NEPOOL Participants Committee Report

November 2025

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

Highlights: October 2025

Settled data through October 29th

- **Peak Hour** on October 6
  - 15,935 MW system peak (Revenue Quality Metered/RQM); hour ending 7:00 P.M.
- **Minimum Telemetered Load**
  - 7,385 MW; hour ending 01:00 P.M. on Saturday, October 18
- **Average Pricing**
  - Day-Ahead (DA) Hub Locational Marginal Price (LMP): $39.98/MWh
  - Real-Time (RT) Hub LMP: $40.38/MWh
  - Natural Gas: $2.31/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $429M up from $350M in October 2024
  - Ancillary Markets* value $16.9M up from $8M in October 2024
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 98.3% during October, down from 98.6% during September
  - Updated September Energy Market value: $358M
- **Net Commitment Period Compensation (NCPC)** total $2.4M
  - Represents 0.6% of monthly Energy Market value
  - First Contingency $2.4M
    - Dispatch Lost Opportunity Cost (DLOC) - $414K; Rapid Response Pricing (RRP) Opportunity Cost - $250K; Posturing - $0; Generator Performance Auditing (GPA) - $177K
    - $69K paid to resources at external locations, down $2K from September
      - $57K charged to Day-Ahead Load Obligation (DALO) at external locations; $7K to Day-Ahead Generation Obligation (DAGO) at external locations; $6K to RT Deviations
  - Second Contingency $18K
  - Distribution and Voltage were zero
- **Forward Capacity Market (FCM)** market value $88.8M
  - FCM peak for 2025 is currently 26,086 MWh

Underlying natural gas data furnished by:

ice Global markets in clear view

*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: **26,586 MW**
  - hour ending 6:00 P.M. on Tuesday, June 24
- FCM Peak Load: **26,086 MW**
  - 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, 9,920 MW in Rest-of-Pool, and 10,783 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 Resources (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: **$15.2M**
- DAAS Settlements:
  - Average daily Gross (pre-closeout) DAAS Credits: **$700K**
    - Includes EIR, TMOR, TMNSR, and TMOR
  - Net (post-closeout) DAAS Credits per MWh Cleared: **$7.87/MWh**
  - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **3.0%**
- FER Credits* as % of total DA E&AS Market Value: **11.9%**
- Energy Gap:
  - Average hourly cleared EIR MWh: **209 MWh**
  - Average hourly cleared FER Price: **$6.13/MWh**

DA E&AS refers to DA Energy and Ancillary Services
*FER credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR)
FER credits are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)

DAAS Results (continued)…

Month	Avg. Daily Total DA 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 DA E&AS Credit	Avg. Daily FER Credit	Avg Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
3/1/2025	$17.3M	$466K	$202K	$3.35	1.2%	$982K	177K	$3.26	6.2%	176
4/1/2025	$13.9M	$332K	$175K	$3.23	1.3%	$760K	128K	$2.66	5.8%	97
5/1/2025	$11.0M	$190K	$52K	$0.94	0.5%	$563K	164K	$2.06	5.2%	155
6/1/2025	$20.2M	$885K	$173K	$2.97	0.9%	$1,287K	156K	$3.15	6.6%	125
7/1/2025	$35.8M	$1,704K	$1,139K	$19.53	3.2%	$1,277K	97K	$3.06	3.7%	55
8/1/2025	$20.2M	$747K	$544K	$9.57	2.7%	$1,292K	143K	$3.02	6.4%	94
9/1/2025	$12.3M	$320K	$184K	$3.21	1.5%	$587K	134K	$1.94	4.8%	104
10/1/2025	$15.2M	$700K	$457K	$7.87	3.0%	$1,812K	198K	$6.13	11.9%	209

About the Table:

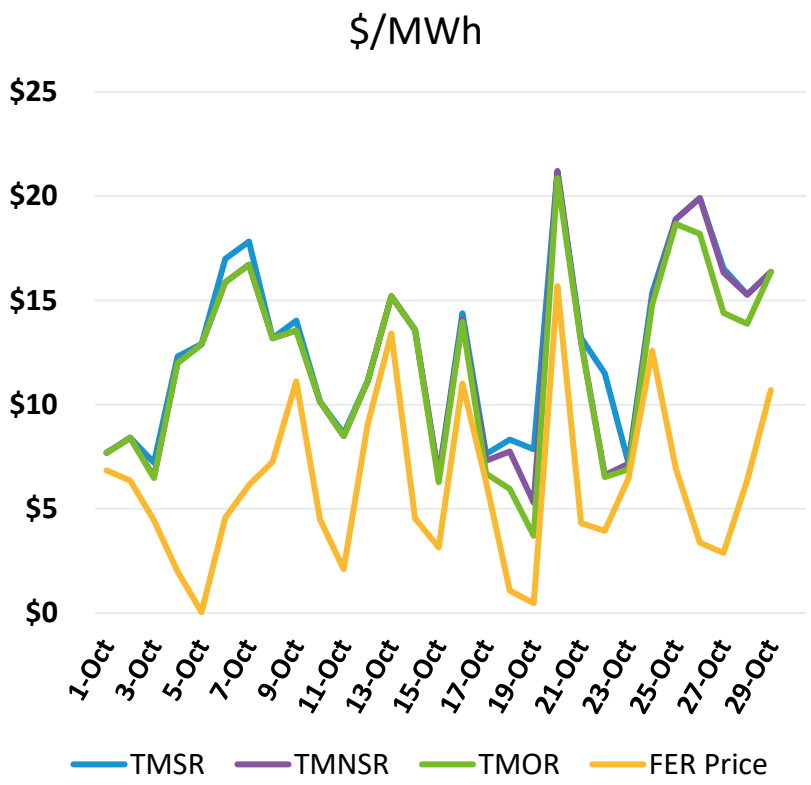
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)
- *'Avg Daily Energy MWh Paid FER Price' reflects Cleared DA Physical Gen and DRR MWh during non-zero FER prices
- Data prior to August (denoted by the line) may not match settlement quality data provided in the Monthly Market Report

Additionally:

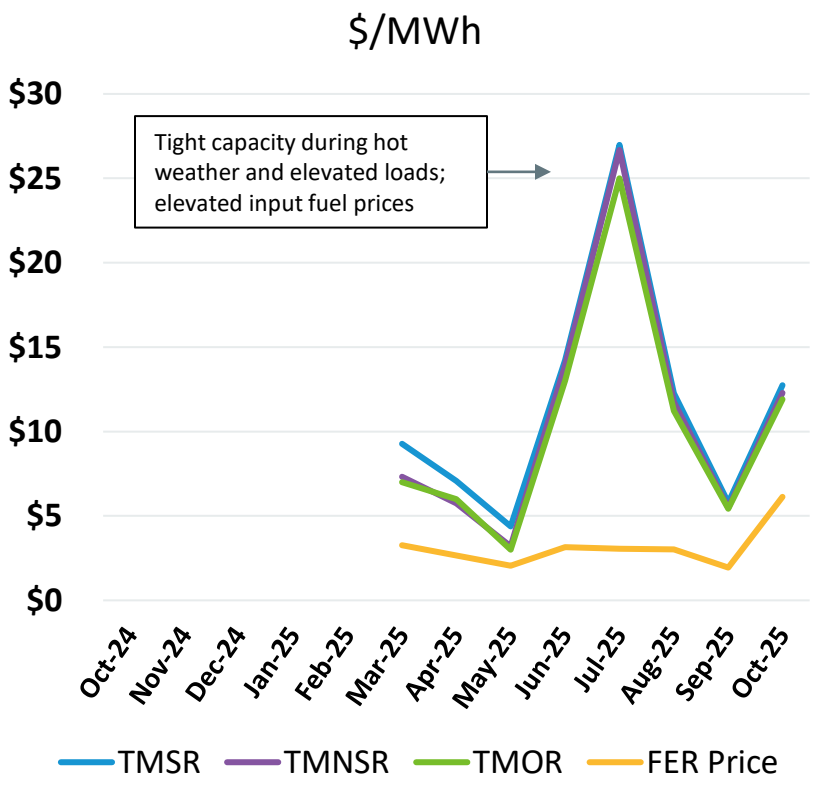
- FER Credits are included in the Monthly Market Report (see Section 7.1.1) found on the ISO Website here. Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

Average Hourly DAAS Prices

Daily This Month

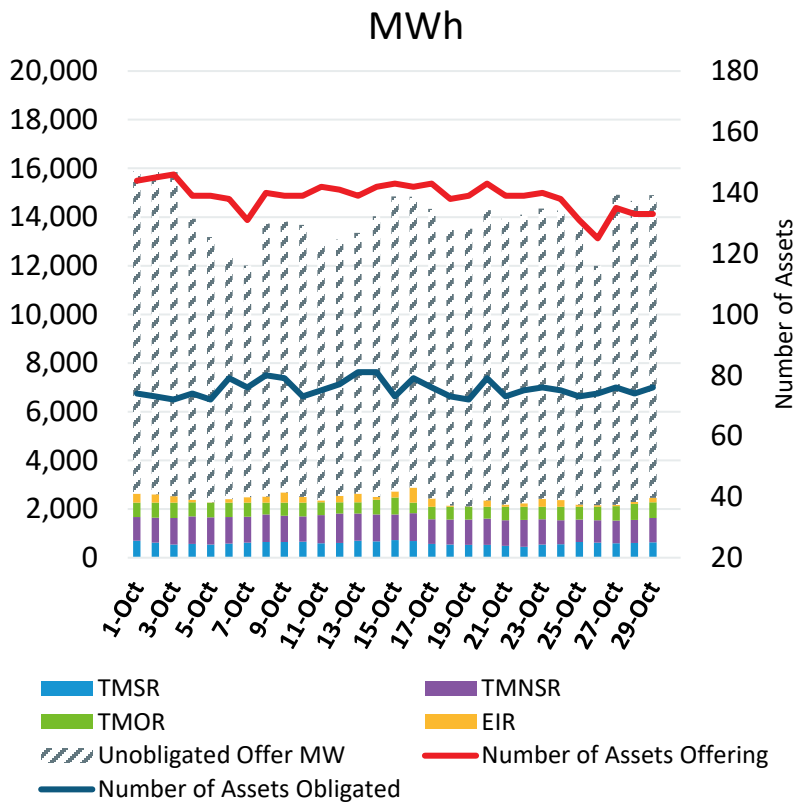


Monthly, Last 13 Months



Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



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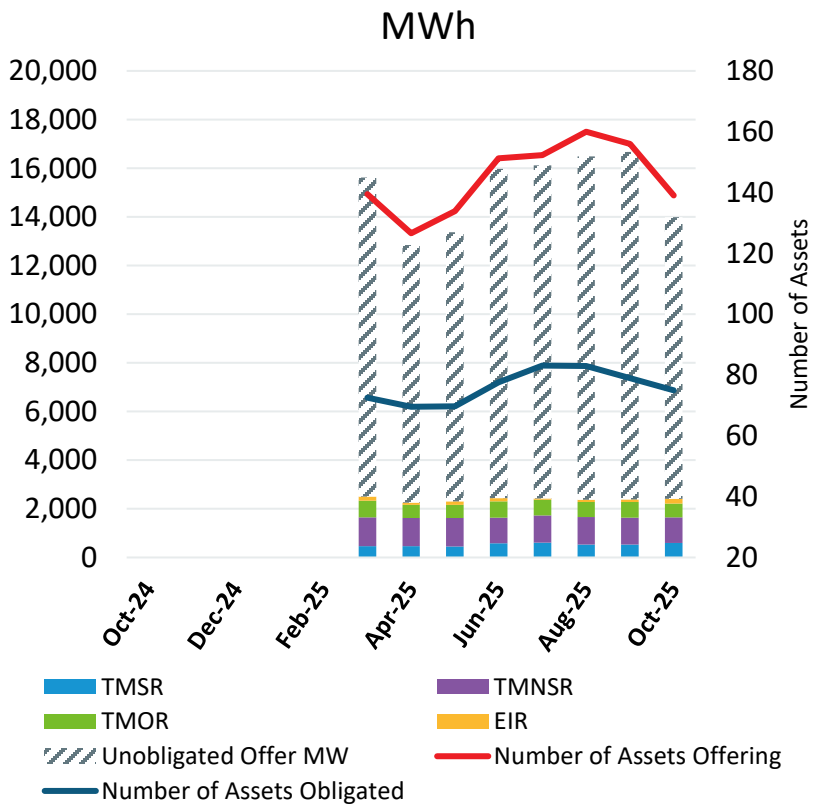


*Unobligated Offer MWh reflect the raw, as-offered DAAS MW amounts that remained unobligated (received no MW reward). This supply does not yet consider additional unit parameter constraints or dispatch constraints and should not be equated with actual capacity available in the dispatch solution.

Highlights

- The ISO is evaluating all submissions and expects to provide a high-level summary of all Longer-Term Proposals at the 11/19/25 PAC
- The 2026 Load Forecast cycle formally began in September
- Stakeholder discussions related to CELT 2026 will continue at the next Load Forecast Committee on November 7

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) was held August 1-5 and results were posted on September 2
  - At the October 7 PSPC meeting and October 22 RC meeting, the ISO presented proposed ICR and related values for the ARA 3 that will be conducted in 2026. RC voted to approve the values.
- CCP 18 (2027-2028)
  - The first annual reconfiguration auction (ARA1) was held June 2-4 and results were posted on July 2
  - At the October 7 PSPC meeting and October 22 RC meeting, the ISO presented proposed ICR and related values for the ARA 2 that will be conducted in 2026. RC voted to approve the values.

CCP – Capacity Commitment Period

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
      - Qualification Determination Notifications were issued on October 17, 2025 and Qualified Capacities will be finalized on November 3, 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

NOVEMBER 6, 2025| BOSTON, MA

ISO New England 2024/2025 Winter Outlook

Vamsi Chadalavada

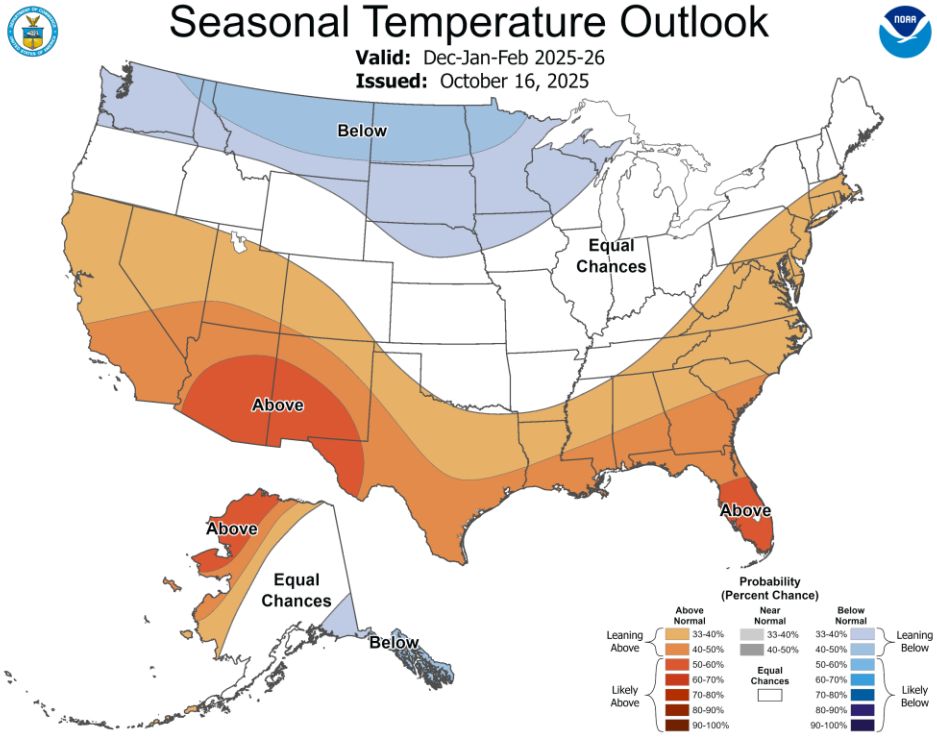
EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

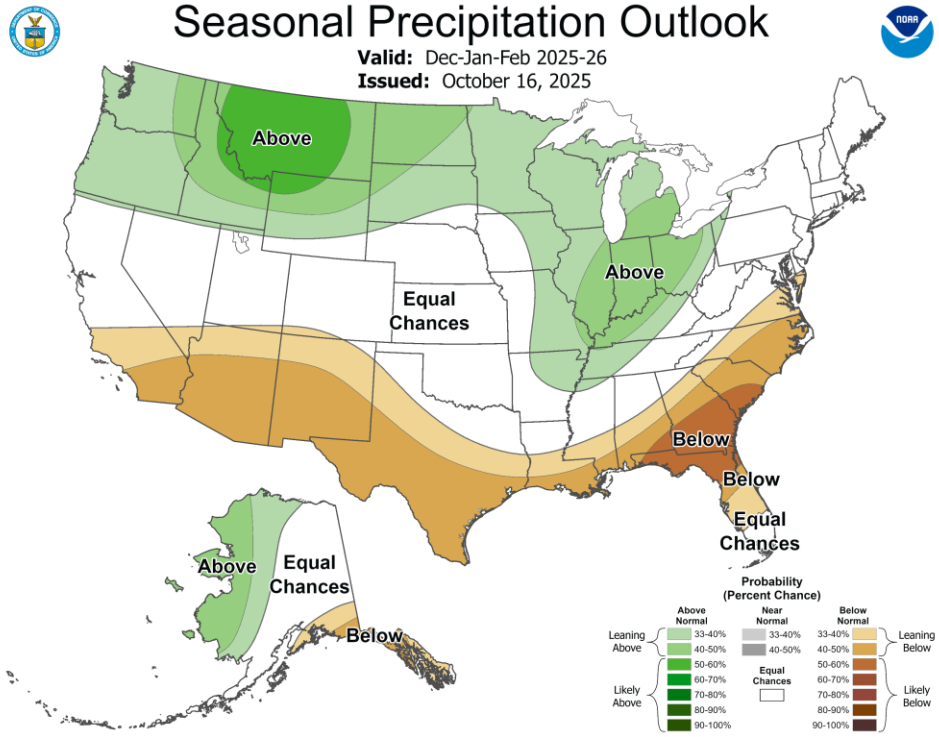
Winter Outlook Highlights

- Winter Outlook
  - The seasonal temperature outlook for the winter months of December through February indicates a 33-40% probability of above normal temperatures for southern New England, and equal chances for either above or below normal temperatures for northern New England
  - An equal chance for above normal or below normal precipitation is forecasted across New England
  - Lowest capacity margin is projected for the week beginning January 10[1]
    - Surplus capacity is projected for the 50/50 load forecast while a slightly negative capacity margin is projected for the 90/10 forecast; projections are based on conservative import and forced outage assumptions
  - Consistent with the existing resource mix and load expectations for this winter, energy shortfall risk associated with extreme winter events does not exceed the Regional Energy Shortfall Threshold (REST)

1 - Based on October 23, 2025 Annual Maintenance Schedule Capacity Analysis

Winter Temperature and Precipitation Outlook





Winter Expectations

- Demand Forecast
  - The Winter 2024/25 peak demand of 19,607 MW occurred on January 22, 2025
  - 50/50 winter peak demand forecast of 20,056 MW, which is ~252 MW (~1.2%) lower than the 2024/25 forecast
  - 90/10 winter peak demand forecast of 21,125 MW, which is ~36 MW (~0.2%) higher than the 2024/25 forecast
- Scheduled Generation and Transmission Outages
  - Generation and transmission outages have been coordinated to minimize any adverse impacts; no significant generation or transmission outages are currently scheduled
- Transfer Capability
  - Transfer capability on the New York Northern AC ties will be increased from 1,400 to 1,600 MW for the winter period

Winter Expectations, cont.

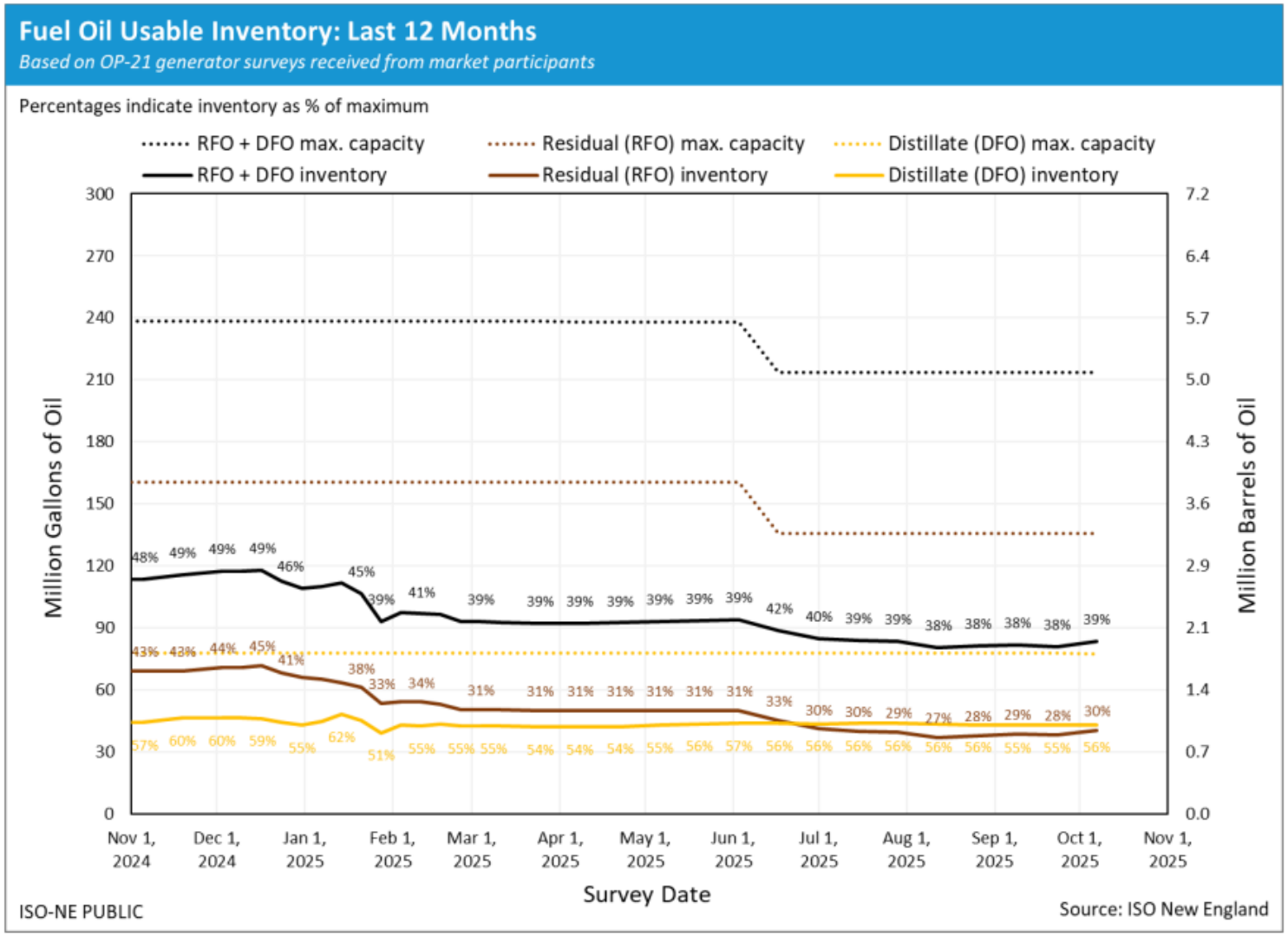
- Natural Gas Deliverability
  - ISO will continue to monitor natural gas deliverability throughout the winter
  - Consistent with past winter seasons, the ISO assumes that approximately 3,900 – 4,800 MW[1] may be at risk due to constrained natural gas pipelines
- Capacity Outlook
  - Projecting the lowest 50/50 capacity margin of ~1,793 MW and lowest 90/10 capacity margin of ~-135 MW for the week beginning January 10[1]
  - Extended periods of cold weather may rapidly deplete stored fuel inventory, and the capacity outlook will be adjusted accordingly

1 - Based on resource Winter Seasonal Claimed Capabilities and not counting OP4 actions

LNG and Fuel Oil Expectations

- Saint John LNG tanks are expected to be full (~10 Bcf) heading into the winter
- Current fuel oil inventory is ~83.6M gallons (~39% of max)
  - Recent fuel surveys and discussions with owners/operators of stations with large fuel oil storage capability indicate that pre-winter replenishment is underway and supply chains are expected to be strong with adequate supply available

Total Usable Fuel Oil in New England



Winter Energy Analysis

- 20 extreme weather events were studied to evaluate the region's energy shortfall risk this winter
  - Studies were performed using ISO's Probabilistic Energy Adequacy Tool (PEAT) and results were compared to the recently developed Regional Energy Shortfall Threshold (REST)
- Similar to the methodology employed for ISO's prior PEAT-based analysis the 20 weather events studied were those identified as having the most significant shortfall risk
  - Peak load across the weather events averages ~21.2 GW with a maximum peak load of 22.3 GW
- Each weather event was studied 720 times (*i.e.*, "cases"); each case represented different combinations of fuel oil inventories, LNG inventories, imports, and generator forced outages

Winter Energy Analysis, cont.

