

NEPOOL Participants Committee Report

August 2025



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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



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Regular Operations Report - Highlights



Highlights: July 2025

Data through July 30th, unless otherwise noted

- **Peak Hour** on July 29
 - 25,295 MW system peak (Revenue Quality Metered/RQM); hour ending 7:00 P.M.
- **Minimum Load** on July 4
 - 9,663 MW (Telemetered); hour ending 12:00 P.M.
- **Average Pricing**
 - Day Ahead (DA) Hub Locational Marginal Price (LMP): \$70.56/MWh
 - Real Time (RT) Hub LMP: \$60.22/MWh
 - Natural Gas: \$4.27/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value \$1B up from \$672M in July 2024
 - Ancillary Markets* value \$40.5M up from \$19.9M in July 2024
 - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 100.5% during July, up from 99.2% during June
 - Updated June Energy Market value: \$589M
- **Net Commitment Period Compensation (NCPC)** total \$4.7M
 - Represents 0.5% of monthly Energy Market value
 - First Contingency \$4.4M
 - Dispatch Lost Opportunity Cost (DLOC) - \$701K; Rapid Response Pricing (RRP) Opportunity Cost - \$581K; Posturing - \$0; Generator Performance Auditing (GPA) - \$0
 - \$84K paid to resources at external locations, down \$166K from June
 - \$40K charged to Day Ahead Load Obligation (DALO) at external locations; \$4K to Day Ahead Generation Obligation (DAGO) at external locations; \$39K to RT Deviations
 - Distribution \$300K; 2nd Contingency and Voltage were zero.
- **Forward Capacity Market (FCM)** market value \$88.6M
 - FCM peak for 2025 is currently 26,184 MWh

Underlying natural gas data furnished by:

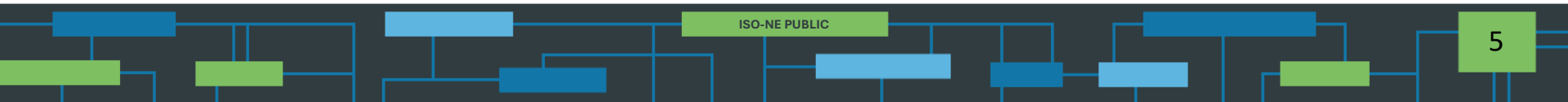


*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund **DA cleared physical energy is the sum of generation, DRR, and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **26,024 MW**
 - hour ending 7:00 P.M. on Tuesday, June 24
- RQM System Peak Load: **26,551 MW** (initial)
 - hour ending 6:00 P.M. on Tuesday, June 24
- FCM Peak Load: **26,184 MW** (preliminary & subject to change)
 - hour ending 7:00 P.M. on Tuesday, June 24
 - At this hour, the capacity zone-level FCM peak loads were 3,357 MW in Northern New England, 2,026 MW in Maine, 10,055 MW in Rest-of-Pool, and 10,746 MW in Southeast New England.

*Telemetered loads are as reported by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Generation (SOG). Due to the difference in calculation methodologies and the impact of SOGs, these values can occur on different days and/or hours. Both are 'net energy for load' concepts and include transmission losses. FCM load values reflect the sum of active, normal load assets that are non-dispatchable, are included in the FCM settlement and do not include transmission losses.



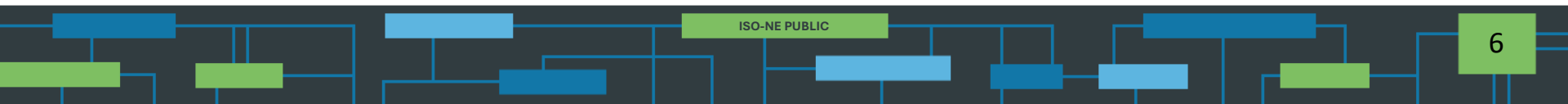
Day Ahead Ancillary Services (DAAS) Results

- Average daily total DA E&AS Market value: **\$36.0M**
- DAAS Settlements:
 - Average daily Gross (pre-closeout) DAAS Credits: **\$1.7M**
 - Includes EIR, TMOR, TMNSR, and TMOR
 - Net (post-closeout) DAAS Credits per MWh Cleared: **\$19.75/MWh**
 - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **3.2%**
- FER Credits* as % of total DA E&AS Market Value: **3.6%**
- Energy Gap:
 - Average hourly cleared EIR MWh: **55 MWh**
 - Average hourly cleared FER Price: **\$3.01/MWh**

Note: E&AS refers to Energy and Ancillary Services

*Forecast Energy Requirements (FER) credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR).

FER credits are allocated to DA Exports and RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARD)



Day Ahead Ancillary Services (DAAS) Results

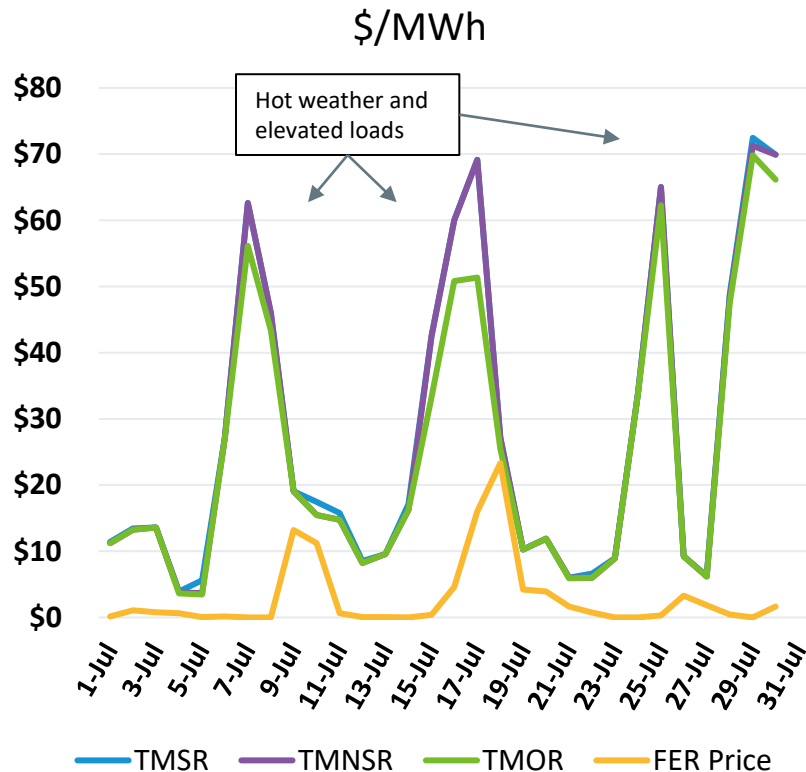
Month	Avg. Daily Total E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total E&AS Credit	FER Credit as % of Total E&AS Credit	Avg. Hourly Cleared EIR Obligation MW	Avg. FER Price
3/1/2025	\$17.3M	\$466K	\$202K	\$3.35	1.2%	6.2%	176	\$3.26
4/1/2025	\$13.9M	\$332K	\$175K	\$3.23	1.3%	5.8%	97	\$2.66
5/1/2025	\$11.0M	\$190K	\$52K	\$0.94	0.5%	5.2%	155	\$2.06
6/1/2025	\$20.2M	\$885K	\$173K	\$2.97	0.9%	6.6%	125	\$3.15
7/1/2025	\$36.0M	\$1,729K	\$1,154K	\$19.75	3.2%	3.6%	55	\$3.01

Note: E&AS refers to Energy and Ancillary Services

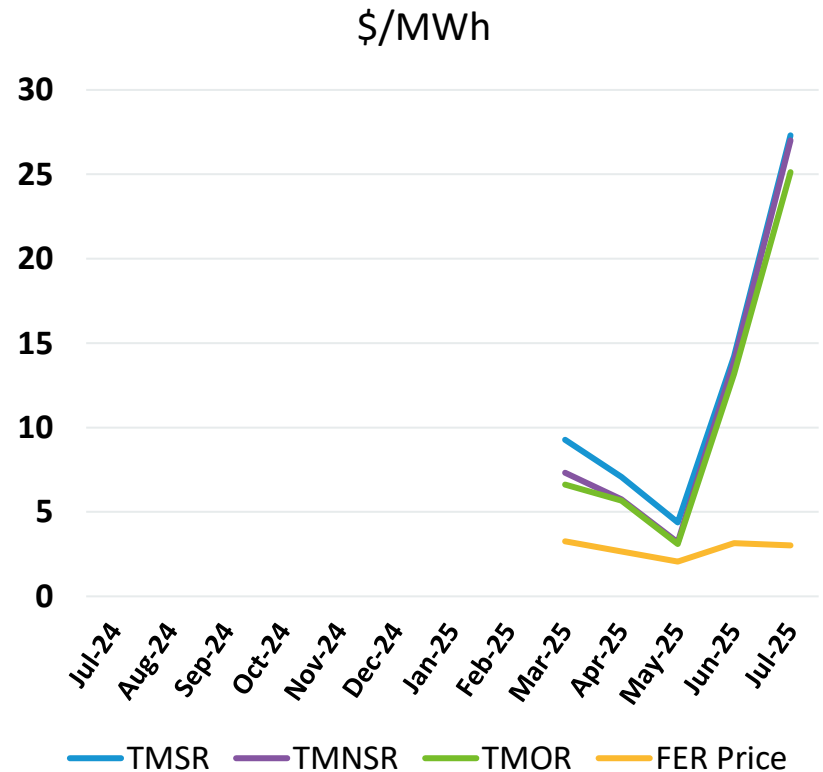
*Forecast Energy Requirements (FER) credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR)
FER credits are allocated to DA Exports and RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARD)

Average Hourly Day Ahead Ancillary Services (DAAS) Prices

Daily This Month



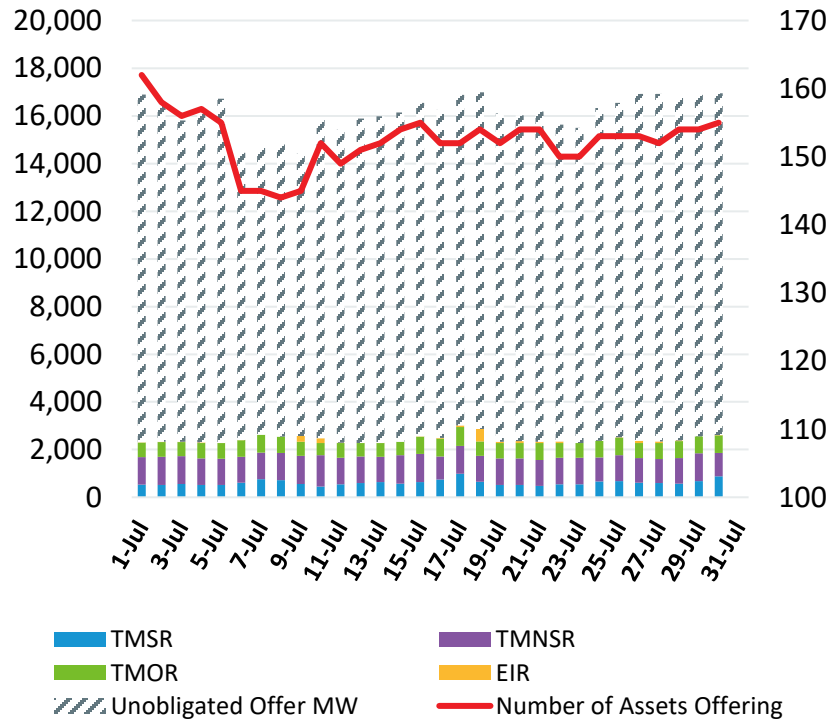
Monthly, Last 13 Months



Average Hourly DAAS Obligated and Unobligated Offer MW*

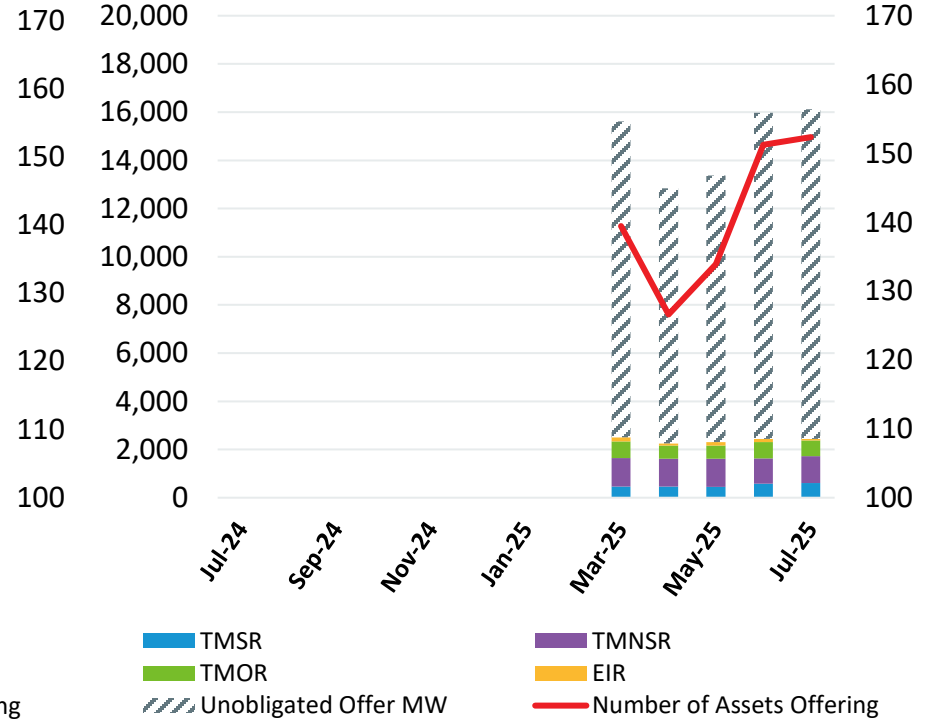
Daily This Month

\$/MWh



Monthly, Last 13 Months

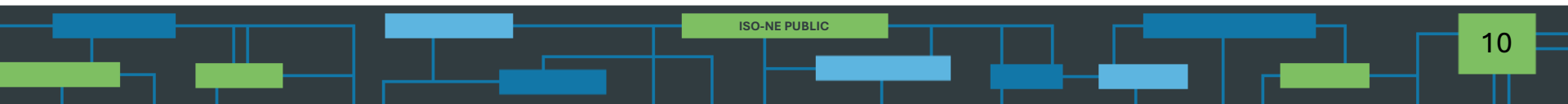
\$/MWh



*Unobligated Offer MW reflect the raw, as-offered DAAS MW amounts that remained unobligated (received no MW reward). This supply does not yet consider additional unit parameter constraints or dispatch constraints and should not be equated with actual capacity available in the dispatch solution.

Highlights

- The draft 2025 Regional System Plan will be discussed at the August 20 PAC meeting
- Benchmark, Policy and Stakeholder-Requested Economic Study Scenarios are complete and the draft report will be issued in August or September



Forward Capacity Market (FCM) Highlights

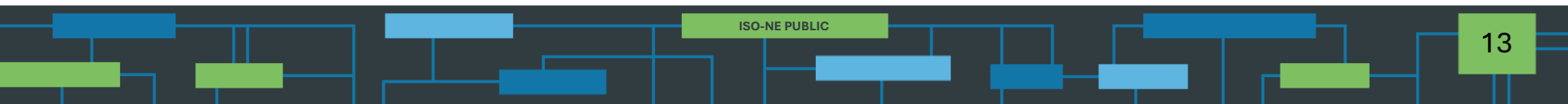
- CCP 16 (2025-2026)
 - The third annual reconfiguration auction (ARA3) was held March 3-5 and results were posted on April 1
- CCP 17 (2026-2027)
 - The second annual reconfiguration auction (ARA2) will be held August 1-5 and results will be posted by September 3
- CCP 18 (2027-2028)
 - ICR and related values for the ARAs to be conducted in 2025 were filed with FERC on November 22, 2024; FERC issued an order accepting the results effective January 21
 - The first annual reconfiguration auction (ARA1) was held June 2-4 and results were posted on July 2

FCM Highlights, cont.

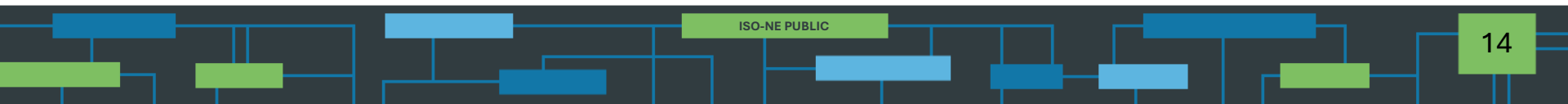
- CCP 19 (2028-2029)
 - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
 - On May 20, 2024 FERC issued an order accepting the additional delay to FCA 19
 - 2024 interim RA qualification process completed on November 1, 2024
 - A total of 1,389 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
 - 2025 interim RA qualification process began in April 2025
 - The Show of Interest submission deadline was April 30, 2025
 - In response to the April 4, 2025 order on the Order No. 2023 compliance filing, the ISO proposed narrow date changes to allow running the Transitional CNR Group Study with the 2025 interim RA qualification process. FERC accepted the proposed date changes in an order on June 30, 2025.
 - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

Load Forecast

- A new hourly forecast methodology was implemented as part of CELT 2025, and was discussed at the Load Forecast Committee (LFC)
- Stakeholder discussions related to CELT 2026 will begin in September at the LFC



SYSTEM OPERATIONS



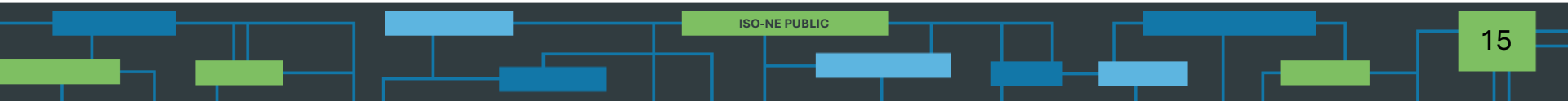
System Operations

<u>Weather Patterns</u>	Boston	Temperature: Above Normal (1.9°F) Max: 99°F, Min: 61°F Precipitation: 3.01" – Below Normal Normal: 3.27"	Hartford	Temperature: Above Normal (2.0°F) Max: 96°F, Min: 54°F Precipitation: 7.81" - Above Normal Normal: 4.17"
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<u>Peak Load:</u>	24,863 MW	July 29, 2025	19:00 (ending)
<u>Mid-Day Minimum Load - Month:</u>	9,663 MW	July 4, 2025	12:00 (ending)
<u>Mid-Day Minimum Load - Historical:</u>	5,318 MW	April 20, 2025	14:00 (ending)

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

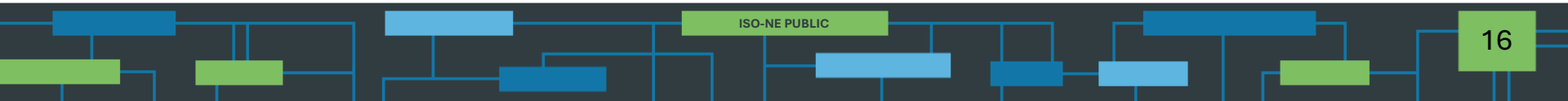
Procedure	Declared	Cancelled	Note
M/LCC 2	07/16/2025 15:30	07/17/2025 21:00	Capacity



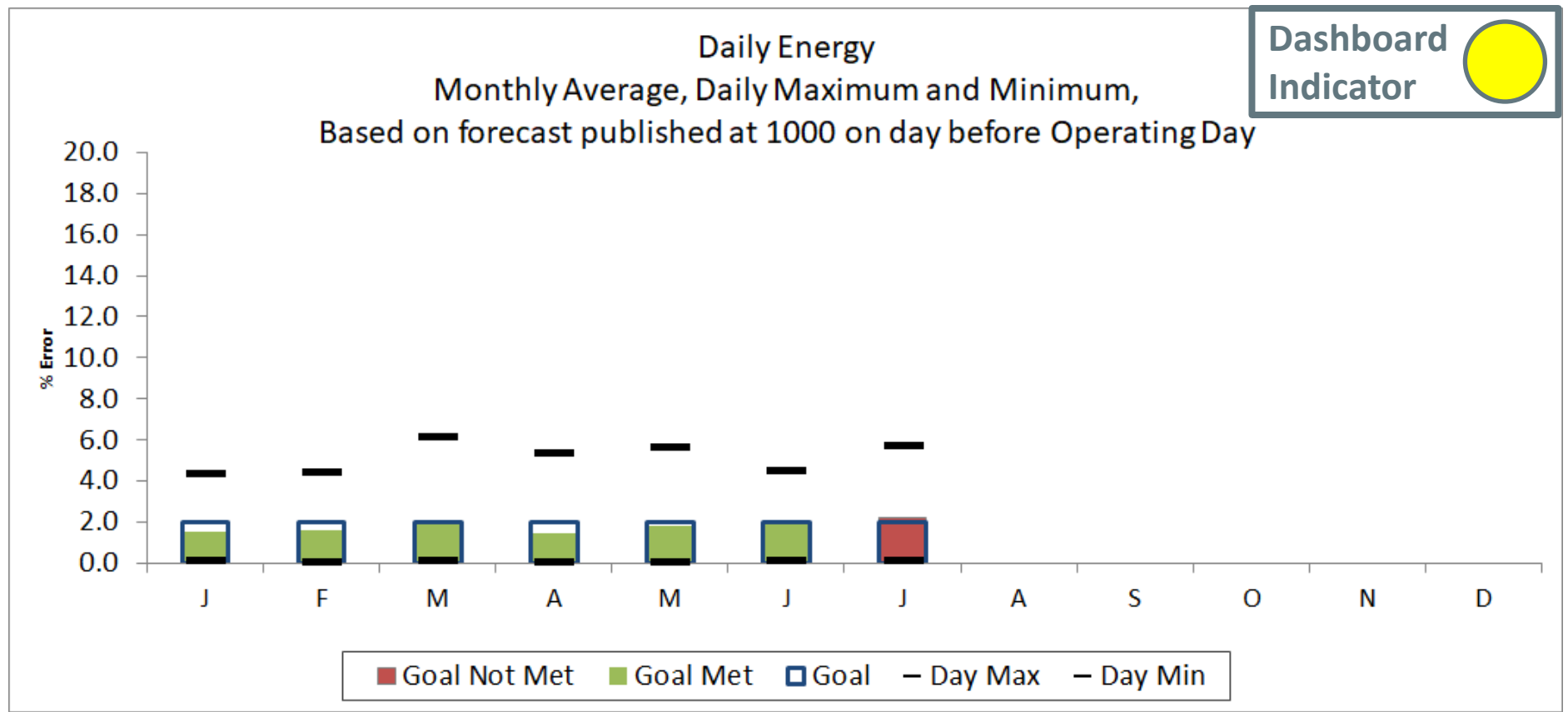
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
7/17/2025	NYISO	650
7/19/2025	IESO	500

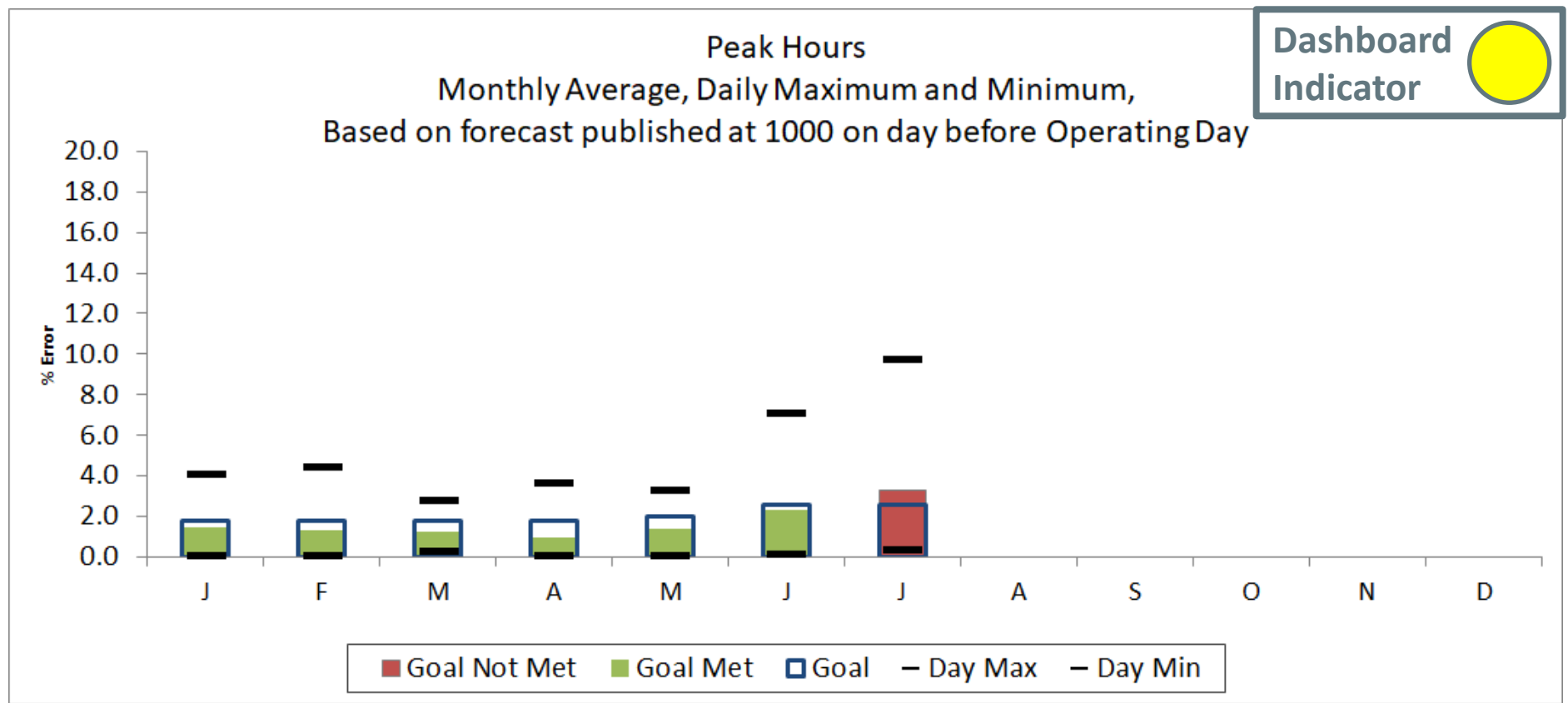


2025 System Operations - Load Forecast Accuracy cont.



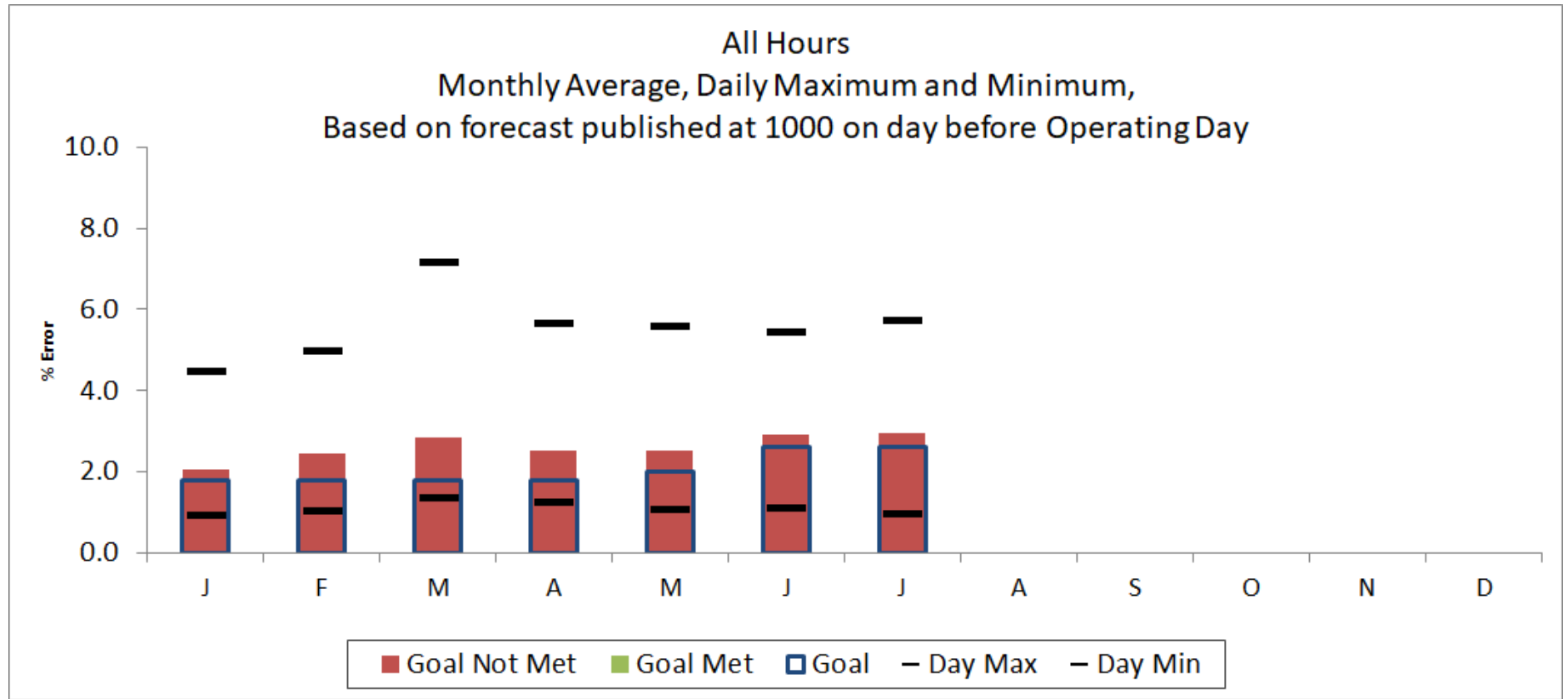
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	4.44	6.10	5.36	5.61	4.48	5.70						6.10
Day Min	0.12	0.04	0.12	0.05	0.06	0.08	0.11						0.04
MAPE	1.54	1.62	1.89	1.45	1.80	1.98	2.24						1.79
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00						

