Weekly Market Summary

January 26-February 1, 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: January 26-February 1, 2026

1.1 Weekly Highlights

Notable Events

- Real-Time LMPs in excess of $630/MWh were caused by high fuel prices and inclement weather in the hours ending 1:00 P.M. and 2:00 P.M. on Monday, January 26.
- 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	$380.95	$183.16	108.0%	$136.31	179.5%
*Real-Time Energy Market; All Hours	$278.24	$189.75	46.6%	$141.98	96.0%
*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)	19,940	20,221	-1.4%	18,298	9.0%
DA Load Obligation (All Zones)	-2,913,610	-2,734,720	6.5%	-2,552,862	14.1%
RT Load Obligation (All Zones)	-2,915,652	-2,732,716	6.7%	-2,529,387	15.3%
DA Cleared Exports (All Interfaces)	-45,442	-61,076	-25.6%	-64,819	-29.9%
RT Scheduled Exports (All Interfaces)	-129,677	-214,215	-39.5%	-127,393	1.8%

Weekly Supply Statistics	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Input Fuel Price (Natural Gas, $/MMBtu)	$66.17	$25.14	163.2%	$10.41	Large
Mass Average Input Fuel Price (Natural Gas, $/MMBtu)	$57.59	$25.31	127.5%	$15.13	280.6%
Metered Generation (MWh)	2,591,217	2,339,624	10.8%	1,959,684	32.2%
Generation Obligation (MWh)	3,100,929	3,002,916	3.3%	2,706,080	14.6%
RT Demand Reduction Obligation (MWh)	307	642	-52.3%	539	-43.2%
Self-Scheduled Generation (MWh)	1,064,828	938,181	13.5%	872,509	22.0%
DA Cleared Imports (MWh - All Interfaces)	444,091	609,025	-27.1%	725,964	-38.8%
RT Scheduled Imports (MWh - All Interfaces)	509,712	663,292	-23.2%	746,396	-31.7%

Market Payments	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead and Real-Time Energy Market Payments ($)	$1,434,768,256	$618,951,590	131.8%	$366,576,565	291.4%
Day-Ahead Ancillary Services Market Payments ($)	$73,797,235	$7,224,602	Large	N/A	N/A
Real-Time Reserve Market Payments ($)	$0	$215,296	-100.0%	$412,620	-100.0%

Underlying natural gas data furnished by: ICE Global markets in clear view

Weekly Market Summary

Day-Ahead Price Separation

- On Wednesday and Thursday, January 28 and 29, depressed pricing in the Maine (ME) Load Zone was caused by binding constraints on the Maine – New Hampshire and Northern New England Scobie Interfaces due to an equipment outage. The equipment outage was restored on January 29.
- On Friday, January 30, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine – New Hampshire and Keene Road Export Interfaces due to patterns of load and generation.
- On Saturday and Sunday, January 31 and February 1, 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.

Real-Time Price Separation

- On Monday and Tuesday, January 26 and 27, depressed pricing in the ME Load Zone was caused by a binding constraint on the Maine – New Hampshire Interface due to the aforementioned equipment outage.
- On Wednesday, January 28, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine – New Hampshire and Northern New England Scobie Interfaces due to the aforementioned equipment outage.
- From Thursday through Saturday, January 29-31, 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 Sunday, February 1, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine – New Hampshire and Northern New England Scobie Interfaces due to patterns of load and generation.

Real-Time Price Corrections

- None.

Year-to-Date Peak Load Statistics*

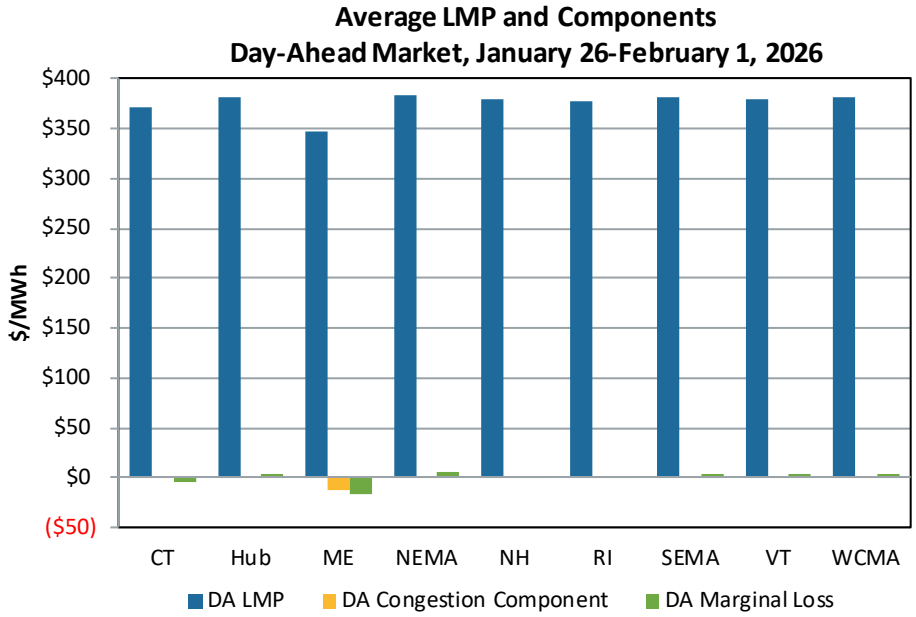
- FCM Peak Load (preliminary, subject to change) is 19,937 MWh and occurred in the hour ending 1:00 P.M. on Sunday, January 25. At this hour, the Capacity Zone-level FCM peak loads were 2,814 MWh in Northern New England, 1,832 MWh in Maine, 7,535 MWh in Rest-of-Pool, and 7,756 MWh in Southeast New England.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

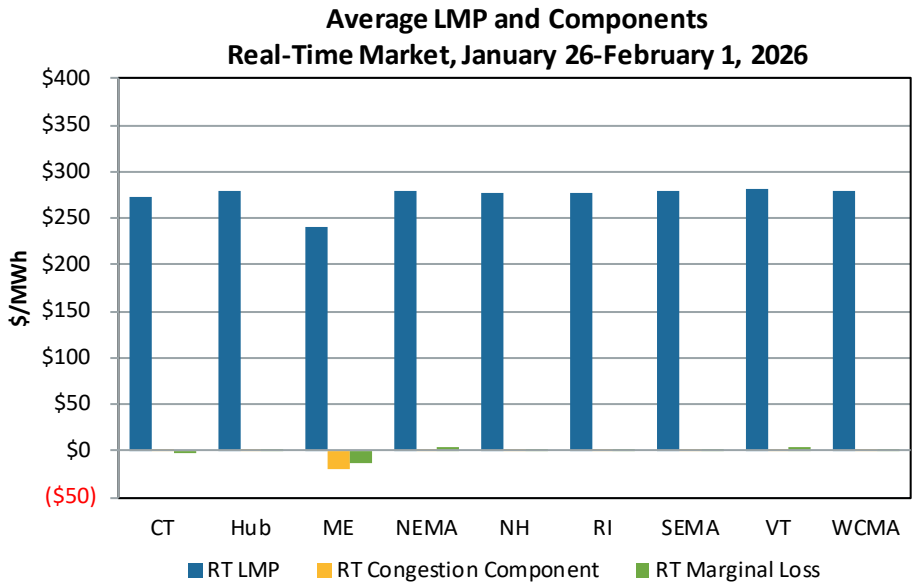
*Due to the difference in calculation methodologies, these values can occur on different days and hours.

