Weekly Market Summary

February 2-8, 2026

About this Report

This report contains eleven sections. They are:

1) The ***Weekly Highlights*** section provides brief explanations of notable events that occurred during the week. The tables provided show market results for the current week, prior week, the same week a year ago, and the percentage change this week vs. the prior week and prior year. The highlights also include a detailed explanation of the Day-Ahead and Real-Time price separation for the current week, along with any Real-Time price corrections.
2) The ***Pricing*** section contains various graphs presenting information about Locational Marginal Prices (LMPs) and its components for the Hub, Load Zones, and external nodes. A table showing descriptive LMP statistics for these locations is also provided.
3) The ***Weekly Demand*** section contains a table describing total Day-Ahead and Real-Time Load Obligation (DALO & RTLO) for the current week, last week, the percentage change from last week, last year, and the percentage change from last year. In addition, there are graphs showing Day-Ahead demand bids and cleared volumes by type. Also included are tables for daily demand bid and virtual volumes and peak load by day with associated Real-Time pricing.
4) The ***Weekly Supply*** section contains tables and graphs of Day-Ahead Generation Obligation accumulated from generation, virtual supply, and imports. These exhibits also include the Day-Ahead Demand Reduction Obligation. Information on Real-Time supply including, metered generation by fuel type, self-scheduled MWh, Real-Time reliability MWh, marginal price setting, and external interface imports.
5) ***Net Commitment Period Compensation (NCPC)*** section includes information and links to the NCPC Summary report.
6) The ***Energy Market Payment*** section contains a table showing the payments associated with the Day-Ahead and Real-Time Energy Markets, a pie chart showing the component percentage of the Day-Ahead Energy Market payment, and a bar chart showing the magnitude of each component's contribution to the total Energy Market payment.
7) The ***Flexible Response Services (FRS)*** section contains tables and graphs related to the FRS clearing rate, the associated closeout charges, cleared FRS product MWh, and FRS payments.
8) The ***Forecast Energy Requirement (FER) and Energy Imbalance Reserves (EIR)*** section contains tables and graphs related to the Forecast Energy Reserve Price (FERP), FER and EIR Obligation MWh, and FER and EIR payments and closeout charges.
9) The ***Real-Time Reserve Market*** section contains a table showing the Real-Time Reserve payments by Reserve Zone, two tables with Real-Time Reserve Clearing Prices data, and a table with information related to Real-Time reserve bias implementation.
10) The ***Capacity Scarcity Condition (CSC)*** section contains preliminary details of any CSC activity that may have occurred during the week.

11) The last section of the report, the ***Glossary and Links*** section, contains additional information concerning the sections listed above, including links to relevant pages on the ISO New England web site.

Note: A supplemental Excel file 'Weekly Market Data 53 Weeks.XLSX', located here, contains the past 53 weeks of data of various concepts including market prices, payments, charges, and MWh values.

Click this icon in the section header to navigate to the glossary section, where definitions are described in more detail, with links to the ISO New England web site.

Weekly Highlights: February 2-8, 2026

1.1 Weekly Highlights

Notable Events

- Real-Time LMPs in excess of $365/MWh were caused by high fuel prices and loads over the forecast in the hour ending 5:00 P.M. on Sunday, February 8.
- In response to severe weather conditions in all of New England, Master/Local Control Center Procedure #2 (M/LCC 2) was implemented on Sunday, January 25 at 9:00 A.M. and remains in effect as of the posting of this report.

Locational Marginal Pricing (LMPs) New England Hub; $/MWh; Average	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead Energy Market; All Hours	$220.32	$380.95	-42.2%	$135.24	62.9%
*Real-Time Energy Market; All Hours	$220.84	$278.24	-20.6%	$132.59	66.6%
*This is the average of the 5-minute pricing intervals within the week.					

Weekly Demand Statistics (MWh)	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Revenue Quality System Peak Load (MWh - Initial)	20,178	19,940	1.2%	18,478	9.2%
DA Load Obligation (All Zones)	-2,809,697	-2,913,610	-3.6%	-2,531,974	11.0%
RT Load Obligation (All Zones)	-2,780,890	-2,915,652	-4.6%	-2,512,795	10.7%
DA Cleared Exports (All Interfaces)	-51,104	-45,442	12.5%	-46,465	10.0%
RT Scheduled Exports (All Interfaces)	-136,453	-129,677	5.2%	-111,872	22.0%

Weekly Supply Statistics	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Input Fuel Price (Natural Gas, $/MMBtu)	$23.32	$66.17	-64.8%	$11.41	104.4%
Mass Average Input Fuel Price (Natural Gas, $/MMBtu)	$26.06	$57.59	-54.7%	$16.52	57.7%
Metered Generation (MWh)	2,357,905	2,591,217	-9.0%	1,890,059	24.8%
Generation Obligation (MWh)	2,977,064	3,100,929	-4.0%	2,675,069	11.3%
RT Demand Reduction Obligation (MWh)	0	307	-100.0%	383	-100.0%
Self-Scheduled Generation (MWh)	926,751	1,064,828	-13.0%	838,624	10.5%
DA Cleared Imports (MWh - All Interfaces)	575,953	444,091	29.7%	724,530	-20.5%
RT Scheduled Imports (MWh - All Interfaces)	619,159	509,712	21.5%	785,010	-21.1%

Market Payments	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead and Real-Time Energy Market Payments ($)	$672,084,696	$1,434,768,256	-53.2%	$358,956,748	87.2%
Day-Ahead Ancillary Services Market Payments ($)	$3,068,415	$73,797,235	-95.8%	N/A	N/A
Real-Time Reserve Market Payments ($)	$12,373	$0	N/A	$533,948	-97.7%

Underlying natural gas data furnished by:

ice Global markets in clear view

Day-Ahead Price Separation

- On Monday, Thursday, and Saturday, February 2, 5, and 7, depressed pricing in the Maine (ME) Load Zone was caused by a binding constraint on the Maine – New Hampshire Interface due to patterns of load and generation.
- On Tuesday and Wednesday, February 3 and 4, elevated pricing in the Rhode Island (RI) Load Zone was caused by binding constraints on the E105 (Hartford Ave – Franklin Square) and F106 (Hartford Ave – Franklin Square) lines due to patterns of load and generation.
- On Sunday, February 8, depressed pricing in the ME Load Zone was caused by a binding constraint on the Northern New England Scobie Interface due to an equipment outage. The equipment outage was restored on February 9.

Real-Time Price Separation

- On Monday, Tuesday, Thursday, and Sunday, February 2, 3, 5, and 8, depressed pricing in the ME Load Zone was caused by a binding constraint on the Maine – New Hampshire Interface due to patterns of load and generation.
- On Saturday, February 7, depressed pricing in the ME Load Zone was caused by binding constraints on the Northern New England Scobie and Maine – New Hampshire Interfaces due to patterns of load and generation.

Real-Time Price Corrections

- From the interval beginning at 2:50 P.M. to 3:50 P.M. on Tuesday, February 3 due to a planned software outage. The resulting five minute LMPs for these intervals at the Hub and Load Zones ranged between $125.01/MWh and $132.46/MWh.

Year-to-Date Peak Load Statistics*

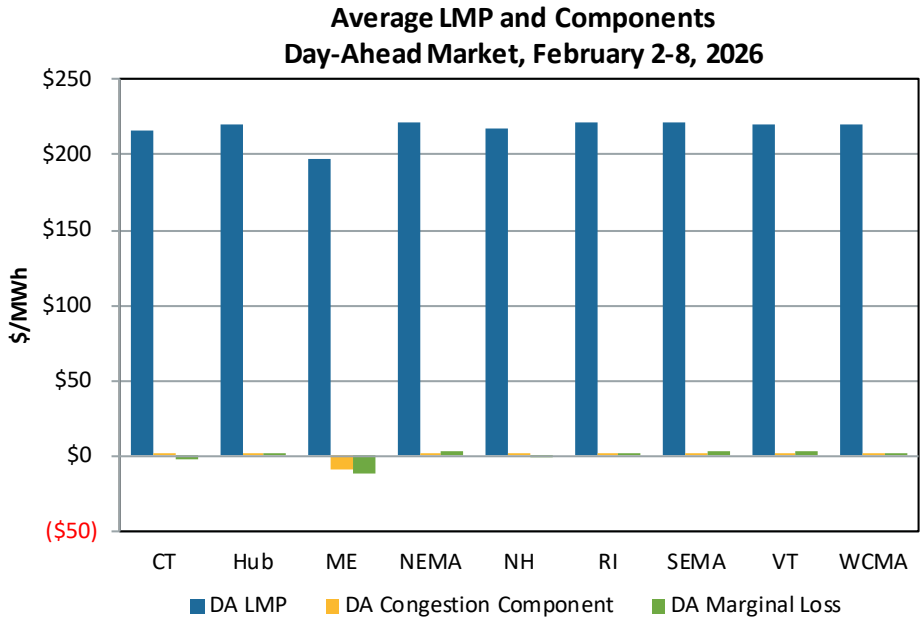
- FCM Peak Load (preliminary, subject to change) is 19,937 MWh and occurred in the hour ending 1:00 P.M. on Sunday, January 25. At this hour, the Capacity Zone-level FCM peak loads were 2,814 MWh in Northern New England, 1,832 MWh in Maine, 7,535 MWh in Rest-of-Pool, and 7,756 MWh in Southeast New England.
- Revenue Quality System Peak Load (initial) is 20,221 MWh and occurred in the hour ending 2:00 P.M. on Sunday, January 25.
- Telemetered System Peak Load is 20,182 MWh and occurred in the hour ending 2:00 P.M. on Sunday, January 25.

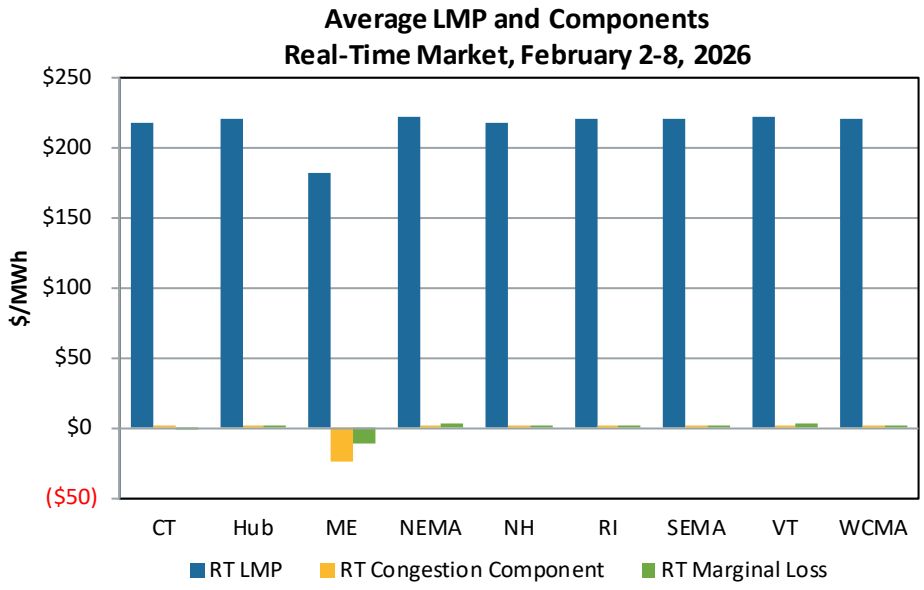
*Due to the difference in calculation methodologies, these values can occur on different days and hours.

