Q4 2025 Report on Market Issues and Performance

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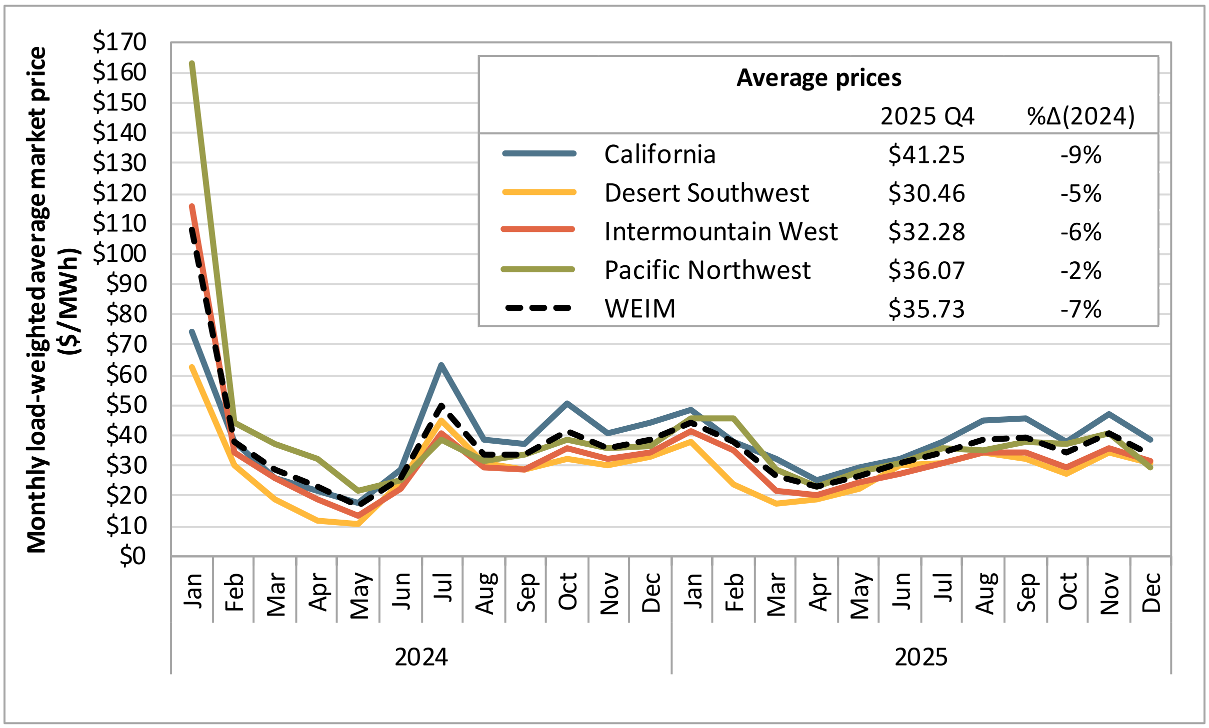
Executive summary

This report covers market performance during the fourth quarter of 2025 (October–December). Overall 15-minute market prices across the Western Energy Imbalance Market (WEIM) averaged $36/MWh, down 7 percent compared to the fourth quarter of 2024, despite higher natural gas prices at most major Western hubs (Figure E. 1). Lower loads and higher renewable output contributed to the quarterly average year-over-year changes in natural gas prices and electricity prices moving in different directions. Q4 2025 had substantially fewer intervals with very high loads and a corresponding decrease in the frequency of high-priced intervals.

Figure E. 1 Monthly load-weighted average 15-minute market energy prices by region



Other key highlights during this quarter include the following:

Supply and load conditions

- **Natural gas prices increased at most major Western hubs in Q4 2025**, with Henry Hub, PG&E Citygate, SoCal Citygate, Northwest Sumas, and NW Opal Wyoming rising 54 percent, 3 percent, 22 percent, 29 percent, and 20 percent, respectively, compared to Q4 2024. El Paso Permian prices fell sharply, decreasing from $1.30/MMBtu to –$0.60/MMBtu.

- **Renewable output increased across the WEIM footprint, with average hourly renewable generation up 2,900 MW (8 percent)** from Q4 2024. [1] This included increases of 1,680 MW (8 percent) in hydro, 640 MW (9 percent) in solar, and 680 MW (9 percent) in wind, along with slight declines in geothermal and biogas-biomass output.
- **Renewable patterns varied by region** with California showing notable increases in hydro and solar generation, the Desert Southwest experiencing higher solar and lower hydro production, the Intermountain West showing significant growth in wind, solar, and hydro, and the Pacific Northwest experiencing an 8 percent year-over-year increase in hydro that represented 86 percent of the region's renewable output.
- **Fuel-mix patterns reflected strong solar production and increased wind and hydro generation**. Mid-day battery charging and evening battery discharging increased significantly in California and the Desert Southwest, contributing to decreased evening natural gas production in both regions. The Intermountain West shifted from net imports to net exports due to higher wind and solar output. Increases in hydro and wind in the Pacific Northwest contributed to significant increases in net exports and decreases in natural gas production compared to Q4 2024.
- **Net interchange patterns shifted across the WEIM** compared to Q4 2024, with California's net imports increasing significantly year-over-year while the Desert Southwest, Intermountain West, and Pacific Northwest all exhibited higher net exports. The Intermountain West region became a net exporter for each hour of the day on average.
- **WEIM transfers averaged 4,020 MW in the fourth quarter of 2025, up from 3,870 MW in the same quarter of 2024.** Transfers between regions continued to be significantly different during mid-day solar hours than during evening and early morning hours. During solar hours, transfers were largely from CAISO and the Intermountain West to other WEIM regions. During non-solar hours, transfers were lower and were largely from the Desert Southwest and the Intermountain West to California and the Pacific Northwest.
- **Dynamic transfer limits between California and the Pacific Northwest continued to exceed static limits in Q4 2025, creating larger transfer capability in the 5-minute market than in the 15-minute market.** As a result, balancing areas in the Pacific Northwest were more frequently separated from the rest of the WEIM system in the 15-minute market than in the 5-minute market. DMM has asked the ISO to clarify why the incremental dynamic transfer capacity cannot also be made available in the 15-minute market.
- **Total generation outages** remained flat in the CAISO balancing area but increased in the California (non-CAISO), Desert Southwest, and Intermountain West regions. The Pacific Northwest remained essentially unchanged due to offsetting shifts in hydro, wind, natural gas, and solar outages.
- **Load across the WEIM averaged 74.4 GW, a decrease of about 1.4 percent compared to the same quarter of 2024.** Average load in the Pacific Northwest increased by 0.4 percent, whereas average load in California, the Desert Southwest, and the Intermountain West decreased by 3.3 percent, 0.3 percent, and 1.8 percent, respectively. There were substantially fewer intervals with high load, above about 90 GW. Peak 5-minute market load for the fourth quarter was 94.0 GW on December 29, 2025, hour-ending 18, interval 11, down significantly from the Q4 2024 peak load of about 110.5 GW.

[1] California includes BANC, CISO, LADWP, and TIDC. Desert Southwest includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC. Intermountain West includes AVA, IPCO, NWMT, and PACE. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

Prices and congestion

- **Real-time prices decreased across the WEIM.** WEIM prices averaged $36/MWh in both the 15-minute and 5-minute markets, down 7 percent and 4 percent, respectively, from Q4 2024. Prices were highest in California at $41/MWh, primarily due to greenhouse gas costs during non-solar hours, and lowest in the Desert Southwest at $30/MWh. Hourly prices followed the net-load pattern, with the highest prices during the morning and evening ramps and lower prices during solar hours.
- **The frequency of high prices above $250/MWh fell sharply across the WEIM,** dropping about 95 percent in the CAISO balancing area and declining significantly across other WEIM areas. Negative prices became more common across the WEIM, reflecting higher renewable production during low-load conditions.
- **Trends in regional price differences continued to be different during mid-day solar hours than during early morning and evening hours.** During mid-day hours, prices in the Pacific Northwest and Northern California were relatively higher than prices in the Desert Southwest and Southern California due largely to excess solar in southern regions. During early morning and evening hours, prices in California balancing areas were higher than the rest of the WEIM due mainly to California greenhouse gas pricing.
- **Prices in the day-ahead market averaged $42/MWh, down about 5 percent compared to Q4 2024.** Average prices in the 15-minute and 5-minute markets were $41/MWh for balancing areas participating in the day-ahead market.
- **Day-ahead peak prices in the Intercontinental Exchange for the Palo Verde trading hub averaged about $32/MWh over the quarter, only $1/MWh higher than ISO 15-minute market prices in the Desert Southwest.** Day-ahead ICE prices for the Mid-Columbia trading hub averaged about $38/MWh, also only $1/MWh higher than ISO 15-minute market prices in the Pacific Northwest.
- **Impacts of congestion on price separation between areas were more moderate** than Q4 2024.
- **Balancing areas in the Pacific Northwest region were more frequently separated from the larger WEIM system by transfer congestion than balancing areas in other regions.** Averaging across both 15-minute and 5-minute markets, Pacific Northwest balancing areas were transfer constrained in about 18 percent of intervals in the import direction and about 16 percent of intervals in the export direction.
- **Day-ahead congestion rent totaled $79 million, down $9 million (11 percent)** from Q4 2024.

Resource sufficiency evaluation

- **Resource sufficiency test failures remained rare across the WEIM** in Q4 2025, with all areas except El Paso Electric failing fewer than 1 percent of intervals across all test types and directions. El Paso Electric failed the downward flexibility test in 1.4 percent of intervals.
- **Five balancing areas opted in to the assistance energy transfer program on at least one day during the quarter.** All of these entities received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. PacifiCorp East received the largest amount of additional transfers in any single interval (594 MW) and the largest amount of additional transfer energy over the quarter (633 MWh).
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in separate quarterly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder

initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[2]

Uplift costs and credits

- **Real-time imbalance offsets for balancing areas participating only in the WEIM real-time markets were an $8 million credit** to WEIM entities, similar to the $7 million credit in the same quarter of 2024. The congestion portion of this offset, largely consisting of congestion rent from WEIM transfer constraints, was a $17.7 million credit. Balancing areas across the WEIM showed a wide range of total real-time imbalance offsets. For example, NorthWestern Energy recorded a $4.6 million charge while PacifiCorp East recorded a $7.4 million credit.
- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $32 million in uplift** in the fourth quarter of 2025, a decrease from $53 million in the same quarter of 2024. During the fourth quarter, real-time congestion imbalance offset costs made up the large majority of these costs at $32 million. The energy portion of the offset was an $8 million credit, while the loss portion was an $8 million charge, largely offsetting each other.
- **Bid cost recovery payments for units in balancing areas participating in both the day-ahead and real-time markets totaled about $36 million** in the fourth quarter of 2025, a slight decrease from the $37 million in bid cost recovery in the fourth quarter of 2024.
- **Bid cost recovery for units in areas participating only in the WEIM totaled about $4.2 million**, a 5 percent decrease from Q4 2024.

Operator adjustments and manual dispatch

- **Operator adjustments to load forecasts in most balancing areas were higher in the 5-minute market than in the 15-minute market.** Notable exceptions included the CAISO balancing area and Bonneville Power Administration. CAISO balancing area load adjustments in the 15-minute market during evening peak net load ramping hours were lower in the fourth quarter of 2025 compared to the fourth quarter of 2024.
- **Operator adjustments to the residual unit commitment process (RUC) procurement target decreased by about 46 percent in the fourth quarter of 2025 compared to the same quarter of 2024.**
- **Manual dispatch energy trends were divergent across WEIM regions.** Compared to Q4 2024, manual dispatch energy decreased in the Desert Southwest and the Intermountain West by 24 percent and 34 percent, respectively, and increased in the California (non-CAISO) region and the Pacific Northwest by 14 percent and 51 percent, respectively. The average hourly total energy from exceptional dispatches in the CAISO balancing area was 190 MW in the fourth quarter of 2025, up 129 percent from the fourth quarter of 2024.

[2] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: https://www.caiso.com/market-operations/market-monitoring/reports-and-presentations#weim-resource

Uncertainty in residual unit commitment, resource sufficiency evaluation, and flexible ramping product

- **Mosaic quantile regression uncertainty requirements for the flexible ramping product and resource sufficiency evaluation were again on average lower than requirements produced using the histogram method.** For the flexible ramping product, coverage rates generally remained close to the 95–97.5 percent target, but the regression coefficients were statistically significant in only 24 percent of intervals. In the resource sufficiency evaluation, coverage ranged between roughly 85 percent and 95 percent across balancing areas, and only 36 percent of regression coefficients were statistically significant.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty much less for intervals at the end of the hour than for intervals at the beginning of the hour.** This is because the model is designed to predict uncertainty in forecasts that are produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, produced between 47.5 and 102.5 minutes before real-time.
- **The ISO set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5th percentile of net load uncertainty on zero days in the quarter.** The 50th percentile target was used on 32 percent of days, and no adjustment was applied on the remaining 68 percent of days.
- **The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty as this RUC adjustment.** Prior to the ISO starting EDAM parallel operations, the ISO intended to set the imbalance reserve up requirement to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO has used the 97.5th percentile target in RUC indicates that this would have made the imbalance reserve product demand curve much too high during most hours. DMM has been highlighting this concern in its public reports. DMM appreciates that the ISO has recently indicated that it plans to set the imbalance reserve up requirement below the 97.5th percentile for a transitional period when EDAM is first implemented.

Ancillary services, available balancing capacity, and flexible ramping product

- **Upward flexible ramping product prices at the system and balancing-area level for the 15-minute market were greater than zero in one or more balancing areas that passed the resource sufficiency evaluation tests during 0.4 percent of intervals** in the fourth quarter of 2025, down from 0.7 percent in the same quarter of 2024. Battery and hydro resources made up 69 percent and 20 percent of upward flexible capacity, respectively. Wind and solar combined to provide 38 percent of downward flexible capacity, and batteries provided 35 percent of downward flexible capacity. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 61 percent in the upward direction and 59 percent in the downward direction. Balancing areas in the Pacific Northwest made up 21 percent of upward flexible capacity and 17 percent of downward flexible capacity.
- **Ancillary service payments totaled $12.7 million in the fourth quarter of 2025, down 29 percent from the same quarter of the previous year.**
- **Available balancing capacity was dispatched for generation shortfalls in less than 1 percent of intervals in all WEIM balancing areas.**

California ISO balancing area congestion revenue rights, transmission and resource adequacy capacity

- **Transmission ratepayers made roughly $5 million from the congestion revenue rights (CRR) auction** in the fourth quarter of 2025, as payments to auctioned congestion revenue rights holders were lower than auction revenues. This was the second quarterly profit for ratepayers in the auction since CRR auction reforms were made in 2016, with the first occurring in Q3 2024.
- **No monthly reservations were made for CAISO balancing area high priority wheel-through rights** for the fourth quarter of 2025. Incremental daily reservations of 10 MW were made for two days in December, with the import portion of the wheel-through at the Malin intertie. To use this reserved capacity, entities may self-schedule up to the reserved amount in the day-ahead market. None of the reserved capacity was used on either of these two days.
- **Real-time resource adequacy bids were sufficient to cover the market requirements for energy and upward ancillary services in the CAISO balancing area in all hours of the fourth quarter.**

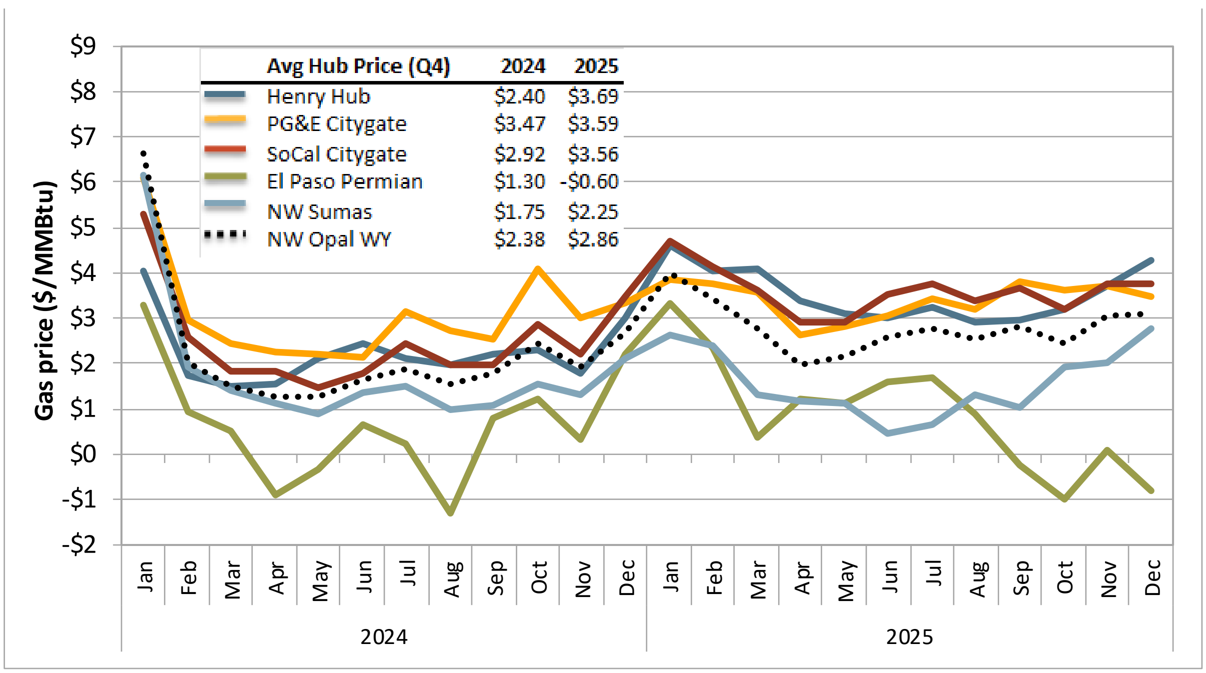
1 Supply conditions

1.1 Natural gas prices

Electricity prices in Western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in Western Energy Imbalance Market (WEIM) balancing areas and other regional markets. Figure 1.1 shows monthly average natural gas prices at key delivery points across the West, as well as the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. Average natural gas prices increased at most major Western trading hubs in the fourth quarter of 2025 compared to the same quarter[3] of 2024. Average fourth quarter prices at Henry Hub, PG&E Citygate, SoCal Citygate, Northwest Sumas, and NW Opal Wyoming increased by 54 percent, 3 percent, 22 percent, 29 percent, and 20 percent, respectively, compared to the fourth quarter of 2024. El Paso Permian prices decreased from a quarterly average of $1.30/MMBtu to -$0.60/MMBtu.

Compared to the third quarter of 2025, natural gas prices at most major Western trading hubs increased. Henry Hub, PG&E Citygate, Northwest Sumas, and Northwest Opal Wyoming increased about 22 percent, 3 percent, 121 percent, and 5 percent, respectively, compared to the previous quarter. However, prices at SoCal Citygate were relatively flat while El Paso Permian decreased by about $1.37/MMBtu.

Figure 1.1 Monthly average natural gas prices



3 Updated data resulted in an adjustment to average quarterly natural gas prices for the second quarter of 2024.

1.2 Renewable generation

In the fourth quarter, the average hourly generation from renewable resources in the WEIM footprint increased by about 2,900 MW (8 percent) compared to the same quarter of 2024.[4] Hydroelectric generation increased by approximately 1,670 MW (8 percent) across the WEIM footprint compared to Q4 2024. Solar generation increased in every region, by approximately 640 MW (9 percent) across the WEIM.[5] Average hourly generation from wind increased by about 680 MW (9 percent), and geothermal and biogas-biomass resources decreased by about 70 MW (5 percent) and 10 MW (2 percent), respectively, across the WEIM footprint compared to the fourth quarter of 2024. The availability of variable energy resources, such as wind and solar resources, contributes to price patterns both seasonally and hourly due to their low marginal cost relative to other resources.

Figure 1.2 to Figure 1.5 show the average monthly renewable generation by fuel type.

- Generation from solar resources made up 44 percent of all renewable output in the California region and increased by 120 MW (3 percent) compared to the fourth quarter of 2024. Hydroelectric generation increased by about 380 MW (19 percent), while wind, geothermal, and biogas-biomass generation decreased slightly year-over-year.
- The Desert Southwest region saw increases in solar (340 MW or 20 percent) and decreases in hydroelectric generation (80 MW or 23 percent), contributing to an overall increase in renewable generation of 160 MW (4 percent) compared to the fourth quarter of 2024.
- Renewable generation in the Intermountain West increased by approximately 1,020 MW (25 percent) compared to the fourth quarter of 2024, with the largest increases attributed to solar and wind generation (170 MW or 30 percent, and 740 MW or 38 percent, respectively). Hydroelectric generation increased by about 120 MW (8 percent) year-over-year.
- In the fourth quarter of 2025, hydroelectric generation represented 86 percent of all renewable generation in the Pacific Northwest, with an increase of 1,250 MW (8 percent) from the same quarter of the previous year. Solar and wind generation increased by about 15 MW (11 percent) and 270 MW (13 percent), respectively.

[4] Figures and data provided in this section are preliminary and may be subject to change.

[5] California includes BANC, CISO, LADWP, and TIDC. Desert Southwest includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC. Intermountain West includes AVA, IPCO, NWMT, and PACE. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

Figure 1.2 California - Average monthly renewable generation

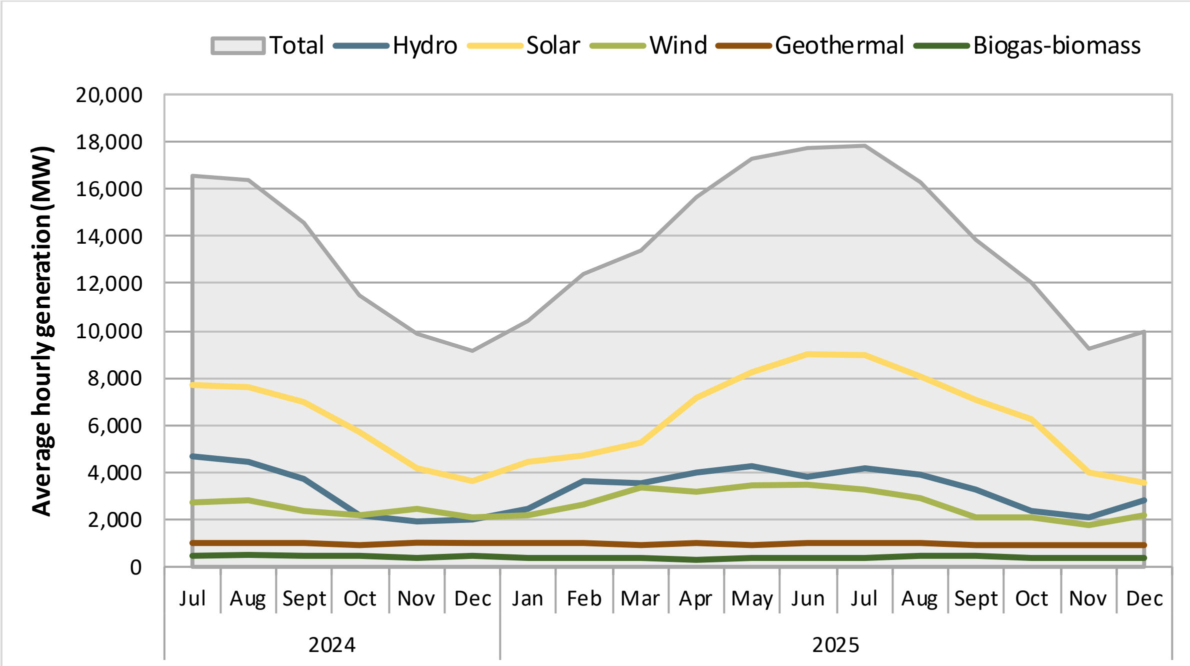


Figure 1.3 Desert Southwest - Average monthly renewable generation

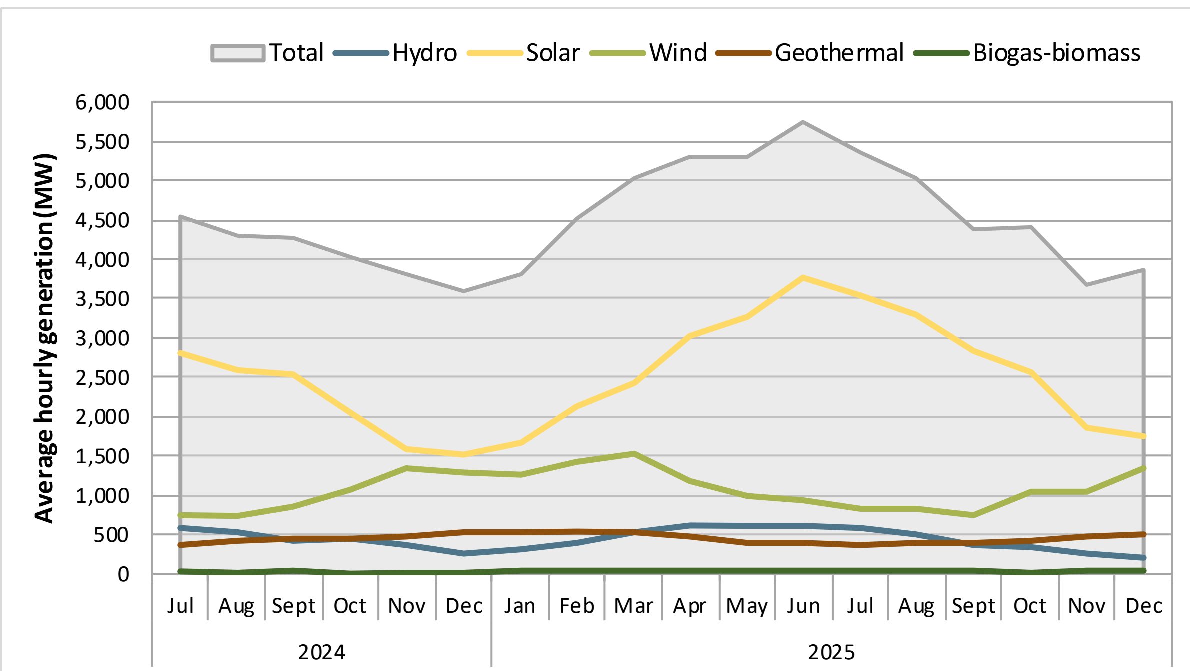


Figure 1.4 Intermountain West - Average monthly renewable generation

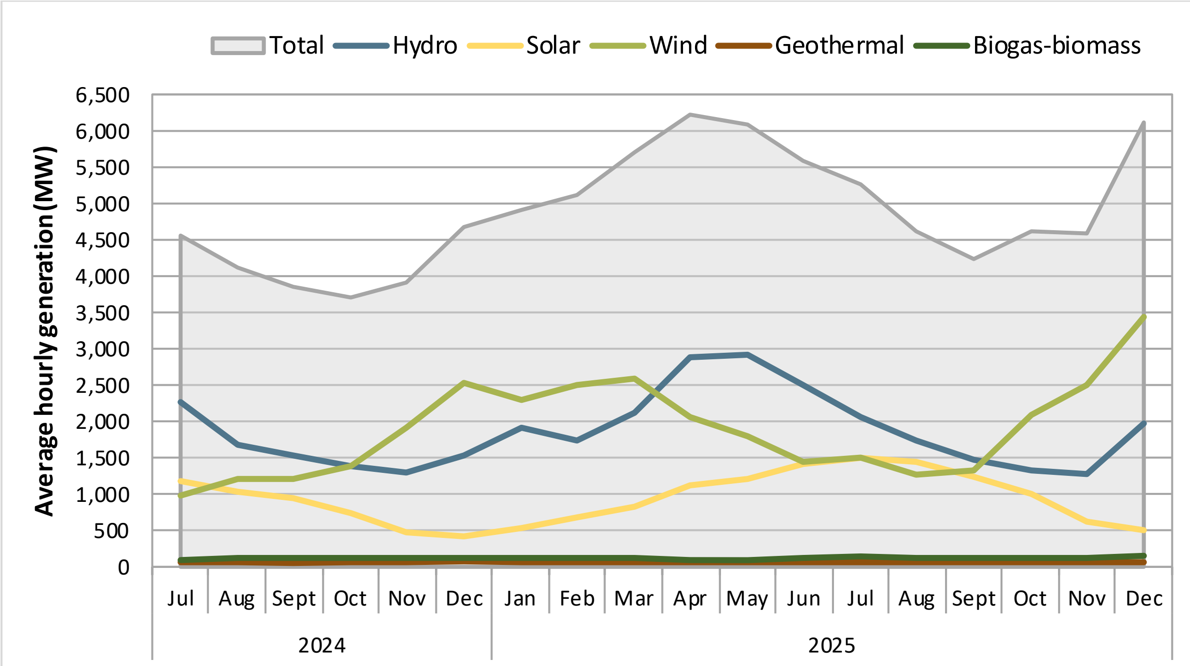


Figure 1.5 Pacific Northwest - Average monthly renewable generation

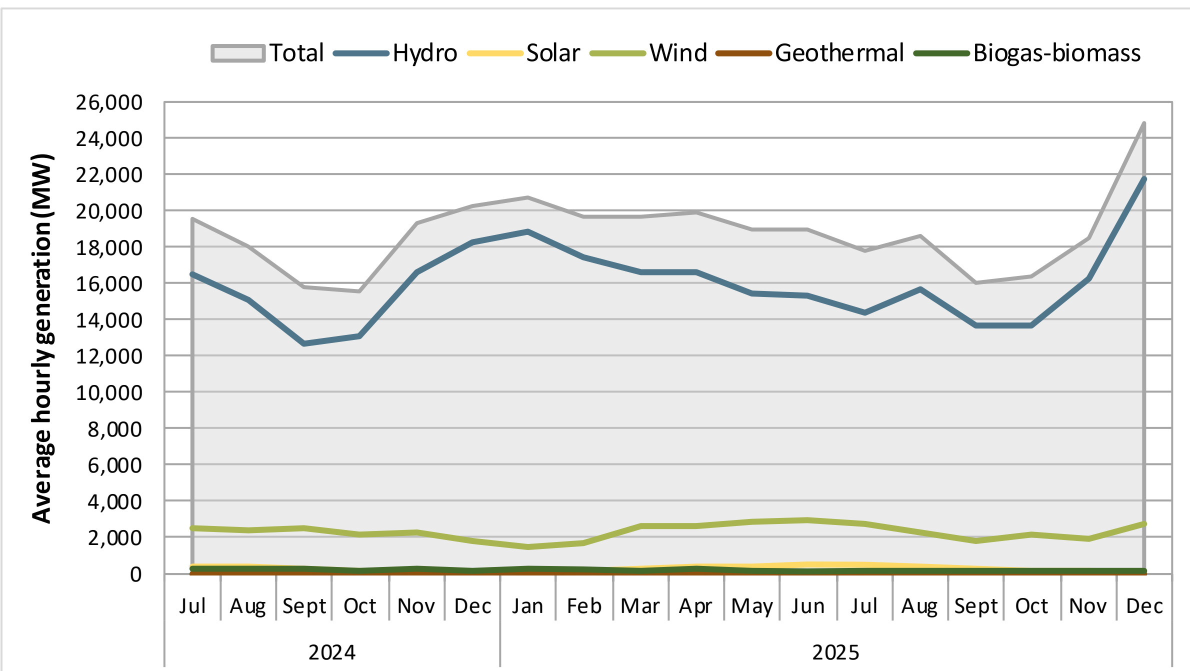
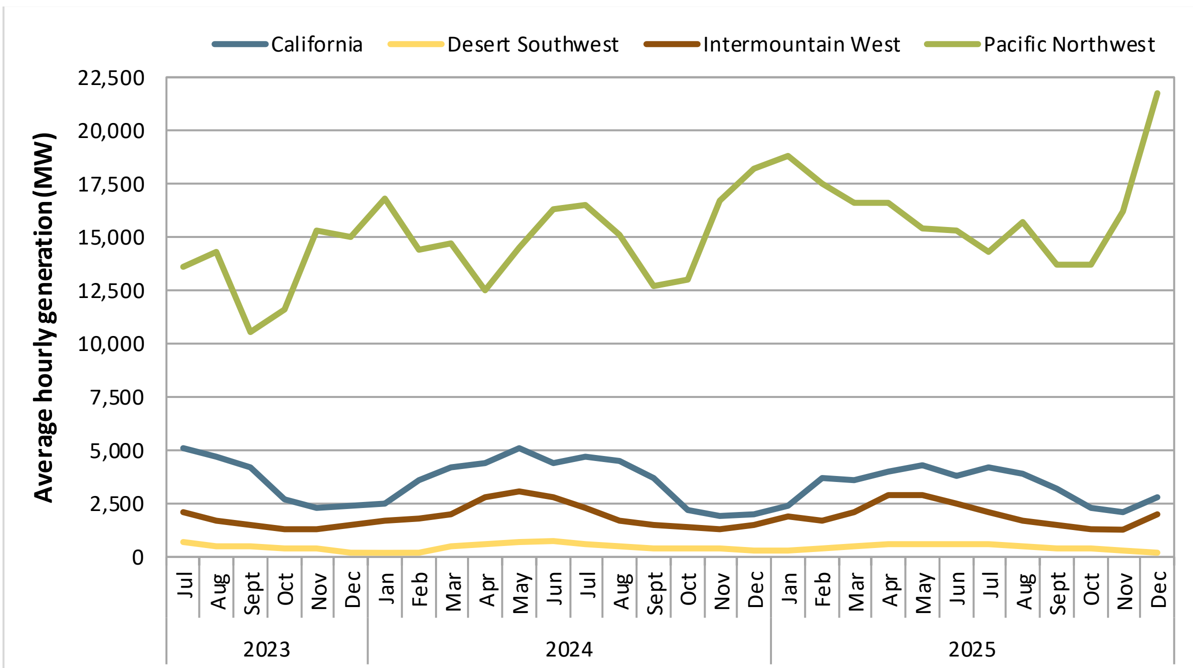


Figure 1.6 shows the monthly average hydroelectric generation from July 2023 to December 2025.

- In the California region, hydroelectric generation increased by 380 MW (19 percent) compared to the fourth quarter of 2024.
- In the Desert Southwest, hydroelectric generation decreased by 80 MW (23 percent) from the fourth quarter of 2024.
- Hydroelectric output in the Intermountain West increased by 115 MW (8 percent) compared to the fourth quarter of 2024.
- In the Pacific Northwest, hydroelectric generation in the fourth quarter of 2025 increased 1,250 MW (8 percent) compared to the same quarter of 2024, and increased 3,280 MW (24 percent) compared to the fourth quarter of 2023.

Figure 1.6 Average monthly hydroelectric generation by region



1.3 Generation by fuel type

Figure 1.7, Figure 1.9, Figure 1.11, and Figure 1.13 show the average hourly generation by fuel type during the fourth quarter of 2025 for each region in the WEIM. Figure 1.8, Figure 1.10, Figure 1.12, and Figure 1.14 show the change in hourly generation by fuel type between the fourth quarters of 2024 and 2025. Positive values represent increased generation compared to the same time last year, and negative values represent a decrease in generation. Change in total load is denoted by the black line.

Total hourly average generation peaks at hour-ending 19 in the California region and in hour-ending 18 in the Desert Southwest, Intermountain West, and Pacific Northwest regions.

As shown in Figure 1.7, there was significant solar generation (represented by the yellow bars) and corresponding load from batteries charging during mid-day hours (represented by the aqua bars below the zero-axis) in California. Natural gas generation decreased in all but hours-ending 12 and 13 in the California region. This was partially due to lower load across all hours, increased imports during morning hours, and increased battery discharge during evening hours.

Outages at coal plants and nuclear plants contributed to a decrease in coal and nuclear generation in the California region. The Intermountain Power Plant in Utah, which supplies energy to LADWP, officially finalized its transition from coal to natural gas in December 2025, also contributing to a decrease in coal generation in the California region.[6]

Natural gas remained the largest source of generation in the Desert Southwest, although it decreased in the afternoon and evening hours compared to the fourth quarter of 2024. The Desert Southwest saw large increases in solar generation and corresponding battery charging in the solar hours and discharging in evening and early morning hours. Net imports decreased (i.e., net exports increased) by an average of 350 MW (33 percent) across all hours; the largest reductions occurred in the evening hours during increased battery discharging.

In the Intermountain West, coal and natural gas continued to be the largest overall sources of generation in the fourth quarter of 2025. Solar generation displaced small amounts of coal generation during mid-day hours, but coal generation increased in non-solar hours. Wind generation increased by an hourly average of 710 MW (36 percent) compared to Q4 2024. Exports increased significantly, by an average of 680 MW (780 percent) each hour, as the Intermountain West shifted from being a net importer in most hours of the fourth quarter of 2024 to a net exporter in all hours of the fourth quarter of 2025.

Hydroelectric generation dominated the generation mix in the Pacific Northwest, accounting for about 70 percent of total generation, as shown in Figure 1.13, and increasing by about 1,270 MW (8 percent) in each hour year-over-year. Net imports and natural gas generation decreased across all hours.

6 See https://www.latimes.com/environment/story/2025-12-04/los-angeles-says-so-long-to-coal and https://ipprenewed.com/ for more information.

Figure 1.7 California - Average hourly generation by fuel type (Q4 2025)

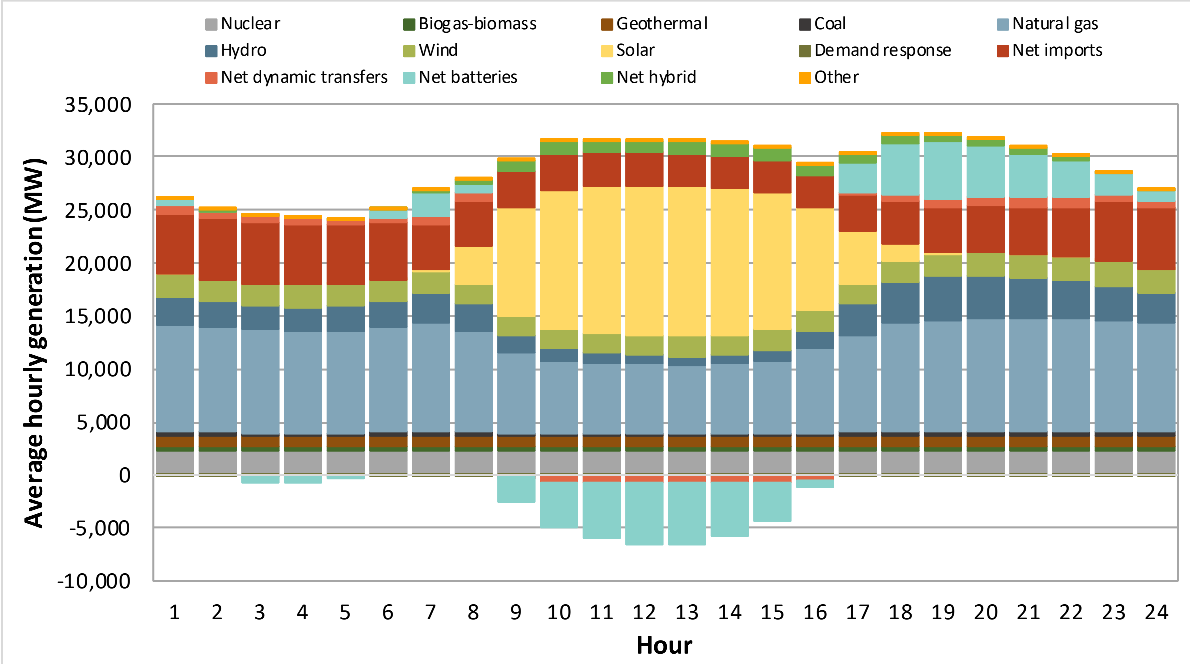


Figure 1.8 California - Change in average hourly generation by fuel type (Q4 2025 vs. Q4 2024)

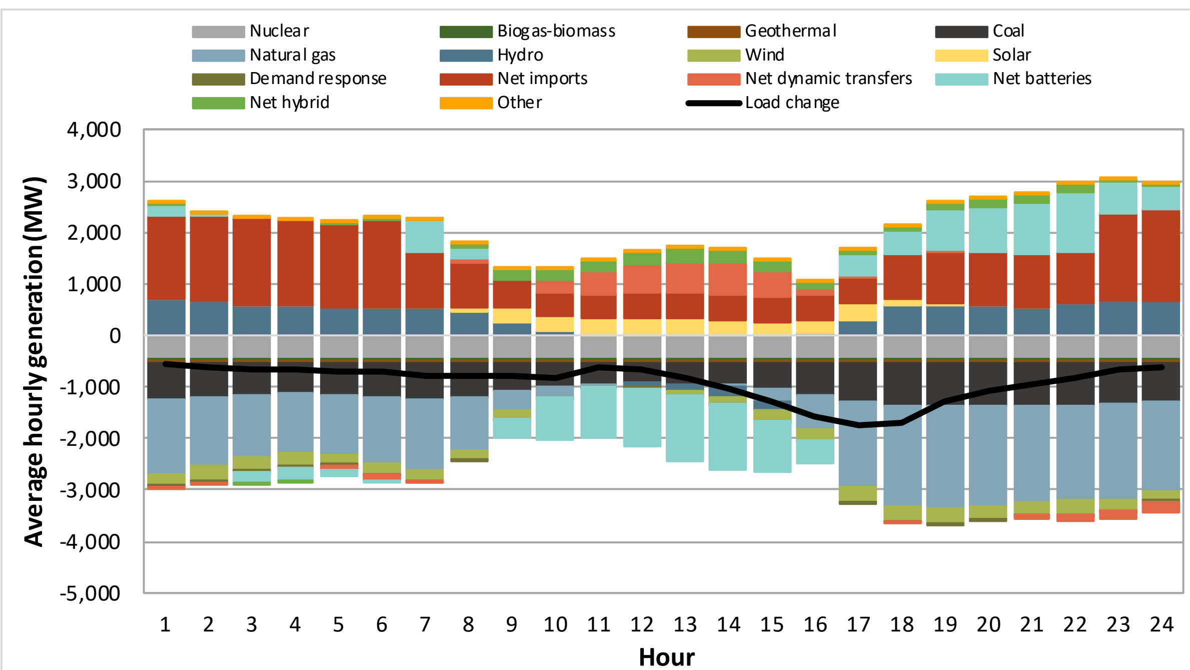


Figure 1.9 Desert Southwest - Average hourly generation by fuel type (Q4 2025)

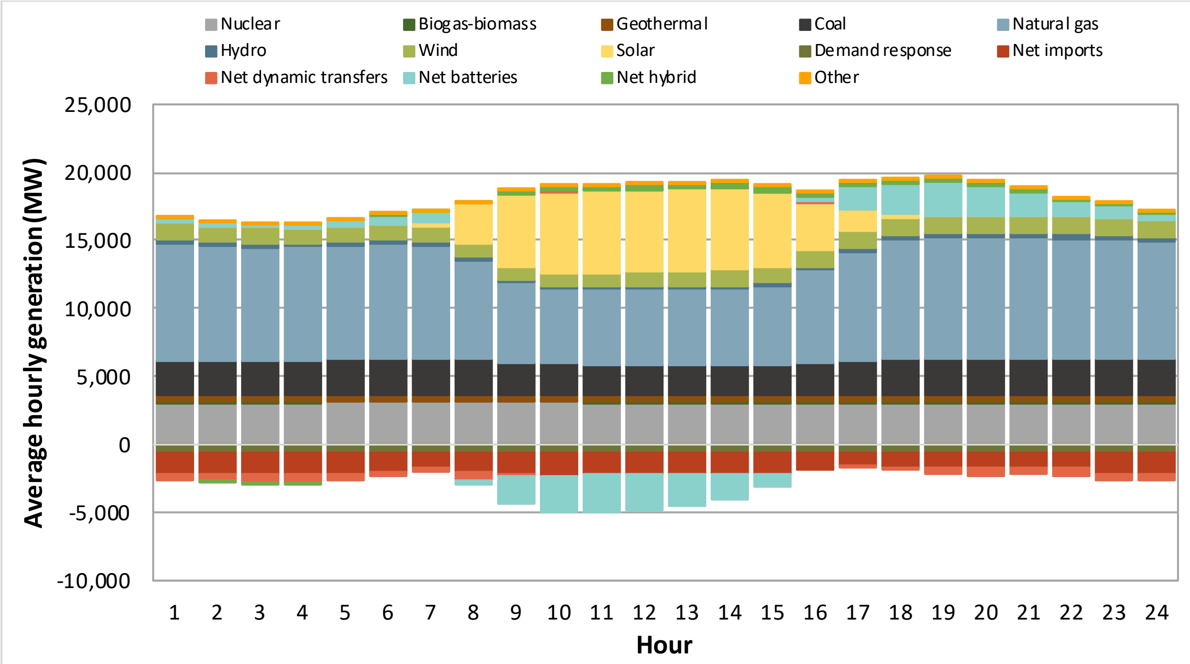


Figure 1.10 Desert Southwest - Change in average hourly generation by fuel type (Q4 2025 vs. Q4 2024)

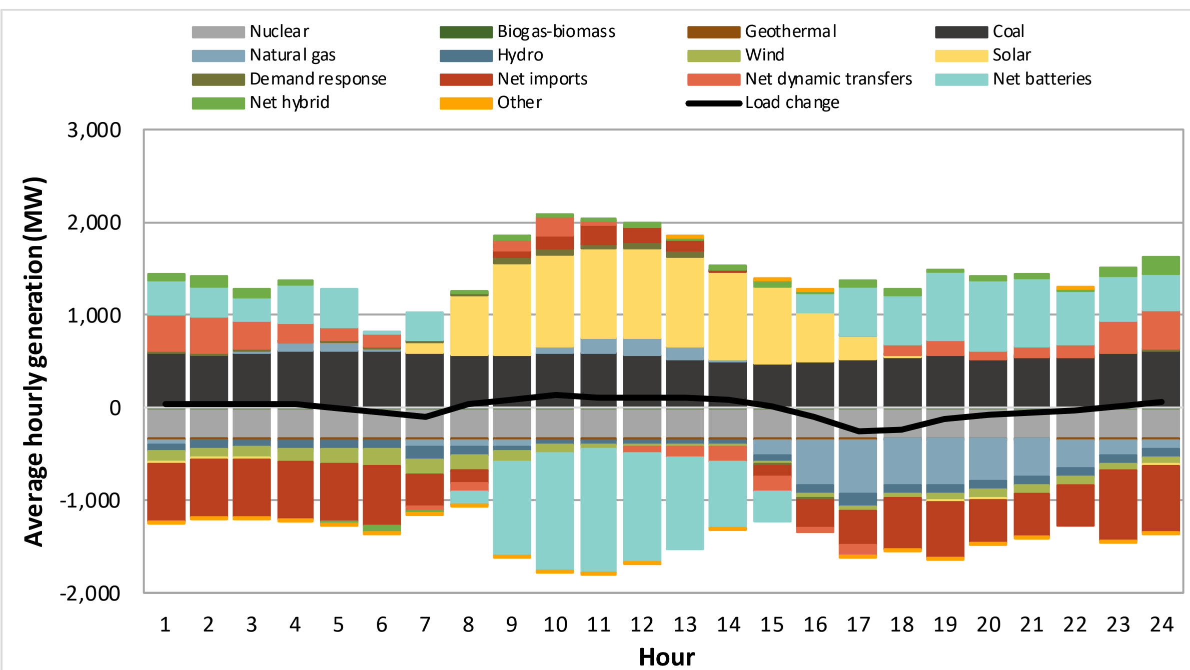


Figure 1.11 Intermountain West - Average hourly generation by fuel type (Q4 2025)

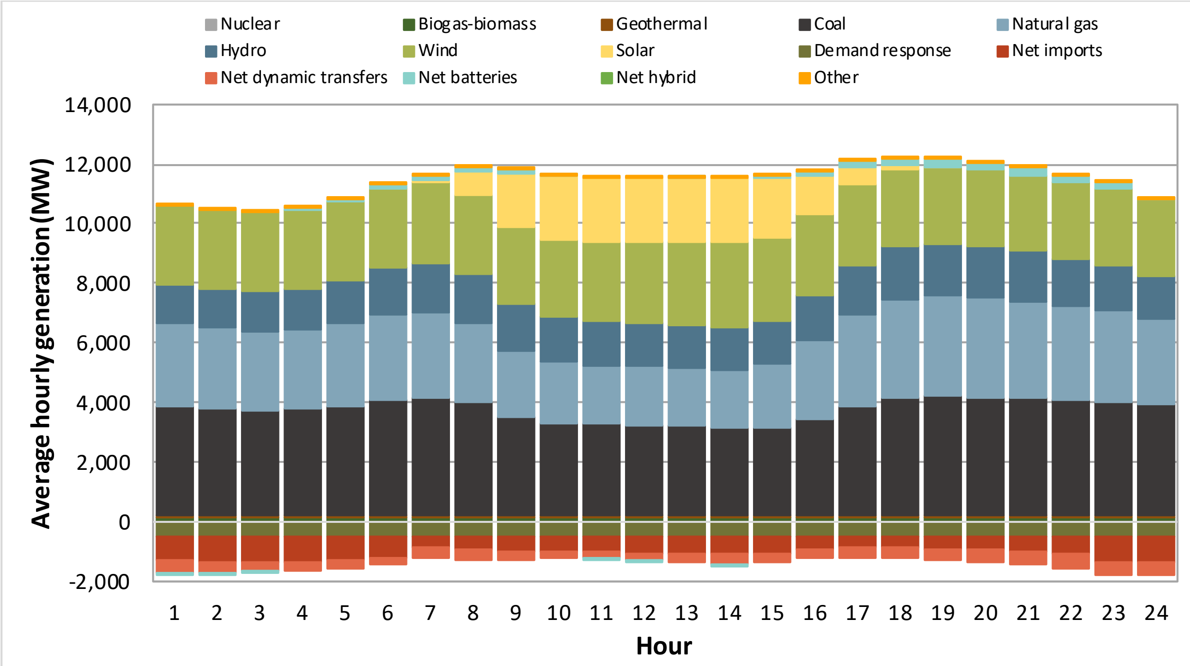


Figure 1.12 Intermountain West - Change in average hourly generation by fuel type (Q4 2025 vs. Q4 2024)

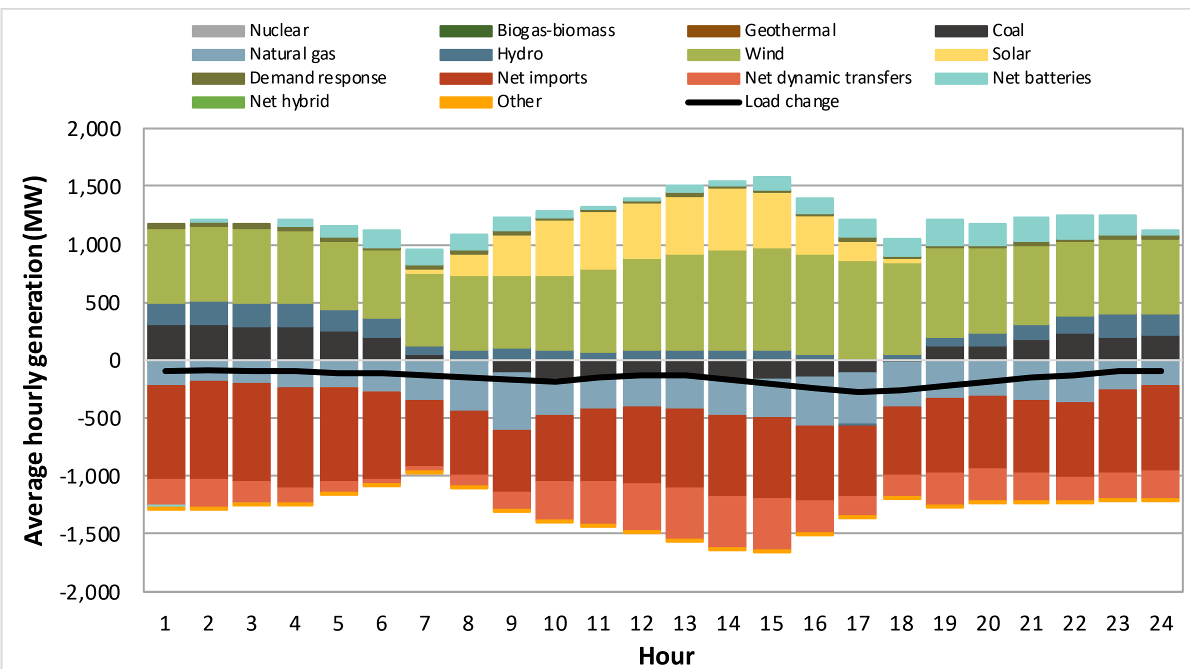


Figure 1.13 Pacific Northwest - Average hourly generation by fuel type (Q4 2025)

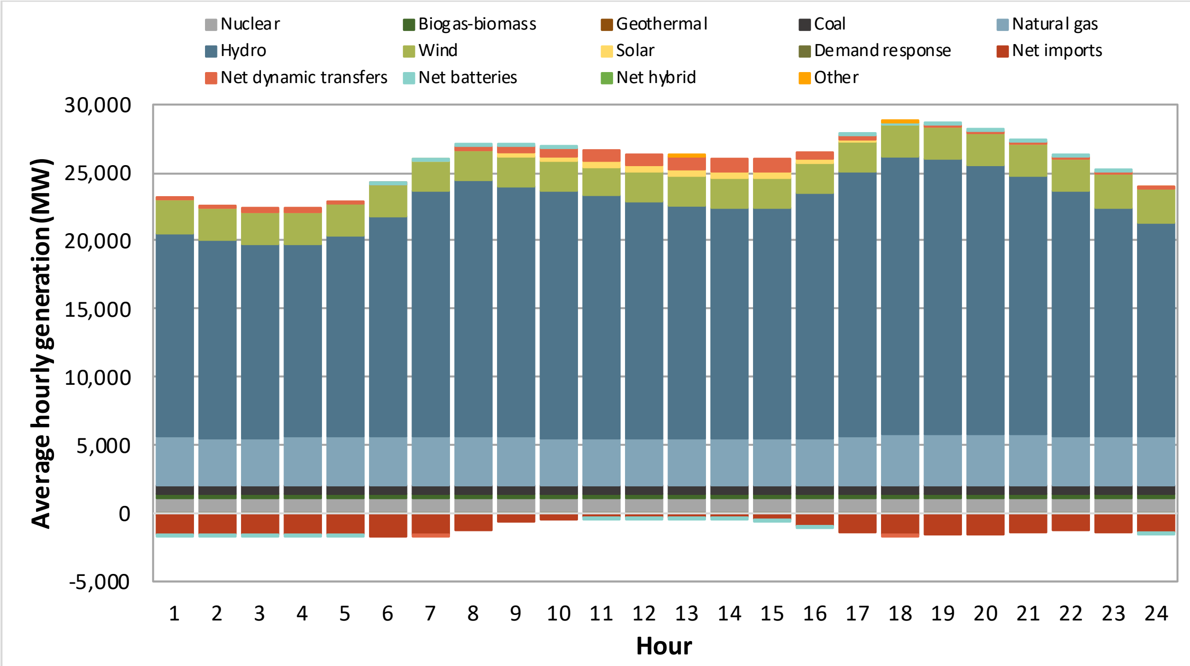
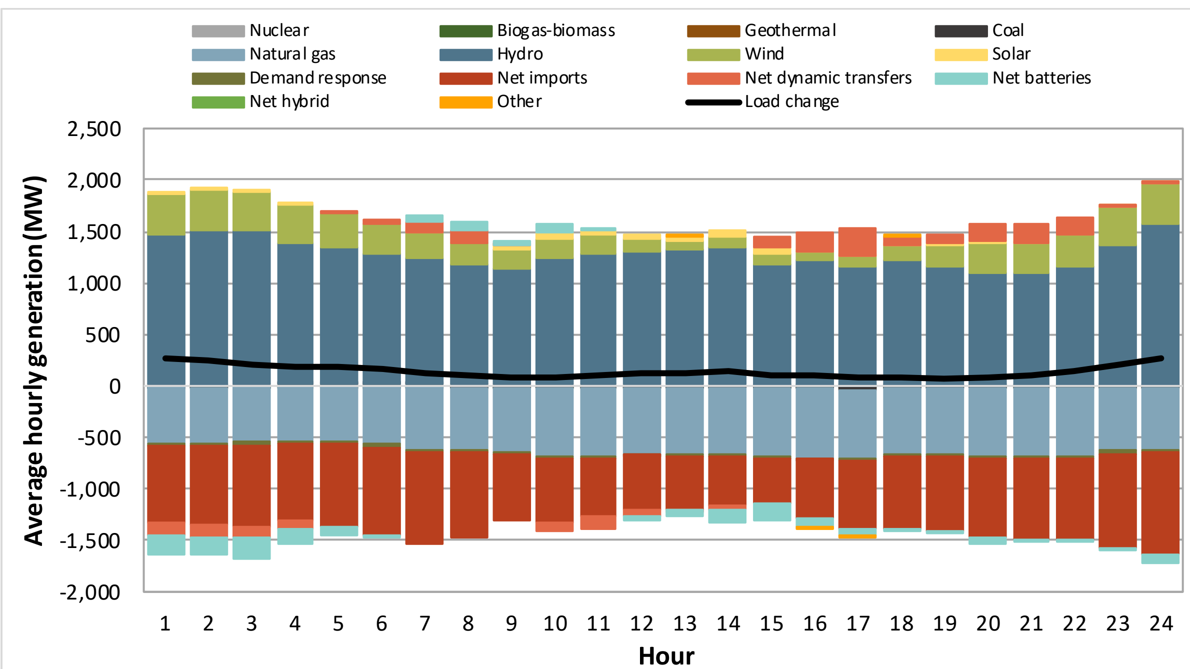


Figure 1.14 Pacific Northwest - Change in average hourly generation by fuel type (Q4 2025 vs. Q4 2024)



1.4 Interchange

Figure 1.15 to Figure 1.22 show average 5-minute market imports, exports, and WEIM transfers (collectively, "interchange") for each region in the WEIM. For each region, the first figure shows the total imports and exports, while the second figure shows only the net interchange.[7] Power flowing into a balancing area is represented as a positive value, while power flowing out of a balancing area is shown as negative. This energy is categorized as follows:

- **Interchange before dynamic transfers** (black line) represents the net interchange into the region before accounting for dynamic WEIM transfers. This includes:
    - **Base WEIM intertie schedules** (stacked blue bars) are fixed intertie transactions between two non-CAISO balancing areas within the WEIM. These transfers are not optimized in the market.
    - **Non-WEIM intertie schedules** (stacked aqua bars) are fixed intertie transactions between a WEIM and a non-WEIM balancing area. These transfers are not optimized in the market.
    - **CAISO intertie schedules** (stacked green bars) are import and export schedules into or out of the CAISO balancing area that result from bid-in or self-scheduled participation in the market.[8] Most CAISO intertie schedules are scheduled in hourly blocks where the hour-ahead scheduling process (HASP) is the final opportunity for these schedules to be optimized in the market.[9]
- **Interchange after dynamic transfers** (red line) represents the final net interchange into and out of all balancing areas, including WEIM transfers that are optimized in the market. This includes the categories above, plus:
    - **Dynamic WEIM transfers** (stacked gold bars) are energy transfers between any two WEIM balancing areas that are optimized in the real-time market.[10]

In comparing the fourth quarters of 2024 and 2025, net interchange after dynamic transfers (red line) increased in California by approximately 1,130 MW (32 percent), and decreased (i.e., net exports increased) in the Desert Southwest by about 240 MW (17 percent), Intermountain West by roughly 920 MW, and Pacific Northwest by about 690 MW. These decreases reflect significant shifts toward net

7 For the total import and export figures, interchange between two balancing areas within the same region is counted as both an import and an export. For example, a 200 MW base WEIM transfer from Arizona Public Service to Salt River Project within the Desert Southwest appears as a 200 MW export for AZPS and a 200 MW import for SRP in the region's total interchange figure. The net interchange figures show only the region's net flow, so this transfer would net to zero and would not appear in the net interchange figure.

8 This category includes all schedules from mirror system resources (MSRs). For CAISO intertie schedules with a WEIM balancing area, a mirror system resource reflects the WEIM balancing area perspective of the intertie schedule. For example, if the hour-ahead scheduling process (HASP) clears a 50 MW import schedule for CAISO on an intertie that includes NV Energy, an equal 50 MW export schedule will be shown on the mirror system resource from NV Energy. Both sides of the intertie schedule are accounted for in these figures.

9 A small subset of CAISO intertie schedules can be modified and optimized in the 15-minute market.

10 This category also includes static transfers, which are optimized in the 15-minute market but held fixed in the 5-minute market.

exports in the Intermountain West and Pacific Northwest, consistent with Figures 1.20 and 1.22, which show both regions moving from net imports in Q4 2024 to net exports across nearly all hours in Q4 2025. The increase in net exports in the Intermountain West and Pacific Northwest was likely due to increases in wind and solar generation as well as hydroelectric generation during all hours in the respective regions.

Figure 1.15 California - Average hourly interchange by quarter

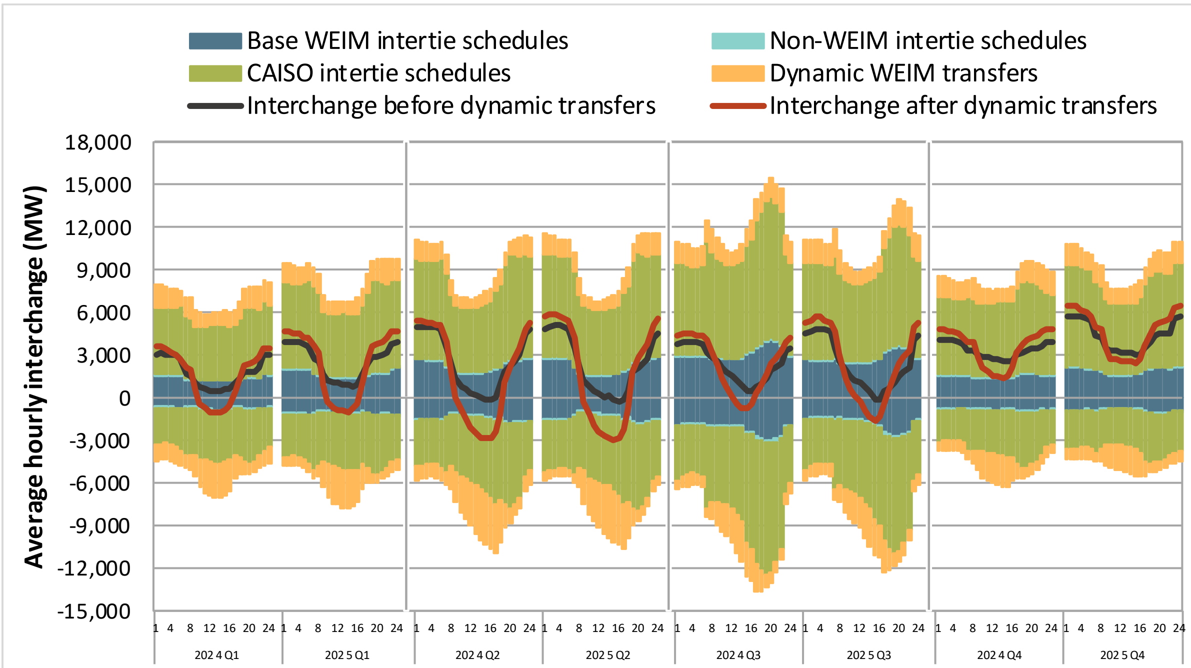


Figure 1.16 California - Average hourly net interchange by quarter

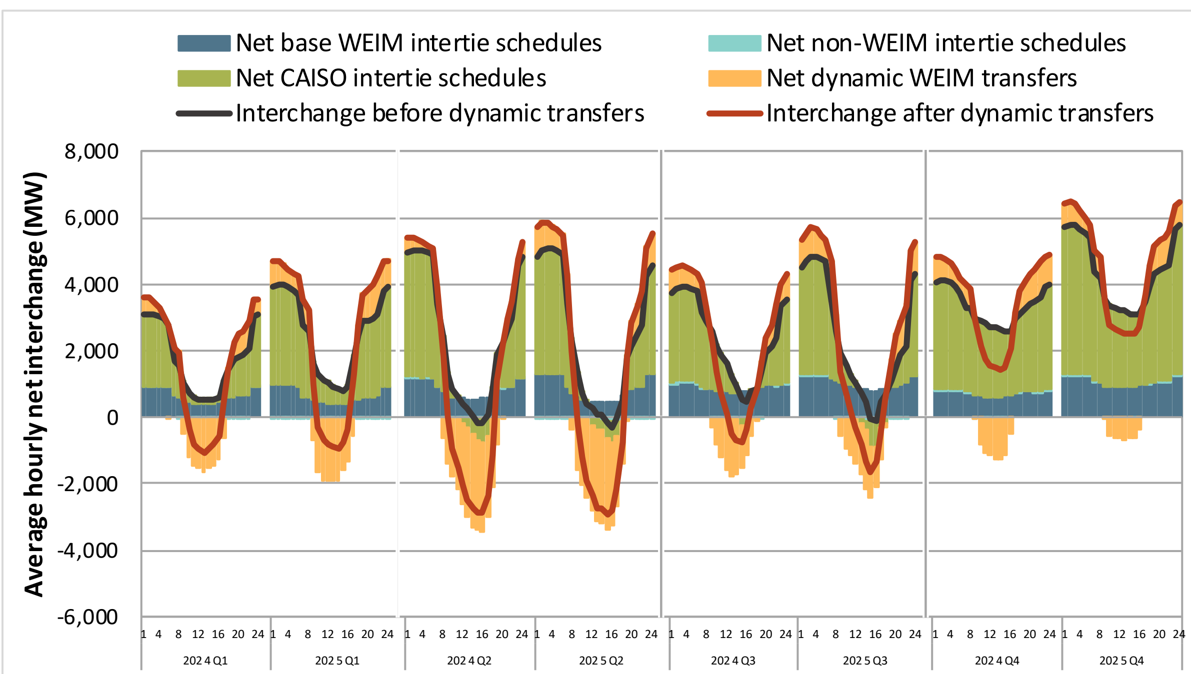


Figure 1.17 Desert Southwest - Average hourly interchange by quarter

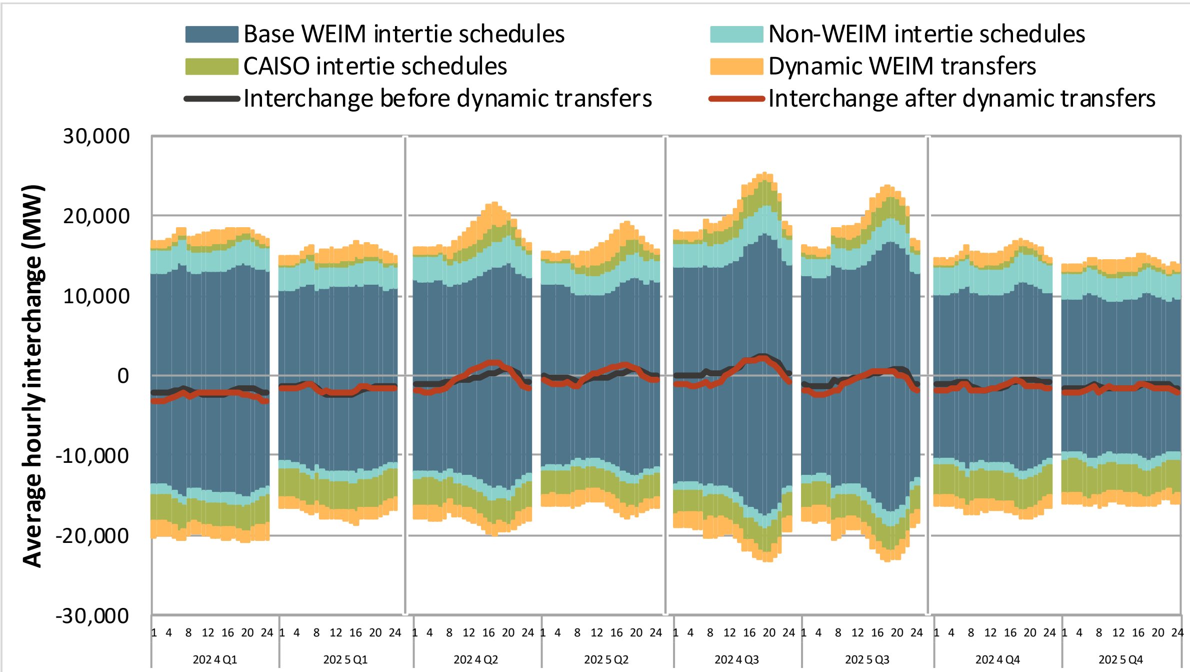


Figure 1.18 Desert Southwest - Average hourly net interchange by quarter

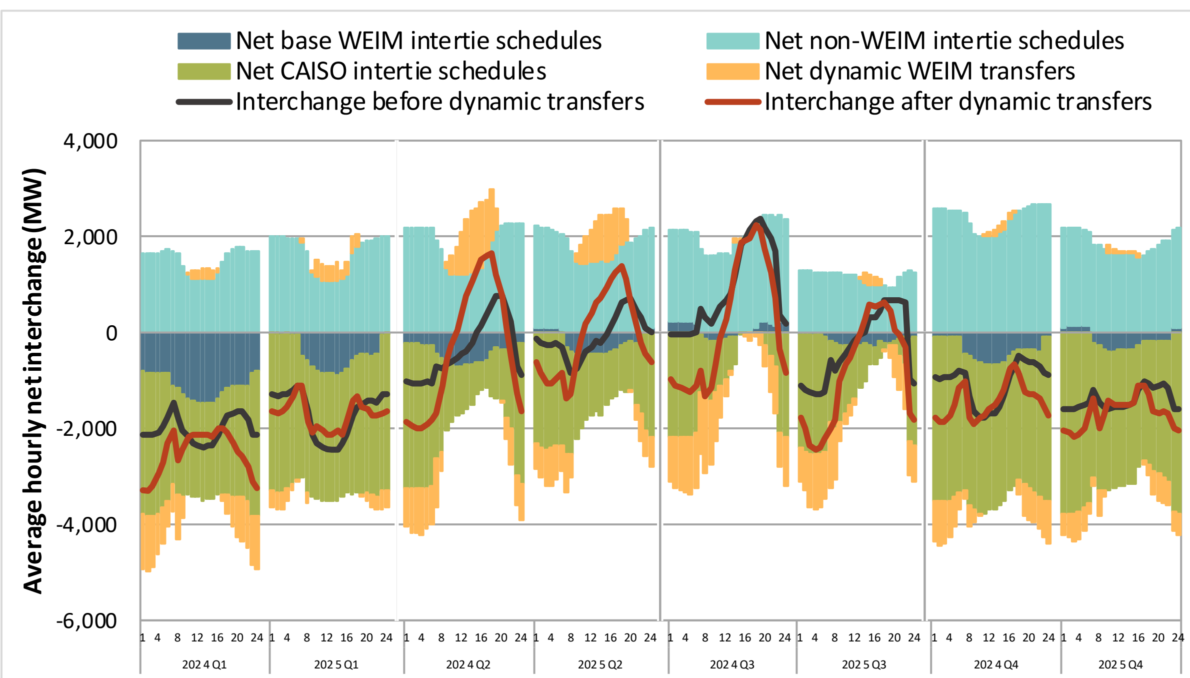


Figure 1.19 Intermountain West - Average hourly interchange by quarter

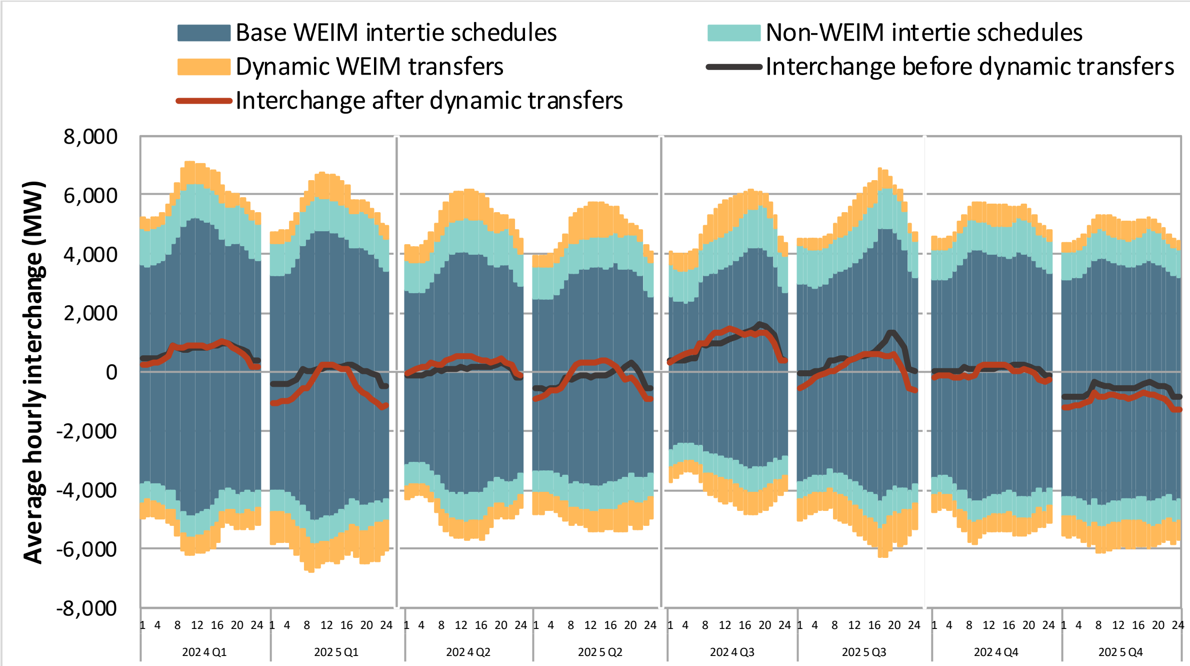


Figure 1.20 Intermountain West - Average hourly net interchange by quarter

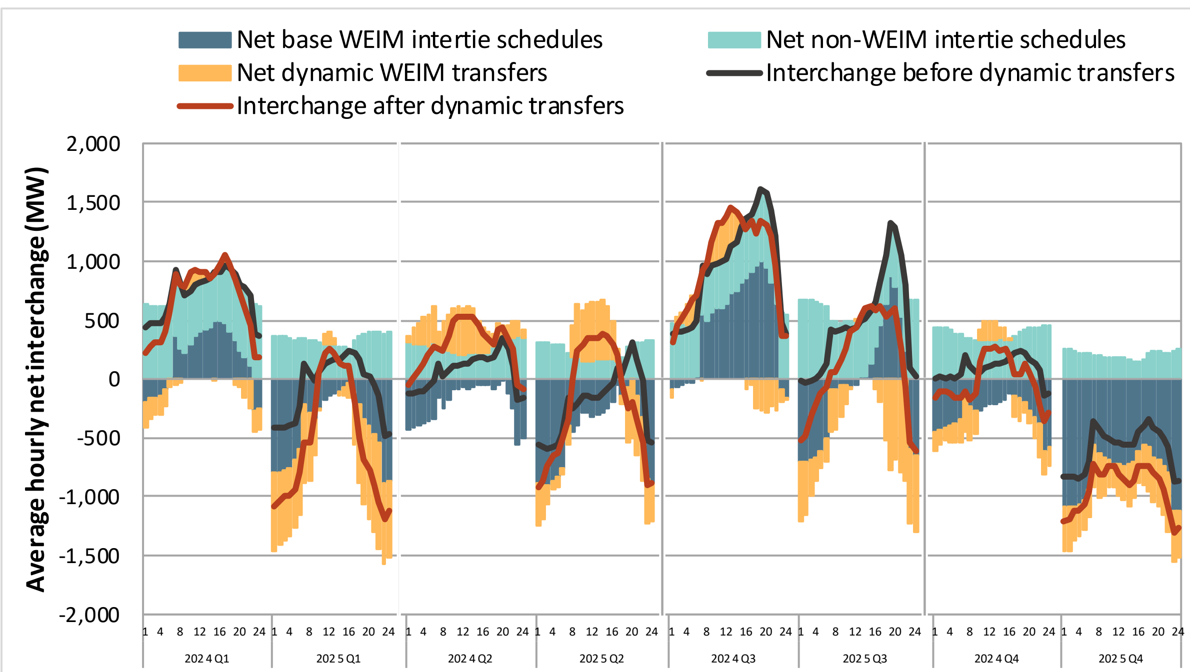


Figure 1.21 Pacific Northwest - Average hourly interchange by quarter

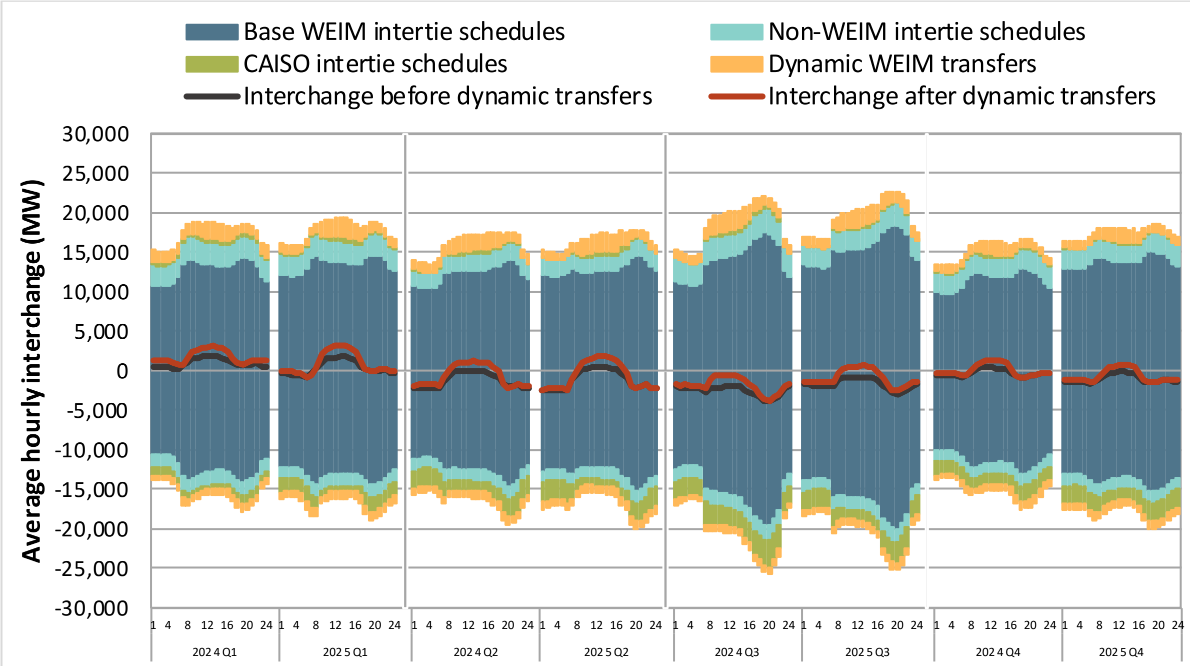
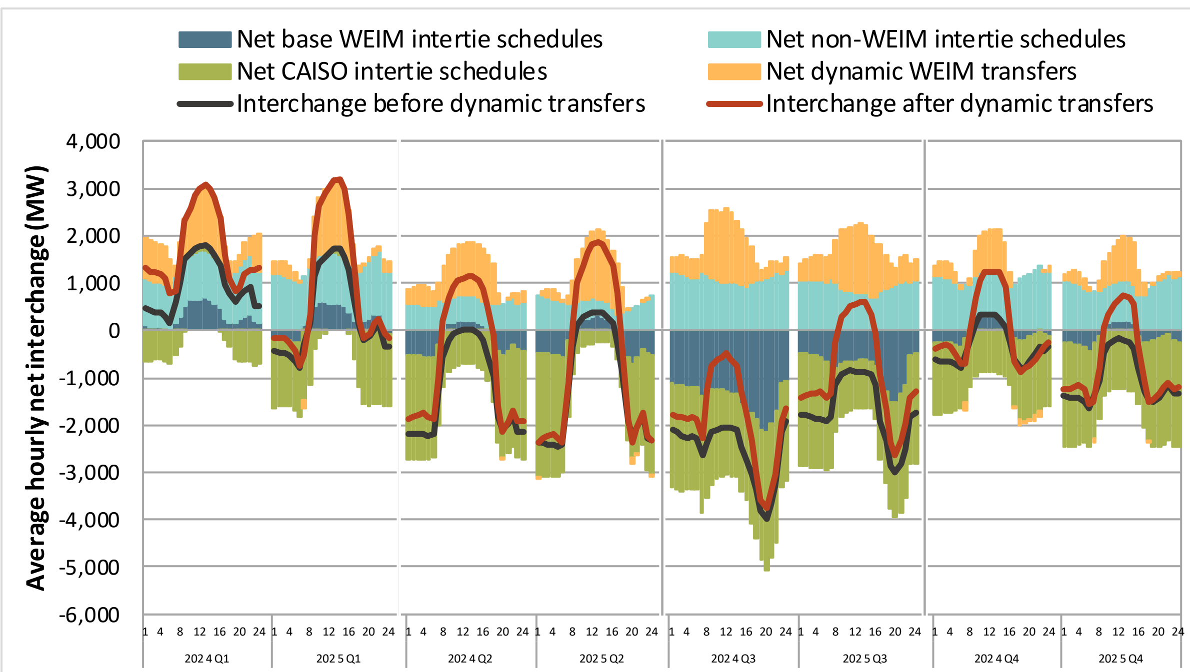


Figure 1.22 Pacific Northwest - Average hourly net interchange by quarter



1.5 Generation outages

This section covers information on generation outages in the California ISO balancing area and the WEIM by region.[11,12] The average generation on outage in the California ISO balancing area was 15,700 MW in the fourth quarter of 2025, which remained essentially flat compared to the fourth quarter of 2024.[13] In the California (non-CAISO) region of the WEIM, outages averaged about 5,000 MW, an increase of about 500 MW from the fourth quarter of 2024. The Desert Southwest region averaged about 11,300 MW of total generation outages, a 16 percent increase from the fourth quarter of 2024. The Intermountain West region averaged about 2,700 MW of total generation outages, a 13 percent increase from the fourth quarter of 2024. The Pacific Northwest region averaged about 3,200 MW of total generation outages, about a three percent decrease from the fourth quarter of 2024.