Pricing

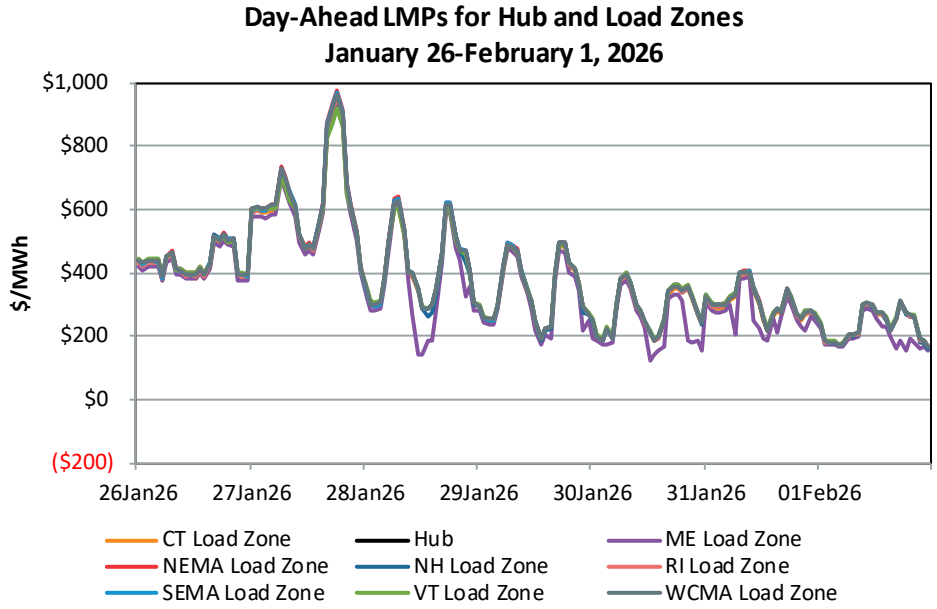
2.1 Pricing

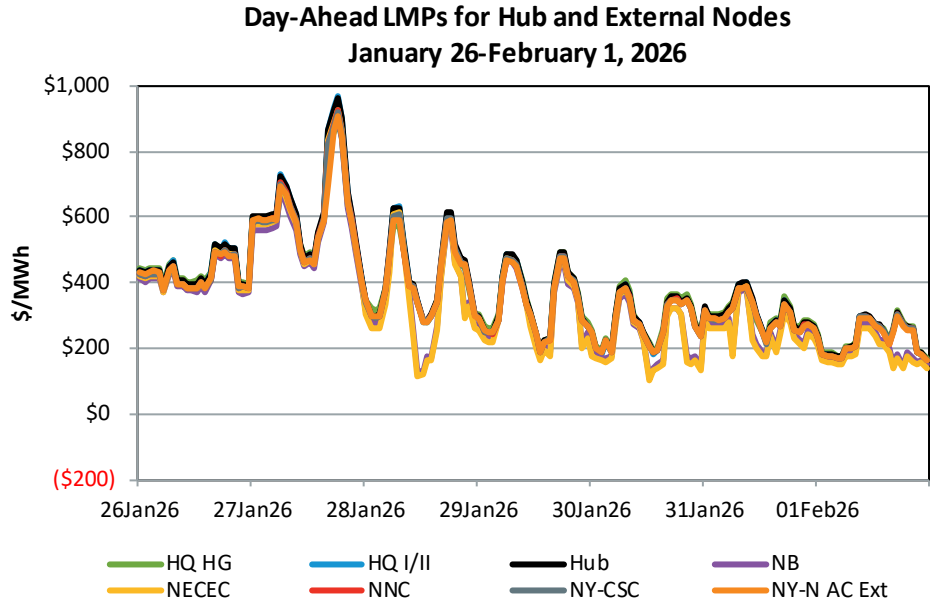
The two graphs below show the weekly average of LMPs, congestion, and marginal loss components at the Hub and Load Zones for both the Day-Ahead and Real-Time Energy Markets.



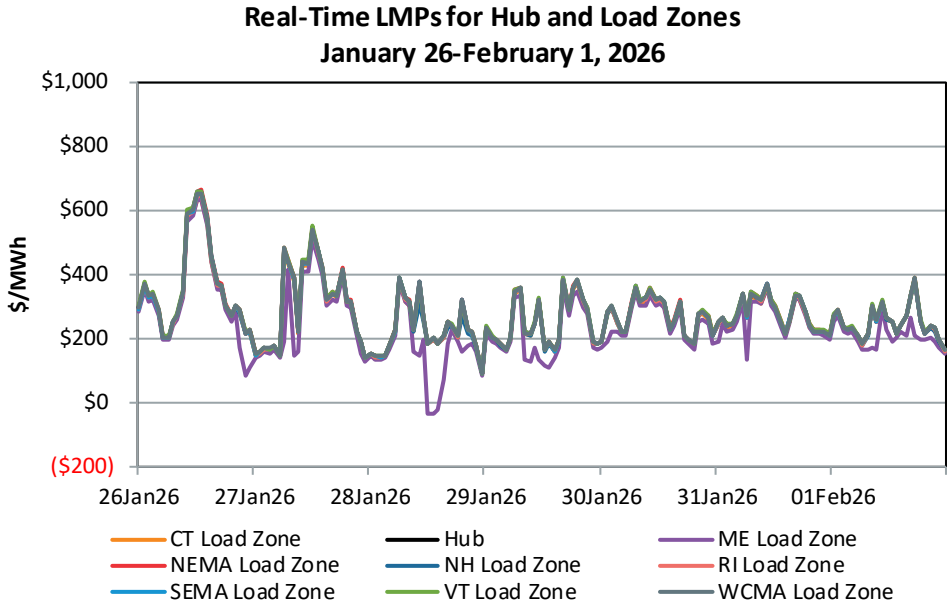


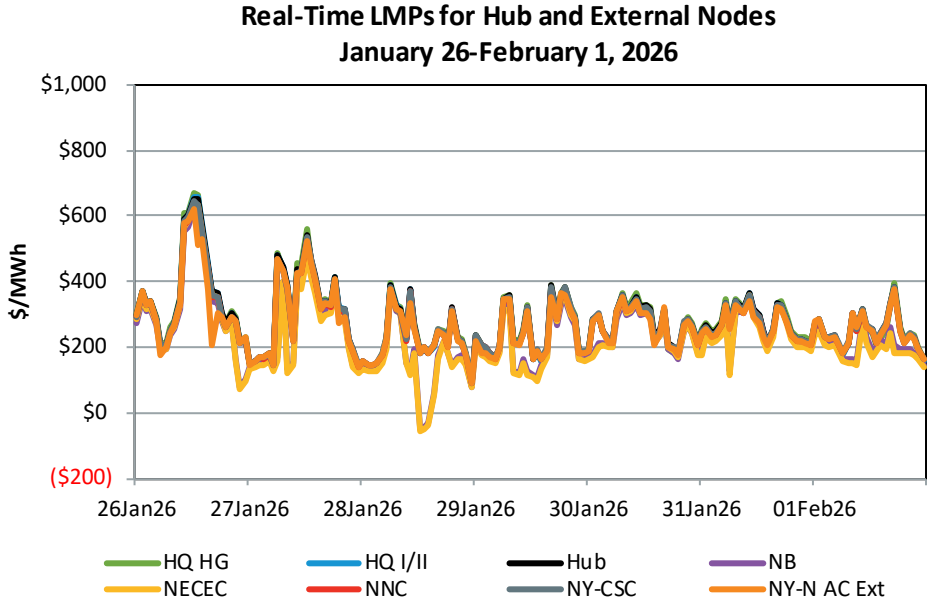
The following two graphs show hourly Day-Ahead LMPs for the Hub, the eight Load Zones, and the seven external nodes. In cases where there is little or no price separation, the lines for multiple locations may be indistinguishable from each other.





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, January 26-February 1, 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	$380.95	$278.24	$165.59	$90.54	$965.11	$653.09	100%	100%	73%	153.55	97.88	64%
ME	$346.67	$240.59	$120.30	$-36.16	$922.05	$632.64	91%	86%	69%	159.87	106.94	67%
NH	$378.52	$276.29	$162.38	$89.44	$960.11	$658.98	99%	99%	73%	153.65	98.73	64%
VT	$379.98	$280.65	$167.37	$91.72	$919.71	$659.73	100%	101%	74%	145.51	98.78	68%
CT	$372.35	$273.71	$164.79	$90.27	$932.29	$635.39	98%	98%	74%	147.99	94.81	64%
RI	$378.02	$276.49	$164.40	$90.12	$960.15	$647.81	99%	99%	73%	152.39	97.10	64%
SEMA	$381.87	$278.37	$165.84	$90.58	$966.76	$653.15	100%	100%	73%	153.77	97.79	64%
WCMA	$381.36	$278.82	$166.04	$90.88	$962.08	$653.71	100%	100%	73%	153.14	97.93	64%
NEMA	$383.34	$280.15	$165.35	$90.72	$975.00	$662.17	101%	101%	73%	155.28	99.21	64%
NB Ext	$338.53	$235.02	$114.06	$-47.79	$901.37	$618.32	89%	84%	69%	156.92	105.77	67%
NY-N AC Ext	$368.25	$267.84	$162.85	$89.10	$910.09	$619.50	97%	96%	73%	142.91	90.53	63%
HQ Ext	$377.54	$275.97	$162.82	$88.70	$967.51	$656.69	99%	99%	73%	154.33	98.55	64%
HG Ext	$378.03	$278.76	$168.19	$90.13	$898.04	$667.94	99%	100%	74%	141.21	100.19	71%
CSC Ext	$370.34	$276.65	$166.26	$91.82	$920.46	$643.35	97%	99%	75%	146.14	95.25	65%
NNC Ext	$370.06	$272.07	$164.35	$89.80	$924.61	$629.92	97%	98%	74%	146.61	93.98	64%
NECEC Ext	$336.73	$230.79	$104.42	$-53.31	$923.65	$633.50	88%	83%	69%	166.68	109.77	66%

