



NEPOOL Participants Committee

System & Market Operations Report – October 2026

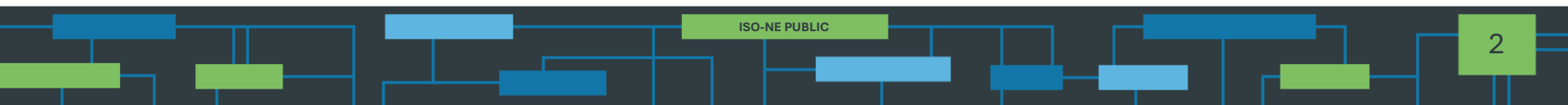
Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



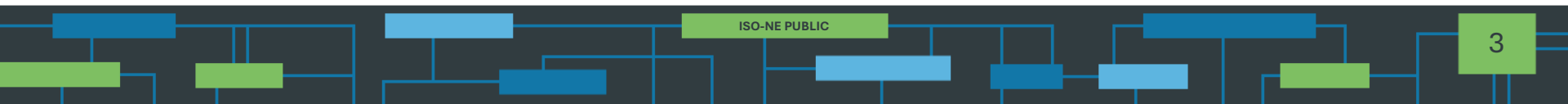
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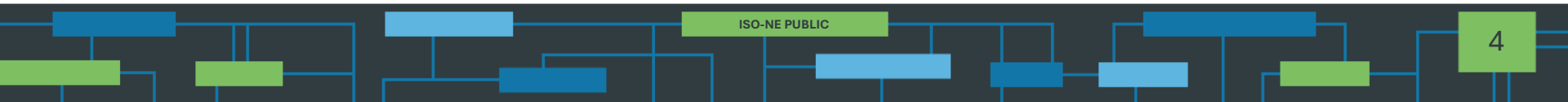


System & Market Operations Report Enhancements

- This month's report carries forward several clarity and usability improvements first introduced in the [June 2026 System & Market Operations Report](#) (see slide 7 of the June report for a summary)
- A “Key Takeaways” slide has been added as part of this month's report (see slide 5)
- To streamline the report, several slides are now marked with footnotes noting that they will be removed in future reports since the information is part of ISO's routine reporting and is readily available elsewhere; in addition to the slides previously noted, these slides to be removed in future reports now also include:
 - Slide 34, DA vs. RT LMPs (\$/MWh)
 - Slide 44, Average Hourly DAAS Prices
 - Slide 45, Average Hourly DAAS Offered
- Further enhancements are planned in the coming months to continue simplifying and improving the report



HIGHLIGHTS



System & Market Operations Report

September Key Takeaways

- A strong nor'easter affected the region from Sept. 24–28 but had minimal impact on the transmission system (see slide no. 8)
- September peak demand (RQM) was ~8% higher than in September 2025 and ~23% lower than in August 2026 (see slide no. 9)
- September total market value (\$) was ~17% higher than in September 2025 and ~30% lower than in August 2026 (see slide no. 10)
- Regional wind generation continues to reach new highs: offshore output peaked at ~1,100 MW on Sept. 24, while combined onshore and offshore output peaked at ~2,000 MW on Sept. 27
- As expected, several significant transmission and generation outages are scheduled in the coming months (see slide no. 23 for a summary of transmission outages)
- ISO has begun its routine winter preparations and will present its Winter Outlook at the November Participants Committee meeting

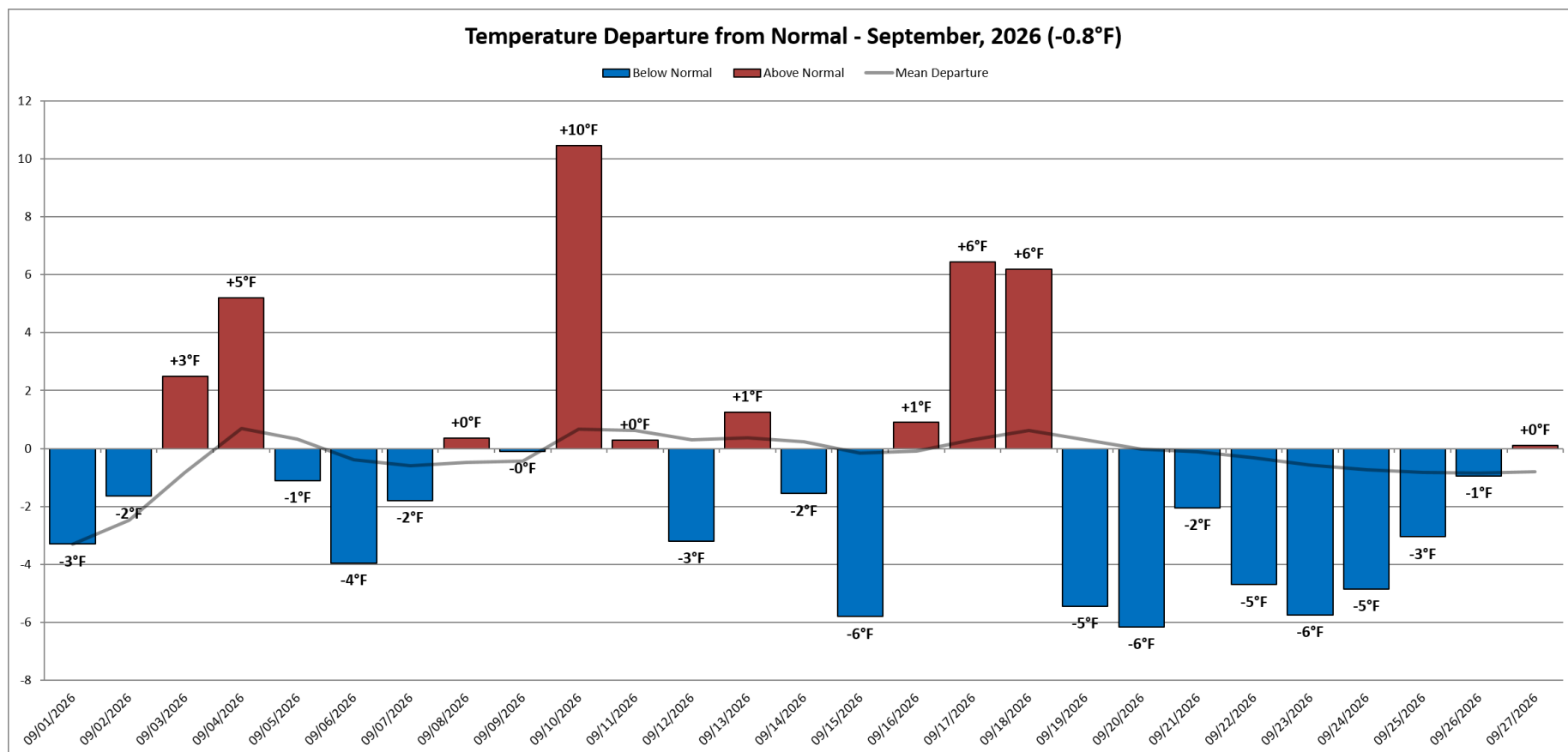
Weather At-a-Glance

*Data Through September 27, 2026**

<i>New England Weather</i>	Sep 2026	Change M-O-M	Change Y-O-Y
Avg Hourly Temperature (°F) <i>(23-City Weighted)</i>	63.1°	-8.8° ↓	-0.8° ↓
<i>Boston Weather</i>			
Temperature Departure from Normal (°F)	-1.1°	-3.6° ↓	-2.0° ↓
Maximum Temperature (°F)	87.0°	-7.0° ↓	1.0° ↑
Minimum Temperature (°F)	49.0°	-13.0° ↓	-2.0° ↓
Avg Hourly Temperature (°F)	65.1°	-10.1° ↓	-1.4° ↓
Precipitation Departure from Normal (inches)	1.17"	3.42" ↑	1.64" ↑
Precipitation (inches)	4.34"	3.36" ↑	1.25" ↑
<i>Hartford Weather</i>			
Temperature Departure from Normal (°F)	-0.9°	-1.6° ↓	-1.7° ↓
Maximum Temperature(°F)	87.0°	-5.0° ↓	1.0° ↑
Minimum Temperature(°F)	43.0°	-12.0° ↓	0.0° —
Avg Hourly Temperature (°F)	64.4°	-8.8° ↓	-1.3° ↓
Precipitation Departure from Normal (inches)	0.59"	-0.01" ↓	1.58" ↑
Precipitation (inches)	4.48"	-0.33" ↓	1.08" ↑

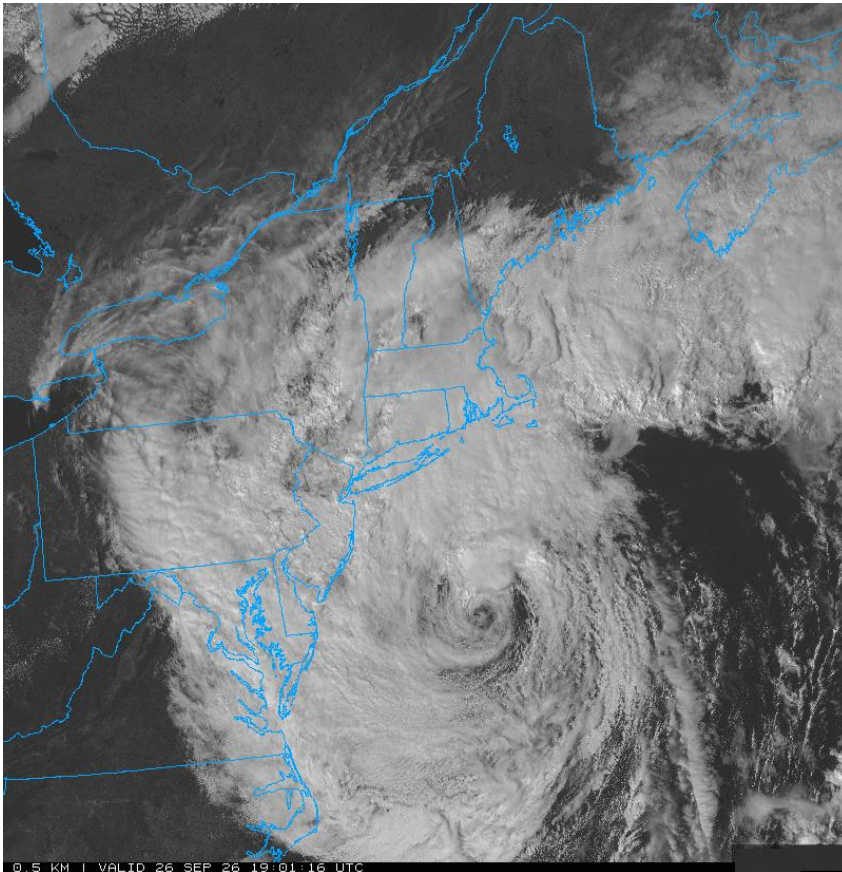
Weather At-a-Glance, cont.

New England 23-City Temperature Departure From Normal – September 2026



*Data Through September 27, 2026

System Operations Highlights



- A strong nor'easter affected the region from September 24–28
- Wind gusts exceeded 70 mph in southeast New England and Long Island, while southern New England received 5–8 inches of rain
- The transmission system experienced minimal disruption, with one unplanned transmission-line outage
- Customer outages peaked at approximately 57,000

Markets At-a-Glance: Demand

Data Through September 27, 2026*

Data Through September 27, 2026*

Average Hourly Net Energy for Load (MWh)^[a]	Sep 2026	% Change M-O-M	% Change Y-O-Y
Revenue Quality Metered (RQM)	12,492	-18.4% ↓	1.9% ↑
Telemetered	11,977	-18.5% ↓	2.4% ↑

Max/Min Hourly System Load (MW)

Maximum RQM	18,669	-22.8% ↓	8.4% ↑
Maximum Telemetered	18,284	-22.9% ↓	8.8% ↑
Minimum Telemetered	7,358	-18.3% ↓	5.2% ↑

Thu, Sep 10, 2026 in HE19

Sat, Sep 19, 2026 in HE13

Year-To-Date Hourly Peak Load (MW)^[b]

RQM	25,832	0.0%	-2.9% ↓
Telemetered	25,361	0.0%	-2.5% ↓
Forward Capacity Market (FCM) Load ^[c]	25,303	0.0%	-2.6% ↓

Thu, Jul 2, 2026 in HE19

Thu, Jul 2, 2026 in HE19

Thu, Jul 2, 2026 in HE19

Other RT Load (Average Hourly MW)

Scheduled Exports	1,837	55% ↑	69% ↑
Energy Storage Load	281	-12% ↓	17% ↑

*Based on available settled days.

[a] RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SORs). Telemetered loads as monitored by the Control Room. Both are 'net energy for load' concepts and therefore include transmission losses. Neither of reflect storage load. Due to the difference in metering quality, derivation, and the impact of SORs, the RQM and Telemetered peaks can occur on different days and/or hours.

[b] Y-T-D % Change Y-O-Y is based on like periods (i.e., through similar months). Y-T-D values are available in the Weekly Market Report found on the ISO [website](#).

[c] FCM load values reflect the sum of active, normal load assets that are non-dispatchable (it excludes storage load), are included in the FCM settlement and do not reflect any transmission losses. FCM Load is Revenue Quality Metered.

Markets At-a-Glance: Payments and Prices

*Data Through September 23, 2026**

*Data Through September 27, 2026**

Market Value (\$ millions)^[a]	Sep 2026	% Change M-O-M	% Change Y-O-Y
Energy Market Value ^[b]	404	-34% ↓	26% ↑
Ancillary Services ^[c]	6	-31% ↓	26% ↑
Forward Capacity Market (FCM)	77	0%	-13% ↓
Net Commitment Period Compensation (NCPC)	1	-37% ↓	-19% ↓
Total	489	-30% ↓	17% ↑

Average Power Prices (\$/MWh)

DA Hub LMP	41.79	-20% ↓	22% ↑
DA Hub LMP Plus Forecast Energy Requirement (FER) Price	43.27	-19% ↓	20% ↑
RT Hub LMP	39.51	-27% ↓	17% ↑

Average Generation Fuel Prices (\$/MMBtu)

Natural Gas (MA Avg.)	1.78	-21% ↓	-12% ↓
Diesel	37.46	16% ↑	110% ↑
No.6 Oil	17.63	17% ↑	59% ↑

*Based on available settled days. Complete month data for Energy Market Value, Capacity Value, and LMPs are available in the Monthly Market Report published circa the 15th of the month found on the ISO [website](#).

[a] Market Value totals are converted to 'equivalent month' values before doing the comparisons to prior months.

[b] Energy Market Value includes net costs associated with satisfying the FER constraint.

[c] Ancillary Services (A/S) = Day-Ahead and Real-Time Reserves, Regulation, less Marginal Loss Revenue Fund.

Underlying natural gas data furnished by:



Markets At-a-Glance: Supply

*Data Through September 23, 2026**

*Data Through September 27, 2026**

	Sep 2026 (MWh)	% Change M-O-M	% Change Y-O-Y
Average Hourly RQM Supply^[a]			
Total RQM Supply	14,619	-13% ↓	8% ↑
Natural Gas	6,052	-28% ↓	-14% ↓
Nuclear	3,312	2% ↑	0%
Solar	648	-14% ↓	-7% ↓
Hydro	429	-27% ↓	11% ↑
Wind	887	69% ↑	150% ↑
Other ^[b]	597	-3% ↓	13% ↑
Hybrid/Solar	78	-15% ↓	-4% ↓
Oil	1	-91% ↓	-90% ↓
Batteries	31	-2% ↓	63% ↑
Demand Response Resources (DRRs)	0.1	-79% ↓	-64% ↓
Scheduled Imports	2,585	2% ↑	124% ↑
Average Hourly Behind-The-Meter (BTM) Solar^[c]	1,322	-18% ↓	-3% ↓

*Based on available settled days.

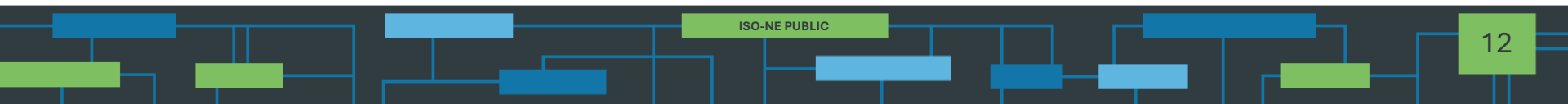
[a] Supply is RQM quality and includes both Modeled and Settlement Only Resources (SORs) and includes DRR and imports. Differs from NEL load due to not being adjusted for exports, Dispatchable Asset Related Demand (DARDs) and inadvertent tie flows.

[b] Other generation includes landfill gas, methane, wood, coal and refuse.

[c] BTM Solar is an average hourly (all hours) estimate. Historically, the majority (~2/3rd) of BTM solar is distributed solar and is not captured in RQM supply numbers.

System Planning Highlights

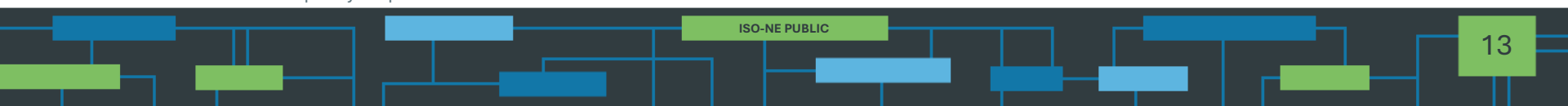
- The ISO posted the preferred Longer-Term Transmission Solution on 8/14/26
 - NESCOE had 30 days (until 9/14/26) to notify the ISO to cancel the RFP or request an alternative cost allocation. NESCOE did not pursue either option
 - The ISO notified the Qualified Transmission Project Sponsors (QTPSs) they were selected and need to execute Selected Qualified Transmission Project Sponsor Agreements within 30 days of the notification (until 10/15/26)
- CELT 2027 forecast discussions begin at the October 23 Load Forecast Committee meeting



Forward Capacity Market (FCM) Highlights

- CCP 17 (2026-2027)
 - The ISO filed the ICR and related values with FERC, for the ARA3 that was conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.
 - The third annual reconfiguration auction (ARA3) was held March 2-4, 2026. Results were posted on March 31, 2026.
- CCP 18 (2027-2028)
 - The second annual reconfiguration auction (ARA2) was held August 3-5, 2026 and results were posted on September 2, 2026.
 - The ISO presented the assumptions for the ICR and related values studies for the ARA3 at the August PSPC meeting.
 - The ISO reviewed the proposed tie benefits values for the ARA3 at the September 17, PSPC meeting.

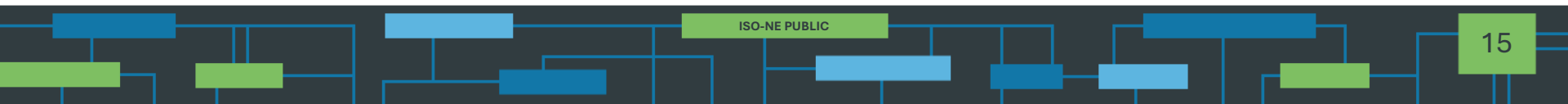
CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement



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
 - 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 completed on November 3, 2025
 - A total of 1,455 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
 - The Transitional CNR Group Study was completed with the completion of the 2025 interim RA qualification process
 - 2026 interim RA qualification process
 - The New Capacity Qualification Package (NCQP) submission window was open June 15-23, 2026
 - Qualification Determination Notifications will be issued on October 16, 2026 and Qualified Capacities will be finalized on November 2, 2026.
 - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

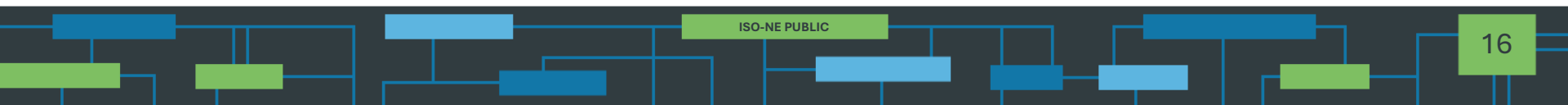
SYSTEM OPERATIONS



NPCC Simultaneous Activation of Ten-Minute Reserve Events

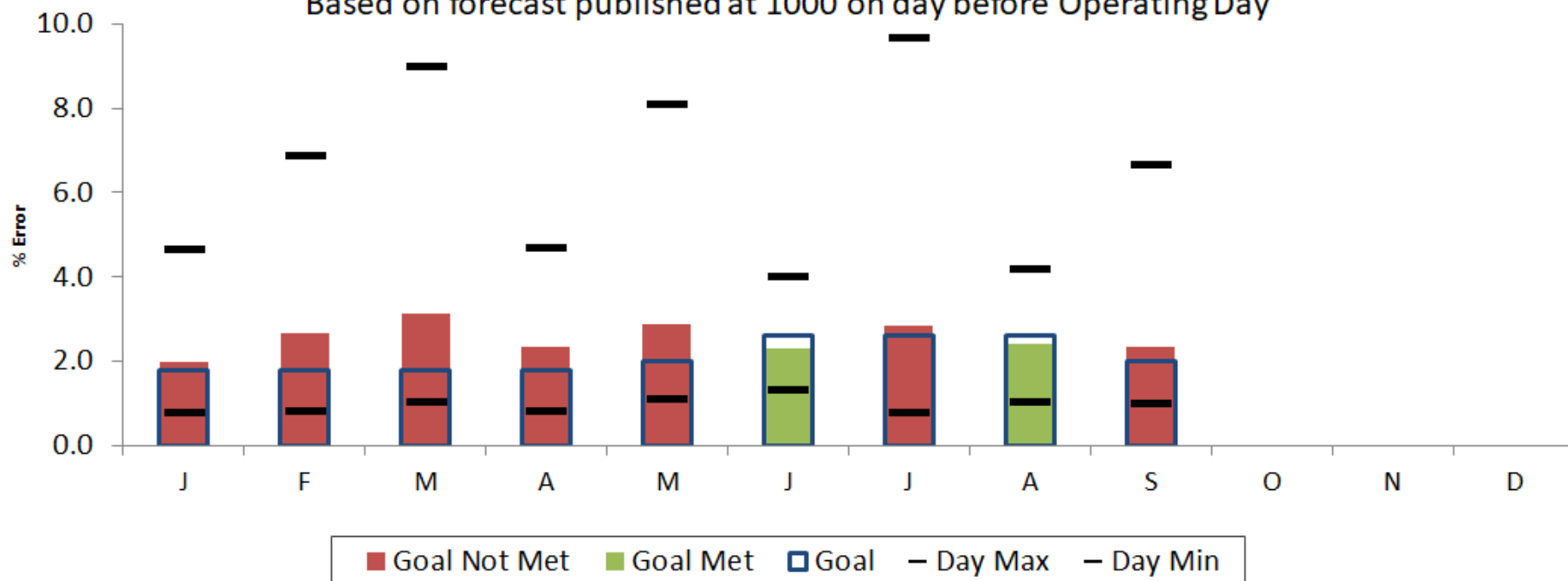
Date	Area	MW Lost
09/02/2026	NYISO	570
09/25/2026	NYISO	1250

