

Weekly Market Summary

September 21-27, 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: September 21-27, 2026

1.1 Weekly Highlights

Notable Events

- None.

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	\$36.12	\$44.30	-18.5%	\$38.04	-5.0%
*Real-Time Energy Market; All Hours	\$28.19	\$44.27	-36.3%	\$34.70	-18.8%

*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 (MW - Initial)	14,246	17,199	-17.2%	16,450	-13.4%
DA Load Obligation (All Zones)	-1,982,891	-2,141,555	-7.4%	-2,211,648	-10.3%
RT Load Obligation (All Zones)	-1,896,935	-2,088,126	-9.2%	-2,145,554	-11.6%
DA Cleared Exports (All Interfaces)	-245,366	-200,478	22.4%	-134,251	82.8%
RT Scheduled Exports (All Interfaces)	-364,974	-313,756	16.3%	-212,540	71.7%

Weekly Supply Statistics	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Input Fuel Price (Natural Gas, \$/MMBtu)	\$1.84	\$2.16	-14.7%	\$2.25	-18.3%
Mass Average Input Fuel Price (Natural Gas, \$/MMBtu)	\$1.36	\$1.94	-29.9%	\$1.97	-31.0%
Metered Generation (MWh)	1,905,250	2,031,388	-6.2%	2,231,066	-14.6%
Generation Obligation (MWh)	2,311,375	2,450,385	-5.7%	2,397,250	-3.6%
RT Demand Reduction Obligation (MWh)	25	19	31.2%	35	-30.4%
Self-Scheduled Generation (MWh)	834,483	846,835	-1.5%	807,622	3.3%
DA Cleared Imports (MWh - All Interfaces)	363,465	375,403	-3.2%	127,681	184.7%
RT Scheduled Imports (MWh - All Interfaces)	406,125	418,997	-3.1%	166,184	144.4%

Market Payments	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead and Real-Time Energy Market Payments (\$)	\$86,440,712	\$109,743,969	-21.2%	\$97,140,730	-11.0%
Day-Ahead Ancillary Services Market Payments (\$)	\$2,698,763	\$2,215,883	21.8%	\$2,316,221	16.5%
Real-Time Reserve Market Payments (\$)	\$3,946	\$28,678	-86.2%	\$12,852	-69.3%

Underlying natural gas data furnished by:



Day-Ahead Price Separation

- From Monday through Thursday, September 21-24, depressed pricing in the Rhode Island (RI) Load Zone was caused by binding constraints on the E183W-1 (Franklin Square - Phillipsdale Tap) and 282-520-2 (Waltham - Watertown) lines due to the planned outage of the T172N-1 (West Farnum Tap - West Farnum), T172N-2 (West Farnum Tap - Woonsocket), T172N-3 (Farnum Pike - West Farnum Tap), T172N-4 (Wolf Hill - Farnum Pike), and T172S-7 (Shunpike - West Cranston) lines and patterns of load and generation. The T172N-1, T172N-2, T172N-3, T172N-4, and T172S-7 lines are expected to be restored on September 30.
- On Monday and Tuesday, September 21 and 22, depressed pricing in the Southeastern Massachusetts (SEMA) Load Zone was caused by a binding constraint on the Barnstable Export Interface due to the planned outage of the 136-1 (Falmouth Tap - Hatchville) and 136E (Falmouth Tap - Falmouth) lines. The 136-1 and 136E lines were restored on September 24.

Real-Time Price Separation

- Negligible.

Real-Time Price Corrections

- The intervals beginning at 1:20 p.m. and 1:25 p.m. on Friday, September 25 due to a software error. The resulting five minute LMPs for these intervals at the Hub and Load Zones ranged between \$24.71/MWh and \$26.32/MWh.

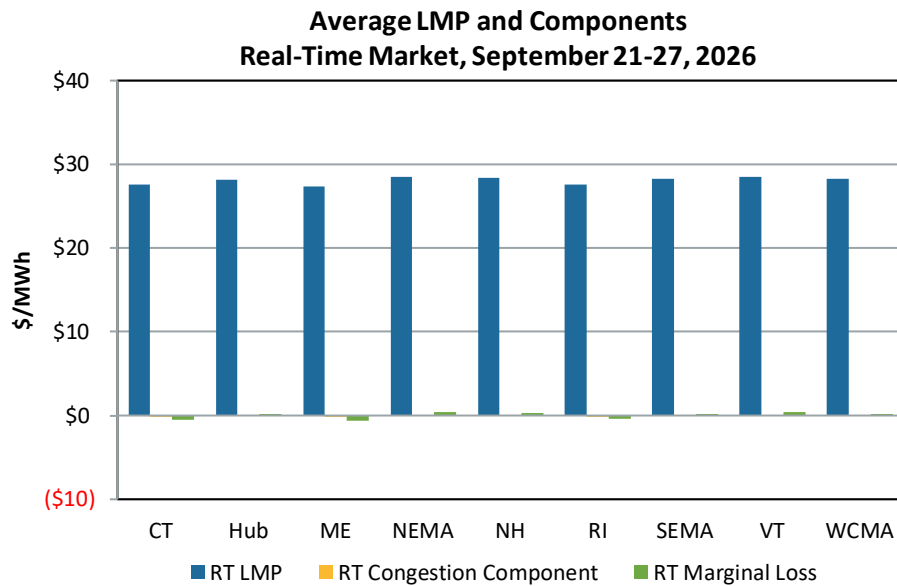
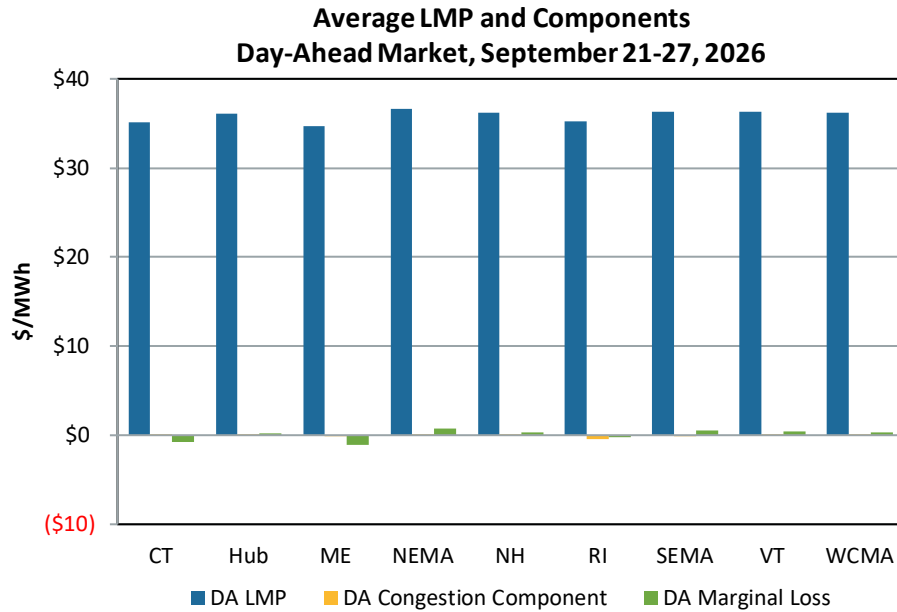
Year-to-Date Peak Load Statistics*

- [FCM Peak Load](#) (preliminary, subject to change) is 25,303 MW and occurred in the hour ending 7:00 P.M. on Thursday, July 2. At this hour, the Capacity Zone-level FCM peak loads were 3,231 MW in Northern New England, 2,034 MW in Maine, and 20,038 MW in Rest-of-Pool.
- [Revenue Quality System Peak Load](#) (initial) is 25,832 MW and occurred in the hour ending 7:00 P.M. on Thursday, July 2.
- [Telemetered System Peak Load](#) is 25,361 MW and occurred in the hour ending 7:00 P.M. on Thursday, July 2.

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

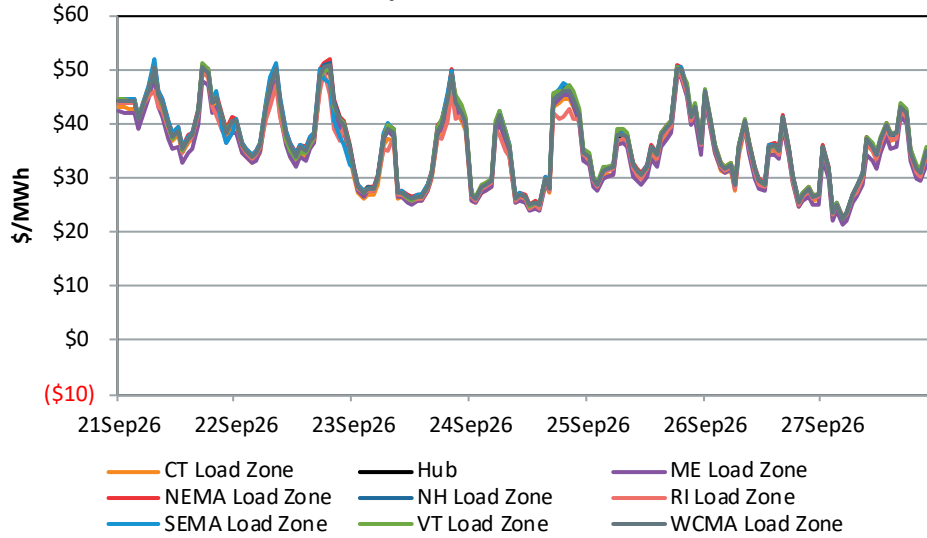
Pricing **2.1 Pricing**

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.