2025 System Operations - Load Forecast Accuracy cont.



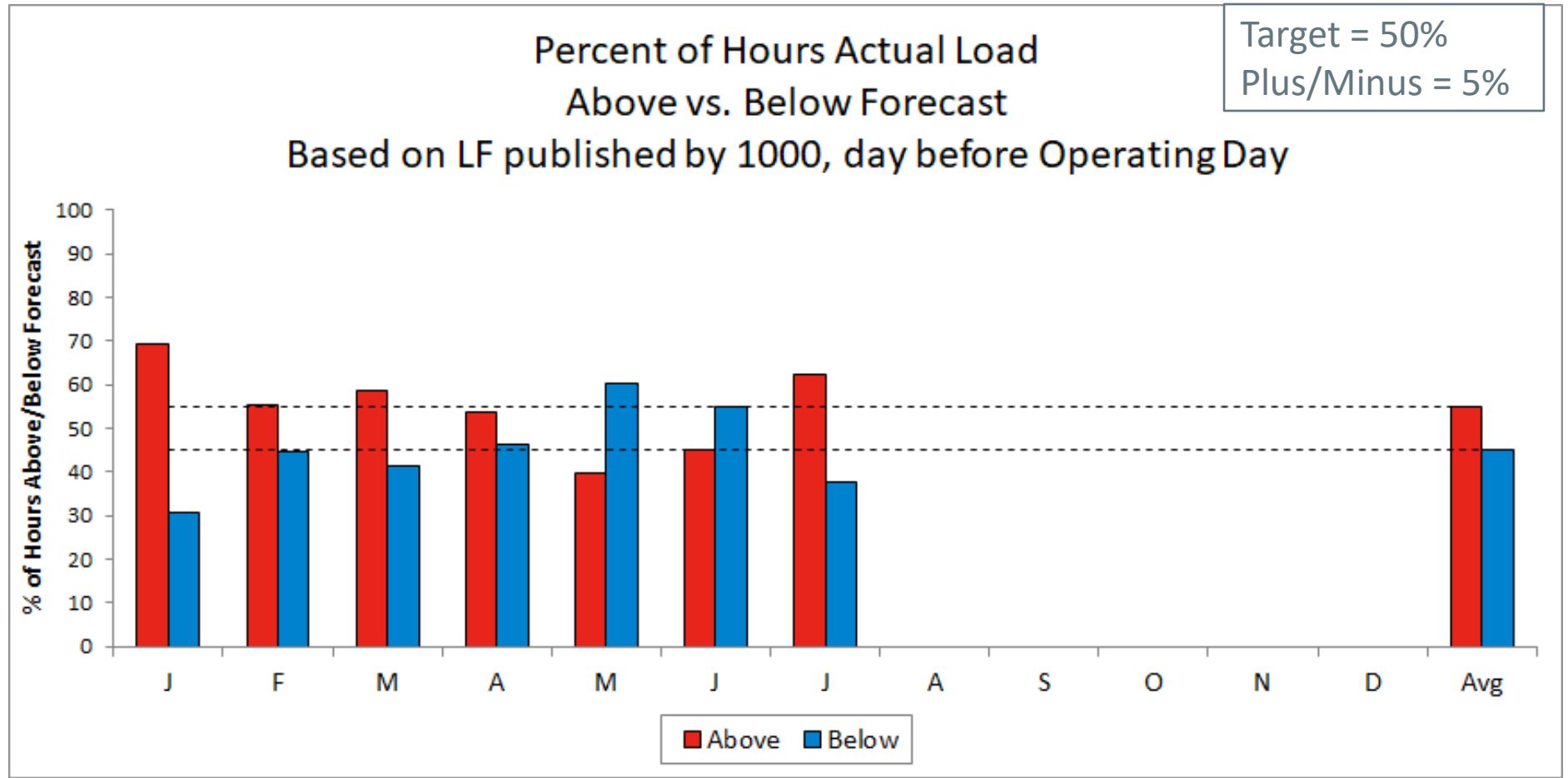
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.41	2.77	3.63	3.29	7.08	9.71						9.71
Day Min	0.03	0.06	0.24	0.03	0.06	0.11	0.34						0.03
MAPE	1.48	1.34	1.29	1.00	1.41	2.30	3.28						1.73
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

2025 System Operations - Load Forecast Accuracy cont.



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.46	4.98	7.13	5.65	5.57	5.44	5.72						7.13
Day Min	0.90	1.02	1.33	1.23	1.07	1.11	0.95						0.90
MAPE	2.07	2.47	2.83	2.53	2.53	2.93	2.94						2.62
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

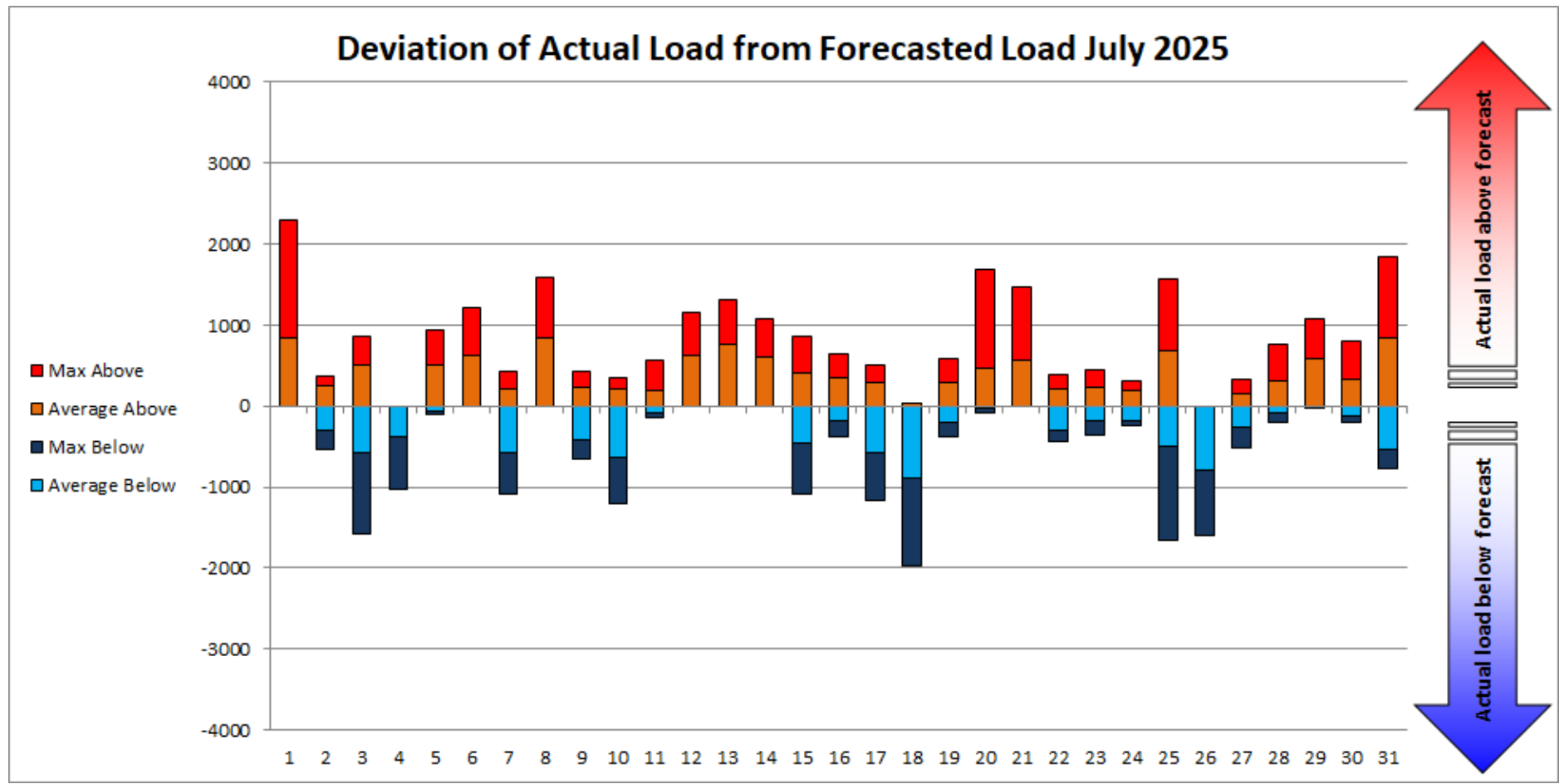
2025 System Operations - Load Forecast Accuracy cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	69.2	55.2	58.5	53.5	39.8	45.1	62.5						55
Below %	30.8	44.8	41.5	46.5	60.2	54.9	37.5						45
Avg Above	280.5	282.1	246.5	255.8	164.5	307.8	397.3						397
Avg Below	-178.6	-287.9	-273.2	-190.7	-254.1	-310.2	-270.0						-310
Avg All	138	24	12	49	-82	-24	145						38



2025 System Operations - Load Forecast Accuracy

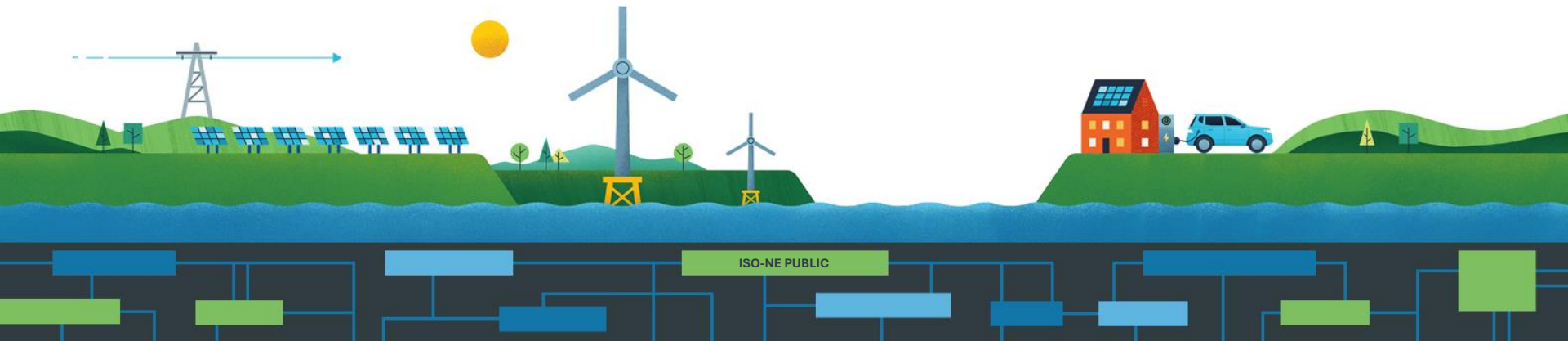


June 24, 2025 OP-4 Event and Capacity Scarcity Condition



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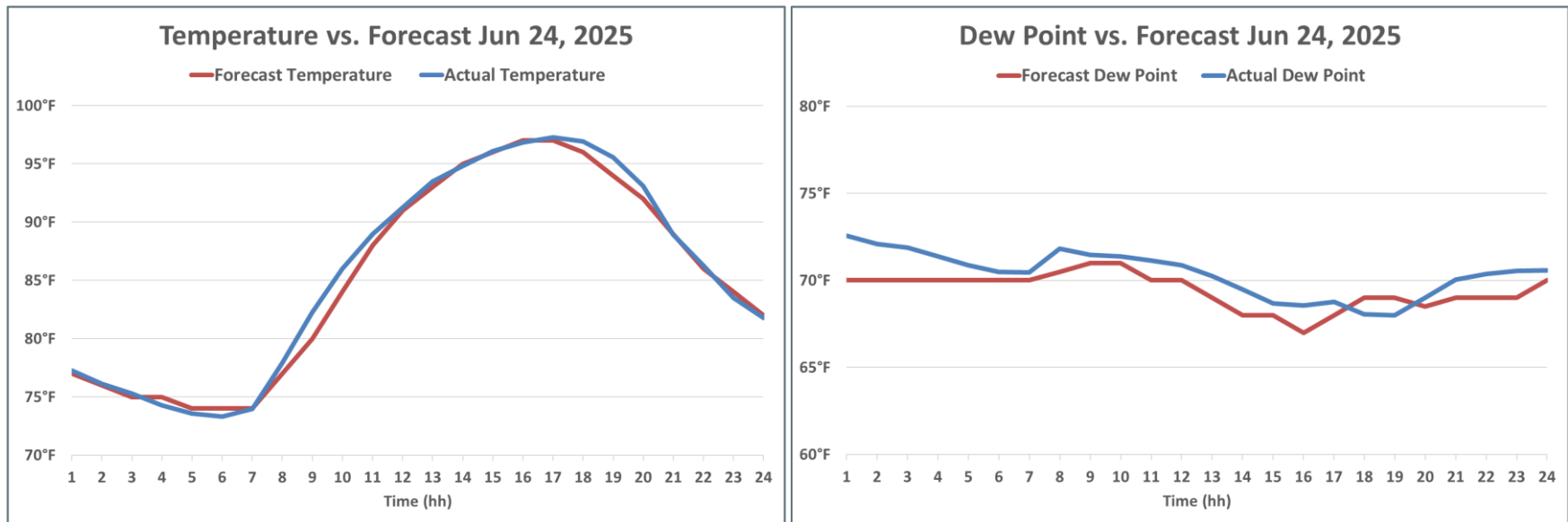
OP-4 and Capacity Scarcity Condition

Tuesday, June 24, 2025

- On the evening of June 23, ISO implemented M/LCC-2, Abnormal Conditions Alert, due to expected high temperatures and dew points across the region along with forecasts of low capacity margins on June 24
 - M/LCC-2 was in effect from 21:00 on 6/23 through 21:00 on 6/25
- ISO's June 24, 2025, [Morning Report](#) estimated a peak hour surplus capacity margin of 106 MW based on expected interchange schedules, available resources, and a forecasted load of 25,800 MW
 - System load peaked at 26,024 MW in HE19
- Generator outages and reductions during the day totaled ~2,560 MW
- System conditions required the implementation of OP-4 Actions 1 & 2 from 17:22 – 21:00 and Actions 3 & 5 from 17:40 – 20:30
- 30-minute Reserve Constraint Penalty Factor (RCPF) violated for the following 5-minute intervals: 17:35 – 20:35
- Neighboring areas were also experiencing tight system conditions; IESO, NYISO, and PJM all declared Energy Emergency Alert (EEA) Level 1 on June 24
 - ISO also declared an EEA Level 1 upon implementing OP-4 Action 2

Weather Conditions on June 24, 2025

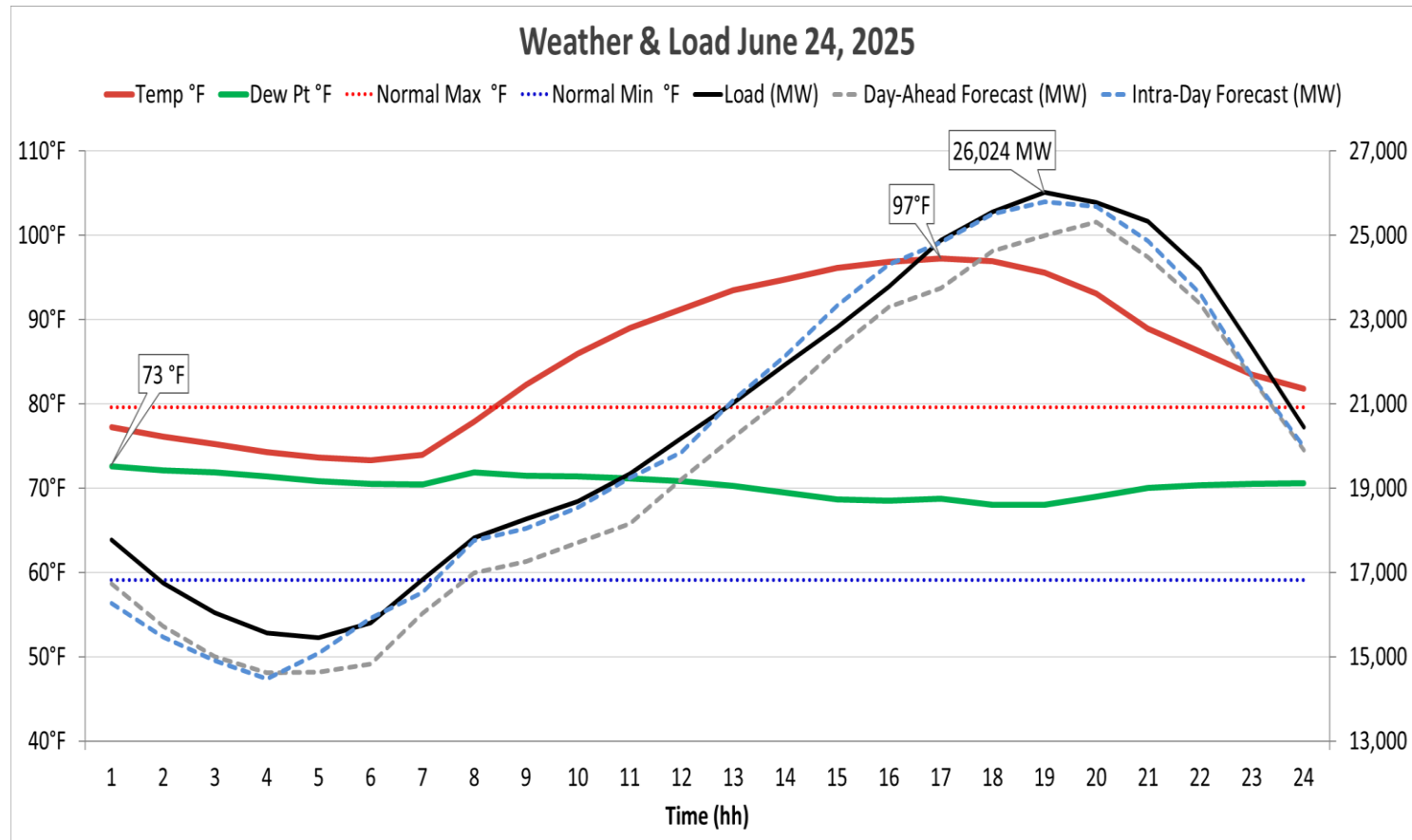
- The temperature forecast was highly accurate for most of the day, but the actual temperature exceeded the forecast by 1.6°F during the peak load hour; the actual temperature peaked at 97°F in HE17
- Actual dew points averaged 1.1°F above the forecast for the day, though the dew point briefly fell below the forecast during the peak load hour



*Note that forecast and actual temperatures and dew points are based on a 23-city weighted average

The June 24 Peak Load of 26,024 MW Was the Highest Load Since July 19, 2013

- ISO's Day-Ahead peak load forecast of 25,310 MW was increased to 25,800 MW on the morning of June 24 based on updated guidance from forecasting models

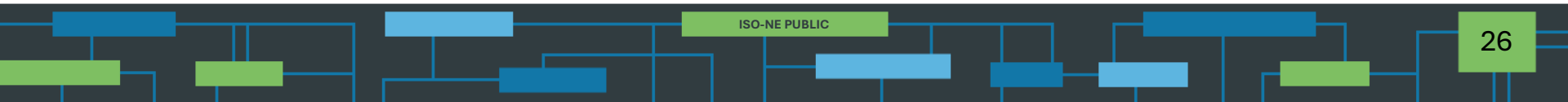


*Note that actual temperatures and dew points are based on a 23-city weighted average

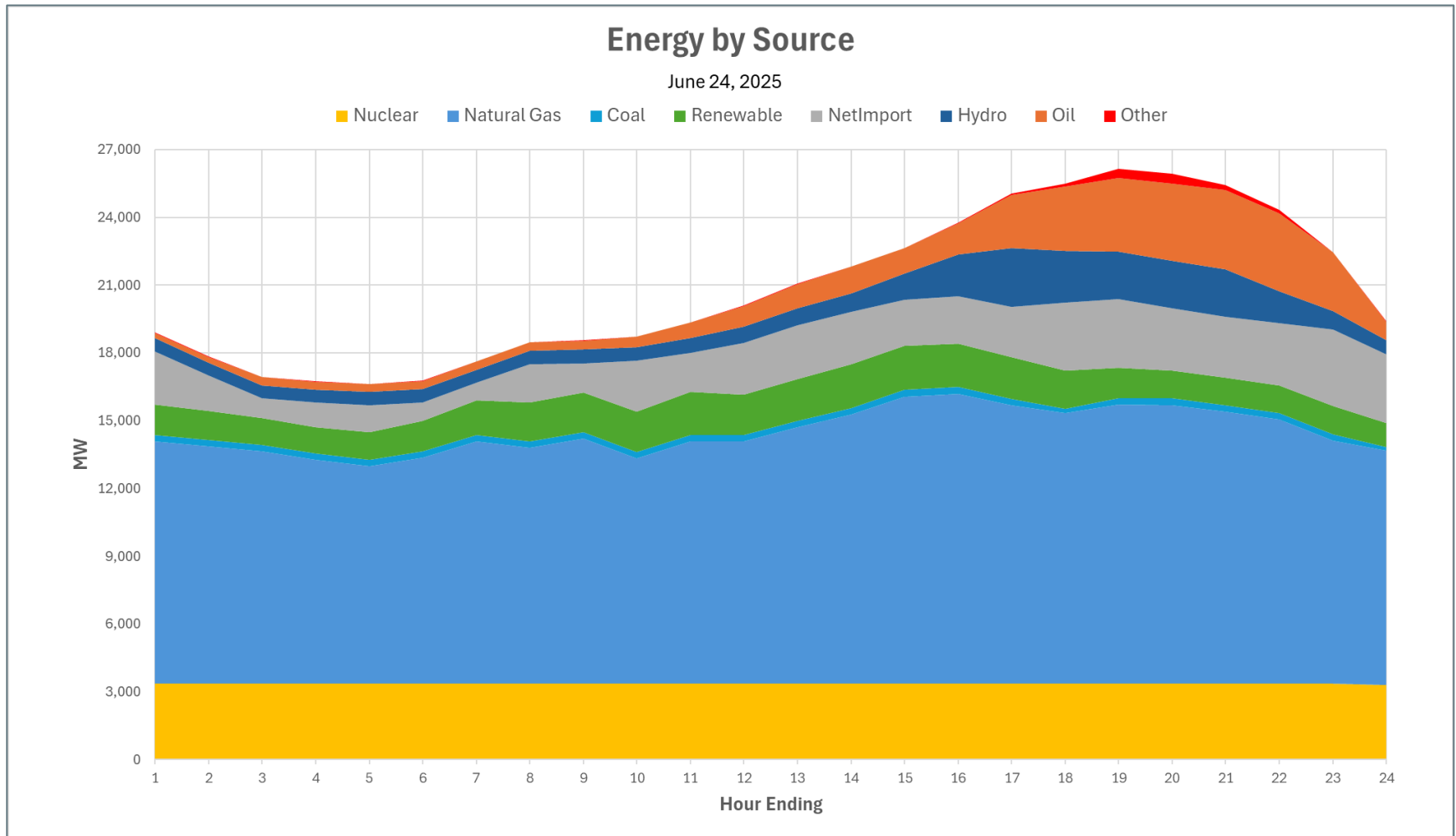
Available Generator Capacity During the Day

- ISO's estimated* peak hour capacity margin of 106 MW included ~1,900 MW of generator outages and reductions (~120 MW planned and ~1,780 MW forced)
- As the operating day progressed, ~800 MW of additional capability became available from generators returning from outages while ~400 MW of additional generation capability was reduced
- Between 16:00 and 17:15, generation capability was further reduced by ~1,060 MW due to unexpected reductions and outages
- In total, approximately 2,560 MW of generator outages and reductions were occurring at the time of OP-4 implementation

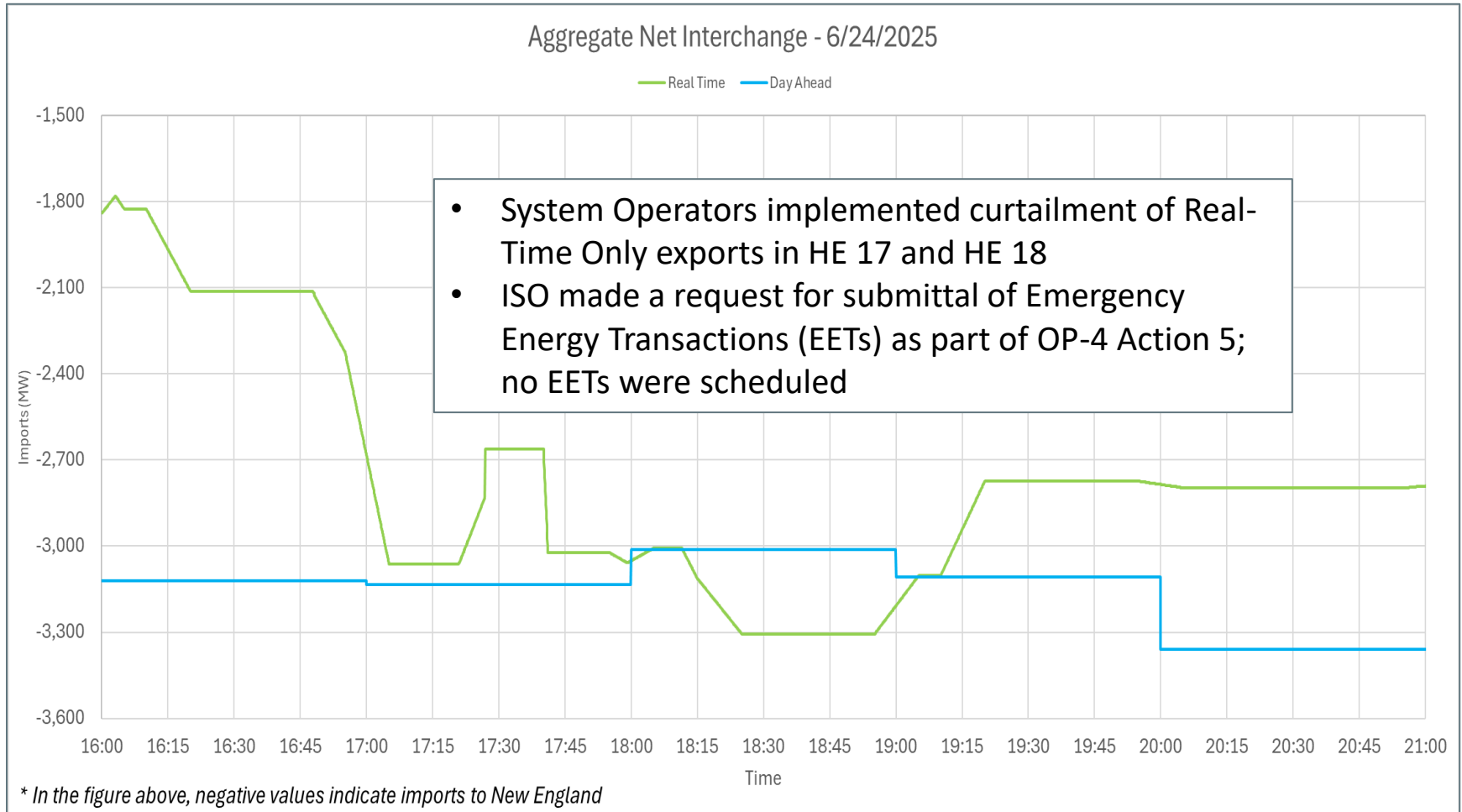
*As estimated on the June 24, 2025 Morning Report