**Data Through September 27, 2026*



2026 Load Forecast Accuracy

All Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published at 1000 on day before Operating Day

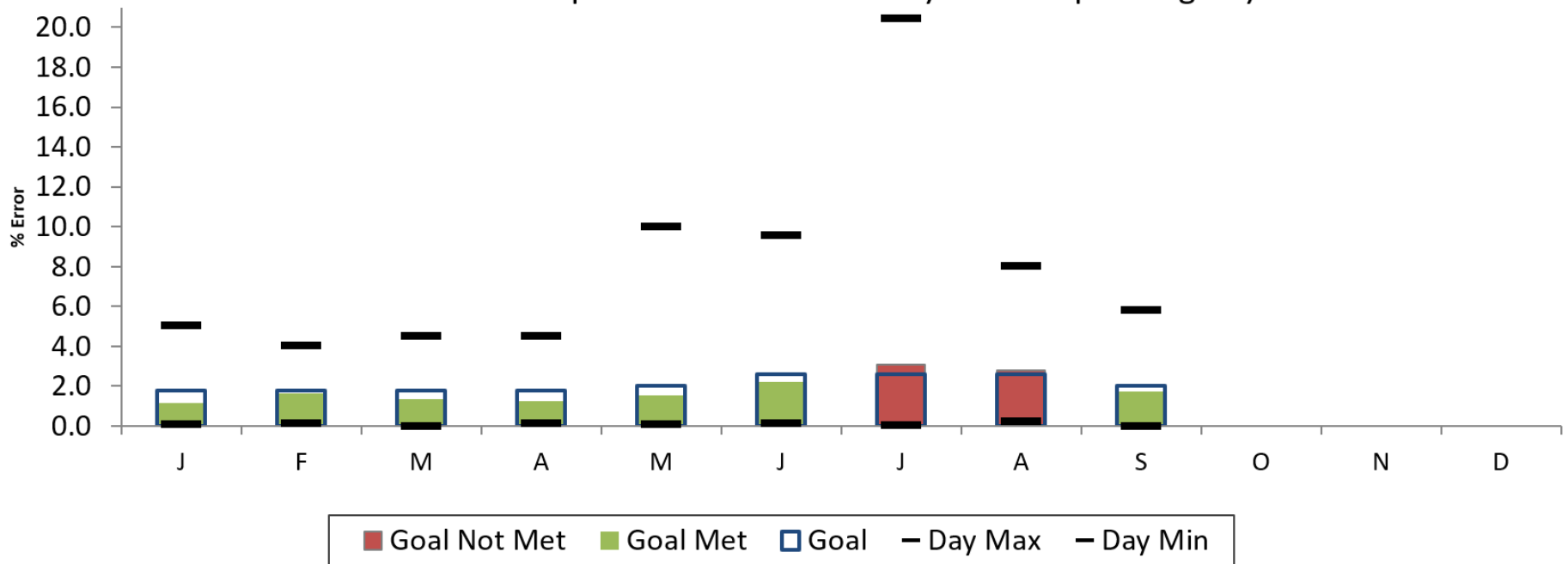


Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.65	6.85	8.96	4.67	8.09	3.99	9.64	4.19	6.64				9.64
Day Min	0.76	0.82	1.01	0.80	1.09	1.29	0.77	1.01	0.98				0.76
MAPE	2.00	2.66	3.14	2.33	2.90	2.30	2.86	2.41	2.36				2.55
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

**Data Through September 27, 2026*

2026 Load Forecast Accuracy, cont.

Peak Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published at 1000 on day before Operating Day

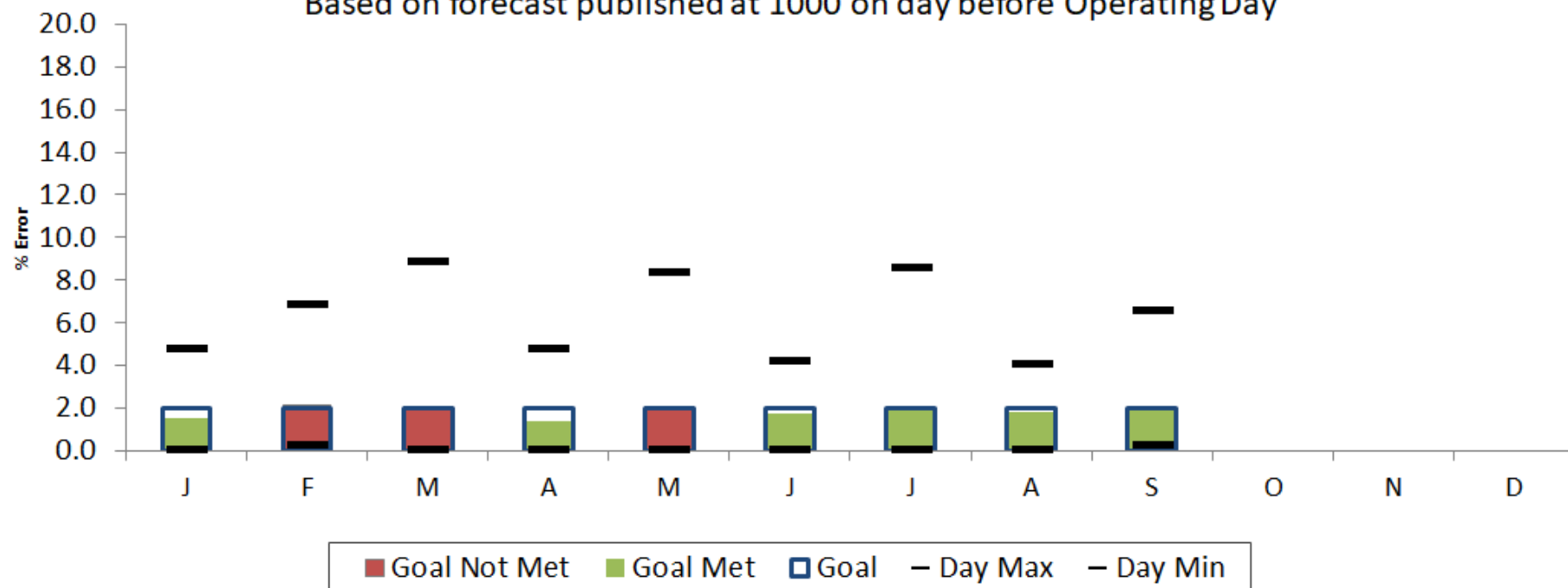


Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05	4.02	4.51	4.51	10.02	9.58	20.46	8.02	5.82				20.46
Day Min	0.08	0.12	0.01	0.16	0.11	0.14	0.03	0.24	0.01				0.01
MAPE	1.17	1.64	1.34	1.24	1.52	2.23	3.08	2.77	1.71				1.86
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

**Data Through September 27, 2026*

2026 Load Forecast Accuracy, cont.

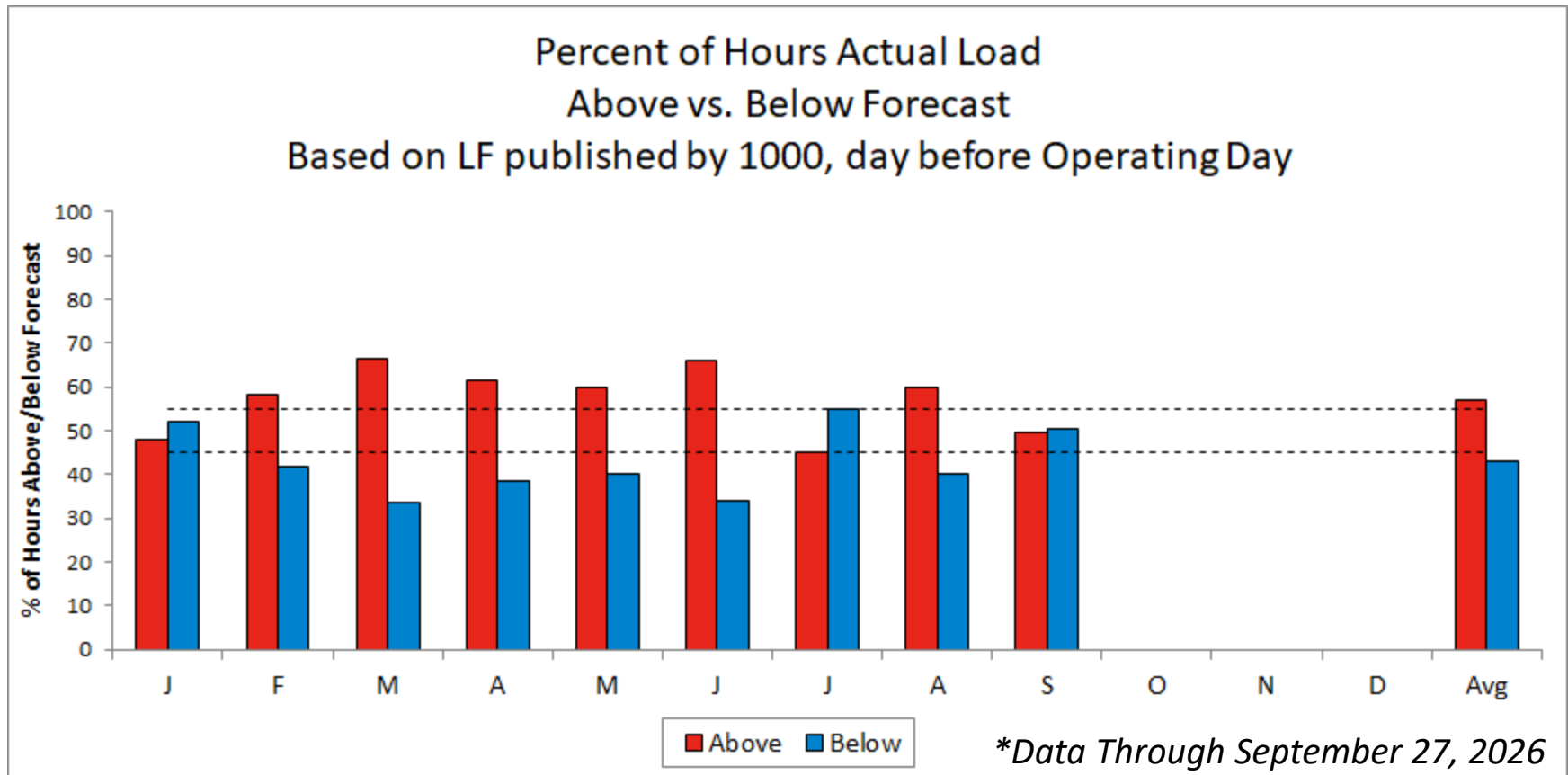
Daily Energy
Monthly Average, Daily Maximum and Minimum,
Based on forecast published at 1000 on day before Operating Day



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74	6.81	8.85	4.75	8.32	4.17	8.54	4.03	6.57				8.85
Day Min	0.01	0.22	0.03	0.00	0.06	0.07	0.03	0.05	0.24				0.00
MAPE	1.57	2.12	2.11	1.42	2.06	1.75	1.94	1.82	1.93				1.86
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00				

**Data Through September 27, 2026*

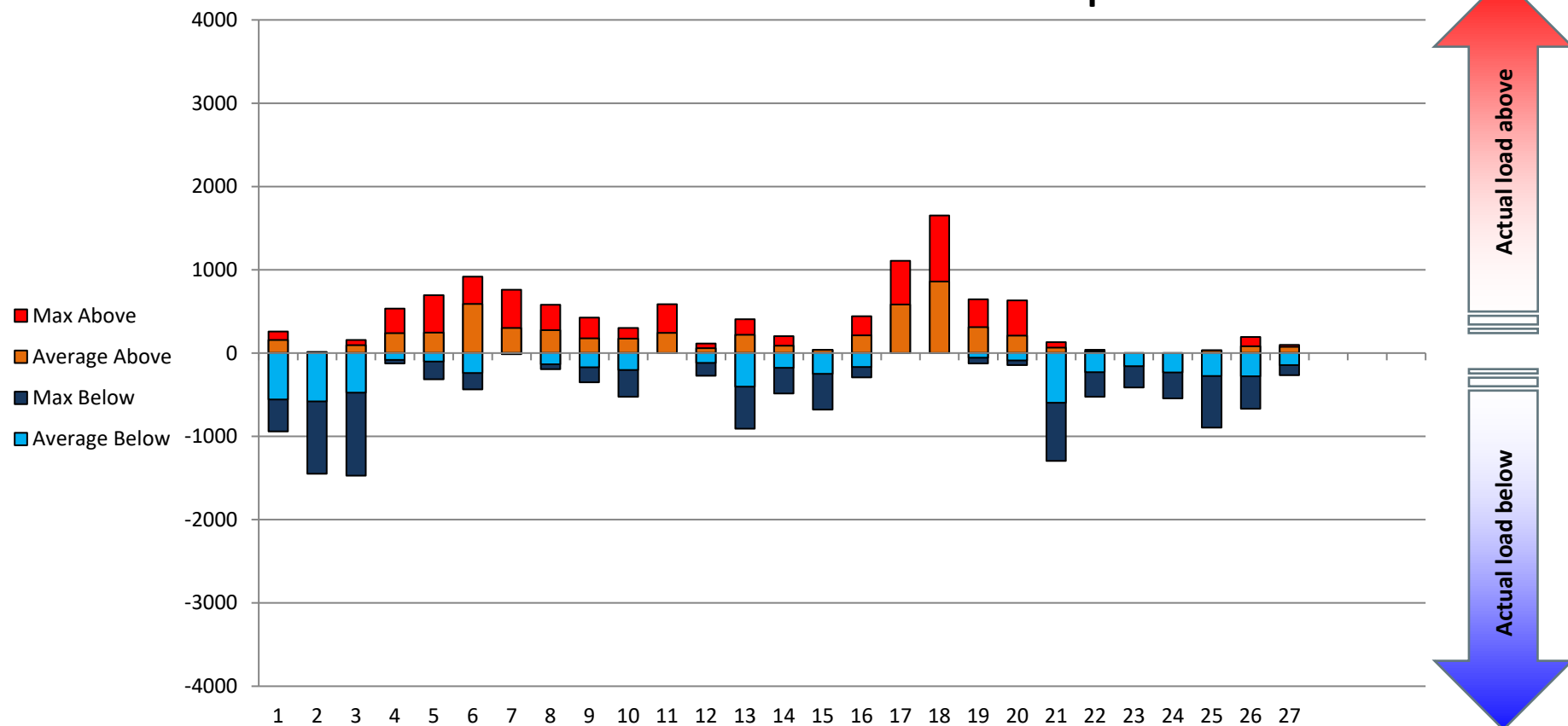
2026 Load Forecast Accuracy, cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	47.8	58.2	66.4	61.4	59.7	66.1	44.9	59.9	49.5				57
Below %	52.2	41.8	33.6	38.6	40.3	33.9	55.1	40.1	50.5				43
Avg Above	203	299.6	325	240.4	296.5	304	259.1	298.3	178.7				325
Avg Below	-233.3	-271.5	-290.0	-157.2	-194.4	-160.0	-432.7	-256.5	-194.6				-433
Avg All	-20	59	130	91	106	138	-139	51	4				46

2026 Load Forecast Accuracy, cont.

Deviation of Actual Load from Forecasted Load September 2026



**Data Through September 27, 2026*

Wind and Solar Power Forecast Error Statistics

- Beginning with the [April 2026 System & Market Operations Report](#), ISO included links to wind and solar forecast error statistics
- Solar forecast error statistics are for front-of-meter solar resources only
- These statistics are updated monthly and published on the ISO-NE external website
- [Wind Generation Forecast Error Statistics](#)
- [Solar Power Forecast Error Statistics](#)

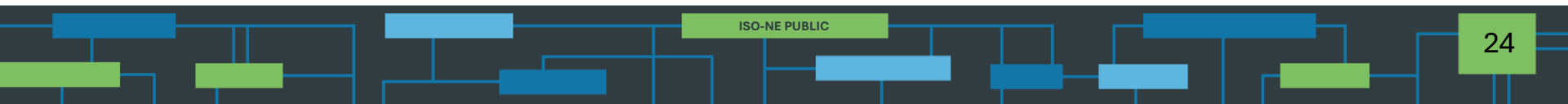
Notable Planned Transmission Outages

- The table below highlights select longer-duration planned outages that impact transfer capability; it is not a comprehensive list of all outages

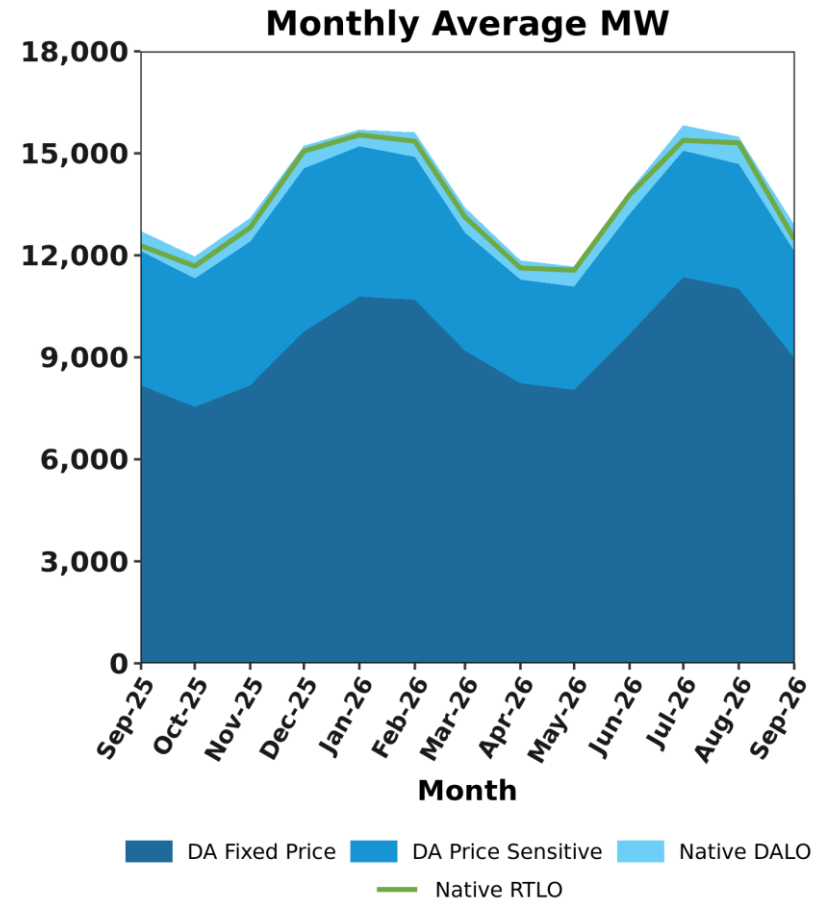
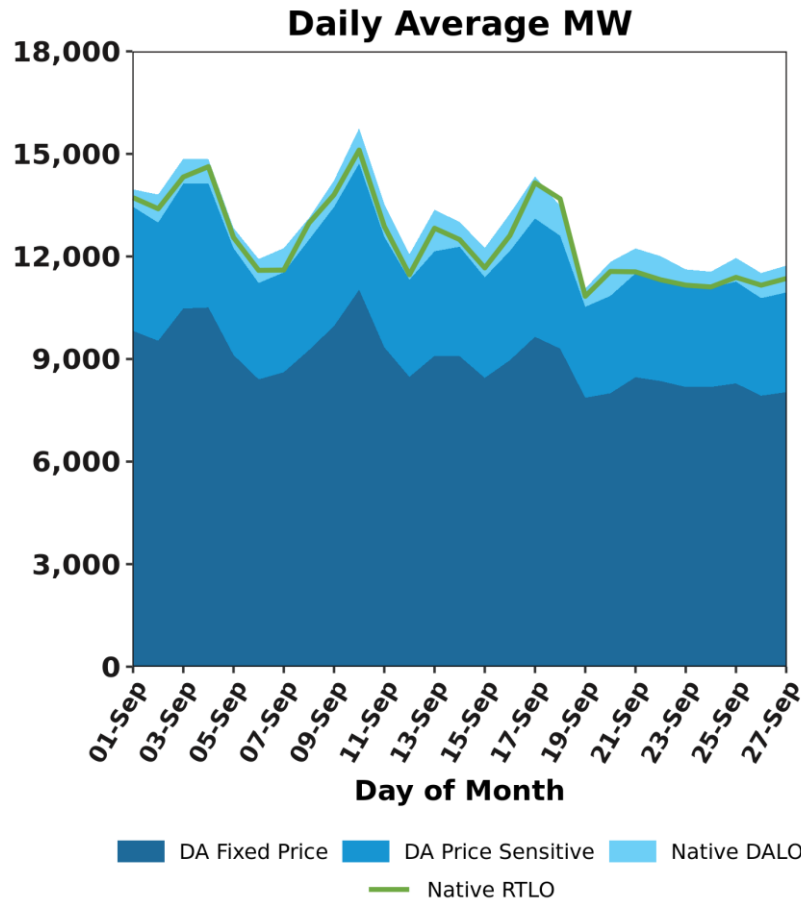
Outage	Start	Planned End	Total Transfer Capability (TTC) Impacts
Phase 2	10-7-2026	11-02-2026	Phase 2 = 0 MW in both directions
Cross Sound Cable	10-19-2026	10-31-2026	CSC = 0 MW in both directions
NECEC	11-05-2026	11-17-2026	TTC = 0 MW
390/3016	11-16-2026	11-20-2026	New Brunswick-New England = 575 MW New England-New Brunswick = 0 MW
393	11-17-2026	11-19-2026	New York – New England = 800 MW New England – New York = 600 MW NNC = 0 MW in both directions
398	11-21-2026	11-24-2026	New York – New England = 1000 MW New England – New York = 600 MW NNC = 60 MW in both directions Phase 2 – New England = 1400 MW

