

JULY 9, 2026



NEPOOL Participants Committee

System & Market Operations Report – July 2026

Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS

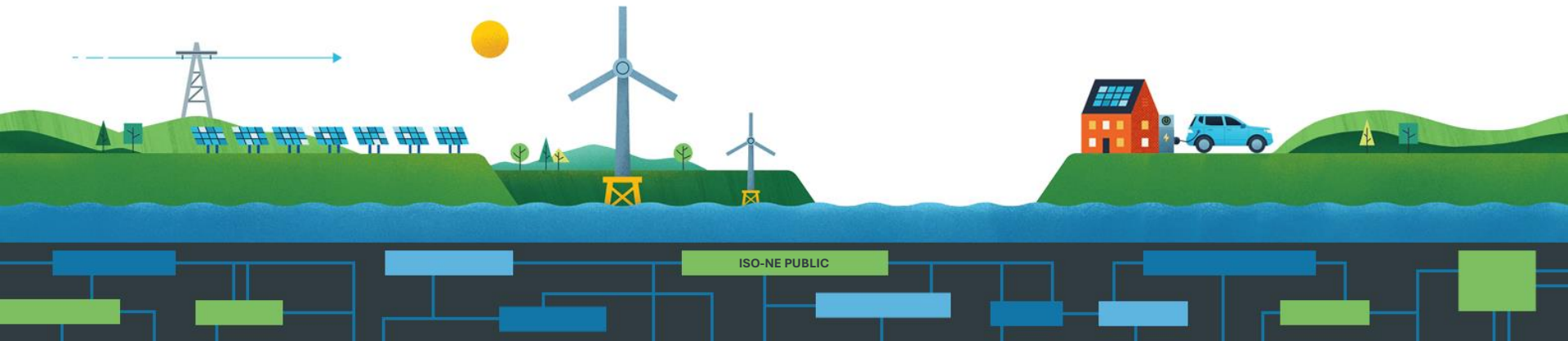
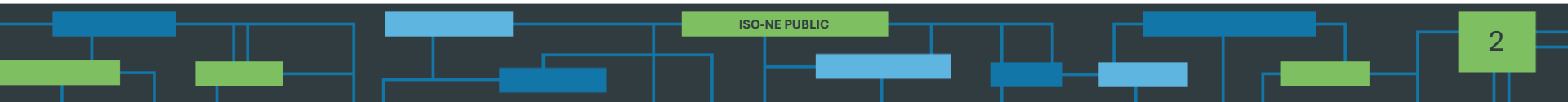


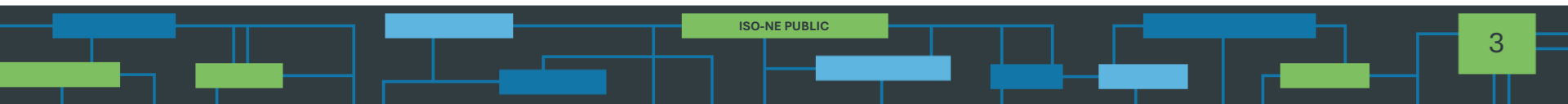
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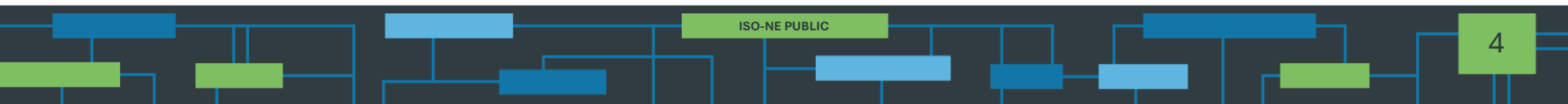


System & Market Operations Report Enhancements

- 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)
 - Note that slide 5, Weather At-a-Glance, has also been updated this month to add more data reporting
- 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; these slides include:
 - Slide 64, Observed FCM Peak Load by Capacity Zone
 - Slide 65, Forward Capacity Market Auctions
 - Slide 75, Total ISO Billings
- Further enhancements are planned in the coming months to continue simplifying and improving the report



HIGHLIGHTS



Weather At-a-Glance

June 2026

<i>New England Weather</i>	Jun-26	Change M-O-M	Change Y-O-Y
Avg Hourly Temperature (°F) (23-City Weighted)	68.8°	10.9° ↑	0.1° ↑

Boston Weather

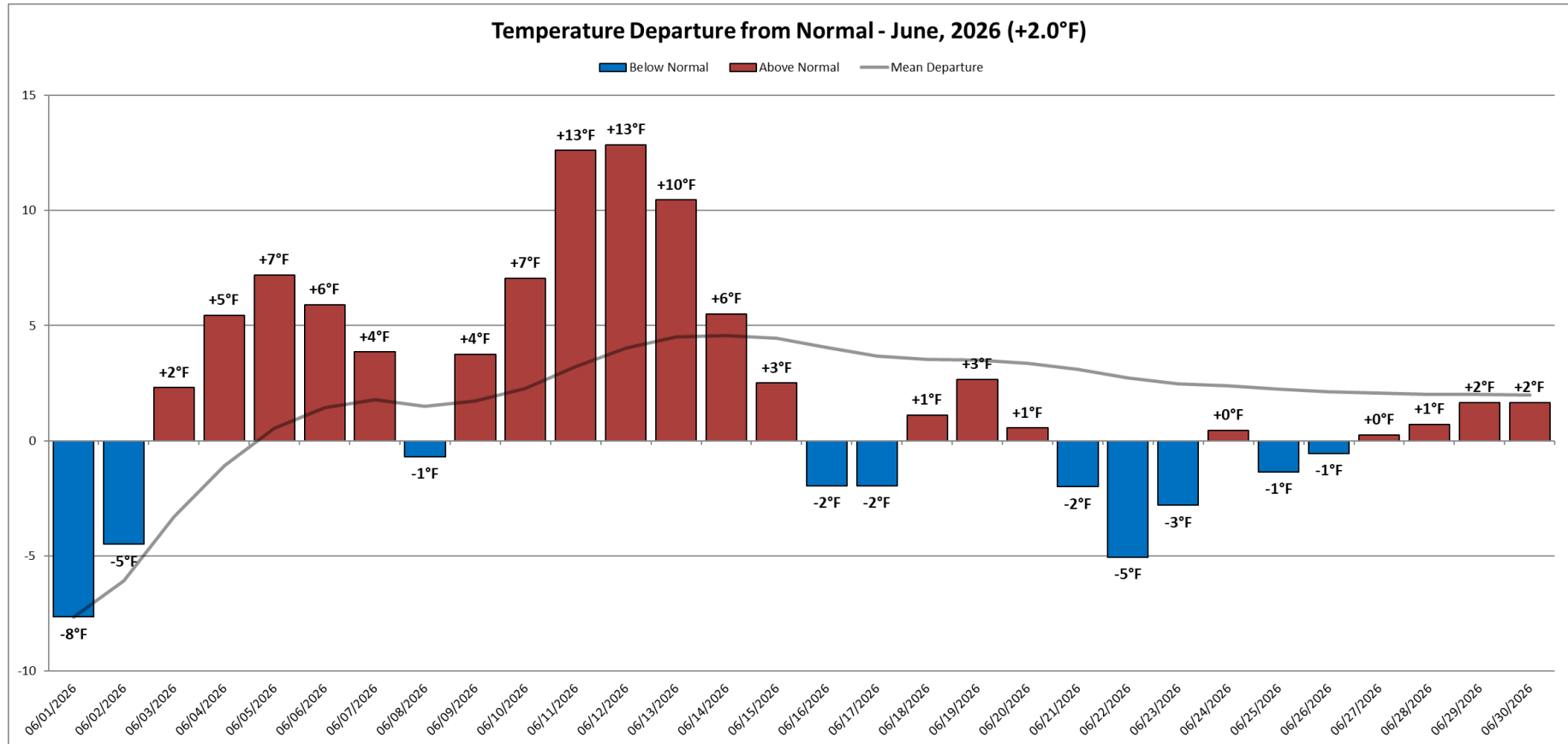
Temperature Departure from Normal (°F)	3.8°	1.4° ↑	2.2° ↑
Maximum Temperature (°F)	91.0°	-5.0° ↓	-11.0° ↓
Minimum Temperature (°F)	49.0°	7.0° ↑	-2.0° ↓
Avg Hourly Temperature (°F)	71.8°	11.0° ↑	2.2° ↑
Precipitation Departure from Normal (inches)	-2.43"	-1.27" ↓	0.14" ↑
Precipitation (inches)	1.46"	-0.63" ↓	0.14" ↑

Hartford Weather

Temperature Departure from Normal (°F)	1.5°	2.1° ↑	-0.3° ↓
Maximum Temperature(°F)	94.0°	-2.0° ↓	-5.0° ↓
Minimum Temperature(°F)	40.0°	4.0° ↑	-5.0° ↓
Avg Hourly Temperature (°F)	70.4°	11.0° ↑	-0.3° ↓
Precipitation Departure from Normal (inches)	-2.69"	-2.09" ↓	-0.54" ↓
Precipitation (inches)	1.59"	-1.60" ↓	-0.54" ↓

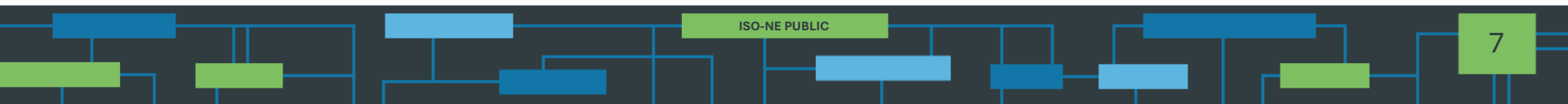
Weather At-a-Glance, cont.

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



System Operations Highlights

- At 12:00 on June 11, ISO declared M/LCC-2, Abnormal Conditions Alert, based on a forecasted capacity deficiency
 - The Morning Report (issued around 8 a.m.) had projected a 65 MW surplus, assuming a peak load of 21,500 MW
 - Before noon, several unplanned generator outages and a load forecast increase to 22,150 MW (driven by higher temperatures and dewpoints) forced ISO to commit two additional generators; the noon Operational Capacity Update Report then projected a 0 MW surplus for the peak hour
 - ISO curtailed Real-Time Only contracts in HE19 to restore flows to day-ahead cleared values
 - Load ultimately peaked in HE19 at 21,145 MW and ISO cancelled the M/LCC-2 alert at 22:00



Markets At-a-Glance: Payments and Prices

Data Through June 30, 2026*

Market Value (\$ millions)^[a]	June 2026	% Change M-O-M	% Change Y-O-Y
Energy Market Value ^[b]	578	24% ↑	-2% ↓
Ancillary Services ^[c]	1	108% ↑	-96% ↓
Forward Capacity Market (FCM)	78	-13% ↓	-13% ↓
Net Commitment Period Compensation (NCPC)	3	-30% ↓	-27% ↓
Total	660	20% ↑	-6% ↓

Average Power Prices (\$/MWh)

DA Hub LMP	50.72	11% ↑	16% ↑
DA Hub LMP Plus Forecast Energy Requirement (FER) Price	51.20	6% ↑	9% ↑
RT Hub LMP	50.92	3% ↑	7% ↑

Average Generation Fuel Prices (\$/MMBtu)

Natural Gas (MA Avg.)	2.60	18% ↑	-10% ↓
No.6 Oil	14.13	-29% ↓	25% ↑
Diesel	25.97	-14% ↓	48% ↑

*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 [here](#).

[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 Forecast Energy Requirement constraint.

[c] Ancillary Services (A/S) = DAAS, Reserves, Regulation, less Marginal Loss Revenue Fund.

Note: May 2026 A/S total was -\$9.8M, driven largely by DAAS closeout charges and Marginal Loss Revenue Fund results

Underlying natural gas data furnished by:



Markets At-a-Glance: Demand

Data Through June 30, 2026*

<i>Average Hourly Net Energy for Load (MWh)^[a]</i>	June 2026	% Change M-O-M	% Change Y-O-Y
--	------------------	---------------------------	---------------------------

Revenue Quality Metered (RQM)	13,783	20.0% ↑	-0.5% ↓
Telemetered	13,034	20.2% ↑	-1.2% ↓

Max/Min Hourly System Load (MW)

Maximum RQM	22,772	16.8% ↑	-14.4% ↓	Fri, Jun 12, 2026 in he18
Maximum Telemetered	22,258	18.9% ↑	-14.5% ↓	Fri, Jun 12, 2026 in he19
Minimum Telemetered	7,721	30.3% ↑	-3.3% ↓	Tue, Jun 2, 2026 in he12

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

RQM	22,772	0.0%	-14.2% ↓	Fri, Jun 12, 2026 in he18
Telemetered	22,258	0.0%	-14.5% ↓	Fri, Jun 12, 2026 in he19
Forward Capacity Market (FCM) Load ^[c]	22,269	0.0%	-14.6% ↓	Fri, Jun 12, 2026 in he19

*Based on available settled days.

[a] Telemetered loads as monitored by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SORs). Both are 'net energy for load' concepts and therefore include transmission losses. Neither of them reflect storage load. Due to the difference in metering quality, derivation, and the impact of SORs, these two 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 [here](#).

[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: Supply

Data Through June 30, 2026*

<i>Average Hourly RQM Supply^[a]</i>	June 2026 (MWh)	% Change M-O-M	% Change Y-O-Y
Total RQM Supply	15,465	18% ↑	1% ↑
Natural Gas	6,509	49% ↑	-12% ↓
Nuclear	2,985	13% ↑	-11% ↓
Hydro	1,129	-2% ↓	14% ↑
Solar	863	20% ↑	15% ↑
Wind	467	-31% ↓	24% ↑
Other ^[b]	552	25% ↑	-11% ↓
Hybrid/Solar	109	19% ↑	28% ↑
Batteries	31	-23% ↓	77% ↑
Oil	20	96% ↑	-80% ↓
Demand Response Resources (DRRs)	1	-65% ↓	-54% ↓
Imports	2,800	-7% ↓	78% ↑
<i>Average Hourly Behind-The-Meter (BTM) Solar^[c]</i>	1,867	20% ↑	19% ↑

*Based on available settled days.

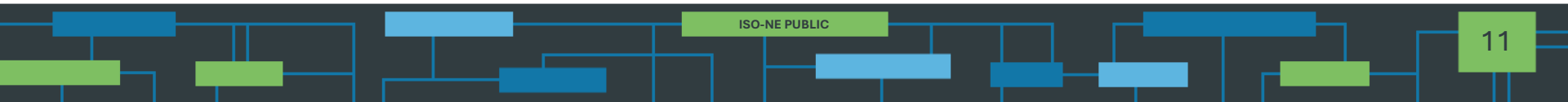
[a] Supply is RQM quality and includes both Modeled and Settlement Only Resources (SORs) and includes DRR and imports. Differs from NEL load due to not being adjusted for exports, Dispatchable Asset Related Demand (DARDs) and inadvertent tie flows.

[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

- The ISO is scheduled to make the preliminary preferred Longer-Term Transmission Solution determination by September 2026



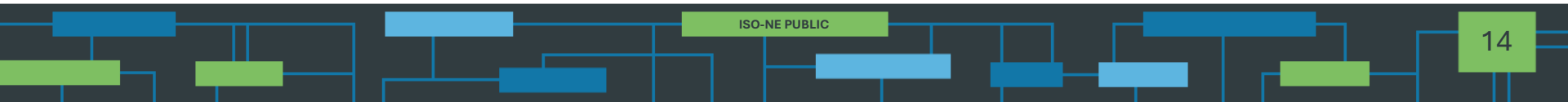
Forward Capacity Market (FCM)

- CCP 17 (2026-2027)
 - The ISO filed the ICR and related values with FERC, for the ARA3 to be 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 ISO filed the ICR and related values with FERC, for the ARA2 to be conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.
 - The second annual reconfiguration auction (ARA2) will be held August 3-5, 2026 and results posted by September 3, 2026.
 - The ISO presented the anticipated schedule for the ICR and related values studies for ARA3 at the June RC meeting.

FCM, cont.

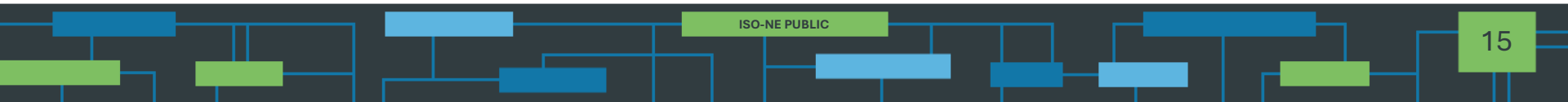
- CCP 19 (2028-2029)
 - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
 - On May 20, 2024 FERC issued an order accepting the additional delay
 - 2024 interim RA qualification process completed on November 1, 2024
 - A total of 1,389 MW (summer Qualified 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 Show of Interest (SOI) window was open April 16-30, 2026
 - The New Capacity Qualification Package (NCQP) submission window was open June 15-23, 2026
 - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

SYSTEM OPERATIONS

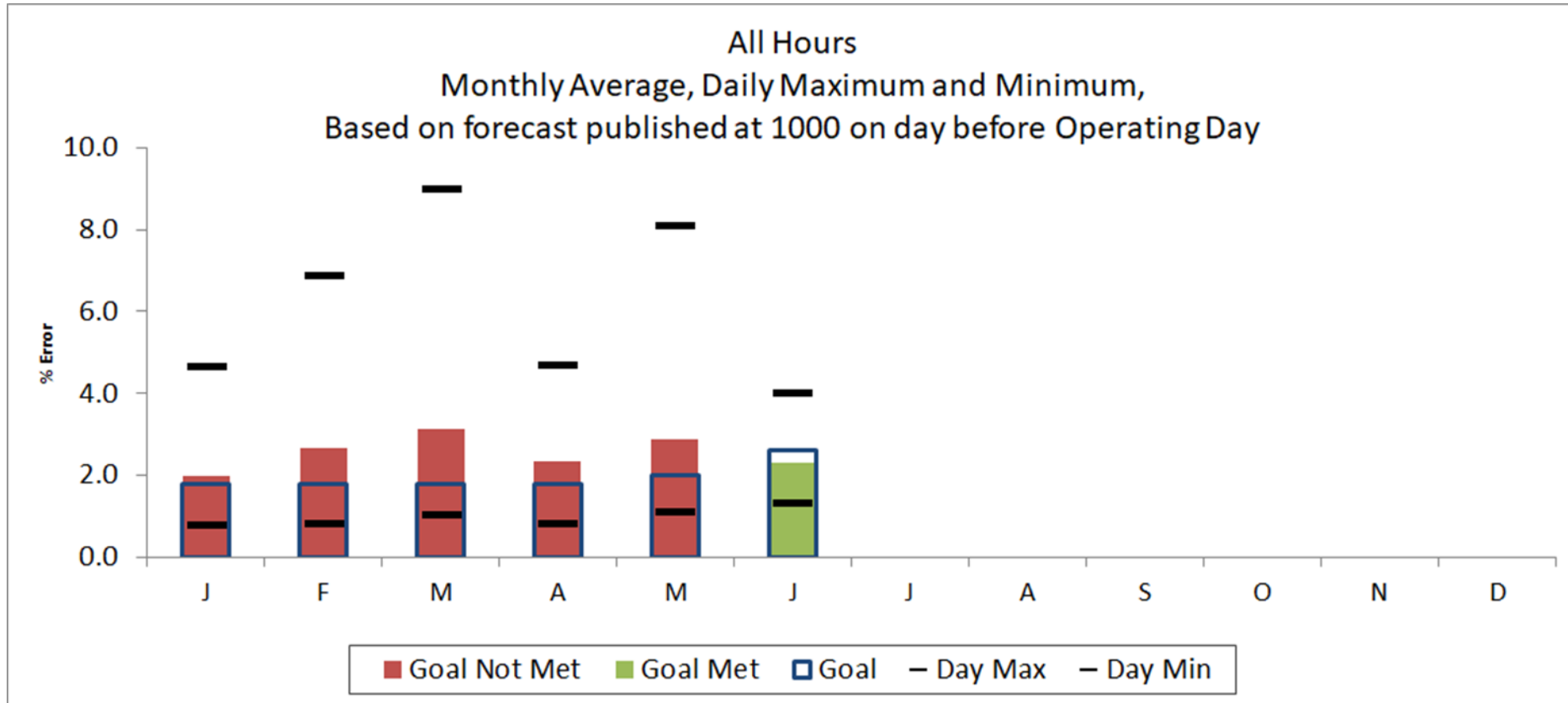


NPCC Simultaneous Activation of Ten-Minute Reserve Events

Date	Area	MW Lost
06/10/2026	IESO	945
06/12/2026	ISO-NE	1050
06/14/2026	ISO-NE	750



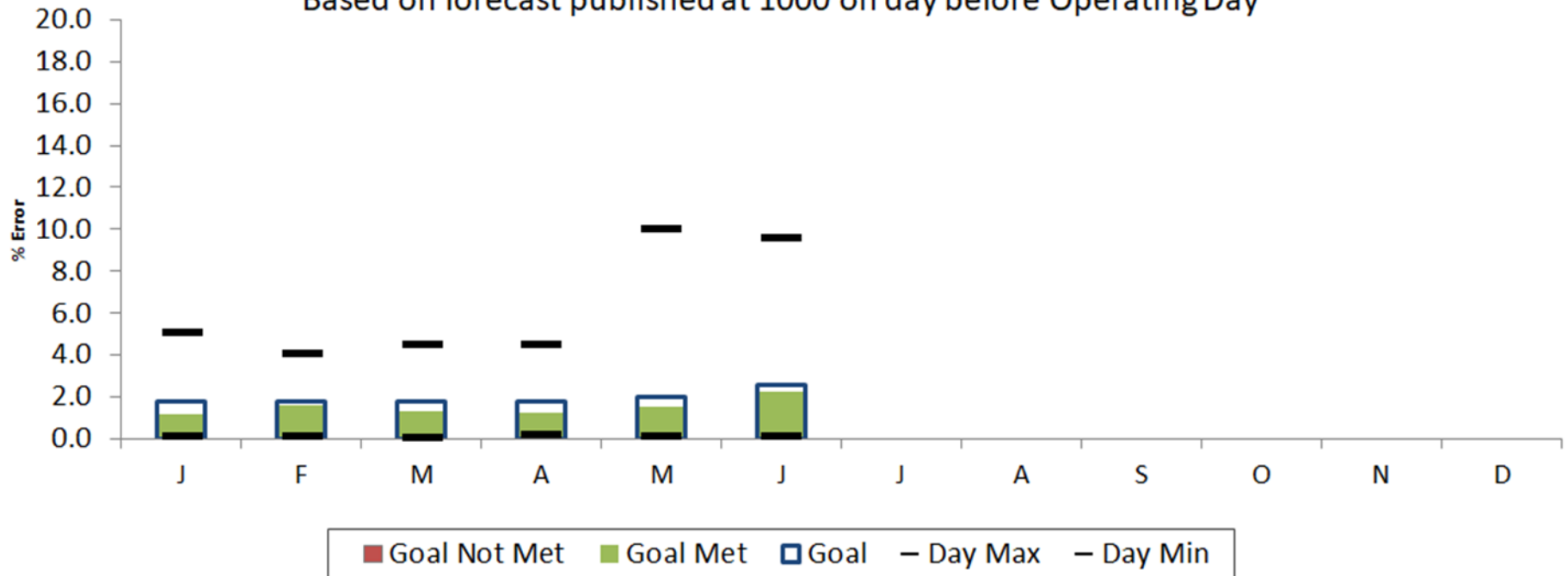
2026 Load Forecast Accuracy



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							8.96
Day Min	0.76	0.82	1.01	0.80	1.09	1.29							0.76
MAPE	2.00	2.66	3.14	2.33	2.90	2.30							2.56
Goal	1.80	1.80	1.80	1.80	2.00	2.60							

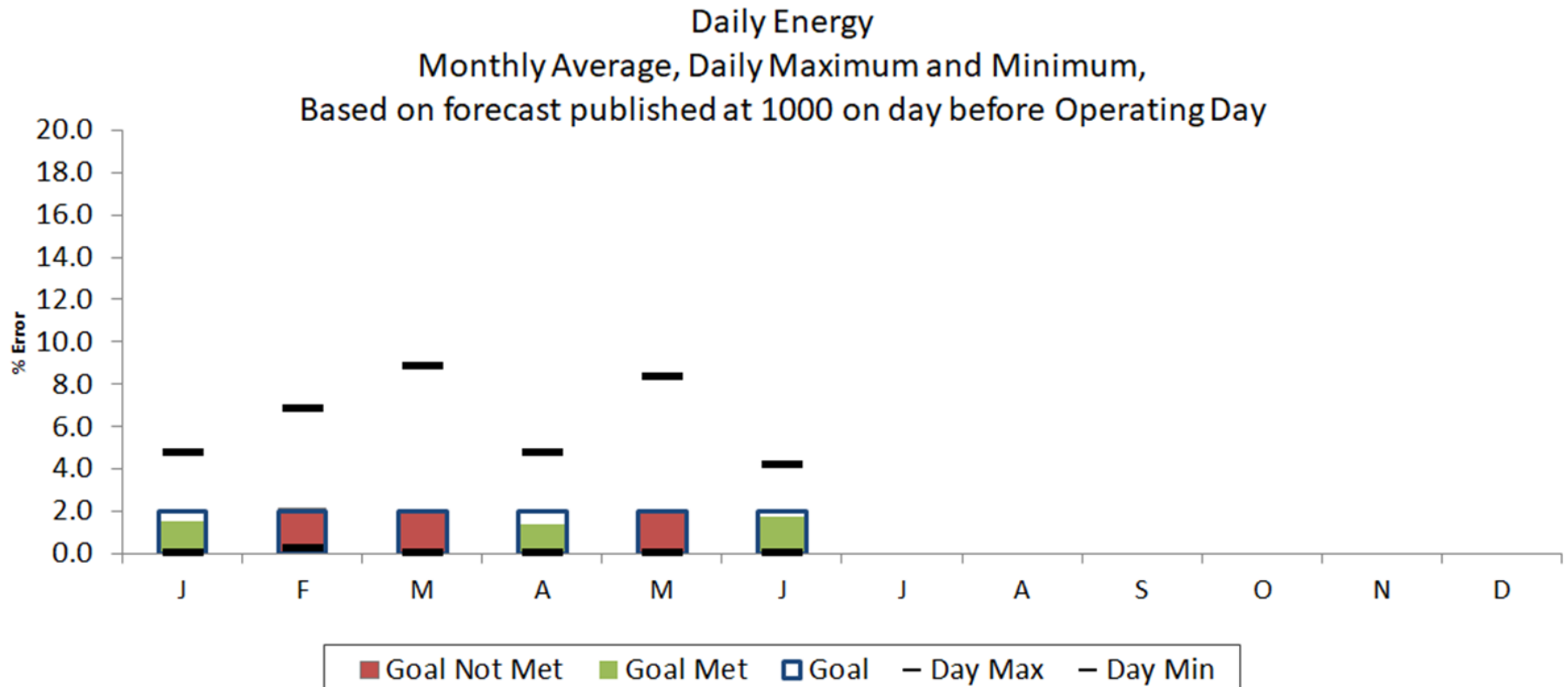
2026 Load Forecast Accuracy, cont.