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

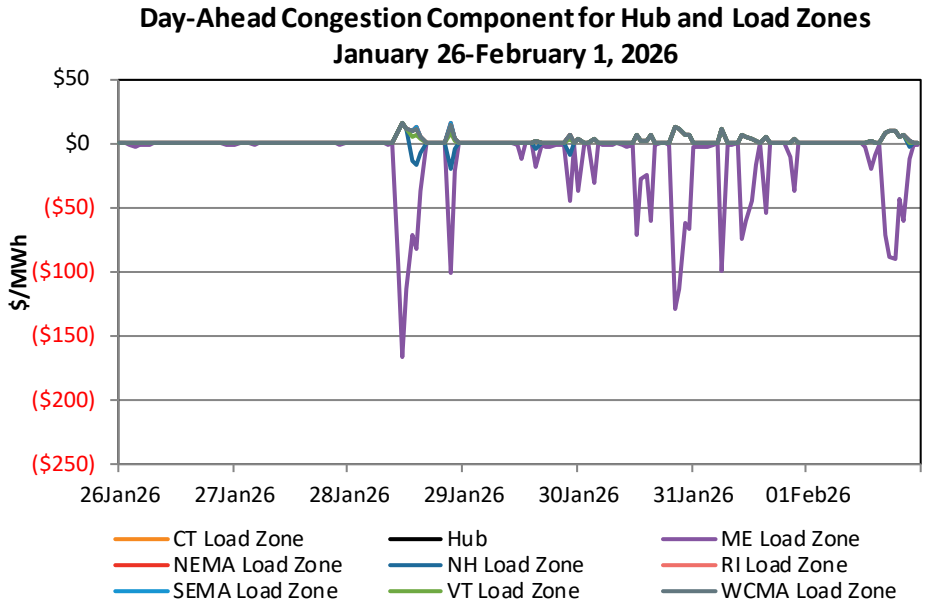
5-Minute LMP Summary (RT Only)
January 26-February 1, 2026

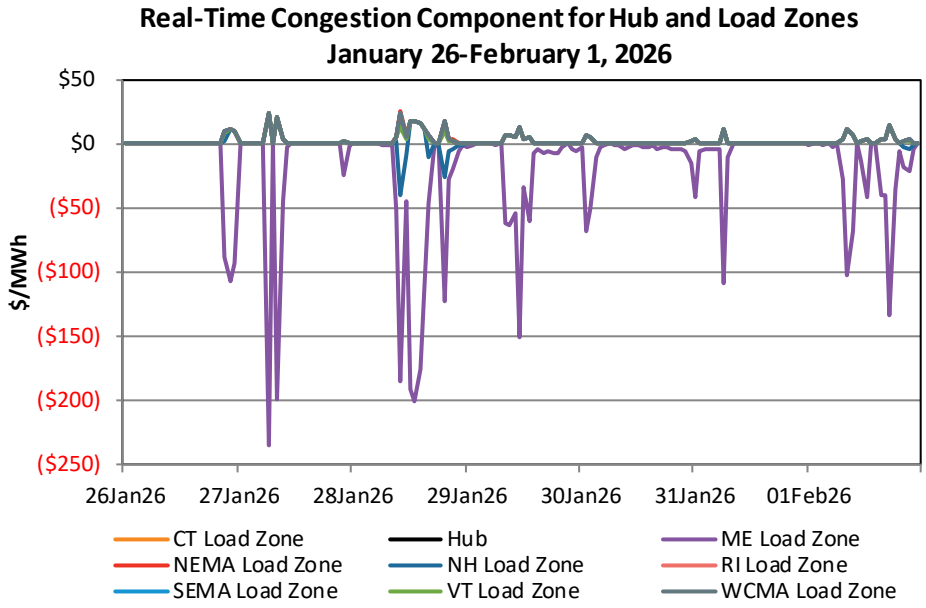
Hub/Zone	Max RT LMP ($/MWh)	Min RT LMP ($/MWh)	RT Std Dev	RT as % of Hub
Hub	$810.82	-$27.60	$106.93	100%
ME	$736.83	-$41.27	$113.20	86%
NH	$808.12	-$27.44	$107.43	99%
VT	$816.64	-$27.88	$107.91	101%
CT	$791.95	-$27.56	$103.78	99%
RI	$806.48	-$27.46	$106.12	99%
SEMA	$810.54	-$27.59	$106.86	100%
WCMA	$811.40	-$27.70	$107.00	100%
NEMA	$815.54	-$27.64	$108.29	101%

5-Minute Energy Component of LMP
January 26-February 1, 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	0.1%	0.2%	0.0%	0.1%	0.1%	5.1%	19.0%	72.0%	3.4%	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.





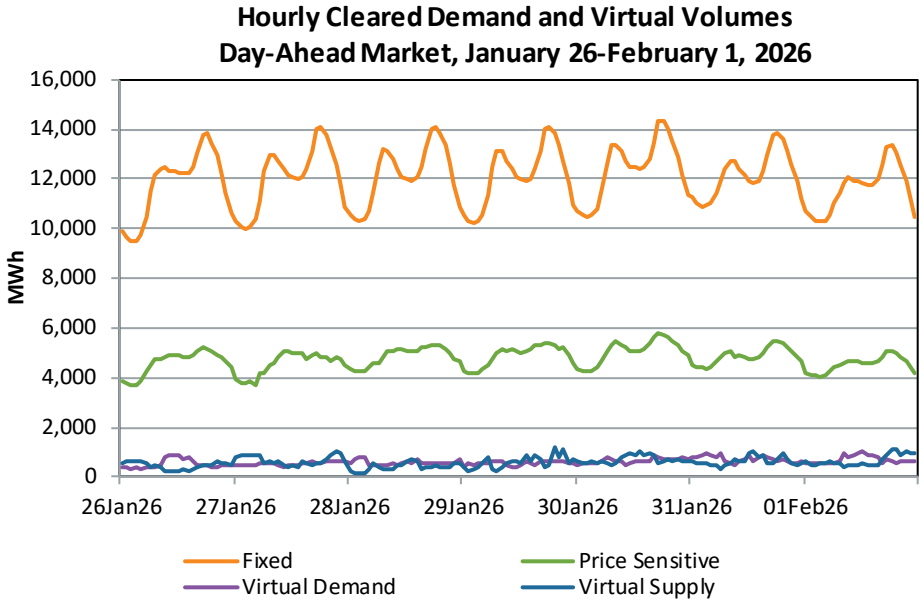
Energy Market Demand

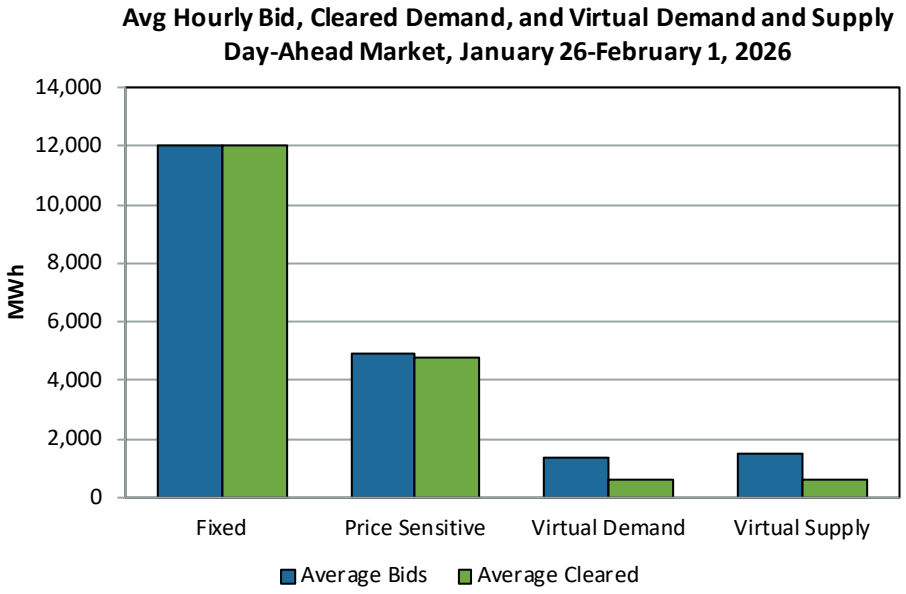
3.1 Day-Ahead Demand

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	44,134	32,881	34.2%	20,634	113.9%
ME	266,825	253,765	5.1%	242,919	9.8%
NH	278,019	258,317	7.6%	244,289	13.8%
VT	107,809	120,619	-10.6%	118,415	-9.0%
CT	689,270	632,355	9.0%	574,560	20.0%
RI	170,779	163,293	4.6%	138,098	23.7%
SEMA	354,236	324,046	9.3%	308,973	14.6%
WCMA	398,426	368,405	8.1%	344,306	15.7%
NEMA	577,934	537,167	7.6%	505,381	14.4%
NB Ext	387	2,100	-81.6%	1,064	-63.6%
NY-N AC Ext	10,820	55,488	-80.5%	52,967	-79.6%
HQ Ext	22,167	21,818	1.6%	5,376	312.3%
HG Ext	34,208	34,340	-0.4%	38,435	-11.0%
CSC Ext	15,112	10,543	43.3%	9,737	55.2%
NNC Ext	54	1,660	-96.7%	2,164	-97.5%
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)