Pricing

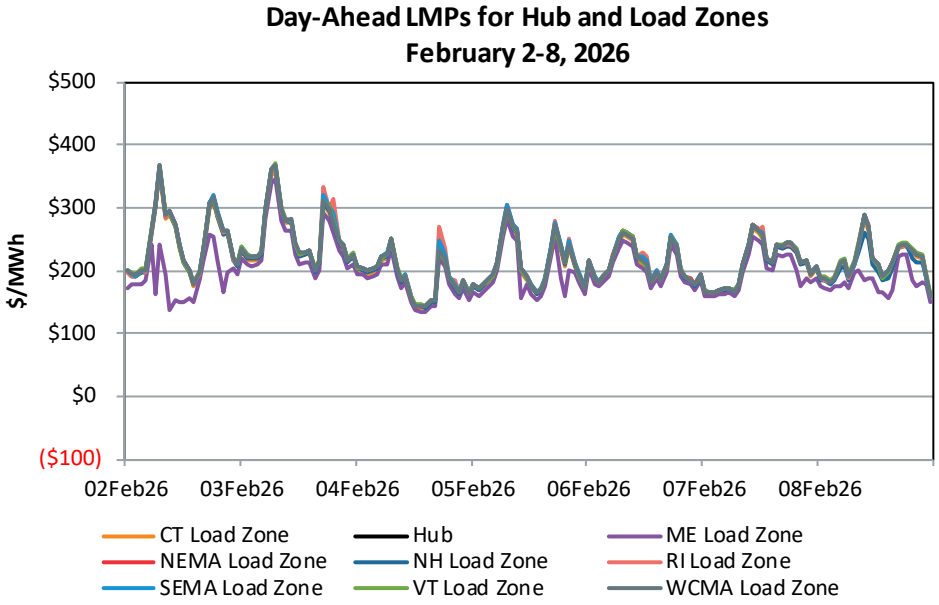
2.1 Pricing

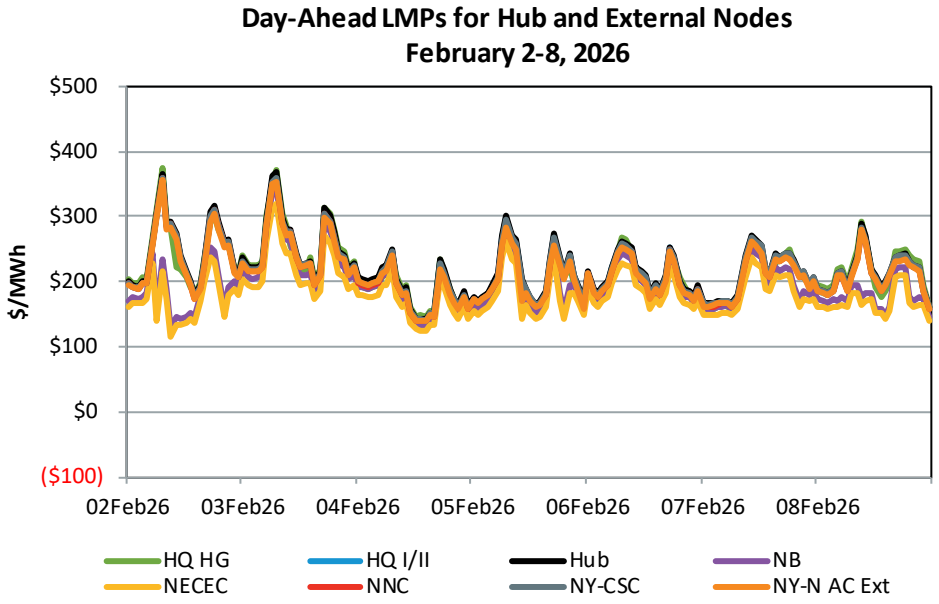
The two graphs below show the weekly average of LMPs, congestion, and marginal loss components at the Hub and Load Zones for both the Day-Ahead and Real-Time Energy Markets.



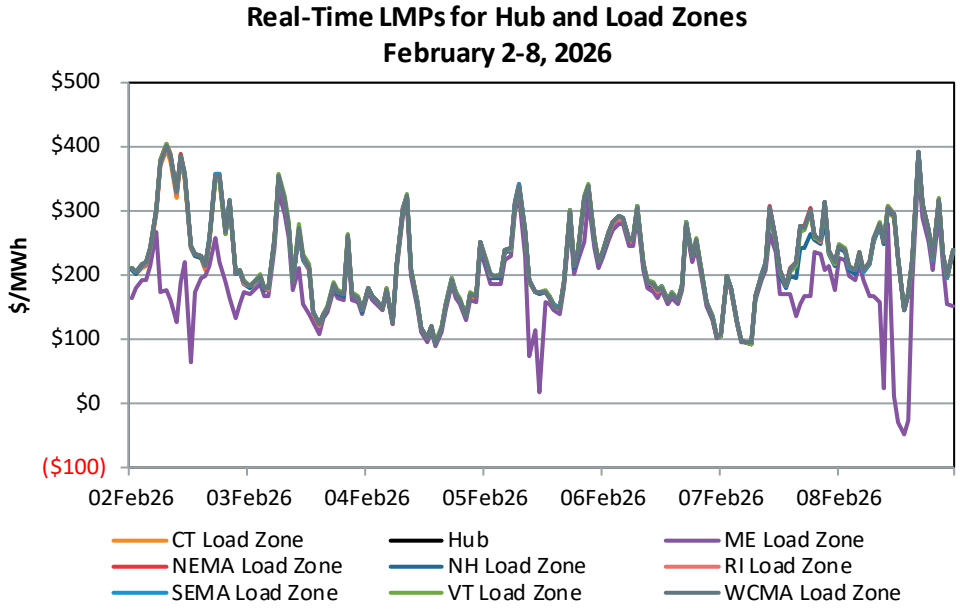


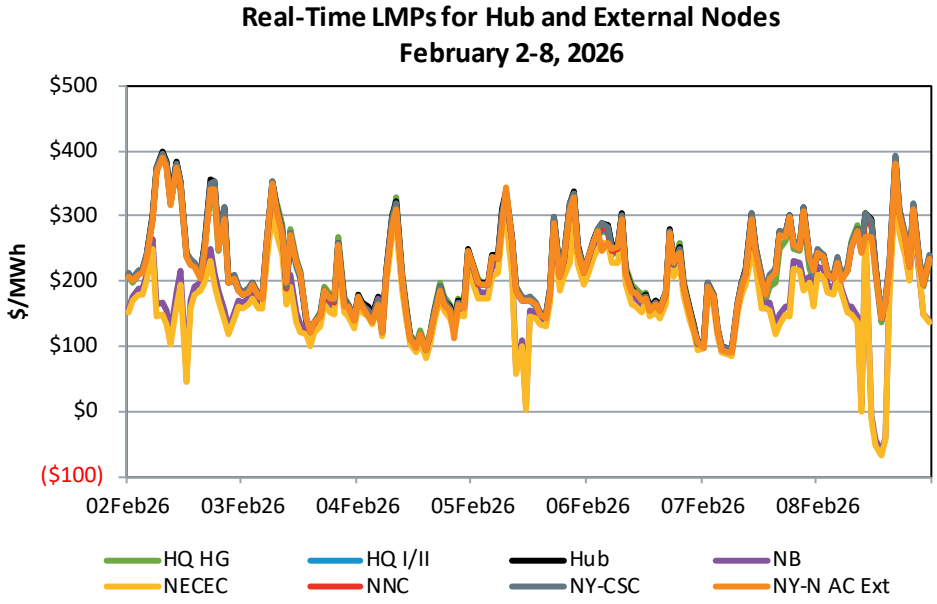
The following two graphs show hourly Day-Ahead LMPs for the Hub, the eight Load Zones, and the seven external nodes. In cases where there is little or no price separation, the lines for multiple locations may be indistinguishable from each other.





The following two graphs show hourly average Real-Time LMPs for the Hub, the eight Load Zones, and the seven external nodes. The 5-minute LMPs are averaged to create hourly values for comparison. The lines for multiple locations may be indistinguishable from each other.





LMP Summary Statistics, February 2-8, 2026

Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	*Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA as % of Hub	*RT as % of Hub	*RT as % of DA	DA Std Dev	*RT Std Dev	*RT Std/DA Std
Hub	$220.32	$220.84	$142.64	$93.38	$367.46	$400.46	100%	100%	100%	43.23	67.24	156%
ME	$197.06	$182.57	$134.58	$-49.29	$344.53	$366.86	89%	83%	93%	37.43	65.83	176%
NH	$217.17	$218.35	$141.80	$92.71	$364.02	$397.36	99%	99%	101%	42.41	65.99	156%
VT	$220.61	$221.87	$144.81	$93.43	$370.13	$403.24	100%	100%	101%	43.06	67.08	156%
CT	$215.87	$217.63	$140.91	$92.31	$359.16	$393.83	98%	99%	101%	41.90	66.06	158%
RI	$221.14	$220.52	$143.44	$93.39	$364.62	$398.47	100%	100%	100%	43.63	66.81	153%
SEMA	$221.66	$221.42	$144.03	$93.64	$368.36	$401.46	101%	100%	100%	43.42	67.24	155%
WCMA	$220.38	$221.24	$142.95	$93.56	$367.48	$401.57	100%	100%	100%	43.13	67.37	156%
NEMA	$221.09	$221.80	$143.38	$93.72	$368.83	$403.34	100%	100%	100%	43.33	67.58	156%
NB Ext	$193.95	$179.32	$130.45	$-62.09	$343.84	$362.19	88%	81%	92%	37.92	66.95	177%
NY-N AC Ext	$212.71	$214.96	$139.16	$91.31	$355.27	$389.20	97%	97%	101%	41.25	65.27	158%
HQ Ext	$217.17	$217.78	$139.08	$91.30	$362.43	$396.88	99%	99%	100%	42.78	66.72	156%
HG Ext	$215.93	$216.32	$146.30	$87.16	$375.00	$398.18	98%	98%	100%	43.66	65.06	149%
CSC Ext	$217.40	$220.45	$140.85	$93.46	$360.61	$397.52	99%	100%	101%	42.06	66.97	159%
NNC Ext	$214.62	$216.53	$139.63	$91.80	$358.76	$393.47	97%	98%	101%	41.89	65.72	157%
NECEC Ext	$181.93	$168.04	$115.92	$-66.53	$319.17	$350.68	83%	76%	92%	35.08	64.85	185%

*This is the average of the 5-minute pricing intervals within the week.