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



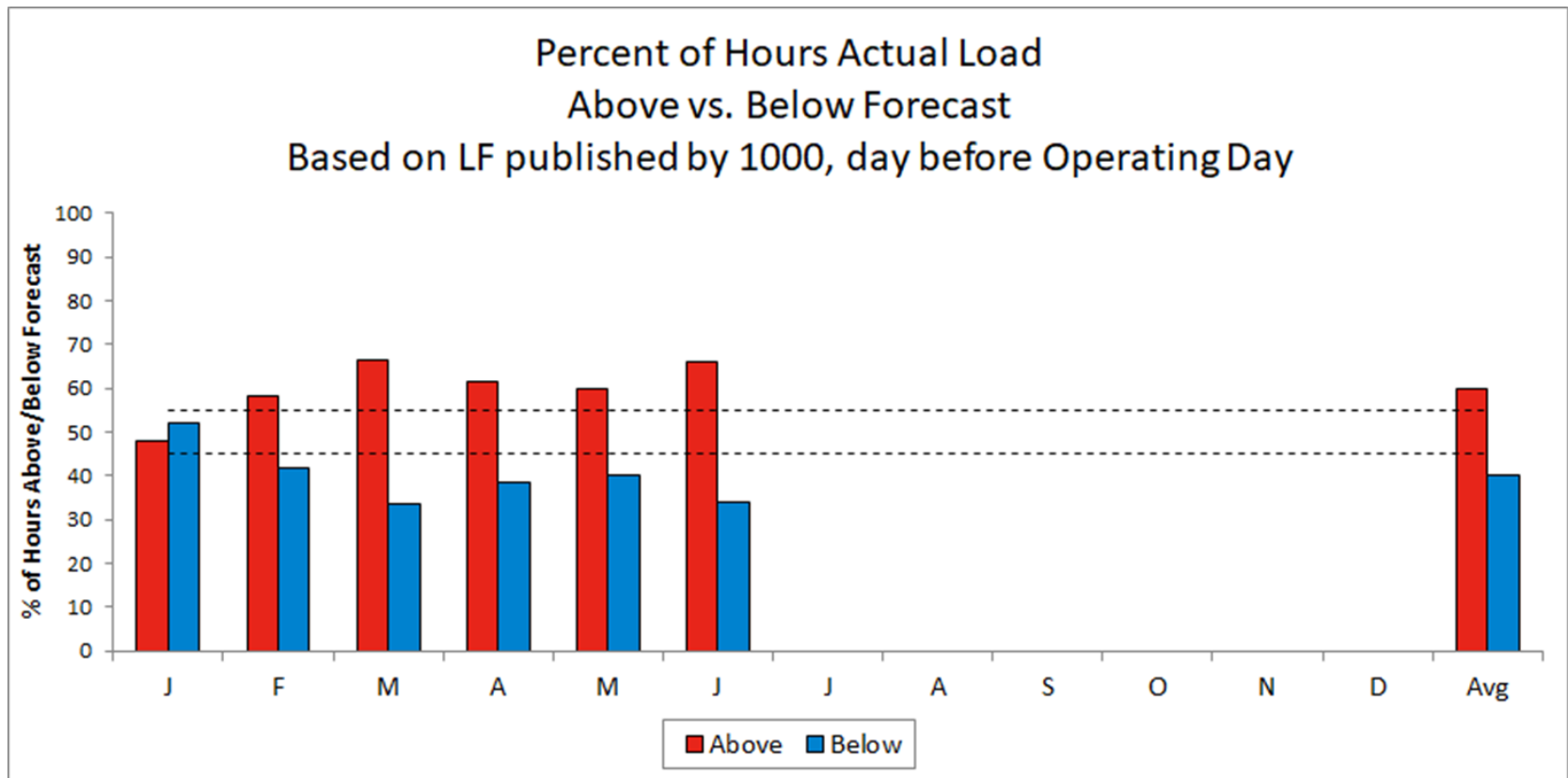
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05	4.02	4.51	4.51	10.02	9.58							10.02
Day Min	0.08	0.12	0.01	0.16	0.11	0.14							0.01
MAPE	1.17	1.64	1.34	1.24	1.52	2.23							1.52
Goal	1.80	1.80	1.80	1.80	2.00	2.60							

2026 Load Forecast Accuracy, cont.



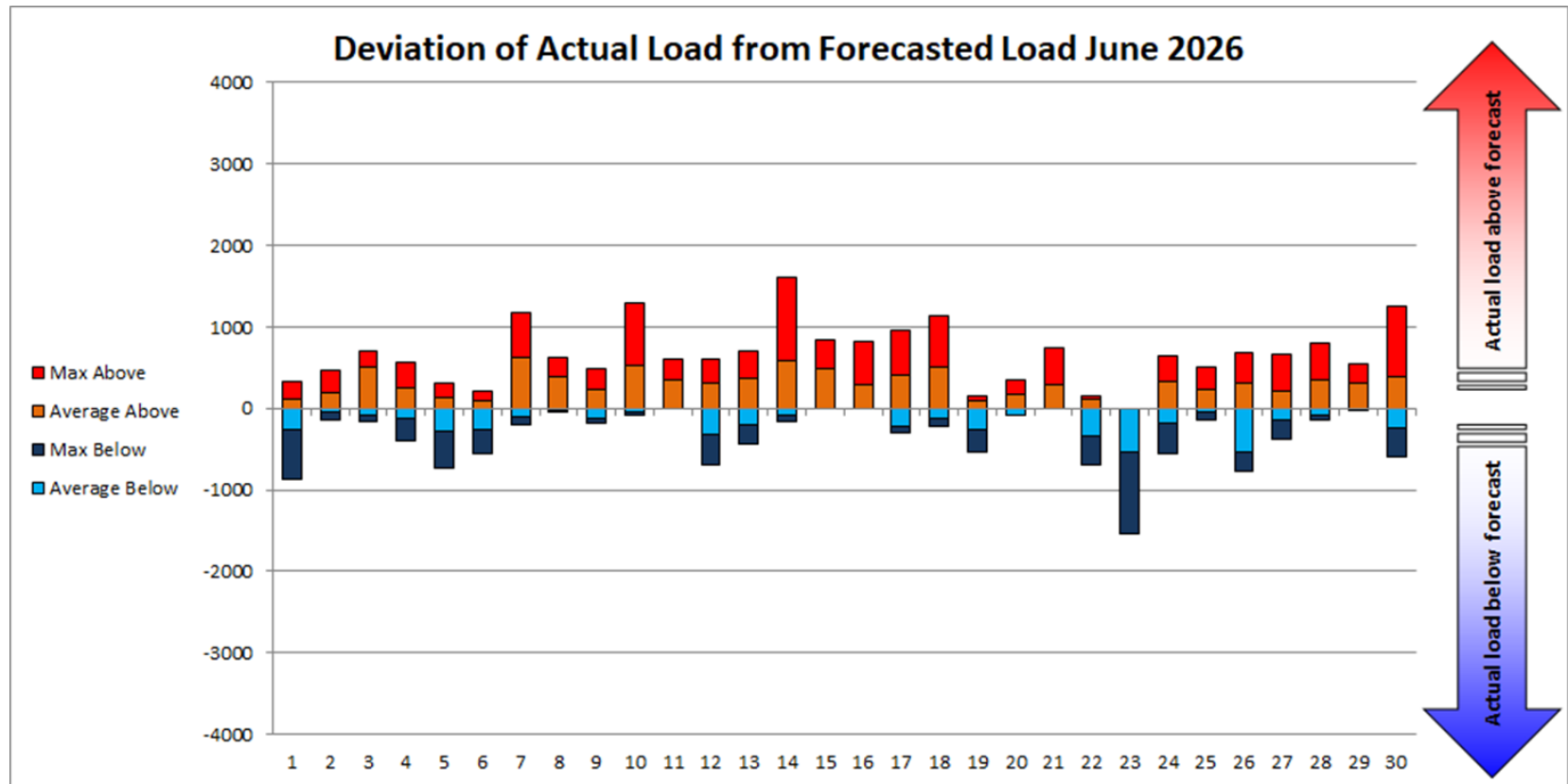
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74	6.81	8.85	4.75	8.32	4.17							8.85
Day Min	0.01	0.22	0.03	0.00	0.06	0.07							0.00
MAPE	1.57	2.12	2.11	1.42	2.06	1.75							1.84
Goal	2.00	2.00	2.00	2.00	2.00	2.00							

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							60
Below %	52.2	41.8	33.6	38.6	40.3	33.9							40
Avg Above	203	299.6	325	240.4	296.5	304							325
Avg Below	-233.3	-271.5	-290.0	-157.2	-194.4	-160.0							-290
Avg All	-20	59	130	91	106	138							84

2026 Load Forecast Accuracy, cont.



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](#)

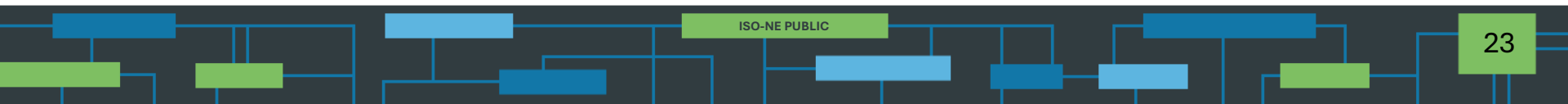
Notable Planned Outages

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

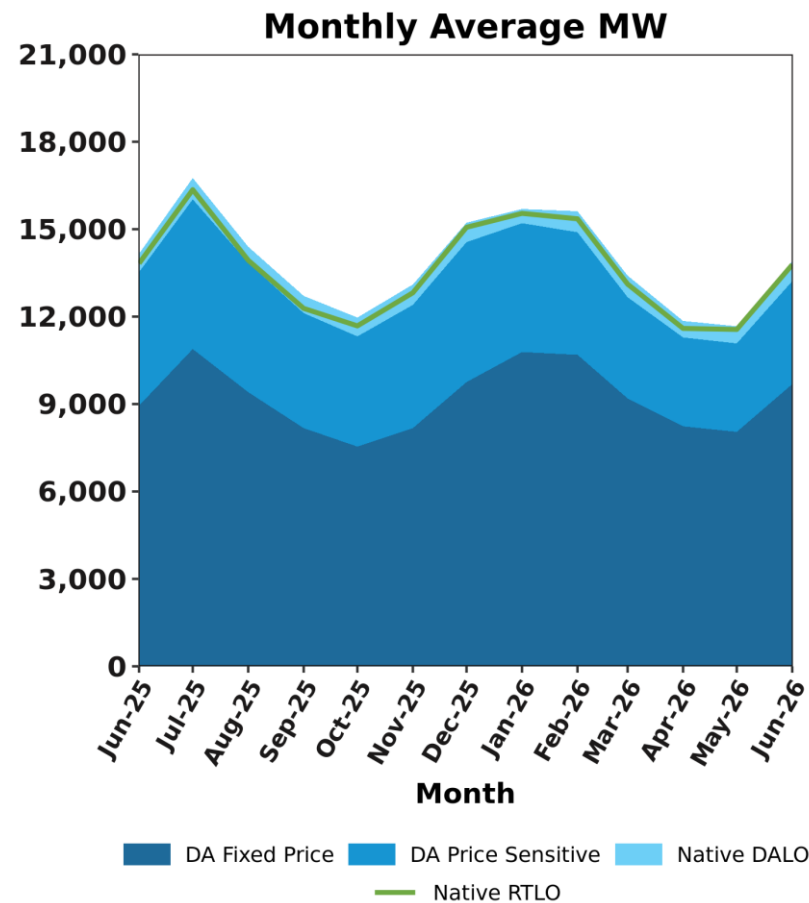
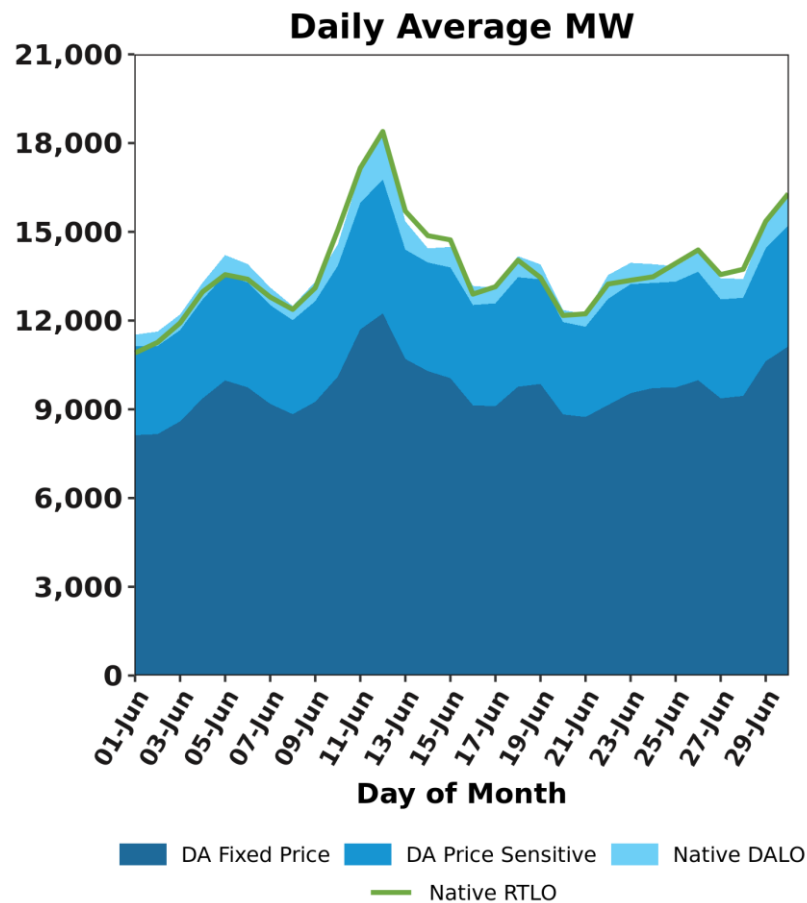
Outage	Start	Planned End	Total Transfer Capability (TTC) Impacts
New Brunswick Generator	04-10-2026	07-27-2026	New Brunswick – New England = 650 MW, New England -New Brunswick = 400 MW
3001	07-20-2026	07-30-2026	New Brunswick – New England = 270 MW, New England -New Brunswick = 0 MW Orrington-South limit up to 785 MW based on adders
Phase 2	10-5-2026	11-02-2026	Phase 2 = 0 MW in both directions

MARKET OPERATIONS

Supply and Demand Volumes

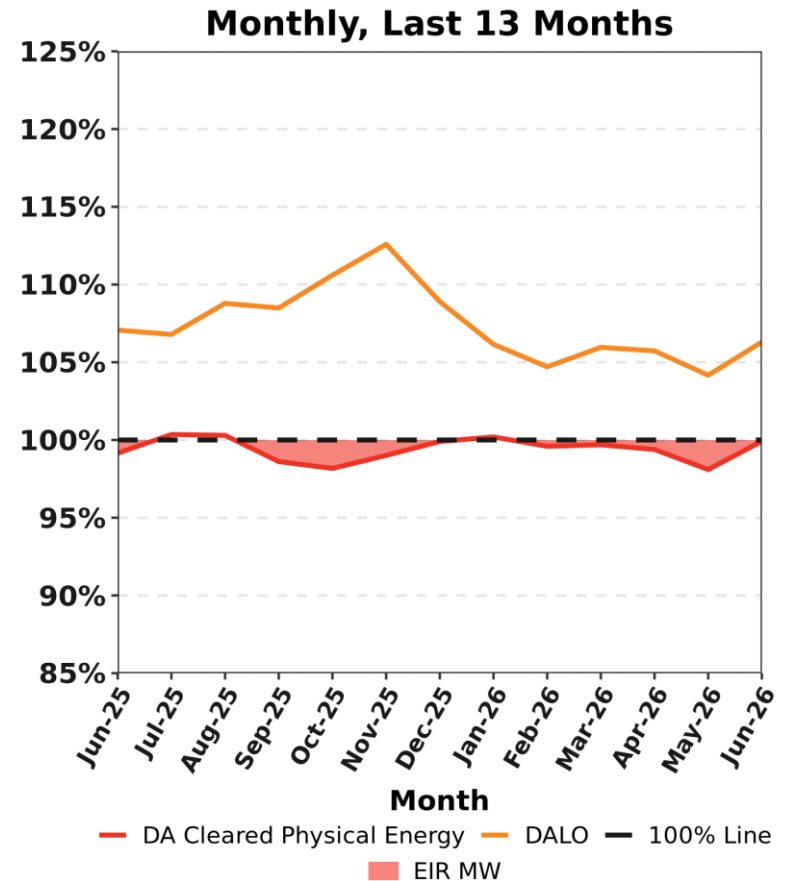
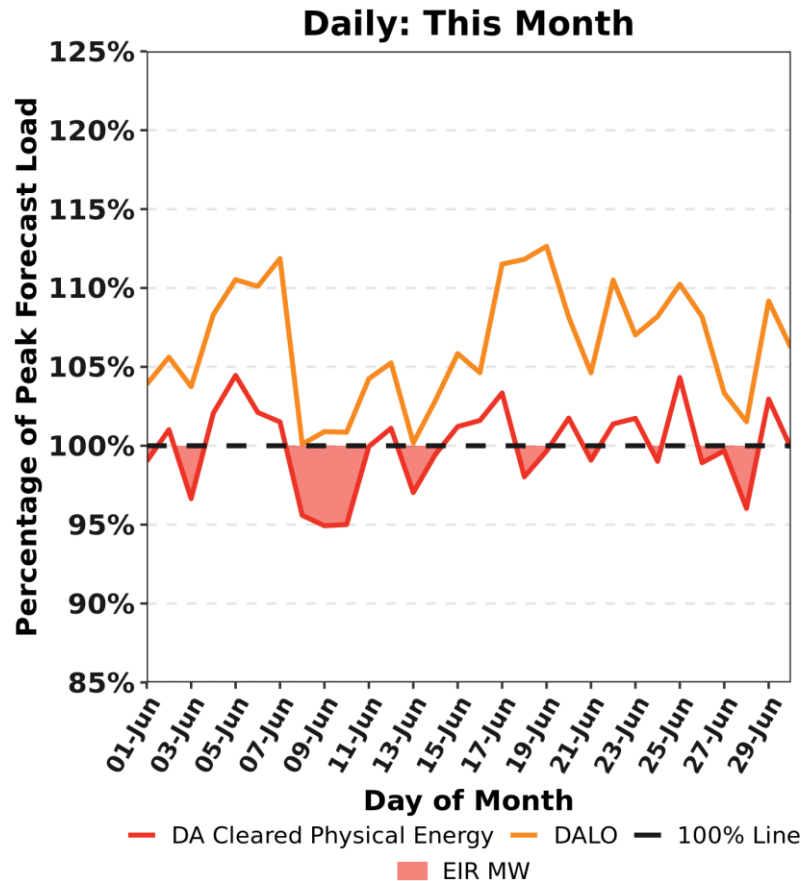