MARKET OPERATIONS

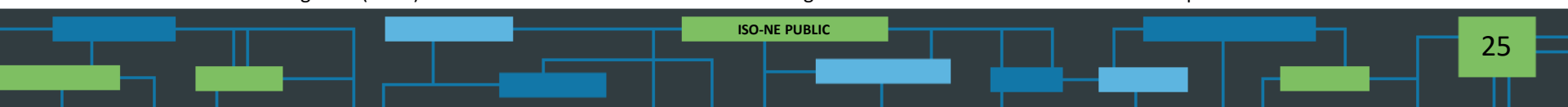
Supply and Demand Volumes



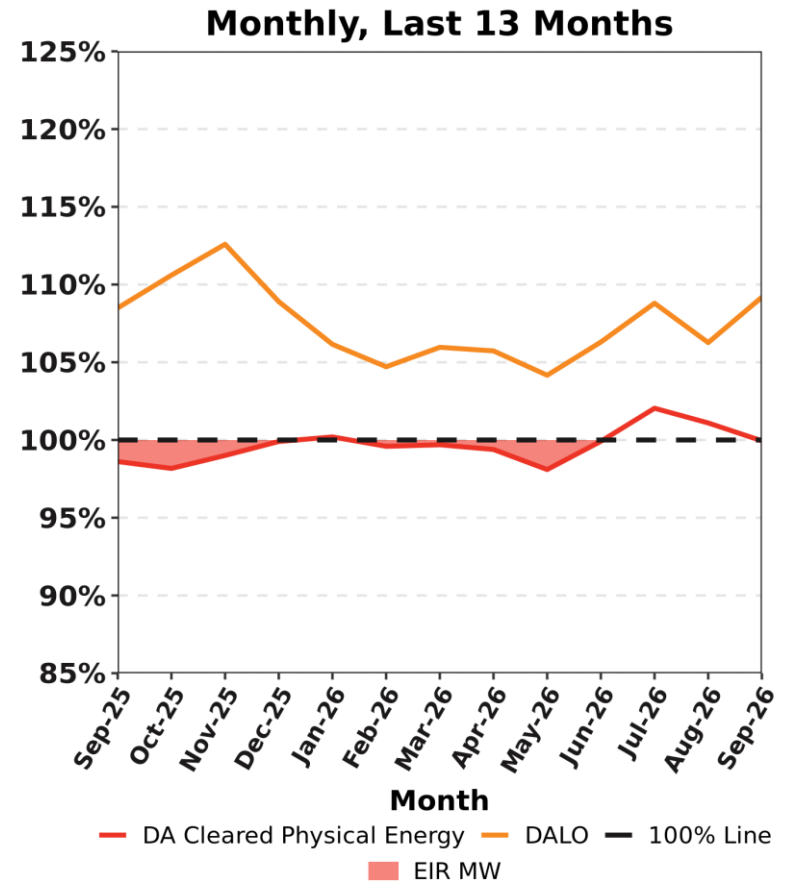
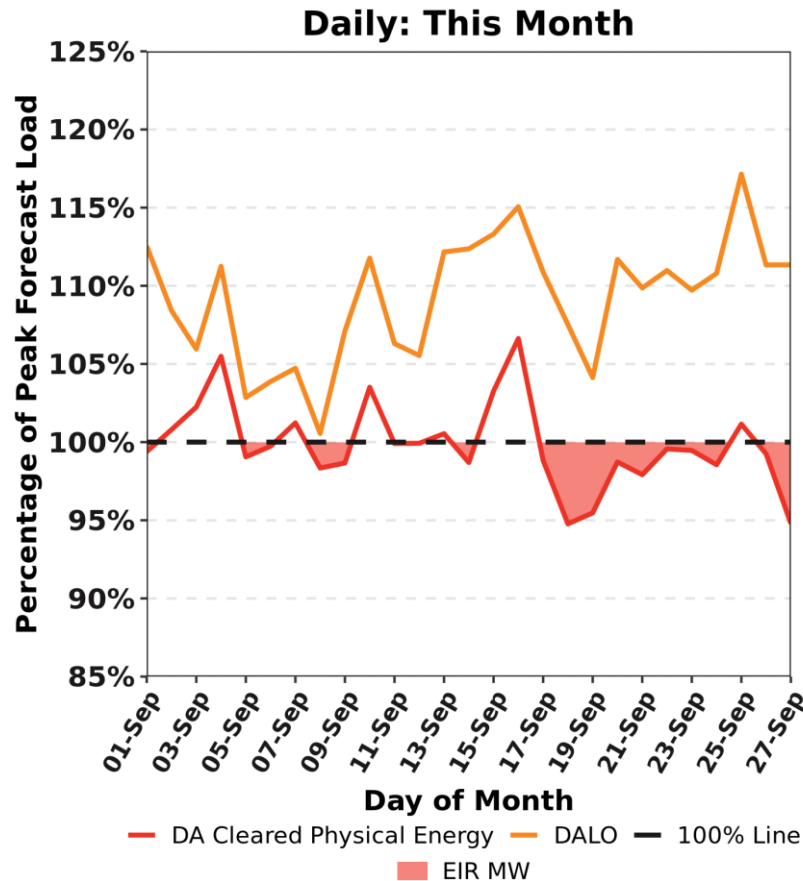
DA Cleared Native Load by Composition Compared to Native RT Load



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.

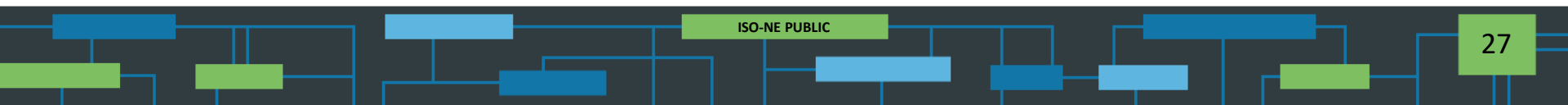
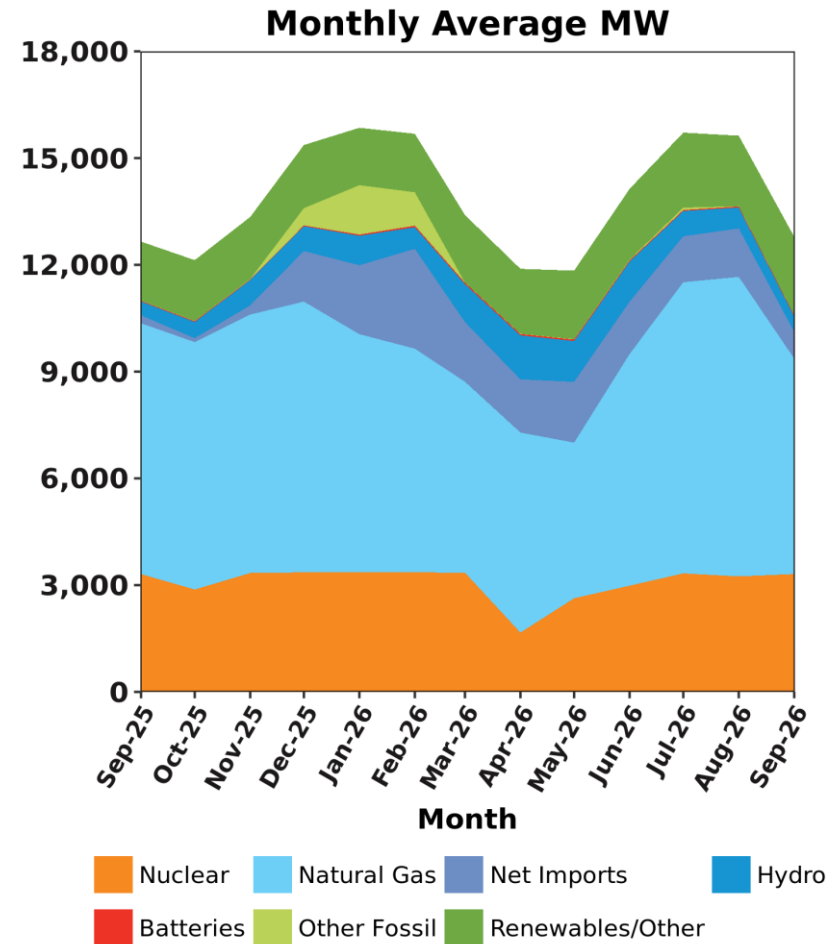
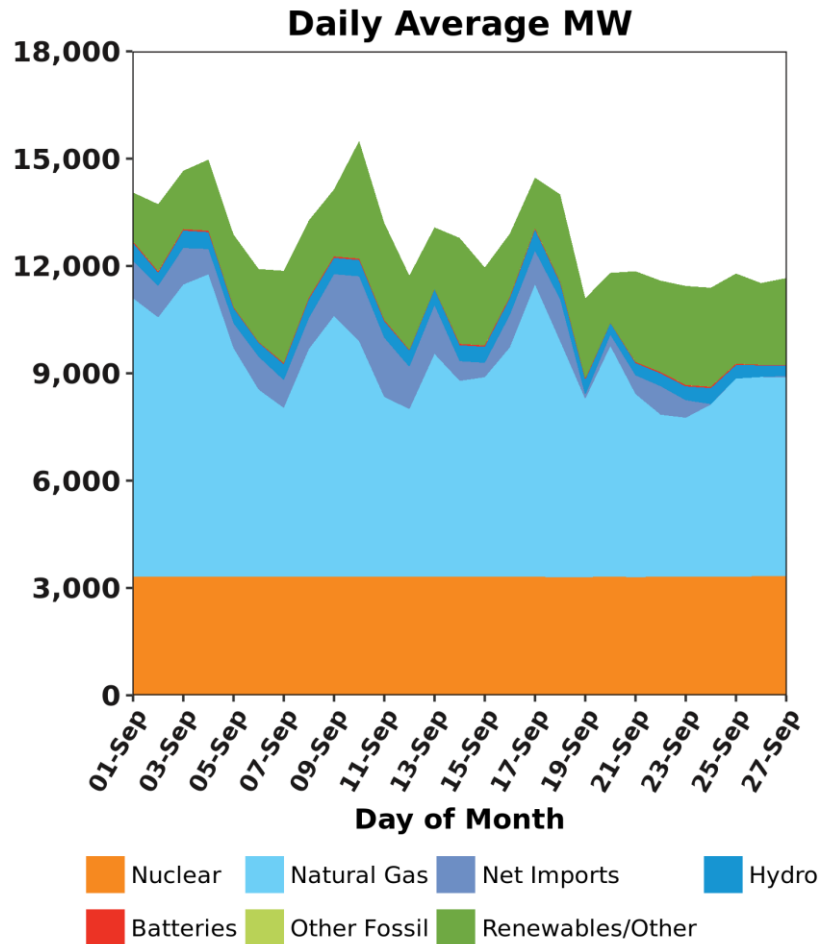


DA Volumes as % of Forecast in Peak Hour

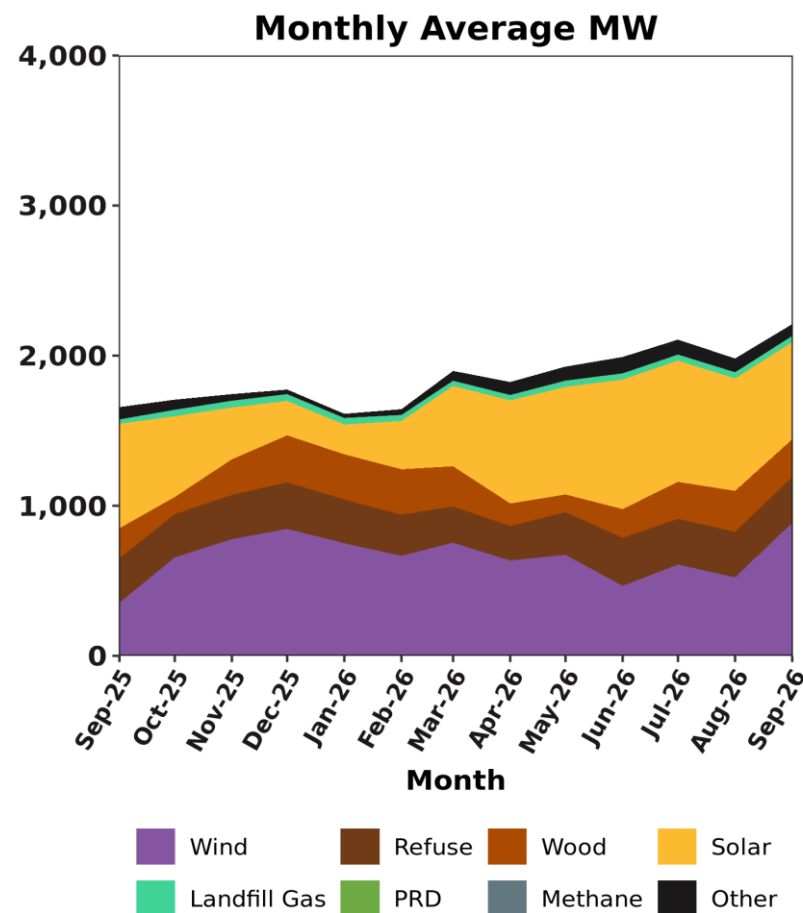
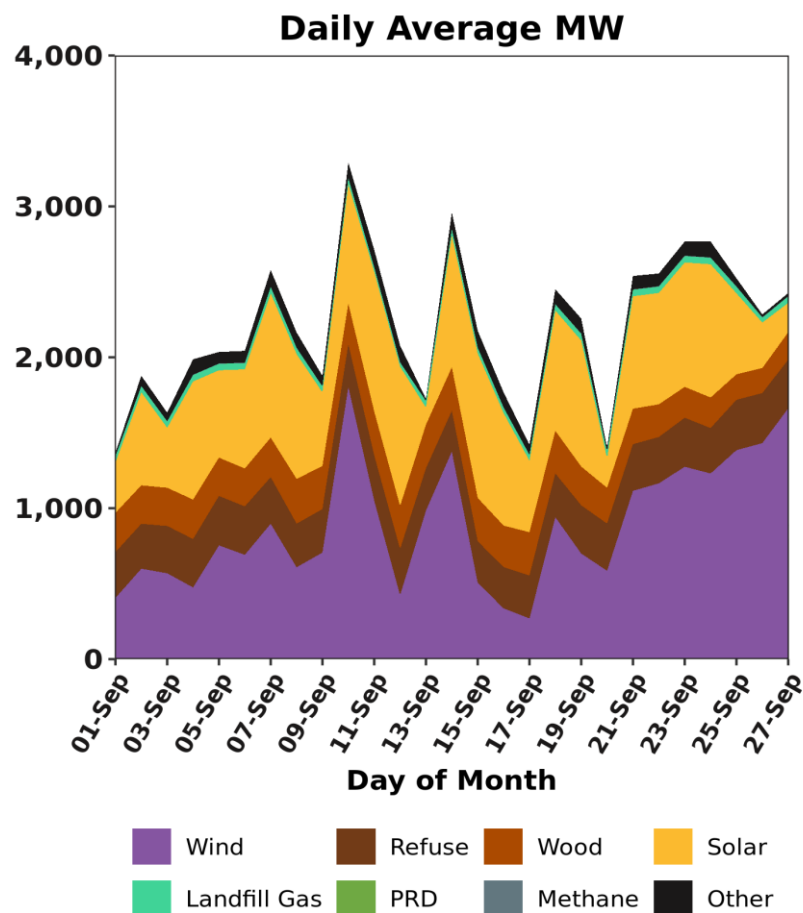


*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

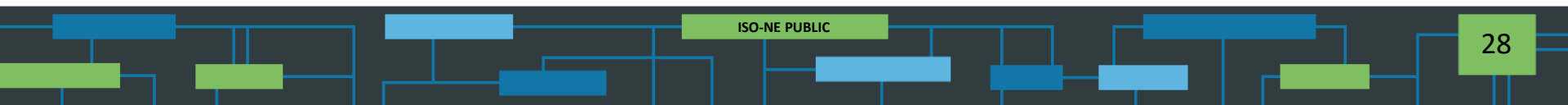
Resource Mix



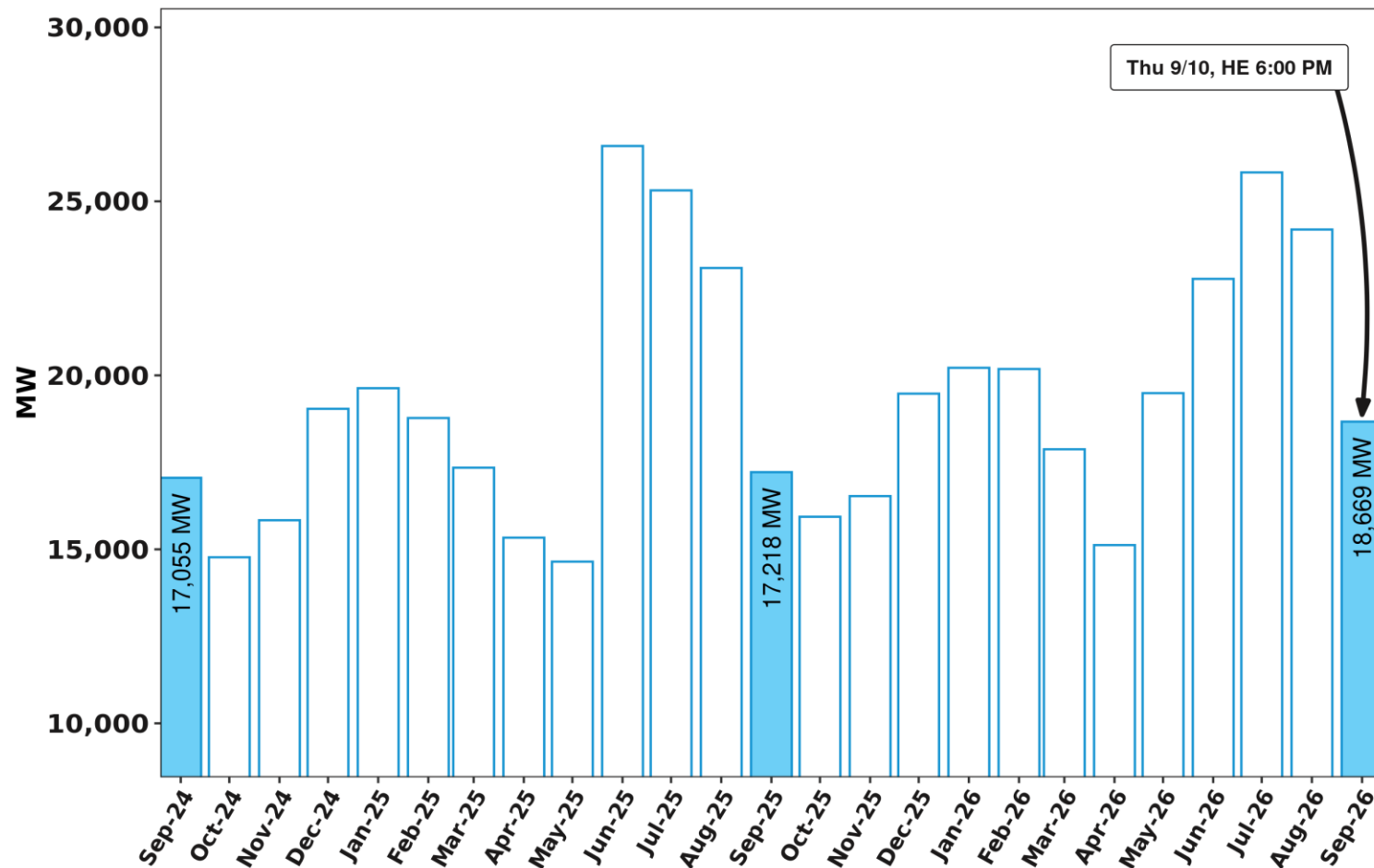
Renewable/Other Generation by Fuel Type



“Other” currently only contains Hybrid Solar/Battery; PRD=Demand Response Resources (DRR)

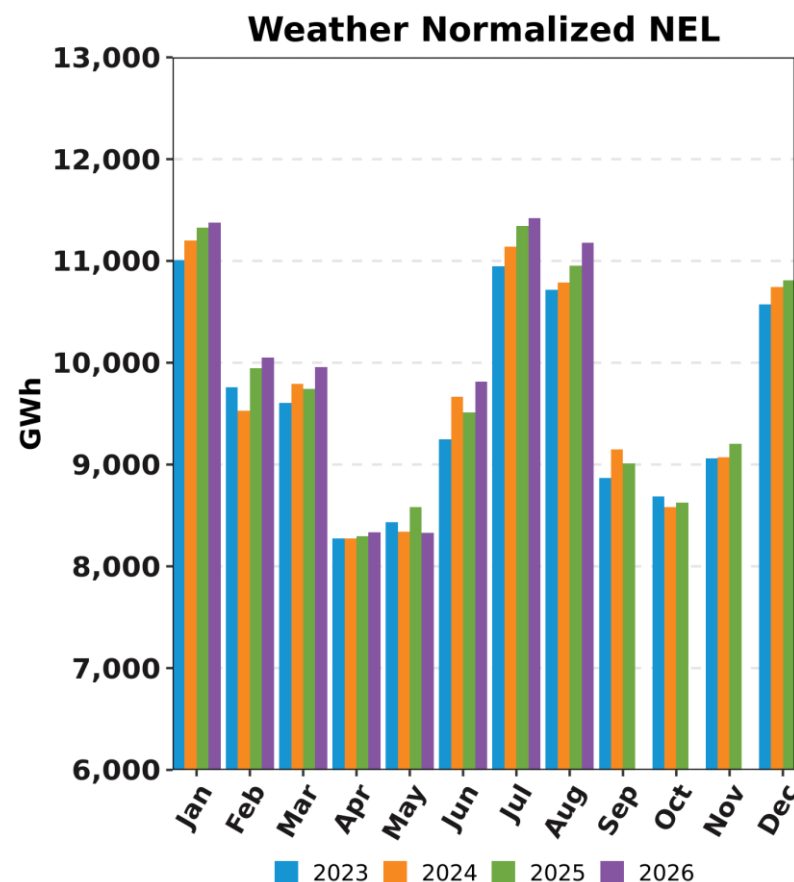
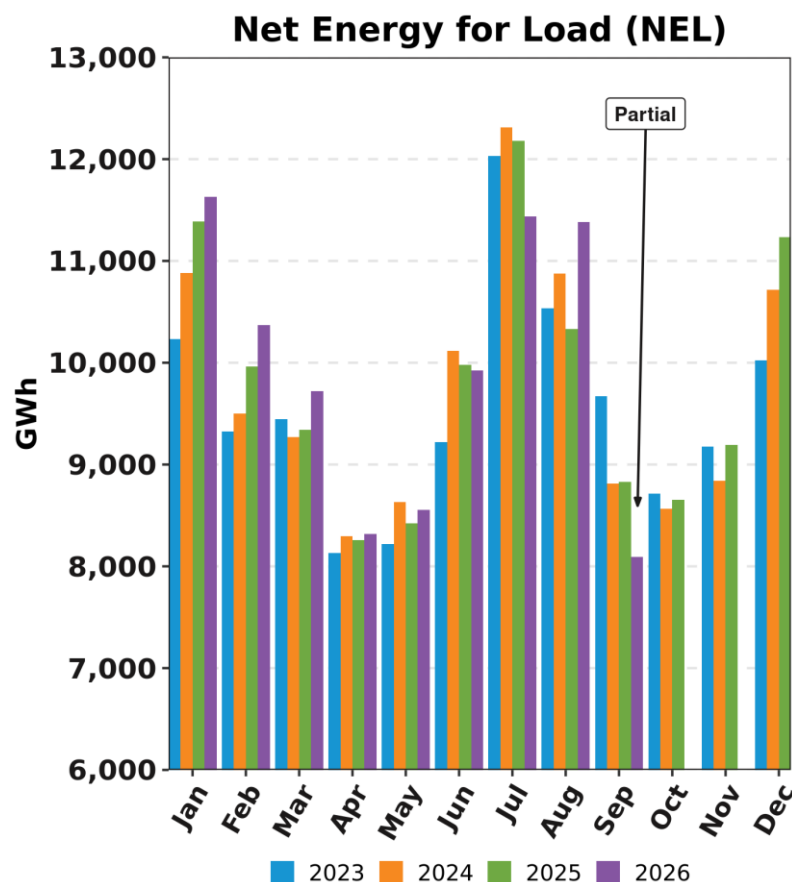