Under the current California ISO outage management system, known as WebOMS, all outages are categorized as either "planned" or "forced". An outage is considered *planned* if a participant submitted it more than seven days prior to the beginning of the outage. WebOMS has a menu of subcategories indicating the reason for the outage. Examples of such categories include plant maintenance, plant trouble, ambient due to temperature, ambient not due to temperature, unit testing, environmental restrictions, transmission induced, transitional limitations, and unit cycling.

1.5.1 Generation outages by region

California ISO balancing area

Figure 1.23 and Figure 1.24 show the quarterly and monthly averages for the California ISO balancing area, respectively, of maximum daily outages during peak hours by type from the first quarter of 2023 through the fourth quarter of 2025. The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period. Looking at the monthly outages presented in Figure 1.24, there are usually more outages in the fall, winter, and early spring than in the summer months, and this trend continued in the fourth quarter of 2025.

During the fourth quarter of 2025, the average total generation on outage in the California ISO balancing area was 15,700 MW, which remained essentially flat compared to the fourth quarter of 2024, as shown in Figure 1.23. Forced maintenance and plant trouble outages decreased by about 1 percent when compared to the same quarter last year. Other forced outages increased by about 3 percent, an increase of about 230 MW. Planned maintenance outages and other planned outages decreased by 5 percent,

[11] The data for 2024 has been updated from 2024 quarterly reports to reflect the new accounting method used to exclude outages of available California Strategic Reliability Reserve participating resource capacity that were submitted to prevent these units from being committed and dispatched by the market. As a result, the total outages reported here for 2024 will be lower for those periods than reported in 2024 reports.

[12] WEIM regions are as follows: California includes BANC, CISO, LADWP, and TIDC. Desert Southwest includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC. Intermountain West includes AVA, IPCO, NWMT, and PACE. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

[13] This is calculated as the average of the daily maximum level of outages, excluding off-peak hours, and excludes the outages used to prevent California Strategic Reliability Reserve participating resource capacity from being committed and dispatched by the market.

about 135 MW on average, and by 8 percent, about 100 MW on average, respectively, compared to the same quarter last year.

Figure 1.23 CAISO balancing area quarterly average of maximum daily generation outages by type – peak hours

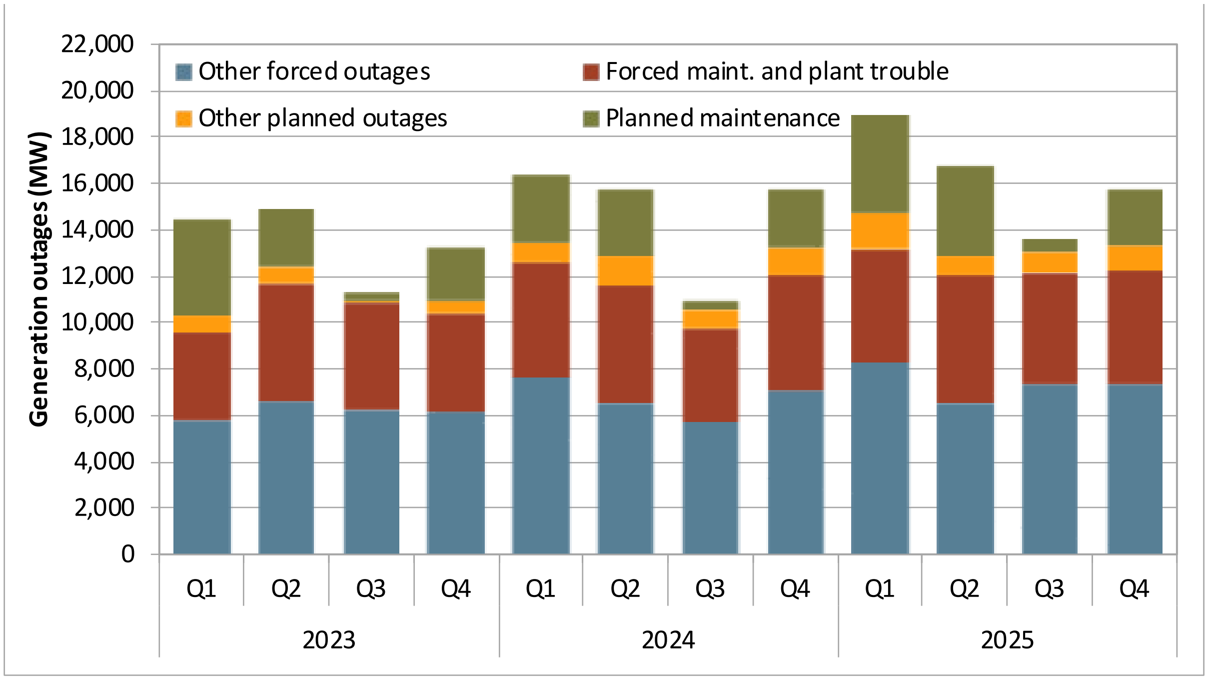
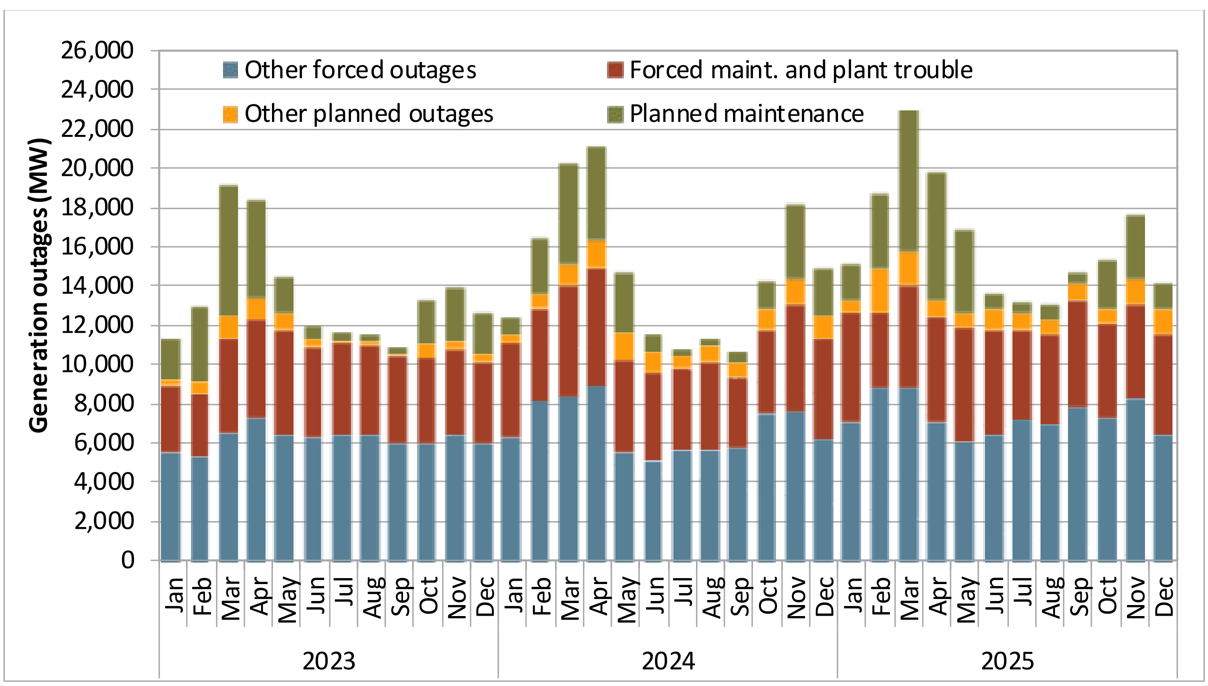


Figure 1.24 CAISO balancing area monthly average of maximum daily generation outages by type – peak hours

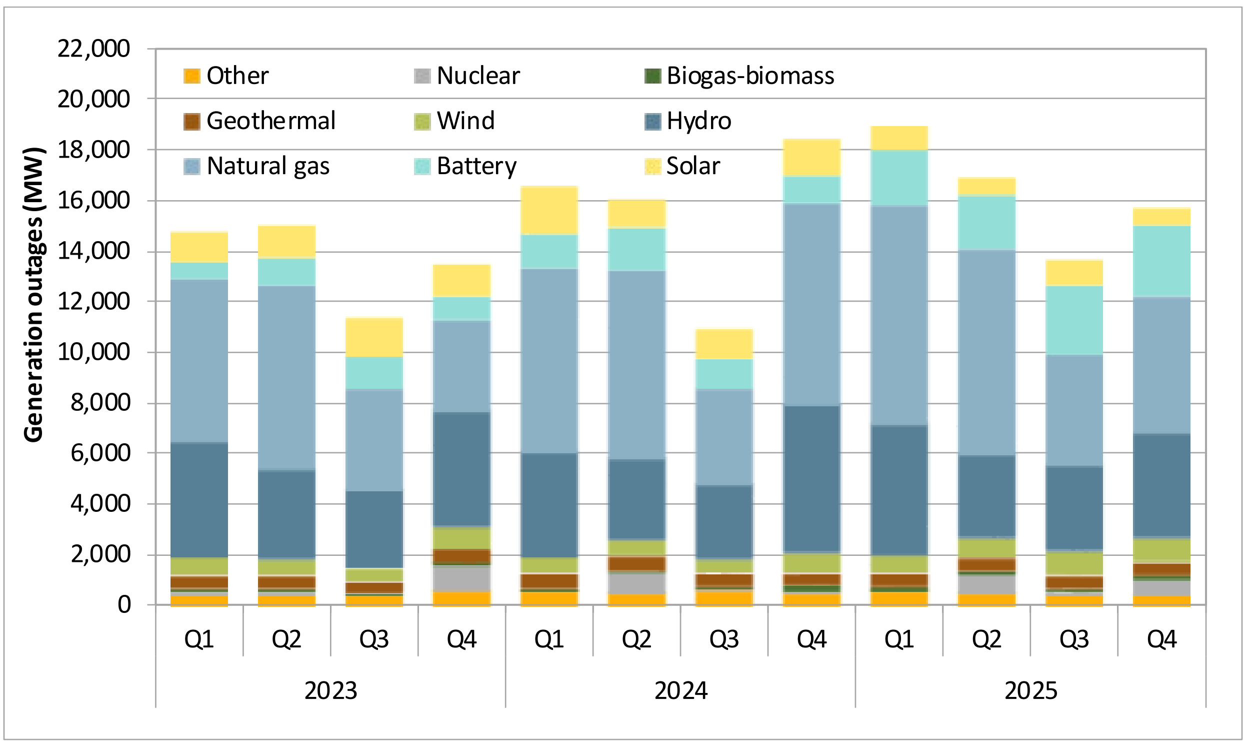


Natural gas, hydroelectric generation, and batteries had the largest volume of outages in the fourth quarter of 2025 and averaged about 5,400 MW, 4,200 MW, and 2,800 MW, respectively. These three fuel types accounted for a combined 79 percent of the generation outages for the quarter. The amount of natural gas generation outages decreased 32 percent relative to the fourth quarter of 2024.

The quarterly average megawatts of battery storage resources on outage increased by 150 percent in the fourth quarter of 2025 compared to the fourth quarter of 2024. The year-over-year increase is partially due to the loss of a number of large storage resources during a fire that occurred in the first quarter of 2025.

Figure 1.25 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[14] Nuclear, wind, battery storage, and geothermal outages increased compared to the fourth quarter of 2024, while outages for all other fuel types decreased.

Figure 1.25 CAISO balancing area quarterly average of maximum daily generation outages by fuel type – peak hours



California (non-CAISO) region

Figure 1.26 and Figure 1.27 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2025 for resources in the California WEIM region, excluding the CAISO balancing area.[15] The typical

[14] In this figure, the "Other" category contains demand response, coal, and additional resources of unique technologies.

[15] The California region includes BANC, LADWP, and TIDC.

seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2025. Average total outages in the fourth quarter were about 5,100 MW, comparable to the fourth quarter of 2024. Planned maintenance outages increased by about 29 percent while other forced outages increased by 6 percent. Outages from natural gas resources increased by about 16 percent.

Figure 1.26 California WEIM region quarterly average of maximum daily generation outages by type – peak hours

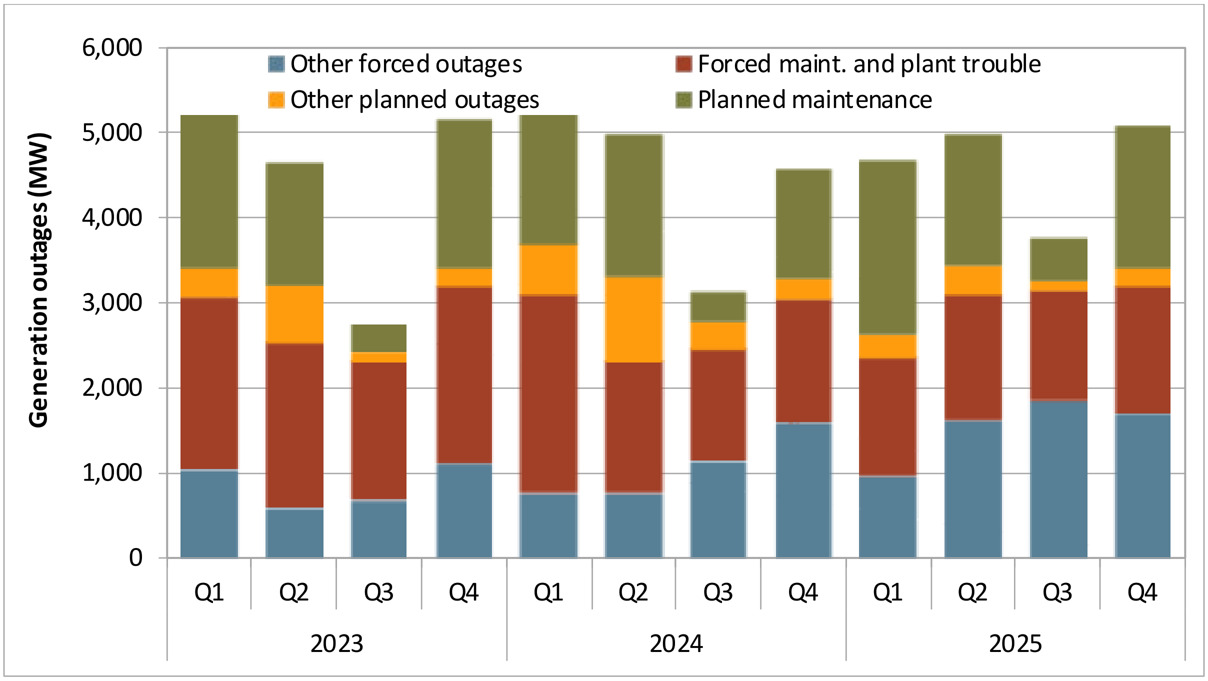
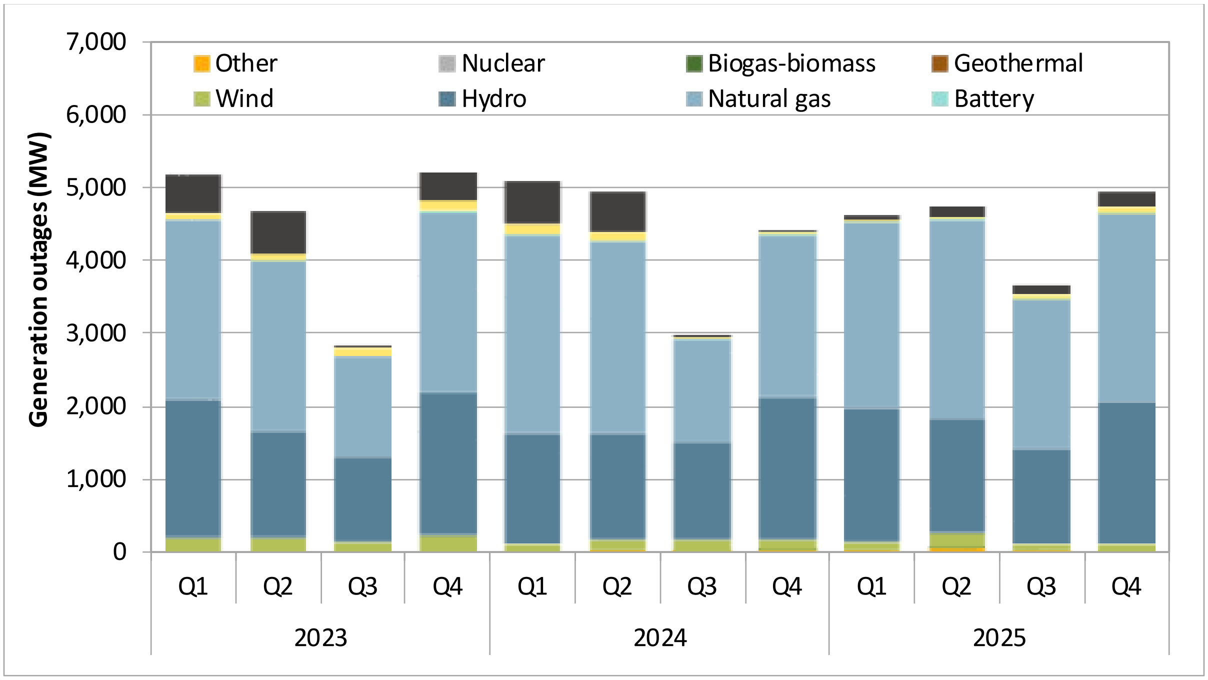


Figure 1.27 California WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Desert Southwest

Figure 1.28 and Figure 1.29 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2025 for entities in the Desert Southwest WEIM region.[16] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in the fourth quarter of 2025. Average total outages increased by approximately 1,600 MW, or 16 percent, compared to the fourth quarter of 2024. The year-over-year increase was primarily driven by increases in natural gas outages.

[16] The Desert Southwest region includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC.

Figure 1.28 Desert Southwest WEIM region quarterly average of maximum daily generation outages by type – peak hours

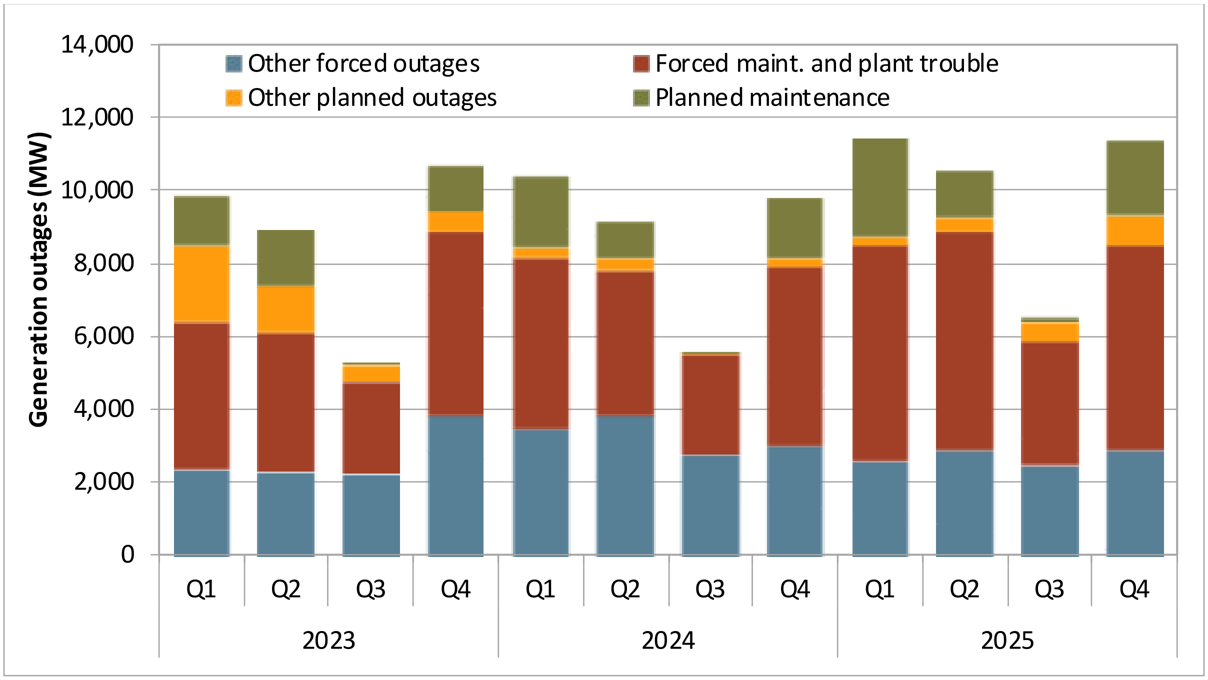
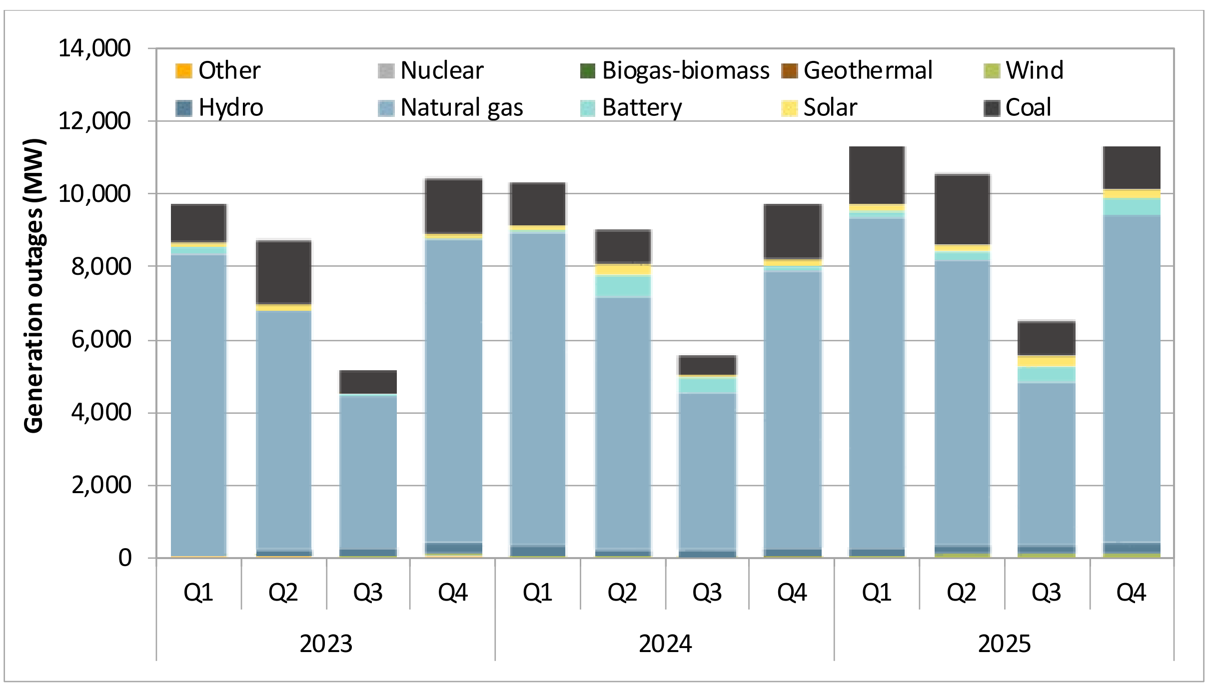


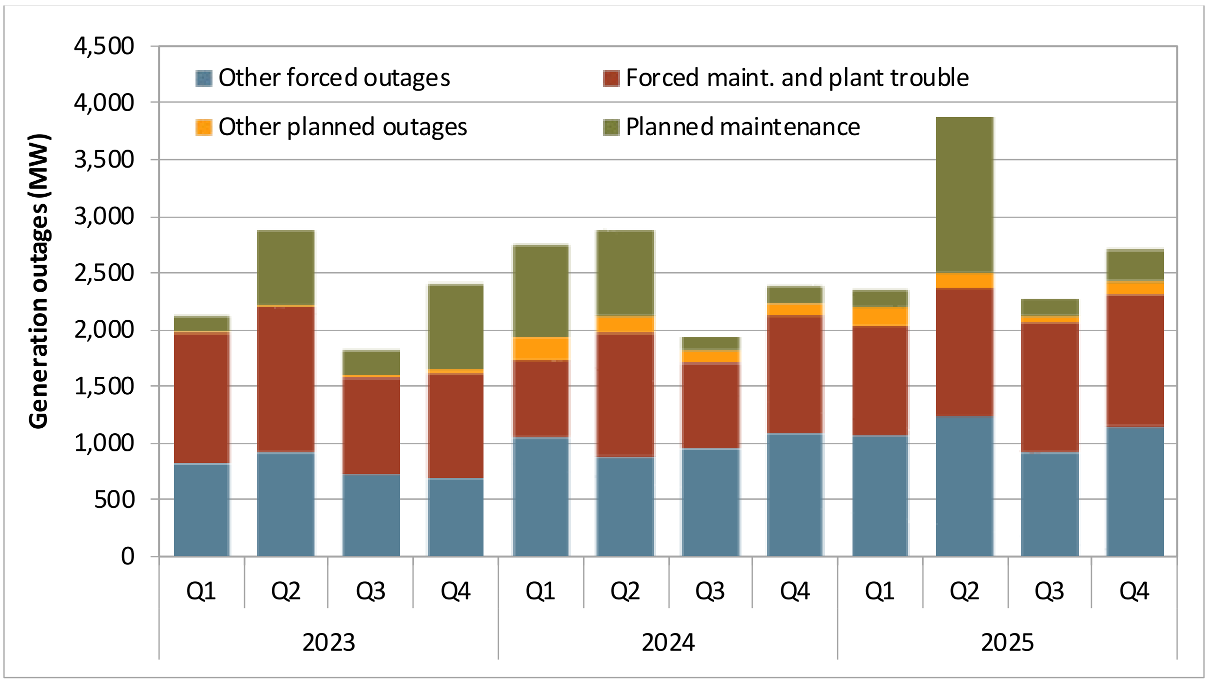
Figure 1.29 Desert Southwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Intermountain West

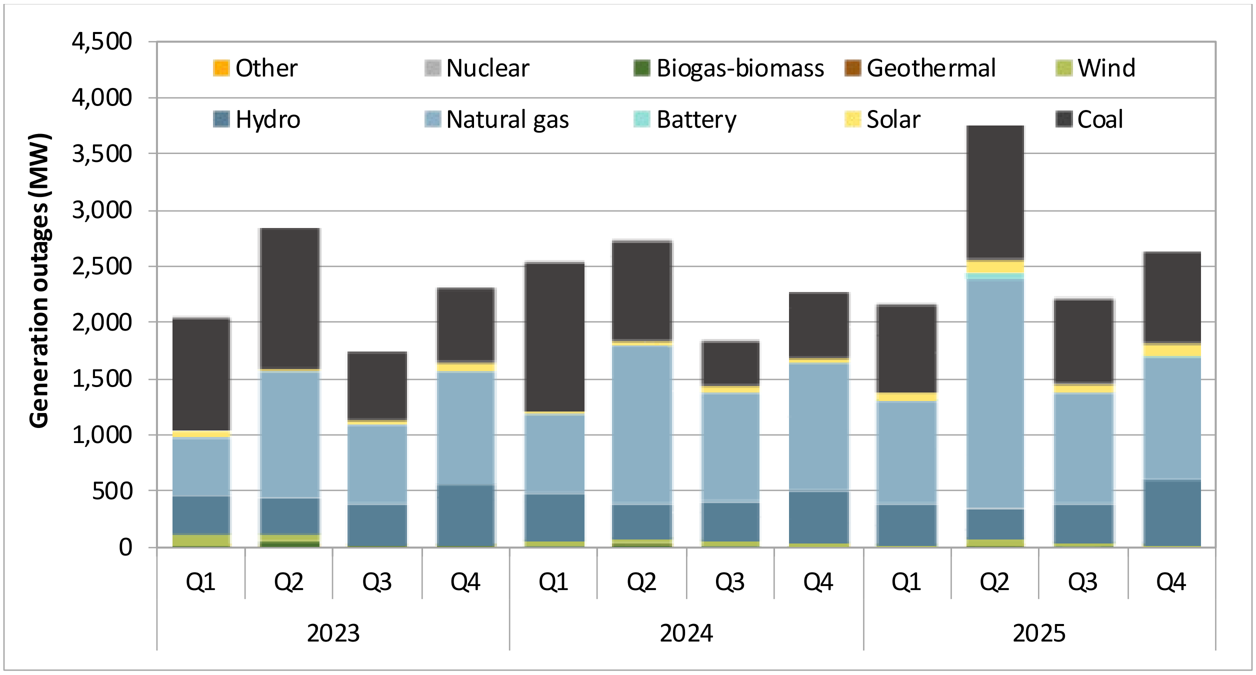
Figure 1.30 and Figure 1.31 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2025 for entities in the Intermountain West WEIM region.[17] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2025. Average total outages increased by approximately 370 MW or 16 percent, mainly driven by an increase in coal generation outages in the fourth quarter of 2025 compared to the fourth quarter of 2024.

Figure 1.30 Intermountain West WEIM region quarterly average of maximum daily generation outages by type – peak hours



17 The Intermountain West region includes AVA, IPCO, NWMT, and PACE.

Figure 1.31 Intermountain West WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Pacific Northwest

Figure 1.32 and Figure 1.33 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2025 for resources in the Pacific Northwest WEIM region.[18] The typical seasonal outage pattern for the Pacific Northwest region diverges from the others, with outages typically peaking in the second quarter while outages in all other quarters remain low. The trend is still primarily driven by planned outages for maintenance, which are generally performed outside of the higher load periods. Average total outages remained essentially flat, approximately a three percent decrease, due to offsetting increases in wind and natural gas, and decreases in hydro and solar, in the fourth quarter of 2025 compared to the fourth quarter of 2024.

[18] The Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

Figure 1.32 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by type – peak hours

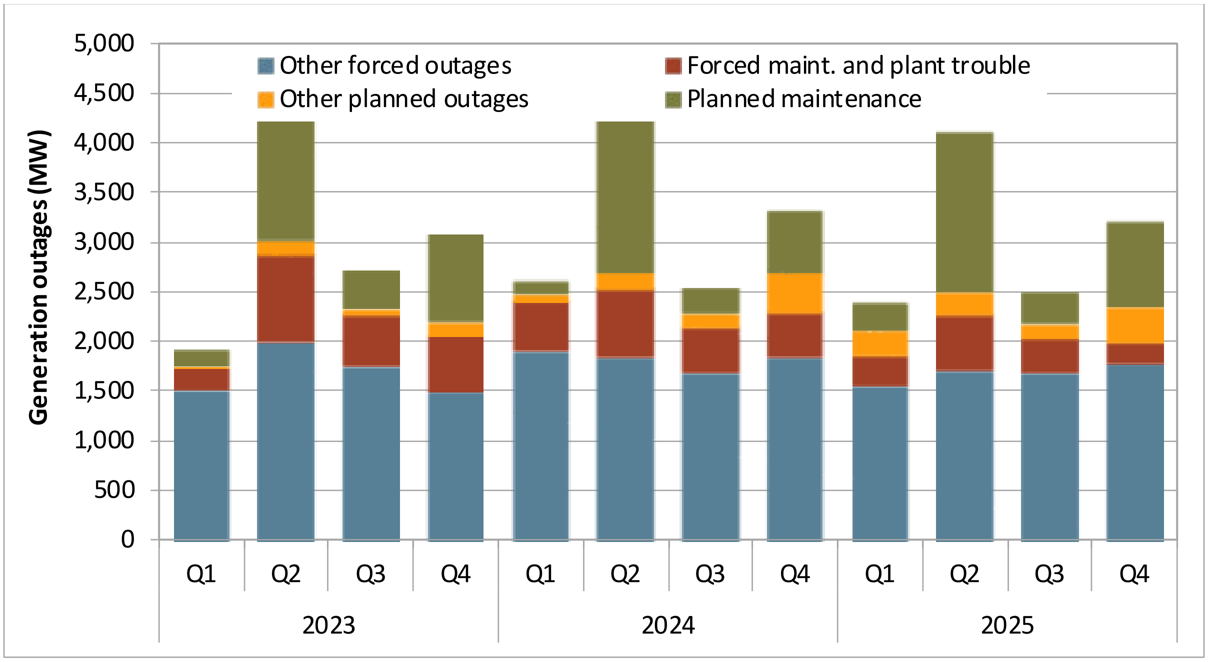
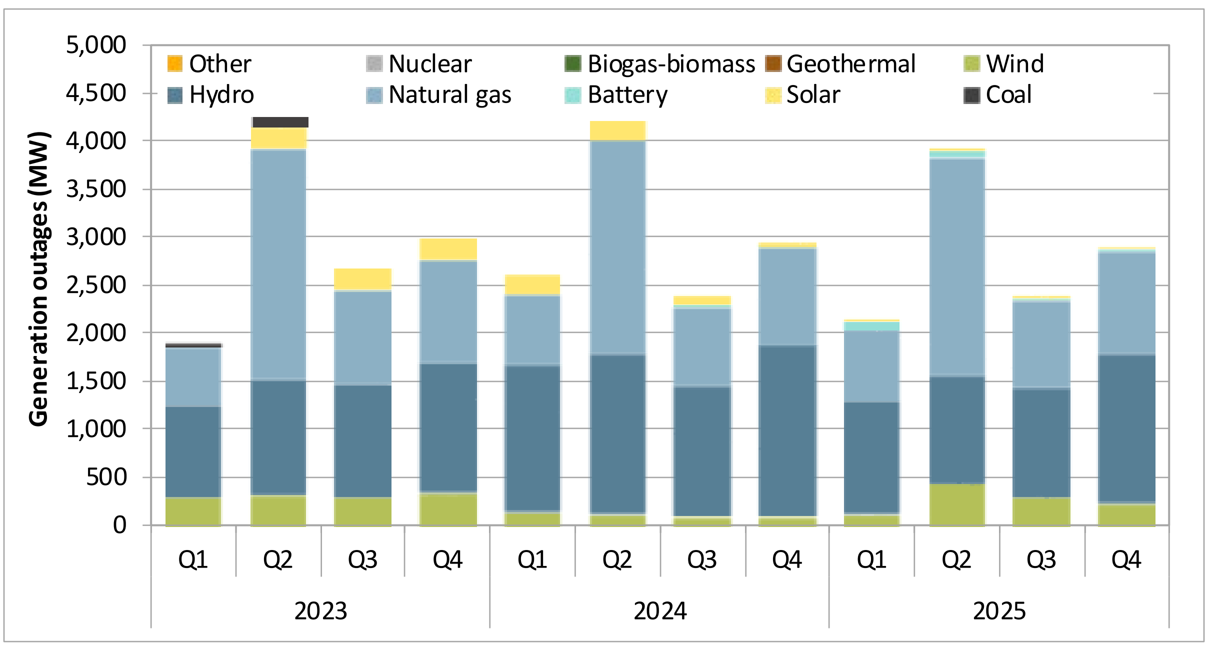


Figure 1.33 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



2 Load conditions

This section provides an overview of load conditions across WEIM regions. The analysis examines load conditions at quarterly, monthly, and hourly levels, categorized by regional groups and individual balancing areas.

The balancing areas are categorized into four geographical regions:

- **California**: includes all balancing areas in California: California ISO (CAISO), the Balancing Authority of Northern California (BANC), Los Angeles Department of Water and Power (LADWP), and Turlock Irrigation District (TIDC).
- **Desert Southwest**: includes Arizona Public Service (AZPS), El Paso Electric (EPE), NV Energy (NEVP), Public Service Company of New Mexico (PNM), Salt River Project (SRP), Tucson Electric (TEPC), and WAPA-Desert Southwest.
- **Intermountain West**: includes Avista Corporation (AVA), Idaho Power Company (IPCO), NorthWestern Energy (NWMT), and PacifiCorp East (PACE).
- **Pacific Northwest**: includes Avangrid Power (AVRN), Bonneville Power Administration (BPA), PacifiCorp West (PACW), Portland General Electric (PGE), Powerex, Puget Sound Energy (PSE), Seattle City Light (SCL), and Tacoma Power (TPWR).

2.1 Average load and load distribution

Figure 2.1 shows the total market load distribution in the 5-minute market.[19] The distribution incorporates load levels from all 5-minute market intervals in Q4 2025 (blue line) and Q4 2024 (gray dashed line).

The horizontal axis represents the load in gigawatts (GW), while the vertical axis displays the probability density function (PDF), which indicates the relative frequency of different load levels.

Figure 2.1 shows how the load in the fourth quarter is distributed across load levels (measured in GW). Higher points on the curve represent load levels that occurred more frequently during the quarter.[20] For instance, in Q4 2025, the curve peaks around 75 GW, indicating that load levels around 75 GW were most frequently observed.[21]

The system load distribution in the fourth quarter of 2025 shows instances of high system loads—load levels above about 90 GW—occurring less frequently than in the same quarter last year. Overall, the load distributions in Q4 2025 and Q4 2024 are similar.

19 The total market load includes any load conformance.

20 To determine the likelihood of the load falling within a specific range, such as between 100 GW and 120 GW, one can assess the area under the curve within that range. The total area under the curve equals 1, so the proportion of the area in any range reflects the probability of the load being in that range.

21 The most frequently observed value in a distribution is also called the mode (or modal value).

Figure 2.1 Quarterly system-wide total 5-minute market load distribution

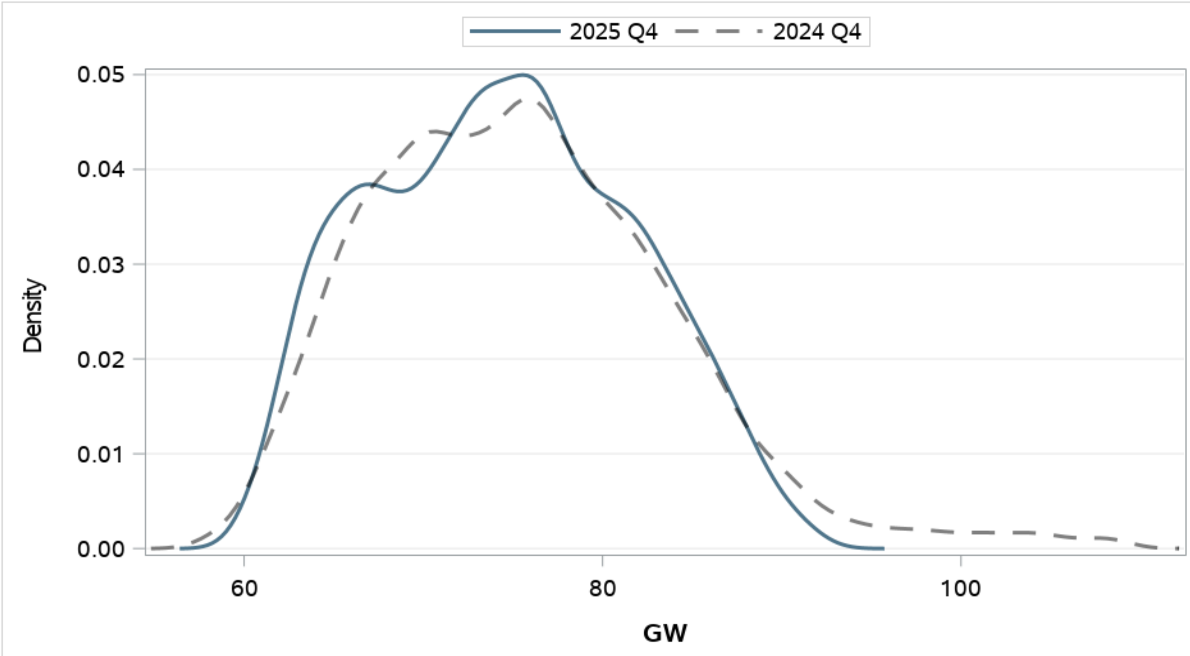


Figure 2.2 shows the monthly average 5-minute market load categorized by region from October 2023 through December 2025. The total system load for this quarter averaged 74.4 GW, representing approximately a 1.4 percent decrease compared to the same quarter of 2024. In all regions but the Pacific Northwest, average load decreased during the fourth quarter of 2025 relative to the fourth quarter of 2024:

- **Pacific Northwest** (green) averaged **23.7 GW**, a 0.4 percent increase.
- **California** (blue) averaged **26.6 GW**, a 3.3 percent decrease.
- **Desert Southwest** (yellow) averaged **14.6 GW**, a 0.3 percent decrease.
- **Intermountain West** (red) averaged **9.5 GW**, a 1.8 percent decrease.

The WEIM total market load tends to be lowest in April and tends to peak in July. Regions such as CAISO, California (non-CAISO), and the Desert Southwest closely aligned with the overall seasonal trends of the total WEIM load, showing higher loads during the summer months. However, in the Pacific Northwest, the highest average loads occur in the winter months, with comparatively low load during summer, and particularly in May, June, and September.

Figure 2.2 Monthly average 5-minute market load by region (GW)

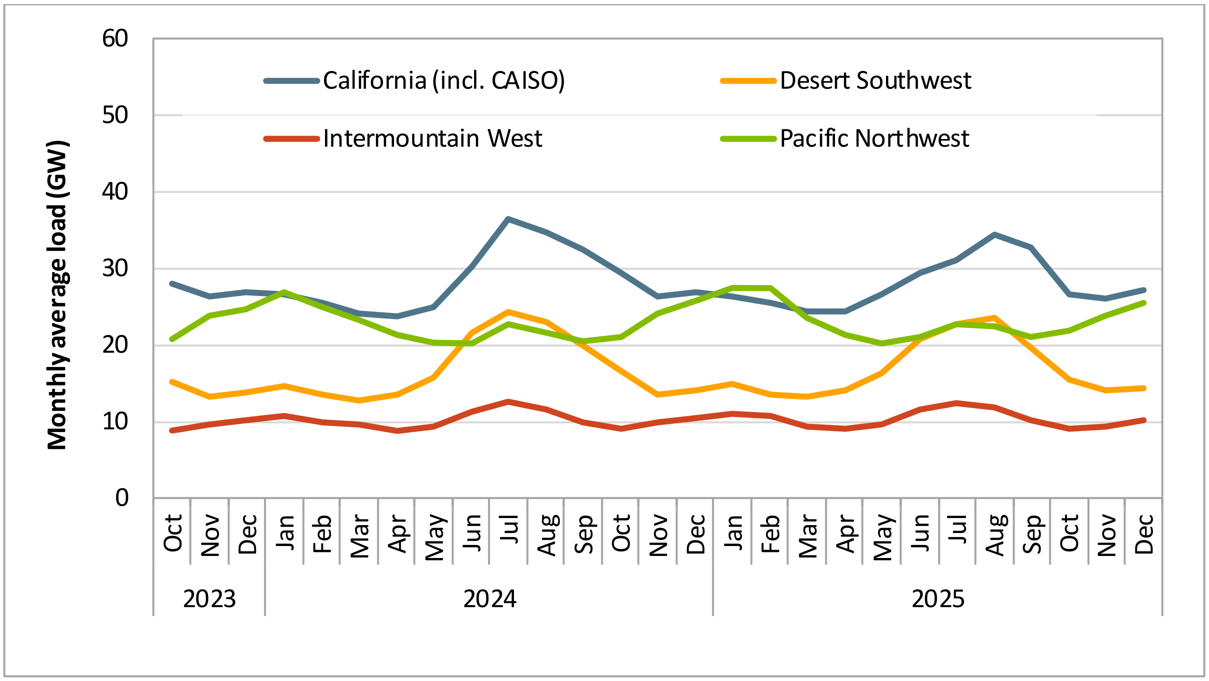
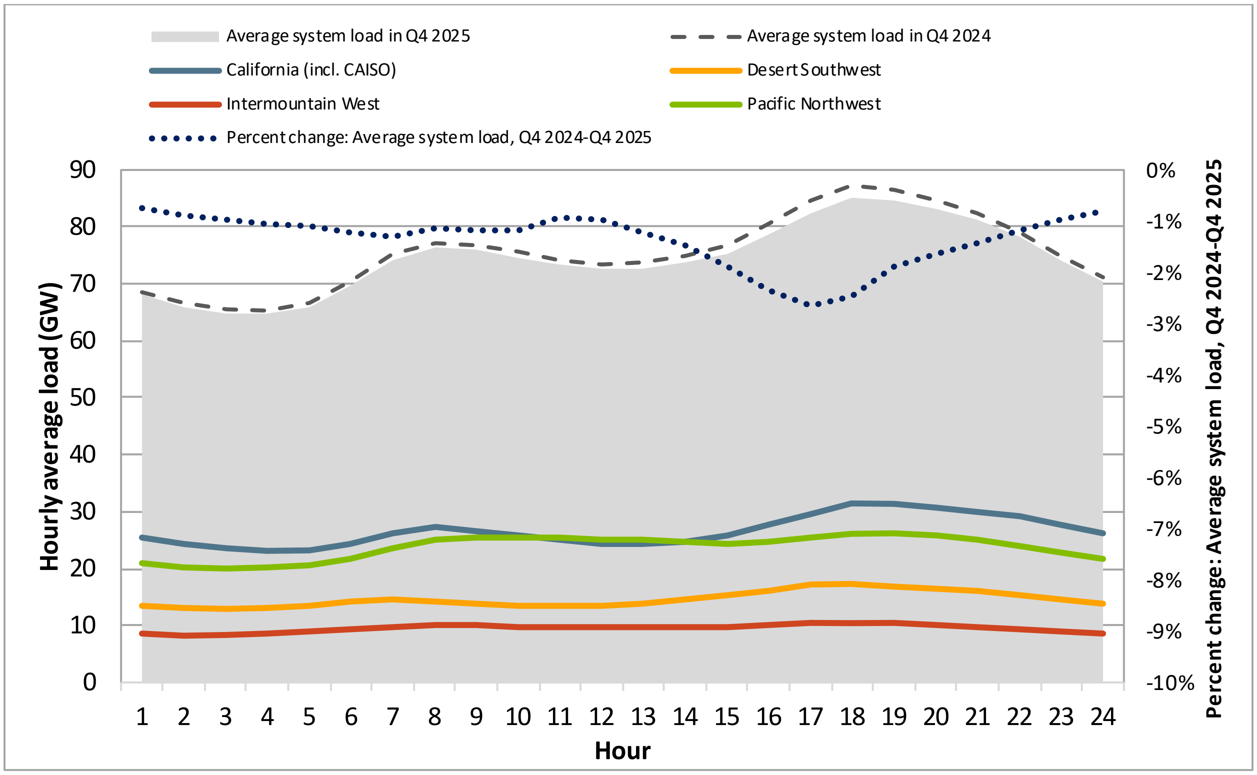


Figure 2.3 displays the hourly average 5-minute market load across different regions in Q4 2025. Each color represents a specific region. The gray area represents the average WEIM system-wide total load for the fourth quarter of 2025 while the black dashed line represents the same for the fourth quarter of 2024. The navy blue dotted line represents the percent change of load between Q4 2024 and Q4 2025, computed for each hour by taking the difference in average system load levels between Q4 2025 and Q4 2024, and then dividing the difference by the average system load level in Q4 2024. The percent change for each hour measures how the average system load has changed in Q4 2025 relative to Q4 2024, expressed as a percentage.

The WEIM system-wide hourly average load peaked at hour-ending 18, reaching 85.1 GW, while the lowest load occurred at hour-ending 4, at 64.6 GW. In Q4 of 2025, the average hourly load in all regions peaked during the evening hours, between hours-ending 18 and 19. The peak average hourly load for each region is given below:

- **Pacific Northwest:** peak load of 26.1 GW at hour-ending 18.
- **California:** peak load of 31.4 GW at hour-ending 19.
- **Desert Southwest**: peak load of 17.3 GW at hour-ending 18.
- **Intermountain West**: peak load of 10.4 GW at hour-ending 18.

Figure 2.3 Hourly average 5-minute market load by region (Q4 2025)



2.2 Peak load

Figure 2.4 shows the highest 5-minute market *system* load forecast for each hour on December 29, 2025, the day with the highest system load during the quarter. The figure also shows corresponding load forecast data for each balancing area for the same 5-minute interval as the system peak for each hour. On this day, the WEIM system load peaked at 94.0 GW during hour-ending 18, interval 11. This was lower than the peak WEIM load during Q4 2024 (110.5 GW).

This heatmap highlights the hour with the peak load for each balancing area on this day. Red indicates the hour of highest load for each balancing area and yellow indicates hours with above-average load for that day. Peak load for balancing areas varied across hours. The system peak occurred during hour-ending 18, and many balancing areas reached their peak load around the same time.

WAPA Desert Southwest and Idaho Power recorded peak load of the day during hour-ending 8, while Bonneville Power Administration, Tacoma Power, PacifiCorp West, and Seattle City Light (all in the Pacific Northwest) reached peak load of the day in hour-ending 10. All other balancing areas reached peak load between hours-ending 17 and 20.

Figure 2.4 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market, December 29, 2025)

Hour	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
SYSTEM	76.9	82.2	86.9	88.6	88.1	86.1	83.2	80.2	78.7	77.9	80.0	84.8	91.9	94.0	93.5	92.2	90.2	87.9	84.0
CAISO	20.3	21.9	23.6	24.1	23.8	22.2	20.4	18.9	18.3	18.5	19.9	22.3	25.5	26.6	26.5	26.1	25.7	25.1	24.3
BANC	1.71	1.85	2.02	2.07	2.08	2.10	2.10	2.12	2.08	2.01	1.95	1.95	2.12	2.22	2.21	2.19	2.16	2.12	2.00
Turlock ID	.26	.28	.30	.31	.31	.32	.32	.32	.32	.32	.32	.32	.34	.35	.35	.34	.34	.33	.31
LADWP	2.11	2.22	2.38	2.46	2.50	2.49	2.44	2.39	2.33	2.36	2.46	2.54	2.67	2.78	2.76	2.74	2.71	2.67	2.56
NV Energy	3.98	4.17	4.30	4.26	4.21	4.07	3.91	3.83	3.74	3.82	3.97	4.20	4.56	4.71	4.69	4.66	4.56	4.51	4.36
Arizona PS	3.66	3.88	3.96	3.85	3.69	3.36	3.14	2.95	2.92	3.05	3.29	3.65	4.02	4.02	4.03	4.04	3.92	3.81	3.57
Tucson Electric	1.13	1.22	1.23	1.23	1.23	1.19	1.19	1.06	1.01	0.99	1.11	1.21	1.29	1.29	1.28	1.25	1.22	1.17	1.10
Salt River Project	3.23	3.38	3.45	3.38	3.41	3.40	3.29	3.22	3.26	3.25	3.33	3.51	3.63	3.69	3.71	3.60	3.55	3.44	3.26
PSC New Mexico	1.64	1.72	1.70	1.68	1.61	1.56	1.49	1.46	1.44	1.47	1.57	1.73	1.84	1.85	1.85	1.85	1.83	1.77	1.71
WAPA - Desert SW	.48	.53	.57	.60	.59	.56	.53	.54	.55	.53	.51	.51	.57	.55	.54	.55	.52	.50	.46
El Paso Electric	.78	.83	.86	.89	.90	.94	.95	.96	.96	.97	.97	1.04	1.08	1.08	1.08	1.07	1.04	.98	.91
PacifiCorp East	6.03	6.35	6.49	6.57	6.46	6.30	6.22	6.14	6.05	6.03	6.13	6.52	6.73	6.83	6.81	6.76	6.68	6.45	6.19
Idaho Power	2.23	2.38	2.50	2.53	2.50	2.41	2.32	2.24	2.17	2.13	2.10	2.21	2.40	2.43	2.42	2.38	2.33	2.24	2.15
NorthWestern	1.47	1.56	1.62	1.63	1.63	1.60	1.59	1.55	1.51	1.50	1.52	1.61	1.67	1.64	1.62	1.61	1.57	1.50	1.42
Avista Utilities	1.38	1.50	1.60	1.66	1.68	1.68	1.66	1.62	1.59	1.54	1.54	1.57	1.69	1.70	1.68	1.65	1.61	1.56	1.46
BPA	8.01	8.59	9.07	9.37	9.41	9.43	9.26	8.94	8.68	8.34	8.26	8.40	8.89	9.06	9.06	8.99	8.77	8.56	8.19
Tacoma Power	.62	.67	.72	.74	.75	.76	.76	.74	.74	.70	.70	.70	.74	.75	.75	.73	.72	.68	.65
PacifiCorp West	2.62	2.87	3.10	3.20	3.22	3.22	3.12	2.94	2.82	2.71	2.71	2.78	3.01	3.11	3.10	3.07	3.00	2.93	2.77
Portland GE	2.71	2.92	3.13	3.23	3.28	3.30	3.23	3.15	3.18	3.11	3.12	3.24	3.40	3.49	3.47	3.42	3.33	3.22	3.06
Puget Sound Energy	3.31	3.60	3.86	4.00	4.06	4.12	4.10	4.01	3.98	3.81	3.77	3.84	4.14	4.16	4.11	4.00	3.87	3.73	3.50
Seattle City Light	1.21	1.32	1.42	1.47	1.49	1.52	1.51	1.51	1.48	1.42	1.41	1.43	1.51	1.52	1.49	1.44	1.40	1.35	1.27
Powerex	7.99	8.41	8.98	9.35	9.33	9.57	9.64	9.65	9.59	9.36	9.42	9.61	10.05	10.08	9.99	9.75	9.44	9.26	8.84

Table 2.1 shows the peak 5-minute market load and date for each balancing area (or region) during the fourth quarter. Nearly all BAAs in California and the Desert Southwest reached their quarterly peak load in October, while balancing areas in the Intermountain West and the Pacific Northwest recorded their Q4 2025 peak load between late November and December. The table also shows each balancing area's load during the system peak load interval on December 29, 2025 (93,950 MW).

Table 2.1 Peak WEIM load (October–December 2025)

	Peak load (October–December, 2025)		Load during WEIM system peak (29-Dec-2025)	
Region/balancing area	**Date**	**Load (MW)**	**Load (MW)**	**Percent**
WEIM system	**29-Dec-25**	**93,950**	**93,950**	
California	**7-Oct-25**	**36,100**	**31,973**	**34%**
California ISO	7-Oct-25	30,205	26,628	28%
BANC	7-Oct-25	2,518	2,215	2%
LADWP	29-Oct-25	3,701	2,779	3%
Turlock Irrig. District	7-Oct-25	475	351	.4%
Desert Southwest	**2-Oct-25**	**24,455**	**17,204**	**18%**
Arizona Public Service	2-Oct-25	6,023	4,024	4%
El Paso Electric	2-Oct-25	1,697	1,083	1.2%
NV Energy	2-Oct-25	5,739	4,709	5%
PSC New Mexico	4-Dec-25	1,970	1,846	2%
Salt River Project	3-Oct-25	6,128	3,693	4%
Tucson Electric	2-Oct-25	2,111	1,293	1%
WAPA - Desert SW	2-Oct-25	1,079	555	.6%
Intermountain West	**1-Dec-25**	**12,640**	**12,591**	**13%**
Avista Utilities	28-Dec-25	1,709	1,697	2%
Idaho Power	29-Dec-25	2,540	2,428	3%
NorthWestern Energy	30-Nov-25	1,716	1,636	2%
PacifiCorp East	18-Dec-25	6,887	6,830	7%
Pacific Northwest	**29-Dec-25**	**32,282**	**32,182**	**34%**
BPA	30-Dec-25	9,550	9,063	10%
PacifiCorp West	30-Dec-25	3,333	3,114	3%
Portland General Electric	25-Nov-25	3,526	3,494	4%
Powerex	28-Dec-25	10,429	10,082	11%
Puget Sound Energy	31-Dec-25	4,189	4,158	4%
Seattle City Light	29-Dec-25	1,526	1,517	2%
Tacoma Power	29-Dec-25	770	753	.8%

3 Operator load forecast adjustments

Operators in WEIM balancing areas can manually adjust the load forecasts used in the real-time markets in order to help maintain system reliability. The ISO refers to this as *imbalance conformance*. These adjustments help account for potential modeling inconsistencies and inaccuracies, and to create additional unloaded ramping capacity in the real-time market.

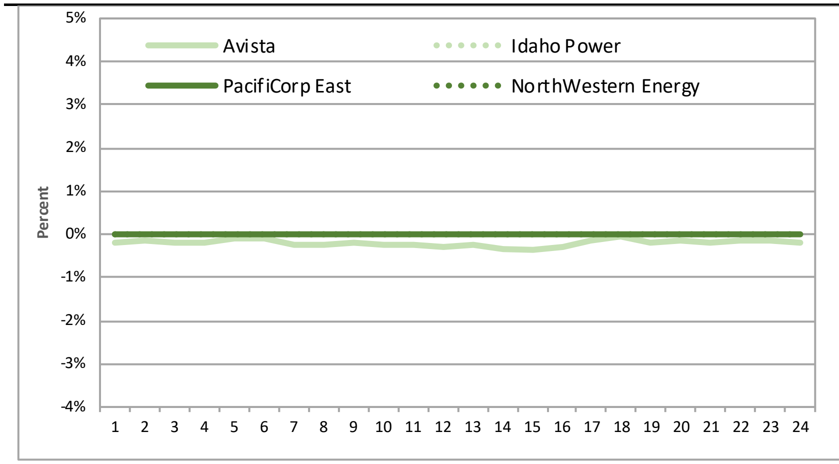
3.1 Imbalance conformance – all balancing areas

The figures below show fourth quarter average hourly imbalance conformance in the 15-minute and 5-minute markets for each balancing area, as a percentage of the balancing area's average load.[22] Generally, imbalance conformance levels were much higher in the 5-minute market than the 15-minute market, with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).

[22] Avangrid Power and Powerex are not shown in these figures. Avangrid Power is a generation-only entity and therefore load conformance cannot be measured as a percent of load. Powerex is not a balancing authority area like other participating WEIM entities and instead uses residual capability of the BC Hydro system to participate in the WEIM. Powerex therefore does not have the ability to enter load bias in the market.

Figure 3.1 Intermountain West: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q4 2025)

15-minute market



5-minute market

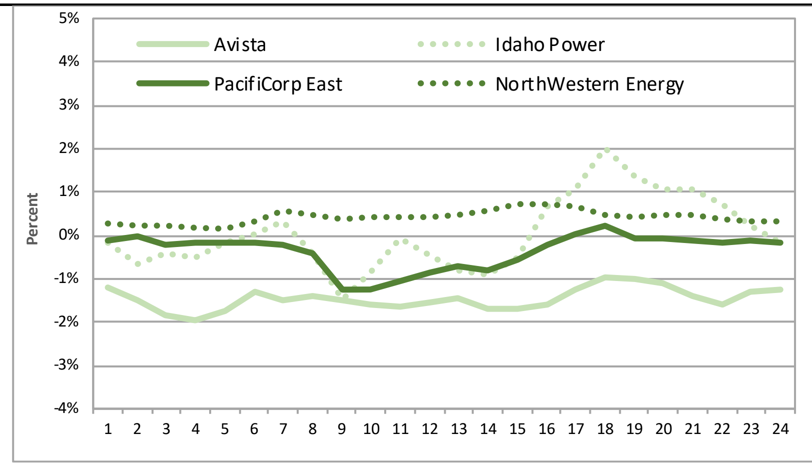
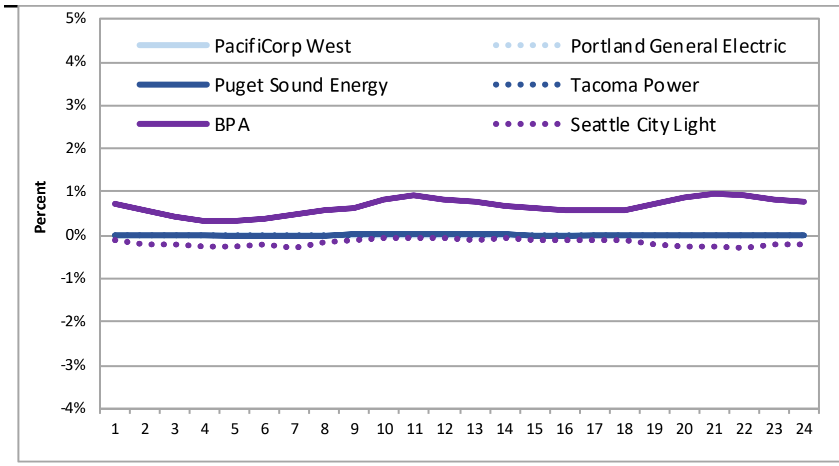


Figure 3.2 Pacific Northwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q4 2025)

15-minute market



5-minute market

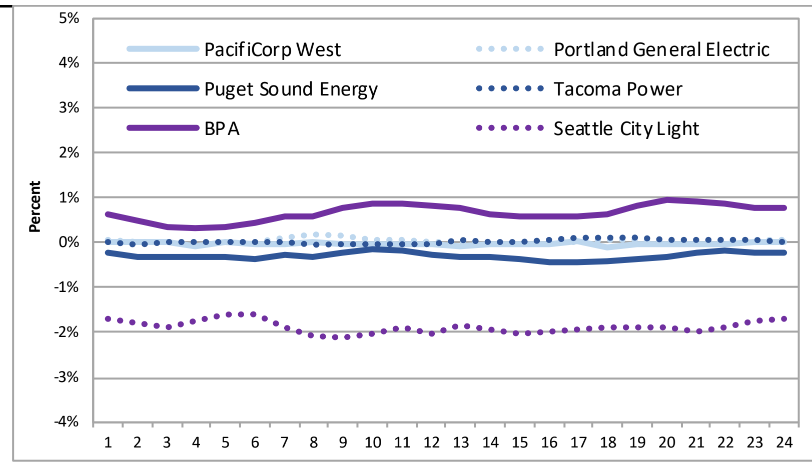
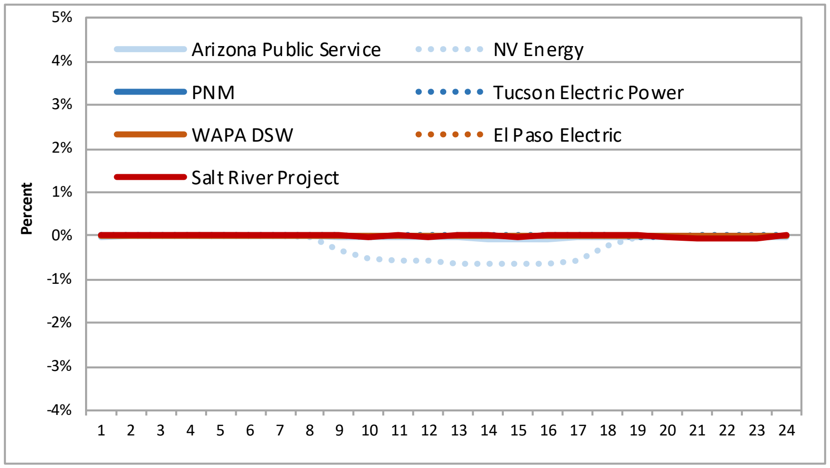


Figure 3.3 Desert Southwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q4 2025)

15-minute market



5-minute market

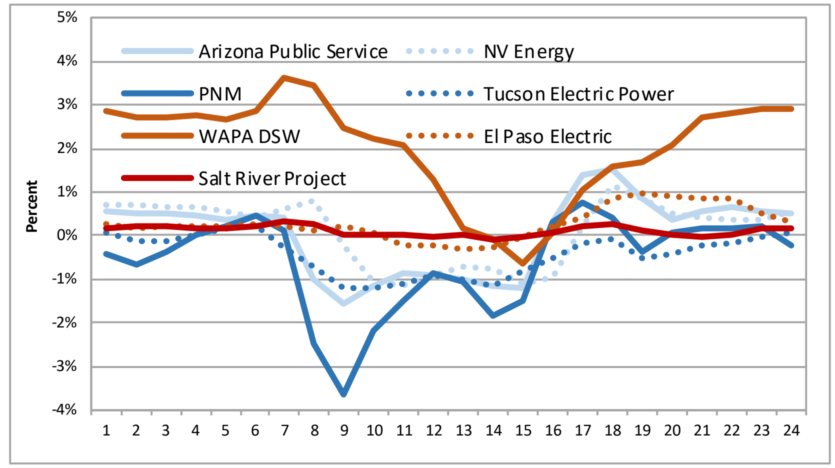
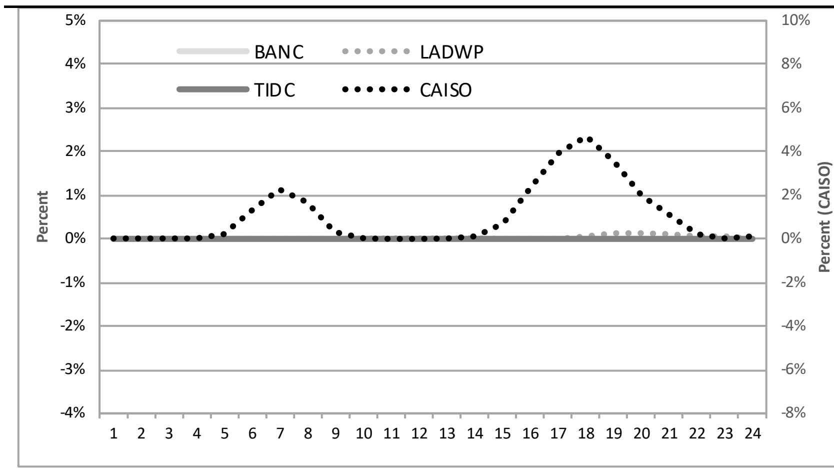
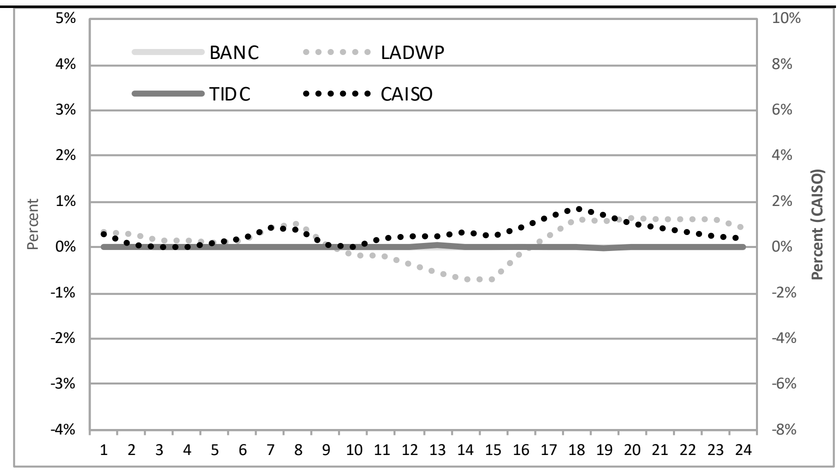


Figure 3.4 California: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q4 2025)

15-minute market



5-minute market



3.2 Imbalance conformance – special report on CAISO BA

The size and frequency of imbalance conformance adjustments by the CAISO balancing area operators in the 15-minute market made it an outlier amongst WEIM areas in the fourth quarter of 2025. This section analyzes the use of imbalance conformance by CAISO balancing area operators.