January 26-February 1, 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	26JAN26	0	0	6,140	667	0	0	2,301	588	2,301
Hub	27JAN26	0	0	11,027	3,544	0	0	5,909	3,503	5,909
Hub	28JAN26	0	0	10,676	6,764	0	0	8,054	2,491	8,054
Hub	29JAN26	0	0	10,039	7,890	0	0	6,927	3,890	6,927
Hub	30JAN26	0	0	11,063	10,693	0	0	7,927	6,604	7,927
Hub	31JAN26	0	0	8,638	7,335	0	0	6,795	5,120	6,795
Hub	01FEB26	0	0	8,011	5,044	0	0	6,220	3,327	6,220
ME	26JAN26	29,002	10,149	1,077	10,639	29,002	10,149	241	6,464	39,391
ME	27JAN26	28,176	9,941	554	8,531	28,176	9,941	7	6,061	38,123
ME	28JAN26	28,549	9,886	515	13,459	28,549	9,886	212	3,680	38,646
ME	29JAN26	27,666	9,935	972	16,565	27,666	9,935	150	6,165	37,750
ME	30JAN26	28,025	10,062	878	21,104	28,025	10,062	202	6,665	38,290
ME	31JAN26	27,442	9,666	936	14,105	27,442	9,666	633	5,912	37,741
ME	01FEB26	27,660	9,557	1,264	17,701	27,660	9,557	510	6,575	37,726
NH	26JAN26	31,294	8,609	983	2,027	31,294	8,609	379	665	40,282
NH	27JAN26	31,549	8,667	449	1,416	31,549	8,617	2	996	40,168
NH	28JAN26	31,528	8,661	519	1,091	31,528	8,646	73	631	40,247
NH	29JAN26	31,479	8,698	759	2,180	31,479	8,698	88	1,202	40,265
NH	30JAN26	32,084	8,782	631	2,613	32,084	8,782	78	1,088	40,944
NH	31JAN26	30,267	8,558	910	1,871	30,267	8,558	419	561	39,243
NH	01FEB26	31,176	5,167	1,493	2,884	31,176	5,167	552	875	36,895
VT	26JAN26	1,604	17,245	900	907	1,604	12,440	378	474	14,421
VT	27JAN26	1,625	16,863	231	880	1,625	6,808	6	786	8,440
VT	28JAN26	1,476	16,664	486	664	1,476	13,219	141	454	14,835
VT	29JAN26	1,458	16,577	726	1,281	1,458	14,324	60	976	15,843
VT	30JAN26	1,609	16,643	686	1,208	1,609	16,604	138	604	18,350
VT	31JAN26	1,472	16,194	894	981	1,472	15,966	418	680	17,856
VT	01FEB26	1,465	16,130	1,403	1,558	1,465	16,130	558	986	18,152
CT	26JAN26	63,842	30,522	3,502	1,998	63,842	30,522	1,139	586	95,503
CT	27JAN26	67,568	32,174	1,251	679	67,568	32,174	173	399	99,914
CT	28JAN26	67,588	32,319	1,654	799	67,588	32,319	471	251	100,379
CT	29JAN26	67,210	32,301	1,614	1,617	67,210	32,301	697	461	100,207
CT	30JAN26	68,473	32,243	1,574	1,098	68,473	32,243	1,009	236	101,725
CT	31JAN26	67,361	31,252	3,037	856	67,361	31,252	1,627	417	100,240
CT	01FEB26	62,868	30,288	2,332	1,385	62,868	30,288	981	483	94,137
RI	26JAN26	17,196	5,960	952	739	17,196	5,960	263	448	23,418
RI	27JAN26	18,025	6,680	712	869	18,025	6,680	67	768	24,771

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	28JAN26	18,112	6,622	973	823	18,112	6,622	245	413	24,979
RI	29JAN26	18,235	6,566	386	1,719	18,235	6,566	84	544	24,885
RI	30JAN26	17,910	6,712	980	1,529	17,910	6,712	188	310	24,810
RI	31JAN26	17,941	6,321	2,481	887	17,941	6,321	739	517	25,001
RI	01FEB26	16,432	6,182	1,373	2,346	16,432	6,182	538	973	23,152
SEMA	26JAN26	35,886	12,405	1,261	152	35,886	12,405	244	152	48,535
SEMA	27JAN26	37,497	13,400	522	186	37,497	13,400	0	186	50,896
SEMA	28JAN26	37,819	13,468	711	524	37,819	13,468	184	282	51,471
SEMA	29JAN26	38,071	12,975	316	620	38,071	12,975	39	202	51,085
SEMA	30JAN26	38,876	13,403	293	731	38,876	13,403	129	179	52,408
SEMA	31JAN26	38,456	13,201	1,525	275	38,456	13,201	656	275	52,313
SEMA	01FEB26	35,098	12,097	1,372	1,133	35,098	12,097	335	768	47,529
WCMA	26JAN26	42,518	12,029	3,129	2,969	42,518	11,892	621	564	55,031
WCMA	27JAN26	43,001	12,870	1,631	318	43,001	12,758	53	318	55,812
WCMA	28JAN26	43,573	13,321	3,290	1,349	43,573	13,184	902	279	57,659
WCMA	29JAN26	43,410	13,034	371	1,511	43,410	12,922	82	334	56,414
WCMA	30JAN26	46,102	13,341	315	1,287	46,102	13,218	140	261	59,460
WCMA	31JAN26	44,747	12,450	2,027	1,005	44,747	12,347	960	269	58,054
WCMA	01FEB26	44,763	11,784	2,122	1,216	44,763	11,666	860	312	57,289
NEMA	26JAN26	61,219	18,753	1,607	94	61,219	18,609	377	94	80,206
NEMA	27JAN26	62,205	19,935	279	197	62,205	19,180	0	197	81,385
NEMA	28JAN26	63,323	19,900	499	243	63,323	19,743	117	243	83,183
NEMA	29JAN26	63,673	19,919	292	777	63,673	19,919	90	353	83,681
NEMA	30JAN26	65,280	20,856	1,041	1,278	65,280	20,856	810	209	86,947
NEMA	31JAN26	64,142	19,527	1,886	527	64,142	19,527	948	341	84,616
NEMA	01FEB26	59,191	17,783	1,873	1,202	59,191	17,783	1,048	581	78,022

3.2 Real-Time Demand

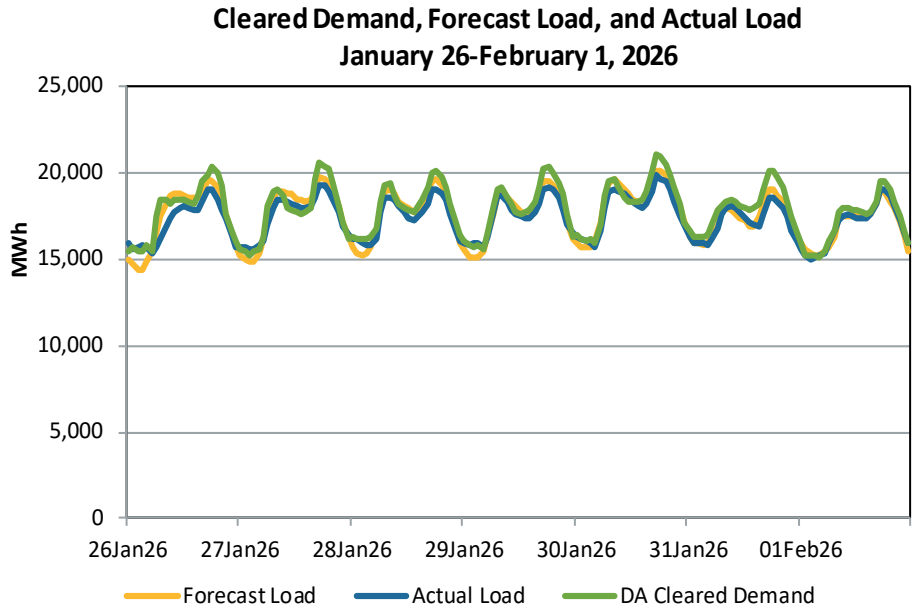
The following table displays the Real-Time Load Obligation at each Load Zone and external nodes for this week, last week, the same week a year ago, and the percent change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
ME	271,047	256,933	5.5%	250,417	8.2%
NH	279,241	265,868	5.0%	251,358	11.1%
VT	130,875	124,151	5.4%	117,143	11.7%
CT	687,110	633,709	8.4%	569,572	20.6%
RI	178,969	166,517	7.5%	157,101	13.9%
SEMA	346,184	320,130	8.1%	292,739	18.3%
WCMA	400,684	376,204	6.5%	346,967	15.5%
NEMA	584,294	541,862	7.8%	505,379	15.6%
NB Ext	4,152	9,868	-57.9%	1,202	245.4%
NY-N AC Ext	49,035	148,379	-67.0%	110,384	-55.6%
HQ Ext	30,448	31,828	-4.3%	0	N/A
HG Ext	69	84	-17.9%	12	475.0%
CSC Ext	45,515	19,102	138.3%	11,730	288.0%
NNC Ext	458	4,954	-90.8%	4,065	-88.7%
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 (MW)	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
26JAN26	18	19,411	$365.83	$349.72	$367.99	$364.07	$354.65	$363.59	$366.30	$365.45	$371.09
27JAN26	19	19,578	$415.75	$398.40	$415.31	$414.74	$405.68	$413.90	$415.32	$415.22	$419.34
28JAN26	19	19,468	$206.35	$189.51	$203.87	$208.14	$203.63	$205.69	$206.32	$207.01	$206.74
29JAN26	19	19,498	$360.17	$331.68	$356.82	$359.99	$355.26	$359.20	$361.85	$360.74	$362.45
30JAN26	18	19,940	$209.96	$194.75	$208.18	$206.95	$206.56	$208.98	$210.73	$209.78	$211.24
31JAN26	19	18,941	$282.30	$273.93	$284.66	$287.13	$275.72	$280.72	$283.83	$282.51	$285.77
01FEB26	18	19,446	$385.72	$210.68	$381.79	$390.28	$381.30	$384.02	$386.32	$387.08	$387.35