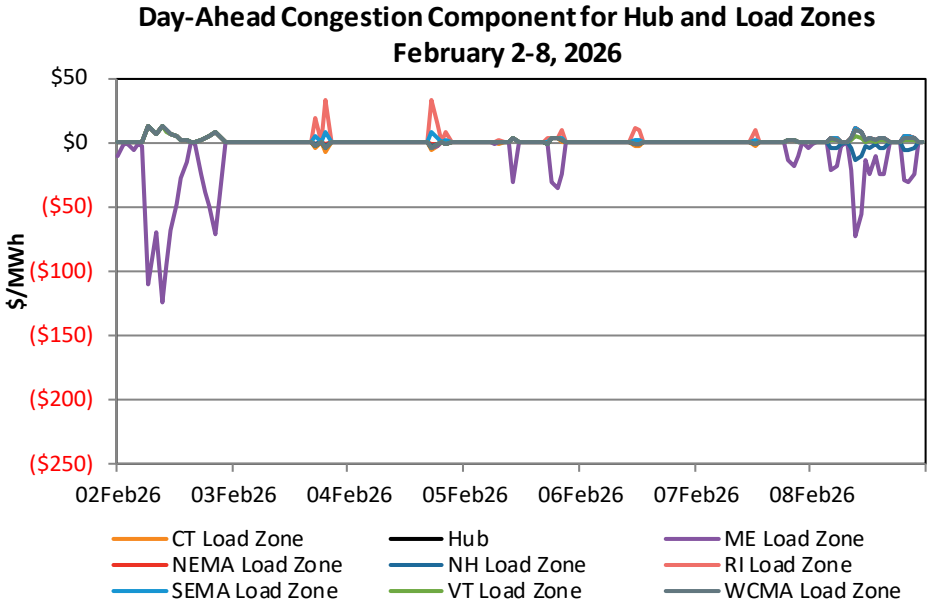
5-Minute LMP Summary (RT Only)
February 2-8, 2026

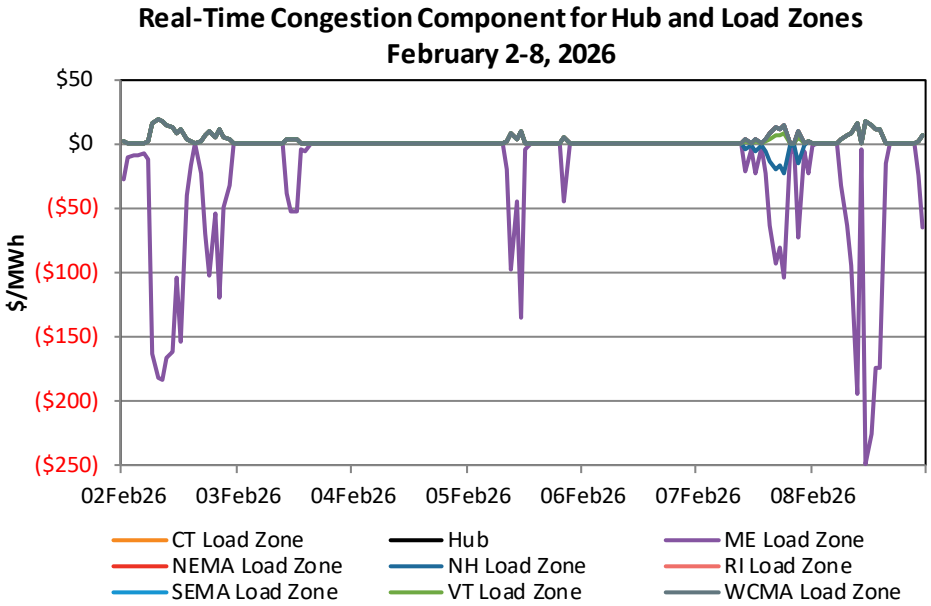
Hub/Zone	Max RT LMP ($/MWh)	Min RT LMP ($/MWh)	RT Std Dev	RT as % of Hub
Hub	$650.90	$74.63	$75.75	100%
ME	$432.72	-$56.55	$72.65	85%
NH	$644.02	$74.63	$74.46	99%
VT	$657.90	$75.59	$75.64	101%
CT	$637.92	$74.00	$74.45	99%
RI	$648.54	$74.69	$75.36	100%
SEMA	$652.55	$74.96	$75.81	100%
WCMA	$649.81	$74.65	$75.88	100%
NEMA	$654.96	$75.25	$76.14	100%

5-Minute Energy Component of LMP
February 2-8, 2026

Frequency Tabulation	< $0.00	$0.00 - $20.99	$21.00 - $40.99	$41.00 - $70.99	$71.00 - $100.99	$100.00 - $150.99	$150.00 - $200.99	$200.00 - $500.99	$500.00 - $1000.99	> $1000.99
5-Minute Energy	0.0%	0.0%	0.0%	0.0%	2.9%	13.0%	29.1%	54.7%	0.3%	0.0%

The next two graphs show hourly Day-Ahead and hourly Real-Time congestion components for the Hub and each of the eight Load Zones. The 5-minute values are averaged to create hourly values for comparison. The lines for multiple locations may be indistinguishable from each other.





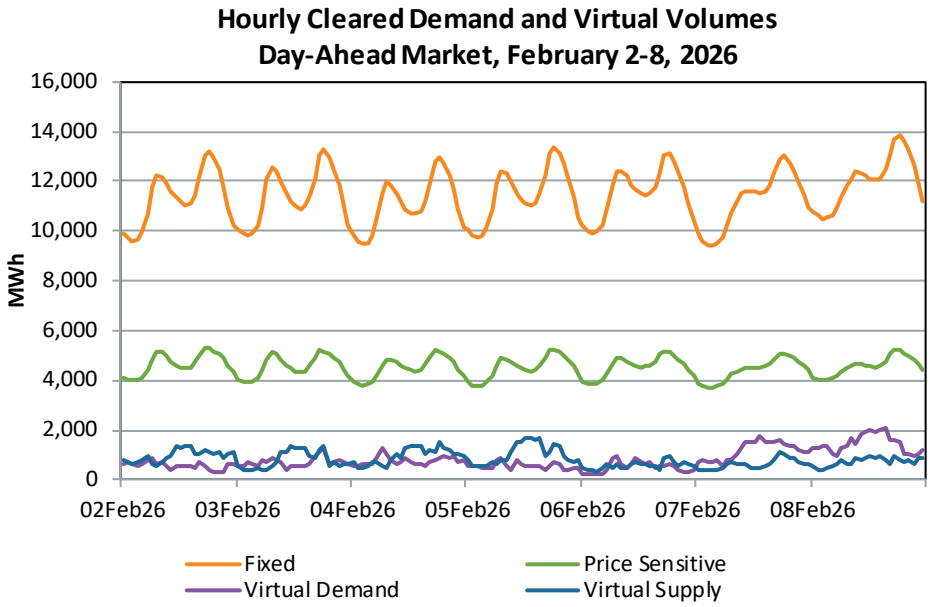
Energy Market Demand

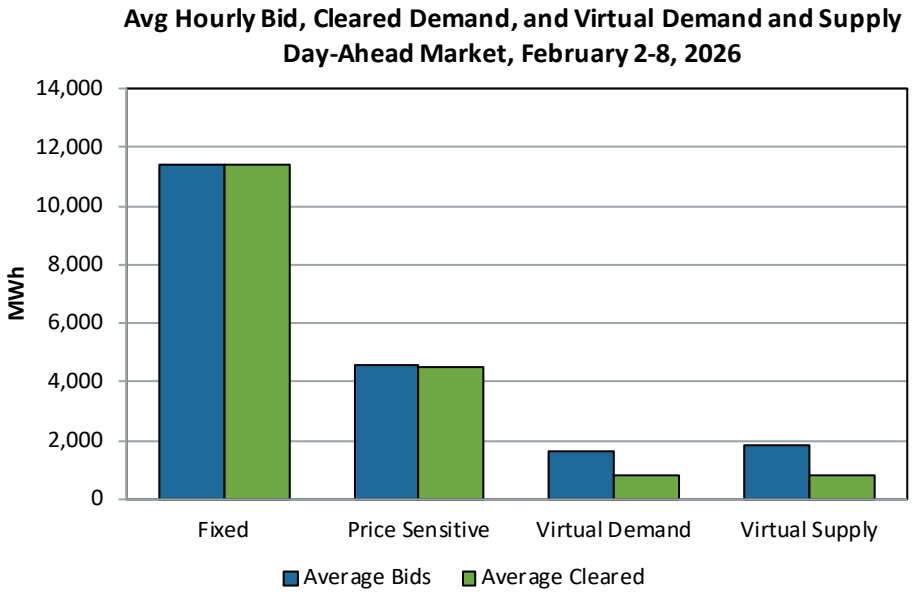
3.1 Day-Ahead Demand

The following table displays the Day-Ahead Load Obligation at the Hub, Load Zones, and external nodes for this week, last week, the same week a year ago and the percent change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
Hub	54,882	44,134	24.4%	22,257	146.6%
ME	252,029	266,825	-5.5%	242,808	3.8%
NH	253,714	278,019	-8.7%	244,769	3.7%
VT	124,521	107,809	15.5%	119,211	4.5%
CT	656,337	689,270	-4.8%	572,059	14.7%
RI	164,439	170,779	-3.7%	139,768	17.7%
SEMA	330,013	354,236	-6.8%	305,133	8.2%
WCMA	380,738	398,426	-4.4%	342,541	11.2%
NEMA	549,121	577,934	-5.0%	500,331	9.8%
NB Ext	2,205	387	469.8%	4,298	-48.7%
NY-N AC Ext	19,969	10,820	84.6%	40,069	-50.2%
HQ Ext	45	22,167	-99.8%	45	0.0%
HG Ext	28,161	34,208	-17.7%	45,161	-37.6%
CSC Ext	39,956	15,112	164.4%	1,791	Large
NNC Ext	517	54	Large	1,861	-72.2%
NECEC Ext	0	0	N/A	N/A	N/A

Participants can bid fixed and price sensitive demand as well as submit virtual demand bids and virtual supply offers into the Day-Ahead Energy Market. The first graph below shows hourly cleared values for these four categories of bids and offers. The second graph shows average hourly values for the week.





Daily Demand Bid and Virtual Volumes by Zone (MWh)

February 2-8, 2026

The following table summarizes Day-Ahead demand bid volumes submitted and cleared at the Hub and in the eight Load Zones (including nodal locations within each Load Zone) along with virtual demand (Decrement or 'Dec') bids and supply (Increment or 'Inc') offers on the same basis.

Location	Day	Fixed Demand Bids	Price Sens. Bids	Dec Bids	Inc Offers	Cleared Fixed Demand	Cleared Price Sens. Demand	Cleared Decs	Cleared Incs	Total DA Demand
Hub	02FEB26	0	0	7,813	6,834	0	0	5,952	5,629	5,952
Hub	03FEB26	0	0	13,271	6,091	0	0	8,459	5,470	8,459
Hub	04FEB26	0	0	8,125	10,161	0	0	6,395	5,114	6,395
Hub	05FEB26	0	0	9,387	6,877	0	0	6,297	5,014	6,297
Hub	06FEB26	0	0	5,159	2,791	0	0	3,061	1,870	3,061
Hub	07FEB26	0	0	12,441	3,936	0	0	10,644	1,327	10,644
Hub	08FEB26	0	0	15,363	3,903	0	0	14,074	3,470	14,074
ME	02FEB26	26,088	9,502	1,261	17,280	26,088	9,502	325	7,183	35,914
ME	03FEB26	25,594	9,463	627	15,397	25,594	9,463	253	4,254	35,310
ME	04FEB26	25,097	9,458	796	19,179	25,097	9,458	370	6,698	34,925
ME	05FEB26	26,698	9,426	1,257	19,492	26,698	9,426	419	9,240	36,543
ME	06FEB26	27,267	9,532	740	13,198	27,267	9,532	470	4,330	37,270
ME	07FEB26	25,850	9,348	1,751	14,849	25,850	9,348	1,188	5,293	36,385
ME	08FEB26	27,618	9,337	2,036	19,051	27,618	9,337	1,072	8,363	38,026
NH	02FEB26	30,373	5,742	751	3,034	30,373	5,742	39	1,884	36,153
NH	03FEB26	29,779	5,966	323	3,326	29,779	5,966	48	1,847	35,794
NH	04FEB26	29,110	6,094	1,486	2,666	29,110	6,094	528	1,907	35,732
NH	05FEB26	30,293	5,959	771	2,726	30,293	5,959	90	2,233	36,342
NH	06FEB26	30,527	5,912	750	1,867	30,527	5,912	374	1,261	36,813
NH	07FEB26	29,469	5,737	1,381	2,028	29,469	5,737	771	613	35,977
NH	08FEB26	31,669	5,332	1,685	1,262	31,669	5,332	476	897	37,476
VT	02FEB26	1,357	15,884	726	2,073	1,357	15,884	139	1,782	17,380
VT	03FEB26	1,379	15,318	343	1,782	1,379	15,318	81	1,432	16,778
VT	04FEB26	1,420	16,005	868	2,139	1,420	16,005	266	1,755	17,692
VT	05FEB26	1,394	16,270	358	2,280	1,394	16,270	100	1,819	17,764
VT	06FEB26	1,463	16,407	368	1,781	1,463	16,407	106	1,205	17,975
VT	07FEB26	1,455	16,397	1,560	1,424	1,455	16,397	955	811	18,807
VT	08FEB26	1,534	16,665	1,367	1,056	1,534	16,665	632	714	18,831
CT	02FEB26	62,540	30,710	2,835	1,809	62,540	30,710	850	908	94,099
CT	03FEB26	62,987	30,270	2,337	3,184	62,987	30,270	881	1,004	94,138
CT	04FEB26	60,966	29,145	7,916	2,452	60,966	29,145	5,186	1,070	95,297
CT	05FEB26	62,798	29,302	2,954	2,210	62,798	29,302	1,324	1,081	93,423
CT	06FEB26	63,200	29,714	1,972	2,204	63,200	29,714	973	977	93,886
CT	07FEB26	61,552	28,965	2,796	1,087	61,552	28,965	2,010	477	92,527
CT	08FEB26	66,659	30,800	4,382	1,065	66,659	30,800	2,787	527	100,246
RI	02FEB26	16,500	6,336	1,359	2,073	16,500	6,336	159	1,011	22,995
RI	03FEB26	16,921	6,203	1,380	2,183	16,921	6,203	328	872	23,451