DA Cleared Native Load by Composition Compared to Native RT Load



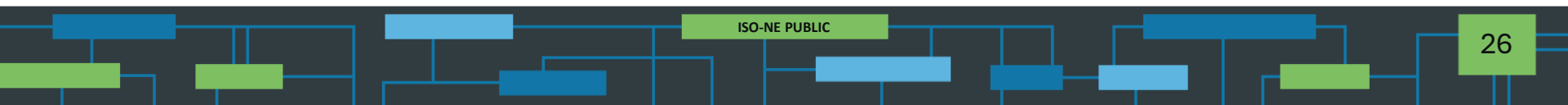
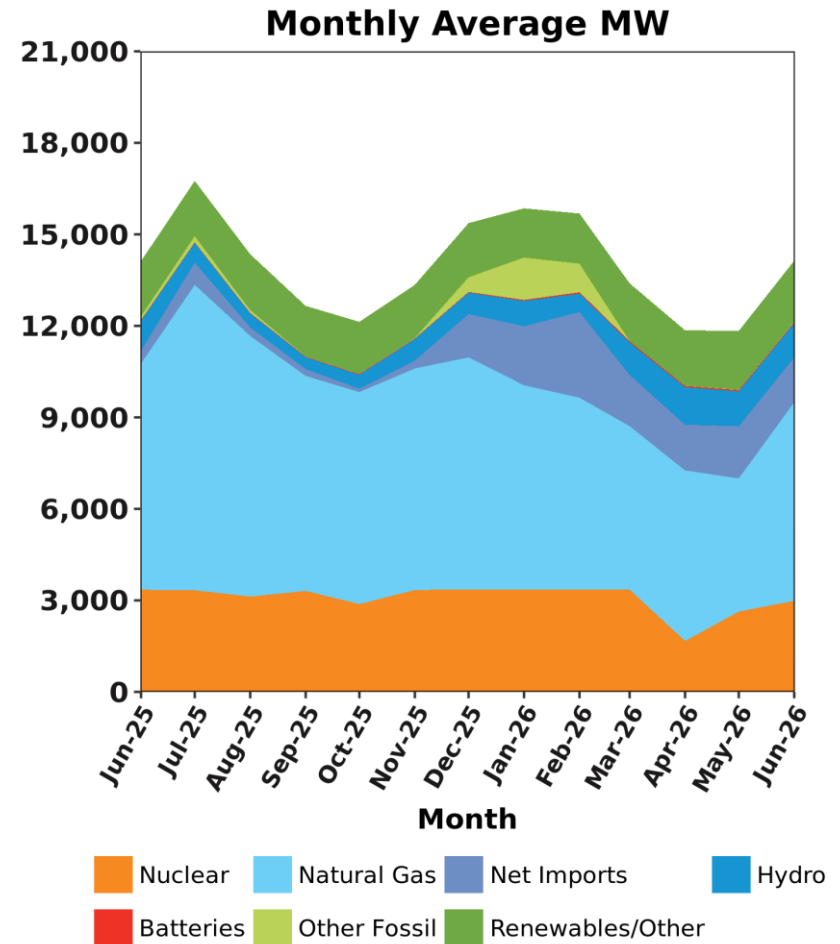
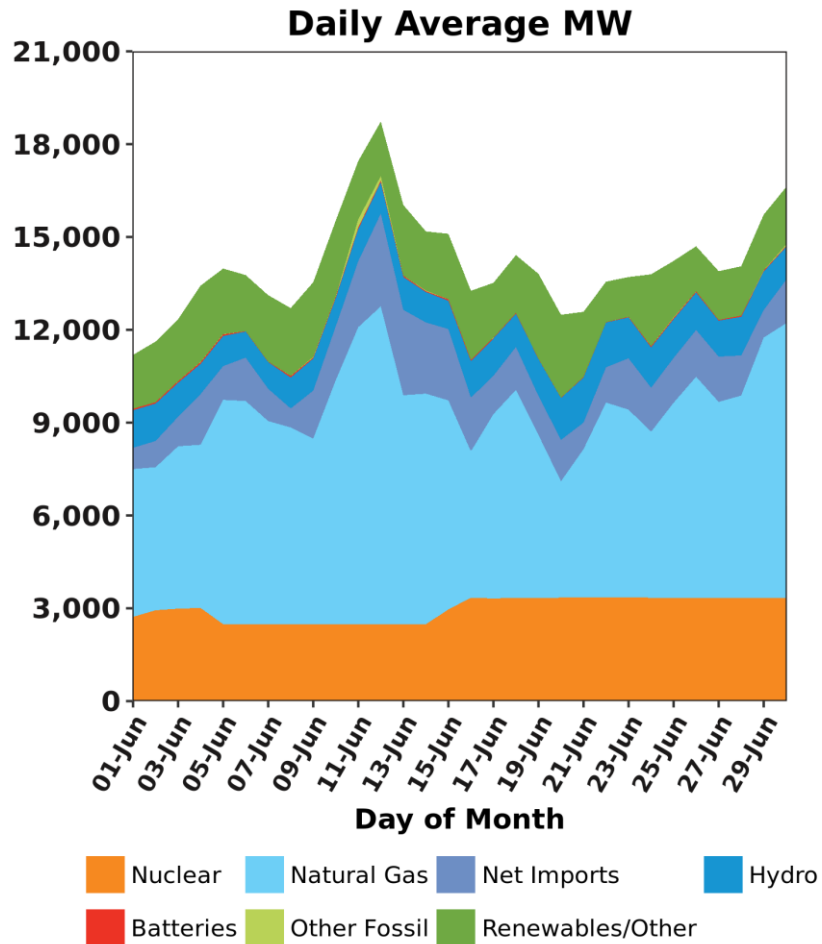
Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

DA Volumes as % of Forecast in Peak Hour

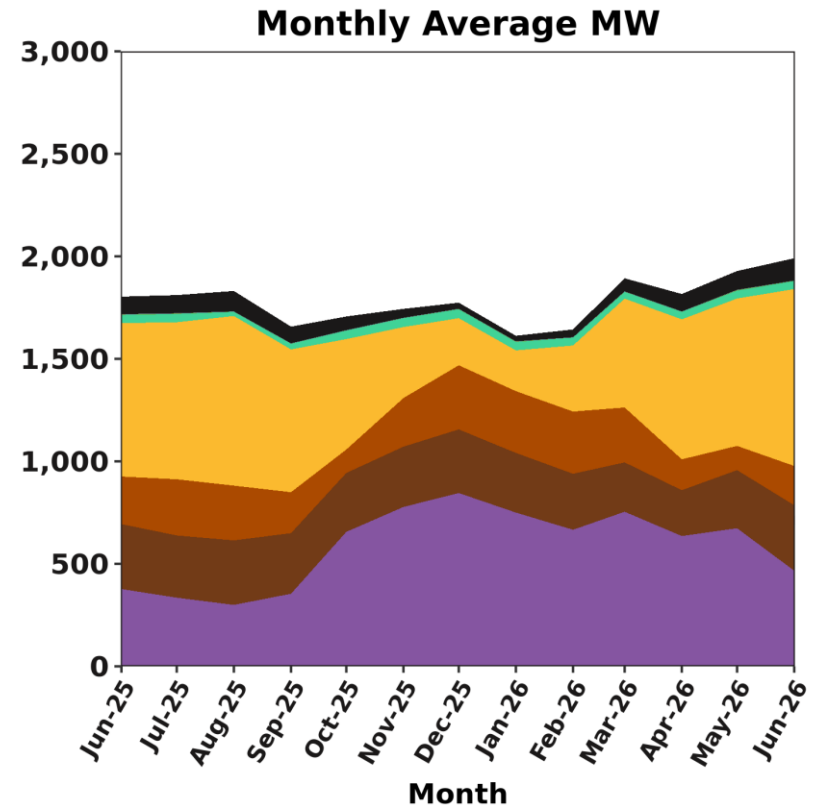
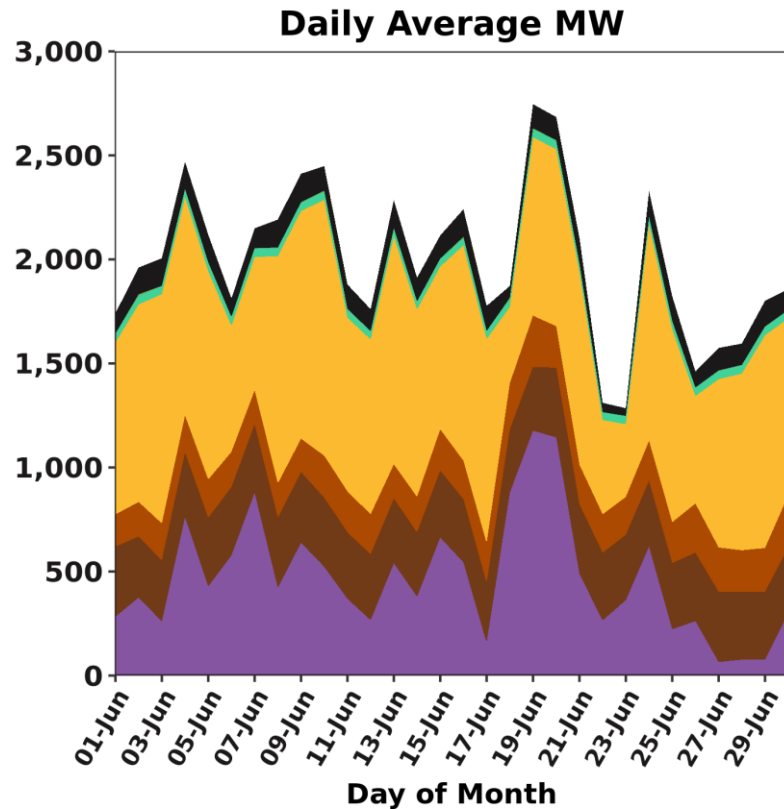


*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Resource Mix



Renewable/Other Generation by Fuel Type

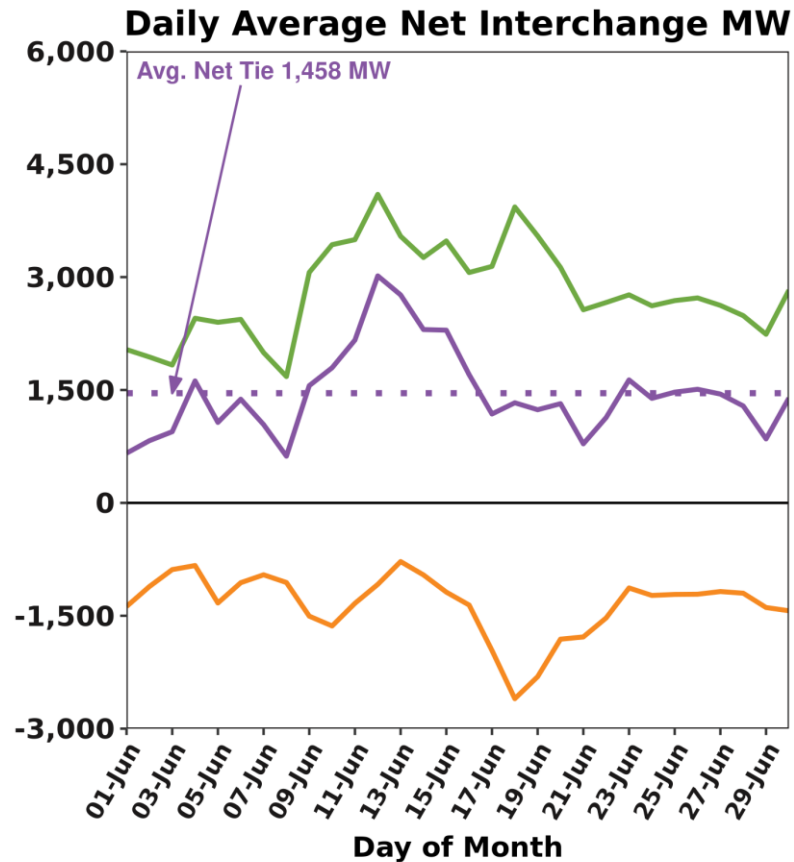


Wind Refuse Wood Solar
Landfill Gas PRD Methane Other

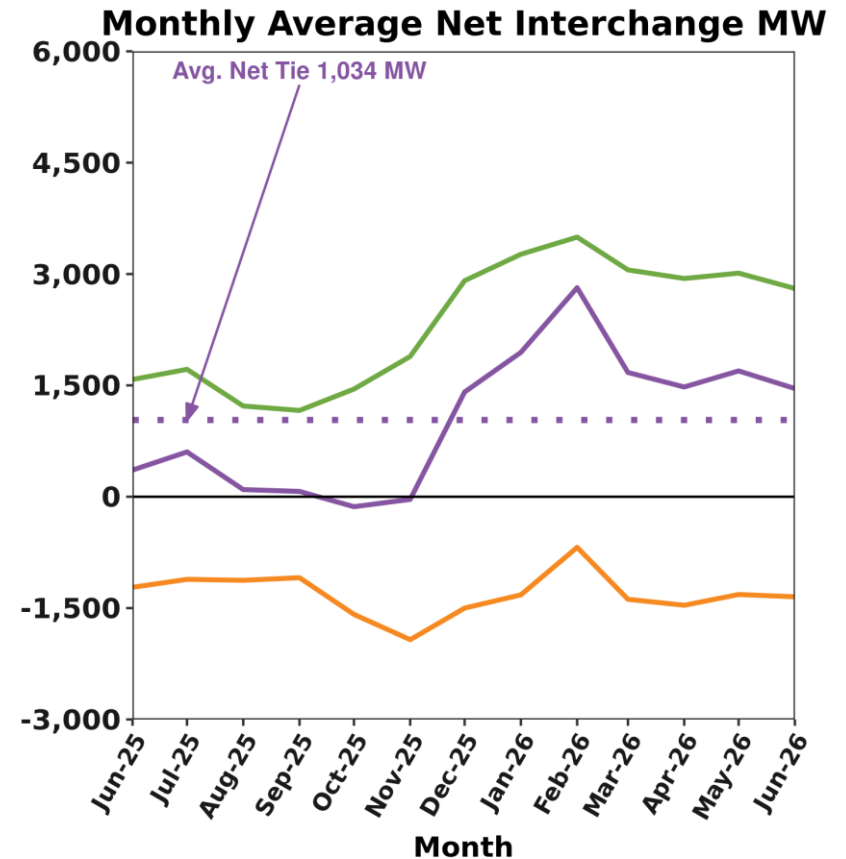
Wind Refuse Wood Solar
Landfill Gas PRD Methane Other

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

RT Net Interchange



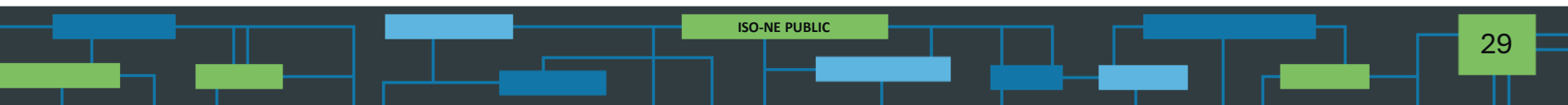
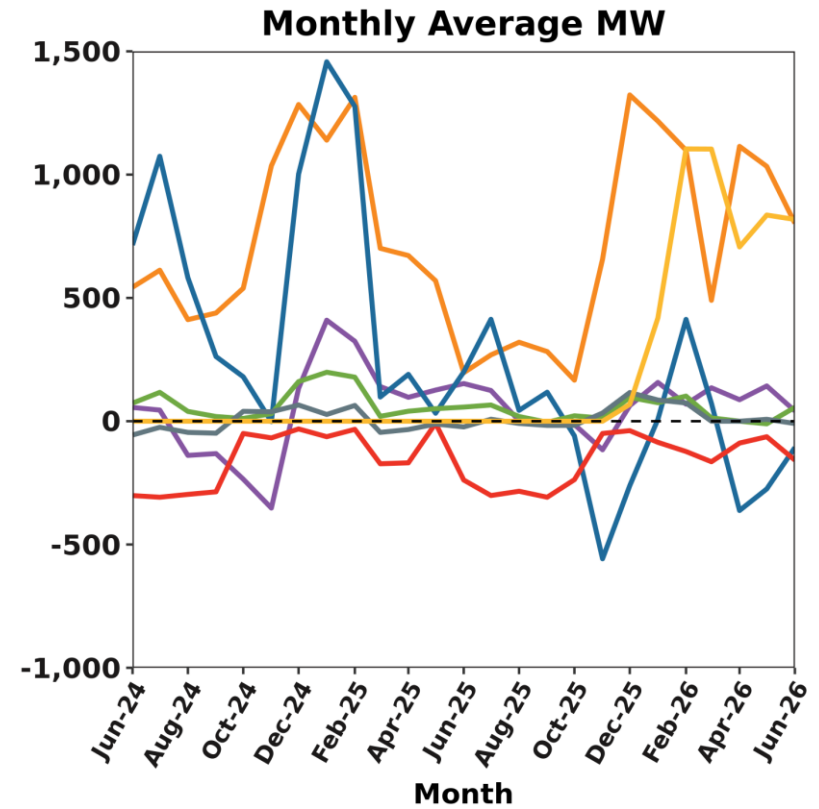
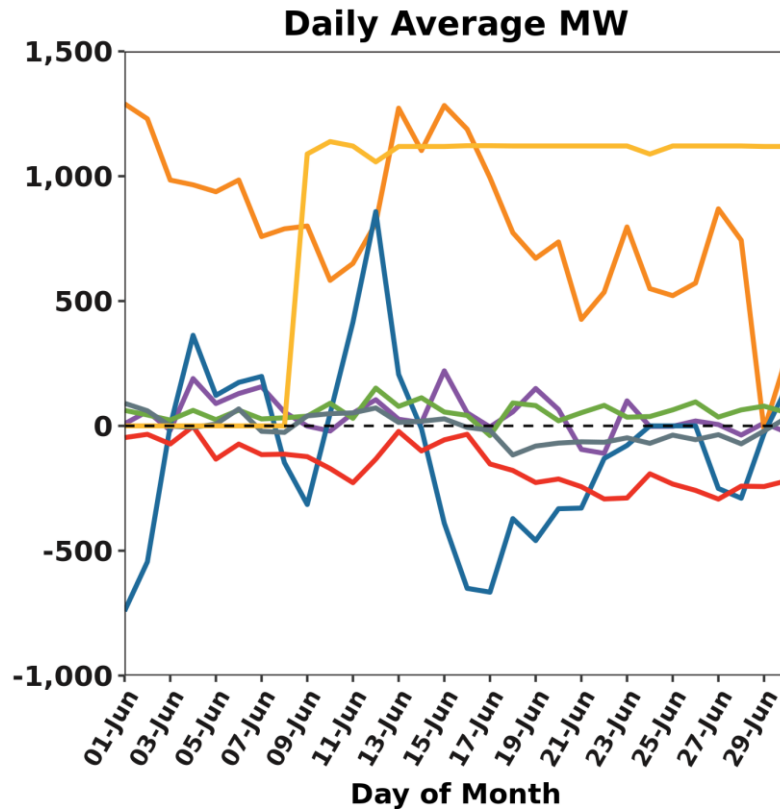
Export Import Net Tie



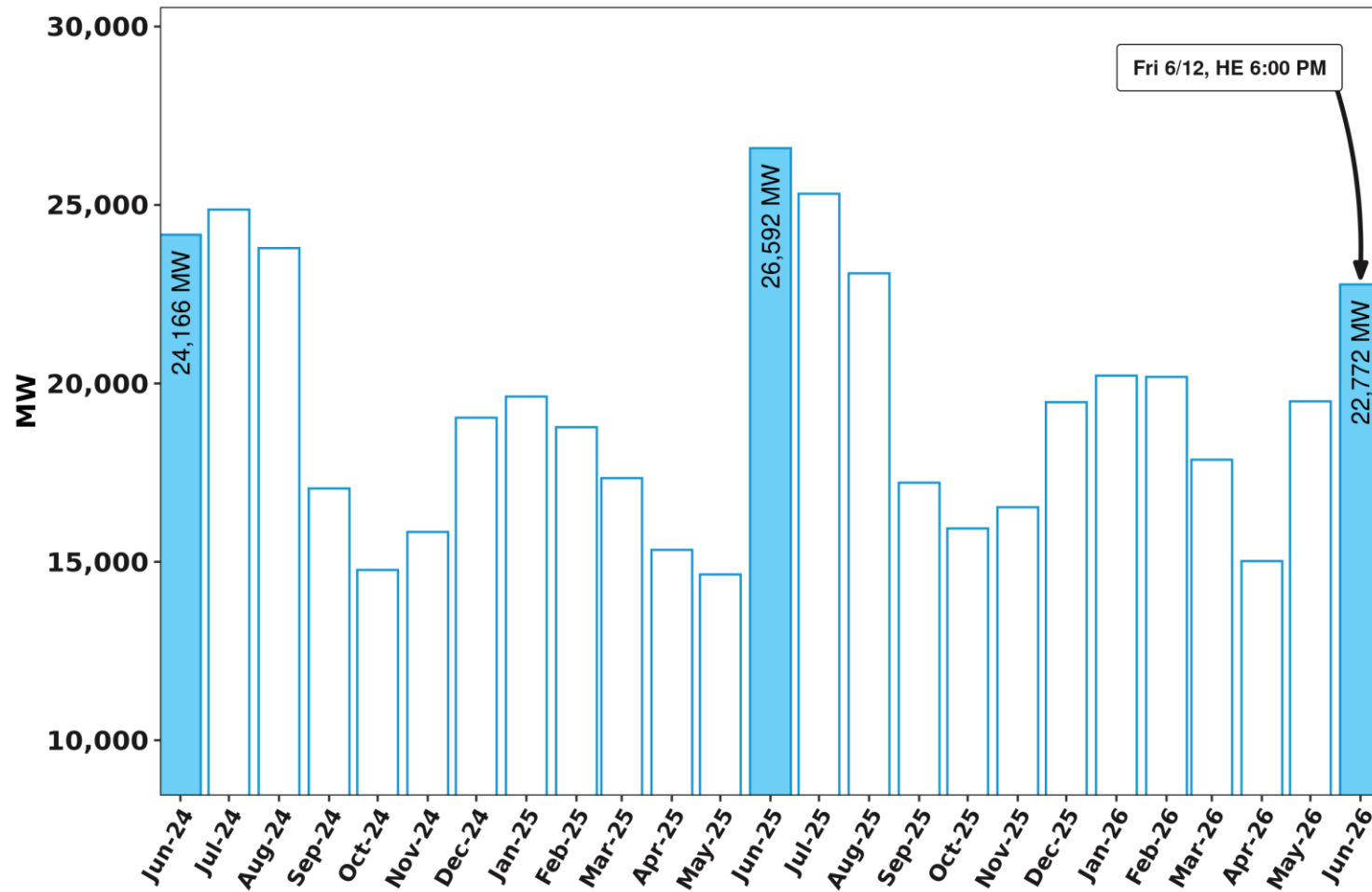
Export Import Net Tie

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

RT Net Interchange by External Interface

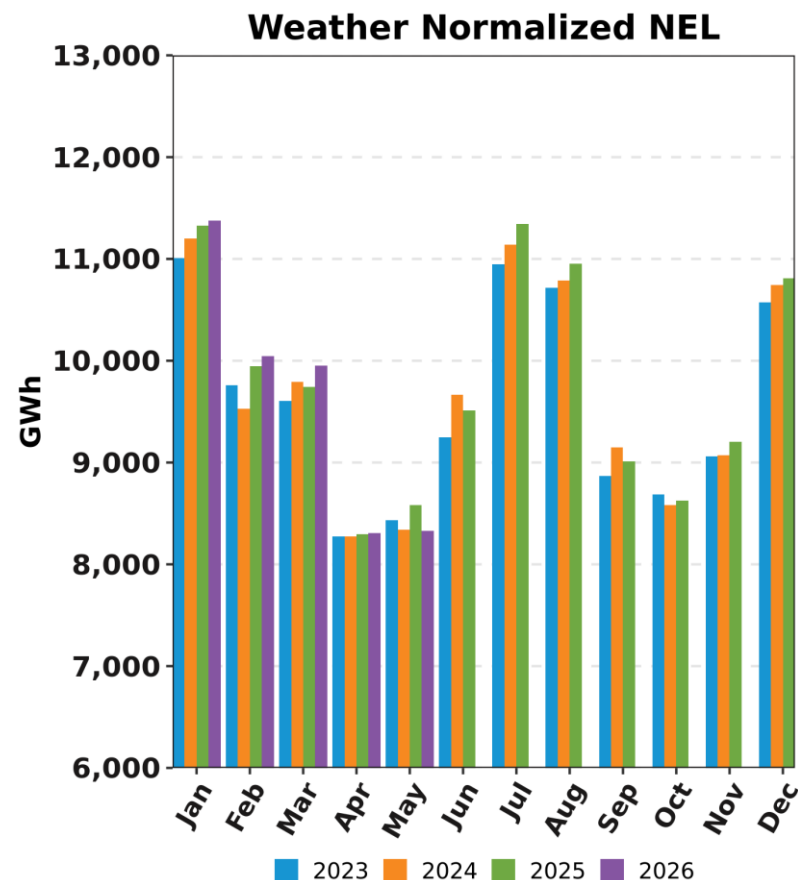
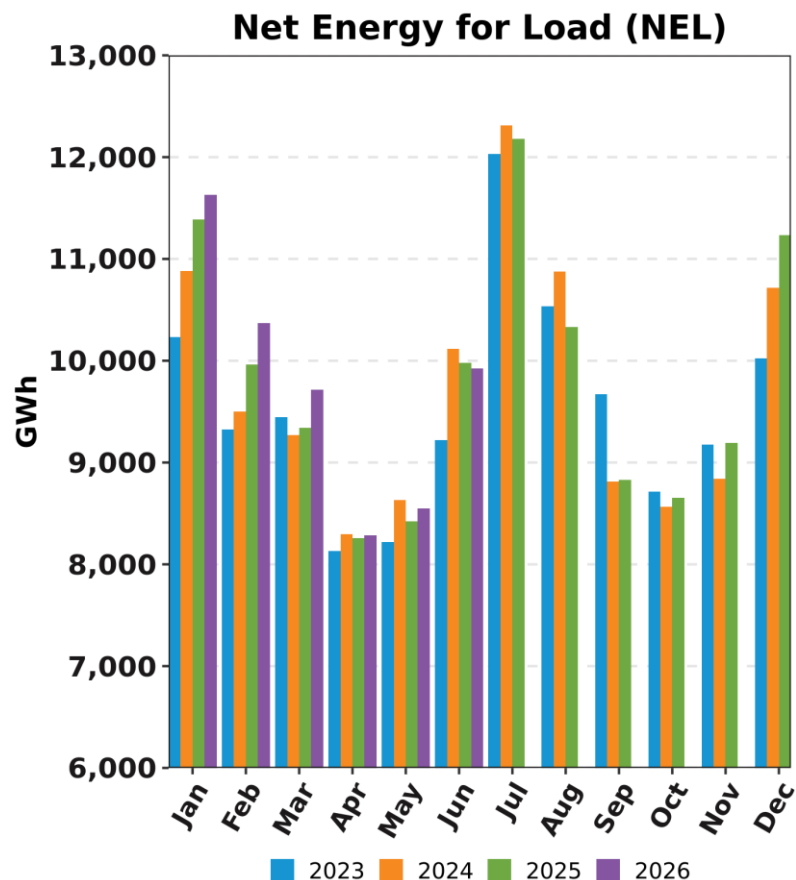