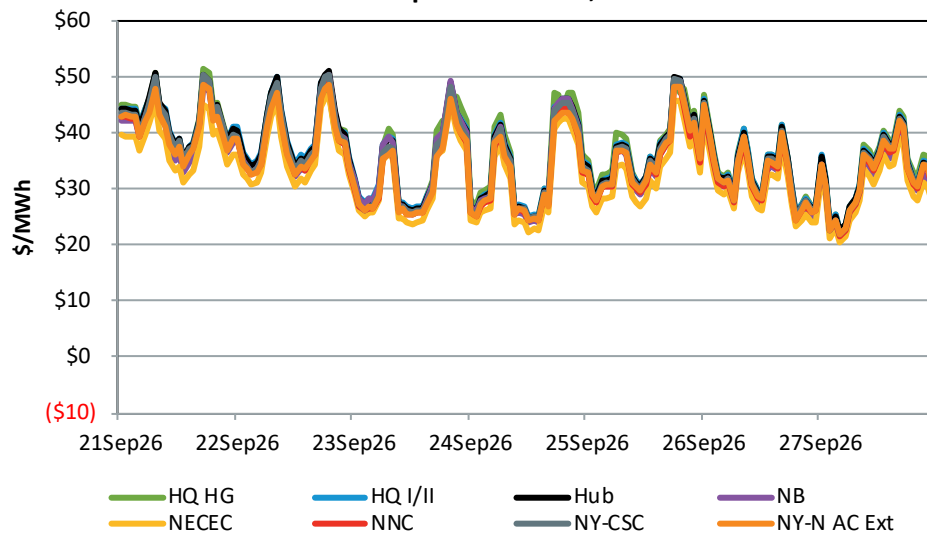


The following two graphs show hourly Day-Ahead LMPs for the Hub, the eight Load Zones, and the seven external nodes. In cases where there is little or no price separation, the lines for multiple locations may be indistinguishable from each other.

**Day-Ahead LMPs for Hub and Load Zones
September 21-27, 2026**

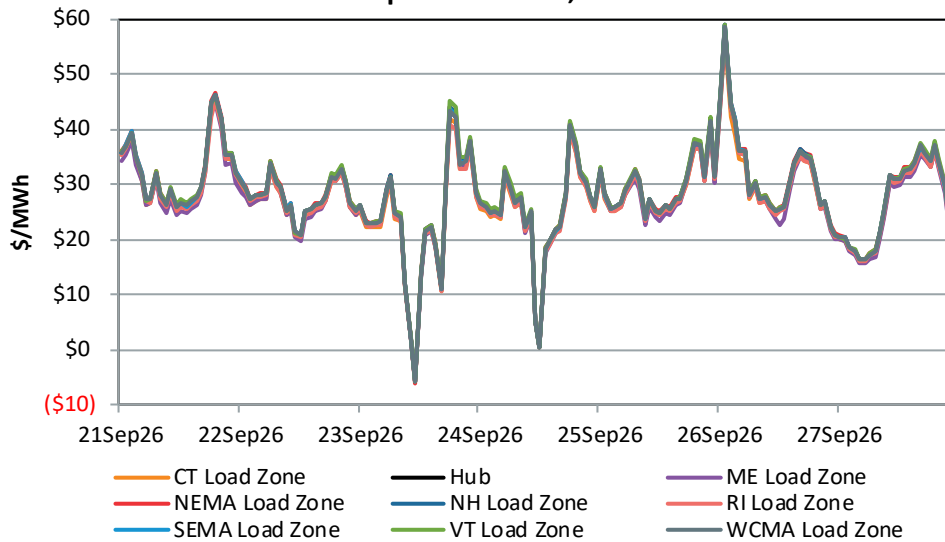


**Day-Ahead LMPs for Hub and External Nodes
September 21-27, 2026**

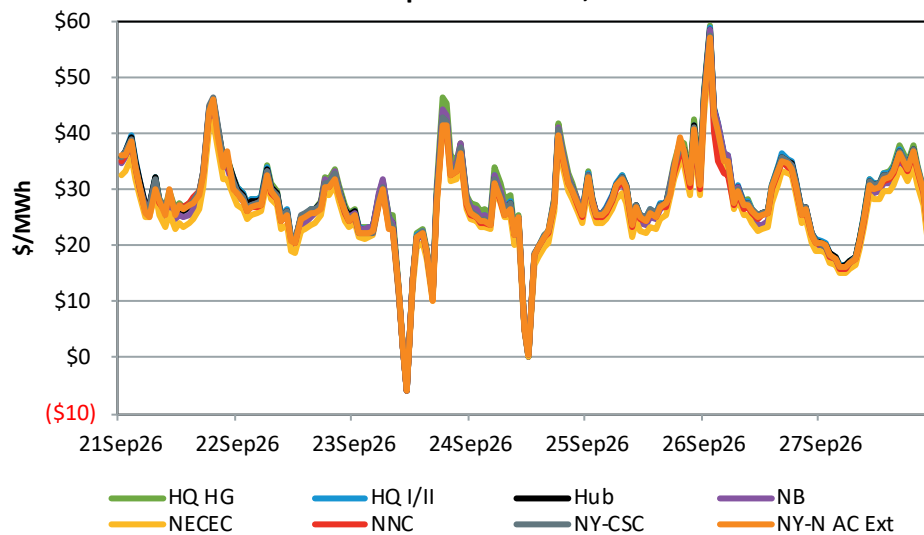


The following two graphs show hourly average Real-Time LMPs for the Hub, the eight Load Zones, and the seven external nodes. The 5-minute LMPs are averaged to create hourly values for comparison. The lines for multiple locations may be indistinguishable from each other.

**Real-Time LMPs for Hub and Load Zones
September 21-27, 2026**



**Real-Time LMPs for Hub and External Nodes
September 21-27, 2026**



LMP Summary Statistics, September 21-27, 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	\$36.12	\$28.19	\$22.58	\$-5.86	\$51.00	\$58.49	100%	100%	78%	7.04	8.10	115%
ME	\$34.65	\$27.39	\$21.37	\$-5.71	\$49.72	\$57.62	96%	97%	79%	6.86	7.98	116%
NH	\$36.23	\$28.33	\$22.49	\$-5.90	\$51.30	\$58.79	100%	100%	78%	7.08	8.16	115%
VT	\$36.35	\$28.52	\$22.64	\$-5.91	\$51.05	\$58.96	101%	101%	78%	7.08	8.21	116%
CT	\$35.07	\$27.54	\$21.86	\$-5.75	\$49.49	\$56.50	97%	98%	79%	6.84	7.85	115%
RI	\$35.19	\$27.59	\$22.34	\$-5.73	\$49.86	\$57.76	97%	98%	78%	6.48	7.91	122%
SEMA	\$36.30	\$28.29	\$22.64	\$-5.89	\$52.09	\$58.83	100%	100%	78%	7.11	8.16	115%
WCMA	\$36.16	\$28.24	\$22.58	\$-5.89	\$50.95	\$58.53	100%	100%	78%	7.02	8.11	115%
NEMA	\$36.59	\$28.49	\$22.73	\$-5.95	\$51.87	\$59.09	101%	101%	78%	7.16	8.19	114%
NB Ext	\$35.01	\$27.73	\$21.70	\$-5.75	\$50.32	\$58.69	97%	98%	79%	6.97	8.13	117%
NY-N AC Ext	\$34.81	\$27.67	\$21.92	\$-5.77	\$48.70	\$57.08	96%	98%	79%	6.58	7.92	120%
HQ Ext	\$36.33	\$28.36	\$22.72	\$-5.93	\$50.44	\$59.04	101%	101%	78%	6.93	8.11	117%
HG Ext	\$36.49	\$28.57	\$22.71	\$-5.89	\$51.48	\$59.11	101%	101%	78%	7.00	8.20	117%
CSC Ext	\$35.53	\$28.07	\$22.02	\$-5.76	\$50.32	\$57.41	98%	100%	79%	6.98	8.05	115%
NNC Ext	\$34.78	\$27.46	\$21.69	\$-5.79	\$49.38	\$56.30	96%	97%	79%	6.78	7.74	114%
NECEC Ext	\$32.73	\$25.97	\$20.51	\$-5.38	\$46.69	\$54.72	91%	92%	79%	6.39	7.56	118%