Weekly Market Summary

Location	Day	Fixed Demand Bids	Price Sens. Bids	Dec Bids	Inc Offers	Cleared Fixed Demand	Cleared Price Sens. Demand	Cleared Decs	Cleared Incs	Total DA Demand
RI	04FEB26	16,253	6,113	1,761	1,873	16,253	6,113	565	933	22,931
RI	05FEB26	17,045	6,127	2,574	1,980	17,045	6,127	276	938	23,447
RI	06FEB26	16,819	6,162	2,385	2,189	16,819	6,162	754	492	23,734
RI	07FEB26	16,184	5,879	1,850	1,744	16,184	5,879	1,351	735	23,414
RI	08FEB26	17,377	6,188	1,989	2,556	17,377	6,188	1,316	1,335	24,881
SEMA	02FEB26	34,219	12,472	849	903	34,219	12,472	174	769	46,864
SEMA	03FEB26	34,820	12,045	641	1,106	34,820	12,045	258	725	47,122
SEMA	04FEB26	34,151	11,629	692	1,163	34,151	11,629	333	921	46,113
SEMA	05FEB26	35,434	11,726	954	965	35,434	11,726	192	738	47,352
SEMA	06FEB26	35,105	11,648	968	1,758	35,105	11,648	450	309	47,202
SEMA	07FEB26	33,893	11,256	1,367	1,187	33,893	11,256	970	399	46,118
SEMA	08FEB26	36,666	11,924	1,916	2,240	36,666	11,924	857	684	49,447
WCMA	02FEB26	42,840	12,430	1,393	2,321	42,840	12,331	451	1,480	55,622
WCMA	03FEB26	42,926	11,984	983	2,759	42,926	11,865	461	1,469	55,253
WCMA	04FEB26	42,054	11,822	777	2,092	42,054	11,715	346	1,799	54,114
WCMA	05FEB26	41,293	11,928	991	1,924	41,293	11,802	248	1,684	53,342
WCMA	06FEB26	41,442	12,051	988	1,848	41,442	11,967	486	1,129	53,896
WCMA	07FEB26	40,796	11,008	4,389	685	40,796	10,900	1,896	262	53,592
WCMA	08FEB26	43,643	11,771	5,263	725	43,643	11,663	3,753	539	59,059
NEMA	02FEB26	58,179	18,877	1,756	2,558	58,179	18,877	236	2,199	77,292
NEMA	03FEB26	59,382	18,682	1,679	3,008	59,382	18,538	375	2,065	78,296
NEMA	04FEB26	57,242	18,162	1,143	2,371	57,242	18,018	584	1,820	75,844
NEMA	05FEB26	60,173	18,294	1,447	2,307	60,173	18,150	448	1,887	78,771
NEMA	06FEB26	60,786	18,036	1,310	1,681	60,786	17,892	645	1,276	79,322
NEMA	07FEB26	59,452	17,334	1,732	556	59,452	17,190	1,327	324	77,969
NEMA	08FEB26	62,741	17,939	3,560	1,446	62,741	17,795	2,122	759	82,658

3.2 Real-Time Demand

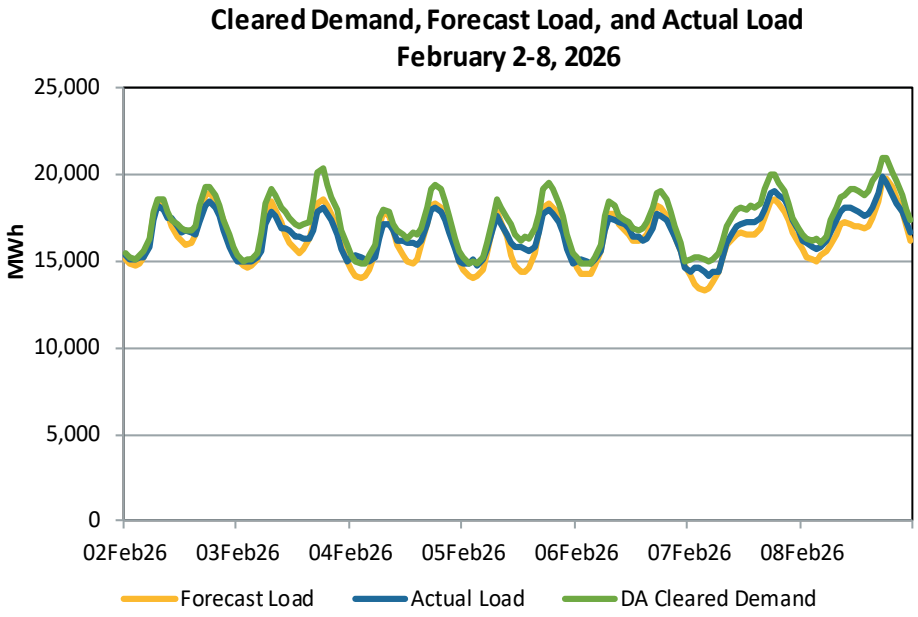
The following table displays the Real-Time Load Obligation at each Load Zone and external nodes for this week, last week, the same week a year ago, and the percent change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
ME	251,110	271,047	-7.4%	245,872	2.1%
NH	264,864	279,241	-5.1%	249,344	6.2%
VT	124,539	130,875	-4.8%	116,445	7.0%
CT	657,942	687,110	-4.2%	568,420	15.7%
RI	170,728	178,969	-4.6%	155,392	9.9%
SEMA	328,559	346,184	-5.1%	288,974	13.7%
WCMA	383,660	400,684	-4.2%	345,757	11.0%
NEMA	551,954	584,294	-5.5%	498,253	10.8%
NB Ext	7,828	4,152	88.5%	6,374	22.8%
NY-N AC Ext	85,837	49,035	75.1%	97,417	-11.9%
HQ Ext	0	30,448	-100.0%	0	N/A
HG Ext	249	69	260.9%	17	Large
CSC Ext	40,543	45,515	-10.9%	4,037	Large
NNC Ext	1,996	458	335.8%	4,027	-50.4%
NECEC Ext	0	0	N/A	N/A	N/A

Real-Time Peak Hour System Load and Associated Average Hourly LMPs

Day	Hour	System Load (MWh)	Hub	Maine Load Zone	NH Load Zone	VT Load Zone	CT Load Zone	RI Load Zone	SEMA Load Zone	WCMA Load Zone	NEMA Load Zone
02FEB26	19	18,827	$354.92	$220.44	$351.33	$349.05	$347.51	$353.63	$355.59	$354.46	$357.11
03FEB26	19	18,405	$171.83	$164.12	$171.07	$175.89	$170.07	$171.83	$172.17	$172.01	$171.88
04FEB26	19	18,446	$171.24	$164.83	$171.74	$173.02	$166.61	$171.70	$172.79	$170.95	$173.12
05FEB26	19	18,340	$212.66	$200.18	$212.00	$215.62	$208.94	$213.21	$213.95	$212.73	$213.61
06FEB26	18	18,046	$280.18	$271.60	$281.15	$282.80	$275.20	$280.71	$281.79	$280.54	$282.45
07FEB26	19	19,391	$302.06	$167.73	$262.98	$297.83	$298.84	$301.65	$302.35	$302.54	$303.65
08FEB26	18	20,178	$309.47	$289.08	$306.32	$309.10	$306.66	$308.61	$309.08	$309.81	$310.32

The graph below compares the hourly quantities of cleared Day-Ahead demand with the forecast and actual load. Cleared demand is the total of cleared fixed demand bids, cleared price sensitive demand bids, and cleared Decrement bids.



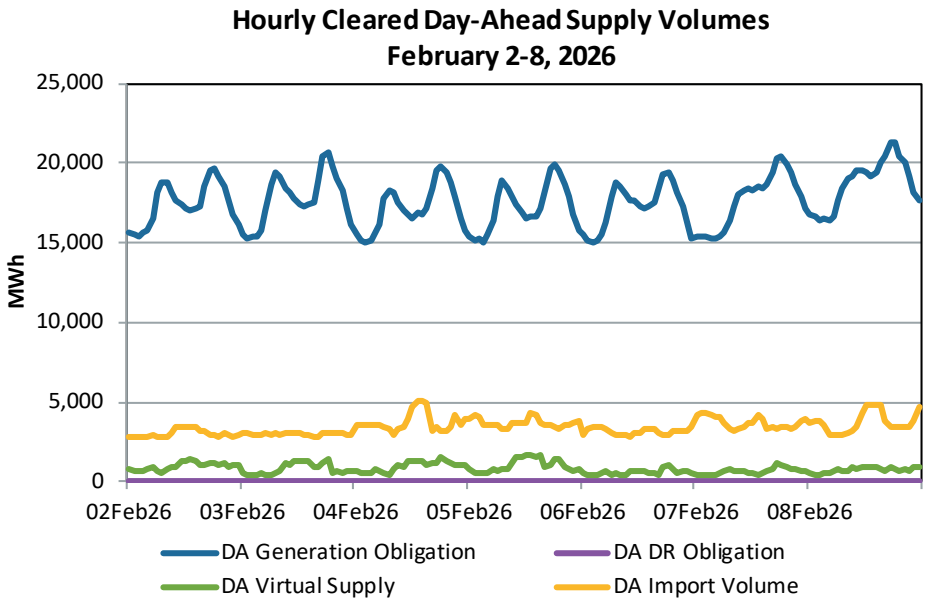
The table below compares the total quantities (MWh) of Day-Ahead Load Obligation with the Real-Time Load Obligation for each Load Zone (including nodal locations within each Load Zone) for the week. Day-Ahead Load Obligation is composed of Day-Ahead cleared demand bids and cleared Decrement bids. Real-Time Load Obligation is comprised of metered load and internal bilateral contracts for load.

Zone	DA Load Obligation (MWh)	RT Load Obligation (MWh)	DA Delta (MWh)	DA % of RT
ME	254,373	254,140	232	100.1%
NH	254,287	265,553	-11,266	95.8%
VT	125,226	124,539	687	100.6%
CT	663,616	657,942	5,675	100.9%
RI	164,853	170,728	-5,875	96.6%
SEMA	330,221	334,872	-4,651	98.6%
WCMA	412,089	421,091	-9,002	97.9%
NEMA	550,152	552,026	-1,874	99.7%

Energy Market Supply

4.1 Day-Ahead Supply

The following graph displays hourly Day-Ahead Generation Obligation, along with cleared Day-Ahead Increment offers (virtual supply), Day-Ahead Demand Reduction (DR) Obligation, and Day-Ahead Import volume.



The following table displays the average hourly Day-Ahead Generation and Day-Ahead Demand Reduction Obligation, along with cleared Day-Ahead Virtual Supply and Day-Ahead Import Volume, for this week, last week, the same week a year ago, and the percent change for each.

