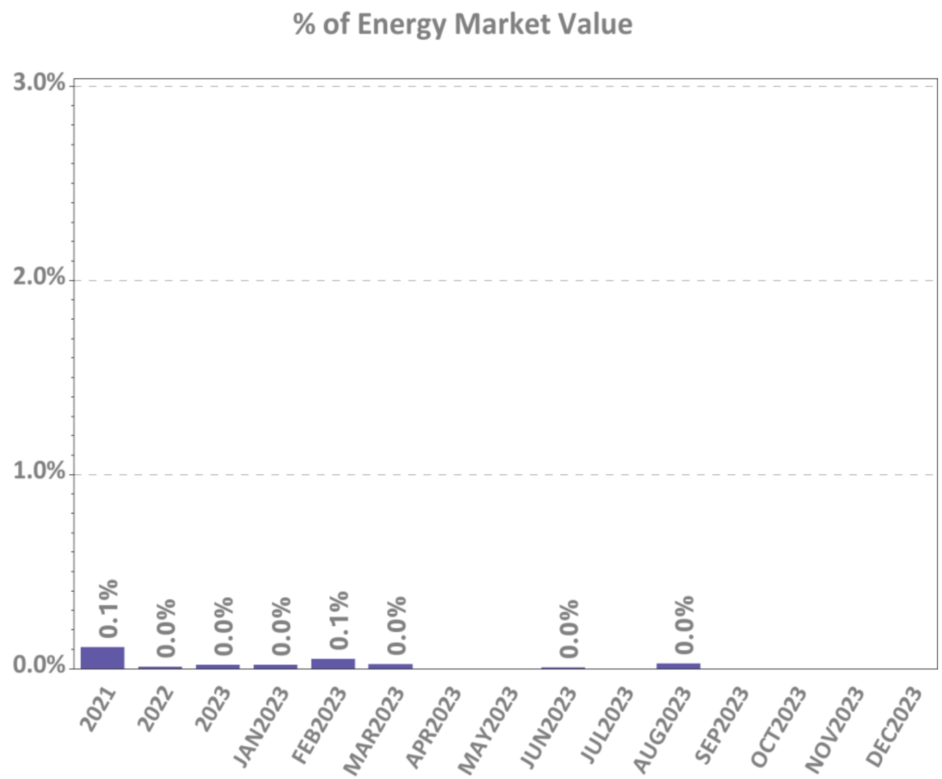




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

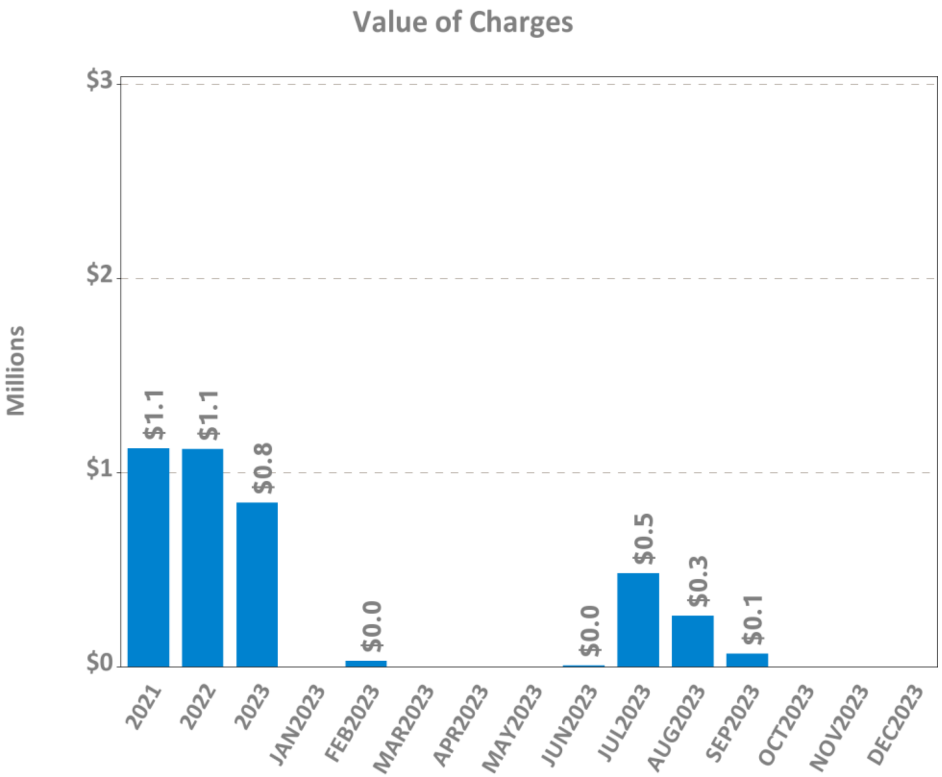
Second Contingency NCPC Charges

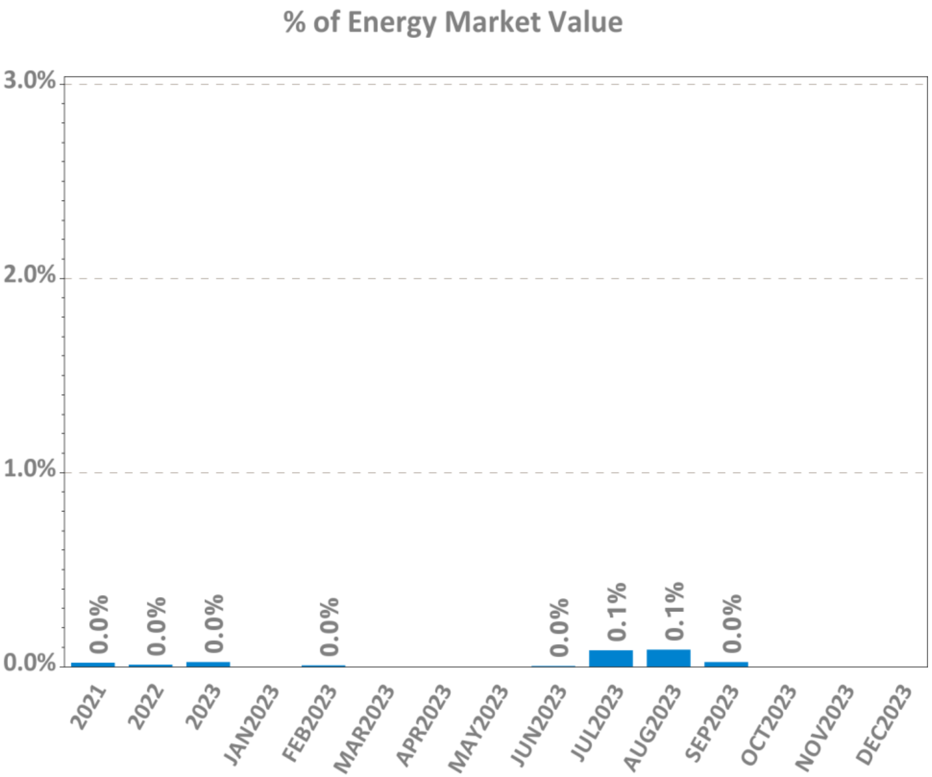




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

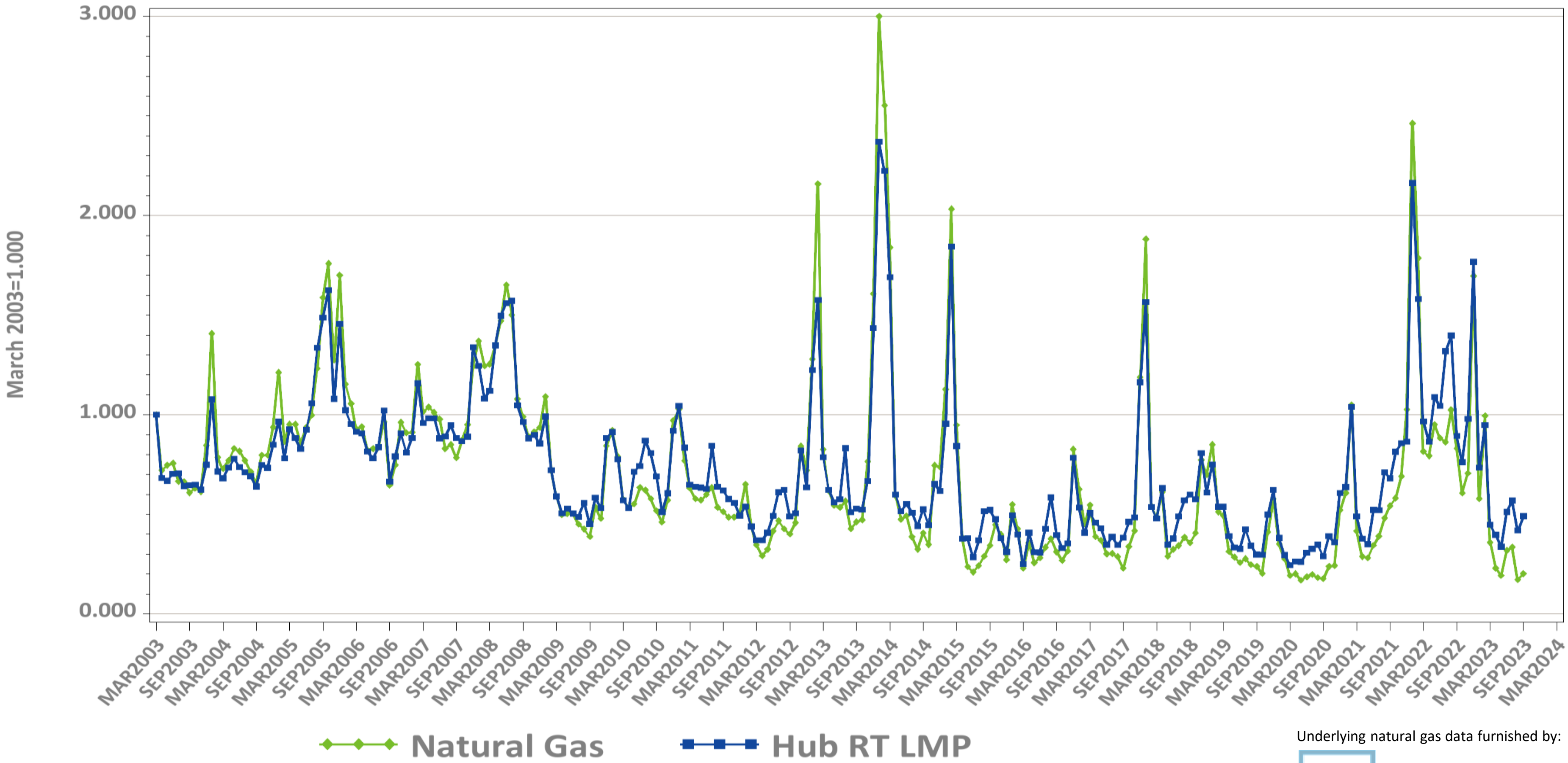
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$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%