RQM System Peak Load MW by Month



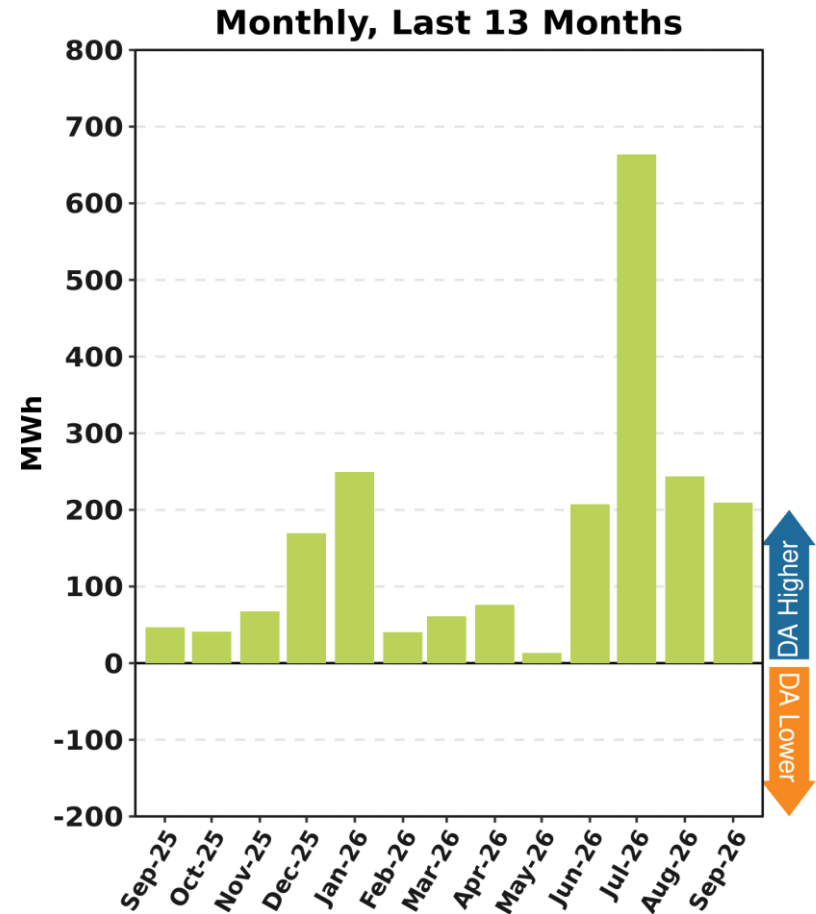
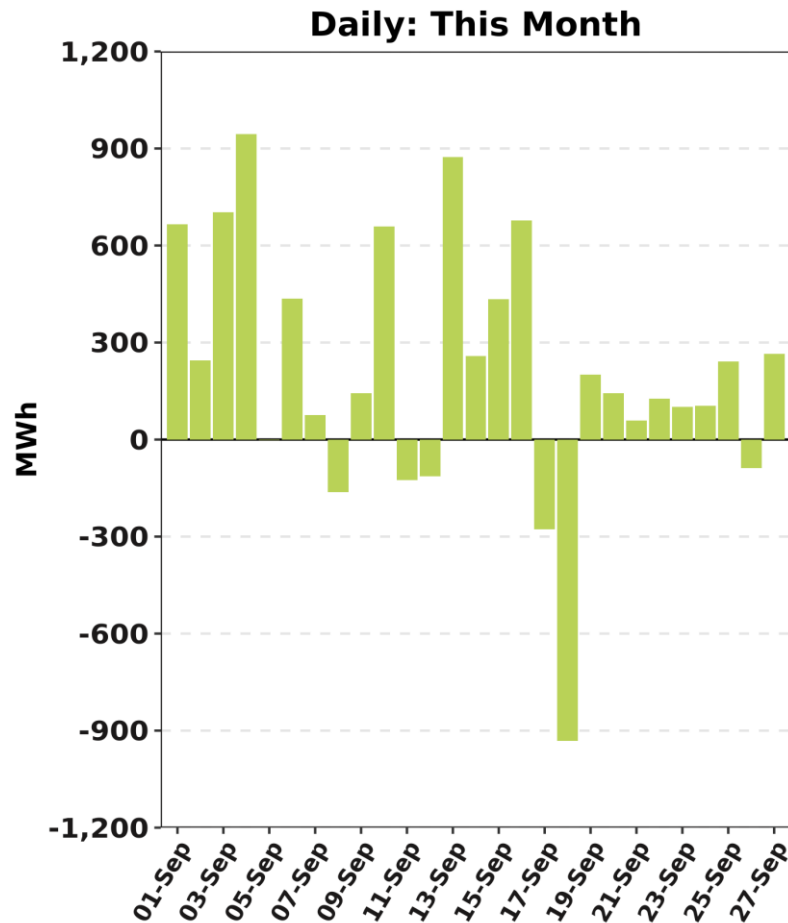
Shaded columns highlight current month and the same month over the prior two years

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



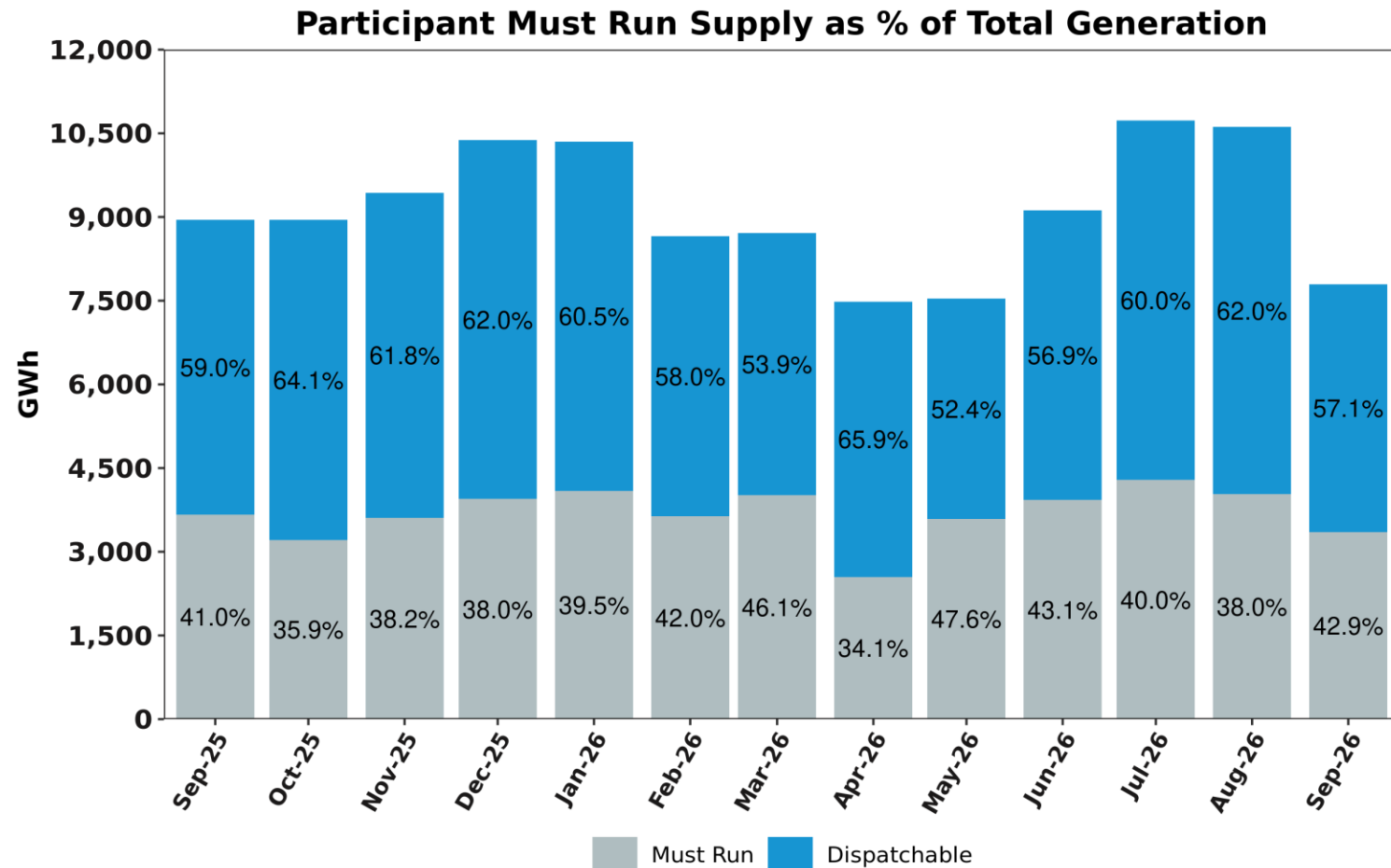
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

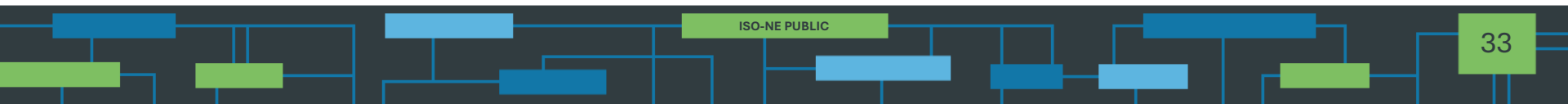
RT Generation Output Offered as Must Run vs Dispatchable



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

MARKET OPERATIONS

Market Pricing



DA vs. RT LMPs (\$/MWh)

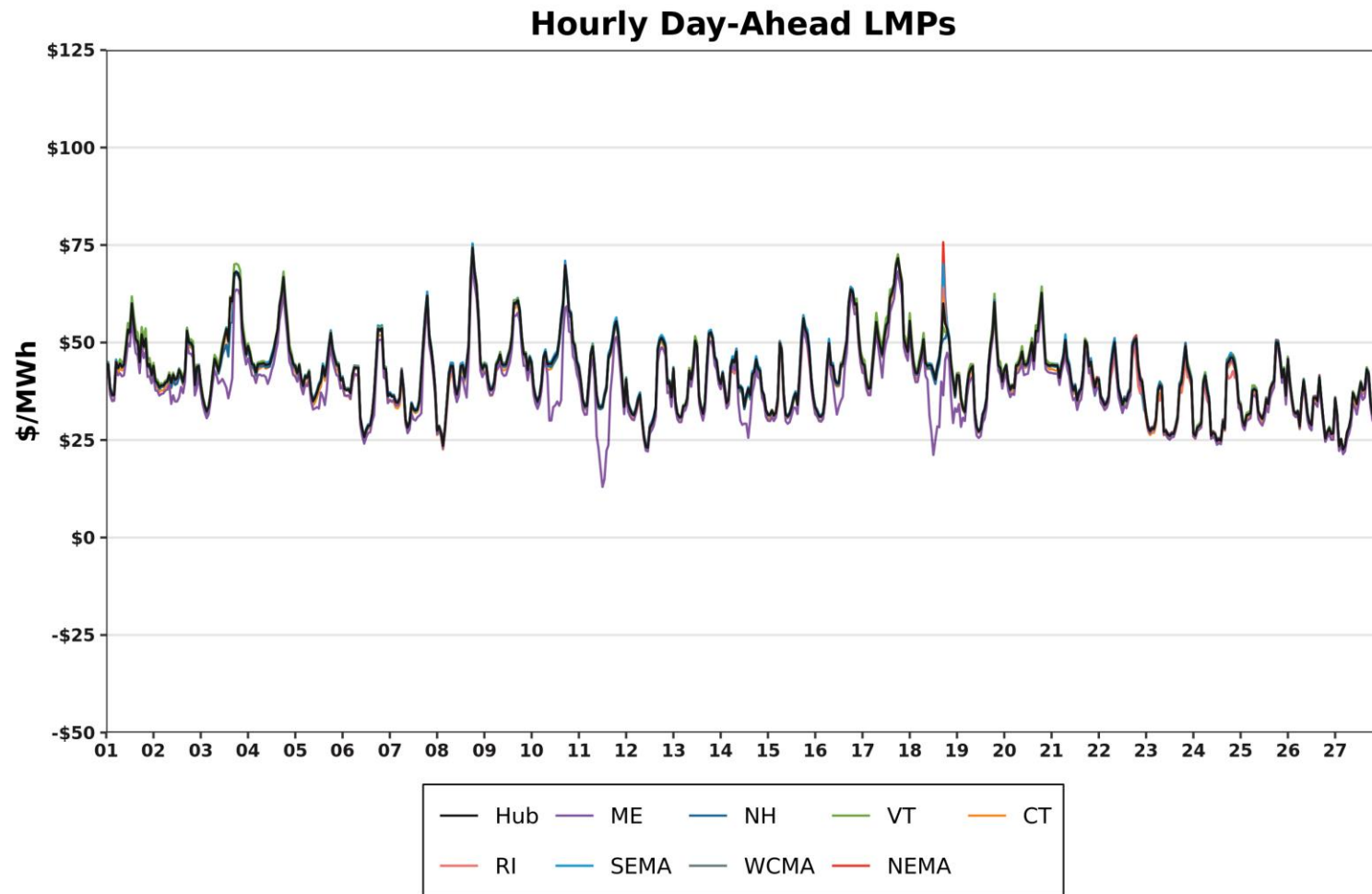
Arithmetic Average

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 %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%
Year 2025	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$68.11	\$66.29	\$68.63	\$68.21	\$66.23	\$67.78	\$68.63	\$68.16	\$68.93
Real-Time	\$66.15	\$63.91	\$66.63	\$66.15	\$64.66	\$65.85	\$66.56	\$66.18	\$66.93
RT Delta %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%

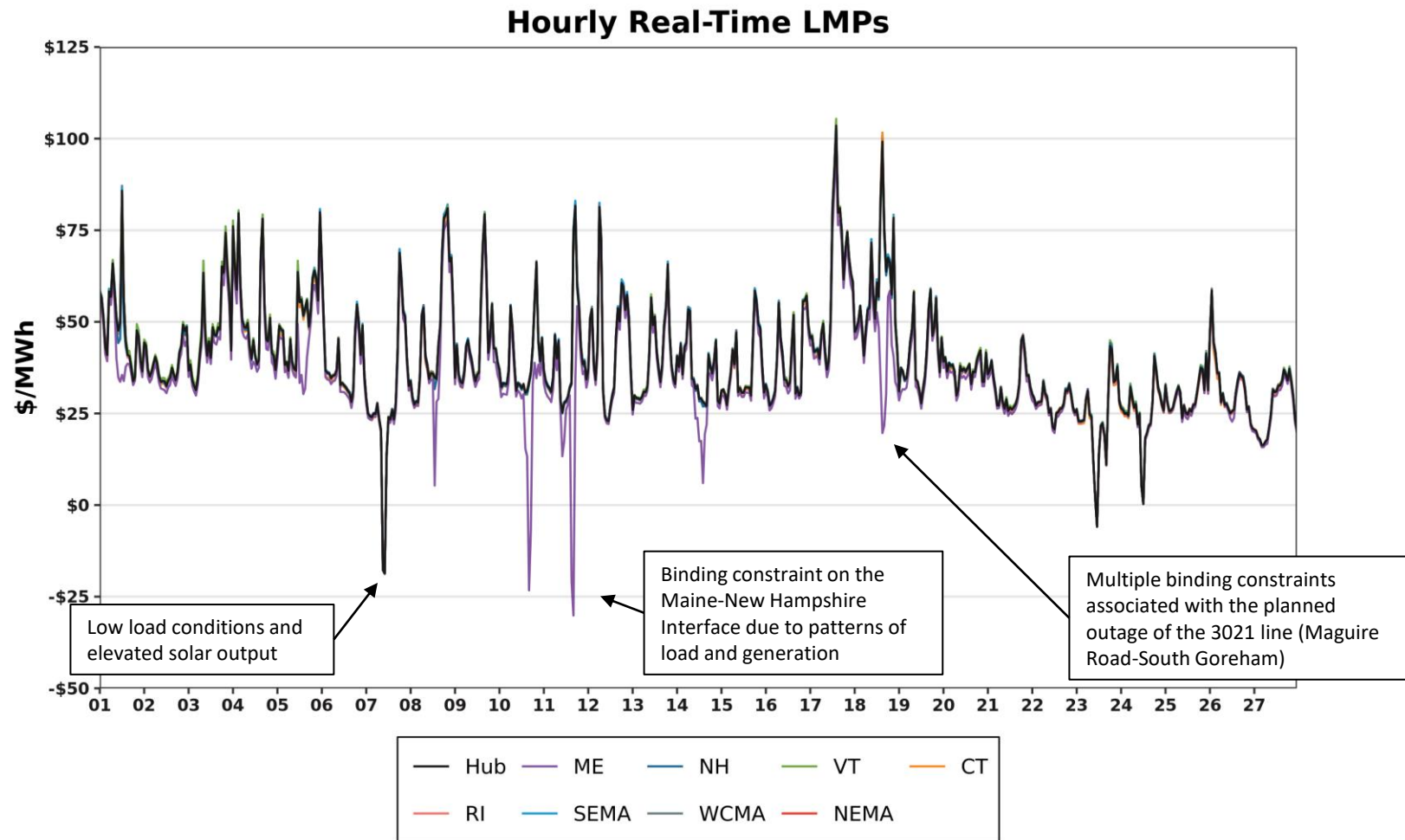
September-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$34.21	\$33.98	\$34.66	\$34.81	\$33.61	\$33.85	\$34.38	\$34.30	\$34.67
Real-Time	\$33.90	\$33.64	\$34.30	\$34.55	\$33.37	\$33.51	\$33.97	\$33.96	\$34.27
RT Delta %	-0.91%	-1.00%	-1.04%	-0.75%	-0.71%	-1.00%	-1.19%	-0.99%	-1.15%
September-26	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$41.79	\$38.75	\$41.49	\$42.05	\$40.76	\$41.23	\$42.17	\$41.80	\$42.16
Real-Time	\$39.51	\$36.09	\$39.24	\$39.73	\$38.77	\$39.00	\$39.78	\$39.56	\$39.79
RT Delta %	-5.46%	-6.86%	-5.42%	-5.52%	-4.88%	-5.41%	-5.67%	-5.36%	-5.62%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	22.16%	14.04%	19.71%	20.80%	21.27%	21.80%	22.66%	21.87%	21.60%
Yr over Yr RT	16.55%	7.28%	14.40%	14.99%	16.18%	16.38%	17.10%	16.49%	16.11%

This information is available in the Monthly Market Report found on the ISO [website](#) and is scheduled for removal from this deck at a future date.

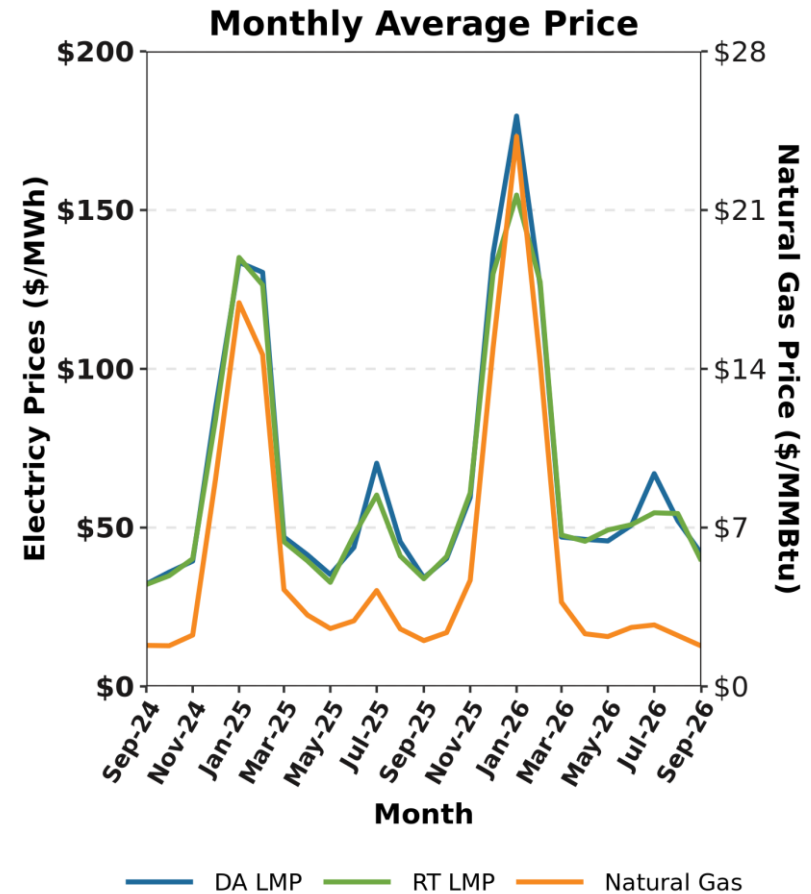
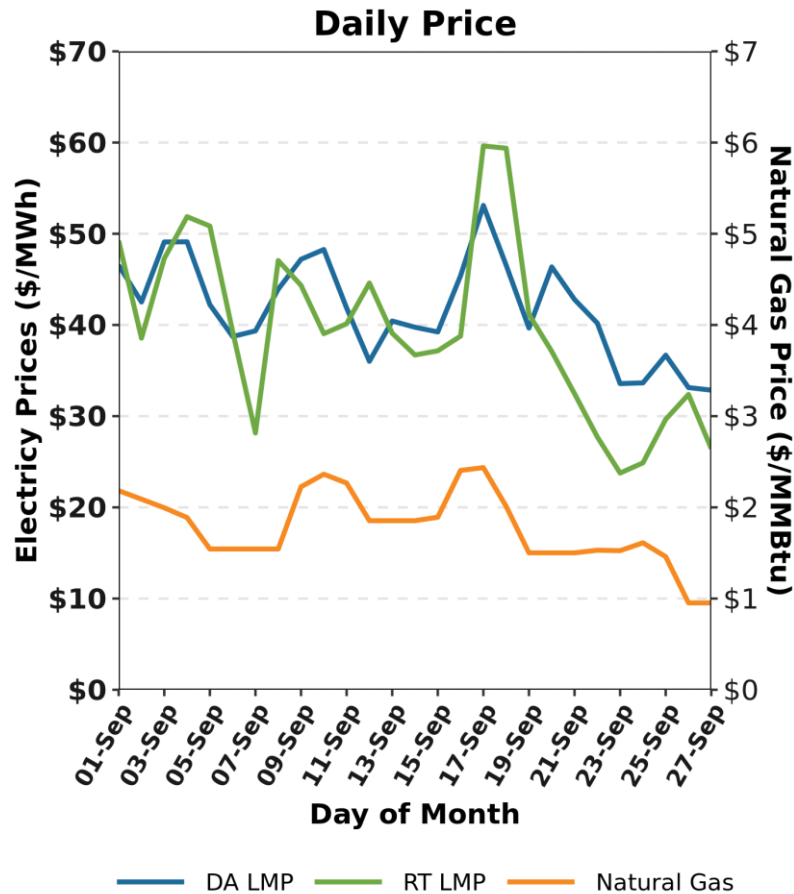
Hourly DA LMPs, September 1-27, 2026