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

5-Minute LMP Summary (RT Only) September 21-27, 2026

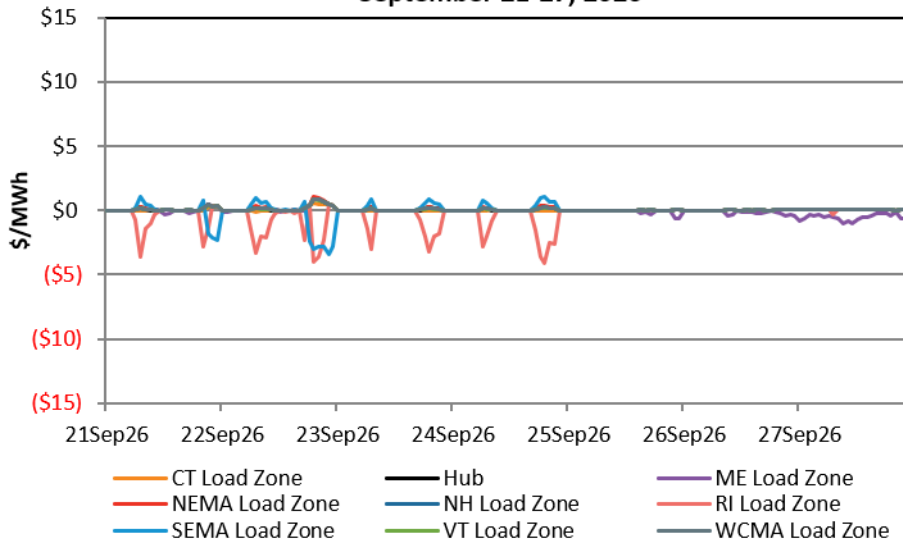
Hub/Zone	Max RT LMP (\$/MWh)	Min RT LMP (\$/MWh)	RT Std Dev	RT as % of Hub
Hub	\$87.75	-\$66.27	\$9.81	100%
ME	\$86.63	-\$64.87	\$9.65	97%
NH	\$88.26	-\$66.90	\$9.88	100%
VT	\$88.43	-\$67.40	\$9.94	101%
CT	\$84.68	-\$64.84	\$9.53	98%
RI	\$86.65	-\$64.65	\$9.56	98%
SEMA	\$88.25	-\$66.57	\$9.87	100%
WCMA	\$87.80	-\$66.51	\$9.83	100%
NEMA	\$88.68	-\$67.34	\$9.93	101%

5-Minute Energy Component of LMP September 21-27, 2026

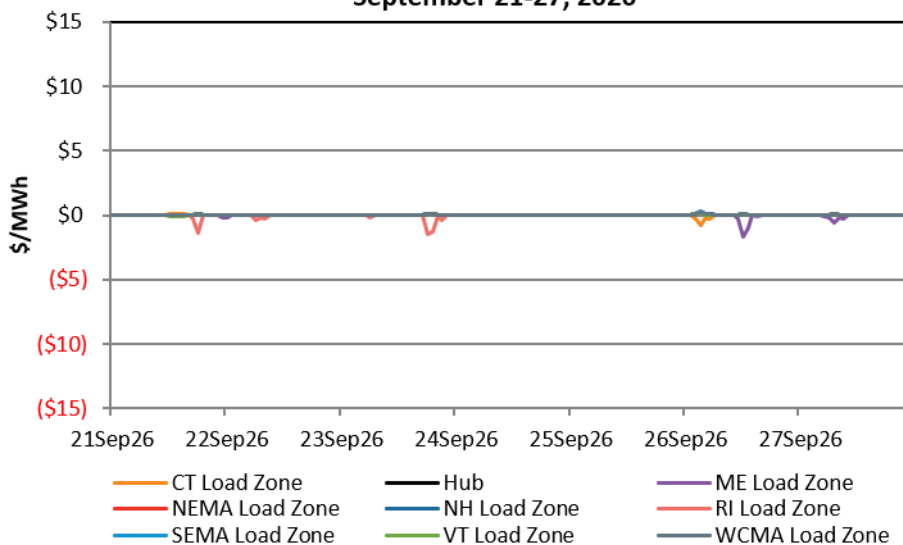
Frequency Tabulation	< \$0.00	\$0.00 - \$20.99	\$21.00 - \$40.99	\$41.00 - \$70.99	\$71.00 - \$100.99	\$100.00 - \$150.99	\$150.00 - \$200.99	\$200.00 - \$500.99	\$500.00 - \$1000.99	>= \$1000.99
5-Minute Energy	1.6%	9.9%	82.0%	6.1%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%

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.

**Day-Ahead Congestion Component for Hub and Load Zones
September 21-27, 2026**



**Real-Time Congestion Component for Hub and Load Zones
September 21-27, 2026**



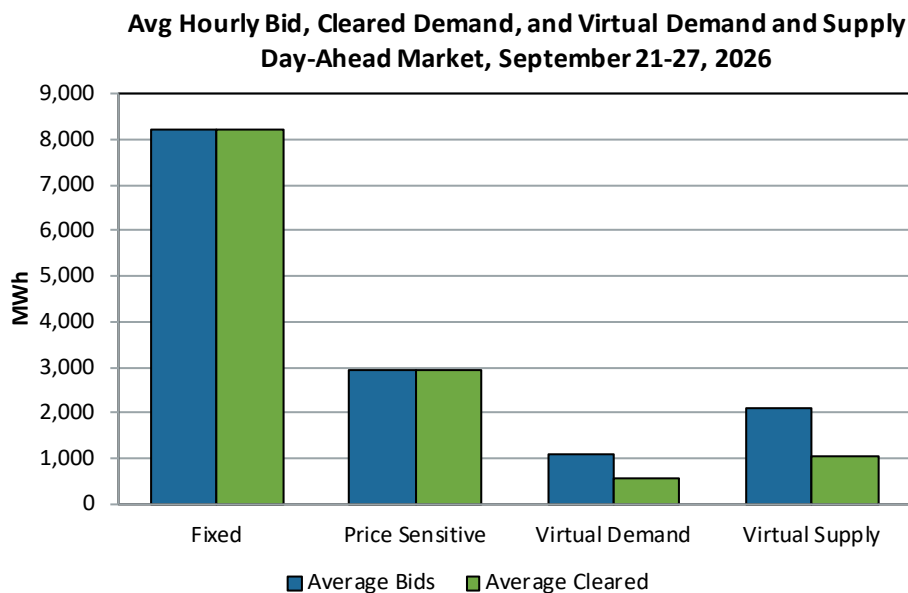
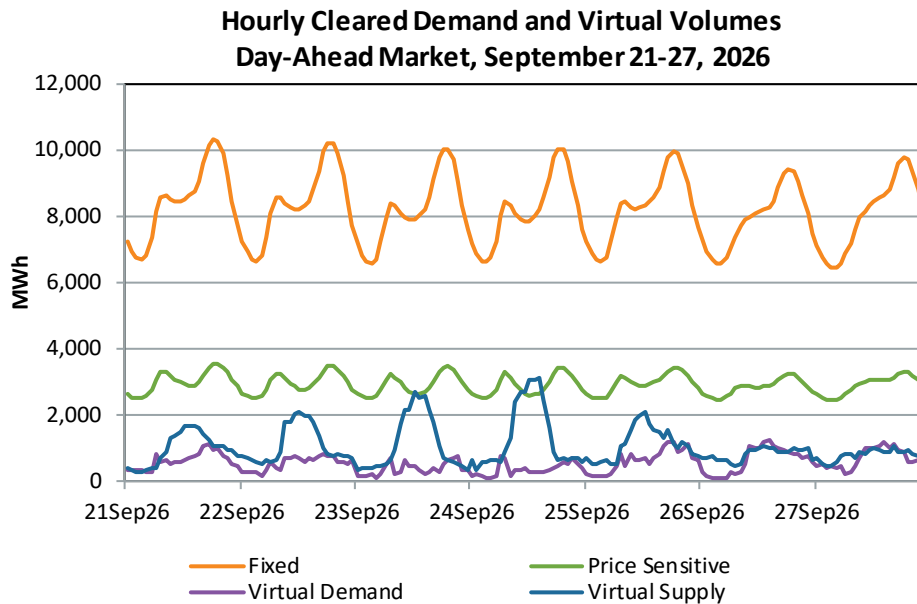
Energy Market Demand

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 percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
Hub	13,654	20,193	-32.4%	15,596	-12.5%
ME	163,721	168,080	-2.6%	181,650	-9.9%
NH	187,241	198,358	-5.6%	204,672	-8.5%
VT	78,722	83,378	-5.6%	88,603	-11.2%
CT	440,059	479,254	-8.2%	505,132	-12.9%
RI	132,541	146,276	-9.4%	153,514	-13.7%
SEMA	236,081	253,723	-7.0%	271,796	-13.1%
WCMA	262,797	276,735	-5.0%	296,271	-11.3%
NEMA	400,923	429,571	-6.7%	456,591	-12.2%
NB Ext	62,180	58,671	6.0%	7,014	Large
NY-N AC Ext	38,360	49,254	-22.1%	73,942	-48.1%
HQ Ext	114,947	58,335	97.0%	0	N/A
HG Ext	83	76	9.2%	10	Large
CSC Ext	41,281	36,582	12.8%	55,703	-25.9%
NNC Ext	3,494	12,089	-71.1%	0	N/A
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)