Type	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
DA Generation Obligation	17,585	18,122	-3.0%	15,859	10.9%
DA Demand Reduction Obligation	0	24	-100.0%	4	-100.0%
DA Cleared Increments	819	594	37.9%	1,029	-20.4%
DA Imports	3,428	2,643	29.7%	4,313	-20.5%

The following table provides the total Day-Ahead Imports by Interface for This Week, Last Week, the same week a year ago and the percent change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	10,468	24,137	-56.6%	60,039	-82.6%
NY-N AC Ext	217,434	175,952	23.6%	279,217	-22.1%
HQ Ext	100,979	83,769	20.5%	287,062	-64.8%
HG Ext	43,068	39,121	10.1%	79,619	-45.9%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	15,844	20,372	-22.2%	18,592	-14.8%
NECEC Ext	188,160	100,740	86.8%	N/A	N/A

4.2 Real-Time Supply

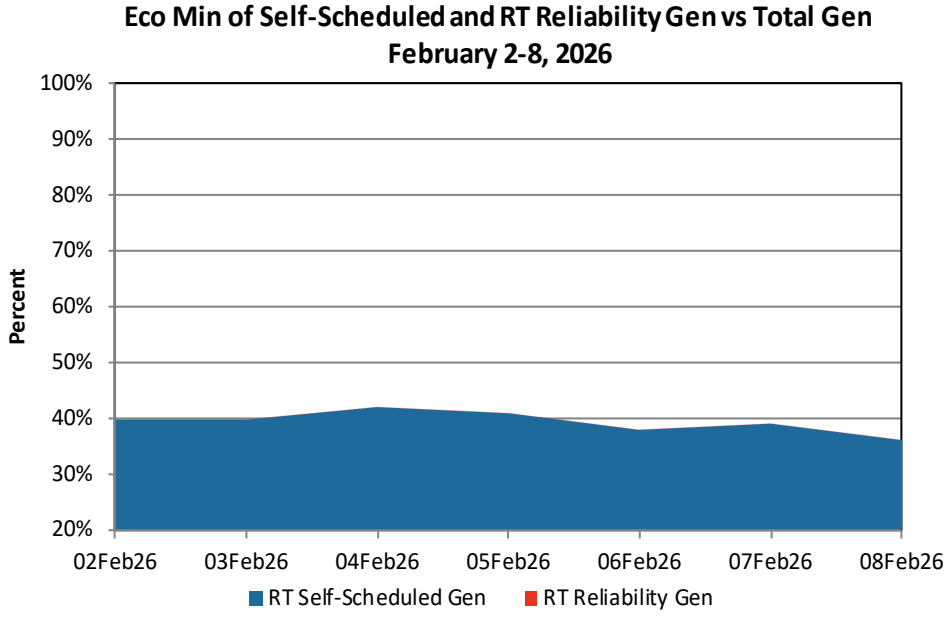
The following table provides daily and weekly totals, in megawatt-hours (MWh), of the amount of electricity produced by classified fuel type during the week. The data provided are for the full system, including "settlement only" resources that do not offer their output into the wholesale markets. The Price Responsive Demand (PRD) category below refers to Demand Reduction from Demand Response Resources (DRR). Annual files of Daily Generation by Fuel Type and further detail of the fuels composing the categories below may be found on the ISO's web site here.

	Metered Generation (Megawatt hours)							
Category	02Feb26	03Feb26	04Feb26	05Feb26	06Feb26	07Feb26	08Feb26	Total
Coal	0	6	6	2	104	68	92	277
Hydro	18,625	15,178	14,722	16,515	16,052	15,314	17,002	113,408
Landfill Gas	822	856	881	904	939	955	936	6,293
Methane	40	54	54	58	55	46	48	356
Natural Gas	111,782	135,435	151,410	146,584	175,939	139,808	127,545	988,502
Nuclear	80,706	80,793	80,771	80,689	80,673	80,656	80,629	564,918
Oil	91,030	72,953	29,760	37,198	34,170	63,136	89,428	417,675
Other	2,250	2,436	2,761	2,580	2,203	683	1,650	14,564
PRD	0	0	0	0	-0	0	0	-0
Refuse	6,212	6,003	5,756	5,887	6,403	7,027	6,220	43,509
Solar	5,072	7,570	6,972	10,153	6,978	1,725	5,997	44,466
Wind	23,312	8,563	14,549	11,746	5,173	15,979	29,728	109,050
Wood	8,073	7,862	8,029	7,754	7,764	7,787	7,620	54,889
Total	347,924	337,709	315,671	320,070	336,453	333,183	366,895	2,357,905

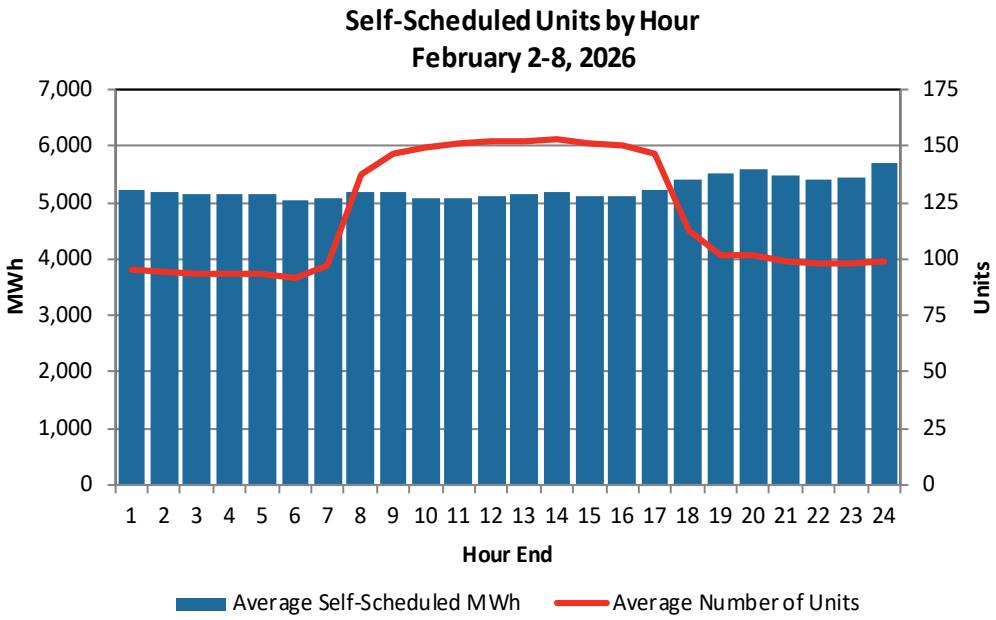
Online generators that are at their Economic Minimum output level are not eligible to set the clearing price. Real-Time Self-Scheduled Generation shown below reflects output by self-scheduled generation and by (non-dispatchable) Settlement Only Resources (SORs). Real-Time Reliability Generation represents the aggregate economic minimum output level of generation committed for reliability reasons. The following table shows the sum of generation self-scheduled (and SORs), and that of Real-Time reliability committed units, and, for reference, the total daily generation in megawatts by day for the current week.

Day	Self-Scheduled MWh	RT Reliability MWh	Total Generation MWh
02Feb26	137,786	0	347,924
03Feb26	135,078	0	337,709
04Feb26	132,811	0	315,671
05Feb26	129,700	0	320,070
06Feb26	128,226	0	336,453
07Feb26	129,930	0	333,183
08Feb26	133,220	0	366,895

The following graph shows the total economic minimum MWh of self-scheduled generation and generation committed for reliability as a percentage of total generation.



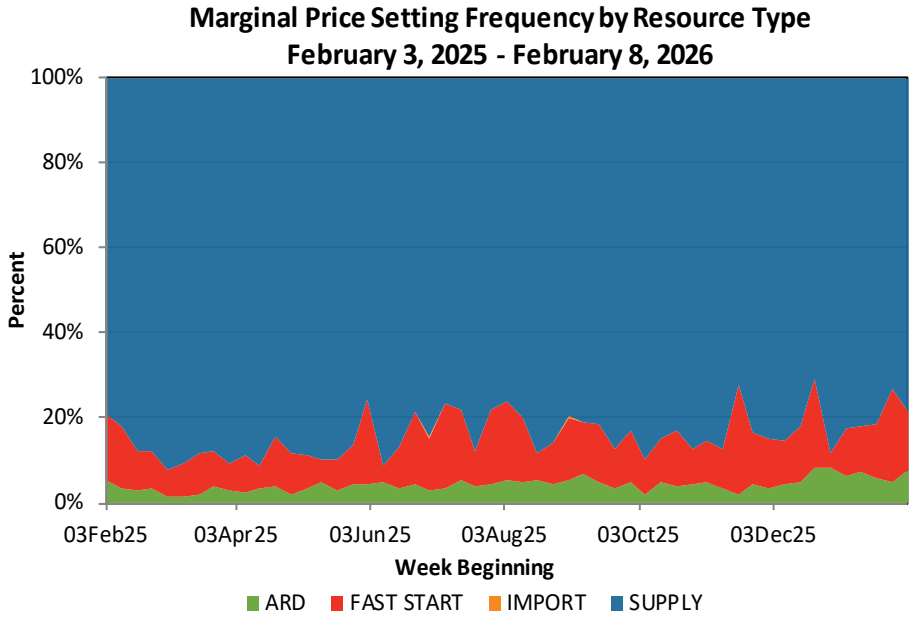
The following graph shows the average number of self-scheduled generating units and MWh for each hour of the last week.



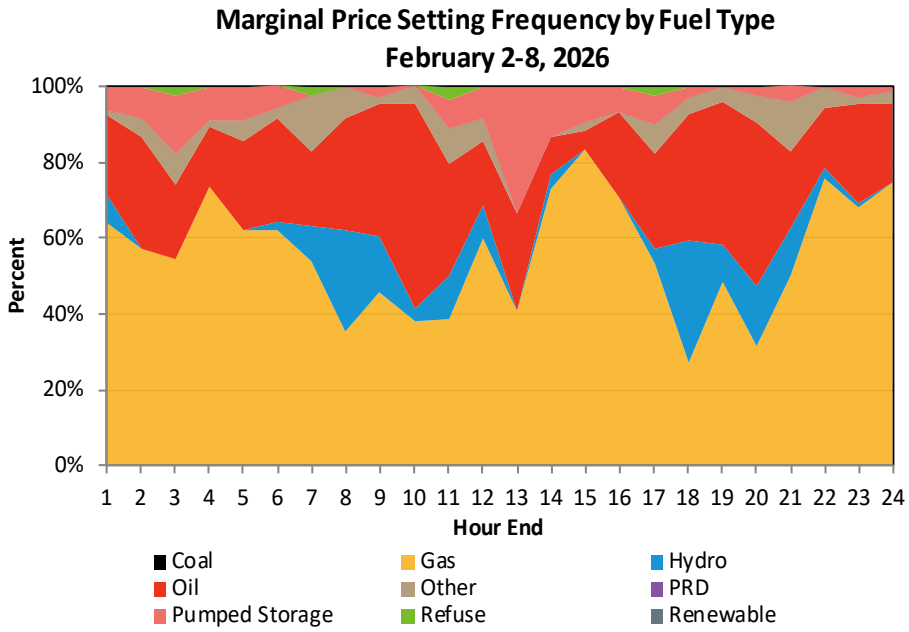
The following table provides the total Real-Time Imports by Interface for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	9,044	24,190	-62.6%	67,864	-86.7%
NY-N AC Ext	255,603	223,075	14.6%	347,621	-26.5%
HQ Ext	138,793	105,382	31.7%	308,851	-55.1%
HG Ext	17,571	10,182	72.6%	37,344	-52.9%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	18,028	23,803	-24.3%	23,330	-22.7%
NECEC Ext	180,120	123,080	46.3%	N/A	N/A

The following graph shows the percentage of time in which a particular resource-type was responsible for setting the price during each of the last 52 weeks.