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO balancing area hour-ahead and 15-minute markets. Figure 3.5 shows CAISO area imbalance conformance adjustments in real-time markets for the fourth quarter of 2024 and 2025. Imbalance conformance over the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. This contributed to higher prices in the 15-minute market than in the 5-minute market over these hours.

Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets increased during morning ramp hours and decreased during evening ramp hours in the fourth quarter of 2025 relative to the same quarter of 2024. During the morning hours, the highest average hourly adjustments were around 500 MW. Imbalance conformance over the evening peak hours reached just over 1,000 MW, about 400 MW lower than the largest average hourly evening adjustments over Q4 2024.

The 5-minute market adjustments increased slightly in the morning ramp hours for the fourth quarter of 2025, compared to the fourth quarter of 2024. Evening 5-minute market adjustments peaked in hour-ending 18 at about 375 MW, about 180 MW lower than in the fourth quarter of 2024.

Figure 3.5 Average CAISO balancing area hourly imbalance conformance adjustment (Q4 2024 and Q4 2025)

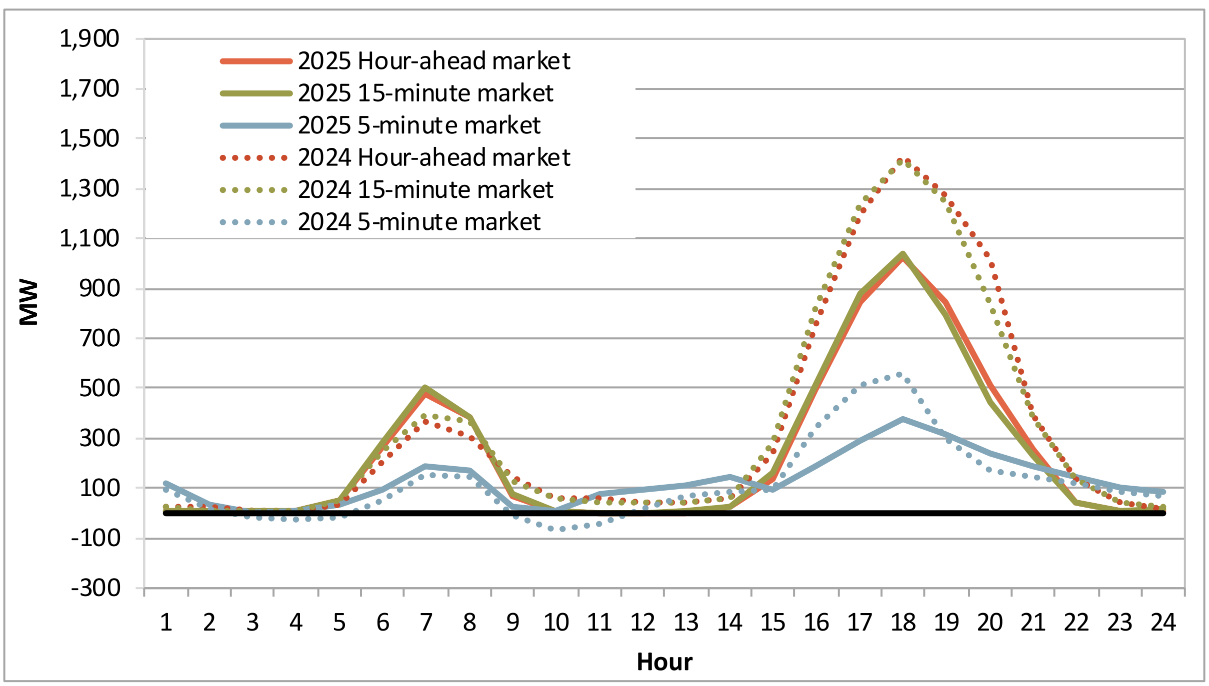
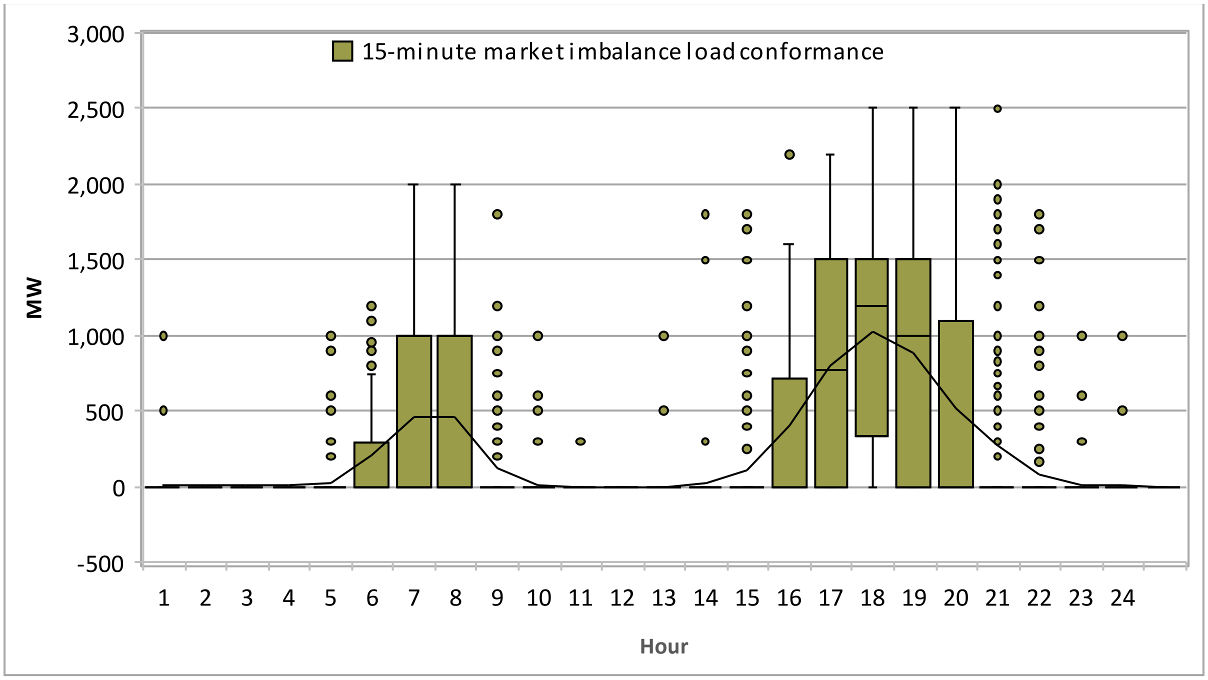


Figure 3.6 shows an hourly distribution of the 15-minute market load adjustments for the fourth quarter of 2025. This box and whisker graph highlights extreme outliers[23] (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well as the mean (line). The extreme outliers are represented by the filled "dots". The outside whiskers do not include these outliers.

Figure 3.6 CAISO BA 15-minute market hourly distribution of operator load adjustments (Q4 2025)



23 A data point is an outlier if it is more than 1.5 * Interquartile Range (IQR) above the third quartile or below the first quartile. The upper outliers are greater than the 3rd quartile + 1.5 x Interquartile Range (IQR), while lower outliers are values less than the 1st quartile less 1.5 x Interquartile Range (IQR).

4 Energy prices

4.1 Real-time energy market prices by region

This section analyzes real-time market prices across the Western Energy Imbalance Market (WEIM). The analysis focuses on monthly and hourly load-weighted average prices at the regional level.[24] Prices are calculated based on the load schedules and corresponding prices at all Aggregated Pricing Nodes (APnodes).[25]

Figure 4.1 and Figure 4.2 display the weighted average monthly electricity prices in the 15-minute and 5-minute markets, respectively, by region from January 2024 to December 2025. Prices in the 15-minute market across the WEIM averaged about $36/MWh in the fourth quarter of 2025, down 7 percent from the same quarter of last year. Prices in the 5-minute market were also $36/MWh, a 4 percent decrease compared to Q4 2024.

In the 15-minute market, California recorded the highest average price at $41/MWh, followed by the Pacific Northwest at $36/MWh. Average prices in these regions were slightly higher than prices in the Intermountain West ($32/MWh) and Desert Southwest regions ($30/MWh). Greenhouse gas (GHG) costs during non-solar hours contributed to higher average prices in California compared to other regions.[26]

24 The California region includes CAISO, BANC, TIDC, and LADWP. The Desert Southwest region includes NEVP, AZPS, TEPC, SRP, PNM, WALC, and EPE. The Intermountain West region includes PACE, IPCO, NWMT, and AVA. The Pacific Northwest includes AVRN, BPA, BCHA, TWPR, PGE, PSEI, and SCL.

25 The load-weighted average is calculated by weighting each interval's price by its corresponding load relative to the total over a specific time period. Monthly average prices for each real-time interval are weighted by their respective loads and divided by the total monthly load for the region. For hourly averages over the quarter, each interval's price is weighted by its load relative to the total load during that hour for the region.

26 The GHG component of electricity prices reflects the additional costs associated with complying with California's cap-and trade program, which requires entities to purchase allowances for their carbon emission to serve load of WEIM balancing areas within California.

Figure 4.1 Weighted average monthly 15-minute market prices by region

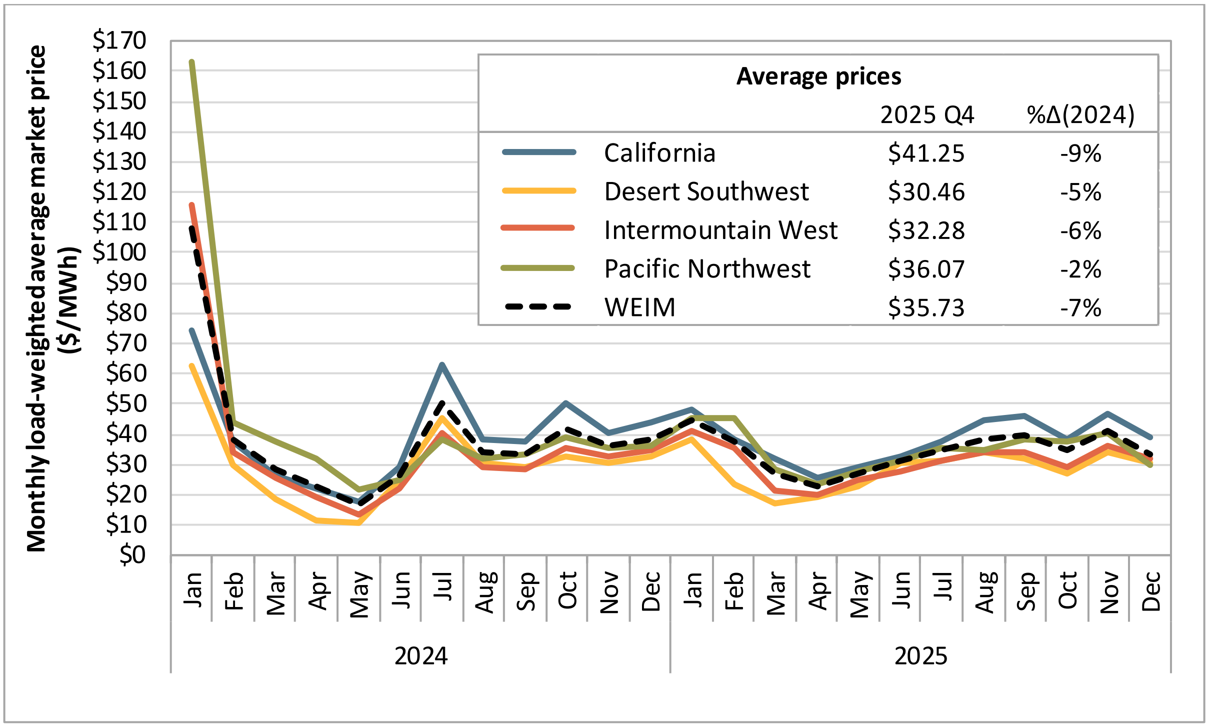


Figure 4.2 Weighted average monthly 5-minute market prices by region

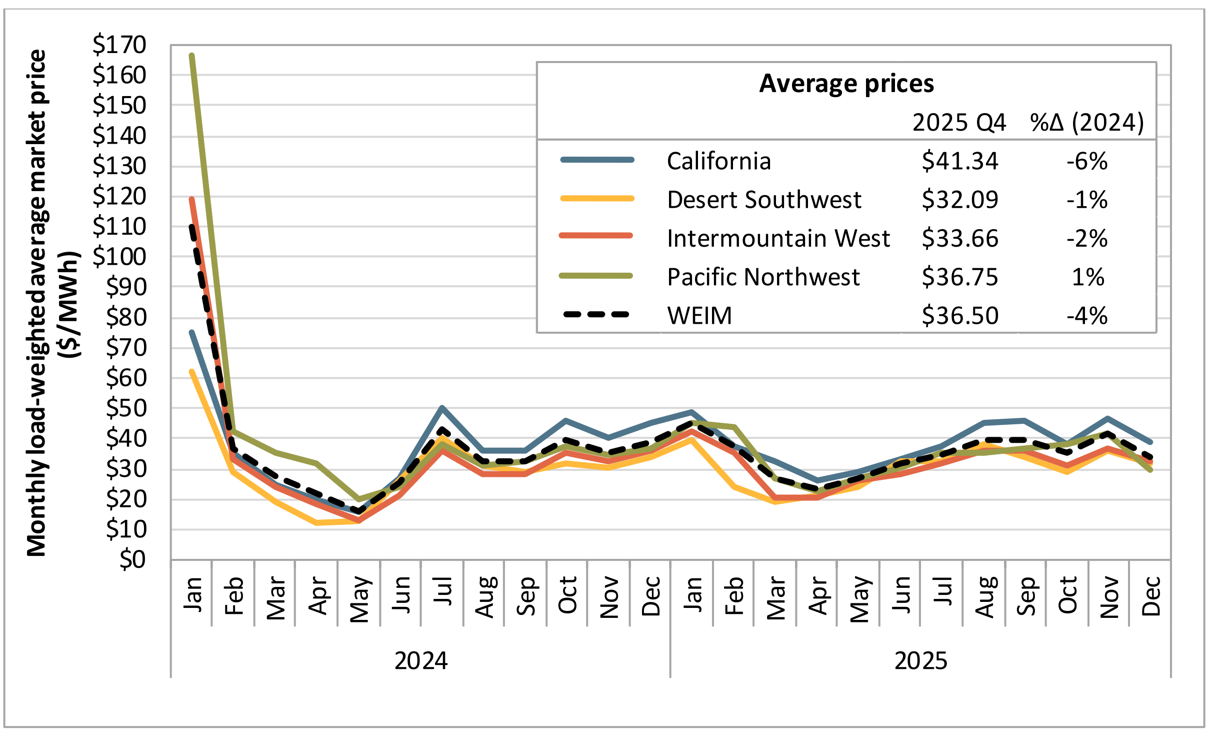


Figure 4.3 and Figure 4.4 illustrate the weighted average hourly prices for the 15-minute and 5-minute markets across regions, along with average system net-load schedules. The shape of hourly prices tended to follow the net-load pattern. This trend was most prominent for prices in the California, Desert Southwest, and Intermountain West regions, with relatively high prices during the morning and evening ramping hours, and lower prices during solar production hours.

The system's average hourly peak net load occurred at hour-ending 19 in both the 15-minute and 5-minute markets, reaching around 77.2 GW and 76.8 GW, respectively. In the 15-minute market, the California, Intermountain West, and Powerex[27] regions experienced peak average prices at hour-ending 18, while the Desert Southwest and Pacific Northwest regions had their highest average prices at hour-ending 7 and 11, respectively. In the 5-minute market, all regions except the Pacific Northwest experienced peak average prices at hour-ending 18, while the Pacific Northwest region experienced peak prices at hour-ending 10.

Real-time market prices in the California region were higher than prices in other regions during non-solar production hours. The main contributor for higher prices in California is the GHG cost, which tends to raise prices in California balancing areas relative to the non-California regions.

Pricing patterns were very different during mid-day solar hours. During these hours, WEIM transfers tended to flow out of California, so GHG costs did not raise California prices relative to other regions. South-to-north congestion patterns during solar hours increased prices in the Pacific Northwest, Powerex and Northern California relative to the Desert Southwest, Southern California and Intermountain West.

27 Powerex (BCHA) is categorized separately from the Pacific Northwest in these figures due to transmission limitations that frequently isolate it from the rest of the WEIM system.

Figure 4.3 Weighted average hourly 15-minute market prices by region (October–December 2025)

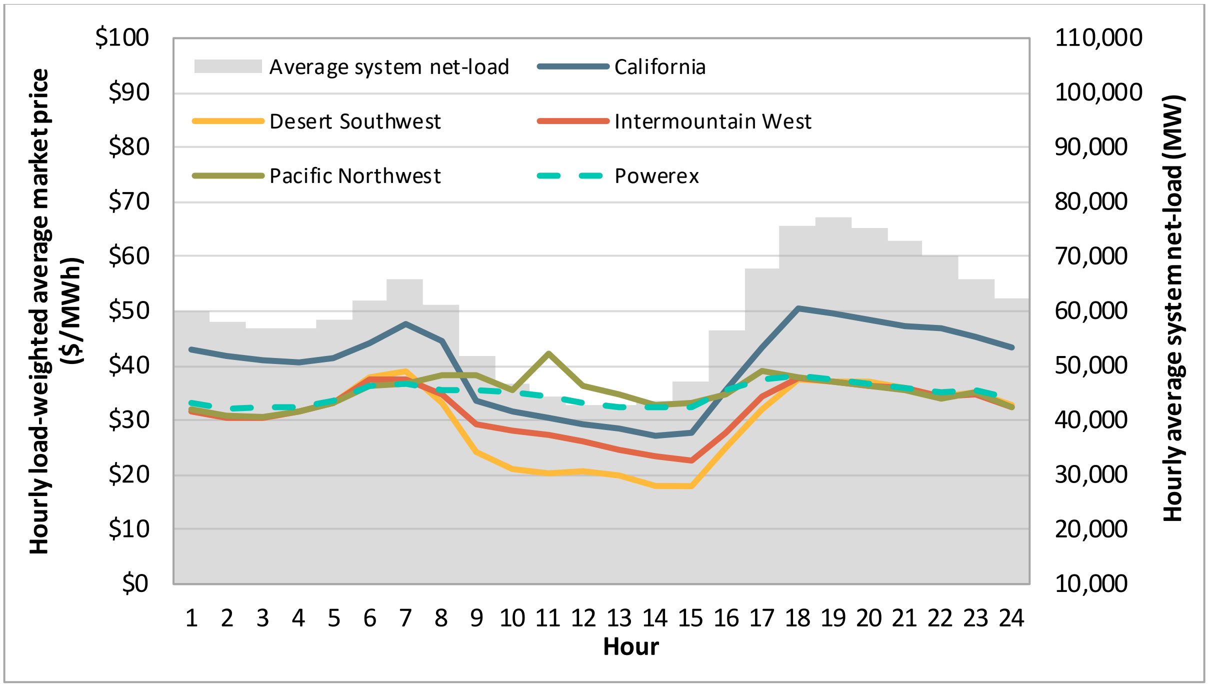
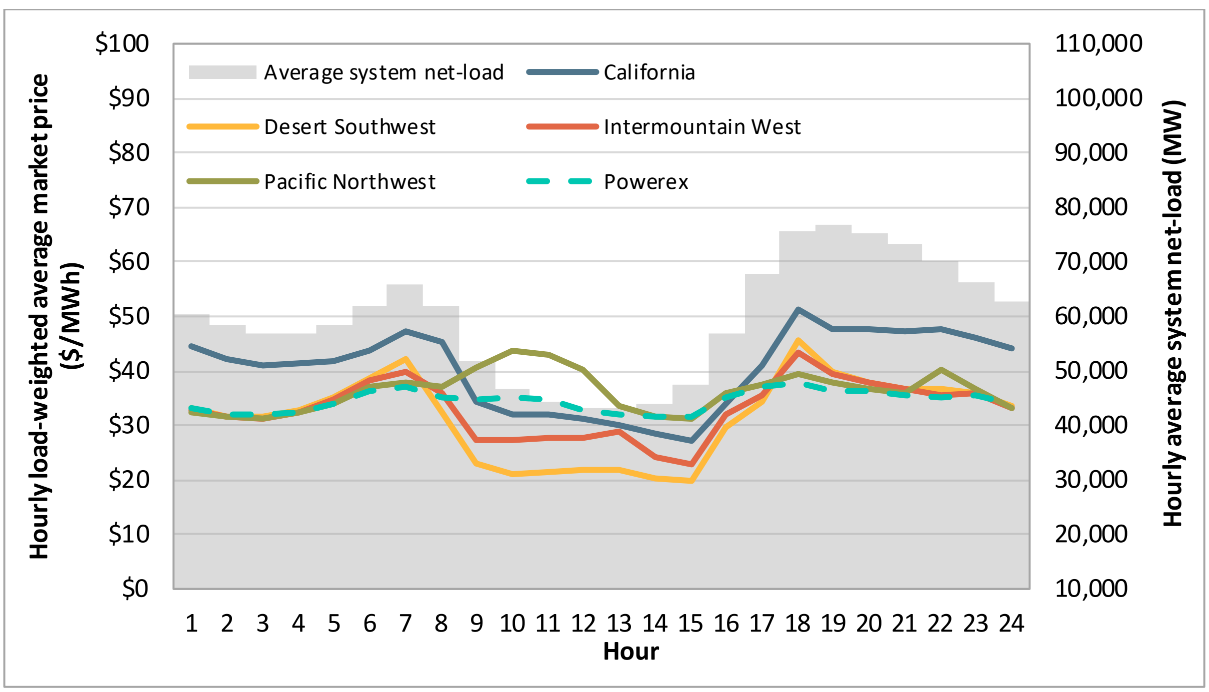


Figure 4.4 Weighted average hourly 5-minute market prices by region (October–December 2025)



4.2 Real-time market prices by balancing area

This section summarizes prices in each Western Energy Imbalance Market (WEIM) balancing area during the fourth quarter of 2025. Figure 4.5 and Figure 4.6 show the average 15-minute and 5-minute market price by component for each balancing authority area in this quarter. These figures highlight how price differences between regions are determined by differences in transmission losses, greenhouse gas compliance costs, and congestion. These components are listed below.

- **System marginal energy cost**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.
- **Congestion from local constraints** is the price impact from transmission constraints within its own balancing area that are restricting the flow of energy. While these constraints are located locally, they can create price impacts across the WEIM and show up as external constraints to other balancing areas, as shown in the figures below.
- **Congestion from external constraints** is the price impact from transmission constraints from a WEIM balancing area outside of its own that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*
- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limits WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraints (ITC) and intertie scheduling limits (ISL).

Significant factors impacting the locational marginal price (LMP) differences between balancing areas included congestion on WEIM transfer constraints and internal congestion from flow-based constraints. GHG costs also contributed to lower prices in non-California balancing areas relative to California areas. These compliance costs are embedded within system marginal energy costs, but are reflected as negative costs (or payments) that are received by other WEIM areas making transfers into California areas through the WEIM. This indicates resources with non-zero GHG costs were often sending the last increment of power to California in the real-time markets.

Internal flow-based constraints in the CAISO balancing area impacted prices in both the 15-minute and 5-minute markets. Congestion on these constraints mainly during mid-day solar hours contributed to prices in Northern California and the Pacific Northwest being relatively higher than prices in Southern California and the Desert Southwest. Congestion on WEIM transfer constraints also contributed to higher prices in the Pacific Northwest and Intermountain West regions.

Figure 4.5 Average 15-minute market prices by balancing area (October–December 2025)

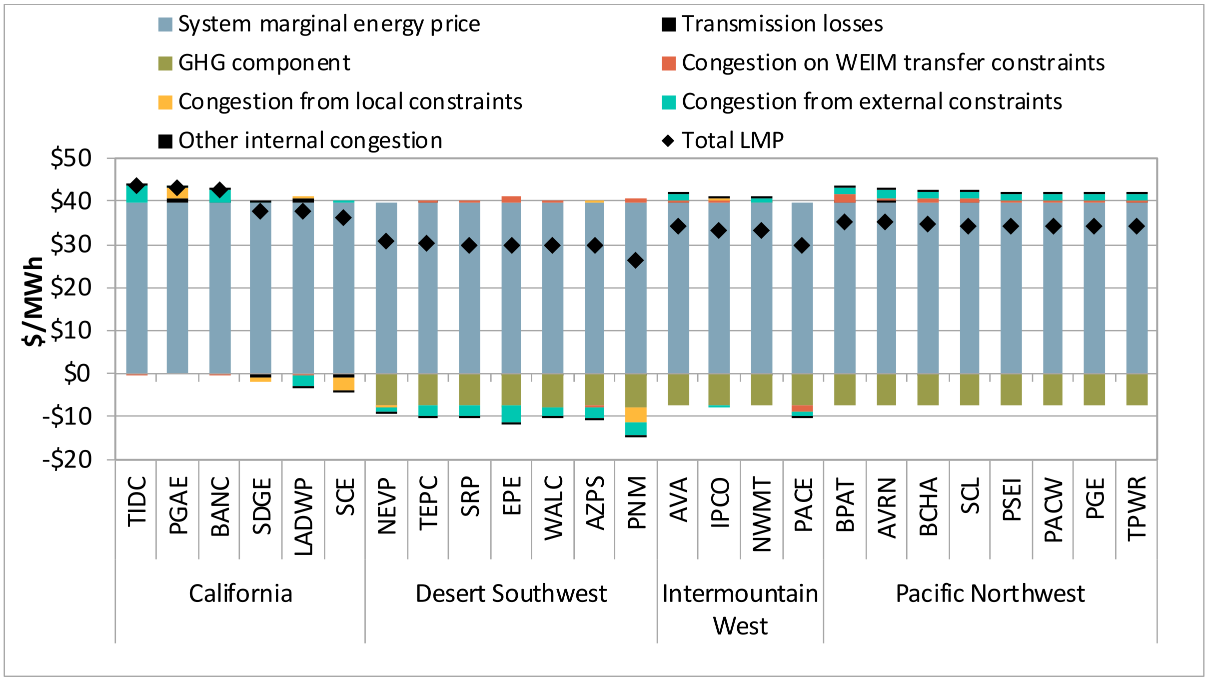


Figure 4.6 Average 5-minute market prices by balancing area (October–December 2025)

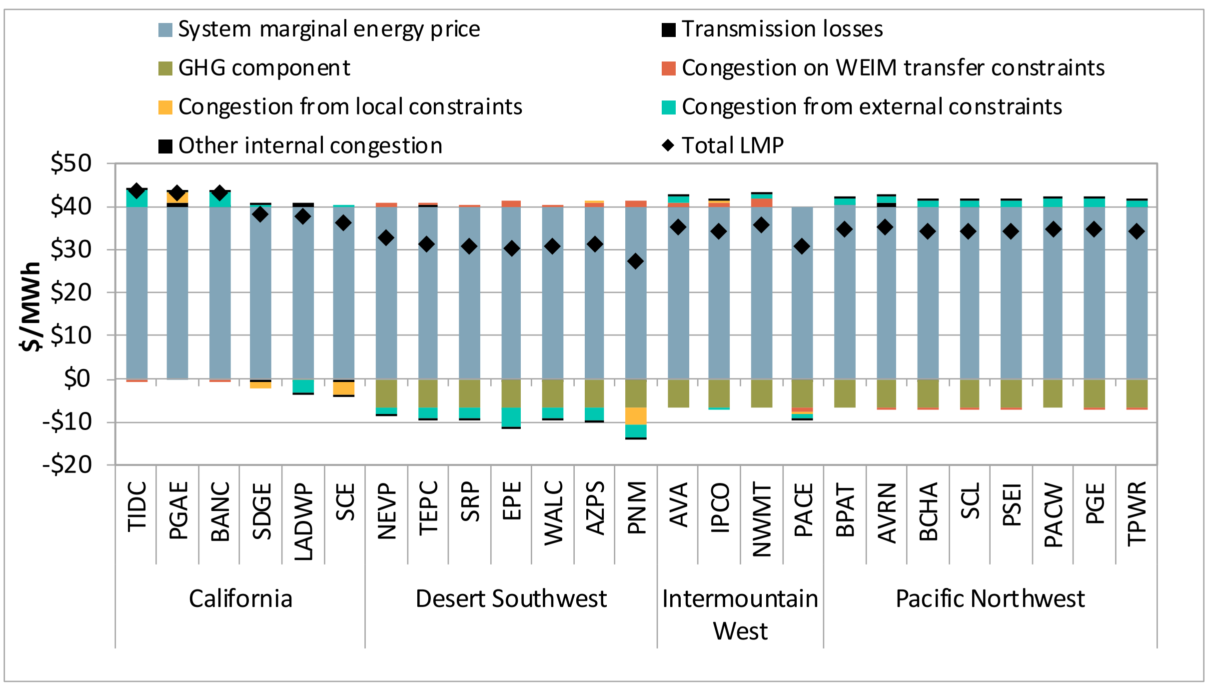


Table 4.1 and Table 4.2 show average 15-minute and 5-minute market prices by month for each balancing area. The color gradient highlights deviation from the average system marginal energy price

(SMEC), shown in the top row. Blue indicates prices below that month's average system price and orange indicates prices above. As shown in these tables, average prices in California balancing areas were generally higher than balancing areas in other regions in both the 15-minute and 5-minute markets in Q4 2025. This was due primarily to California greenhouse gas pricing.

Table 4.3 and Table 4.4 show average hourly prices in the 15-minute and 5-minute markets during the fourth quarter. During mid-day solar hours, prices were generally higher in the Pacific Northwest and Northern California than in the Desert Southwest, Southern California, and parts of the Intermountain West. This pattern was primarily driven by south-to-north congestion on WEIM transfer and internal flow-based constraints. When internal or transfer constraints limit the amount of energy that can flow from areas with lower cost supply to areas with higher cost supply, prices will be higher on the side of the constraint with higher cost supply.

During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM due mainly to California greenhouse gas pricing.

Table 4.1 Average monthly 15-minute market prices

2024	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMEC	$89	$38	$28	$22	$16	$26	$51	$36	$35	$46	$41	$42
PG&E (CAISO)	$78	$40	$30	$28	$21	$28	$61	$36	$36	$56	$46	$46
SCE (CAISO)	$65	$31	$17	$11	$9	$24	$50	$35	$33	$38	$35	$40
BANC	$77	$41	$31	$29	$21	$27	$58	$37	$37	$56	$46	$45
Turlock ID	$78	$41	$33	$31	$21	$25	$54	$37	$39	$61	$47	$45
LADWP	$68	$32	$18	$12	$11	$27	$55	$40	$35	$40	$37	$38
NV Energy	$65	$30	$19	$13	$10	$22	$42	$29	$28	$33	$29	$31
Arizona PS	$59	$28	$18	$8	$8	$21	$45	$30	$27	$30	$26	$31
Tucson Electric	$59	$27	$15	$9	$11	$21	$39	$26	$26	$28	$27	$31
Salt River Project	$54	$25	$14	$9	$10	$25	$38	$31	$28	$30	$26	$30
PSC New Mexico	$69	$35	$18	$14	$10	$24	$43	$29	$28	$27	$57	$29
WAPA - Desert SW	$60	$29	$14	$7	$10	$21	$42	$29	$27	$32	$26	$32
El Paso Electric	$53	$24	$15	$9	$13	$27	$38	$25	$26	$27	$27	$30
PacifiCorp East	$76	$31	$22	$16	$12	$21	$39	$28	$27	$35	$31	$33
Idaho Power	$112	$35	$27	$20	$13	$22	$37	$28	$28	$37	$34	$35
NorthWestern	$151	$38	$29	$24	$18	$21	$36	$28	$29	$30	$33	$33
Avista Utilities	$155	$38	$30	$26	$18	$21	$33	$28	$29	$39	$36	$35
Avangrid	$164	$38	$31	$25	$18	$21	$32	$28	$33	$40	$37	$36
BPA	$182	$39	$30	$27	$20	$23	$40	$31	$33	$40	$37	$35
Tacoma Power	$165	$39	$31	$26	$18	$20	$32	$27	$32	$38	$36	$36
PacifiCorp West	$170	$38	$30	$25	$17	$20	$31	$27	$32	$39	$36	$36
Portland GE	$165	$38	$32	$27	$17	$21	$32	$27	$32	$39	$36	$35
Puget Sound Energy	$167	$39	$31	$27	$18	$21	$33	$28	$32	$38	$35	$36
Seattle City Light	$167	$40	$30	$28	$18	$20	$31	$27	$32	$40	$36	$37
Powerex	$72	$54	$49	$43	$27	$32	$42	$36	$33	$36	$35	$34

2025	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMEC	$46	$40	$28	$24	$28	$32	$37	$42	$43	$38	$46	$36
PG&E (CAISO)	$49	$40	$31	$27	$30	$34	$38	$43	$48	$42	$50	$37
SCE (CAISO)	$43	$30	$25	$18	$24	$28	$35	$42	$39	$32	$42	$34
BANC	$49	$40	$31	$25	$29	$35	$39	$43	$48	$43	$49	$36
Turlock ID	$51	$40	$32	$28	$30	$36	$41	$44	$51	$46	$49	$36
LADWP	$45	$30	$28	$21	$27	$31	$37	$43	$42	$34	$44	$36
NV Energy	$38	$26	$20	$18	$24	$28	$31	$33	$33	$28	$35	$30
Arizona PS	$35	$22	$18	$15	$19	$25	$30	$33	$31	$26	$34	$29
Tucson Electric	$36	$22	$18	$16	$20	$26	$30	$32	$31	$27	$34	$30
Salt River Project	$35	$22	$19	$24	$20	$30	$30	$33	$32	$26	$34	$29
PSC New Mexico	$37	$14	-$1	$14	$19	$43	$31	$40	$32	$24	$31	$25
WAPA - Desert SW	$36	$22	$19	$15	$19	$25	$30	$33	$31	$28	$33	$28
El Paso Electric	$34	$19	$8	$17	$26	$32	$31	$33	$33	$26	$34	$29
PacifiCorp East	$39	$30	$19	$18	$23	$27	$30	$34	$33	$26	$34	$29
Idaho Power	$42	$35	$22	$26	$25	$28	$31	$34	$34	$33	$36	$30
NorthWestern	$41	$39	$25	$21	$24	$28	$31	$33	$34	$32	$38	$30
Avista Utilities	$43	$41	$26	$21	$24	$28	$31	$33	$35	$34	$38	$30
Avangrid	$44	$44	$26	$21	$27	$30	$33	$34	$38	$38	$40	$28
BPA	$43	$45	$26	$22	$28	$33	$36	$36	$41	$39	$40	$28
Tacoma Power	$43	$43	$26	$22	$26	$29	$35	$34	$38	$36	$39	$28
PacifiCorp West	$43	$43	$25	$20	$26	$29	$31	$33	$37	$37	$39	$27
Portland GE	$43	$43	$25	$20	$26	$29	$32	$34	$38	$37	$39	$28
Puget Sound Energy	$43	$43	$26	$23	$27	$29	$37	$34	$39	$36	$39	$28
Seattle City Light	$43	$43	$26	$22	$26	$29	$37	$34	$39	$36	$39	$29
Powerex	$48	$46	$33	$27	$29	$31	$36	$33	$34	$36	$39	$29

Table 4.2 Average monthly 5-minute market prices

	2024 Jan	2024 Feb	2024 Mar	2024 Apr	2024 May	2024 Jun	2024 Jul	2024 Aug	2024 Sep	2024 Oct	2024 Nov	2024 Dec	2025 Jan	2025 Feb	2025 Mar	2025 Apr	2025 May	2025 Jun	2025 Jul	2025 Aug	2025 Sep	2025 Oct	2025 Nov	2025 Dec
SMEC	$85	$35	$26	$20	$14	$24	$43	$34	$34	$44	$40	$43	$47	$39	$29	$25	$28	$32	$37	$42	$43	$38	$46	$36
PG&E (CAISO)	$79	$38	$28	$26	$19	$26	$49	$34	$35	$51	$45	$46	$50	$39	$32	$28	$29	$34	$38	$43	$48	$43	$50	$38
SCE (CAISO)	$63	$29	$16	$9	$8	$22	$42	$33	$32	$37	$35	$41	$44	$30	$26	$19	$24	$29	$35	$43	$40	$33	$42	$35
BANC	$79	$39	$30	$27	$20	$25	$48	$34	$36	$52	$45	$45	$50	$39	$32	$26	$29	$35	$39	$43	$48	$44	$49	$37
Turlock ID	$79	$40	$31	$29	$19	$24	$45	$35	$38	$57	$46	$46	$51	$39	$33	$30	$30	$36	$41	$44	$51	$46	$49	$37
LADWP	$66	$30	$17	$10	$10	$27	$50	$45	$35	$39	$37	$38	$45	$30	$28	$21	$27	$32	$38	$45	$43	$34	$44	$36
NV Energy	$65	$29	$19	$12	$9	$21	$37	$29	$28	$33	$30	$32	$40	$25	$21	$22	$25	$29	$32	$35	$34	$30	$37	$32
Arizona PS	$59	$26	$17	$8	$8	$21	$40	$32	$27	$30	$27	$33	$37	$23	$19	$16	$20	$27	$32	$37	$32	$29	$35	$31
Tucson Electric	$58	$28	$16	$10	$14	$24	$34	$26	$27	$27	$28	$32	$38	$23	$21	$18	$23	$27	$32	$35	$33	$28	$35	$31
Salt River Project	$53	$24	$17	$10	$13	$29	$37	$31	$29	$30	$27	$32	$37	$23	$20	$26	$23	$34	$32	$36	$33	$28	$35	$30
PSC New Mexico	$70	$34	$18	$16	$12	$25	$37	$28	$28	$27	$50	$30	$39	$15	$3	$15	$20	$44	$32	$43	$34	$27	$32	$25
WAPA - Desert SW	$59	$28	$14	$6	$9	$21	$37	$29	$27	$32	$27	$32	$37	$22	$20	$16	$20	$27	$31	$36	$32	$29	$34	$30
El Paso Electric	$52	$24	$15	$8	$18	$25	$36	$24	$26	$27	$27	$32	$36	$19	$10	$17	$27	$33	$32	$39	$34	$27	$33	$32
PacifiCorp East	$73	$30	$21	$15	$11	$20	$35	$27	$27	$34	$31	$34	$40	$30	$18	$18	$25	$28	$32	$36	$34	$27	$36	$30
Idaho Power	$119	$34	$25	$19	$13	$21	$34	$28	$28	$36	$34	$35	$43	$34	$21	$25	$27	$29	$32	$35	$35	$35	$37	$31
NorthWestern	$161	$37	$28	$26	$18	$20	$33	$28	$30	$31	$34	$34	$42	$39	$25	$22	$25	$29	$32	$35	$35	$33	$39	$35
Avista Utilities	$164	$37	$29	$27	$18	$20	$32	$28	$29	$37	$36	$36	$43	$41	$25	$22	$25	$29	$32	$34	$36	$36	$39	$30
Avangrid	$168	$37	$29	$24	$16	$20	$33	$28	$31	$39	$37	$37	$44	$42	$24	$20	$26	$30	$33	$35	$37	$38	$40	$29
BPA	$184	$37	$28	$26	$17	$22	$38	$29	$32	$38	$35	$36	$44	$43	$24	$20	$26	$31	$35	$36	$40	$38	$40	$28
Tacoma Power	$170	$37	$29	$26	$17	$20	$32	$27	$31	$37	$35	$36	$43	$42	$24	$21	$26	$29	$34	$35	$37	$36	$39	$29
PacifiCorp West	$171	$37	$28	$24	$16	$20	$32	$27	$31	$38	$36	$36	$43	$41	$23	$19	$25	$29	$32	$34	$36	$37	$39	$29
Portland GE	$169	$37	$29	$26	$16	$20	$32	$27	$31	$38	$35	$36	$43	$41	$24	$19	$25	$29	$32	$34	$37	$37	$39	$28
Puget Sound Energy	$175	$37	$29	$27	$16	$20	$33	$27	$31	$37	$34	$36	$43	$41	$24	$22	$26	$29	$36	$35	$37	$36	$39	$28
Seattle City Light	$171	$37	$28	$26	$16	$20	$31	$27	$31	$38	$35	$36	$45	$41	$24	$21	$25	$29	$36	$35	$37	$36	$39	$29
Powerex	$72	$53	$48	$43	$27	$30	$42	$36	$33	$36	$35	$34	$47	$45	$33	$27	$28	$30	$36	$33	$34	$36	$39	$29

Table 4.3 Average hourly 15-minute market prices (October–December)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$43	$42	$41	$40	$41	$44	$47	$44	$34	$32	$31	$29	$28	$27	$27	$35	$42	$49	$49	$48	$47	$46	$45	$43
PG&E (CAISO)	$44	$42	$42	$41	$42	$44	$48	$48	$42	$41	$38	$35	$34	$32	$34	$41	$47	$53	$51	$50	$48	$48	$46	$44
SCE (CAISO)	$42	$41	$40	$40	$41	$43	$46	$40	$25	$22	$22	$22	$22	$20	$20	$29	$38	$46	$46	$46	$45	$45	$44	$42
BANC	$43	$42	$41	$40	$41	$44	$47	$47	$41	$40	$39	$36	$35	$34	$35	$41	$46	$50	$49	$49	$47	$47	$45	$43
Turlock ID	$43	$42	$41	$40	$41	$44	$47	$46	$43	$43	$42	$39	$38	$37	$38	$44	$48	$51	$50	$48	$47	$47	$45	$43
LADWP	$43	$40	$41	$41	$41	$45	$47	$41	$27	$23	$23	$23	$23	$22	$21	$33	$40	$50	$49	$49	$48	$47	$45	$43
NV Energy	$32	$31	$31	$32	$33	$37	$38	$34	$27	$25	$24	$23	$23	$20	$20	$27	$33	$37	$37	$37	$36	$35	$35	$33
Arizona PS	$32	$31	$31	$32	$33	$37	$38	$32	$23	$21	$21	$21	$20	$18	$17	$24	$32	$37	$37	$36	$36	$34	$35	$33
Tucson Electric	$32	$31	$31	$32	$33	$37	$37	$32	$23	$24	$22	$21	$21	$19	$19	$29	$33	$38	$37	$36	$36	$34	$35	$33
Salt River Project	$32	$31	$31	$32	$33	$37	$39	$32	$23	$21	$21	$21	$20	$19	$18	$26	$32	$37	$37	$36	$36	$34	$35	$33
PSC New Mexico	$31	$30	$30	$31	$33	$38	$43	$30	$21	$10	$8	$9	$8	$8	$8	$23	$32	$37	$36	$35	$35	$33	$36	$32
WAPA - Desert SW	$32	$31	$31	$32	$33	$37	$38	$32	$21	$19	$16	$24	$31	$18	$17	$24	$32	$37	$37	$36	$33	$34	$35	$33
El Paso Electric	$29	$30	$30	$30	$32	$36	$42	$38	$21	$14	$19	$25	$20	$15	$21	$23	$37	$38	$35	$43	$34	$33	$34	$34
PacifiCorp East	$32	$30	$30	$31	$33	$37	$37	$33	$25	$23	$23	$22	$20	$19	$18	$24	$32	$37	$37	$36	$36	$34	$35	$32
Idaho Power	$32	$31	$31	$32	$33	$37	$38	$37	$32	$32	$31	$30	$29	$27	$27	$33	$35	$38	$37	$36	$36	$34	$35	$33
NorthWestern	$32	$31	$31	$31	$32	$37	$38	$36	$34	$32	$31	$30	$29	$27	$27	$31	$37	$38	$38	$36	$36	$34	$35	$32
Avista Utilities	$31	$31	$31	$31	$33	$37	$38	$37	$35	$35	$34	$33	$32	$30	$30	$34	$37	$39	$38	$36	$36	$34	$35	$33
Avangrid	$32	$31	$31	$32	$34	$37	$37	$38	$37	$36	$36	$35	$34	$33	$33	$35	$40	$38	$38	$36	$36	$35	$35	$33
BPA	$32	$31	$31	$32	$33	$36	$37	$39	$40	$36	$37	$35	$36	$33	$34	$35	$41	$40	$37	$36	$35	$35	$36	$33
Tacoma Power	$32	$31	$30	$31	$33	$36	$36	$37	$36	$35	$35	$34	$32	$32	$32	$34	$37	$37	$37	$36	$36	$34	$35	$33
PacifiCorp West	$32	$31	$31	$32	$33	$36	$36	$38	$36	$35	$35	$34	$33	$32	$32	$34	$39	$37	$37	$36	$35	$34	$35	$32
Portland GE	$32	$31	$31	$32	$33	$36	$36	$38	$36	$35	$36	$34	$33	$32	$32	$34	$37	$37	$37	$36	$35	$34	$35	$32
Puget Sound Energy	$32	$31	$30	$32	$33	$36	$36	$37	$36	$35	$35	$34	$33	$32	$32	$34	$37	$37	$37	$36	$36	$34	$35	$33
Seattle City Light	$32	$31	$30	$32	$32	$36	$36	$37	$36	$35	$36	$34	$33	$32	$32	$34	$36	$37	$37	$41	$35	$34	$35	$33
Powerex	$33	$32	$32	$32	$34	$36	$37	$36	$35	$35	$35	$34	$33	$32	$32	$35	$38	$38	$37	$37	$36	$35	$36	$34

Table 4.4 Average hourly 5-minute market prices (October–December)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$44	$42	$41	$41	$42	$43	$47	$45	$34	$32	$32	$31	$30	$28	$27	$34	$41	$50	$47	$47	$47	$47	$46	$44
PG&E (CAISO)	$45	$43	$42	$42	$42	$44	$48	$49	$44	$41	$39	$36	$35	$34	$34	$39	$44	$54	$49	$49	$49	$49	$47	$45
SCE (CAISO)	$43	$42	$40	$40	$41	$43	$46	$40	$24	$21	$23	$24	$24	$22	$19	$28	$37	$47	$45	$46	$46	$46	$45	$43
BANC	$44	$42	$41	$41	$42	$43	$47	$48	$43	$41	$40	$38	$37	$35	$35	$40	$44	$52	$48	$48	$47	$48	$46	$44
Turlock ID	$44	$42	$41	$41	$42	$43	$47	$48	$44	$43	$43	$40	$39	$38	$37	$42	$45	$53	$47	$48	$47	$48	$46	$44
LADWP	$44	$41	$42	$42	$42	$44	$47	$42	$26	$23	$24	$25	$25	$22	$19	$30	$38	$50	$48	$48	$48	$49	$47	$44
NV Energy	$33	$32	$32	$33	$35	$38	$40	$35	$30	$27	$25	$25	$25	$23	$25	$34	$36	$43	$39	$37	$37	$36	$36	$34
Arizona PS	$33	$32	$32	$33	$35	$38	$40	$33	$21	$21	$22	$22	$21	$20	$22	$26	$34	$48	$41	$37	$36	$40	$36	$34
Tucson Electric	$33	$32	$31	$33	$36	$38	$38	$32	$25	$22	$23	$23	$22	$19	$18	$31	$36	$45	$38	$37	$36	$36	$36	$34
Salt River Project	$33	$32	$32	$33	$35	$38	$40	$32	$21	$21	$22	$22	$21	$19	$17	$33	$34	$42	$38	$37	$36	$36	$36	$34
PSC New Mexico	$33	$31	$31	$32	$35	$38	$54	$29	$11	$9	$9	$11	$10	$9	$9	$26	$34	$42	$38	$36	$36	$34	$35	$33
WAPA - Desert SW	$33	$32	$32	$33	$35	$38	$40	$32	$20	$20	$21	$25	$28	$19	$17	$27	$34	$42	$38	$37	$36	$36	$36	$34
El Paso Electric	$32	$31	$30	$31	$34	$38	$48	$20	$15	$14	$15	$21	$24	$17	$17	$33	$36	$46	$42	$48	$36	$34	$34	$33
PacifiCorp East	$33	$31	$31	$32	$35	$38	$39	$33	$21	$22	$22	$23	$28	$19	$17	$27	$34	$43	$38	$37	$36	$35	$36	$33
Idaho Power	$33	$32	$32	$33	$35	$38	$40	$37	$32	$32	$33	$32	$29	$27	$26	$34	$37	$44	$39	$37	$37	$36	$36	$34
NorthWestern	$33	$31	$31	$33	$34	$38	$39	$38	$33	$32	$32	$32	$31	$32	$32	$47	$37	$45	$46	$43	$37	$35	$36	$33
Avista Utilities	$31	$31	$32	$33	$35	$38	$42	$42	$35	$35	$35	$34	$32	$30	$30	$35	$38	$44	$39	$37	$37	$35	$36	$34
Avangrid	$33	$32	$32	$33	$34	$38	$39	$38	$36	$37	$36	$35	$36	$32	$31	$36	$38	$40	$39	$37	$37	$36	$36	$33
BPA	$32	$31	$31	$32	$34	$37	$38	$37	$35	$36	$36	$35	$33	$32	$32	$36	$38	$39	$38	$36	$36	$35	$36	$33
Tacoma Power	$32	$35	$31	$32	$34	$37	$37	$37	$35	$36	$35	$34	$32	$31	$31	$35	$36	$39	$37	$36	$36	$34	$35	$33
PacifiCorp West	$32	$35	$33	$32	$33	$37	$38	$38	$35	$35	$35	$34	$35	$31	$30	$35	$36	$40	$38	$36	$36	$35	$35	$33
Portland GE	$32	$31	$31	$32	$34	$37	$38	$38	$35	$36	$35	$34	$35	$31	$30	$35	$36	$39	$38	$36	$36	$35	$35	$33
Puget Sound Energy	$32	$31	$31	$32	$34	$37	$37	$37	$35	$36	$35	$34	$32	$31	$31	$35	$37	$39	$37	$36	$35	$34	$35	$33
Seattle City Light	$32	$31	$31	$32	$32	$37	$37	$37	$35	$36	$35	$34	$32	$31	$31	$35	$36	$39	$37	$41	$35	$34	$36	$33
Powerex	$33	$32	$32	$33	$34	$36	$37	$35	$35	$35	$35	$33	$32	$32	$32	$35	$37	$38	$37	$36	$35	$35	$36	$34

4.3 Day-ahead market price comparison

This section analyzes day-ahead and real-time market prices for balancing areas in the day-ahead market. Currently, this is just the California ISO balancing area.

Load weighted average day-ahead market prices were about $42/MWh in the fourth quarter of 2025, down 5 percent from $44/MWh in the fourth quarter of 2024. Average prices in the CAISO balancing area's day-ahead, 15-minute, and 5-minute markets combined decreased by about 7 percent compared to the fourth quarter of the previous year. The average price of the three markets this quarter decreased to $41/MWh from $45/MWh in the same quarter of 2024.

Figure 4.7 shows load-weighted average monthly energy prices during all hours across all Aggregated Pricing Nodes (APnodes). Prices are calculated based on the load schedules and corresponding prices at these pricing nodes.[28] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from January 2024 to December 2025.

Over the quarter, prices in the day-ahead market averaged $42/MWh and prices in the 15-minute and 5-minute markets both averaged $41/MWh. November had the highest prices, with an average over the three markets of about $47/MWh.

[28] The load-weighted average is calculated by weighting each interval's price by its corresponding load relative to the total over a specific time period. For monthly average, prices for each real-time interval are weighted by their respective loads and divided by the total monthly load for the region. For hourly averages over the quarter, each interval's price is weighted by its load relative to the total load during that hour for the region.

Figure 4.7 also shows monthly average gas prices at PG&E Citygate from January 2024 to December 2025. The chart shows that the monthly variation of the electricity prices is correlated with gas prices. The PG&E Citygate gas price increased to $3.60/MMBtu this quarter, up from $3.48/MMBtu in the same quarter last year.

This correlation between electricity and gas prices can be attributed to gas-fired units often serving as the price-setting units within the market. A high gas price increases the marginal cost of generation for gas-fired units and non-gas-fired resources with opportunity costs indexed to gas prices. Market bids reflect these higher marginal costs.

Figure 4.7 Monthly average PG&E Citygate gas price and load-weighted average electricity prices for balancing areas in day-ahead market

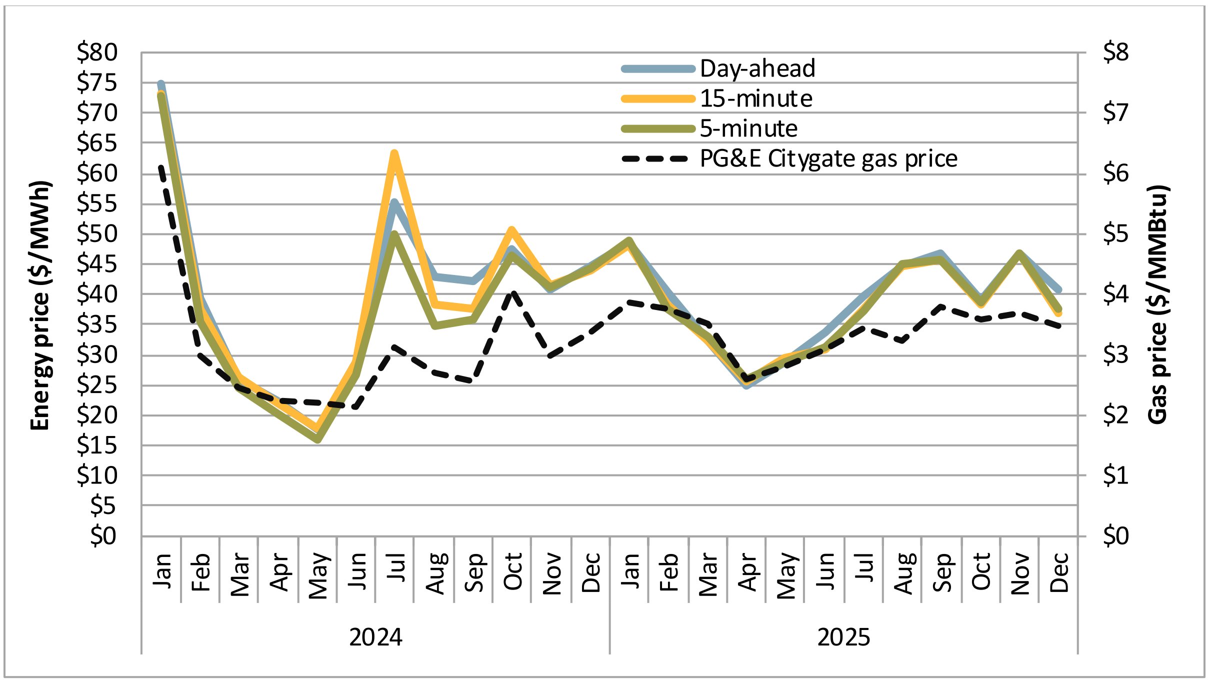


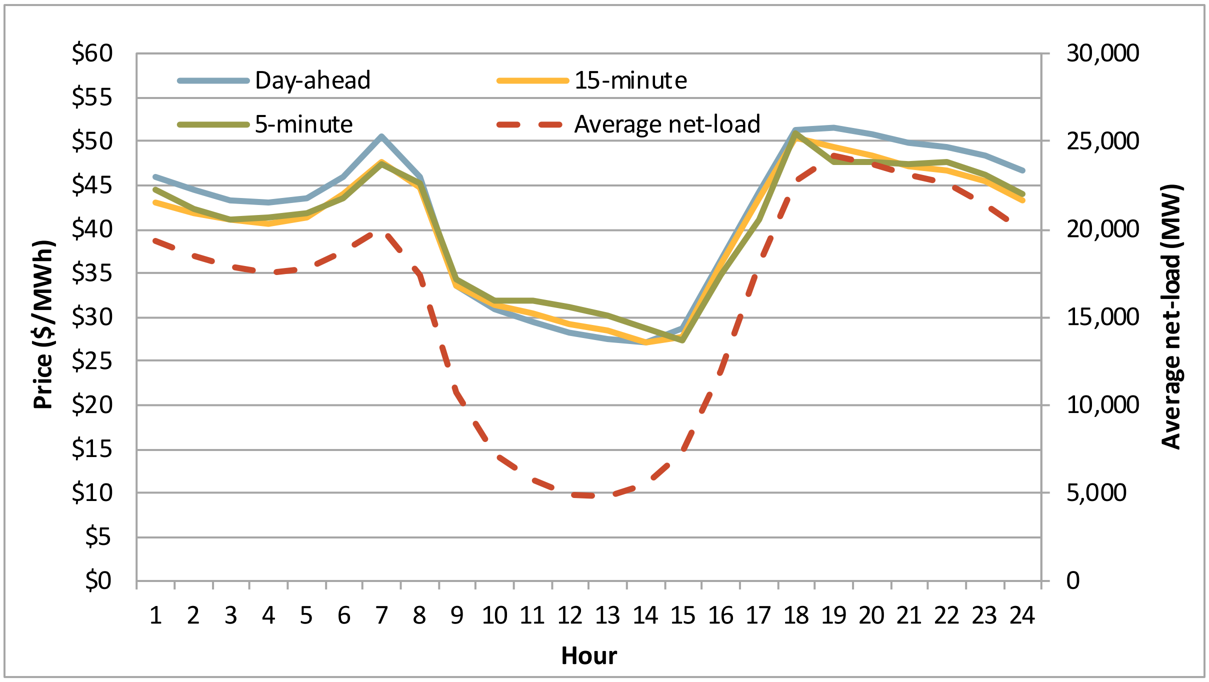
Figure 4.8 illustrates the hourly load-weighted average electricity prices for the fourth quarter compared to the average hourly net-load.[29] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets are measured by the left axis, while the average hourly net-load (red dashed line) is measured by the right axis.

Average hourly prices continue to follow the net-load pattern, with the highest energy prices during the morning and evening peak net-load hours. Energy prices and net-load both increased sharply during the early evening hours. Average energy prices across all three markets peaked at hour-ending 18, at around $51/MWh, while average net-load peaked at hour-ending 19, reaching 24,181 MW.

[29] Net-load is calculated by subtracting the generation produced by wind and solar that is directly connected to the California ISO grid from actual load.

During hour-ending 18, the day-ahead load-weighted average electricity price was $51/MWh, the 15-minute price was $50/MWh, and the 5-minute price was $51/MWh. Overall, prices across the three markets converged well during most hours.

Figure 4.8 Hourly load-weighted average energy prices for balancing areas in day-ahead market (CAISO October–December)



4.4 Bilateral price comparison

Figure 4.9 and Figure 4.10 compare 15-minute prices in different regions of the WEIM during peak hours (hours-ending 7 through 22) to day-ahead prices for comparable markets. These figures show the monthly average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

As shown in Figure 4.9, day-ahead prices in the Intercontinental Exchange for the Mid-Columbia trading hub averaged $38/MWh in Q4 2025, very similar to ISO 15-minute market prices in the Pacific Northwest ($37/MWh). Day-ahead Mid-Columbia ICE prices were notably lower than average ISO day-ahead market prices at the Pacific Gas and Electric load node ($46/MWh).

Day-ahead prices in the Intercontinental Exchange for the Palo Verde trading hub averaged about $32/MWh over the quarter, similar to ISO 15-minute market prices in the Desert Southwest ($31/MWh).

Day-ahead Palo Verde ICE prices were notably lower than average ISO day-ahead market prices at the Southern California Edison load node ($37/MWh).

Figure 4.9 Mid-C bilateral ICE vs. Pacific Northwest 15-minute market prices (peak hours)

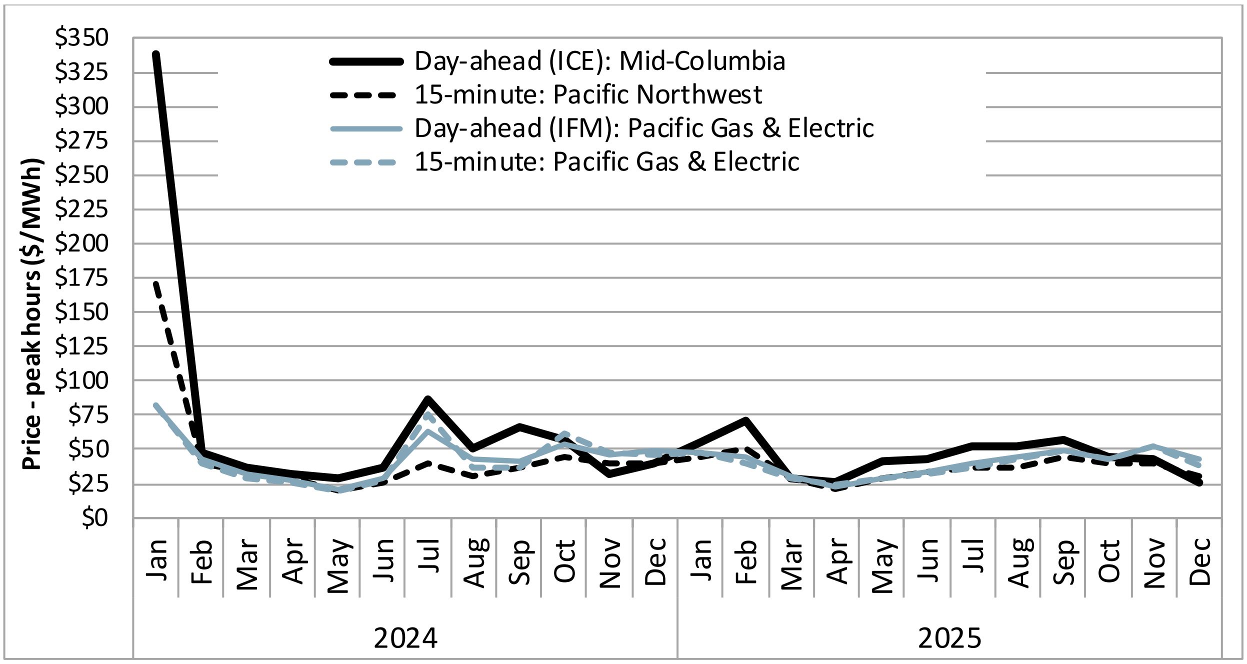


Figure 4.10 Palo Verde bilateral ICE vs. Desert Southwest 15-minute market prices (peak hours)

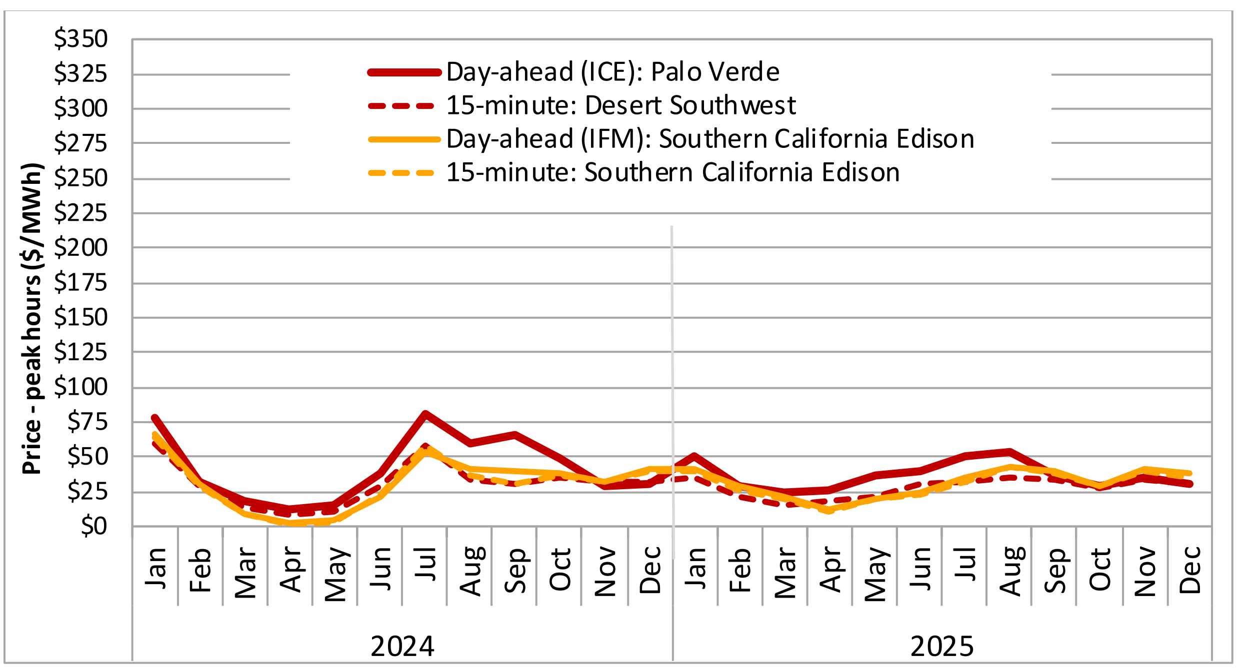


Figure 4.11 compares monthly average prices in the bilateral and ISO day-ahead markets for 2024 through the fourth quarter of 2025. The California ISO market day-ahead prices are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs).

Over the quarter, bilateral day-ahead prices at Mid-Columbia and Palo Verde averaged about $38/MWh and $32/MWh, respectively, while ISO day-ahead prices at Pacific Gas and Electric and Southern California Edison averaged around $46/MWh and $37/MWh, respectively.

Figure 4.11 Monthly average day-ahead and bilateral market prices

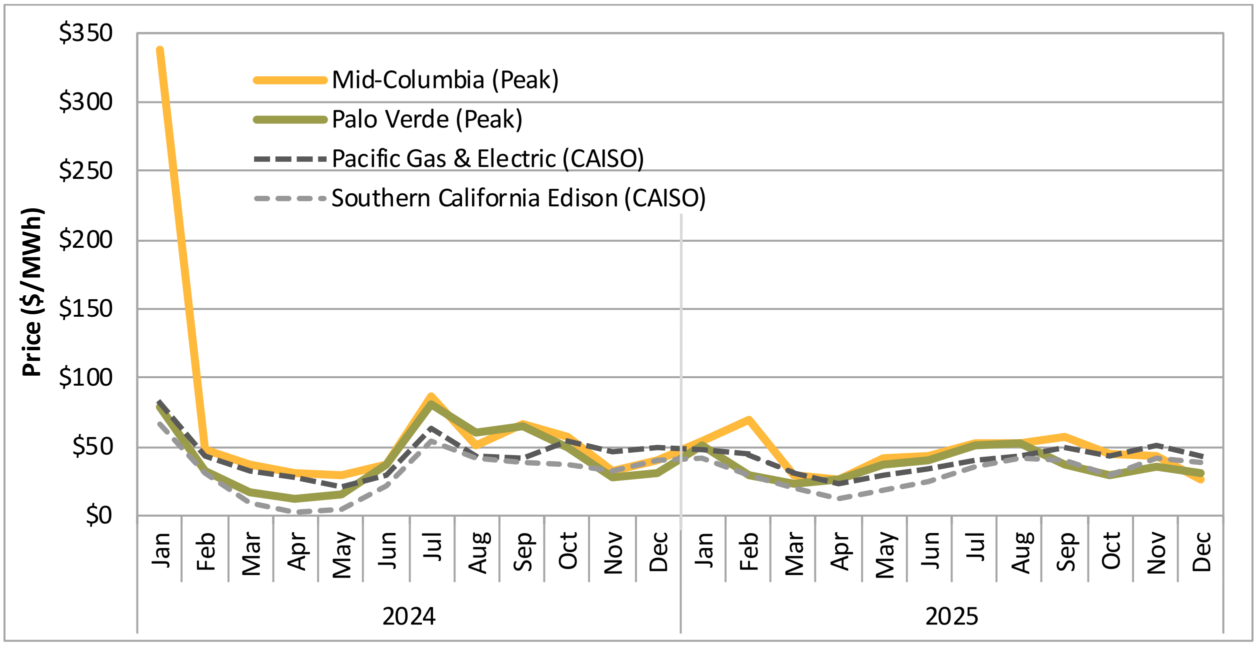
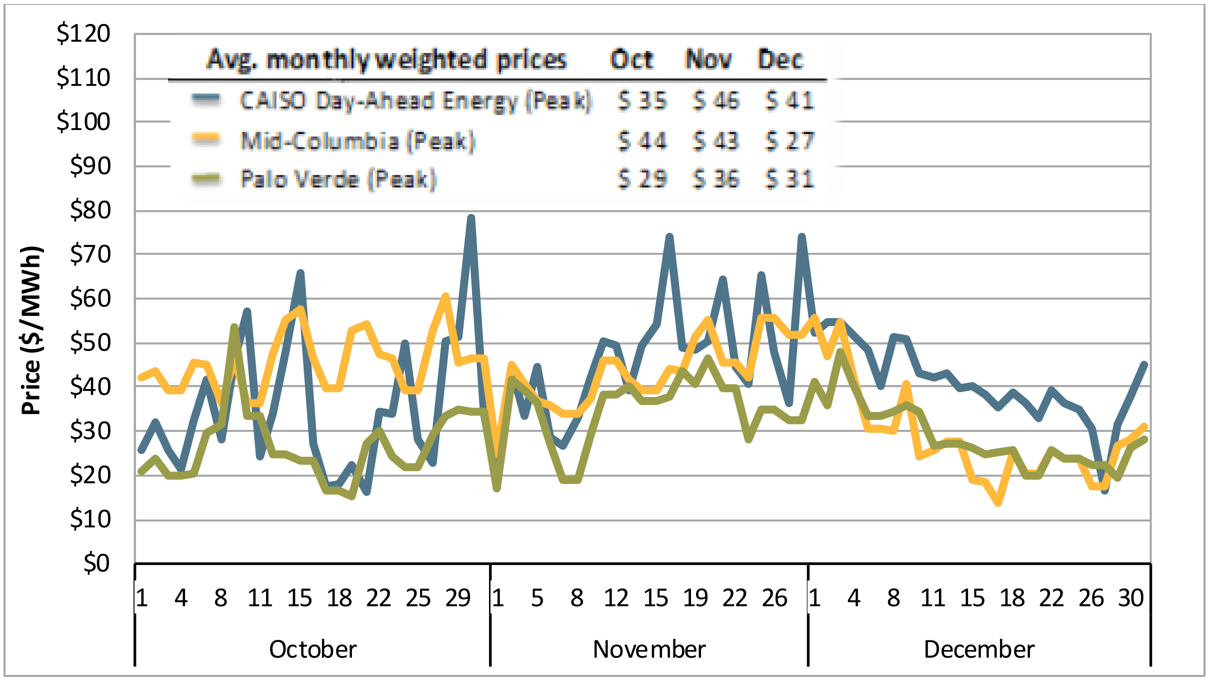


Figure 4.12 shows daily California ISO market day-ahead load weighted average peak prices across the three largest load aggregation points—Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric—as well as averages for the bilateral day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the ISO markets. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

On average, prices at Mid-Columbia exceeded those at Palo Verde in October and November by 52 percent and 21 percent, respectively; however, in December, prices at Mid-Columbia were 13 percent lower.

The California ISO FERC Order 831 policy will increase the ISO market energy bid cap to $2,000/MWh if a 16-hour block peak bilateral price, scaled and shaped into hourly prices according to the shape of ISO market hourly prices, exceeds $1,000/MWh. The ISO implemented enhancements to the maximum import bid price hourly energy shaping factor on November 16, 2024.[30] The ISO did not raise the energy bid cap and penalty prices to $2,000/MWh in the fourth quarter of 2025.

Figure 4.12 Day-ahead California ISO and bilateral market prices (October–December)



Average day-ahead bilateral prices from the Intercontinental Exchange were also compared to real-time hourly energy prices traded at the Mid-Columbia and Palo Verde hubs for all hours of the quarter, using data published by Powerdex. At the Mid-Columbia hub, average day-ahead prices were greater than the average real-time prices (from Powerdex) by about $0.75/MWh. At the Palo Verde hub, average day-ahead prices were lower than average real-time prices (from Powerdex) by about $3.20/MWh.

4.5 Price variability

This section analyzes the frequency of prices exceeding $250/MWh and the occurrence of negative prices. Two groups of balancing authority areas (BAAs) were included: the first group consists of those participating in both the day-ahead and real-time markets, which as of this quarter includes only the California ISO balancing area.[31] The second group comprises balancing areas participating exclusively in the real-time market, which includes all WEIM entities aside from the California ISO balancing area.

30 *Modification of Maximum Import Bid Price Hourly Energy Shaping Factor effective 11/16/24*, California ISO market notice, November 13, 2024: https://www.caiso.com/notices/modification-of-maximum-import-bid-price-hourly-energy-shaping-factor-effective-11-16-24#:~:text=The%20California%20ISO's%20Price%20Formation%20Enhancements%20modification,modification%20is%20in%20Business%20Practice%20Manual%20(BPM)

31 The frequency is calculated by counting the number of intervals with extreme prices at either the Default Load Aggregation Point (DLAP) for the CAISO balancing area, or EIM Load Aggregation Point (ELAP) for the WEIM areas not participating in the day-ahead market. The frequency is expressed as a ratio of these occurrences to the total number of intervals for each month, multiplied by the number of DLAPs and ELAPs within each group.