- Key Assumptions
  - Existing resource mix
  - Vineyard Wind and New England Clean Energy Connect (NECEC) in-service
  - ~8.5 GW of behind-the-meter (BTM) PV nameplate capacity
  - Up to 1.2 Bcf/d of LNG injection capability from Saint John LNG and the Everett Marine Terminal (EMT)

Energy Analysis Results Show Minimal Risk When Compared Against REST Criteria

- The recently adopted REST criteria is defined as follows:
  - acceptable shortfall **magnitude** of **3%**
  - acceptable shortfall **duration** of **18 hours**
  - magnitude and duration must **both** be exceeded for the REST to be violated
- ISO's PEAT-based evaluation of extreme events for this winter resulted in **shortfall magnitude of 0.1% and shortfall duration of 0.7 hours, both well below the established REST criteria**
  - As an extreme tail risk measure, maximum (i.e., worst-case) 21-day energy shortfall is ~168,000 MWh (equivalent to ~2% of the total 21-day energy demand)
- Study results are consistent with the existing resource mix and expectations for load this winter

Winter Energy Analysis Summary

- The worst-case 21-day energy shortfall quantities result from a low probability combination of several uncertainties (*i.e.*, low LNG, low fuel oil, low imports, high forced outages)
- In the worst cases, energy shortfall begins on day 14 or later thus allowing time for additional actions
  - ISO expects that in the event of a forecasted energy shortfall, market-based incentives will encourage relief in the form of market response, including additional fuel replenishment
- In advance of a forecasted energy shortfall, and in addition to anticipated market response, ISO would implement additional preventive measures, as necessary
  - Reducing exports and/or scheduling of additional imports
  - Posturing of generators with stored fuels in short supply
  - Seeking waivers of emissions or air permit limitations under Section 202c of the Federal Power Act
  - Coordinated conservation appeals

Winter Preparations

- ISO staff hosted the Generator Winter Readiness Seminar with Market Participants on October 29, 2025
- Will distribute a Winter Generator Readiness Survey to all generators prior to November 1, 2025 with responses due by December 1, 2025
- Completed the annual Natural Gas Critical Infrastructure Survey process to ensure critical infrastructure is not part of automatic or manual load shed schemes
- Dual fuel audits of ~30 generators totaling ~6,500 MW of capacity to be completed prior to December 1, 2025
- Generator Fuel and Emissions Surveys and 21-Day Energy Assessments will be performed weekly (or daily, if required) during the winter season
  - 21-day Energy Assessment results and summaries of generator fuel surveys are posted weekly to the ISO public website

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.6°F) Max: 84°F, Min: 40°F Precipitation: 4.96" – Above Normal Normal: 4.03"	Hartford	Temperature: Above Normal (1.0°F) Max: 85°F, Min: 29°F Precipitation: 4.62" - Above Normal Normal: 4.52"

Peak Load:	15,482 MW	October 06, 2025	19:00 (ending)
Mid-Day Minimum Load - Month:	7,385 MW	October 18, 2025	13:00 (ending)
Mid-Day Minimum Load - Historical:	5,318 MW	April 20, 2025	14:00 (ending)

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

Procedure	Declared	Cancelled	Note
NONE			

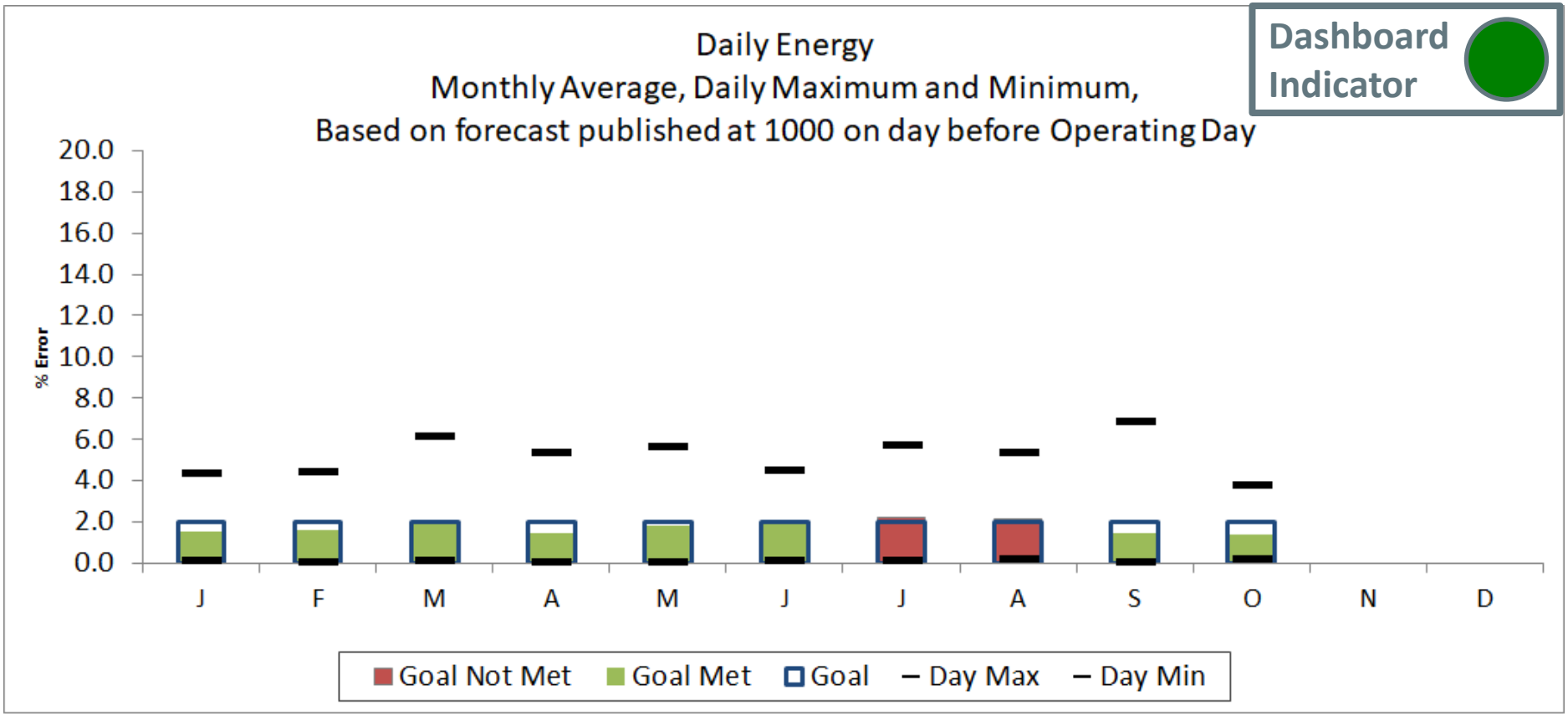
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
10/27/2025	ISO-NE	690

2025 System Operations - Load Forecast Accuracy cont.

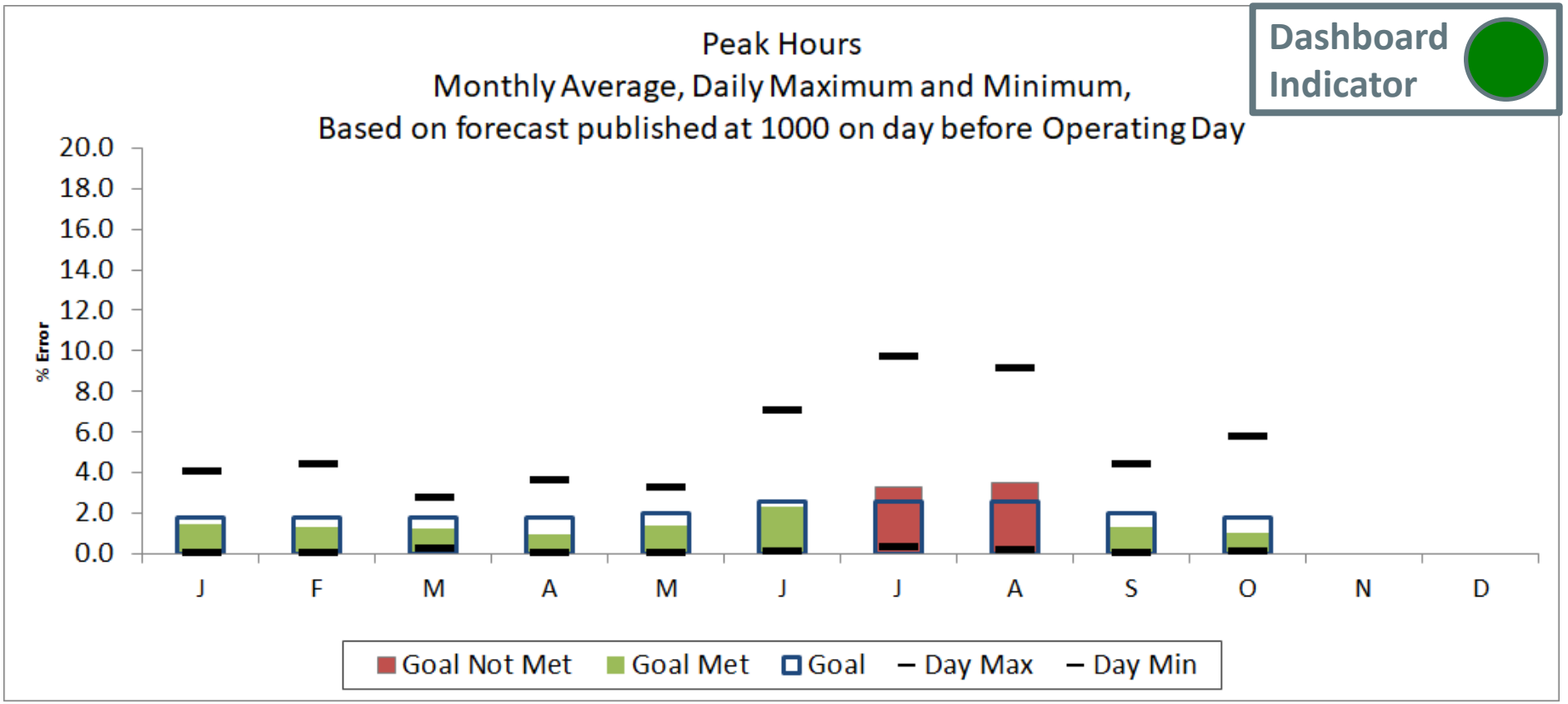
Dashboard Indicator



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	5.34	6.81	3.73			6.81
Day Min	0.12	0.04	0.12	0.05	0.06	0.08	0.11	0.16	0.05	0.18			0.04
MAPE	1.54	1.62	1.89	1.45	1.80	1.98	2.24	2.12	1.46	1.39			1.75
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00			

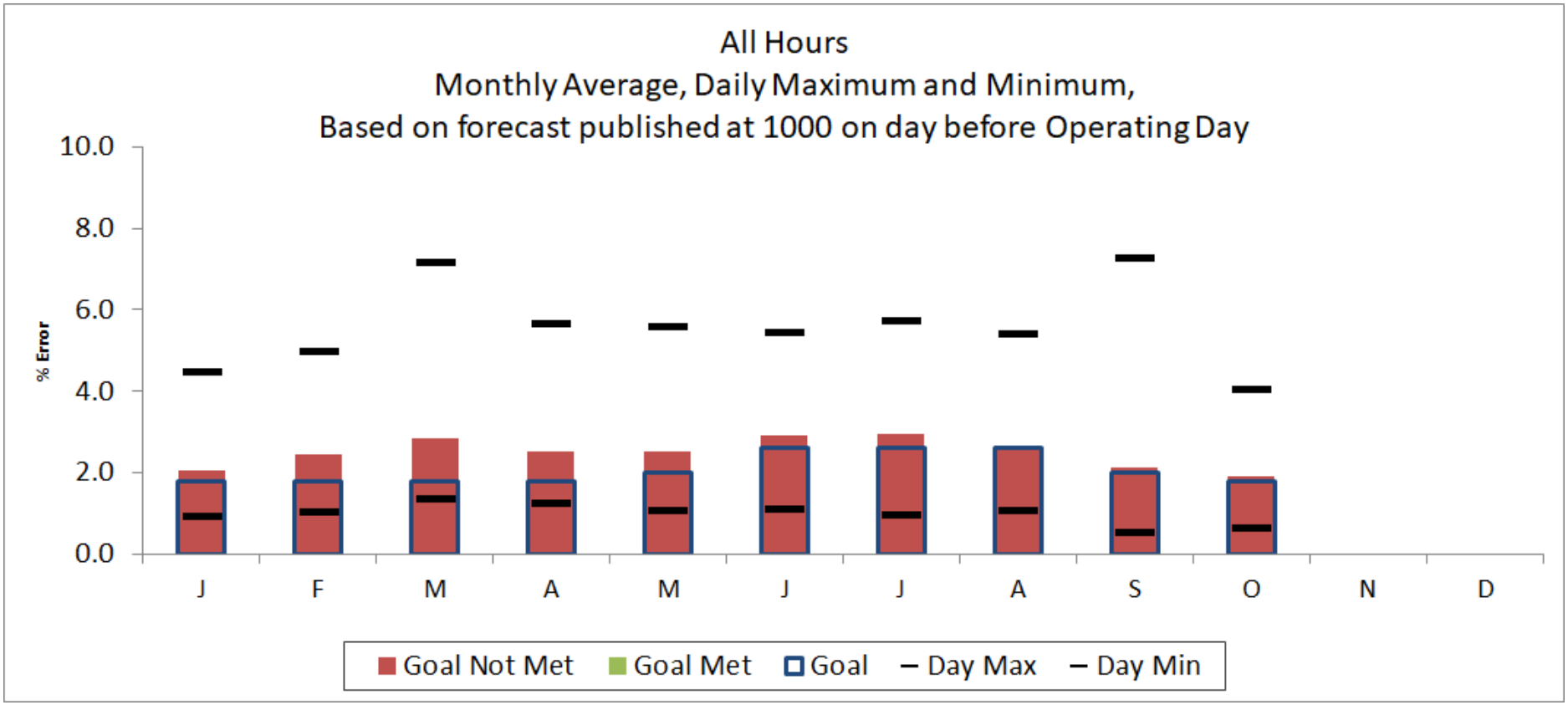
2025 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



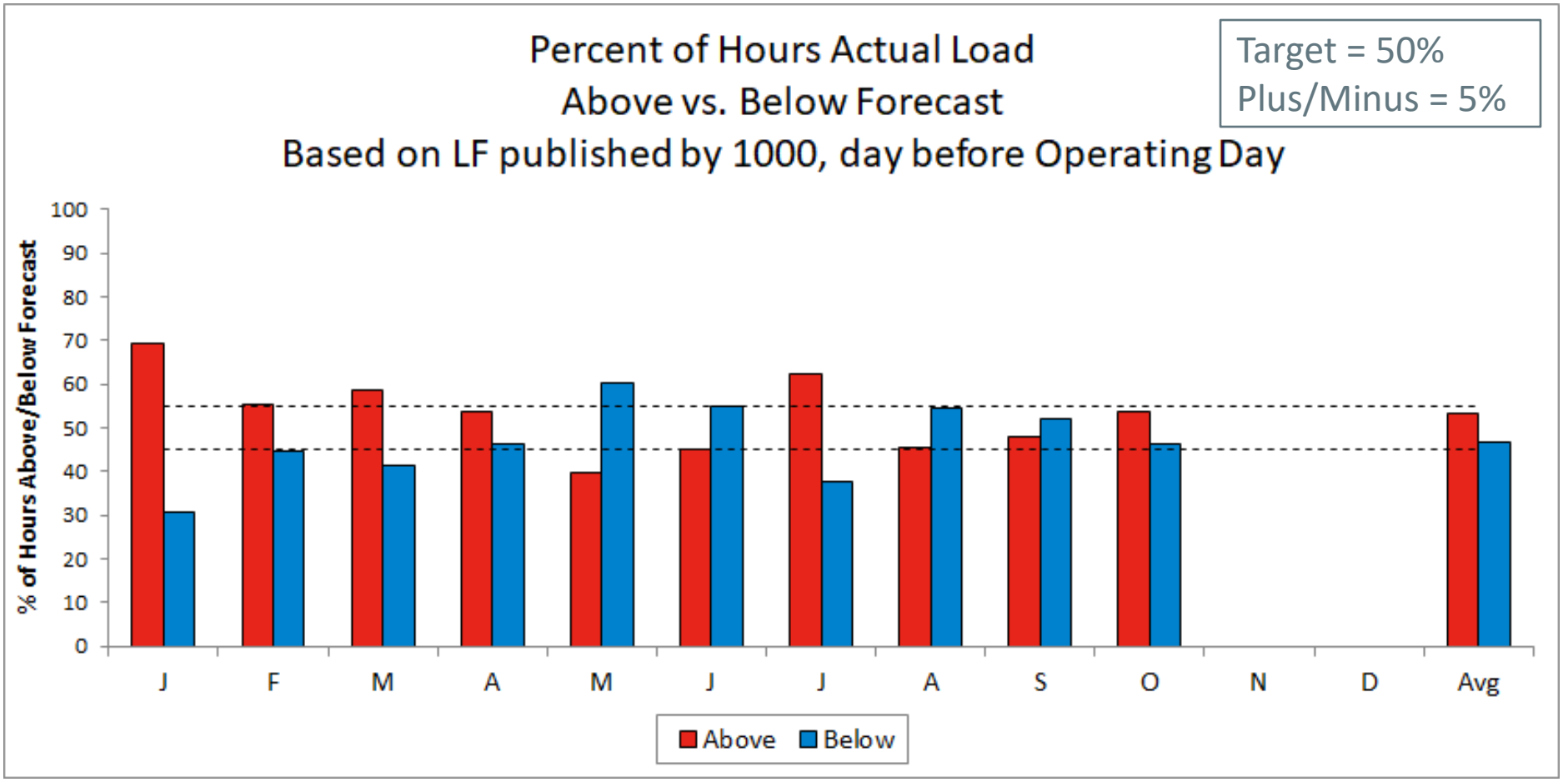
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.41	2.77	3.63	3.29	7.08	9.71	9.15	4.43	5.77			9.71
Day Min	0.03	0.06	0.24	0.03	0.06	0.11	0.34	0.15	0.05	0.12			0.03
MAPE	1.48	1.34	1.29	1.00	1.41	2.30	3.28	3.48	1.30	1.02			1.80
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2025 System Operations - Load Forecast Accuracy cont.



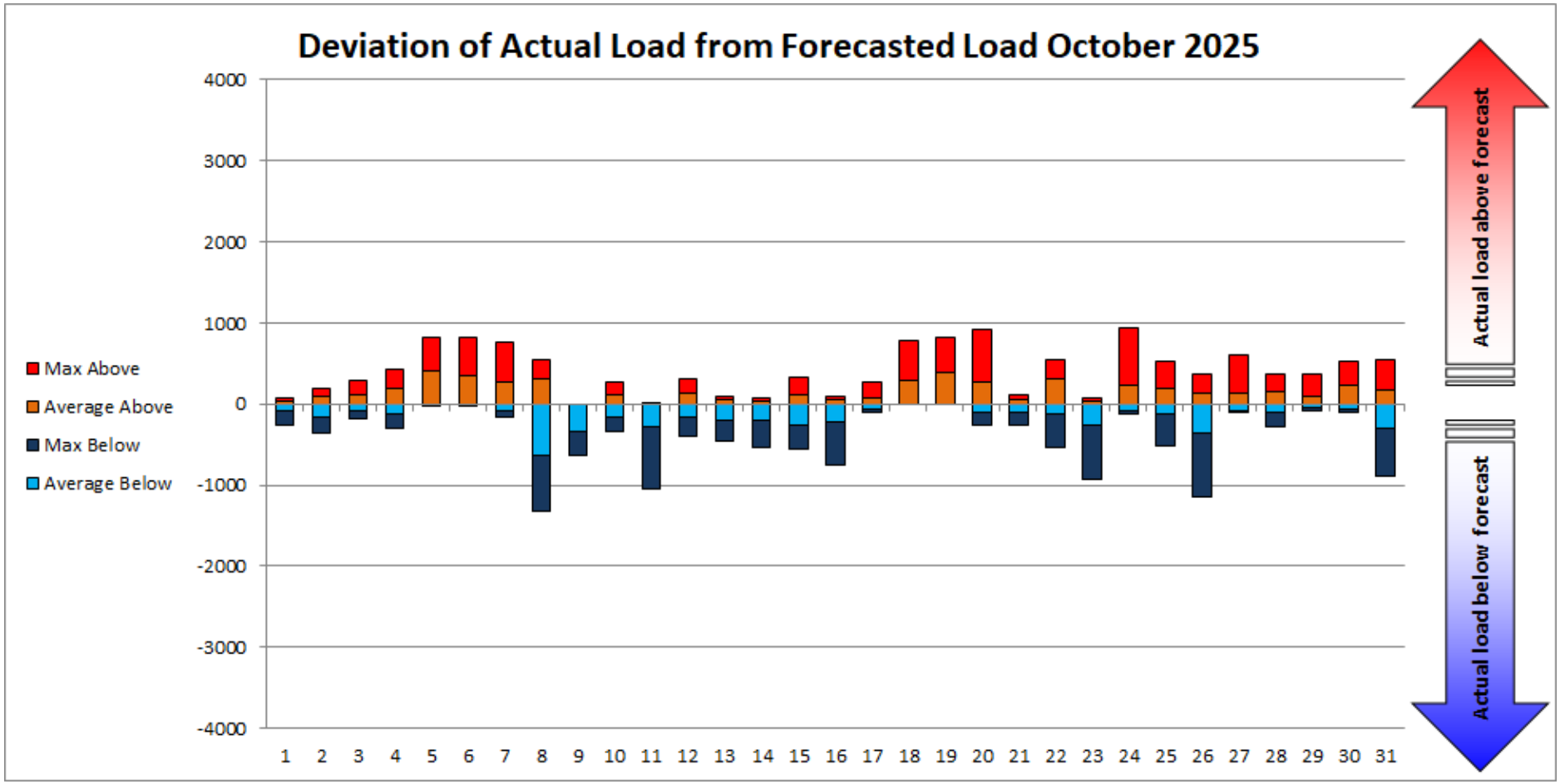
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.46	4.98	7.13	5.65	5.57	5.44	5.72	5.41	7.24	4.01			7.24
Day Min	0.90	1.02	1.33	1.23	1.07	1.11	0.95	1.07	0.52	0.64			0.52
MAPE	2.07	2.47	2.83	2.53	2.53	2.93	2.94	2.68	2.13	1.92			2.50
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