Energy Supplies by Source – June 24, 2025



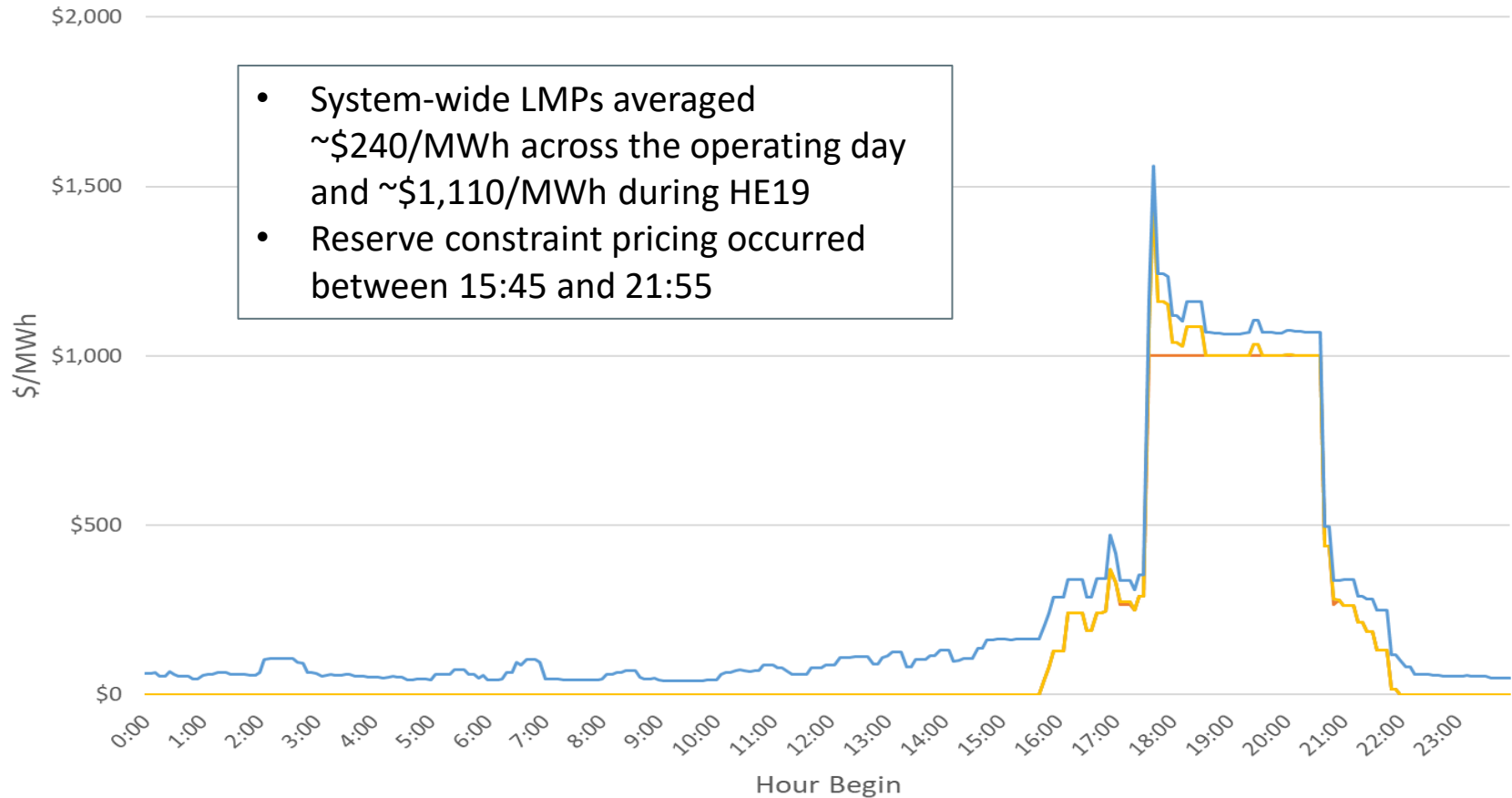
Net Interchange Flows – Day Ahead and Real Time



Real-Time System Energy and Reserve Pricing

06/24/25 System Energy and Reserve Pricing

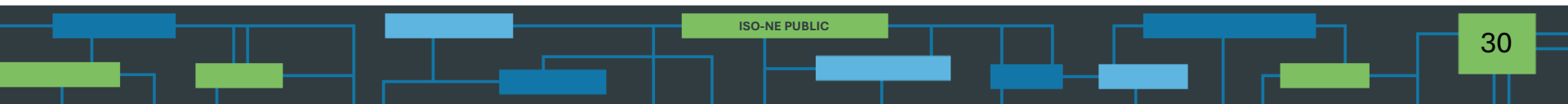
— TMOR — TMSR — TMNSR — LMP



Summary of Capacity Scarcity Condition Intervals

5-Minute Intervals	System 30 Min Reserve Constraint Penalty Factor (\$1,000 MW/hr)	System 10 Min Reserve Constraint Penalty Factor (\$1,500 MW/hr)
17:35 – 18:30 (12 Intervals)	Violated	Binding
18:35 – 19:20 (10 Intervals)	Violated	N/A
19:25 – 19:40 (4 Intervals)	Violated	Binding
19:45 – 19:55 (3 Intervals)	Violated	N/A
20:00 – 20:05 (2 Intervals)	Violated	Binding
20:10 – 20:35 (6 Intervals)	Violated	N/A

- A Capacity Scarcity Condition results from the **violation** of the System 30 Minute Operating Reserve constraint or the System 10 Minute Operating Reserve constraint in any one 5-minute interval

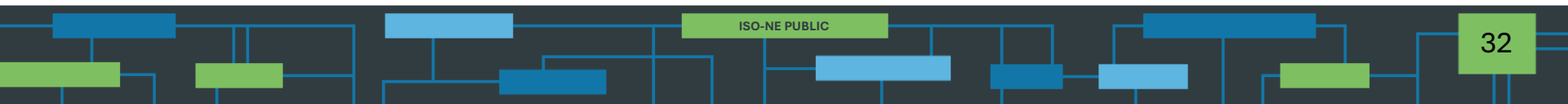


PFP Settlements Summary for June 24, 2025

- **Duration:** 3.08 hours (37 consecutive 5-min intervals)
- **Capacity Balancing Ratio:** 1.031 (event average)
 - System RT needs exceeded total CSO MW by 3.1% (890 MW avg.)
- **Substantial resource “over-performance”** by CSO and non-CSO resources, averaging 3,972 MW (per hour)
- **Performance credits and charges:**
 - “Overperformance” **credits:** \$114.3 million
 - “Underperformance” **charges:** \$97.1 million, net of stopped losses
 - Additional details next slides

Explanation of Performance Highlights and Tables Ahead

1. **Summary of Performance Payments:** A breakdown of credits and charges, stopped-losses amount, and pool-wide allocation of surplus payments and stopped-losses.
2. **Summary of Stop-Loss Allocation:** Info on total CSO MW that stopped out, and cost (per CSO MW) of net settlement charges.
3. **Performance of Resources with CSO relative to share of System Requirements :** Performance of CSO resources by resource type.
4. **Performance Payment Credits by Resource Type and Obligation:** A breakdown of payment info by CSO/non-CSO and by resource type (generation, import, demand response, and settlement only resource).
5. **Performance Payment Charges by Resource Type:** A breakdown of charges by resource type (generation, import, demand response, and settlement only resource) before/after application of stop-loss limit, and final charges.
6. **Hourly Imports by Interface:** A breakdown of hourly imports by CSO/non-CSO and interface.



Summary of Performance Payments

Performance Payment Credits (Charges) (MR1 Sec. III.13.7.2, 13.7.3)	
Performance Payment Credits	Million \$
To Resources with CSO	\$ 67.80
To Resources without CSO	\$ 46.50
Total	\$ 114.30
Performance Payment Charges	
Before Application of Stop-Loss Limit	\$ (123.50)
Total Stopped-Losses	\$ 26.40
Total	\$ (97.10)
Excess (Deficient) Pool-wide Performance Payments	
Surplus Before Application of Stop-Loss Limit	\$ 9.20
Total Stopped-Losses	\$ (26.40)
Total After Application of Stop-Loss Limit	\$ (17.20)

Summary of Stop-Loss Allocation

Allocation of Excess (Deficient) Performance Payments (MR1 Sec III.13.7.4)

CSO MW for Allocation of Excess (Deficient) Perf. Pmt.	Units	Amount
Total CSO MW in June 2025	MW	28,740
CSO MW with Stopped-Losses	MW	2,812
CSO MW without Stopped-Losses	MW	25,927

Allocation of Excess (Deficient) Performance Payments

Excess (Deficient) Pool-wide Performance Payments	Million \$	\$ (17.20)
Allocation Rate of Deficient Performance Payments	\$ / MW	\$ (663.40)

Performance of Resources with CSO relative to share of System Requirements*

**Resource's Actual MW compared to Balancing Ratio x CSO MW*

Resource Type	Total CSO MW	Zero Performance	Performance < 25%	Performance 25%-50%	Performance 50%-75%	Performance 75%-100%	Performance 100%-125%	Performance >125%
Gen	26,256	6.4%	3.8%	5.1%	8.9%	51.0%	11.1%	13.7%
Import	1,235	10.0%	0.0%	0.0%	0.0%	30.0%	10.0%	50.0%
DR	792	9.5%	38.1%	23.8%	8.6%	8.6%	4.8%	6.7%
SOR	457	14.2%	29.5%	23.3%	10.6%	5.8%	2.6%	14.0%

*Percent values are calculated by taking the Resource count with average Capacity Performance Scores in each category divided by the total number of Resources in each category. No resource performed at exactly 100% of Balancing Ratio x CSO MW.

Performance Payment Credits by Resource Type and Obligation

Resource Type	Resources without CSO (\$ in Millions)	Resources with CSO (\$ in Millions)	Performance Payment Credits (\$ in Millions)
Gen	\$7.7	\$28.5	\$36.2
Import	\$33.6	\$36.7	\$70.3
DR	\$0.0	\$0.7	\$0.7
SOR	\$5.2	\$1.9	\$7.1
Total¹	\$46.5	\$67.8	\$114.3

¹ Reported under “Performance Payment Credits” section on slide 33

Performance Payment Charges by Resource Type

Resource Type	Before Application of Stop-Loss Limit ¹ (\$ in Millions)	After Application of Stop-Loss Limit ² (\$ in Millions)	Performance Payment Charges ³ (\$ in Millions)
Gen	(\$98.4)	(\$82.9)	(\$99.1)
Import	(\$1.4)	(\$0.9)	(\$1.7)
DR	(\$15.3)	(\$8.4)	(\$8.5)
SOR	(\$8.4)	(\$4.9)	(\$5.0)
Total	(\$123.5)	(\$97.1)	(\$114.3)

^{1, 2} Reported under “Performance Payment Charges” section on slide 33

³ After application of stop-loss limit and allocation of excess (deficient) performance payments (per MR1 Sec III.13.7.4).

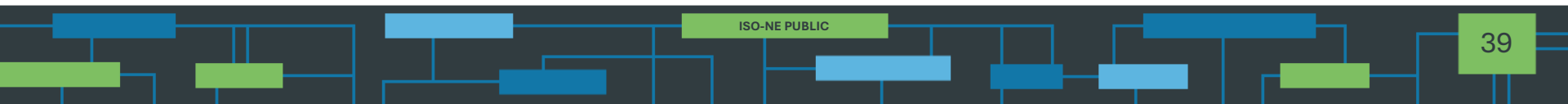
Hourly Imports by Interface

Hour End	New York Ties ¹		Canadian Interfaces ²		Total Import MWh		
	CSO	Non CSO	CSO	Non CSO	CSO	Non CSO	Total
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
6:00 PM	345	523	2177	419	2522	942	3464
7:00 PM	348	1333	2169	466	2517	1799	4316
8:00 PM	244	866	2287	466	2531	1332	3863
9:00 PM	60	501	2357	473	2417	974	3391

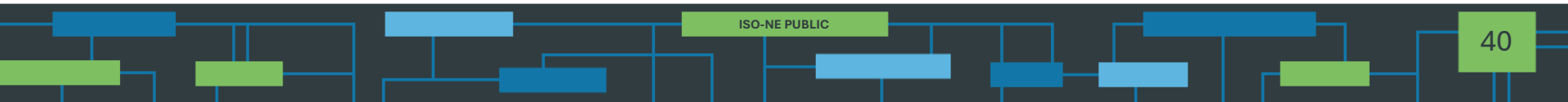
¹ New York Ties include NY Northern A/C, NY NNC and NY Cross Sound Cable.

² Canadian interfaces include HQ Phase II, Highgate and New Brunswick ties.

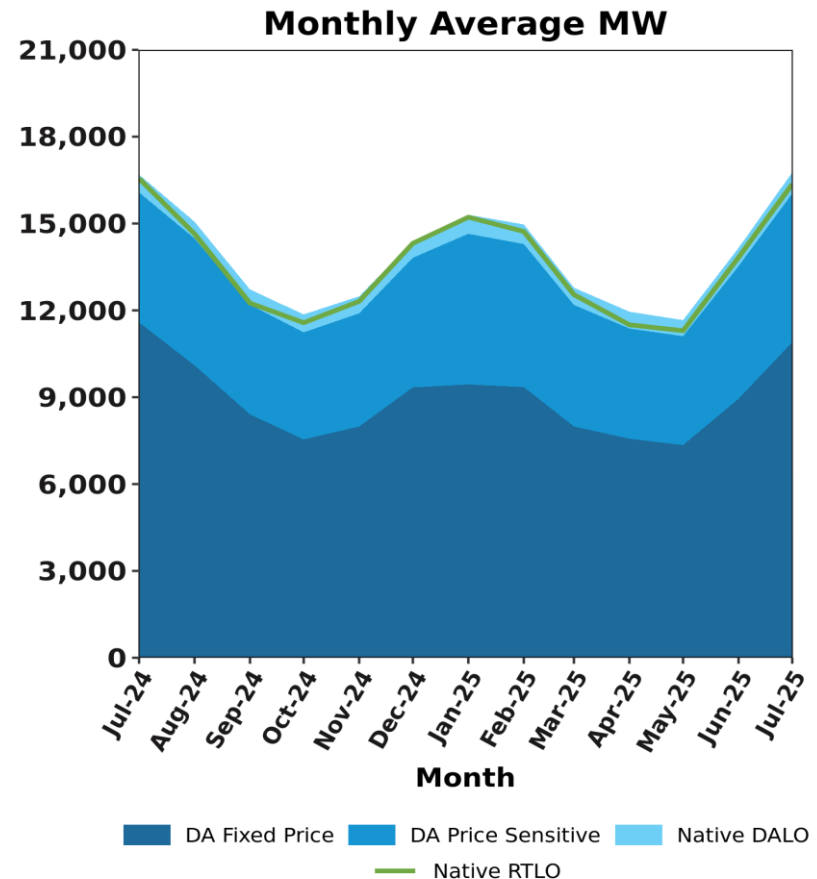
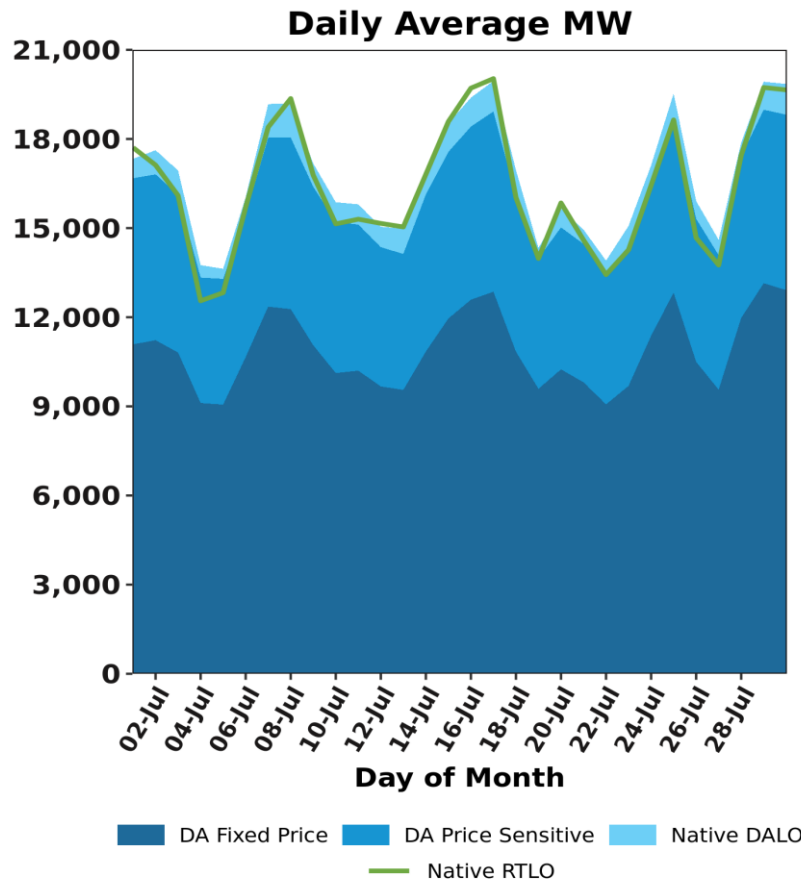
MARKET OPERATIONS



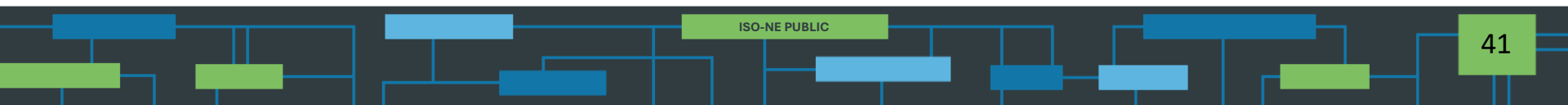
SUPPLY AND DEMAND VOLUMES



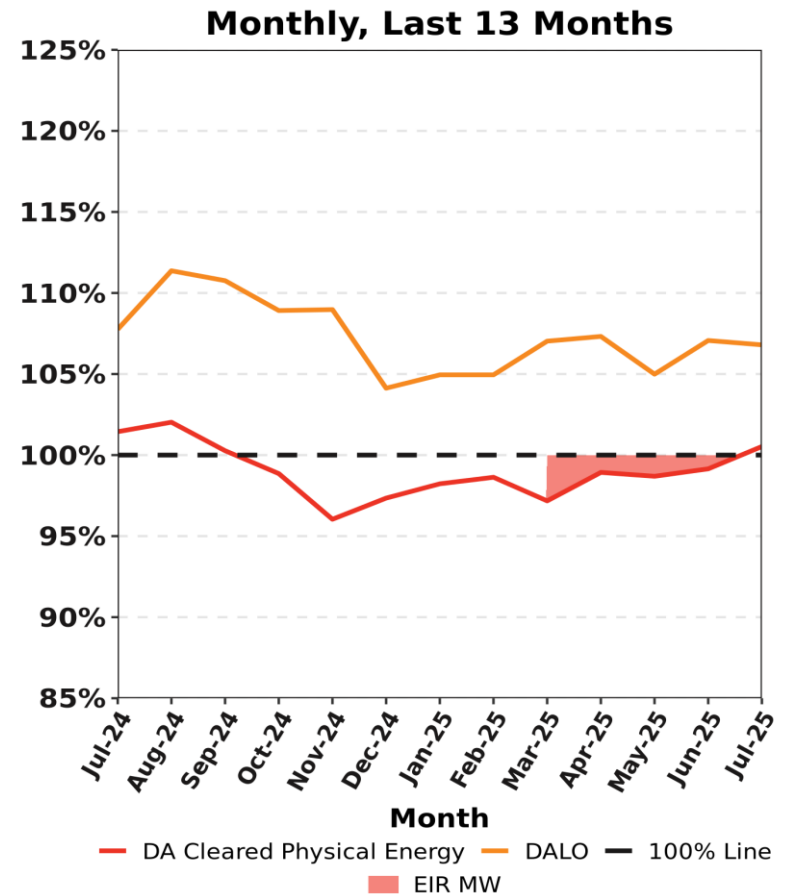
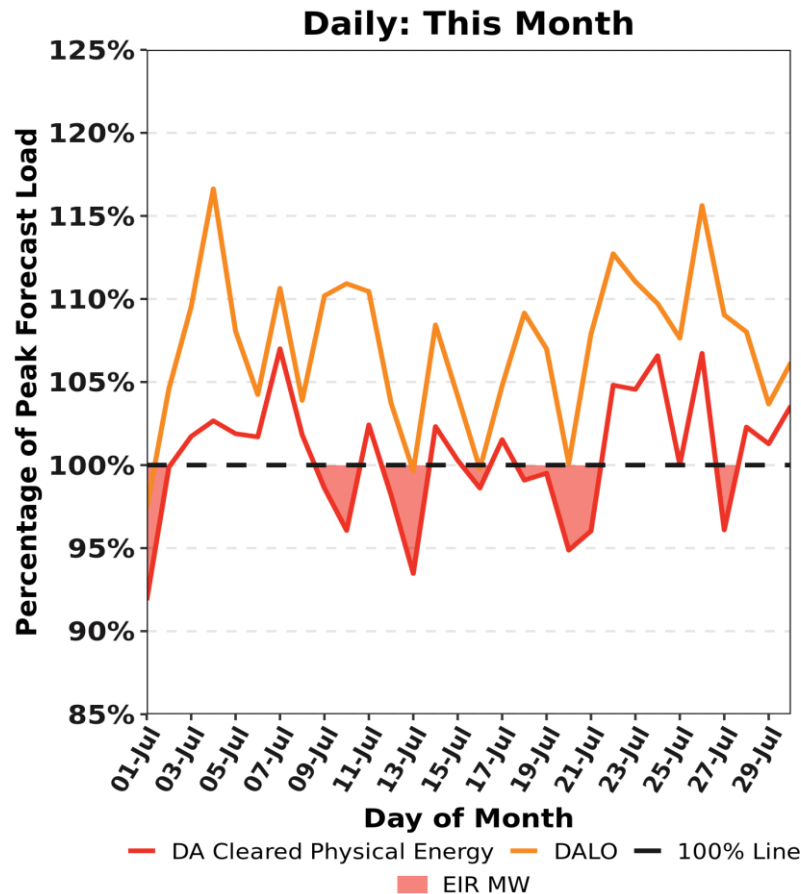
DA Cleared Native Load by Composition Compared to Native RT Load



Native Day Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real Time Load Obligation (RTLO) is the sum of all internal real time load obligation. Modeled transmission losses and exports are excluded in these charts.

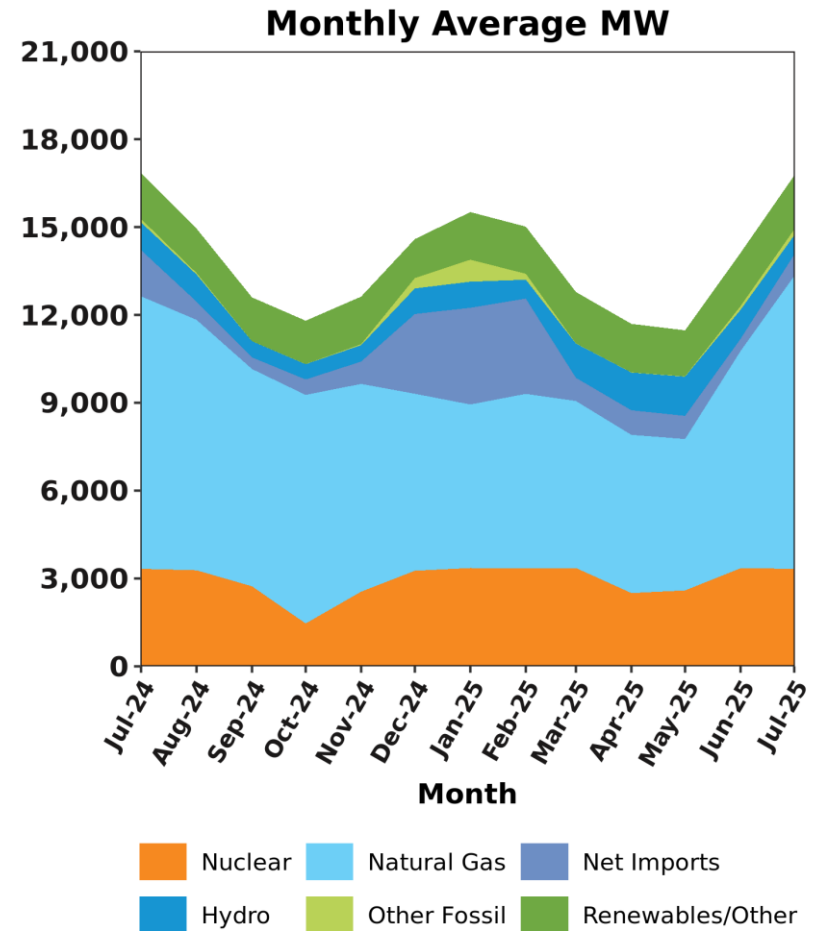
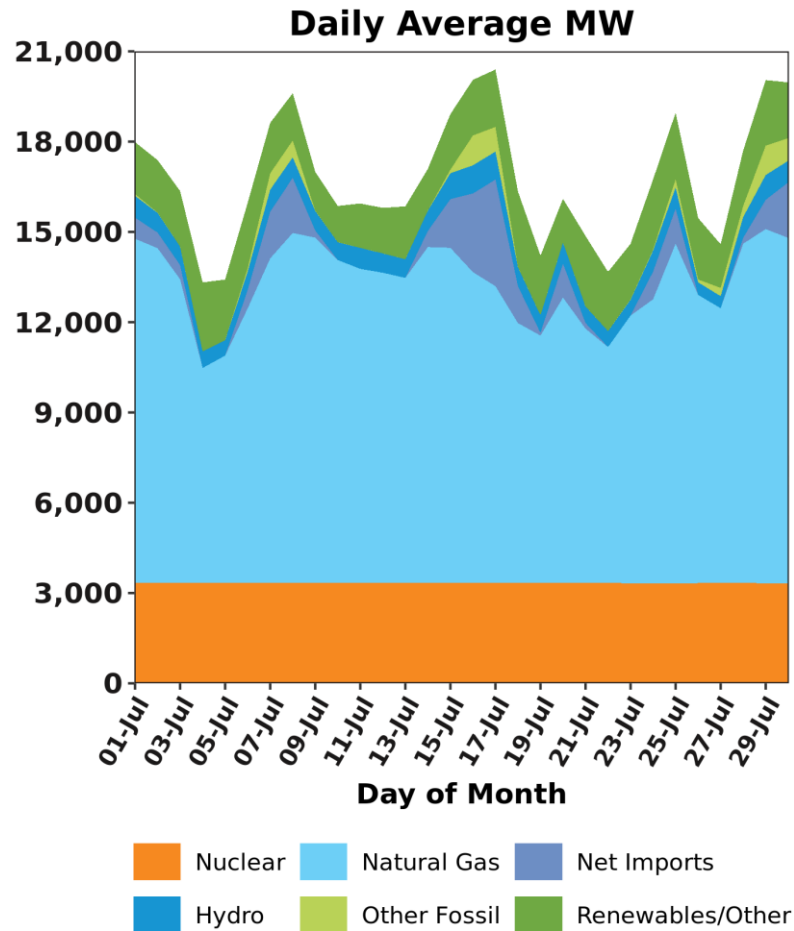