High prices

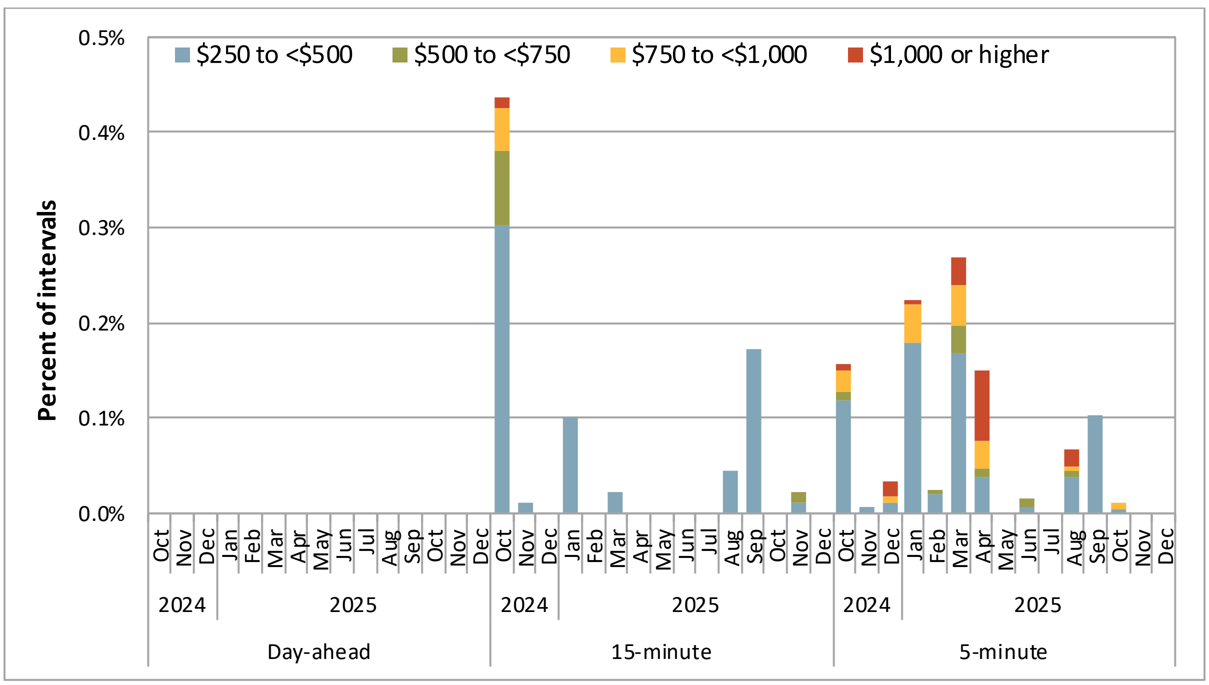
Figure 4.13 shows the monthly frequency of high prices across all three markets for the balancing area participating in both the day-ahead and real-time markets from October 2024 to December 2025.[32] Figure 4.14 illustrates the monthly frequency of high prices for balancing areas participating only in the real-time market during the same period.[33]

In the day-ahead market, the frequency of high prices over $250/MWh was zero percent this quarter, in line with the same quarter last year.

In the 15-minute market, the frequency of high prices for the balancing area participating in the day-ahead market decreased by 95 percent, dropping from 0.15 percent in Q4 2024 to 0.01 percent in Q4 2025. For balancing areas participating exclusively in the real-time market, the frequency of high 15-minute market prices also decreased notably, from 0.12 percent in Q4 2024 to 0.05 percent in Q4 2025.

In the 5-minute market, the frequency of high prices for the balancing area participating in the day-ahead market decreased by 94 percent, down from 0.07 percent in Q4 2024 to 0.004 percent in Q4 2025. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market decreased by 57 percent, from 0.12 percent to 0.05 percent.

Figure 4.13 Frequency of high prices in BAAs participating in the day-ahead market (CAISO)



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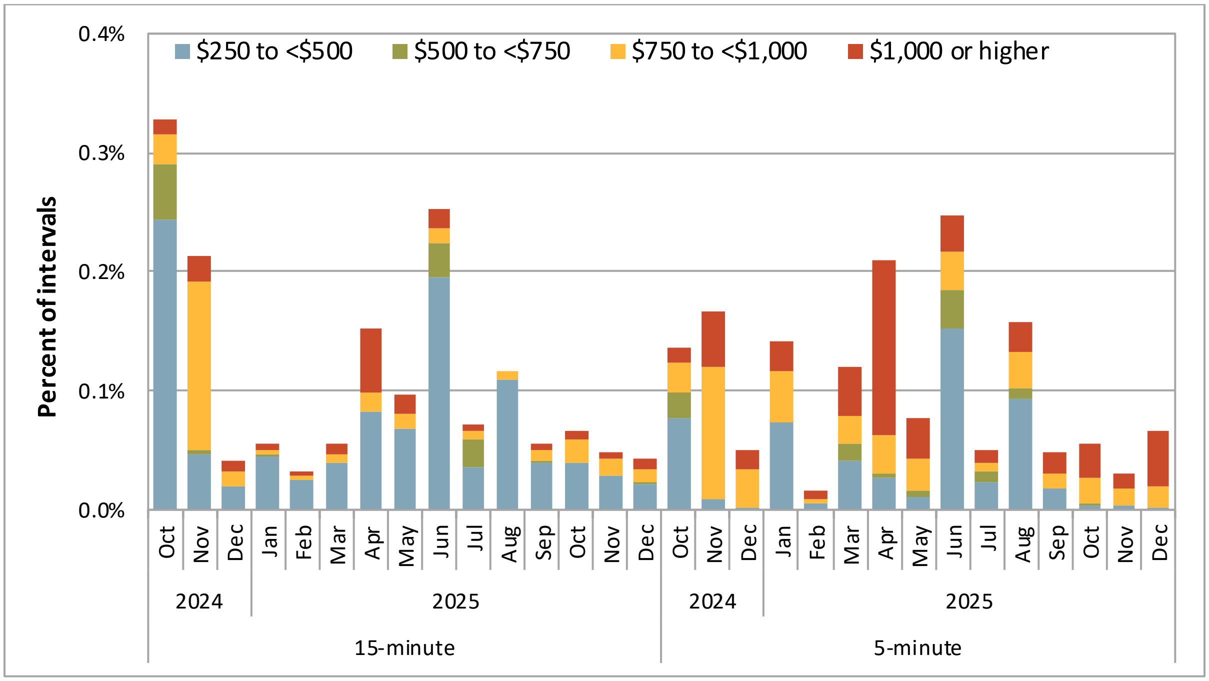
32 The frequency of high prices was measured at the three largest DLAPs within the California ISO balancing area: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

33 The frequency of high prices was measured at EIM Load Aggregation Points (ELAPs).

Figure 4.14 Frequency of high prices in BAAs participating only in the real-time markets



Negative prices

Figure 4.15 and Figure 4.16 show the frequency of negative prices across two groups of balancing areas: those participating in the day-ahead market and those participating only in the real-time markets, spanning the period from October 2024 to December 2025.

Negative prices tend to be most common when renewable production is high and demand is low. This is because in these scenarios, renewable resources are more likely to be the marginal energy source, and low-cost renewable resources often bid at or below zero dollars.

For balancing areas participating in the day-ahead market—currently just the CAISO balancing area—the frequency of negative prices increased in the three markets. In the day-ahead market, the frequency increased from 2.2 percent to 2.7 percent compared to the same quarter of the previous year. In the 15-minute market, it increased from 3.1 percent to 3.9 percent, and in the 5-minute market, it increased from 3.4 percent to 4.3 percent.

For the BAAs participating exclusively in the real-time markets—all balancing areas in WEIM besides CAISO—the frequency of negative prices also showed an increase across the 15-minute and 5-minute markets, with an average increase of 14 percent compared to the same quarter of the previous year. For instance, in the 15-minute market, the frequency increased from 2 percent to 2.2 percent. In the 5-minute market, it increased from 2.3 percent to 2.7 percent during this quarter.

Figure 4.15 Frequency of negative prices in BAAs participating in the day-ahead market (CAISO)

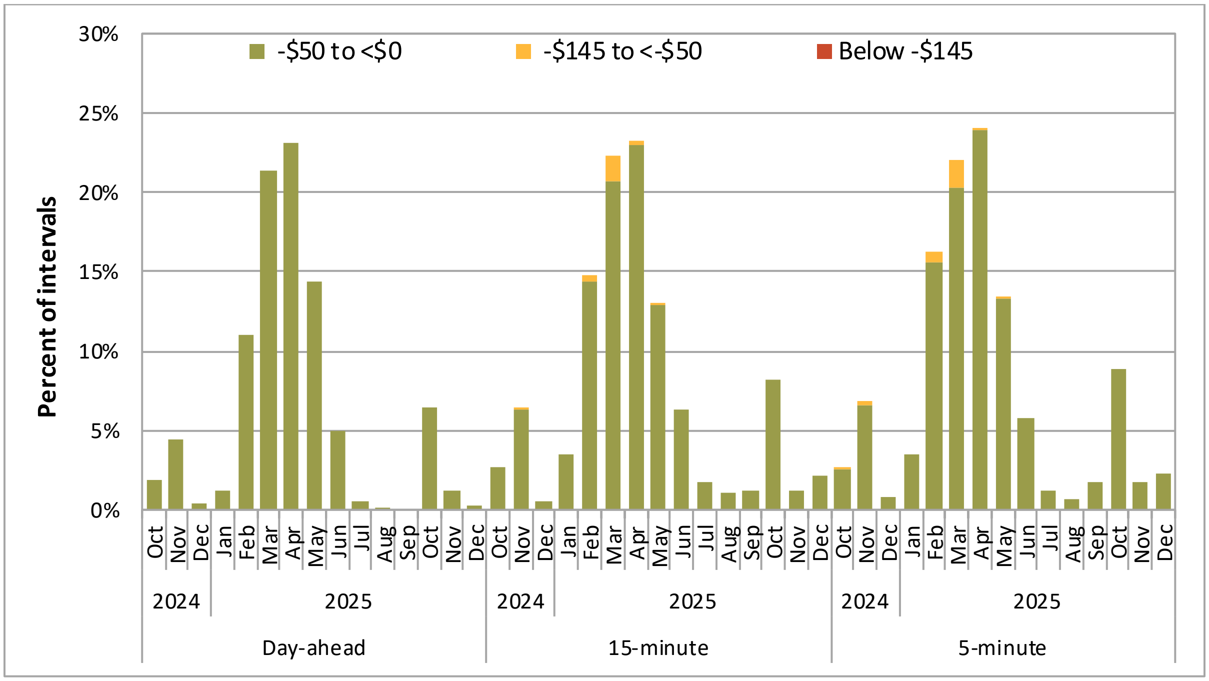
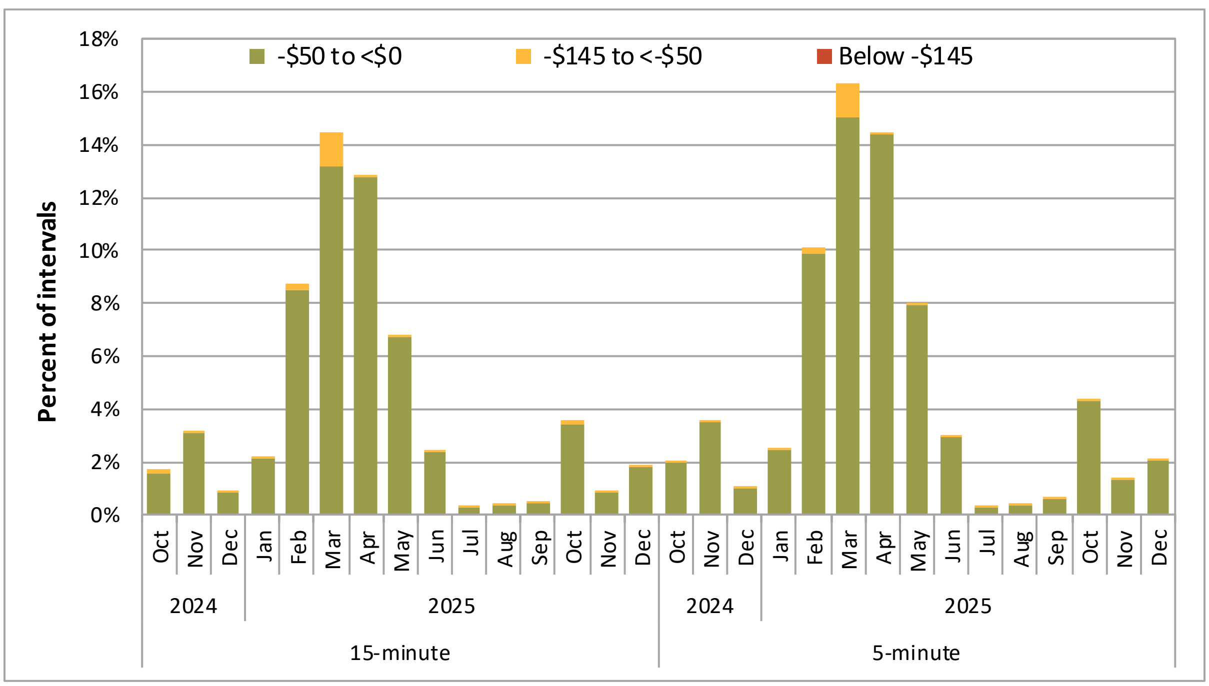


Figure 4.16 Frequency of negative prices in BAAs participating only in the real-time markets



5 WEIM transfers

This section provides an overview of WEIM transfers as well as constraints impacting WEIM transfers. Key observations from the quarter include the following:

The average volume of WEIM transfers across the system was 4,020 MW during the fourth quarter of 2025, compared to 4,660 MW in the previous quarter and 3,870 MW in the same quarter of the previous year. These transfers helped to displace expensive generation and meet load across the footprint.

WEIM transfers between regions continued to be significantly different during mid-day (solar hours) than during evening and early morning (non-solar) hours. During solar hours, transfers were largely from the CAISO and Intermountain West balancing areas to other WEIM regions. During non-solar hours, transfers were lower and largely from the Desert Southwest and Intermountain West regions to California and the Pacific Northwest. On average for each hour of the quarter, the Intermountain West region was exporting out of the region on net.

The Pacific Northwest region continued to have the lowest transfer capacity into and out of their region. Additional transfer capacity in the 5-minute market relative to the 15-minute market between the Pacific Northwest and California regions resulted in less WEIM import congestion in the 5-minute market than in the 15-minute market, but balancing areas in the Pacific Northwest region were still frequently separated by congestion from the larger WEIM system.

Transfers for El Paso Electric, LADWP, and Tucson Electric Power were regularly constrained by intertie constraints that each balancing area can use to manage total or net WEIM transfers into or out of their system. Net exports for El Paso Electric were constrained in around 2.5 percent of intervals while net exports for LADWP were constrained in around 1.4 percent of intervals because of a limit set on net transfers for the balancing area. For Tucson Electric Power, total imports were constrained in around 3 percent of intervals while total exports were constrained in around 2 percent of intervals.

5.1 Energy transfer

One of the key benefits of the WEIM is the ability to transfer energy between balancing areas in the 15-minute and 5-minute markets. These transfers reflect regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint.

WEIM transfers are defined as either base, dynamic, or static. Base WEIM transfers are fixed bilateral transactions between WEIM entities and are not optimized in the market. Dynamic WEIM transfers are optimized in all markets. Static WEIM transfers are a smaller set of transfers between the Pacific Northwest and California regions that are only optimized in the 15-minute market. WEIM transfers in this section exclude the base WEIM transfer schedules and therefore reflect only dynamic or static WEIM transfer schedules optimized in the market.

Figure 5.1 summarizes the average volume of WEIM transfers in the 5-minute market by hour during the last five quarters. During the fourth quarter of 2025, the average volume of transfers across the system was around 4,020 MW, down from the previous quarter when it was around 4,660 MW. In comparison to the same quarter of the previous year, the average volume of transfers in 2025 was higher (4,020 MW versus 3,870 MW for the fourth quarter of 2024).

Figure 5.2 summarizes average inter-regional transfers by hour during the last five quarters.[34] Figure 5.3 shows the same information for only Q4 2025. The bars show *net* WEIM transfers for each region by hour.[35] Net WEIM exports for a region are shown as negative and net WEIM imports for a region are shown as positive. WEIM transfers between regions continued to be significantly different during mid-day (solar hours) than during evening and early morning (non-solar) hours. During solar hours, transfers were largely from the CAISO and Intermountain West balancing areas to other WEIM regions. During non-solar hours, transfers were lower and largely from the Desert Southwest and Intermountain West regions to California and the Pacific Northwest. On average during the fourth quarter of 2025, the Intermountain West region exported on net in every hour.

Figure 5.4 and Figure 5.5 show average WEIM transfers in the 5-minute market by balancing area in the mid-day and peak periods during the quarter.[36] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area.

As shown in Figure 5.4, the CAISO balancing area exported on net over 1,000 MW on average out to neighboring balancing areas during the mid-day hours. These hours typically contain the highest levels of exports out of the CAISO balancing area because of significant solar production. These exports were largely to balancing areas in the Pacific Northwest and California regions. During the peak period (Figure 5.5), balancing areas in the Intermountain West and Desert Southwest regions exported on net around 960 MW on average out to balancing areas outside this combined region (mostly to California).

[34] See Appendix A for figures on the average hourly transfers by quarter for each WEIM balancing area.

[35] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system.

[36] In these charts, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 5.1 Average 5-minute market WEIM transfer volume by hour and quarter (5-minute market, Q4 2024 – Q4 2025)

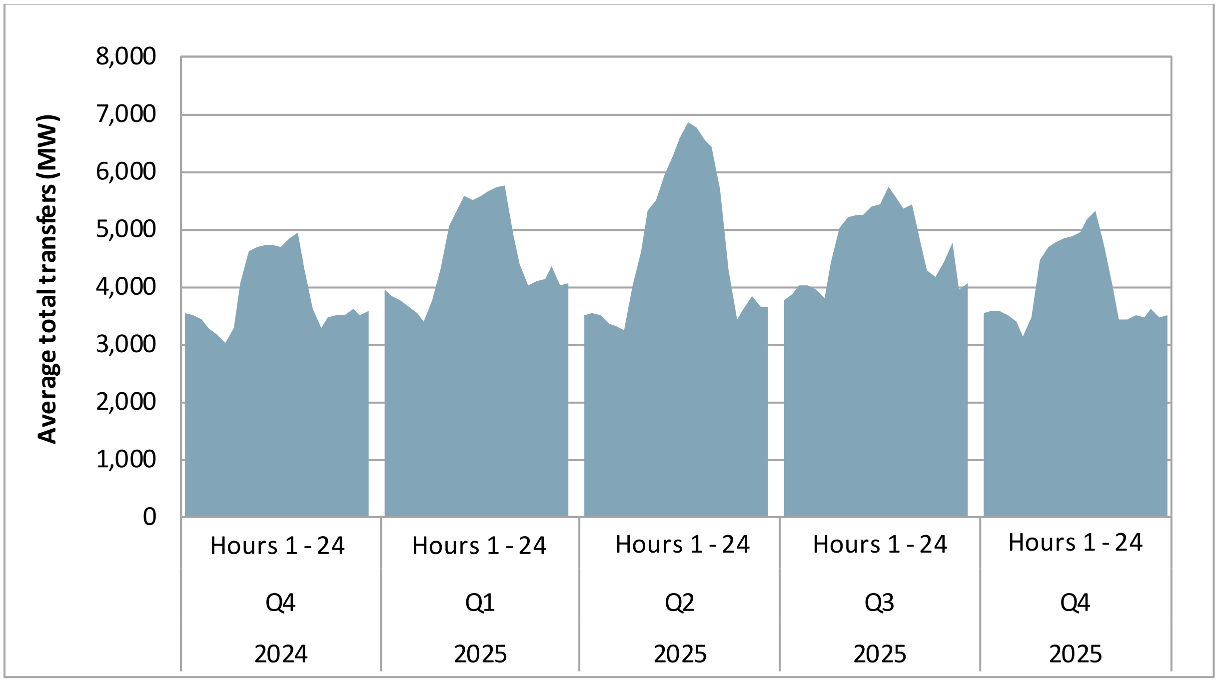


Figure 5.2 Average 5-minute market inter-regional WEIM transfers by hour (Q4 2024 – Q4 2025)

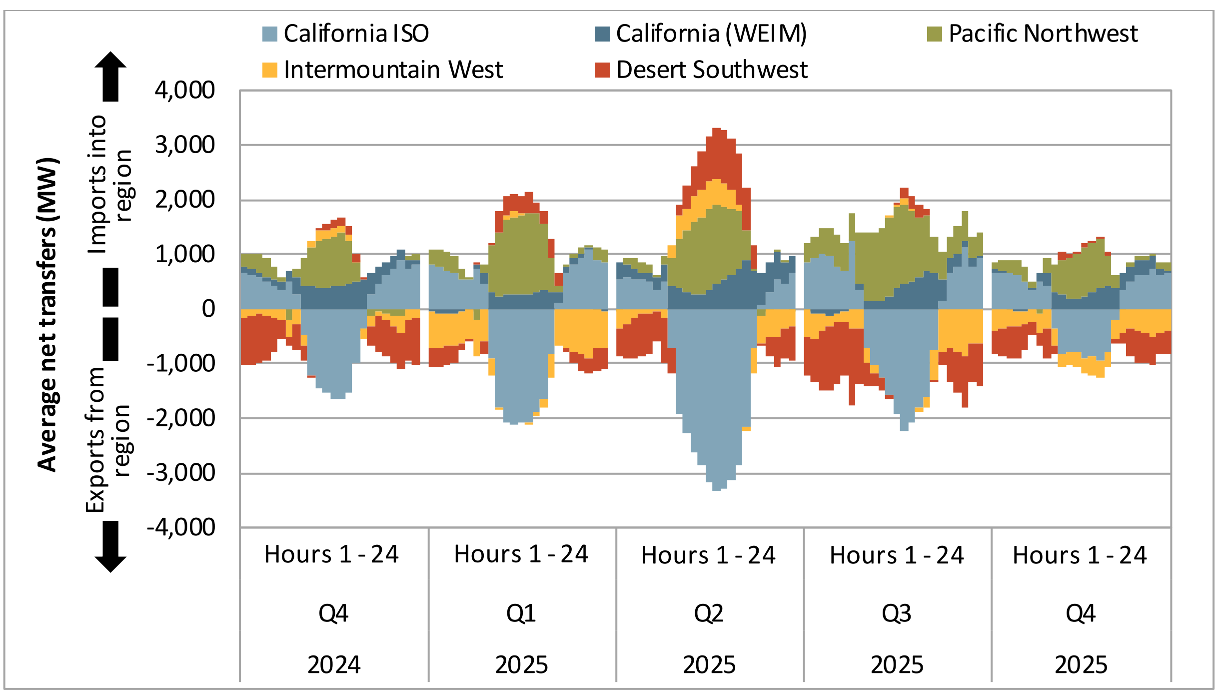


Figure 5.3 Average 5-minute market inter-regional WEIM transfers by hour (Q4 2025)

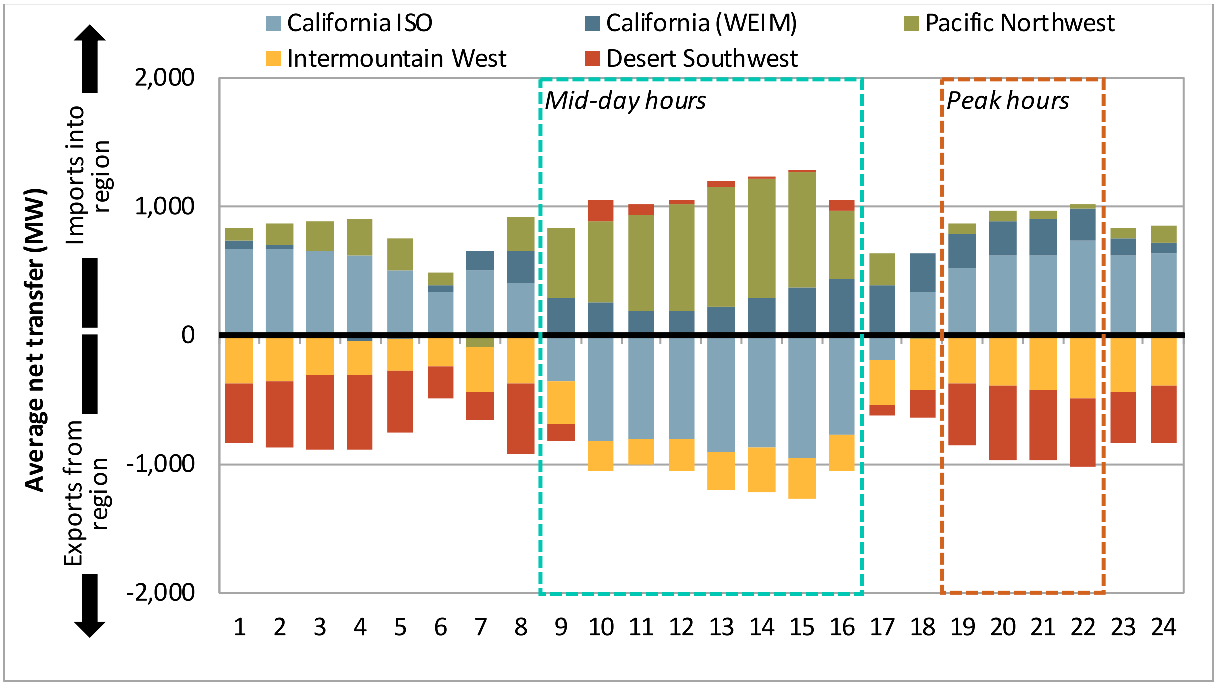


Figure 5.4 Average 5-minute market WEIM exports in mid-day hours (Q4 2025)

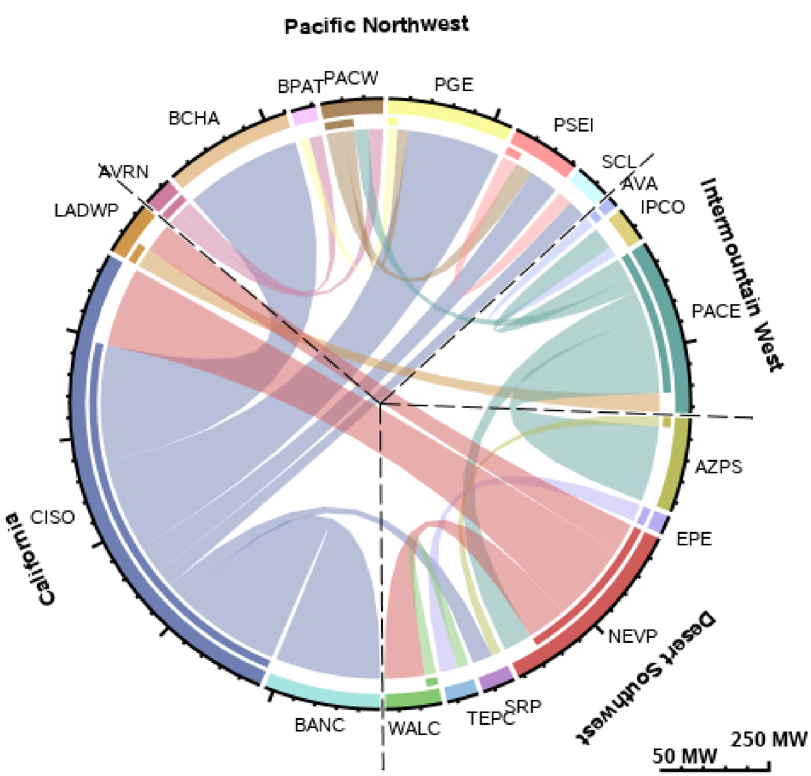
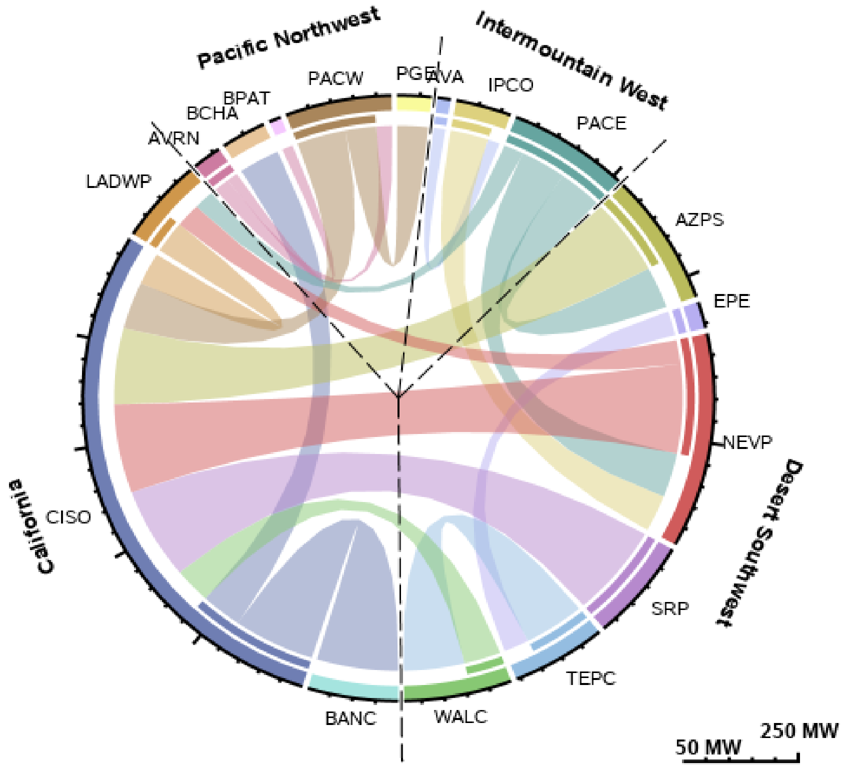


Figure 5.5 Average 5-minute market WEIM exports in peak load hours (Q4 2025)



5.2 WEIM transfer limits

WEIM transfers between areas are constrained by *transfer limits*. These limits largely reflect transmission and interchange rights made available to the market by participating WEIM entities.

Figure 5.6 shows WEIM transfer capacity (or transfer limits) that is available in the 5-minute market to support the transfer of energy between balancing areas and regions in the Western Energy Imbalance Market.[37] The width of each path reflects the size of the WEIM transfer capacity. WEIM transfer capacity between each balancing area within a region is shown in gray, while transfer capacity from a balancing area into and out of the region is aggregated, and shown in the colored paths.

[37] Transfer capacity (limits) were categorized by the average limit from both the import and export direction. Transfer paths with 5 or less MW of transfer capacity on average for the quarter are not shown.

Figure 5.6 Average 5-minute market WEIM transfer limits by balancing area (Q4 2025)

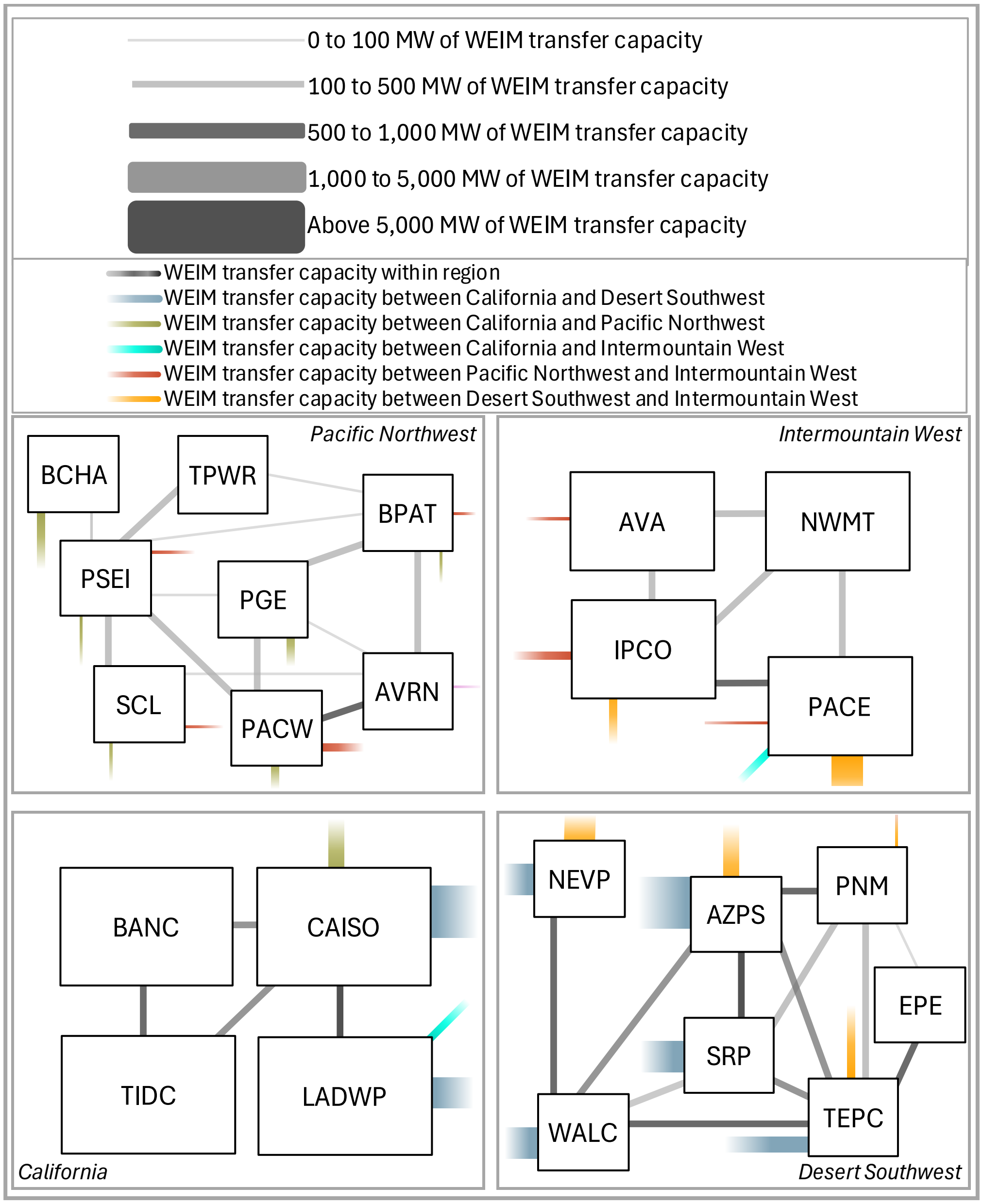


Table 5.1 summarizes average regional transfer capacity.[38] Total WEIM transfer capacity between balancing areas *within a region* is shown in the gray cells. Transfer capacity *between regions* is shown in the remaining cells. The sum of each column reflects the average total import capacity into the region, while the sum of each row reflects the average total export capacity out of the region.

[38] These amounts only reflect scheduling limits on individual WEIM Energy Transfer System Resources (ETSRs) and therefore do not account for either (1) total scheduling limits that can be the result of a resource sufficiency evaluation failure or (2) intertie constraints that can limit WEIM transfers.

Most WEIM transfer schedules are defined as *dynamic* where transfers are optimized in both the 15-minute and 5-minute markets, generally using the same transmission limits. However, for paths between California and the Pacific Northwest where there are dynamic transmission capability constraints, it is necessary to differentiate between static WEIM transfers that are used for the 15-minute energy transfer schedule and limit (and are not re-optimized in the 5-minute market); and dynamic WEIM transfers that are only used for the incremental 5-minute energy transfer schedule and limit. For transfers between California and the Pacific Northwest (green cells), the first number shows the transfer capacity on static transfers in the 15-minute market, while the second number shows the incremental transfer capacity that is available on dynamic transfers in the 5-minute market.

For the Pacific Northwest region, there was an average of around 1,121 MW of import transfer capacity and 725 MW of export transfer capacity into or out of the region in the 15-minute market. The lack of transfer capacity out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

Table 5.1 Average regional WEIM transfer limits (Q4 2025)

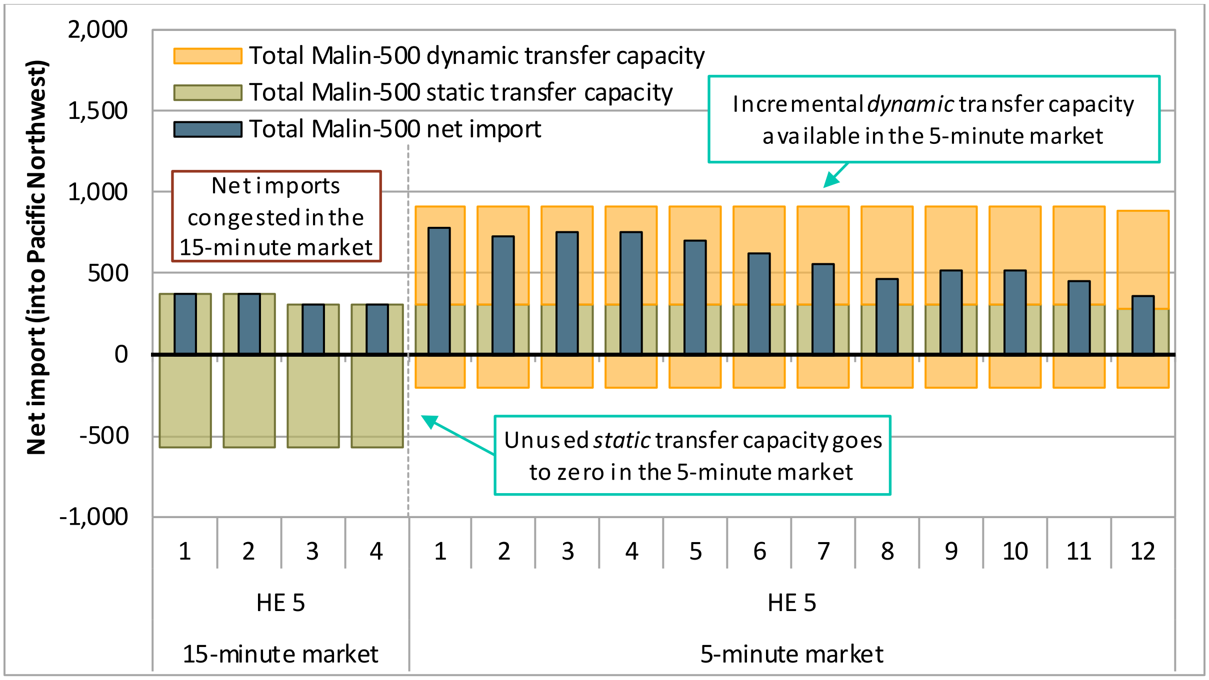
Dynamic WEIM transfer capacity within region (15-minute market)
Dynamic WEIM transfer capacity out of region (15-minute market)
Static WEIM transfer capacity out of region (15-minute market) / Incremental dynamic capacity out of region (5-minute market)

From region	To region: California	Desert Southwest	Intermountain West	Pacific Northwest	*Total out-of-region export limit*
California	22,933	31,852	226	766 / 401	32,844 / 401
Desert Southwest	32,964	55,765	2,038		35,002
Intermountain West	232	1,710	3,714	355	2,297
Pacific Northwest	507 / 232		218	4,402	725 / 232
Total out-of-region import limit	33,703 / 232	33,562	2,482	1,121 / 401	

In the fourth quarter, additional transfer capacity in the 5-minute market between the Pacific Northwest and California helped to alleviate WEIM transfer congestion in the Pacific Northwest. In particular, around 400 MW of additional import capacity on dynamic WEIM transfer paths from California into the Pacific Northwest resulted in less WEIM import congestion in the 5-minute market relative to the 15-minute market.

As an example, Figure 5.7 shows net transfer capacity and imports going into the Pacific Northwest on the Malin 500 intertie for an hour (hour-ending 5). The green bars show the static transfer capacity in the 15-minute and 5-minute markets. The yellow bars show incremental dynamic transfer capacity that was available in the 5-minute market. The dark blue bars show the net import that was optimized in both markets. Here, imports on the static transfers going into the Pacific Northwest in the 15-minute market reached their limits, contributing to congestion and higher prices in the 15-minute market. In the 5-minute market, around 600 MW of additional import capacity in this hour on the dynamic transfers alleviated the congestion between the balancing areas in the Pacific Northwest and the rest of the WEIM system. DMM has asked the ISO to review why this transfer capacity can't be made available in the 15-minute market.

Figure 5.7 Total transfer capacity and net imports on Malin 500 into the Pacific Northwest (November 25, 2025 HE5)



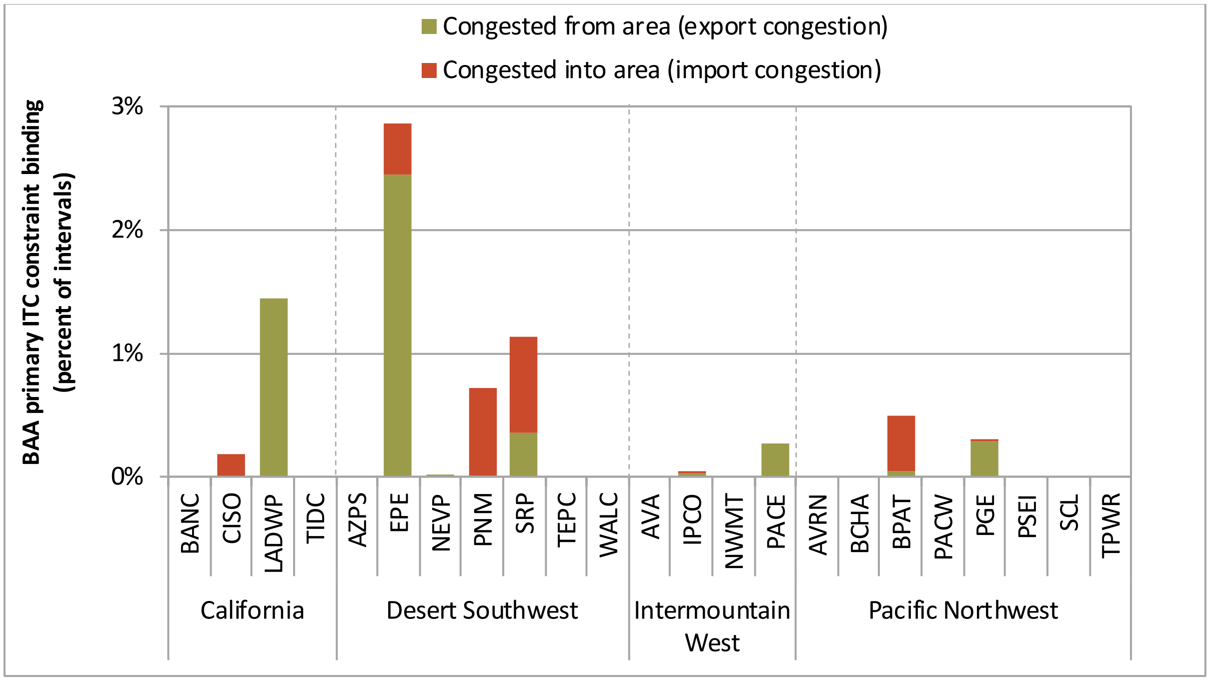
5.3 WEIM intertie constraints

An intertie constraint (ITC) is a scheduling limit applied to a specified set of scheduling points or intertie resources. This ensures that net transfers of the imports or exports (considering counterflow) do not violate the physical or contractual limits. In the WEIM, these can also be used to manage WEIM transfers in a balancing area. Here, a *primary* intertie constraint is modeled for each balancing area that is mapped to all of their non-base WEIM transfers. A WEIM entity can use this constraint to effectively manage all these WEIM transfers into or out of their system, on net, without needing to adjust individual transfer limits.

Figure 5.8 shows the percent of intervals in the 5-minute market in which the primary intertie constraint—that limits all non-base WEIM transfers on net for a balancing area—was binding in either the import or export direction, resulting in congestion. Of note, net *exports* for El Paso Electric were constrained in around 2.5 percent of intervals because of this constraint. When this constraint was binding in the export direction, net exports were limited to roughly 120 MW on average. The constraint limiting net exports for LADWP was binding in roughly 1.4 percent of intervals. When this constraint was binding, net exports were limited to around 600 MW.

The CAISO balancing area used its primary WEIM intertie constraint to limit net WEIM transfers for around 6.5 hours between September 30 and October 1 following some data issues. During this period, net imports and exports were mostly limited to 500 MW. The result is that the rest of the WEIM system was separated and export constrained at a lower price relative to the CAISO balancing area.

Figure 5.8 Frequency of primary ITC constraint binding for net WEIM transfers (5-minute market, Q4 2025)



A WEIM entity can also set up intertie constraints that are mapped to a subset of their WEIM transfers (non-primary). For example, the entity can set up an intertie constraint that is mapped to only WEIM transfers at a specific intertie. A WEIM entity can also create an intertie constraint that is mapped to either only WEIM imports or only WEIM exports, which will limit total imports or total exports rather than net WEIM transfers. During the quarter, Tucson Electric enforced an intertie constraint that was binding for total WEIM imports in around 3 percent of intervals and for total WEIM exports in around 2 percent of intervals. The limit was around 500 MW on average in both directions when these constraints were binding.

6 Congestion

This section analyzes the impact of congestion from various constraint types in the real-time market and in the day-ahead market. Congestion in a nodal energy market occurs when the market model determines that flows have reached or exceeded the limit of a transmission constraint. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission-constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions.

Figure 6.1 through Figure 6.3 show the average impact of congestion on real-time market prices in Q4 of 2024 and 2025. Blue bars represent the 2024 impact, while red bars represent the 2025 values. The congestion impact was calculated as the average price impact across both the 15-minute and 5-minute markets for all intervals during the quarter.

Figure 6.1 shows the total price impact from all congestion sources—WEIM transfer and internal flow-based constraints. Figure 6.2 isolates the impact from WEIM transfer constraints. Figure 6.3 shows the impact from internal flow-based constraints.[39]

Similar to the same quarter last year, the Q4 congestion pattern showed a south-to-north trend, but with lower magnitude compared to quarters one and two. This quarter, congestion contributed to relatively higher prices in the Northern California, Intermountain West, and Pacific Northwest regions relative to the Desert Southwest and Southern California regions.

WEIM transfer constraints remained a key contributor to the overall price impact, with prices elevated across most BAAs in both this quarter and the same quarter last year. While no price spikes were observed, as seen in PNM last year, transfer congestion contributed to elevating prices in most BAAs relative to the CAISO BAA. Transfer congestion contributed to reducing prices in PACE and LADWP relative to the CAISO BAA.

Internal congestion contributed to a south-to-north price separation this quarter, following the same general trend as the same quarter of last year, with slightly lower magnitude. Internal congestion contributed to relatively higher prices in Northern California, the Intermountain West, and the Pacific Northwest relative to prices in Southern California and the Desert Southwest.

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39 Language in the report describing congestion as “increasing" or “decreasing” a price is describing the change relative to the particular reference bus used in that market. The ISO uses a particular reference bus—distributed amongst load nodes according to the load at each node’s percentage of total load. However, in theory, any node could be used as the reference bus, and changing the reference bus would change the value of how much congestion “increased” or “decreased” prices at a node relative to the reference bus. While the specific value of an increase or decrease in congestion price is relative to the reference bus, the *difference* between the impact of congestion on one node and another node is not dependent on the reference bus. Therefore, in assessing the impacts of congestion on prices, DMM suggests the reader focus on the difference of the price impacts between nodes or areas, and not on the specific value of an increase or decrease to one node or area.

Figure 6.1 Average impact of total congestion on real-time market price (2024–2025)

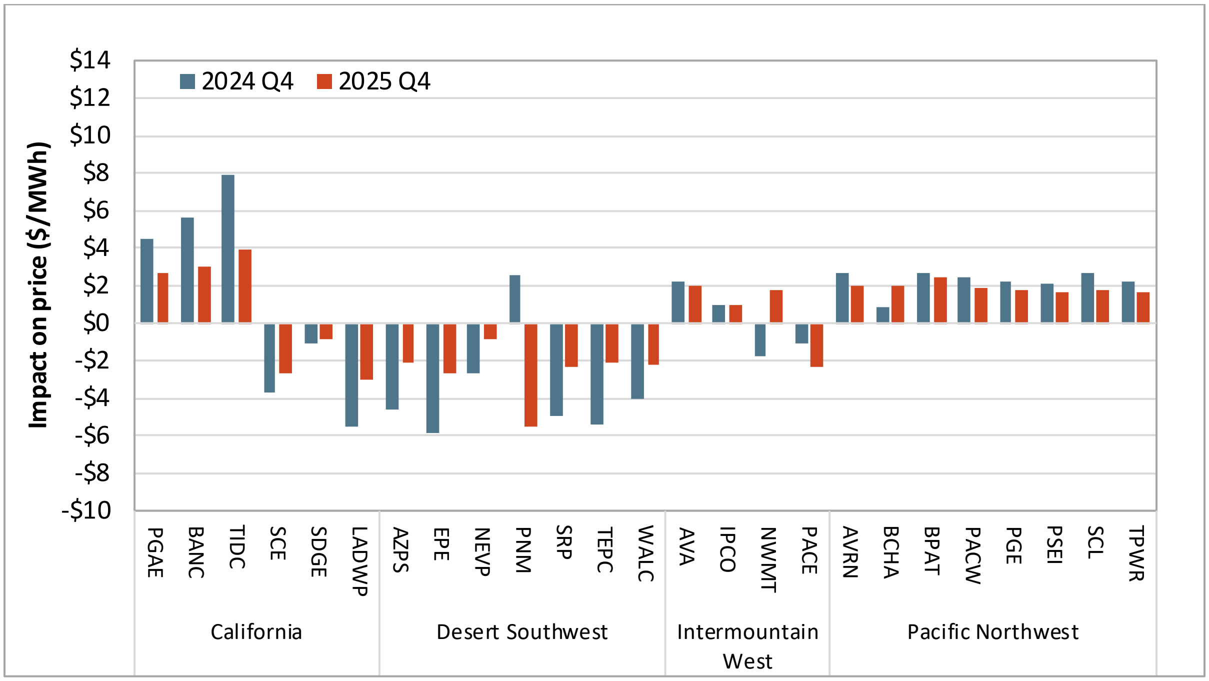


Figure 6.2 Average impact of transfer congestion on real-time market price (2024–2025)

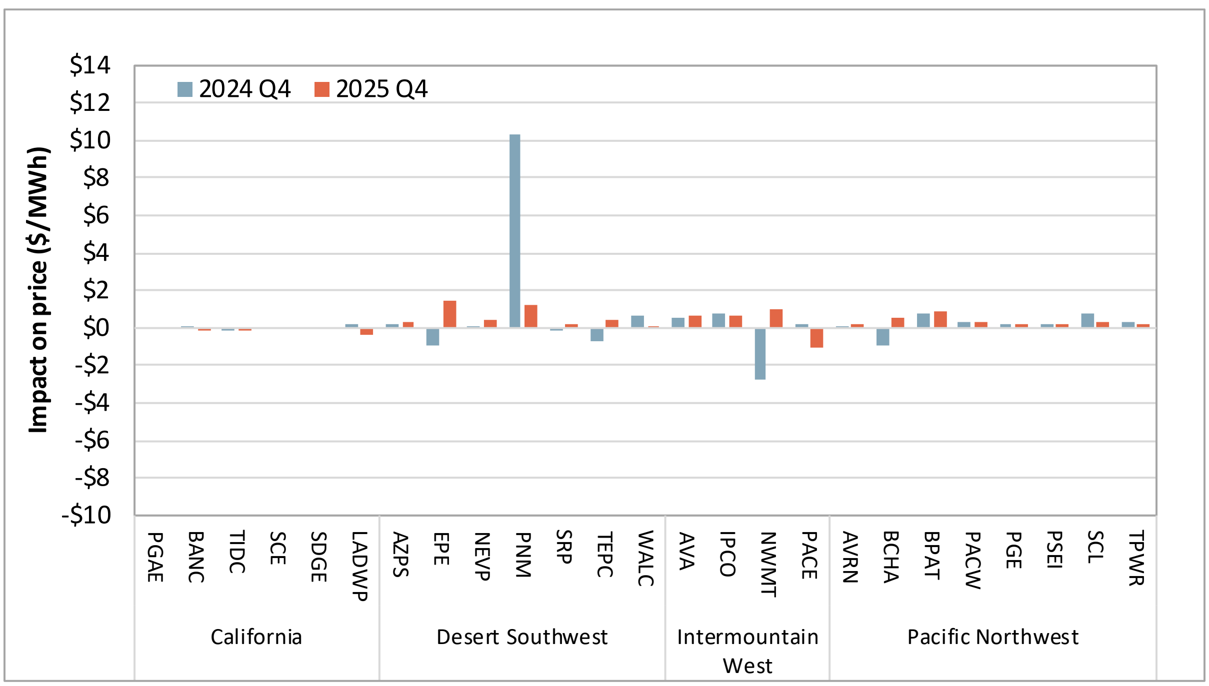
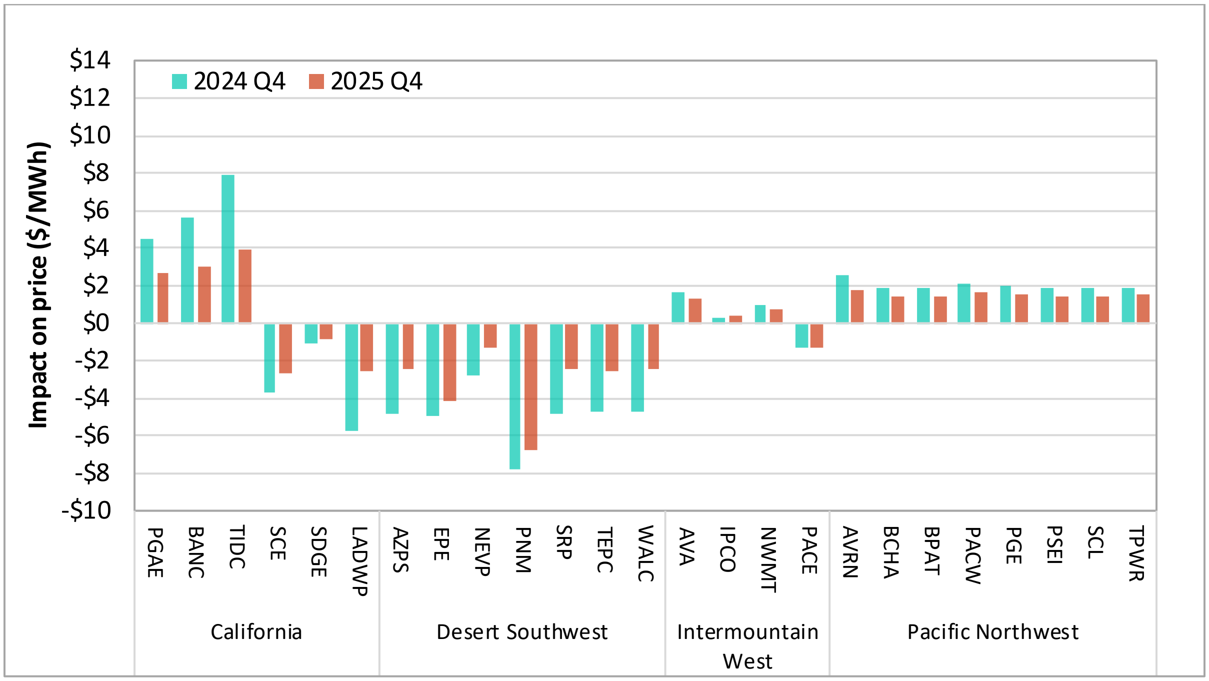


Figure 6.3 Average impact of internal congestion on real-time market price (2024–2025)



The following sections present further details on price impacts from different sources of congestion. Section 6.1 addresses congestion on the constraints limiting WEIM transfers between balancing areas in the real-time market. Section 6.2 addresses real-time market internal congestion.[40] Section 6.3 analyzes day-ahead market congestion rent and loss surpluses. Section 6.4 addresses intertie constraint congestion in the day-ahead market. Lastly, Section 6.5 addresses the impact of internal congestion on the day-ahead market.

6.1 WEIM transfer constraint congestion

When limits on constraints impacting WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to prevailing system prices. Figure 6.4 shows the percent of intervals and overall price impact of 15-minute market WEIM transfer constraint congestion in each balancing area during the quarter.[41] Figure 6.5 shows the same information for the 5-minute market. The congestion on the WEIM transfer constraints is measured relative to a reference price in the CAISO balancing area. Congested from area reflects that prices are lower in the balancing area because of limited export capability out of the area or region, relative to the

[40] This report defines internal congestion as congestion on any constraint within a balancing authority area. Therefore, the effect of internal congestion on the CAISO balancing area may include effects of congestion from transmission elements within WEIM balancing areas. Analysis of internal congestion excludes transfer constraints and intertie constraint congestion.

[41] The frequency is calculated as the number of intervals where the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices. This accounts for any constraint that can limit WEIM transfers between balancing areas, including (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraint and intertie scheduling limits.

CAISO (and connected WEIM system). Congestion into area reflects that prices are higher within an area or region because of limited import capability into the area or region.[42]

WEIM transfer congestion was especially prevalent this quarter in the Pacific Northwest. The average frequency of congested intervals was 18 percent in the import direction and 16 percent in the export direction, measured across both the 15-minute and 5-minute markets. As a result, prices in the Pacific Northwest were elevated by an average of $0.9/MWh in the 15-minute market, and decreased by about $0.1/MWh in the 5-minute market.

In the Pacific Northwest, transfer congestion occurred more often in the 15-minute market than in the 5-minute market. Average binding frequency across both import and export directions reached 17 percent in the 15-minute market, compared to 15 percent in the 5-minute market. This difference reflects additional transfer capacity between the Pacific Northwest and California regions in the 5-minute market, as discussed further in Chapter 5.

Powerex (BCHA) was frequently constrained relative to the CAISO balancing area because of WEIM transfer congestion during the quarter. In the 5-minute market, Powerex was import constrained during around 37 percent of intervals and export constrained during around 31 percent of intervals. On average for the quarter, Powerex prices were $1.2/MWh higher because of WEIM transfer congestion in the 15-minute market, and $0.1/MWh lower in the 5-minute market. The overall price impact remained relatively small as Powerex experienced congestion in both import and export directions—offsetting price increases from import congestion with decreases from export congestion.

In the Desert Southwest, prices were generally elevated relative to system prices due to transfer congestion, particularly in the 5-minute market. EPE and TEPC experienced a relatively high frequency of transfer congestion in the Desert Southwest region. This was partly because these BAAs manage the net WEIM transfer into or out of their systems through intertie constraints.

42 When a balancing area has net WEIM transfer import congestion into the area, the market software triggers local market power mitigation procedures for resources in that area. If bid in supply after removing the three largest suppliers is less than the generation dispatched in the area in the market power mitigation run, bids in excess of the higher of default energy bids and the competitive locational marginal price (LMP) will be replaced by the higher of default energy bids and the competitive LMP.

Figure 6.4 Frequency and impact of WEIM transfer congestion in the 15-minute market (Q4 2025)

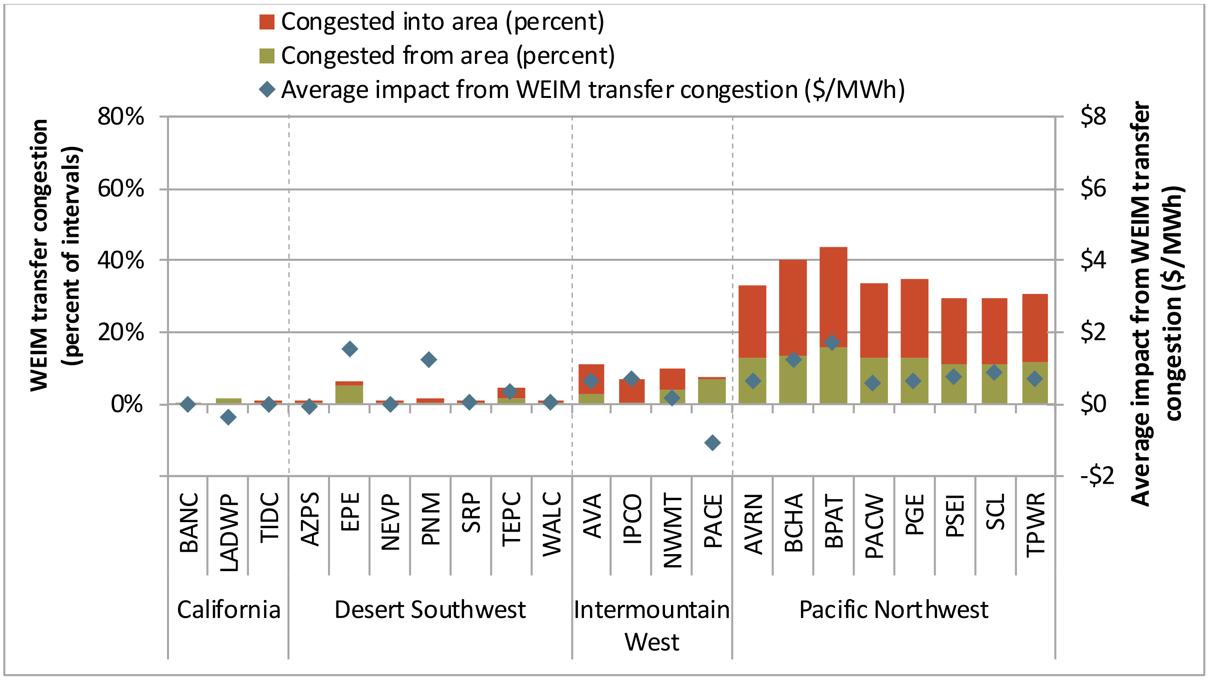
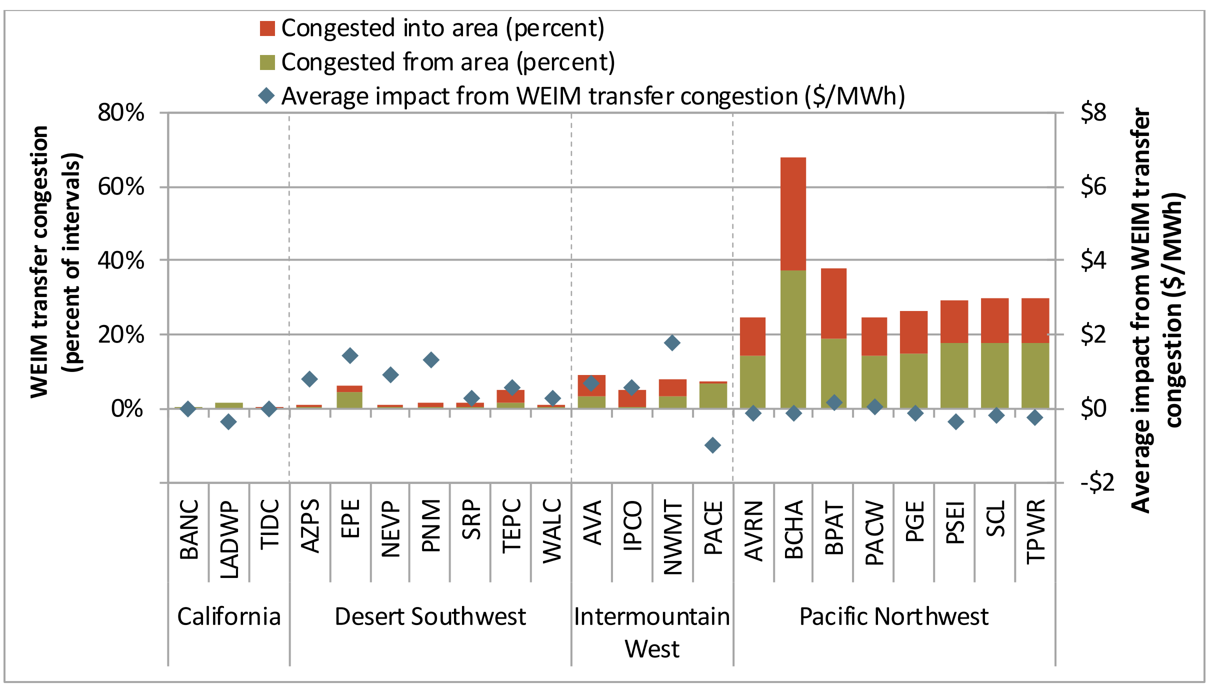


Figure 6.5 Frequency and impact of WEIM transfer congestion in the 5-minute market (Q4 2025)



6.2 Internal congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across the WEIM.[43] This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas. The impact from transfer constraints is discussed above in Section 6.1.

The impact of congestion on each pricing node in the system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[44]

In this quarter, internal congestion was on average in the south-to-north direction, as excess solar in southern regions during mid-day hours contributed to causing congestion that set prices higher in Northern California, the Intermountain West and the Pacific Northwest relative to prices in Southern California and the Desert Southwest.

Figure 6.6 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAPs) and EIM load aggregation points (ELAPs) in the fourth quarter of 2025. The blue bars represent the 15-minute market price impact, and the yellow bars indicate the 5-minute market price impact from internal constraints.

Congestion patterns in the 15-minute and 5-minute markets were generally similar in direction and magnitude. Overall, congestion impact was slightly higher in the 5-minute market than in the 15-minute market.

[43] This report defines internal congestion as congestion on any constraint within a balancing authority area. Therefore, the effect of internal congestion on the CAISO balancing area may include effects of congestion from transmission elements within other WEIM balancing areas. Analysis of internal congestion excludes transfer constraints and intertie constraint congestion.

[44] This approach does not include price differences that result from transmission losses.

Figure 6.6 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (October–December 2025)

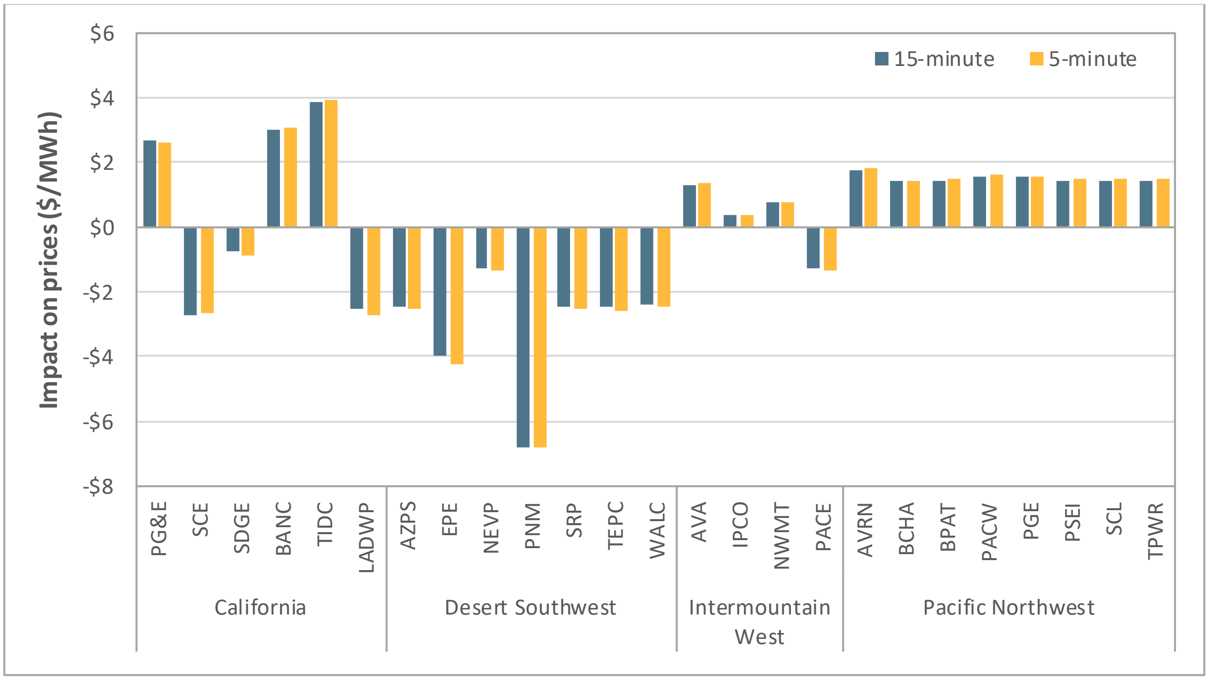


Figure 6.7 and Figure 6.8 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the fourth quarter of 2025 and 2024, respectively. Overall, both years exhibited south-to-north congestion during solar production hours. The magnitude of price separation was modest this quarter compared to the same quarter of 2024. However, further downward pressure on PNM's price was observed, driven by internal congestion during solar hours.