Hourly RT LMPs, September 1-27, 2026



Wholesale Electricity vs Natural Gas Price by Month

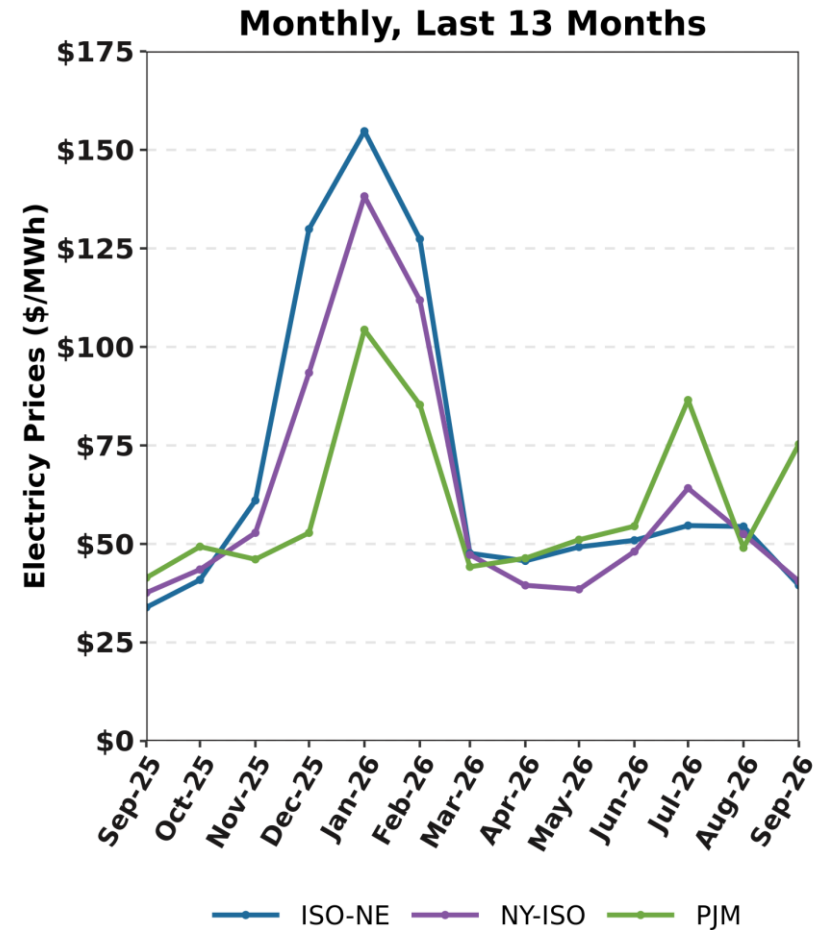
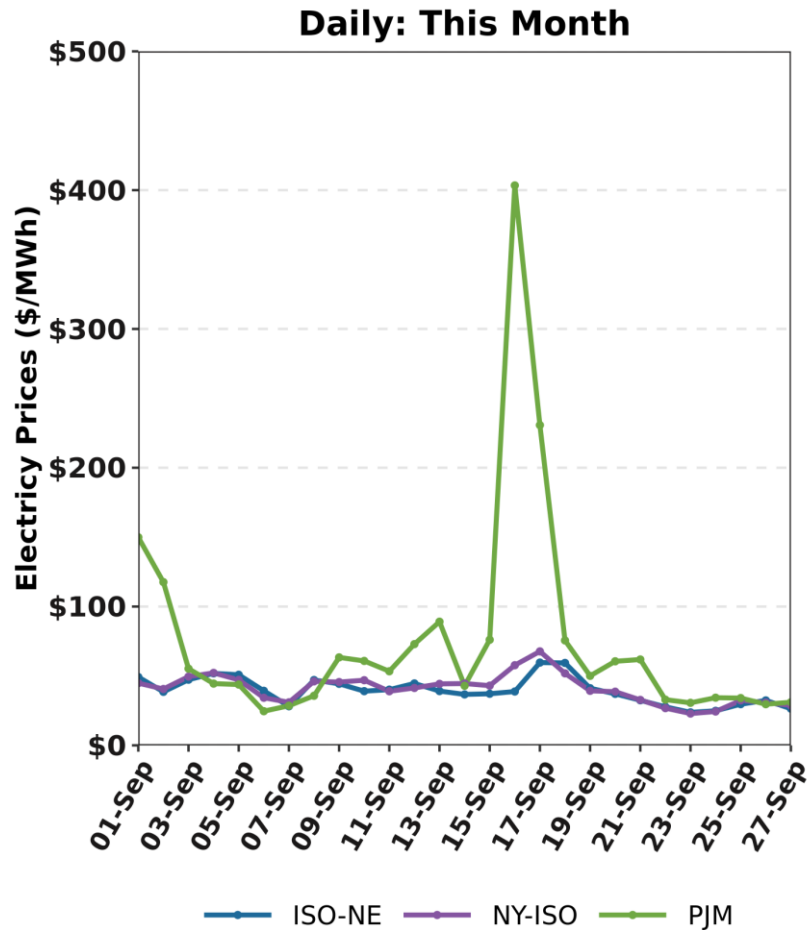


Gas price is average of Massachusetts delivery points

Underlying natural gas data furnished by:

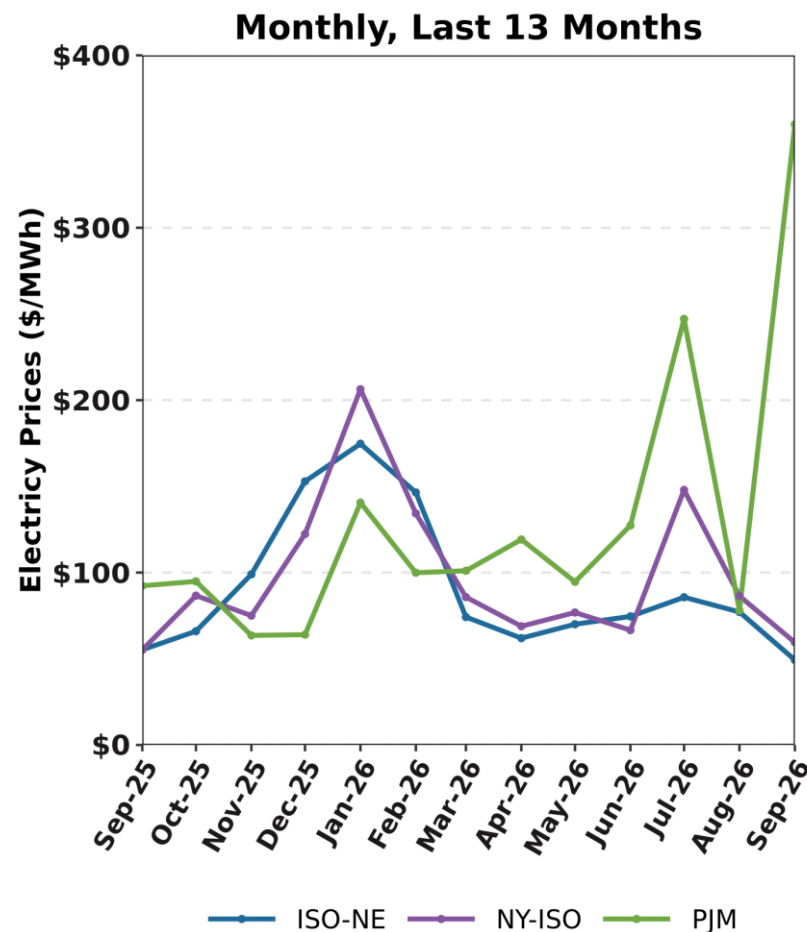
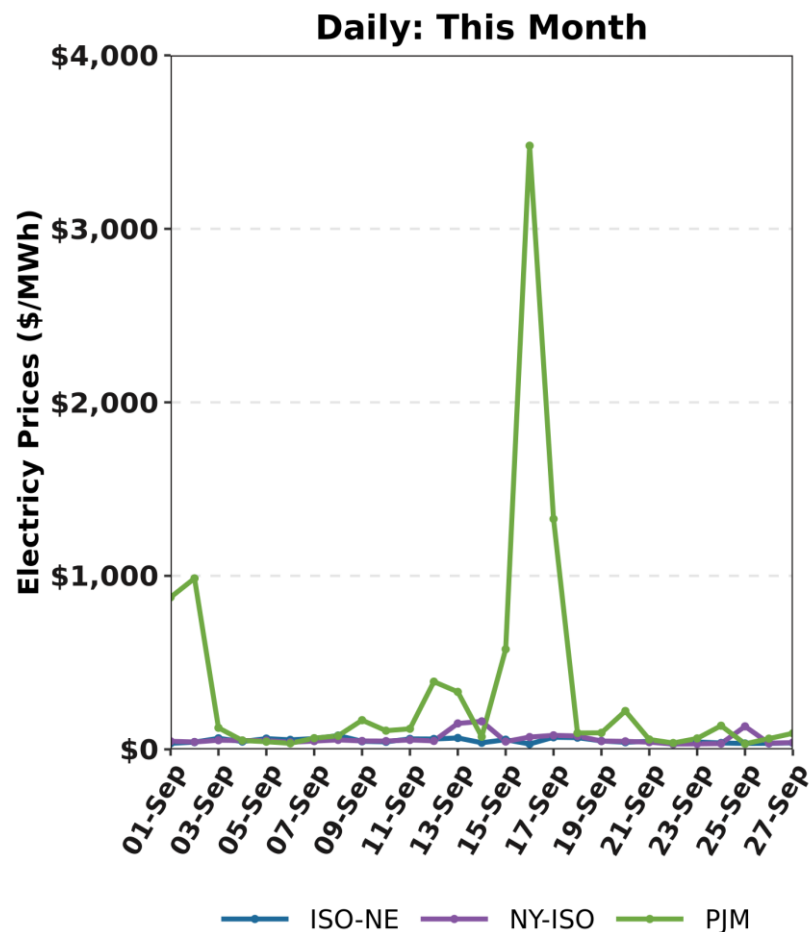


New England, NY, and PJM Hourly Average RT Prices by Month

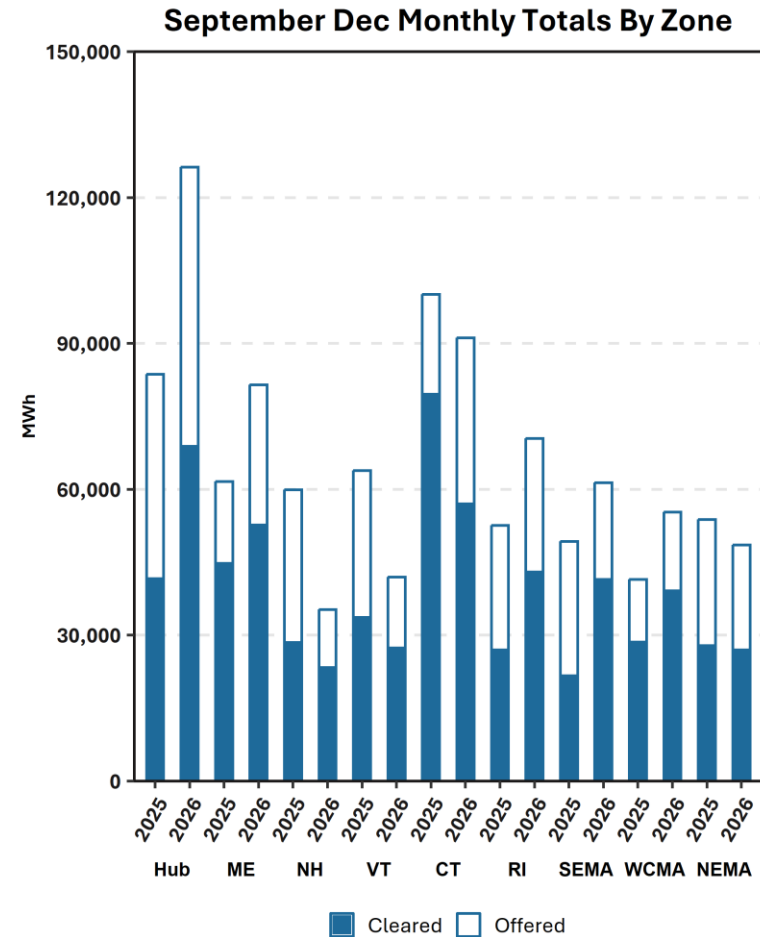
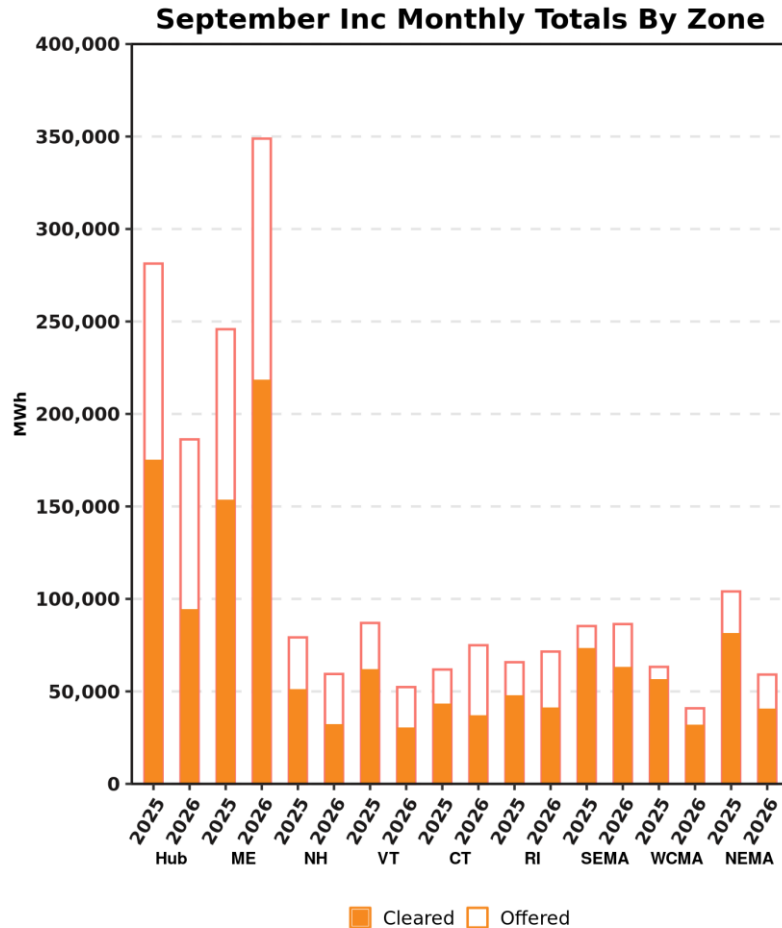


Hourly average prices are shown

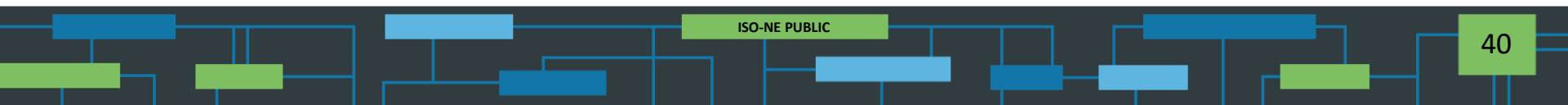
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours



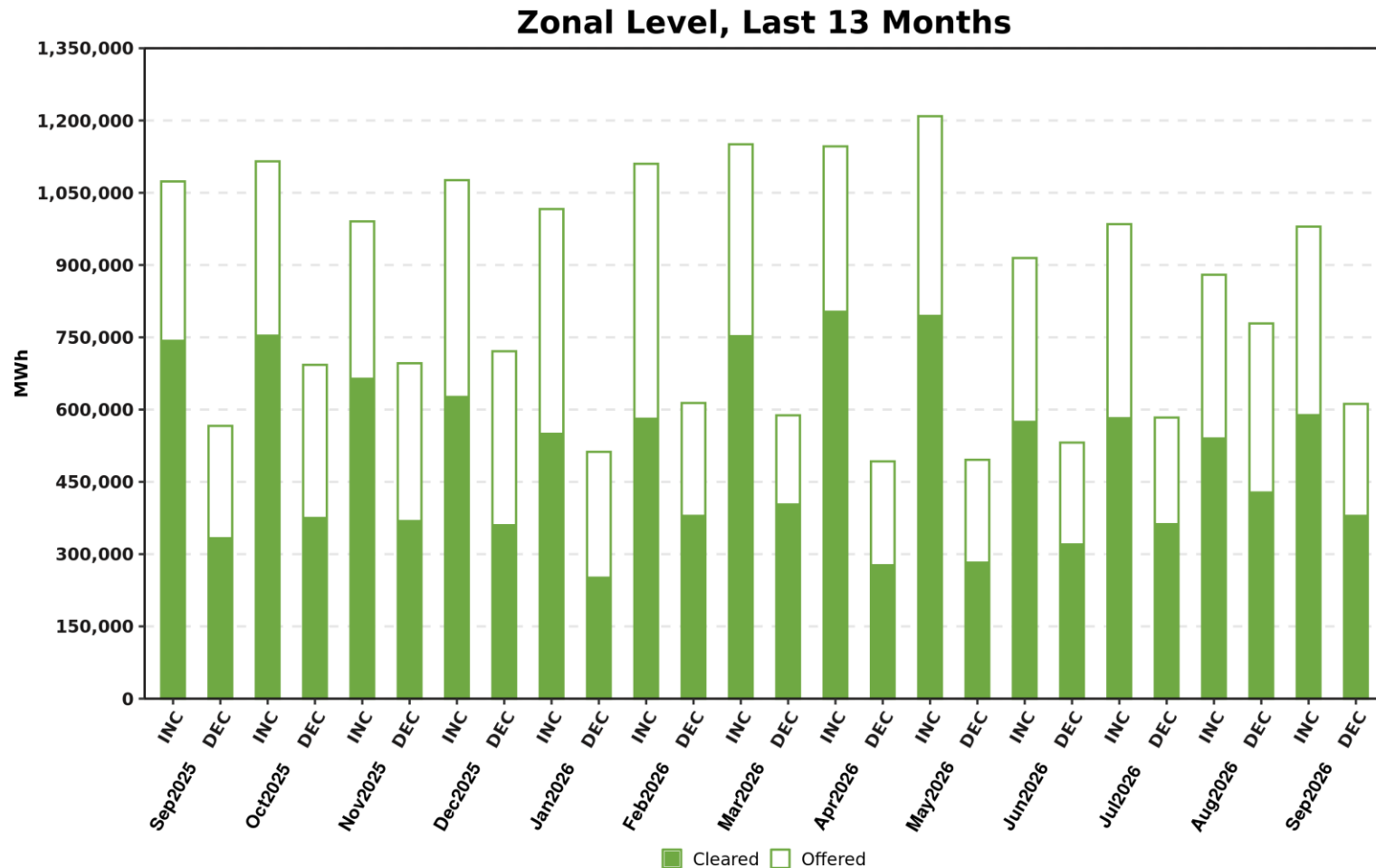
Zonal Increment Offers and Decrement Bid Amounts



Includes nodal activity within the zone; excludes external nodes

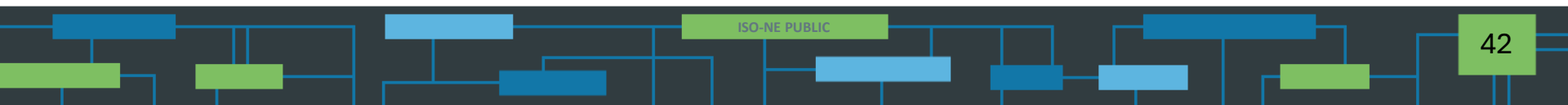


Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

DAY-AHEAD ANCILLARY SERVICES (DAAS)



DAAS Results

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
09/01/2025	\$12.3M	\$320K	\$184K	\$3.21	1.5%	\$587K	138K	\$1.94	4.8%	104
10/01/2025	\$15.5M	\$719K	\$478K	\$8.21	3.1%	\$1,911K	202K	\$6.50	12.3%	209
11/01/2025	\$24.8M	\$1,123K	\$458K	\$7.85	1.9%	\$2,550K	210K	\$8.00	10.3%	135
12/01/2025	\$60.9M	\$2,131K	\$1,053K	\$18.20	1.7%	\$4,916K	227K	\$13.42	8.1%	107
01/01/2026	\$91.1M	\$4,617K	\$3,241K	\$55.53	3.6%	\$12,042K	203K	\$29.54	13.2%	127
02/01/2026	\$55.1M	\$1,678K	\$857K	\$14.78	1.6%	\$3,369K	157K	\$8.70	6.1%	104
03/01/2026	\$17.4M	\$667K	\$357K	\$6.43	2.1%	\$422K	91K	\$1.32	2.4%	32
04/01/2026	\$15.4M	\$463K	\$119K	\$2.23	0.8%	\$641K	107K	\$2.34	4.2%	81
05/01/2026	\$15M	\$425K	\$-187K	\$-3.40	-1.2%	\$674K	133K	\$2.49	4.5%	101
06/01/2026	\$19.3M	\$483K	\$63K	\$1.17	0.3%	\$186K	60K	\$0.48	1.0%	17
07/01/2026	\$32.1M	\$1,161K	\$784K	\$14.55	2.4%	\$649K	126K	\$1.46	2.0%	35
08/01/2026	\$22.1M	\$665K	\$418K	\$7.78	1.9%	\$642K	114K	\$1.47	2.9%	31
09/01/2026	\$15.1M	\$412K	\$337K	\$6.23	2.2%	\$456K	121K	\$1.48	3.0%	55

About the Table:

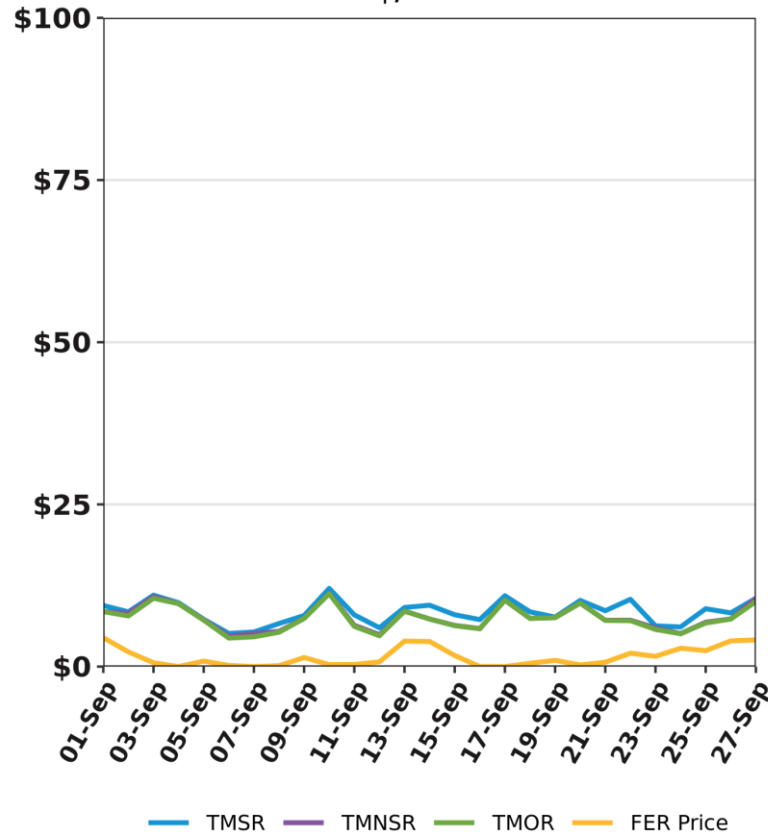
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with 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

Additionally:

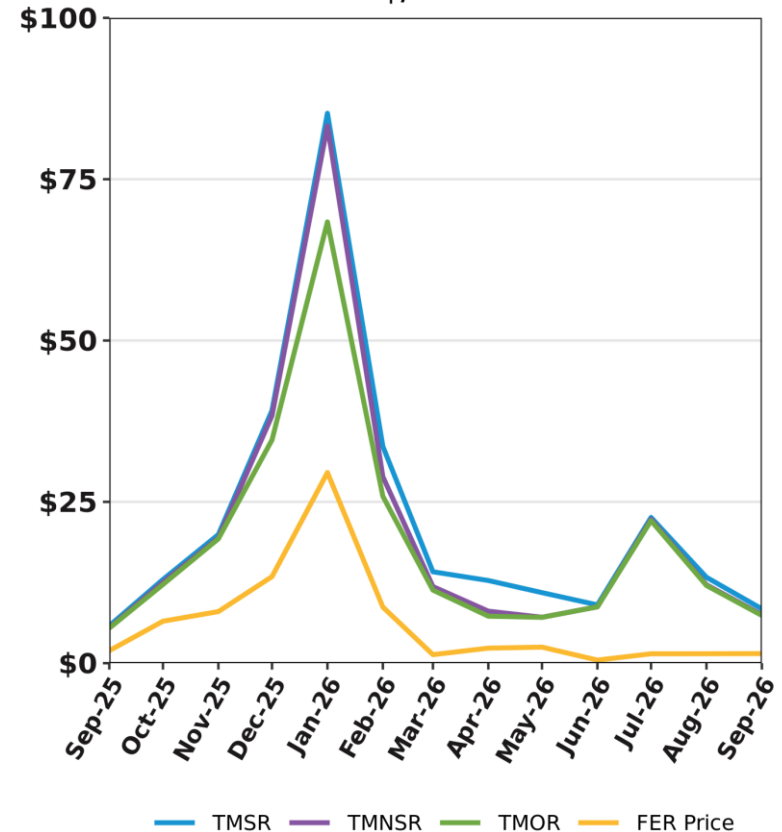
- FER Credits are included in the Monthly Market Operations Report (see Section 7.1.1) found on the ISO [website](#). Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

Average Hourly DAAS Prices

Daily This Month
\$/MWh



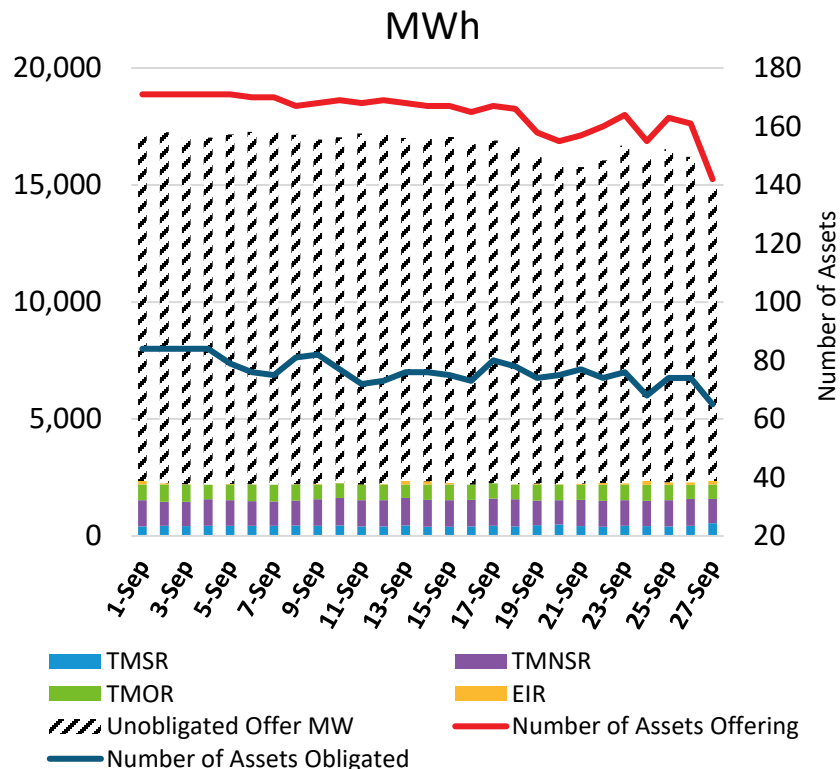
Monthly, Last 13 Months
\$/MWh



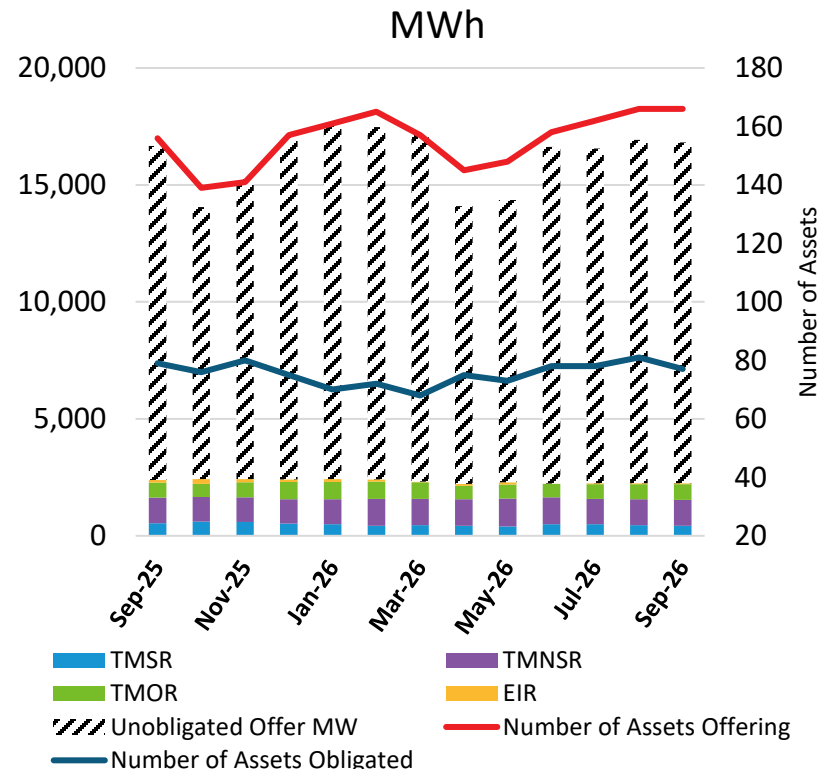
This information is available in the Monthly Market Report found on the ISO [website](#) and is scheduled for removal from this deck at a future date.

Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month

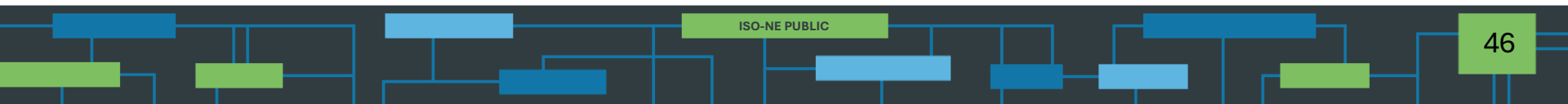


Monthly, Last 13 Months

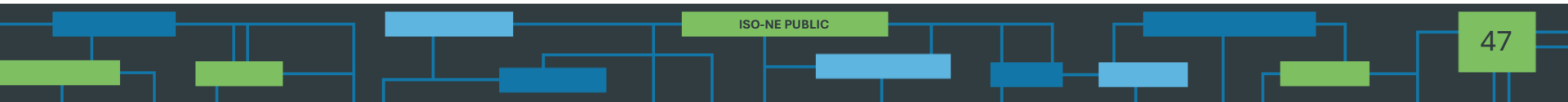


*Unobligated Offer MWh reflect the raw, as-offered DAAS MW amounts that remained unobligated (received no MW reward). This supply does not yet consider additional unit parameter constraints or dispatch constraints and should not be equated with actual capacity available in the dispatch solution. This information is available in the Monthly Market Report found on the ISO [website](#) and is scheduled for removal from this deck at a future date.

BACK-UP DETAIL



NEW GENERATION

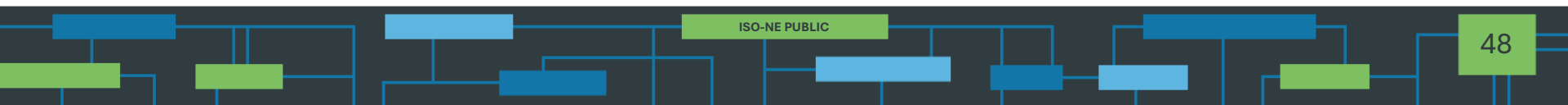


New Generation Update

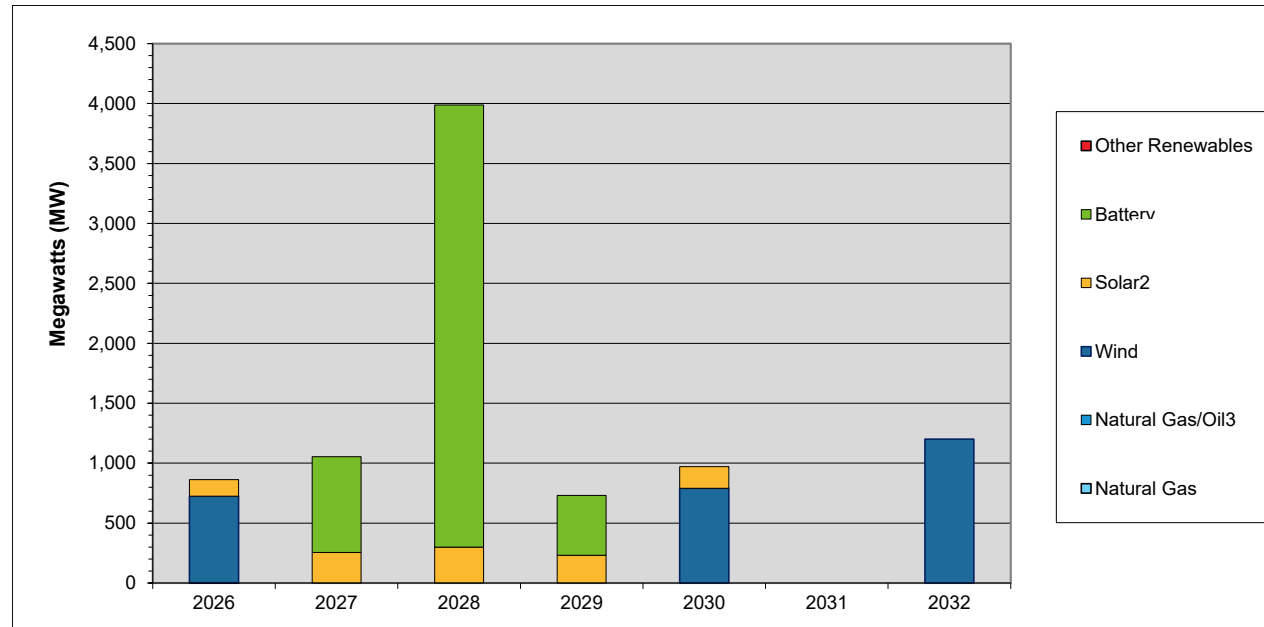
Based on Queue as of 09/28/26

- In total, 46* generation projects are currently being tracked by the ISO, totaling approximately 10,008 MW

* Total does not include CNR Only requests



Projected Annual Capacity Additions *By Supply Fuel Type*



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total ¹
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	0	799	3,690	500	0	0	0	4,989	56.6
Solar ²	140	255	299	232	180	0	0	1,106	12.6
Wind	722	0	0	0	791	0	1,200	2,713	30.8
Natural Gas/Oil ³	0	0	0	0	0	0	0	0	0.0
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	862	1,054	3,989	732	971	0	1,200	8,808	100.0

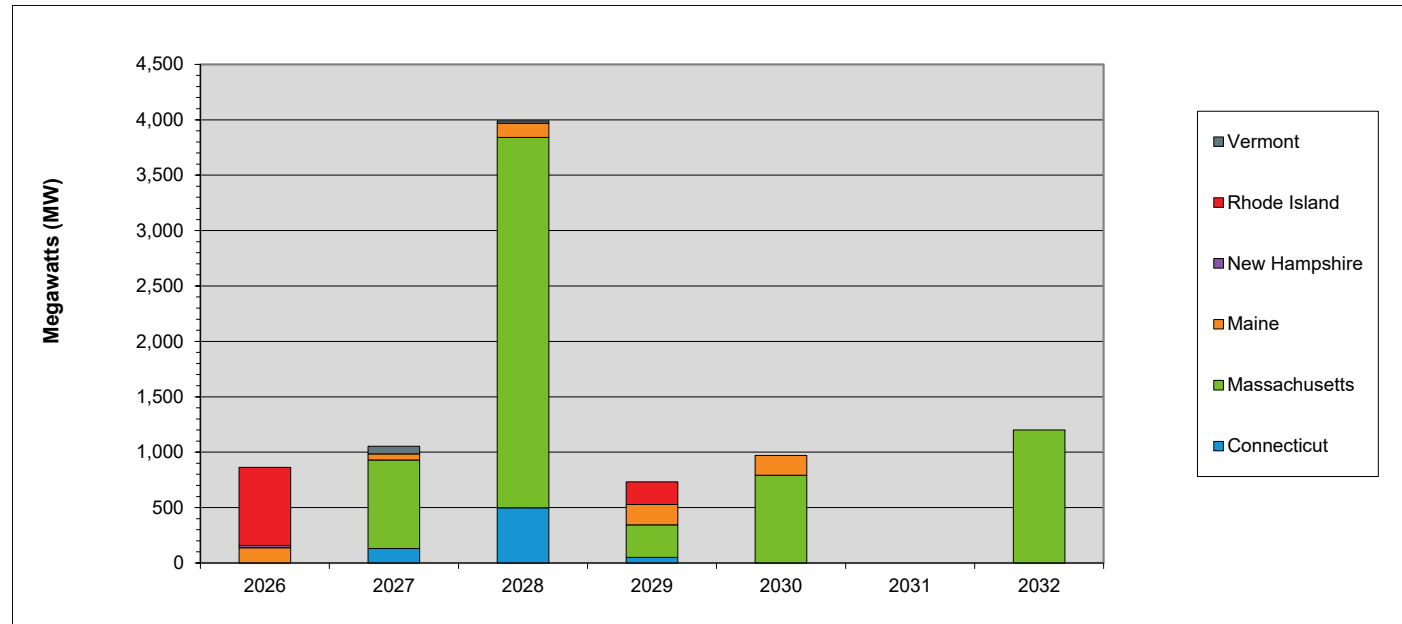
¹ Sum may not equal 100% due to rounding

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



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total ¹
Vermont	0	70	20	0	0	0	0	90	1.0
Rhode Island	704	0	0	205	0	0	0	909	10.3
New Hampshire	20	0	0	0	0	0	0	20	0.2
Maine	138	54	129	182	180	0	0	683	7.8
Massachusetts	0	799	3,343	295	791	0	1,200	6,428	73.0
Connecticut	0	131	497	50	0	0	0	678	7.7
Totals	862	1,054	3,989	732	971	0	1,200	8,808	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	21	4,989	2	454	19	4,535
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	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0
Solar	20	1,106	3	136	17	970
Wind	5	3,913	2	722	3	3,191
Total	46	10,008	7	1,312	39	8,696

- 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	0	0	0	0	0	0
Peaker	41	6,095	5	590	36	5,505
Wind Turbine	5	3,913	2	722	3	3,191
Total	46	10,008	7	1,312	39	8,696

- 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

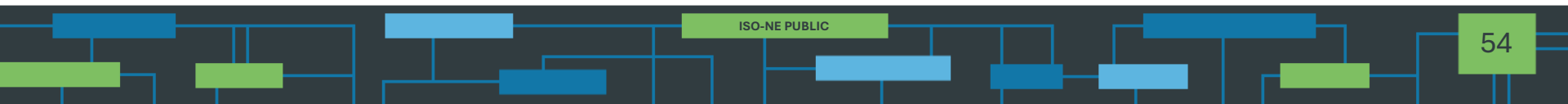
New Generation Projection

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	21	4,989	0	0	0	0	21	4,989	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	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	20	1,106	0	0	0	0	20	1,106	0	0
Wind	5	3,913	0	0	0	0	0	0	5	3,913
Total	46	10,008	0	0	0	0	41	6,095	5	3,913

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

FORWARD CAPACITY MARKET



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	384.960	-107.403
	Passive Demand	2,316.815	2,314.068	-2.747	2,314.705	0.637	2,254.722	-59.983
Demand Total		2,939.669	2,898.981	-40.688	2,807.068	-91.913	2,639.682	-167.386
Generator	Non-Intermittent	26,507.420	26,715.489	208.069	26,271.866	-443.623	26,314.531	42.665
	Intermittent	1,356.084	1,286.589	-69.495	1,310.622	24.033	1,205.314	-105.308
Generator Total		27,863.504	28,002.078	138.574	27,582.488	-419.59	27,519.845	-62.643
Import Total		566.998	564.079	-2.919	636.310	72.231	409.310	-227.000
Grand Total*		31,370.171	31,465.138	94.967	31,025.866	-439.272	30,568.837	-457.029
Net ICR (NICR)		30,305	30,395	90	30,600	205	30,050	-550

* 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	410.941	7.057		
	Passive Demand	2,070.498	2,851.331	780.833	2,010.568	-840.763		
Demand Total		2,614.078	3,255.215	641.137	2,421.509	-833.706		
Generator	Non-Intermittent	27,026.635	25,822.288	-1,204.347	26,192.205	369.917		
	Intermittent	1,450.872	890.415	-560.457	1,479.423	589.008		
Generator Total		28,477.507	26,712.703	-1,764.804	27,671.628	958.925		
Import Total		464.835	1,234.800	769.965	614.235	-620.565		
Grand Total*		31,556.420	31,202.718	-353.702	30,707.372	-495.346		
Net ICR (NICR)		30,550.000	30,415.000	-135.000	29,855.000	-560.000		

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

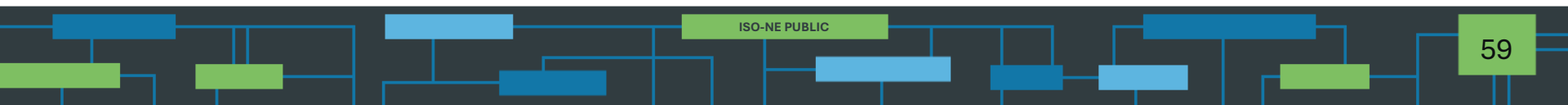
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes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

NET COMMITMENT PERIOD COMPENSATION

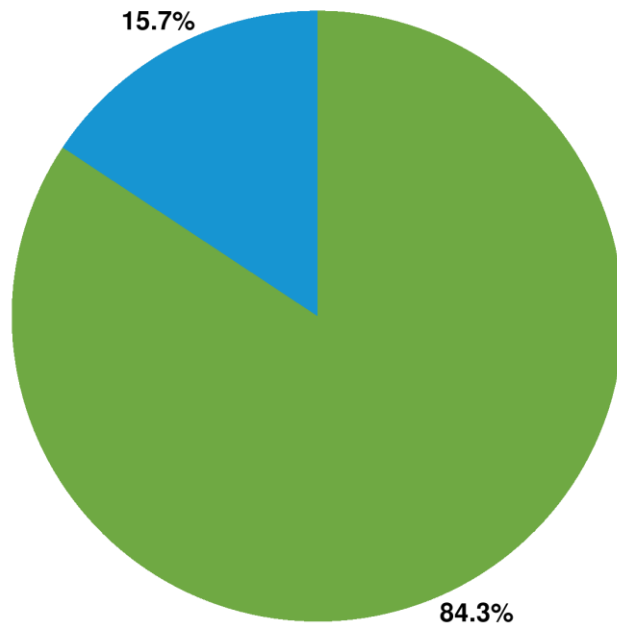


NCPC Highlights

- **Net Commitment Period Compensation (NCPC) total \$1.3M**
 - Represents 0.3% of monthly Energy Market value
 - First Contingency \$1.3M
 - Dispatch Lost Opportunity Cost (DLOC) - \$496K; Rapid Response Pricing (RRP) Opportunity Cost - \$81K; Posturing - \$0; Generator Performance Auditing (GPA) - \$0
 - \$52K paid to resources at external locations, down \$43K from August
 - \$23K charged to Day-Ahead Load Obligation (DALO) at external locations; <\$1K to Day-Ahead Generation Obligation (DAGO) at external locations; \$29K to RT Deviations
 - 2nd Contingency, Distribution and Voltage was zero