September 21-27, 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	21SEP26	0	0	4,619	2,805	0	0	2,748	2,148	2,748
Hub	22SEP26	0	0	4,367	5,306	0	0	2,132	3,014	2,132
Hub	23SEP26	0	0	1,818	8,765	0	0	619	3,407	619
Hub	24SEP26	0	0	1,547	11,836	0	0	411	7,065	411
Hub	25SEP26	0	0	3,543	7,289	0	0	1,641	3,570	1,641
Hub	26SEP26	0	0	3,959	5,184	0	0	2,467	2,271	2,467
Hub	27SEP26	0	0	4,874	4,168	0	0	3,637	1,620	3,637
ME	21SEP26	17,174	5,711	3,130	10,826	17,174	5,711	2,323	8,018	25,208
ME	22SEP26	17,619	5,552	3,558	12,503	17,619	5,552	2,534	9,545	25,705
ME	23SEP26	17,326	5,507	3,264	11,860	17,326	5,507	1,934	7,364	24,766
ME	24SEP26	16,940	5,407	3,201	11,643	16,940	5,407	1,732	7,690	24,078
ME	25SEP26	17,678	5,561	2,390	13,196	17,678	5,561	1,390	9,435	24,628
ME	26SEP26	17,112	5,298	3,652	15,449	17,112	5,298	2,687	9,234	25,096
ME	27SEP26	17,947	5,481	2,722	13,480	17,947	5,481	2,101	8,363	25,528
NH	21SEP26	22,099	5,225	965	1,516	22,099	5,225	698	1,216	28,022
NH	22SEP26	21,676	5,248	962	1,480	21,676	5,248	532	1,138	27,456
NH	23SEP26	21,514	5,177	799	2,496	21,514	5,177	489	1,651	27,180
NH	24SEP26	21,686	5,156	837	2,838	21,686	5,156	351	1,924	27,193
NH	25SEP26	21,361	5,095	1,857	1,883	21,361	5,095	1,126	1,465	27,582
NH	26SEP26	19,915	4,792	1,380	2,109	19,915	4,792	941	1,285	25,648
NH	27SEP26	20,654	4,708	1,013	1,960	20,654	4,708	708	1,432	26,070
VT	21SEP26	1,000	10,156	1,017	1,387	1,000	10,156	663	914	11,818
VT	22SEP26	1,018	9,525	1,102	1,796	1,018	9,525	531	1,295	11,074
VT	23SEP26	210	9,193	1,234	3,284	210	9,193	786	1,304	10,189
VT	24SEP26	1,093	9,405	1,041	2,224	1,093	9,405	515	1,490	11,013
VT	25SEP26	1,099	9,803	1,183	1,895	1,099	9,803	908	1,256	11,809
VT	26SEP26	1,137	10,619	1,523	2,720	1,137	10,619	765	1,575	12,520
VT	27SEP26	1,082	11,296	1,218	2,298	1,082	11,296	814	1,296	13,192
CT	21SEP26	48,127	16,430	2,618	2,453	48,127	16,430	1,870	1,821	66,427
CT	22SEP26	46,802	16,631	2,532	2,459	46,802	16,631	1,451	1,870	64,883
CT	23SEP26	46,368	15,990	1,718	3,598	46,368	15,990	1,420	2,235	63,778
CT	24SEP26	46,165	15,665	2,133	4,086	46,165	15,665	1,629	2,673	63,459
CT	25SEP26	46,498	16,042	2,358	3,830	46,498	16,042	1,929	2,154	64,468
CT	26SEP26	44,989	14,845	2,270	1,815	44,989	14,845	1,460	945	61,293
CT	27SEP26	45,408	14,954	2,165	1,559	45,408	14,954	1,646	779	62,008
RI	21SEP26	15,092	3,867	2,813	2,540	15,092	3,867	1,723	1,882	20,682
RI	22SEP26	14,777	3,733	2,746	3,054	14,777	3,733	1,708	2,080	20,218

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	23SEP26	14,723	3,697	1,213	4,716	14,723	3,697	1,107	2,448	19,526
RI	24SEP26	14,347	3,702	960	4,281	14,347	3,702	772	2,584	18,820
RI	25SEP26	14,769	3,750	2,996	3,647	14,769	3,750	1,409	1,802	19,927
RI	26SEP26	13,998	3,515	1,692	2,599	13,998	3,515	842	959	18,355
RI	27SEP26	13,980	3,555	1,958	3,473	13,980	3,555	1,163	1,255	18,697
SEMA	21SEP26	25,564	8,966	3,363	4,270	25,564	8,966	2,648	4,013	37,178
SEMA	22SEP26	24,893	8,624	3,055	4,052	24,893	8,624	2,562	3,573	36,079
SEMA	23SEP26	24,395	8,301	1,168	4,115	24,395	8,301	1,016	3,127	33,711
SEMA	24SEP26	24,574	8,329	2,042	4,564	24,574	8,329	1,693	3,810	34,597
SEMA	25SEP26	25,031	8,827	2,679	4,345	25,031	8,827	1,988	3,398	35,846
SEMA	26SEP26	24,263	8,635	2,173	1,985	24,263	8,635	853	750	33,750
SEMA	27SEP26	24,286	8,792	1,740	2,355	24,286	8,792	1,037	1,042	34,115
WCMA	21SEP26	28,799	9,117	1,646	1,077	28,799	9,117	1,140	1,039	39,056
WCMA	22SEP26	28,151	9,119	1,434	1,358	28,151	9,119	851	1,265	38,121
WCMA	23SEP26	28,028	9,132	680	2,323	28,028	9,132	489	1,798	37,649
WCMA	24SEP26	27,786	9,096	767	2,212	27,786	9,096	417	1,770	37,298
WCMA	25SEP26	28,256	9,230	2,127	1,795	28,256	9,230	1,605	1,691	39,091
WCMA	26SEP26	26,715	8,483	2,520	1,459	26,715	8,483	1,695	1,006	36,893
WCMA	27SEP26	27,107	8,521	1,437	1,392	27,107	8,521	1,038	949	36,665
NEMA	21SEP26	45,348	13,391	773	1,534	45,348	13,391	446	1,478	59,184
NEMA	22SEP26	45,561	13,071	625	2,275	45,561	13,071	229	1,985	58,861
NEMA	23SEP26	43,755	13,062	689	4,215	43,755	13,062	336	3,015	57,154
NEMA	24SEP26	43,741	12,934	491	4,144	43,741	12,934	266	2,494	56,941
NEMA	25SEP26	44,167	13,179	1,241	3,322	44,167	13,179	634	1,821	57,980
NEMA	26SEP26	42,115	12,254	1,175	2,626	42,115	12,254	899	1,006	55,268
NEMA	27SEP26	42,269	12,822	2,144	2,909	42,269	12,671	1,348	969	56,287

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 percentage change for each.

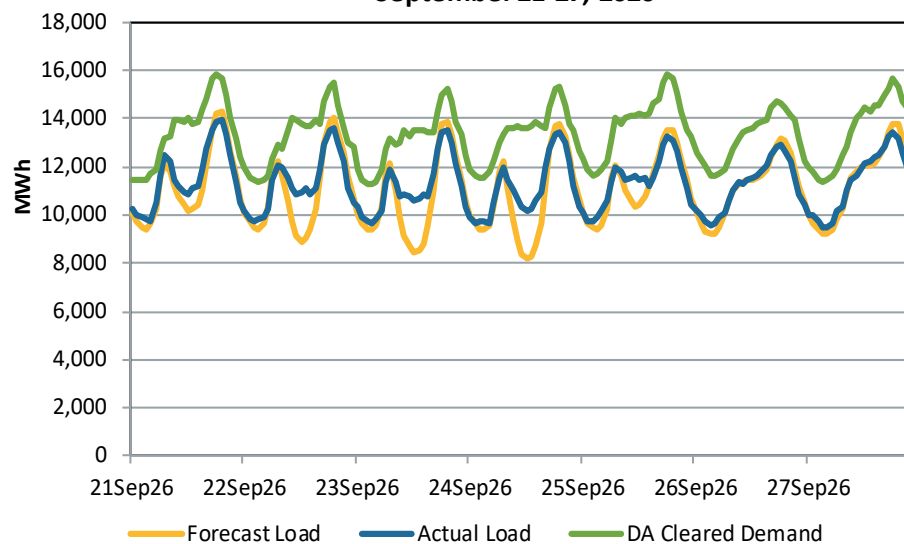
Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
ME	169,737	176,027	-3.6%	193,443	-12.3%
NH	187,265	198,050	-5.4%	202,395	-7.5%
VT	76,542	79,716	-4.0%	84,014	-8.9%
CT	425,096	482,921	-12.0%	496,149	-14.3%
RI	124,437	140,558	-11.5%	145,944	-14.7%
SEMA	230,340	252,030	-8.6%	257,196	-10.4%
WCMA	255,935	277,597	-7.8%	286,700	-10.7%
NEMA	386,329	430,272	-10.2%	442,797	-12.8%
NB Ext	65,755	60,063	9.5%	10,486	Large
NY-N AC Ext	130,900	134,975	-3.0%	140,392	-6.8%
HQ Ext	114,884	57,926	98.3%	0	N/A
HG Ext	450	552	-18.5%	6,372	-92.9%
CSC Ext	41,972	43,395	-3.3%	55,290	-24.1%
NNC Ext	11,013	16,845	-34.6%	0	N/A
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
21SEP26	20	14,246	\$46.17	\$44.60	\$46.23	\$46.00	\$45.51	\$45.19	\$46.37	\$46.27	\$46.60
22SEP26	20	13,895	\$31.07	\$30.61	\$31.40	\$31.69	\$30.42	\$30.43	\$31.23	\$31.14	\$31.43
23SEP26	20	13,830	\$42.33	\$42.22	\$43.07	\$43.95	\$41.10	\$39.88	\$42.53	\$42.41	\$42.99
24SEP26	20	13,709	\$36.64	\$36.30	\$37.15	\$37.48	\$35.83	\$35.83	\$36.77	\$36.69	\$37.11
25SEP26	19	13,587	\$33.88	\$33.66	\$34.32	\$34.50	\$33.05	\$33.18	\$34.09	\$33.90	\$34.33
26SEP26	19	13,247	\$34.68	\$34.26	\$35.10	\$34.96	\$33.73	\$33.92	\$34.89	\$34.72	\$35.20
27SEP26	19	13,810	\$34.01	\$33.07	\$34.26	\$34.58	\$33.30	\$33.26	\$34.12	\$34.09	\$34.41

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.