RQM System Peak Load MW by Month



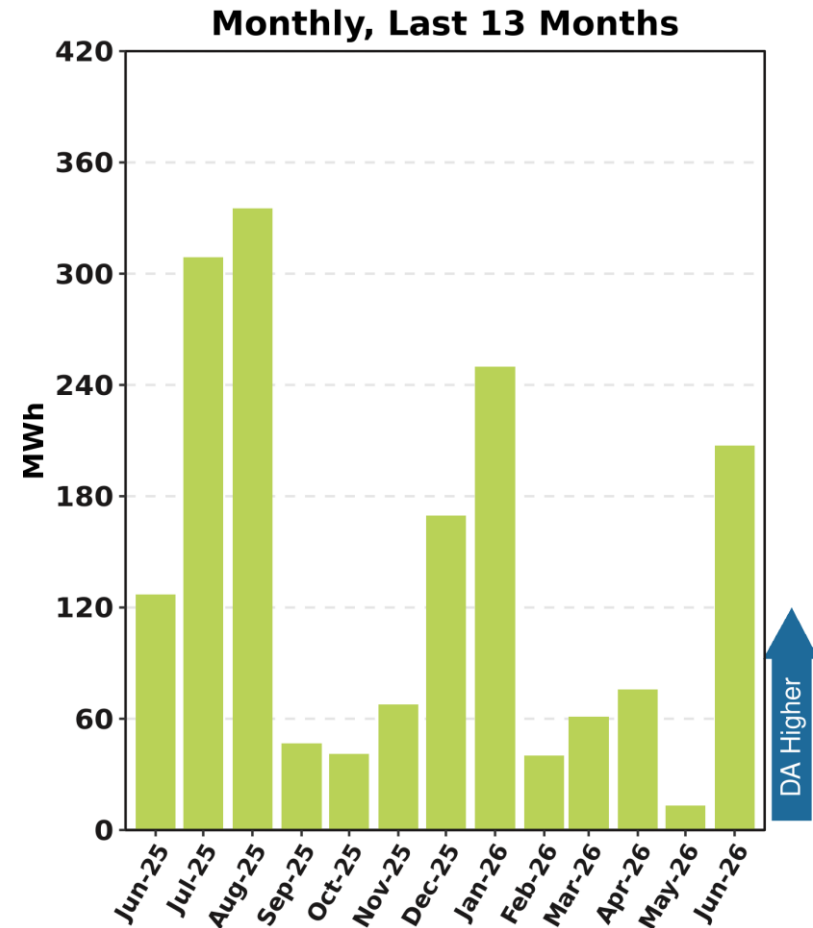
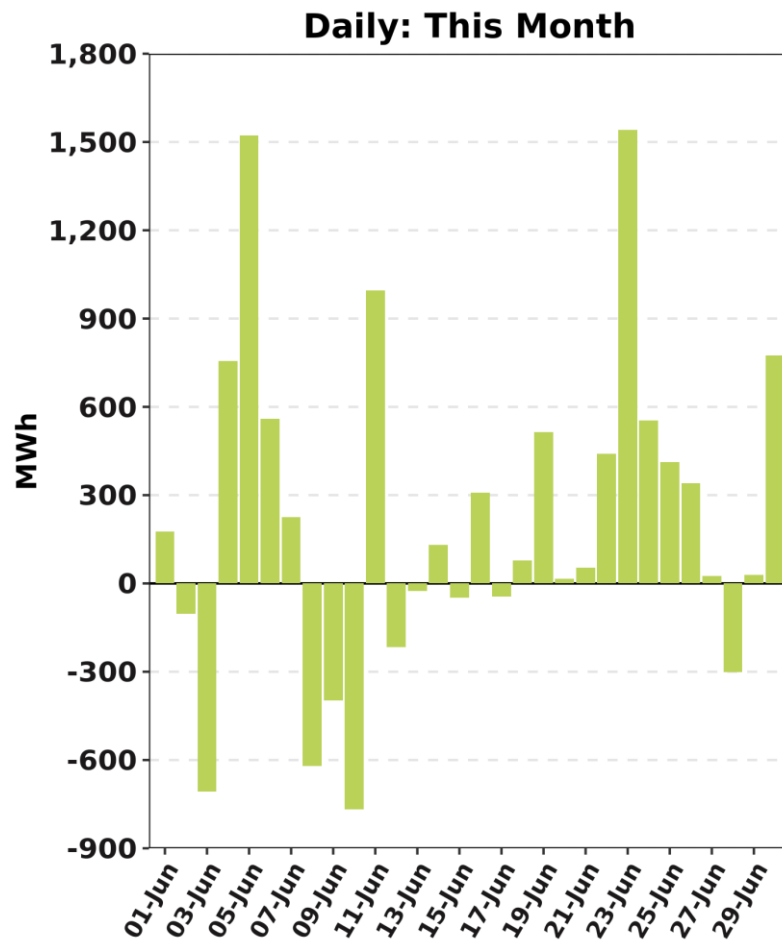
Shaded columns highlight current month and the same month over the prior two years

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



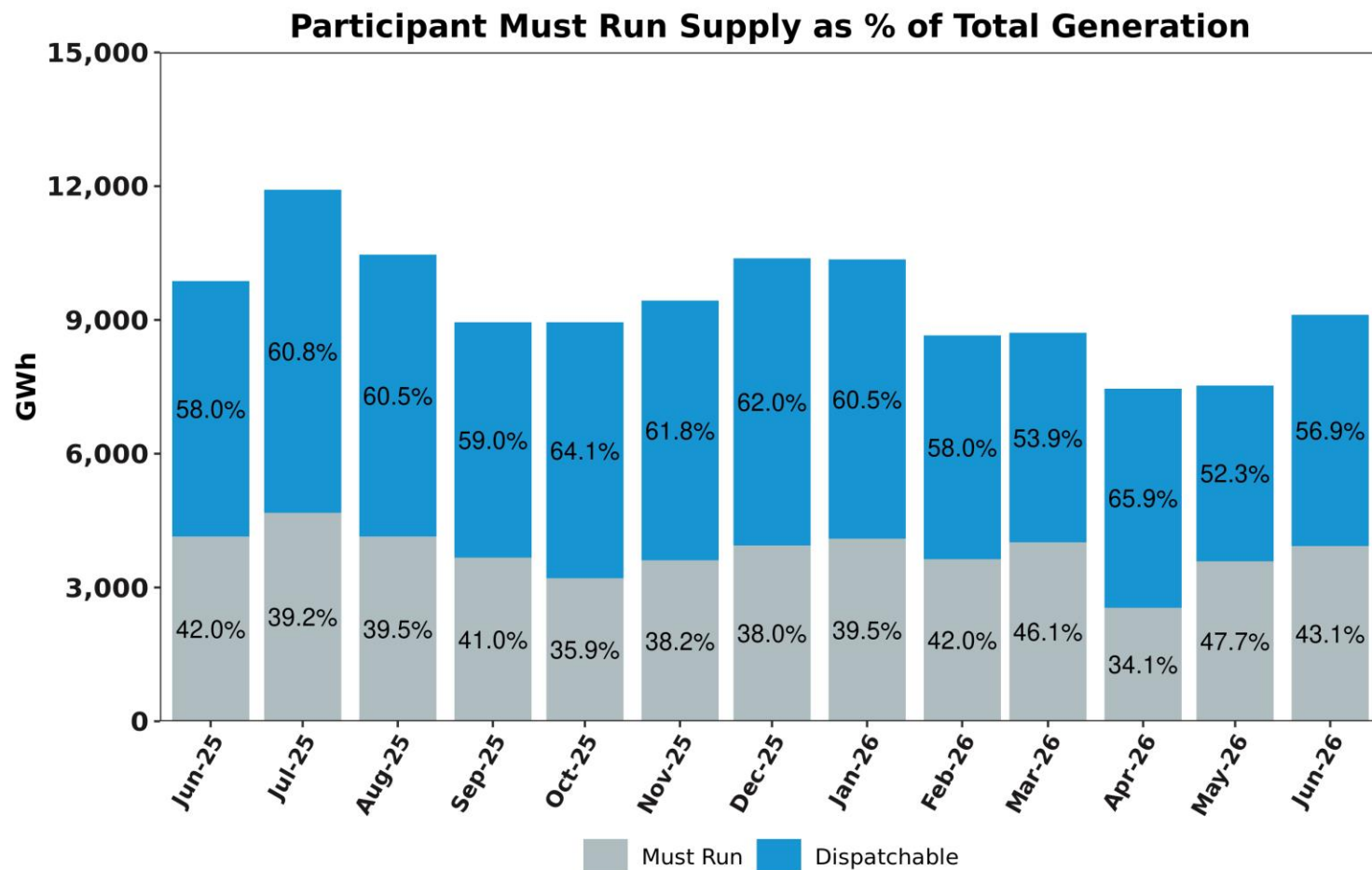
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

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

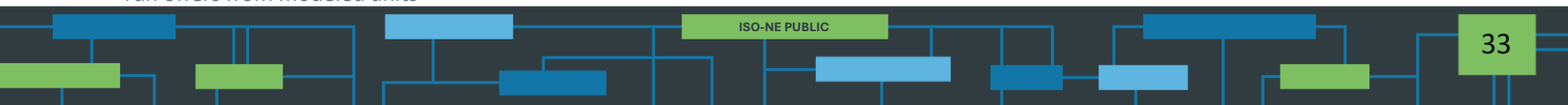


Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

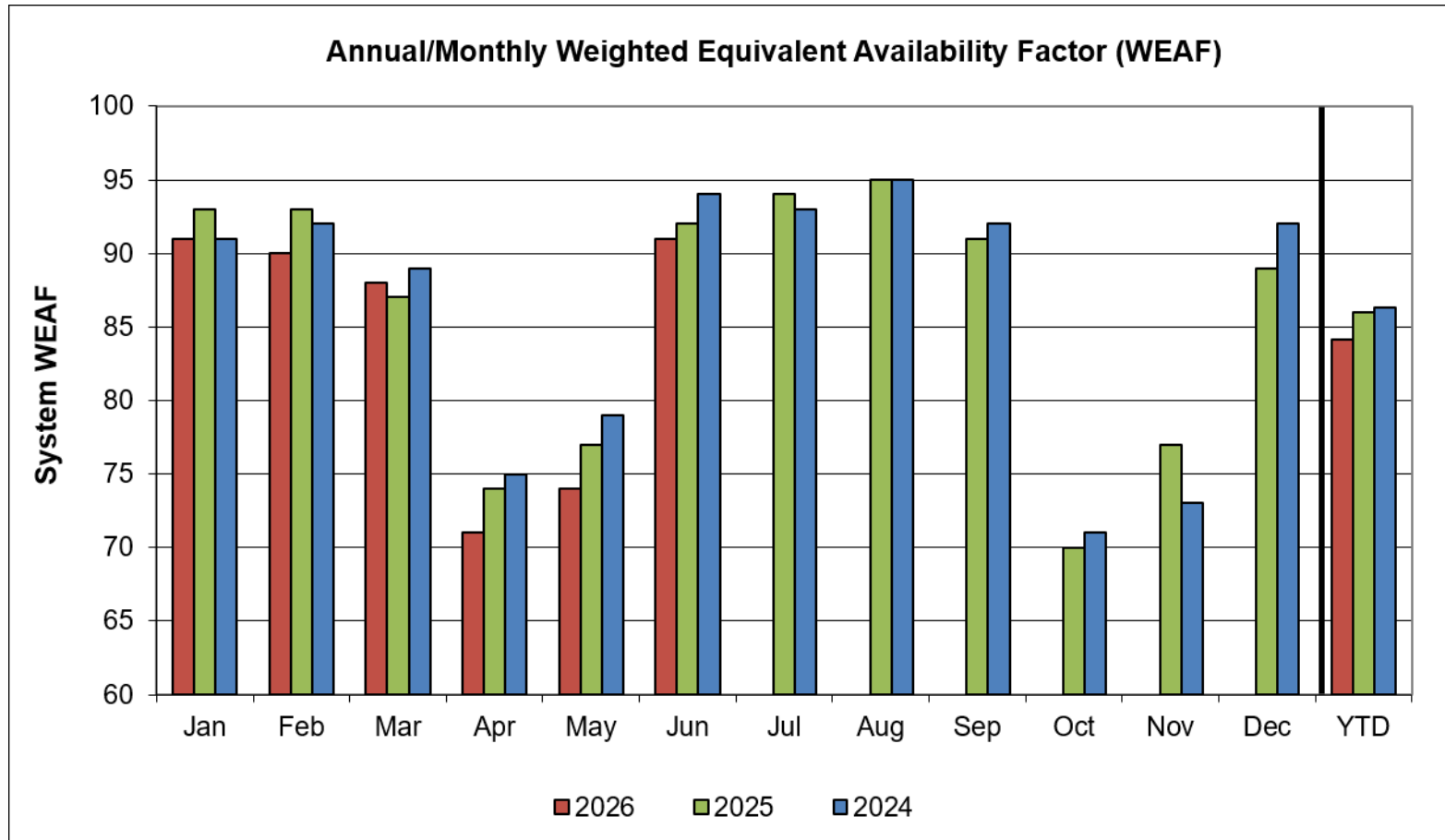
RT Generation Output Offered as Must Run vs Dispatchable



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

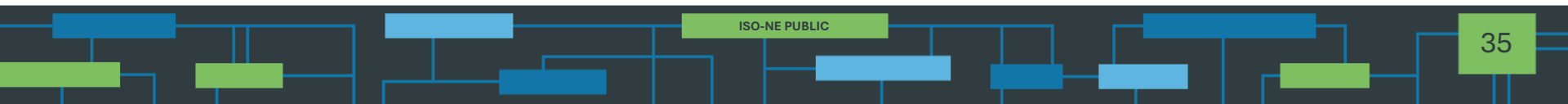


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2026	91	90	88	71	74	91							84
2025	93	93	87	74	77	92	94	95	91	70	77	89	86
2024	91	92	89	75	79	94	93	95	92	71	73	92	86

Data as of 6/30/26

MARKET OPERATIONS

Market Pricing



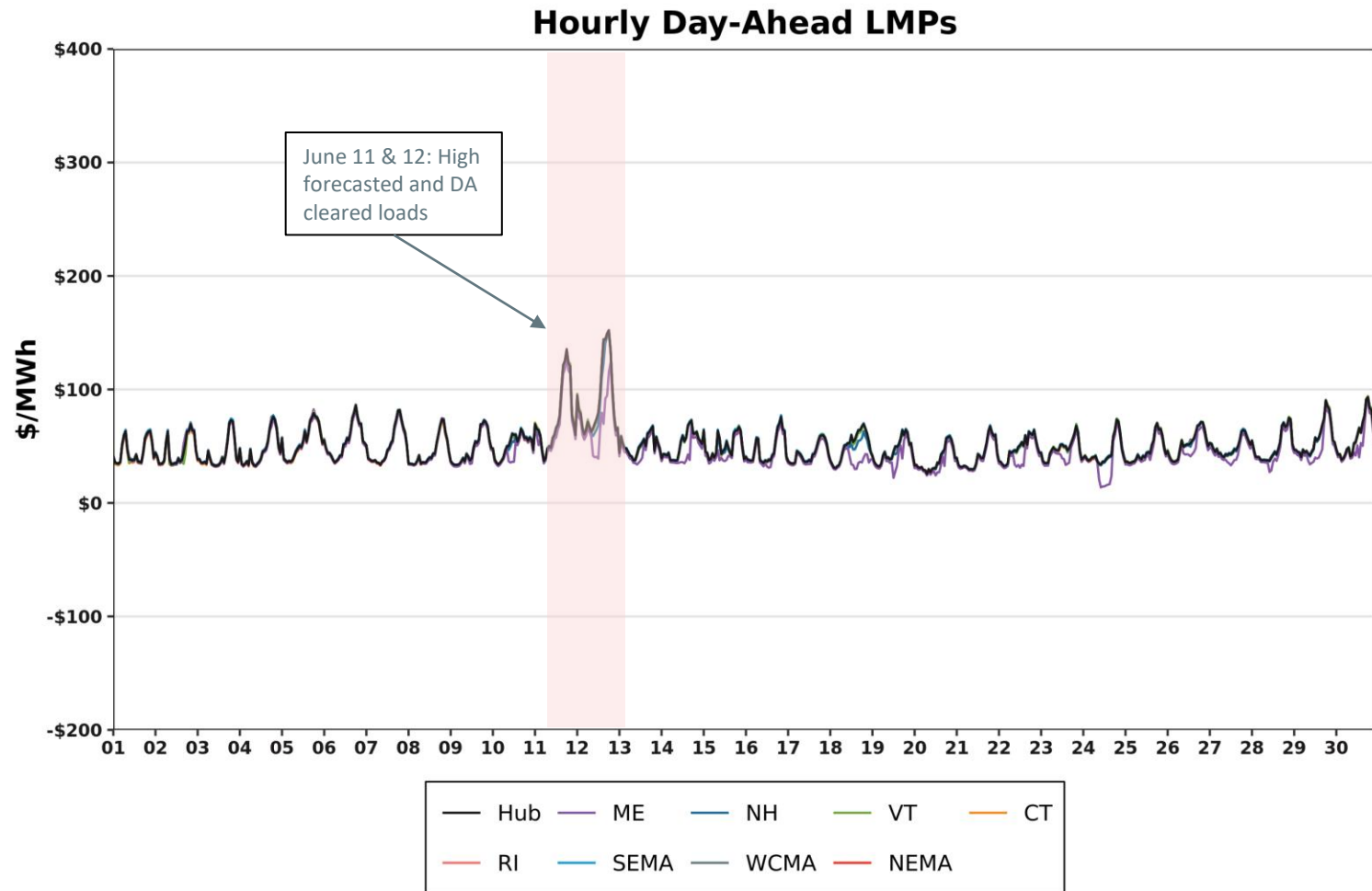
DA vs. RT LMPs (\$/MWh)

Arithmetic Average

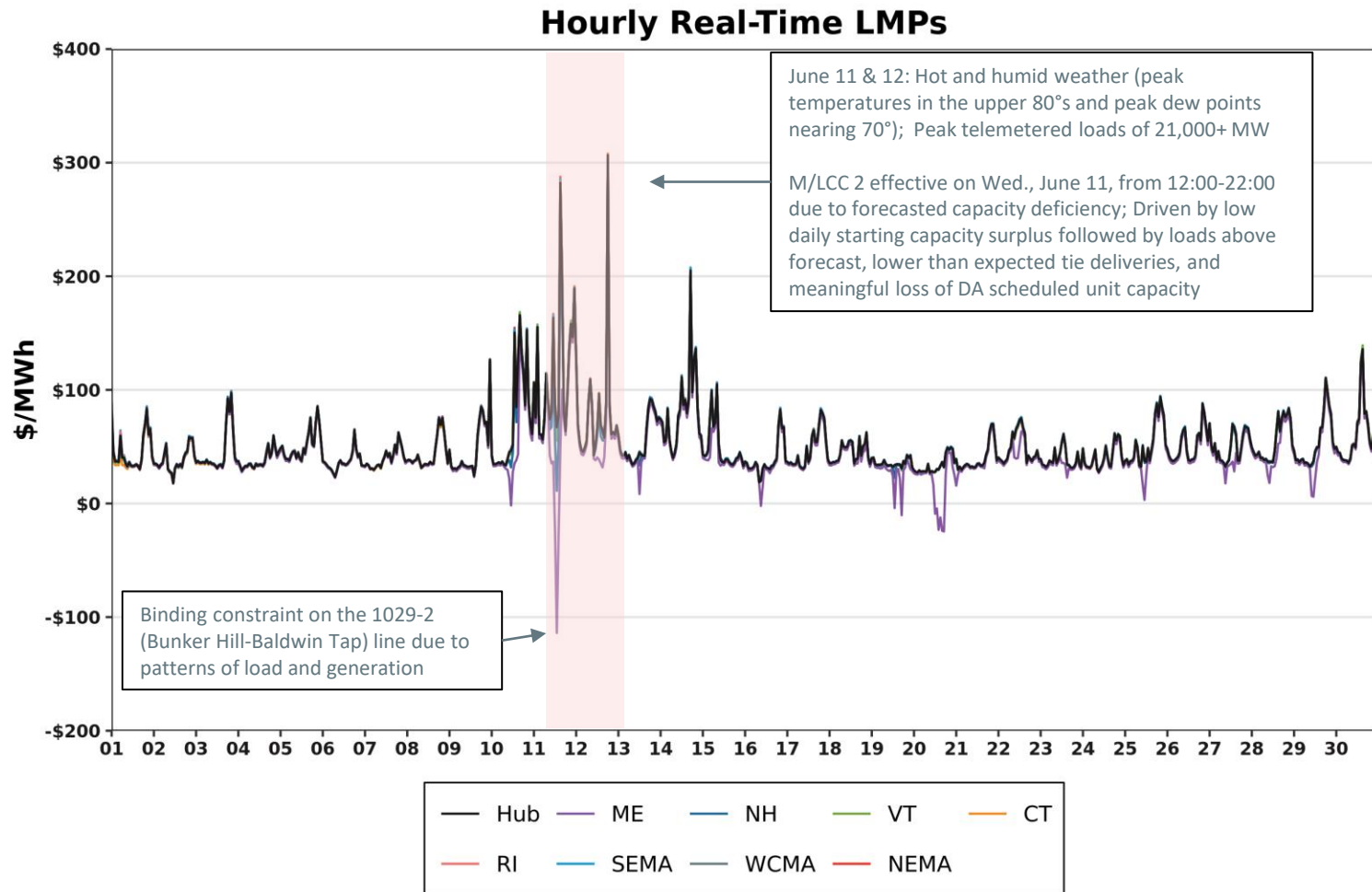
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$41.35	\$41.07	\$41.72	\$41.11	\$40.17	\$41.28	\$41.70	\$41.37	\$41.91
Real-Time	\$39.37	\$38.79	\$39.65	\$39.23	\$38.46	\$39.17	\$39.62	\$39.37	\$39.77
RT Delta %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%
Year 2025	Hub	ME	NH	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%