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	45.3	48.1	53.5			53
Below %	30.8	44.8	41.5	46.5	60.2	54.9	37.5	54.7	51.9	46.5			47
Avg Above	280.5	282.1	246.5	255.8	164.5	307.8	397.3	225.4	213.7	161.8			397
Avg Below	-178.6	-287.9	-273.2	-190.7	-254.1	-310.2	-270.0	-308.7	-179.5	-157.1			-310
Avg All	138	24	12	49	-82	-24	145	-81	1	12			19

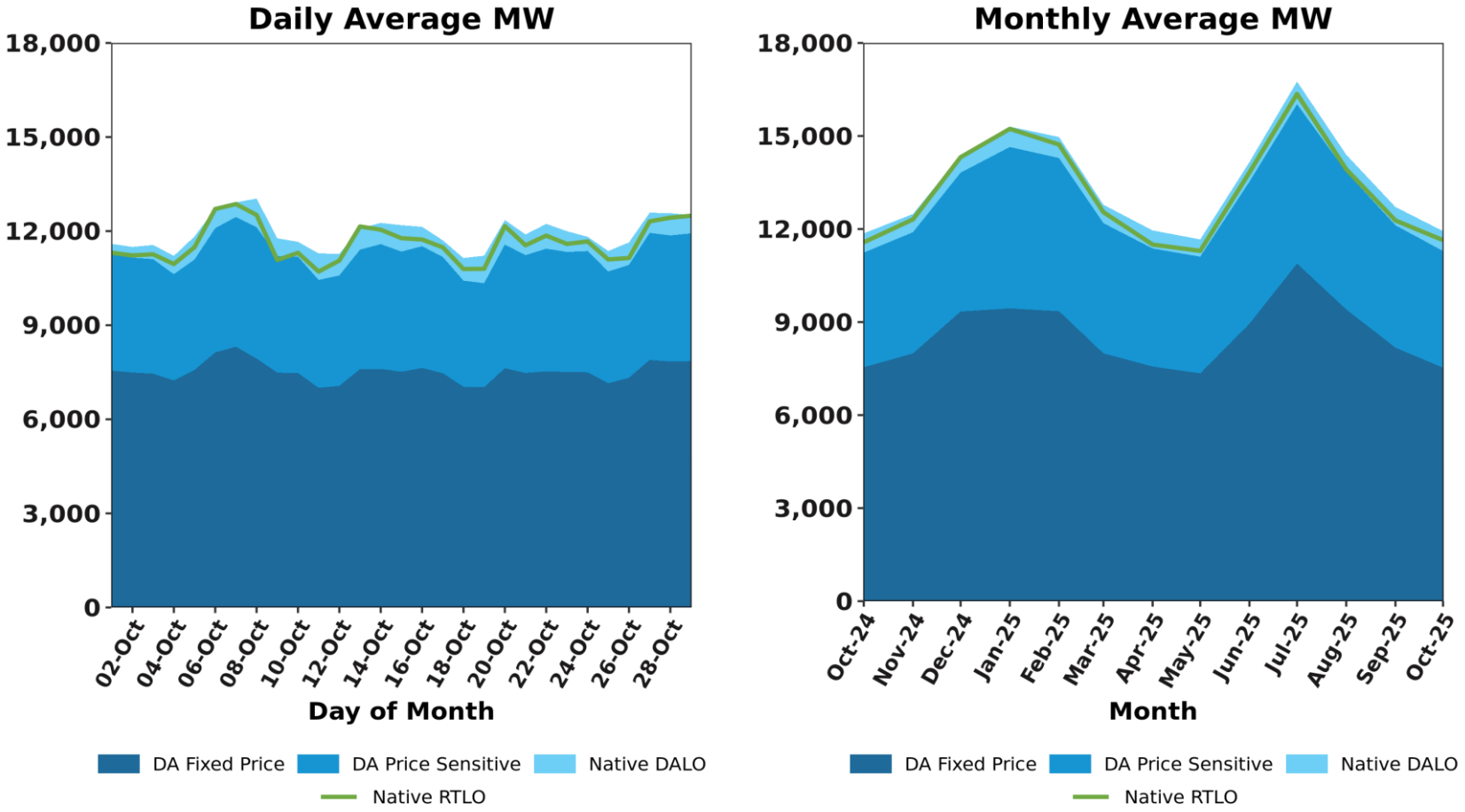
2025 System Operations - Load Forecast Accuracy



MARKET OPERATIONS

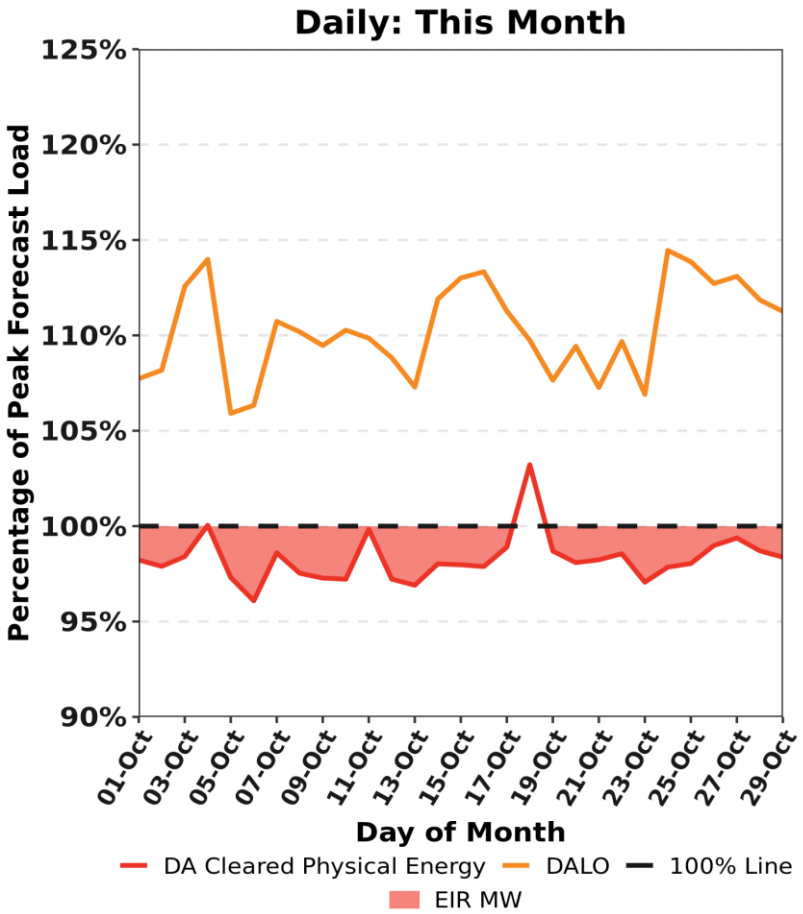
SUPPLY AND DEMAND VOLUMES

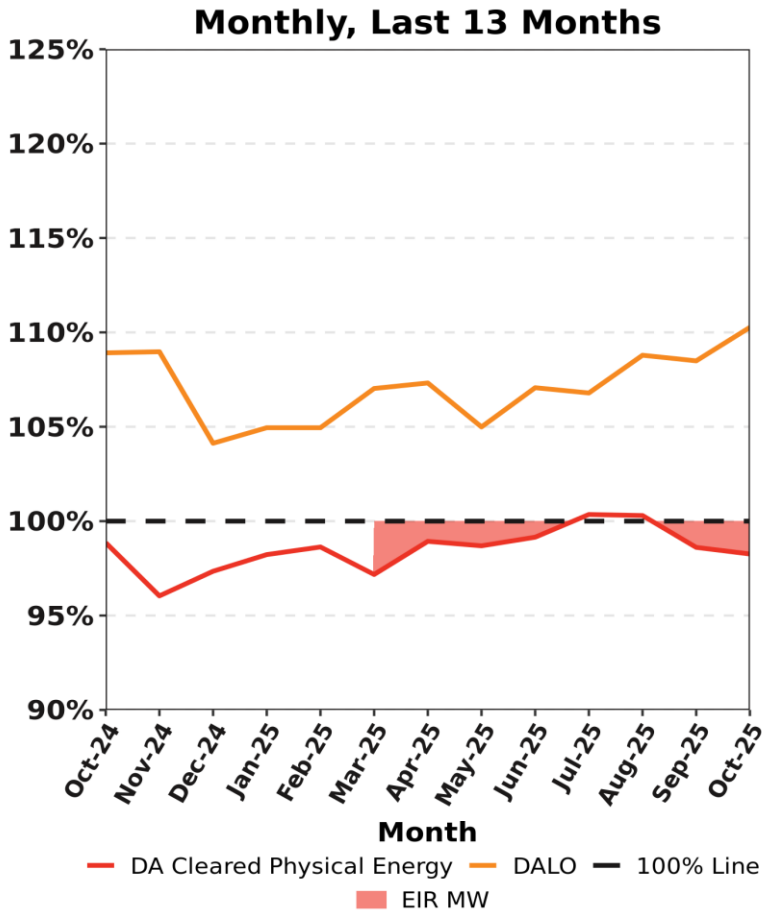
DA Cleared Native Load by Composition Compared to Native RT Load



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





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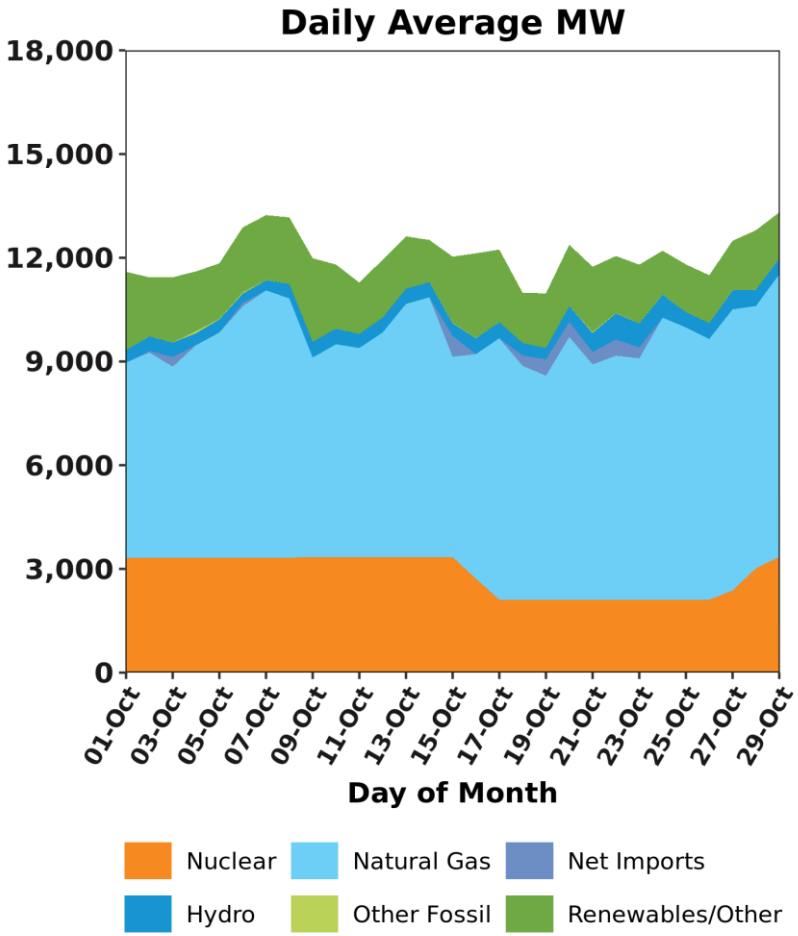
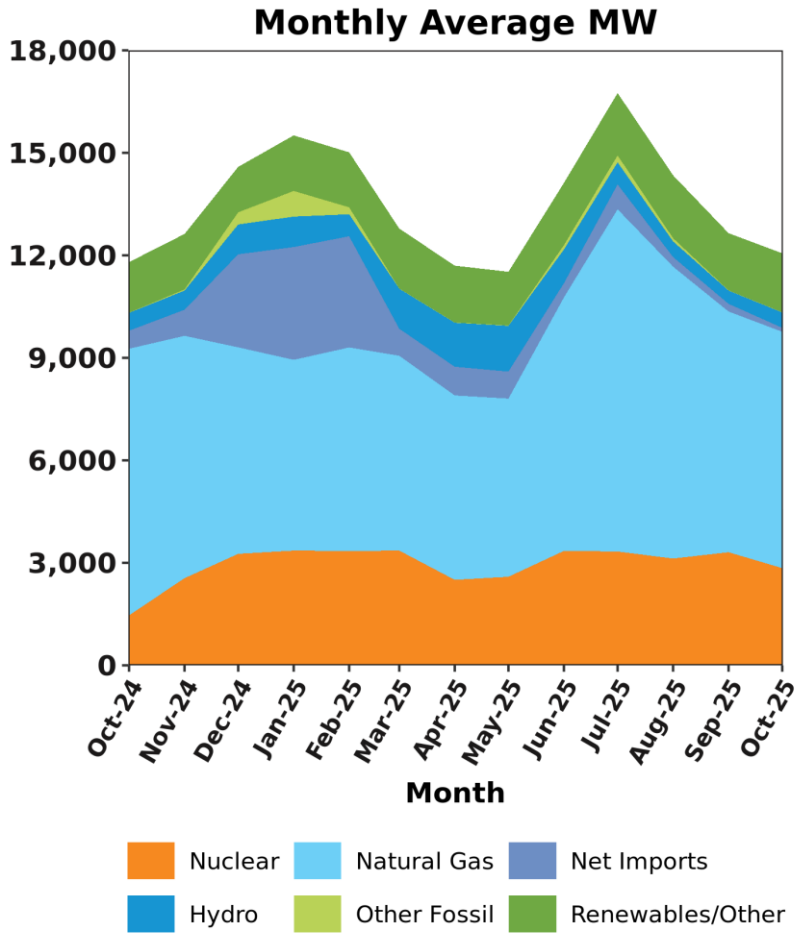
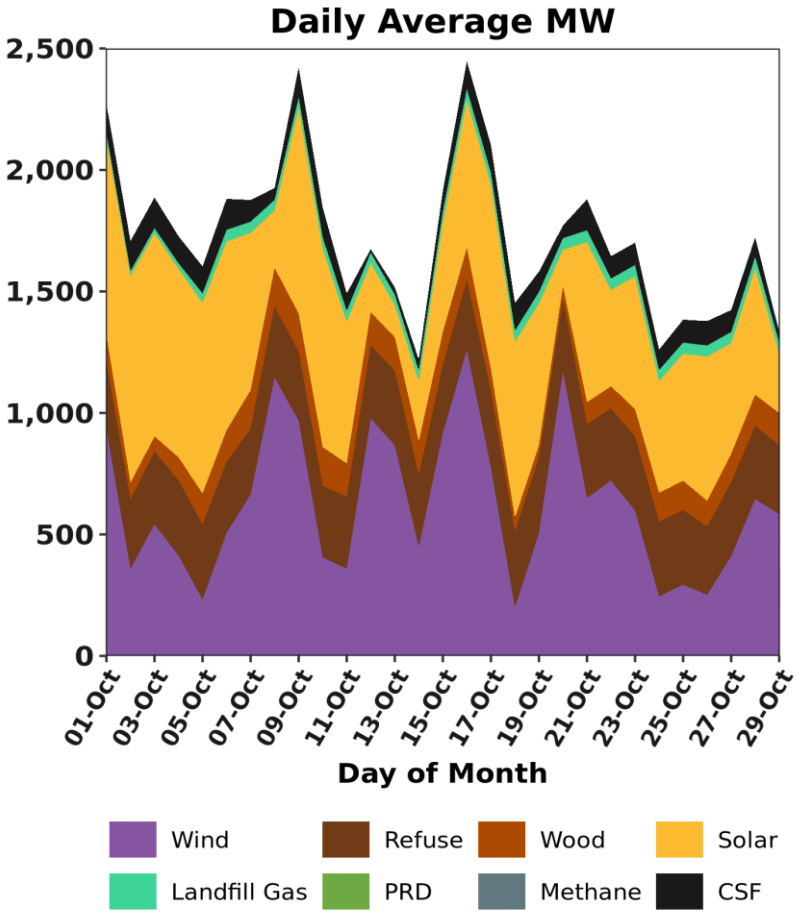
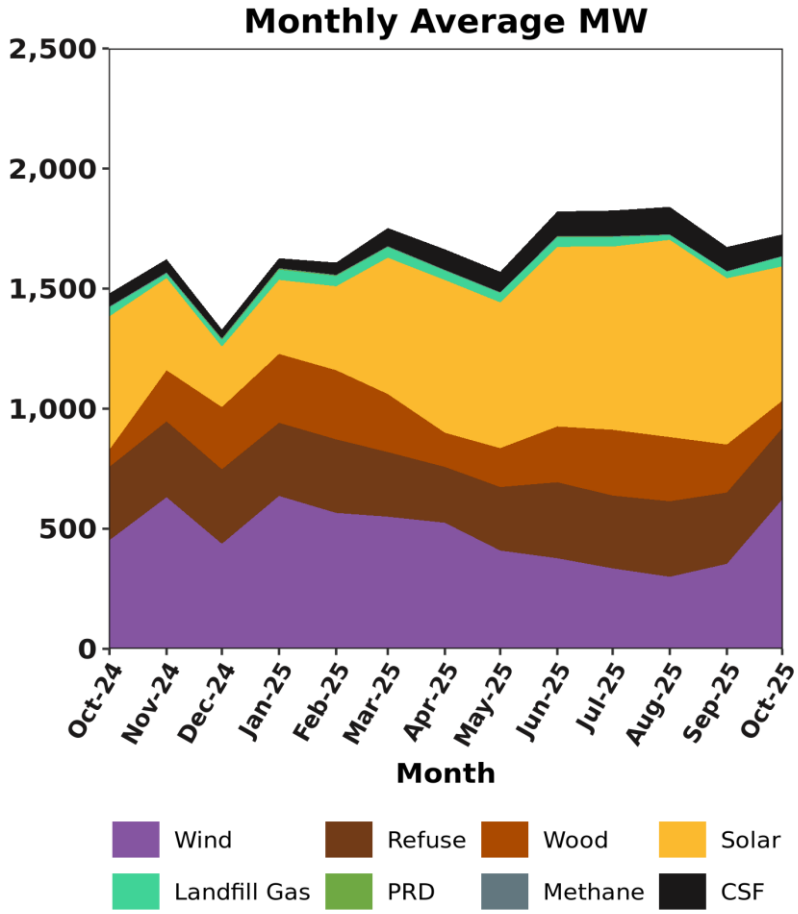
Resource Mix





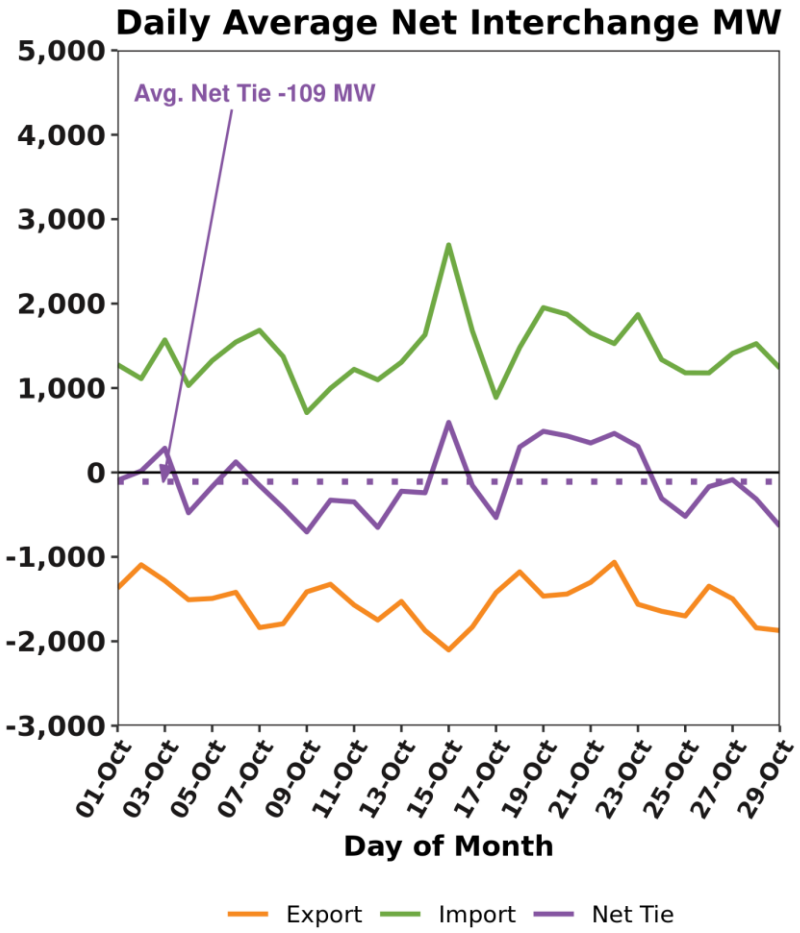
Renewable Generation by Fuel Type

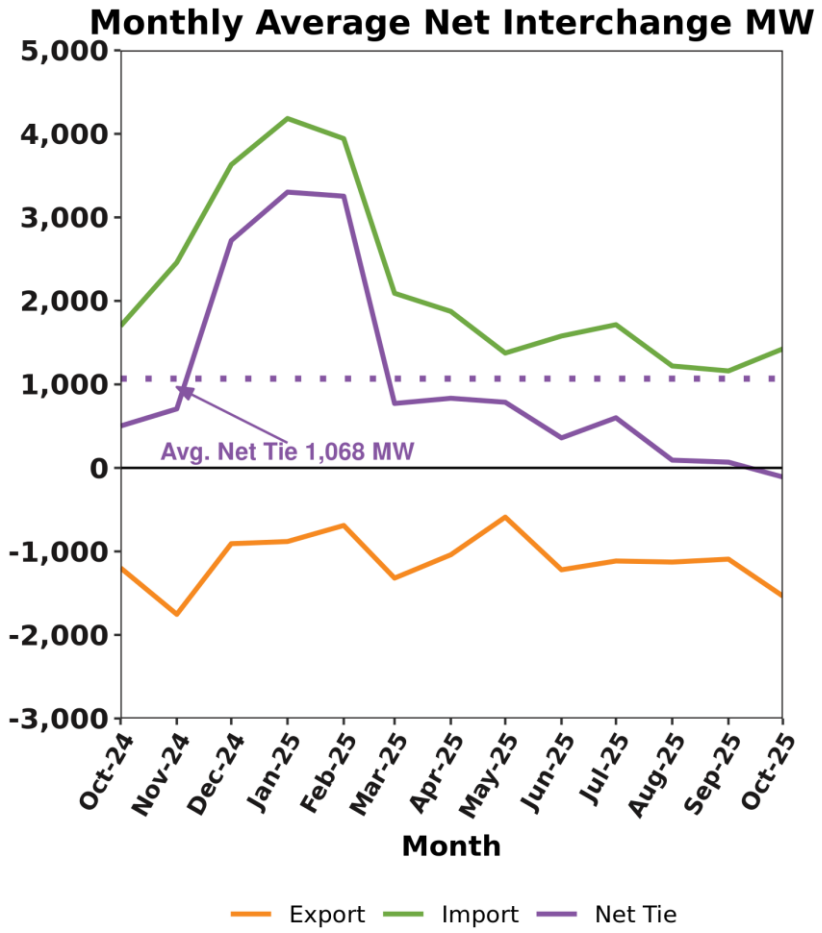




CSF = Continuous Storage Facilities (a.k.a. Batteries); PRD=Demand Response Resources (DRR)