September-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$67.78	$65.80	$65.79	$67.53	$66.53	$67.02	$67.67	$67.29	$67.23
Real-Time	$61.80	$60.52	$60.09	$61.54	$60.75	$61.05	$61.73	$61.44	$61.38
RT Delta %	-8.8%	-8.0%	-8.7%	-8.9%	-8.7%	-8.9%	-8.8%	-8.7%	-8.7%
September-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.25	$30.30	$30.43	$31.16	$30.92	$30.54	$31.05	$30.95	$30.92
Real-Time	$34.11	$33.18	$33.13	$33.94	$33.59	$33.37	$33.89	$33.74	$33.69
RT Delta %	9.2%	9.5%	8.9%	8.9%	8.6%	9.3%	9.2%	9.0%	9.0%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-53.9%	-54.0%	-53.7%	-53.9%	-53.5%	-54.4%	-54.1%	-54.0%	-54.0%
Yr over Yr RT	-44.8%	-45.2%	-44.9%	-44.8%	-44.7%	-45.3%	-45.1%	-45.1%	-45.1%

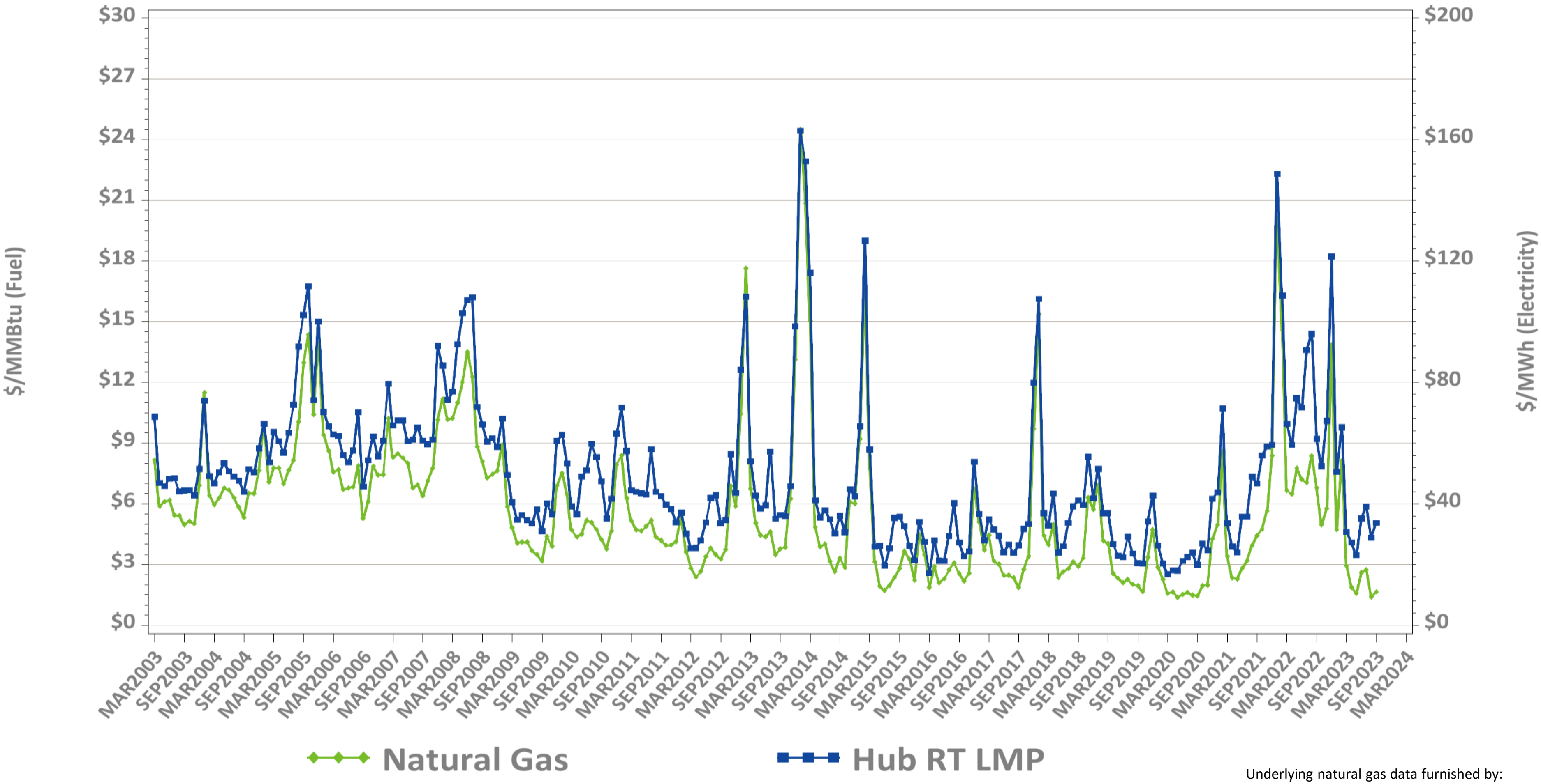
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

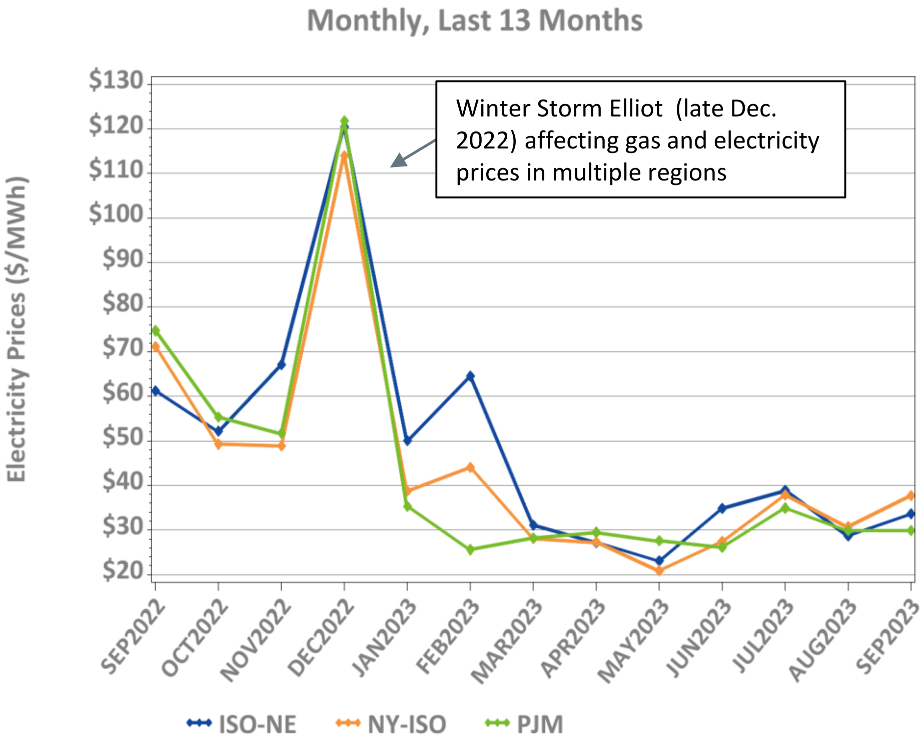
ice Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