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.



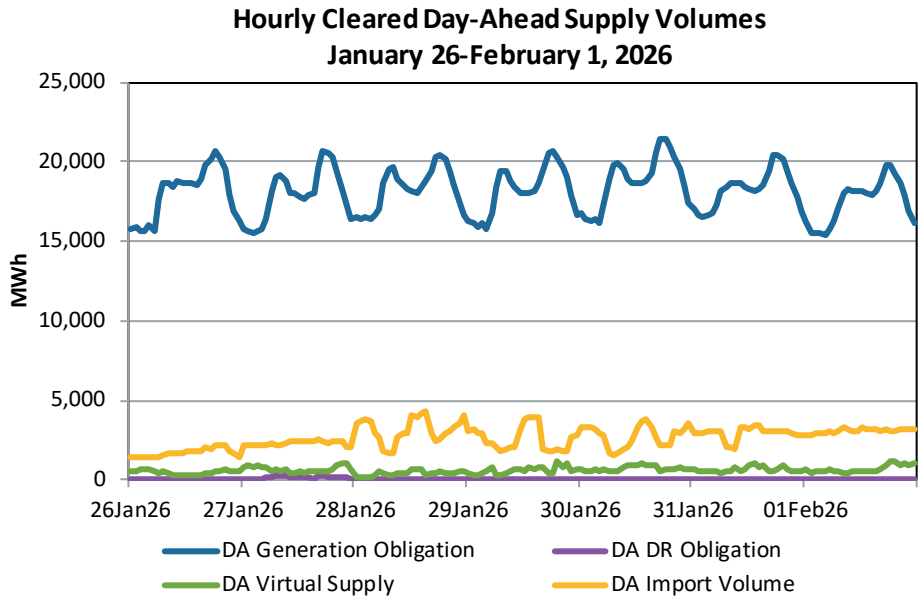
The table below compares the total quantities (MWh) of Day-Ahead Load Obligation with the Real-Time Load Obligation for each Load Zone (including nodal locations within each Load Zone) for the week. Day-Ahead Load Obligation is composed of Day-Ahead cleared demand bids and cleared Decrement bids. Real-Time 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	267,668	272,923	-5,256	98.1%
NH	278,044	279,978	-1,934	99.3%
VT	107,896	130,875	-22,979	82.4%
CT	692,105	687,110	4,995	100.7%
RI	171,016	178,969	-7,953	95.6%
SEMA	354,236	352,264	1,972	100.6%
WCMA	420,475	429,199	-8,725	98.0%
NEMA	578,038	584,334	-6,296	98.9%

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	18,122	17,343	4.5%	16,090	12.6%
DA Demand Reduction Obligation	24	3	Large	4	Large
DA Cleared Increments	594	786	-24.5%	953	-37.7%
DA Imports	2,643	3,625	-27.1%	4,321	-38.8%

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	24,137	36,536	-33.9%	66,116	-63.5%
NY-N AC Ext	175,952	236,454	-25.6%	278,948	-36.9%
HQ Ext	83,769	122,715	-31.7%	294,933	-71.6%
HG Ext	39,121	48,211	-18.9%	73,337	-46.7%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	20,372	11,623	75.3%	12,631	61.3%
NECEC Ext	100,740	153,486	-34.4%	N/A	N/A

4.2 Real-Time Supply

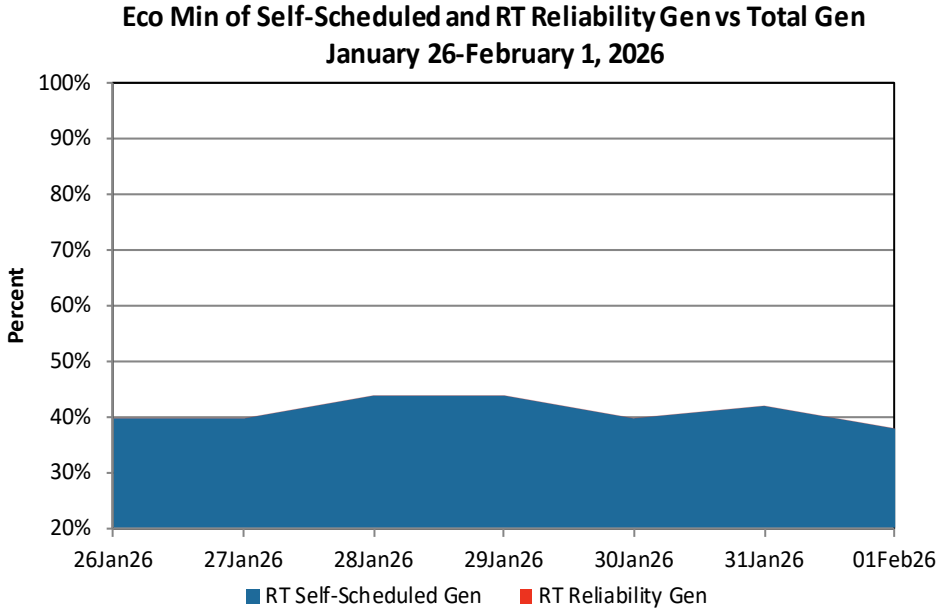
The following table provides daily and weekly totals, in megawatt-hours (MWh), of the amount of electricity produced by classified fuel type during the week. The data provided are for the full system, including "settlement only" resources that do not offer their output into the wholesale markets. The 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	26Jan26	27Jan26	28Jan26	29Jan26	30Jan26	31Jan26	01Feb26	Total
Coal	100	24	79	0	0	1	10	215
Hydro	21,199	19,836	19,977	21,216	22,702	17,757	14,093	136,780
Landfill Gas	923	919	1,004	948	883	848	862	6,387
Methane	44	50	48	47	48	41	42	318
Natural Gas	122,275	114,321	108,464	113,329	132,232	119,037	108,346	818,003
Nuclear	80,652	80,689	80,683	80,700	80,699	80,698	80,703	564,824
Oil	127,157	120,069	115,514	107,217	102,672	108,160	108,373	789,163
Other	1,124	1,195	1,181	1,614	1,526	1,121	866	8,627
PRD	153	75	39	27	13	0	0	307
Refuse	6,861	6,239	5,673	5,630	5,653	5,972	5,768	41,797
Solar	448	1,292	2,249	3,118	3,335	3,793	2,759	16,993
Wind	18,388	17,106	18,197	26,008	29,854	15,800	26,625	151,979
Wood	8,248	8,142	7,619	8,027	7,939	8,054	8,101	56,130
Total	387,572	369,958	360,728	367,880	387,556	361,280	356,548	2,591,523