June-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$43.75	\$42.04	\$43.82	\$43.75	\$42.95	\$43.52	\$44.13	\$43.84	\$44.24
Real-Time	\$47.56	\$44.40	\$47.46	\$47.60	\$47.16	\$47.26	\$47.84	\$47.65	\$48.02
RT Delta %	8.71%	5.61%	8.31%	8.80%	9.80%	8.59%	8.41%	8.69%	8.54%
June-26	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	\$50.72	\$45.94	\$50.02	\$50.38	\$49.38	\$50.47	\$51.33	\$50.69	\$51.21
Real-Time	\$50.92	\$44.91	\$49.86	\$50.35	\$49.75	\$50.59	\$51.45	\$50.91	\$51.43
RT Delta %	0.39%	-2.24%	-0.32%	-0.06%	0.75%	0.24%	0.23%	0.43%	0.43%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	15.93%	9.28%	14.15%	15.15%	14.97%	15.97%	16.32%	15.62%	15.75%
Yr over Yr RT	7.06%	1.15%	5.06%	5.78%	5.49%	7.05%	7.55%	6.84%	7.10%

Hourly DA LMPs, June 1-30, 2026

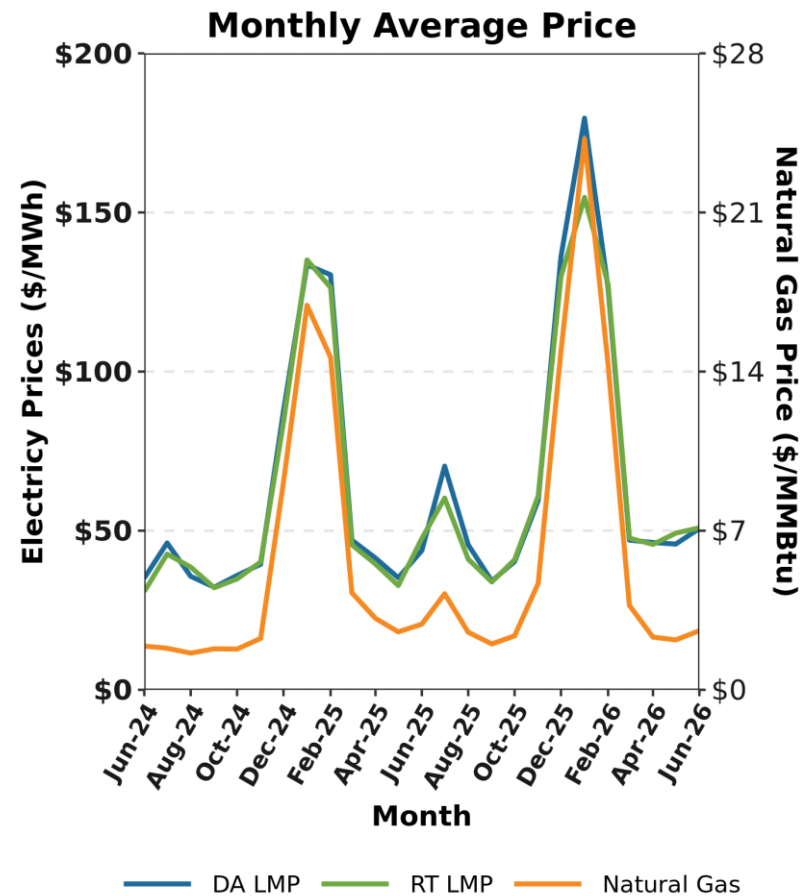
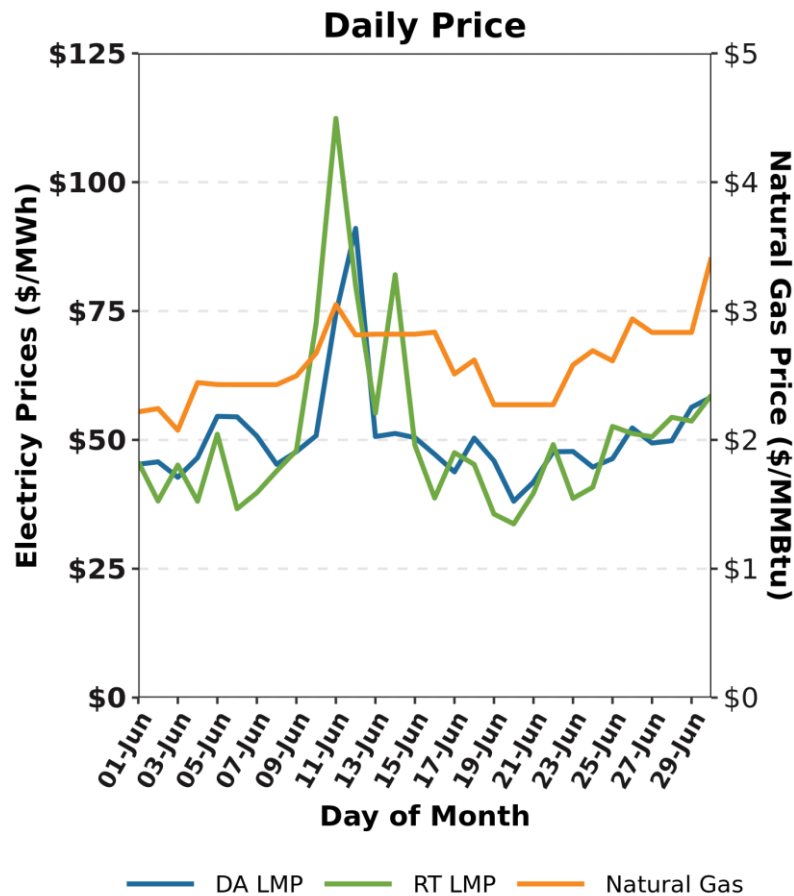


Hourly RT LMPs, June 1-30, 2026



Gas price is average of Massachusetts delivery points. M/LCC 2 = Master/Local Control Center Procedure No. 2

Wholesale Electricity vs Natural Gas Price by Month

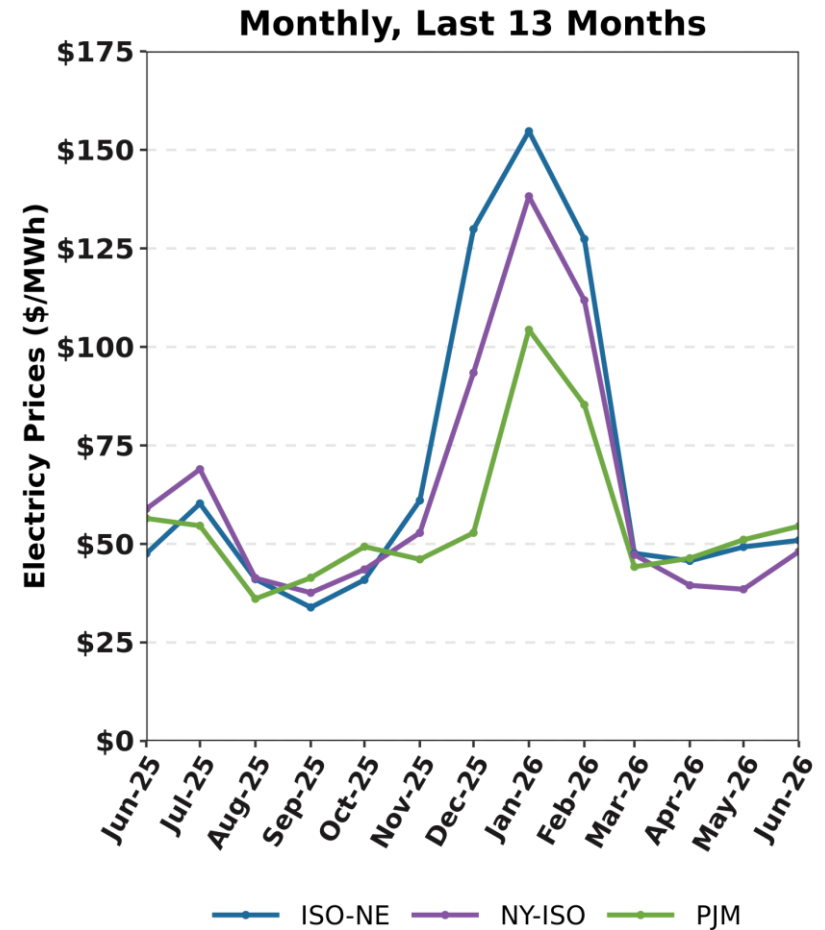
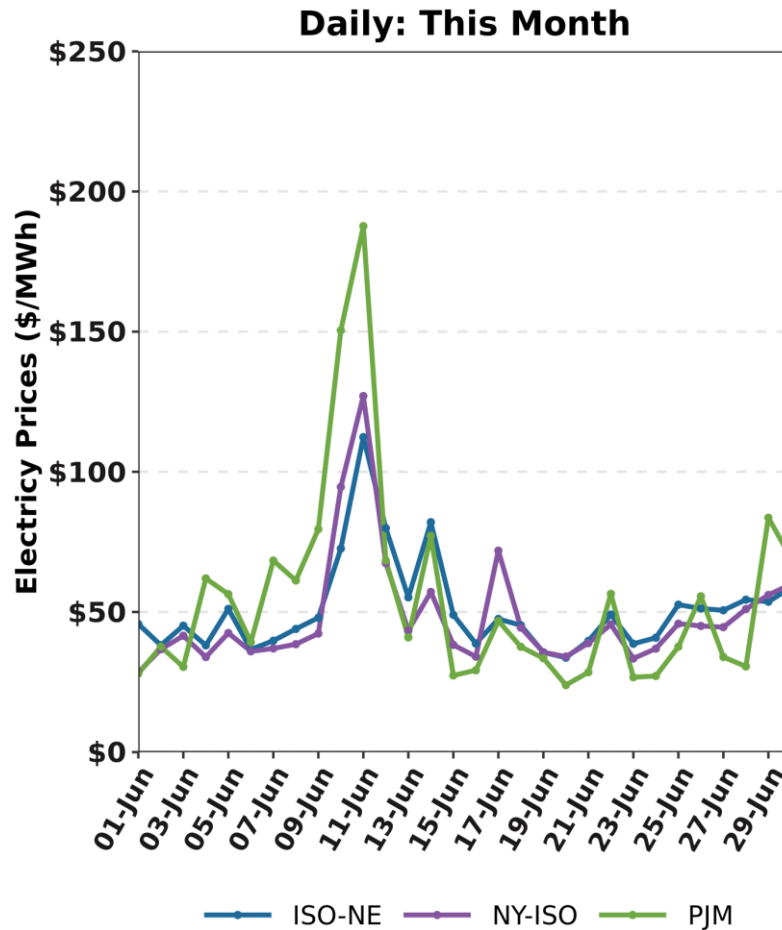


Gas price is average of Massachusetts delivery points

Underlying natural gas data furnished by:

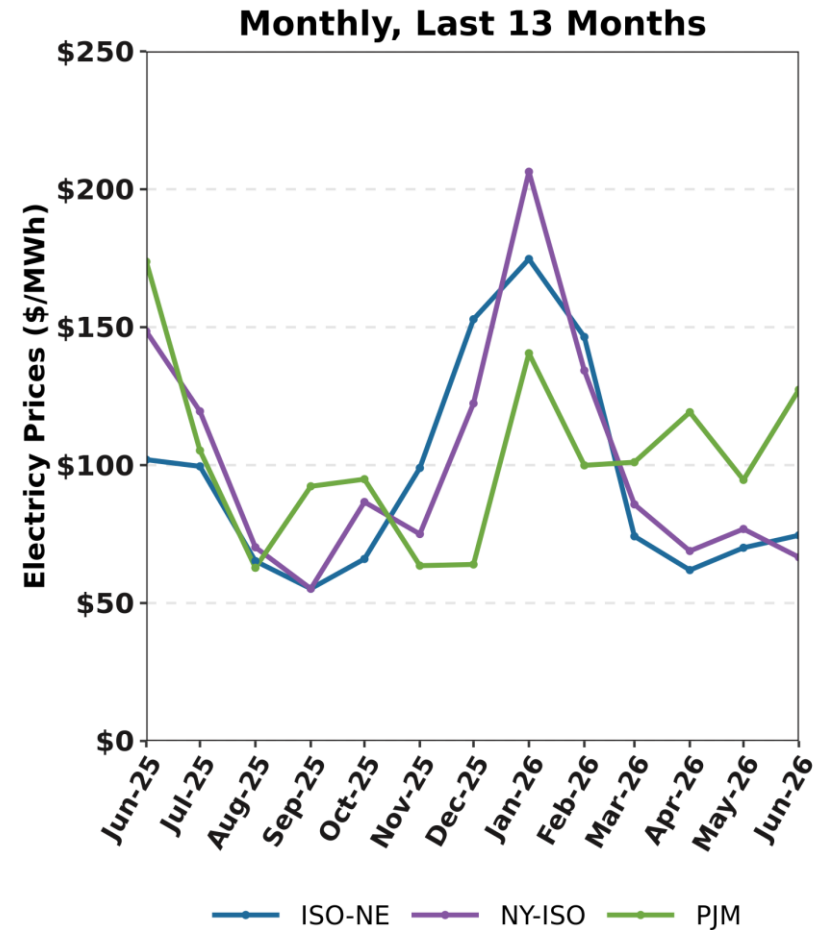
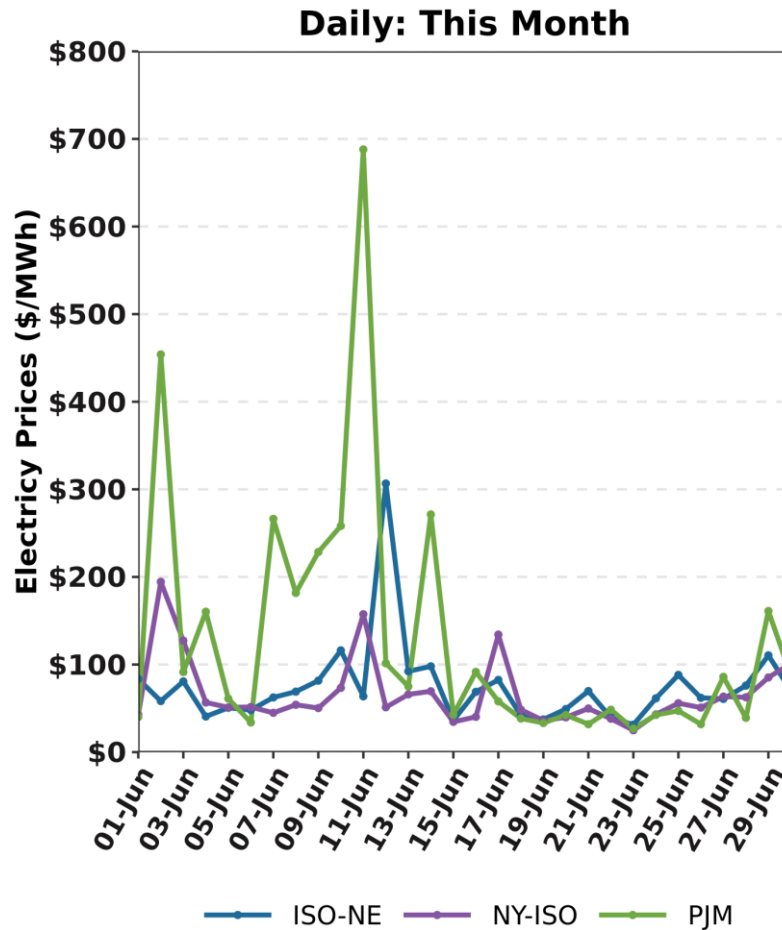


New England, NY, and PJM Hourly Average RT Prices by Month

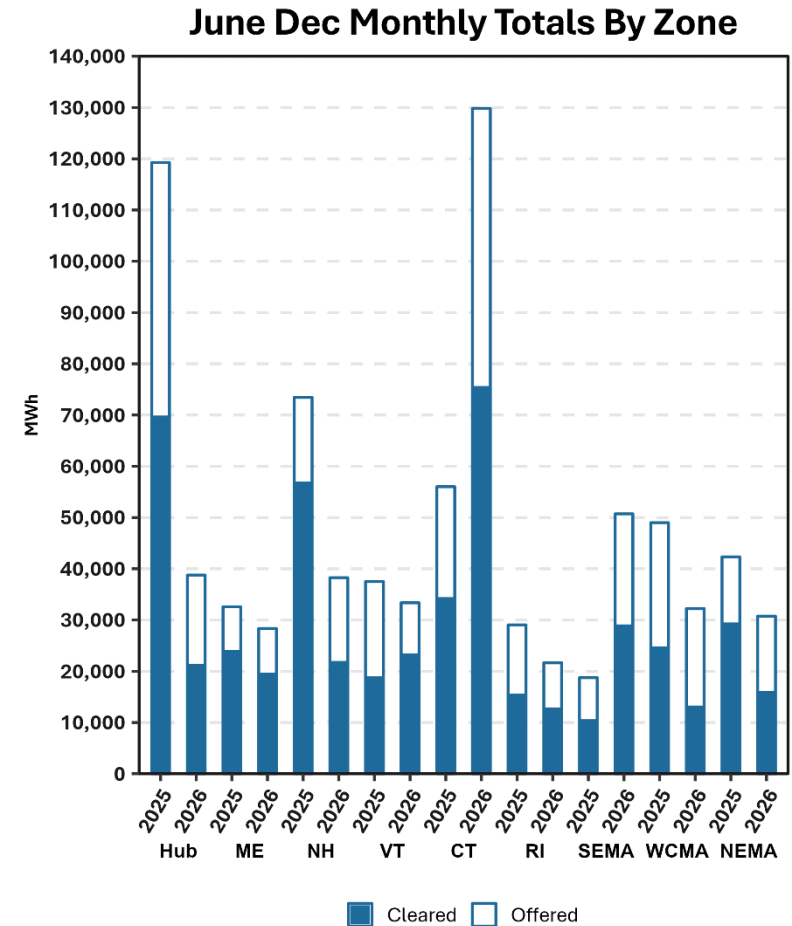
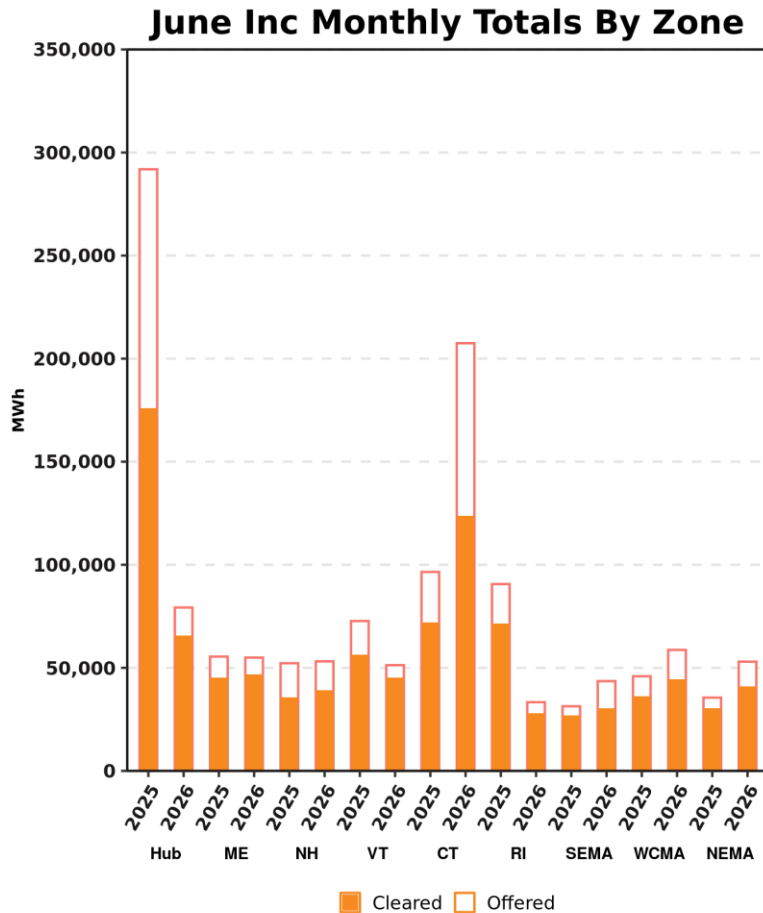


Hourly average prices are shown

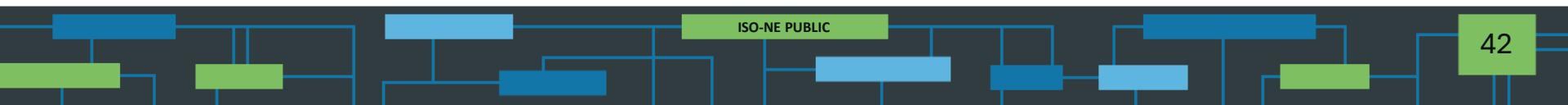
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours



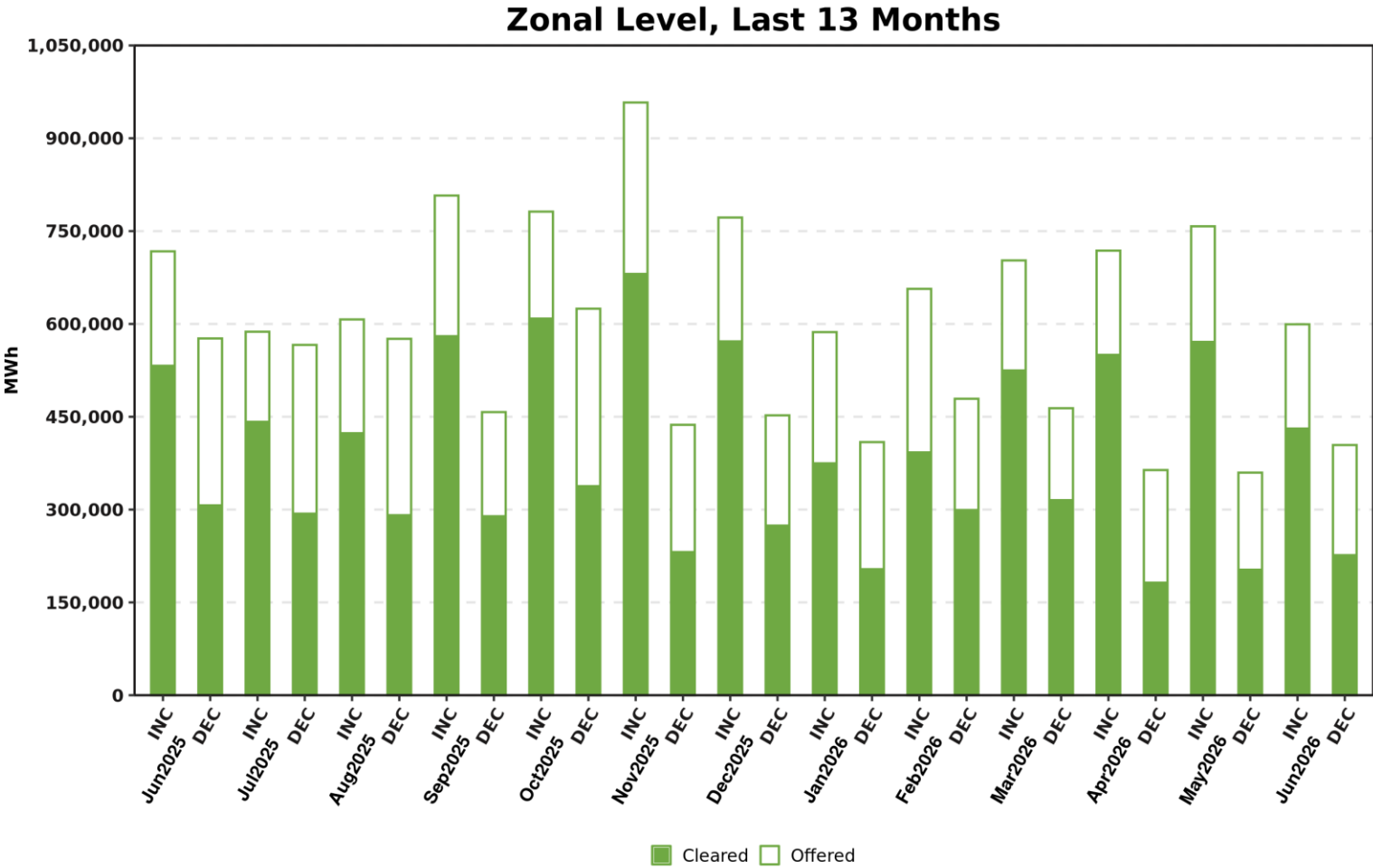
Zonal Increment Offers and Decrement Bid Amounts