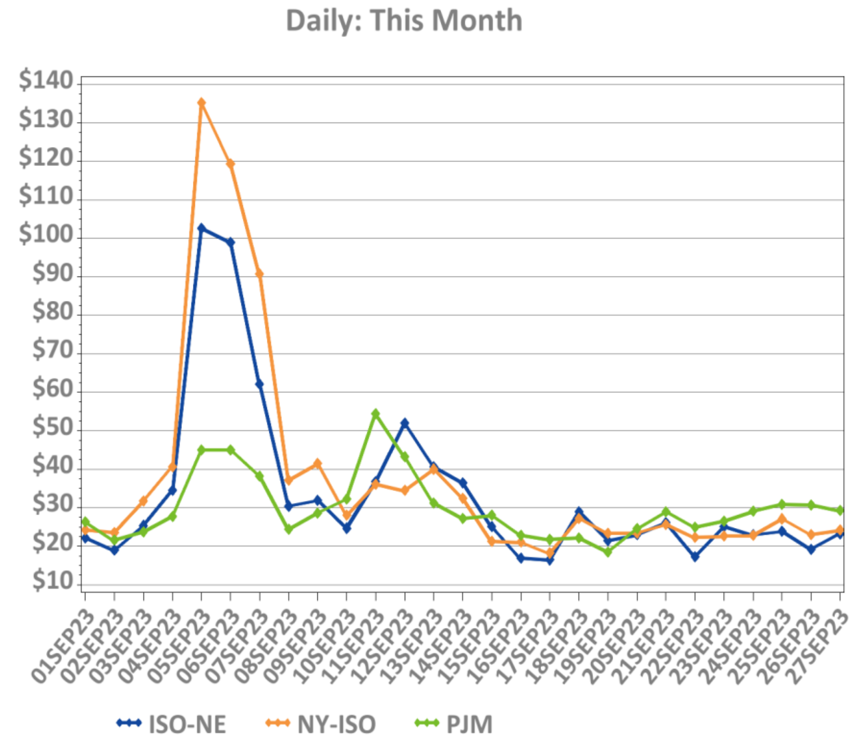


Underlying natural gas data furnished by: ICE Global markets in clear view

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

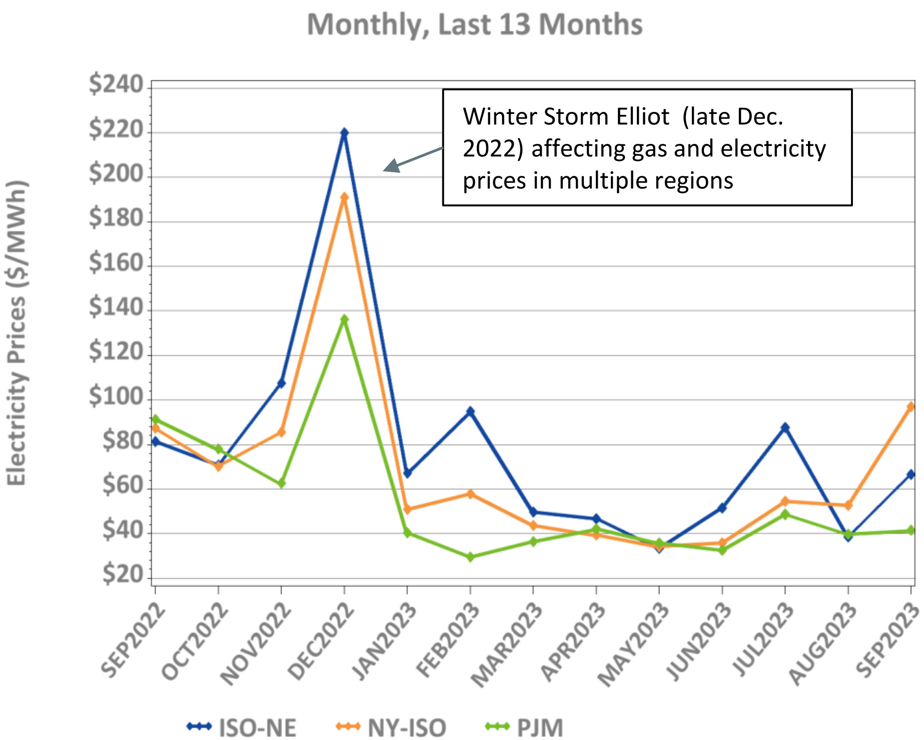


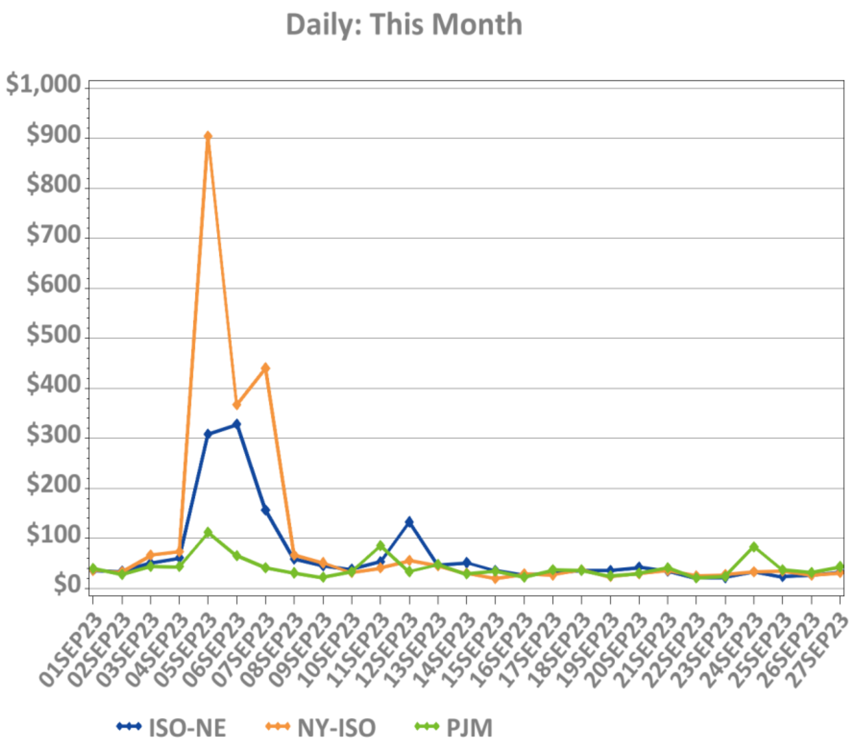
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





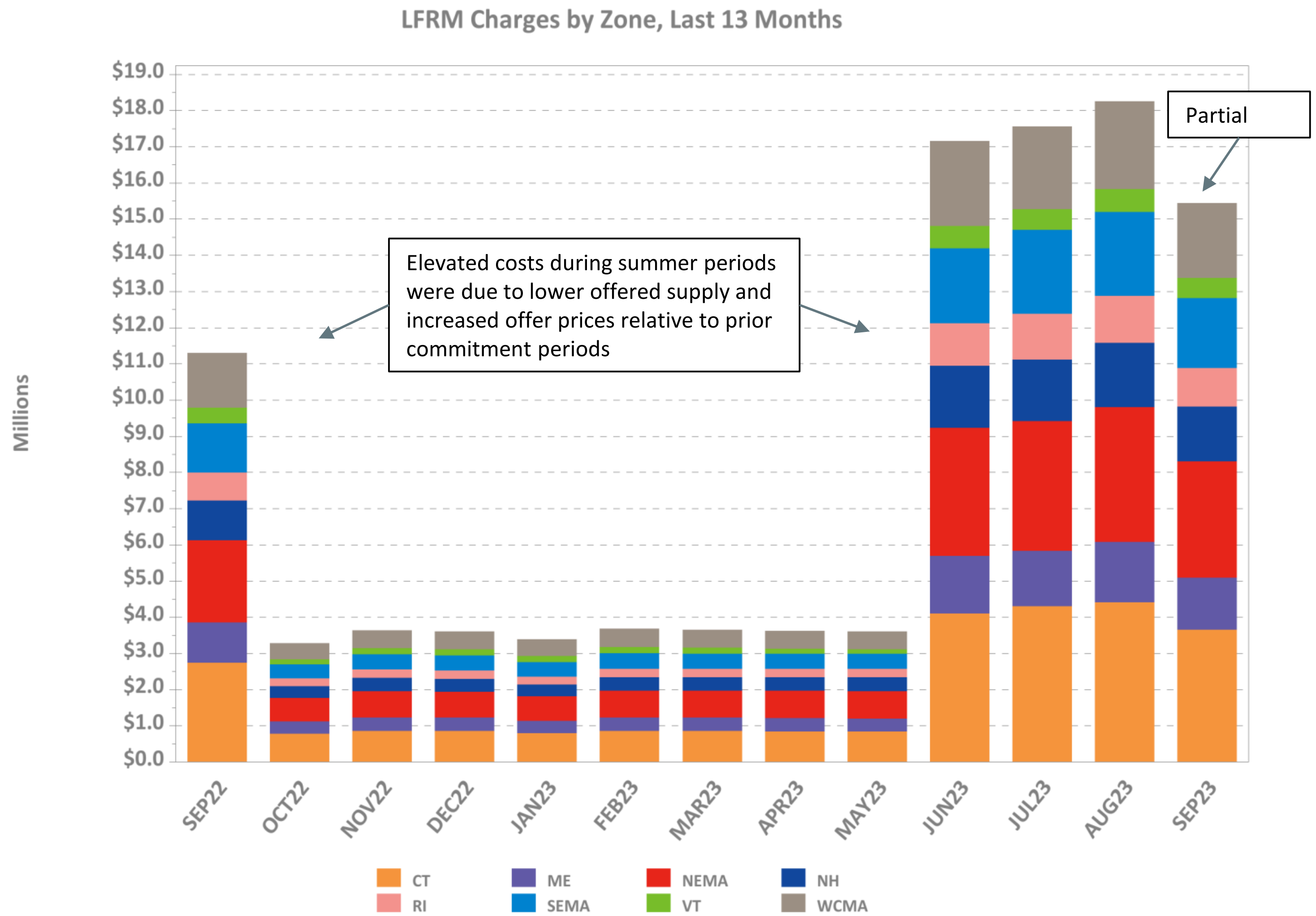
***Forecasted New England daily peak hours reflected**

Reserve Market Results – September 2023

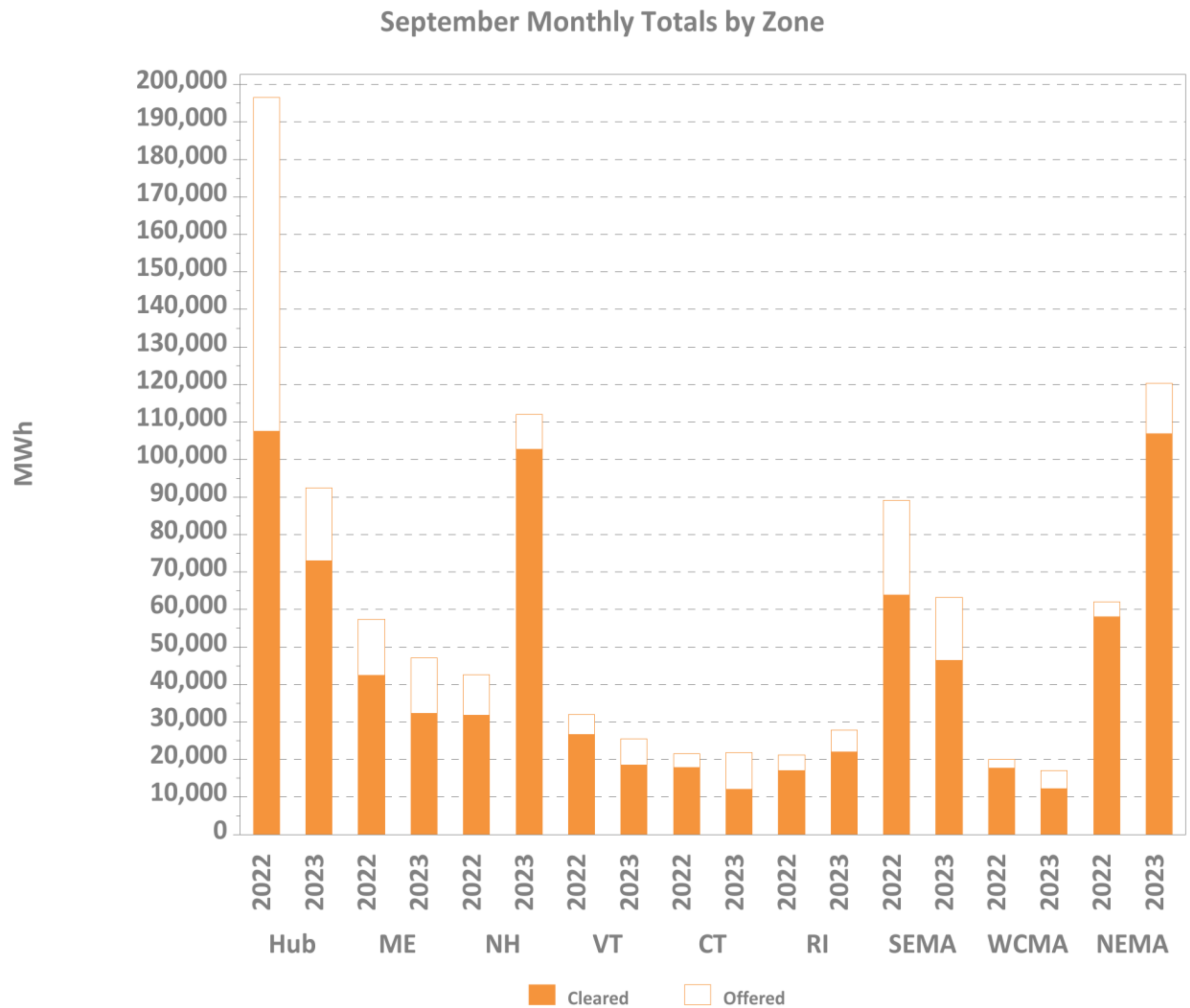
- Maximum potential Forward Reserve Market payments of $17M were reduced by credit reductions of $0.6M, failure-to-reserve penalties of $1.0M and failure-to-activate penalties of $10K, resulting in a net payout of $15.4M or 91% of maximum
  - Rest of System: $12.69M/13.96M (91%)
  - Southwest Connecticut: $0.44M/0.45M (99%)
  - Connecticut: $2.2M/2.51M (88%)
  - NEMA: $0.1M/0.1M (100%)
- $3.3M total Real-Time credits were reduced by $1.8M in Forward Reserve Energy Obligation Charges for a net of $1.5M in Real-Time Reserve payments
  - Rest of System: 177 hours, $450K
  - Southwest Connecticut: 177 hours, $580K
  - Connecticut: 177 hours, $204K
  - NEMA: 179 hours, $252K