DA Volumes as % of Forecast in Peak Hour

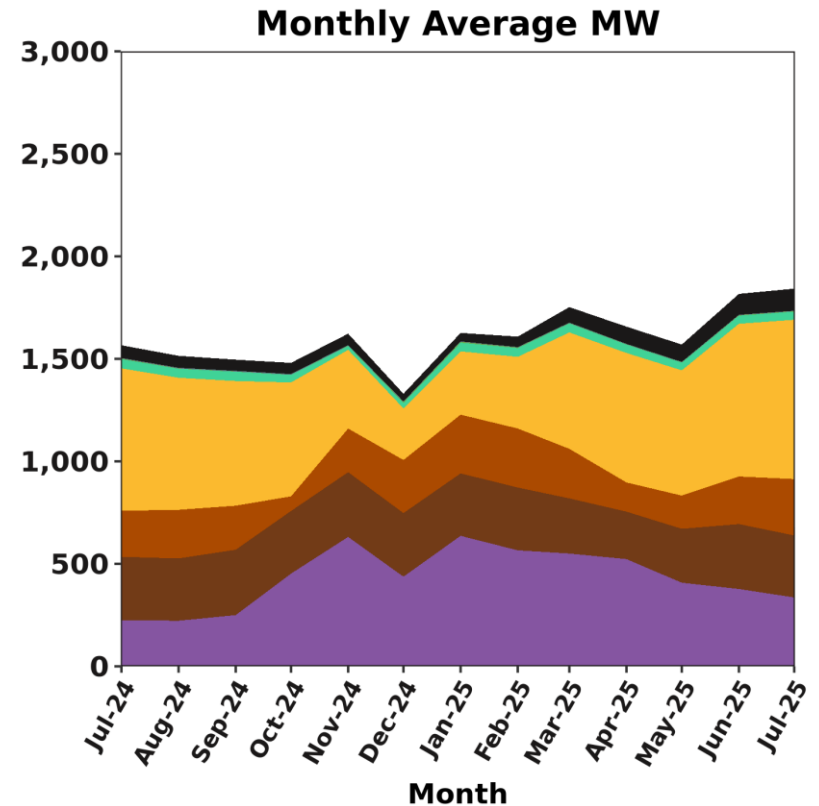
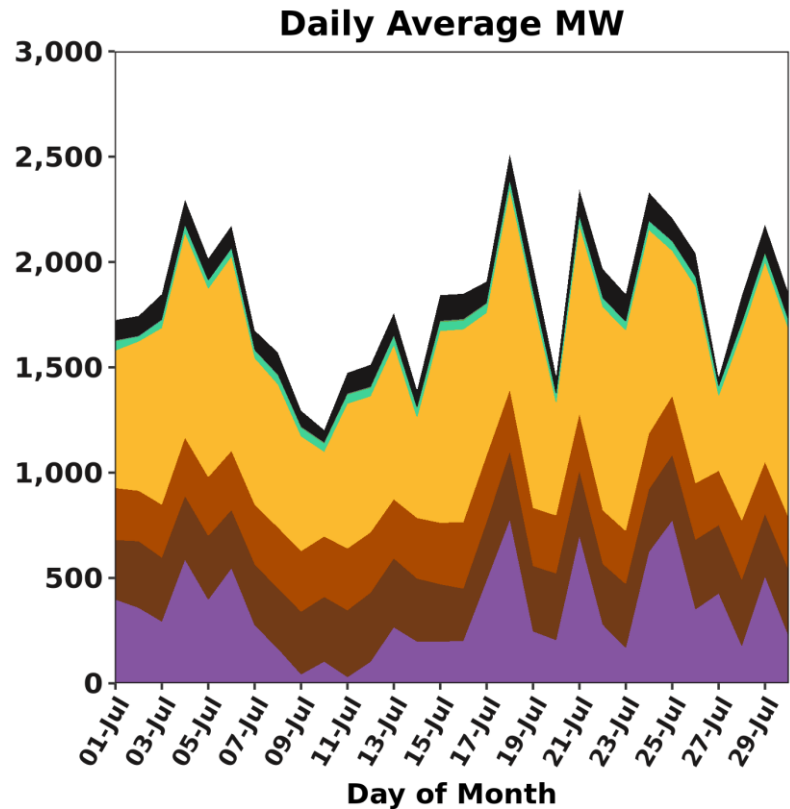


DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

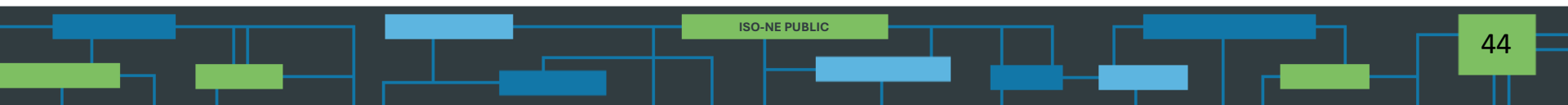
Resource Mix



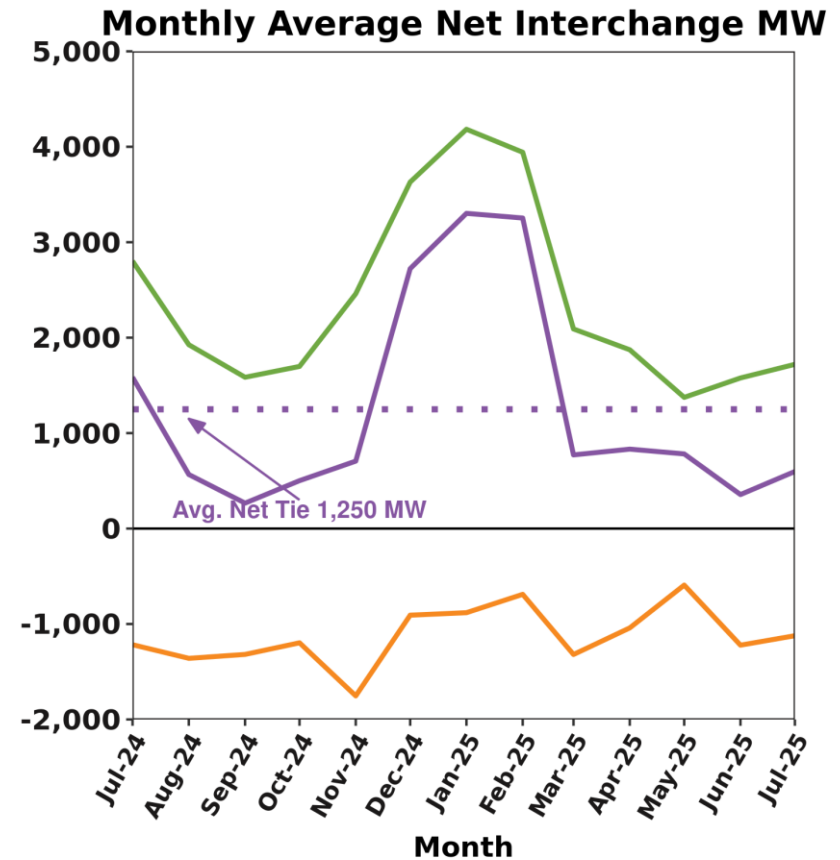
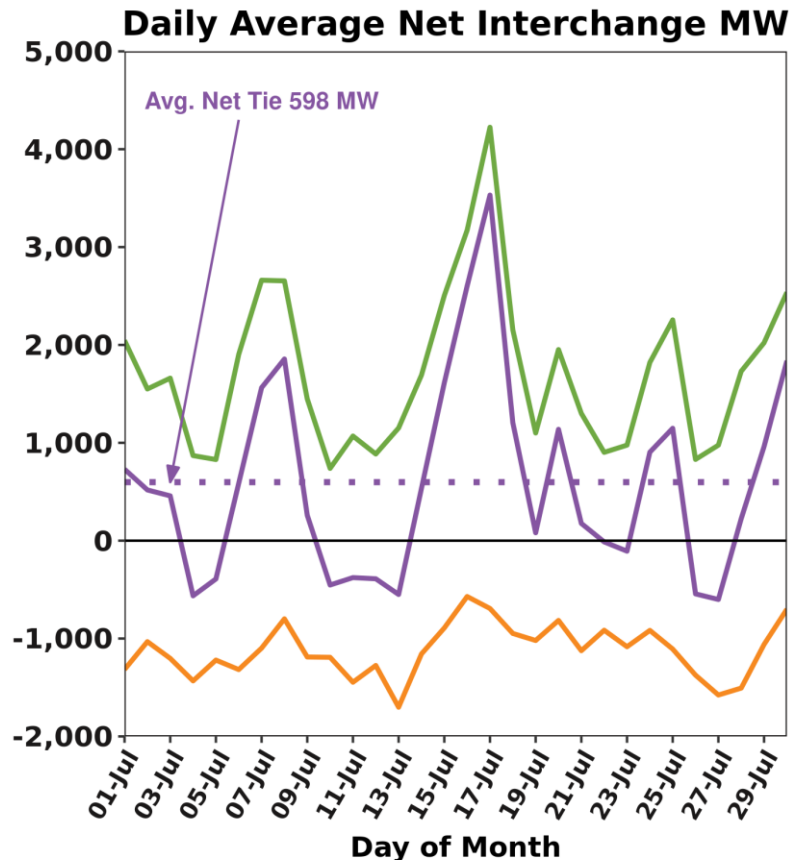
Renewable Generation by Fuel Type



CSF = Continuous Storage Facilities (a.k.a. Batteries)



RT Net Interchange

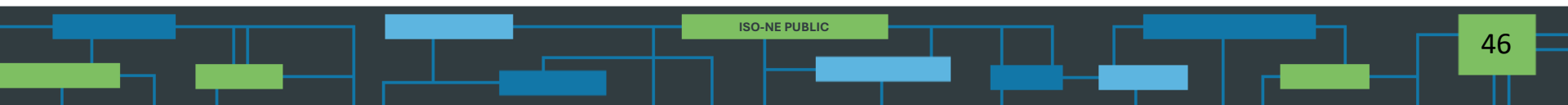
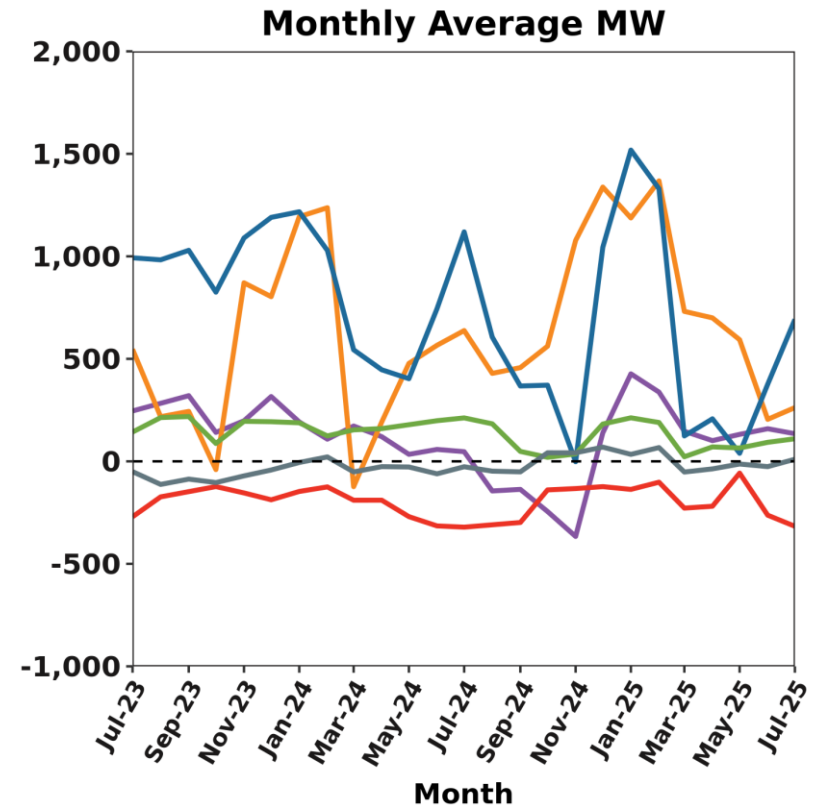
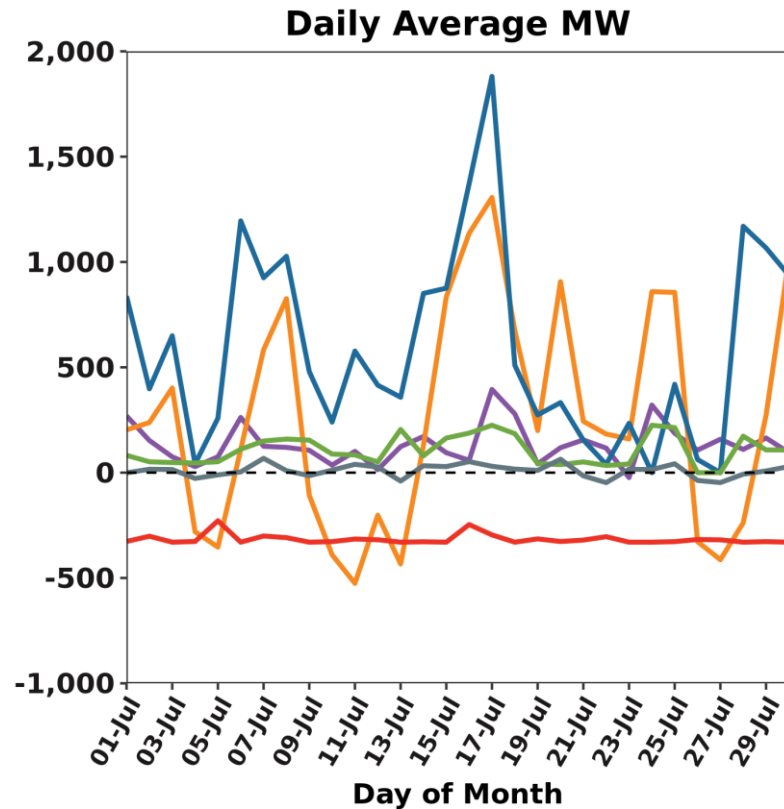


Export Import Net Tie

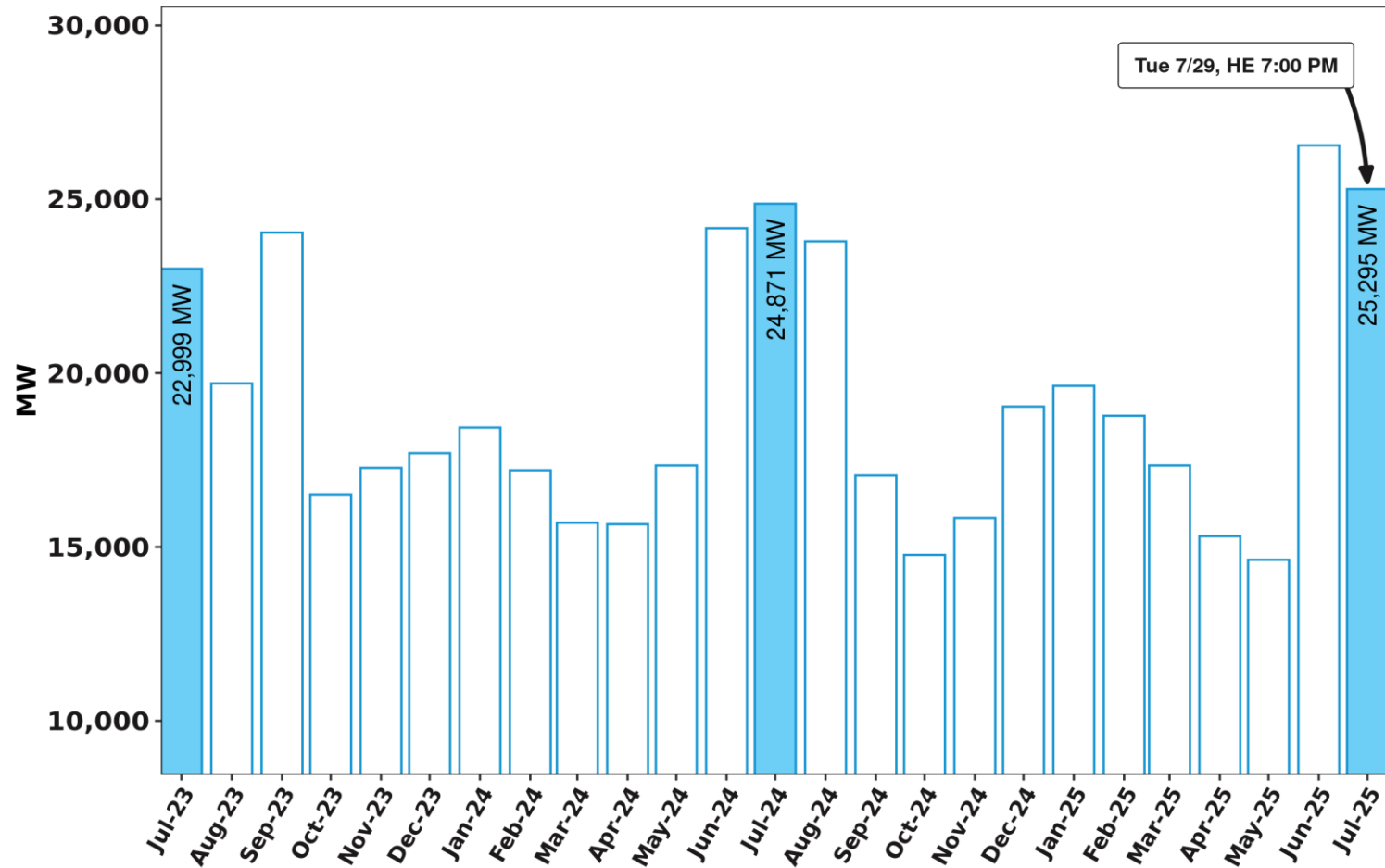
Export Import Net Tie

Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface

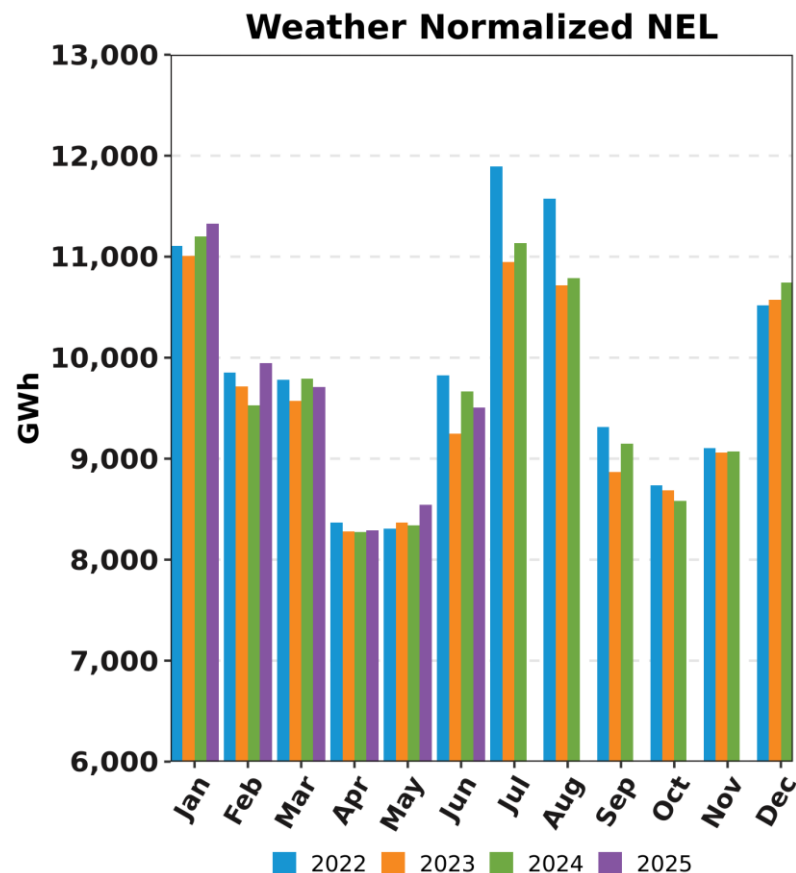
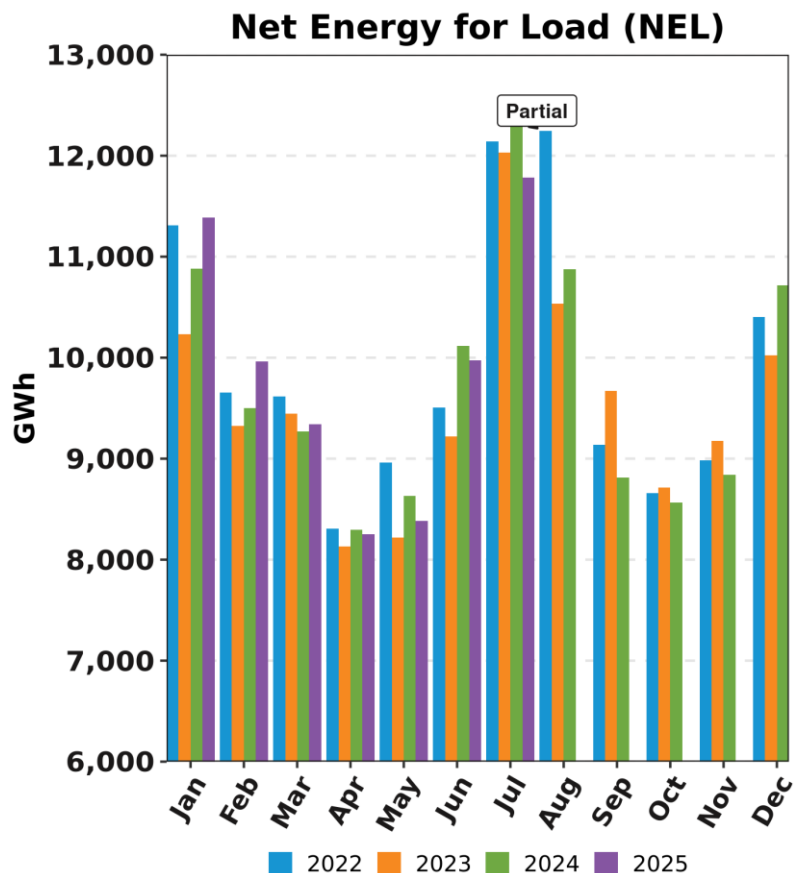


RQM System Peak Load MW by Month



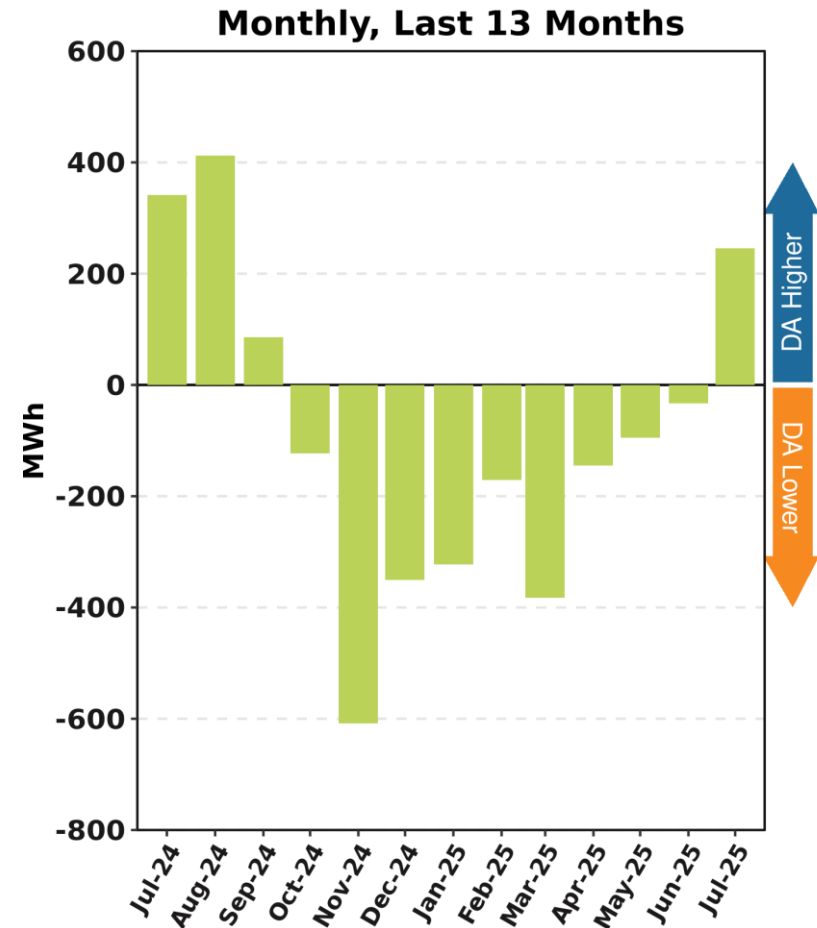
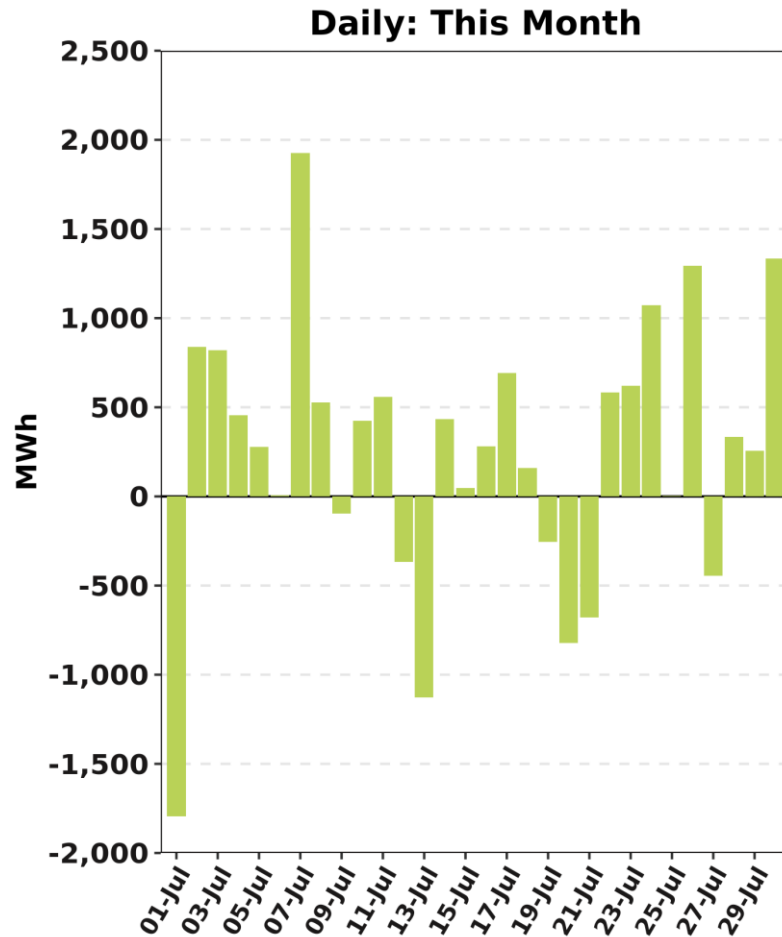
Shaded columns highlight current month and the same month over the prior two years