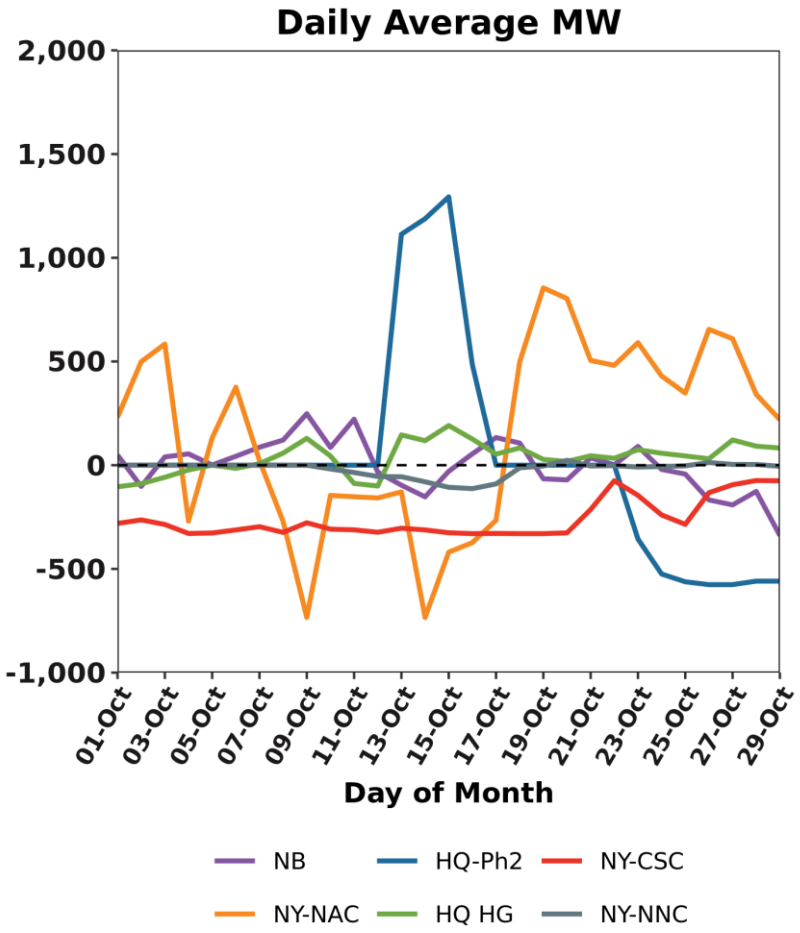
RT Net Interchange

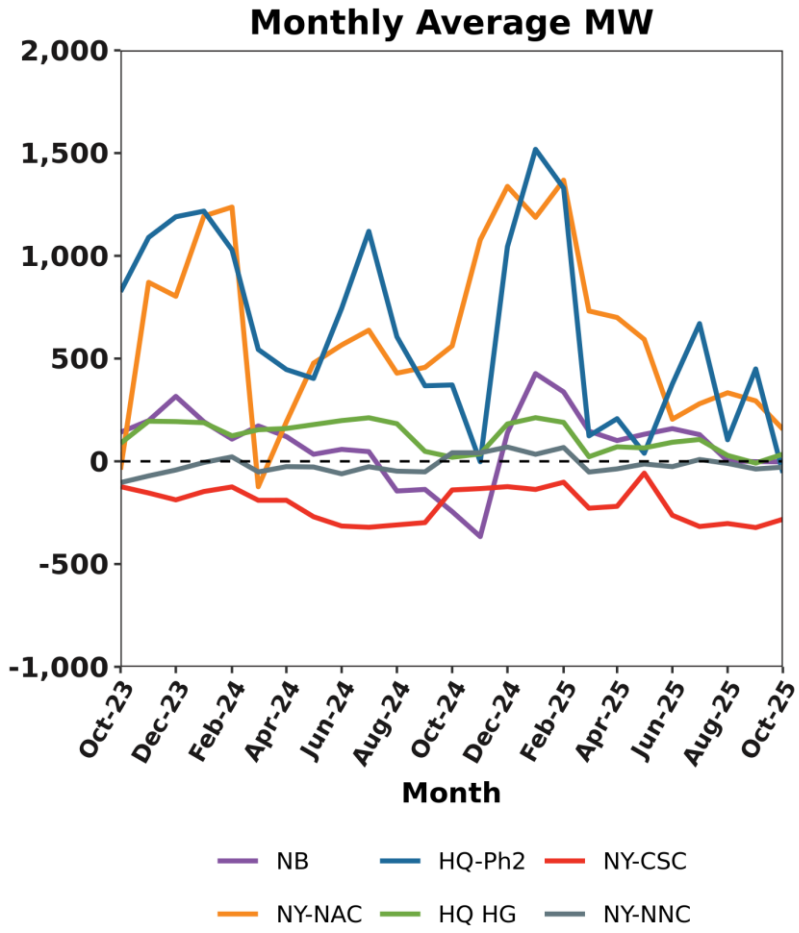




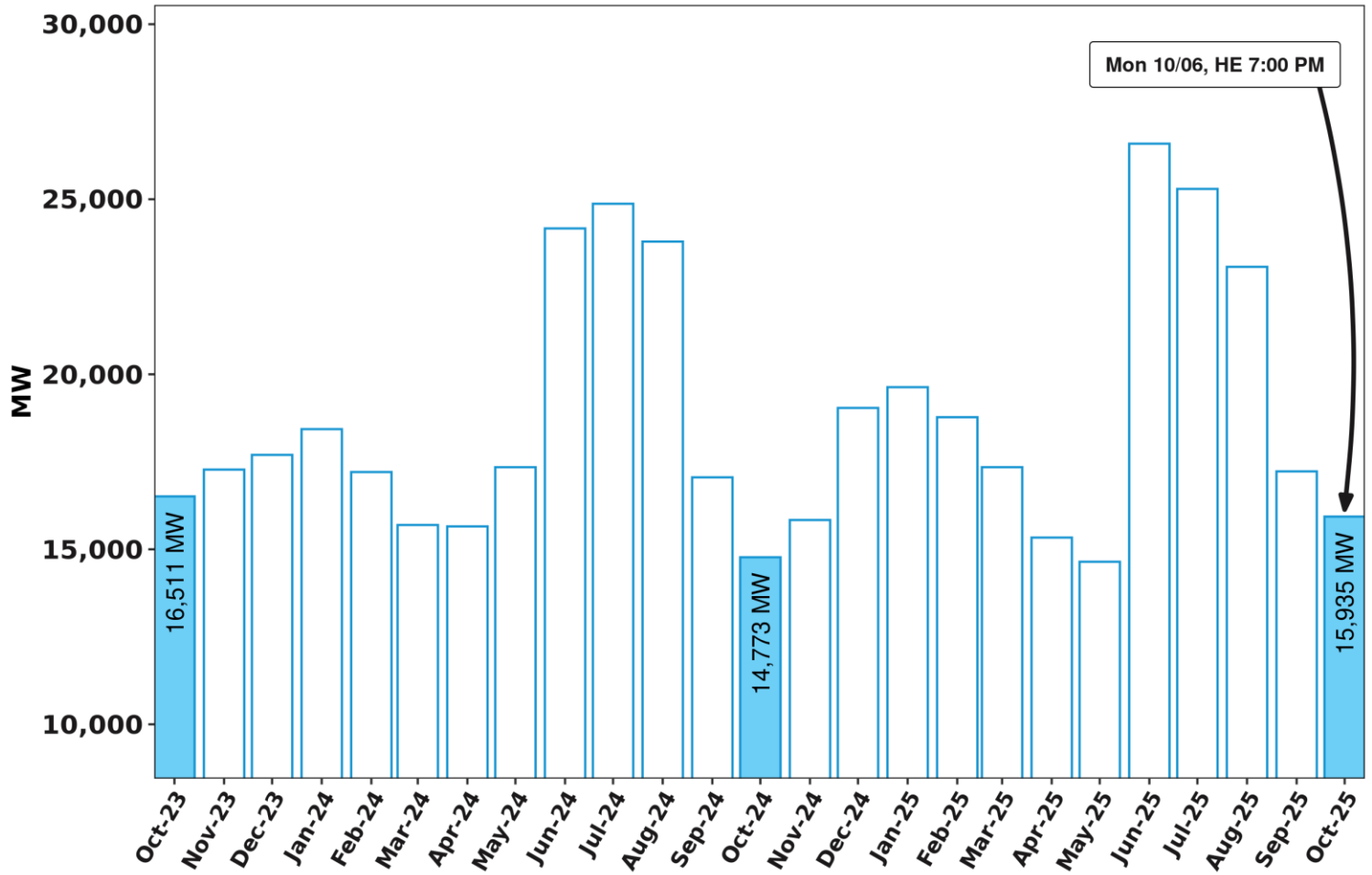
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



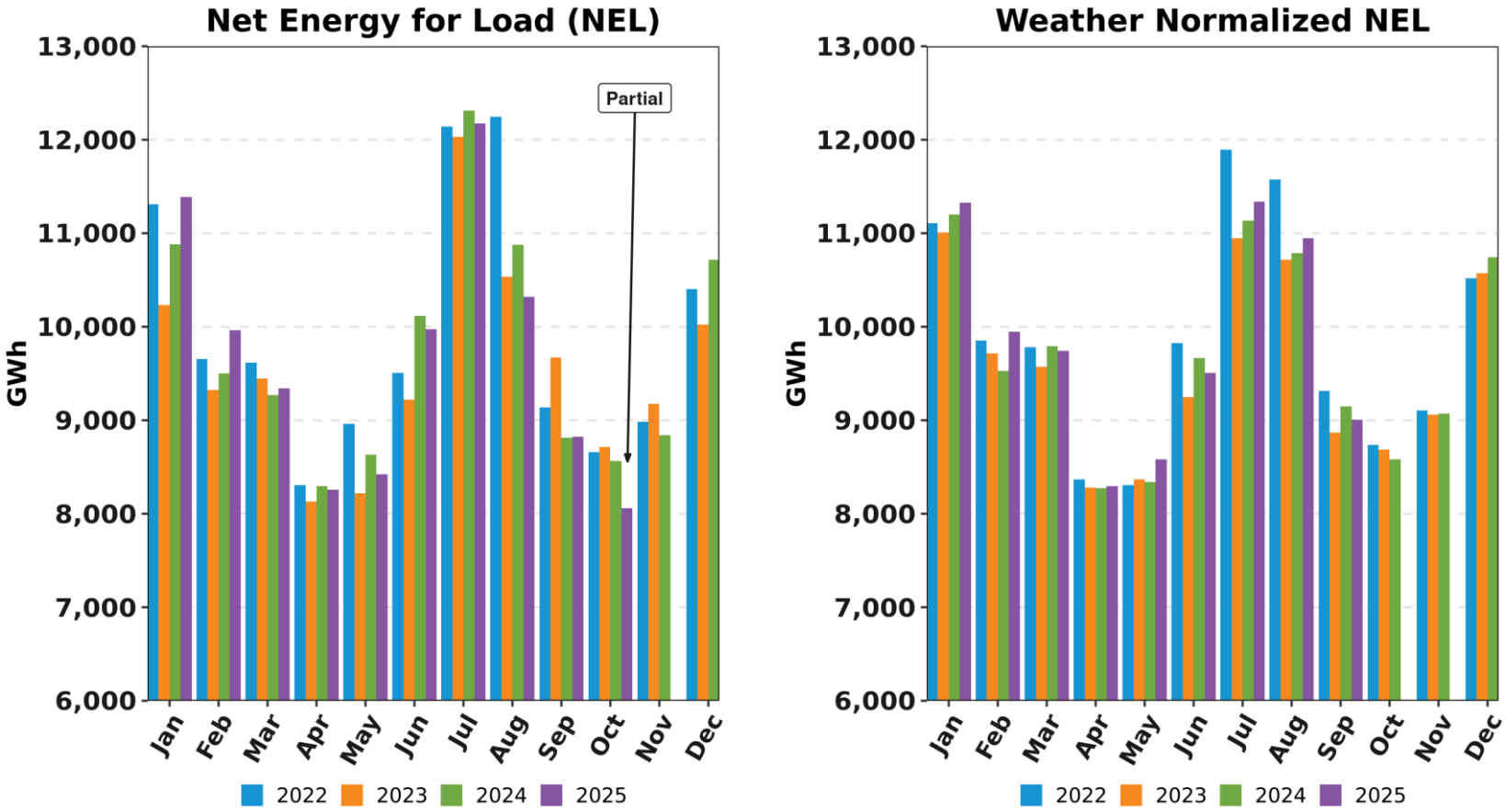


RQM System Peak Load MW by Month



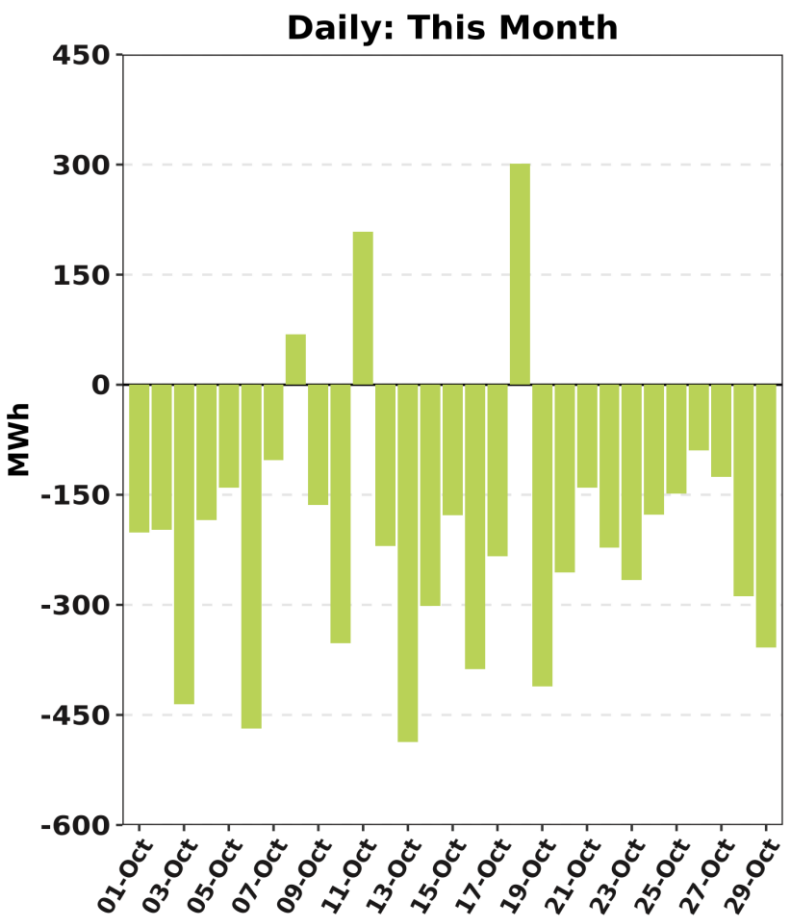
Shaded columns highlight current month and the same month over the prior two years

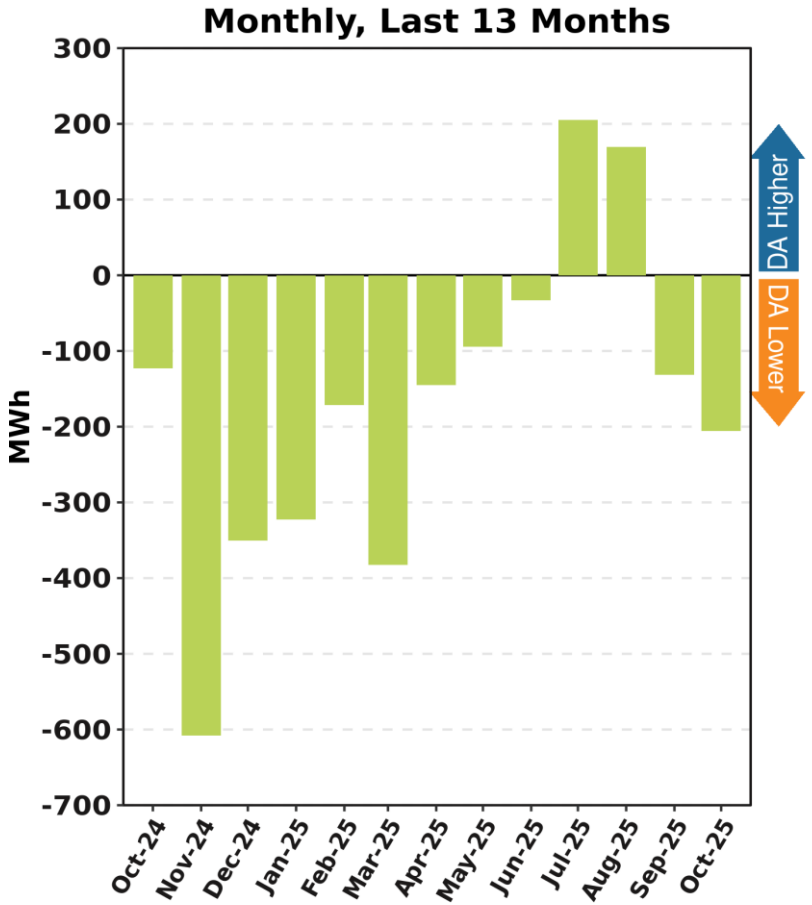
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



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 + 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.

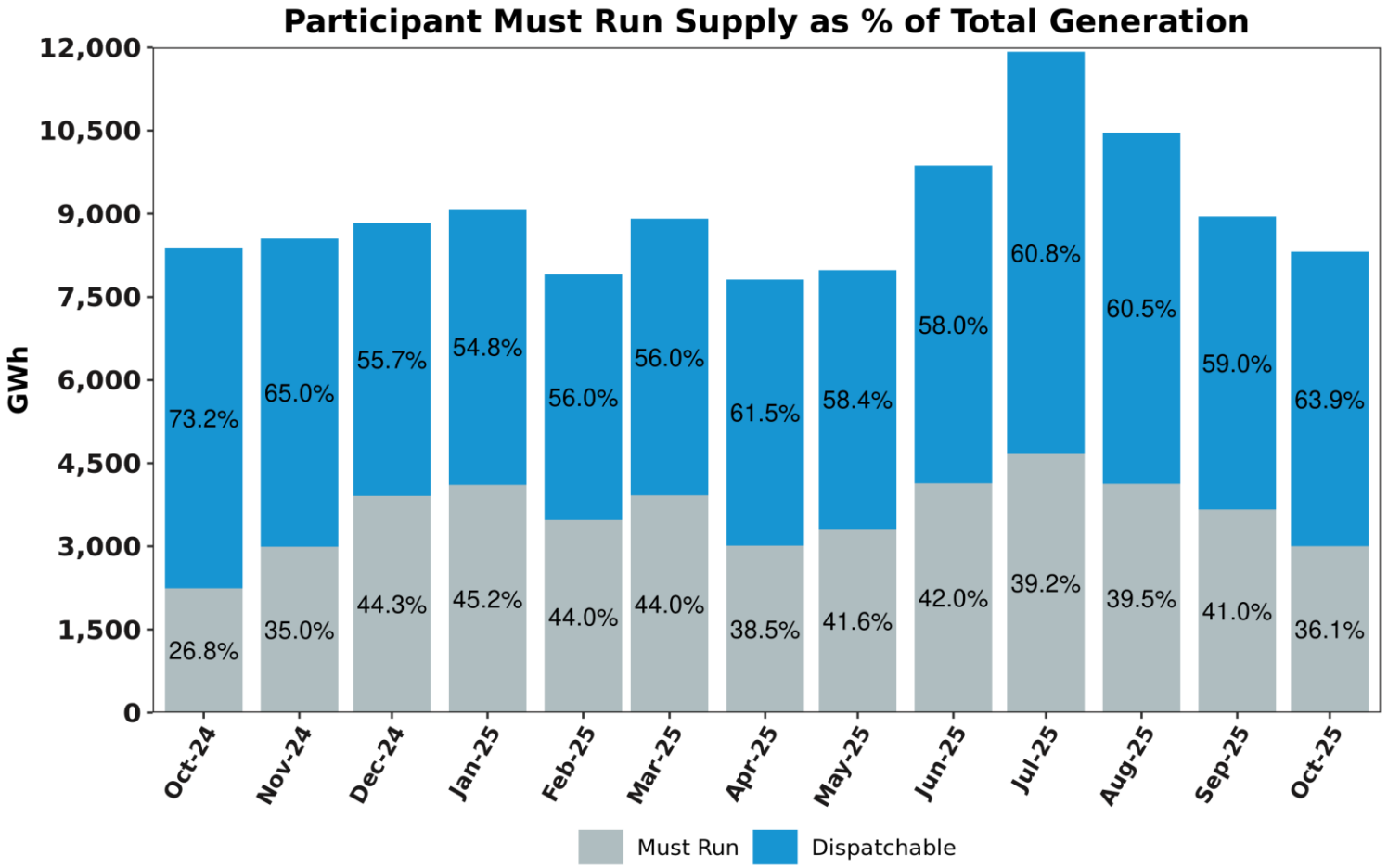
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour





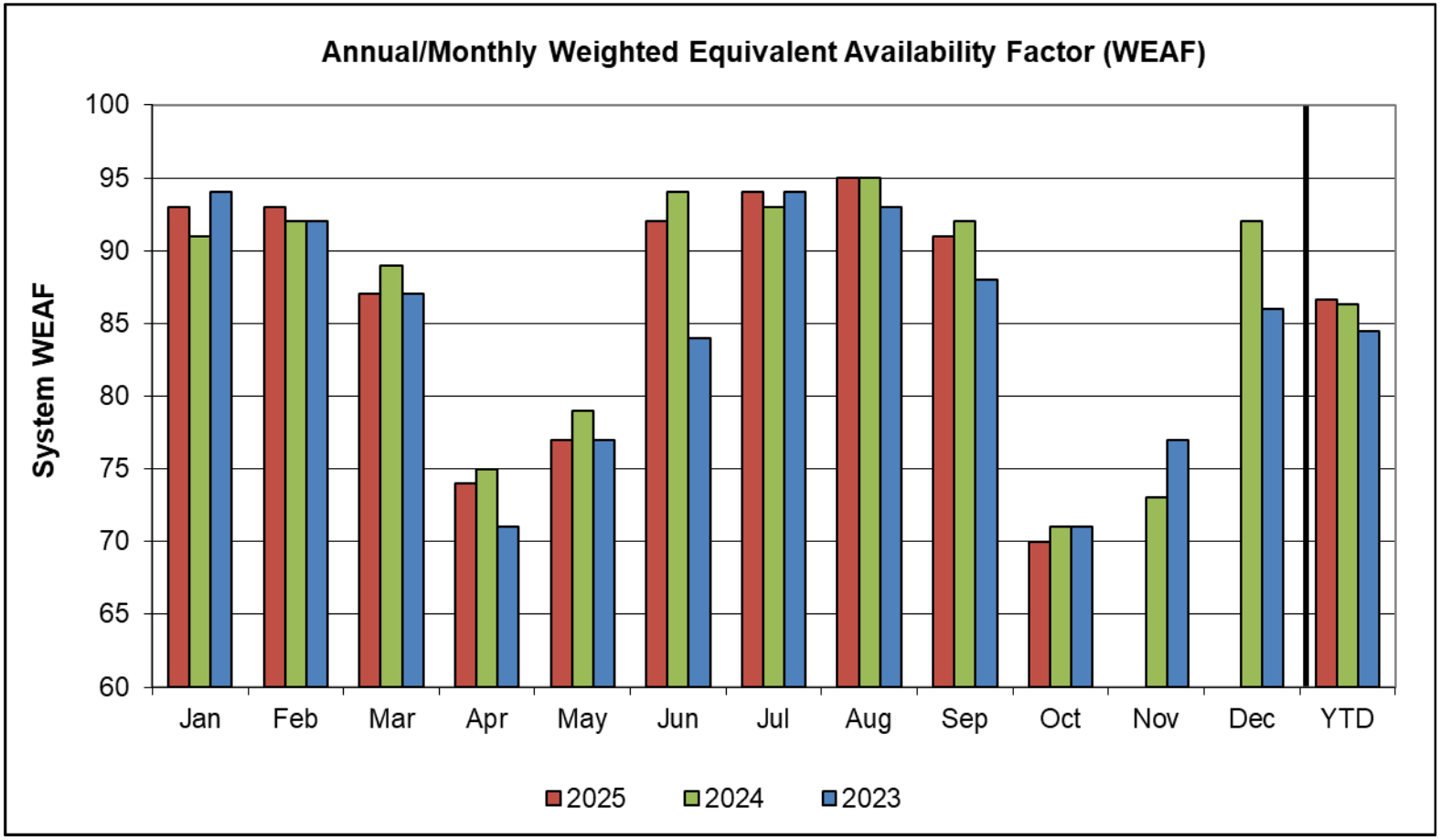
Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