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

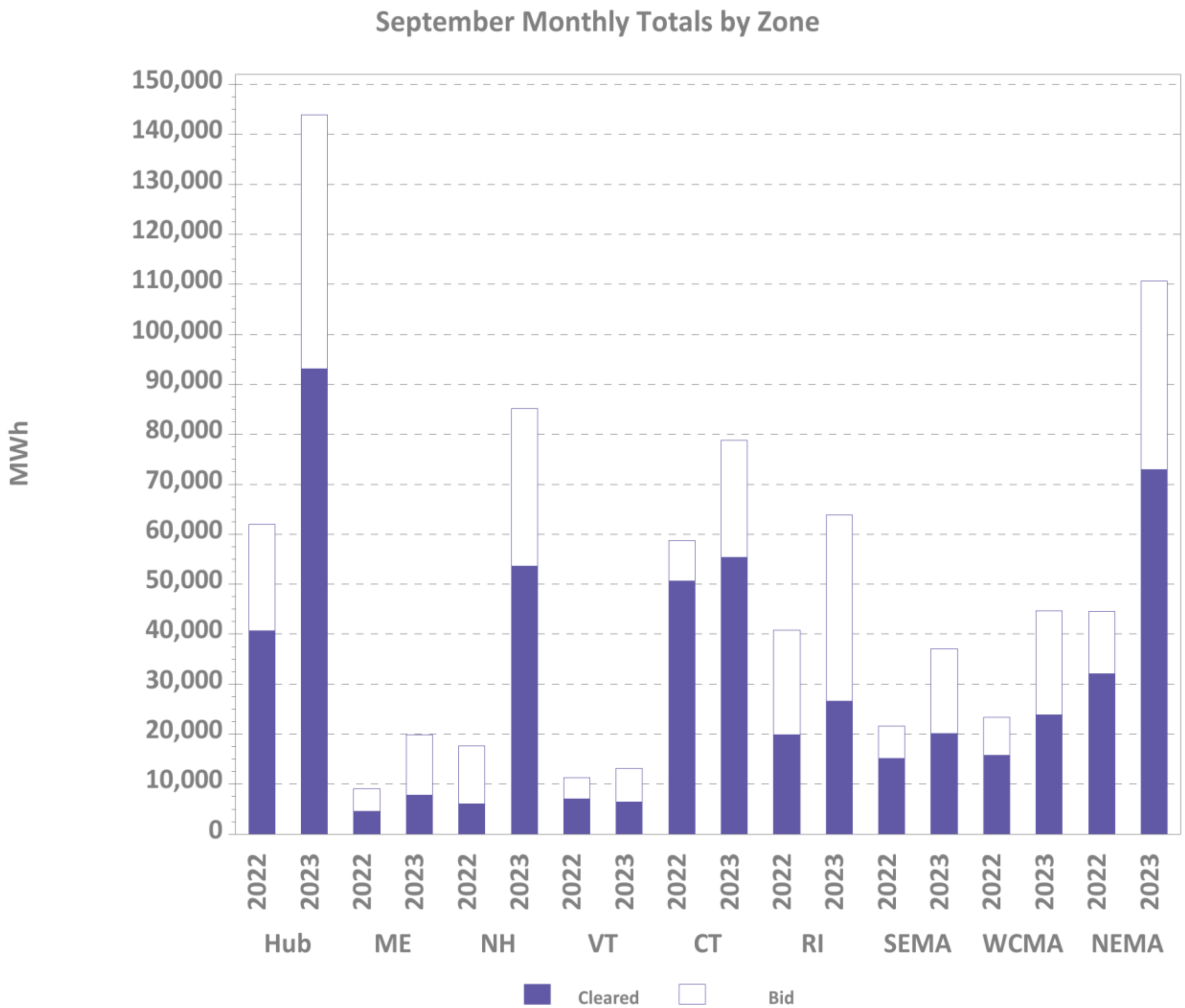
LFRM Charges to Load by Load Zone ($)



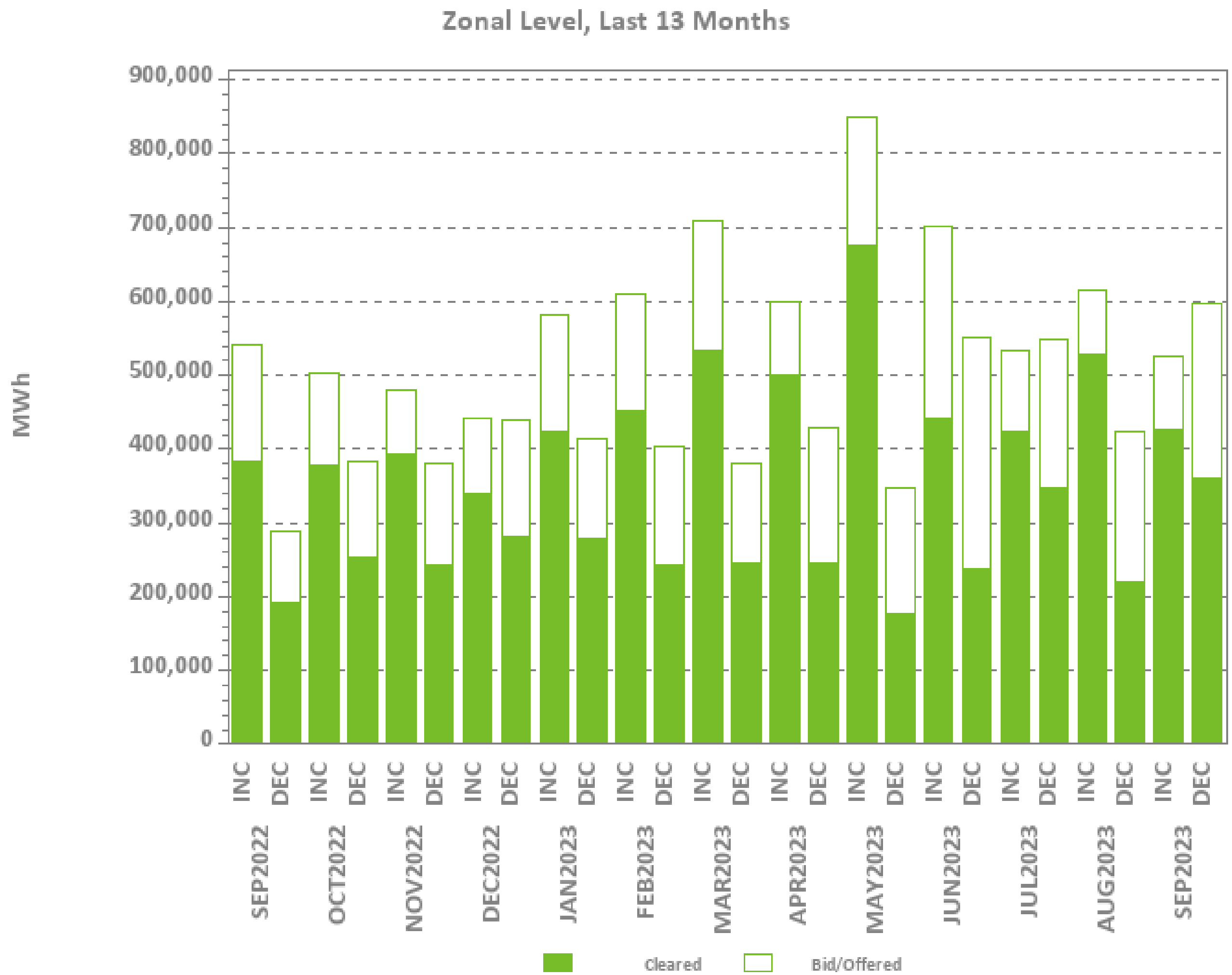
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