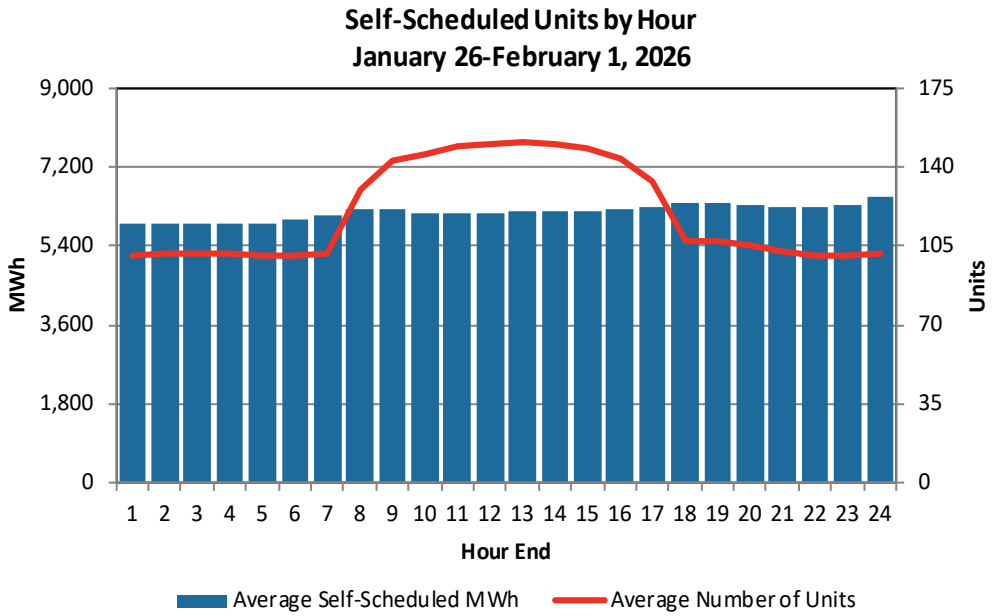
Online generators that are at their Economic Minimum output level are not eligible to set the clearing price. Real-Time Self-Scheduled Generation shown below reflects output by self-scheduled generation and by (non-dispatchable) Settlement Only Resources (SORs). Real-Time Reliability Generation represents 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
26Jan26	154,423	0	387,572
27Jan26	147,377	0	369,958
28Jan26	160,448	0	360,728
29Jan26	160,418	0	367,880
30Jan26	156,391	0	387,556
31Jan26	150,896	0	361,280
01Feb26	134,874	0	356,548

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



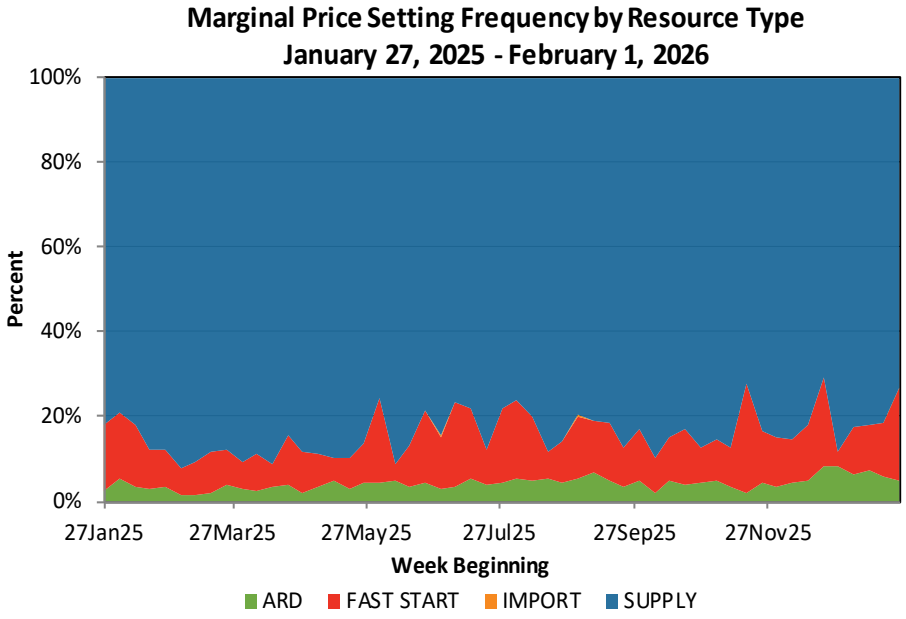
The following graph shows the average number of self-scheduled generating units and MWh for each hour of the last week.



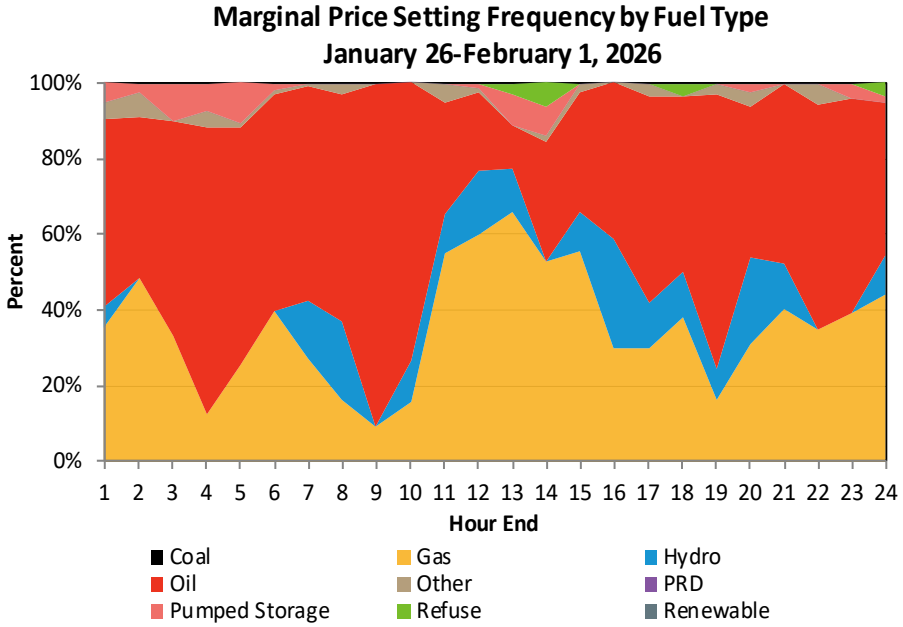
The following table provides the total Real-Time Imports by Interface for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	24,190	42,425	-43.0%	73,062	-66.9%
NY-N AC Ext	223,075	303,026	-26.4%	345,313	-35.4%
HQ Ext	105,382	135,929	-22.5%	270,831	-61.1%
HG Ext	10,182	15,128	-32.7%	37,812	-73.1%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	23,803	14,682	62.1%	19,378	22.8%
NECEC Ext	123,080	152,102	-19.1%	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 55% 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

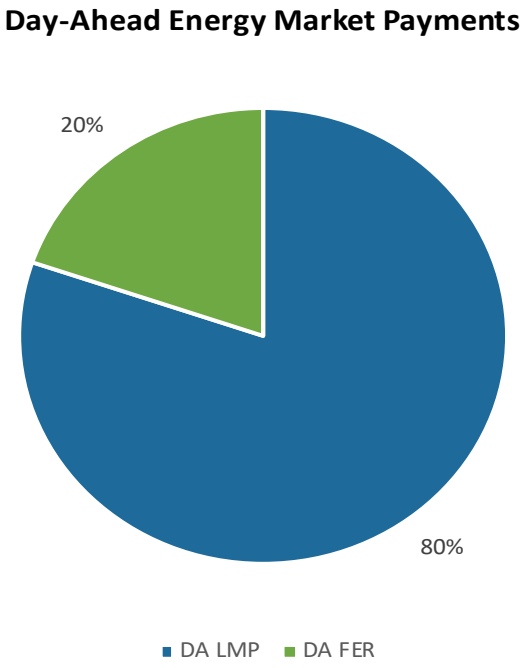
6.1 Energy Market Payments

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.

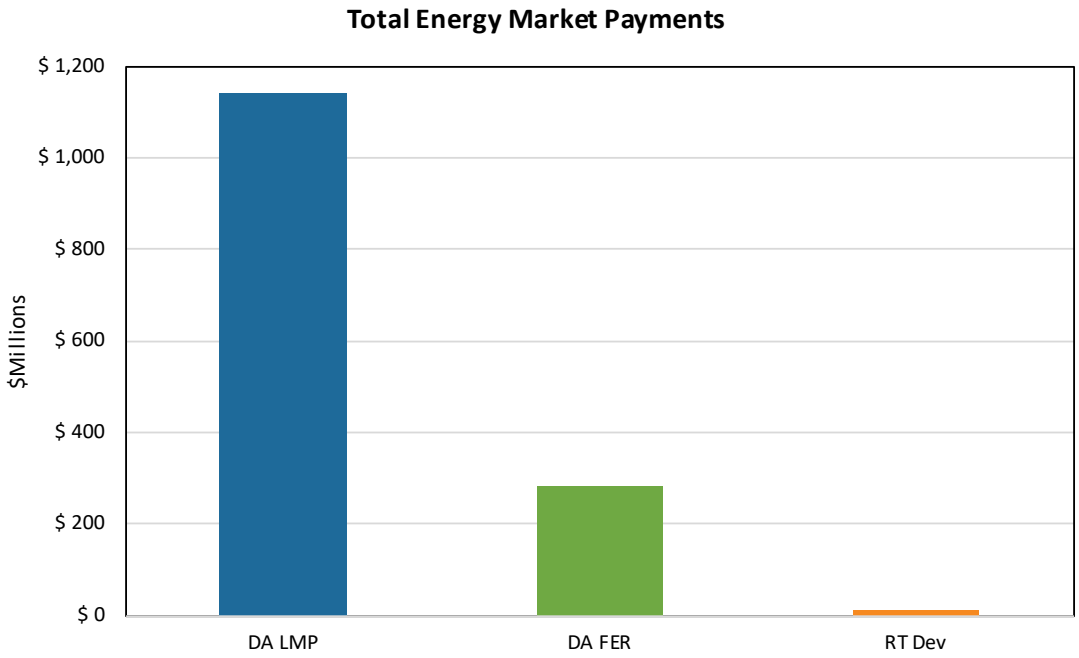
Energy Market Payment Summary
January 26-February 1, 2026