**Cleared Demand, Forecast Load, and Actual Load
September 21-27, 2026**



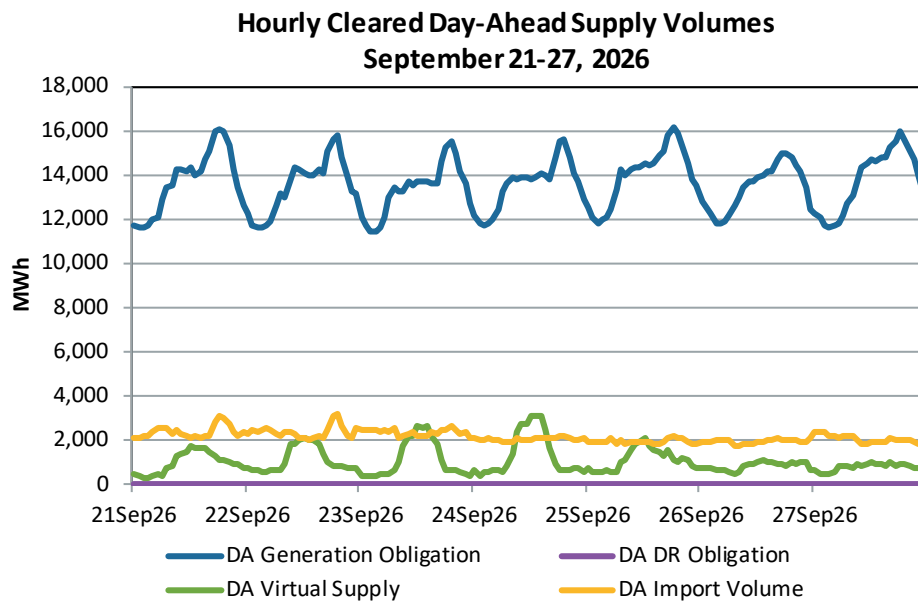
The table below compares the total quantities (MWh) of Day-Ahead Load Obligation with the Real-Time Load Obligation for each Load Zone (including nodal locations within each Load Zone) for the week. Day-Ahead Load Obligation is composed of Day-Ahead cleared demand bids and cleared Decrement bids. Real-Time 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	176,102	172,880	3,222	101.9%
NH	189,152	187,673	1,479	100.8%
VT	81,615	76,542	5,073	106.6%
CT	446,315	425,096	21,219	105.0%
RI	136,225	124,438	11,787	109.5%
SEMA	246,554	232,367	14,187	106.1%
WCMA	291,589	291,508	81	100.0%
NEMA	401,685	386,430	15,254	103.9%

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 percentage change for each.

Type	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
DA Generation Obligation	13,600	14,294	-4.9%	14,172	-4.0%
DA Demand Reduction Obligation	0	0	N/A	0	N/A
DA Cleared Increments	1,056	1,023	3.3%	891	18.6%
DA Imports	2,163	2,235	-3.2%	760	184.7%

The following table provides the total Day-Ahead 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	544	336	61.9%	18,753	-97.1%
NY-N AC Ext	159,188	147,618	7.8%	108,927	46.1%
HQ Ext	13,996	34,454	-59.4%	1	Large
HG Ext	704	4,030	-82.5%	0	N/A
CSC Ext	50	0	N/A	0	N/A
NNC Ext	727	686	6.0%	0	N/A
NECEC Ext	188,256	188,280	-0.0%	N/A	N/A

4.2 Real-Time Supply

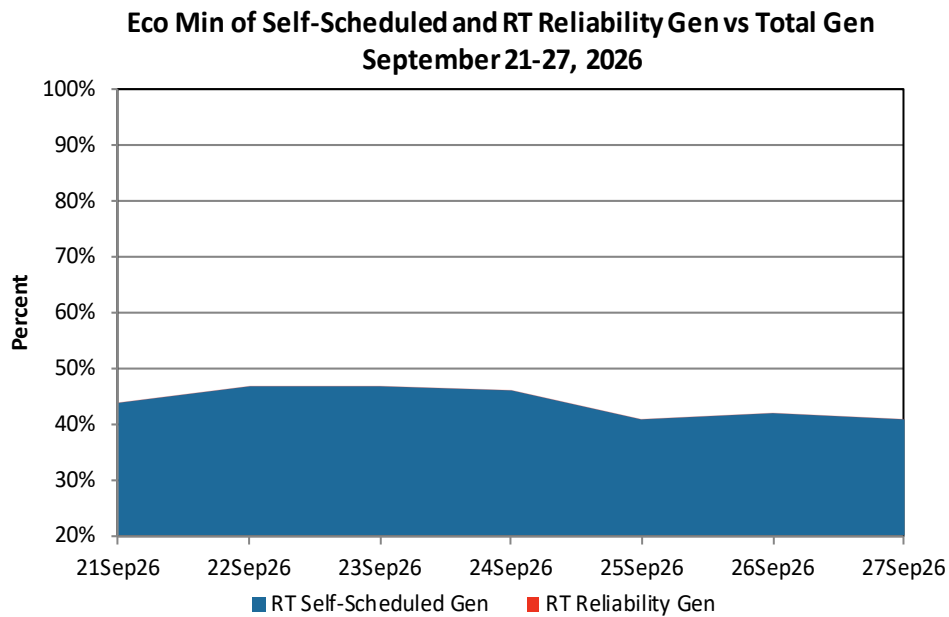
The following table provides daily and weekly totals, in megawatt-hours (MWh), of the amount of electricity produced by classified fuel type during the week. The data provided are for the full system, including “settlement only” resources that do not offer their output into the wholesale markets. The 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](#).

Category	Metered Generation (Megawatt hours)							Total
	21Sep26	22Sep26	23Sep26	24Sep26	25Sep26	26Sep26	27Sep26	
Batteries	628	909	885	911	817	354	439	4,943
Hydro	8,218	8,602	9,276	10,702	9,047	7,811	7,047	60,703
Landfill Gas	1,019	1,015	1,024	1,033	1,045	794	1,018	6,948
Methane	52	59	60	54	56	49	43	373
Natural Gas	122,733	108,811	106,774	115,692	132,961	133,630	133,107	853,708
Nuclear	79,358	79,441	79,419	79,391	79,520	79,911	80,041	557,081
Oil	28	0	50	14	46	2	0	140
Other	2,134	2,020	2,246	2,534	1,292	450	500	11,176
PRD	25	0	0	0	0	0	0	25
Refuse	7,416	7,353	7,789	7,216	8,000	7,955	7,739	53,468
Solar	17,885	17,714	19,791	21,192	12,883	7,228	4,683	101,376
Wind	26,765	27,963	30,592	29,527	33,240	34,351	39,886	222,324
Wood	5,642	5,205	4,908	4,864	4,054	3,986	4,352	33,011
Total	271,903	259,092	262,814	273,130	282,961	276,521	278,855	1,905,276