RT Generation Output Offered as Must Run vs Dispatchable



Includes generation and DRR. Must Run (non-dispatchable) category reflects full output of Settlement Only Resources (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	95	91	70			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 10/27/25

MARKET PRICING

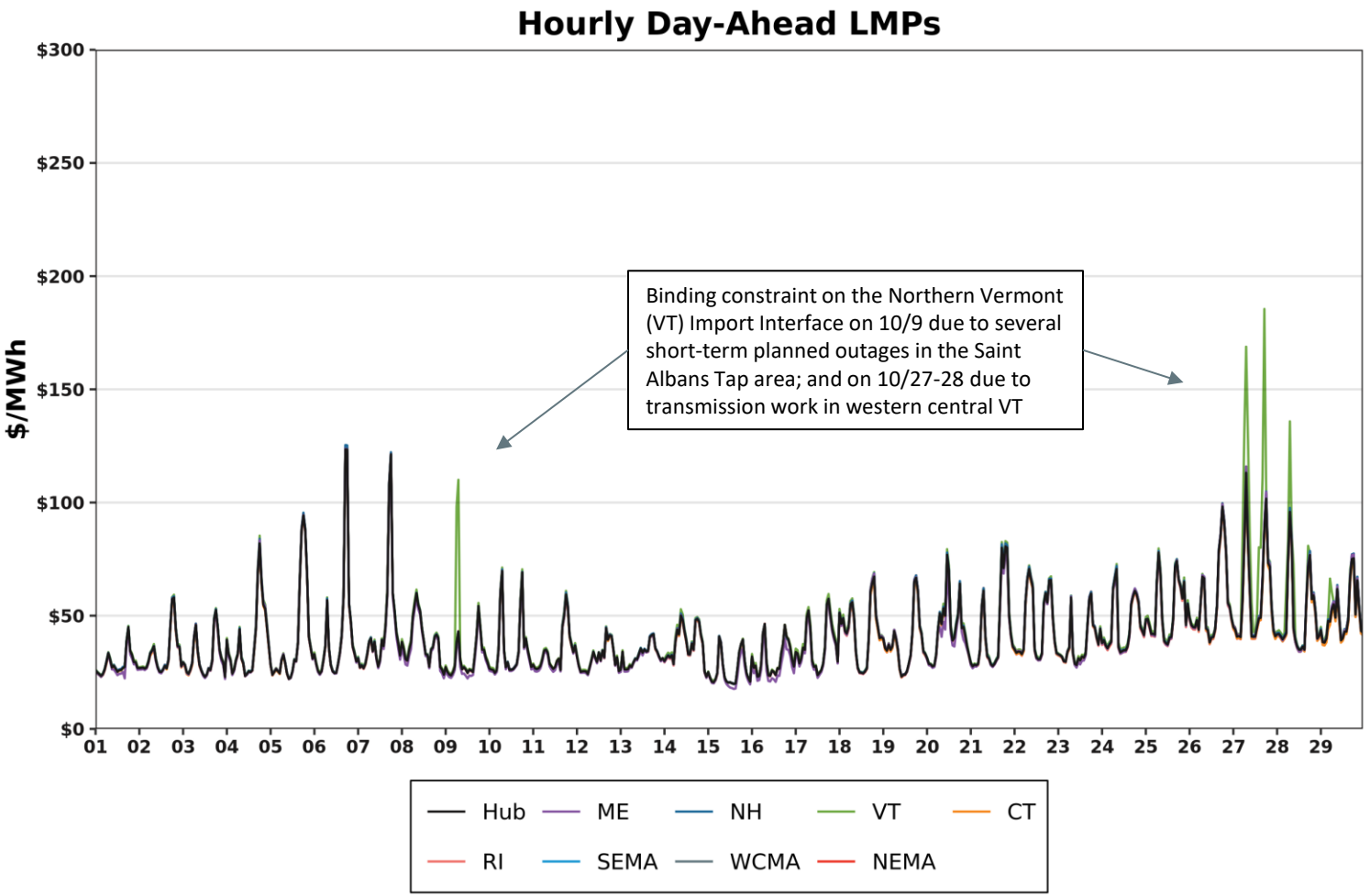
DA vs. RT LMPs ($/MWh)

Arithmetic Average

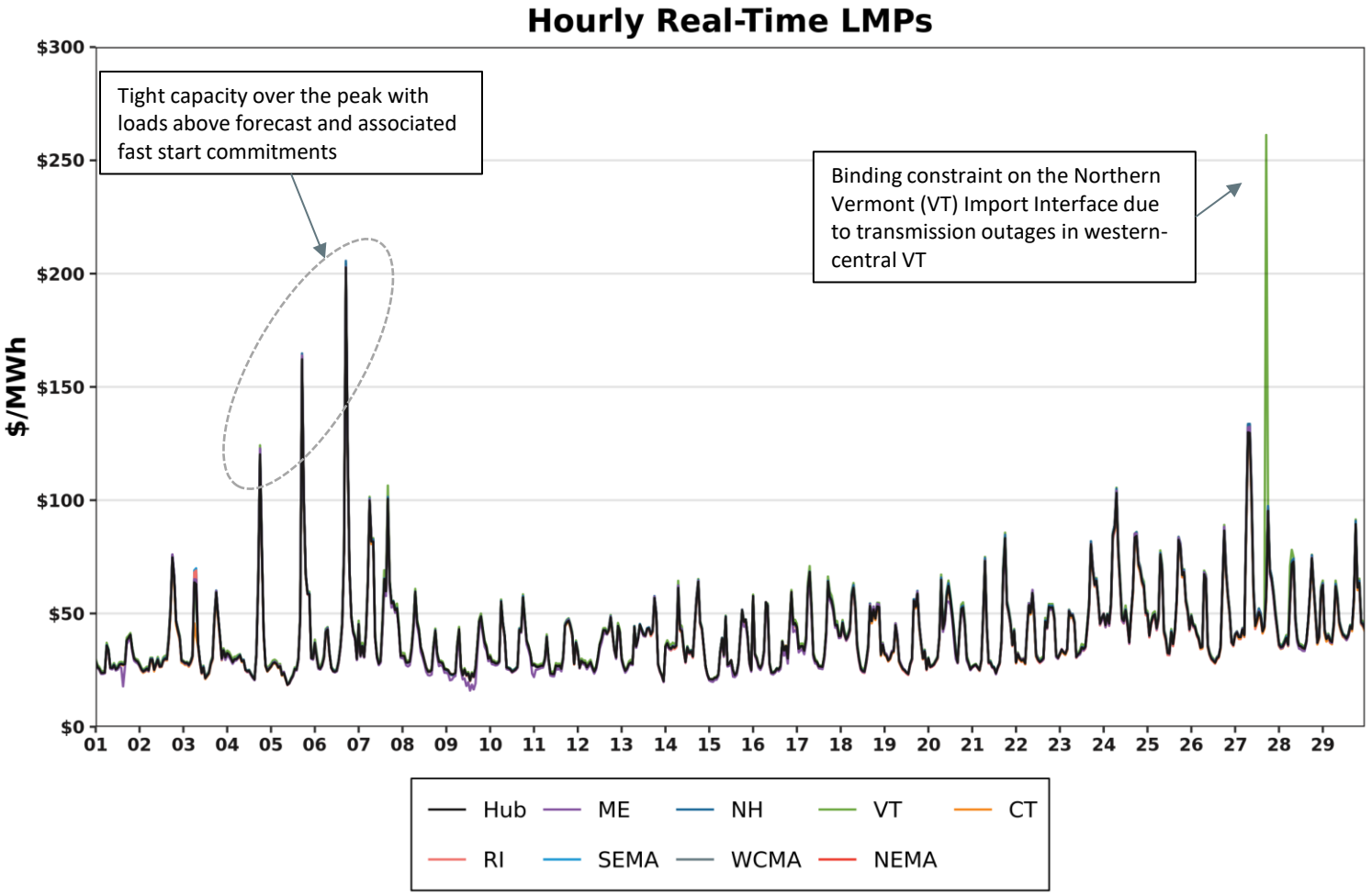
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$37.04	$36.59	$37.22	$36.78	$36.25	$36.89	$37.34	$37.07	$37.35
Real-Time	$35.91	$35.36	$36.05	$35.55	$35.26	$35.71	$36.17	$35.92	$36.21
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%
Year 2024	**Hub**	**ME**	**NH**	**VT**	**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%

October-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$35.97	$36.25	$36.54	$36.41	$34.96	$35.29	$35.99	$35.99	$36.40
Real-Time	$34.84	$35.14	$35.42	$35.29	$34.00	$34.22	$34.78	$34.84	$35.25
RT Delta %	-3.14%	-3.06%	-3.07%	-3.08%	-2.75%	-3.03%	-3.36%	-3.20%	-3.16%
October-25	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Day-Ahead	$39.98	$39.27	$40.32	$41.75	$39.56	$39.39	$40.04	$40.06	$40.29
Real-Time	$40.38	$39.81	$40.78	$41.66	$39.98	$39.76	$40.31	$40.46	$40.66
RT Delta %	1.00%	1.38%	1.14%	-0.22%	1.06%	0.94%	0.67%	1.00%	0.92%
Annual Diff.	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Yr over Yr DA	11.15%	8.33%	10.34%	14.67%	13.16%	11.62%	11.25%	11.31%	10.69%
Yr over Yr RT	15.90%	13.29%	15.13%	18.05%	17.59%	16.19%	15.90%	16.13%	15.35%

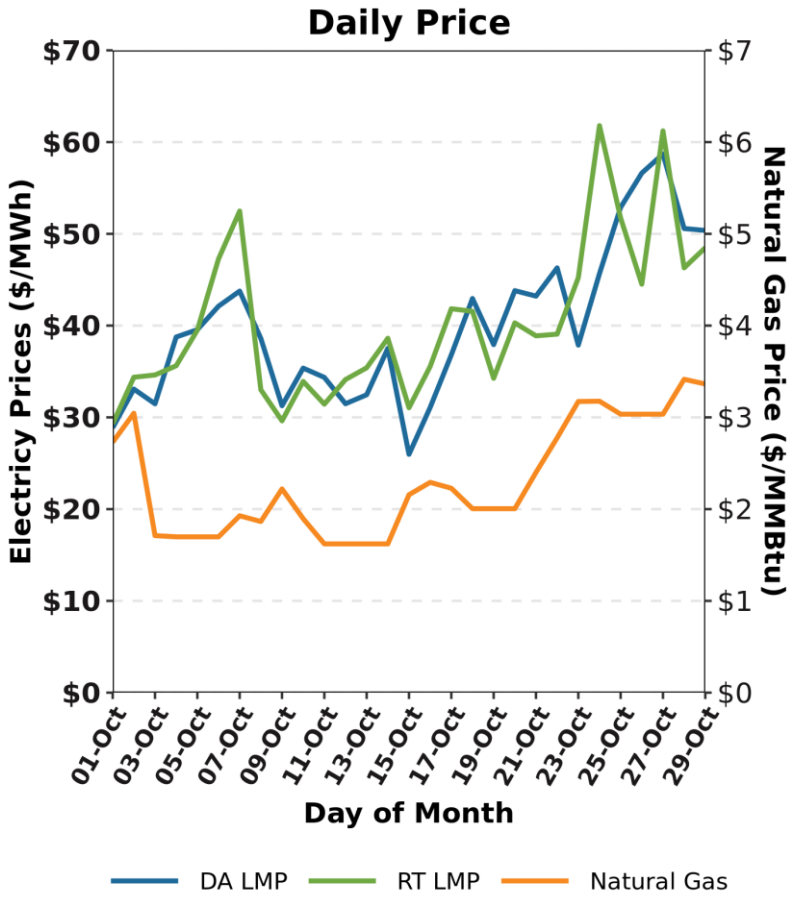
Hourly DA LMPs, October 1-29, 2025

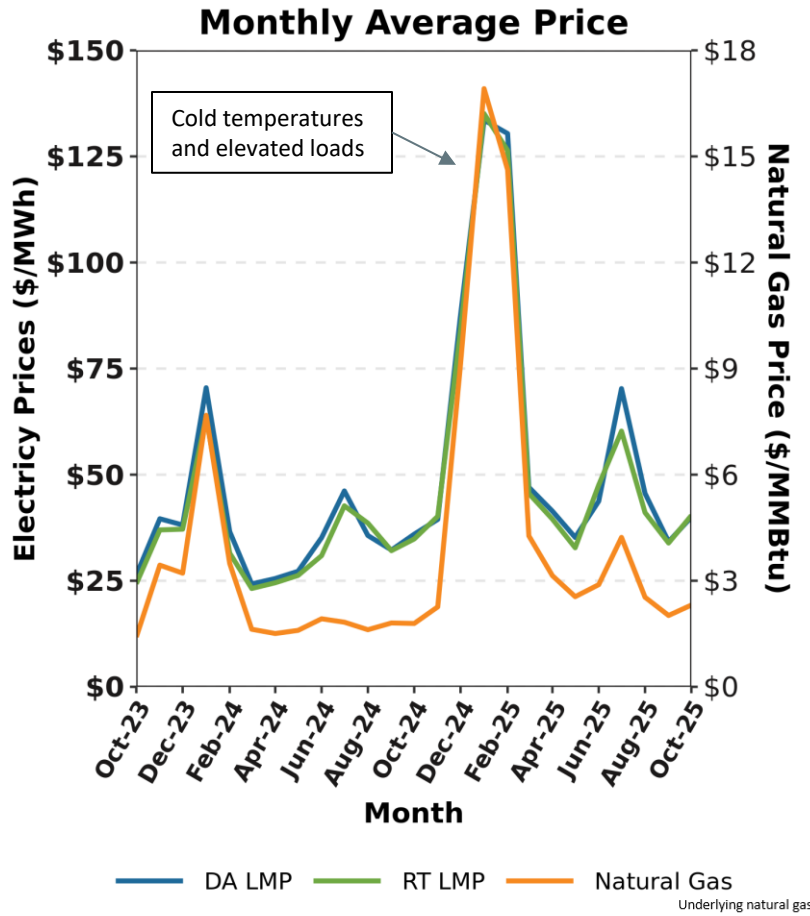


Hourly RT LMPs, October 1-29, 2025



Wholesale Electricity vs Natural Gas Price by Month



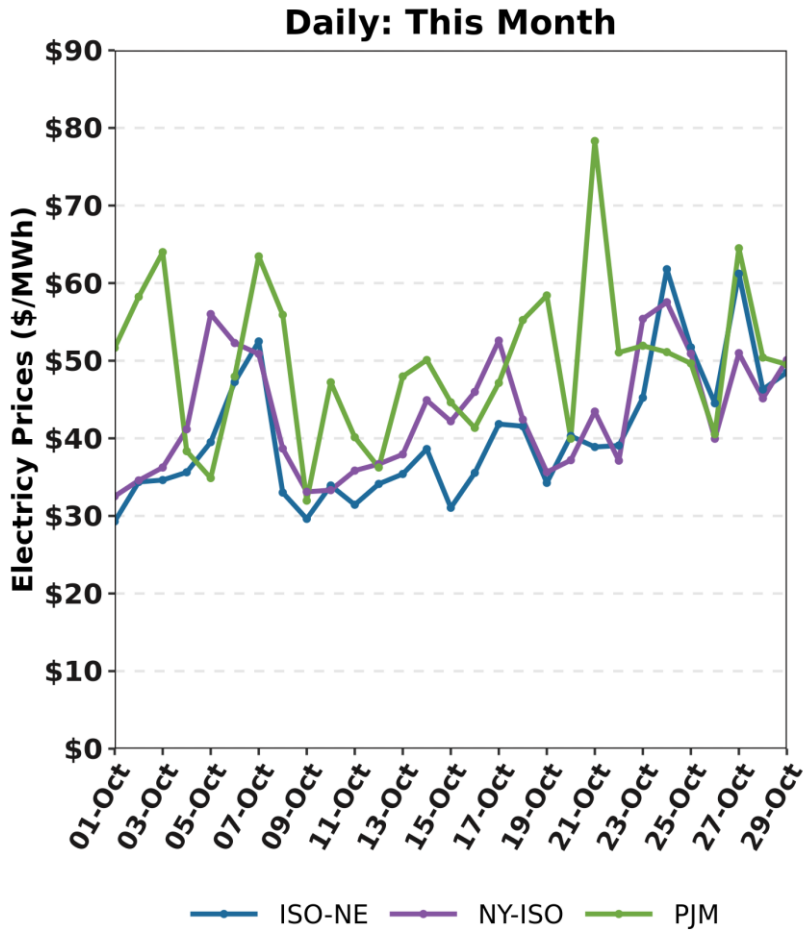


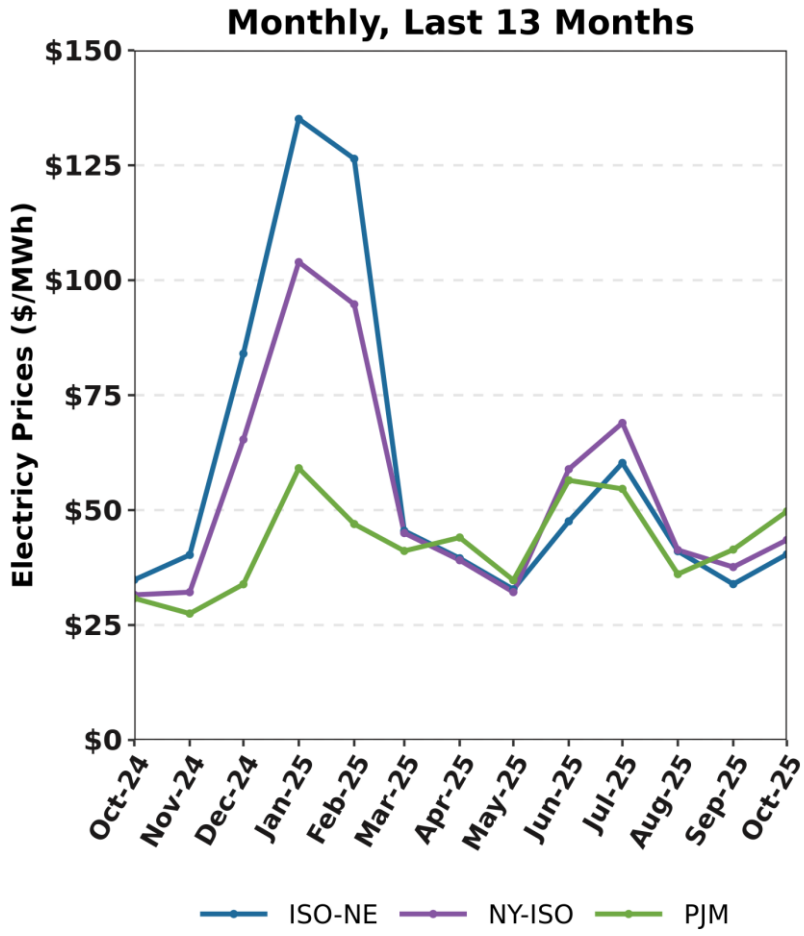
Gas price is average of Massachusetts delivery points

Underlying natural gas data furnished by:

ice Global markets in clear view

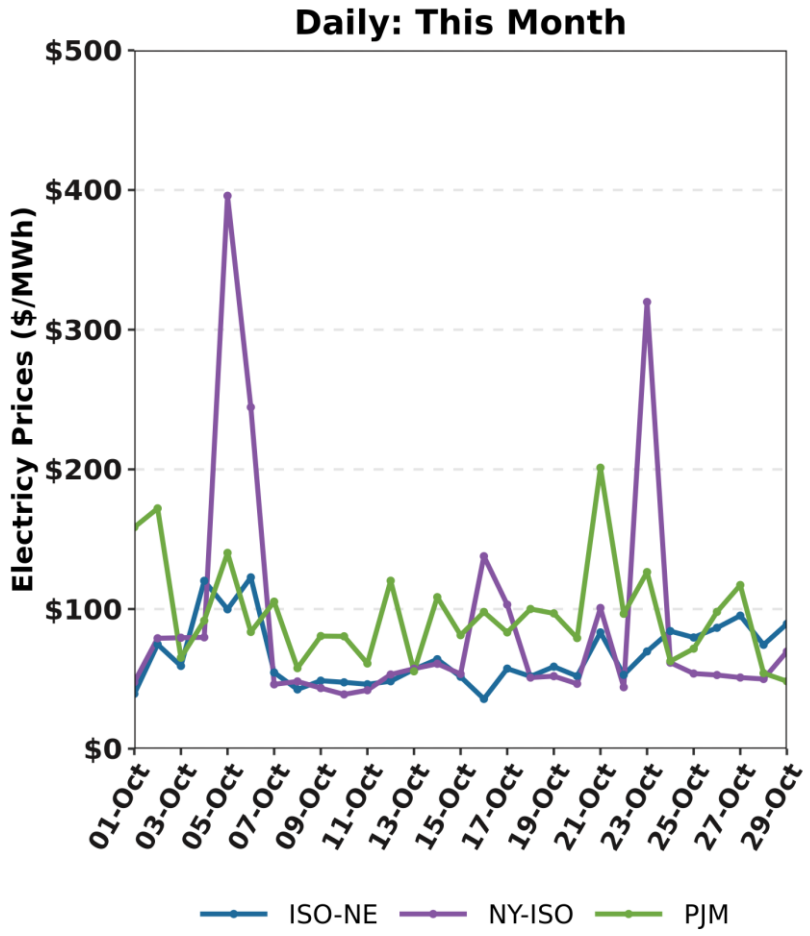
New England, NY, and PJM Hourly Average RT Prices by Month