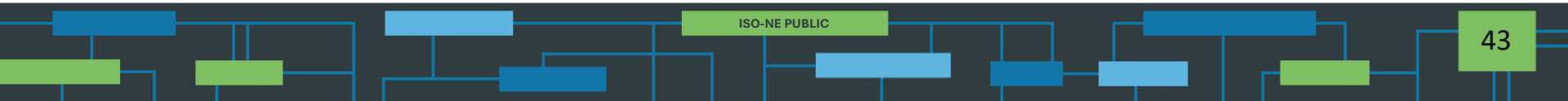
Includes nodal activity within the zone; excludes external nodes



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
06/01/2025	\$20.1M	\$885K	\$173K	\$2.97	0.9%	\$1,287K	160K	\$3.15	6.4%	125
07/01/2025	\$35.6M	\$1,704K	\$1,139K	\$19.53	3.2%	\$1,277K	114K	\$3.06	3.6%	55
08/01/2025	\$20.2M	\$747K	\$544K	\$9.57	2.7%	\$1,292K	147K	\$3.02	6.4%	94
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

About the Table:

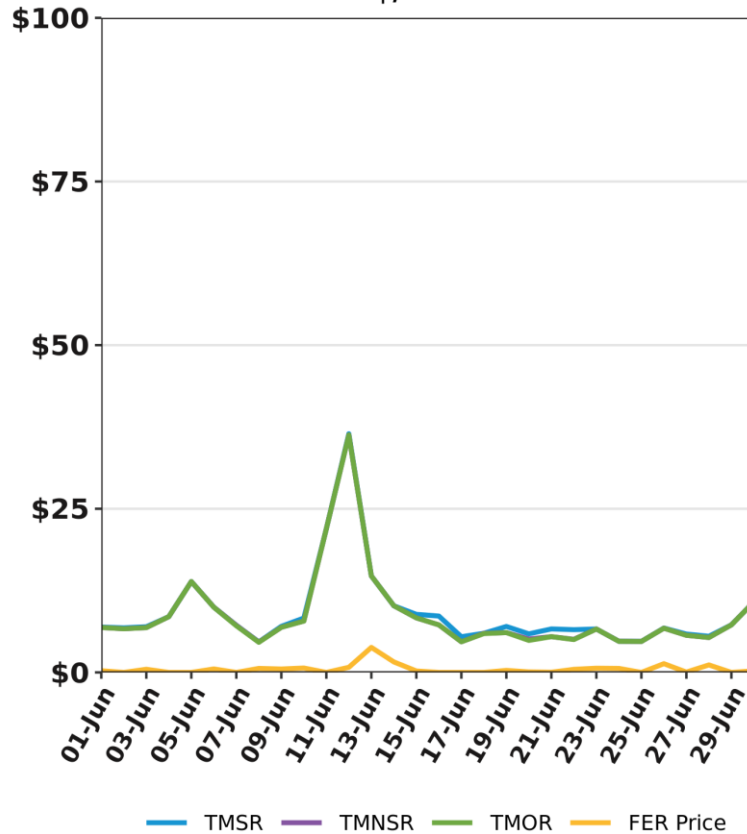
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with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

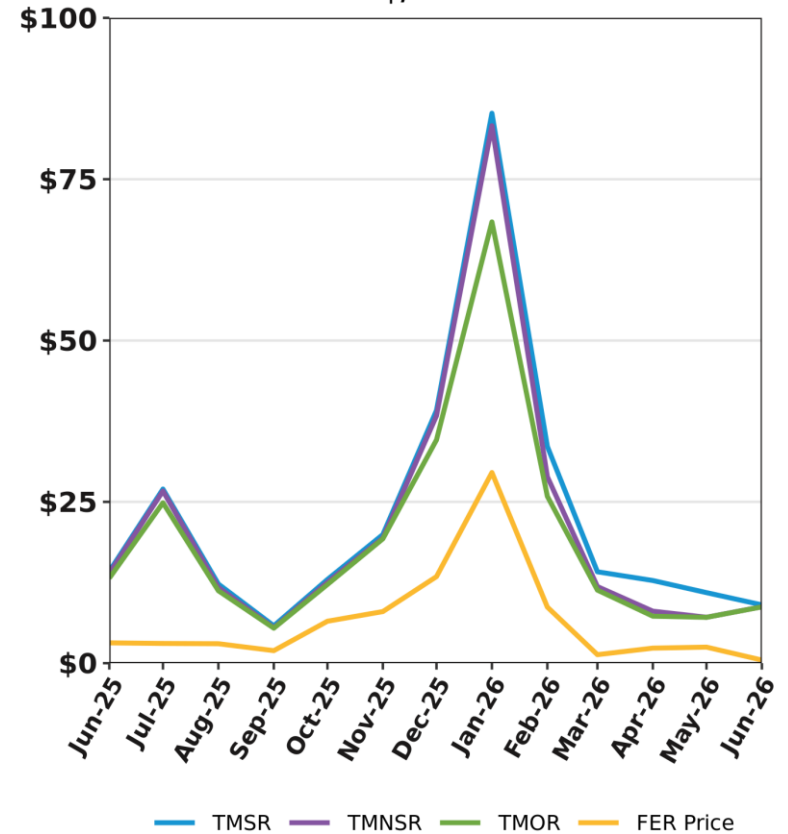
- FER Credits are included in the Monthly Market Operations Report (see Section 7.1.1) found on the ISO Website [here](#). Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

Average Hourly DAAS Prices

Daily This Month
\$/MWh

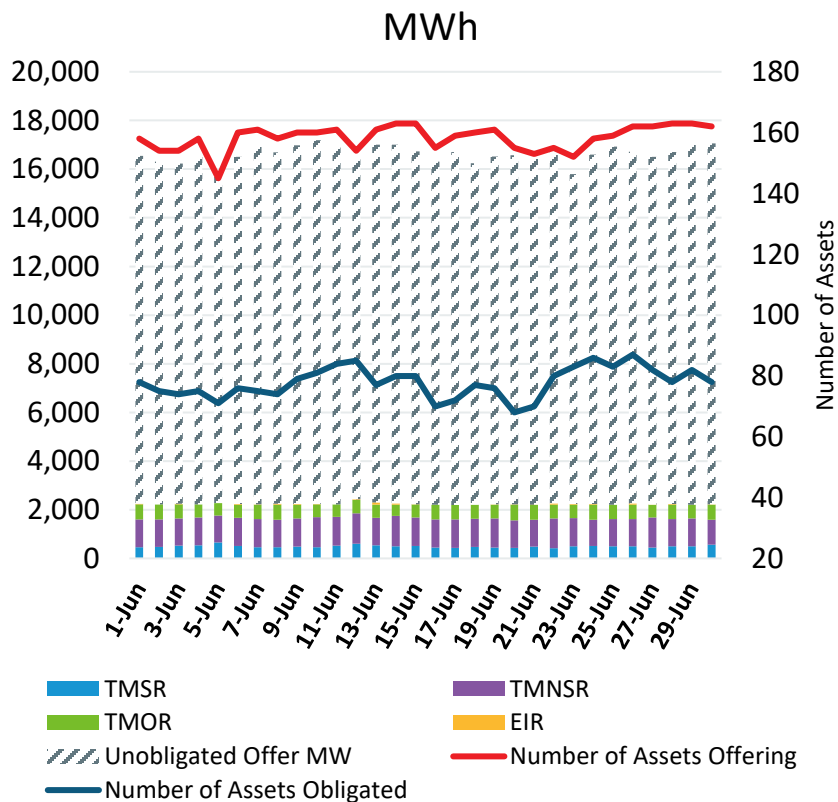


Monthly, Last 13 Months
\$/MWh

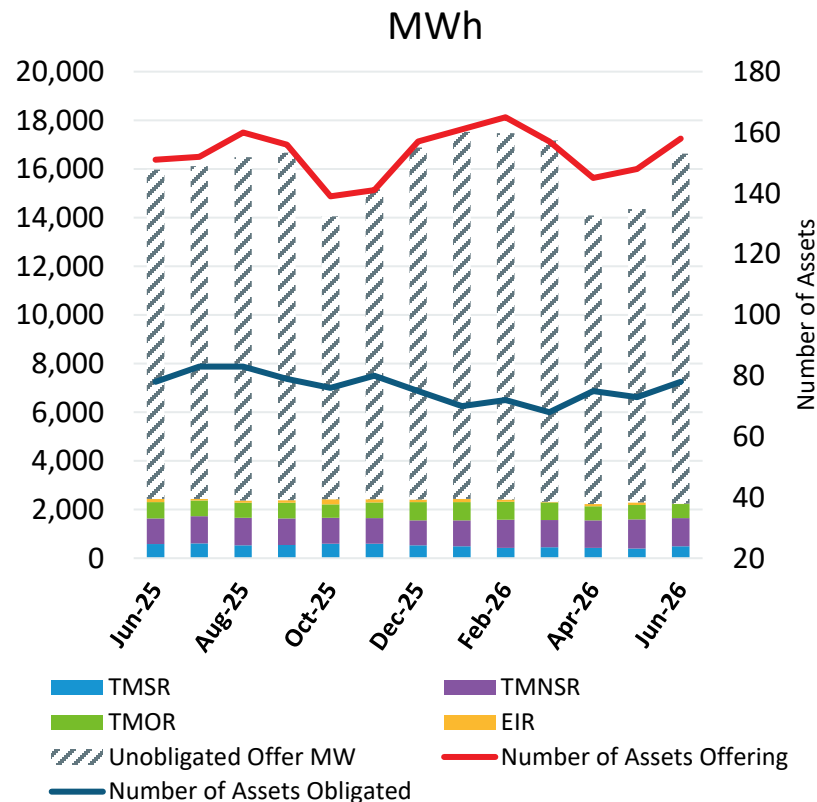


Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month

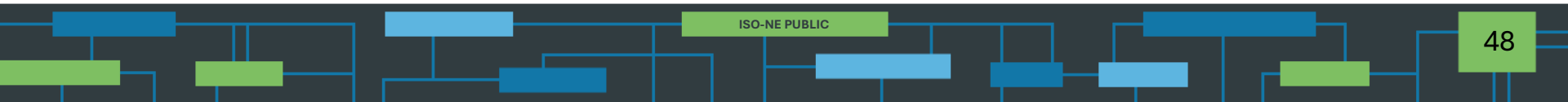


Monthly, Last 13 Months

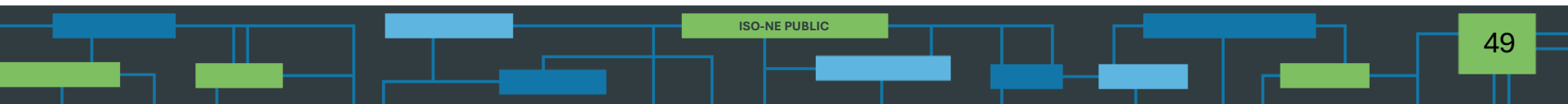


*Unobligated Offer MWh reflect the raw, as-offered DAAS MW amounts that remained unobligated (received no MW reward). This supply does not yet consider additional unit parameter constraints or dispatch constraints and should not be equated with actual capacity available in the dispatch solution.

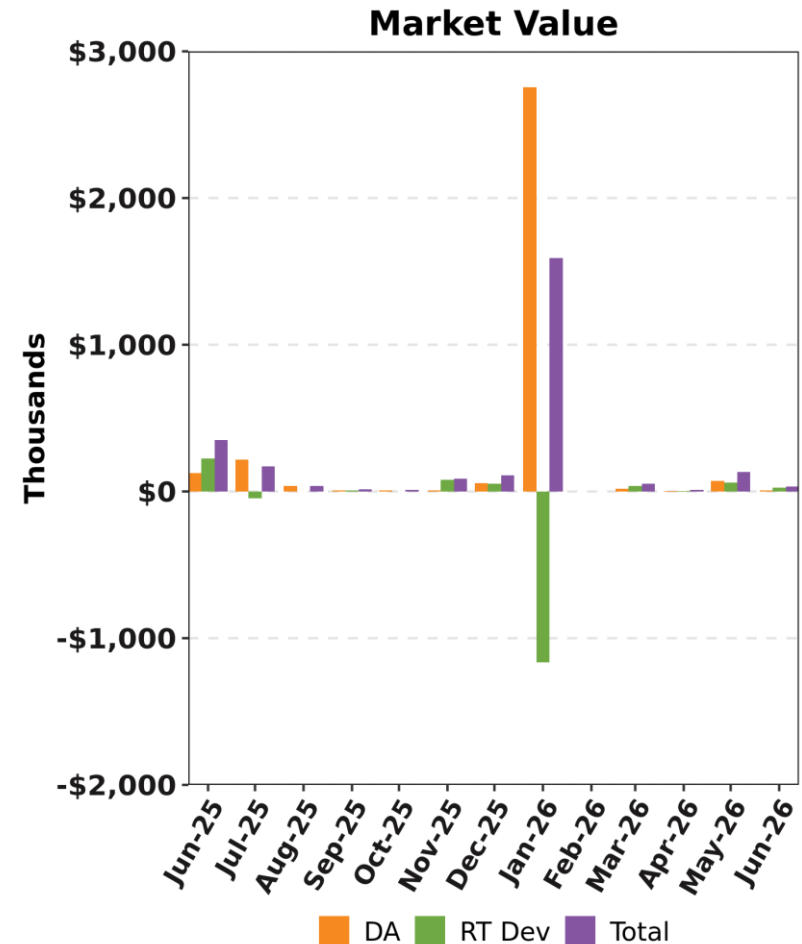
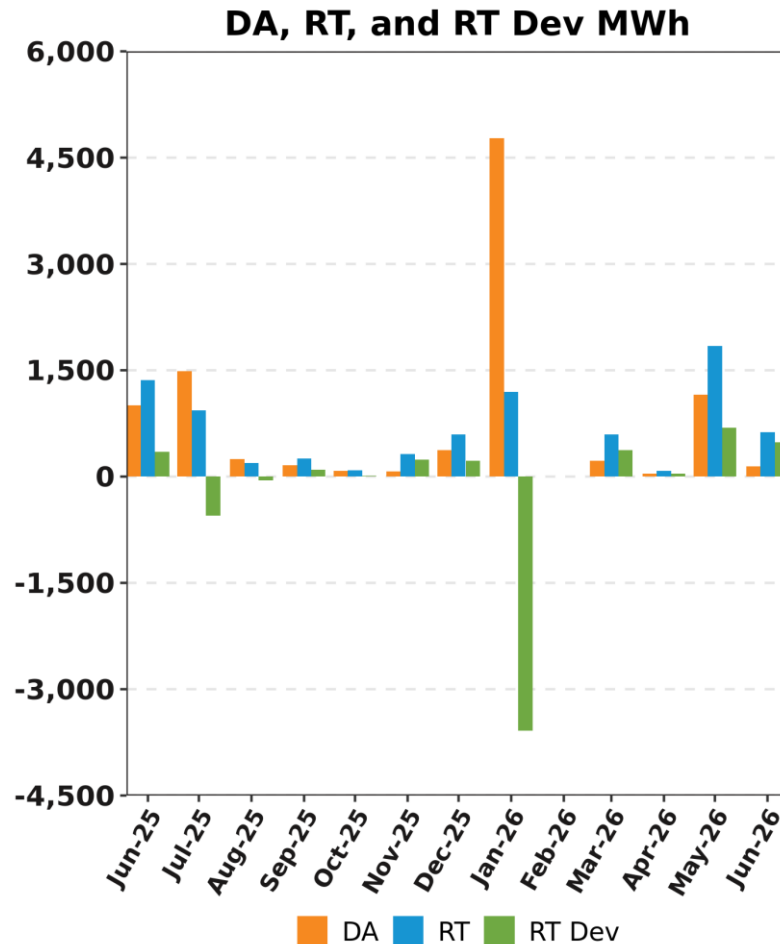
BACK-UP DETAIL



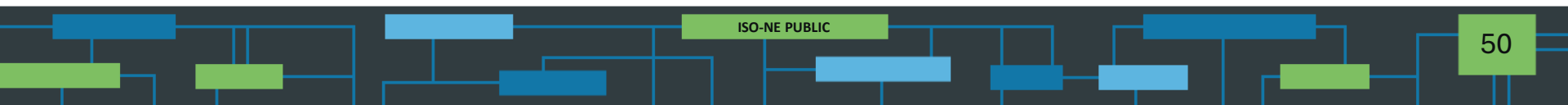
DEMAND RESPONSE



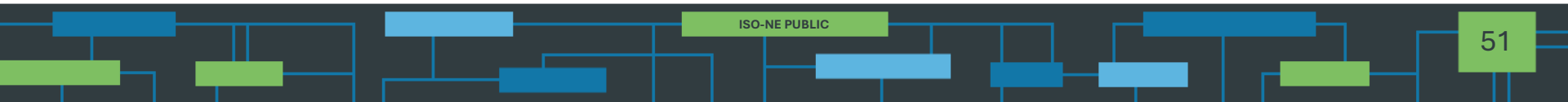
Demand Response Resource (DRR) Energy Market Activity by Month



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



NEW GENERATION

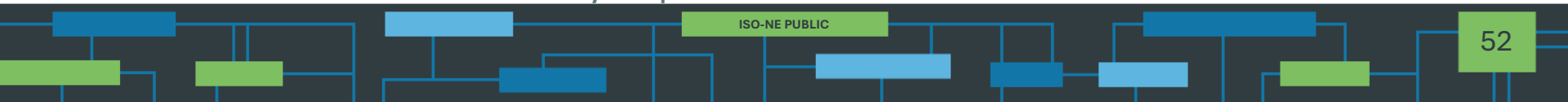


New Generation Update

Based on Queue as of 07/03/26

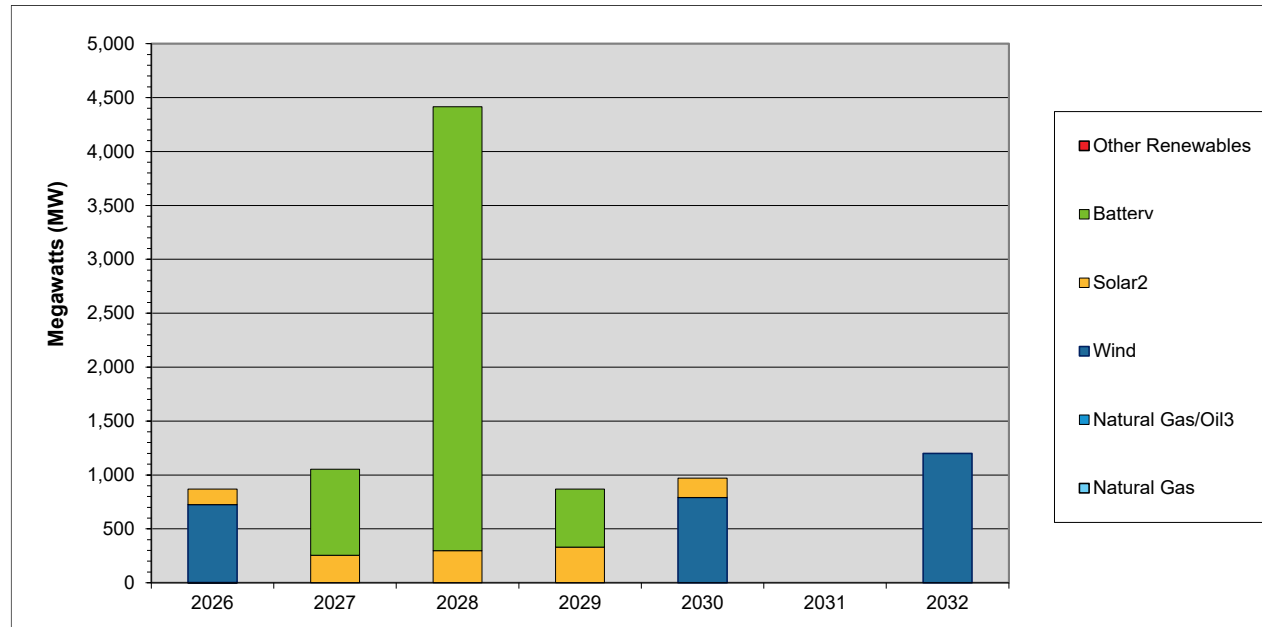
- The interconnection queue has been updated to reflect the projects that have submitted the required materials to participate in the Order No. 2023 Transitional Cluster Study
- In total, 52* generation projects are currently being tracked by the ISO, totaling approximately 10,576 MW

* 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	4,115	538	0	0	0	5,452	58.1
Solar ²	145	255	299	332	180	0	0	1,211	12.9
Wind	722	0	0	0	791	0	1,200	2,713	28.9
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	867	1,054	4,414	870	971	0	1,200	9,376	100.0

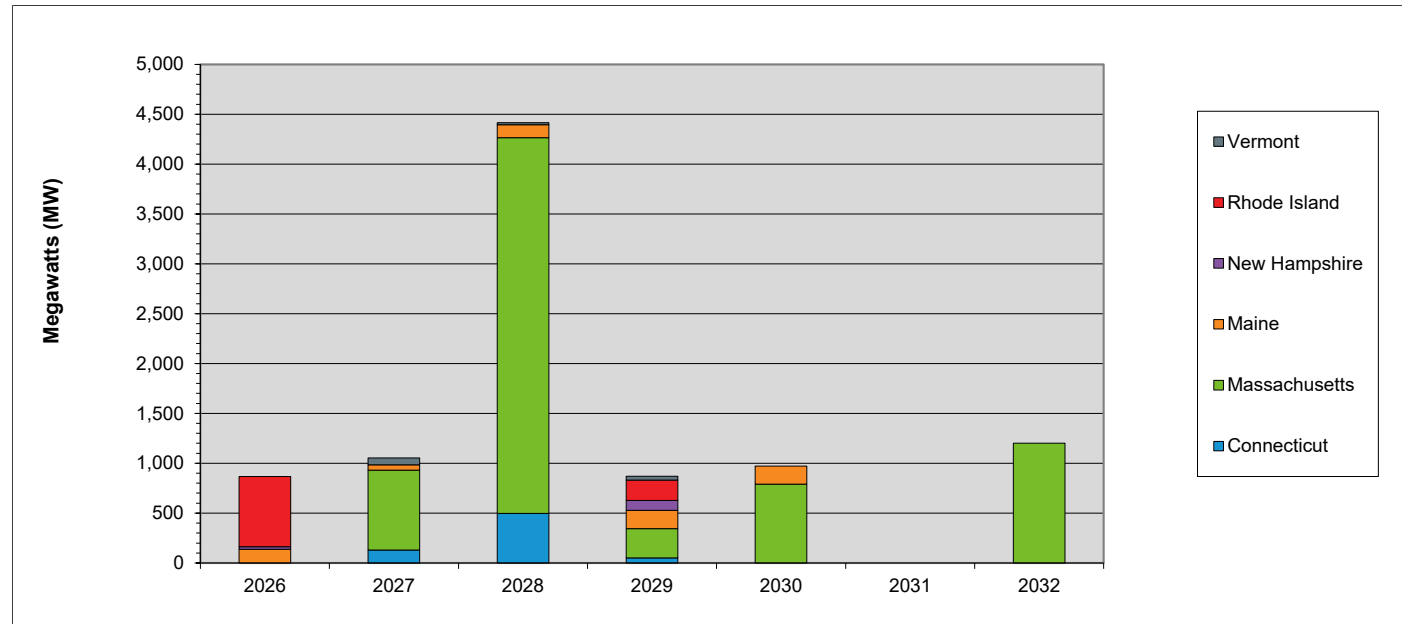
¹ Sum may not equal 100% due to rounding