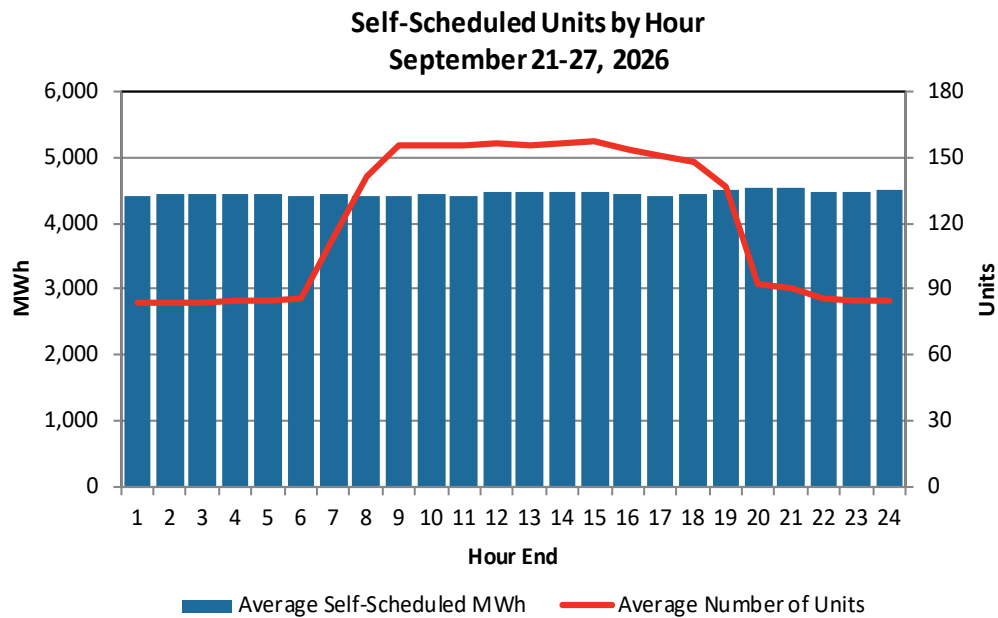
Online generators that are at their Economic Minimum output level are not eligible to set the clearing price. Real-Time Self-Scheduled Generation shown below reflects output by self-scheduled generation and by (non-dispatchable) Settlement Only Resources (SORs). Real-Time Reliability Generation represents 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
21Sep26	120,038	0	271,901
22Sep26	120,697	0	259,092
23Sep26	122,380	0	262,813
24Sep26	124,882	0	273,130
25Sep26	116,729	0	282,961
26Sep26	115,511	0	276,522
27Sep26	114,245	0	278,855

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



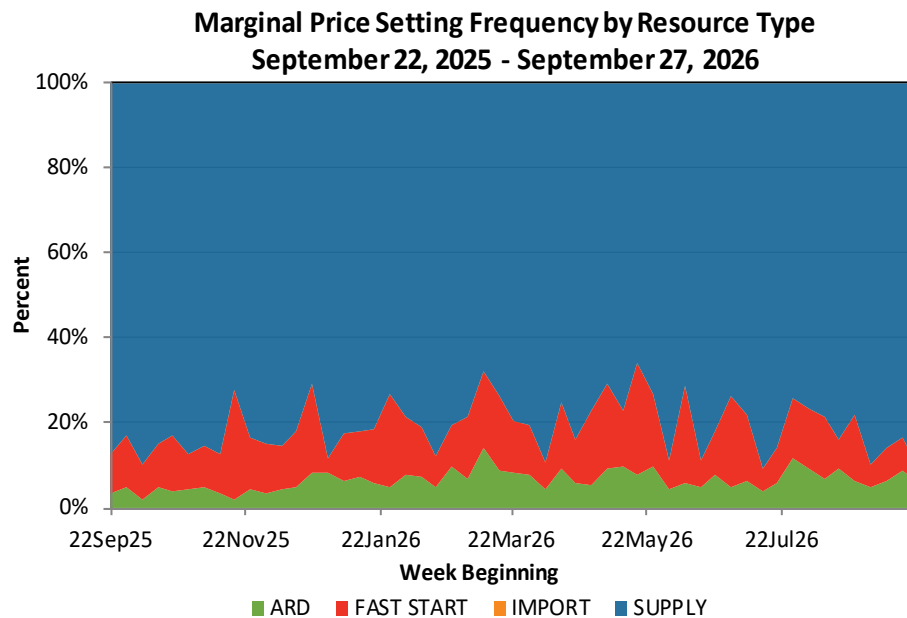
The following graph shows the average number of self-scheduled generating units and MWh for each hour of the last week.



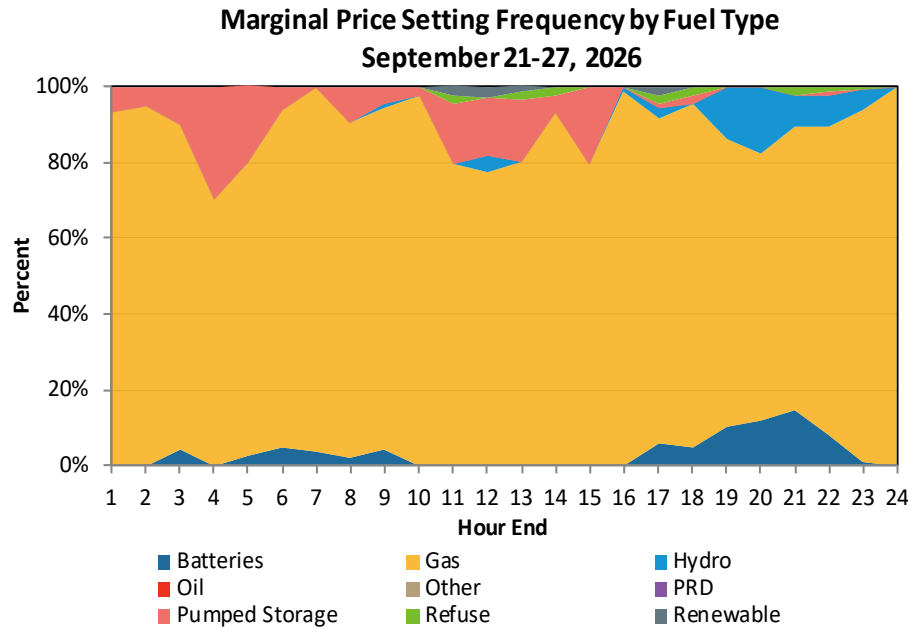
The following table provides the total Real-Time Imports by Interface for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	522	483	8.1%	15,960	-96.7%
NY-N AC Ext	198,135	186,551	6.2%	146,128	35.6%
HQ Ext	14,485	32,877	-55.9%	0	N/A
HG Ext	3,751	9,269	-59.5%	4,096	-8.4%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	975	1,537	-36.6%	0	N/A
NECEC Ext	188,257	188,280	0.0%	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 81% 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**

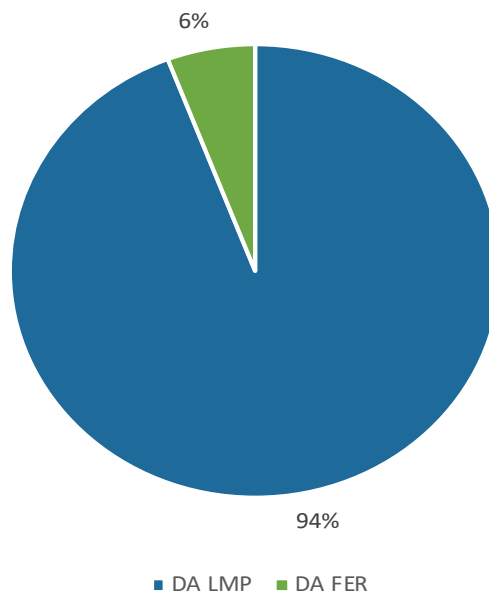
The table below displays the three components that make up the Energy Market payment for the prior week. These are payments made in relation to Day-Ahead LMPs, payments associated with the Day-Ahead Forecast Energy Requirement (FER), and payments related to deviations from Day-Ahead energy positions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

Energy Market Payment Summary
September 21-27, 2026

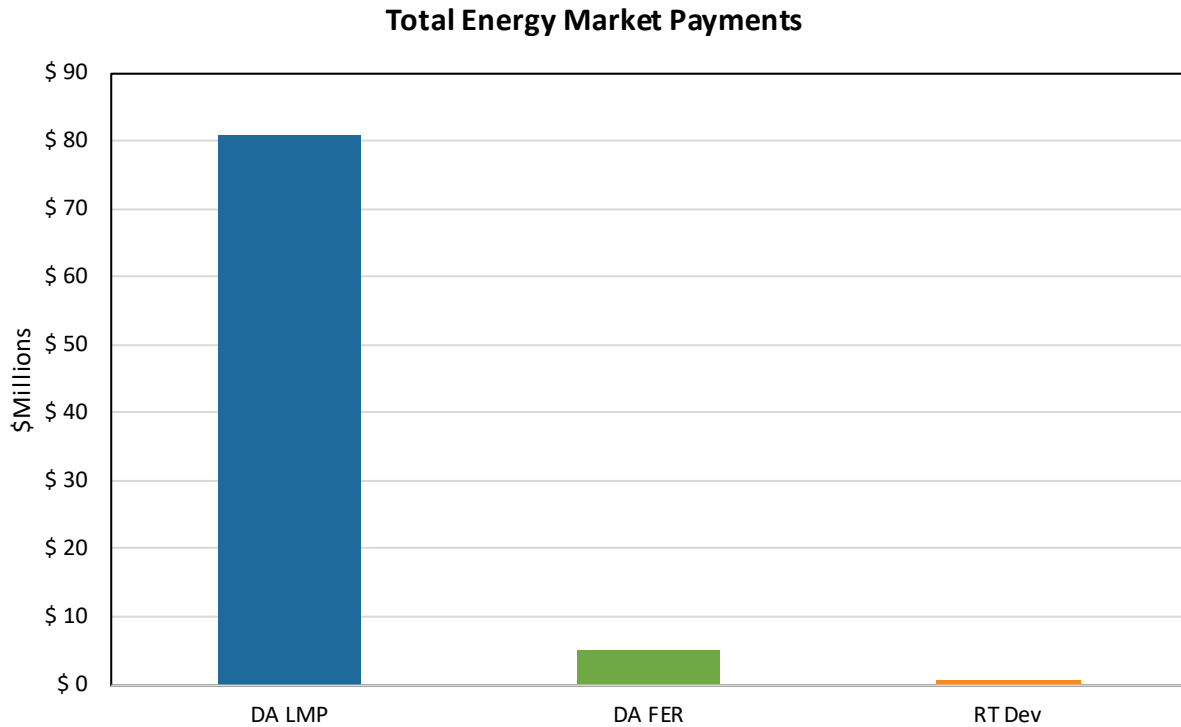
DA LMP Payments (A)	DA FER Payments (B)	RT Dev Payments (C)	Energy Market Payment (D=A+B+C)
\$80,937,966	\$4,978,152	\$524,594	\$86,440,712