The next graph shows the percentage of time in which a registered fuel type was responsible for setting the price during each hour of the last week. The Price Responsive Demand (PRD) category below refers to Demand Reduction Obligation from Demand Response Resources (DRR). The exhibit only summarizes the intervals in which one unit was marginal, which was 60% of all intervals during the week. For a load-weighted analysis of marginality, see Section 3.2 of Quarterly Markets Report, located here.



Net Commitment Period Compensation (NCPC)

5.1 Net Commitment Period Compensation

NCPC information does not appear in this report. Aggregate NCPC data continues to be provided in the supplemental Excel file on a one-week lag.

An NCPC Summary report is published to the Market Performance Reports webpage each Thursday or Friday.

The NCPC summary features daily-level summary charges and includes new detailed information concerning:

- Day-Ahead (DA) and Real-Time (RT) First Contingency payments to both internal and external payees
- DA and RT Second Contingency payments, including reliability region detail
- Voltage, Distribution, and Generator Performance Audit detail
- RT Detail for these concepts: Out of Merit, Canceled Starts, Hourly Shortfall, Posturing, Rapid Response Pricing Opportunity Cost, and Dispatch Lost Opportunity Cost

This report also includes a companion spreadsheet that contains daily, year-to-date totals for each of these concepts. The report and spreadsheet are also posted here, select 'NCPC Summary' from the document type filter on the left side of the page.

Energy Market Payments

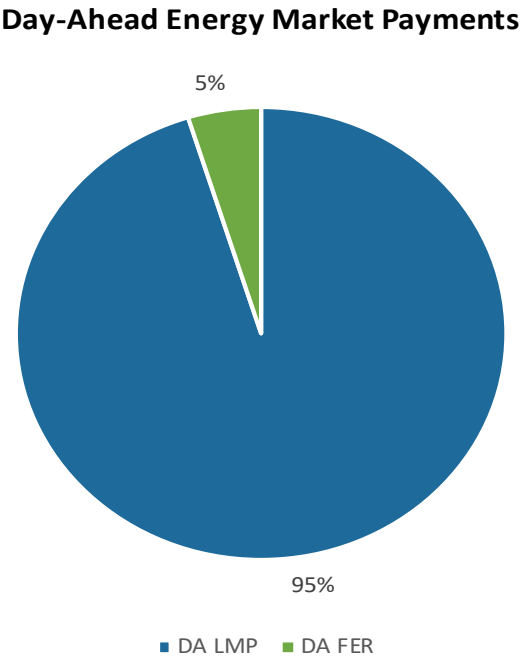
6.1 Energy Market Payments

The table below displays the three components that make up the Energy Market payment for the prior week. These are payments made in relation to Day-Ahead LMPs, payments associated with the Day-Ahead Forecast Energy Requirement (FER), and payments related to deviations from Day-Ahead energy positions that occur in Real-Time.

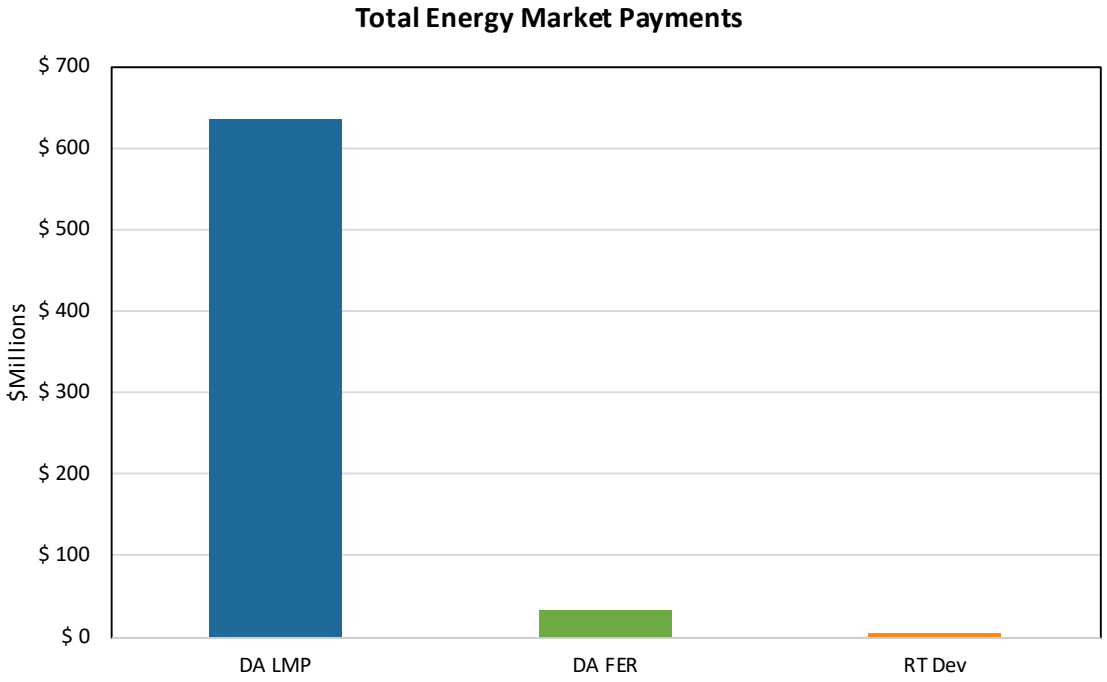
Energy Market Payment Summary
February 2-8, 2026

DA LMP Payments (A)	DA FER Payments (B)	RT Dev Payments (C)	Energy Market Payment (D=A+B+C)
$635,845,372	$32,169,955	$4,069,368	$672,084,696

The following chart shows the percentage contribution of the two components of the Day-Ahead Energy Market payment.



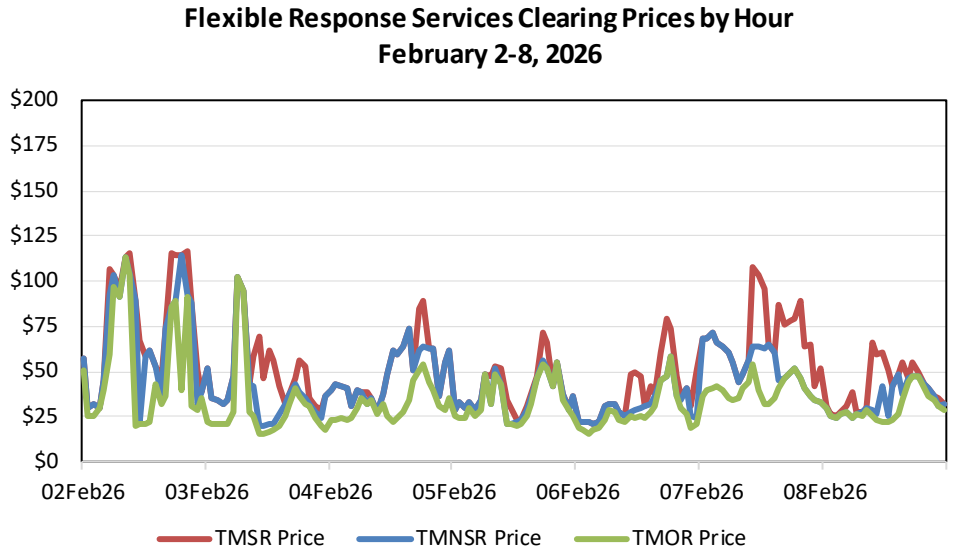
The chart below shows the magnitude of each component's contribution to the total Energy Market payment.



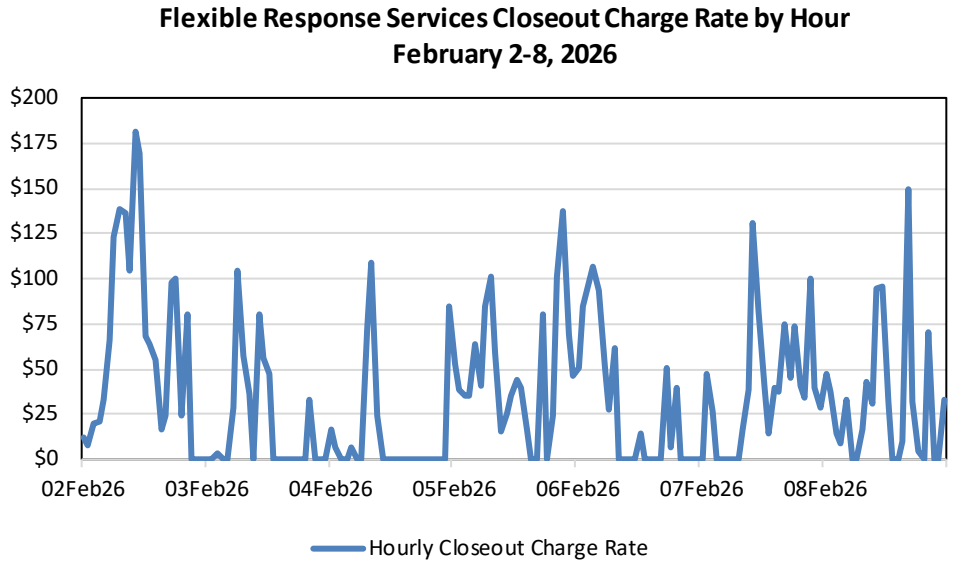
Flexible Response Services (FRS)

7.1 FRS Pricing

The following graph shows the hourly FRS Clearing Prices for the past week.



The hourly closeout charge rate is the max of the (RT Hub LMP – Strike Price) and 0. The graph below shows the hourly closeout charge rate during the week.



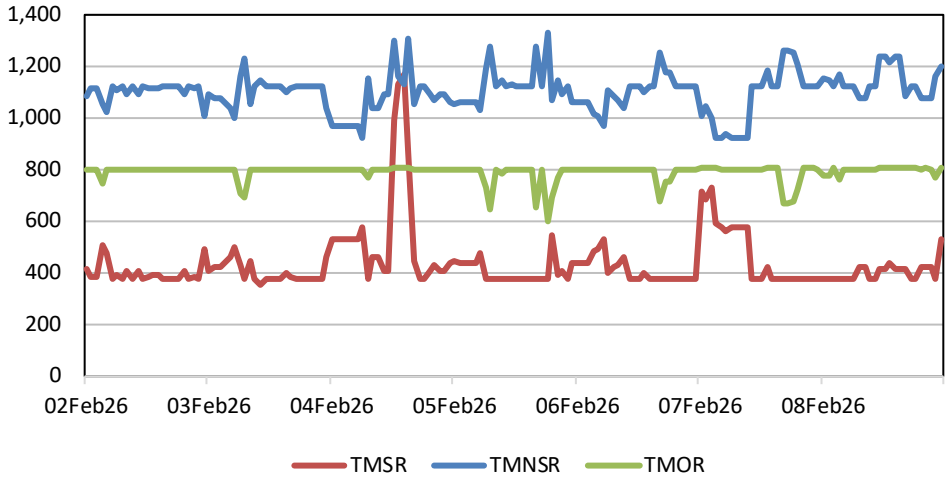
Percentage of Hours with Closeout Charge Rates
February 2-8, 2026

Frequency Tabulation	$0.00	$0.01 - $4.99	$5.00 - $9.99	$10.00 - $19.99	$20.00 - $49.99	$50.00 - $99.99	>= $100.00
Hourly Closeout Charge Rate	37.5%	1.2%	3.0%	7.1%	23.8%	17.9%	9.5%

7.2 FRS Quantities

The following graph shows the Hourly Cleared MW of each FRS product.