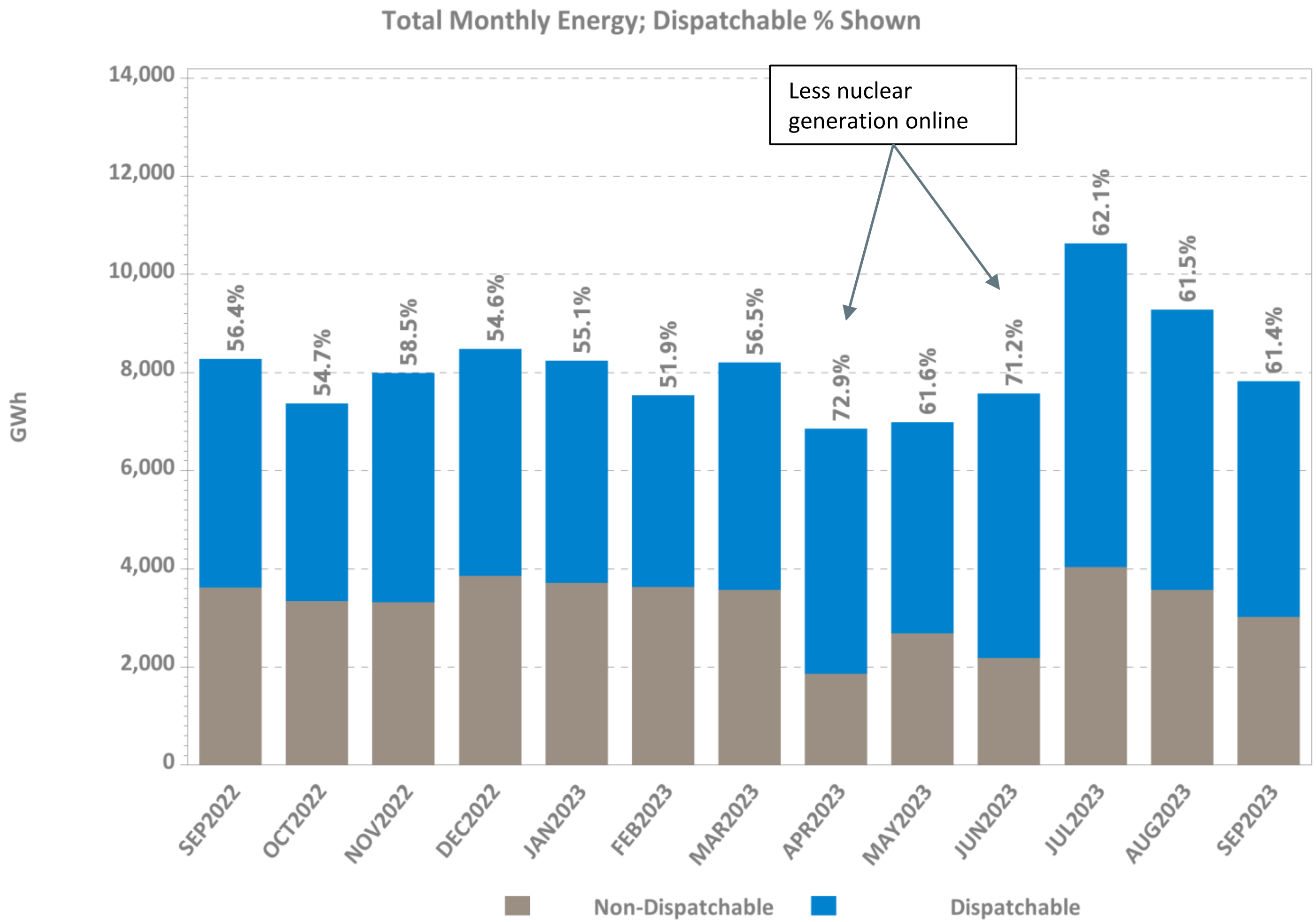


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- 2023-24 RSP will continue the streamlining efforts started with the 2021 RSP
- 2023-24 RSP will focus on being an overview narrative about ISO’s system planning and the outlook for the New England grid
- The draft 2023-24 RSP was shared with stakeholders on August 16 and comments were received
  - Few comments were submitted
- RSP Public Meeting will be held on November 1 and will be concurrent with the ISO Open Board Meeting
  - Presentation from Debra Lew, Associate Director, Energy Systems Integration Group
  - Registration is now open

Planning Advisory Committee (PAC)

- October 18 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - E183W 115 kV Line Rebuild (Rhode Island Energy)
    - M13 & L14 115 kV Line Rebuild (Rhode Island Energy)
    - S171N & T172N 115 kV Line Rebuild (Rhode Island Energy)
    - K42 Transmission Line Replacement Project Update (VELCO)
  - New England Transmission Owners "NETO" Asset Management Process
  - Economic Planning for the Clean Energy Transition (EPCET) – Additional Policy Sensitivity Results
  - 2050 Transmission Study: Final Results and Estimated Costs

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

2050 Transmission Study

- 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
- 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
- Consultant to perform cost estimates has been selected – Electrical Consultants Inc. (ECI)
- ECI is working on developing cost estimates for potential transmission additions
- Development of transmission solutions will continue throughout the first half of 2023
- Additional discussion on solution development occurred at the 4/20/23 and 7/25/23 PAC meetings
- Discussion on potential solution costs is expected at the 10/18/23 PAC meeting
- Draft report is scheduled for release by 11/1/23

Economic Studies

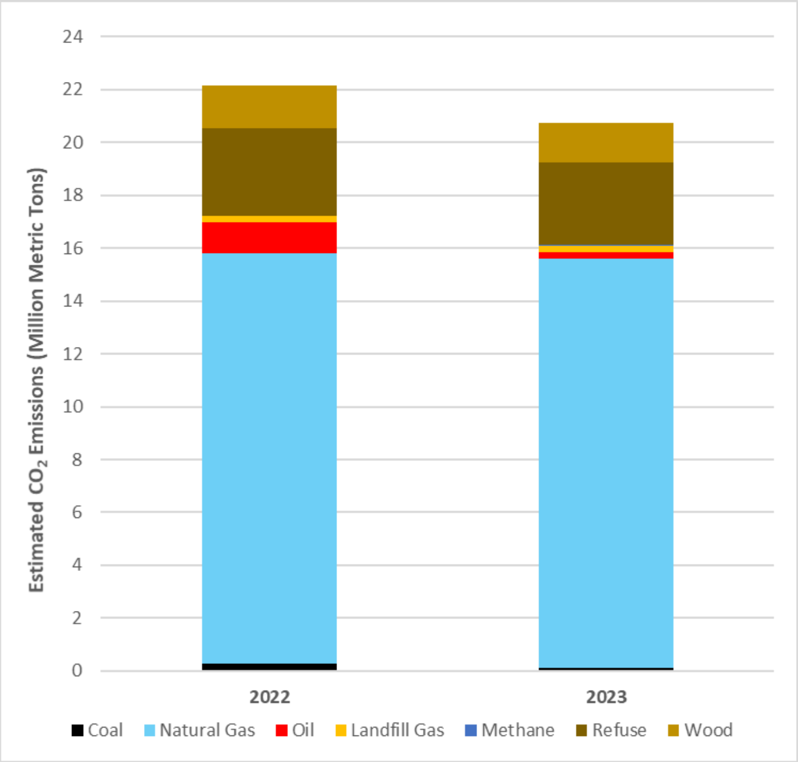
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented new modeling features, assumptions and results from the Benchmark and Market Efficiency Need scenarios, an overview of the capacity expansion model and how it will be used in the Policy scenario. The ISO presented preliminary results from the Policy scenario in June 2023. Sensitivity results were presented in July and August.
    - FGRS Phase 2 is now the Stakeholder-Requested Scenario in EPCET

Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard
  - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability “gaps” that remain will be identified
  - High-level outline was presented at the April PAC

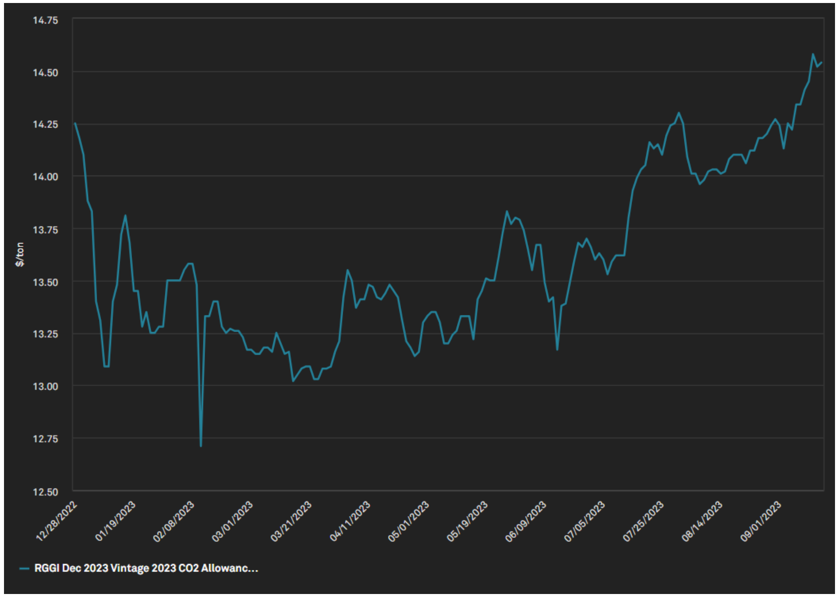
New England Power System Carbon Emissions

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



Data as of 9/10/2023

RGGI Allowance Prices



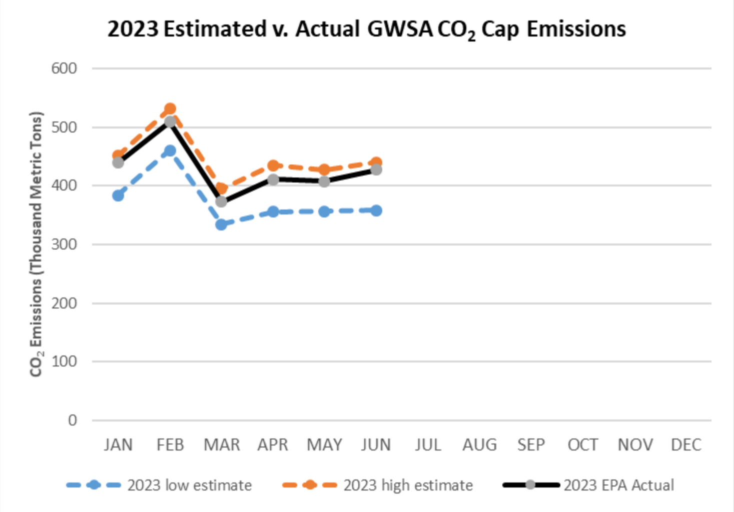
- 9/18/23: RGGI allowance spot price - $14.54
- 9/26/23: Third RGGI Program Review Public Meeting
  - Draft agenda includes an Environmental Justice and Equity section

RGGI – Regional Greenhouse Gas Initiative

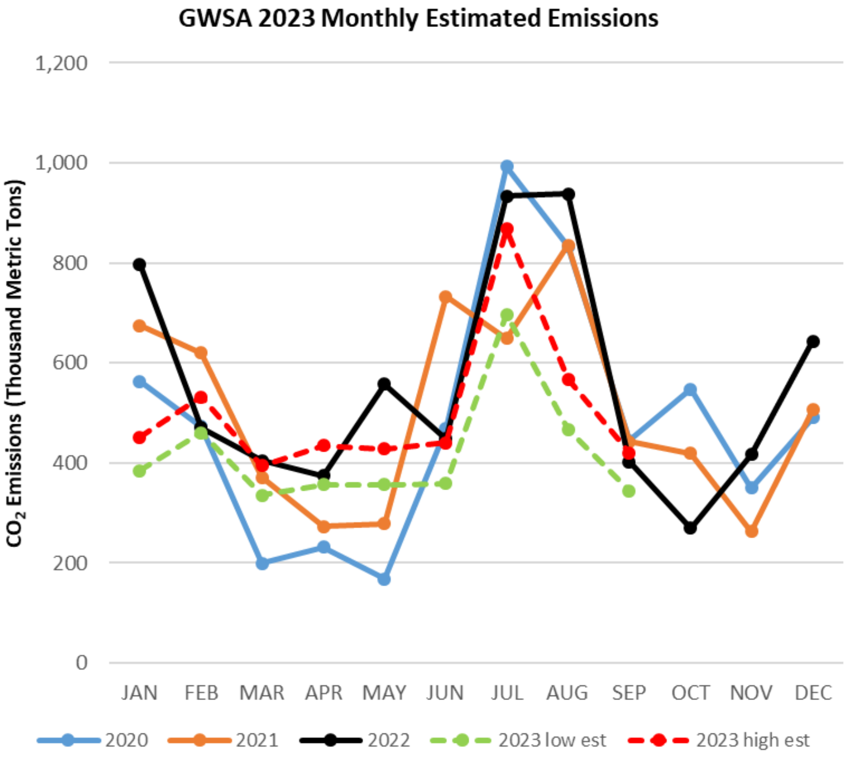
Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 9/20/23, September 2023 estimated GWSA CO_2 emissions range between **344,257** and **419,808** metric tons
  - Year-to-date 2023 estimated emissions range between **48%** and **58%** of the 2023 cap of 7.84 MMT
- According to the EPA CAMPD, Q1 and Q2 (January-June) GWSA CO_2 emissions were **2.57** MMT. Q1 and Q2 emissions were **33%** 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

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 9/21/2023

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*	Dec-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 9/21/2023

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 9/21/2023

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 9/21/2023

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	Dec-23	3
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 9/21/2023

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 9/21/2023

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 9/21/2023

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-26	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 9/21/2023

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	1

SEMA/RI Reliability Projects, cont.