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	38	0	0	0	128	1.4
Rhode Island	704	0	0	205	0	0	0	909	9.7
New Hampshire	25	0	0	100	0	0	0	125	1.3
Maine	138	54	129	182	180	0	0	683	7.3
Massachusetts	0	799	3,768	295	791	0	1,200	6,853	73.1
Connecticut	0	131	497	50	0	0	0	678	7.2
Totals	867	1,054	4,414	870	971	0	1,200	9,376	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	25	5,452	2	454	23	4,998
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	22	1,211	4	141	18	1,070
Wind	5	3,913	2	722	3	3,191
Total	52	10,576	8	1,317	44	9,259

- 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	47	6,663	6	595	41	6,068
Wind Turbine	5	3,913	2	722	3	3,191
Total	52	10,576	8	1,317	44	9,259

- 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

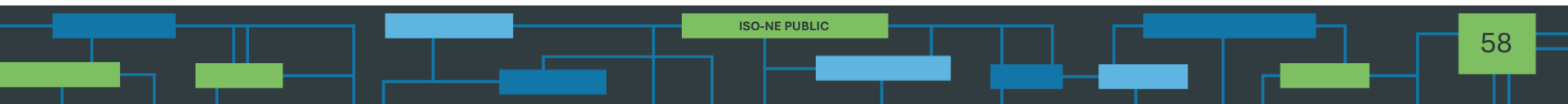
New Generation Projection

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	25	5,452	0	0	0	0	25	5,452	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	22	1,211	0	0	0	0	22	1,211	0	0
Wind	5	3,913	0	0	0	0	0	0	5	3,913
Total	52	10,576	0	0	0	0	47	6,663	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				
	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

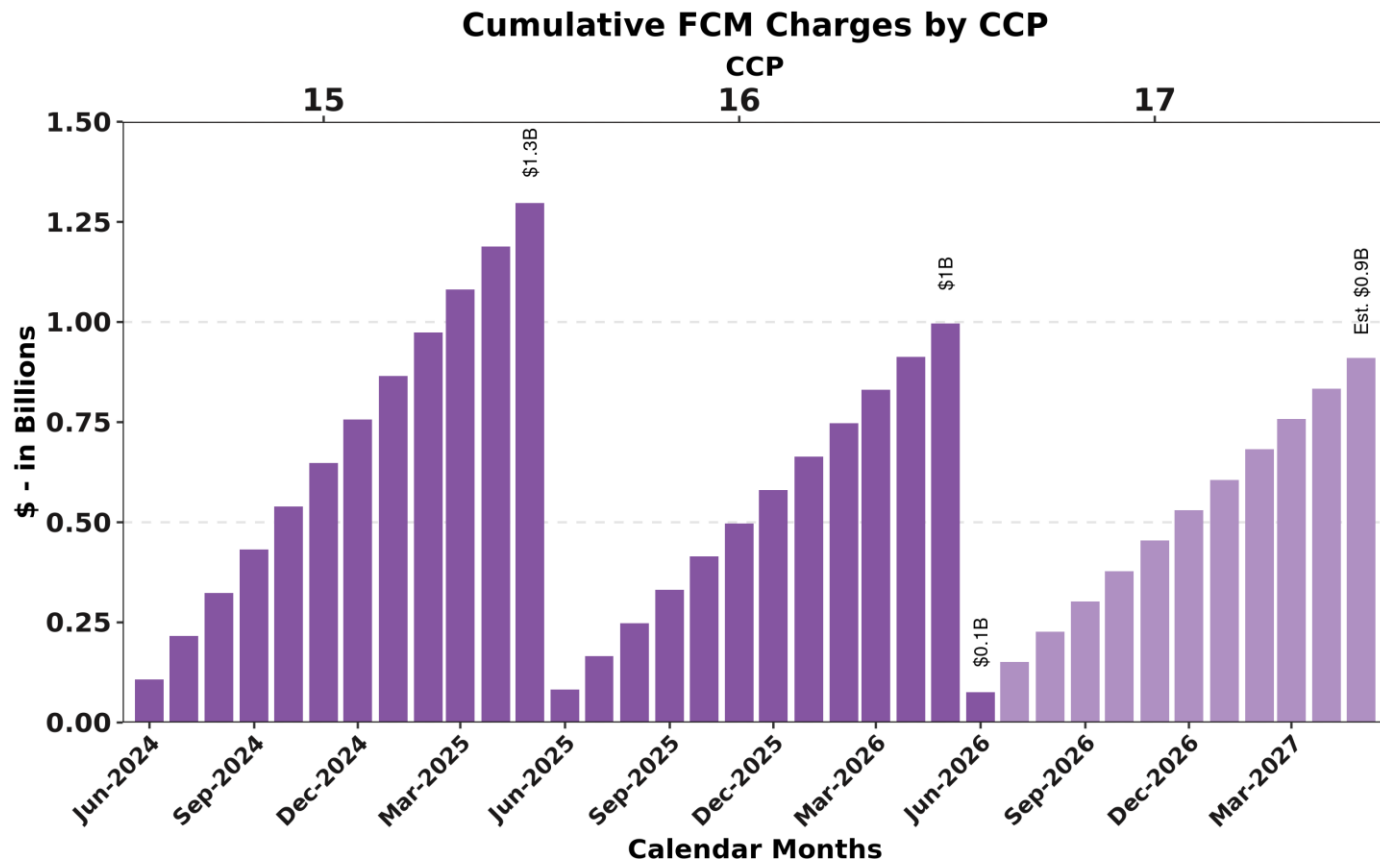
Observed FCM Peak Load by Capacity Zone

- Observed FCM Peak Load: **22,269 MW** (preliminary & subject to change)
 - hour ending 7:00 p.m. on Friday, June 12
 - By Capacity Zone:
 - Northern New England: 2,906 MW
 - Maine: 1,577 MW
 - Rest-of-Pool: 17,785 MW

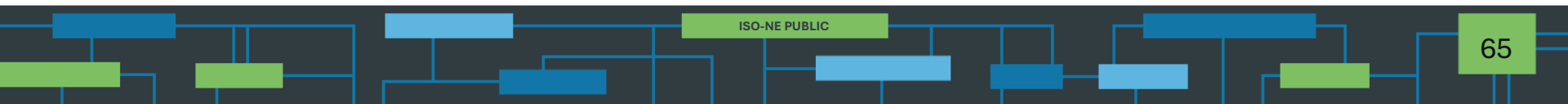
*Telemetered loads are as reported by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SORs). Due to the difference in calculation methodologies and the impact of SORs, these values can occur on different days and/or hours. Both are 'net 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.

This breakout is available in the Weekly Market Report found on the ISO Website [here](#) and is scheduled for removal from this deck at a future date.

Forward Capacity Market Auctions

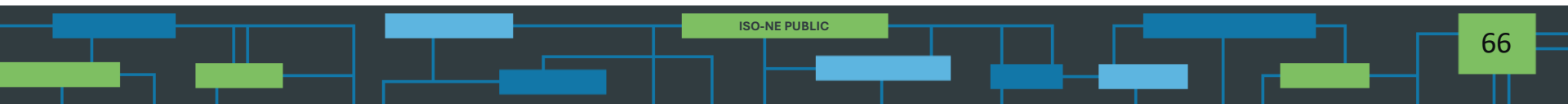


NET COMMITMENT PERIOD COMPENSATION



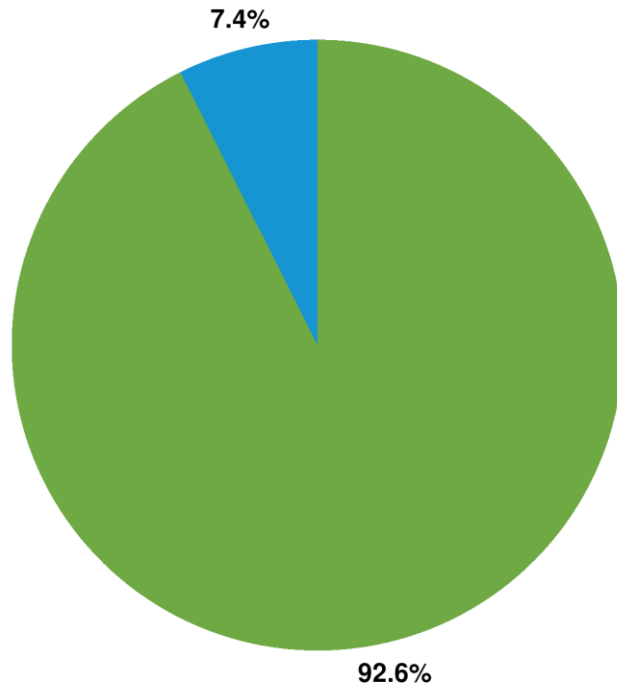
NCPC Highlights

- **Net Commitment Period Compensation (NCPC)** total \$3M
 - Represents 0.5% of monthly Energy Market value
 - First Contingency \$3M
 - Dispatch Lost Opportunity Cost (DLOC) - \$768K; Rapid Response Pricing (RRP) Opportunity Cost - \$383K; Posturing - \$0; Generator Performance Auditing (GPA) - \$0
 - \$41K paid to resources at external locations, down \$16K from May
 - \$3K charged to Day-Ahead Load Obligation (DALO) at external locations;
 - <\$1K to Day-Ahead Generation Obligation (DAGO) at external locations;
 - \$38K to RT Deviations
 - Second Contingency \$4K
 - Distribution and Voltage were zero



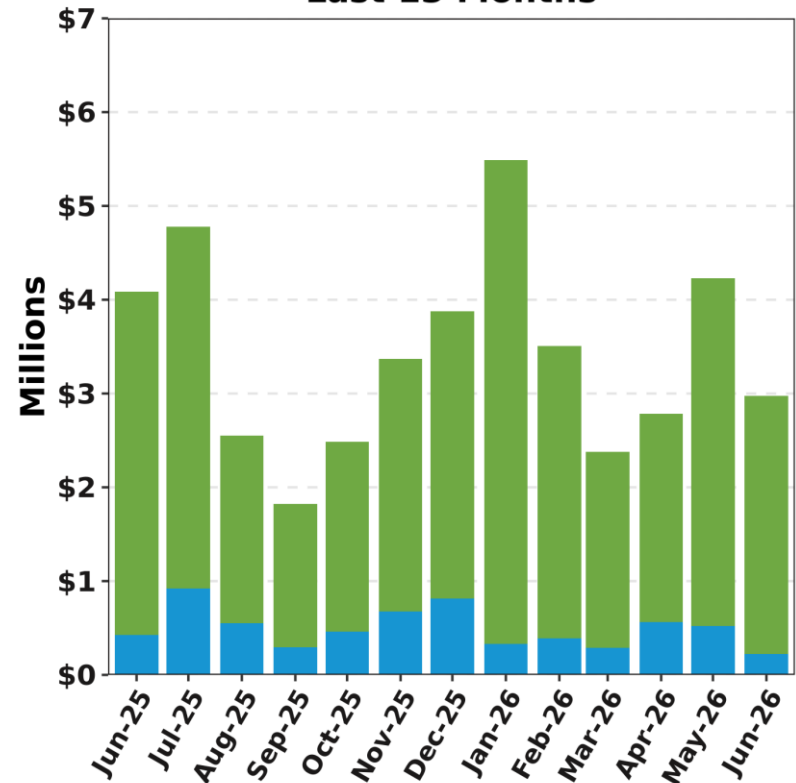
DA and RT NCPC Charges

Jun-26 Total = \$3 M



Day-Ahead Real-Time

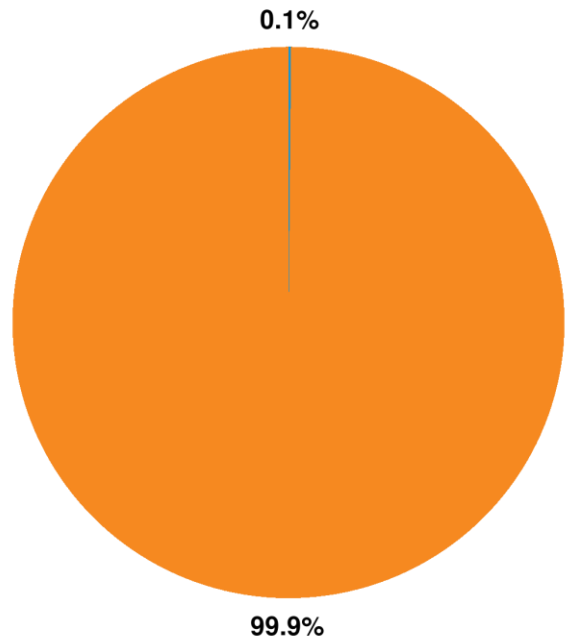
Last 13 Months



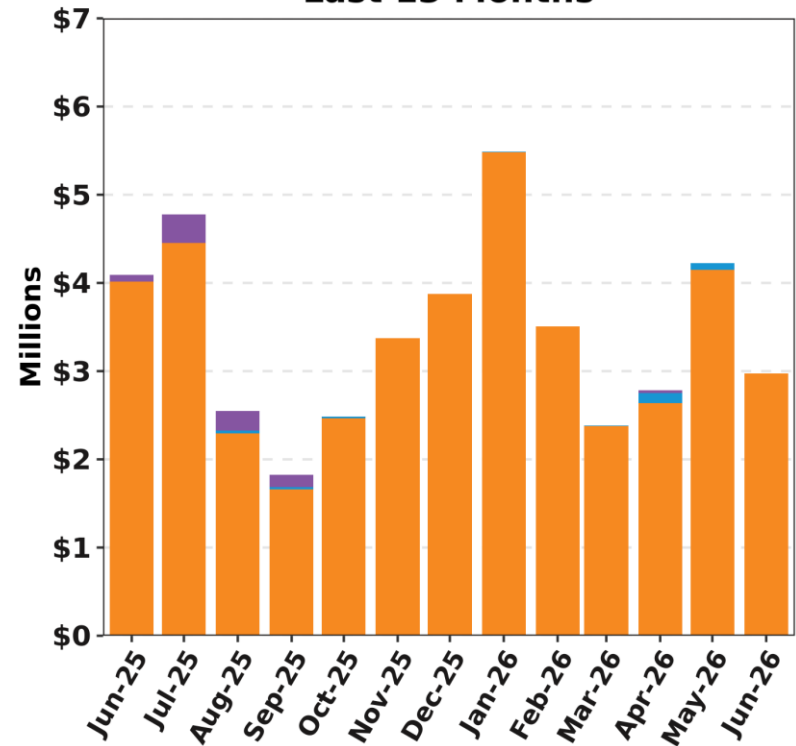
Day-Ahead Real-Time

NCPC Charges by Type

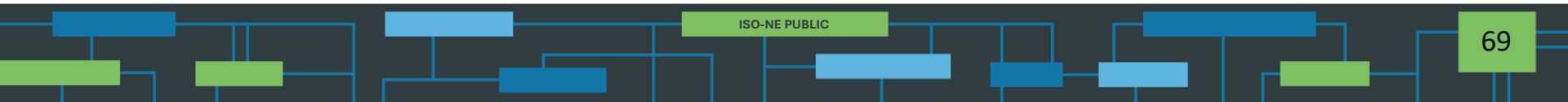
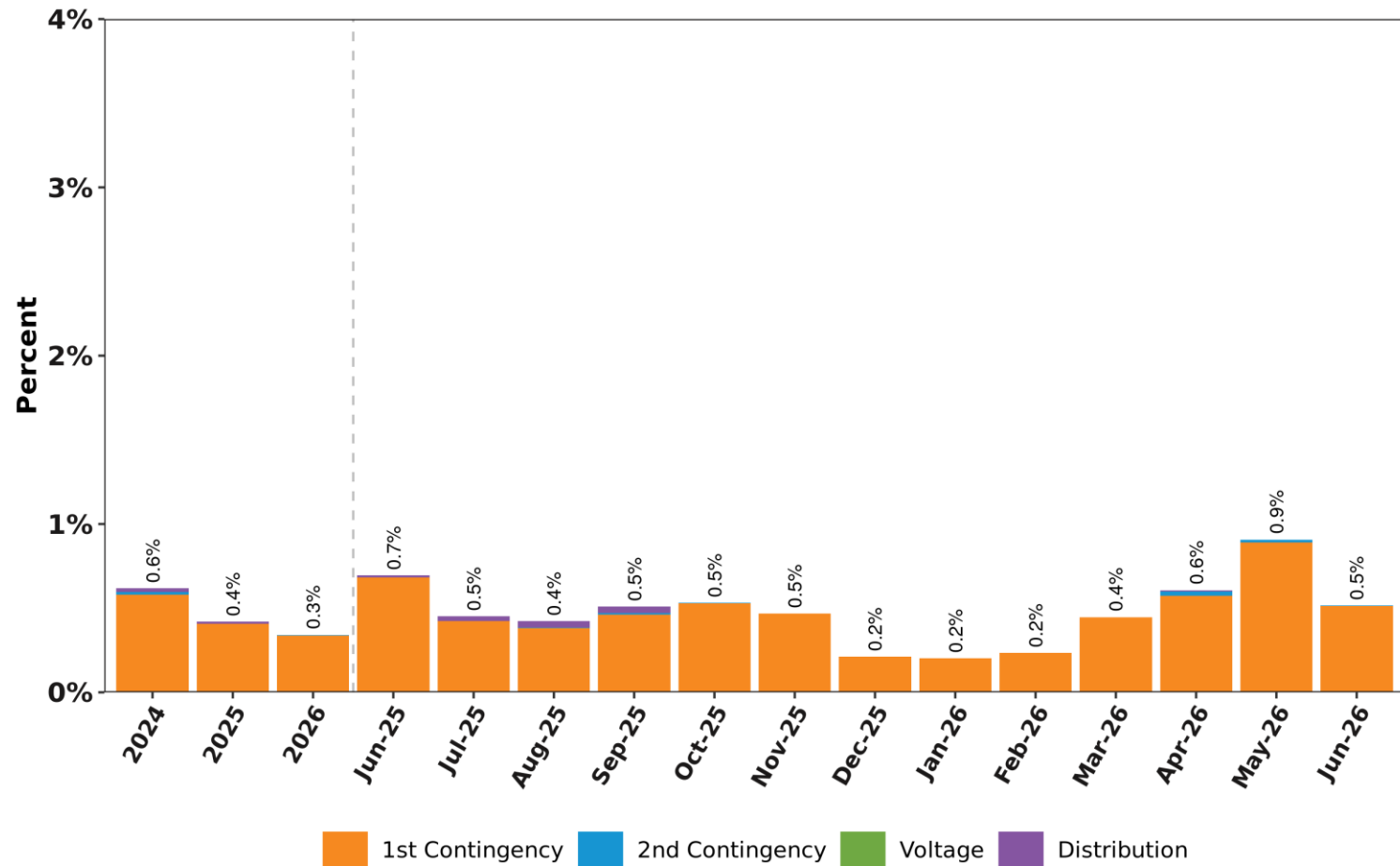
Jun-26 Total = \$3 M