DA LMP Payments (A)	DA FER Payments (B)	RT Dev Payments (C)	Energy Market Payment (D=A+B+C)
$1,139,904,708	$280,769,196	$14,094,353	$1,434,768,256

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



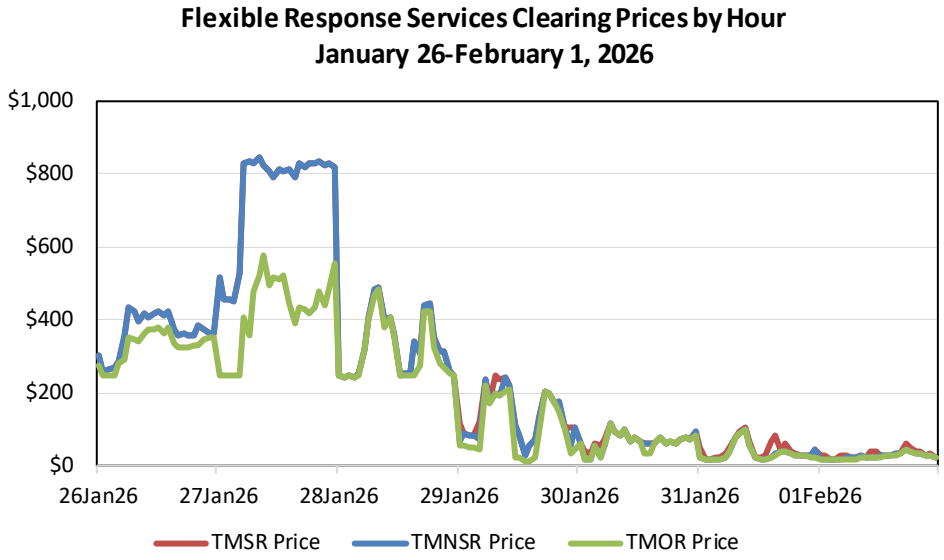
The chart below shows the magnitude of each component's contribution to the total Energy Market payment.



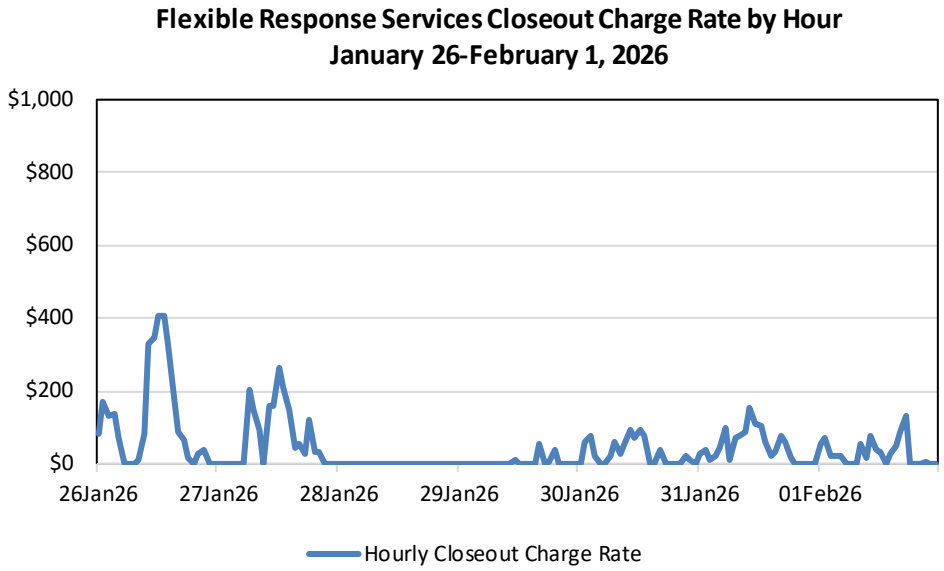
Flexible Response Services (FRS)

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.



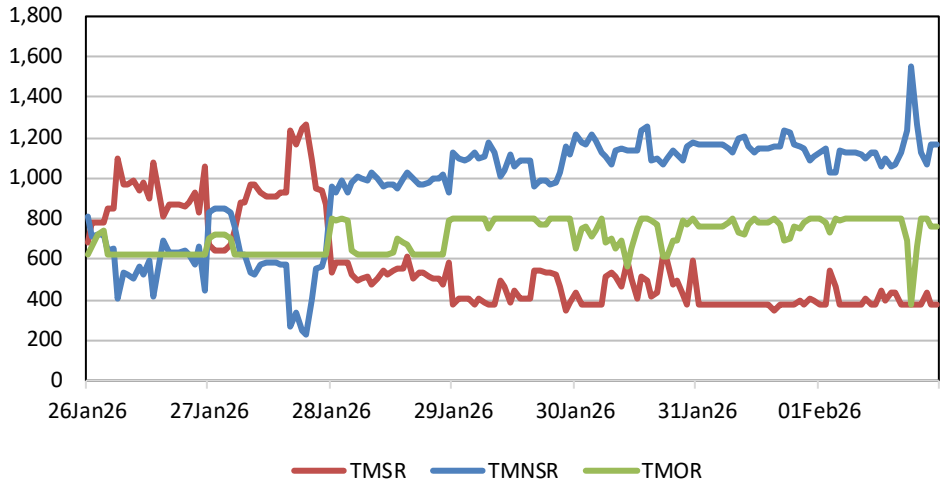
Percentage of Hours with Closeout Charge Rates
January 26-February 1, 2026

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	46.9%	3.6%	1.2%	5.4%	13.7%	16.1%	13.1%

7.2 FRS Quantities

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

Cleared Flexible Response Services MW by Hour
January 26-February 1, 2026



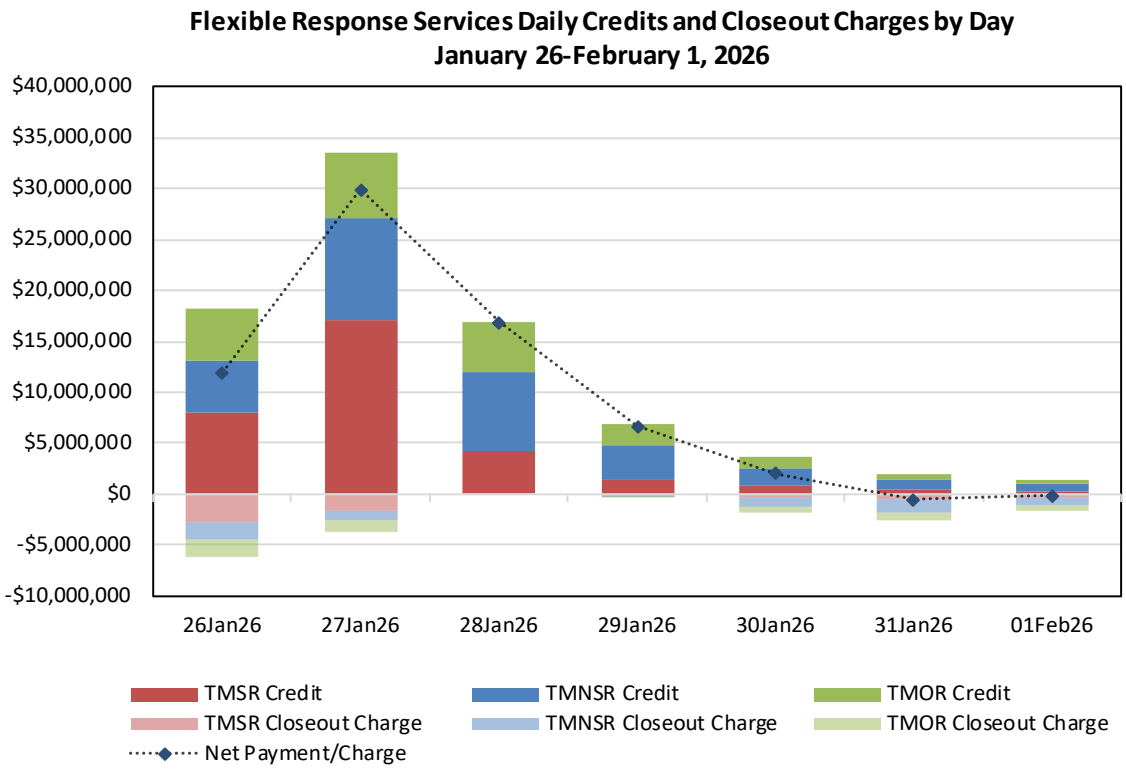
7.3 FRS Payments

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
January 26-February 1, 2026