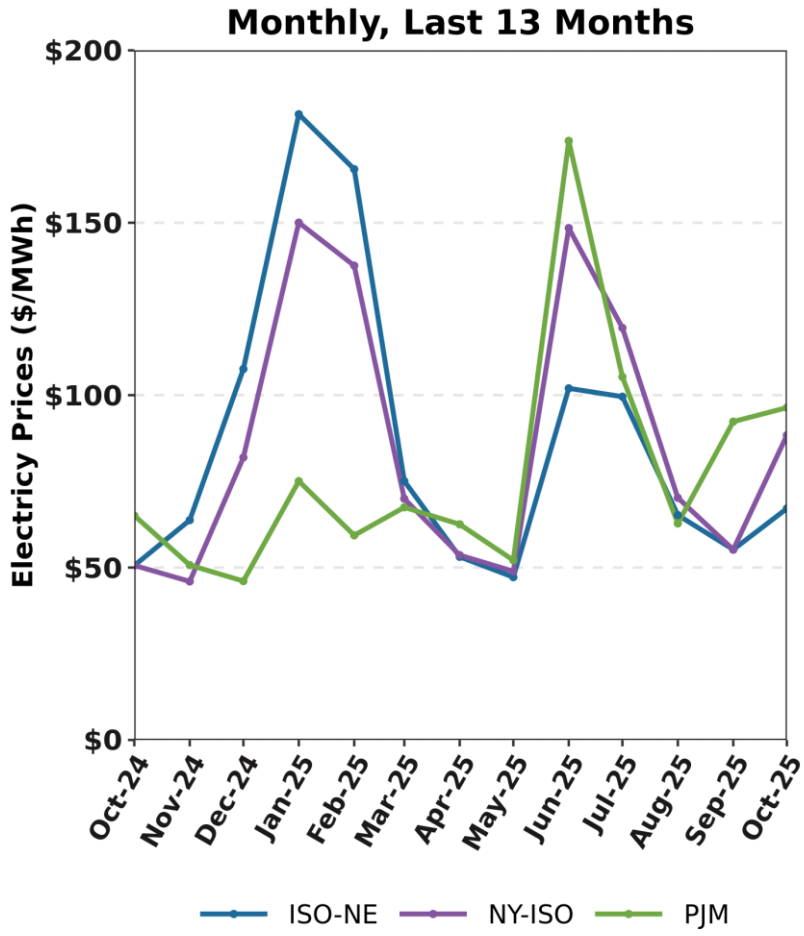




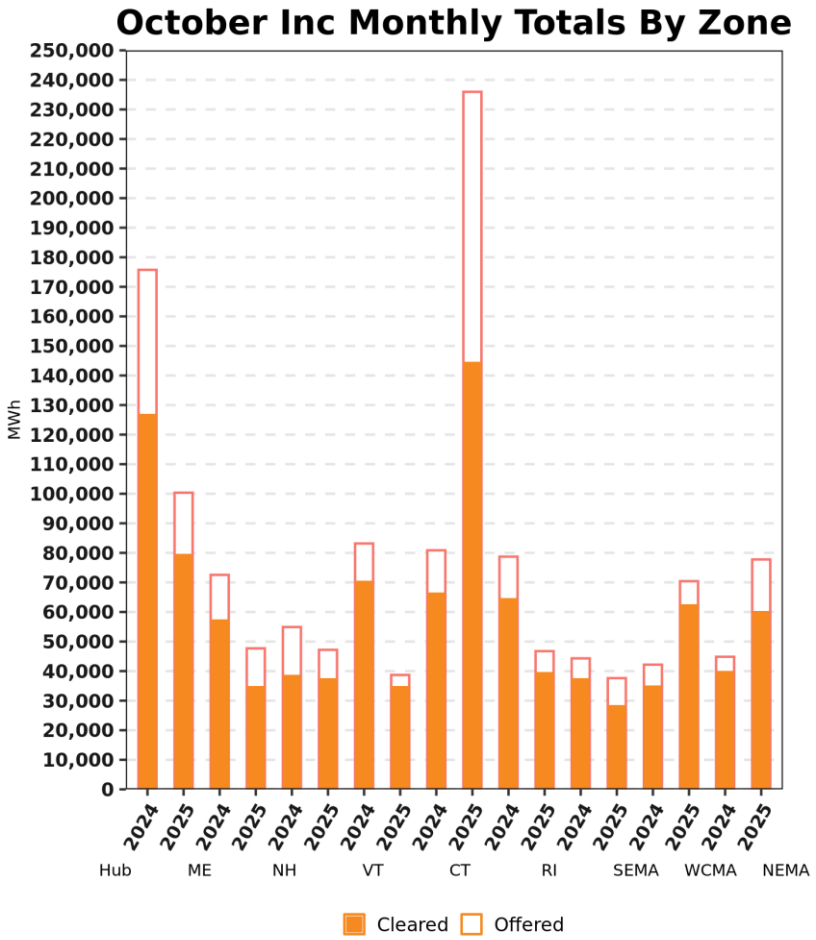
Hourly average prices are shown

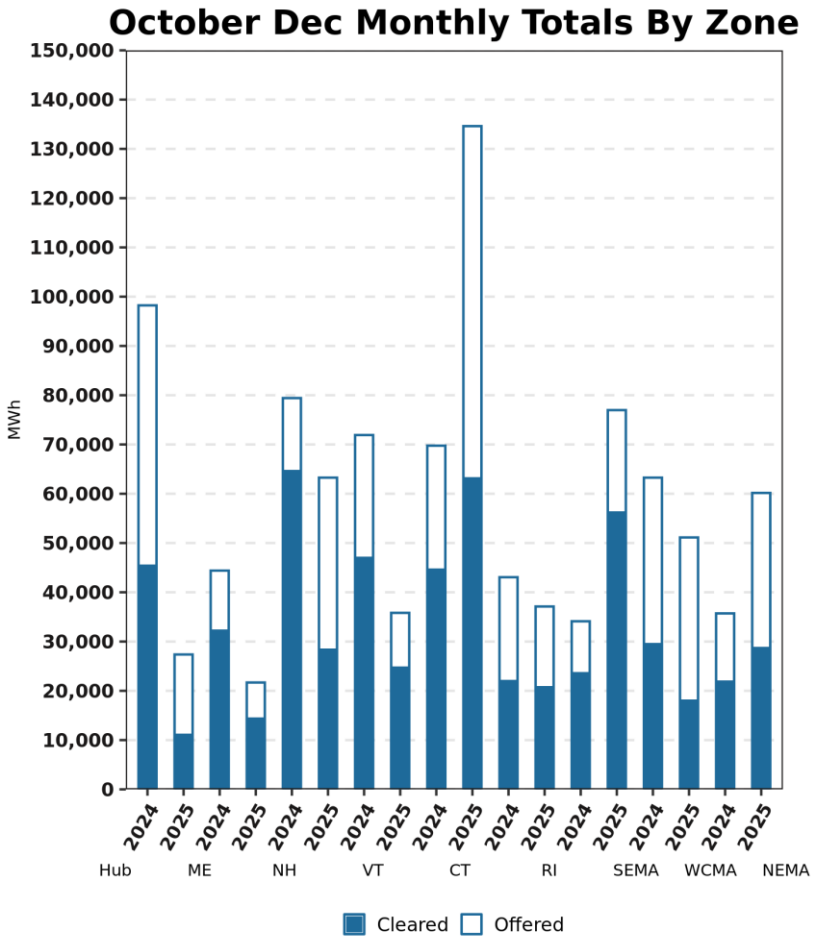
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





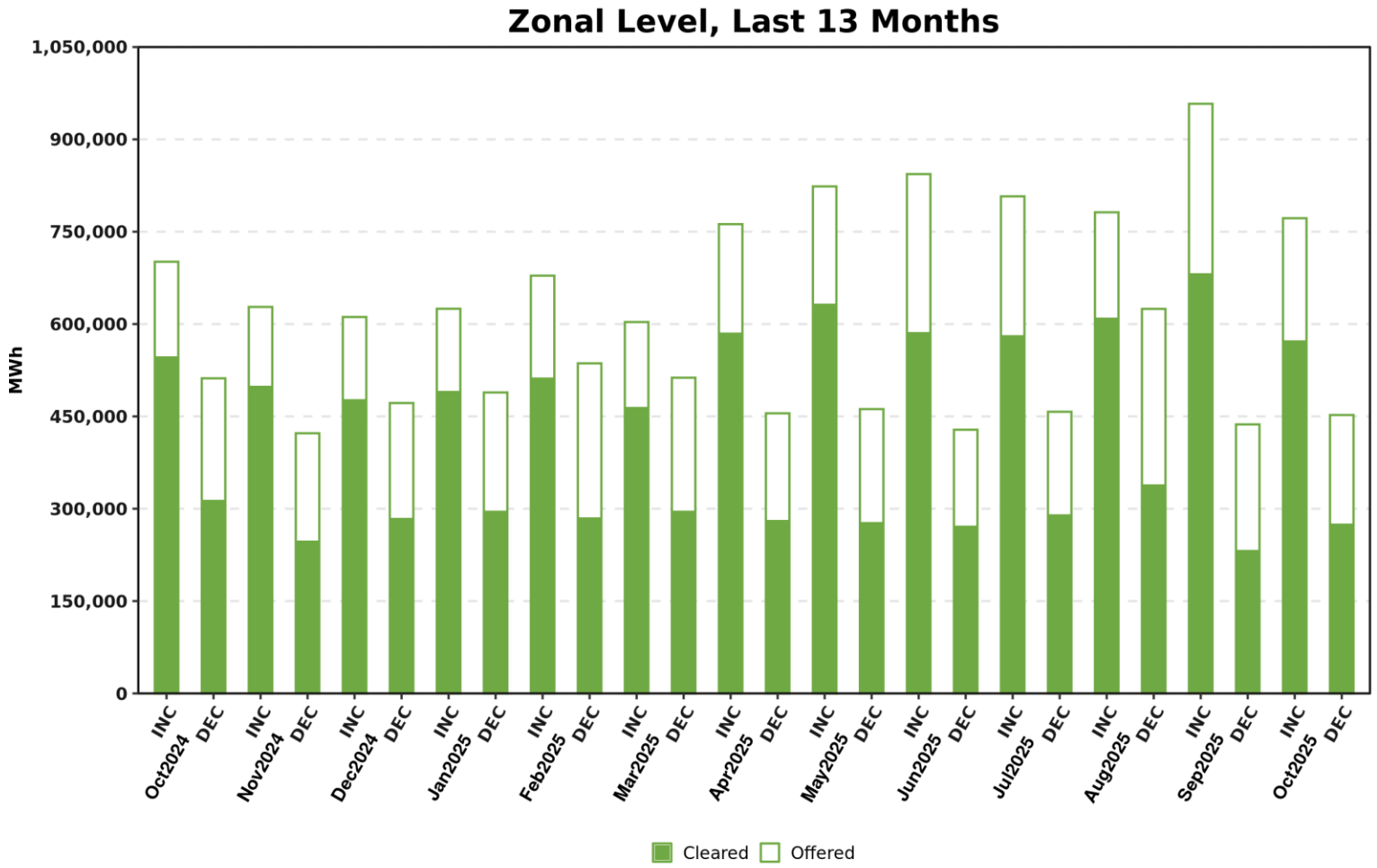
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids

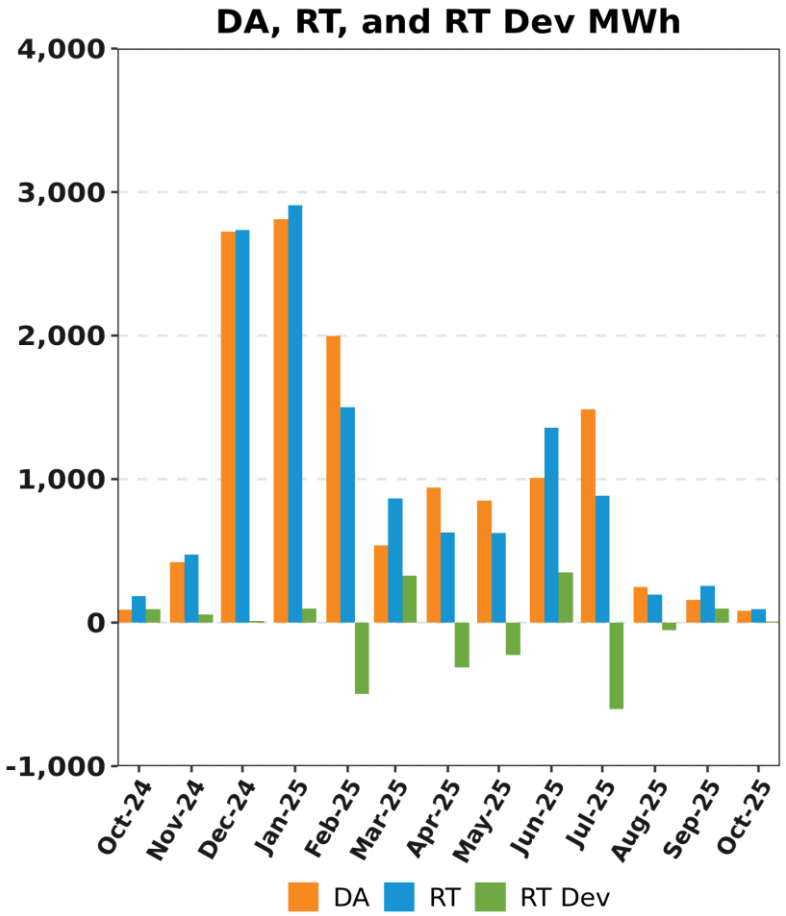


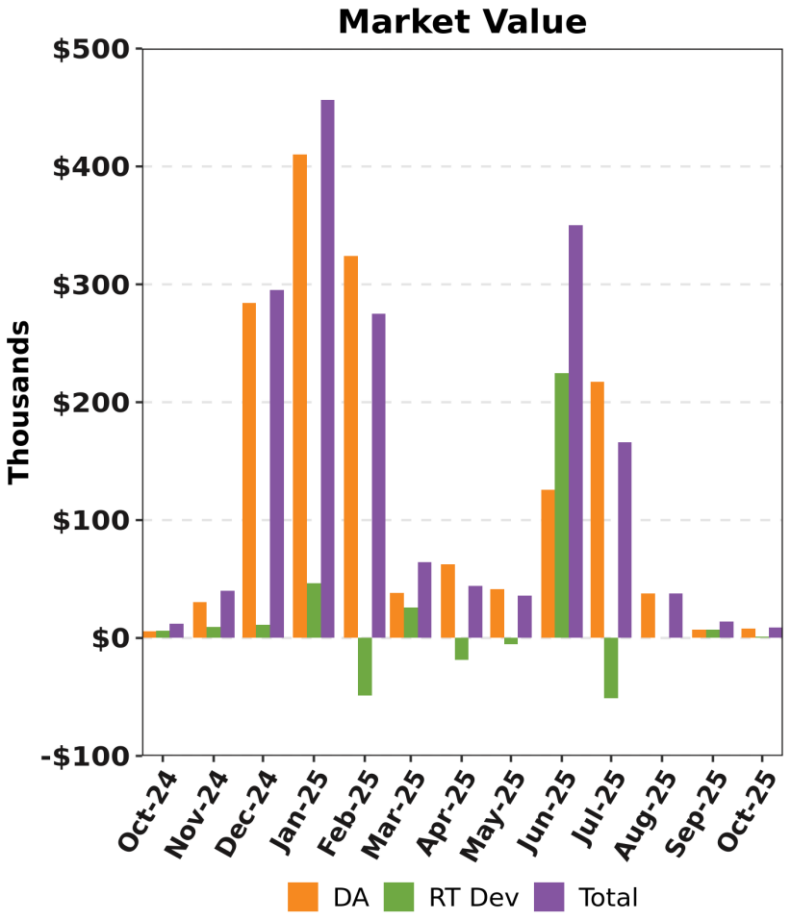
Includes nodal activity within the zone; excludes external nodes

BACK-UP DETAIL

DEMAND RESPONSE

Demand Response Resource (DRR) 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

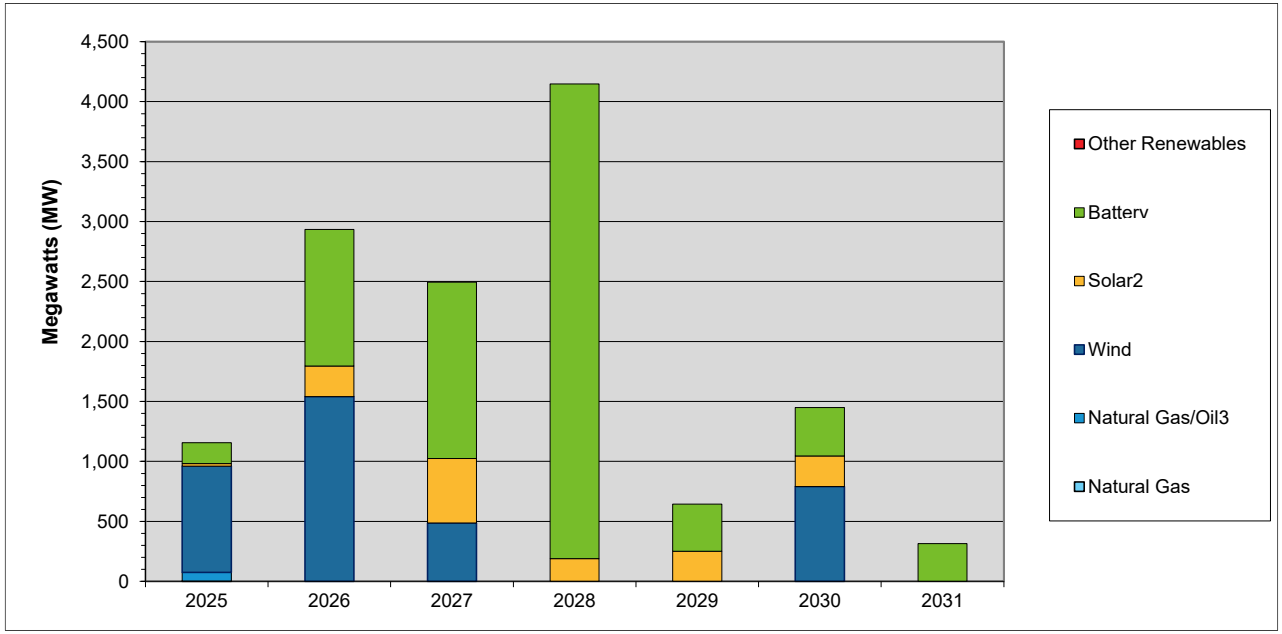
Based on Queue as of 10/28/25

- The interconnection queue has been updated to reflect the projects that have submitted the required materials to participate in the Order No. 2023 Transitional Cluster Study
- In total, 69* generation projects are currently being tracked by the ISO, totaling approximately 15,559 MW

* Total does not include CNR Only requests

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	175	1,140	1,471	3,957	392	404	315	7,854	59.8
Solar[2]	20	255	537	190	252	254	0	1,508	11.5
Wind	886	1,540	487	0	0	791	0	3,704	28.2
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.6
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	**1,154**	**2,935**	**2,495**	**4,147**	**644**	**1,449**	**315**	**13,139**	**100.0**

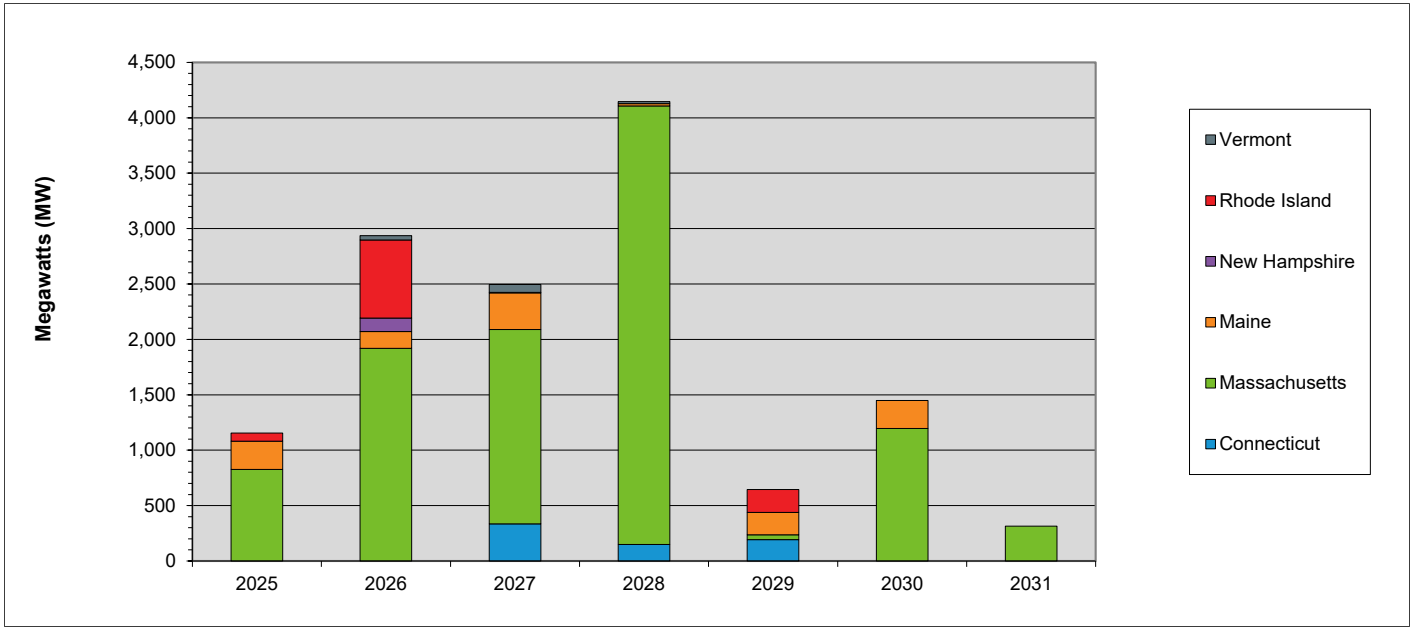
[1] Sum may not equal 100% due to rounding

[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

Chart is based on the dates listed in the interconnection queue and in many cases does not reflect accurately achievable dates for proposed projects

Projected Annual Generator Capacity Additions
By State



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total[1]
Vermont	0	38	70	20	0	0	0	128	1.0
Rhode Island	73	704	0	0	205	0	0	982	7.5
New Hampshire	0	122	5	0	0	0	0	127	1.0
Maine	254	151	331	20	202	254	0	1,212	9.2
Massachusetts	827	1,920	1,753	3,957	45	1,195	315	10,012	76.2
Connecticut	0	0	336	150	192	0	0	678	5.2
Totals	**1,154**	**2,935**	**2,495**	**4,147**	**644**	**1,449**	**315**	**13,139**	**100.0**

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

Chart is based on the dates listed in the interconnection queue and in many cases does not reflect accurately achievable dates for proposed projects

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	31	7,854	2	425	29	7,429
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	27	1,528	4	76	23	1,452
Wind	10	6,104	3	877	7	5,227
Total	69	15,559	9	1,378	60	14,181

- 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	58	9,382	6	501	52	8,881
Wind Turbine	10	6,104	3	877	7	5,227
Total	69	15,559	9	1,378	60	14,181

- 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	31	7,854	0	0	0	0	31	7,854	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	27	1,528	0	0	0	0	27	1,528	0	0
Wind	10	6,104	0	0	0	0	0	0	10	6,104
Total	69	15,559	0	0	1	73	58	9,382	10	6,104

- 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	492.363	-92.550		
	Passive Demand	2,316.815	2,314.068	-2.747	2,314.705	0.637		
Demand Total		**2,939.669**	**2,898.981**	**-40.688**	**2,807.068**	**-91.913**		
Generator	*Non-Intermittent*	26,507.420	26,715.489	208.069	26,271.866	-443.623		
	Intermittent	1,356.084	1,286.589	-69.495	1,310.622	24.033		
Generator Total		**27,863.504**	**28,002.078**	**138.574**	**27,582.488**	**-419.59**		
Import Total		**566.998**	**564.079**	**-2.919**	**636.310**	**72.231**		
Grand Total*		**31,370.171**	**31,465.138**	**94.967**	**31,025.866**	**-439.272**		
Net ICR (NICR)		**30,305**	**30,395**	**90**	**30,600**	**205**		