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

Day-Ahead Energy Market Payments



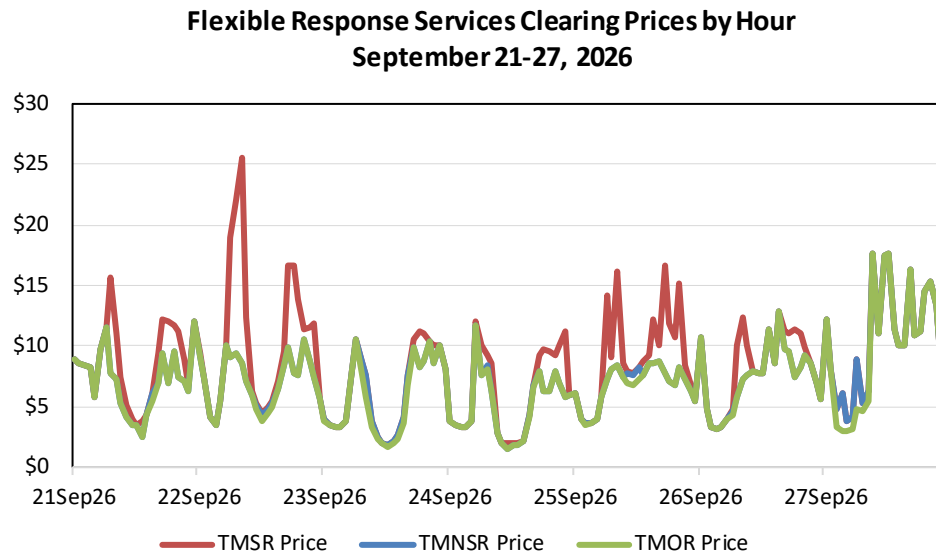
The chart below shows the magnitude of each component's contribution to the total Energy Market payment.



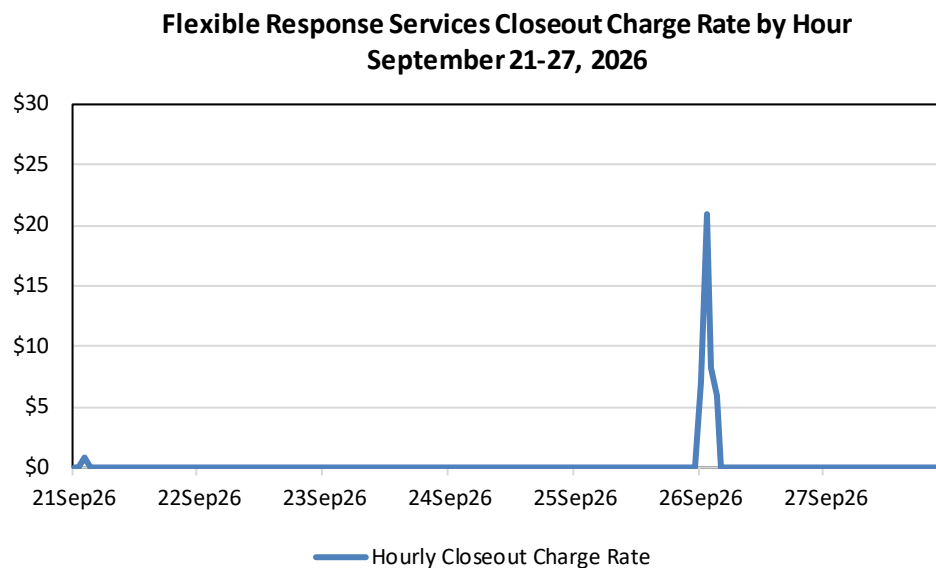
Flexible Response Services (FRS) ⓘ

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.

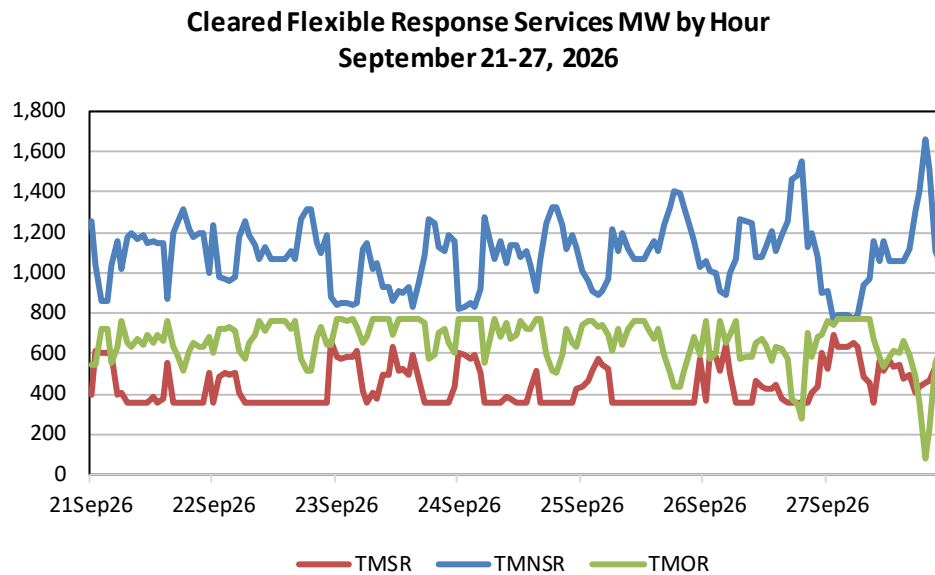


Percentage of Hours with Closeout Charge Rates September 21-27, 2026

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	97.0%	0.6%	1.8%	0.0%	0.6%	0.0%	0.0%