Cleared Flexible Response Services MW by Hour
February 2-8, 2026



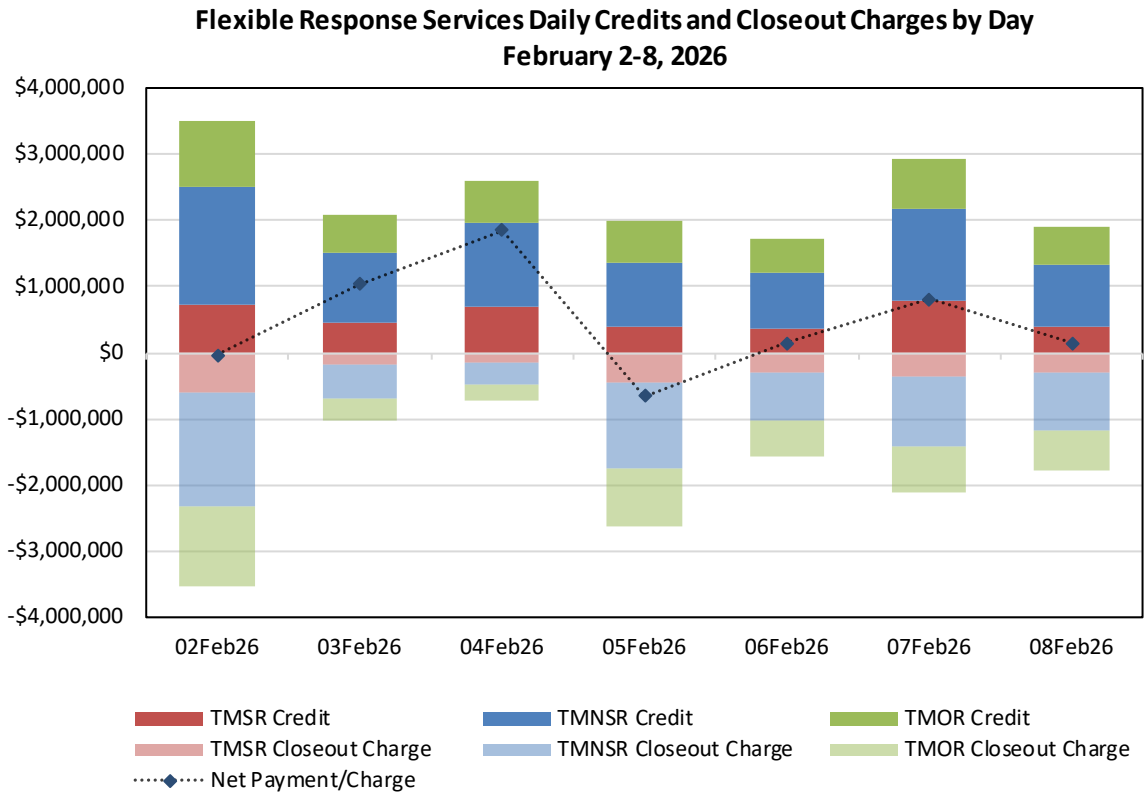
7.3 FRS Payments

FRS payments made to units during the prior week are shown in the following table. FRS procurements are made to satisfy the system level requirement for these services. The figures below are preliminary, and subject to revision during the settlement process.

Flexible Response Services Payment Summary
February 2-8, 2026

Product Type	FRS Payments (A)	FRS Closeout Charges (B)	FRS Net Payments/Charges (C=A+B)
TMSR	$3,801,158	-$2,372,265	$1,428,893
TMNSR	$8,271,887	-$6,462,239	$1,809,647
TMOR	$4,617,597	-$4,577,940	$39,657
Total	$16,690,642	-$13,412,444	$3,278,198

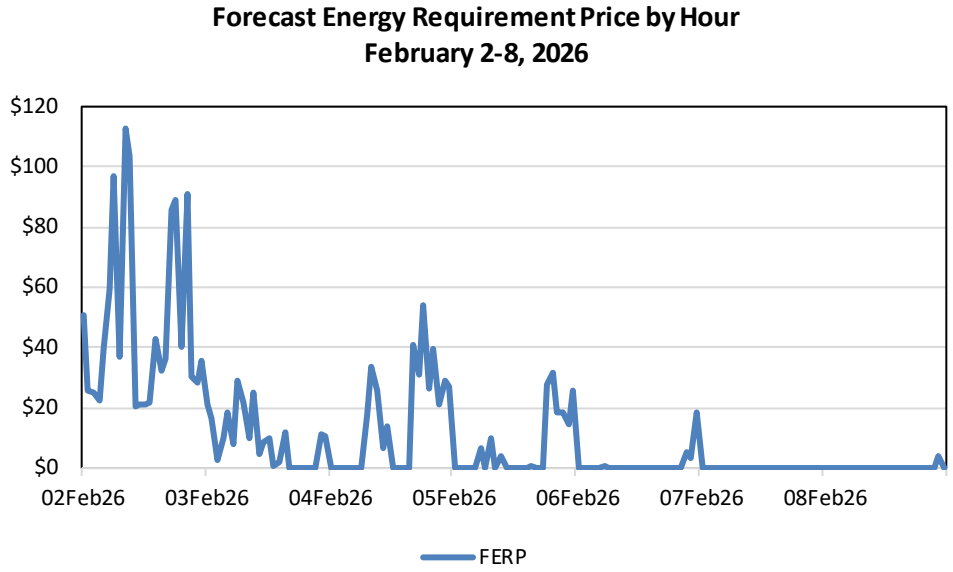
The following graph shows the daily Credit and Closeout charges by FRS product type:



Forecast Energy Requirement (FER) and Energy Imbalance Reserves (EIR)

8.1 FER and EIR Pricing

Payments to units for both FER and EIR Obligations are made based on the Forecast Energy Requirement Price (FERP). The graph below shows the FERP by hour.



The following table shows the Daily and Weekly Average FERP during the reporting week.

Average Daily and Weekly Forecast Energy Requirement Price ($/MWh)
February 2-8, 2026

02Feb26	03Feb26	04Feb26	05Feb26	06Feb26	07Feb26	08Feb26	Weekly Average
$48.73	$9.22	$15.34	$6.54	$1.19	$0.00	$0.18	$11.60

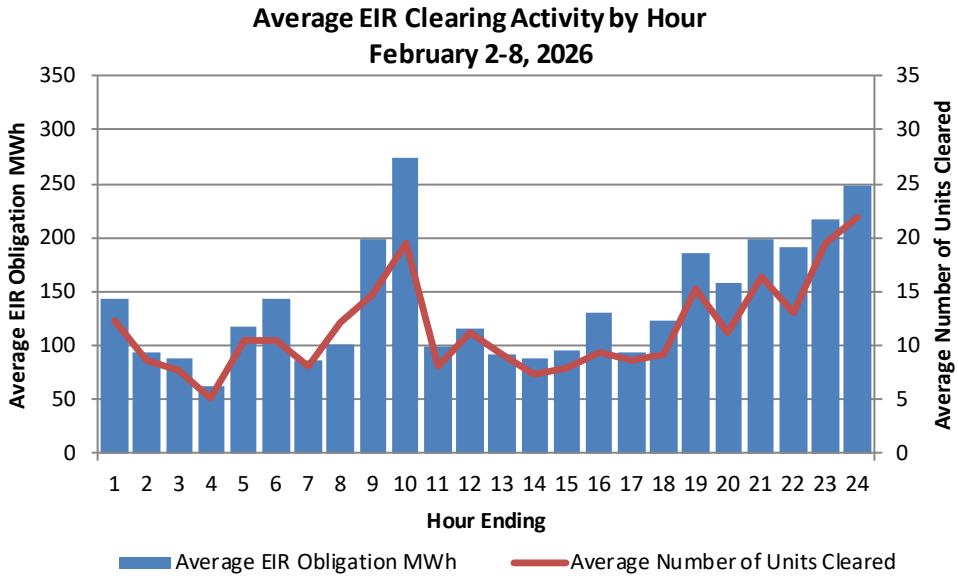
The following table shows the distribution of the hourly FERP during the reporting week.

Hourly Forecast Energy Requirement Price Distribution
February 2-8, 2026

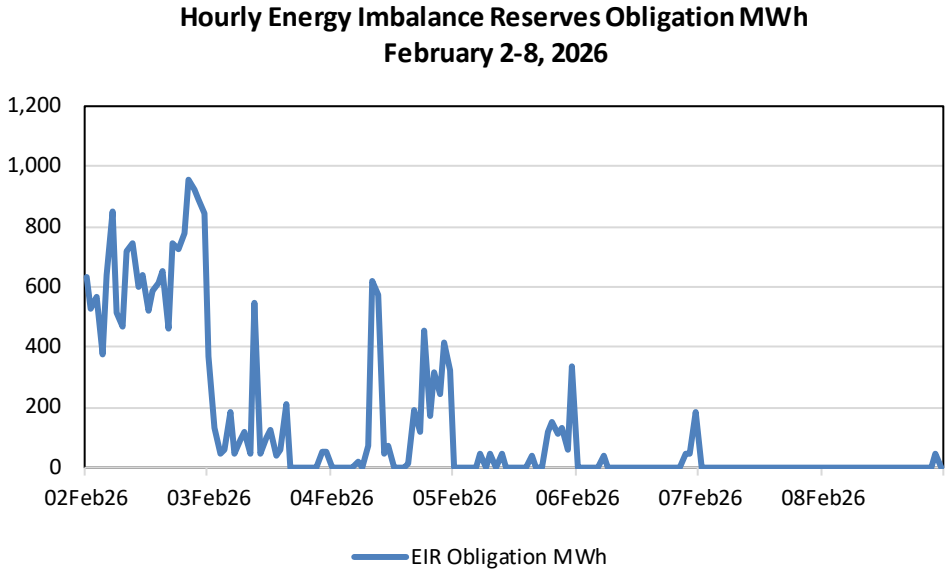
Frequency Tabulation	$0.00	$0.01 - $4.99	$5.00 - $9.99	$10.00 - $19.99	$20.00 - $49.99	$50.00 - $99.99	>= $100.00
FERP	58.3%	5.4%	4.8%	7.1%	19.0%	4.2%	1.2%

8.2 EIR Obligations

The following graph shows both the average hourly cleared EIR Obligation MWh and the average hourly number of units cleared during the reporting week.



The following graph shows the hourly EIR Obligation MWh values for the week.



The table below shows the distribution of the hourly EIR Obligation MWh during the reporting week.

Energy Imbalance Reserves Obligation MWh Distribution
February 2-8, 2026

Frequency Tabulation	0 MWh	0.01-49.99 MWh	50.0-99.99 MWh	100.0-249.99 MWh	250.0-499.99 MWh	500.0-999.99 MWh	>= 1,000 MWh
EIR Obligation MWh	57.1%	9.5%	4.8%	8.9%	5.4%	14.3%	0.0%

8.3 FER and EIR Payments

FER payments made to total cleared DA Generation MWh, DA Import MWh, DA DRR MWh, along with EIR Obligation MWh during the reporting week are shown in the following table. These figures are preliminary, and subject to revision during the settlement process.

Daily Forecast Energy Requirement and Energy Imbalance Reserves Payment Summary
February 2-8, 2026

Day	DA FER Payments (A)	EIR Payments (B)	EIR Closeout Charges (C)	EIR Net Payments/Charges (D=B+C)	DA FER and EIR Net Payments/Charges (E=A+D)
02Feb26	$19,271,492	$813,938	-$997,190	-$183,252	$19,088,240
03Feb26	$3,557,917	$40,287	-$35,703	$4,584	$3,562,502
04Feb26	$6,191,298	$117,661	-$113,920	$3,741	$6,195,039
05Feb26	$2,652,513	$23,191	-$60,039	-$36,848	$2,615,664
06Feb26	$429,373	$3,921	-$2,133	$1,788	$431,160
07Feb26	$0	$0	$0	$0	$0
08Feb26	$67,363	$204	$0	$204	$67,568
Total	$32,169,955	$999,203	-$1,208,985	-$209,782	$31,960,173

Real-Time Reserve Market

9.1 Real-Time Reserve Payments

Real-Time Reserve Payment Summary by Reserve Zone
February 2-8, 2026

DAY	CT	NEMABSTN	ROS	SWCT	Total
02FEB26	$0.00	$0.00	$0.00	$0.00	$0.00
03FEB26	$0.00	$0.00	$0.00	$0.00	$0.00
04FEB26	$0.00	$0.00	$0.00	$0.00	$0.00
05FEB26	$968.05	$257.88	$7,649.25	$957.09	$9,832.27
06FEB26	$68.50	$41.75	$2,251.38	$179.18	$2,540.81
07FEB26	$0.00	$0.00	$0.00	$0.00	$0.00
08FEB26	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,036.55	$299.63	$9,900.63	$1,136.27	$12,373.08

The following table shows Real-Time Reserve clearing prices. These figures are also preliminary and subject to revision during the settlement process.