Figure 6.7 Overall impact of internal congestion on price separation in the 15-minute market by hour (October–December 2025)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	0.4	0.4	0.3	0.2	0.4	0.3	0.7	3.1	7.1	8.1	6.2	5.0	4.6	4.9	6.0	5.2	3.9	2.6	1.6	1.0	0.7	0.7	0.7	0.5
BANC	0.3	0.3	0.2	0.2	0.3	0.3	0.6	2.8	7.6	8.6	8.1	7.0	6.7	7.2	7.5	5.8	3.9	1.0	0.8	0.9	0.6	0.5	0.5	0.3
Turlock ID	0.2	0.3	0.1	0.1	0.3	0.2	0.2	2.6	9.0	10.8	11.1	9.7	9.4	10.0	10.3	8.4	5.4	1.9	1.1	0.7	0.5	0.5	0.5	0.3
SCE	-0.2	-0.2	-0.2	-0.1	-0.1	-0.2	-0.2	-2.6	-7.8	-9.2	-7.8	-6.7	-5.7	-5.8	-6.3	-5.3	-3.6	-1.4	-0.8	-0.3	-0.1	0.0	0.0	-0.1
SDG&E	1.1	0.6	0.4	0.8	0.7	1.0	1.5	-0.3	-5.9	-7.1	-5.7	-5.0	-3.4	-3.2	-3.0	-1.3	1.1	1.8	1.9	1.5	1.4	1.1	0.9	1.0
LADWP	-0.1	0.0	0.0	0.0	0.1	0.0	-0.5	-3.1	-7.7	-9.1	-7.9	-6.4	-6.1	-5.9	-6.5	-3.3	-2.5	-0.7	-0.6	-0.1	0.1	0.2	0.1	0.0
NV Energy	-0.1	0.0	0.0	0.0	0.1	0.0	-0.2	-2.0	-3.9	-4.3	-3.8	-3.1	-2.6	-2.7	-3.1	-2.4	-1.3	-0.7	-0.4	0.0	0.0	0.0	0.0	-0.1
Arizona PS	-0.1	-0.2	-0.2	0.1	0.1	0.0	-0.1	-3.3	-7.5	-8.4	-7.1	-5.8	-5.2	-5.3	-5.8	-4.2	-2.4	-1.2	-0.8	-0.3	-0.4	-0.1	-0.1	0.0
Tucson Electric	-0.1	-0.2	-0.2	0.0	0.0	0.0	-0.2	-3.3	-7.4	-8.2	-7.1	-5.9	-5.2	-5.4	-6.0	-4.3	-2.4	-1.2	-0.8	-0.4	-0.5	-0.2	-0.2	-0.1
Salt River Project	-0.1	-0.2	-0.2	0.1	0.1	0.0	0.0	-3.4	-7.5	-8.4	-7.1	-5.7	-5.1	-5.3	-5.7	-4.2	-2.5	-1.2	-0.9	-0.3	-0.4	-0.1	-0.1	0.0
PSC New Mexico	-1.1	-0.9	-0.7	-0.9	-0.2	0.2	-2.9	-8.8	-18.8	-24.9	-20.7	-18.3	-16.9	-15.3	-15.5	-7.4	-2.5	-1.2	-0.9	-1.0	-0.9	-1.5	-0.5	-0.9
WAPA - Desert SW	-0.1	-0.1	-0.1	0.1	0.1	0.0	-0.1	-3.2	-7.3	-8.1	-7.0	-5.7	-5.1	-5.2	-5.7	-4.1	-2.4	-1.2	-0.8	-0.3	-0.4	-0.1	-0.1	0.0
El Paso Electric	-0.5	-0.5	-0.3	-0.4	-0.1	0.1	-1.8	-5.8	-11.8	-14.5	-11.3	-10.3	-9.5	-8.8	-6.8	-5.3	-2.2	-1.3	-0.9	-0.8	-0.8	-0.8	-0.3	-0.4
PacifiCorp East	-0.3	-0.2	-0.2	-0.2	-0.2	-0.3	-0.5	-1.7	-3.2	-3.7	-3.3	-3.0	-2.5	-2.1	-2.8	-2.4	-1.0	-0.7	-0.4	-0.4	-0.3	-0.5	-0.4	-0.3
Idaho Power	-0.1	0.0	0.0	-0.1	-0.1	-0.1	-0.2	0.9	1.1	1.4	1.3	1.3	0.7	0.5	0.9	1.7	0.6	-0.3	-0.2	-0.2	-0.1	-0.2	-0.2	-0.1
NorthWestern	-0.1	0.0	0.0	-0.1	-0.2	0.0	0.0	1.0	2.6	2.5	2.4	2.1	1.8	2.0	2.2	1.7	1.0	0.2	0.1	-0.1	-0.1	-0.2	-0.2	-0.1
Avista Utilities	0.0	0.0	0.0	-0.1	-0.2	-0.1	0.0	1.6	4.0	4.2	3.9	3.4	3.0	3.3	3.8	3.1	1.8	0.4	0.2	-0.1	-0.1	-0.2	-0.2	0.0
Avangrid	0.0	0.1	0.0	0.0	0.0	0.0	0.1	2.0	5.0	5.3	5.0	4.1	4.0	4.4	4.8	4.0	2.6	0.6	0.3	0.0	0.0	-0.2	-0.2	0.0
BPA	0.0	0.0	0.0	-0.1	-0.2	-0.1	0.0	1.8	4.6	4.7	4.5	3.7	3.2	3.5	4.0	3.0	1.8	0.4	0.2	-0.1	-0.1	-0.2	-0.2	0.0
Tacoma Power	0.0	0.0	0.0	-0.1	-0.2	-0.1	0.0	1.8	4.5	4.7	4.3	3.7	3.3	3.6	4.1	3.3	1.9	0.4	0.2	-0.1	-0.1	-0.2	-0.2	0.0
PacifiCorp West	0.0	0.0	0.0	-0.1	-0.2	-0.1	0.0	2.0	4.8	5.0	4.7	3.9	3.5	3.8	4.4	3.6	2.2	0.5	0.2	-0.1	-0.1	-0.2	-0.2	0.0
Portland GE	0.0	0.0	0.0	-0.1	-0.2	-0.1	0.0	1.9	4.8	5.0	4.6	3.9	3.5	3.8	4.3	3.5	2.1	0.5	0.2	-0.1	-0.1	-0.2	-0.2	0.0
Puget Sound Energy	0.0	0.0	0.0	-0.1	-0.2	-0.1	0.0	1.8	4.5	4.7	4.3	3.7	3.3	3.6	4.1	3.3	1.9	0.4	0.2	-0.1	-0.1	-0.2	-0.2	0.0
Seattle City Light	0.0	0.0	0.0	-0.1	-0.2	-0.1	0.0	1.8	4.5	4.7	4.3	3.7	3.3	3.6	4.1	3.3	1.9	0.4	0.2	-0.1	-0.1	-0.2	-0.2	0.0
Powerex	0.0	0.0	0.0	-0.1	-0.2	-0.1	0.0	1.7	4.4	4.6	4.2	3.6	3.2	3.5	4.0	3.2	1.9	0.4	0.2	-0.1	-0.1	-0.2	-0.2	0.0

Figure 6.8 Overall impact of internal congestion on price separation in the 15-minute market by hour (October–December 2024)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	0.7	0.7	0.6	0.8	0.8	0.9	1.0	4.0	7.2	8.0	7.0	6.2	6.7	7.7	8.4	8.0	9.3	13.0	15.9	4.8	2.8	1.9	1.5	0.8
BANC	0.8	0.7	0.6	0.8	0.9	0.9	0.9	4.7	10.7	12.6	12.3	11.0	11.5	13.2	14.4	11.4	8.5	8.7	9.6	3.5	2.8	1.7	1.4	0.7
Turlock ID	0.9	0.8	0.7	0.9	1.1	1.0	1.0	5.5	14.7	18.7	18.4	16.5	16.9	19.3	21.4	17.6	13.7	10.1	11.1	4.1	3.1	1.9	1.5	0.8
SCE	-0.3	-0.2	-0.2	-0.1	0.1	0.3	0.5	-2.0	-8.5	-11.1	-11.0	-9.7	-9.8	-11.1	-11.1	-7.3	-3.6	-3.5	-4.5	-1.4	-1.0	-0.6	-0.1	-0.3
SDG&E	1.4	0.9	0.2	0.5	0.7	0.4	1.0	-0.2	-3.4	-5.7	-5.5	-6.5	-7.0	-7.6	-6.6	-3.3	-0.2	0.9	0.4	2.1	2.8	2.5	1.4	1.0
LADWP	-0.9	-1.1	-1.1	-1.0	-1.6	-3.2	-4.6	-9.7	-9.6	-12.3	-12.7	-11.3	-11.7	-11.2	-10.6	-6.6	-8.9	-7.7	-6.2	-2.7	-1.8	-1.1	-4.2	-0.8
NV Energy	-0.3	-0.4	-0.3	-0.3	-0.4	-0.6	-0.9	-3.5	-5.4	-6.4	-6.2	-5.8	-6.0	-6.3	-6.4	-4.1	-3.4	-4.0	-4.2	-1.7	-1.2	-0.5	-0.8	-0.2
Arizona PS	-0.6	-0.6	-0.4	-0.4	-0.5	-0.6	-1.1	-5.1	-10.4	-12.0	-11.8	-10.4	-10.9	-11.9	-12.4	-8.1	-5.2	-5.5	-5.9	-2.8	-2.1	-1.1	-1.1	-0.4
Tucson Electric	-0.6	-0.6	-0.4	-0.4	-0.5	-0.6	-1.1	-5.0	-10.1	-11.6	-11.4	-10.0	-10.6	-11.5	-12.0	-7.9	-5.1	-5.4	-5.8	-2.8	-2.1	-1.1	-1.1	-0.4
Salt River Project	-0.6	-0.6	-0.4	-0.4	-0.5	-0.6	-1.1	-5.1	-10.5	-12.0	-11.8	-10.4	-10.9	-12.0	-12.5	-8.2	-5.2	-5.5	-6.0	-2.8	-2.2	-1.1	-1.1	-0.5
PSC New Mexico	0.3	-0.3	-0.5	-0.6	0.3	0.6	-1.8	-8.6	-16.3	-20.9	-18.3	-19.4	-23.0	-22.8	-19.8	-14.6	-7.3	-7.5	-7.2	-4.7	-3.4	-1.7	-0.5	-0.1
WAPA - Desert SW	-0.5	-0.6	-0.4	-0.4	-0.5	-0.7	-1.1	-5.0	-10.2	-11.7	-11.6	-10.3	-10.6	-11.7	-12.1	-7.9	-5.0	-5.4	-5.8	-2.7	-2.0	-1.0	-1.0	-0.4
El Paso Electric	-4.5	-3.2	-3.0	-3.3	-3.7	-4.5	-4.6	-8.0	-11.8	-13.7	-12.6	-11.8	-9.6	-9.4	-10.4	-0.9	-1.5	-0.2	-1.5	2.4	1.0	-0.5	-3.6	-3.7
PacifiCorp East	-0.7	-0.7	-0.6	-0.7	-0.7	-0.9	-1.1	-1.3	-1.2	-1.4	-1.4	-1.6	-1.9	-1.9	-1.7	-1.5	-2.0	-2.1	-2.2	-1.2	-1.1	-0.9	-0.9	-0.7
Idaho Power	0.0	0.0	0.0	-0.1	-0.1	-0.1	0.0	0.2	0.7	0.9	1.0	1.2	1.5	1.5	1.5	0.8	0.0	-0.4	-1.7	-0.3	-0.2	0.0	0.0	0.0
NorthWestern	0.1	0.1	0.1	0.0	-0.1	0.0	0.1	0.9	2.0	2.9	3.2	3.1	3.2	3.5	3.8	2.4	0.9	-0.1	-1.5	0.0	0.0	-0.3	0.1	0.1
Avista Utilities	0.1	0.2	0.1	0.0	-0.1	0.0	0.2	1.8	4.2	4.9	4.8	4.6	4.9	5.3	5.5	3.5	1.5	0.8	-1.2	0.2	0.1	-0.3	0.2	0.1
Avangrid	0.2	0.2	0.2	0.0	0.0	0.2	0.5	2.7	5.7	6.8	6.8	6.5	6.8	7.6	8.1	5.3	2.7	1.2	-1.0	0.6	0.7	0.2	0.4	0.1
BPA	0.1	0.2	0.1	0.0	-0.1	0.0	0.2	2.0	4.6	5.5	5.4	5.2	5.3	5.8	6.2	4.2	2.0	0.9	-1.1	0.3	0.5	-0.1	0.2	0.1
Tacoma Power	0.1	0.2	0.1	0.0	0.0	0.0	0.2	2.0	4.6	5.5	5.4	5.2	5.3	5.9	6.1	4.1	1.9	0.9	-1.1	0.3	0.5	-0.3	0.2	0.1
PacifiCorp West	0.1	0.2	0.2	0.0	0.0	0.1	0.4	2.2	4.9	5.9	5.7	5.4	5.7	6.5	6.9	4.6	2.2	1.1	-1.0	0.5	0.5	1.1	0.3	0.1
Portland GE	0.1	0.2	0.1	0.0	0.0	0.1	0.2	2.1	4.9	5.7	5.6	5.3	5.5	6.2	6.8	4.4	2.1	1.1	-1.0	0.4	0.5	-0.2	0.3	0.1
Puget Sound Energy	0.1	0.2	0.1	0.0	0.0	0.0	0.2	2.0	4.5	5.5	5.4	5.2	5.3	5.9	6.1	4.1	1.9	0.9	-1.1	0.3	0.5	-0.3	0.2	0.1
Seattle City Light	0.1	0.2	0.1	0.0	-0.1	0.0	0.2	2.0	4.5	5.5	5.4	5.2	5.2	5.9	6.1	4.0	1.8	0.9	-1.1	0.3	0.3	-0.3	0.2	0.1
Powerex	0.1	0.2	0.1	0.0	-0.1	0.0	0.2	1.9	4.5	5.3	5.3	5.1	5.2	5.7	6.0	3.8	1.8	0.9	-1.1	0.3	0.2	-0.3	0.2	0.1

Congestion in the 15-minute market from internal, flow-based constraints

Table 6.1 shows the quarterly impact of congestion from individual constraints on prices across the WEIM for the 15-minute market. The table reports the top 50 constraints based on their aggregate impact and price separation across DLAPs and ELAPs. Constraints with minimal impact are consolidated under the “other” category, which appears in the second-to-last row of the second column.

The three constraints that had the greatest impact on price separation in the 15-minute market were the Gates-Midway #1 500 kV line, the Panoche-Gates #2 230 kV line, and Gates-Midway #2 500 kV line.

Gates-Midway #1 500 kV line

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) contributed to south-to-north congestion. As a result, prices in Northern California, the Intermountain West, and the Pacific Northwest were elevated relative to prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar production hours, from hours-ending 9 to 15.

Panoche-Gates #2 230 kV line

The Panoche-Gates #2 230 kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) contributed to south-to-north congestion. As a result, prices in Northern California, the Intermountain West, and the Pacific Northwest were pushed upward relative to prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar production hours, from hours-ending 9 to 15.

Gates-Midway #2 500 kV line

The Gates-Midway #2 500 kV line (30056_GATES2_500_30060_MIDWAY_500_BR_2_1) contributed to south-to-north congestion. As a result, prices in Northern California, the Intermountain West, and the Pacific Northwest were elevated relative to prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar production hours, from hours-ending 9 to 16.

Other notable constraints were the PNM constraints. These constraints consistently contributed to significant price separation of EPE and PNM from the rest of WEIM.

Table 6.1 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary constraints (WEIM, October–December)[45]

BAA	Constraint	Average quarter impact ($/MWh)																								
		California						Desert Southwest							Intermountain West				Pacific Northwest							
		PG&E	BANC	TIDC	SCE	SDG&E	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	Line_FC-CH1_345KV	.03	.	.	.07	.08	.04	.10	-.25	.	-.51	.11	.03	.09	.	-.10	.00	-.16	.	.	.	.	.	.	.	.
	Line_FC-CH2_345KV	.02	.	.	.04	.04	.03	.05	-.15	.	-.28	.06	.	.04	.	-.05	-.01	-.09	.	.	.	.	.	.	.	.
CISO	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	.91	1.04	1.09	-1.16	-1.12	-1.14	-1.04	-.95	-.65	-.91	-1.03	-1.01	-1.03	.66	-.02	.48	-.37	.83	.70	.72	.77	.76	.72	.72	.72
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	.33	.44	.53	-.39	-.38	-.37	-.33	-.26	-.10	-.22	-.33	-.33	-.33	.17	.	.03	.	.21	.20	.20	.22	.21	.20	.20	.20
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	.24	.32	.33	-.30	-.29	-.29	-.26	-.24	-.17	-.23	-.26	-.26	-.26	.22	.08	.16	-.07	.27	.23	.22	.25	.24	.23	.23	.23
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	.05	.67	1.52	-.36	-.34	-.30	-.10	-.02	.	-.01	-.10	-.06	-.10	.02	.	.	.	.14	.02	.02	.05	.05	.03	.03	.03
	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	.08	.13	.10	-.16	-.15	-.15	-.14	-.13	-.09	-.12	-.14	-.14	-.14	.10	.03	.08	-.03	.13	.11	.11	.12	.12	.11	.11	.11
	6110_COI_N-S	.09	.09	.09	.07	.06	.06	.06	.05	.04	.05	.05	.05	.06	-.11	-.03	-.09	.	-.10	-.11	-.12	-.12	-.12	-.11	-.11	-.11
	99002_MOE-ELD_500_24042_ELDORDO_500_BR_1_2	.04	.04	.04	.04	.01	.06	-.14	-.21	.07	-.23	-.14	-.14	-.09	.01	.00	.	-.04	.03	.01	.02	.02	.02	.02	.02	.02
	30900_GATES_230_30970_MIDWAY_230_BR_1_1	.06	.08	.09	-.08	-.07	-.07	-.06	-.05	-.04	-.05	-.06	-.06	-.06	.05	.	.03	.00	.06	.05	.04	.05	.05	.05	.05	.05
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	.04	.07	.07	-.07	-.07	-.07	-.06	-.06	-.04	-.06	-.06	-.06	-.06	.05	.01	.03	-.02	.06	.05	.05	.05	.05	.05	.05	.05
	22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	.	.	.	.	1.12	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	.16	.	.	-.20	-.19	-.08	-.02	-.01	.	-.01	-.02	-.02	-.02	.	.	.	.	.	.	.	.	.	.	.	.
	7440_MetcalfImport_Mossld-Metclf	.10	.	.07	-.04	-.04	-.04	-.04	-.03	-.03	-.03	-.04	-.03	-.04	.	-.02	.	-.03	.	.	.	.	.	.	.	.
	MIGUEL_BKs_MXFLW_NG	.01	.	.	.02	.21	.	-.06	-.05	.	-.04	-.06	-.06	-.05	.	.	.	.	.	.	.	.	.	.	.	.
	24801_DEVERS_500_24804_DEVERS_230_XF_1_P	.02	.02	.02	.01	.00	.02	-.06	-.05	-.01	-.05	-.07	-.06	-.05	.	-.01	.	-.02	.	.	.	.	.	.	.	.
	SYLMAR-AC_BG_NG	.01	.01	.01	.02	.00	-.13	-.02	-.02	-.02	-.02	-.02	-.02	-.02	.00	.00	.00	-.01	.01	.01	.01	.01	.01	.01	.01	.01
	6410_CP7_NG	.02	.02	.02	-.02	-.02	-.02	-.02	-.02	-.01	-.02	-.02	-.02	-.02	.01	.00	.01	-.01	.01	.01	.01	.01	.01	.01	.01	.01
	7820_PK_EC_OVERLOAD_NG	.00	.00	.00	.01	.15	.00	-.03	-.03	-.01	-.02	-.03	-.03	-.02	.	.	.	-.01	.	.	.	.	.	.	.	.
	6410_CP10_NG	.02	.02	.02	-.02	-.02	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.01	.00	.01	.00	.01	.01	.01	.01	.01	.01	.01	.01
	35352_WHISMAN_115_35356_MNTAVSA_115_BR_1_1	.11	.	.03	-.07	-.07	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	.00	.	.	.01	.08	.	-.02	-.02	.	-.01	-.02	-.02	-.02	.	.	.	-.01	.	.	.	.	.	.	.	.
	7690-CONTRL-INYOKN_EXP_NG	.00	.	.	-.20	-.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	35120_NEWARKD_115_36851_NORTHERN_115_BR_1_1	.05	.	-.16	.00	.00	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	22464_MIGUEL_230_22468_MIGUEL_500_XF_81	.00	.	.	.01	.08	.	-.02	-.02	.	-.01	-.02	-.02	-.02	.	.	.	.	.	.	.	.	.	.	.	.
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-.01	-.01	-.01	.01	.01	.01	.01	.01	.00	.00	.01	.01	.01	-.01	.00	-.01	.00	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01
	22886_SUNCREST_230_92861_SUNCTP2_230_BR_2_1	.00	.	.	.01	.07	.	-.02	-.02	.	-.01	-.02	-.02	-.02	.	.	.	.	.	.	.	.	.	.	.	.
	35642_METCALF_115_30735_METCALF_230_XF_2	.06	.	.	-.06	-.05	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	25201_LEWIS_230_24137_SERRANO_230_BR_1_1	.00	.	.	.02	.02	.	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.	.	.	.	.	.	.	.	.	.	.	.
	OMS50004IV-MLOUTAGE_NG	.00	.	.	.01	.06	.	-.01	-.01	.00	.00	-.01	-.01	-.01	.	.	.	.00	.	.	.	.	.	.	.	.
	22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1	.01	.	.	.02	-.08	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	99254_J.HINDS2_230_24806_MIRAGE_230_BR_1_1	.02	.	.	.06	.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	7760_DEV_RDB_ALIS	.	.00	.00	.	.	.00	-.01	-.01	.00	-.01	-.02	-.01	-.01	.	.	.	.00	.	.	.	.	.	.	.	.
	7430_CP6_NG	.01	.03	.	-.01	-.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30635_NWKDIST_230_30731_LSESTRS_230_BR_1_1	.03	-.01	.	.00	.00	.	.	.	.	.	.	.	.	.	.	.	.	-.01	.	.	.	.	.	.	.
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1_1	.	.	.	.	.05	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
IPCO	MPSNT342	.00	.00	.00	-.06	-.07	-.06	-.09	-.10	-.12	-.11	-.09	-.09	-.09	.11	.44	.03	-.23	.07	.10	.09	.10	.10	.10	.10	.10
	MPSNT341	.	.	.	.	.	-.01	-.01	-.01	-.02	-.02	-.01	-.01	-.01	.02	.05	.	-.03	.01	.02	.02	.02	.02	.02	.02	.02
LADWP	WECC_Path_41	.01	.01	.01	.01	.00	-.07	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.00	.	.	-.01	.00	.00	.00	.00	.00	.00	.00	.00
	RIN_AWY1	.	.	.	.	.	.06	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
NEVP	CAL-WSS__106	.	.01	.01	.	.	.	.	.	-.02	.	.	.	.	.	-.01	.	-.01	.00	.	.	.	.	.	.	.
PACE	WINDSTAREXPORTTCOR	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	-.07	.	.	.	.	.	.	.	.
PNM	115WTGatPEGS	.02	.	.	.05	.12	.	.	-.96	.	-3.13	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvNH	.	.	.	.	.	.	.	-.28	.	-.49	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	HIMO-WESP1	.	.	.	.	.	.	.	.05	.	.08	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvGYTH	.	.	.	.	.	.	.	-.03	.	-.07	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	GYTH_Gallup_Enr	.	.	.	.	.	.	.	-.03	.	-.07	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115Wingate_Cin	.	.	.	.	.	.	.	-.03	.	-.06	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115Mendo_Winga	.	.	.	.	.	.	.	-.03	.	-.06	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvDL_Wm_Pi	.	.	.	.	.	.	.	.04	.	.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Other	.15	.01	.02	.01	.05	.04	-.06	.00	-.03	-.02	-.06	-.05	-.07	.00	-.02	.02	-.06	.03	.01	.03	.02	.02	.02	.01	.02
	Total	2.69	2.99	3.90	-2.70	-0.76	-2.50	-2.43	-3.96	-1.28	-6.77	-2.43	-2.47	-2.37	1.31	.35	.77	-1.28	1.75	1.41	1.42	1.57	1.54	1.46	1.45	1.46

45 For visualization purposes, numbers are rounded to two decimal points. As a result, values below 0.005 appear as 0.00, even if they are non-zero. Blank cells with dots indicate that no shift factor exists for the pricing node within the DLAP or ELAP, signifying either no impact from the constraint or their shift factors were too small.

6.3 Congestion rent and loss surpluses

Figure 6.9 shows that in the fourth quarter of 2025, congestion rent and loss surpluses were $79 million and $34.8 million, respectively.[46] The congestion rent surplus was down $9 million, or 11 percent, compared to the fourth quarter of 2024.[47] The loss surplus was down about $4.7 million compared to Q4 2024.

Congestion rent consists of rents from internal constraints and interties. Congestion rent from internal constraints decreased from $86 million to $76 million, but intertie congestion rent increased from $2.3 million to $2.8 million this quarter compared to the same quarter in 2024.

In the day-ahead market, hourly congestion rent collected on a constraint is roughly equal to the product of the shadow price and the megawatt flow on that constraint. The daily congestion rent is the sum of hourly congestion rents collected on all constraints for all trading hours of the day.

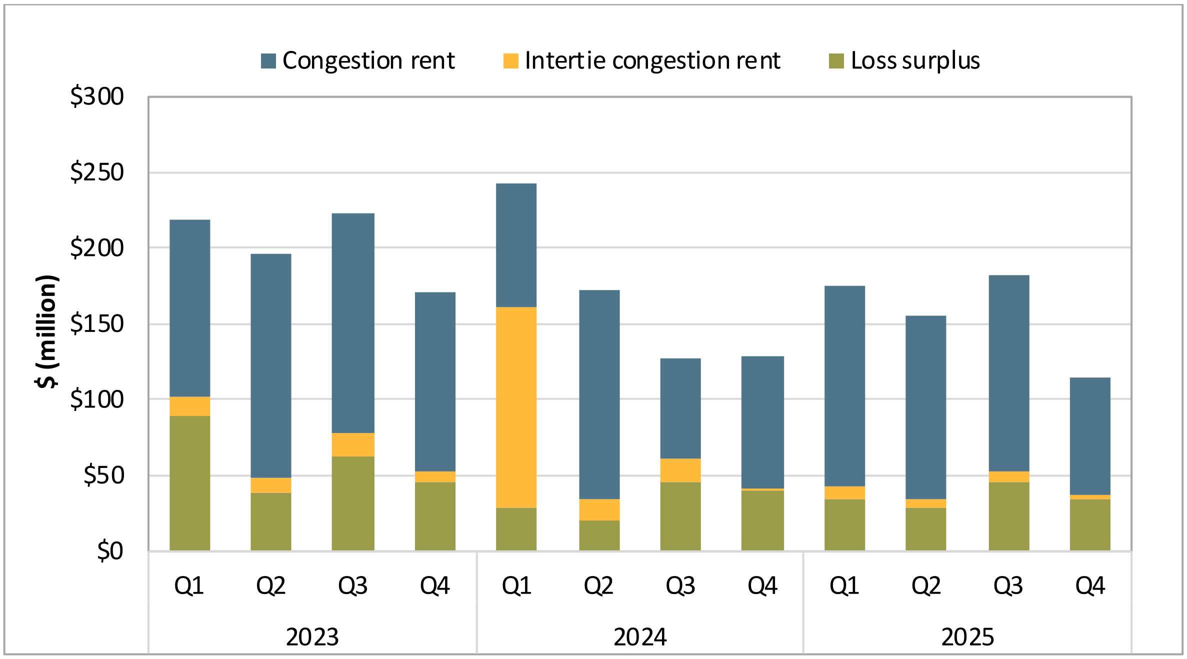
The loss surplus represents the difference between what load pays for the loss component of the locational marginal price (LMP) and what generation gets paid from the loss component of the LMP in the day-ahead market. The magnitude of the loss component of the LMP is directly proportional to the energy component of the LMP, so the loss surplus values should correlate with day-ahead market electricity prices and load quantities over time.

The loss surplus decreased from $39.4 million to $34.8 million —a 12 percent decrease—this quarter compared to the same period last year. This decrease was driven by lower energy prices.

[46] Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date.

[47] DMM adjusted the source data for congestion rent by removing day-ahead congestion rent calculated through the Nodal Pricing Model (NPM). The ISO provides the Nodal Pricing Model day-ahead service for PacifiCorp, which is used solely for internal Net Power Cost allocation within PACW and PACE balancing areas. As a result, updated congestion rent values no longer include NPM-based congestion rent in any of DMM's quarterly or annual reports published after July 2025.

Figure 6.9 Day-ahead congestion rent and loss surplus by quarter (2023–2025)



6.4 Congestion on interties

Total intertie congestion rent in the day-ahead market was $2.8 million, up from $2.3 million in the fourth quarter of 2024. The major driver was increased congestion rent on the Malin and NOB interties in the import direction. Although combined congestion rent declined on Palo Verde and IPP Utah by $0.7 million in this quarter compared to the same quarter of 2024, the reduction was offset by $1.3 million in gains on Malin and NOB import congestion rent.

The total intertie congestion charges reported by DMM represent the products of the shadow prices multiplied by the binding limits for the intertie constraints. For a supplier or load serving entity trying to import power over an intertie congested in the import direction, assuming a radial line, the congestion price represents the difference between the higher price of generation on the California ISO side of the intertie and the lower price of import bids outside of the California ISO area. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO area at points corresponding to these interties.

Figure 6.10 shows total intertie congestion charges in the day-ahead market from the fourth quarter of 2024 to the fourth quarter of 2025. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 6.11 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 6.2 provides a detailed summary of congestion rent and frequency over a broader set of interties, differentiating imports and exports. As highlighted in these charts and table:

- Compared to the fourth quarter of 2024, the total intertie congestion rent increased from $2.3 million to $2.8 million.

- The majority of congestion occurred at Malin and NOB. These two interties accounted for 81 percent of total congestion rent this quarter.
- Congestion frequency remained similar to the same period last year. A notable change was the increase in import congestion frequency at Malin and NOB, which reached 3.5 percent and 2.9 percent, respectively.

Figure 6.10 Day-ahead congestion charges on major interties

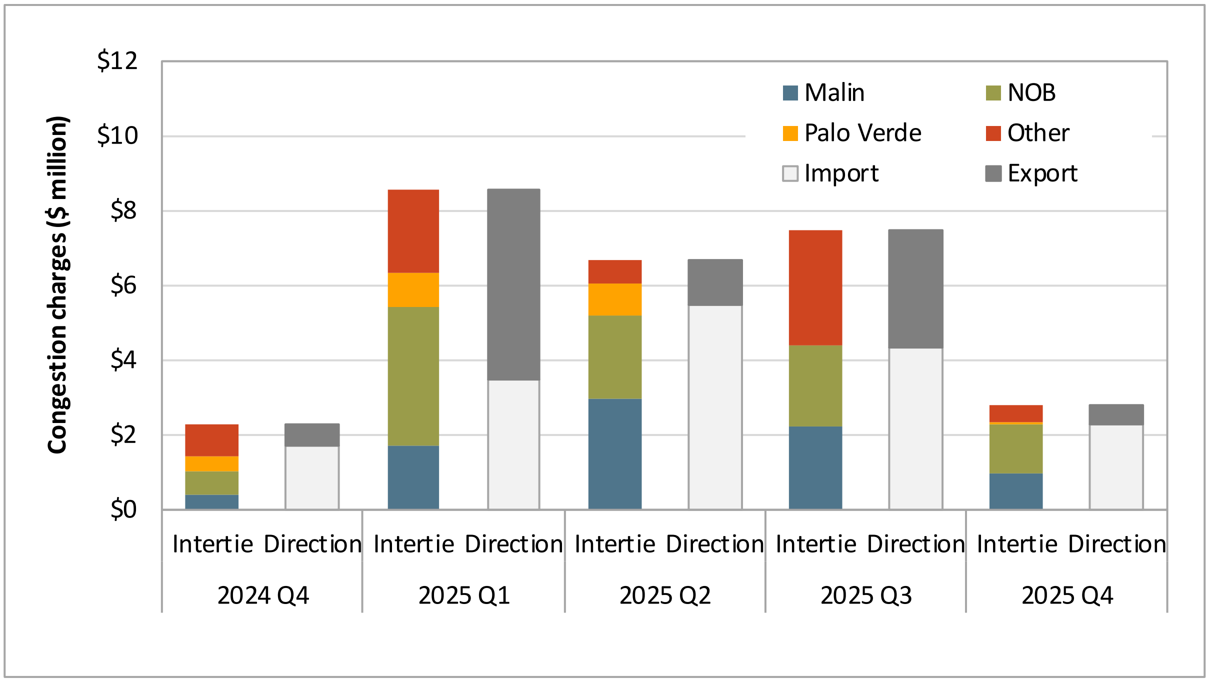


Figure 6.11 Frequency of congestion on major interties in the day-ahead market

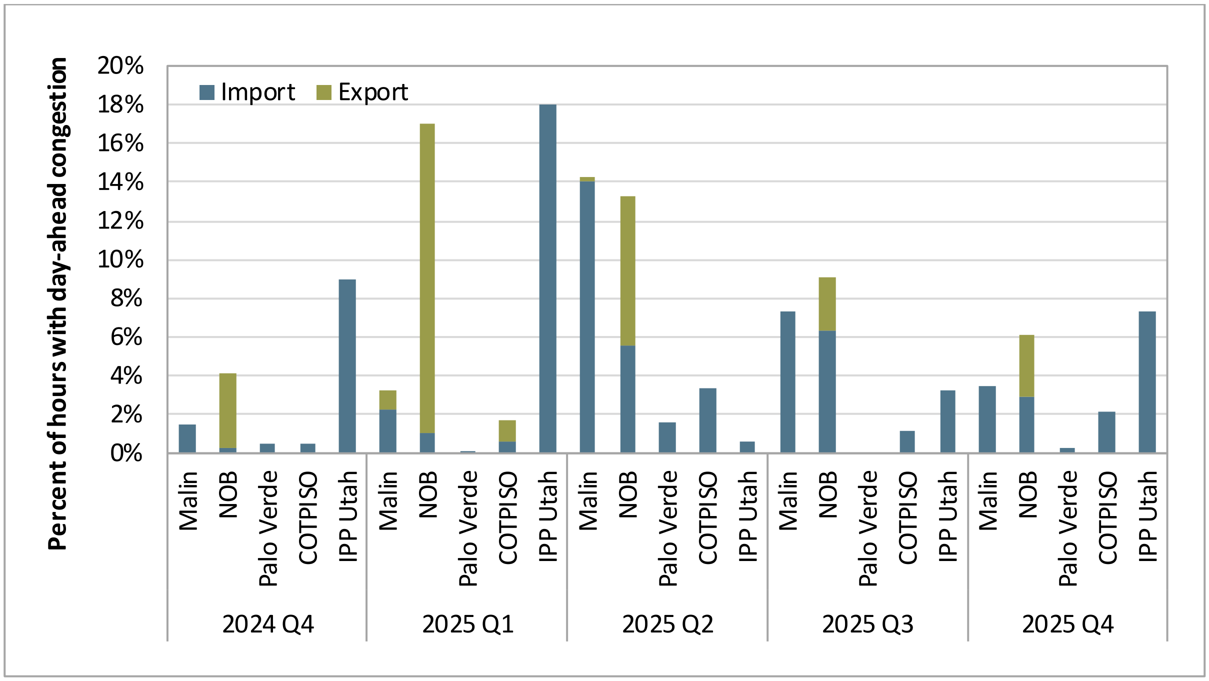


Table 6.2 Summary of intertie congestion in day-ahead market (2024–2025)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2024 Q4	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2024 Q4	2025 Q1	2025 Q2	2025 Q3	2025 Q4
Northwest											
Malin	I	$396	$565	$2,904	$2,223	$949	1.5%	2.3%	14.0%	7.3%	3.5%
	E		$1,169	$53				1.0%	.3%		
NOB	I	$76	$190	$1,600	$1,983	$781	.3%	1.0%	5.6%	6.3%	2.9%
	E	$573	$3,483	$661	$180	$530	3.8%	16.0%	7.7%	2.8%	3.2%
COTPISO	I	$26	$12	$29	$11	$92	.5%	.6%	3.4%	1.2%	2.2%
	E		$397					1.1%			
Cascade	I										
	E										
Summit	I			$23	$11				.5%	.1%	
	E										
Southwest											
Palo Verde	I	$412	$944	$828		$92	.5%	0.0%	1.6%		.3%
	E										
IPP Utah	I	$782	$1,754	$13	$103	$354	9.0%	18.0%	.6%	3.2%	7.3%
	E										
IPP DC Adelanto	I										
	E			$33	$92				.7%	.8%	
Mona	I	$3					0.0%				
	E		$30	$238	$2,856			.6%	2.0%	3.7%	
Mead	I		$9					0.0%			
	E			$155					.2%		
Merchant	I										
	E										
Silver Peak	I										
	E			$11	$1				1.3%	.5%	
Mercury	I										
	E										
Other	I	$0		$104							
	E		$16	$50							
Import total (I)		$1,696	$3,475	$5,501	$4,332	$2,268					
Export total (E)		$573	$5,096	$1,200	$3,128	$530					
Total		$2,268	$8,570	$6,701	$7,460	$2,798					

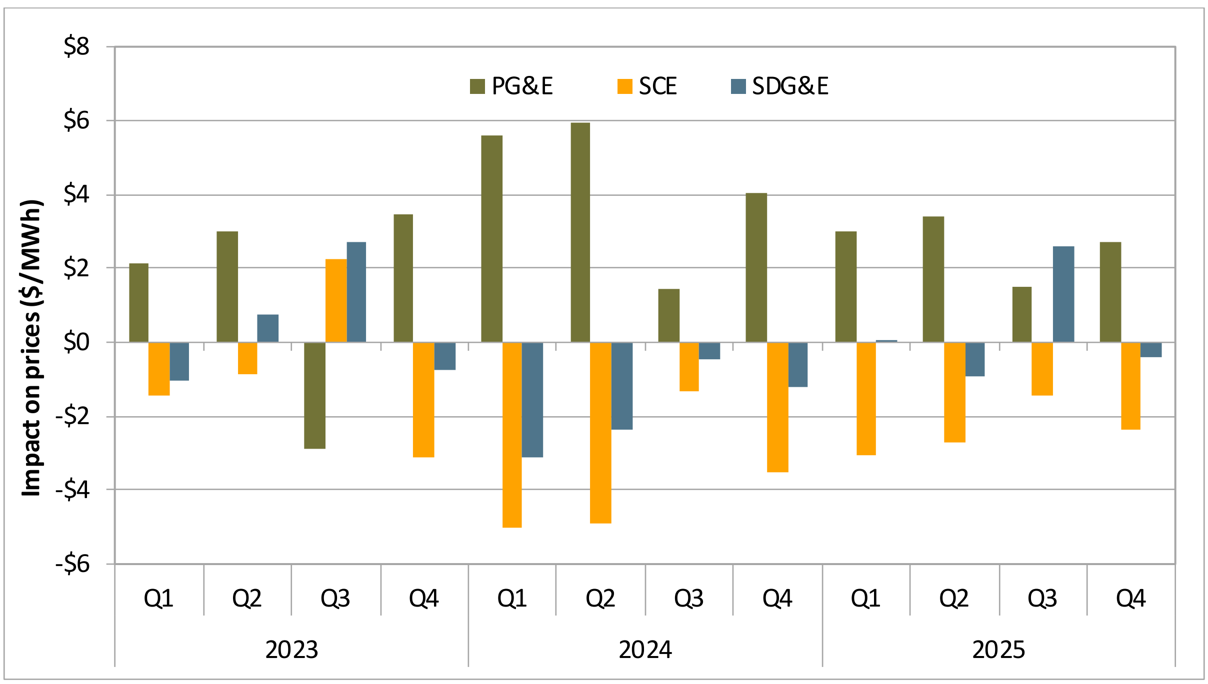
* I: import, E: export

6.5 Internal congestion in the day-ahead market

Figure 6.12 shows the overall impact of congestion on day-ahead market prices in each load area from Q1 2023 to Q4 2025. Figure 6.13 shows the frequency of congestion. Highlights for this quarter include:

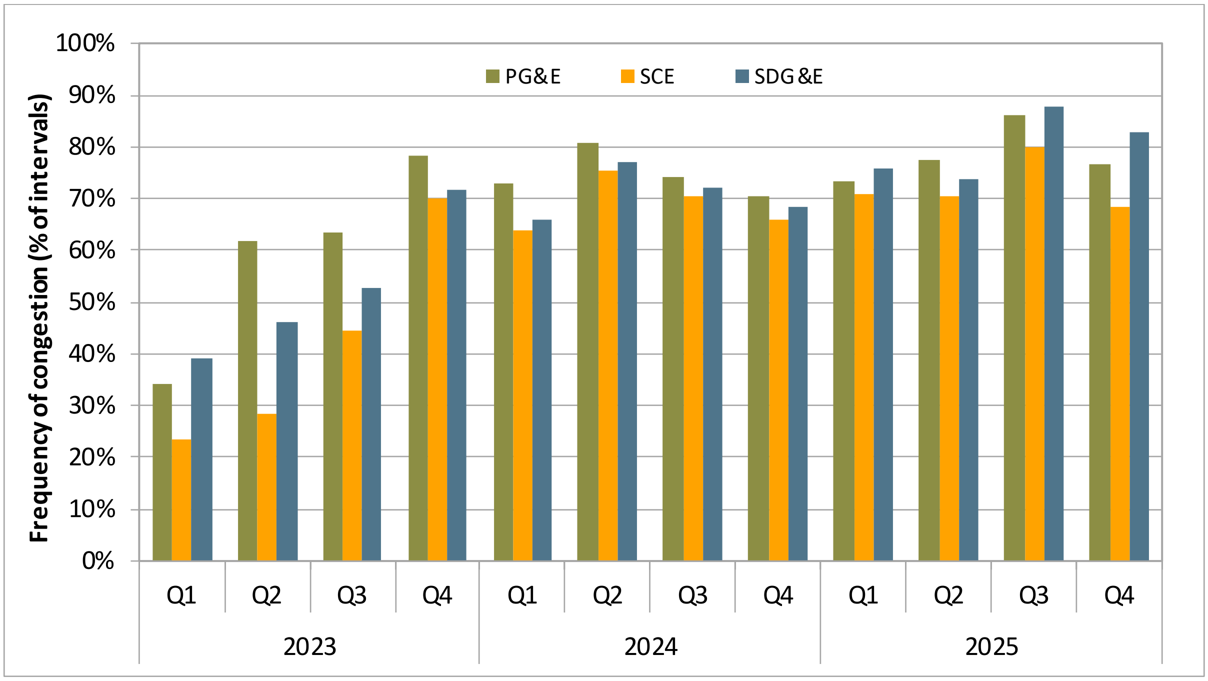
- Day-ahead congestion continued to exhibit a south-to-north pattern this quarter, similar to the same period last year, though the resulting price separation was less pronounced.
- Prices in PG&E were elevated by $2.7/MWh, while prices in SCE and SDG&E were reduced by $2.4/MWh and $0.4/MWh, respectively, due to internal congestion.[48]
- The percentage of hours in which congestion impacted DLAP prices remained high this quarter, with SDG&E experiencing congestion during 83 percent of hours on average.
- The primary constraints affecting day-ahead market prices were the Gates-Midway #1 500 kV, the Panoche-Gates #2 230 kV, and the Moss Landing – Las Aguilas #1 230 kV line.

Figure 6.12 Overall impact of congestion on price separation in the day-ahead market



48 Language in the report describing congestion as "increasing" or "decreasing" a price is describing the change relative to the particular reference bus used in that market. The ISO uses a particular reference bus—distributed amongst load nodes according to the load at each node's percentage of total load. However, in theory, any node could be used as the reference bus, and changing the reference bus would change the value of how much congestion "increased" or "decreased" prices at a node relative to the reference bus. While the specific value of an increase or decrease in congestion price is relative to the reference bus, the *difference* between the impact of congestion on one node and another node is not dependent on the reference bus. Therefore, in assessing the impacts of congestion on prices, DMM suggests the reader focus on the difference of the price impacts between nodes or areas, and not on the specific value of an increase or decrease to one node or area.

Figure 6.13 Hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 6.3 breaks down the congestion effect on price separation during the quarter by constraint.[49] The table presents the top 25 most congested lines, ranked by their impact, while the "Other" category shows the average impact of the remaining constraints. Color shading is used in the table to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact on prices, while blue represents a negative impact—the stronger the shading, the greater the impact in either the positive or negative direction.

The constraints with the greatest impact on day-ahead price separation for the quarter were the Gates-Midway #1 500 kV, the Panoche-Gates #2 230 kV, and the Moss Landing – Las Aguilas #1 230 kV line.

Gates-Midway #1 500 kV line

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) bound in 11 percent of hours over the quarter. For the quarter, on average, prices in PG&E were pushed upward by $0.79/MWh and prices in SCE and SDG&E were pushed down by $0.63/MWh and $0.6/MWh, respectively, due to this constraint. This transmission line was generally binding during solar generation hours, from hour-ending 8 through hour-ending 16.

49 DMM calculates the congestion impact from constraints by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *"Other"*. In addition, constraints with price impact of less than $0.01/MWh for all load aggregation points (LAPs) in the region are grouped in *"Other"*.

Panoche-Gates #2 230 kV line

The Panoche-Gates #2 230 kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) bound in 16 percent of hours over the quarter. For the quarter, on average, prices in PG&E were elevated by $0.63/MWh and prices in SCE and SDG&E were lowered by $0.5/MWh and $0.47/MWh, respectively, due to this constraint. This transmission line was generally binding during solar generation hours, from hour-ending 9 through hour-ending 16.

Moss Landing – Las Aguilas #1 230 kV line

The Moss Landing – Las Aguilas #1 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in 12 percent of hours over the quarter. For the quarter, on average, prices in PG&E were raised by $0.42/MWh and prices in SCE and SDG&E were decreased by $0.31/MWh and $0.3/MWh, respectively, due to this constraint. This transmission line was generally binding during solar generation hours, from hour-ending 9 through hour-ending 16.

In this quarter, SDG&E prices were elevated due to multiple constraints, each primarily affecting the SDG&E area.

Table 6.3 Impact of congestion on day-ahead prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	11.3%	.79	-.63	-.60
30790_PANOCHE_230_30900_GATES_230_BR_2_1	16.3%	.63	-.5	-.47
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	11.6%	.42	-.31	-.3
22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	62.8%	-.06	-.04	.92
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	17.6%	.37	-.29	-.26
7820_TL230S_OVERLOAD_NG	14.9%	-.04	-.02	.31
MIGUEL_BKs_MXFLW_NG	1.4%	-.03	-.01	.23
35352_WHISMAN_115_35356_MNTAVSA_115_BR_1_1	9.2%	.07	-.07	-.07
30056_GATES2_500_30060_MIDWAY_500_BR_2_1	1.1%	.08	-.06	-.06
30900_GATES_230_30970_MIDWAY_230_BR_1_1	1.1%	.05	-.04	-.04
22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1	1.0%	.	.02	-.11
7820_TL23040_IV_SPS_NG	4.4%	-.01	-.01	.1
6410_CP10_NG	0.5%	.04	-.03	-.03
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	0.4%	.03	-.03	-.02
24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	0.4%	-.03	.03	-.01
30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	1.0%	.03	-.02	-.02
33020_MORAGA_115_35101_SNLNDRO_115_BR_2_1	14.2%	.02	-.03	-.03
35120_NEWARKD_115_36851_NORTHERN_115_BR_1_1	4.4%	.03	-.02	-.02
7820_PK_EC_OVERLOAD_NG	2.0%	-.01	.00	.05
OMSIV-SXOUTAGE_NG	.5%	-.01	.	.05
22420_SILVERGT_69.0_22144_CORONADO_69.0_BR_1_1	0.6%	.	.	.05
22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1_1	4.6%	.	.	.04
30055_GATES1_500_30057_DIABLO_500_BR_1_1	0.5%	.02	-.01	-.01
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	.4%	.	.00	.03
22532_MURRAY_69.0_22306_GARFIELD_69.0_BR_1_1	2.4%	.	.	.03
Other		.34	-.3	-.16
Total		2.73	-2.37	-.4

7 Resource sufficiency evaluation

As part of the WEIM design, each area, including the California ISO balancing area, is subject to a resource sufficiency evaluation. The resource sufficiency evaluation allows the market to optimize transfers between participating WEIM entities while deterring WEIM balancing areas from relying on other WEIM areas for capacity or flexibility.

The evaluation is performed prior to each hour to ensure that generation in each area is sufficient without relying on transfers from other balancing areas. The evaluation is made up of four tests: the power flow feasibility test, the balancing test, the bid range capacity test, and the flexible ramping sufficiency test. Failures of two of the tests can constrain transfer capability:

- **The bid range capacity test (capacity test)** requires that each area provide incremental bid-in capacity to meet the imbalance between load, intertie, and generation base schedules.
- **The flexible ramping sufficiency test (flexibility test)** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area that has not opted in to assistance energy transfers fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers into that area cannot be increased.[50] If an area fails either test in the downward direction, transfers out of that area cannot be increased.

7.1 Frequency of resource sufficiency evaluation failures

Figure 7.1 and Figure 7.2 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 7.3 and Figure 7.4 provide the same information for the downward direction.[51] The dash indicates the area did not fail the test during the month.

During the fourth quarter of 2025:

- El Paso Electric failed the flexibility test in the downward direction in 1.4 percent of all intervals. El Paso Electric failed all other test types in all other directions in less than 1 percent of all intervals.
- All other balancing areas failed any test type in any direction in less than 1 percent of all intervals.

50 Normally, if an area fails either test in the upward direction, net WEIM imports during the hour cannot exceed the greater of either the base transfer or the optimal transfer from the last 15-minute interval. The assistance energy transfers (AET) option gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Balancing areas can opt in to AET to prevent their WEIM transfers from being limited during a test failure but will be subject to an ex-post surcharge.

51 Results exclude known invalid test failures. These can occur because of a market disruption, software defect, or other error.

Figure 7.1 Frequency of upward capacity test failures by month and area (percent of intervals)

	2024			2025											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	—	.1	—	—	—	—	—	—	—	—	—	—	—	—
Avangrid	—	—	—	.1	—	—	—	—	—	—	.3	—	—	—	—
Avista	.1	—	—	—	—	—	—	.1	—	—	—	.1	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	.1	—	—	—	—	—	—	.0	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	—	.1	.0	.1	.1	.1	.3	—	.2	.1	.0	—	.1	.1	—
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
LADWP	—	—	—	.1	—	—	—	.1	—	—	—	—	—	—	—
NorthWestern En.	—	—	.3	—	—	—	—	—	—	—	—	.2	.0	—	.1
NV Energy	—	—	—	—	—	—	—	—	—	.0	.1	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	.0	.0	—	—
PacifiCorp West	.1	.3	.0	.4	.2	.1	.0	.1	.0	.1	.1	.7	.4	.2	.7
Portland Gen. Elec.	—	—	—	—	.0	.0	—	—	.1	—	.1	—	—	—	—
Powerex	—	—	—	—	—	—	—	—	—	—	—	.0	—	—	—
PSC of New Mexico	.4	3.1	—	.1	—	.1	.1	—	—	—	—	—	.1	—	.1
Puget Sound En.	.1	—	.1	—	—	—	.1	.2	—	.1	.0	—	.1	—	—
Salt River Proj.	.1	—	—	.1	—	—	.7	—	.3	—	.2	.0	.1	.0	—
Seattle City Light	.3	.0	.1	.1	—	.0	—	—	.1	.0	—	—	.0	—	.2
Tacoma Power	.0	.1	—	—	—	—	—	.1	—	.2	—	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	.0	—	—	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	.1	—	—
WAPA DSW	.1	—	—	.3	—	.1	.1	.1	.1	.0	.1	1.1	—	—	—

Figure 7.2 Frequency of upward flexibility test failures by month and area (percent of intervals)

	2024			2025											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	—	.1	.0	—	—	—	—	—	—	—	—	—	.0	—
Avangrid	.5	.1	.4	.1	.2	.2	.1	.0	—	.2	—	.0	—	.1	.1
Avista	.0	—	—	—	—	—	—	.3	—	—	—	—	—	—	—
BANC	—	—	—	—	—	—	—	.0	—	—	—	—	—	—	—
BPA	—	.1	.1	—	.1	.5	.1	.0	.0	—	—	—	.1	.1	.3
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.2	.3	.4	.1	—	.4	.2	.3	.2	.4	.1	.0	.6	1.2	.6
Idaho Power	.0	—	—	.1	.4	1.2	2.9	.6	.0	—	.1	—	.1	—	—
LADWP	—	.1	—	—	—	.1	.1	.0	—	—	.0	—	—	—	—
NorthWestern En.	.1	.2	.2	.1	1.2	—	—	—	.0	—	—	.0	.0	—	—
NV Energy	—	—	—	.1	—	.1	.0	.0	—	—	.1	.0	—	—	—
PacifiCorp East	.1	.0	—	.1	.1	.0	.0	—	—	.0	.2	.2	.4	.1	.1
PacifiCorp West	—	.3	.1	.3	.1	.0	.1	.2	.0	—	.0	.5	.2	.3	.5
Portland Gen. Elec.	.1	—	—	—	—	.2	.1	—	.0	—	—	—	—	.0	.1
Powerex	—	—	—	—	—	—	—	—	—	—	—	.0	—	—	.0
PSC of New Mexico	.3	7.1	.2	.3	.3	.4	.8	—	.0	.1	—	.0	.7	.3	.4
Puget Sound En.	.4	—	.5	—	—	.1	.7	1.0	.0	.1	.0	.1	—	—	—
Salt River Proj.	.2	—	—	.0	—	.1	1.8	.0	.6	—	.2	.3	.0	.1	—
Seattle City Light	.1	.1	—	—	—	—	—	—	—	—	—	—	—	—	.1
Tacoma Power	—	.1	.0	.0	—	.0	.0	—	—	—	—	—	—	.1	.0
Tucson Elec. Pow.	.2	.1	.1	.1	—	—	.0	.2	.0	—	—	.0	.1	.2	.1
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	.0	—	—	—
WAPA DSW	.2	—	.1	.1	—	.4	.1	.2	—	.0	—	—	—	—	—

Figure 7.3 Frequency of downward capacity test failures by month and area (percent of intervals)

	2024			2025											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avangrid	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avista	.0	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	.1	.1	—	—	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.1	.0	—	.1	—	.1	.2	.0	.2	.3	.1	.2	.2	.4	.3
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
LADWP	—	—	—	.0	.1	—	—	.0	—	—	—	.1	—	—	—
NorthWestern En.	—	.0	—	—	.1	.1	.0	—	—	—	—	.1	—	—	—
NV Energy	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	.1	—	—	—	—
PacifiCorp West	—	—	—	—	.1	—	.1	.1	.3	.0	—	.2	—	.6	.0
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	.1	—	—	—	—	—	—	—	—	—	—	—	—	—
PSC of New Mexico	—	.2	—	—	—	—	—	—	—	—	—	—	—	—	—
Puget Sound En.	—	—	—	—	—	.0	—	—	—	—	—	—	—	—	—
Salt River Proj.	—	—	.3	.1	.0	.1	—	—	.1	—	—	—	—	—	—
Seattle City Light	—	.1	.0	—	—	—	—	—	—	—	—	—	—	—	—
Tacoma Power	—	—	—	—	—	—	—	—	—	.1	—	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Figure 7.4 Frequency of downward flexibility test failures by month and area (percent of intervals)

	2024			2025											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	.3	.2	—	—	.1	.1	.0	.0	—	—	—	.1	.0	.1
Avangrid	—	—	—	—	—	—	—	—	.1	—	—	—	—	—	—
Avista	.6	—	—	—	.0	—	—	—	—	—	.1	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	.8	.2	—	—	—	.1	—	—	—	.3	.1	—	.2
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.0	—	.2	.2	.4	.4	.6	.5	.0	—	—	.0	.8	1.0	2.2
Idaho Power	—	—	—	—	—	.1	—	.1	—	—	—	—	.0	—	—
LADWP	—	—	—	.2	1.5	.6	—	—	—	—	—	—	.2	.0	.1
NorthWestern En.	2.2	.2	.1	.2	—	.6	—	.1	.0	.0	—	.1	.2	—	.8
NV Energy	—	—	—	—	.0	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	.5	—	.0	—	.0	.4	—	—	—	—
PacifiCorp West	.0	.0	—	—	—	.1	.0	.0	.0	.1	.1	.0	—	.5	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	.1	—	—	.0	.0	.0	—	—	—	—	—	—	—	—
PSC of New Mexico	.3	2.0	.1	—	—	—	—	—	—	.0	—	—	—	—	—
Puget Sound En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Salt River Proj.	.1	—	.5	.6	.4	1.2	—	—	.1	—	.0	—	—	.0	.0
Seattle City Light	.0	.2	.1	—	—	.2	.0	—	.1	.3	—	—	.1	.0	—
Tacoma Power	—	—	—	—	.0	—	—	.1	—	.3	—	—	—	.1	—
Tucson Elec. Pow.	—	—	—	—	.0	—	—	—	.1	—	—	—	—	—	—
Turlock Irrig. Dist.	.1	.1	—	—	—	.0	.1	.1	—	.3	.1	—	—	—	.0
WAPA DSW	—	.0	—	—	.1	—	—	—	—	—	—	—	—	.7	1.5

7.2 Assistance energy transfers

The assistance energy transfer (AET) option gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Without AET, a balancing area failing either the upward flexibility or upward capacity test would have net WEIM imports limited to the greater of either the base transfer or the optimal transfer from the last 15-minute market interval. Balancing areas can voluntarily opt in to the AET program to prevent their WEIM transfers from being limited during an upward resource sufficiency evaluation failure, but will be subject to an ex-post surcharge. Balancing areas must opt in or opt out of the program in advance of the trade date.[52]

The assistance energy transfer surcharge is applied during any interval in which an opt-in balancing area fails the upward flexibility or capacity test. The surcharge is calculated as the *applicable real-time assistance energy transfer* times the real-time bid cap.[53] The applicable AET quantity is based on the lesser of either (1) the tagged dynamic WEIM transfers or (2) the amount by which the balancing area failed the resource sufficiency evaluation. If the tagged dynamic WEIM transfers are less than the amount by which the balancing area failed the resource sufficiency evaluation, then the applicable AET quantity is also reduced by a credit. The credit is either upward available balancing capacity for WEIM entities or cleared regulation up for the ISO balancing area.

Opting in to the assistance energy transfer program does not guarantee that the balancing area will achieve additional WEIM supply following a resource sufficiency evaluation failure (compared to opting out of the program). It only removes the import limit that would have been in place following a test failure, allowing the market to freely and optimally schedule WEIM transfers based on supply and demand conditions in the system. If the import limit following a test failure was set high such that it is not restricting the optimal solution, then opting in or opting out of the program will have no effect on WEIM import supply in that interval.

Table 7.1 shows the days in which a balancing area was opted in to receiving assistance energy transfers during the quarter. Five balancing areas were opted in to the program on at least one day during this period: Avangrid, Idaho Power, NorthWestern Energy, PacifiCorp East, and PacifiCorp West. Idaho Power opted in to AET on all but four days (88 days) during the fourth quarter. All other balancing areas were opted in to AET on all days during the quarter (92 days).

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52 Assistance energy transfer designation requests are submitted to Master File as *opt-in* or *opt-out* and include both a start and end date. The standard timeline to implement an opt-in or opt-out request is at least five business days in advance of the start date. An *emergency* opt-in request is also available, should reliability necessitate this, for two business days in advance of the start date. For more information, see: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1525&IsDlg=0

53 The soft bid cap is $1,000/MWh and can increase to the hard bid cap of $2,000/MWh under certain conditions.

Table 7.1 Assistance energy transfer opt-in designations by balancing area (October–December 2025)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Oct. 1 - Dec. 31	92
Idaho Power	Oct. 1 - Nov. 4, Nov. 9 - Dec. 31	88
NorthWestern Energy	Oct. 1 - Dec. 31	92
PacifiCorp East	Oct. 1 - Dec. 31	92
PacifiCorp West	Oct. 1 - Dec. 31	92

Table 7.2 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during the quarter and its impact following a resource sufficiency evaluation failure. First, the table shows the number of 15-minute intervals in which a balancing area failed the upward resource sufficiency evaluation after opting in to AET. These are the intervals in which the WEIM import limit following the test failure was removed—giving the WEIM entity access to WEIM supply that may not have been available otherwise. During the quarter, all five balancing areas failed the resource sufficiency evaluation during at least one interval while opted in to the program.

Table 7.2 also shows the percent of failure intervals in the 5-minute market in which the balancing area achieved additional WEIM imports due to opting in to AET. The table also shows the average and maximum WEIM imports added in the 5-minute market because of AET. While opted in to receiving assistance energy transfers, PacifiCorp West failed the resource sufficiency evaluation during 64 intervals, receiving an additional 17 MW on average during these intervals (and a maximum of 175 MW). PacifiCorp East received the highest maximum additional transfers during failure intervals while opted in to AET, at 594 MW, and received a total of 633 MWh in imports added.

Table 7.2 Resource sufficiency evaluation failures during assistance energy transfer opt-in (October–December 2025)

Balancing area	Days opted in to AET	RSE failures under AET (15-min. intervals)	Percent of failure intervals with additional WEIM imports due to AET	Average WEIM imports added (MW)	Max WEIM imports added (MW)	Total WEIM imports added (MWh)
Avangrid	92	4	50%	17	76	17
Idaho Power	88	4	17%	5	37	5
NorthWestern Energy	92	6	33%	22	125	33
PacifiCorp East	92	21	65%	121	594	633
PacifiCorp West	92	64	34%	17	175	276

Table 7.3 summarizes the total cost from assistance energy transfers.[54] AET is settled during any interval in which the balancing area both opted in to receiving assistance energy transfers and failed the resource sufficiency evaluation. The applicable quantity that is settled for AET is based on the lower of

54 Total costs are based on settlement values available at the time of drafting and can be subject to change. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date.

the resource sufficiency evaluation insufficiency or the WEIM imports.[55] The price is the real-time bid cap, typically $1,000/MWh. Table 7.3 also shows the total cost per *WEIM imports added*. WEIM imports added are measured as net WEIM imports in the 5-minute market above what the limit would have been following the resource sufficiency evaluation failure without opting in to AET.

Table 7.3 Cost of assistance energy transfers (October–December 2025)

Balancing area	RSE failures under AET (15-min. intervals)	Total WEIM imports added (MWh)	Total cost of assistance energy transfers ($)	Total cost per added WEIM imports ($/MWh)
Avangrid	4	17	$5,920	$345
Idaho Power	4	5	$6,198	$1,337
NorthWestern Energy	6	33	$56,375	$1,733
PacifiCorp East	21	633	$272,585	$430
PacifiCorp West	64	276	$407,014	$1,476

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[56] These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.

8 Real-time imbalance offset costs

Total real-time imbalance offset costs for balancing areas participating in the day-ahead market were $32 million in the fourth quarter of 2025.[57,58] The energy portion of the offset ($8 million credit) and the loss portion of the offset ($8 million charge) largely negated each other while the real-time *congestion* imbalance offset costs made up the large majority of the costs in the fourth quarter of 2025 ($32 million charge). Total real-time imbalance offset costs in the fourth quarter of 2025 were lower compared to the same quarter of 2024, when they were $53 million.

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a $8 million credit to WEIM entities, similar to the $7 million credit in the same quarter of 2024. During the fourth quarter of 2025, the congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $17.7 million credit. The energy portion of the offset was around a $11.2 million charge while the loss portion of the offset was a $1.7 million credit.

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55 If the dynamic WEIM transfers are less than the amount by which the balancing area failed the resource sufficiency evaluation, then the applicable AET quantity is also reduced by a credit. The credit is either upward available balancing capacity for WEIM entities or cleared regulation up for the ISO balancing area.

56 Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

57 Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date.

58 CAISO is currently the only balancing area participating in the day-ahead market.

The real-time imbalance offset cost is the difference between the total money *paid out* and the total money collected by the California ISO settlement process for energy in the real-time markets. This settlement is calculated separately for each balancing area. Any revenue surplus or revenue shortfall within this settlement is allocated to measured demand (for the California ISO balancing area) or the WEIM entity scheduling coordinator (for the WEIM balancing areas).[59]

The real-time imbalance offset settlement consists of three components. Any revenue imbalance from the congestion components of real-time energy prices is collected through the *real-time congestion imbalance offset charge* (RTCIO). Similarly, any revenue imbalance from the loss component of real-time energy prices is collected through the *real-time loss imbalance offset charge*, while any remaining revenue imbalance is recovered through the r*eal-time imbalance energy offset charge* (RTIEO). Figure 8.1 shows monthly imbalance offset costs by component since 2023 for balancing areas participating in the day-ahead market.

Figure 8.1 Monthly real-time imbalance offset costs (balancing areas in day-ahead market)

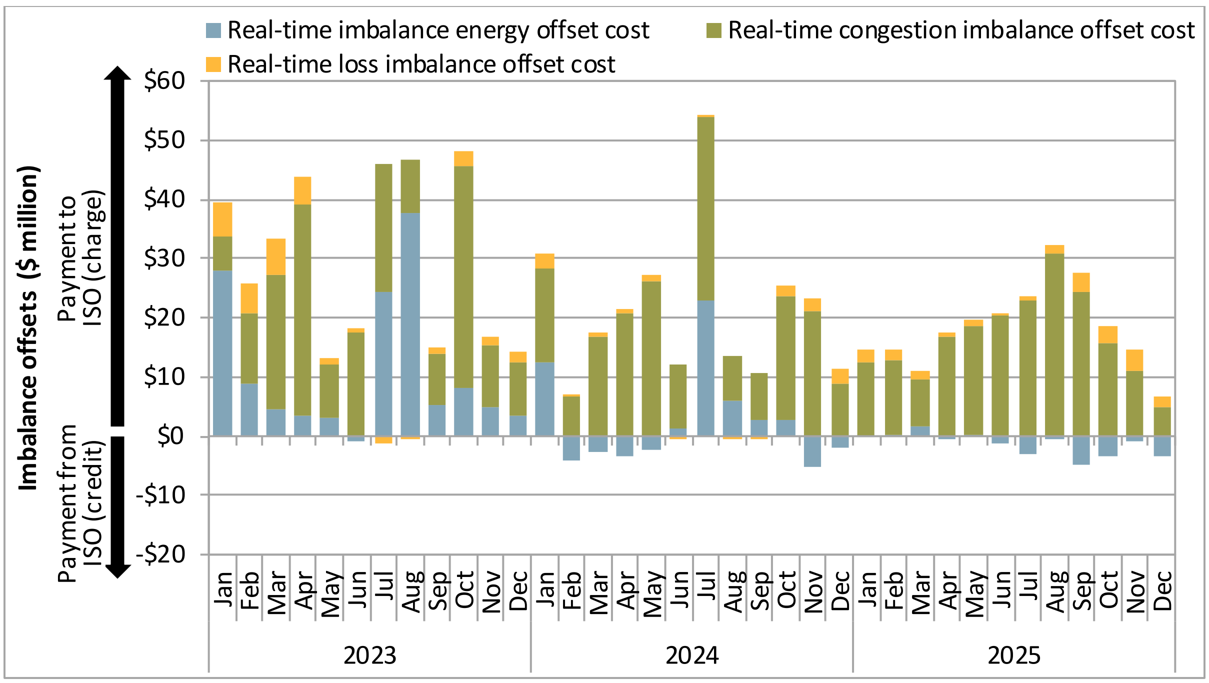

Figure 8.2 shows monthly imbalance offset costs for balancing areas only participating in the WEIM real-time markets. Offset amounts for each balancing area and charge type (energy, congestion, or losses) were assessed as positive or negative over the month, and shown collectively in the corresponding bars. The lighter-colored bars reflect positive amounts (or charges for revenue shortfall), while the darker bars reflect negative amounts (or credits for revenue surplus). Total imbalance offsets in 2024 and 2025 were largely lower compared to 2023.

Figure 8.3 through Figure 8.5 show the quarterly real-time energy, congestion, or loss imbalance offsets from Q4 2024 through Q4 2025 for each balancing area participating only in the WEIM. Figure 8.6 shows

59 Measured demand is physical load plus exports.

the *total* real-time imbalance offset charges for each quarter and balancing area during the same period. Charges for revenue shortfall are shown in red, while credits for revenue surplus are shown in black. The color gradient highlights balancing areas with either greater revenue shortfall (orange) or revenue surplus (blue) over the period. Of note in the fourth quarter:

- Revenue *shortfall* from imbalance energy offsets for NorthWestern Energy was $4.6 million (charge).
- Revenue *shortfall* from imbalance energy offsets for NV Energy was $3.8 million (charge).
- Revenue *shortfall* for the Public Service Company of New Mexico was $2.4 million (charge) from imbalance energy offsets and $2.7 million from congestion imbalance offsets.
- Revenue *surplus* from imbalance energy offsets for Puget Sound Energy was $3.9 million (credit).
- Revenue *surplus* for PacifiCorp East was $7.4 million (credit) from congestion imbalance offsets and $1.6 million (credit) for loss imbalance offsets.

Figure 8.2 Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)

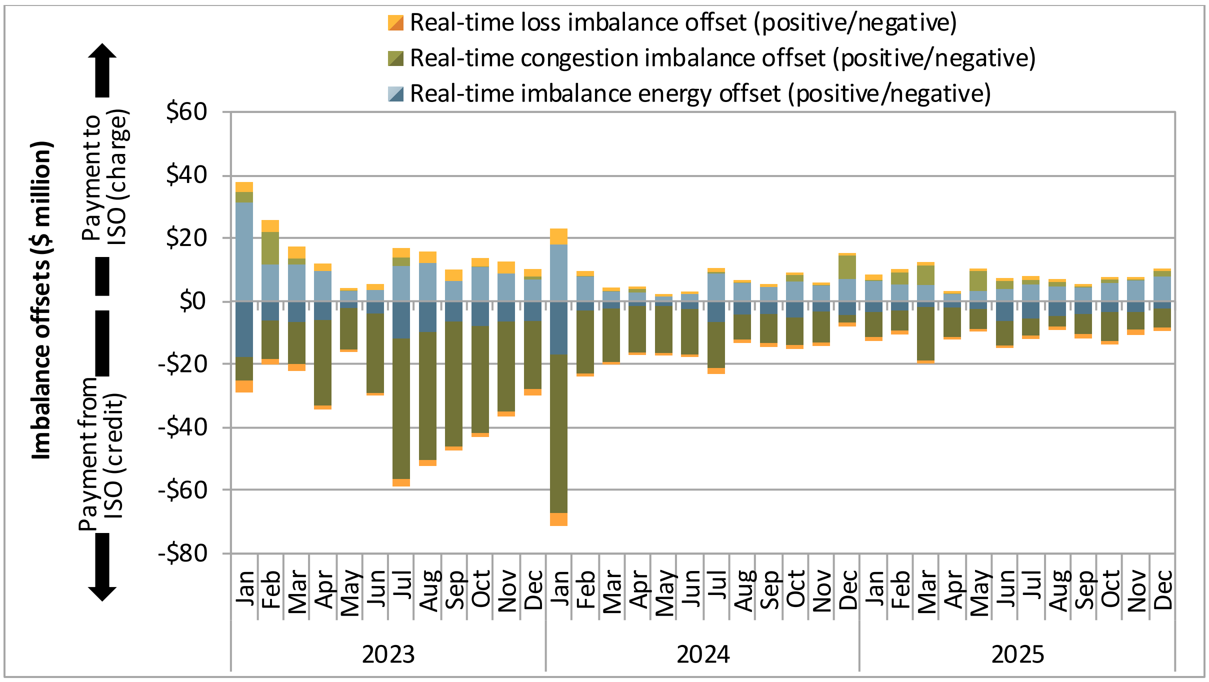

Figure 8.3 Real-time imbalance energy offsets by quarter and balancing area ($ millions)

	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Arizona Public Service	3	3	1	4	3
Avangrid	.5	.3	0	.1	.3
Avista	.1	.1	0	0	0
BANC	.3	0	.5	.6	.2
Bonneville Power Administration	.6	.6	.4	.4	.2
El Paso Electric	0	0	.3	.1	.1
Idaho Power	.3	2	.1	.9	.8
LADWP	.2	.2	.2	.1	.1
NorthWestern Energy	4	5	2	3	5
NV Energy	1	2	1	2	4
PacifiCorp East	4	.7	2	2	.1
PacifiCorp West	5	2	3	4	2
Portland General Electric	.1	.2	.1	.1	.3
Powerex	.2	0	.2	.2	.1
Public Service Company of NM	3	3	1	1	2
Puget Sound Energy	4	4	2	4	4
Salt River Project	2	2	3	3	1
Seattle City Light	.5	0	.3	1	1
Tacoma Power	0	0	0	0	0
Tucson Electric Power	0	.1	0	0	.1
Turlock Irrigation District	.4	.2	.4	.7	.7
WAPA Desert Southwest	0	.4	.1	.7	.5

Figure 8.4 Real-time congestion imbalance offsets by quarter and balancing area ($ millions)

	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Arizona Public Service	.2	.6	.1	1	.5
Avangrid	.1	.3	.4	.5	.3
Avista	.1	.2	.3	.2	.3
BANC	0	0	0	0	0
Bonneville Power Administration	0	2	1	.4	.9
El Paso Electric	.1	.1	.4	.9	.8
Idaho Power	0	1	1	.7	1
LADWP	5	1	.1	.3	1
NorthWestern Energy	.6	.5	.2	0	.5
NV Energy	.3	1	.8	.3	.5
PacifiCorp East	12	4	.4	2	7
PacifiCorp West	.8	3	2	1	2
Portland General Electric	1	3	3	2	1
Powerex	1	9	6	2	2
Public Service Company of NM	2	10	8	.6	3
Puget Sound Energy	.9	2	2	1	.9
Salt River Project	.7	.8	4	.6	.2
Seattle City Light	.2	.6	.6	.5	.3
Tacoma Power	0	.1	.1	.1	.1
Tucson Electric Power	2	.8	2	1	.7
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	0	.1	0	0	.1

Figure 8.5 Real-time loss imbalance offsets by quarter and balancing area ($ millions)

	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Arizona Public Service	.2	.2	.2	.3	0
Avangrid	.2	.1	.1	.1	.2
Avista	0	0	0	0	0
BANC	0	0	0	.2	.1
Bonneville Power Administration	.1	.1	0	.1	0
El Paso Electric	.1	.1	.1	.2	.1
Idaho Power	.5	.4	.2	.3	.1
LADWP	.2	.2	.1	.1	.5
NorthWestern Energy	.1	.1	.1	.1	.1
NV Energy	.1	.1	.2	.1	.1
PacifiCorp East	2	1	.5	2	2
PacifiCorp West	.4	.5	.3	0	.4
Portland General Electric	.1	.1	.2	.4	.1
Powerex	.6	2	.7	1	.7
Public Service Company of NM	.1	.2	.1	.1	.1
Puget Sound Energy	0	0	0	0	.2
Salt River Project	.2	.1	0	.3	.5
Seattle City Light	.3	.5	.4	.6	.4
Tacoma Power	0	0	0	0	0
Tucson Electric Power	.3	.1	0	.2	.1
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	0	.1	0	0	0

Figure 8.6 Total real-time imbalance offsets by quarter and balancing area ($ millions)

	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Arizona Public Service	3	4	1	4	3
Avangrid	.2	.1	.6	.6	.2
Avista	.1	.1	.3	.2	.3
BANC	.3	0	.5	.5	.1
Bonneville Power Administration	.6	1	.8	.9	.7
El Paso Electric	.1	.2	.2	.9	.8
Idaho Power	.8	.1	1	2	.2
LADWP	6	1	.1	.5	1
NorthWestern Energy	4	4	1	3	4
NV Energy	.6	.5	.2	2	3
PacifiCorp East	9	5	1	1	9
PacifiCorp West	6	5	5	5	4
Portland General Electric	.8	3	2	2	1
Powerex	.4	7	5	1	.9
Public Service Company of NM	6	12	10	2	5
Puget Sound Energy	5	6	4	5	5
Salt River Project	3	3	7	4	.3
Seattle City Light	.5	0	.4	1	1
Tacoma Power	0	0	.1	.1	.1
Tucson Electric Power	2	.7	2	1	.9
Turlock Irrigation District	.4	.2	.4	.7	.7
WAPA Desert Southwest	0	.4	.1	.6	.5

9 Bid cost recovery

During the fourth quarter of 2025, estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market totaled about $36 million.[60] This was a 3 percent decrease from the $37 million in bid cost recovery in the fourth quarter of 2024. Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM) totaled about $4.2 million. WEIM area bid cost recovery payments decreased 5 percent from Q4 2024.[61]

Figure 9.1 shows monthly bid cost recovery payments in the fourth quarter of 2025 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $10.6 million, down from $13 million in the fourth quarter of 2024. Bid cost recovery payments associated with residual unit commitment during the quarter totaled about $8.5 million, or about $2.3 million higher than the fourth quarter of 2024. Bid cost recovery associated with the real-time market (green bars) for areas that participate in the day-ahead market totaled about $16.9 million, which was about $0.9 million lower than the same quarter of 2024.

Figure 9.2 shows monthly bid cost recovery payments paid to units in areas participating only in the WEIM. Bid cost recovery payments to these units were greatest in the Desert Southwest and California[62] regions at $3.2 million and $819,000, respectively. Bid cost recovery payments to the Intermountain West and Pacific Northwest regions totaled around $132,000 and $130,000, respectively.

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. In the fourth quarter of 2025, about $34.5 million of bid cost recovery payments were made to gas resources, 89 percent of which were paid to units participating in both the day-ahead market and the WEIM. About $3.1 million and $1.9 million of payments were made to hydroelectric and battery resources, respectively. California ISO implemented changes[63] to the real-time bid cost recovery calculation for battery resources in September 2025. The ISO will continue to re-settle bid cost recovery payments for earlier trade dates going back to December 1, 2024.

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60 CAISO is the only balancing area currently participating in the day-ahead market.

61 The bid cost recovery payment amounts in this report are different than what is reported in the previous reports due to resettlements.

62 Figure 9.1 includes only non-CAISO balancing authority areas.

63 See here for more information: https://stakeholdercenter.caiso.com/StakeholderInitiatives/storage-bid-cost-recovery-and-default-energy-bids-enhancements?_gl=1*xtuuk2*_ga*MTU1OTc5MzcwNi4xNzUwNDM5NjY0*_ga_NDS4B4M2WP*czE3NzA2NzIxMjMkbzk3JGcxJHQxNzcwNjczMzAzJGo2MCRsMCRoMA..