Status as of 9/21/2023

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 9/21/2023

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 9/21/2023

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	Dec-23	3
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 9/21/2023

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 9/21/2023

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 9/21/2023

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	Dec-23	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	3

Upper Maine Solution Projects

Status as of 9/21/2023

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

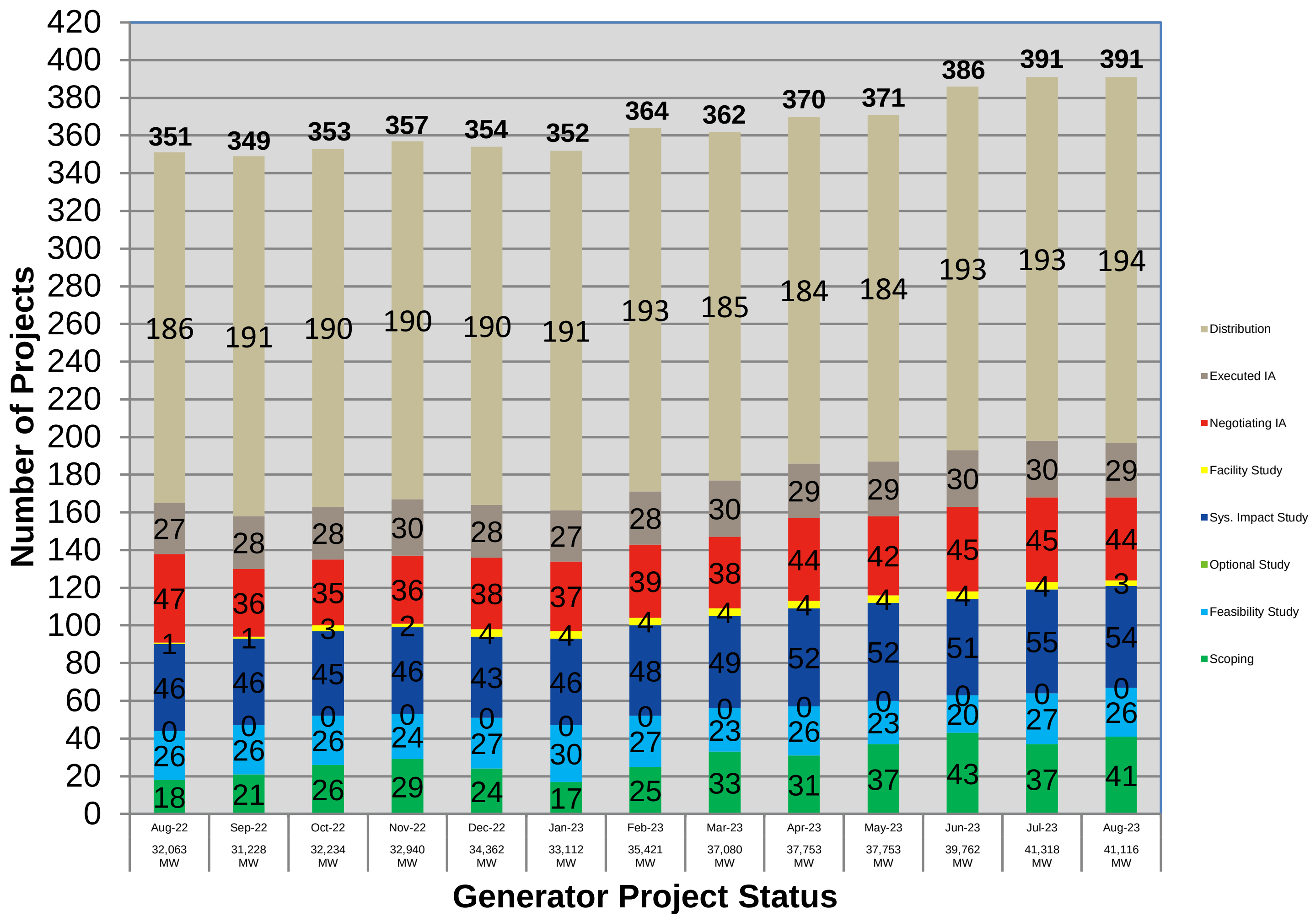
Upper Maine Solution Projects, cont.

Status as of 9/21/2023

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 September 1, 2023



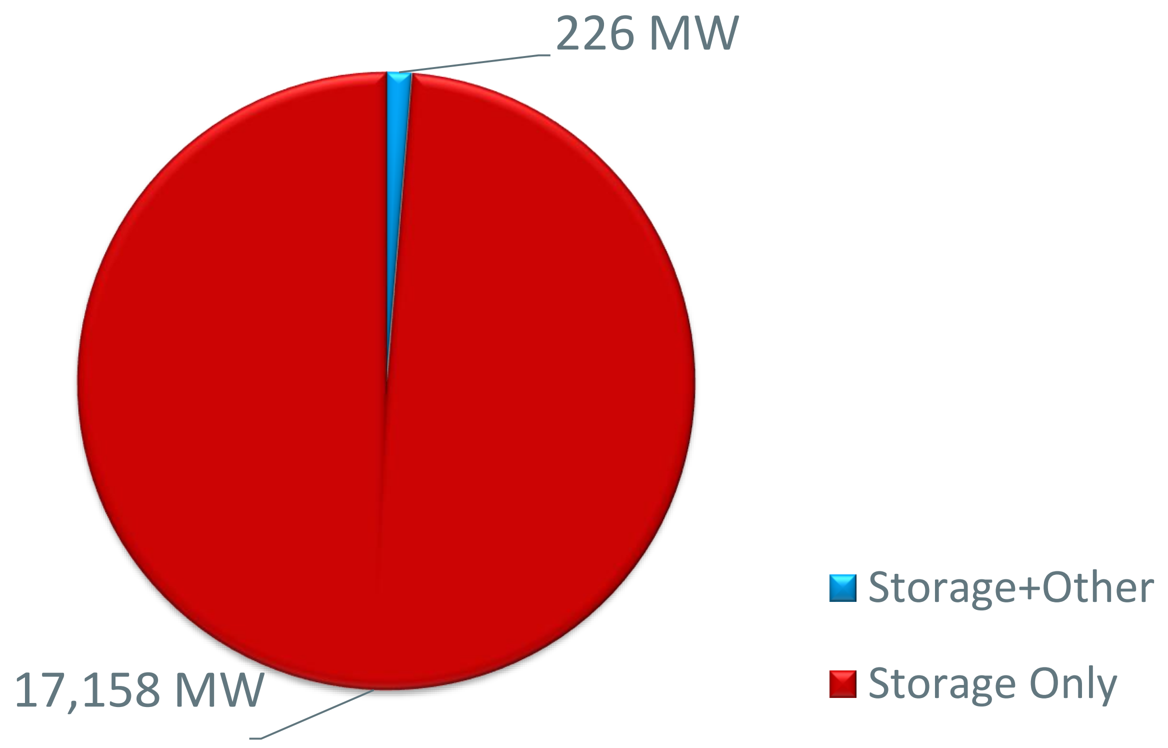
10 ETUs in Scoping, 6 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 2 in SIS

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

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

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



OPERABLE CAPACITY ANALYSIS

Fall 2023 and Preliminary Winter 2023/24 Analysis

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning November 4, 2023.

- The lowest 50/50 and 90/10 Preliminary Winter Operable Capacity Margins are projected for week beginning December 9, 2023.

OPERABLE CAPACITY ANALYSIS

Fall 2023 Analysis

Fall 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov. - 2023[2] CSO (MW)	Nov. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,237	31,743
Active Demand Capacity Resource (+) [5]	518	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	3,948	4,560
Gas Generator Outages MW (-)	2,996	3,837
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,392	21,256
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,005	17,005
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,310	19,310
Operable Capacity Margin	82	1,946

[1]Operable Capacity is based on data as of **September 25, 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 **September 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 4, 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.

Fall 2023 Operable Capacity Analysis

90/10 Load Forecast	Nov. - 2023[2] CSO (MW)	Nov. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,237	31,743
Active Demand Capacity Resource (+) [5]	518	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	3,948	4,560
Gas Generator Outages MW (-)	2,996	3,837
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,392	21,256
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,662	17,662
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,967	19,967
Operable Capacity Margin	-575	1,289

[1]Operable Capacity is based on data as of **September 25, 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 **September 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 4, 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.

Fall 2023 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 25, 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 September, October & November.

Report created: 9/25/2023

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
10/14/2023	28364	418	941	66	5262	2388	2800	0	19339	16324	2305	18629	710	N	Fall 2023
10/21/2023	28364	418	941	66	4629	2822	2800	0	19538	16685	2305	18990	548	N	Fall 2023
10/28/2023	28237	518	958	223	4172	2768	3600	0	19396	16890	2305	19195	201	N	Fall 2023
11/4/2023	28237	518	958	223	3948	2996	3600	0	19392	17005	2305	19310	82	Y	Fall 2023
11/11/2023	28237	518	958	223	4645	1324	3600	0	20367	17347	2305	19652	715	N	Fall 2023
11/18/2023	28237	518	958	223	2543	1178	3600	192	22423	18079	2305	20384	2039	N	Fall 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 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.

Fall 2023 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 25, 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 September, October & November.