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



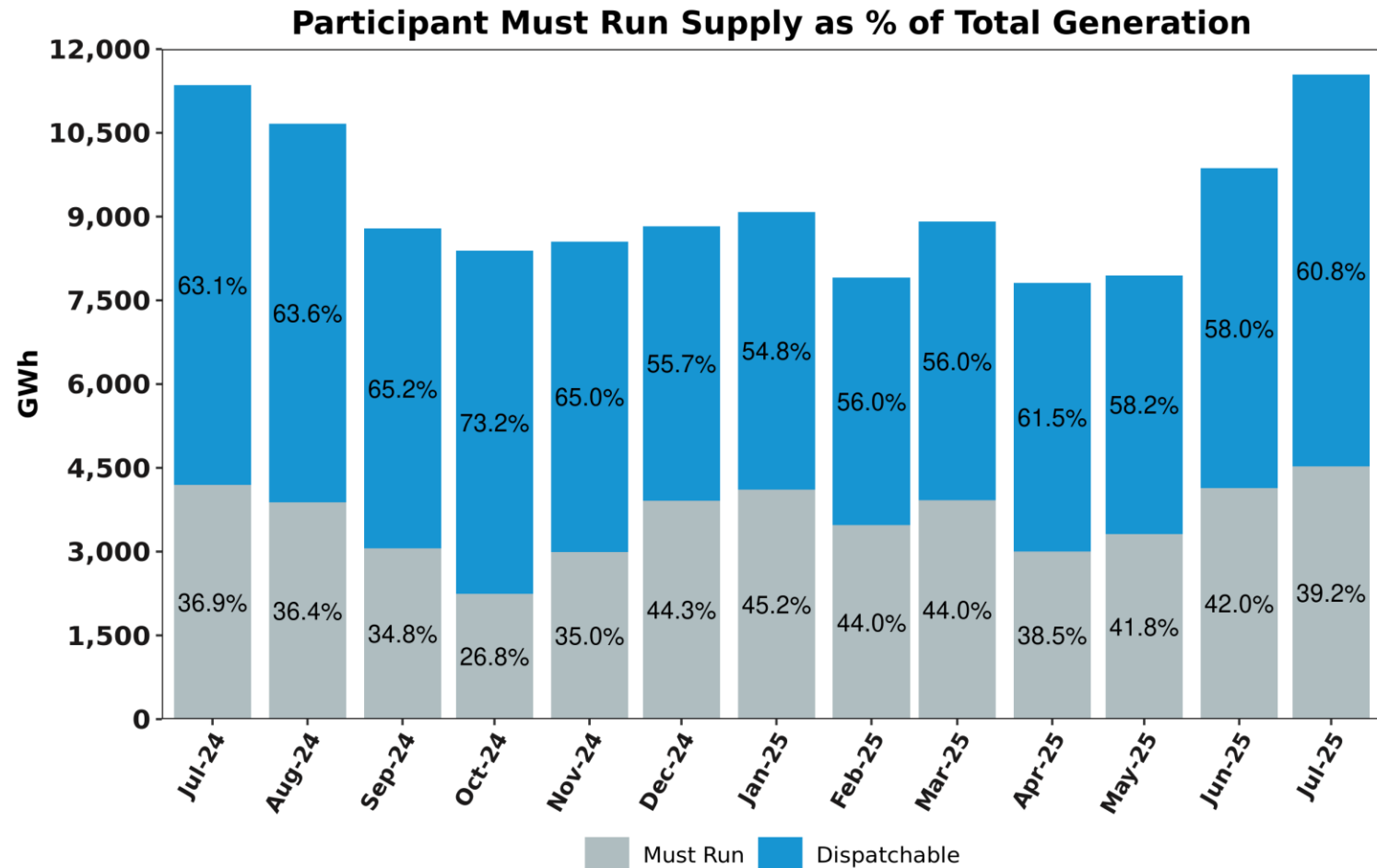
NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized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

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

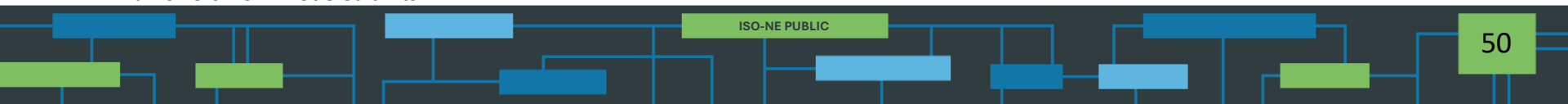


Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

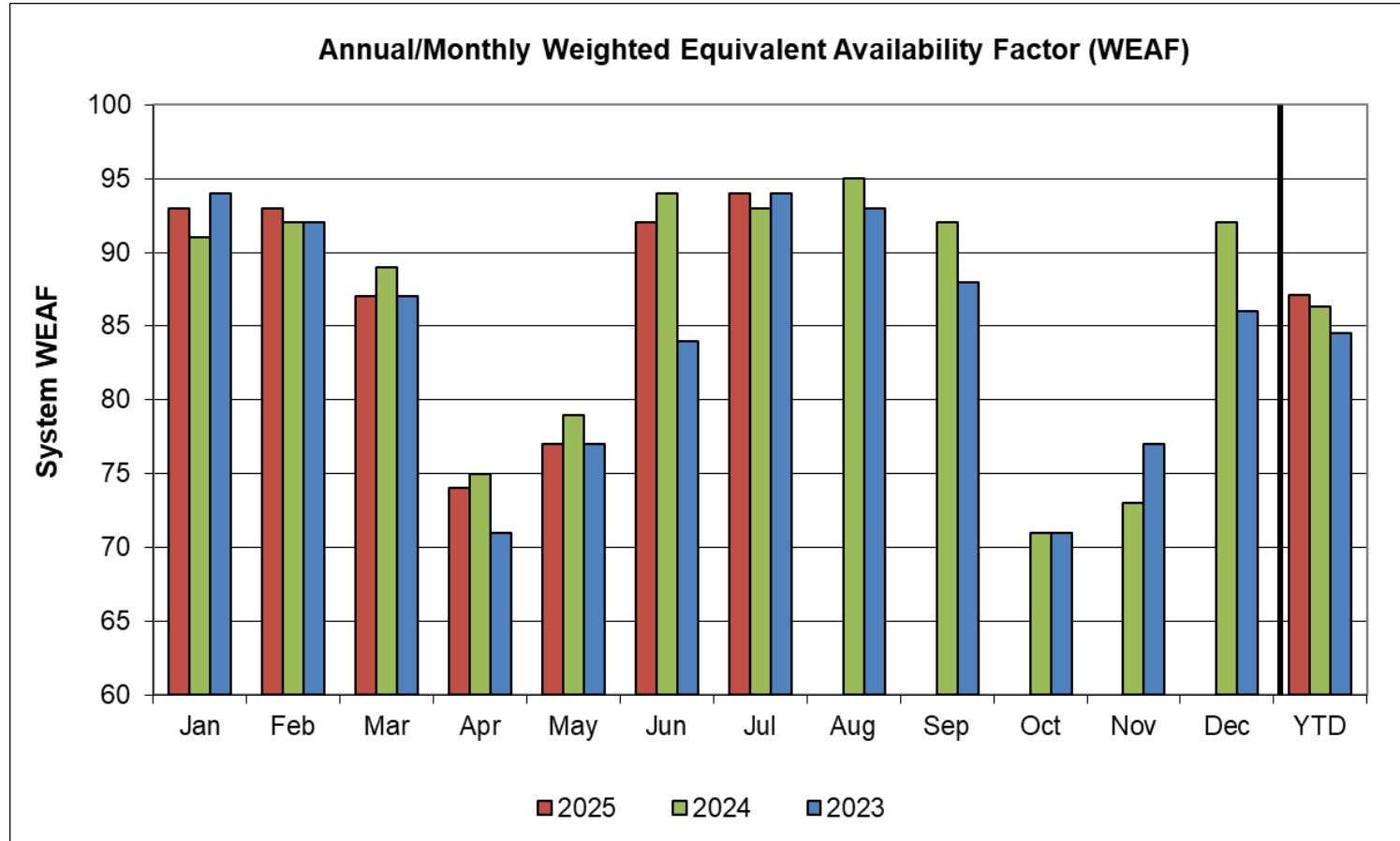
RT Generation Output Offered as Must Run vs Dispatchable



Includes generation and DRR. Must Run (non-dispatchable) category reflects full output of settlement-only generation (SOG) as well as must run offers from modeled units



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2025	93	93	87	74	77	92	94						87
2024	91	92	89	75	79	94	93	95	92	71	73	92	86
2023	94	92	87	71	77	84	94	93	88	71	77	86	85

Data as of 7/29/25

MARKET PRICING



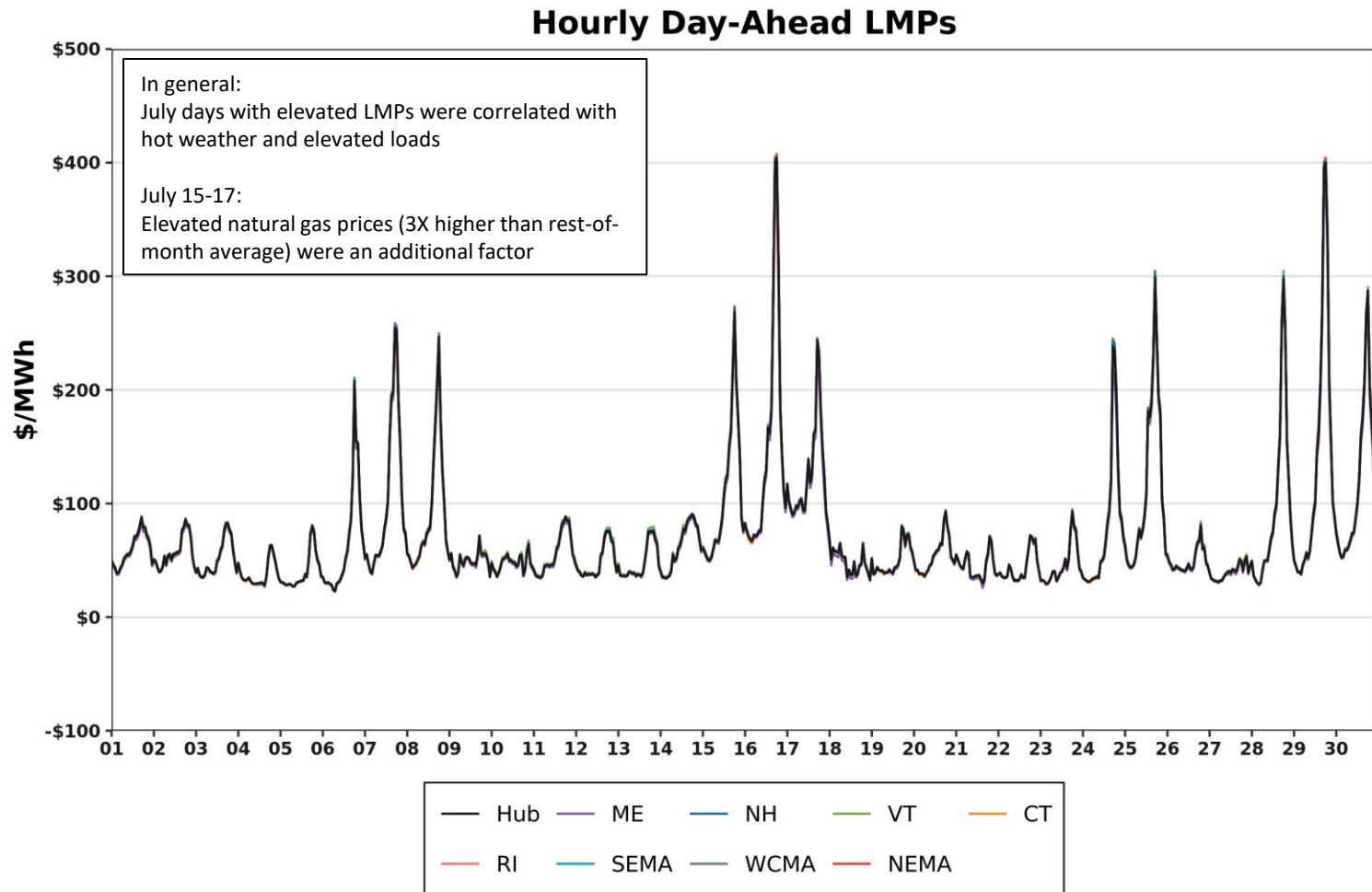
DA vs. RT LMPs (\$/MWh)

Arithmetic Average

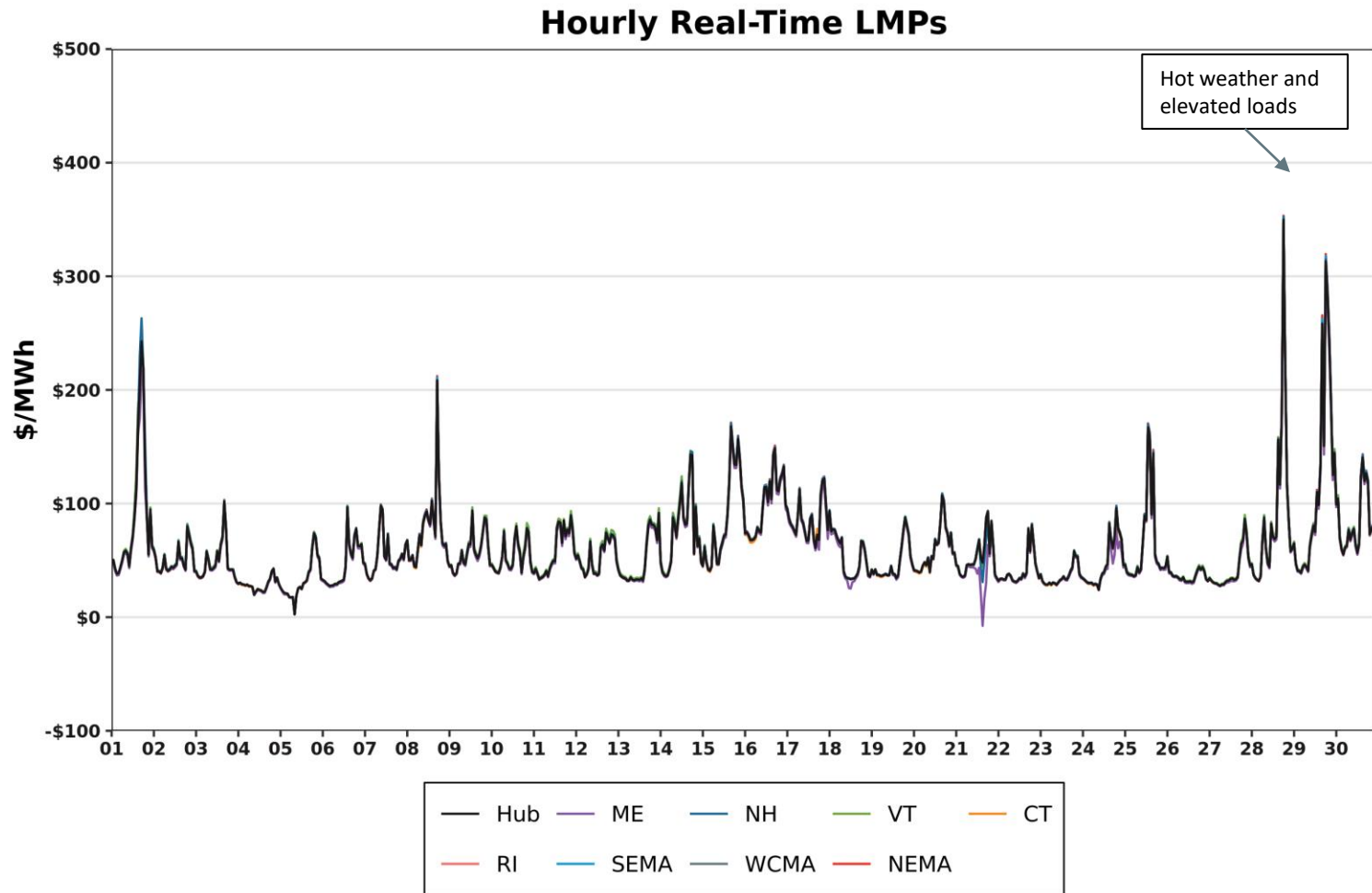
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day Ahead	\$37.04	\$36.59	\$37.22	\$36.78	\$36.25	\$36.89	\$37.34	\$37.07	\$37.35
Real Time	\$35.91	\$35.36	\$36.05	\$35.55	\$35.26	\$35.71	\$36.17	\$35.92	\$36.21
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day Ahead	\$41.35	\$41.07	\$41.72	\$41.11	\$40.17	\$41.28	\$41.70	\$41.37	\$41.91
Real Time	\$39.37	\$38.79	\$39.65	\$39.23	\$38.46	\$39.17	\$39.62	\$39.37	\$39.77
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%

July-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day Ahead	\$46.16	\$45.32	\$46.76	\$45.85	\$45.13	\$45.72	\$46.48	\$46.27	\$46.91
Real Time	\$42.65	\$42.09	\$43.30	\$42.68	\$42.00	\$42.29	\$42.90	\$42.79	\$43.31
RT Delta %	-7.60%	-7.13%	-7.40%	-6.91%	-6.94%	-7.50%	-7.70%	-7.52%	-7.67%
July-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day Ahead	\$70.56	\$68.37	\$70.89	\$71.18	\$69.43	\$69.96	\$70.99	\$70.79	\$71.40
Real Time	\$60.22	\$58.04	\$60.59	\$60.99	\$59.72	\$59.63	\$60.52	\$60.40	\$60.93
RT Delta %	-14.65%	-15.11%	-14.53%	-14.32%	-13.99%	-14.77%	-14.75%	-14.68%	-14.66%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	52.86%	50.86%	51.60%	55.25%	53.84%	53.02%	52.73%	52.99%	52.21%
Yr over Yr RT	41.20%	37.89%	39.93%	42.90%	42.19%	41.00%	41.07%	41.15%	40.68%

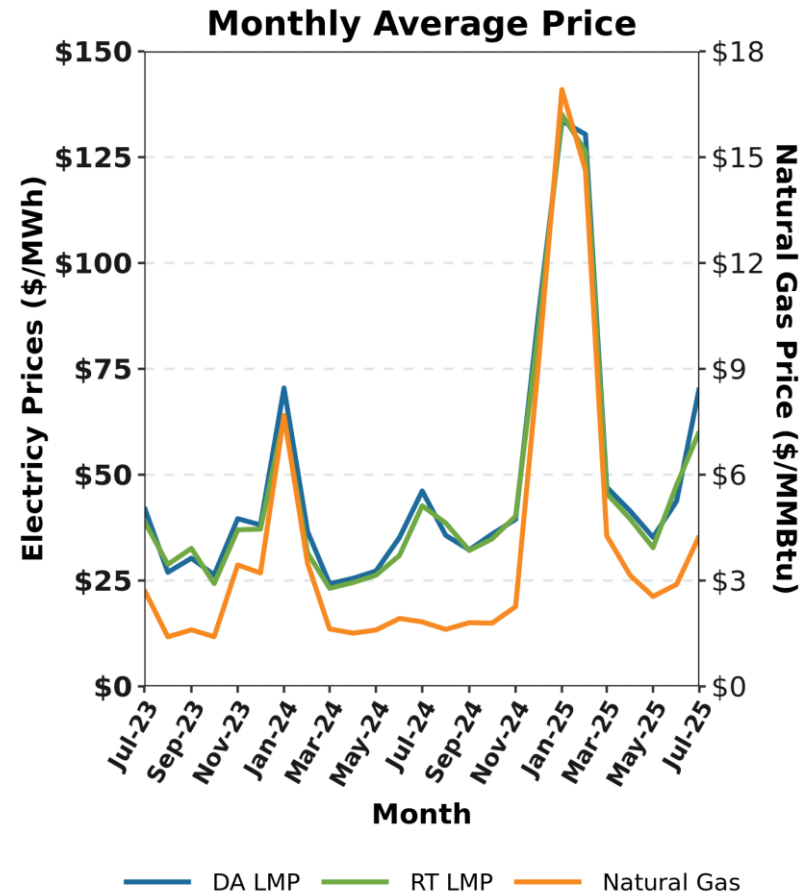
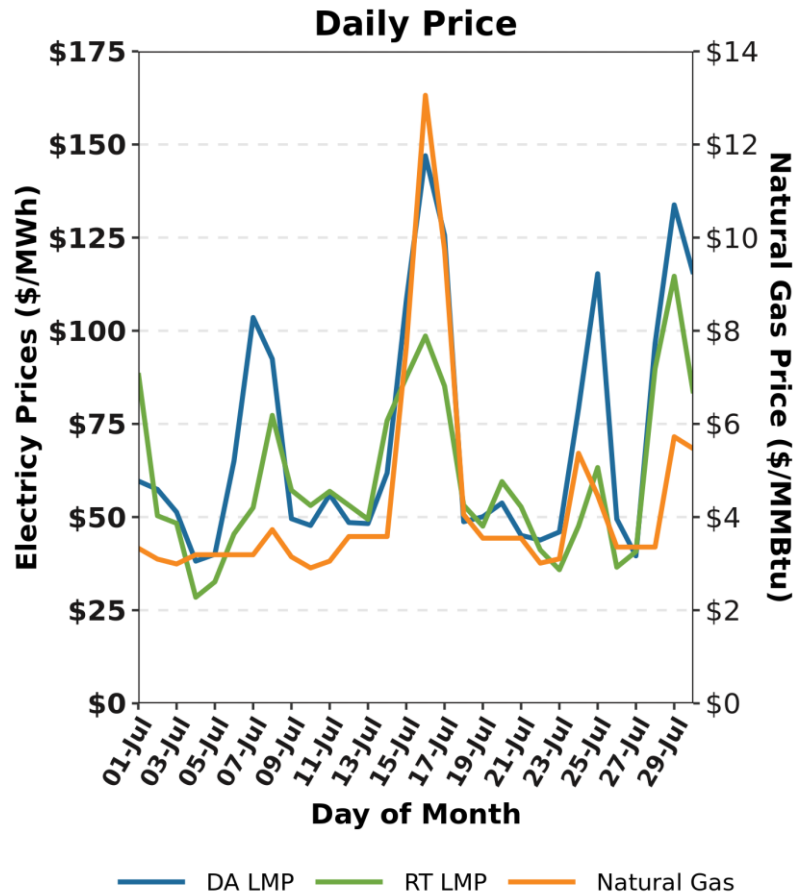
Hourly DA LMPs, July 1-30, 2025



Hourly RT LMPs, July 1-30, 2025



Wholesale Electricity vs Natural Gas Price by Month



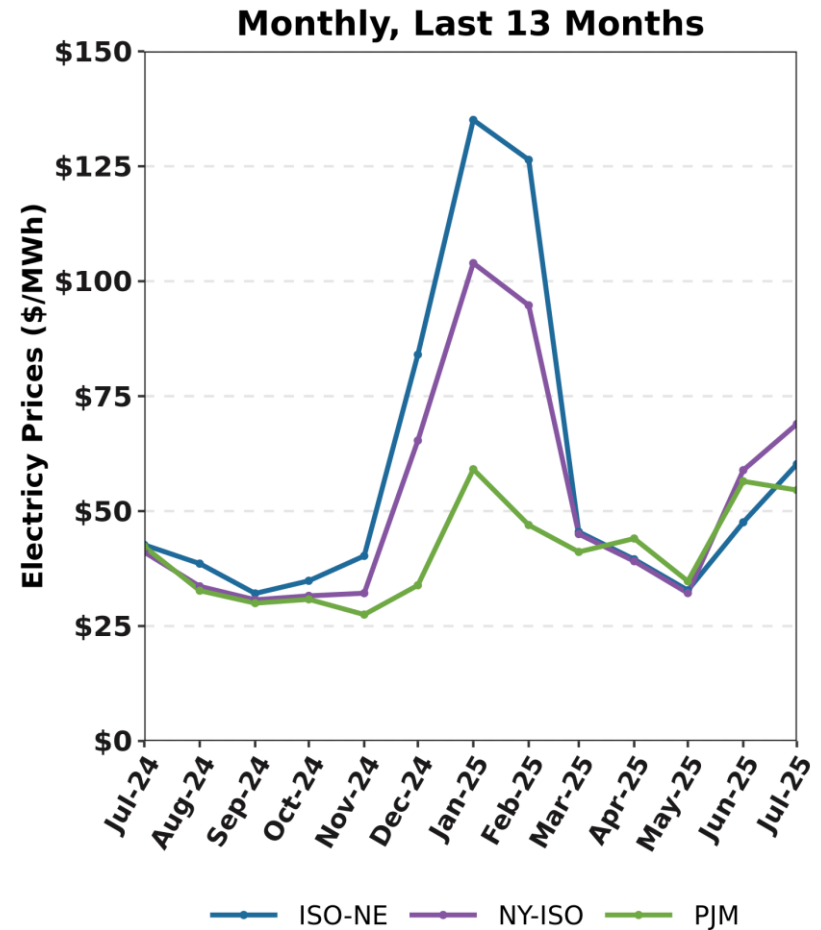
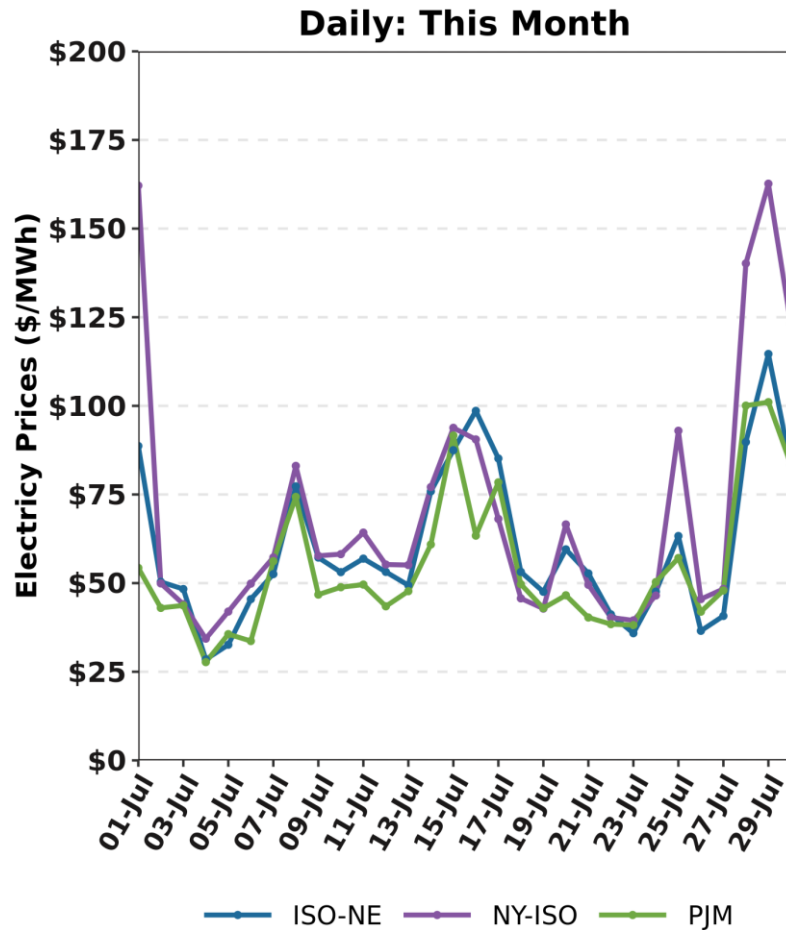
Underlying natural gas data furnished by:



Gas price is average of Massachusetts delivery points

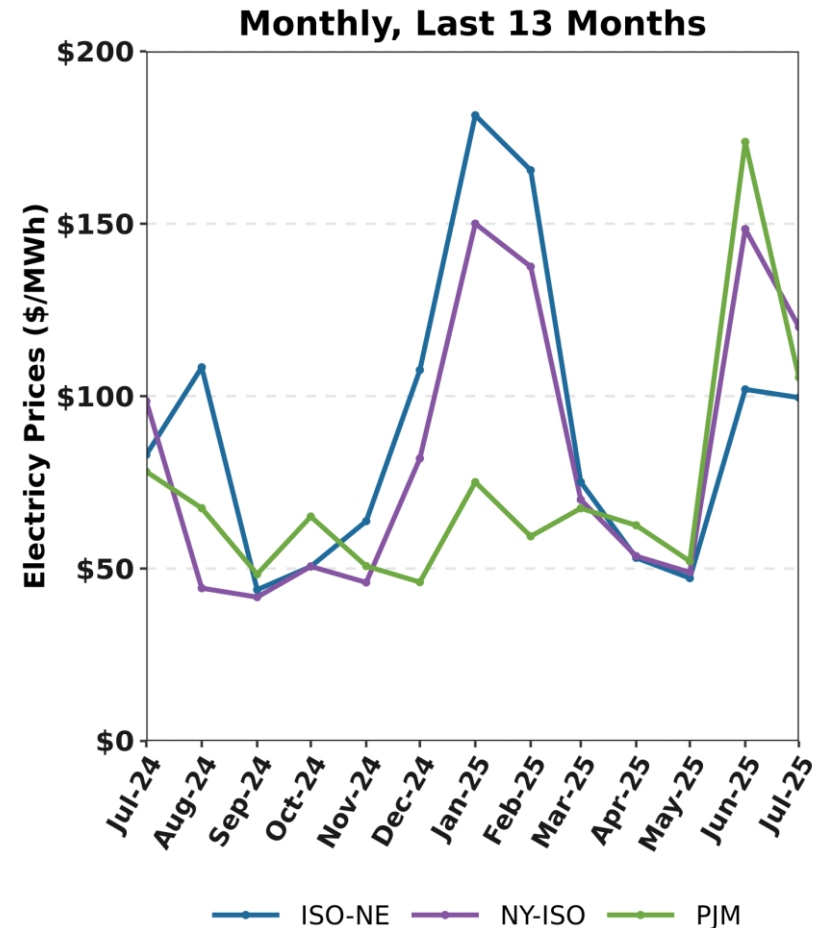
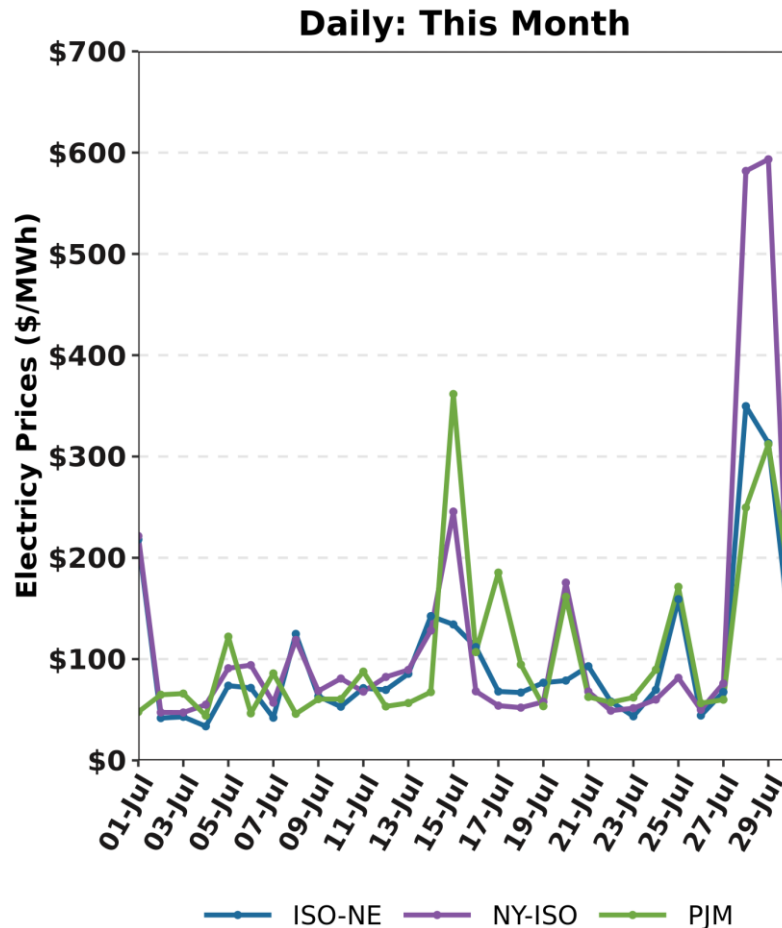
ISO-NE PUBLIC

New England, NY, and PJM Hourly Average RT Prices by Month

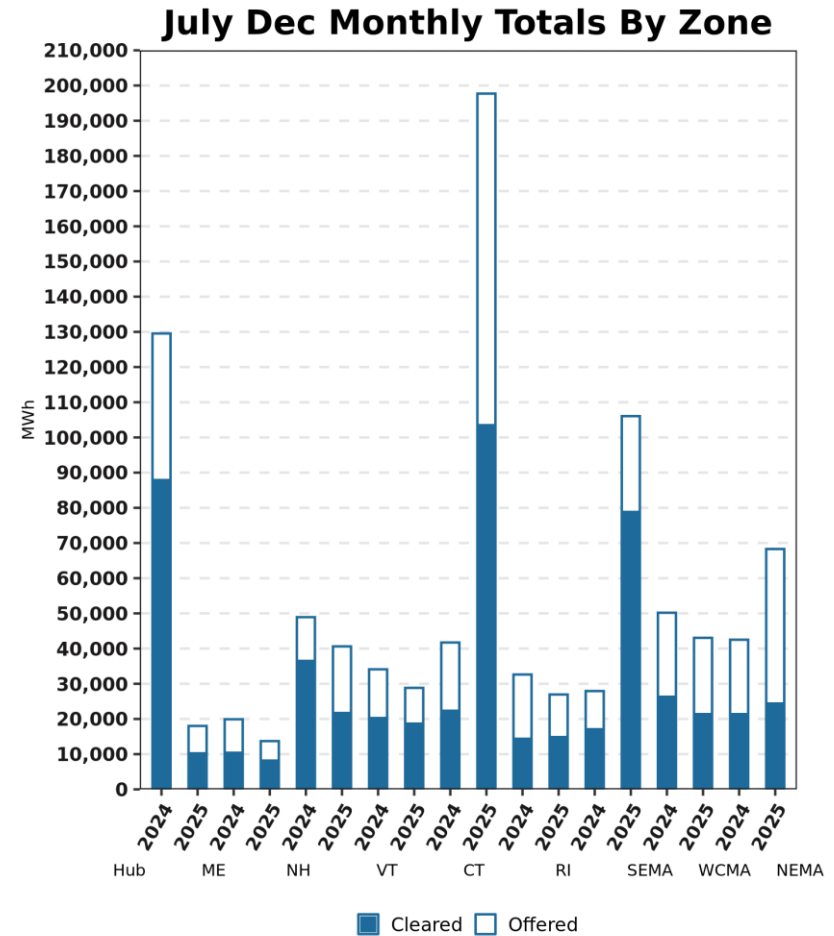
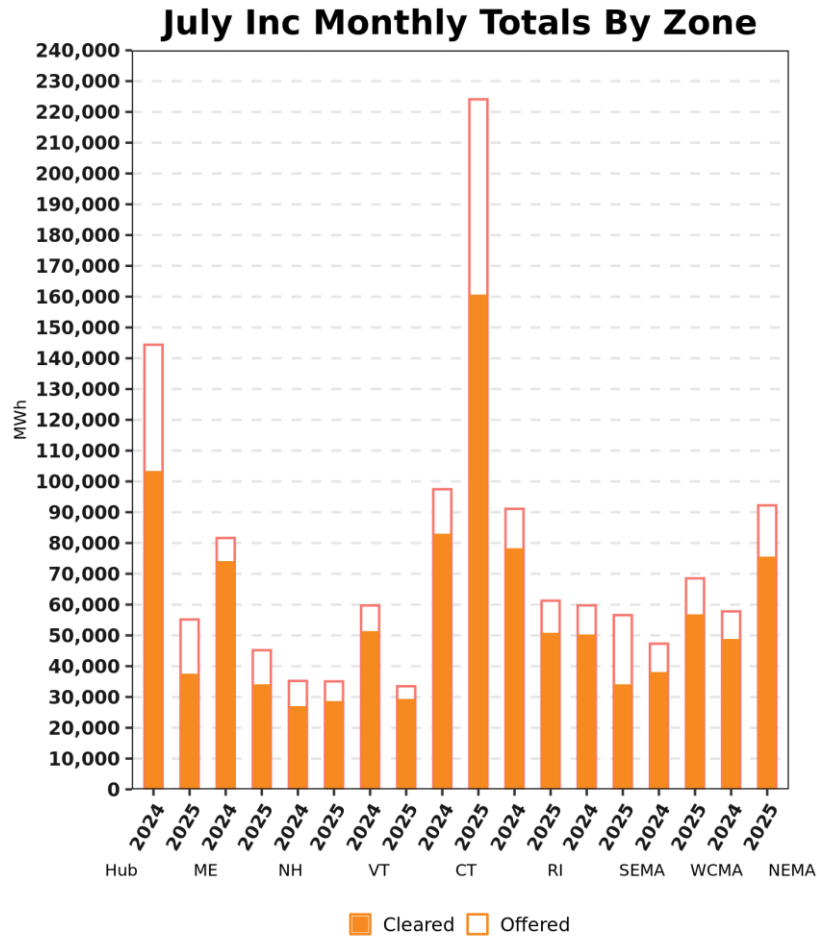


Hourly average prices are shown

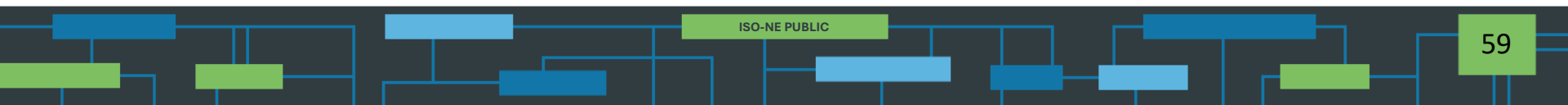
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours



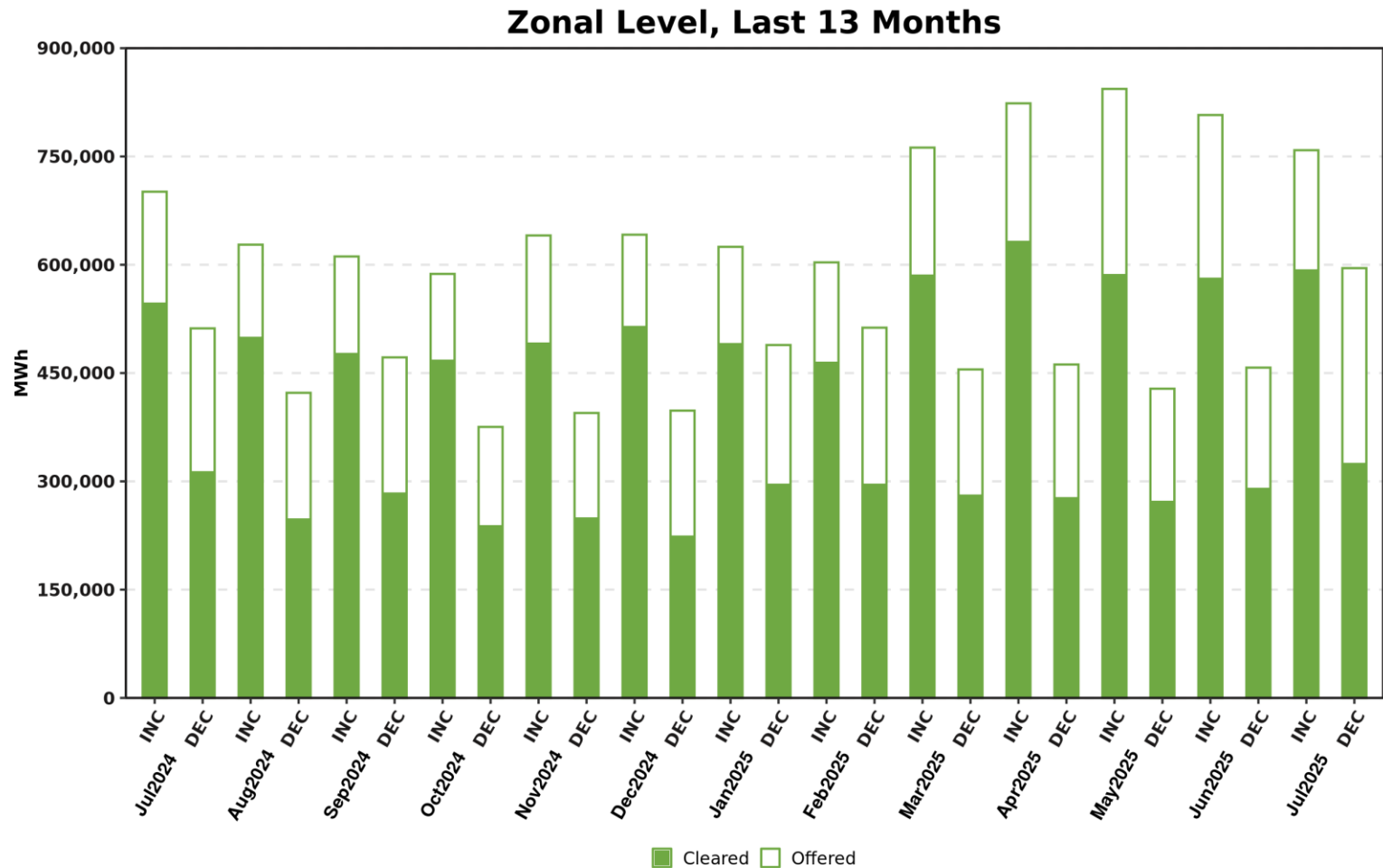
Zonal Increment Offers and Decrement Bid Amounts



Includes nodal activity within the zone; excludes external nodes

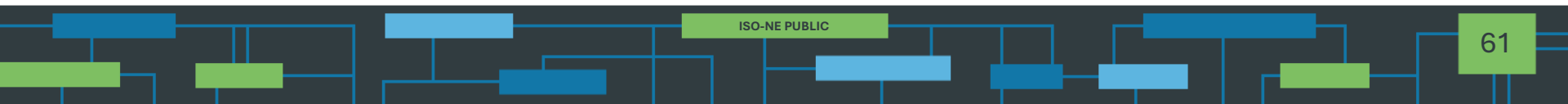


Total Increment Offers and Decrement Bids

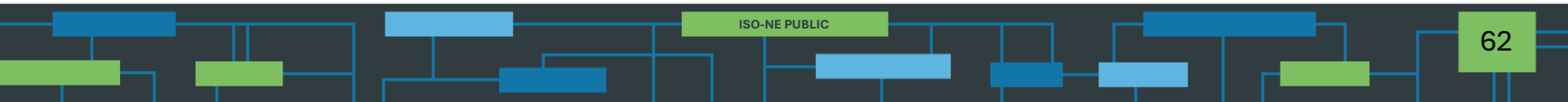


Includes nodal activity within the zone; excludes external nodes

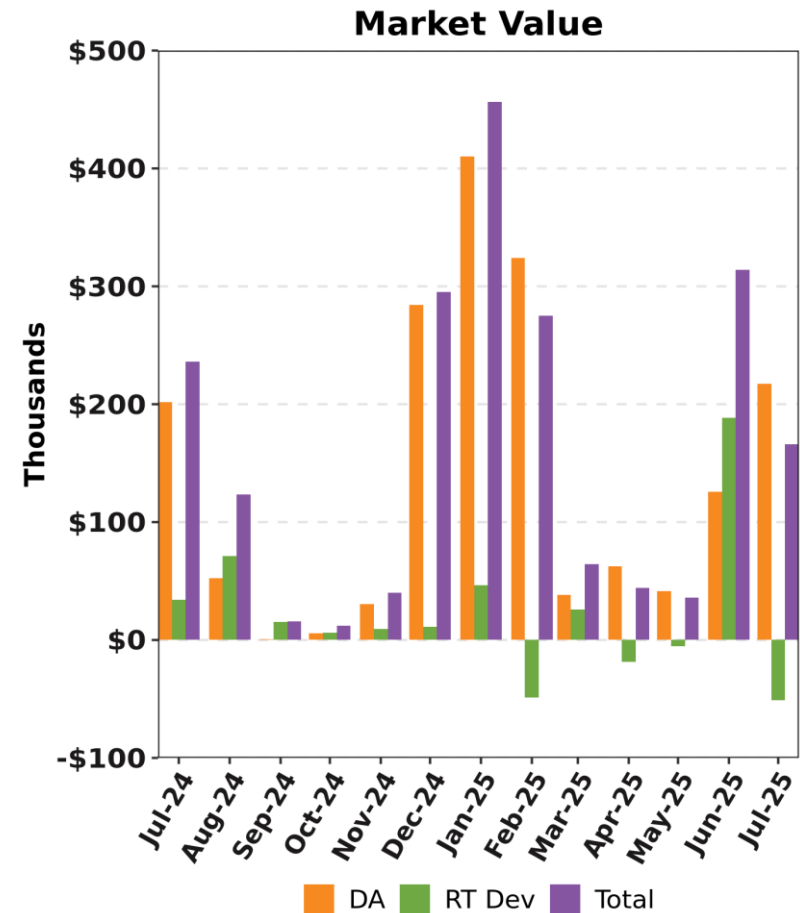
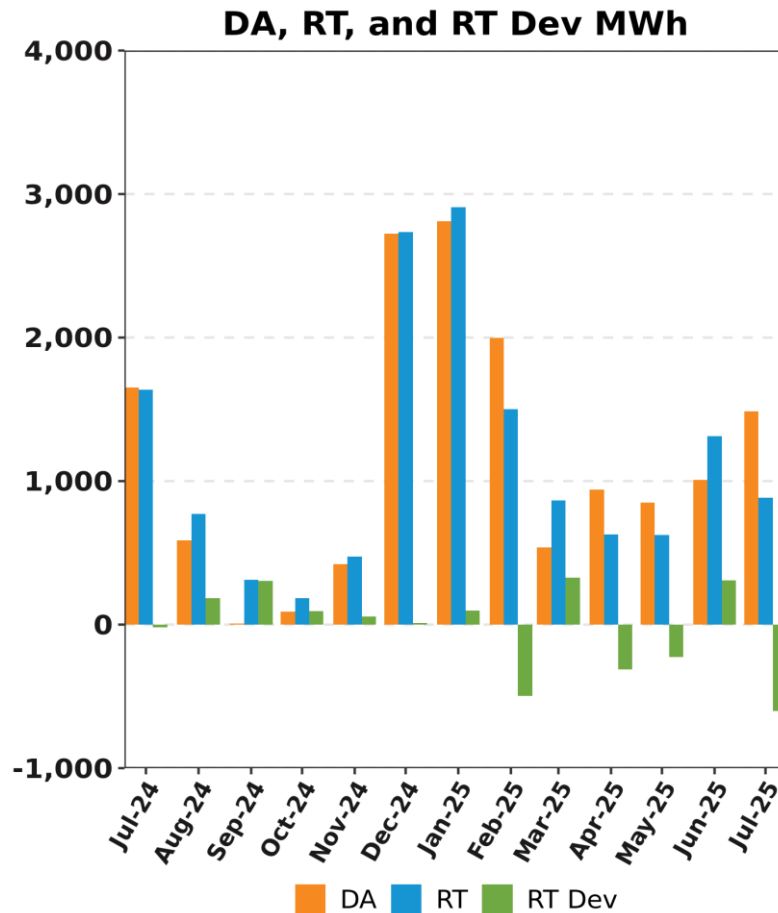
BACK-UP DETAIL



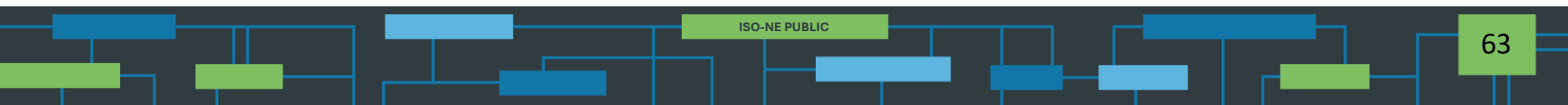
DEMAND RESPONSE



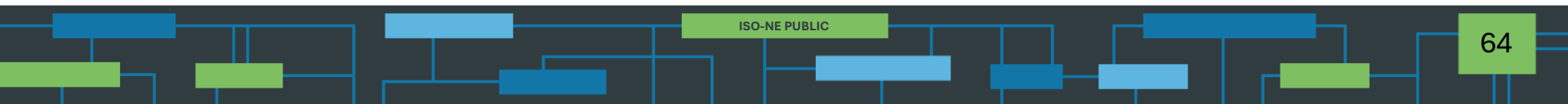
Price Responsive Demand (PRD) Energy Market Activity by Month



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



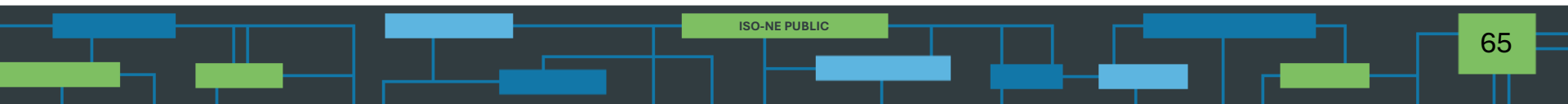
NEW GENERATION



New Generation Update

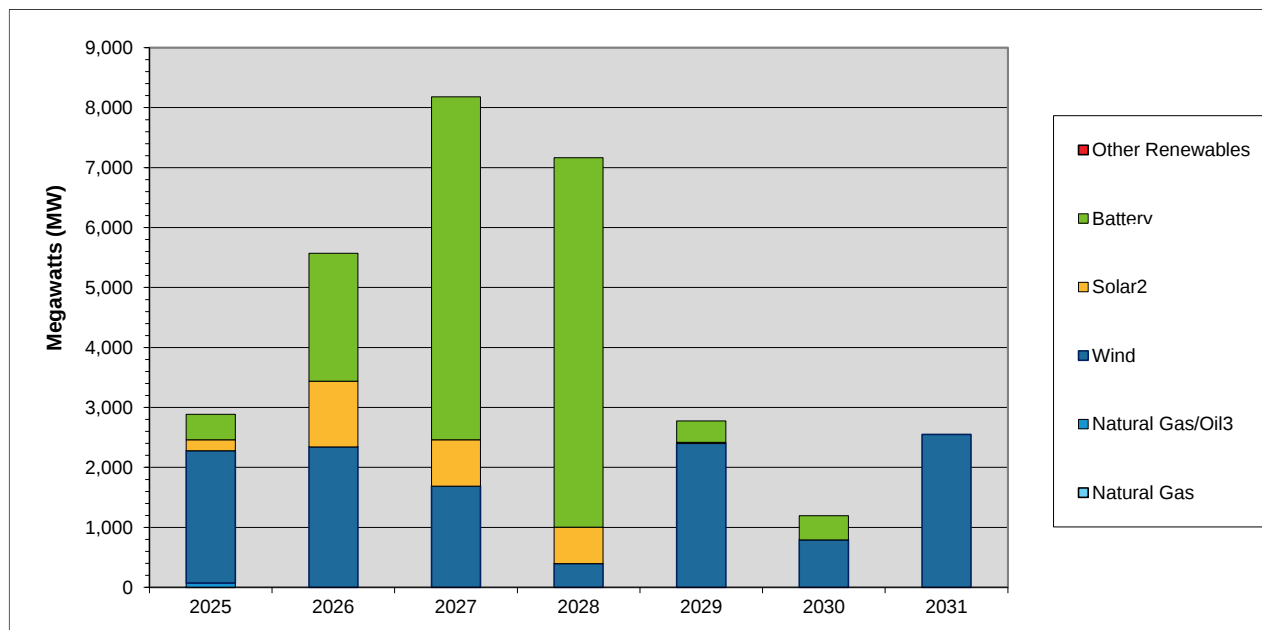
Based on Queue as of 08/01/25

- No new projects were added to the interconnection queue since the last update
 - Any new ISO Interconnection Requests seeking to successfully enter the Order No. 2023 Transitional Cluster Study process were required to be submitted by June 13, 2024 at 23:59
 - Thereafter, the creation of new ISO Interconnection Requests is now suspended until the next Cluster Entry Window opens
 - ISO is no longer tracking non-FERC jurisdictional interconnection projects in the ISO queue
- In total, 139 generation projects are currently being tracked by the ISO, totaling approximately 33,918 MW



Projected Annual Capacity Additions

By Supply Fuel Type



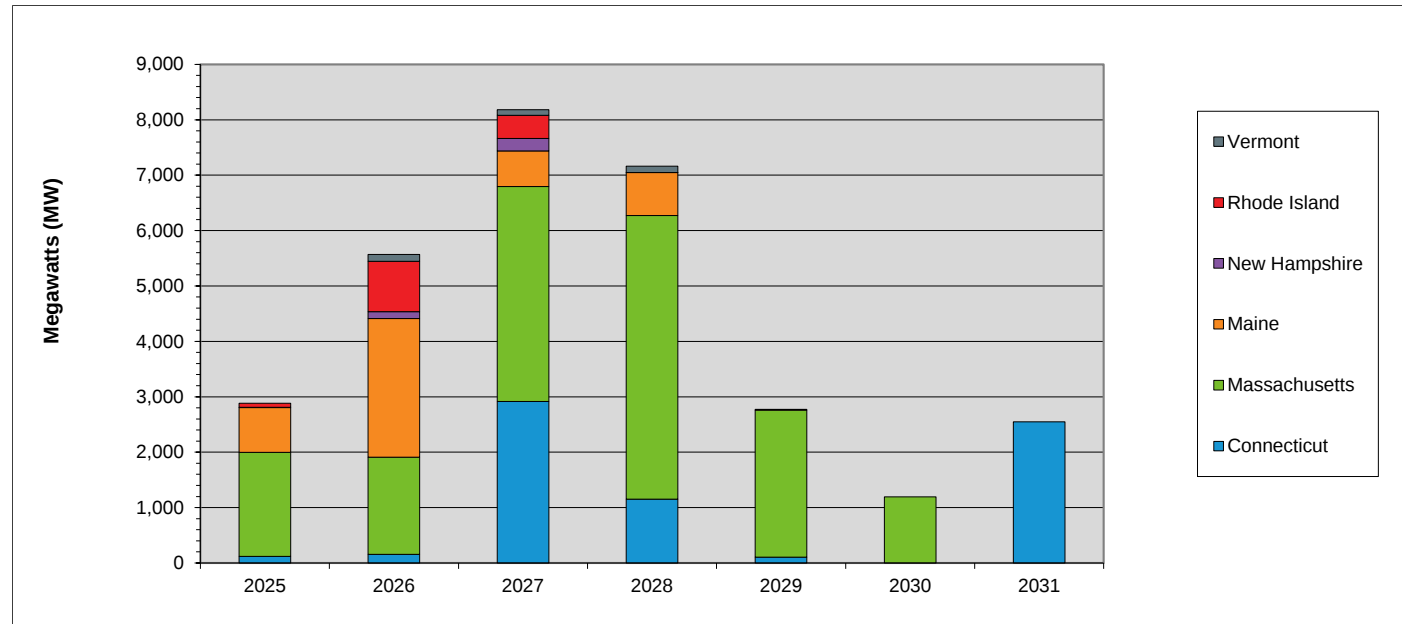
	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total ¹
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	425	2,134	5,718	6,161	357	404	0	15,199	50.1
Solar ²	182	1,093	776	608	17	0	0	2,676	8.8
Wind	2,204	2,344	1,687	394	2,400	791	2,550	12,370	40.8
Natural Gas/Oil ³	73	0	0	0	0	0	0	73	0.2
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	2,884	5,571	8,181	7,163	2,774	1,195	2,550	30,318	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

Projected Annual Generator Capacity Additions By State



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total ¹
Vermont	0	128	101	115	0	0	0	344	1.1
Rhode Island	73	909	415	0	0	0	0	1,397	4.6
New Hampshire	5	122	226	1	0	0	0	354	1.2
Maine	809	2,503	645	777	17	0	0	4,751	15.7
Massachusetts	1,877	1,755	3,880	5,118	2,654	1,195	0	16,479	54.4
Connecticut	120	154	2,914	1,152	103	0	2,550	6,993	23.1
Totals	2,884	5,571	8,181	7,163	2,774	1,195	2,550	30,318	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	78	15,199	2	425	76	14,774
Fuel Cell	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73
Nuclear	0	0	0	0	0	0
Solar	37	2,676	5	121	32	2,555
Wind	23	15,970	2	859	21	15,111
Total	139	33,918	9	1,405	130	32,513

- 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	0	0	0	0	0	0
Intermediate	1	73	0	0	1	73
Peaker	115	17,875	7	546	108	17,329
Wind Turbine	23	15,970	2	859	21	15,111
Total	139	33,918	9	1,405	130	32,513