Real-Time Reserve Clearing Price Frequency, Local Reserve Zones
February 2-8, 2026

Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals	Percent of Non-Zero 5-Minute Intervals During the Week						
			<=$10	$10.01-$50	$50.01-$100	$100.01-$200	$200.01-$500	$500.01-$1000	>$1,000
TMSR	99.4%	0.6%	46.2%	53.8%	0.0%	0.0%	0.0%	0.0%	0.0%
TMNSR	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
TMOR	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Real-Time Reserve Clearing Price Frequency, Local Reserve Zones
February 2-8, 2026

Local Reserve Zone	Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals
Connecticut	TMSR	99.4%	0.6%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
NEMA/Boston	TMSR	99.4%	0.6%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Rest Of System	TMSR	99.4%	0.6%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Southwest Connecticut	TMSR	99.4%	0.6%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%

The table below displays the time intervals, reserve types, and bias adjustment values for any reserve bias adjustments during this week.

Real-Time Reserve Bias
February 2-8, 2026

Local Day	Reserve Bias
February 2-8, 2026	None

Capacity Scarcity Conditions (CSC)

10.1 Capacity Scarcity Conditions

A Capacity Scarcity Condition (CSC) occurs when there is a deficiency in one or more of the three reserve requirements and the reserve-constraint penalty factor (RCPF) is setting the Real-Time Reserve price. More information can be found here in section III.13.7.2.1.

The preliminary balancing ratio is a value representing the initially calculated relationship between the required capacity and the total Capacity Supply Obligation during a CSC. The balancing ratio is computed using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

The OP-4 Actions are the eleven actions, outlined by Operating Procedure 4, that ISO-NE uses to restore capacity during periods of capacity deficiency. More information and descriptions of each OP-4 Action can be found here.

The tables below display the time intervals, OP-4 Actions, and preliminary balancing ratio for any Capacity Scarcity Conditions during this week.

System-wide Capacity Scarcity Condition Detail[1]
February 2-8, 2026

Day	5-Minute Interval Beginning	Location	OP-4 Actions	Preliminary Balancing Ratio
There were no System-wide Capacity Scarcity Condition events during this period.				

Local Capacity Scarcity Condition Detail
February 2-8, 2026

Day	5-Minute Interval Beginning	Location	OP-4 Actions	Preliminary Balancing Ratio
There were no Local Capacity Scarcity Condition events during this period.				

[1] The initial value may change at time of actual market settlement.

Glossary and Links

11.1 Peak Load Statistics

FCM System Load

FCM system load is the sum of active load assets that are non-dispatchable and that are included in the FCM settlement. Information is used to establish a load asset's contribution to the peak system load for purposes of the Forward Capacity Market (FCM). For more information on the FCM annual system peak day, hour, and load, see the ISO website here.

Revenue Quality System Load

The revenue quality system load is the metered settlement value of the system 'net energy' for load concept. It is defined as the sum of generation, net external interchange, and the reduction provided by dispatched Demand Response Resources (DRR), less load from pumped storage units and energy storage devices.

Telemetered System Load

The telemetered system load value represents the calculated 'real-time' demand for electricity in the New England Balancing Authority Area that represents a telemetered aggregation of generation, net interchange, DRR reconstitution and excluding pumping load.

11.2 Locational Marginal Price (LMP)

A LMP is a calculated price of wholesale electric energy at a pricing node, Load Zone, reliability region, or the Hub. LMPs are comprised of three components: energy, congestion, and marginal losses. The energy component is the same at all locations, while the congestion and marginal loss components can vary among locations. More information on LMPs can be found at the ISO web site here.

Analyze: Weekly Average Day-Ahead LMP Statistics, Hub and Load Zones (53 weeks, Excel format.)
TAB NAME: 'Avg DA and RT LMP Hub and Zones'

Analyze: Weekly Average Congestion and Loss Components, Hub and Load Zones (53 weeks, Excel format.)
TAB NAME: 'Average Congestion and Loss'

11.3 Day-Ahead and Real-Time Energy Markets

Day-Ahead and Real-Time Demand

Participants can bid fixed and price sensitive demand into the Day-Ahead Energy Market. They can also submit virtual demand bids called Decrement (Dec) bids as well as External Transaction bids. Day-Ahead Load Obligation (DALO) is the result of clearing the Day-Ahead Energy Market, and is aggregated by location. DALO is the total MWh of cleared demand bids, cleared Decs, and cleared External Transaction sales at all locations. Real-Time Load Obligation (RTLO) is the total MWh of a participant's metered load including External Transaction sales.

Analyze: Weekly Total Day-Ahead and Real-Time Load Obligation, Hub and Zones (53 weeks, Excel format)

TAB NAME: 'Total DA and RT Load Obligation'

Day-Ahead and Real-Time Supply

Participants can bid "must run" and Economic supply into the Day-Ahead Energy Market. They can also submit virtual supply offers called Increment (Inc) offers as well as External Transaction offers. Day-Ahead Generation Obligation (DAGO) is the result of clearing the Day-Ahead Energy Market, and is aggregated by Location. DAGO is the total MWh of cleared supply offers, cleared Inc offers, and cleared External Transaction purchases at all locations. Real-Time Generation Obligation (RTGO) is equal to the MWh of energy provided by Generators and External Transaction purchases at that Location. Real-Time Generation Obligation Deviation is the total MWh of a participant's metered generation less their DAGO positions.

Analyze: Weekly Total Day-Ahead Generation Obligation, Hub and Zones (53 weeks, Excel format)
TAB NAME: 'DA Supply'

Analyze: Marginal Fuel Type by Week (53 weeks, Excel format).
TAB NAME: 'Percent Marginal Fuel Type'

Analyze: Marginal Resource Type by Week (53 weeks, Excel format).
TAB NAME: 'Percent Marginal Resource Type'

System Load

System Load is 'net energy' for load on the system and is defined as the sum of generation and net external interchange, less pumping load. This total also includes the grossed up demand response value, and excludes demand from energy storage devices. Real-Time Load Obligation is the sum of all revenue quality metered load within the control area plus Real-Time External Transaction sales.

For more information on the Day-Ahead and Real-Time Energy Markets and associated charges, see the ISO web site here for Day-Ahead and here for Real-Time.

11.4 Net Commitment Period Compensation (NCPC)

NCPC is the payment to a market participant for its Generator, Asset-Related Demand (ARD), Demand Response Resource (DRR), or External Transaction that did not recover its effective offer costs from the energy market during an operating day. The NCPC payment is intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule. Typically, a resource receiving NCPC was operated out of merit to protect the overall resource adequacy and transmission security of specific locations or of the entire balancing authority area.

For more information on the Day-Ahead and Real-Time Energy Markets and associated charges, see the ISO web site here for Day-Ahead and here for Real-Time.

11.5 Energy Market Payments

The Energy Market payment is made up of three components: payments made in relation to Day-Ahead LMPs, payments associated with Day-Ahead Forecast Energy Requirement (FER), and payments related to deviations in Real-Time.

The Day-Ahead Energy Market is a financial market where market participants purchase and sell electric energy at financially binding Day-Ahead prices for the following day. This market is the financially binding schedule of commitments for the purchase and sale of energy the ISO develops each day according to the bid and offer data that market participants submit to the market. A supply offer or a demand bid will generally clear the Day-Ahead market if its associated price is less than or equal to the hourly Locational Marginal Price (LMP) at its location, as system conditions allow.

The Day-Ahead market allows buyers and sellers to hedge against price volatility in the Real-Time Energy Market by locking in energy prices before the operating day.

The FER is equal to the load forecast, and it is satisfied by a combination of the Day-Ahead Energy Imbalance Reserves (EIR) product and cleared Day-Ahead energy supplied by Generator Assets, Demand Response Resources, and net Imports. The Forecast Energy Requirement Price (FERP) is the clearing price for the FER (analogous to how the LMP is the clearing price for the energy balance constraint). A MWh of cleared Day-Ahead energy from a physical supply resource will be paid the LMP + FERP, because that MWh contributes to both the energy balance and FER constraints. A MWh of cleared EIR, in contrast, is paid only the FERP, because it contributes to the FER, but not to the energy balance constraint. EIR payments are part of the Day-Ahead Ancillary Services market, and are not included in the Day-Ahead Energy Market value.

Payments in the Real-Time Energy Market are based upon deviations in the participants' actual operation in Real-Time from their Day-Ahead energy positions. These deviations are multiplied by the Real-Time LMP at the associated location to arrive at the Real-Time Energy Market payment total.

For more information on the Energy Market Payments, see the ISO web site located here.

Analyze: Energy Market Payments, by Week (53 weeks, Excel format)
TAB NAME: 'Energy Market Payments'

11.6 Flexible Response Services (FRS) Market

The Day-Ahead Ancillary Services (DAAS) Market replaced the Forward Reserve Market as of March 1, 2025. The DAAS Market is designed to procure and transparently price the ancillary service capabilities needed for a reliable, next-day operating plan with an evolving generation fleet.

One component of the DAAS market clears Day-Ahead flexible response services to ensure that the system is prepared to recover from sudden source-loss contingencies and can respond quickly to fluctuations in net load during the operating day. These are referred to as Flexible Response Services (FRS), and are analogous to the Ten-Minute Spinning Reserves (TMSR), Ten-Minute Non-Spinning Reserves (TMNSR), and Thirty-Minute Operating Reserves (TMOR). These three products (TMSR, TMNSR, and TMOR) will also have a closeout charge based on the Hub Real-Time LMP. All three of the FRS requirements are set on a region-wide basis.

For more information on the DAAS Market, see the ISO web site located here.

Analyze: DAAS Market Results, by Week (53 weeks, Excel format)
TAB NAME: 'DAAS Market'

11.7 Forecast Energy Requirement (FER) and Energy Imbalance Reserves (EIR) Market

For more information on the FER component, see *11.5 Energy Market Payments*.

The EIR component of the DAAS Market clears a new Day-Ahead ancillary service to cover the "gap" when the Day-Ahead market's physical energy supply awards are below the ISO's forecast Real-Time load. These MWh of cleared EIR are paid only the FERP, because they contribute to the FER, but not to the energy balance constraint. EIR is also subject to a closeout charge based on the Hub Real-Time LMP, and the EIR requirement is set on a region-wide basis.

For more information on the DAAS Market, see the ISO web site located here.

Analyze: Energy Market Payments, by Week (53 weeks, Excel format)
TAB NAME: 'Energy Market Payments'

Analyze: DAAS Market Results, by Week (53 weeks, Excel format)
TAB NAME: 'DAAS Market'

11.8 Real-Time Reserve Market

The Real-Time LMP calculation process simultaneously sets Real-Time Reserve Market Clearing Prices (RMCP) for Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR), and Thirty-Minute Operating Reserve (TMOR).

For more information on the Real-Time Reserve Market, see the ISO web site located here.

Analyze: Real-Time Reserve Market Results, by Week (53 weeks, Excel format)
TAB NAME: 'Real-Time Reserve Market'

Document Revision History		
Date	**Version**	**Remarks**
2/11/2026	Original	Initial posting.