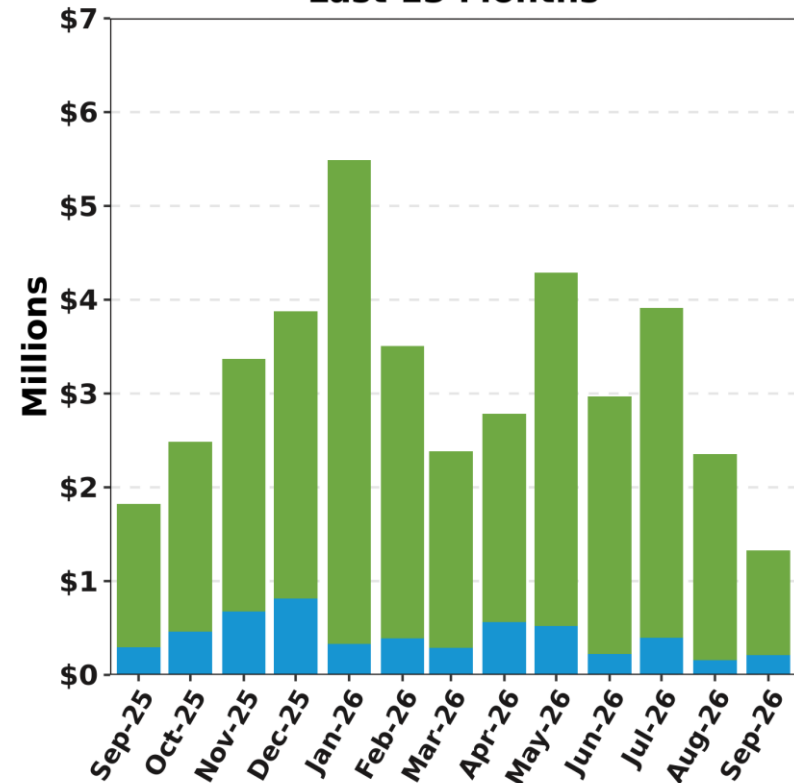
DA and RT NCPC Charges

Sep-26 Total = \$1.3 M



Day-Ahead Real-Time

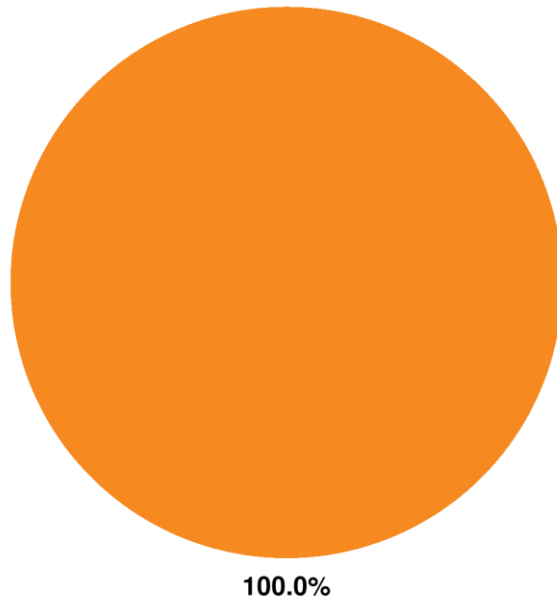
Last 13 Months



Day-Ahead Real-Time

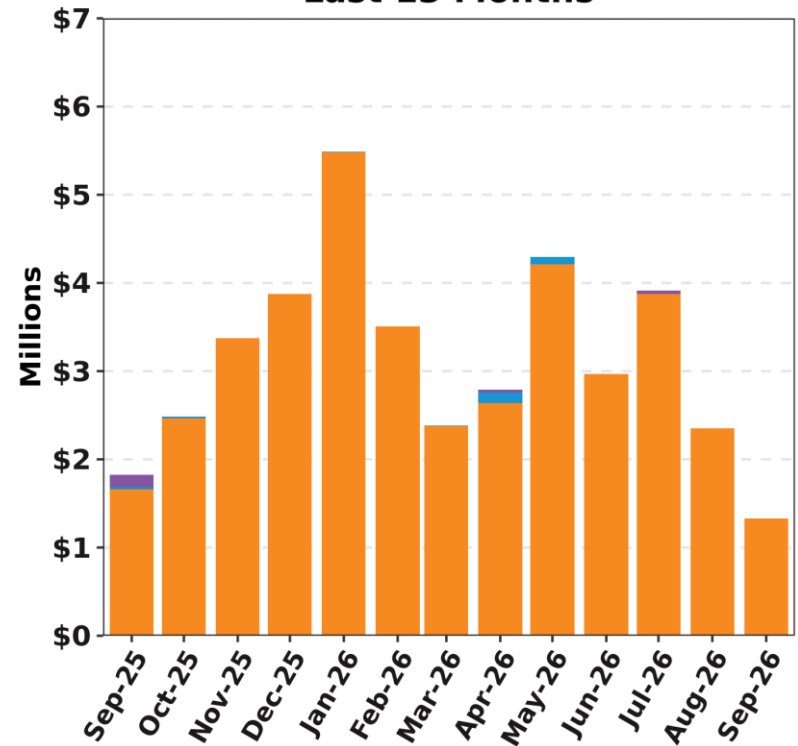
NCPC Charges by Type

Sep-26 Total = \$1.3 M



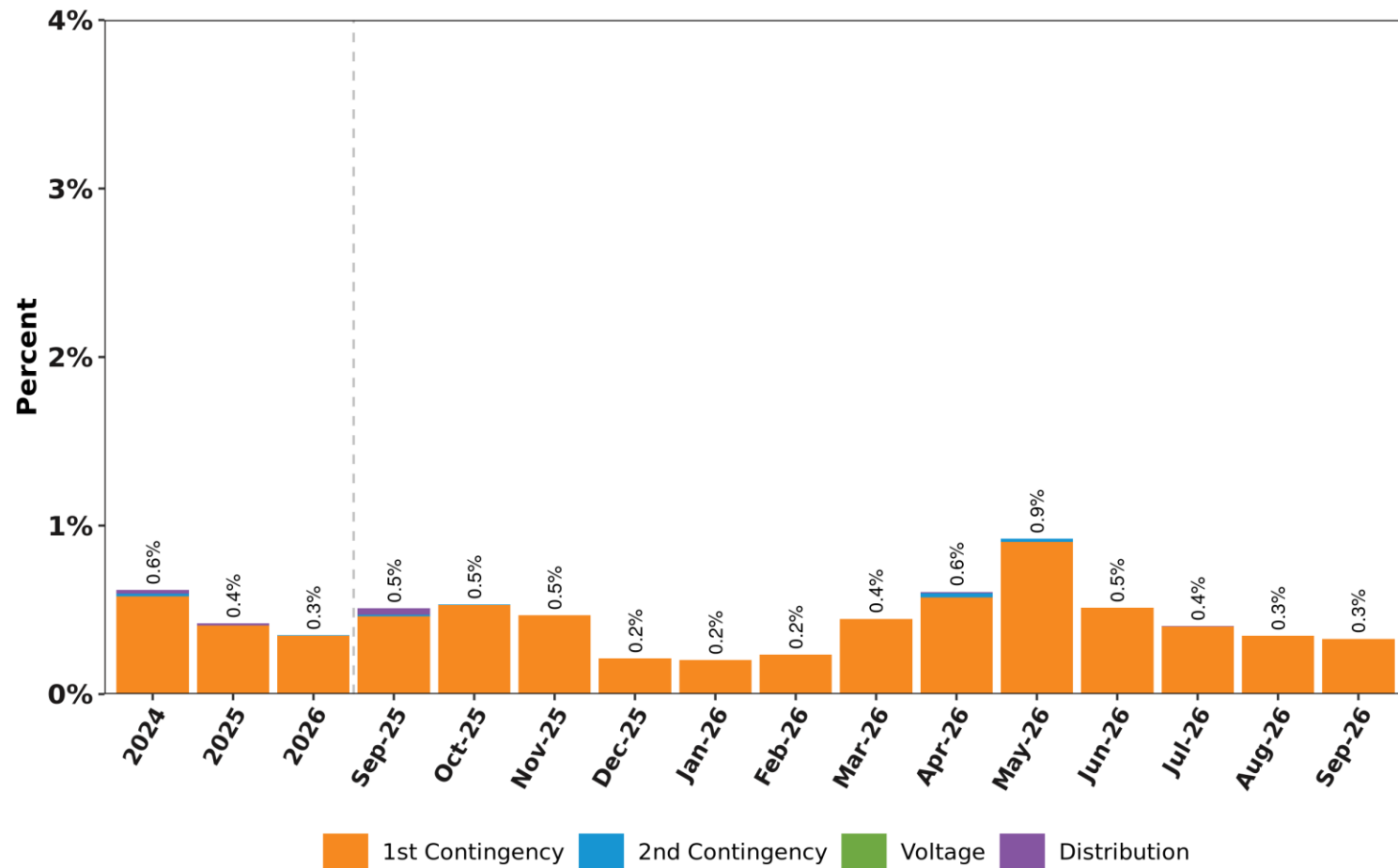
1st Contingency 2nd Contingency
Voltage Distribution

Last 13 Months



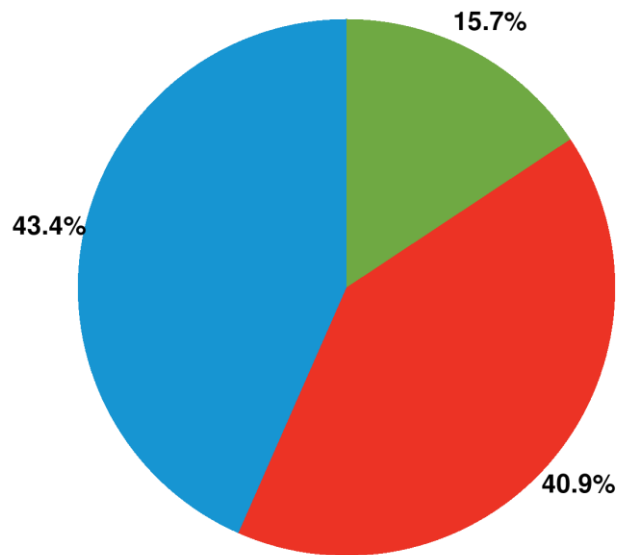
1st Contingency 2nd Contingency
Voltage Distribution

NCPC Charges by Type as Percent of Energy Market Value

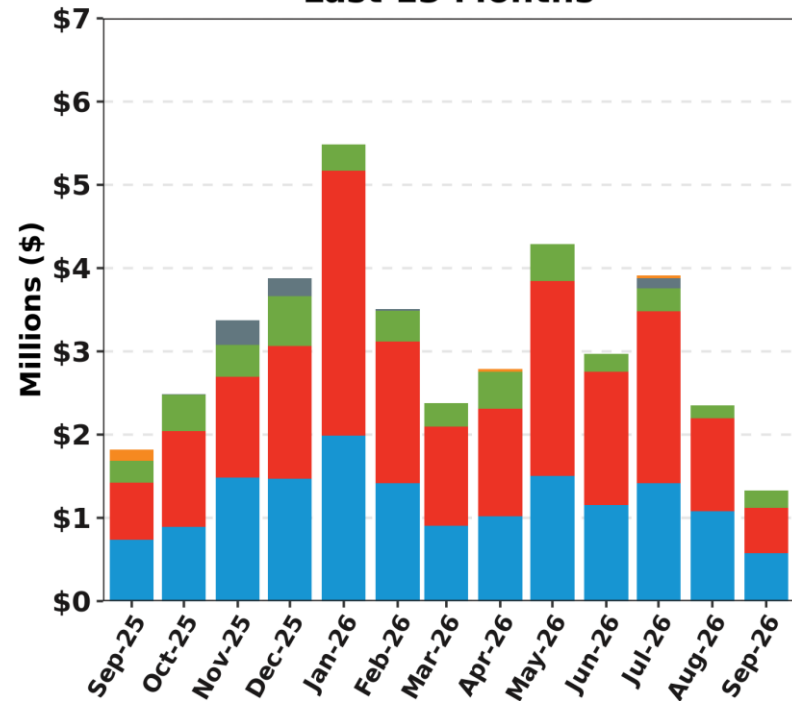


NCPC Charge Allocations

Sep-26 Total = \$1.3 M

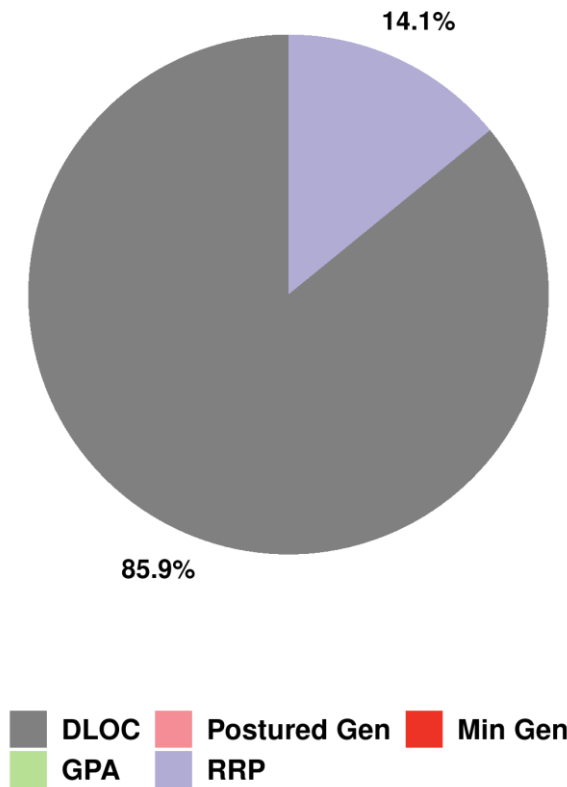


Last 13 Months

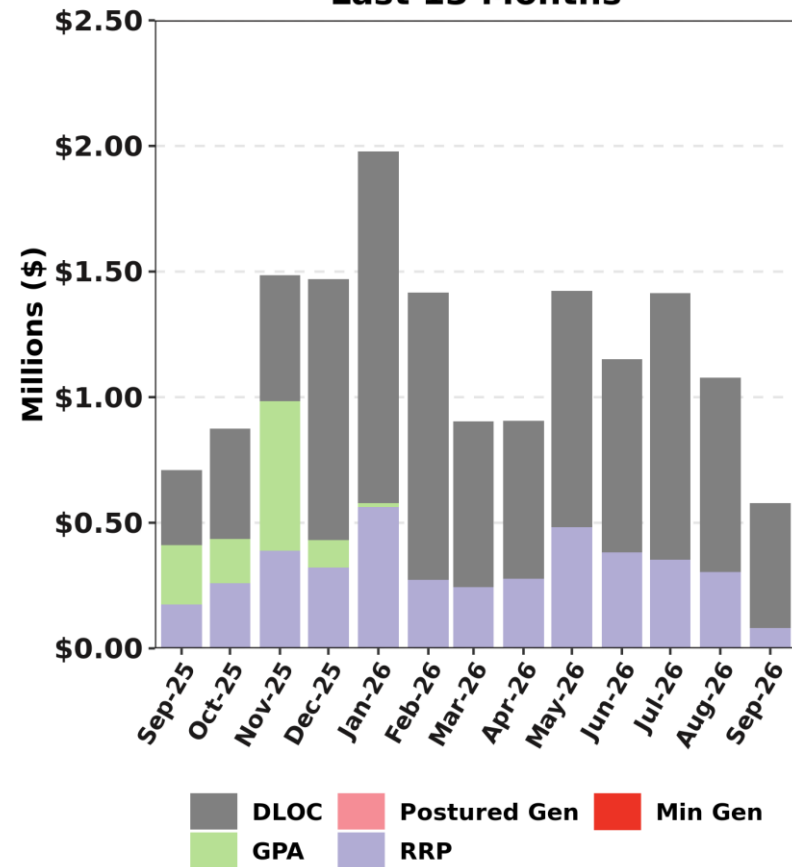


RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

Sep-26 Total = \$0.6 M



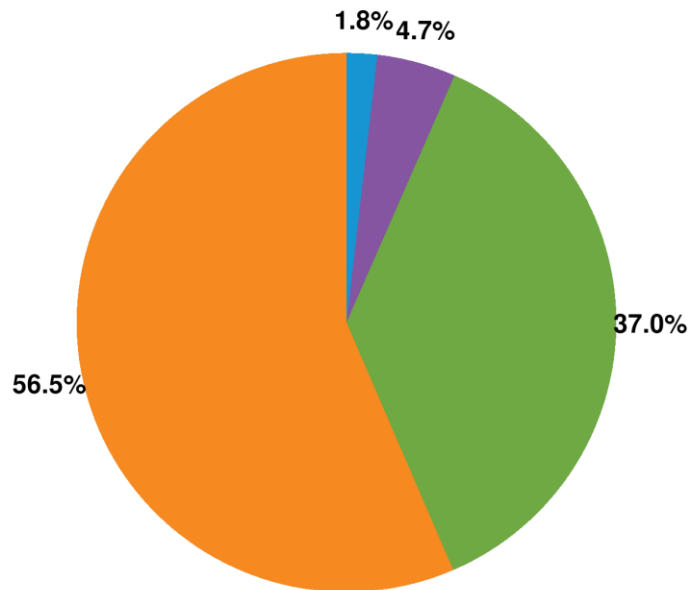
Last 13 Months



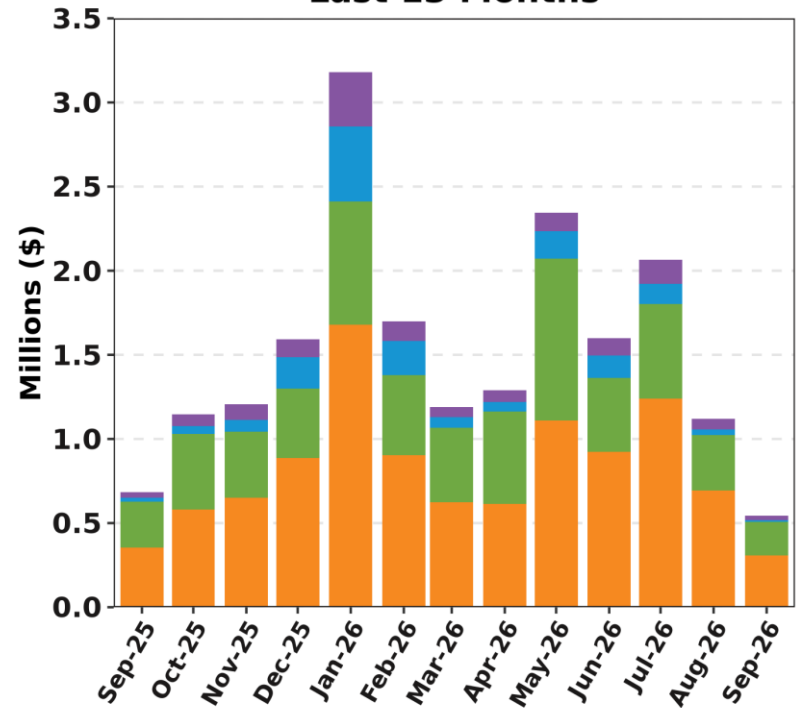
The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

RT First Contingency Charges by Deviation Type

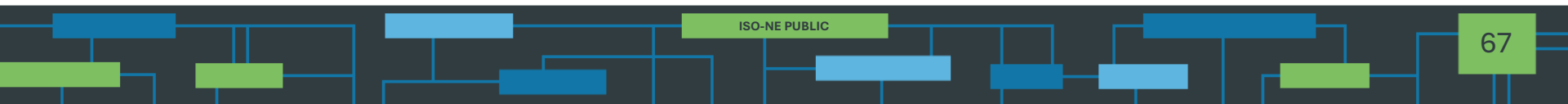
Sep-26 Total = \$0.5 M



Last 13 Months



REGIONAL SYSTEM PLAN (RSP)



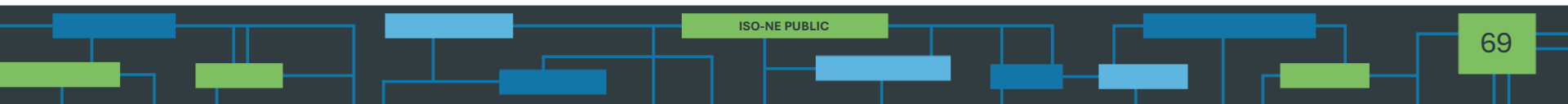
Planning Advisory Committee (PAC)

- October 22 PAC Meeting Tentative Agenda Topics (note that the agenda is still under review)*
 - Asset Condition Projects
 - W-149 115kV Line Asset Condition Refurbishment (NGRID)
 - Otter River #615 Substation Asset Replacement (NGRID)
 - I-135/I-135N/J-136N Asset Condition Refurbishment (NGRID)
 - Line 330 ACR Project (Eversource)
 - RSP Project List and Asset Condition List October 2026 Update
 - Transmission Planning Guide Process update

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

Economic Studies: 2026 Study

- The 2026 Economic Study was launched in January
 - The ISO presented results of the public survey, as part of a lessons learned, and Benchmark Scenario assumptions at PAC
 - The ISO opened the Stakeholder-Requested scenario window through July 24, one stakeholder submitted a request
 - The Benchmark results were presented at PAC this summer, the Policy and Stakeholder-Requested cases will be discussed this fall and winter



2025 Longer-Term Transmission Planning (LTTP) RFP

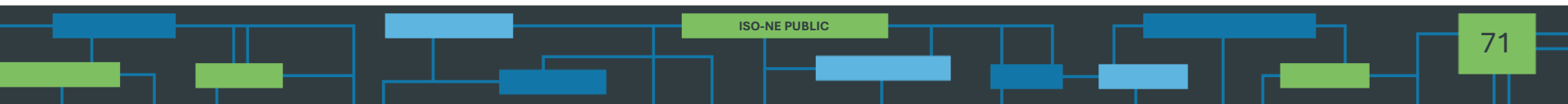
- On 12/13/24, NESCOE provided its LTTP RFP request describing the needs to be addressed by 2035:
 - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
 - Increase the Surowiec-South interface capacity to at least 3,200 MW
 - Develop new infrastructure (e.g., substation) at Pittsfield, 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 provided an update on the initial review of proposals and results of the RFP objective analysis (transfer limits & wind accommodation) at the March PAC meeting and a follow-up at the May PAC meeting
- The ISO presented the preliminary preferred Longer-Term Transmission Solution at the July 2026 PAC meeting
- The ISO posted the preferred Longer-Term Transmission Solution on 8/14/26
 - NESCOE had 30 days (until 9/14/26) to notify the ISO to cancel the RFP or request an alternative cost allocation. NESCOE did not pursue either option
 - The ISO notified the Qualified Transmission Project Sponsors (QTPSs) they were selected and need to execute Selected Qualified Transmission Project Sponsor Agreements within 30 days of the notification (until 10/15/26)

* 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 (LTP) RFP, cont.