Figure 9.1 Monthly bid cost recovery payments for day-ahead market area

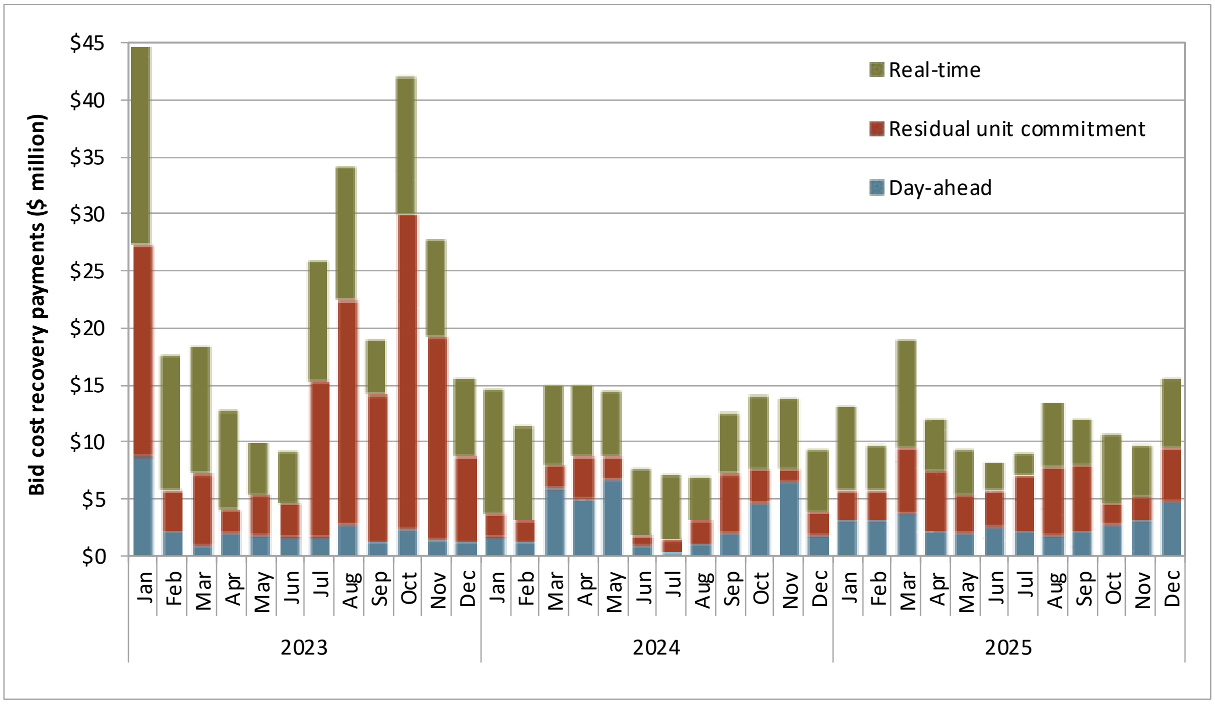
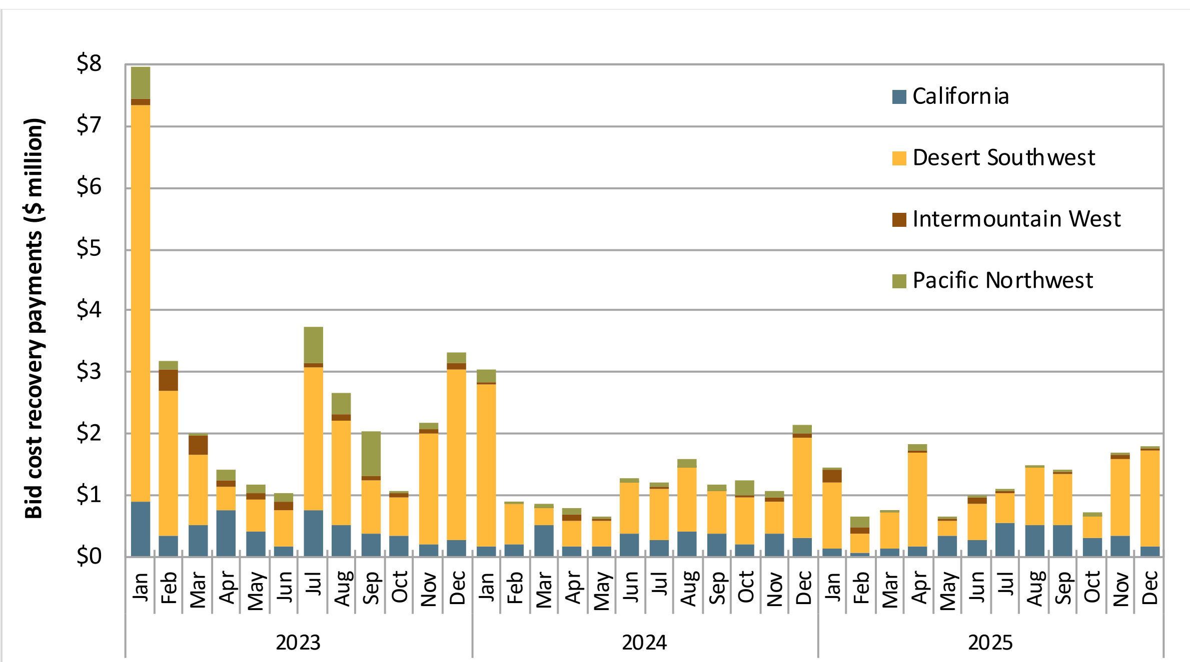


Figure 9.2 Monthly bid cost recovery payments for the WEIM



10 Flexible ramping product

This chapter analyzes flexible ramping product prices and procurement. Key findings in this chapter include:

- For balancing areas that passed the resource sufficiency evaluation, upward flexible ramping product prices in the 15-minute market were greater than zero for one or more balancing areas in this system during 0.4 percent of intervals, down from 0.7 percent in the fourth quarter of 2024. At the balancing area level, El Paso Electric (EPE) had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 1.7 percent of intervals.
- Battery and hydro resources made up 69 percent and 20 percent of upward flexible ramping product, respectively. Wind and solar combined to provide 38 percent of downward flexible capacity, and batteries provided 35 percent of downward flexible capacity.
- The CAISO balancing area continued to make up the majority of upward and downward flexible ramping product awards, at around 61 percent in the upward direction and 59 percent in the downward direction. Balancing areas in the Pacific Northwest made up 21 percent of upward flexible capacity and 17 percent of downward flexible capacity. The Desert Southwest and Intermountain West made up about 11 percent of flexible capacity each in the downward direction.

10.1 Background

The flexible ramping product is designed to enhance reliability and market performance by procuring upward and downward flexible ramping capacity in the real-time market, to help manage volatility and uncertainty surrounding net load forecasts.[64] The amount of flexible capacity the product procures is derived from a demand curve, which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs. Flexible capacity is procured and priced at a nodal level to better ensure that sufficient transmission is available for the capacity to be utilized.

The flexible ramping product demand curves are implemented in the ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This “requirement” for rampable capacity reflects the upper end of uncertainty in each direction that might materialize.[65] Therefore, it is sometimes referred to as the *flex ramp requirement* or uncertainty requirement.

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for the group of balancing areas that instead pass the resource sufficiency evaluation is pooled together to meet the uncertainty requirement for the rest of the system. Both the requirement

[64] The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market run and the three corresponding 5-minute market runs. Procurement in the 5-minute market is aimed at ensuring that enough ramping capacity is available to manage differences between consecutive 5-minute market intervals.

[65] Based on a 95 percent confidence interval.

for the pass-group and the requirement for balancing areas that fail the resource sufficiency evaluation are calculated using a method called *mosaic quantile regression*. This method applies regression techniques on historical data to produce a series of coefficients that define the relationship between forecast information (load, solar, or wind) and the extreme percentile of uncertainty that might materialize (95 percent confidence interval). These coefficients are then combined with current forecast information for each interval to determine the uncertainty requirement.

Flexible capacity awards are produced through two deployment scenarios that adjust the expected net load forecast in the following interval by the lower and upper ends of uncertainty that might materialize. The uncertainty requirement is distributed at a nodal level to load, solar, and wind resources based on allocation factors that reflect the estimated contribution of these resources to potential uncertainty. The result is more deliverable upward and downward flexible capacity awards that do not violate transmission or transfer constraints.

10.2 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.[66] The first component is the shadow price associated with meeting the flexible ramp requirement either for the group of balancing areas that pass the resource sufficiency evaluation or the individual balancing areas that fail the tests.

The nodal price also includes components to reflect any congestion based on the dispatch of flexible capacity in the deployment scenarios. This accounts for any congestion on WEIM transfer constraints between balancing areas as well as congestion on transmission constraints.[67] These components can create price differences across nodes in the WEIM based on the demand for flexibility in the system and the feasibility for flexible capacity at a node to meet that demand. For the transmission constraints, only the base-case flow based constraints and nomogram constraints are modeled and enforced in the deployment scenarios. Contingency flowgate constraints were briefly activated on June 4, 2024, and de-activated on June 12 due to performance issues with the solution run-times.[68] Using the same constraints for both the real-time market and flexible ramping product deployment scenarios is important in order to prevent conditions in which procured flexible capacity is actually stranded behind transmission constraint congestion, and therefore not able to address materialized uncertainty.

The pass-group constraint maintains that the sum of flexible capacity in the group of balancing areas that pass the resource sufficiency evaluation equals the group's uncertainty requirement (minus any relaxation). The ability to relax the requirement is allowed by *slack variables*. This allows flexible capacity to be forgone when the cost of procuring flexible capacity is higher than the benefit it provides (or when flexible capacity is not available).

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66 For details on the deployment scenario constraints and how the ISO derives flexible ramping prices from them, see *Business Requirements Specification – Flexible Ramp Product: Deliverability*, California ISO, August 19, 2022, pp 89-90: https://www.caiso.com/documents/businessrequirementsspecifications12-flexiblerampingproduct-deliverability.pdf

67 Congestion on WEIM transfer constraints is reflected through the individual balancing area power balance constraint in the deployment scenarios. This constraint considers both flexible ramping awards and flexible ramping requirements in addition to WEIM supply, load, and WEIM transfers between the areas.

68 *Market Performance and Planning Forum*, Q2, California ISO, June 27, 2024, slides 170-171: https://www.caiso.com/documents/presentation-market-performance-planning-forum-jun-27-2024.pdf

The slack variables are implemented for each balancing area.[69] The cost associated with the slack variable (cost of relaxing the requirement) is reflected by a demand curve. The demand curves are based on each balancing area's expected cost of a power balance constraint violation for the level of flexible capacity forgone.[70] The more flexibility forgone, the greater the likelihood of a power balance constraint violation and therefore greater expected cost. For a balancing area in the pass-group, the slack variable (or end of the demand curve) is limited by its distributed share of the pass-group uncertainty requirement.

The shadow price on the constraint for procuring flexible capacity in the pass-group has frequently been zero. When the shadow price on this constraint is zero, this generally reflects that flexible capacity within the wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available.[71] Here, the flexible capacity requirement for the group of balancing areas that passed the resource sufficiency evaluation can be met by resources with zero opportunity cost for providing that flexibility.

Figure 10.1 shows the percent of intervals in which the shadow price on the pass-group constraint was non-zero (constraint binding) for upward and downward flexible capacity. This reflects more widespread prices for flexible capacity within the group of balancing areas that passed the resource sufficiency evaluation, but does not account for any congestion that may affect the price of flexible capacity at the nodal level.[72] The pass-group constraint for procuring *upward* flexible capacity in both the 15-minute and 5-minute markets was binding in about 0.1 percent or less of intervals on average during the quarter. The pass-group constraint for procuring *downward* flexibility in the 15- and 5-minute markets was also binding very infrequently, in less than 0.1 percent of intervals on average.

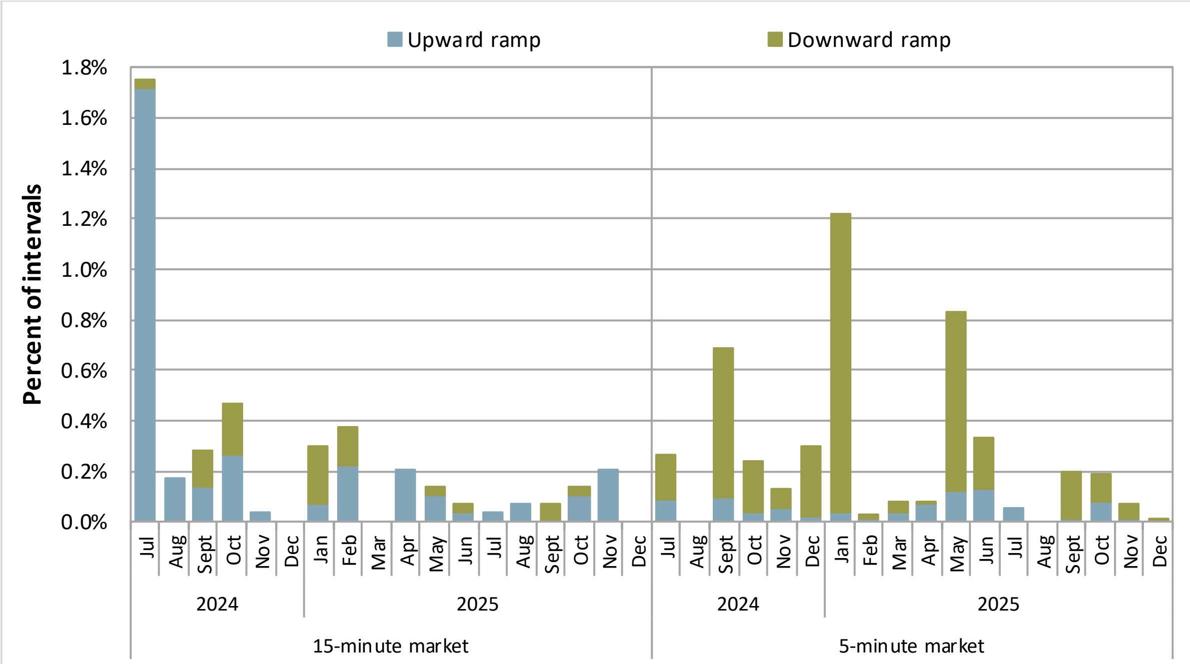
69 Or for each surplus zone in the case of the CAISO balancing area (by transmission access charge—or TAC—area) and the Balancing Authority of Northern California (by custom load aggregation point).

70 For upward flexible capacity, the demand curves are capped at $247/MWh.

71 This pass-group constraint is intended to limit the sum of all flexible ramp capacity in the passing group. The limit is the group's total flexible ramp requirement. The formulation of the deployment scenario also includes an individual power balance constraint for each balancing area in the pass-group, which considers the balancing area's energy load and supply, flexible ramping product requirement and supply, and transfers of energy and flexible ramping product. Given this individual power balance constraint for each balancing area, the pass-group flexible ramping capacity constraint may be redundant. This complicates the interpretation of the meaning of the shadow price of this pass-group constraint, and other constraints, in the deployment scenario in some cases. The potential redundancy of the constraint may also result in abnormal flexible ramping prices in some situations.

72 This figure does not account for congestion on WEIM transfer constraints between the areas in the pass-group. It also does not account for any congestion on flow-based constraints.

Figure 10.1 Frequency of flexible ramping product prices from pass-group constraint



The price of flexible capacity for a node in a balancing area that passed the resource sufficiency evaluation can still be positive even when the shadow price on the constraint for procuring pass-group-level flexible capacity is zero (e.g., not binding). This can occur because of congestion on WEIM transfer constraints that might separate a balancing area from the rest of the system. Here, outside flexible capacity may not be feasible to meet the isolated balancing area's share of pass-group uncertainty and this requirement may be relaxed, resulting in a localized price for flexible capacity. Congestion on binding transmission constraints in the deployment scenario can also create a localized price for flexible capacity.

Figure 10.2[73] summarizes the frequency of flexible ramping product prices in either the wider pass-group or transfer-constrained balancing areas within the pass-group. The blue bars are identical to the 15-minute market upward ramping capacity information shown in Figure 10.1, summarizing the frequency in which the constraint for meeting pass-group flexible capacity requirements was binding. The figure adds the percent of intervals in which the constraint that reflects WEIM transfer congestion in the deployment scenario was binding for one or more balancing areas in the pass-group—*and the pass-group constraint was not also binding*. This reflects additional flexible ramping product prices within at least one balancing area. In most cases, these prices were within one isolated balancing area in the pass-group that was not able to meet its share of pass-group uncertainty.

The frequency of upward flexible ramping product prices was very low across the pass-group. For balancing areas that passed the resource sufficiency evaluation, upward flexible ramping product prices in the 15-minute market were greater than zero for one or more balancing areas in the system during

73 Localized flexible ramping product prices within the pass-group that are entirely driven by congestion on transmission constraints are not reflected in this figure.

about 0.4 percent of intervals in the fourth quarter of 2025, down from 0.7 percent in the same quarter of 2024. In December, there were no intervals in which the constraint for meeting pass-group upward flexible capacity requirements was binding.

Figure 10.2 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

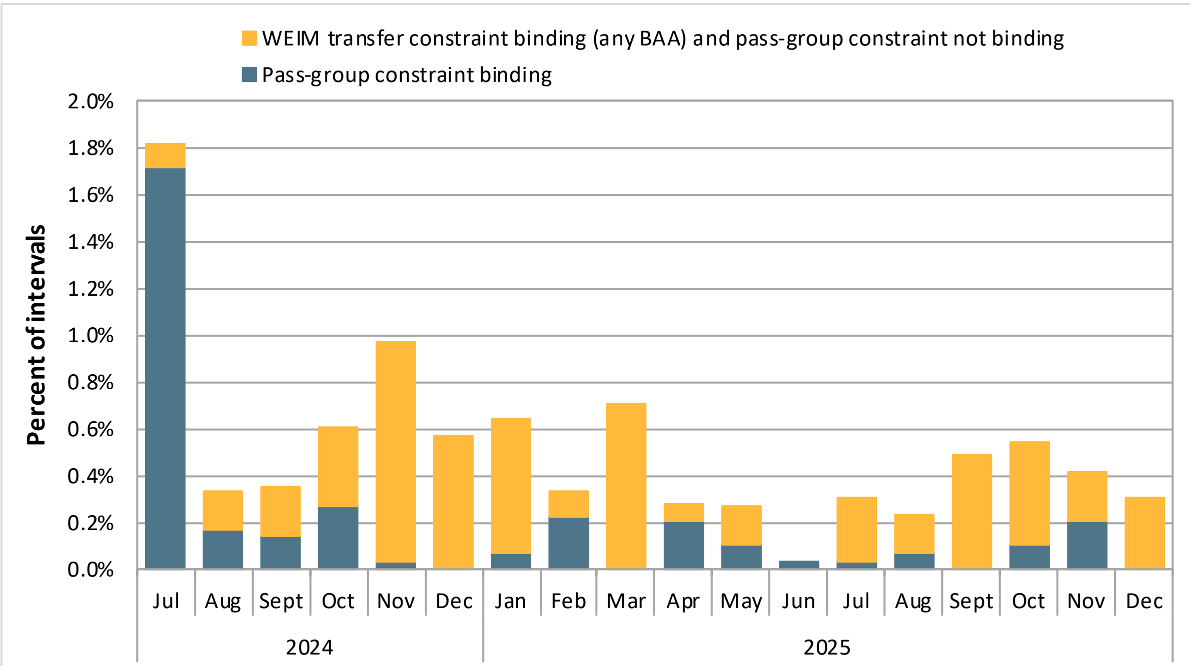


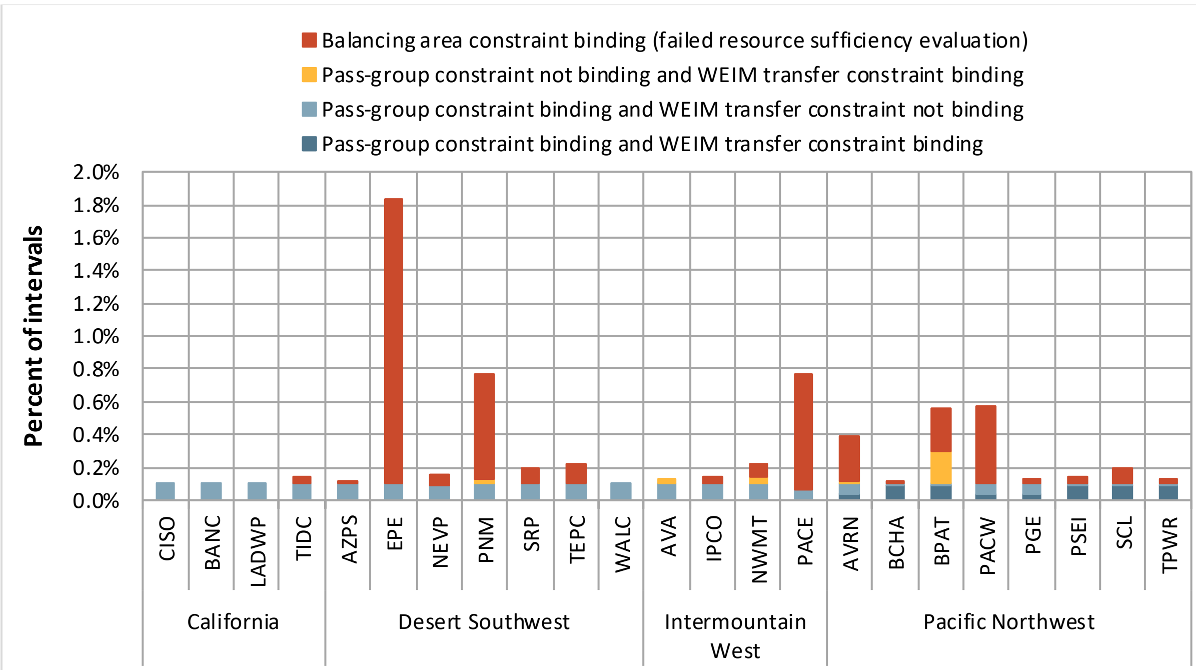
Figure 10.3 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the quarter. These results are shown separately by the constraint contributing to that price:

- **Balancing area constraint binding (failed resource sufficiency evaluation)** indicates that the balancing area failed the resource sufficiency evaluation and there is a price for upward flexible capacity within the balancing area. When a balancing area fails the resource sufficiency evaluation, the area will not have access to any diversity benefit of reduced uncertainty over a larger footprint and will instead need to meet its uncertainty needs from flexible capacity within its area only. This is shown by the red bars in Figure 10.3.
- **Pass-group constraint not binding and WEIM transfer constraint binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is no price for upward flexible capacity within the wider pass-group; but because of WEIM transfer congestion into the balancing area, there is a price for upward flexible capacity within the balancing area. This is shown in yellow.
- **Pass-group constraint binding and WEIM transfer constraint not binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group. This is shown in light blue below.
- **Pass-group constraint binding and WEIM transfer constraint binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group; but because of WEIM transfer congestion out of the balancing area,

there is typically no price for upward flexible capacity within the balancing area. This is shown in dark blue.

During the quarter, the pass-group constraint was binding very infrequently for upward flexible capacity in the 15-minute market, during around 0.10 percent of intervals. Most balancing areas in the California region did not fail the resource sufficiency evaluation during the quarter or experience flexible ramping product prices as a result. El Paso Electric had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 1.7 percent of intervals. Some of these can be associated with failure of the second run of the resource sufficiency evaluation at 55 minutes prior to the hour, which impacts the first interval of each hour.[74]

Figure 10.3 Frequency of upward flexible ramping product prices by balancing area and constraint



74 There are three runs of the resource sufficiency evaluation, at 75 minutes (first run), 55 minutes (second run), and 40 minutes (final run) prior to each evaluation. The first and second runs are sometimes considered the advisory runs, with the final evaluation occurring at 40 minutes prior to the hour. For procuring and pricing flexible capacity in the first 15-minute market interval of each hour, the market uses the results from the second run of the resource sufficiency evaluation. This is based on the latest information available at the time of this market run.

10.3 Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the group of WEIM balancing areas that pass the resource sufficiency evaluation. Figure 10.4 and Figure 10.5 show the average upward or downward flexible capacity that was procured from various fuel types.

During the quarter, battery resources continued contributing to much of the upward and downward flexible capacity, making up about 69 percent of upward flexible capacity and 35 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (20 percent). Wind and solar resources combined made up around 38 percent of downward flexible capacity.

Figure 10.4 Average upward pass-group flexible ramp procurement by fuel type (15-minute market, Q4 2025)

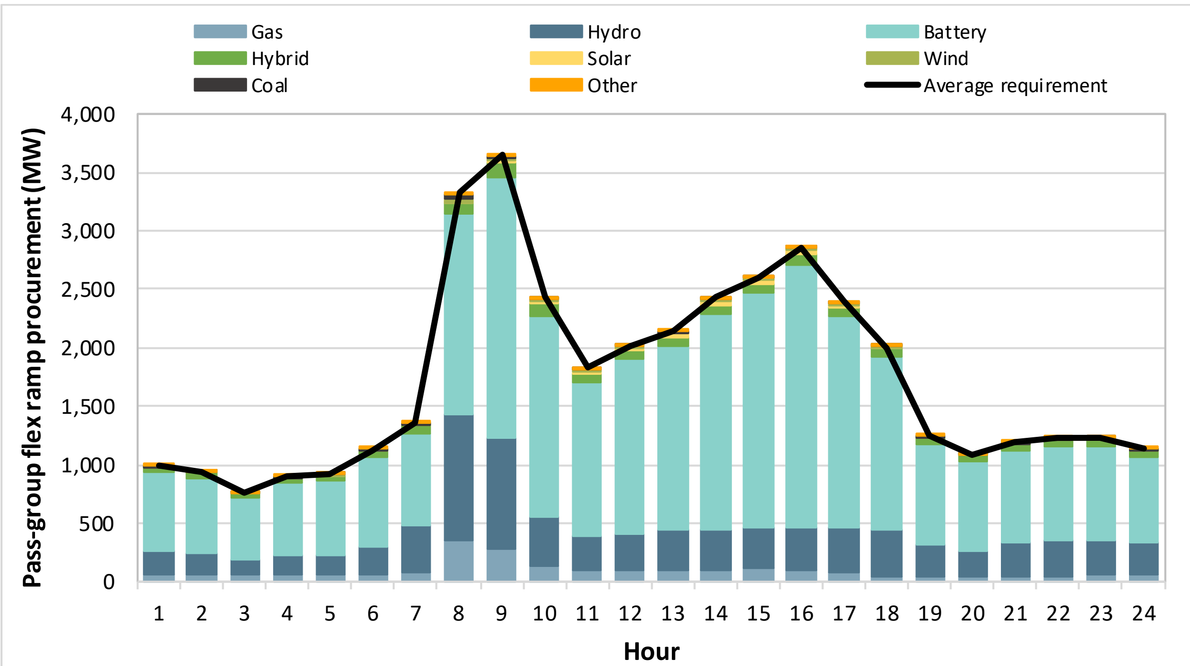


Figure 10.5 Average downward pass-group flexible ramp procurement by fuel type (15-minute market, Q4 2025)

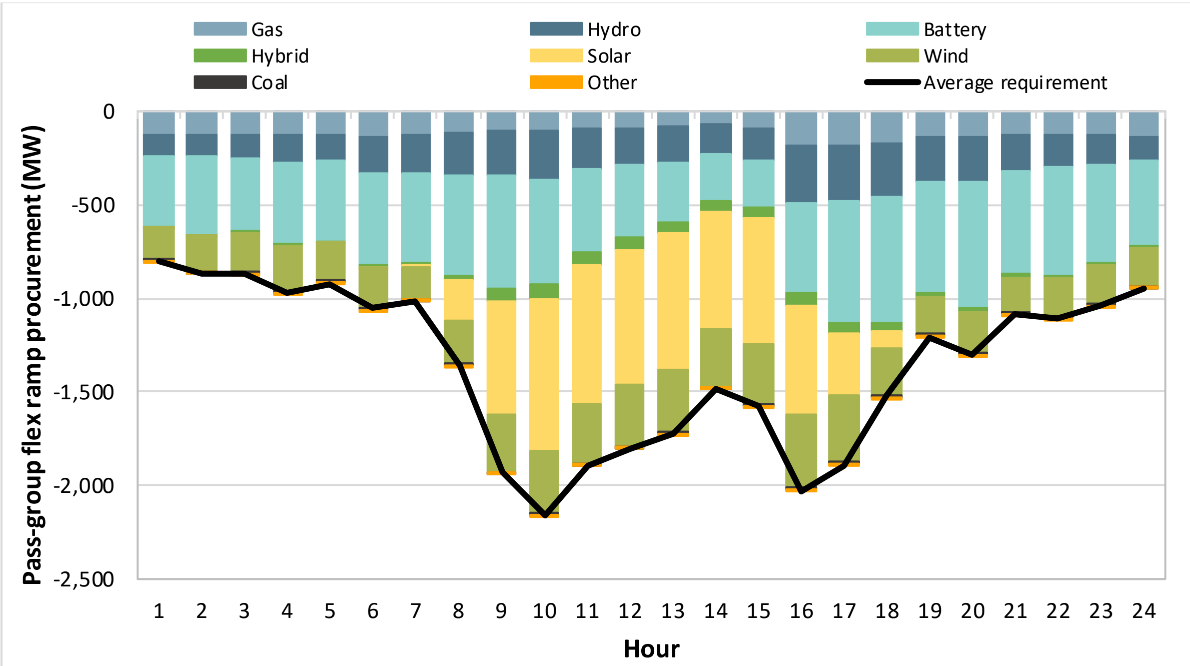


Figure 10.6 and Figure 10.7 show the average upward or downward flexible capacity that was procured in various regions.[75] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained, along with one or more other balancing areas relative to the greater WEIM system. During the quarter, the California ISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 61 percent in the upward direction and 59 percent in the downward direction. Balancing areas in the Pacific Northwest made up 21 percent of upward flexible capacity and 17 percent of downward flexible capacity. The Desert Southwest and Intermountain West made up about 11 percent of flexible capacity each in the downward direction.

[75] California (WEIM) includes BANC, LADWP, and Turlock Irrigation District. Desert Southwest includes Arizona Public Service, NV Energy, PNM, Salt River Project, El Paso Electric, Tucson Electric Power, and WAPA (DSW). Intermountain West includes Idaho Power, NorthWestern Energy, PacifiCorp East, and Avista. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power.

Figure 10.6 Average upward pass-group flexible ramp procurement by region (15-minute market, Q4 2025)

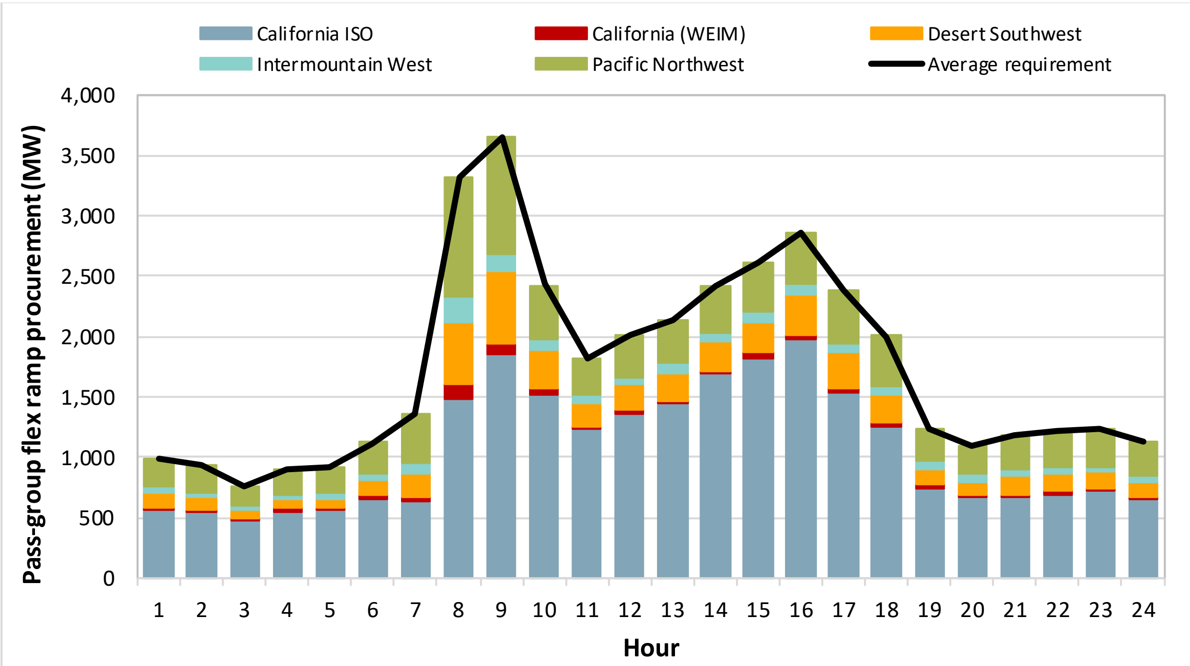
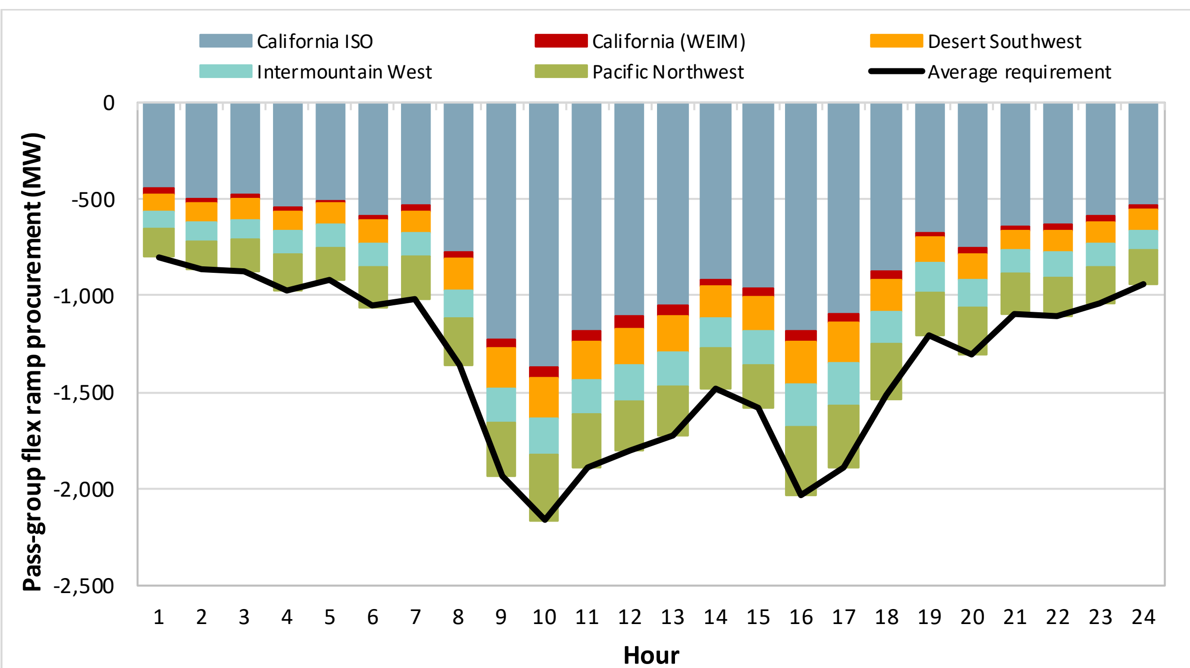


Figure 10.7 Average downward pass-group flexible ramp procurement by region (15-minute market, Q4 2025)



11 Uncertainty calculation assessment

This section discusses uncertainty considered in different applications of the market, including the flexible ramping product (FRP), resource sufficiency evaluation (RSE), and the residual unit commitment (RUC) adjustment. Each of these market processes uses a method called *mosaic quantile regression* to calculate and account for uncertainty that may materialize.[76] This chapter reviews the results of the uncertainty calculation and assesses the regression method.

DMM evaluates the performance of this model using three main criteria:

- **Accuracy:** accuracy is measured using the coverage rate, which reflects the percentage of realized uncertainties that falls within the forecast prediction interval.
- **Efficiency:** a forecast is considered efficient if it maintains the target coverage (e.g., 95 percent) while producing a relatively narrow prediction interval (requirement).
- **Validity:** DMM tests whether regression coefficients are statistically different from zero at the 10 percent significance level ($p<0.1$).[77]

Measurements of the uncertainty requirements and coverage in this section are based on actual market results. The statistical significance metrics are based on DMM's replication of the ISO's mosaic quantile regression method.[78]

11.1 Flexible ramping product uncertainty results and special issues

The flexible ramping product procures flexible capacity to cover uncertainty that may materialize in the real-time market. By design, the *uncertainty requirement* captures the extreme ends of net load uncertainty and it can be optimally relaxed based on the trade-off between the cost of procuring additional flexible ramping capacity and the expected cost of a power balance relaxation. For the 15-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 15-minute market net load forecast and the binding 5-minute market forecasts. For the 5-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 5-minute market forecast and the binding 5-minute market forecast.

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76 For further details on the regression methodology, a simplified explanation is available in chapter 11 of DMM's 2024 annual report, pp 240–243: https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf

For a more technical review, see the DMM special report, *Review of mosaic quantile regression for estimating net lad uncertainty*, November 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

77 Statistical testing is used to determine whether a regression coefficient is significantly different from zero, which suggests the presence of a non-random pattern in historical data. This relationship may be useful for forecasting—if the historical pattern continues into the future. However, statistical significance alone does not guarantee forecast accuracy; if the pattern does not persist, the model may still perform poorly despite showing past significance. If a coefficient is not statistically significant, it may indicate either no meaningful pattern or an unstable pattern that could result in inaccurate forecasts. The model produces two main coefficients (a linear and a quadratic term), and DMM evaluates model validity based on whether either is statistically significant at the 10 percent level.

78 This choice is made because there are no statistical significance tests available based on the ISO's estimations.

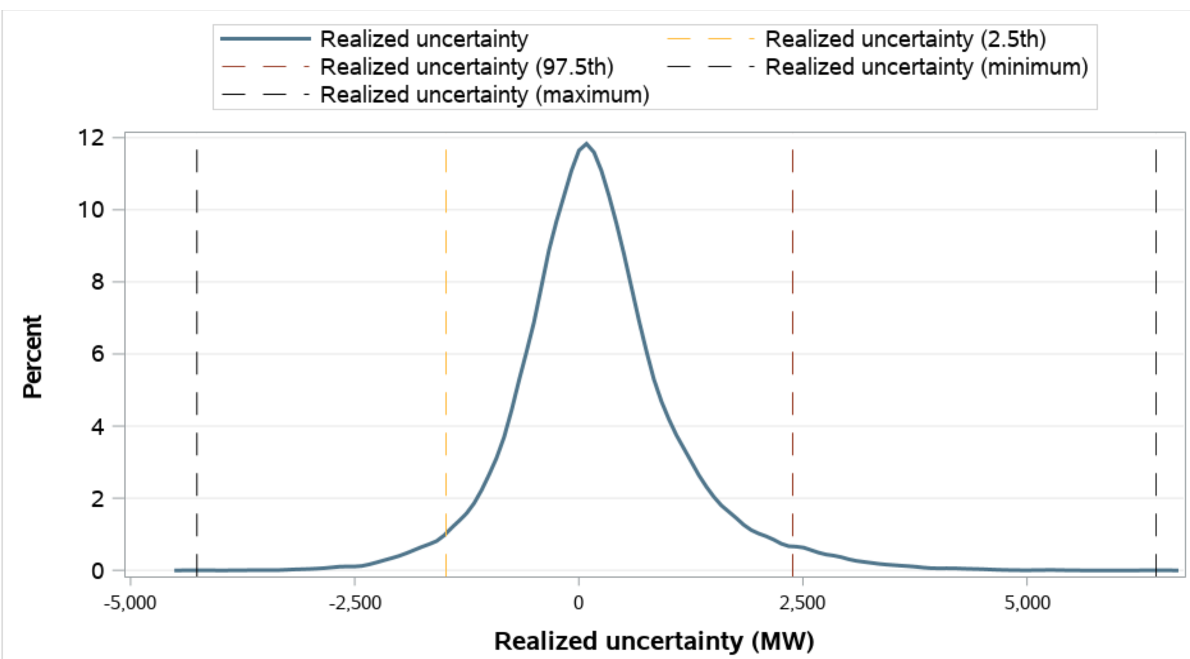
The flexible ramping product uses an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. For the group of balancing areas that instead pass the resource sufficiency evaluation (known as the pass-group), flexible capacity is pooled together to meet the group's uncertainty requirement.

Figure 11.1 illustrates the distribution of realized uncertainty in the flexible ramping product (FRP) for the group of balancing areas that passed the resource sufficiency evaluation (RSE) for the fourth quarter of 2025. The distribution is depicted as a blue line, with the extreme percentiles highlighted: the lowest 2.5th percentile in yellow, the 97.5th percentile in red, and the black dashed lines indicating the minimum and maximum values.

The range from the upper 2.5 percent of uncertainty to its maximum spans from 2,400 MW to over 6,400 MW, reflecting a long tail distribution. These long tails in the distribution could indicate that the uncertainty is influenced by rare, extreme events rather than typical fluctuations. When the distribution is skewed upward, the result is a longer tail on the upper end. This may indicate the influence of systematic patterns, rather than purely random variations.

The extreme long tail in the distribution of realized uncertainty is potentially influenced by several factors. One key factor is the variability in the number of balancing authority areas within the RSE pass-group; the composition is not always constant. Sometimes, all balancing areas in the WEIM pass the RSE, while other times only a subset does. This variability affects the scale of aggregated uncertainty for the pass-groups. Additionally, extreme weather events and rapid changes in demand further contribute to this long tail.

Figure 11.1 Distribution of realized uncertainty in FRP (pass-group, October–December 2025)



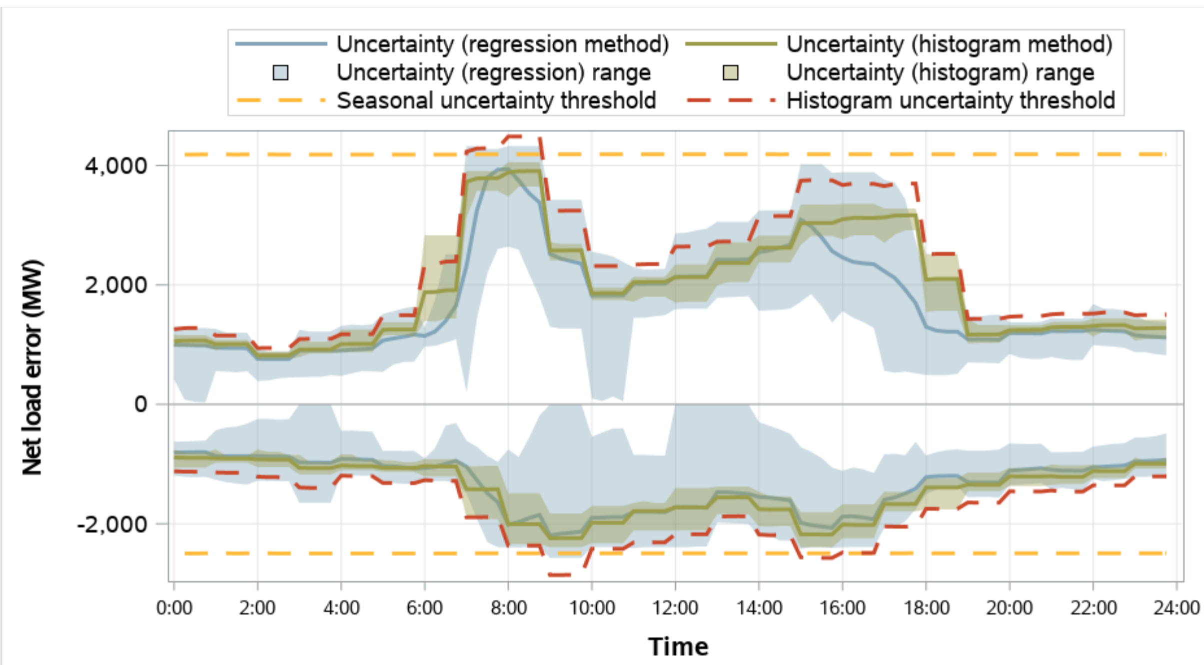
11.1.1 Results of flexible ramping product uncertainty calculation

Figure 11.2 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation (RSE), both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the historical 180-day period) and with the mosaic quantile regression method. The green and blue lines show the average upward and downward uncertainty from each method while the areas around the lines show the minimum and maximum amount over the quarter. The dashed red and yellow lines show the average histogram and seasonal thresholds, respectively, during the period.[79]

Figure 11.3 shows the same information for 5-minute market uncertainty, which reflects the difference between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the quantile regression approach was typically lower or comparable to uncertainty calculated with the histogram approach. However, results of the regression-based approach vary more widely, including periods with much lower uncertainty.

Figure 11.2 15-minute market pass-group uncertainty requirements (October–December 2025)



79 Two ceiling thresholds are applied to help prevent extreme outlier results from impacting the final uncertainty.

Figure 11.3 5-minute market pass-group uncertainty requirements (October–December 2025)

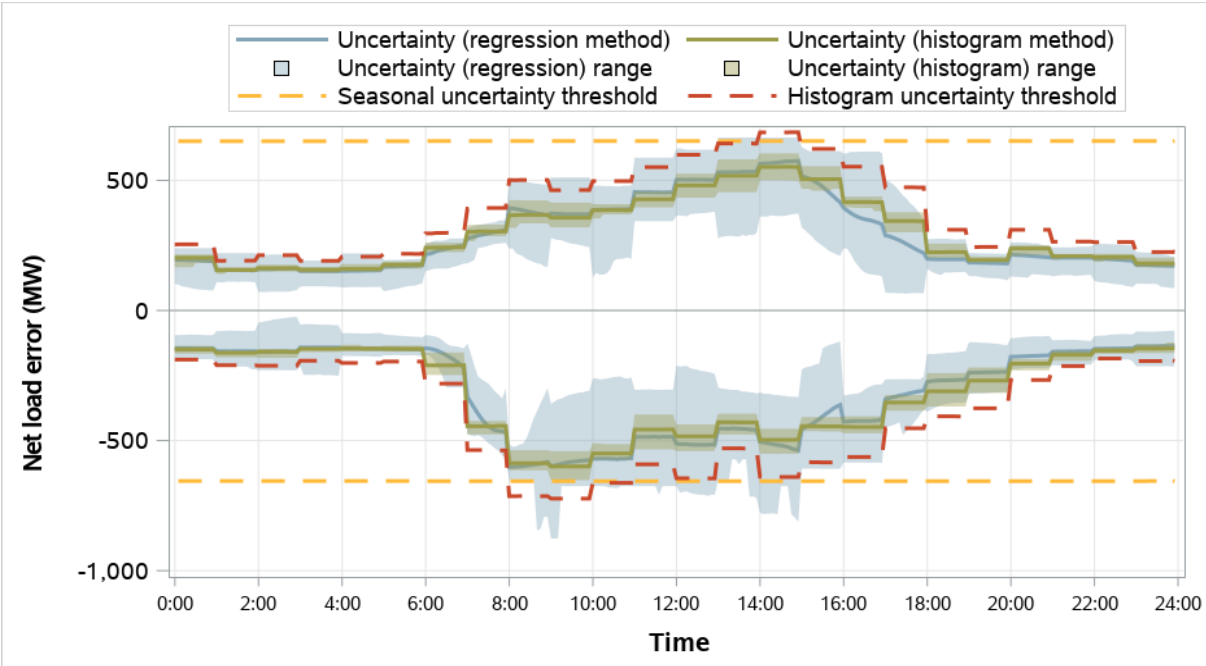


Table 11.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the pass-group (based on a 95 percent confidence interval). The coverage shows how often the realized uncertainty fell within the requirement for the same interval.[80]

In the flexible ramping product (FRP), due to the different composition of the upward and downward RSE pass-group, each direction is evaluated with a target coverage of 97.5 percent.[81] In both markets and directions, uncertainty forecasted by mosaic regression generally had lower coverage and lower requirements.

80 Realized 15-minute market uncertainty is measured as the difference between binding 5-minute market net load forecasts and the advisory 15-minute market net load forecast. Realized 5-minute market net load error is measured as the difference between the binding 5-minute market net load forecast and the advisory 5-minute market net load forecast.

81 The composition of the RSE pass-group differs for each direction. For instance, at a given interval, the RSE pass-group for upward uncertainty might include all 23 BAAs, while for the same interval the pass-group for downward uncertainty could include only 20. These disparities mean that the actual uncertainty for the pass-group is different in each direction. Since the regression employs the 97.5th percentile for upward uncertainty and the 2.5th percentile for downward uncertainty, the target coverage for each direction is set at 97.5 percent.

Table 11.1 Average pass-group uncertainty requirements (October–December 2025)

Market	Direction	Requirement			Coverage		
		Histogram	Mosaic	*Difference*	Histogram	Mosaic	*Difference*
15-minute market	Up	1,960	1,742	-218	98.0%	97.5%	-0.5%
	Down	1,439	1,357	-82	97.9%	97.4%	-0.5%
5-minute market	Up	299	290	-9	97.7%	97.6%	-0.1%
	Down	319	312	-7	97.6%	97.5%	-0.1%

Table 11.2 presents the percentage of statistically significant coefficients across various quantile regressions for the 15-minute market calculation of pass-group uncertainty. The results are based on DMM's replication.

The mosaic regression is primarily designed to forecast net load uncertainty, with the mosaic variable serving as the main predictor in this regression. The three additional quantile regressions—load, solar, and wind—function as intermediate regressions used to construct the mosaic variable.[82]

The percentages in the table indicate the proportion of estimated coefficients that were statistically different from zero among all regression estimations in this quarter. Each regression includes two primary coefficients: a quadratic term and a linear term.[83] The percentages represent the proportion of regression where at least one of these coefficients was statistically significant. The significance level was set at 10 percent.

Table 11.2 Test for statistical significance of the mosaic quantile regression in FRP (October–December 2025)[84]

Regression type	All hours	Peak hours(1)
Mosaic	24%	38%
Load	26%	29%
Solar	60%	76%
Wind	50%	67%

(1): Peak hours include hour-ending (HE) from 7 to 9 and HE from 17 to 21.

The coefficient for the mosaic variable was statistically significant during only 24 percent of intervals. This means that in 76 percent of cases, the mosaic variable did not show a strong pattern with historical

82 For a more detailed description of how the three other quantile regressions are used to construct the mosaic variable, see the DMM special report, *Review of mosaic quantile regression for estimating net load uncertainty*, November 20, 2023, pp 6-10: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

83 The mosaic quantile regression includes three coefficients: an intercept, a quadratic term for the mosaic variable, and a linear term for the mosaic variable. The percentage of significant coefficients is determined by whether either the quadratic term or the linear term is statistically different from zero at the 0.1 significance level. This significance is calculated for both upward and downward uncertainty estimations, and then averaged.

84 The current ISO regression sample in FRP includes duplicate independent variables, which can artificially inflate statistical significance. DMM addresses this by aggregating data to remove duplicates before running regression.

uncertainty.[85] Whether the mosaic variable is high or low, the uncertainty does not consistently respond with similarly high or low levels of uncertainty. Consequently, when looking at future data, even if the mosaic variable is high, it is unclear whether the uncertainty will be high or low.

Low statistical significance suggests that the regression often fails to identify a meaningful relationship. This failure could stem from either no relationship or inconsistent relationship. While it is difficult to quantify the proportion of cases due to no relationship versus inconsistency, mathematically, if no relationship exists, the quantile regression outcomes will converge to the histogram results.[86] Intuitively, this occurs because a no relationship implies that the mosaic variable provides no additional information for forecasting. As a result, the forecast relies solely on the historical net load uncertainty data, which is the histogram method.

In Table 11.2 the average hourly requirement and performance metrics show a high degree of similarity between the histogram and mosaic regression method. This resemblance can be explained by the low percentage of statistically significant coefficients.

11.2 Resource sufficiency evaluation uncertainty results

Uncertainty is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the resource sufficiency evaluation (RSE). Here, balancing areas must show enough upward and downward ramping flexibility over an hour to meet both the forecasted change in demand *as well as uncertainty*.[87] This additional requirement in the flexibility test is also based on a 95 percent confidence interval for uncertainty that might materialize. This section analyzes the performance of the mosaic quantile regression in the resource sufficiency evaluation.

Figure 11.4 shows the distribution of realized 15-minute uncertainty in the RSE for each balancing authority area (BAA) for the fourth quarter of 2025. Here, realized uncertainty is defined as the net load forecast difference between the forecasts used in the resource sufficiency evaluation and those in the binding 5-minute market runs. To facilitate comparison across different BAAs, the realized uncertainty has been standardized by its mean and standard deviation.[88] This eliminates scale issues and allows for a

85 Quantile regression assesses patterns that may exist at a specific percentile of the sample. For the flexible ramping product, the 97.5th and 2.5th percentiles reflect the extreme upper or lower 2.5 percent of uncertainty relative to the mosaic variable. If the pattern is strong, it indicates a clear relationship at these extremes. Conversely, a weak pattern suggests that the relationship is less pronounced or not robust.

86 For a detailed discussion on the theoretical background and empirical findings regarding the resemblance between the mosaic quantile regression and the histogram method, see the DMM special report, *Review of mosaic quantile regression for estimating net load uncertainty*, Nov 20, 2023, p 5 and pp 31-33: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

87 The flexibility test also includes a discount to account for *diversity benefit*. System-level flexible ramping needs are smaller than the sum of the needs of individual balancing areas because of reduced uncertainty across a larger footprint. Balancing areas therefore receive a prorated diversity benefit discount in the test based on this proportion.

88 Standardizing involves calculating the z-score, which is done by subtracting the mean of uncertainty from each data point and then dividing the result by the standard deviation. This process transforms the data so that it has a mean of zero and a standard deviation of one. This is helpful for comparing uncertainty across different BAAs because it removes the scale difference between them. Each BAA has different absolute levels of uncertainty, but by standardizing, all areas are brought onto the same scale. This allows for a direct comparison of their relative volatility and makes it easier to see which BAA experiences more or less uncertainty.

clear assessment of relative volatility in realized uncertainty among BAAs. Additionally, the figure displays the standardized average upward and downward requirement imposed in the market, enabling a comparison of each BAA's requirement relative to its own uncertainty, as well as in relation to other areas.

Figure 11.4 Standardized realized uncertainty and requirement for RSE (October–December 2025)

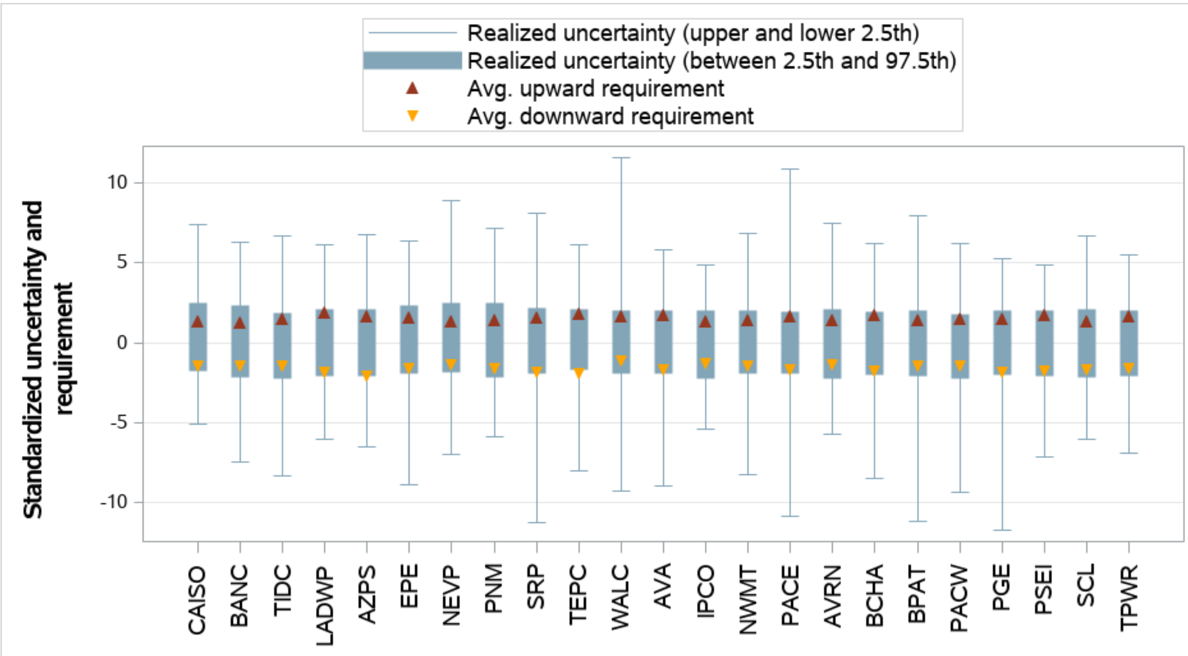


Figure 11.4 provides a comparison of the realized uncertainty across different BAAs for this quarter. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 2.5th percentile to the minimum value of realized uncertainty. The triangle markers show the average upward and downward requirement applied in the market, based on the ISO's estimates.

Key observations include:

- **Long tails**: Most BAAs exhibit a long tail distribution. The range of uncertainty beyond the 2.5th and 97.5th percentiles is wider than the main distribution of data.
- **Asymmetry in uncertainty:** Not all have symmetric uncertainty distributions. Some tend to have more positive uncertainty, while others skew more negative.
- **Requirement**: The requirements reflect the forecasted outcomes of the mosaic regression. Some BAAs exhibited a narrower range of requirements compared to others, which may indicate the regression model performed differently across BAAs.

11.2.1 Results of resource sufficiency evaluation uncertainty calculation

Table 11.3 summarizes the average requirements and coverage for uncertainty in the resource sufficiency evaluation using both the histogram and mosaic quantile regression methods. In this table, *requirement* shows the average uncertainty component considered in the upward and downward flexibility test requirements. Coverage measures how frequently that realized uncertainty—as measured by the difference between binding 5-minute market net load forecasts and net load forecasts in the resource sufficiency evaluation (RSE)—fell within the calculated uncertainty requirements for the same interval.

In the RSE, the mosaic regression method resulted in coverage levels largely below the 95 percent target. This is mostly due to a disparity with the underlying data used to estimate resource sufficiency evaluation uncertainty, as discussed in the following section. On average across all hours, the uncertainty calculated from the regression method was less than the histogram method for almost all of the WEIM entities. The resource sufficiency evaluation uncertainty calculated from the regression method covered between 85 and 95 percent of realized uncertainty across all balancing areas.

Table 11.3 Average resource sufficiency evaluation uncertainty requirements and coverage (October–December 2025)

	Upward uncertainty			Downward uncertainty			Coverage		
Balancing area	**Histogram**	**Mosaic**	**Difference**	**Histogram**	**Mosaic**	**Difference**	**Histogram**	**Mosaic**	**Difference**
Arizona Public Service	297	238	-59	254	227	-27	95%	94%	-1%
Avangrid	202	162	-40	183	133	-51	92%	91%	-1%
Avista	55	56	0	64	61	-3	92%	91%	0%
BANC	45	39	-6	45	38	-7	93%	90%	-3%
Bonneville Power Admin.	230	190	-40	272	212	-60	92%	90%	-2%
California ISO	1,335	1,152	-182	838	748	-90	94%	92%	-2%
El Paso Electric	52	43	-9	45	38	-7	96%	92%	-4%
Idaho Power	135	126	-9	167	156	-12	86%	85%	-1%
LADWP	164	156	-7	150	143	-7	95%	94%	-1%
NorthWestern Energy	75	73	-3	88	78	-10	90%	89%	-1%
NV Energy	262	209	-53	222	183	-39	95%	92%	-3%
PacifiCorp East	471	431	-41	617	586	-31	94%	92%	-2%
PacifiCorp West	94	87	-7	146	117	-29	91%	90%	-1%
Portland General Electric	121	111	-10	121	115	-6	92%	91%	-2%
Powerex	153	153	0	158	158	0	92%	92%	0%
PNM	198	168	-30	182	178	-4	94%	93%	-1%
Puget Sound Energy	160	154	-6	147	148	1	92%	92%	0%
Salt River Project	146	133	-13	131	120	-12	94%	93%	-1%
Seattle City Light	18	18	-1	20	19	-1	90%	89%	-1%
Tacoma Power	12	12	0	12	12	0	93%	92%	-1%
Tucson Electric Power	110	99	-11	88	83	-5	96%	95%	-1%
Turlock Irrigation District	7	7	0	8	7	-1	91%	89%	-2%
WAPA Desert Southwest	40	32	-7	26	24	-2	91%	88%	-3%

Table 11.4 summarizes the percentage of statistically significant coefficients during all hours and peak hours, based on DMM's replication of the regression. The balancing areas are listed in descending order, starting with those with the highest percentage of significant coefficients. Overall, 36 percent of regression coefficients were significant in Q4 2025, indicating that 64 percent of the regression estimations were based on either weak or inconsistent patterns.

Table 11.4 Test for statistical significance of mosaic quantile regression in RSE (October–December)[89]

BAA	Percent of significant coefficients	
	All hours	Peak hours(1)
Avangrid	92%	95%
PacifiCorp West	69%	69%
Arizona PS	64%	59%
BPA	64%	62%
NorthWestern	46%	35%
Idaho Power	46%	56%
CAISO	40%	55%
NV Energy	39%	50%
PacifiCorp East	36%	49%
El Paso Electric	36%	42%
Avista Utilities	33%	27%
Salt River Project	31%	32%
Puget Sound Energy	29%	34%
LADWP	28%	37%
PSC New Mexico	27%	33%
Tucson Electric	25%	33%
Portland GE	22%	23%
BANC	21%	26%
WAPA - Desert SW	19%	23%
Powerex	17%	22%
Seattle City Light	11%	19%
Turlock ID	11%	9%
Tacoma Power	11%	11%
Average	36%	39%

(1): Peak hours include hour-ending (HE) from 7 to 9 and HE from 17 to 21.

11.2.2 RSE uncertainty special issue — time horizon for predicting uncertainty

The regression model used for the resource sufficiency evaluation is currently designed to predict uncertainty in forecasts produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, typically produced between 47.5 and 102.5 minutes before real-time.

89 The current ISO regression sample in RSE includes duplicate independent variables, which can artificially inflate statistical significance. DMM addresses this by aggregating data to remove duplicates before running regression.

The resource sufficiency evaluation uses exactly the same underlying historical data to perform the regressions and calculate uncertainty as the flexible ramping product in the 15-minute market.[90] This data is based on the difference from advisory forecasts in the 15-minute market to the corresponding binding forecasts in the 5-minute market. The regressions use this data to produce hourly coefficients that define the relationship between the forecasts and uncertainty. This calculation reflects 45 to 55 minutes in which uncertainty may materialize between the applicable 15-minute and 5-minute market runs.

However, the resource sufficiency evaluation occurs over a different timeframe than what is considered for procuring 15-minute market flexible capacity. Figure 11.5 illustrates the timeframe of uncertainty considered for the flexible ramping product in the 15-minute market, and how it compares with the timeframe of the resource sufficiency evaluation.[91] For the flexible ramping product, the calculation is designed to capture uncertainty that may materialize around a single upcoming (advisory) interval. However, the resource sufficiency evaluation considers forecast information from *four* 15-minute intervals within an hour. When comparing the forecast values used in each interval of the resource sufficiency evaluation to corresponding 5-minute market intervals, there exists a larger gap of time for uncertainty to materialize.

In comparing the first 15-minute test interval of the RSE to corresponding 5-minute market intervals, the timeframe and potential for net load uncertainty to materialize is similar to the timeframe of the 15-minute market flexible ramping product uncertainty calculation. However, in the later test intervals, the gap between the predicted forecasts at the time of the resource sufficiency evaluation and the real-time forecasts widens, reaching above 100 minutes. The current determination of the regression coefficients for predicting net load uncertainty for the resource sufficiency evaluation (based on short-term historical data) does not capture the increased net load uncertainty associated with the longer-term horizon of this market process.[92]

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the resource sufficiency evaluation. Figure 11.6 shows the average coverage rate across all balancing areas by interval. Here, coverage is measured as the percent of intervals when realized uncertainty from the forecasts considered in the resource sufficiency evaluation to the 5-minute market forecasts fell within the calculated uncertainty requirement for the same interval. The calculated uncertainty covered the realized uncertainty much less for intervals at the end of the hour compared to the beginning of the hour because the current calculation is not designed to capture uncertainty that can realize over a longer-term horizon.

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90 A balancing-area-specific flexible ramping product uncertainty requirement will be enforced for any balancing area that failed the resource sufficiency evaluation.

91 The figure shows the time horizon for the resource sufficiency evaluation ran 55 minutes prior to the hour (T-55 RSE). While the final test is run at 40 minutes prior to the hour, the load and renewable forecasts used in the final test are held fixed from the forecasts in the T-55 RSE. This is intended to reduce unexpected failures that would be caused by forecast variation between the T-55 and T-40 resource sufficiency evaluations.

92 The resource sufficiency evaluation and flexible ramping product uncertainty calculations for a single balancing area use the same hourly regression coefficients (produced from the same short-term historical data) but are combined with the current forecast information at the time of each market process to determine the final uncertainty. Here, longer-term forecast information at the time of the resource sufficiency evaluation is combined with the short-term regression coefficients.

Figure 11.5 Comparison of timeframe considered for the flexible ramping product and resource sufficiency evaluation

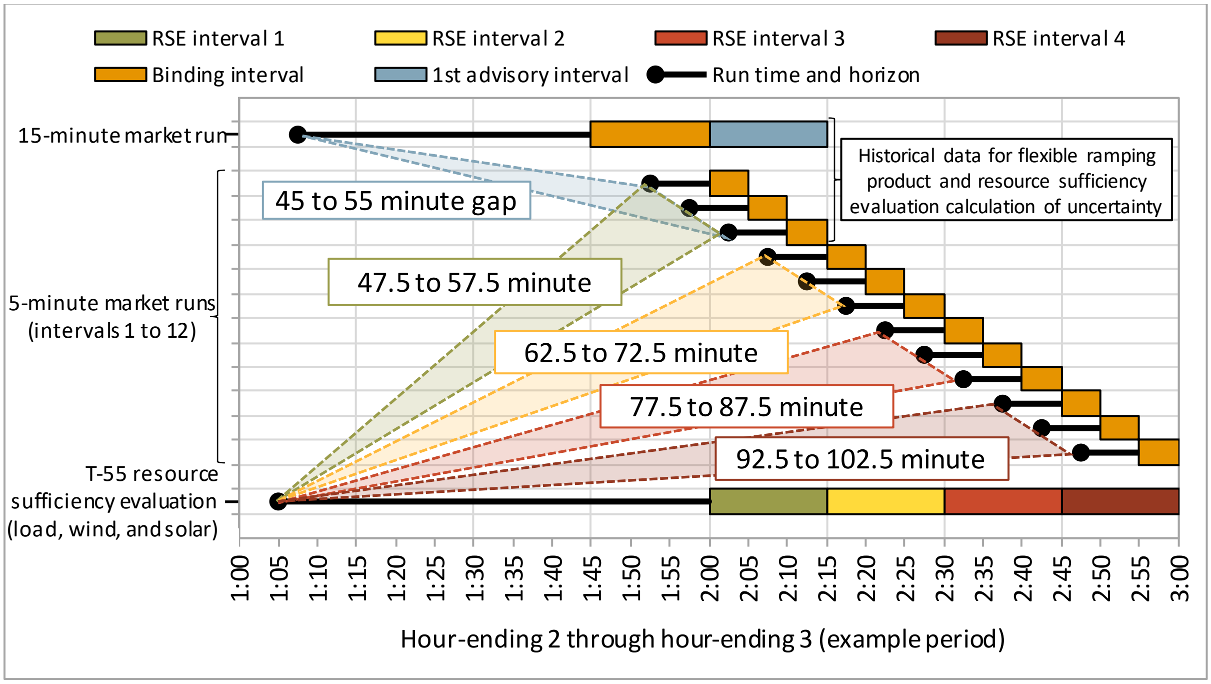
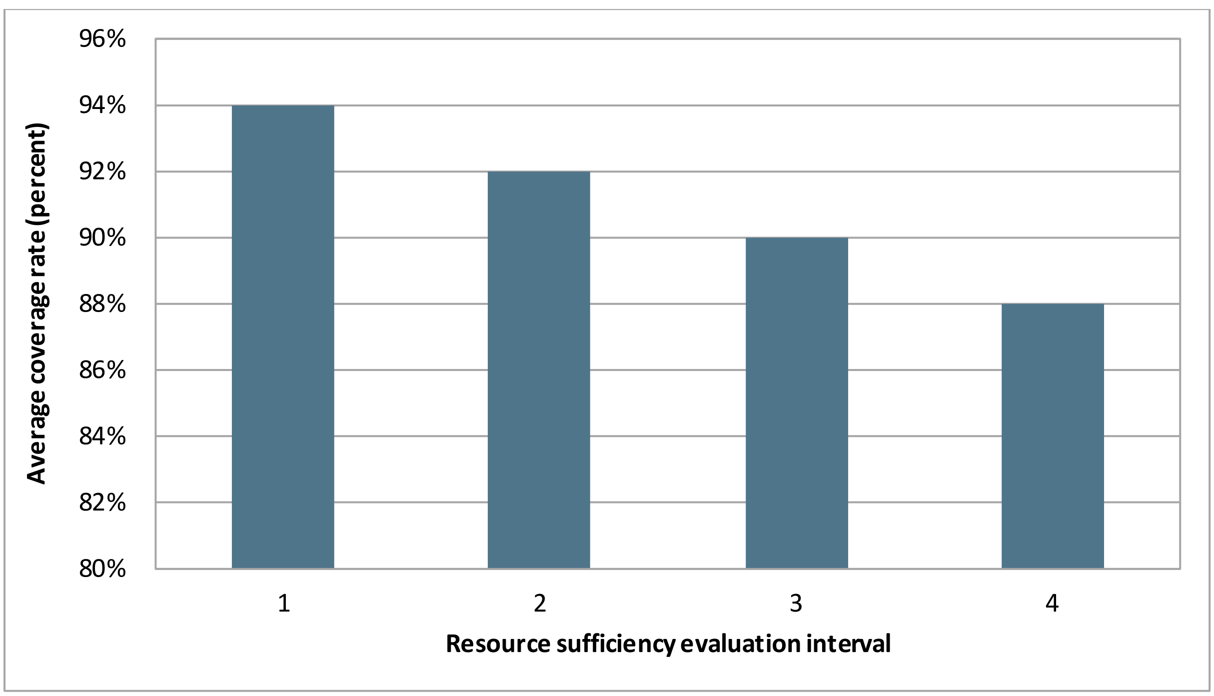


Figure 11.6 Average coverage rate by resource sufficiency evaluation interval (October–December 2025)



11.3 Residual unit commitment uncertainty results

Uncertainty is often added to the residual unit commitment (RUC) target load requirement. This adjustment is used to ensure there is sufficient capacity to account for uncertainty that may materialize between the day-ahead and real-time markets. For the residual unit commitment market adjustment, uncertainty is defined as the difference between the day-ahead net load forecast and 15-minute market forecasts.

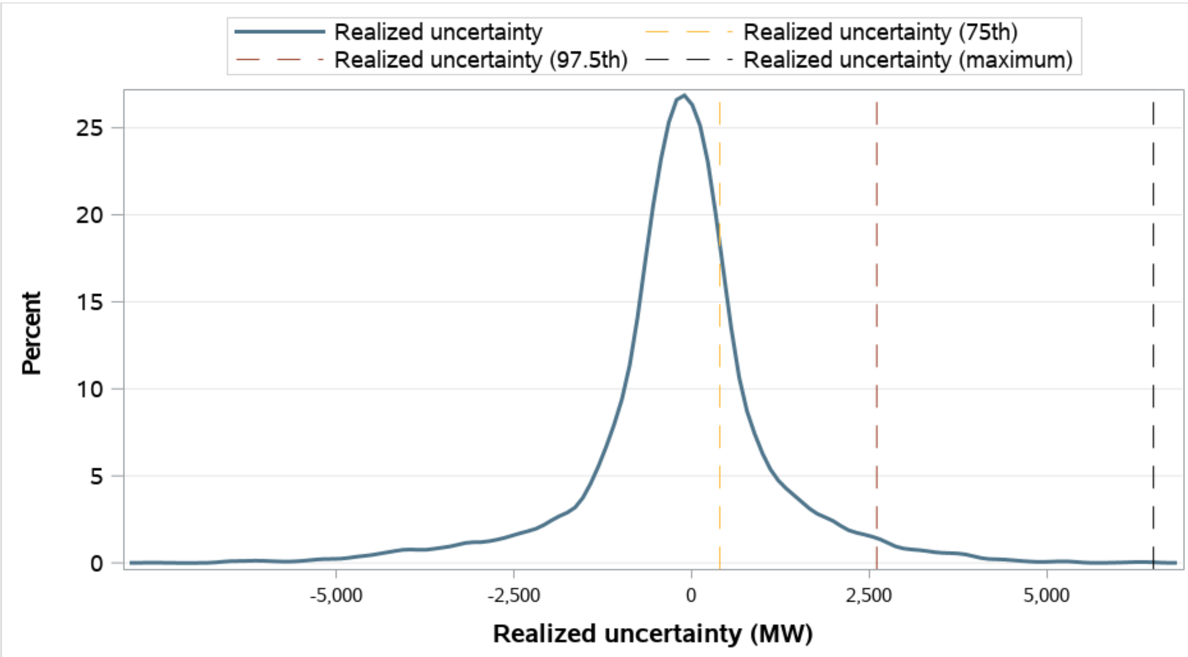
The ISO uses the *mosaic quantile regression* to calculate the RUC adjustments. The percentile target is adjusted each day based on conditions in the system. Under periods with moderate operational uncertainty, the operating procedure calls for using an adjustment that will procure enough capacity 50 percent of the time (i.e., the 50th percentile of upward uncertainty).[93] The ISO can adjust the calculation on any day to instead use the 75th or 97.5th percentile during periods of higher loads, higher forecast uncertainty, or in extreme conditions. During periods with low operational uncertainty, the 25th percentile or no adjustment can also be applied.