Product Type	FRS Payments (A)	FRS Closeout Charges (B)	FRS Net Payments/Charges (C=A+B)
TMSR	$32,112,369	-$5,397,779	$26,714,590
TMNSR	$29,876,468	-$5,701,428	$24,175,040
TMOR	$20,568,102	-$4,940,551	$15,627,551
Total	$82,556,939	-$16,039,759	$66,517,181

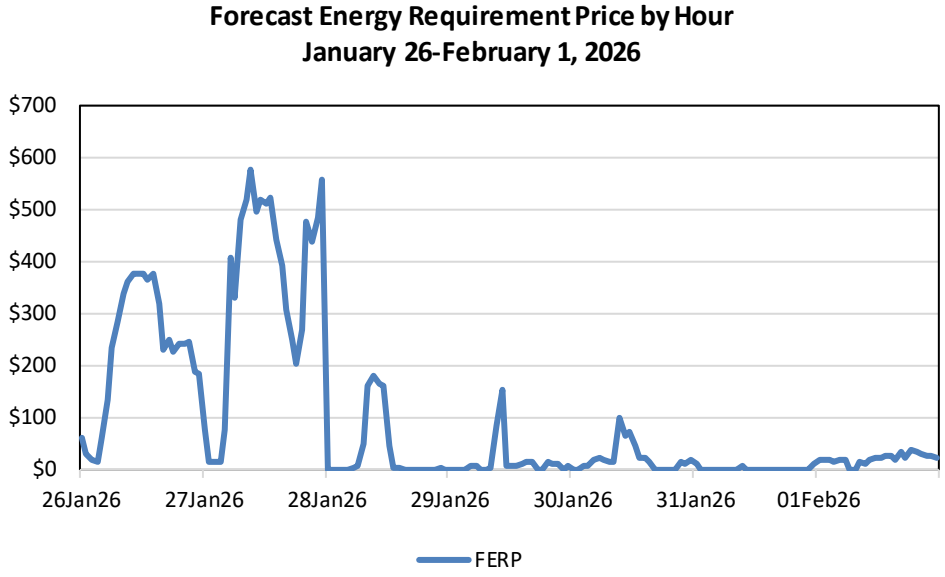
The following graph shows the daily Credit and Closeout charges by FRS product type:



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)
January 26-February 1, 2026

26Jan26	27Jan26	28Jan26	29Jan26	30Jan26	31Jan26	01Feb26	Weekly Average
$231.18	$349.80	$32.88	$15.74	$21.33	$1.33	$21.94	$96.31

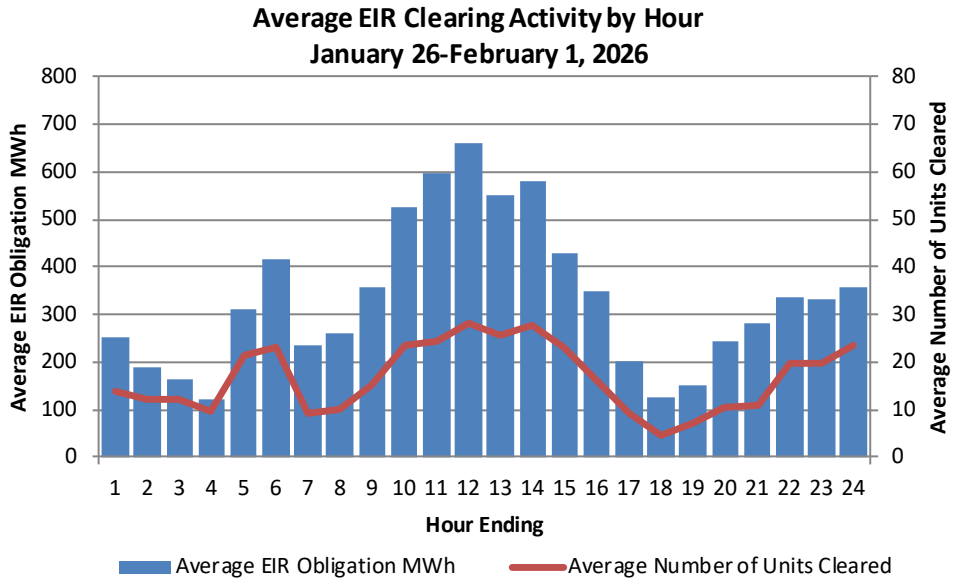
The following table shows the distribution of the hourly FERP during the reporting week.

Hourly Forecast Energy Requirement Price Distribution
January 26-February 1, 2026

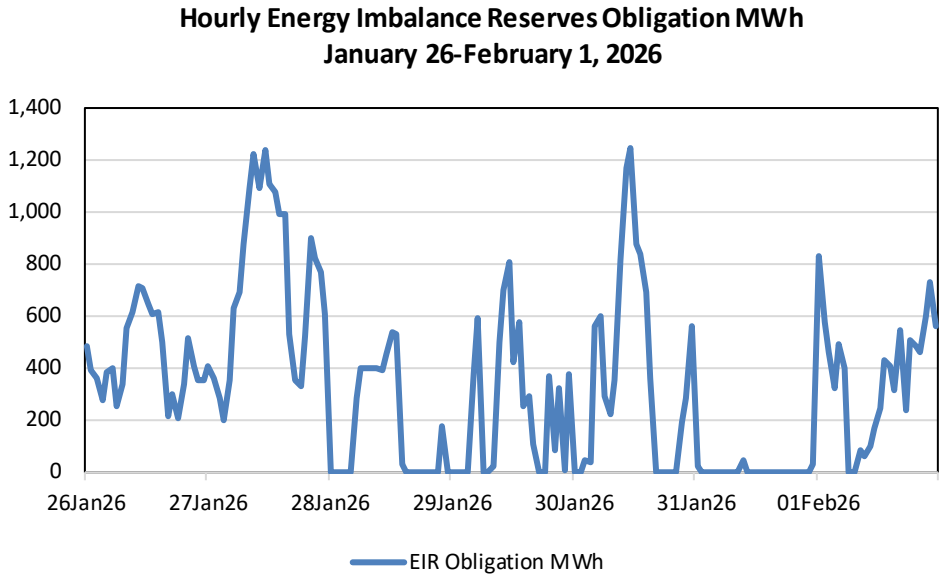
Frequency Tabulation	$0.00	$0.01 - $4.99	$5.00 - $9.99	$10.00 - $19.99	$20.00 - $49.99	$50.00 - $99.99	>= $100.00
FERP	30.3%	3.0%	6.5%	17.9%	11.9%	4.2%	26.2%

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
January 26-February 1, 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	30.3%	4.8%	1.8%	6.5%	28.0%	23.8%	4.8%

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
January 26-February 1, 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)
26Jan26	$97,885,160	$2,704,983	-$1,629,411	$1,075,572	$98,960,732
27Jan26	$143,889,002	$7,369,900	-$1,585,167	$5,784,734	$149,673,736
28Jan26	$14,246,010	$327,568	$0	$327,568	$14,573,578
29Jan26	$6,666,079	$196,406	-$29,785	$166,622	$6,832,701
30Jan26	$8,772,733	$394,812	-$434,116	-$39,305	$8,733,428
31Jan26	$533,962	$1,081	-$4,546	-$3,465	$530,497
01Feb26	$8,776,249	$228,485	-$260,155	-$31,670	$8,744,579
Total	$280,769,196	$11,223,235	-$3,943,180	$7,280,055	$288,049,251

Real-Time Reserve Market

9.1 Real-Time Reserve Payments

Real-Time Reserve Payment Summary by Reserve Zone
January 26-February 1, 2026

DAY	CT	NEMABSTN	ROS	SWCT	Total
26JAN26	$0.00	$0.00	$0.00	$0.00	$0.00
27JAN26	$0.00	$0.00	$0.00	$0.00	$0.00
28JAN26	$0.00	$0.00	$0.00	$0.00	$0.00
29JAN26	$0.00	$0.00	$0.00	$0.00	$0.00
30JAN26	$0.00	$0.00	$0.00	$0.00	$0.00
31JAN26	$0.00	$0.00	$0.00	$0.00	$0.00
01FEB26	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00

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
January 26-February 1, 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	100.0%	0.0%	0.0%	0.0%	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
January 26-February 1, 2026

Local Reserve Zone	Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals
Connecticut	TMSR	100.0%	0.0%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
NEMA/Boston	TMSR	100.0%	0.0%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Rest Of System	TMSR	100.0%	0.0%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Southwest Connecticut	TMSR	100.0%	0.0%
	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
January 26-February 1, 2026

Local Day	Reserve Bias
January 26-February 1, 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]
January 26-February 1, 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
January 26-February 1, 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**
2/4/2026	Original	Initial posting.