- Preferred Longer-Term Transmission Solution: LTP A1
 - Lead QTPS: Central Maine Power (CMP)
 - Joint Proposal: Yes, w/ Public Service of New Hampshire (PSNH) and NSTAR (Eversource)
 - Type: AC transmission in ME and NH
 - Cost Containment: Yes
 - Projected Benefit-to-Cost Ratio: 2.10
 - Construction Start: Q1 2029, In-Service Date: Q4 2032
 - Design Summary
 - Wind interconnection POI: Pittsfield
 - New 345 kV lines: Pittsfield-Coopers Mills & Buxton-Deerfield (70 mi total)
 - Rebuild Larrabee Rd-Surowiec 115 kV line to operate at 345 kV
 - Several reconductored 345 & 115 kV lines
 - Retire ME Yankee 345 kV substation, build new adjacent Old Ferry Rd 345 kV
 - New STATCOMs: Eight 400 MVAR @ 345 kV
 - New Phase Angle Regulators: Four 750 MVA @ 345 kV
 - Minor corollary upgrade: Three upgraded 115 kV breakers at Orrington



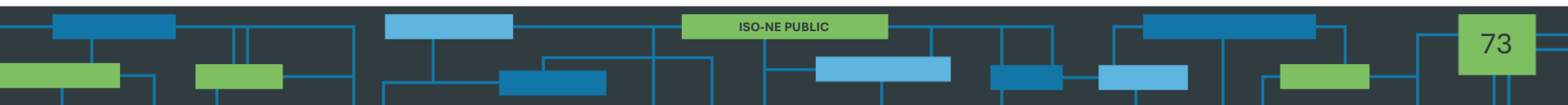
Permanent Asset Condition Reviewer

- ISO engaged with the Transmission Committee (TC) and the PTO Administrative Committee (PTO-AC) regarding the development of this new role. The proposal was the product of robust discussion and incorporated numerous stakeholder-suggested revisions
- Final changes to the Transmission Operating Agreement (TOA) and ISO's Open Access Transmission Tariff (OATT) were presented and voted on at the August Participants Committee meeting
 - The PC voted in favor of the proposal
- Interim project reviews underway to inform permanent design
- Targeting January 2027 go-live, subject to FERC acceptance and operating budget
- Tariff changes were filed on August 17, 2026

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 9/24/2026

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Oct-20	4
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Oct-20	4
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

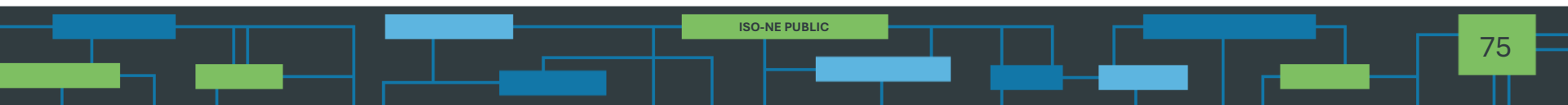
SEMA/RI Reliability Projects, cont.

Status as of 9/24/2026

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	Dec-29	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	Jul-27	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

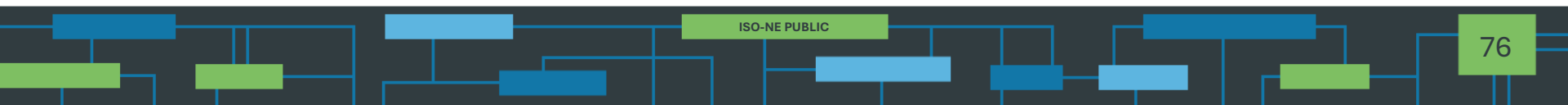


SEMA/RI Reliability Projects, cont.

Status as of 9/24/2026

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	Jul-27	3



SEMA/RI Reliability Projects, cont.

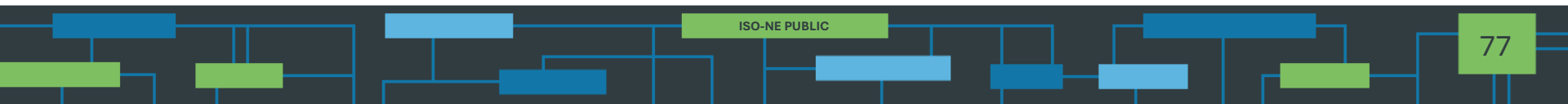
Status as of 9/24/2026

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	Nov-25	4
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

* Does not include the reconductoring work over the Cape Cod canal

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

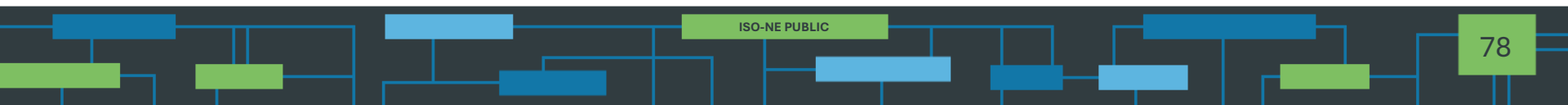


SEMA/RI Reliability Projects, cont.

Status as of 9/24/2026

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

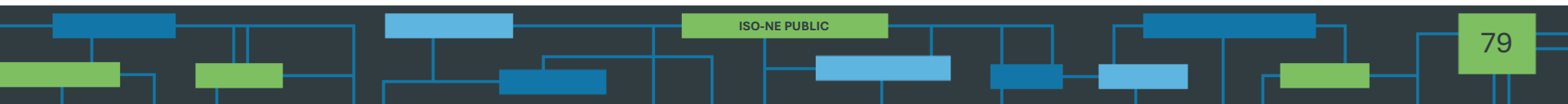


Upper Maine Solution Projects

Status as of 9/24/2026

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	Dec-29	2
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-29	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-30	2
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



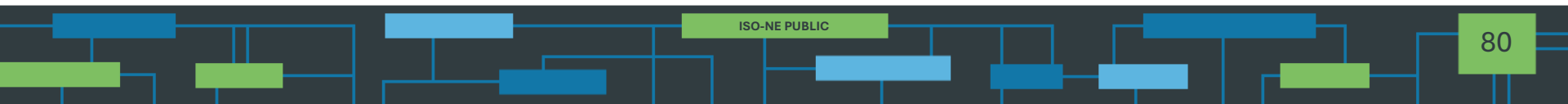
Upper Maine Solution Projects, cont.

Status as of 9/24/2026

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	Dec-26	3

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

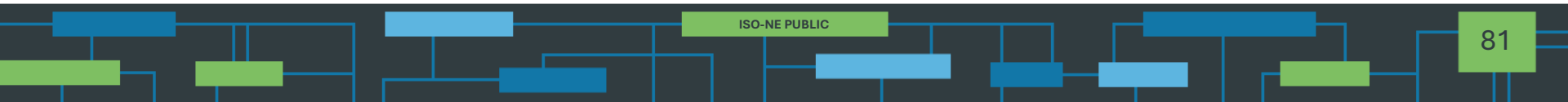


Boston 2033 Solutions Study

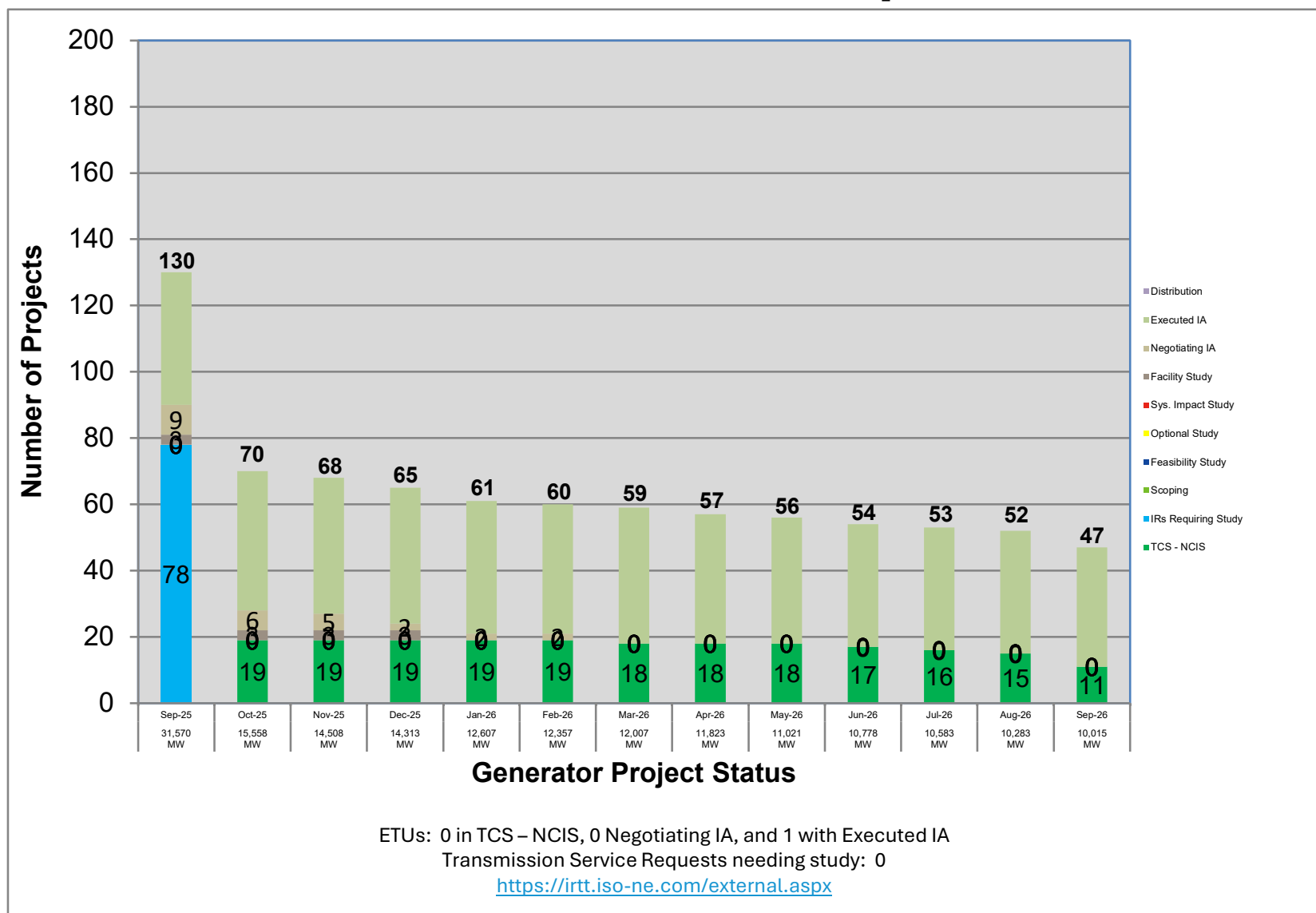
Status as of 9/24/2026

Project Benefit: Addresses system needs in the Boston area

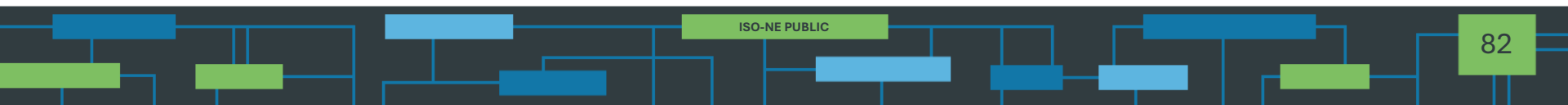
RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1933	Install one 80 MVAR shunt reactor at the 115 kV Electric Avenue Substation	Dec-28	1
1934	Protection systems modification associated with the Stoughton RAS at three 345 kV substations (Stoughton, West Walpole and Holbrook) and two 115 kV substations (Hyde Park and K-Street)	Mar-27	1



Status of Tariff Studies as of September 24, 2026



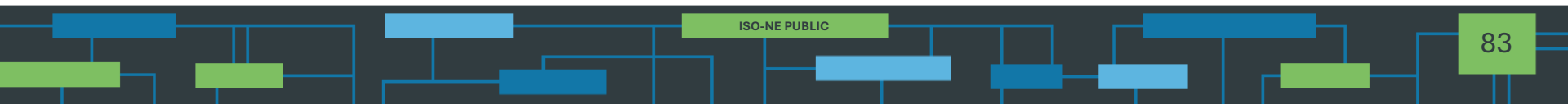
Additional notes provided on next slide



Status of Tariff Studies as of September 24, 2026, cont.

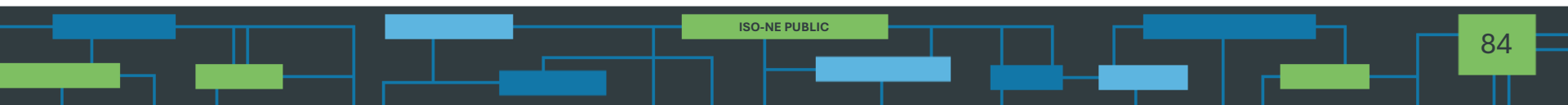
- Additional Notes

- The final Transitional Cluster Study Report was issued on August 6, 2026
- The Cluster Request Window for the first regular Cluster Study opens on October 5, 2026 and will be open for 45 Calendar Days
- The interconnection queue has been closed since June 13, 2024



OPERABLE CAPACITY ANALYSIS

Fall 2026 Analysis



Fall 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov - 2026 ² CSO (MW)	Nov - 2026 ² SCC (MW)
Operable Capacity MW ¹	27,213	29,317
Active Demand Capacity Resource (+) ⁵	349	275
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	97	97
Non Gas-fired Planned Outage MW (-)	2,499	2,906
Gas Generator Outages MW (-)	2,593	2,802
Allowance for Unplanned Outages (-) ⁴	3,600	3,600
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,376	20,790
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	17,623	17,623
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,685	19,685
Operable Capacity Margin	-309	1,105

¹Operable Capacity is based on data as of **September 22, 2026** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 22, 2026**.

² Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 7, 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.

Fall 2026 Operable Capacity Analysis

90/10 Load Forecast	Nov - 2026 ² CSO (MW)	Nov - 2026 ² SCC (MW)
Operable Capacity MW ¹	27,213	29,317
Active Demand Capacity Resource (+) ⁵	349	275
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	97	97
Non Gas-fired Planned Outage MW (-)	2,499	2,906
Gas Generator Outages MW (-)	2,593	2,802
Allowance for Unplanned Outages (-) ⁴	3,600	3,600
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,376	20,790
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	18,461	18,461
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,523	20,523
Operable Capacity Margin	-1,147	267

¹ Operable Capacity is based on data as of **September 22, 2026** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 22, 2026**.

² Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 7, 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.

Fall 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 22, 2026 - 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 October through November.

Report created: 9/22/2026

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas- Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50- 50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50- 50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
10/10/2026	27068	320	409	16	3921	3150	2800	0	17942	16138	2062	18200	-258	N	Fall 2026
10/17/2026	27068	320	409	16	2978	3282	2800	0	18753	16991	2062	19053	-300	N	Fall 2026
10/24/2026	27068	320	409	16	2940	2991	2800	0	19082	17326	2062	19388	-306	N	Fall 2026
10/31/2026	27213	349	409	97	2518	1906	3600	0	20044	17517	2062	19579	465	N	Fall 2026
11/7/2026	27213	349	409	97	2499	2593	3600	0	19376	17623	2062	19685	-309	Y	Fall 2026
11/14/2026	27213	349	409	97	2085	2319	3600	0	20064	17941	2062	20003	61	N	Fall 2026
11/21/2026	27213	349	409	97	133	1082	3600	288	22965	18621	2062	20683	2282	N	Fall 2026

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 2026 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:** 115% 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)
- Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.
- Operable Capacity Season Label:** Applicable season and year.

Fall 2026 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 22, 2026 - 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 October through November.

Report created: 9/22/2026

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	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
10/10/2026	27068	320	409	16	3921	3150	2800	0	17942	16906	2062	18968	-1026	N	Fall 2026
10/17/2026	27068	320	409	16	2978	3282	2800	0	18753	17798	2062	19860	-1107	N	Fall 2026
10/24/2026	27068	320	409	16	2940	2991	2800	0	19082	18150	2062	20212	-1130	N	Fall 2026
10/31/2026	27213	349	409	97	2518	1906	3600	0	20044	18350	2062	20412	-368	N	Fall 2026
11/7/2026	27213	349	409	97	2499	2593	3600	0	19376	18461	2062	20523	-1147	Y	Fall 2026
11/14/2026	27213	349	409	97	2085	2319	3600	0	20064	18794	2062	20856	-792	N	Fall 2026
11/21/2026	27213	349	409	97	133	1082	3600	453	22800	19506	2062	21568	1232	N	Fall 2026

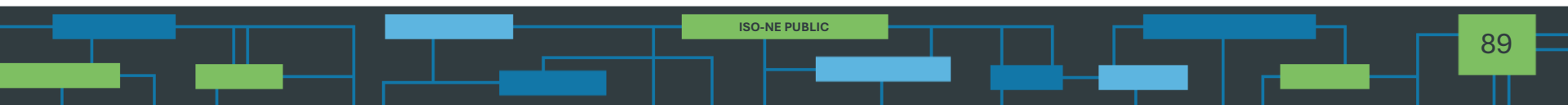
Column Definitions

- CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
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- 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 2026 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:** 115% 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)
- Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.
- Operable Capacity Season Label:** Applicable season and year.

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

OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2026/27 Analysis



Preliminary Winter 2026/27 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan - 2027 ² CSO (MW)	Jan - 2027 ² SCC (MW)
Operable Capacity MW ¹	27,429	29,317
Active Demand Capacity Resource (+) ⁵	348	275
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	98	98
Non Gas-fired Planned Outage MW (-)	21	342
Gas Generator Outages MW (-)	0	14
Allowance for Unplanned Outages (-) ⁴	2,800	2,800
Generation at Risk Due to Gas Supply (-) ³	3,728	4,122
Net Capacity (NET OPCAP SUPPLY MW)	21,735	22,821
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	20,483	20,483
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,545	22,545
Operable Capacity Margin	-810	276

¹Operable Capacity is based on data as of **September 22, 2026** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 22, 2026**.

² Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 9, 2027**.

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

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

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

Preliminary Winter 2026/27 Operable Capacity Analysis

90/10 Load Forecast	Jan - 2027 ² CSO (MW)	Jan - 2027 ² SCC (MW)
Operable Capacity MW ¹	27,429	29,317
Active Demand Capacity Resource (+) ⁵	348	275
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	98	98
Non Gas-fired Planned Outage MW (-)	21	342
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) ⁴	2,800	2,800
Generation at Risk Due to Gas Supply (-) ³	4,539	5,052
Net Capacity (NET OPCAP SUPPLY MW)	20,924	21,891
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	21,457	21,457
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,519	23,519
Operable Capacity Margin	-2,595	-1,628

¹ Operable Capacity is based on data as of **September 22, 2026** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 22, 2026**.

² Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 9, 2027**.

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

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

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

Preliminary Winter 2026/27 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 22, 2026 - 50-50 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in December through March.

Report created: 9/22/2026

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	
11/28/2026	27213	349	409	97	173	325	3600	1337	22633	19285	2062	21347	1286	N	Winter 2026/2027
12/5/2026	27429	348	409	98	149	822	3200	982	23131	19469	2062	21531	1600	N	Winter 2026/2027
12/12/2026	27429	348	409	98	100	0	3200	2368	22616	19735	2062	21797	819	N	Winter 2026/2027
12/19/2026	27429	348	409	98	21	0	3200	2745	22318	19746	2062	21808	510	N	Winter 2026/2027
12/26/2026	27429	348	409	98	21	0	3200	3134	21929	19803	2062	21865	64	N	Winter 2026/2027
1/2/2027	27429	348	409	98	21	0	2800	3733	21730	20055	2062	22117	-387	N	Winter 2026/2027
1/9/2027	27429	348	409	98	21	0	2800	3728	21735	20483	2062	22545	-810	Y	Winter 2026/2027
1/16/2027	27429	348	409	98	23	0	2800	3583	21878	20483	2062	22545	-667	N	Winter 2026/2027
1/23/2027	27429	348	409	98	23	0	2800	3134	22327	20483	2062	22545	-218	N	Winter 2026/2027
1/30/2027	27429	348	409	98	32	0	3100	2835	22317	20278	2062	22340	-23	N	Winter 2026/2027
2/6/2027	27429	348	409	98	21	0	3100	2536	22627	20032	2062	22094	533	N	Winter 2026/2027
2/13/2027	27429	348	409	98	62	0	3100	2237	22885	20006	2062	22068	817	N	Winter 2026/2027
2/20/2027	27429	348	409	98	52	0	3100	1788	23344	19764	2062	21826	1518	N	Winter 2026/2027
2/27/2027	27429	348	409	98	270	430	2200	1059	24325	18854	2062	20916	3409	N	Winter 2026/2027
3/6/2027	27429	348	409	98	286	1073	2200	0	24725	18533	2062	20595	4130	N	Winter 2026/2027
3/13/2027	27429	348	409	98	780	767	2200	0	24537	18353	2062	20415	4122	N	Winter 2026/2027
3/20/2027	27429	348	409	98	258	1801	2200	0	24025	18017	2062	20079	3946	N	Winter 2026/2027
3/27/2027	27213	349	409	98	100	2595	2700	0	22674	17496	2062	19558	3116	N	Winter 2026/2027

Column Definitions

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- 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 2026 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:** 115% 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)
- Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.
- Operable Capacity Season Label:** Applicable season and year.

Preliminary Winter 2026/27 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 22, 2026 - 90/10 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in December through March.

Report created: 9/22/2026

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	
11/28/2026	27213	349	409	97	173	325	3600	2251	21719	20201	2062	22263	-544	N	Winter 2026/2027
12/5/2026	27429	348	409	98	149	822	3200	1970	22143	20394	2062	22456	-313	N	Winter 2026/2027
12/12/2026	27429	348	409	98	100	0	3200	3355	21629	20673	2062	22735	-1106	N	Winter 2026/2027
12/19/2026	27429	348	409	98	21	0	3200	3864	21199	20684	2062	22746	-1547	N	Winter 2026/2027
12/26/2026	27429	348	409	98	21	0	3200	4280	20783	20744	2062	22806	-2023	N	Winter 2026/2027
1/2/2027	27429	348	409	98	21	0	2800	4408	21055	21008	2062	23070	-2015	N	Winter 2026/2027
1/9/2027	27429	348	409	98	21	0	2800	4539	20924	21457	2062	23519	-2595	Y	Winter 2026/2027
1/16/2027	27429	348	409	98	23	0	2800	4331	21130	21457	2062	23519	-2389	N	Winter 2026/2027
1/23/2027	27429	348	409	98	23	0	2800	4032	21429	21457	2062	23519	-2090	N	Winter 2026/2027
1/30/2027	27429	348	409	98	32	0	3100	4032	21120	21242	2062	23304	-2184	N	Winter 2026/2027
2/6/2027	27429	348	409	98	21	0	3100	3583	21580	20984	2062	23046	-1466	N	Winter 2026/2027
2/13/2027	27429	348	409	98	62	0	3100	3284	21838	20957	2062	23019	-1181	N	Winter 2026/2027
2/20/2027	27429	348	409	98	52	0	3100	2686	22446	20703	2062	22765	-319	N	Winter 2026/2027
2/27/2027	27429	348	409	98	270	430	2200	1807	23577	19751	2062	21813	1764	N	Winter 2026/2027
3/6/2027	27429	348	409	98	286	1073	2200	238	24487	19414	2062	21476	3011	N	Winter 2026/2027
3/13/2027	27429	348	409	98	780	767	2200	439	24098	19225	2062	21287	2811	N	Winter 2026/2027
3/20/2027	27429	348	409	98	258	1801	2200	0	24025	18873	2062	20935	3090	N	Winter 2026/2027
3/27/2027	27213	349	409	98	100	2595	2700	0	22674	18328	2062	20390	2284	N	Winter 2026/2027

Column Definitions

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*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