- 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

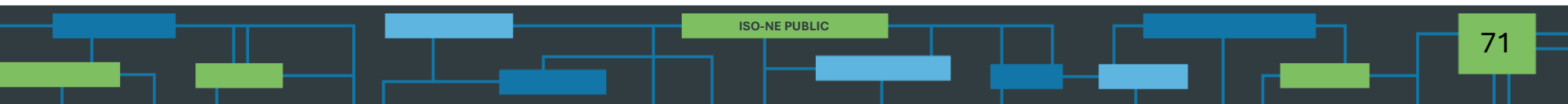
New Generation Projection

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	78	15,199	0	0	0	0	78	15,199	0	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	37	2,676	0	0	0	0	37	2,676	0	0
Wind	23	15,970	0	0	0	0	0	0	23	15,970
Total	139	33,918	0	0	1	73	115	17,875	23	15,970

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

FORWARD CAPACITY MARKET



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	461.416	-118.276
	Passive Demand	3,212.865	3,211.403	-1.462	3,134.652	-76.751	3,113.332	-21.32
Demand Total		3,890.538	3,884.804	-5.734	3,714.344	-170.460	3,574.748	-139.596
Generator	Non-Intermittent	28,154.203	27,714.778	-439.425	27,081.653	-633.125	27,132.413	50.76
	Intermittent	1,089.265	1,073.794	-15.471	1,056.601	-17.193	865.694	-190.907
Generator Total		29,243.468	28,788.572	-454.896	28,138.254	-650.318	27,998.107	-140.147
Import Total		1,487.059	1297.132	-189.927	1,249.545	-47.587	1,193.583	-55.962
Grand Total*		34,621.065	33,970.508	-650.557	33,102.143	-868.365	32,766.438	-335.705
Net ICR (NICR)		33,270	31,775	-1,495	31,545	-230	31,380	-165

* 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 2024-2028 CCP Month 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	504.466	-85.416	437.780	-66.686
	Passive Demand	2,557.256	2,579.120	21.864	2,574.367	-4.753	2,568.703	-5.664
Demand Total		3,322.606	3,169.002	-153.604	3,078.833	-90.169	3,006.483	-72.350
Generator	Non-Intermittent	26,805.003	26,643.379	-161.624	26,503.730	-139.649	26,049.059	-454.671
	Intermittent	1,178.933	1,146.783	-32.15	989.265	-157.518	912.376	-76.889
Generator Total		27,983.936	27,790.162	-193.774	27,492.995	-297.167	26,961.435	-531.560
Import Total		1,503.842	1,247.601	-256.241	1,244.601	-3.000	1,234.800	-9.801
Grand Total*		32,810.384	32,206.765	-603.619	31,816.429	-390.336	31,202.718	-613.711
Net ICR (NICR)		31,645	30,585	-1,060	30,775	190	30,300	-475

* 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 2024-2028 CCP Month 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	584.913	-37.941				
	Passive Demand	2,316.815	2,314.068	-2.747				
Demand Total		2,939.669	2,898.981	-40.688				
Generator	Non-Intermittent	26,507.420	26,715.489	208.069				
	Intermittent	1,356.084	1,286.589	-69.495				
Generator Total		27,863.504	28,002.078	138.574				
Import Total		566.998	564.079	-2.919				
Grand Total*		31,370.171	31,465.138	94.967				
Net ICR (NICR)		30,305	30,395	90.000				

* 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 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 18

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	543.580	403.884	-139.696				
	Passive Demand	2,070.498	2,851.331	780.833				
Demand Total		2,614.078	3,255.215	641.137				
Generator	Non-Intermittent	27,026.635	25,822.288	-1,204.347				
	Intermittent	1,450.872	890.415	-560.457				
Generator Total		28,477.507	26,712.703	-1,764.804				
Import Total		464.835	1,234.800	769.965				
Grand Total*		31,556.420	31,202.718	-353.702				
Net ICR (NICR)		30,550.000	30,415.000	-135.000				

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

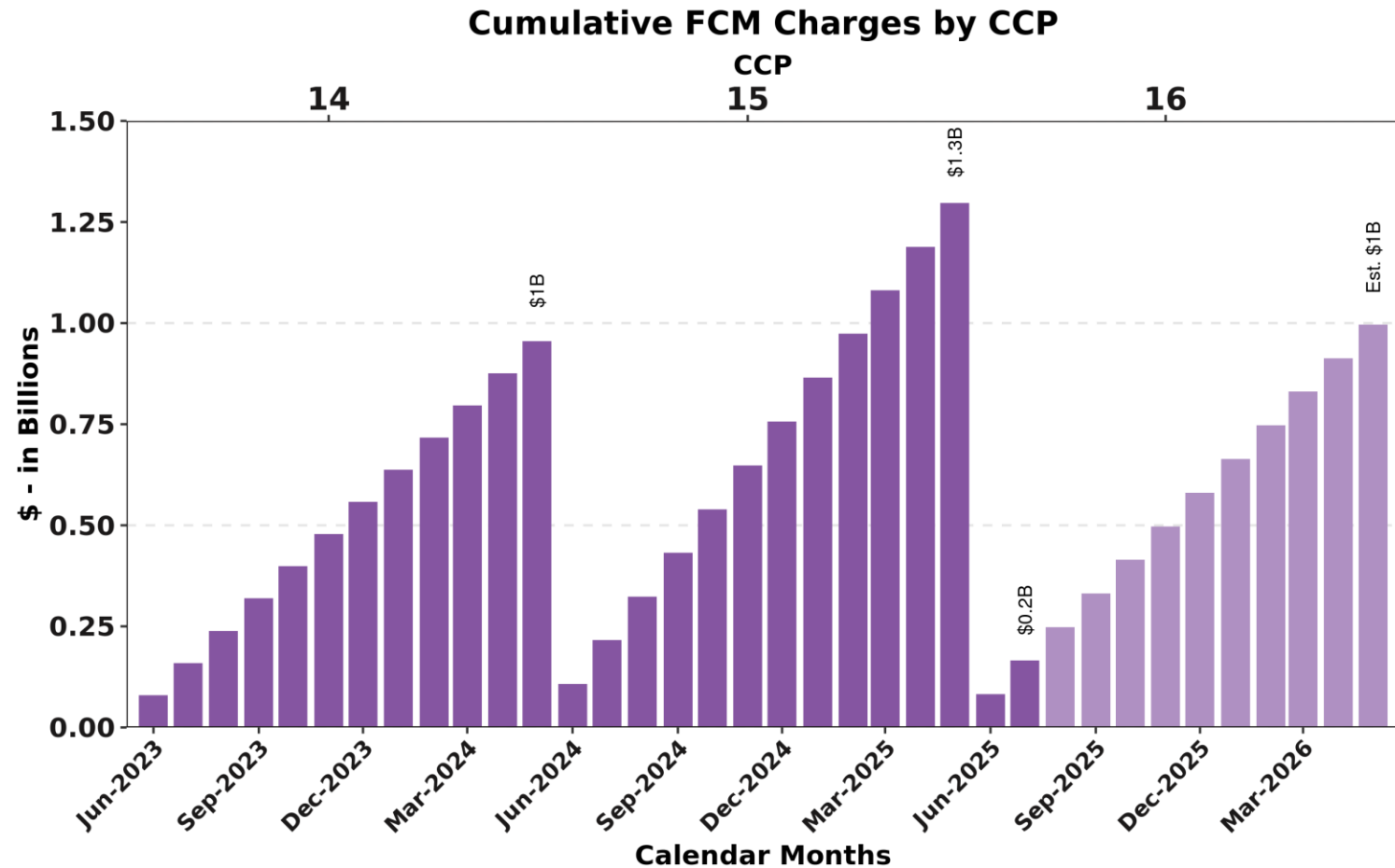
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

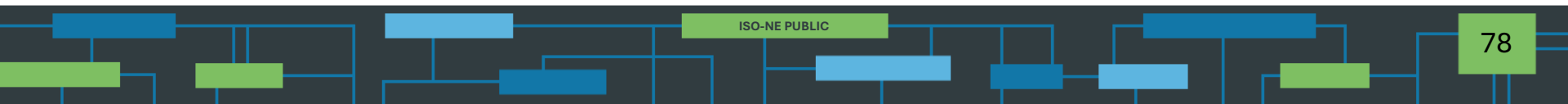
Commitment Period	Active/Passive	Existing	New	Grand Total
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3,085.734	514.072	3,599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3,386.703	653.541	4,040.244
2023-24	Active	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
2026-27	Active	615.369	7.485	622.854
	Passive	2,194.172	122.643	2,316.815
	Grand Total	2,809.541	130.128	2,939.669
2027-28	Active	543.58	0.0	543.58
	Passive	1,965.515	104.983	2070.498
	Grand Total	2,509.095	104.983	2,614.498

Forward Capacity Market Auctions



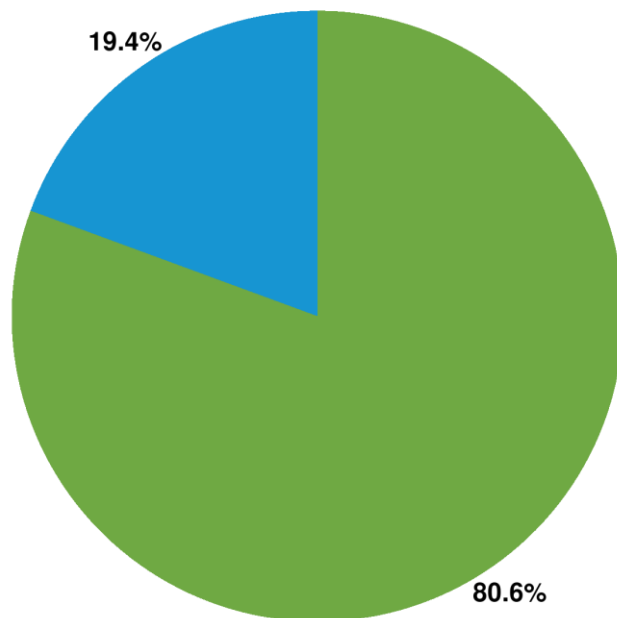
The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

NET COMMITMENT PERIOD COMPENSATION



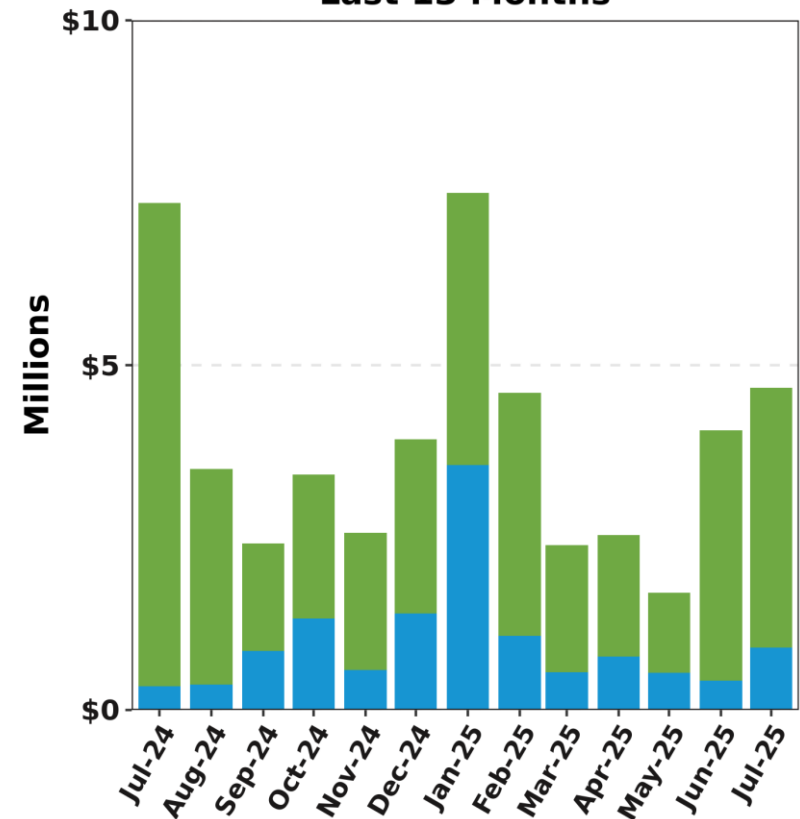
DA and RT NCPC Charges

Jul-25 Total = \$4.7 M



Day-Ahead Real-Time

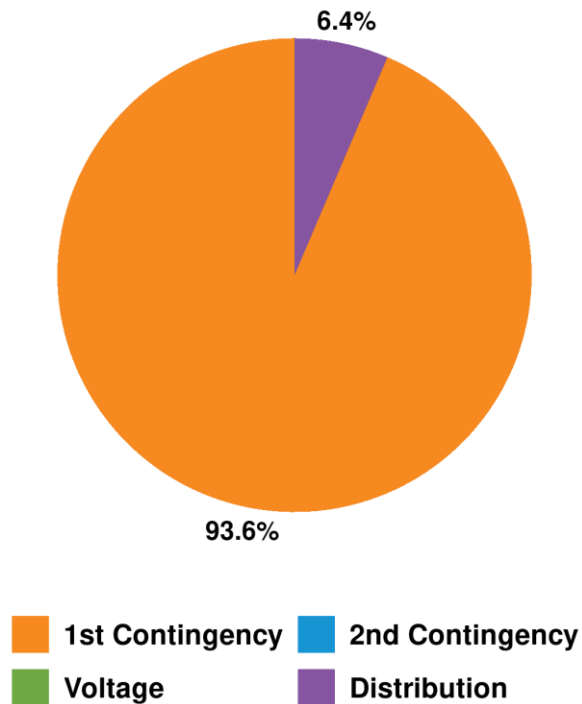
Last 13 Months



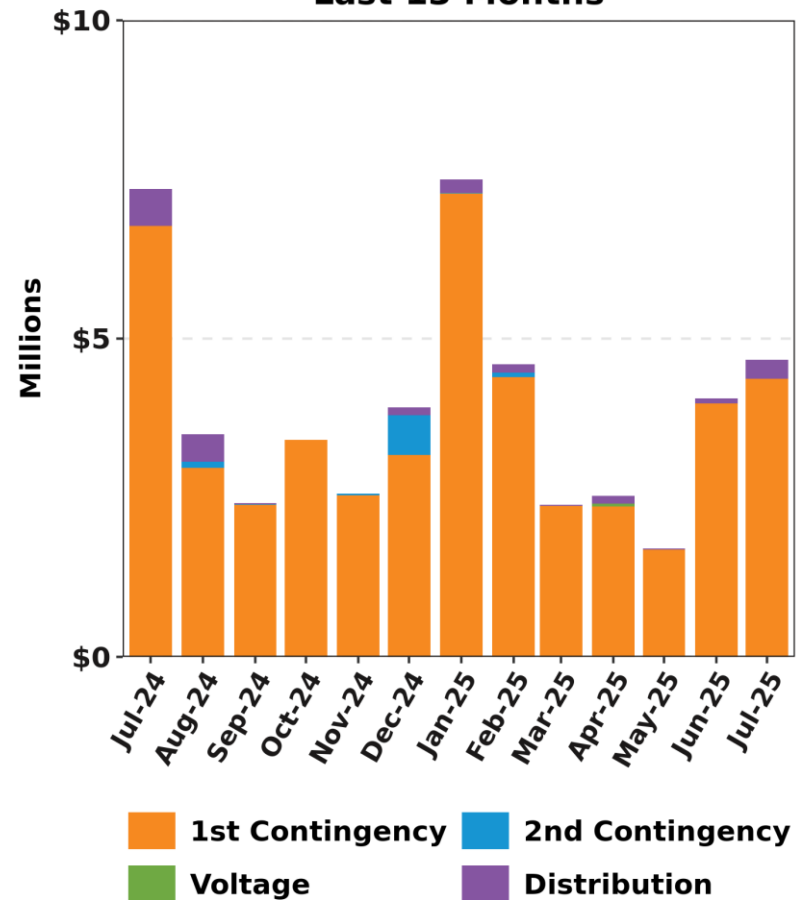
Day-Ahead Real-Time

NCPC Charges by Type

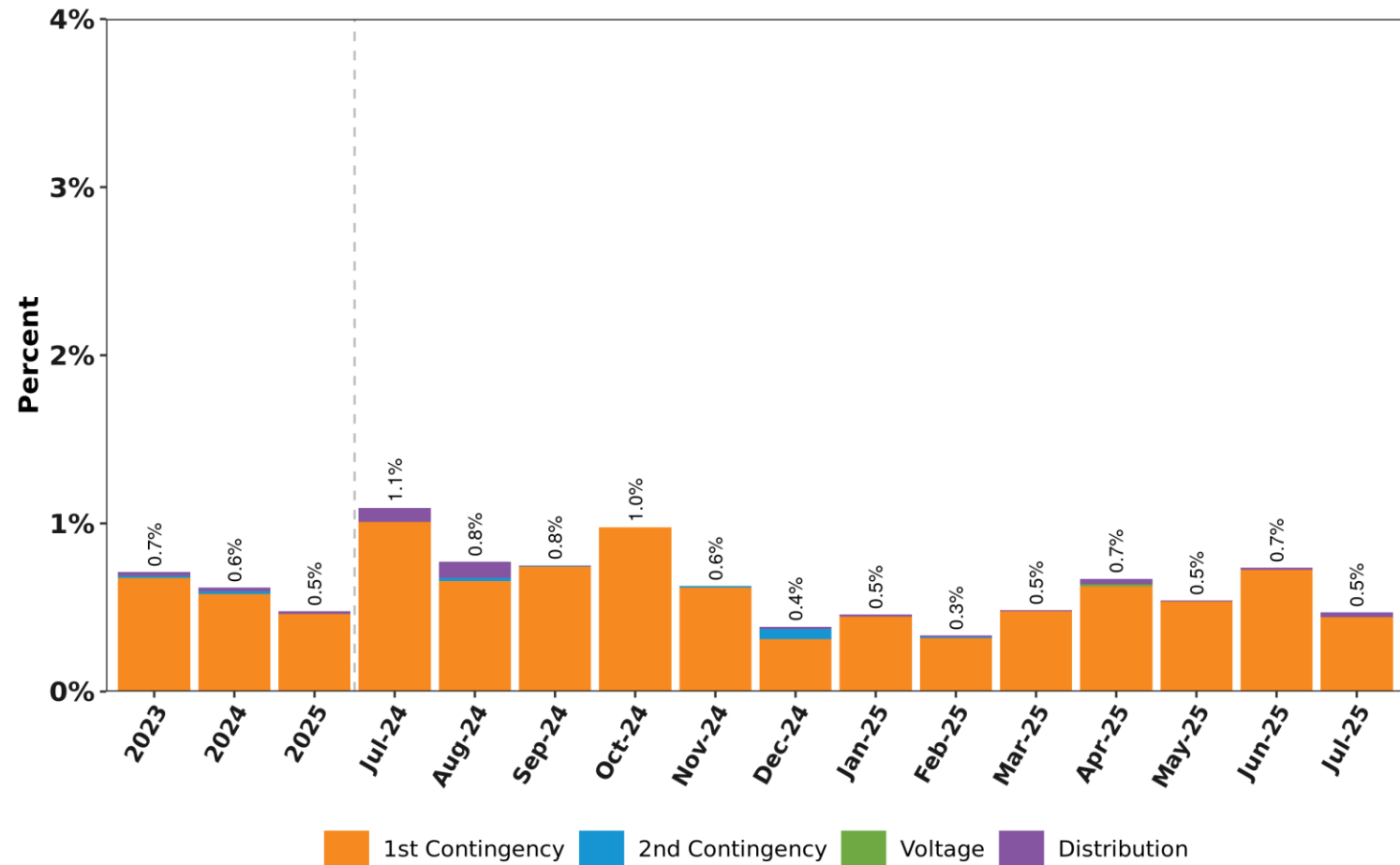
Jul-25 Total = \$4.7 M



Last 13 Months

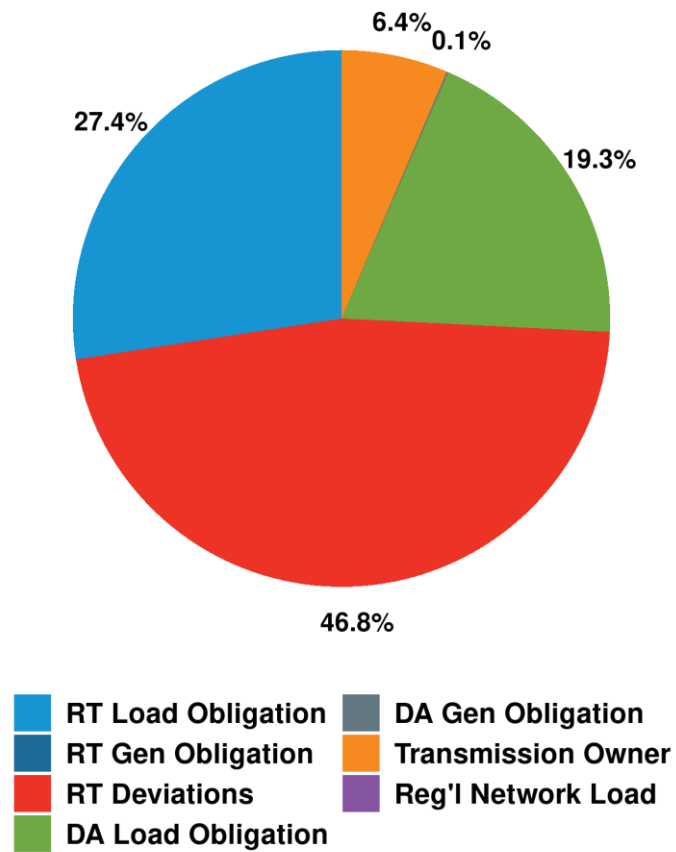


NCPC Charges by Type as Percent of Energy Market Value

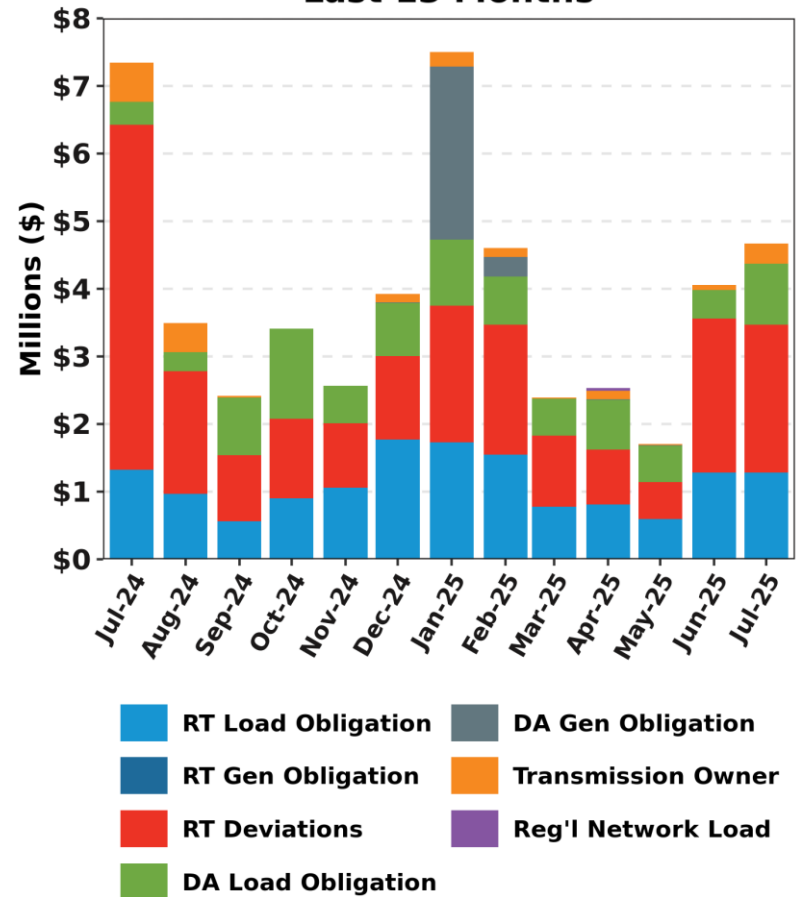


NCPC Charge Allocations

Jul-25 Total = \$4.7 M

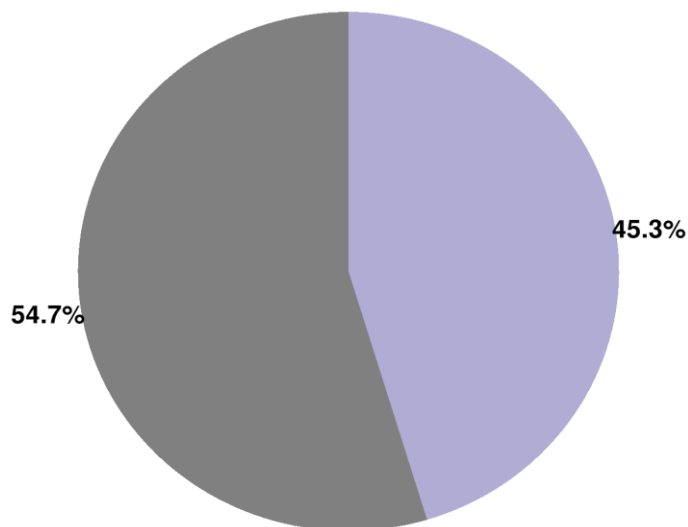


Last 13 Months



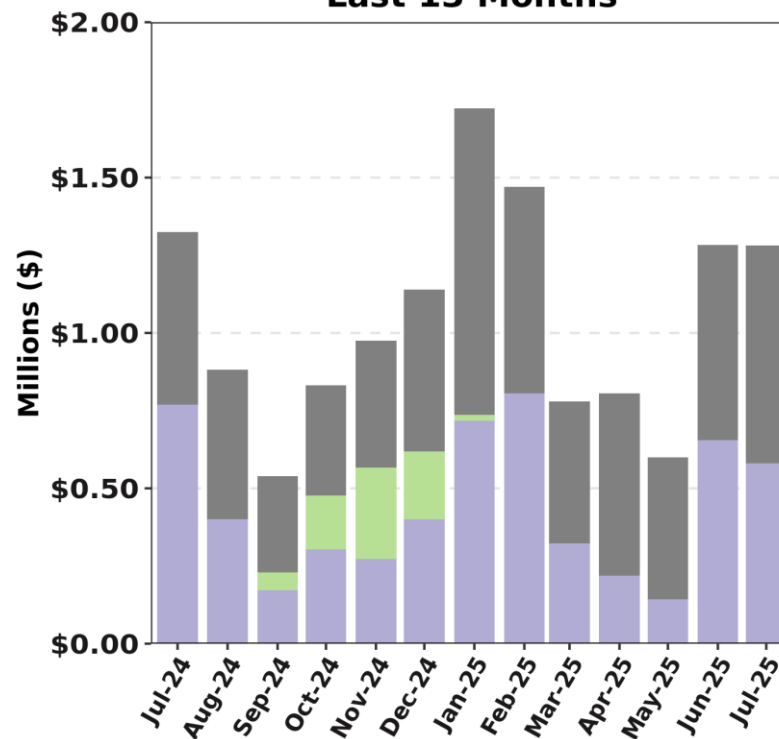
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