7.2 FRS Quantities

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



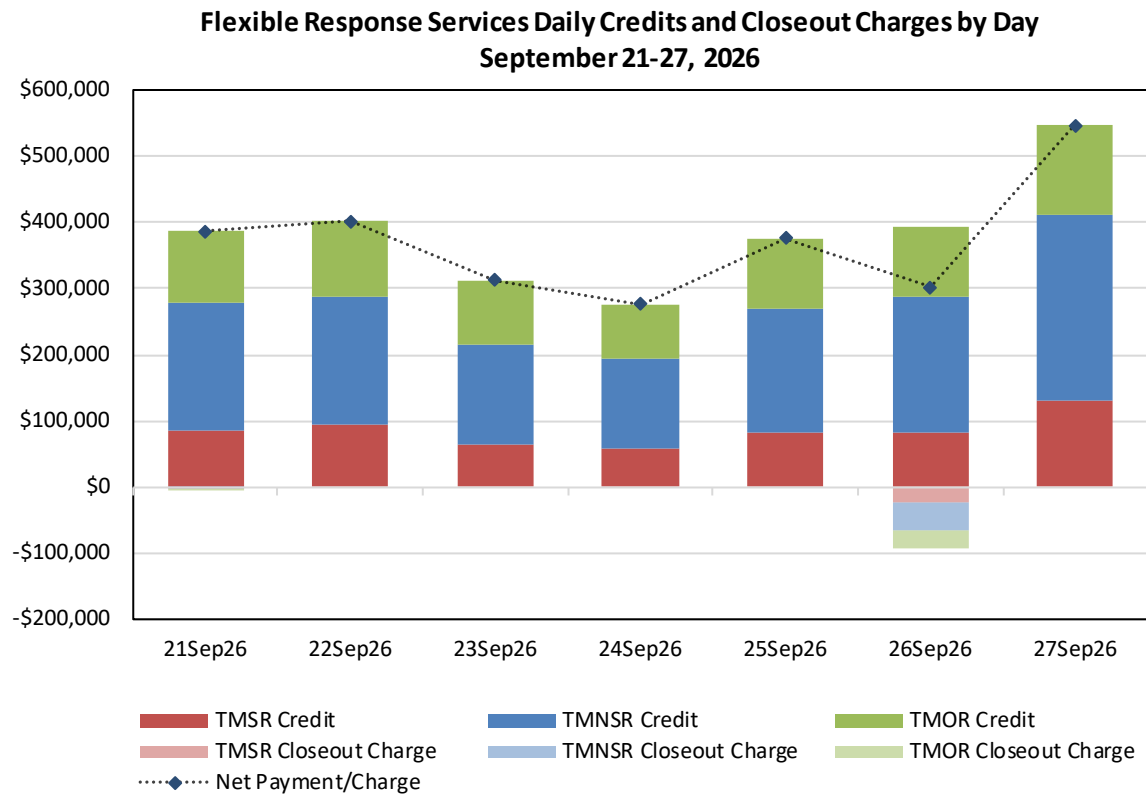
7.3 FRS Payments

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 September 21-27, 2026

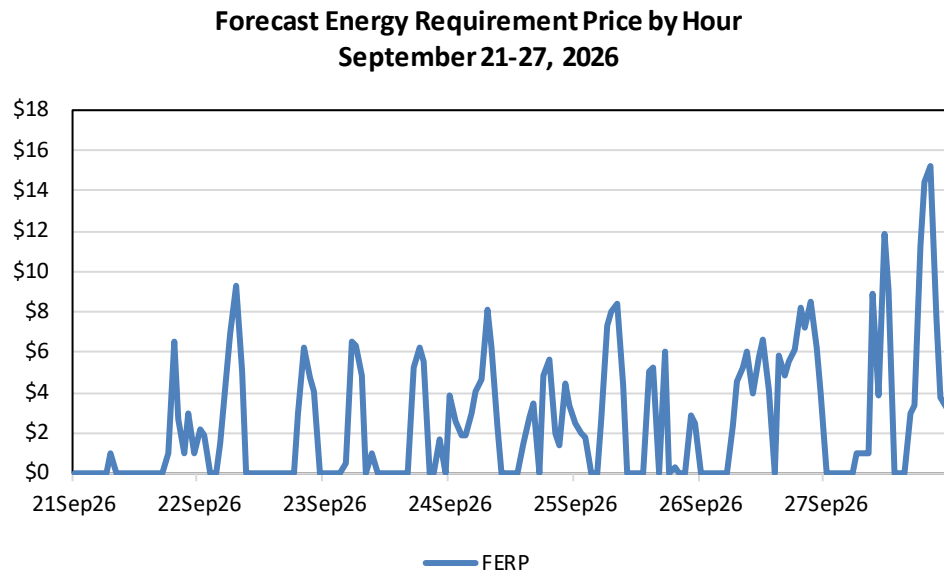
Product Type	FRS Payments (A)	FRS Closeout Charges (B)	FRS Net Payments/Charges (C=A+B)
TMSR	\$594,801	-\$23,622	\$571,179
TMNSR	\$1,350,063	-\$42,888	\$1,307,175
TMOR	\$748,482	-\$27,547	\$720,935
Total	\$2,693,346	-\$94,057	\$2,599,289

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)
September 21-27, 2026**

21Sep26	22Sep26	23Sep26	24Sep26	25Sep26	26Sep26	27Sep26	Weekly Average
\$0.67	\$2.06	\$1.58	\$2.83	\$2.46	\$3.96	\$4.11	\$2.53

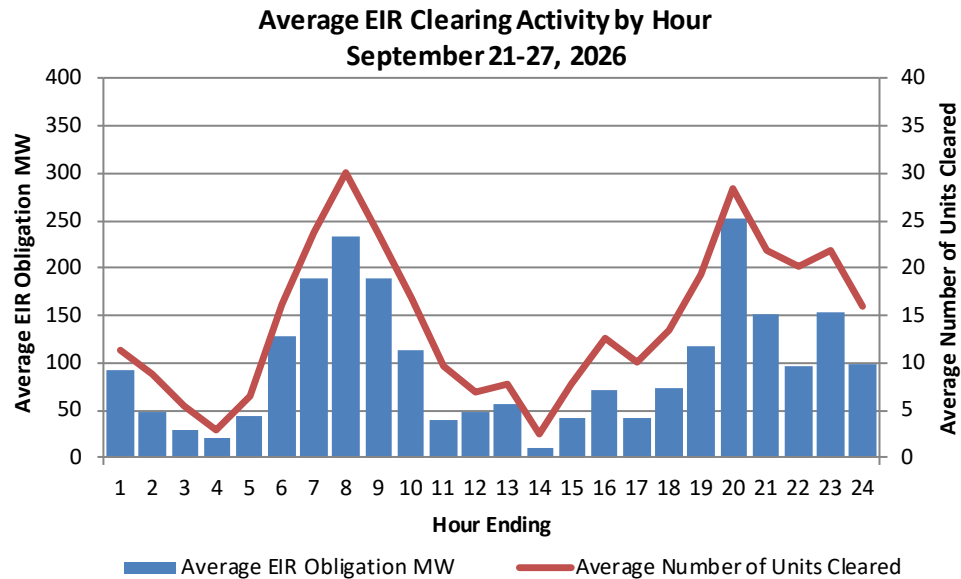
The following table shows the distribution of the hourly FERP during the reporting week.

**Hourly Forecast Energy Requirement Price Distribution
September 21-27, 2026**

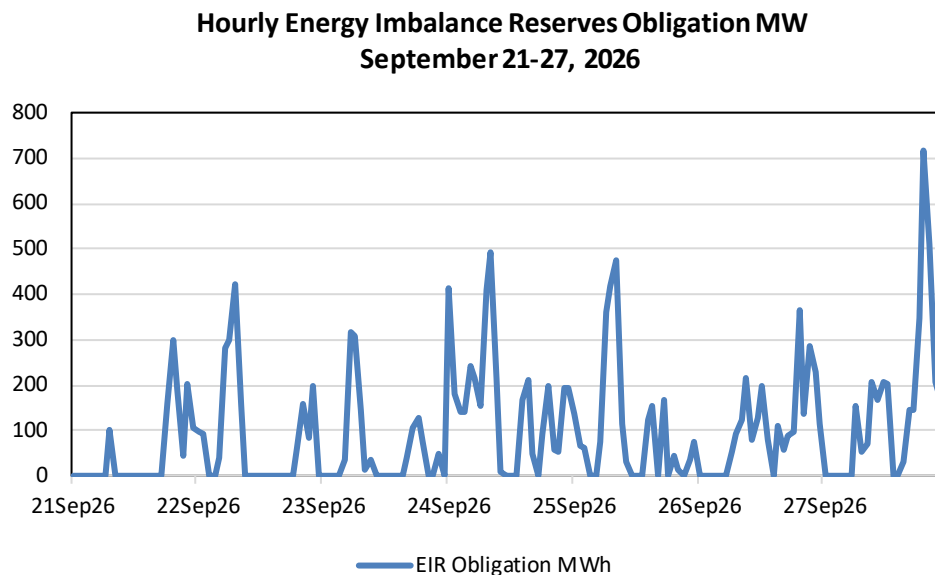
Frequency Tabulation	\$0.00	\$0.01 - \$4.99	\$5.00 - \$9.99	\$10.00 - \$19.99	\$20.00 - \$49.99	\$50.00 - \$99.99	>= \$100.00
FERP	44.7%	33.3%	19.6%	2.4%	0.0%	0.0%	0.0%

8.2 EIR Obligations

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



The following graph shows the hourly EIR Obligation MW 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
September 21-27, 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	41.7%	8.3%	12.5%	27.4%	8.9%	1.2%	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
September 21-27, 2026**

Day	DA FER Payments	EIR Payments	EIR Closeout Charges	EIR Net Payments/Charges	DA FER and EIR Net Payments/Charges
	(A)	(B)	(C)	(D=B+C)	(E=A+D)
21Sep26	\$209,658	\$3,450	\$0	\$3,450	\$213,108
22Sep26	\$578,260	\$10,942	\$0	\$10,942	\$589,201
23Sep26	\$457,737	\$6,650	\$0	\$6,650	\$464,387
24Sep26	\$751,649	\$16,030	\$0	\$16,030	\$767,679
25Sep26	\$664,240	\$14,008	\$0	\$14,008	\$678,249
26Sep26	\$1,110,312	\$15,447	\$0	\$15,447	\$1,125,760
27Sep26	\$1,206,295	\$32,946	\$0	\$32,946	\$1,239,241
Total	\$4,978,152	\$99,474	\$0	\$99,474	\$5,077,626

Real-Time Reserve Market

9.1 Real-Time Reserve Payments

**Real-Time Reserve Payment Summary by Reserve Zone
September 21-27, 2026**

DAY	CT	NEMABSTN	ROS	SWCT	Total
21SEP26	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
22SEP26	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
23SEP26	\$198.31	\$52.55	\$1,258.39	\$297.23	\$1,806.48
24SEP26	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
25SEP26	\$606.73	\$116.49	\$1,134.33	\$282.01	\$2,139.56
26SEP26	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
27SEP26	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total	\$805.04	\$169.04	\$2,392.72	\$579.24	\$3,946.04

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
September 21-27, 2026**

Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals	Percentage 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	99.6%	0.4%	50.0%	50.0%	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
September 21-27, 2026**

Local Reserve Zone	Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals
Connecticut	TMSR	99.6%	0.4%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
NEMA/Boston	TMSR	99.6%	0.4%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Rest Of System	TMSR	99.6%	0.4%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Southwest Connecticut	TMSR	99.6%	0.4%
	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 September 21-27, 2026

Local Day	Reserve Bias
September 21-27, 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:

$$(\text{Load} + \text{Reserve Requirement}) / \text{Total Capacity Supply Obligation}$$

The OP-4 Actions are the eleven actions, outlined by Operating Procedure 4, that ISO-NE uses 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 Detail¹
September 21-27, 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
September 21-27, 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 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
9/30/2026	Original	Initial posting.