Report created: 9/25/2023

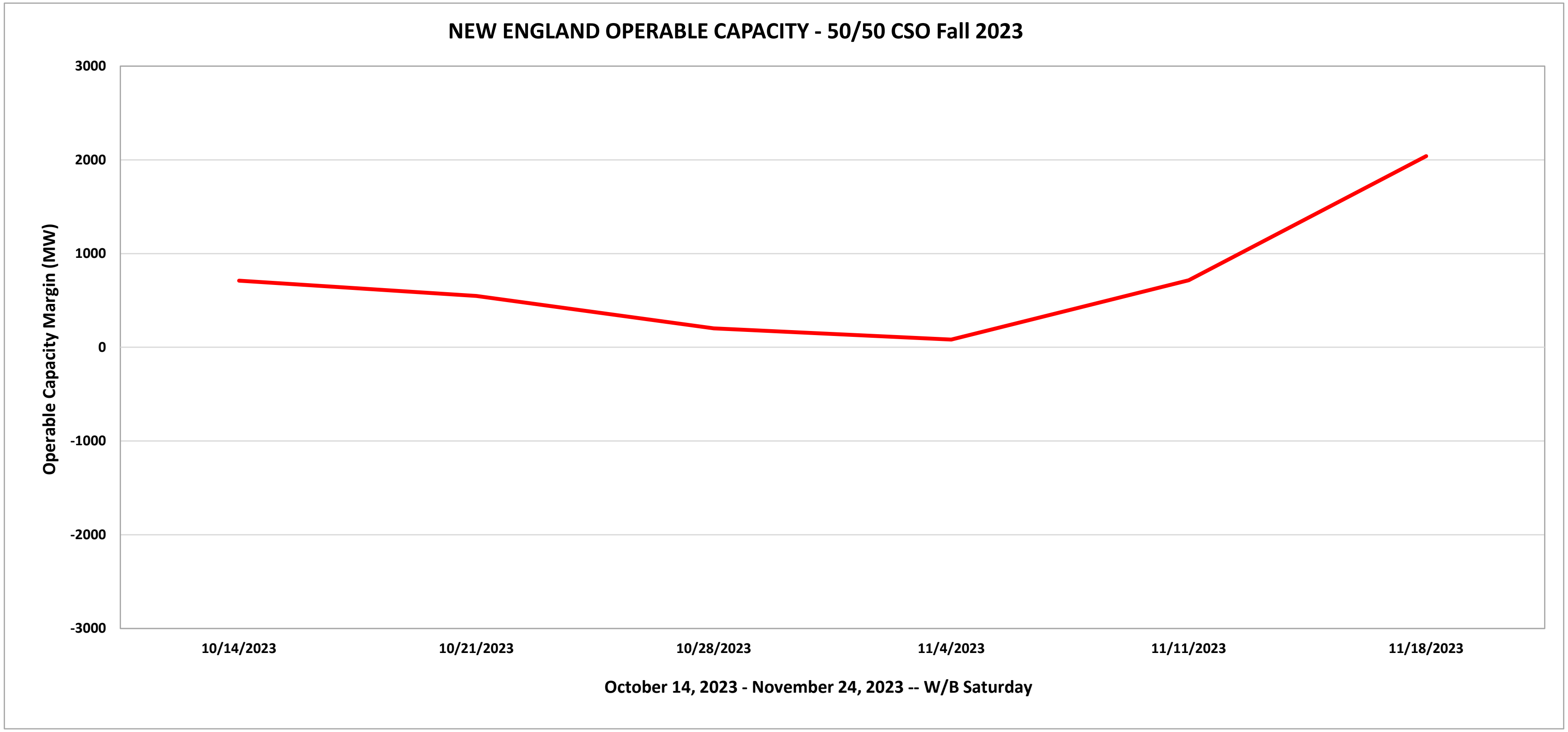
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
10/14/2023	28364	418	941	66	5262	2388	2800	0	19339	16957	2305	19262	77	N	Fall 2023
10/21/2023	28364	418	941	66	4629	2822	2800	0	19538	17331	2305	19636	-98	N	Fall 2023
10/28/2023	28237	518	958	223	4172	2768	3600	0	19396	17543	2305	19848	-452	N	Fall 2023
11/4/2023	28237	518	958	223	3948	2996	3600	0	19392	17662	2305	19967	-575	Y	Fall 2023
11/11/2023	28237	518	958	223	4645	1324	3600	0	20367	18015	2305	20320	47	N	Fall 2023
11/18/2023	28237	518	958	223	2543	1178	3600	357	22258	18773	2305	21078	1180	N	Fall 2023

Column Definitions

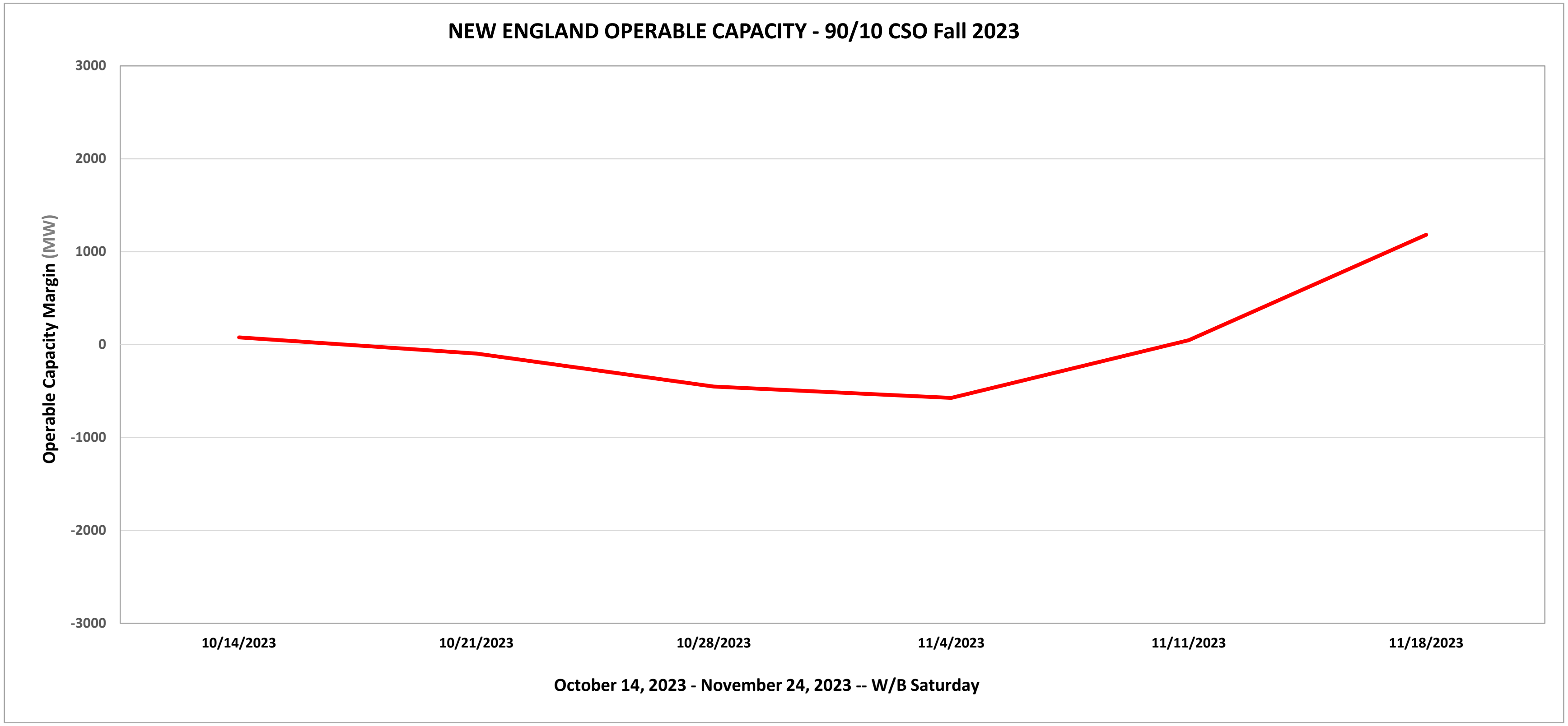
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can 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 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.

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

Fall 2023 Operable Capacity Analysis
50/50 Forecast (Reference)



Fall 2023 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2023/24 Analysis

Preliminary Winter 2023/24 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Dec. - 2023[2] CSO (MW)	Dec. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,334	31,743
Active Demand Capacity Resource (+) [5]	522	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	2,200	2,378
Gas Generator Outages MW (-)	676	896
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	1,692	1,356
Net Capacity (NET OPCAP SUPPLY MW)	22,269	25,423
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,464	19,464
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,769	21,769
Operable Capacity Margin	500	3,654

[1]Operable Capacity is based on data as of **September 25, 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 **September 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **December 9, 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 2023/24 Operable Capacity Analysis

90/10 Load Forecast	Dec. - 2023[2] CSO (MW)	Dec. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,334	31,743
Active Demand Capacity Resource (+) [5]	522	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	2,200	2,378
Gas Generator Outages MW (-)	676	896
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	2,679	2,489
Net Capacity (NET OPCAP SUPPLY MW)	21,282	24,290
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,199	20,199
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,504	22,504
Operable Capacity Margin	-1,222	1,786

[1] Operable Capacity is based on data as of **September 25, 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 **September 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **December 9, 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 2023/24 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 25, 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 December through March.

Report created: 9/25/2023

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
11/25/2023	28237	518	958	223	2631	797	3600	865	22043	18794	2305	21099	944	N	Winter 2023/2024
12/2/2023	28334	522	958	223	2027	951	3200	853	23006	19177	2305	21482	1524	N	Winter 2023/2024
12/9/2023	28334	522	958	223	2200	676	3200	1692	22269	19464	2305	21769	500	Y	Winter 2023/2024
12/16/2023	28334	522	958	223	1339	731	3200	2014	22753	19475	2305	21780	973	N	Winter 2023/2024
12/23/2023	28334	522	958	223	0	421	3200	2713	23703	19537	2305	21842	1861	N	Winter 2023/2024
12/30/2023	28334	522	958	223	0	366	2800	3367	23504	19808	2305	22113	1391	N	Winter 2023/2024
1/6/2024	28334	522	958	223	0	366	2800	3362	23509	20269	2305	22574	935	N	Winter 2023/2024
1/13/2024	28334	522	958	223	0	366	2800	3217	23654	20269	2305	22574	1080	N	Winter 2023/2024
1/20/2024	28334	522	958	223	0	366	2800	2768	24103	20269	2305	22574	1529	N	Winter 2023/2024
1/27/2024	28334	522	958	223	59	33	3100	2802	24043	20049	2305	22354	1689	N	Winter 2023/2024
2/3/2024	28334	522	958	223	59	33	3100	2503	24342	19784	2305	22089	2253	N	Winter 2023/2024
2/10/2024	28334	522	958	223	59	33	3100	2204	24641	19755	2305	22060	2581	N	Winter 2023/2024
2/17/2024	28334	522	958	223	0	33	3100	1755	25149	19495	2305	21800	3349	N	Winter 2023/2024
2/24/2024	28334	522	958	223	52	33	3100	1456	25396	18516	2305	20821	4575	N	Winter 2023/2024
3/2/2024	28334	522	958	223	105	33	2200	381	27318	18170	2305	20475	6843	N	Winter 2023/2024
3/9/2024	28334	522	958	223	1354	404	2200	0	26079	17976	2305	20281	5798	N	Winter 2023/2024
3/16/2024	28334	522	958	223	1354	501	2200	0	25982	17614	2305	19919	6063	N	Winter 2023/2024
3/23/2024	28334	522	958	223	1361	778	2200	0	25698	17054	2305	19359	6339	N	Winter 2023/2024
3/30/2024	28232	518	958	223	815	1796	2700	0	24620	16379	2305	18684	5936	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.