Jul-25 Total = \$1.3 M



DLOC
 Postured Gen
 Min Gen
 GPA
 RRP

Last 13 Months

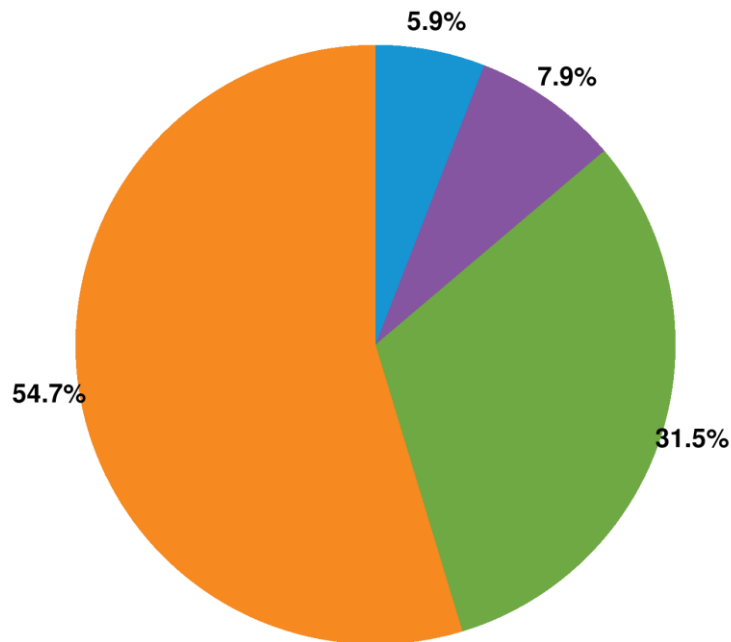


DLOC
 Postured Gen
 Min Gen
 GPA
 RRP

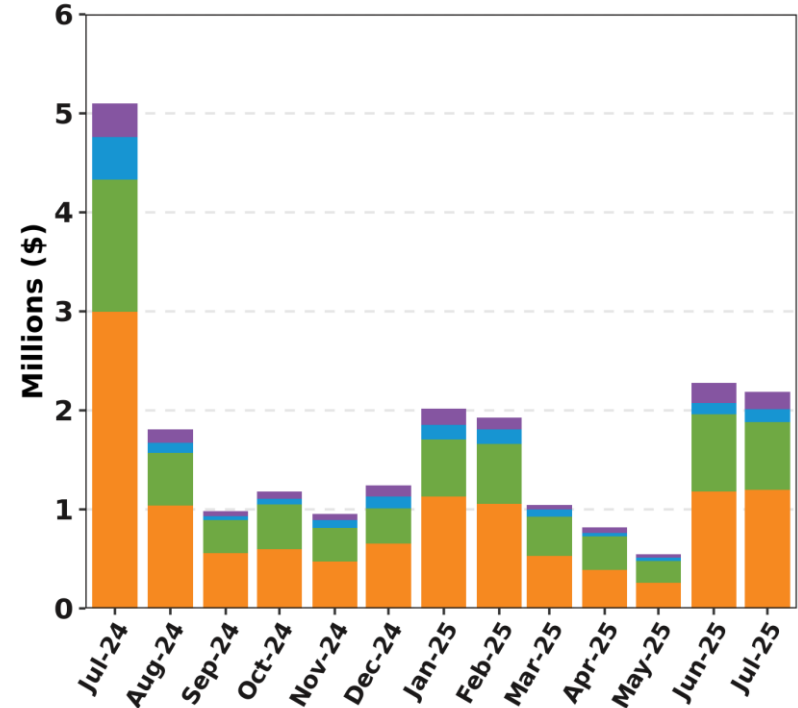
The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

RT First Contingency Charges by Deviation Type

Jul-25 Total = \$2.2 M



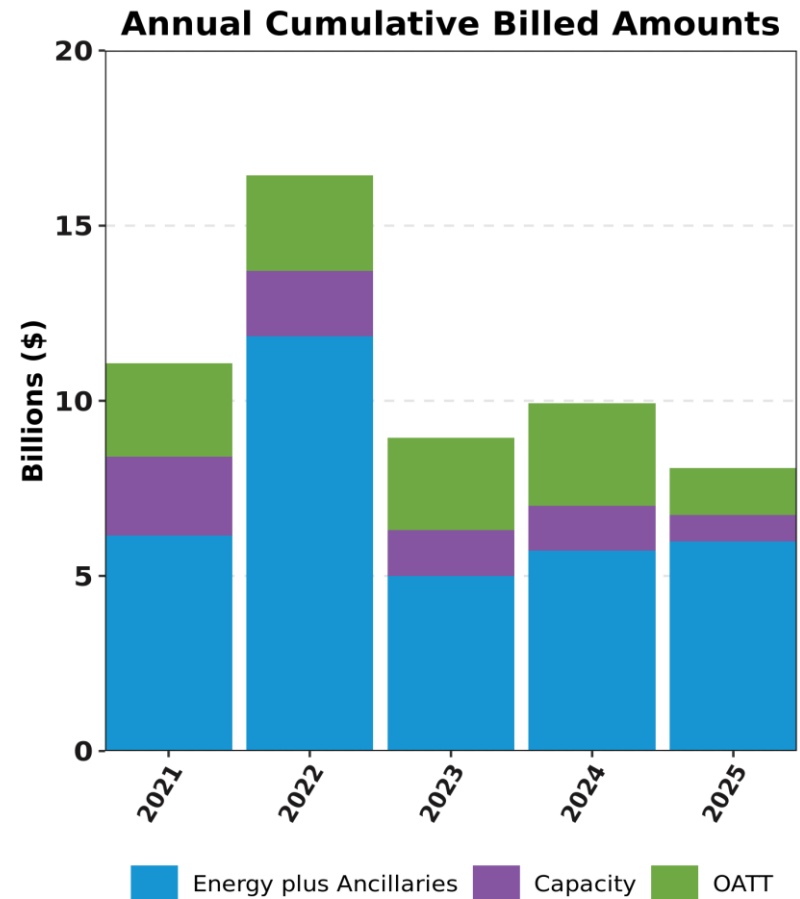
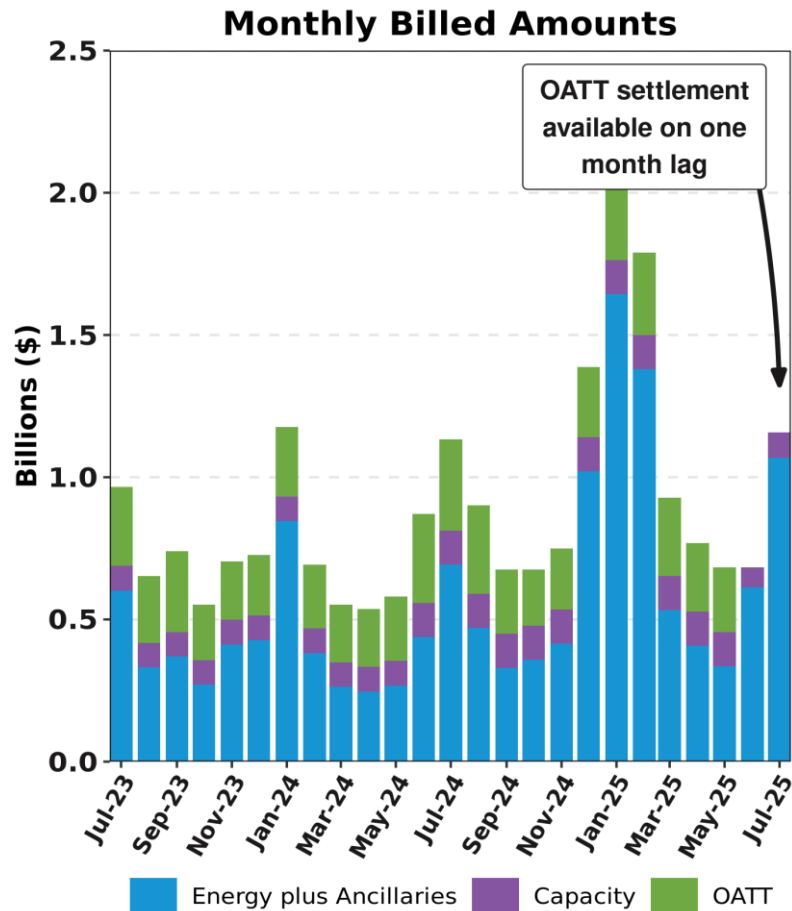
Last 13 Months



ISO BILLINGS

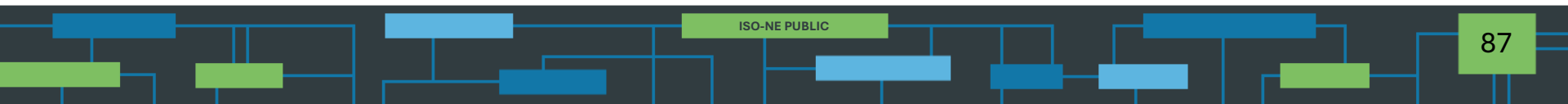


Total ISO Billings



Ancillaries = Reserves, Regulation, NCPC, minus Marginal Loss Revenue Fund. OATT = RNS, Through and Out, Schedule 9

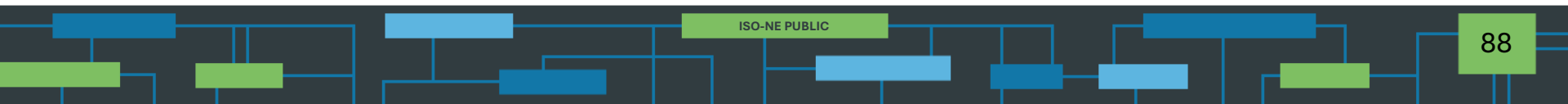
REGIONAL SYSTEM PLAN (RSP)



Planning Advisory Committee (PAC)

- August 20 PAC Meeting Agenda Topics*
 - Asset Condition Projects
 - Line 1759 Copperweld and Asset Condition Structure Replacement Project (Eversource)
 - Scobie Pond 345 kV Trench Replacement & Control House Expansion Project – Project Update (Eversource)
 - CMP Structure Replacement Program (CEII)
 - Draft 2025 Regional System Plan
 - DER Model Parameters and Fault Impedance Methodology
 - Load Power Factor Assumptions in Planning Studies
 - 2024 Economic Study: System Efficiency Needs Scenario

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



2025 Longer-Term Transmission Planning RFP

- NESCOE provided a letter on 10/16/24 discussing potential transmission needs for a Longer-term Transmission Planning (LTP) RFP, which was discussed at the 10/23/24 PAC meeting
- On 12/13/24, NESCOE provided its LTP request describing the needs to be addressed by 2035:
 - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
 - Increase the Surowiec-South interface capacity to at least 3,200 MW
 - Develop new infrastructure (e.g., substation) at Pittsfield, Maine that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind**
- NESCOE's LTP request was discussed at the 12/18/24 PAC meeting
- Further discussion on details of the RFP, led by the ISO, occurred at the 1/23/25 PAC meeting, and additional discussion occurred at the 2/26/25 PAC meeting
- QTPS training on the use of Responsive occurred on 2/20/25
- The ISO issued the LTP RFP on 3/31/25, with proposals due by 9/30/25

* Unless a bidder can demonstrate supply chain issues that warrant a later in-service date

** Bidders may propose alternate locations which would be more efficient and cost-effective

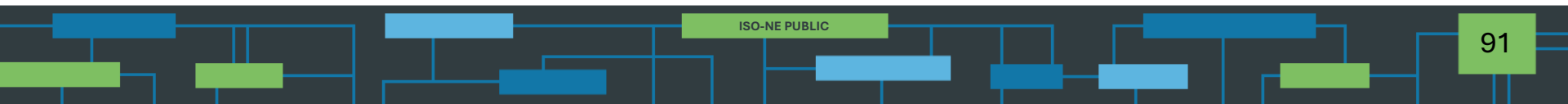
Economic Studies: 2024 Study

- 2024 Economic Study
 - This study is the first use of new Economic Study Process Tariff language
 - The study was initiated at the January 2024 PAC meeting and will be completed this year unless a Request for Proposal is triggered
 - Benchmark, Policy and Stakeholder-Requested Scenarios are complete and the draft report will be issued in August or September
 - System Efficiency Needs Scenario is being analyzed between now and Q4 2025
 - Economic Study Phase 2 Tariff changes were accepted by FERC on 6/20/25, with an effective date of 6/23/25

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 7/29/2025

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	Mar-24	4
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

Greater Boston Projects, cont.

Status as of 7/29/2025

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, 1672*	Install a new 115 kV line from Sudbury to Hudson	Dec-24, Jun-25*	4, 4

* The new 115 KV line from Sudbury to Hudson is currently in-service with some station work remaining at Hudson.

Greater Boston Projects, cont.

Status as of 7/29/2025

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 7/29/2025

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	Mar-24	4
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 7/29/2025

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 7/29/2025

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 7/29/2025

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-26	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 7/29/2025

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	4
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-26	2

SEMA/RI Reliability Projects, cont.

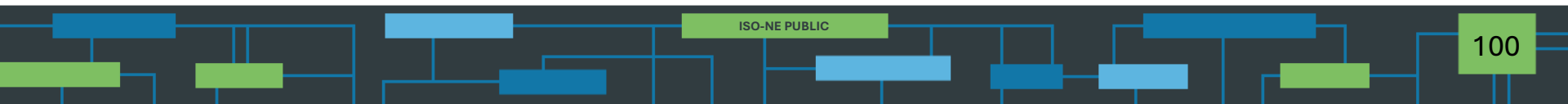
Status as of 7/29/2025

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 7/29/2025

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

New Hampshire Solution Projects

Status as of 7/29/2025

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	Jun-25	4
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Oct-24	4
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec 24	4
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 7/29/2025

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	Aug-24	4
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	Aug-25	4

Upper Maine Solution Projects, cont.

Status as of 7/29/2025

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	Nov-24	4
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jul-24	4
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Jun-26	2

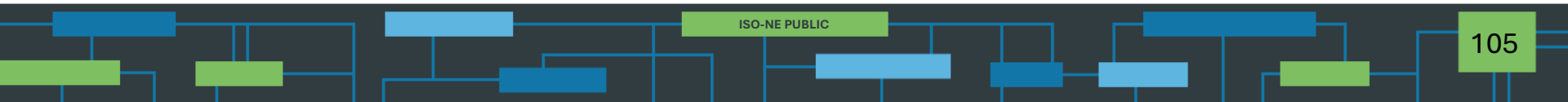
* Cancelled per the Upper Maine Solutions Study Addendum that was published on January 11, 2024

Boston 2033 Solutions Study

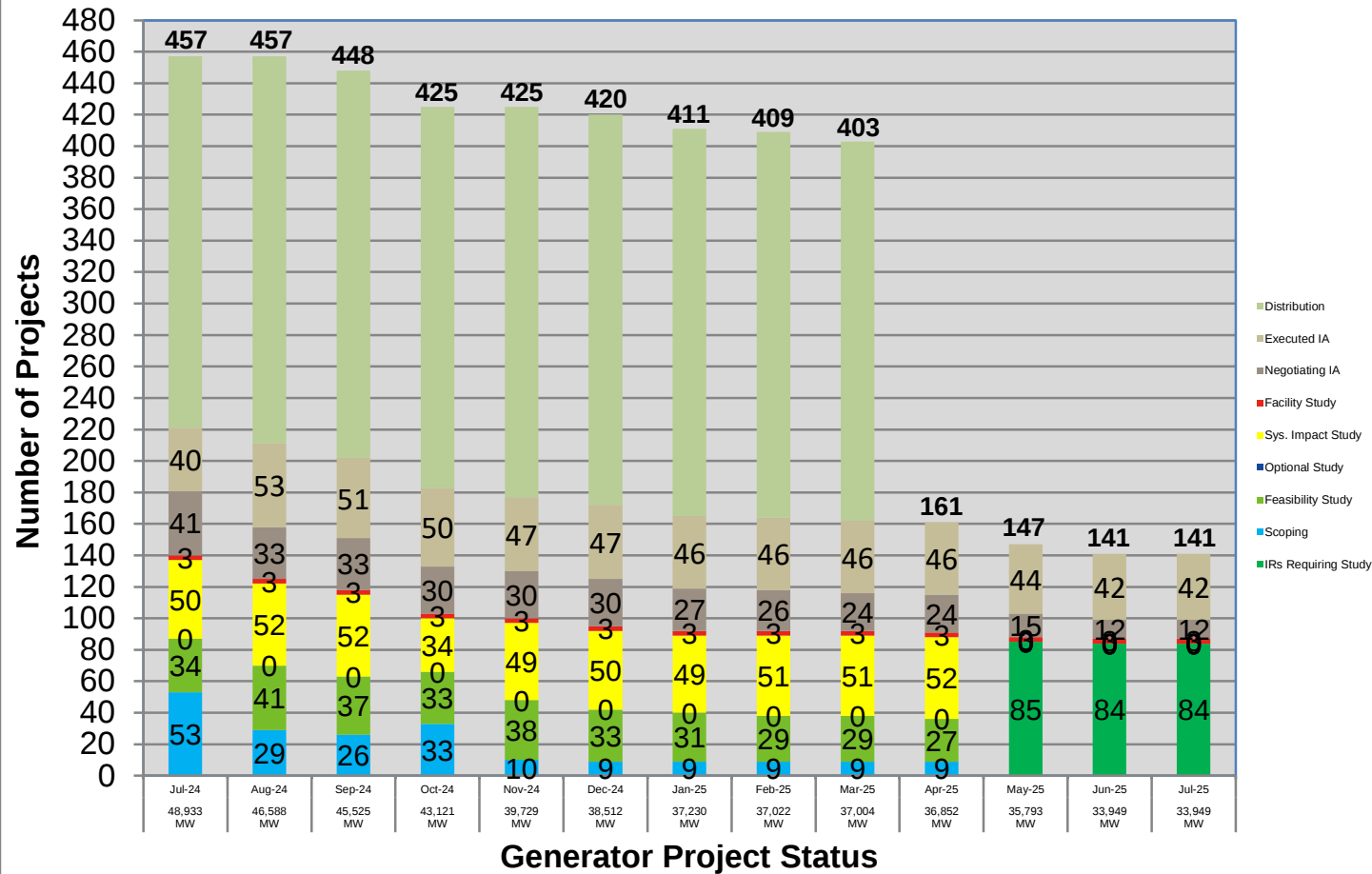
Status as of 7/29/2025

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1933	Install one 80 MVAR shunt reactor at the 115 kV Electric Avenue Substation	Dec-28	1
1934	Protection systems modification associated with the Stoughton RAS at three 345 kV substations (Stoughton, West Walpole and Holbrook) and two 115 kV substations (Hyde Park and K-Street)	Jun-26	1



Status of Tariff Studies as of July 29, 2025



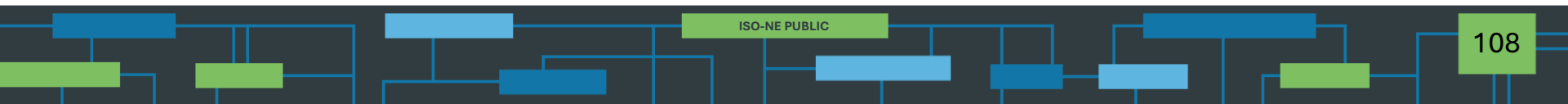
Note: As of April 2025, the ISO is no longer tracking Distribution Projects in its interconnection queue. Also, the values starting in May 2025 reflect that, as a result of the Order No. 2023 response from FERC, the ISO is no longer performing serial interconnection studies.

Note on Air Emissions Slides

- For more timely reporting and stakeholder convenience, the data and information included in this report on air emissions can now be found by visiting the ISO website, under System Planning > Plans and Studies > Environmental and Emissions Reports
 - <https://www.iso-ne.com/system-planning/system-plans-studies/emissions>
- Monthly and year-to-date emissions by fuel type are reported in the ISO Newswire article series, [Monthly Wholesale Electricity Prices and Demand in New England](#) (link can be found on the page above)

OPERABLE CAPACITY ANALYSIS

Summer 2025 Analysis



Summer 2025 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Aug - 2025 ² CSO (MW)	Aug - 2025 ² SCC (MW)
Operable Capacity MW ¹	26,012	27,439
Active Demand Capacity Resource (+) ⁵	325	355
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,277	1,277
Non Commercial Capacity (+)	452	452
Non Gas-fired Planned Outage MW (-)	1,405	2,159
Gas Generator Outages MW (-)	20	36
Allowance for Unplanned Outages (-) ⁴	2,100	2,100
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,541	25,228
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	24,803	24,803
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,928	26,928
Operable Capacity Margin	-2,387	-1,700

¹Operable Capacity is based on data as of **July 18, 2025** 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 **July 18, 2025**.

² Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **August 2, 2025**.

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.

Summer 2025 Operable Capacity Analysis

90/10 Load Forecast	Aug - 2025 ² CSO (MW)	Aug - 2025 ² SCC (MW)
Operable Capacity MW ¹	26,012	27,439
Active Demand Capacity Resource (+) ⁵	325	355
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,277	1,277
Non Commercial Capacity (+)	452	452
Non Gas-fired Planned Outage MW (-)	1,405	2,159
Gas Generator Outages MW (-)	20	36
Allowance for Unplanned Outages (-) ⁴	2,100	2,100
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,541	25,228
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	25,886	25,886
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,011	28,011
Operable Capacity Margin	-3,470	-2,783

¹Operable Capacity is based on data as of **July 18, 2025** 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 **July 18, 2025**.

² Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **August 2, 2025**.

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.

Summer 2025 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 18, 2025 - 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 August through mid September.

Report created: 7/18/2025

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	
8/2/2025	26012	325	1277	452	1405	20	2100	0	24541	24803	2125	26928	-2387	Y	Summer 2025
8/9/2025	26012	325	1277	452	179	20	2100	0	25767	24803	2125	26928	-1161	N	Summer 2025
8/16/2025	26012	325	1277	452	139	20	2100	0	25807	24803	2125	26928	-1121	N	Summer 2025
8/23/2025	26012	325	1277	452	135	20	2100	0	25811	24803	2125	26928	-1117	N	Summer 2025
8/30/2025	26072	404	1235	464	192	20	2100	0	25863	24803	2125	26928	-1065	N	Summer 2025
9/6/2025	26072	404	1235	464	189	20	2100	0	25866	24803	2125	26928	-1062	N	Summer 2025
9/13/2025	26072	404	1235	464	306	20	2100	0	25749	24803	2125	26928	-1179	N	Summer 2025

Column Definitions

- CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
- 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 participate in the Day-Ahead and Real-Time Energy Markets.
- External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
- Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
- 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.
- 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.
- 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.
- 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.
- CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8-9)
- Peak Load Forecast MW:** Provided in the annual 2025 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).
- Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
- CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
- CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
- Operable Capacity Season Label:** Applicable season and year.
- Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Summer 2025 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 18, 2025 - 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 August through mid September.

Report created: 7/18/2025

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	
8/2/2025	26012	325	1277	452	1405	20	2100	0	24541	25886	2125	28011	-3470	Y	Summer 2025
8/9/2025	26012	325	1277	452	179	20	2100	0	25767	25886	2125	28011	-2244	N	Summer 2025
8/16/2025	26012	325	1277	452	139	20	2100	0	25807	25886	2125	28011	-2204	N	Summer 2025
8/23/2025	26012	325	1277	452	135	20	2100	0	25811	25886	2125	28011	-2200	N	Summer 2025
8/30/2025	26072	404	1235	464	192	20	2100	0	25863	25886	2125	28011	-2148	N	Summer 2025
9/6/2025	26072	404	1235	464	189	20	2100	0	25866	25886	2125	28011	-2145	N	Summer 2025
9/13/2025	26072	404	1235	464	306	20	2100	0	25749	25886	2125	28011	-2262	N	Summer 2025

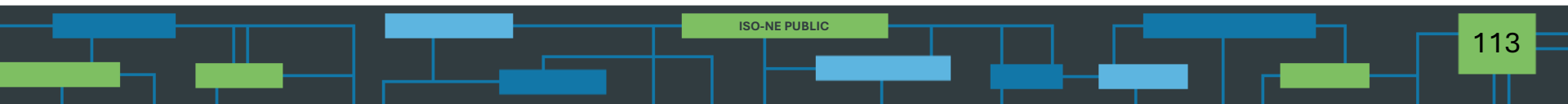
Column Definitions

- CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
- 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 participate in the Day-Ahead and Real-Time Energy Markets.
- External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
- Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
- 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.
- 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.
- 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.
- 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.
- CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8-9)
- Peak Load Forecast MW:** Provided in the annual 2025 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).
- Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
- CSO Net Required Capacity MW:** (Net Load Obligation) (10+11-12)
- CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
- Operable Capacity Season Label:** Applicable season and year.
- 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

OPERABLE CAPACITY ANALYSIS

Preliminary Fall 2025 Analysis



Preliminary Fall 2025 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Sept - 2025 ² CSO (MW)	Sept - 2025 ² SCC (MW)
Operable Capacity MW ¹	26,072	27,439
Active Demand Capacity Resource (+) ⁵	404	355
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	770	770
Non Commercial Capacity (+)	464	464
Non Gas-fired Planned Outage MW (-)	1,855	2,555
Gas Generator Outages MW (-)	925	946
Allowance for Unplanned Outages (-) ⁴	2,100	2,100
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,830	23,427
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	21,167	21,167
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,292	23,292
Operable Capacity Margin	-462	135

¹Operable Capacity is based on data as of **July 18, 2025** 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 **July 18, 2025**.

² Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 20, 2025**.

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 Fall 2025 Operable Capacity Analysis

90/10 Load Forecast	Sept - 2025 ² CSO (MW)	Sept - 2025 ² SCC (MW)
Operable Capacity MW ¹	26,072	27,439
Active Demand Capacity Resource (+) ⁵	404	355
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	770	770
Non Commercial Capacity (+)	464	464
Non Gas-fired Planned Outage MW (-)	1,855	2,555
Gas Generator Outages MW (-)	925	946
Allowance for Unplanned Outages (-) ⁴	2,100	2,100
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,830	23,427
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	22,091	22,091
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,216	24,216
Operable Capacity Margin	-1,386	-789

¹ Operable Capacity is based on data as of **July 18, 2025** 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 **July 18, 2025**.

² Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 20, 2025**.

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 Fall 2025 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 18, 2025 - 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 through November.

Report created: 7/18/2025

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas- Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50- 50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50- 50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
9/20/2025	26072	404	770	464	1855	925	2100	0	22830	21167	2125	23292	-462	Y	Fall 2025
9/27/2025	26229	404	770	573	1885	2359	2800	0	20932	16018	2125	18143	2789	N	Fall 2025
10/4/2025	26229	404	770	573	3467	3693	2800	0	18016	16051	2125	18176	-160	N	Fall 2025
10/11/2025	26229	404	770	573	3078	3471	2800	0	18627	16898	2125	19023	-396	N	Fall 2025
10/18/2025	26229	404	1235	573	2556	3445	2800	0	19640	17232	2125	19357	283	N	Fall 2025
10/25/2025	26229	404	1235	573	1184	3623	2800	0	20834	17422	2125	19547	1287	N	Fall 2025
11/1/2025	26229	404	1235	573	1037	1951	3600	0	21853	17528	2125	19653	2200	N	Fall 2025
11/8/2025	26229	404	1235	573	576	1997	3600	0	22268	17843	2125	19968	2300	N	Fall 2025
11/15/2025	26229	404	1235	573	473	1462	3600	0	22906	18520	2125	20645	2261	N	Fall 2025
11/22/2025	26229	404	1235	573	37	1224	3600	247	23333	19180	2125	21305	2028	N	Fall 2025

Column Definitions

- CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
- 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 participate in the Day-Ahead and Real-Time Energy Markets.
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- 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.
- 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.
- 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.
- 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.
- CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
- Peak Load Forecast MW:** Provided in the annual 2025 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).
- Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
- CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
- CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
- Operable Capacity Season Label:** Applicable season and year.
- Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Preliminary Fall 2025 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 18, 2025 - 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 through November.

Report created: 7/18/2025

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas- Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90- 10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90- 10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
9/20/2025	26072	404	770	464	1855	925	2100	0	22830	22091	2125	24216	-1386	Y	Fall 2025
9/27/2025	26229	404	770	573	1885	2359	2800	0	20932	16863	2125	18988	1944	N	Fall 2025
10/4/2025	26229	404	770	573	3467	3693	2800	0	18016	16897	2125	19022	-1006	N	Fall 2025
10/11/2025	26229	404	770	573	3078	3471	2800	0	18627	17789	2125	19914	-1287	N	Fall 2025
10/18/2025	26229	404	1235	573	2556	3445	2800	0	19640	18141	2125	20266	-626	N	Fall 2025
10/25/2025	26229	404	1235	573	1184	3623	2800	0	20834	18341	2125	20466	368	N	Fall 2025
11/1/2025	26229	404	1235	573	1037	1951	3600	0	21853	18452	2125	20577	1276	N	Fall 2025
11/8/2025	26229	404	1235	573	576	1997	3600	0	22268	18784	2125	20909	1359	N	Fall 2025
11/15/2025	26229	404	1235	573	473	1462	3600	73	22833	19496	2125	21621	1212	N	Fall 2025
11/22/2025	26229	404	1235	573	37	1224	3600	1352	22228	20191	2125	22316	-88	N	Fall 2025

Column Definitions

- CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
- 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 participate in the Day-Ahead and Real-Time Energy Markets.
- External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
- Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
- 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.
- 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.
- 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.
- 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.
- CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
- Peak Load Forecast MW:** Provided in the annual 2025 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).
- Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
- CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
- CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
- Operable Capacity Season Label:** Applicable season and year.
- 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

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