* 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

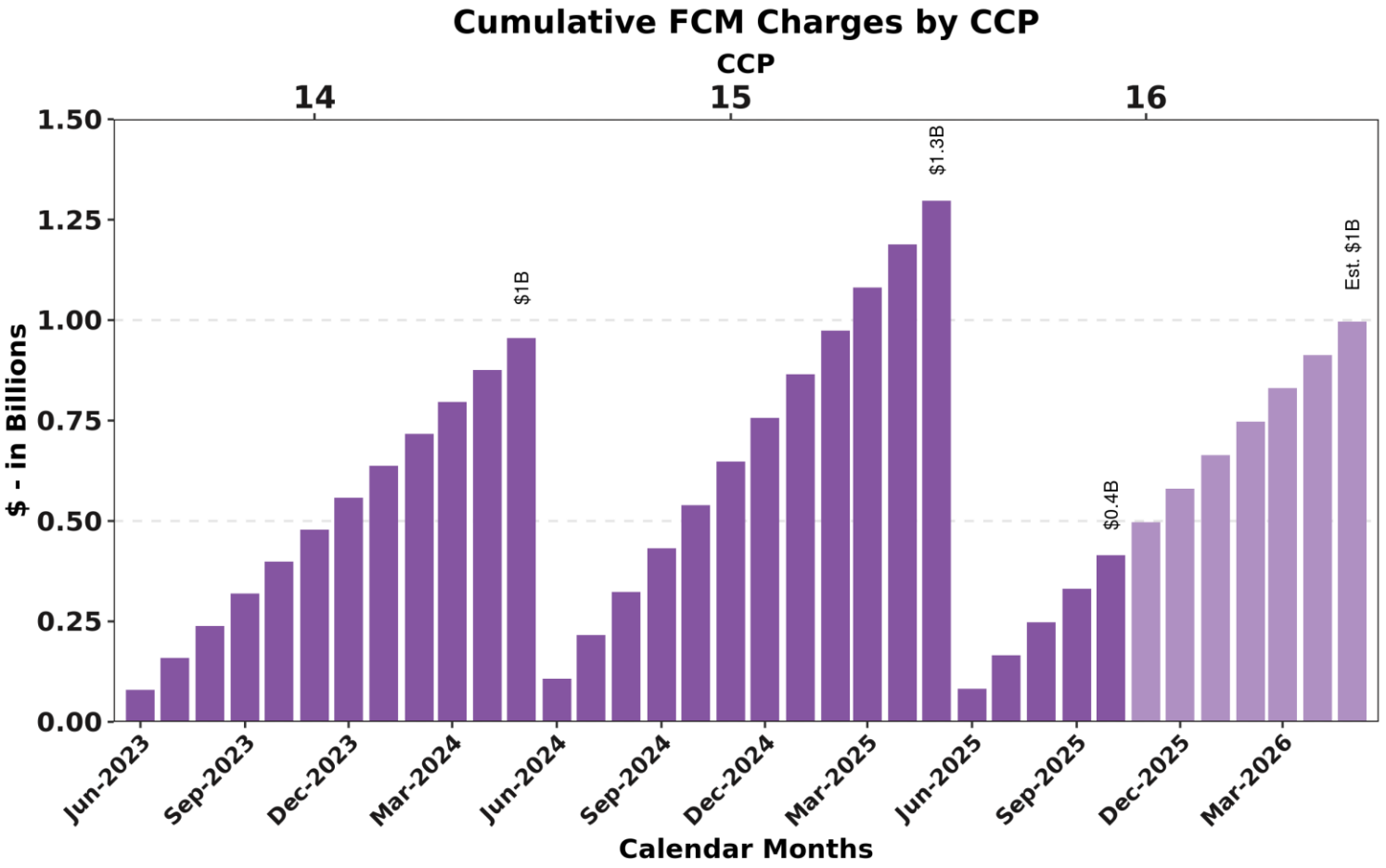
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes 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**

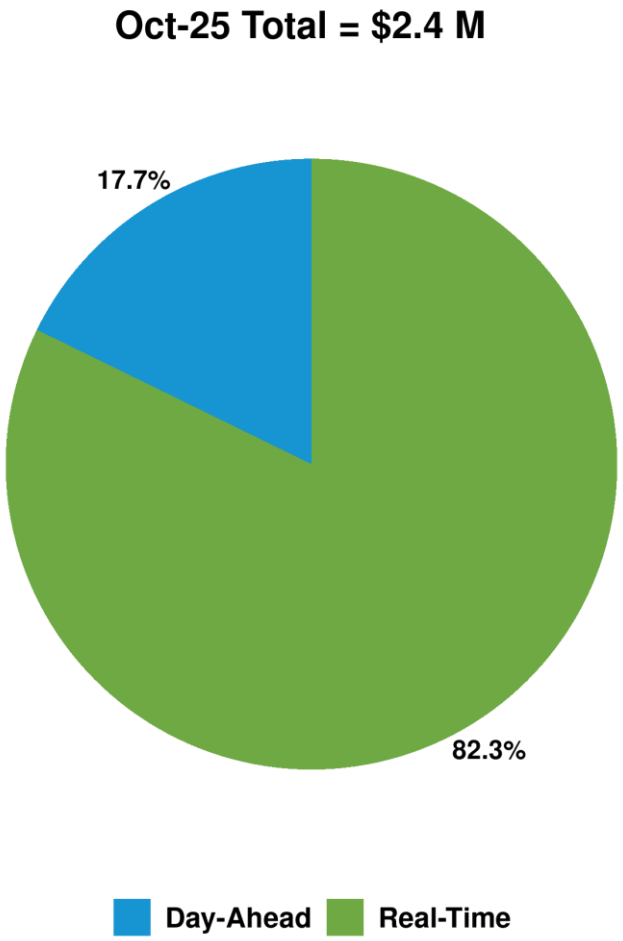
Forward Capacity Market Auctions

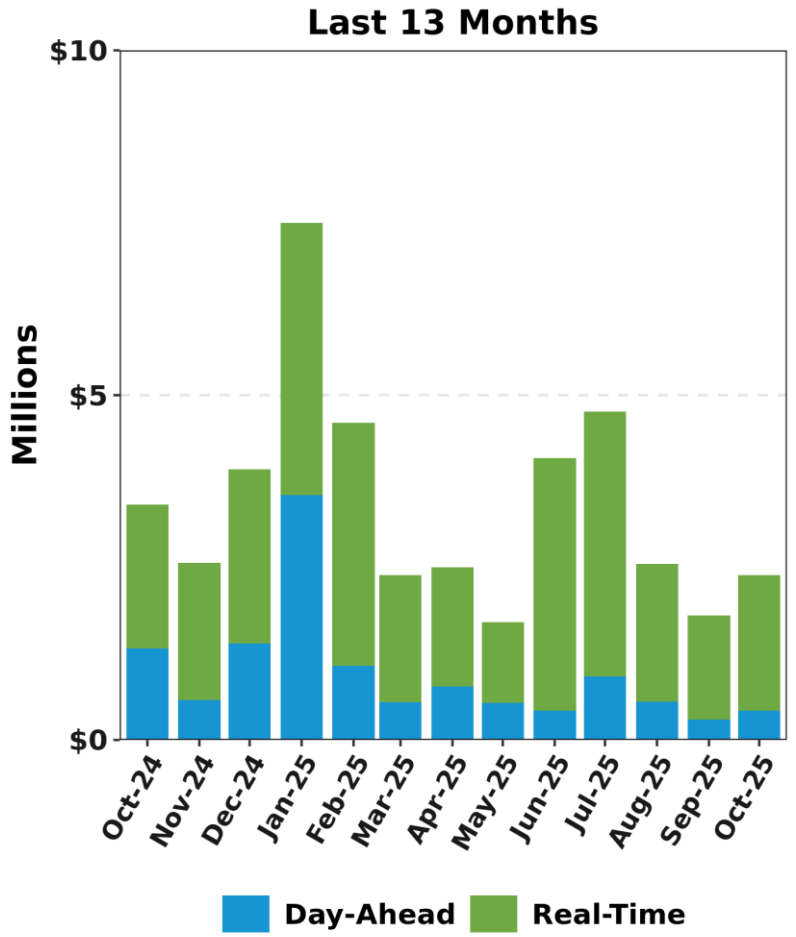


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

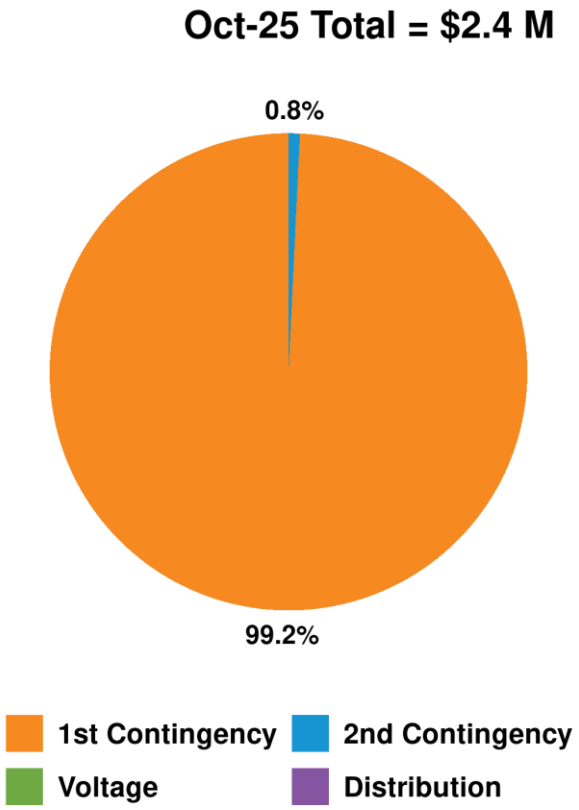
NET COMMITMENT PERIOD COMPENSATION

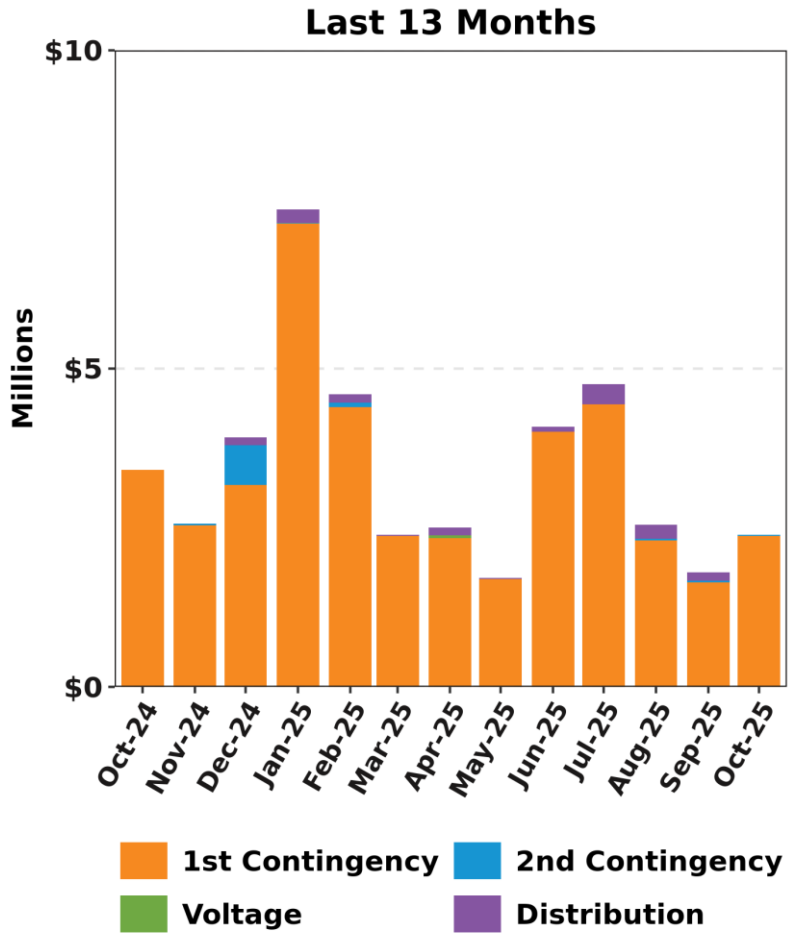
DA and RT NCPC Charges



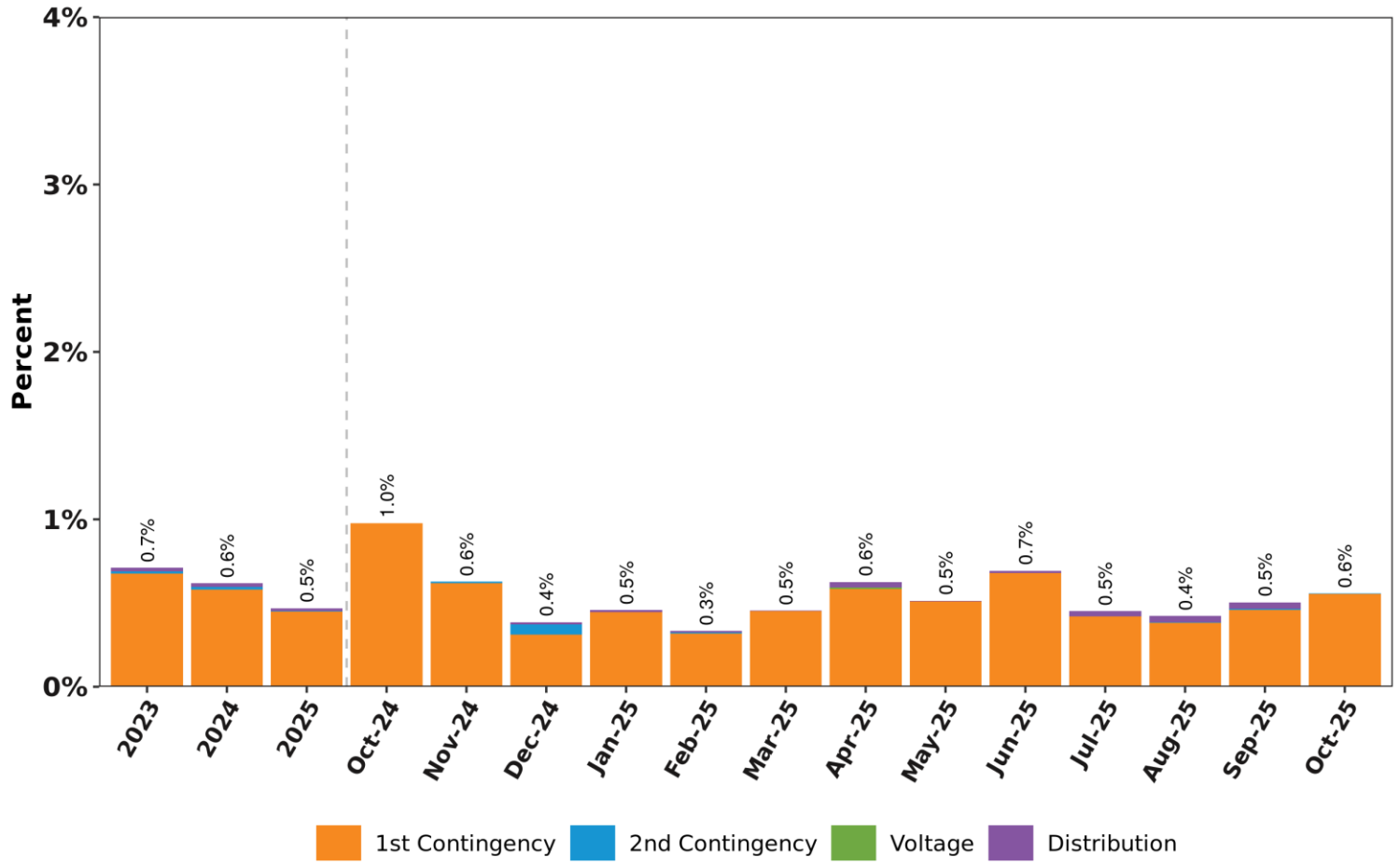


NCPC Charges by Type

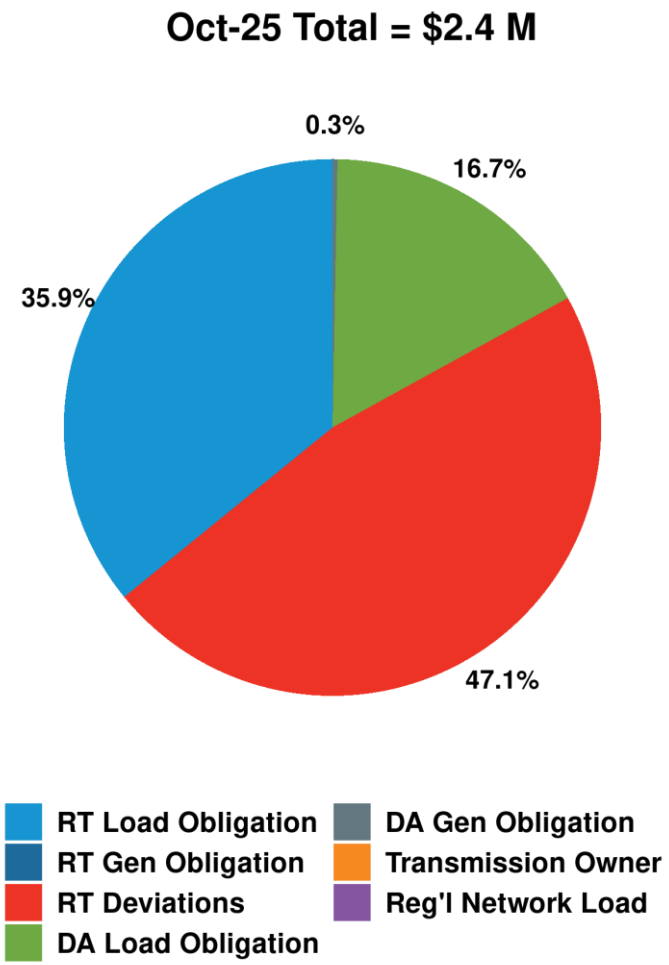


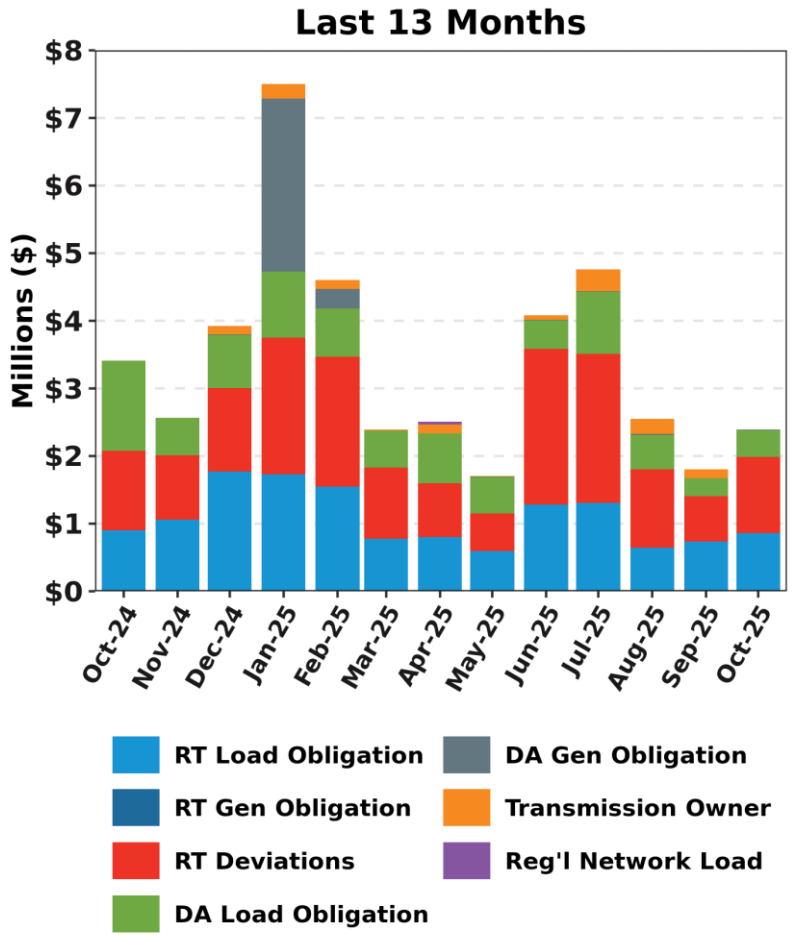


NCPC Charges by Type as Percent of Energy Market Value

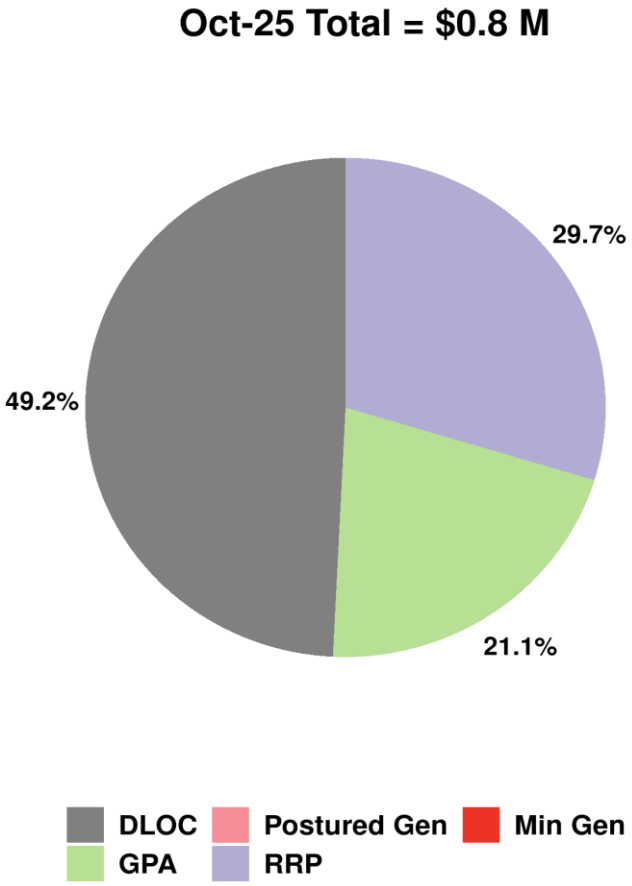


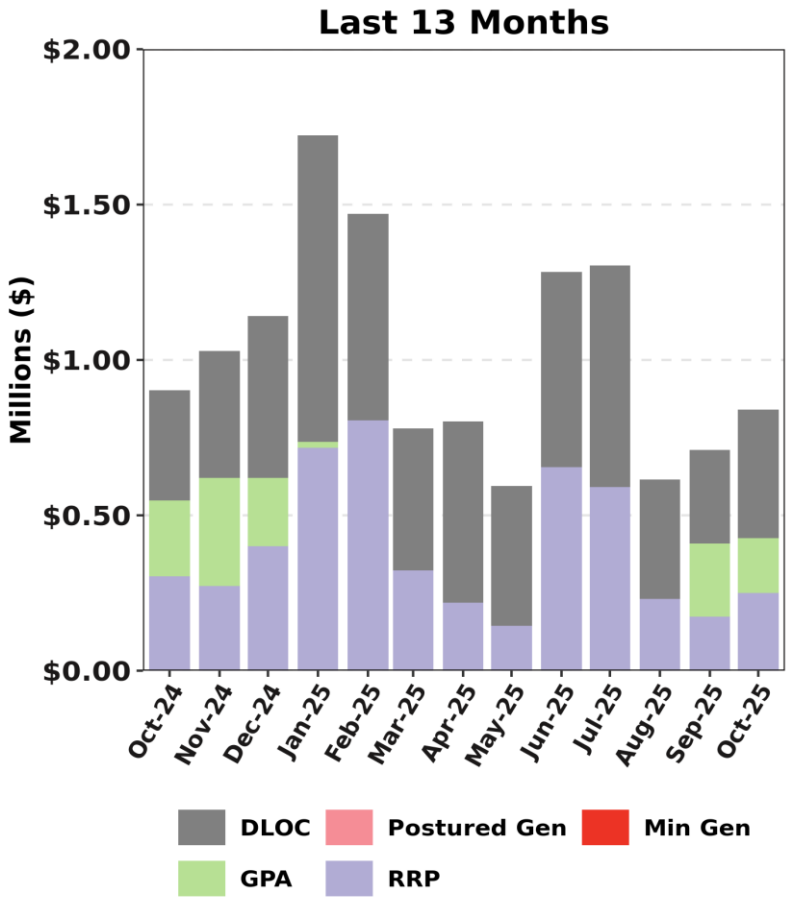
NCPC Charge Allocations





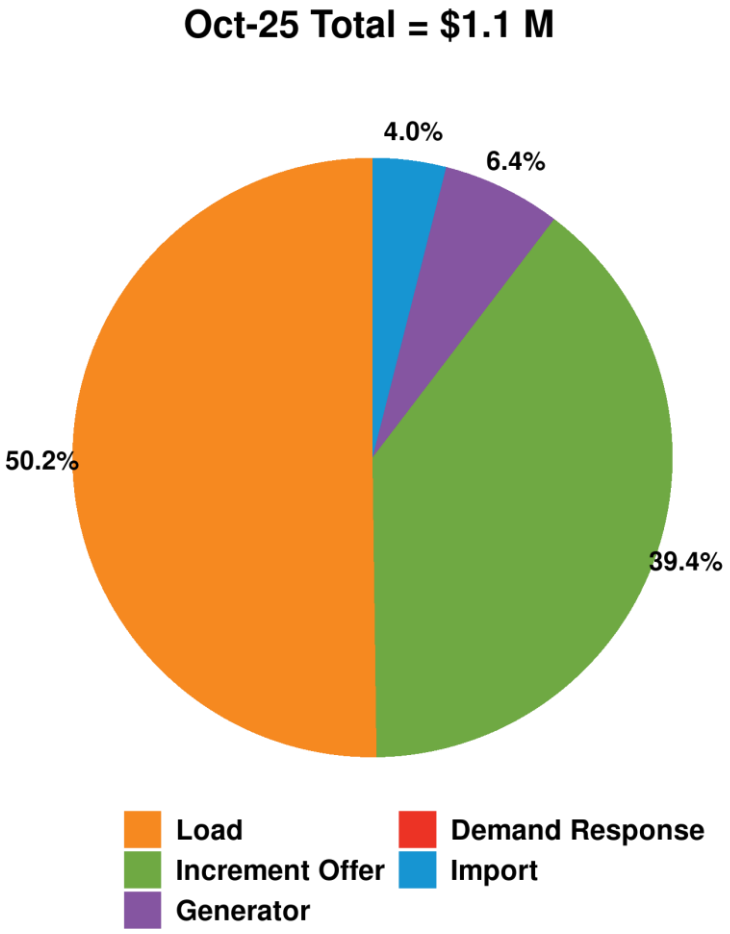
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