Last 13 Months

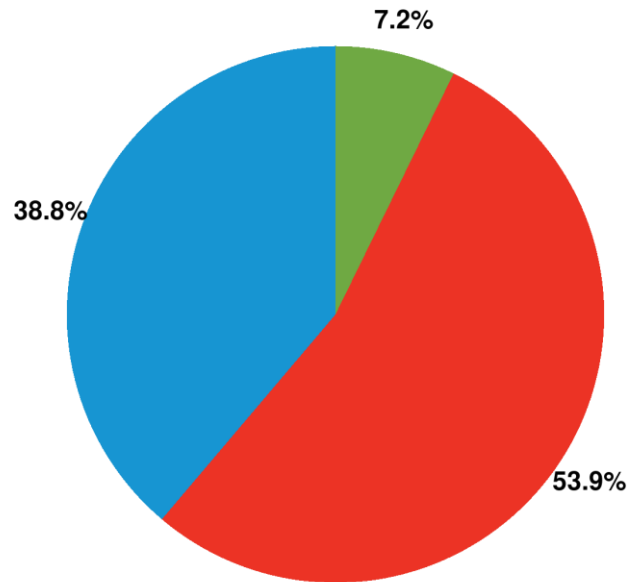


NCPC Charges by Type as Percent of Energy Market Value

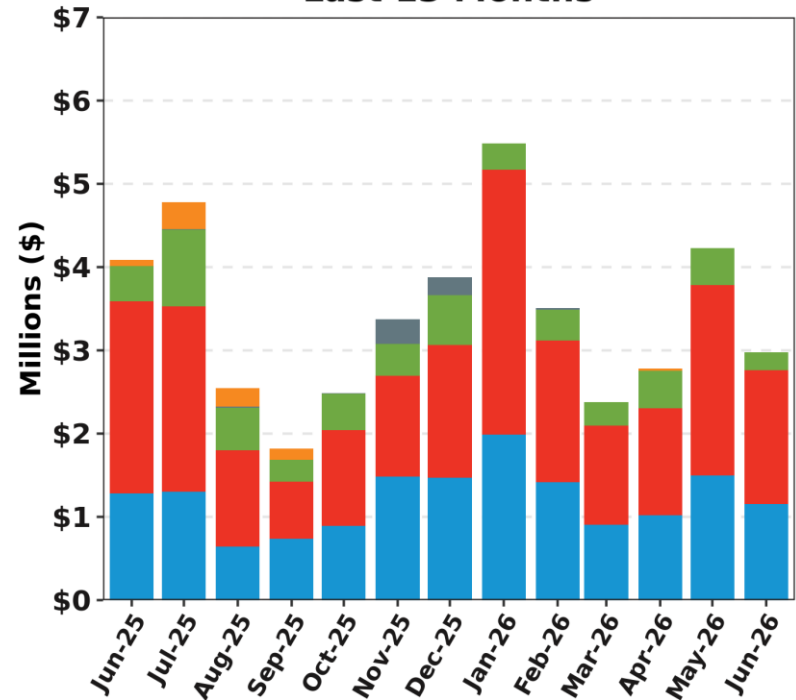


NCPC Charge Allocations

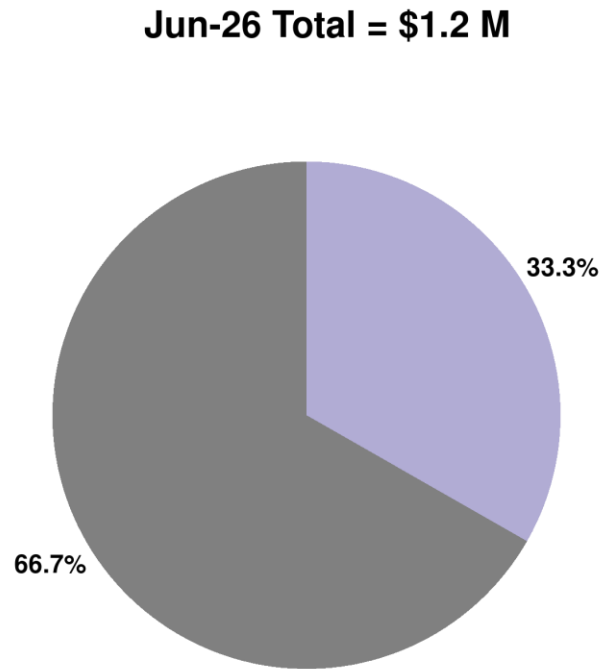
Jun-26 Total = \$3 M



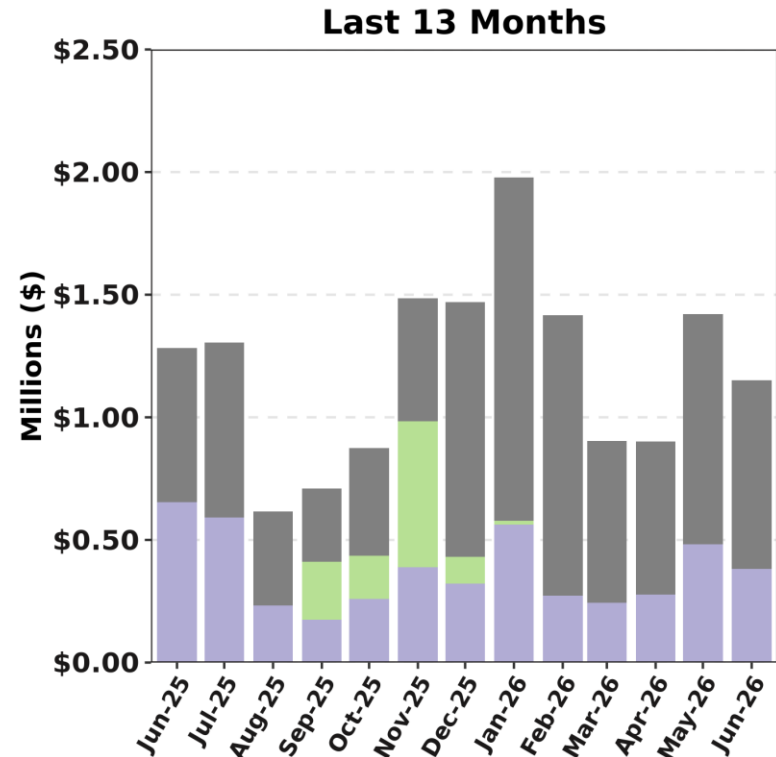
Last 13 Months



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



DLOC Postured Gen Min Gen
GPA RRP

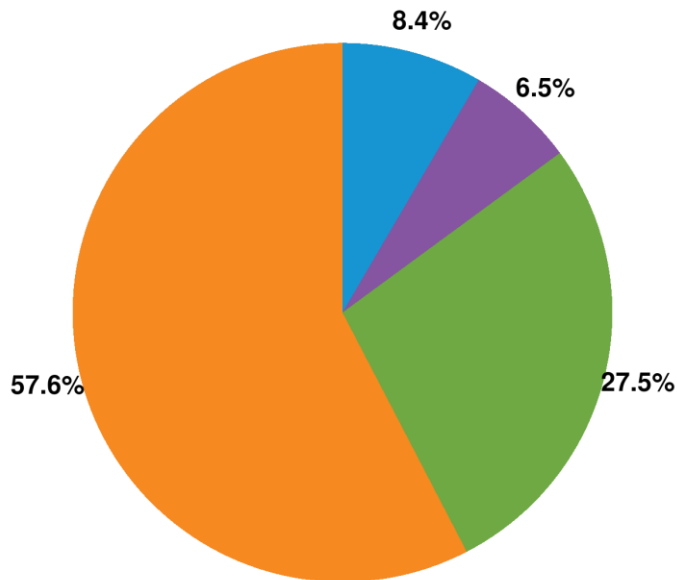


DLOC Postured Gen Min Gen
GPA RRP

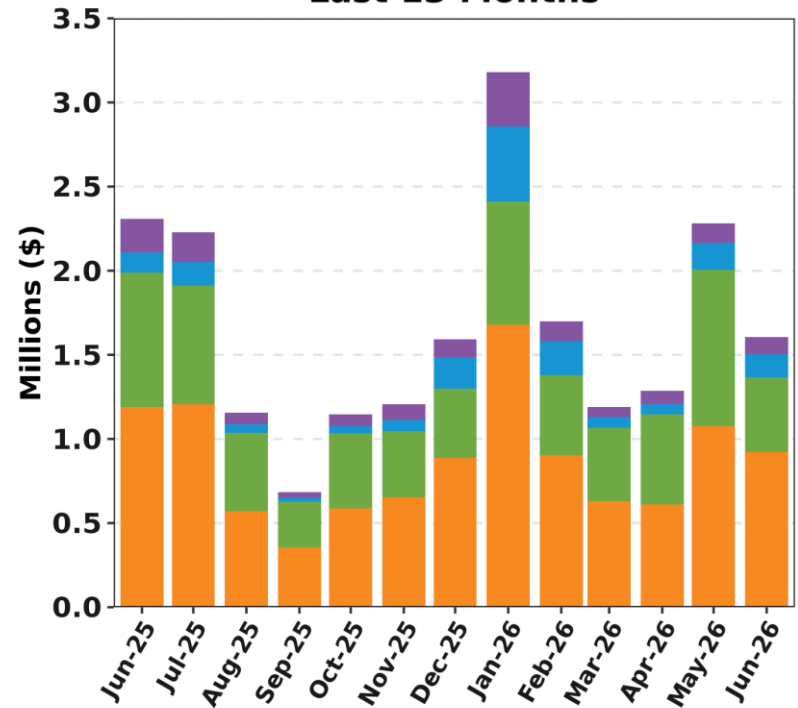
The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

RT First Contingency Charges by Deviation Type

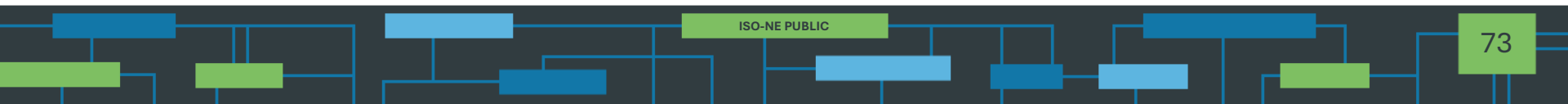
Jun-26 Total = \$1.6 M



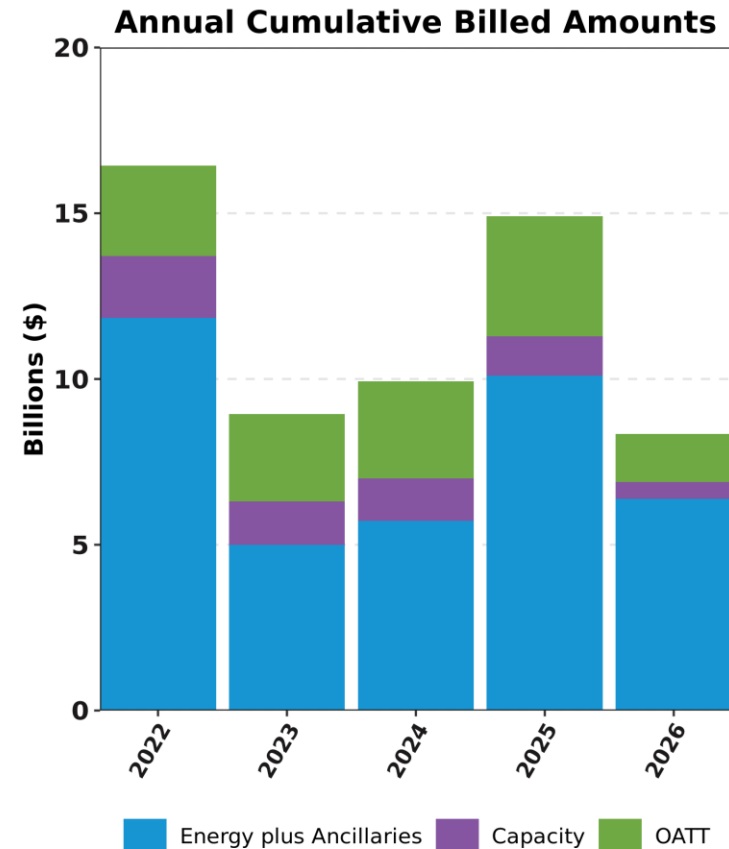
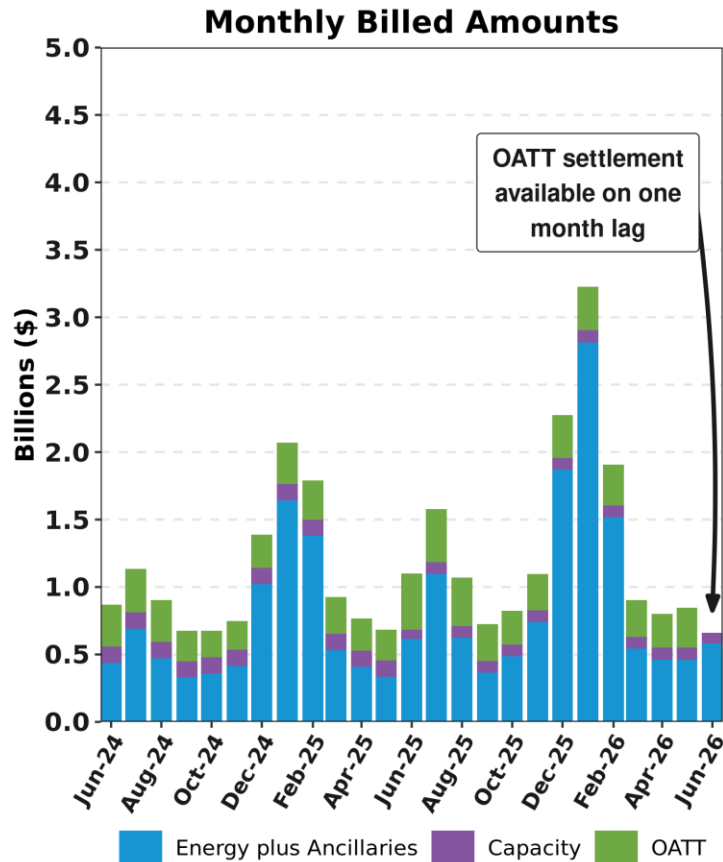
Last 13 Months



ISO BILLINGS



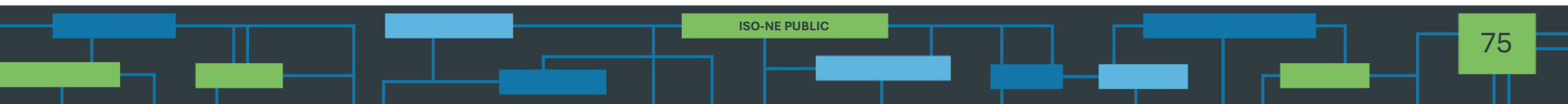
Total ISO Billings



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

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

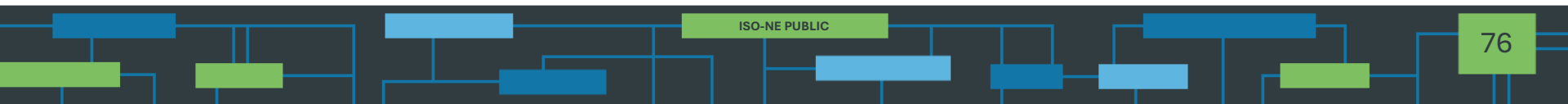
REGIONAL SYSTEM PLAN (RSP)



Planning Advisory Committee (PAC)

- July 28 PAC Meeting Potential Agenda Topics (note that the agenda is still under review)*
 - Asset Condition Projects
 - Line 191 OPGW Replacement Project (Eversource)
 - 345 kV Circuit Breaker Replacements - Ludlow (WMA), Fitzwilliam (NH) and Scovill Rock (CT) (Eversource)
 - 211-514X 115 kV Line Refurbishment and Reconductoring (Eversource)
 - O-15N Asset Condition Replacement (NGRID)
 - 394/397 Asset Condition Replacement (NGRID)
 - I-135S/J-136S Asset Condition Replacement (NGRID)
 - W-149 115 kV Line Asset Condition Refurbishment (NGRID)
 - TO LSP Public Policy Memos (NGRID)
 - 2027 RNS Rate Overview and Forecast (Eversource)
 - Highland Substation Rebuild & Synchronous Condenser Addition Cost Update (Avangrid CMP)
 - 2036 New England Short Circuit Needs Assessment (CEII)
 - 2025 Longer-Term Transmission Planning Request for Proposals – Preliminary Preferred Solution
 - Asset Condition Reviewer Update
 - Interim Asset Condition Review - 1670/1771
 - Interim Asset Condition Review - 325/331/344

* 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 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 is scheduled to make the preliminary preferred Longer-Term Transmission Solution determination by September 2026

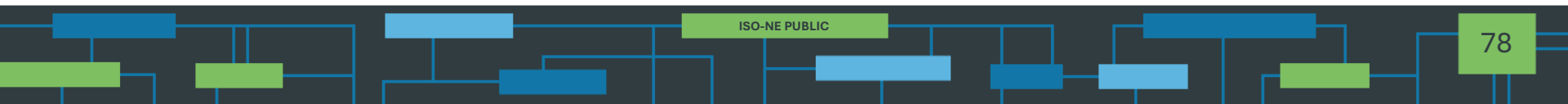
* Unless a bidder can demonstrate supply chain issues that warrant a later in-service date

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

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

- 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

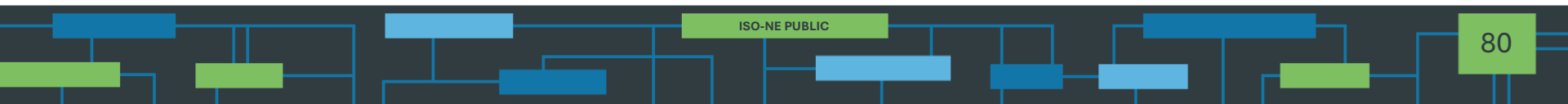


Permanent Asset Condition Reviewer

- The ISO began discussions of the permanent asset condition reviewer function at the January TC and further discussions are ongoing
 - ISO-NE would serve as the region's independent, advisory Asset Condition Reviewer (ACR) for Asset Condition Projects (ACPs). The function would provide early, technically rigorous reviews of need, scope, alternatives, and cost drivers, without directing projects or making prudency or siting determinations
- Final changes to the Transmission Operating Agreement (TOA) and ISO's Open Access Transmission Tariff (OATT) were presented and voted on at the June TC meeting
 - The TC voted in favor of the proposal
 - The next stakeholder vote will take place at the PC in August
- Interim project reviews underway to inform permanent design
- Targeting January 2027 go-live, subject to FERC acceptance and operating budget; tariff changes targeted for Q3 2026 filing

Economic Studies: 2026 Study

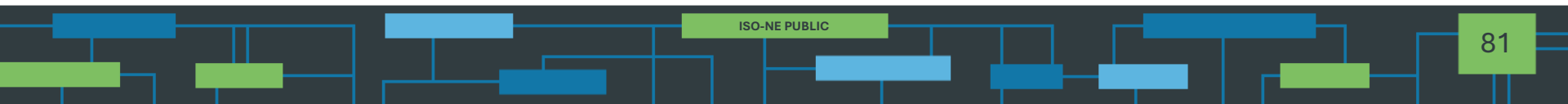
- The 2026 Economic Study was launched in January
 - The ISO presented results of the public survey, as part of a lessons learned, and Benchmark Scenario assumptions at PAC
 - The ISO has opened the Stakeholder-Requested scenario window through July 24
 - The Benchmark results will be presented at PAC this summer



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 6/29/2026

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 6/29/2026

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	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 6/29/2026

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	Dec-26	3

SEMA/RI Reliability Projects, cont.

Status as of 6/29/2026

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 6/29/2026

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 6/29/2026

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-28	2
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	Dec-29	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 6/29/2026

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

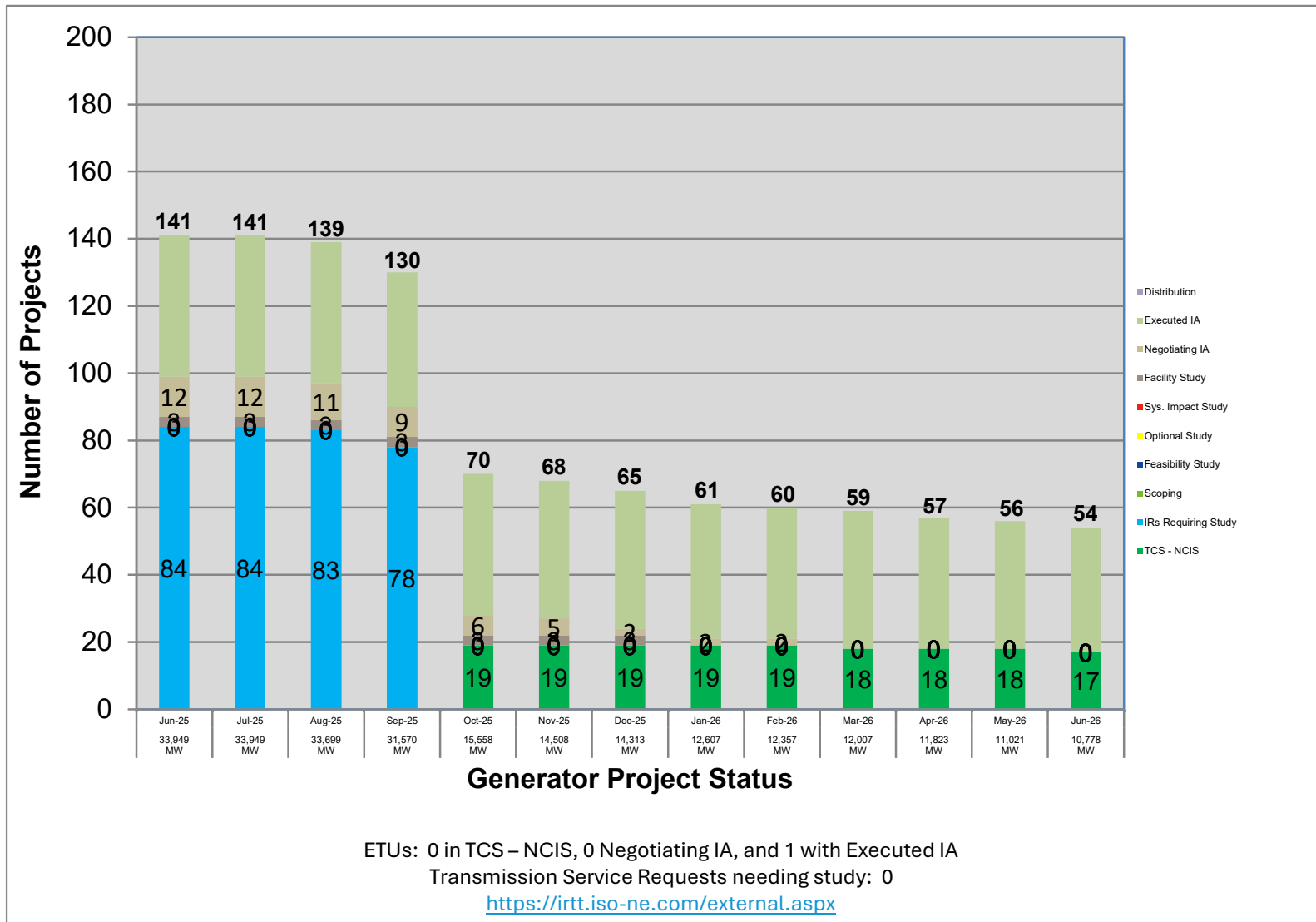
Boston 2033 Solutions Study

Status as of 6/29/2026

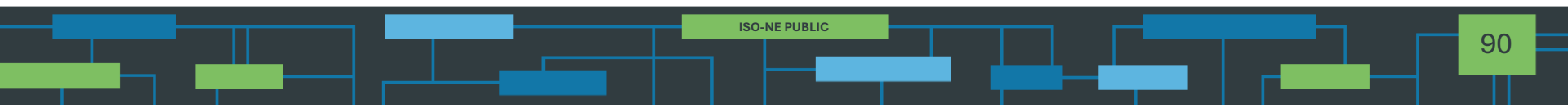
Project Benefit: Addresses system needs in the Boston area

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 June 30, 2026

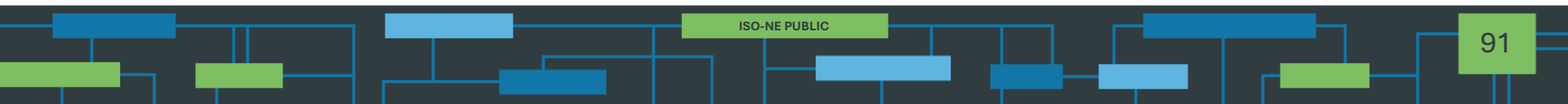


Additional notes provided on next slide



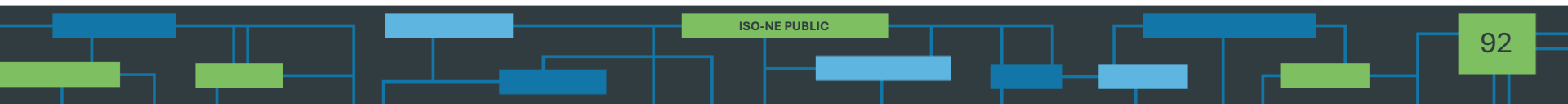
Status of Tariff Studies as of June 30, 2026, cont.

- Additional Notes
 - 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.
 - The interim TCS report was issued on June 7, 2026



OPERABLE CAPACITY ANALYSIS

Summer 2026 Analysis



Summer 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Aug - 2026 ² CSO (MW)	Aug - 2026 ² SCC (MW)
Operable Capacity MW ¹	26,744	27,861
Active Demand Capacity Resource (+) ⁵	321	319
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	15	15
Non Gas-fired Planned Outage MW (-)	1,531	1,836
Gas Generator Outages MW (-)	332	349
Allowance for Unplanned Outages (-) ⁴	2,100	2,100
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,526	24,319
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	25,228	25,228
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,290	27,290
Operable Capacity Margin	-3,764	-2,971

¹Operable Capacity is based on data as of **July 6, 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 **July 6, 2026**.

² Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **August 1, 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.

Summer 2026 Operable Capacity Analysis

90/10 Load Forecast	Aug - 2026 ² CSO (MW)	Aug - 2026 ² SCC (MW)
Operable Capacity MW ¹	26,744	27,861
Active Demand Capacity Resource (+) ⁵	321	319
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	15	15
Non Gas-fired Planned Outage MW (-)	1,531	1,836
Gas Generator Outages MW (-)	332	349
Allowance for Unplanned Outages (-) ⁴	2,100	2,100
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,526	24,319
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	26,473	26,473
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,535	26,473
Operable Capacity Margin	-5,009	-4,216

¹ Operable Capacity is based on data as of **July 6, 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 **July 6, 2026**.

² Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **August 1, 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.

Summer 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 6, 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 July through mid September.

Report created: 7/6/2026

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
7/25/2026	26698	324	475	15	436	36	2100	0	24940	25228	2062	27290	-2350	N	Summer 2026
8/1/2026	26744	321	409	15	1531	332	2100	0	23526	25228	2062	27290	-3764	Y	Summer 2026
8/8/2026	26744	321	409	15	1518	20	2100	0	23851	25228	2062	27290	-3439	N	Summer 2026
8/15/2026	26744	321	409	15	293	20	2100	0	25076	25228	2062	27290	-2214	N	Summer 2026
8/22/2026	26744	321	409	15	278	332	2100	0	24779	25228	2062	27290	-2511	N	Summer 2026
8/29/2026	26744	321	409	15	269	20	2100	0	25100	25228	2062	27290	-2190	N	Summer 2026
9/5/2026	26965	350	409	42	290	0	2100	0	25376	25228	2062	27290	-1914	N	Summer 2026
9/12/2026	26965	350	409	42	290	0	2100	0	25376	25228	2062	27290	-1914	N	Summer 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.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.

Summer 2026 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 6, 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 July through mid September.

Report created: 7/6/2026

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	
7/25/2026	26698	324	475	15	436	36	2100	0	24940	26473	2062	28535	-3595	N	Summer 2026
8/1/2026	26744	321	409	15	1531	332	2100	0	23526	26473	2062	28535	-5009	Y	Summer 2026
8/8/2026	26744	321	409	15	1518	20	2100	0	23851	26473	2062	28535	-4684	N	Summer 2026
8/15/2026	26744	321	409	15	293	20	2100	0	25076	26473	2062	28535	-3459	N	Summer 2026
8/22/2026	26744	321	409	15	278	332	2100	0	24779	26473	2062	28535	-3756	N	Summer 2026
8/29/2026	26744	321	409	15	269	20	2100	0	25100	26473	2062	28535	-3435	N	Summer 2026
9/5/2026	26965	350	409	42	290	0	2100	0	25376	26473	2062	28535	-3159	N	Summer 2026
9/12/2026	26965	350	409	42	290	0	2100	0	25376	26473	2062	28535	-3159	N	Summer 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.

*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