Preliminary Winter 2023/24 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 25, 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 December through March.

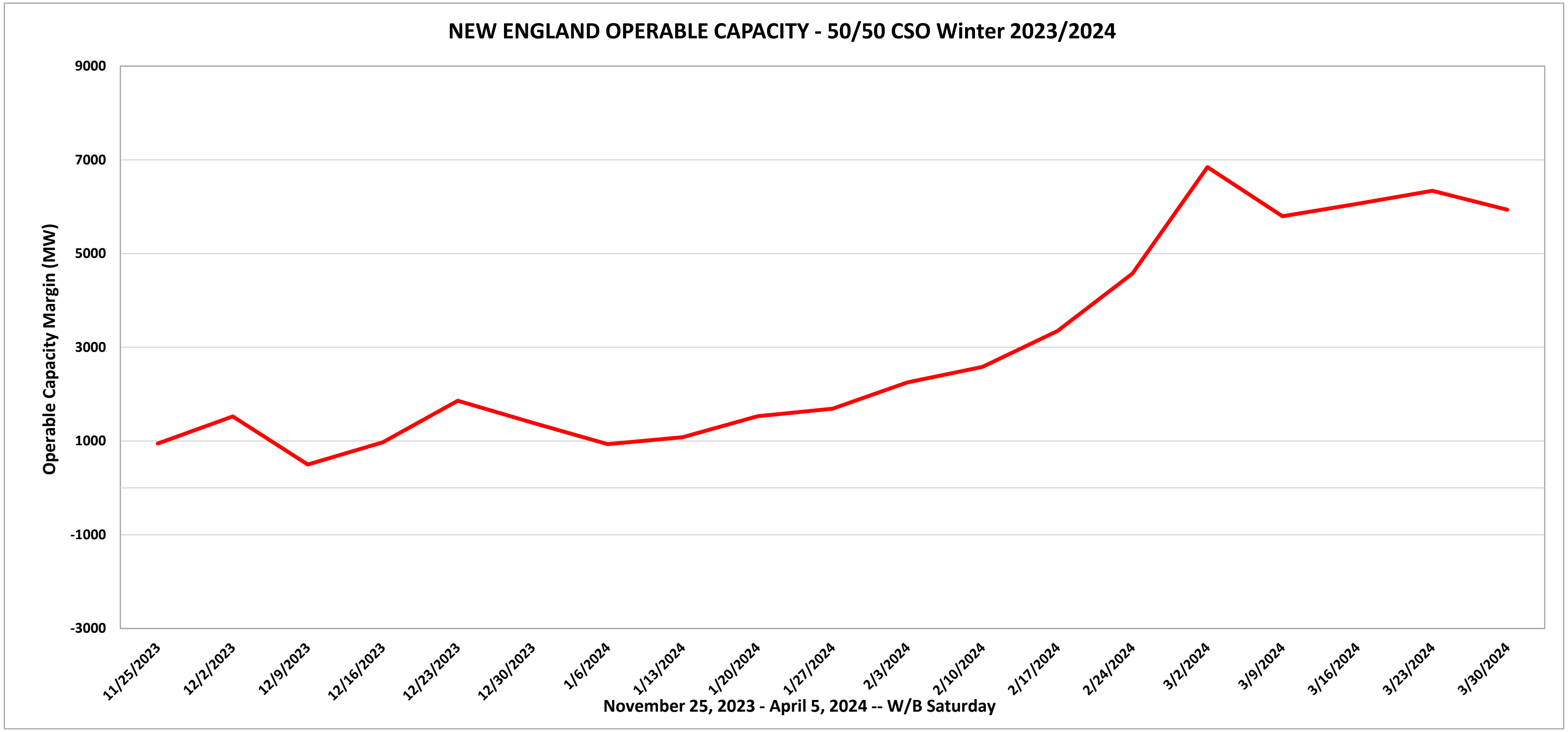
Report created: 9/25/2023

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
11/25/2023	28237	518	958	223	2631	797	3600	1779	21129	19512	2305	21817	-688	N	Winter 2023/2024
12/2/2023	28334	522	958	223	2027	951	3200	1841	22018	19903	2305	22208	-190	N	Winter 2023/2024
12/9/2023	28334	522	958	223	2200	676	3200	2679	21282	20199	2305	22504	-1222	Y	Winter 2023/2024
12/16/2023	28334	522	958	223	1339	731	3200	3133	21634	20211	2305	22516	-882	N	Winter 2023/2024
12/23/2023	28334	522	958	223	0	421	3200	3859	22557	20274	2305	22579	-22	N	Winter 2023/2024
12/30/2023	28334	522	958	223	0	366	2800	4042	22829	20555	2305	22860	-31	N	Winter 2023/2024
1/6/2024	28334	522	958	223	0	366	2800	4173	22698	21032	2305	23337	-639	N	Winter 2023/2024
1/13/2024	28334	522	958	223	0	366	2800	3965	22906	21032	2305	23337	-431	N	Winter 2023/2024
1/20/2024	28334	522	958	223	0	366	2800	3666	23205	21032	2305	23337	-132	N	Winter 2023/2024
1/27/2024	28334	522	958	223	59	33	3100	3999	22846	20804	2305	23109	-263	N	Winter 2023/2024
2/3/2024	28334	522	958	223	59	33	3100	3550	23295	20530	2305	22835	460	N	Winter 2023/2024
2/10/2024	28334	522	958	223	59	33	3100	3251	23594	20500	2305	22805	789	N	Winter 2023/2024
2/17/2024	28334	522	958	223	0	33	3100	2653	24251	20231	2305	22536	1715	N	Winter 2023/2024
2/24/2024	28334	522	958	223	52	33	3100	2204	24648	19218	2305	21523	3125	N	Winter 2023/2024
3/2/2024	28334	522	958	223	105	33	2200	1278	26421	18860	2305	21165	5256	N	Winter 2023/2024
3/9/2024	28334	522	958	223	1354	404	2200	802	25277	18659	2305	20964	4313	N	Winter 2023/2024
3/16/2024	28334	522	958	223	1354	501	2200	0	25982	18285	2305	20590	5392	N	Winter 2023/2024
3/23/2024	28334	522	958	223	1361	778	2200	0	25698	17705	2305	20010	5688	N	Winter 2023/2024
3/30/2024	28232	518	958	223	815	1796	2700	0	24620	17014	2305	19319	5301	N	Winter 2023/2024

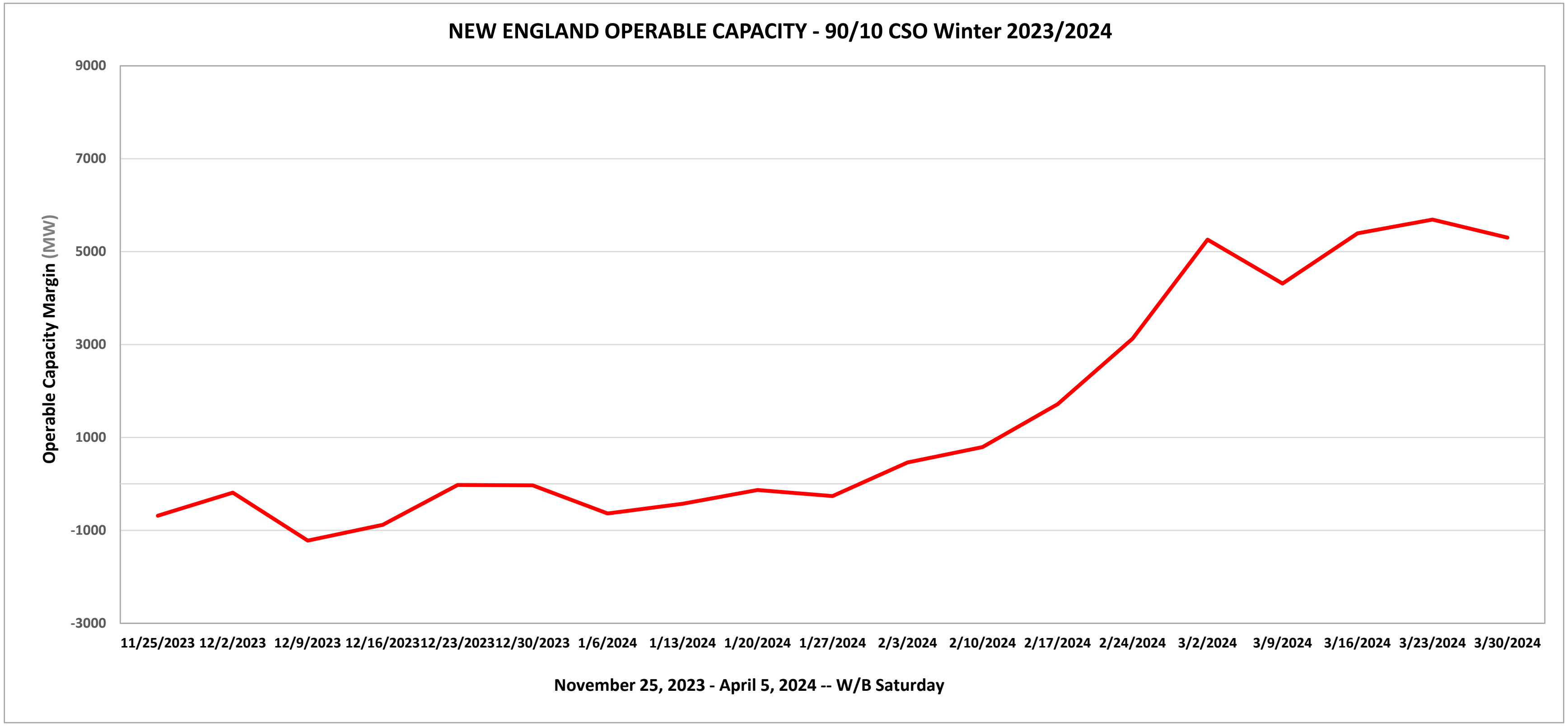
Column Definitions

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.

Preliminary Winter 2023/24 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Winter 2023/24 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