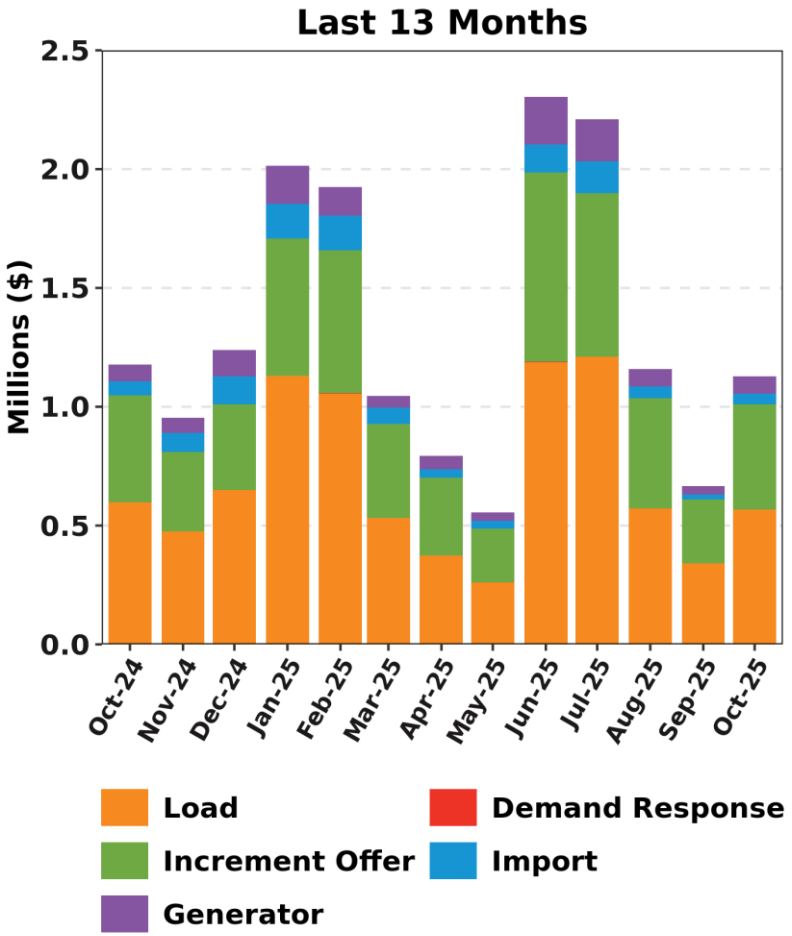




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

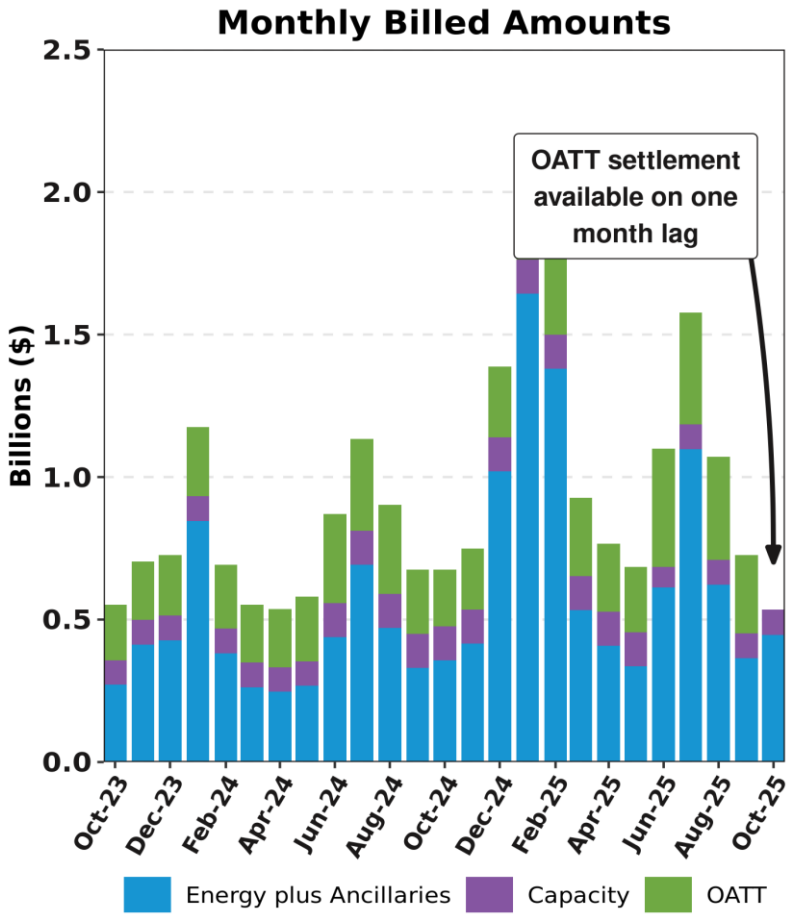
RT First Contingency Charges by Deviation Type

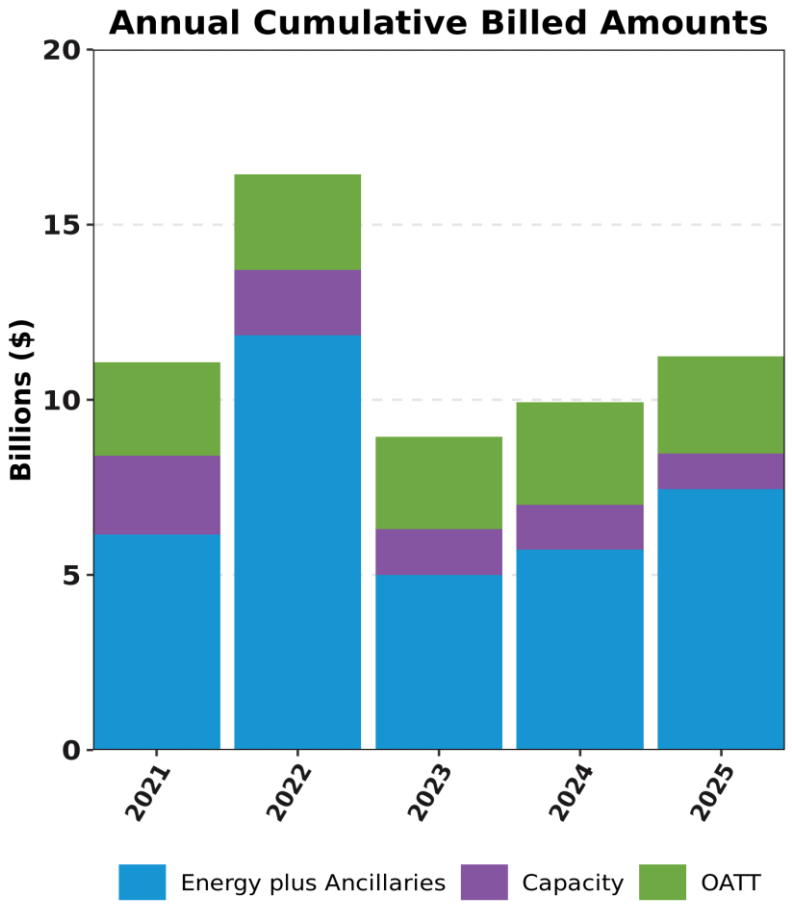




ISO BILLINGS

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)

- November 19 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - 1870S Wood River-Shunock Line Rebuild (RIE)
    - 323 345 kV Line Asset Condition Refurbishment (NGRID)
    - 394/397 345 kV Lines Asset Condition Refurbishment (NGRID)
    - Overview of Proposed Updates to New England Transmission Owner (NETO) PAC Presentation Template and Asset Condition Process Guide (Eversource)
  - 2025 LTTP RFP: Longer-Term Proposal Overview

* 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 (LTTP) RFP

- On 12/13/24, NESCOE provided its LTTP RFP 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**
- The ISO issued the RFP on 3/31/25, with proposals due by 9/30/25
- The ISO is evaluating all submissions and expects to provide a high-level summary of all Longer-Term Proposals at the 11/19/25 PAC

* 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

2025 Longer-Term Transmission Planning (LTTP) RFP, cont.

- Total of 6 Longer-Term Proposals submitted
  - 4 are joint proposals
- Total of 4 different lead QTPSs (3 non-incumbents, 1 incumbent)
  - 4 additional QTPSs are participating as part of joint proposals (all are incumbents)
- Project Designs
  - 3 primarily AC transmission
  - 3 primarily HVDC transmission
  - All designs claim they support 1200 MW of northern ME wind
  - Claimed Surowiec-South Limits: 3200-3800 MW (3200 MW target)
  - Claimed Maine-New Hampshire Limits: 3000-3600 MW (3000 MW target)
- Project Installed Costs*
  - Low of $0.96B
  - High of $4.04B
- In-Service Dates: Q4 2032 to Q3 2035 (12/31/2035 target)

* Costs may include estimates for corollary upgrades

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 report and factsheet were issued in September
    - There was also a public webinar in 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.

SEMA/RI Reliability Projects

Status as of 10/27/2025

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 10/27/2025

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	Jun-28	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 10/27/2025

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 10/27/2025

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 10/27/2025

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

Upper Maine Solution Projects

Status as of 10/27/2025

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 10/27/2025

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

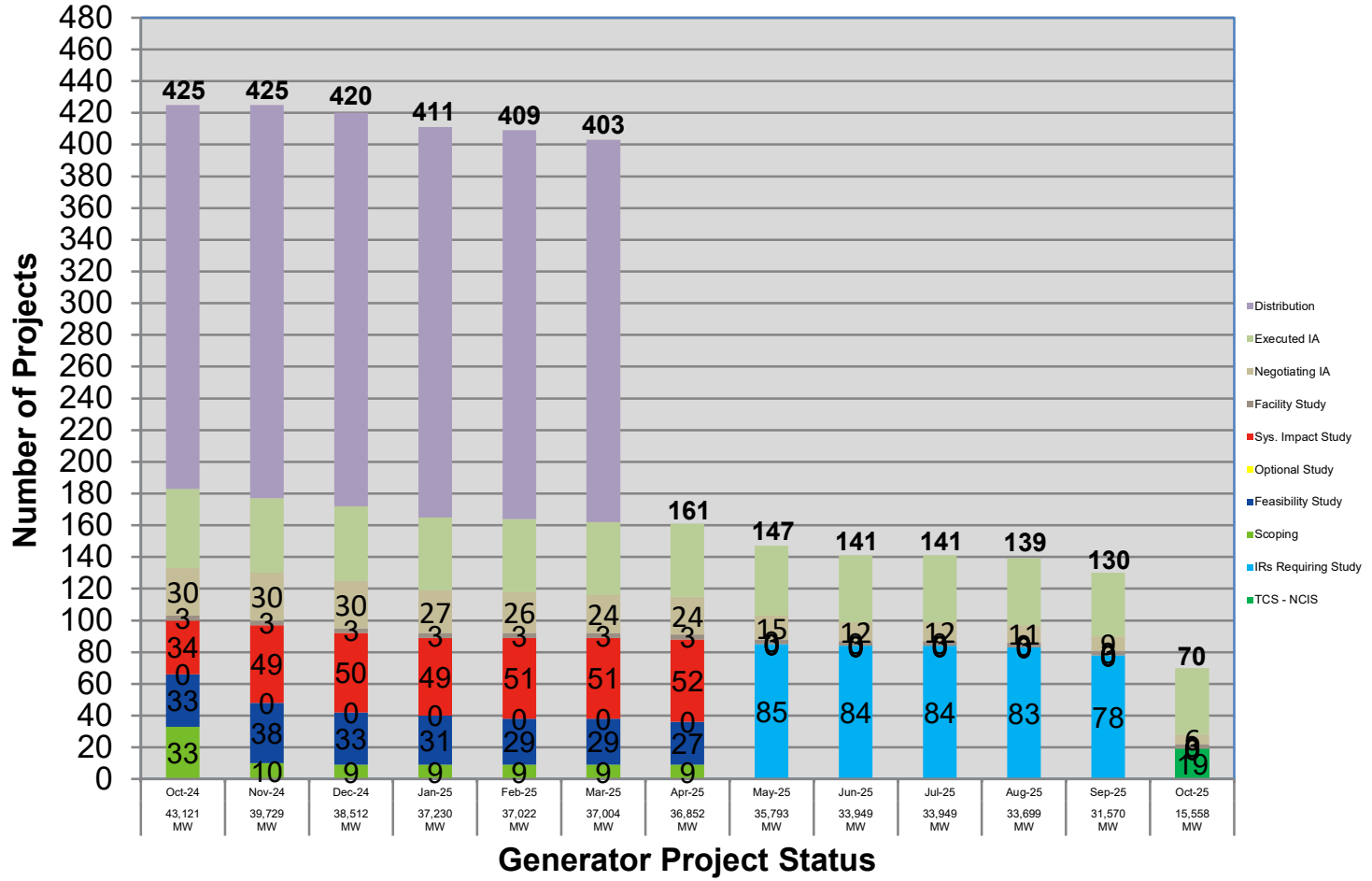
Boston 2033 Solutions Study

Status as of 10/27/2025

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)	May-26	1

Status of Tariff Studies as of October 28, 2025



ETUs: 0 in TCS – NCIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 4 with Executed IA
Transmission Service Requests needing study: 0
https://irtt.iso-ne.com/external.aspx

Additional Notes provided on next slide

Status of Tariff Studies as of October 28, 2025, cont.

Additional Notes:

- *As of April 2025, the ISO is no longer tracking Distribution Projects in its interconnection queue.*
- *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.*
- *The "TCS – NCIS" category represents projects that did not complete a system impact study before April 4, 2025 and require study in the Transitional Cluster Study (TCS) according to the Network Capability Interconnection Standard (NCIS). Such projects may also be studied in the TCS according to the Capacity Capability Interconnection Standard (CCIS). There are additional projects in the TCS that are seeking to augment their Network Resource Interconnection Service (NRIS) to Capacity Network Resource Interconnection Service (CNRIS) (and thus will only be studied in the TCS according to the CCIS), but are included in the Executed IA/Negotiating IA totals.*

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

Fall 2025 Analysis

Fall 2025 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov - 2025[2] CSO (MW)	Nov - 2025[2] SCC (MW)
Operable Capacity MW [1]	26,436	29,806
Active Demand Capacity Resource (+) [5]	340	305
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,198	1,198
Non Commercial Capacity (+)	189	189
Non Gas-fired Planned Outage MW (-)	1,242	2,486
Gas Generator Outages MW (-)	2,796	3,562
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)	20,525	21,850
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,233	18,233
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,358	20,358
Operable Capacity Margin	167	1,492

[1]Operable Capacity is based on data as of **October 23, 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 **October 23, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 15, 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.

Fall 2025 Operable Capacity Analysis

90/10 Load Forecast	Nov - 2025[2] CSO (MW)	Nov - 2025[2] SCC (MW)
Operable Capacity MW [1]	26,436	29,806
Active Demand Capacity Resource (+) [5]	340	305
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,198	1,198
Non Commercial Capacity (+)	189	189
Non Gas-fired Planned Outage MW (-)	1,242	2,486
Gas Generator Outages MW (-)	2,796	3,562
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)	20,525	21,850
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,205	19,205
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,330	21,330
Operable Capacity Margin	-805	520

[1]Operable Capacity is based on data as of **October 23, 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 **October 23, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 15, 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.

Fall 2025 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 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 November.

FALSE

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
11/8/2025	26436	340	1198	189	1417	3079	3600	0	20067	17567	2125	19692	375	N	Fall 2025
11/15/2025	26436	340	1198	189	1242	2796	3600	0	20525	18233	2125	20358	167	Y	Fall 2025
11/22/2025	26436	340	1198	189	593	1917	3600	0	22053	18883	2125	21008	1045	N	Fall 2025

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 participate 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 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).

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 2025 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 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 November.

Report created: 10/23/2025

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
11/8/2025	26436	340	1198	189	1417	3079	3600	0	20067	18504	2125	20629	-562	N	Fall 2025
11/15/2025	26436	340	1198	189	1242	2796	3600	0	20525	19205	2125	21330	-805	Y	Fall 2025
11/22/2025	26436	340	1198	189	601	1370	3600	1206	21386	19890	2125	22015	-629	N	Fall 2025

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 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).
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**

OPERABLE CAPACITY ANALYSIS

Winter 2025/26 Analysis

Winter 2025/26 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan - 2026[2] CSO (MW)	Jan - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,390	29,806
Active Demand Capacity Resource (+) [5]	403	305
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	568	568
Non Gas-fired Planned Outage MW (-)	43	1,171
Gas Generator Outages MW (-)	0	33
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,583	3,936
Net Capacity (NET OPCAP SUPPLY MW)	22,170	23,974
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,056	20,056
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,181	22,181
Operable Capacity Margin	-11	1,793

[1]Operable Capacity is based on data as of **October 23, 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 **October 23, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 10, 2026.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2025/26 Operable Capacity Analysis

90/10 Load Forecast	Jan - 2026[2] CSO (MW)	Jan - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,390	29,806
Active Demand Capacity Resource (+) [5]	403	305
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	568	568
Non Gas-fired Planned Outage MW (-)	43	1,171
Gas Generator Outages MW (-)	0	33
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,331	4,795
Net Capacity (NET OPCAP SUPPLY MW)	21,422	23,115
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,125	21,125
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,250	23,250
Operable Capacity Margin	-1,828	-135

[1]Operable Capacity is based on data as of **October 23, 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 **October 23, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 10, 2026.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2025/26 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 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 December through March.

FALSE

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
11/29/2025	26640	403	1235	318	601	1108	3200	507	23180	19063	2125	21188	1992	N	Winter 2025/2026
12/6/2025	26640	403	1235	318	84	608	3200	1760	22944	19324	2125	21449	1495	N	Winter 2025/2026
12/13/2025	26640	403	1235	318	55	0	3200	2745	22596	19334	2125	21459	1137	N	Winter 2025/2026
12/20/2025	26640	403	1235	318	45	0	3200	3134	22217	19390	2125	21515	702	N	Winter 2025/2026
12/27/2025	26640	403	1235	318	45	0	3200	3733	21618	19390	2125	21515	103	N	Winter 2025/2026
1/3/2026	26390	403	1235	568	22	0	2800	3728	22046	19637	2125	21762	284	N	Winter 2025/2026
1/10/2026	26390	403	1235	568	43	0	2800	3583	22170	20056	2125	22181	-11	Y	Winter 2025/2026
1/17/2026	26390	403	1235	568	116	0	2800	3134	22546	20056	2125	22181	365	N	Winter 2025/2026
1/24/2026	26390	403	1235	568	49	0	2800	2835	22912	20056	2125	22181	731	N	Winter 2025/2026
1/31/2026	26390	403	1235	568	23	0	3100	2536	22937	19855	2125	21980	957	N	Winter 2025/2026
2/7/2026	26390	403	1235	568	20	0	3100	2237	23239	19615	2125	21740	1499	N	Winter 2025/2026
2/14/2026	26390	403	1235	568	20	0	3100	1788	23688	19589	2125	21714	1974	N	Winter 2025/2026
2/21/2026	26390	403	1235	568	56	0	3100	1489	23951	19352	2125	21477	2474	N	Winter 2025/2026
2/28/2026	26390	403	1235	568	203	167	2200	247	25779	18461	2125	20586	5193	N	Winter 2025/2026
3/7/2026	26390	403	1235	568	184	413	2200	0	25799	18147	2125	20272	5527	N	Winter 2025/2026
3/14/2026	26390	403	1235	568	174	594	2200	0	25628	17970	2125	20095	5533	N	Winter 2025/2026
3/21/2026	26390	403	1235	568	236	594	2200	0	25566	17641	2125	19766	5800	N	Winter 2025/2026
3/28/2026	26233	404	1235	568	262	1002	2700	0	24476	17132	2125	19257	5219	N	Winter 2025/2026

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
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3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

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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 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).

11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.

12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)

13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

14. Operable Capacity Season Label: Applicable season and year.

15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2025/26 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 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 December through March.

Report created: 10/23/2025

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
11/29/2025	26640	403	1235	318	601	1108	3200	1684	22003	20080	2125	22205	-202	N	Winter 2025/2026
12/6/2025	26640	403	1235	318	84	608	3200	2747	21957	20354	2125	22479	-522	N	Winter 2025/2026
12/13/2025	26640	403	1235	318	55	0	3200	3864	21477	20365	2125	22490	-1013	N	Winter 2025/2026
12/20/2025	26640	403	1235	318	45	0	3200	4280	21071	20424	2125	22549	-1478	N	Winter 2025/2026
12/27/2025	26640	403	1235	318	45	0	3200	4408	20943	20424	2125	22549	-1606	N	Winter 2025/2026
1/3/2026	26390	403	1235	568	22	0	2800	4539	21235	20684	2125	22809	-1574	N	Winter 2025/2026
1/10/2026	26390	403	1235	568	43	0	2800	4331	21422	21125	2125	23250	-1828	Y	Winter 2025/2026
1/17/2026	26390	403	1235	568	116	0	2800	4032	21648	21125	2125	23250	-1602	N	Winter 2025/2026
1/24/2026	26390	403	1235	568	49	0	2800	4032	21715	21125	2125	23250	-1535	N	Winter 2025/2026
1/31/2026	26390	403	1235	568	23	0	3100	3583	21890	20914	2125	23039	-1149	N	Winter 2025/2026
2/7/2026	26390	403	1235	568	20	0	3100	3284	22192	20661	2125	22786	-594	N	Winter 2025/2026
2/14/2026	26390	403	1235	568	20	0	3100	2686	22790	20633	2125	22758	32	N	Winter 2025/2026
2/21/2026	26390	403	1235	568	56	0	3100	2237	23203	20384	2125	22509	694	N	Winter 2025/2026
2/28/2026	26390	403	1235	568	203	167	2200	1144	24882	19446	2125	21571	3311	N	Winter 2025/2026
3/7/2026	26390	403	1235	568	185	167	2200	1039	25005	19114	2125	21239	3766	N	Winter 2025/2026
3/14/2026	26390	403	1235	568	174	594	2200	0	25628	18928	2125	21053	4575	N	Winter 2025/2026
3/21/2026	26390	403	1235	568	236	594	2200	0	25566	18582	2125	20707	4859	N	Winter 2025/2026
3/28/2026	26233	404	1235	568	262	1002	2700	0	24476	18045	2125	20170	4306	N	Winter 2025/2026

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.
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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 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).
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**

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