The adjustment can also be applied to only select hours. During periods with moderate uncertainty, the adjustment is typically applied only to the peak morning and peak evening hours (around six or seven hours). During periods with more operational uncertainty, the adjustment is generally applied to either mid-day hours (around 16 hours) or all hours.

Figure 11.7 shows this quarter's distribution of realized uncertainty between the net load forecasts of the day-ahead market and the 15-minute market. This distribution represents all uncertainties observed in the 15-minute market intervals for this quarter and serves as the forecasting target. The first notable feature is that net load uncertainty in the day-ahead time horizon ranged from -7,500 MW to 6,500 MW. The distribution shows a long tail, with the area between the red dashed line and the black dashed line highlighting the range from the 97.5th percentile of uncertainty up to the maximum value. This area ranged from 2,600 MW to 6,500 MW. A long tail could indicate rare but impactful events, such as unexpected weather changes or some other cause of a sudden shift in demand or renewable resource output.

93 See CAISO Operating Procedure 1210, October 1, 2025, pp 12-13: https://www.caiso.com/Documents/1210.pdf

Figure 11.7 Distribution of realized uncertainty between RUC and 15-minute market net load forecasts (October–December 2025)



11.3.1 Results of uncertainty calculation for residual unit commitment

During the fourth quarter, no RUC adjustment was applied above the 50th percentile. Figure 11.8 shows the average RUC adjustment on each day, across all hours.[94] The figure also shows the estimated percentile that was used to determine the additional requirements for each day.[95] During the fourth quarter, the 97.5th and 75th percentile targets were not applied (unlike the same quarter of the previous year). The 50th percentile target was applied on 32 percent of days. No adjustment was applied on the remaining 68 percent of days.

Figure 11.9 shows the average RUC adjustment for each day during only the last quarter. The dotted black line (right axis) shows the number of hours in which the adjustment was applied. Adjustments are generally applied for either all hours, mid-day hours (roughly 16 hours), or peak morning and evening hours (roughly six or seven hours).[96] When the adjustment was applied during the quarter, it was typically applied to the peak morning and evening hours.

94 In the hours when no adjustment is applied, the residual unit commitment adjustment for uncertainty is 0 MW, resulting in a lower daily average.

95 Data on the percentile used to calculate the RUC adjustments for each day was not available. The percentiles shown here were estimated from the magnitude of the adjustments.

96 The exact hours considered for the "mid-day" or "peak" hours can vary during the year. Typically, the *peak* morning and evening hours include the morning hours 7 to 9 as well as 3-4 hours in the evening (total of around 6-7 hours). The mid-day hours typically start in hour 7 and go through hour 22.

The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty as this RUC adjustment. Prior to the ISO starting EDAM parallel operations in the first quarter of 2026, the ISO intended to set the imbalance reserve up requirement to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO has used the 97.5th percentile target in RUC indicates that this would have made the imbalance reserve product demand curve much too high during most hours. DMM has been highlighting this concern in its public reports for over a year. DMM appreciates that the ISO has recently indicated that it plans to set the imbalance reserve up requirement below the 97.5th percentile during a transitional period after EDAM's initial implementation.

Figure 11.8 Average residual unit commitment adjustment by day (all hours)

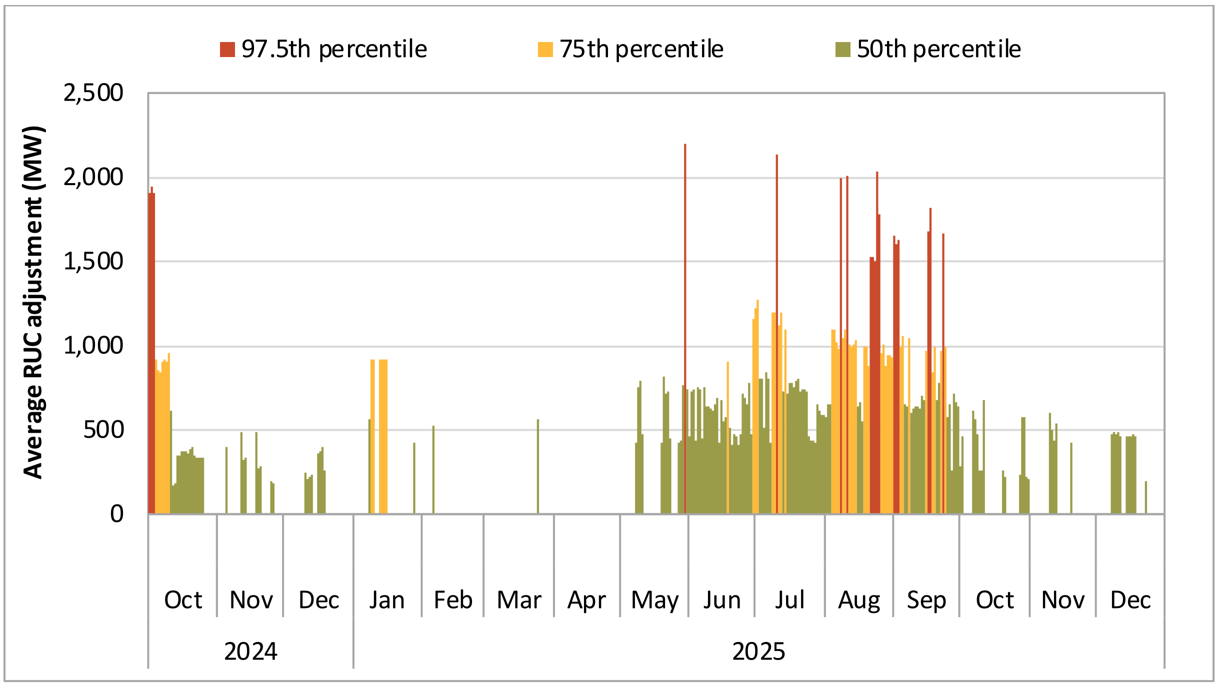


Figure 11.9 Average residual unit commitment adjustment by day (all hours, Q4 2025)

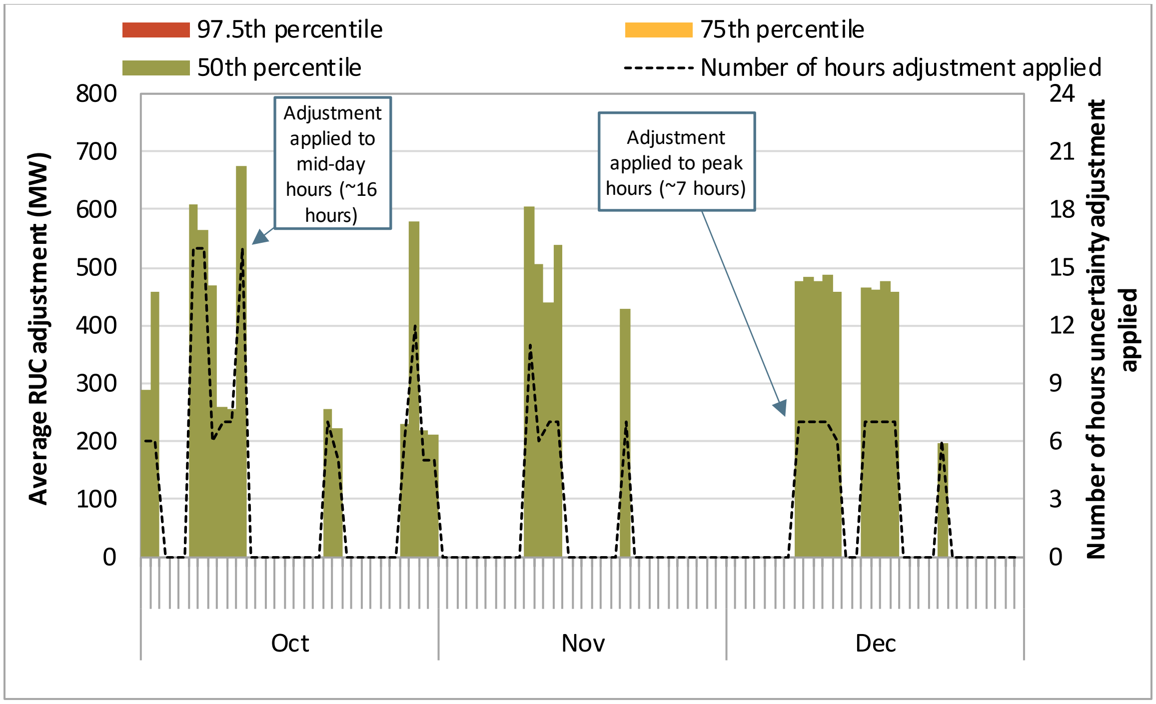


Table 11.5 summarizes the average requirement and coverage based on the percentile target that was selected and the hours it was applied (either mid-day hours or peak hours). Coverage shows the percent of 15-minute market intervals in which realized uncertainty from the day-ahead market to the real-time market was below the RUC adjustment quantity. The average requirement and coverage were assessed only in hours the uncertainty adjustment was applied.

Table 11.5 Average residual unit commitment uncertainty adjustment and coverage (Q4 2025)

Percentile target	Hours applied	Number of days	Percent of days	Average requirement (MW)	Coverage
50th percentile	Mid-day hours	5	5%	1,026	76%
	Peak hours	24	26%	1,431	86%

Table 11.6 represents DMM's simulation of the RUC adjustment using the mosaic quantile regression. Unlike the current market practice, this simulation estimates RUC adjustments for all hours in the quarter. It provides insight into the different percentiles used in the market and illustrates the likely outcomes if a specific percentile were applied to forecast the RUC adjustment across all hours of the quarter.

The first section of the table shows the average requirement across different percentile values from the DMM replication. The middle section of the table shows the percentage of statistically significant coefficients, and the last section shows the coverage rate for each percentile regression.

The 97.5th percentile regression showed a 1 percent rate of statistical significance, likely due to sample size. This specific percentile regression focuses on only 4 to 5 observations.[97] While an underlying pattern may exist, the small sample size of 4 to 5 observations is insufficient to find such a pattern, resulting in no statistical significance.

The coverage rates for regression were notably inflated. For example, the 50th percentile regression, designed to capture 50 percent of realized uncertainty, showed coverage rates of 72 percent, and 77 percent during peak hours.

This inflation arises from two key factors. First, while the realized uncertainty represents the difference between day-ahead and 15-minute net load forecasts, available as four uncertainty realizations per hour, the regression model forecasts the maximum uncertainty for each hour. This discrepancy inflated the result. As shown in Figure 11.7, the realized uncertainty distribution indicated the 50th percentile value was around -110 MW, meaning that a -110 MW requirement would effectively achieve 50 percent coverage. However, the 50th percentile regression averaged around 602 MW (as shown in Table 11.6). This means that the regression is producing over 710 MW more than ideal, due to the practice of forecasting the maximum uncertainty per hour. Second, the regression in RUC estimates only the upper bound of uncertainty, meaning any negative uncertainty is automatically covered, contributing to the inflated coverage rate.

Table 11.6 DMM simulation for RUC adjustment using mosaic quantile regression (all hours: October–December 2025)[98]

	Requirement (MW)		Percent of significant coefficients		Coverage	
	All hours	Peak hours(1)	All hours	Peak hours	All hours	Peak hours
Replication (97.5th)	2,027	2,322	1%	4%	98%	98%
Replication (75th)	1,092	1,406	23%	51%	88%	90%
Replication (50th)	602	965	33%	55%	72%	77%
Replication (25th)	144	550	36%	52%	53%	59%

(1): Peak hours include hour-ending (HE) from 7 to 9 and HE from 17 to 21.

97 Quantile regression identifies patterns within a subset of data. A 97.5th percentile regression targets the upper 2.5 percent of uncertainty, requiring a large sample size. The sampling methodology in mosaic regression shares similarities between the RUC adjustment and other market applications, employing either symmetric or past 180-day sampling, ultimately selecting data from 180 days. The ISO further filters for the same hour as the forecasting hour. A key distinction for the RUC adjustment forecast lies in its day-ahead forecast data, resulting in only one observation per hour. In contrast, other real-time uncertainty calculations have mosaic variable and uncertainties available across 4 to 12 intervals per hour, leaving the RUC adjustment forecast's sampling size at 180 observations.

98 This simulation includes DMM's replication of RUC adjustment using all hours from this quarter, unlike the current market practice which applies RUC adjustment only during selected hours.

12 Manual dispatch

This section analyzes manual dispatches for the California ISO balancing area, known as exceptional dispatches, as well as manual dispatches in balancing areas across the WEIM. Exceptional dispatches in the CAISO balancing area are covered separately from those in other WEIM areas due to significant differences in settlement procedures.

12.1 Western Energy Imbalance Market manual dispatch

Western Energy Imbalance Market (WEIM) areas sometimes need to dispatch resources out-of-market for reliability, to manage transmission constraints, or for other reasons. These manual dispatches are similar to exceptional dispatches in the California ISO. Manual dispatches within the WEIM are issued by individual WEIM entities for their respective balancing authority areas and not by CAISO. Manual dispatches may be issued for both participating and non-participating resources.

Like exceptional dispatches in the CAISO balancing area, manual dispatches in the WEIM do not set prices, and the reasons for these manual dispatches are similar to those given for the CAISO exceptional dispatches. However, manual dispatches in the WEIM are not settled in the same manner as exceptional dispatches within the CAISO balancing area. Energy from these manual dispatches is settled on the market clearing price, similar to uninstructed energy. This eliminates the possibility of exercising market power either by setting prices or by being paid “as-bid” at above-market prices.

Figure 12.1 through Figure 12.4 summarize the average hourly incremental and decremental manual dispatch activity of participating and non-participating resources for each WEIM region. The California region, however, has no manual dispatch energy from non-participating resources.

When comparing the fourth quarter of 2025 to the fourth quarter of 2024, incremental manual dispatch energy from participating resources (yellow bars) decreased in all regions except California. The Desert Southwest, Intermountain West, and Pacific Northwest decreased by 15 percent, 39 percent, and 73 percent, respectively, while the California region increased by 6 percent. Similarly, when comparing the fourth quarter of 2025 to the same quarter in 2024, incremental manual dispatch energy from non-participating resources (red bars) decreased in the Desert Southwest and Intermountain West regions by 83 percent and 36 percent, respectively, while the Pacific Northwest region increased by 32 percent.

From the fourth quarter of 2024 to the fourth quarter of 2025, decremental manual dispatch energy from participating resources (green bars) decreased in all regions except California. The Desert Southwest, Intermountain West, and Pacific Northwest decreased by 8 percent, 32 percent, and 16 percent, respectively, while the California region increased by 27 percent. When comparing the fourth quarter of 2025 to the same quarter in 2024, decremental manual dispatch energy from non-participating resources (blue bars) decreased in the Desert Southwest and Intermountain West regions by 79 percent and 14 percent, respectively, while the Pacific Northwest increased by 104 percent.

Overall, combined incremental and decremental manual dispatch energy decreased in the Desert Southwest and the Intermountain West by 24 percent and 34 percent, respectively, and increased in the California (non-CAISO) region and the Pacific Northwest by 14 percent and 51 percent, respectively.

Figure 12.1 WEIM manual dispatches – California

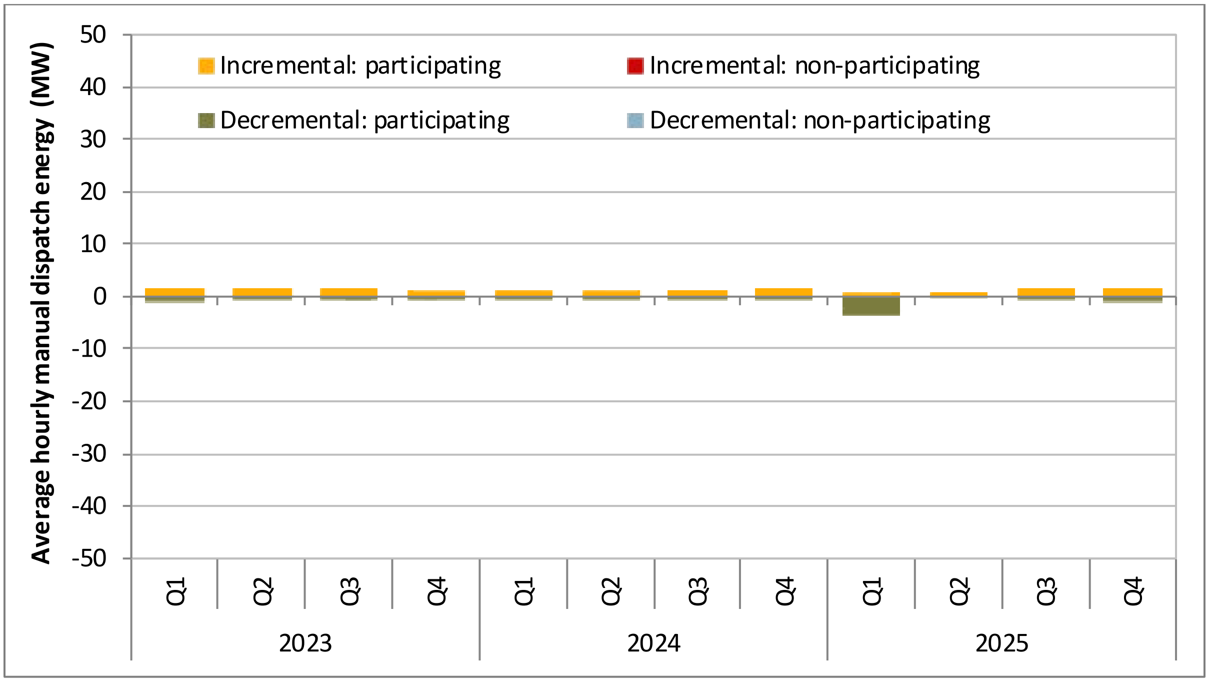


Figure 12.2 WEIM manual dispatches – Desert Southwest

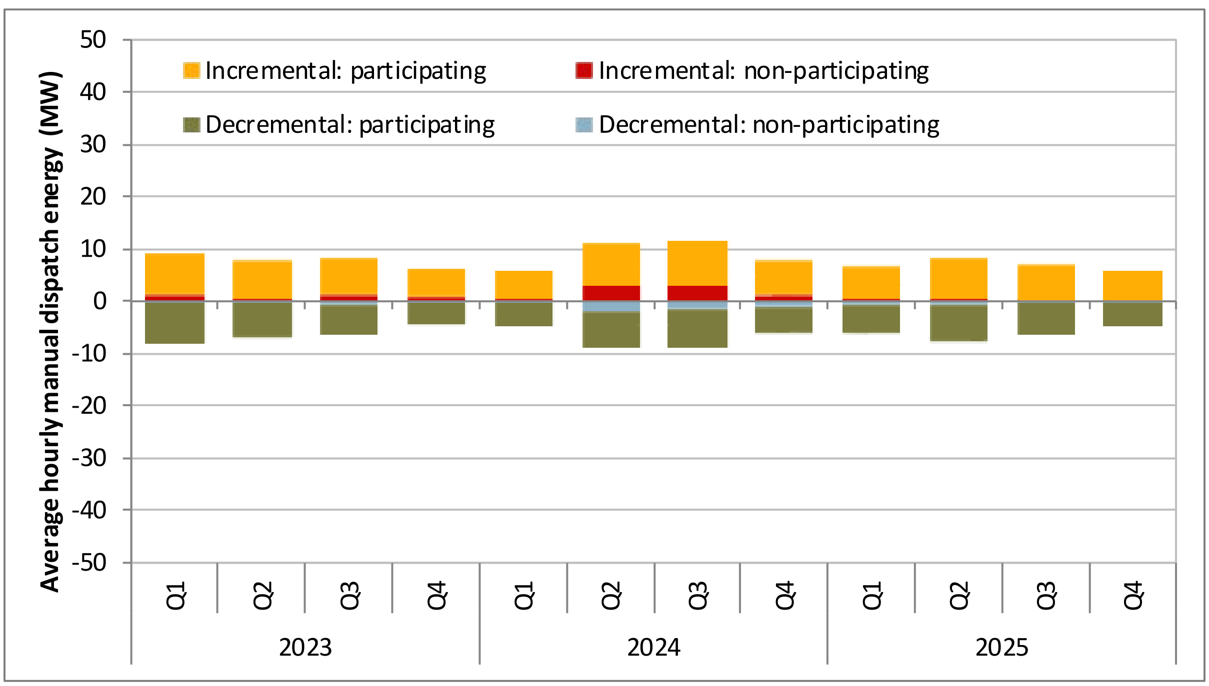


Figure 12.3 WEIM manual dispatches – Intermountain West

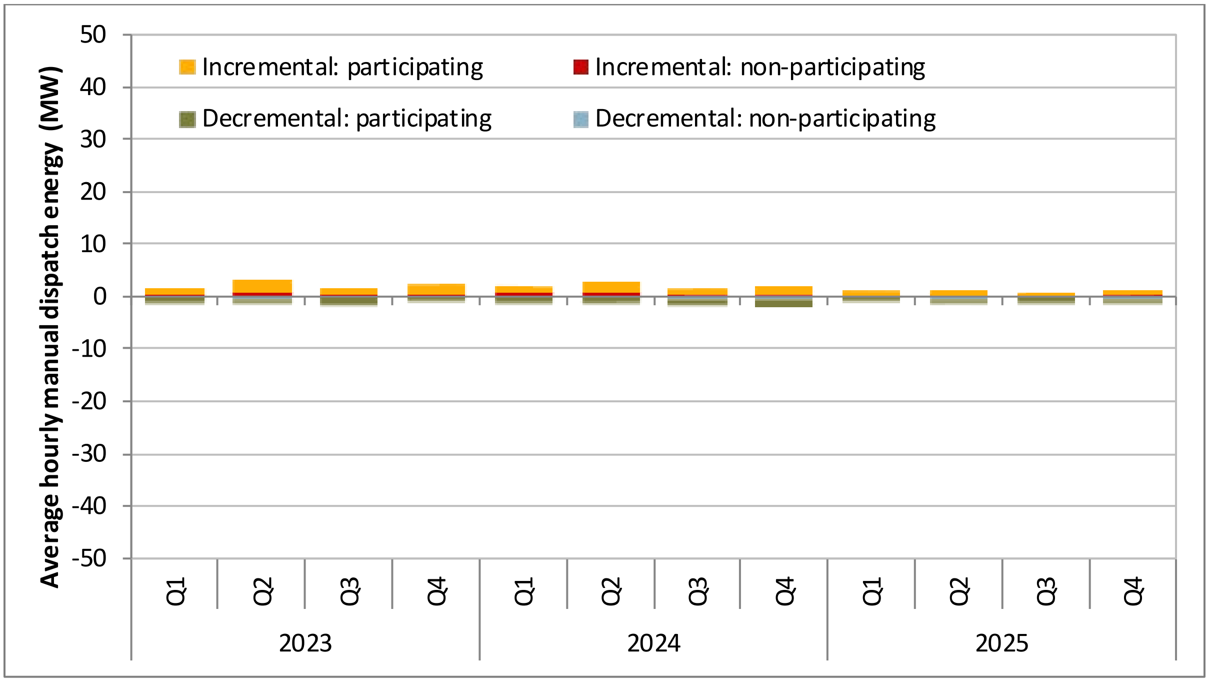
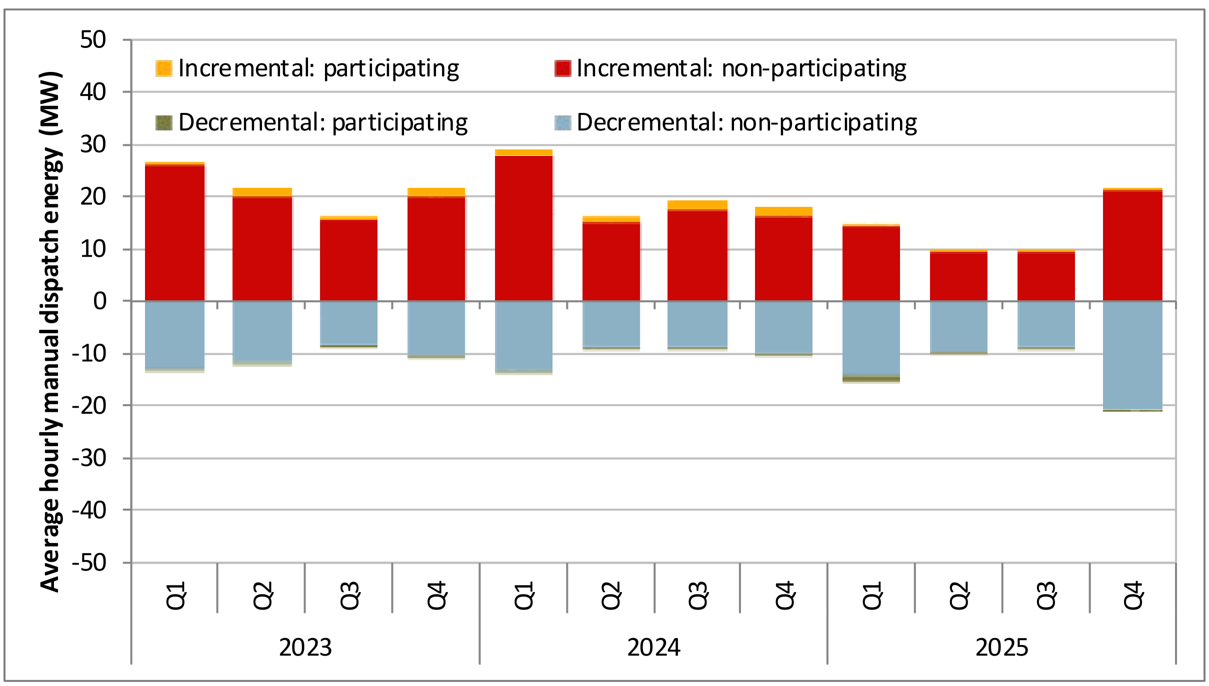


Figure 12.4 WEIM manual dispatches – Pacific Northwest



12.2 California ISO balancing area exceptional dispatch

This section analyzes exceptional dispatches for the California ISO balancing area. Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an *out-of-market* or manual dispatch. While exceptional dispatches are necessary for reliability, they may create uplift costs because out-of-market payments to the resources may exceed market prices. Manual dispatch compensation may also create opportunities for the exercise of temporal market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.
- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would have likely cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as in-sequence real-time energy.
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in out-of-sequence real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market-clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to the local market power mitigation provisions in the California ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

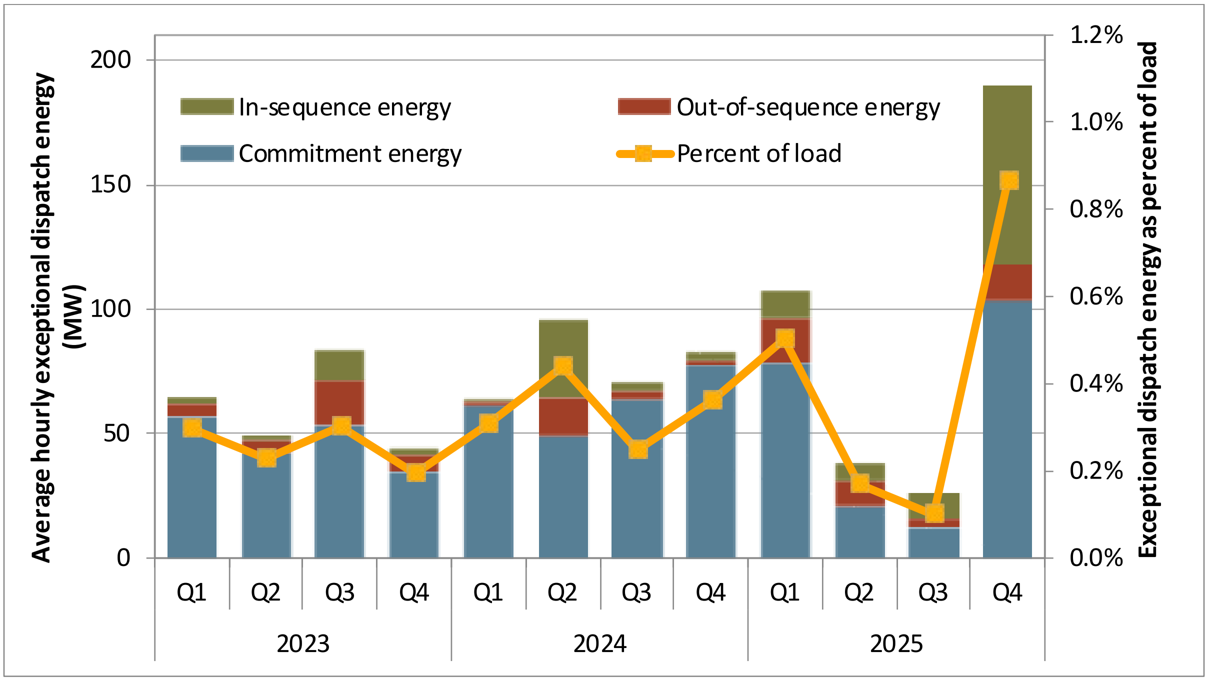
Energy from exceptional dispatch

Energy from exceptional dispatches reached the highest level in three years, yet continues to account for under 1 percent of total load in the California ISO balancing area, represented by the yellow line in Figure 12.5. As shown in Figure 12.5, the average hourly total energy from exceptional dispatches—including minimum load energy from unit commitments—was 190 MW in the fourth quarter of 2025, which is a 129 percent increase from the fourth quarter of 2024.[99]

In the fourth quarter of 2025, exceptional dispatches for unit commitments (blue) accounted for about 54 percent of all exceptional dispatch energy; about 8 percent was from out-of-sequence energy (red), and the remaining 38 percent was from in-sequence energy (green), as shown in Figure 12.5.

[99] All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

Figure 12.5 Average hourly energy from exceptional dispatch

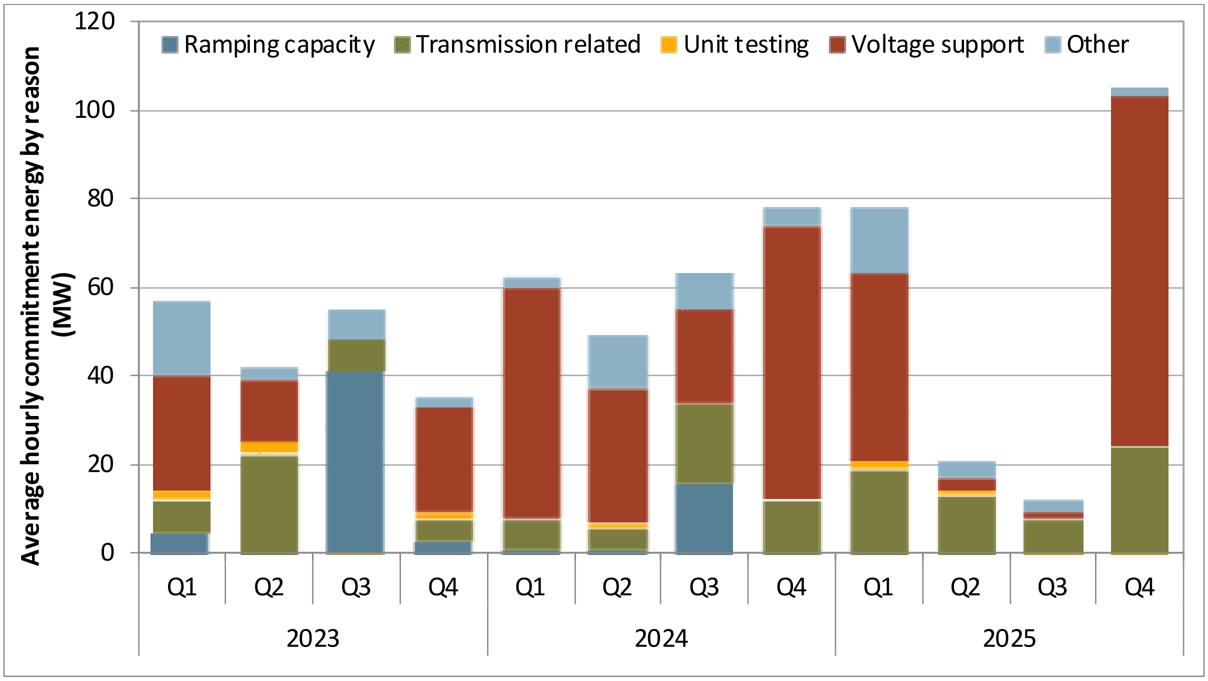


Exceptional dispatches for unit commitment

The California ISO balancing area operators occasionally find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. In these instances, the California ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at minimum load. Multi-stage generating units may be committed to operate at the minimum output of a specific multistage generator configuration, e.g., one-by-one or duct firing.

Figure 12.6 shows the reasons for minimum load energy exceptional dispatches: ramping capacity (dark blue), transmission related (green), unit testing (yellow), voltage support (red), and other (light blue). The total average minimum load energy from unit commitment exceptional dispatches in the fourth quarter of 2025 was 104 MW, above the 78 MW average minimum load energy from unit commitment in the fourth quarter of 2024.

Figure 12.6 Average minimum load energy from exceptional dispatch unit commitments

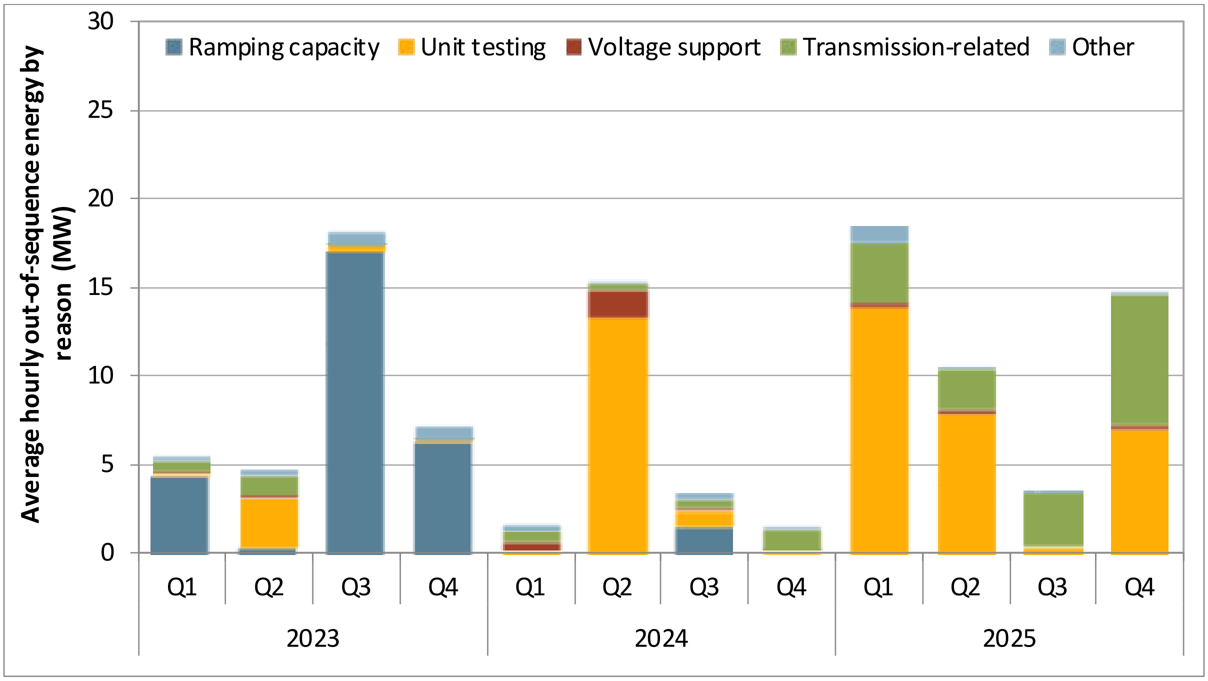


Exceptional dispatches for energy

Figure 12.7 shows the average hourly out-of-sequence exceptional dispatch energy by reason for each quarter from Q1 2023 through Q4 2025. The two primary reasons logged for out-of-sequence energy in the fourth quarter of 2025 were transmission-related (green bars) and unit testing (yellow bars). Transmission-related exceptional dispatches are issued for any transmission-related modeling limitations that may arise from transmission maintenance, lack of voltage support at proper levels, and incomplete or inaccurate information about the transmission network. Out-of-sequence energy due to transmission-related exceptional dispatches (green bars) increased in the fourth quarter of 2025 compared to the fourth quarter of 2024. This increase is largely due to exceptional dispatches to mitigate transmission outages in Northern California.

Average hourly out-of-sequence energy due to unit testing (yellow bars) increased in the fourth quarter of 2025 compared to the same quarter in 2024. This increase largely occurred in December related to wind, battery storage, and hydro resources.

Figure 12.7 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

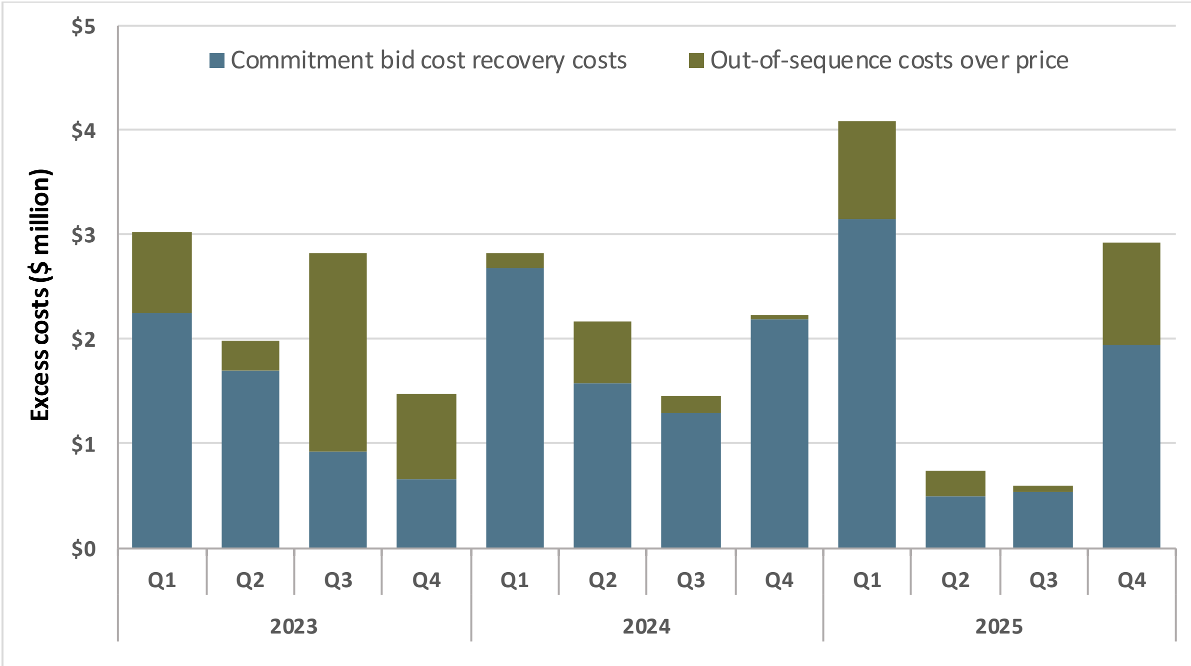
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for these costs.

Units exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference between their market bid price and their locational marginal energy price.

Figure 12.8 shows the estimated costs for unit commitment and exceptional dispatch for energy above minimum load whose bid price exceeded the resource's locational marginal price. In the fourth quarter of 2025, out-of-sequence energy costs were $990,000, an increase from $47,000 in the fourth quarter of 2024. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the fourth quarter were $1.9 million, an 11 percent decrease from the fourth quarter of 2024. Overall, the additional costs associated with exceptional dispatches in the fourth quarter of 2025 increased by 11 percent compared to the fourth quarter of 2024.

Figure 12.8 Excess exceptional dispatch cost by type



13 Convergence bidding

Convergence bidding is designed to align day-ahead and 15-minute market prices by allowing financial arbitrage between the two markets. In this quarter, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. Financial entities and marketers continued to receive the vast majority of profits from convergence bidding. Net revenues for convergence bidders were about $7.2 million for the fourth quarter, after inclusion of about $4.7 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply.[100]

13.1 Convergence bidding revenues

Figure 13.1 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total bid cost recovery charges (red bars), and net payments for all convergence bidding after accounting for bid cost recovery charges (black line).

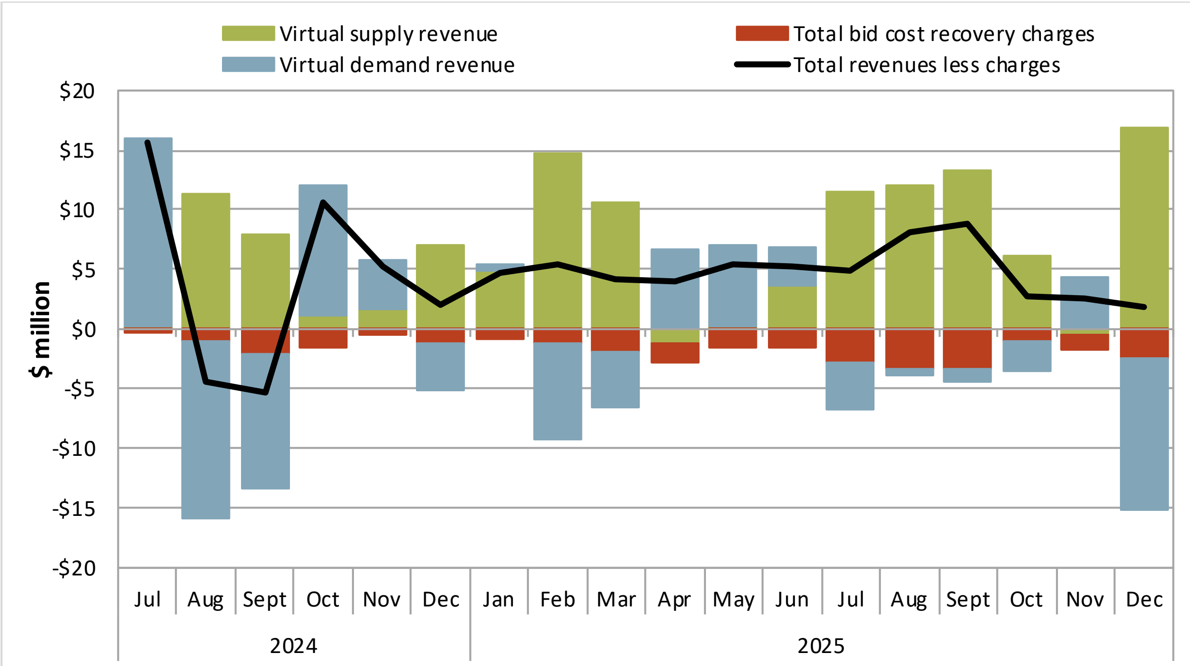
Before accounting for bid cost recovery, virtual supply revenues were about $6.2 million, -$0.5 million, and $17.0 million for October, November, and December, respectively. Virtual demand revenues were about -$2.5 million, $4.3 million, and -$12.7 million for October, November, and December, respectively.

Bid cost recovery charges allocated to virtual bids were about $1.1 million, $1.1 million, and $2.5 million for October, November, and December, respectively. The majority of bid cost recovery allocated to virtual bidding participants in this quarter was charged to the residual unit commitment (RUC) tier 1 allocation, which helps offset costs related to periods with net virtual supply. Virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in RUC. When market revenues do not cover the commitment costs of resources committed in RUC, the resources receive bid cost recovery payments, and some of this bid cost recovery is allocated to virtual supply during periods with net virtual supply.

Net convergence bidding revenues were positive during all months of the quarter, totaling $7.2 million. In comparison, net market revenues were around $17.7 million in the fourth quarter of 2024.

100 Figures and data provided in this chapter are preliminary and may be subject to change.

Figure 13.1 Convergence bidding revenues and bid cost recovery charges



13.2 Net revenues and volumes by participant type

Table 13.1 compares the distribution of convergence bidding cleared volumes and revenues, before and after taking into account bid cost recovery, in millions of dollars, among different groups of convergence bidding participants.[101,102]

After accounting for bid cost recovery, financial entities received about 88 percent of the total revenue earned from convergence bidding. Financial entities and marketers accounted for about 82 percent and 10 percent, respectively, of the cleared volume of virtual trades in the fourth quarter.

[101] This table summarizes data from the California ISO settlements database and is based on a snapshot of a given day after the end of the period. DMM strives to provide the most up-to-date data before publishing. Updates occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date. More detail on the settlement cycle can be found on the California ISO settlements page: http://www.caiso.com/market/Pages/Settlements/Default.aspx

[102] DMM has defined financial entities as participants who do not own physical power, and only participate in the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the California ISO markets as physical generators and load serving entities, respectively. Marketers include participants on the interties, as well as participants whose portfolios are not primarily focused on physical or financial participation in the California ISO market.

Table 13.1 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues/losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2024 Q4								
Financial	3,510	3,817	7,327	$10.39	$8.72	-$2.60	$6.12	$16.51
Marketer	461	483	943	$0.19	$0.56	-$0.21	$0.35	$0.54
Physical load	28	78	106	$0.15	$0.13	-$0.12	$0.00	$0.15
Physical generation	111	235	346	$0.29	$0.53	-$0.37	$0.17	$0.46
Total	**4,110**	**4,613**	**8,722**	**$11.02**	**$9.94**	**-$3.30**	**$6.64**	**$17.66**

Trading entities	Average hourly megawatts			Revenues/losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2025 Q4								
Financial	4,375	5,116	9,492	-$8.22	$18.06	-$3.58	$14.48	$6.27
Marketer	550	621	1,171	-$1.84	$2.95	-$0.35	$2.60	$0.75
Physical load	54	96	150	-$0.25	$0.31	-$0.18	$0.13	-$0.12
Physical generation	333	455	788	-$0.51	$1.34	-$0.58	$0.76	$0.25
Total	**5,312**	**6,288**	**11,601**	**-$10.82**	**$22.66**	**-$4.69**	**$17.97**	**$7.15**

14 Ancillary services and available balancing capacity

While ancillary service requirements increased from the fourth quarter of 2025 compared to 2024, ancillary service payments decreased. Average requirements for regulation up, regulation down, and operating reserves increased 21 MW (5 percent), 28 MW (3 percent), and 110 MW (8 percent), respectively. Ancillary service payments totaled $12.7 million, a 29 percent decrease from the same quarter of the previous year. Available balancing capacity was dispatched to address power balance infeasibilities in less than 1 percent of intervals in all WEIM balancing areas.[103]

14.1 Ancillary service requirements

The California ISO procures four ancillary services for the CAISO balancing area in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves. Procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) minimum operating reliability criteria and North American Electric Reliability Corporation's (NERC) control performance standards.

The California ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions.[104] Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency, or (3) 10 percent of forecasted solar production.[105] Operating reserve requirements in real-time are calculated similarly, except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

Starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. Since the second quarter of 2023, CAISO operators have procured 20 percent of operating reserves as spinning reserves, and the rest as non-spinning reserves.

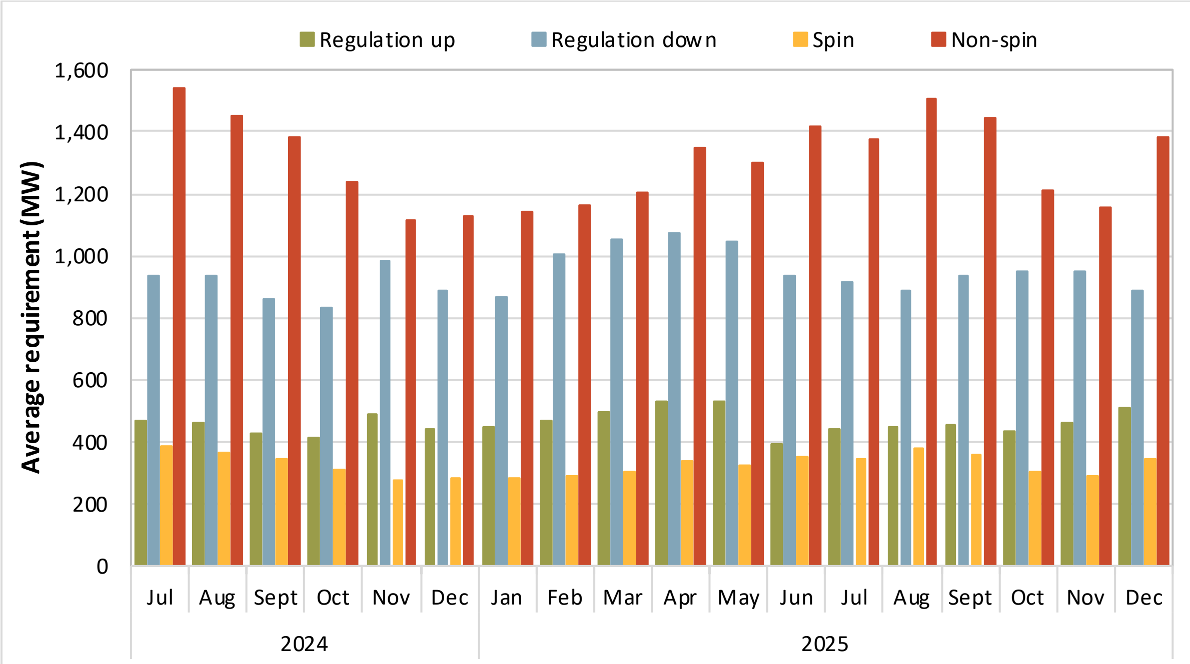
Figure 14.1 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation up requirements increased about 21 MW (5 percent) compared to the fourth quarter of 2024, and regulation down requirements increased about 28 MW (3 percent). Average operating reserves requirements increased about 110 MW (8 percent) compared to the fourth quarter of 2024.

[103] Figures and data provided in this chapter are preliminary and may be subject to change.

[104] More information on ancillary services requirements and procurement for internal and expanded regions is available in: *2020 Annual Report on Market Issues & Performance*, Department of Market Monitoring, August 2021, p 161: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

[105] As of April 2024, CAISO operators lowered the contribution of forecasted solar production in determining day-ahead operating reserve requirements from 15 percent to 10 percent. CAISO operators determined they could change the requirement because of the growing fleet of new solar resources that can respond quickly to voltage issues.

Figure 14.1 Average monthly day-ahead ancillary service requirements



14.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. No scarcity events occurred in the fourth quarter of 2025.

Under the ancillary service scarcity price mechanism, the California ISO balancing area pays a predetermined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger.

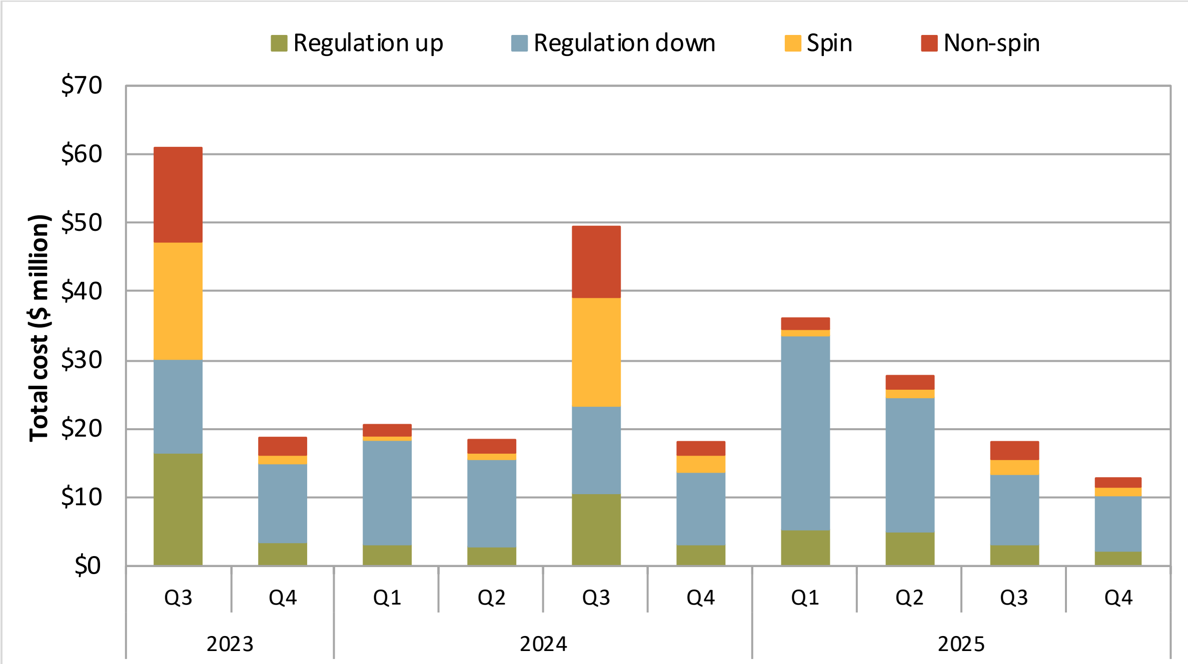
14.3 Ancillary service costs

Ancillary service payments totaled $12.7 million in the fourth quarter of 2025, around $5.3 million (or 29 percent) less than the same quarter of the previous year.

Figure 14.2 shows the total cost of procuring ancillary service products by quarter.[106] Payments for regulation up, regulation down, spinning reserve, and non-spinning reserve decreased 32 percent, 23 percent, 54 percent, and 33 percent, respectively, compared to the fourth quarter of 2024.

[106] The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards. As noted elsewhere in the report, settlements values are based on statements available at the time of drafting and will be updated in future reports.

Figure 14.2 Ancillary service cost by product



14.4 Available balancing capacity

Available balancing capacity (ABC) allows for market recognition and accounting of capacity that WEIM participants have available for reliable system operations but that is not bid into the market. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each WEIM entity in their hourly resource plans. The available balancing capacity mechanism enables the ISO system software to deploy such capacity through the market and prevents market infeasibilities that may arise without the availability of this capacity.

Table 14.1[107] summarizes the frequency of upward and downward available balancing capacity offered in each area in the fourth quarter. Available balancing capacity was dispatched in less than 1 percent of intervals for all areas in the 15-minute and 5-minute markets.

[107] Previous versions of this table published in the Department of Market Monitoring 2024 Q4 Report and the 2025 Q1 Report on Market Issues and Performance contained incorrect values in ABC Down Offered categories: https://www.caiso.com/documents/2024-fourth-quarter-report-on-market-issues-and-performance-mar-26-2025.pdf

https://www.caiso.com/documents/2025-first-quarter-report-on-market-issues-and-performance-jun-23-2025.pdf

Table 14.1 Frequency of available balancing capacity offered (Q4)

		ABC Up				ABC Down			
		Offered		Scheduled		Offered		Scheduled	
		Percent of hours	Average MW	Percent of intervals (15-min.)	Percent of intervals (5-min.)	Percent of hours	Average MW	Percent of intervals (15-min.)	Percent of intervals (5-min.)
California	BANC	99.8%	84	0.0%	0.0%	99.8%	88	0.0%	0.0%
	LADWP	53.1%	53	0.0%	0.0%	0.0%	N/A	0.0%	0.0%
	Turlock Irrigation District	99.8%	15	0.0%	0.0%	99.8%	5	0.0%	0.0%
Desert Southwest	Arizona Public Service	99.8%	83	.1%	.1%	99.8%	82	0.0%	0.0%
	El Paso Electric	0.0%	N/A	0.0%	0.0%	0.0%	N/A	0.0%	0.0%
	NV Energy	99.6%	70	0.0%	0.0%	86.7%	67	0.0%	0.0%
	PSC New Mexico	0.0%	N/A	0.0%	0.0%	27.0%	67	0.0%	0.0%
	Salt River Project	99.8%	99	.1%	0.0%	99.0%	50	.1%	0.0%
	Tucson Electric	99.8%	29	.3%	.1%	99.8%	31	0.0%	0.0%
	WAPA - Desert Southwest	0.0%	N/A	0.0%	0.0%	0.0%	N/A	0.0%	0.0%
Intermountain West	Avista Utilities	99.8%	10	0.0%	0.0%	99.8%	10	0.0%	0.0%
	Idaho Power	0.0%	N/A	0.0%	0.0%	0.0%	N/A	0.0%	0.0%
	NorthWestern Energy	99.6%	5	.2%	.2%	99.3%	5	0.0%	0.0%
	PacifiCorp East	98.5%	113	0.0%	0.0%	99.8%	197	0.0%	0.0%
Pacific Northwest	Avangrid	99.8%	51	0.0%	0.0%	0.0%	N/A	0.0%	0.0%
	Powerex	99.8%	1,136	0.0%	0.0%	99.8%	600	0.0%	0.0%
	Bonneville Power Admin.	99.8%	325	0.0%	.2%	99.8%	332	0.0%	0.0%
	PacifiCorp West	41.6%	26	0.0%	0.0%	96.6%	52	0.0%	0.0%
	Portland General Electric	99.2%	30	0.0%	0.0%	0.0%	N/A	0.0%	0.0%
	Puget Sound Energy	0.0%	N/A	0.0%	0.0%	0.0%	N/A	0.0%	0.0%
	Seattle City Light	0.0%	N/A	0.0%	0.0%	0.0%	N/A	0.0%	0.0%
	Tacoma Power	70.3%	6	0.0%	0.0%	96.9%	13	0.0%	0.0%

15 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the fourth quarter of 2025 was 13 percent higher than the same quarter of 2024. Operator adjustments to the RUC procurement target decreased by about 46 percent for the same period. CAISO balancing area methods for determining operator adjustments are discussed in detail in Chapter 11 above on uncertainty.

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real-time. The residual unit commitment market is a key component of the day-ahead market that runs immediately after the integrated forward market. The residual unit commitment market procures capacity sufficient to bridge the gap between the amount of physical supply cleared in the integrated forward market and the amount of physical supply that may be needed to meet actual real-time demand.

15.1 Residual unit commitment requirement

The quantity of residual unit commitment procured is determined by several automatically calculated components, as well as any adjustments that operators make to increase residual unit commitment requirements for reliability purposes. Figure 15.1 shows the average incremental residual unit commitment requirement by component relative to the integrated forward market component of the day-ahead market.

The green bars reflect the need to replace cleared net virtual supply bids, which can offset physical supply in the integrated forward market run.

The blue bars in Figure 15.1 depict the day-ahead forecasted load versus cleared day-ahead capacity, which includes both physical supply and net virtual supply. This represents the difference between the California ISO day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). On average, this factor contributed towards lowering residual unit commitment requirements by 20 MW per hour in the fourth quarter of 2025.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market, illustrated by the yellow bars in Figure 15.1. On average, eligible intermittent resource adjustments were adjusted downward by about 770 MW, which is a decrease of about 20 percent from Q4 2024.

Lastly, operators will often increase the residual unit commitment market's target load requirement to a value above the day-ahead market load forecast. This allows the residual unit commitment market to procure extra capacity to account for uncertainty that may materialize in the load forecast and scheduled physical supply. The red bars in Figure 15.1 show the average adjustment to the residual unit commitment requirement. During 2023 and 2024, there were significant changes to how these amounts were determined. The operator adjustments and the changes in the methodology are described in Chapter 11 above on uncertainty. On average, operator adjustments were about 130 MW, which is a 45 percent decrease from Q4 2024.

Figure 15.2 shows the hourly distribution of these operator adjustments during the fourth quarter of 2025. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour.

Figure 15.1 Average incremental residual unit commitment requirement by component

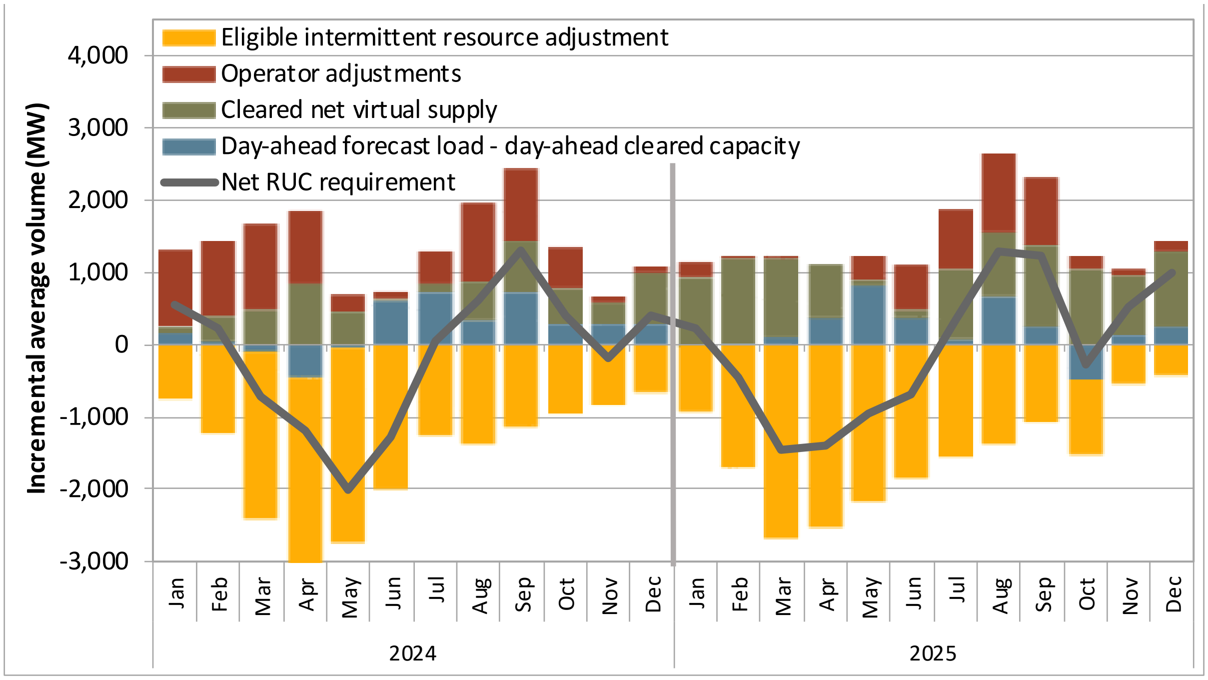
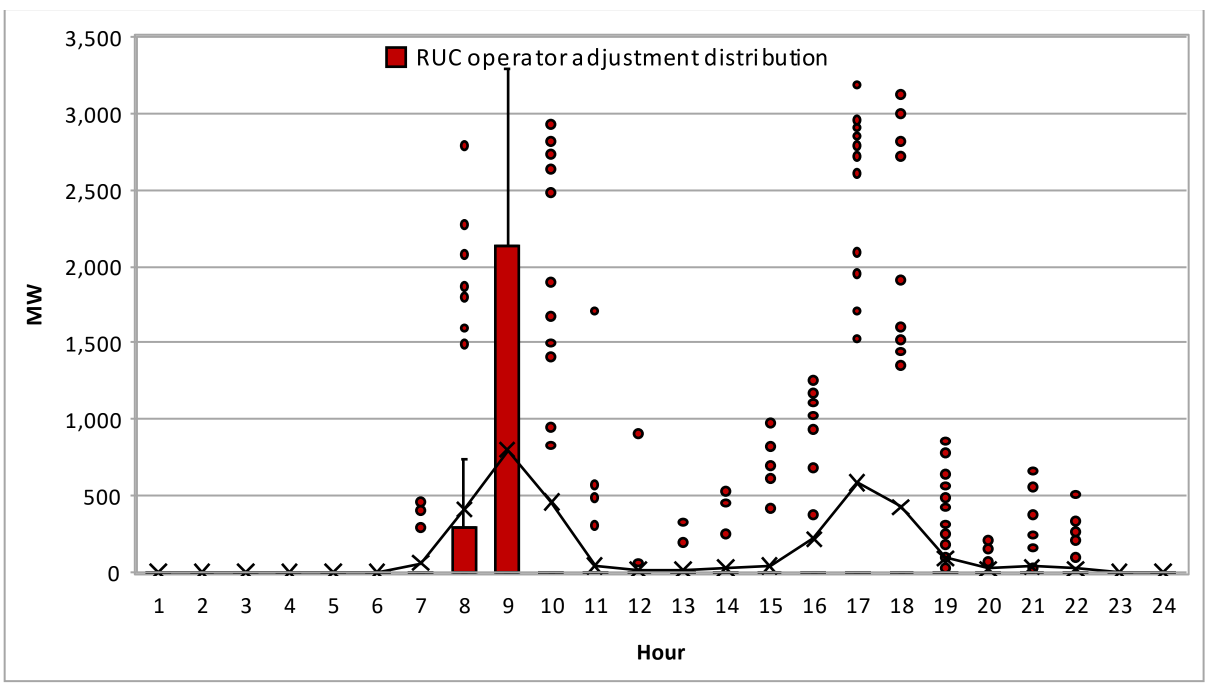


Figure 15.2 Hourly distribution of residual unit commitment operator adjustments (October–December 2025)

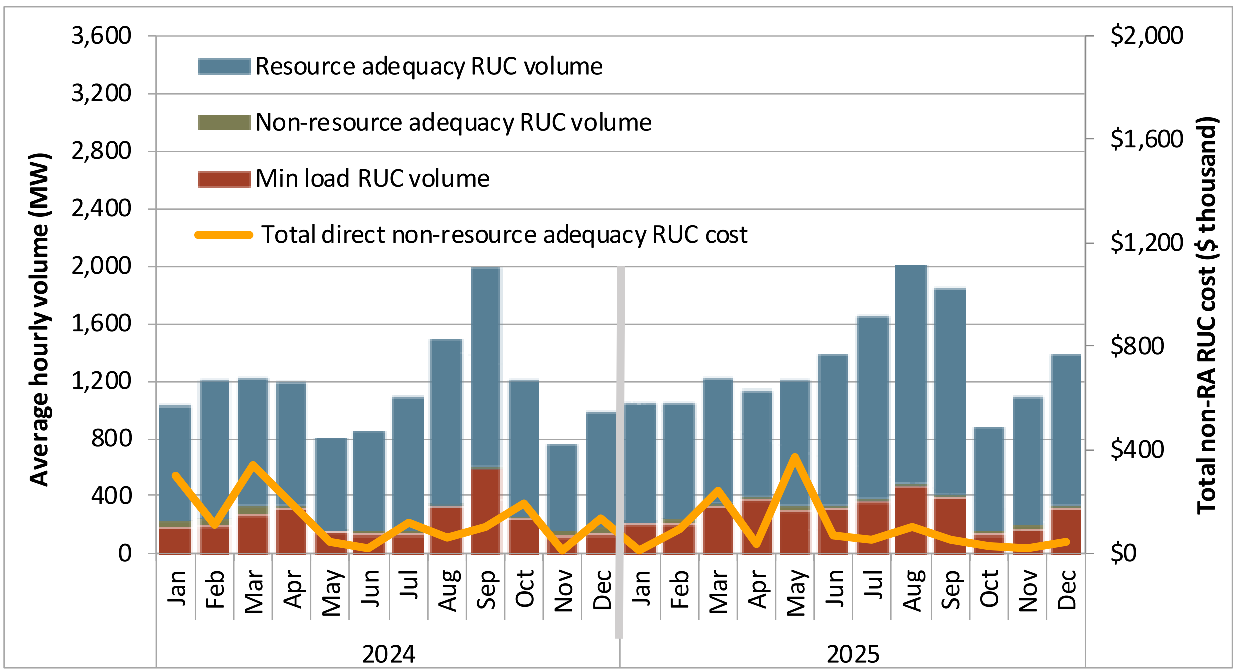


15.2 Residual unit commitment procurement and costs

Figure 15.3 shows the monthly average hourly residual unit commitment (RUC) procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The average residual unit commitment procurement for the fourth quarter of 2025 increased by 13 percent to about 1,100 MW, from an average of about 1,000 MW in the same quarter of 2024. Of the 1,100 MW capacity, the capacity committed to operate at minimum load averaged about 210 MW.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments, as only non-resource adequacy units receiving awards in this process receive RUC capacity payments.[108] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 15.3. In the fourth quarter of 2025, these costs were about $89,000.

Figure 15.3 Residual unit commitment costs and volume



108 If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

16 Congestion revenue rights

Congestion revenue right auction returns

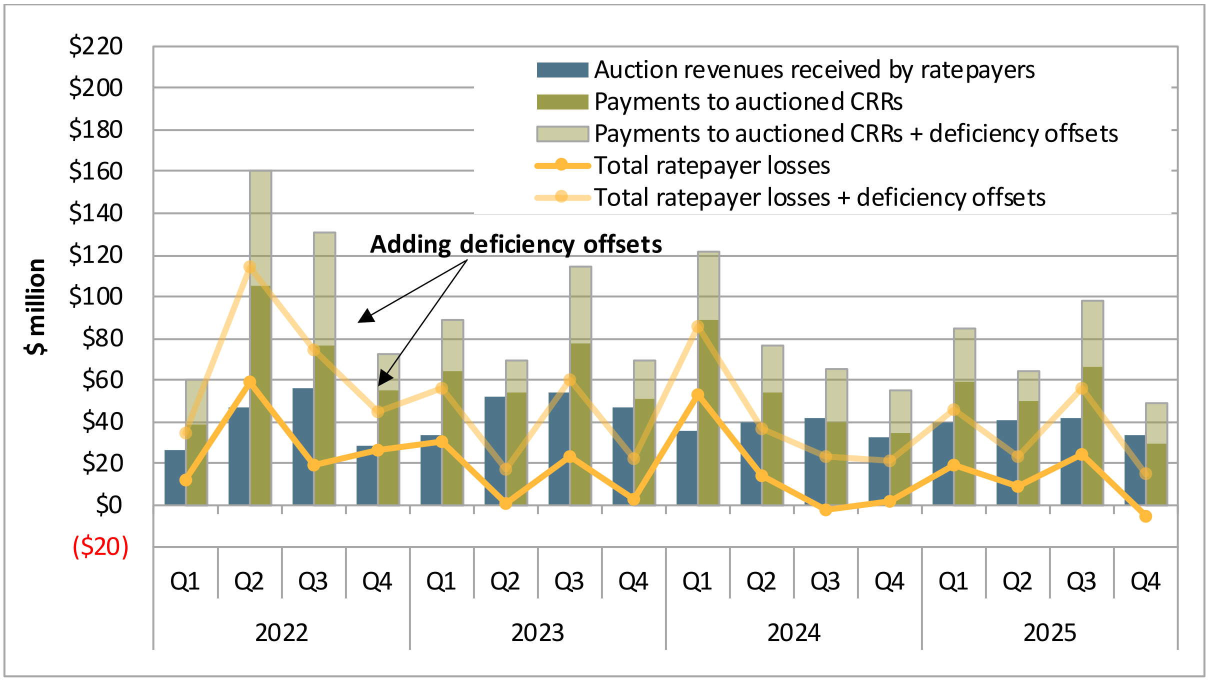
Profits from the congestion revenue rights (CRR) auction by non-load serving entities are calculated by summing revenue paid out to congestion revenue rights purchased by these entities, and then subtracting the auction price paid for these rights. While this represents a profit to entities purchasing rights in the auction, it represents a loss to transmission ratepayers. Figure 16.1 compares the following for each of the last several quarters:

- Auction revenues received by ratepayers from congestion revenue rights sold in the auction (blue bars).[109]
- Net payments, based on day-ahead market congestion rents, made to the non-load serving entities purchasing congestion revenue rights in the auction (green bars).
- Deficiency offsets are the reduction in payments to CRR holders as implemented under Track 1B reforms (transparent portion of green bars and yellow line). Deficiency offsets occur when day-ahead market congestion rents are not sufficient to cover “nominal payments” to auctioned CRRs. Nominal payments are those that would be made to CRRs based only on the quantity of CRRs over a path and the difference between source and sink congestion prices.
- Total ratepayer losses are the difference between auction revenues received by load serving entities and payments made to non-load serving entities (yellow line).

Transmission ratepayers made $5 million during the fourth quarter of 2025, as payments to auctioned congestion revenue rights holders were lower than auction revenues. This was the second quarterly profit for ratepayers in the auction since Q3 2016, with the first occurring in Q3 2024.

[109] The auction revenues received by ratepayers are the auction revenues from congestion revenue rights paying into the auction less the revenues paid to “counter-flow” rights. Similarly, day-ahead payments made by ratepayers are net of payments by “counter-flow” rights.

Figure 16.1 Auction revenues and payments to non-load serving entities



During the fourth quarter of 2025:

- Financial entities lost $3.1 million from auction rights, in line with a $0.4 million loss in Q4 2024, but it represented a notable reversal from the Q3 2025 profit of $21.8 million. Total revenue deficit offsets were about $17.8 million in this quarter.[110]
- Marketers lost $1 million from auctioned rights, a reversal from a $1 million profit in the same quarter of 2024. Total revenue deficit offsets were over $1.1 million.
- Physical generation entities lost $0.8 million from auctioned rights, a reversal from a $1.1 million in profit in Q4 2024. Total revenue deficit offsets were $1 million.

The $5 million auction profit in the fourth quarter of 2025 was about 7 percent of day-ahead congestion rent. This was a reversal from Q4 2024, when ratepayers experienced net loss equal to 2 percent of total

[110] The total congestion rent is calculated by constraint and compared to the total CRR payments across all scheduling coordinators (SCs) from the constraint. If the CRR payments are greater than the congestion rent collected for a constraint, the difference is charged as an offset to the SCs with net flows on the constraint.

congestion rent.[111] The average ratepayer losses were 28 percent of day-ahead congestion rent during the three years before the track 1A and 1B changes (2016 through 2018).[112,113]

The impact of track 1A changes, which limit the types of congestion revenue rights that can be sold in the auction, cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under track 1B reduced total payments to non-load serving entities by about $20 million in the fourth quarter. The track 1B effects on auction bidding behavior and reduced auction revenues are not known.

Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction continues to cause millions of dollars in losses to transmission ratepayers each year, while exposing transmission ratepayers to a risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. If the ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends the ISO convert the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers. In late 2024, DMM posted a whitepaper analyzing a potential option for this kind of alternative CRR auction design.[114]

111 DMM adjusted the source data for congestion rent by removing day-ahead congestion rent calculated through the Nodal Pricing Model (NPM). The ISO provides the Nodal Pricing Model day-ahead service for PacifiCorp, which is used solely for internal Net Power Cost allocation within PACW and PACE balancing areas. As a result, updated congestion rent values no longer include NPM-based congestion rent in any of DMM's quarterly or annual reports published after July 2025. Therefore, the share of auction losses in total congestion rent may differ from values reported in the previous reports, due to updates in the source data.

112 *Congestion Revenue Rights Auction Efficiency - Track 1A Draft Final Proposal Addendum*, California ISO, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

113 *Congestion Revenue Rights Auction Efficiency - Track 1B Draft Final Proposal Second Addendum*, California ISO, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

114 *Willing seller market design for congestion revenue rights,* Department of Market Monitoring, October 23, 2024: https://www.caiso.com/documents/willing-counterparty-whitepaper-oct-23-2024.pdf

17 Transmission service and market scheduling priorities

The ISO began developing a framework that establishes high-priority wheeling through scheduling priorities in the CAISO balancing area following the power outages in the summer of 2020. In July 2021, the ISO started the Transmission Service and Market Scheduling Priorities (TSMSP) initiative that had two phases: an interim phase to establish wheeling-through priorities for the challenging system conditions in the summer of 2022, and a longer-term framework that started in 2024. External suppliers and load serving entities can now reserve the capacity to self-schedule wheel-through transactions that have the same scheduling priority as CAISO demand in advance of the market runs on rolling monthly and daily timeframes.[115]

No monthly reservations were made for CAISO balancing area high priority wheel-through rights for the fourth quarter of 2025. Incremental daily reservations of 10 MW were made for two days in December, with the import portion of the wheel-through at the Malin intertie. To use this reserved capacity, entities may self-schedule up to the reserved amount in the day-ahead market. None of the reserved capacity was used on either of these two days.

[115] For more information about specific TSMSP implementation details, please refer to the wheeling rights section of the *Q2 2024 Report on Market Issues and Performance*, November 22, 2024: https://www.caiso.com/documents/2024-second-quarter-report-on-market-issues-and-performance-nov-22-2024.pdf

18 Resource adequacy

18.1 Available resource adequacy bids compared to CAISO balancing area market requirements

The CPUC resource adequacy (RA) program and CAISO availability incentive mechanisms are intended to ensure suppliers make sufficient generation capacity available to the CAISO balancing area to meet the area's load and ancillary service requirements. Insufficient available resource adequacy capacity to meet the balancing area's load and ancillary service requirements may indicate a shortcoming in the overall CPUC-CAISO resource adequacy program. Insufficient capacity can arise from a combination of factors, including:

1) Low procurement requirements for load serving entities;
2) Rules that may over-count capacity from resources, such as variable energy resources and use-limited resources, that may not be available during tight system conditions;
3) Procurement of low quality or poorly maintained resources that may not be available during tight system conditions; and
4) CAISO balancing area performance penalties not properly incentivizing resources to maintain availability during tight system conditions.

Some resource adequacy capacity does not have an obligation to bid into the real-time markets if it did not receive a day-ahead market award. Therefore, non-resource adequacy capacity displacing resource adequacy capacity in the real-time market can cause insufficient resource adequacy capacity in real-time to cover market requirements, rather than being a shortcoming in the resource adequacy program design. As a result, in this metric assessing resource adequacy availability, DMM counts the quantity of real-time bids from non-resource adequacy capacity that displaces resource adequacy that had bid into the day-ahead market but did not have a real-time must offer obligation.

Real-time resource adequacy bids, including bids from variable energy resources (VERs) above their resource adequacy values, were sufficient to cover the market requirements for energy and upward ancillary services in the CAISO balancing area in all hours of the fourth quarter.

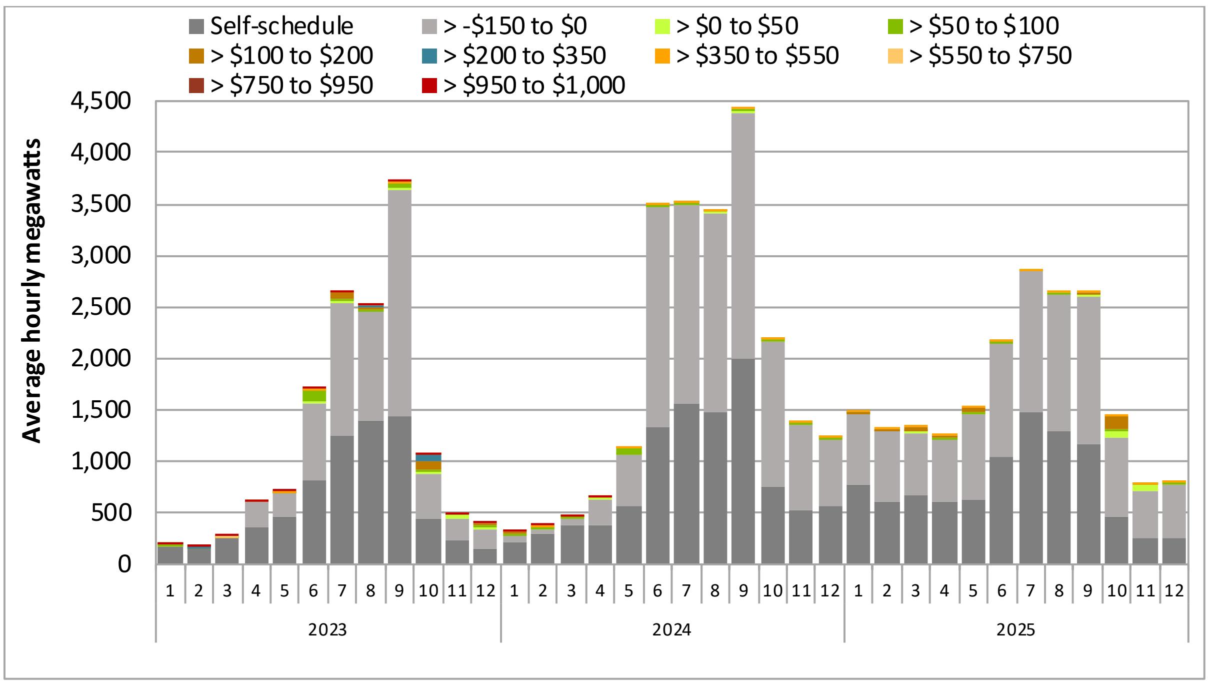
18.2 Resource adequacy import bids

In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource specific import resource adequacy resources must bid into the California ISO markets at or below $0/MWh during the availability assessment hours.[116] These rules became effective at the beginning of 2021.

Figure 18.1 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[117] The dark grey bars reflect import capacity that was self-scheduled. The light grey bars show imports bid at or below $0/MWh. The remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market bid above $0/MWh.

Overall bid-in levels of resource adequacy imports decreased in October, November, and December by 34 percent, 43 percent, and 35 percent, respectively, compared to the same months of 2024. Overall, resource adequacy import bids in Q4 2025 decreased 37 percent from Q4 2024.

Figure 18.1 Average hourly resource adequacy imports by price bin



[116] In 2021, Phase 1 (March 20) and Phase 2 (June 13) of the FERC Order No. 831 compliance tariff amendment were implemented. Phase 1 allows resource adequacy imports to bid over the soft offer cap of $1,000/MWh when the maximum import bid price (MIBP) is over $1,000/MWh or when the California ISO has accepted a cost-verified bid over $1,000/MWh. Phase 2 imposed bidding rules capping resource adequacy import bids over $1,000/MWh at the greater of the MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh.

[117] Peak hours in this analysis reflect non-weekend and non-holiday periods between hours-ending 17 and 21.

APPENDIX

Appendix A | Western Energy Imbalance Market area specific metrics

Sections A.1 to A.23 include figures for each WEIM area showing hourly locational marginal price (LMP) and dynamic transfers.[118] These figures are included for both the 15-minute and 5-minute markets.

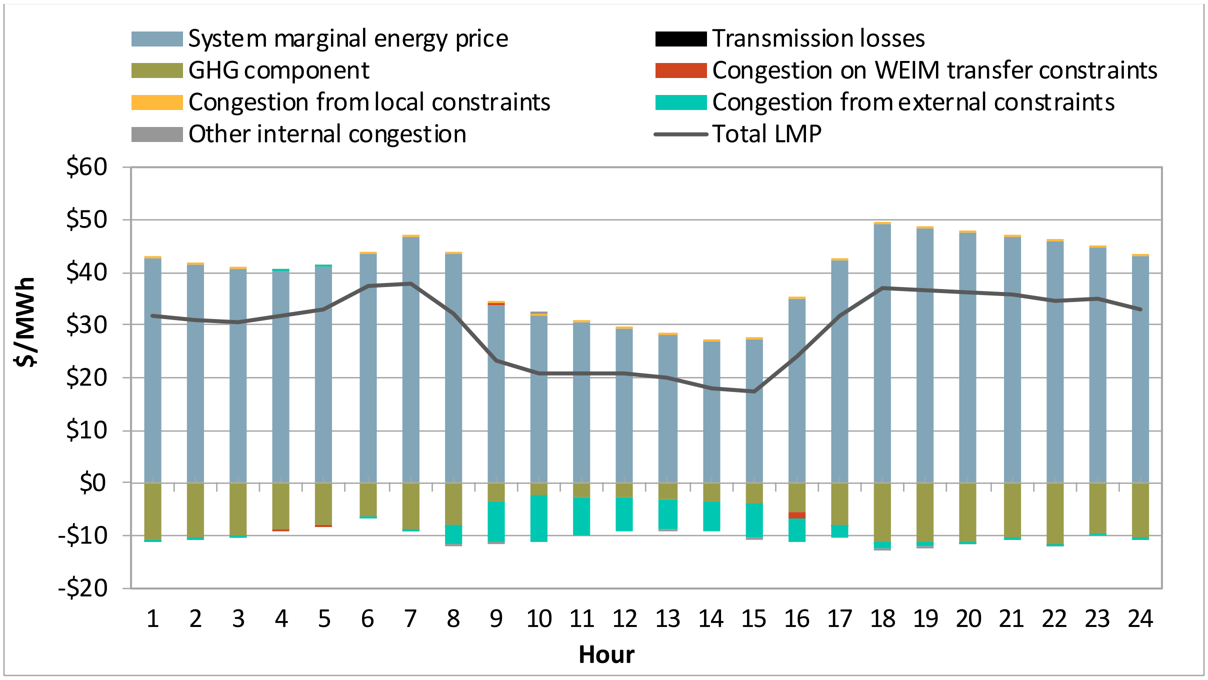
The hourly locational marginal price decomposition figures break down the price into seven separate components. These components, listed below, can influence the prices in an area positively or negatively, depending on the circumstances.

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.
- **Congestion from local constraints** is the price impact from transmission constraints within its own balancing area that are restricting the flow of energy. While these constraints are located locally, they can create price impacts across the WEIM and show up as external constraints in the figures below to other balancing areas.
- **Congestion from external constraints** is the price impact from transmission constraints from a WEIM balancing area outside of its own that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*
- **Congestion on WEIM transfer constraints** is the price impact from any constraints that limit WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits following a resource sufficiency evaluation failure, or (3) intertie constraint (ITC) and intertie scheduling limit (ISL).

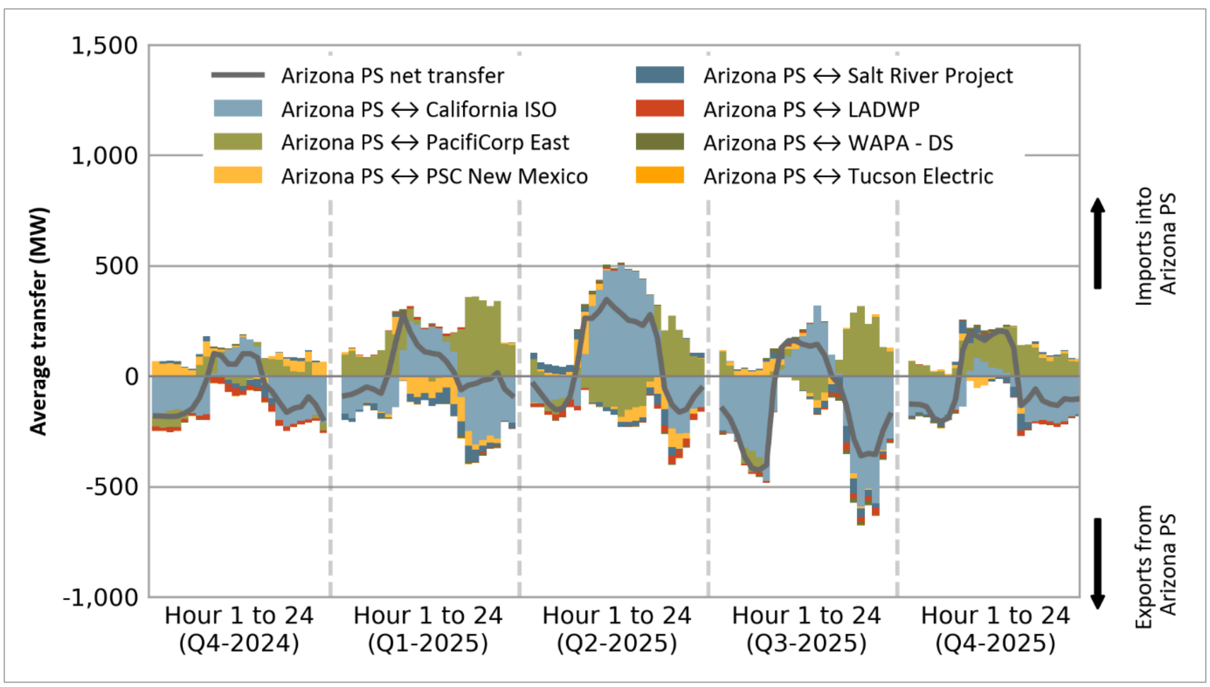
[118] These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will not appear in the figures.

A.1 Arizona Public Service

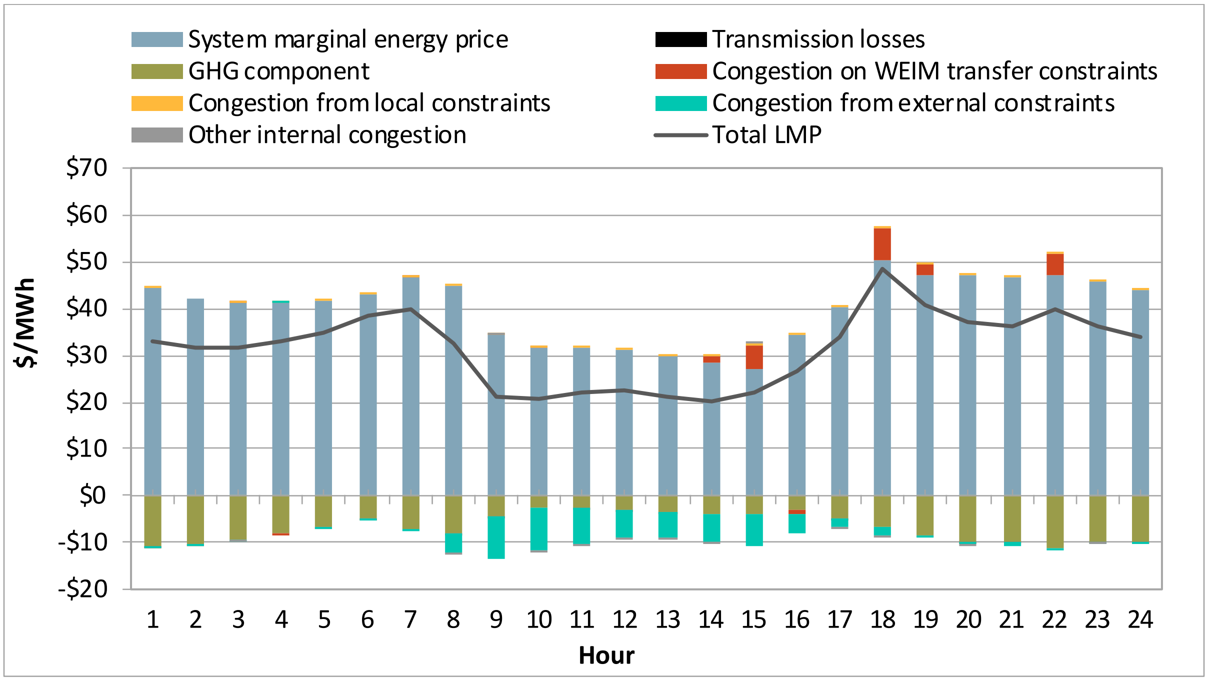
Appendix Figure A.1 Average hourly 15-minute price by component (Q4 2025)



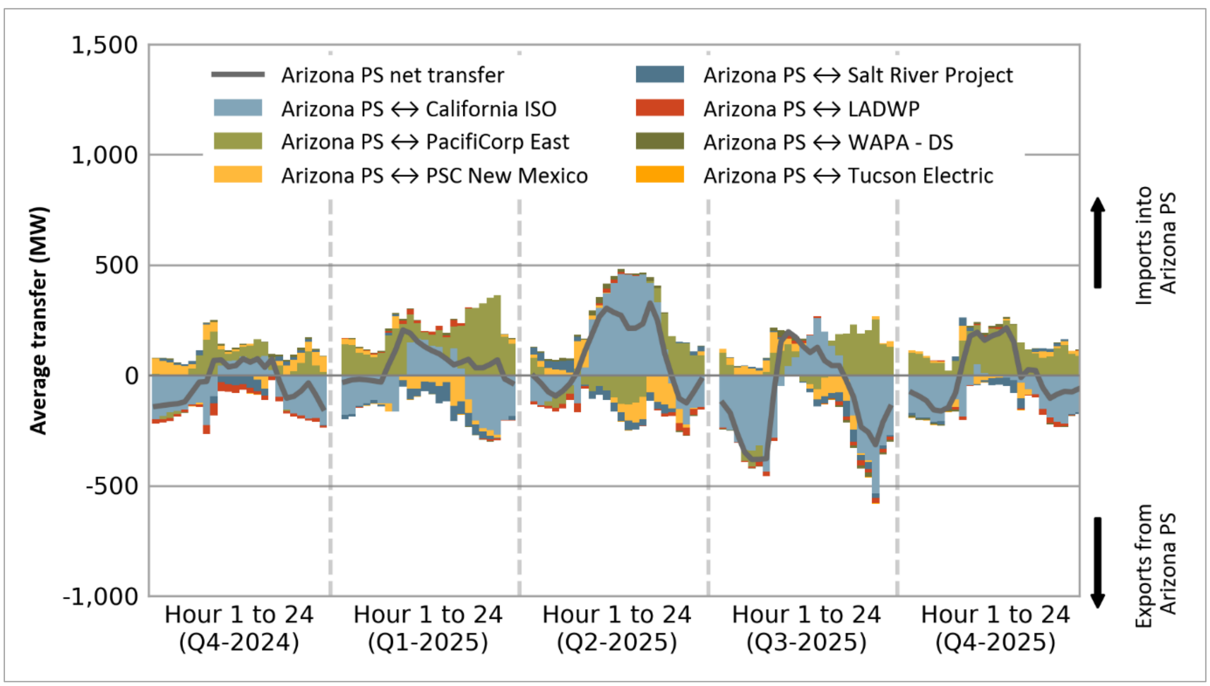
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q4 2025)

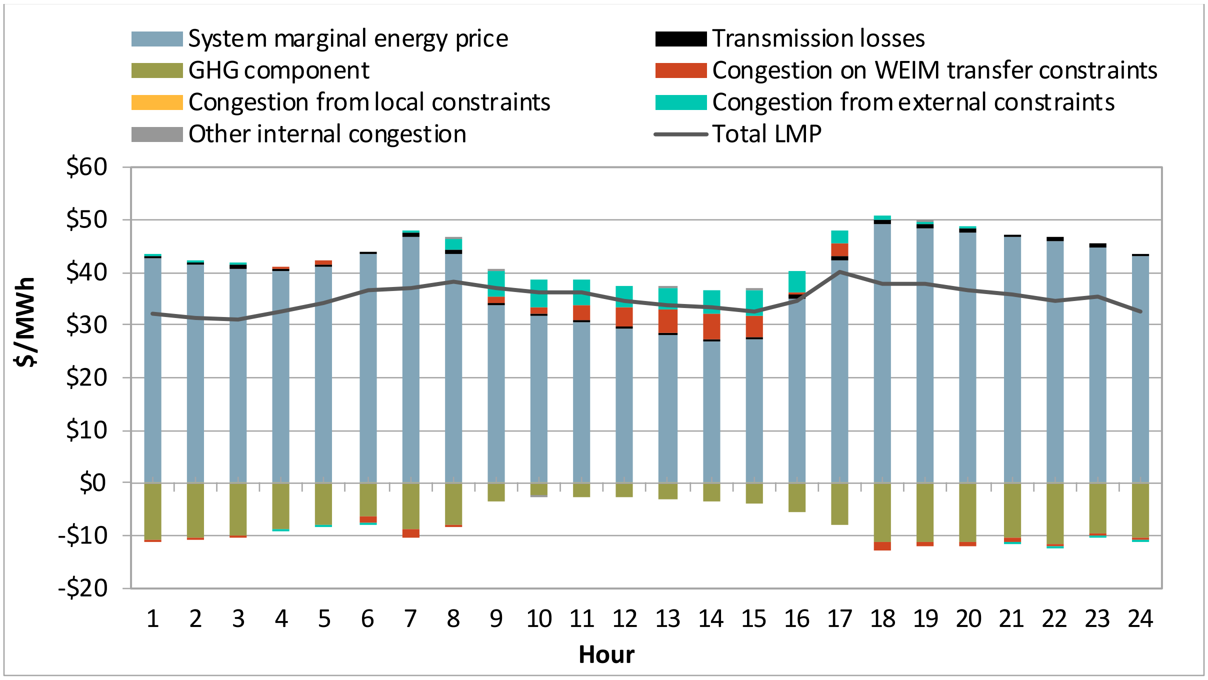


Appendix Figure A.4 Average hourly 5-minute market transfers

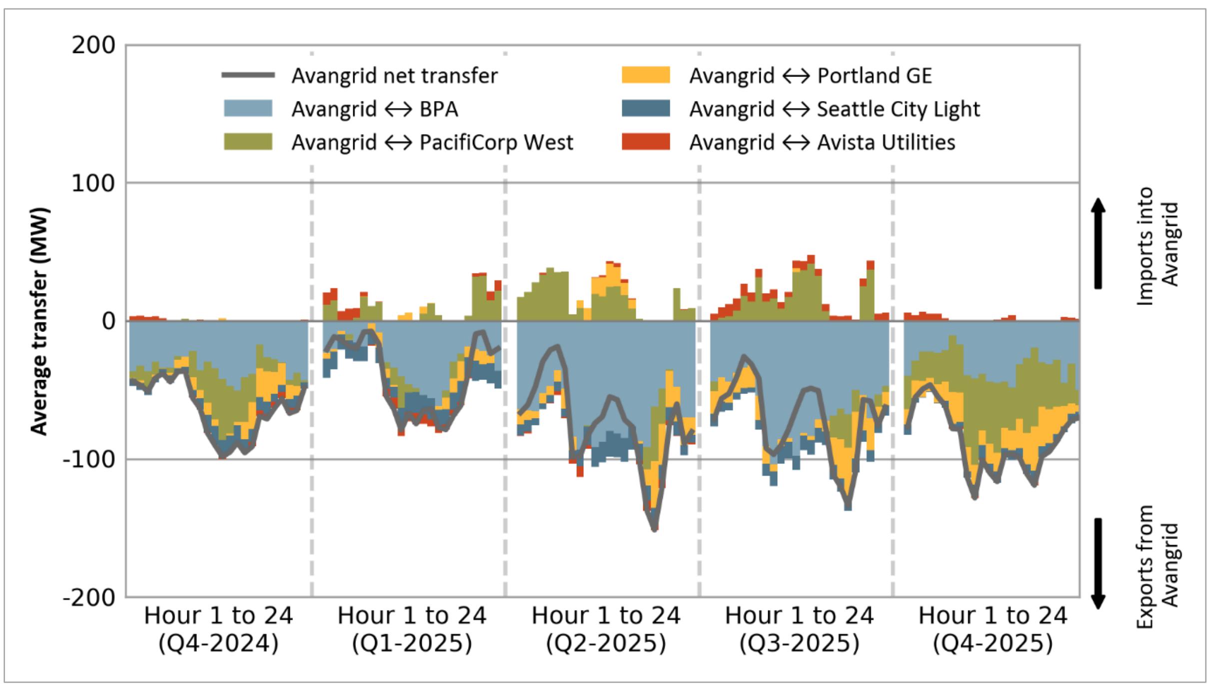


A.2 Avangrid

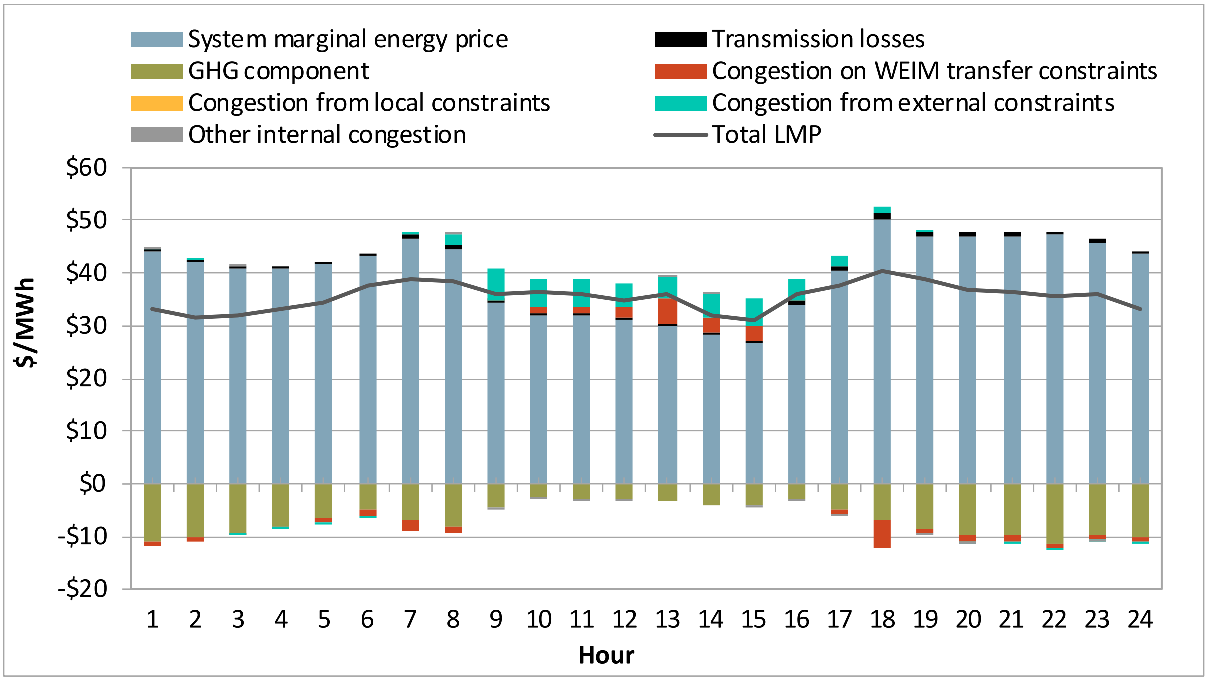
Appendix Figure A.5 Average hourly 15-minute price by component (Q4 2025)



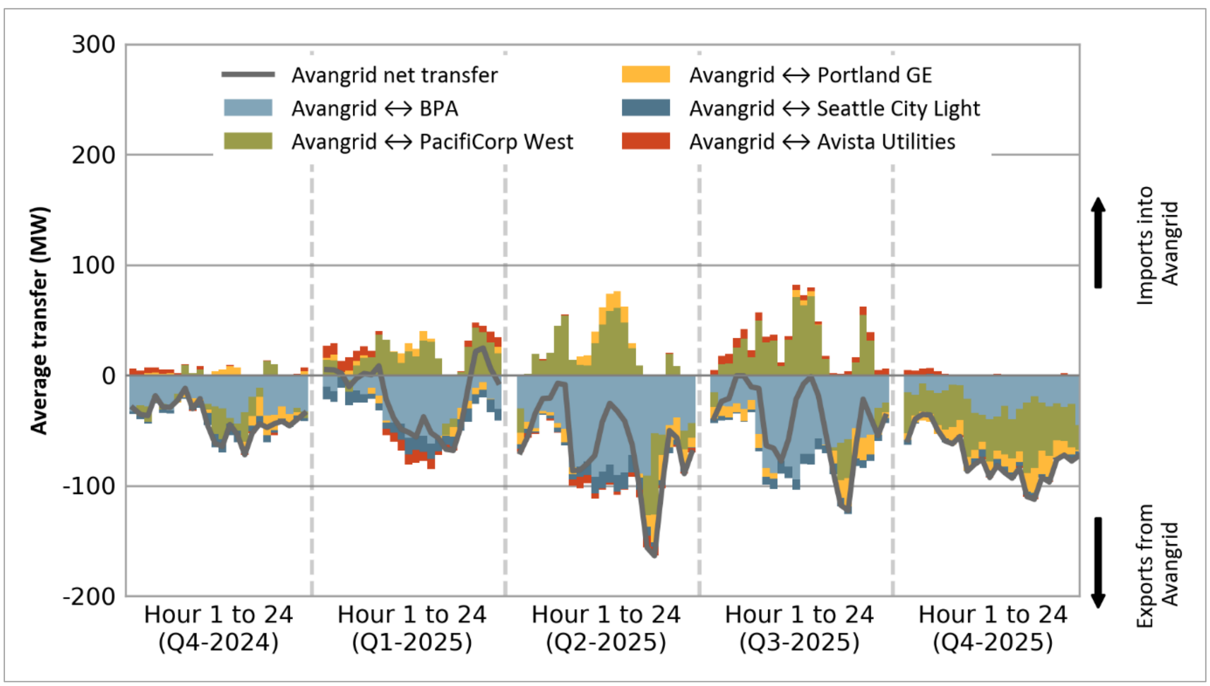
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q4 2025)

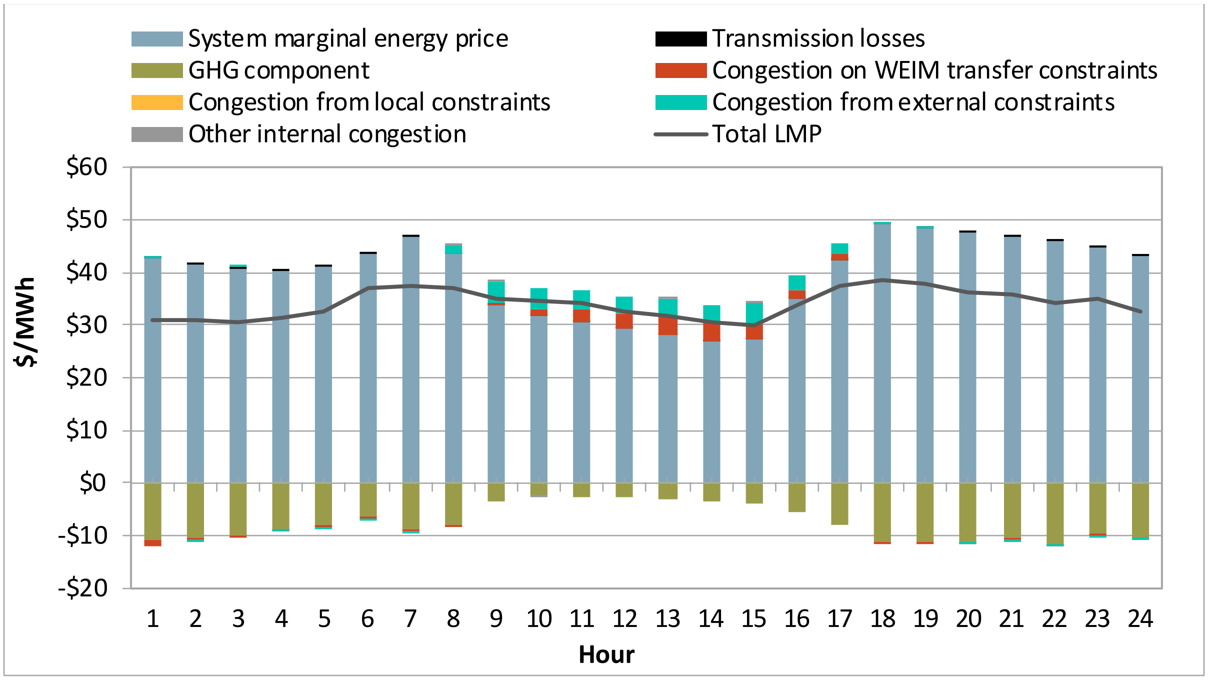


Appendix Figure A.8 Average hourly 5-minute market transfers

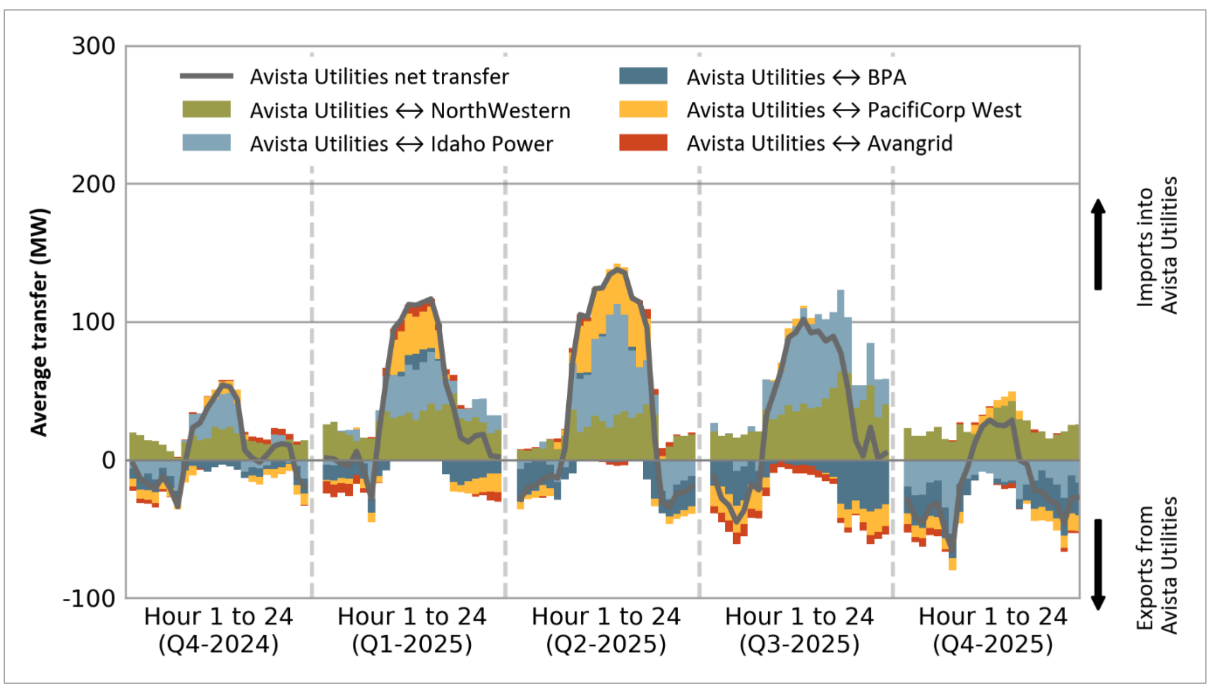


A.3 Avista Utilities

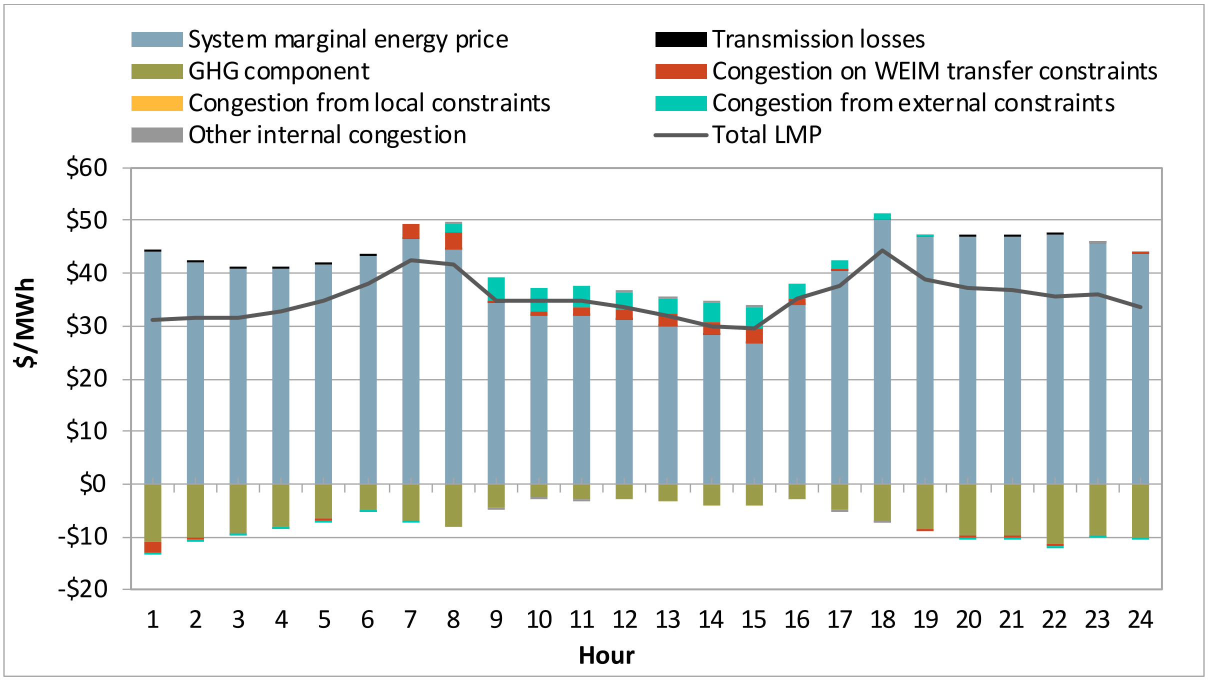
Appendix Figure A.9 Average hourly 15-minute price by component (Q4 2025)



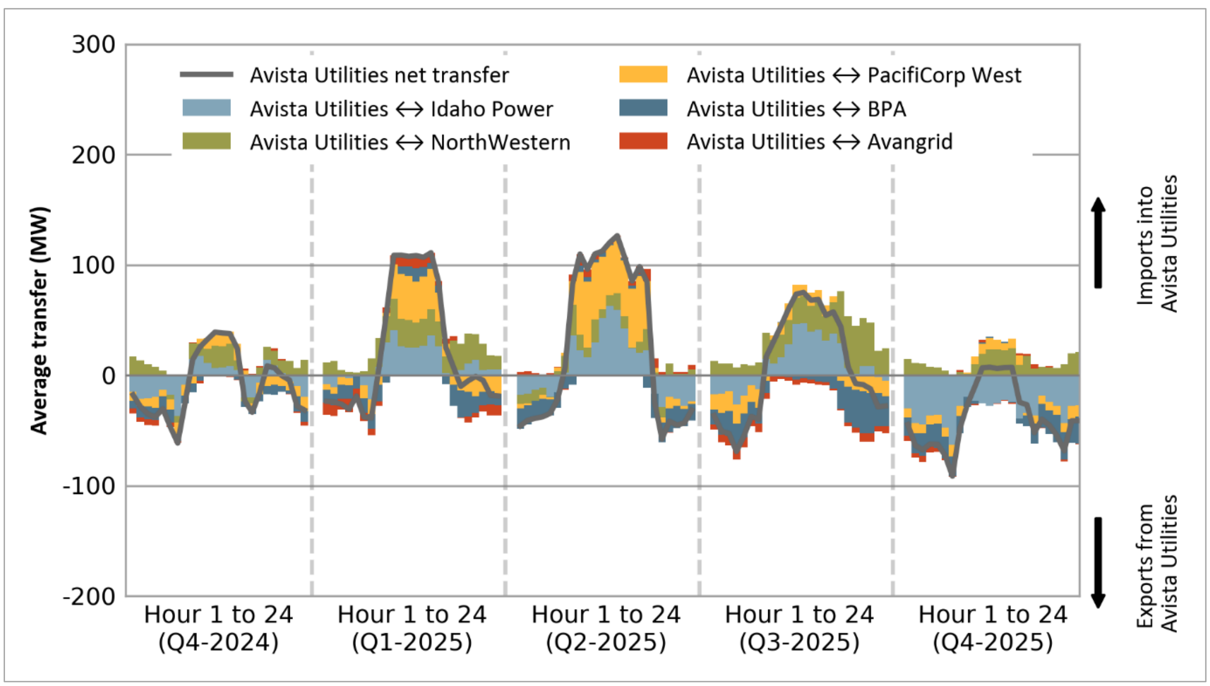
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q4 2025)

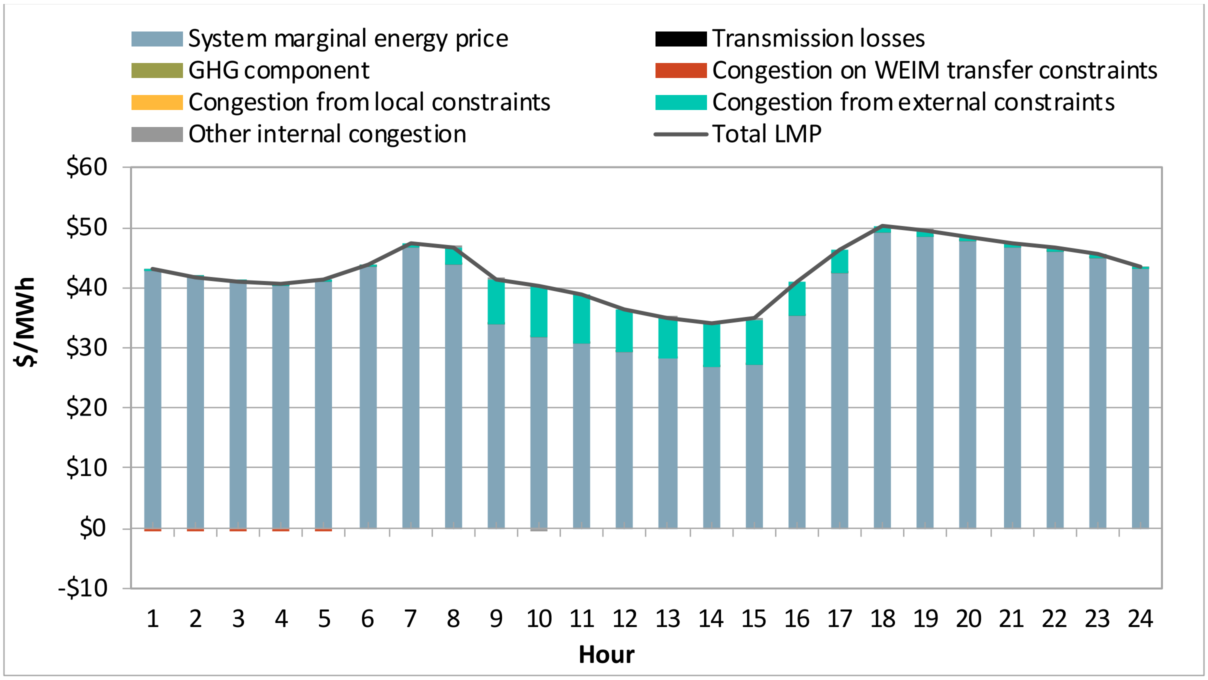


Appendix Figure A.12 Average hourly 5-minute market transfers

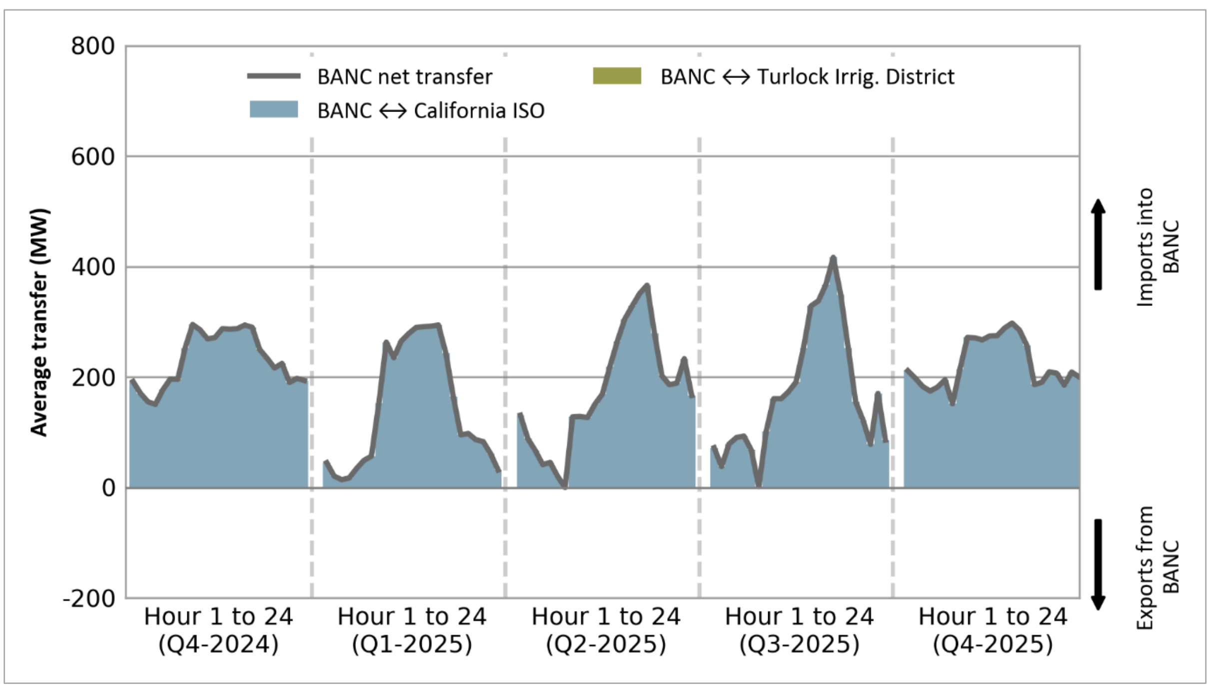


A.4 Balancing Authority of Northern California

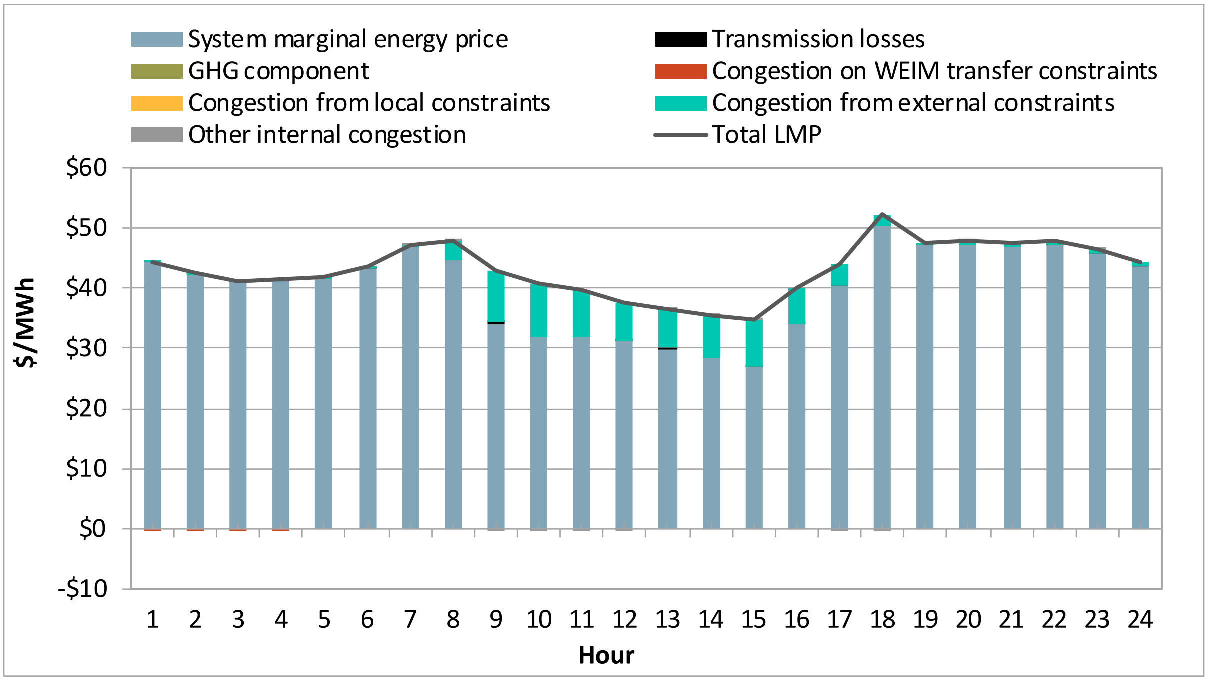
Appendix Figure A.13 Average hourly 15-minute price by component (Q4 2025)



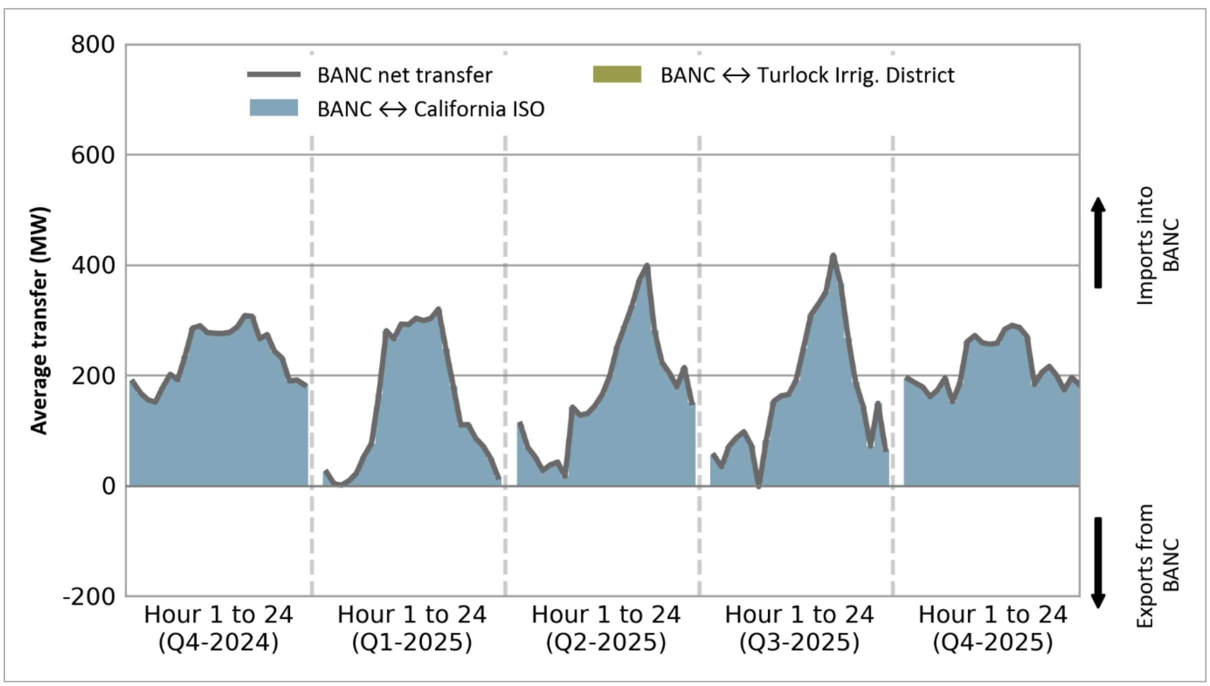
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q4 2025)

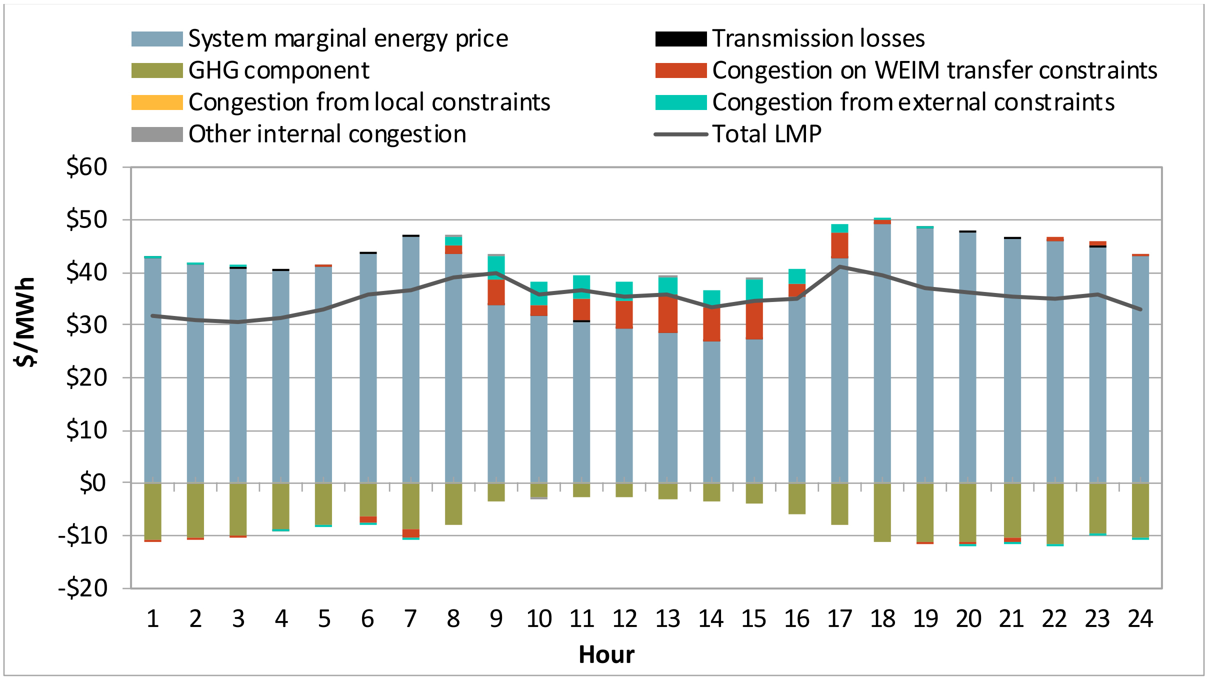


Appendix Figure A.16 Average hourly 5-minute market transfers

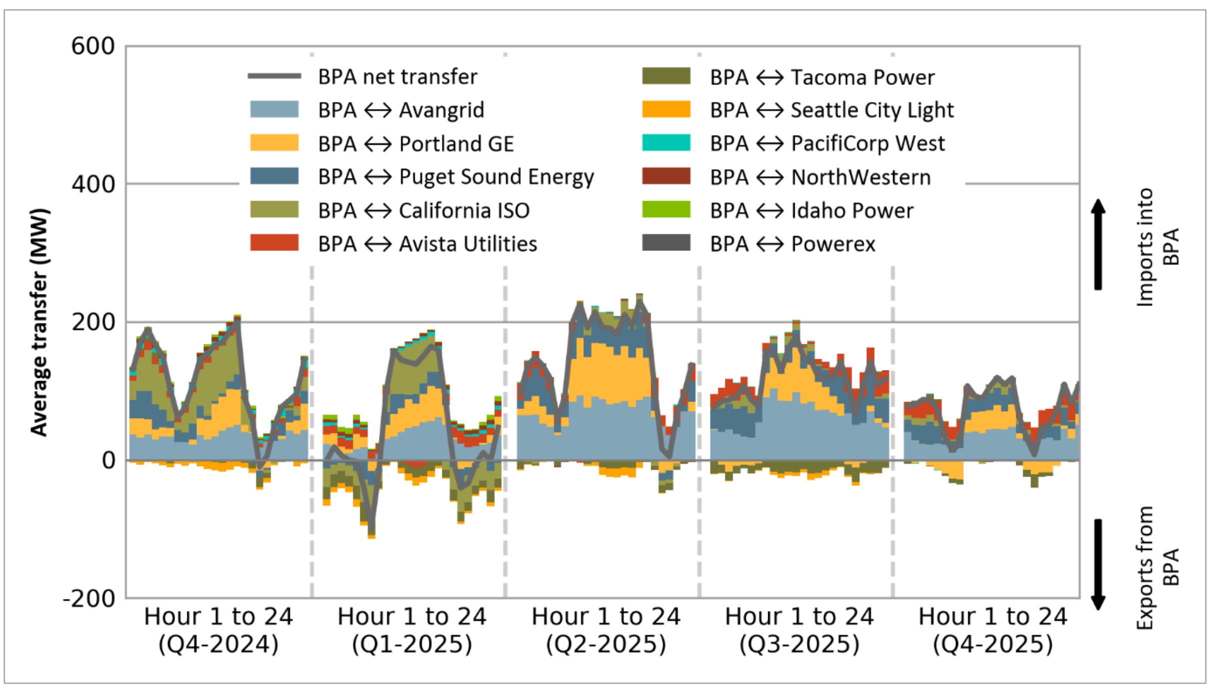


A.5 Bonneville Power Administration

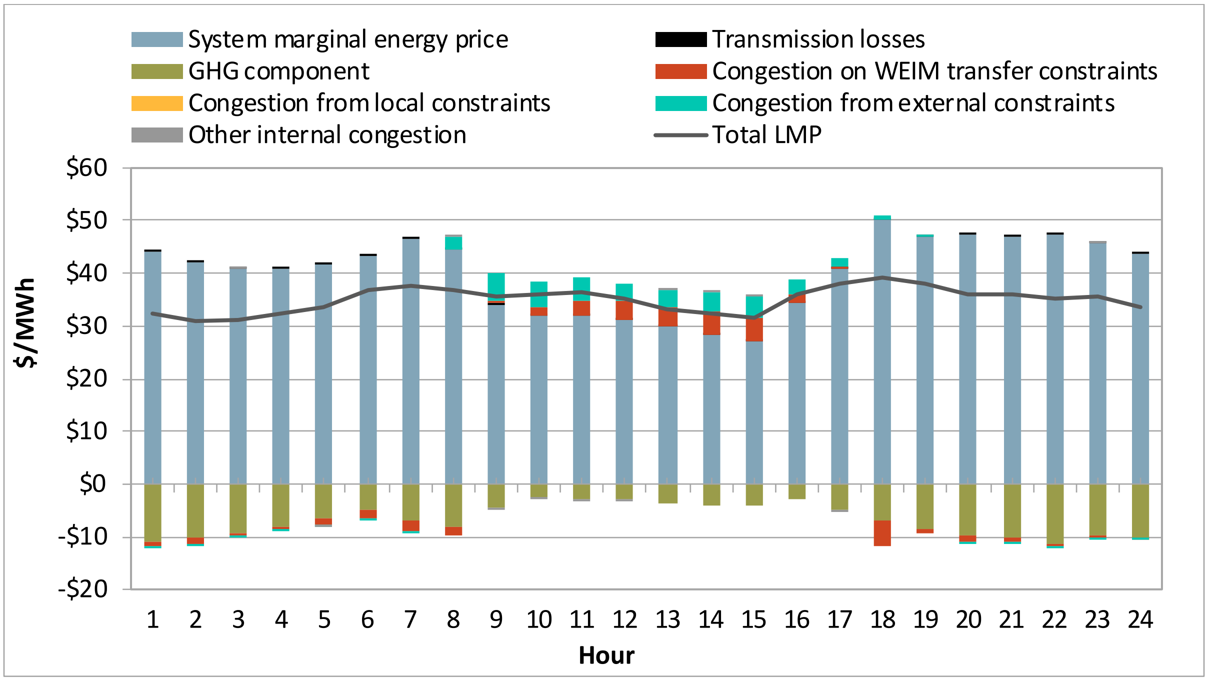
Appendix Figure A.17 Average hourly 15-minute price by component (Q4 2025)



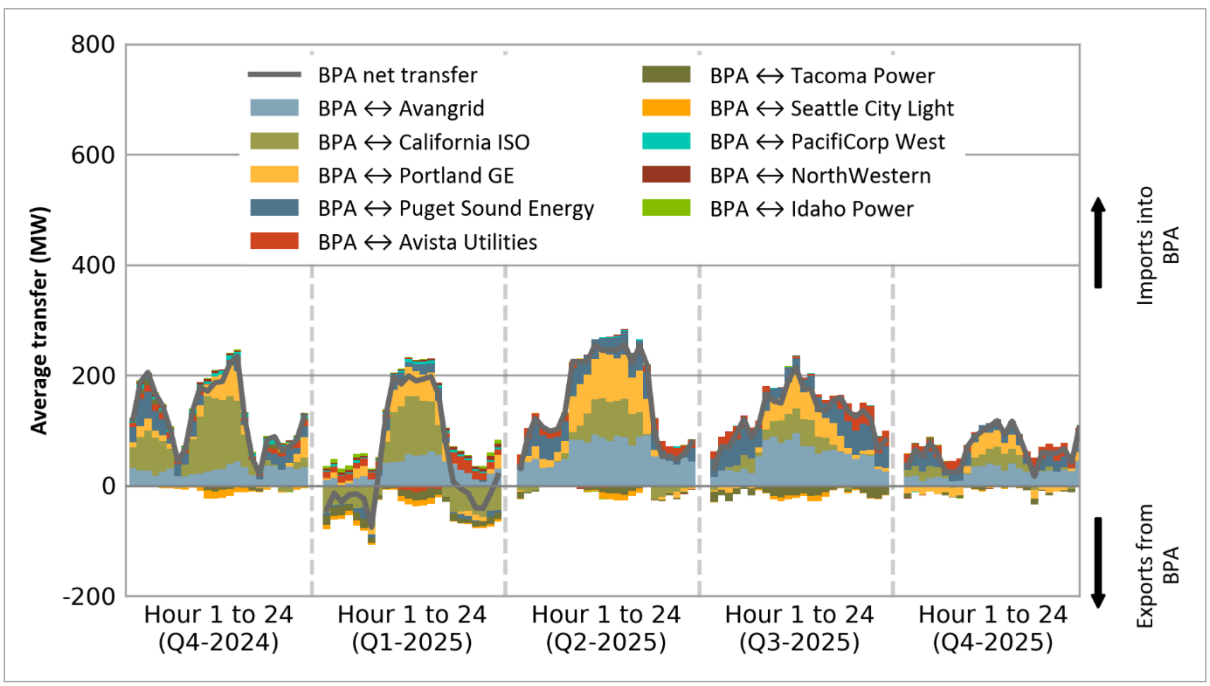
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q4 2025)

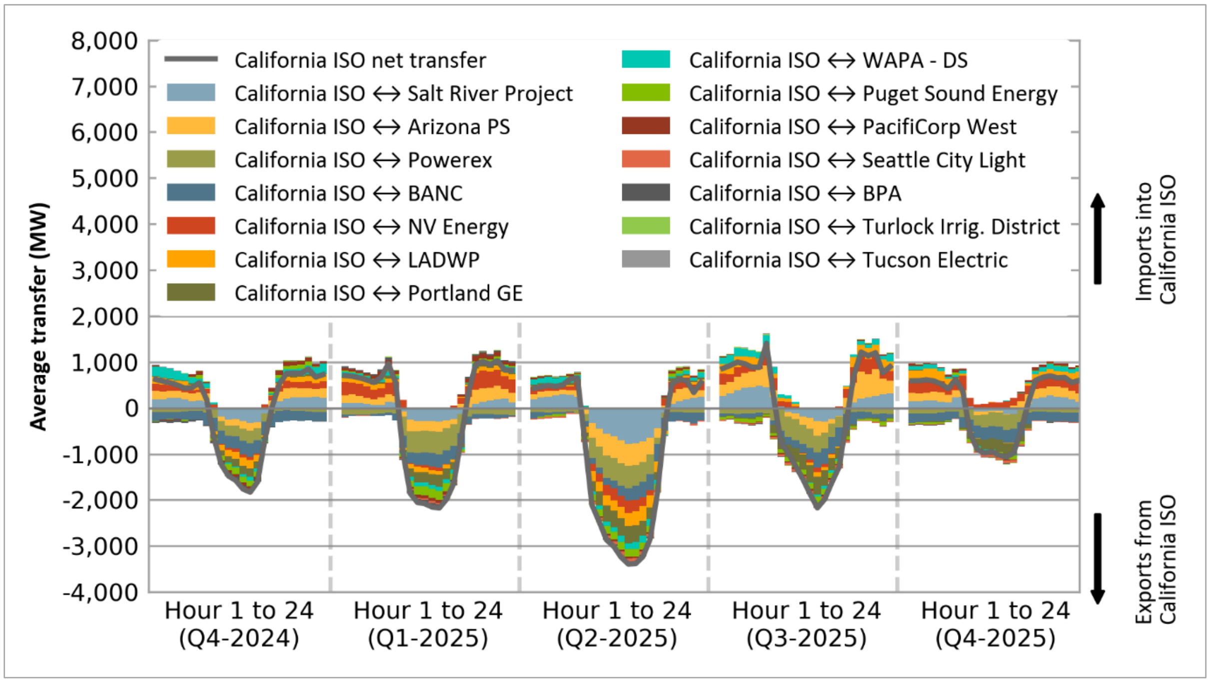


Appendix Figure A.20 Average hourly 5-minute market transfers

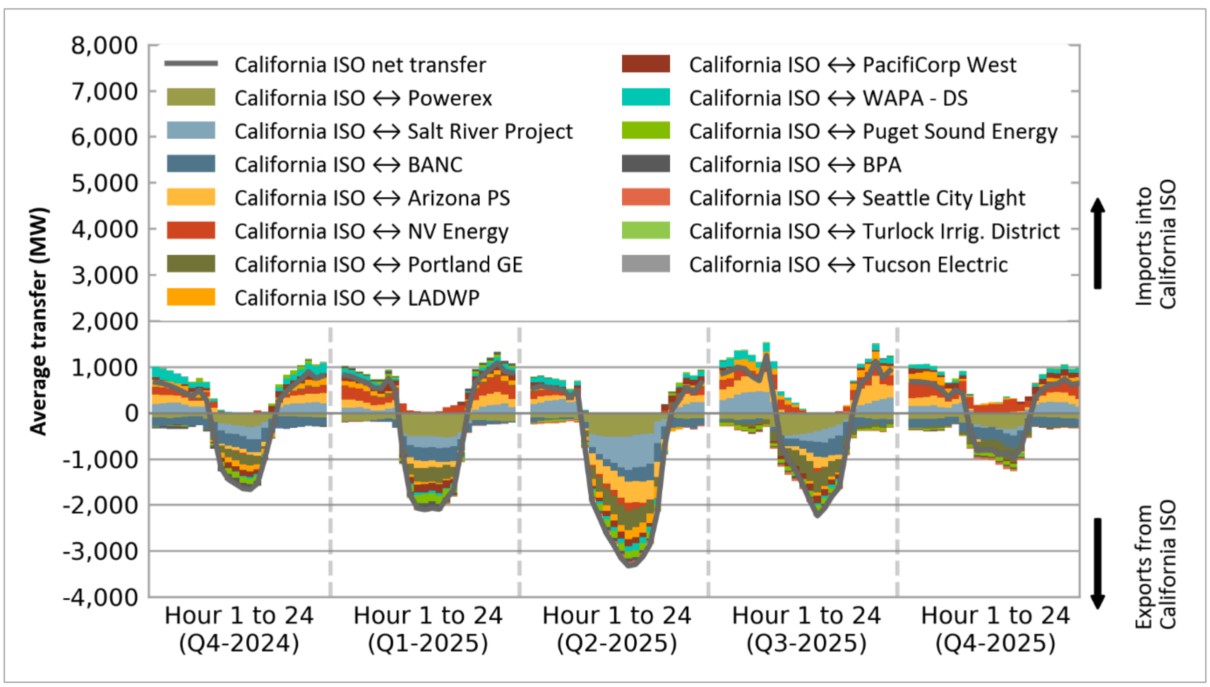


A.6 California ISO

Appendix Figure A.21 Average hourly 15-minute market transfers

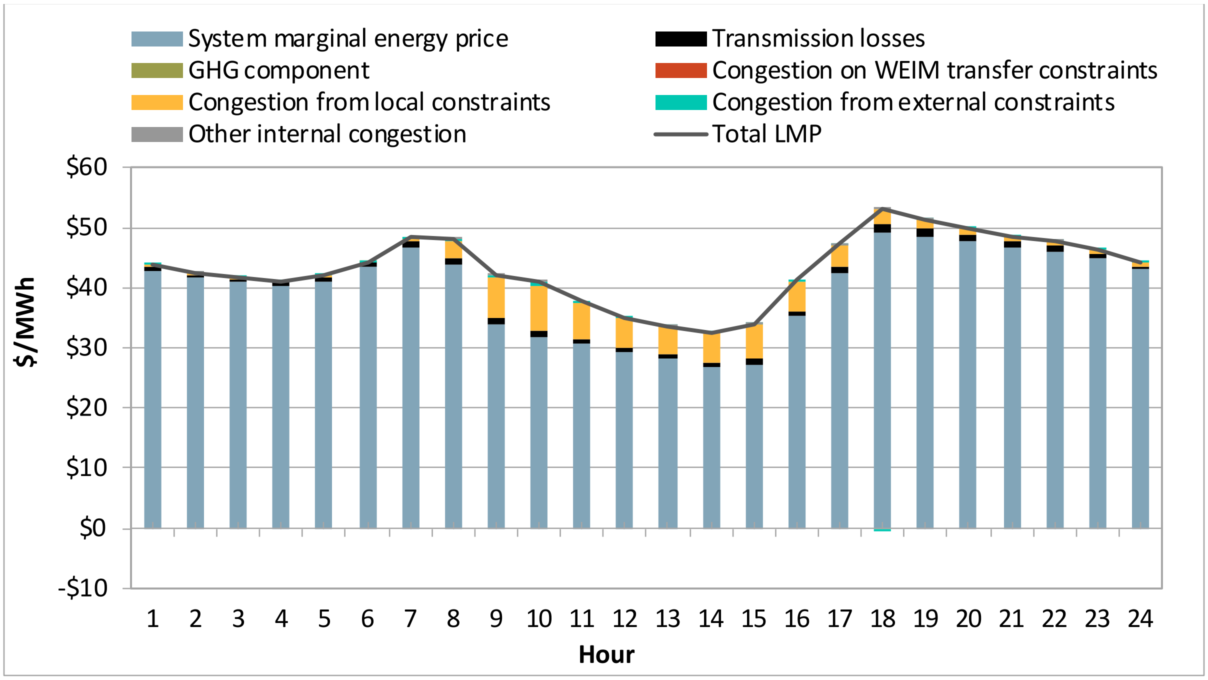


Appendix Figure A.22 Average hourly 5-minute market transfers

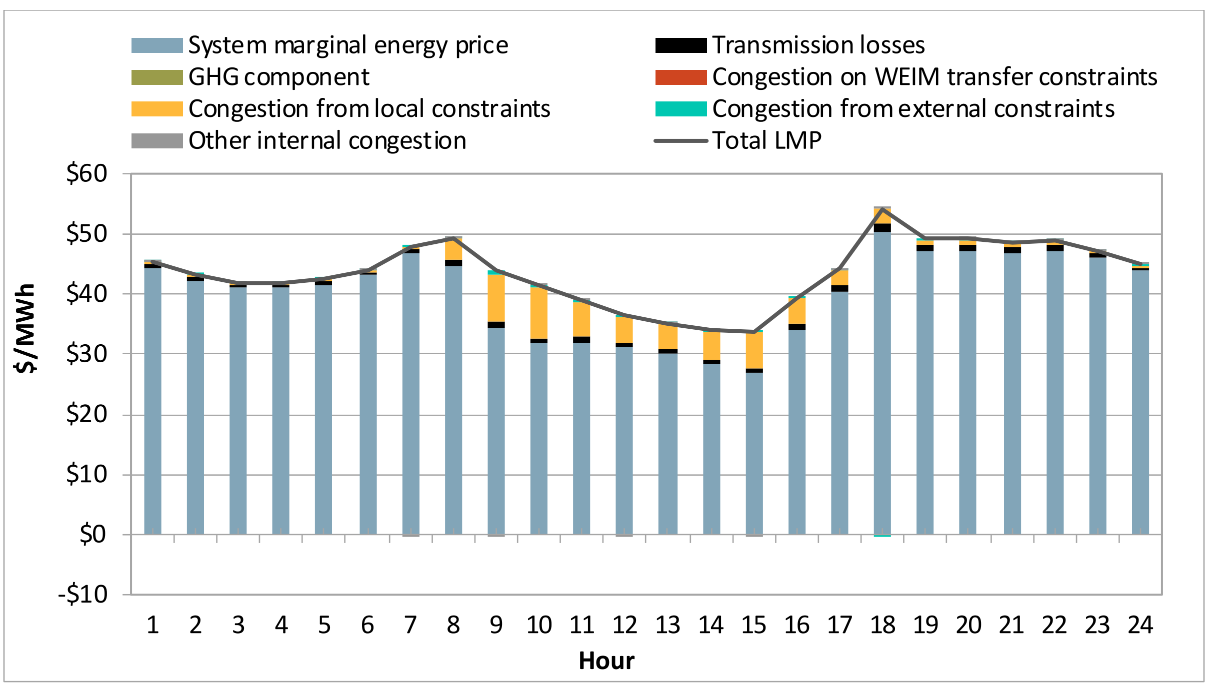


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q4 2025)

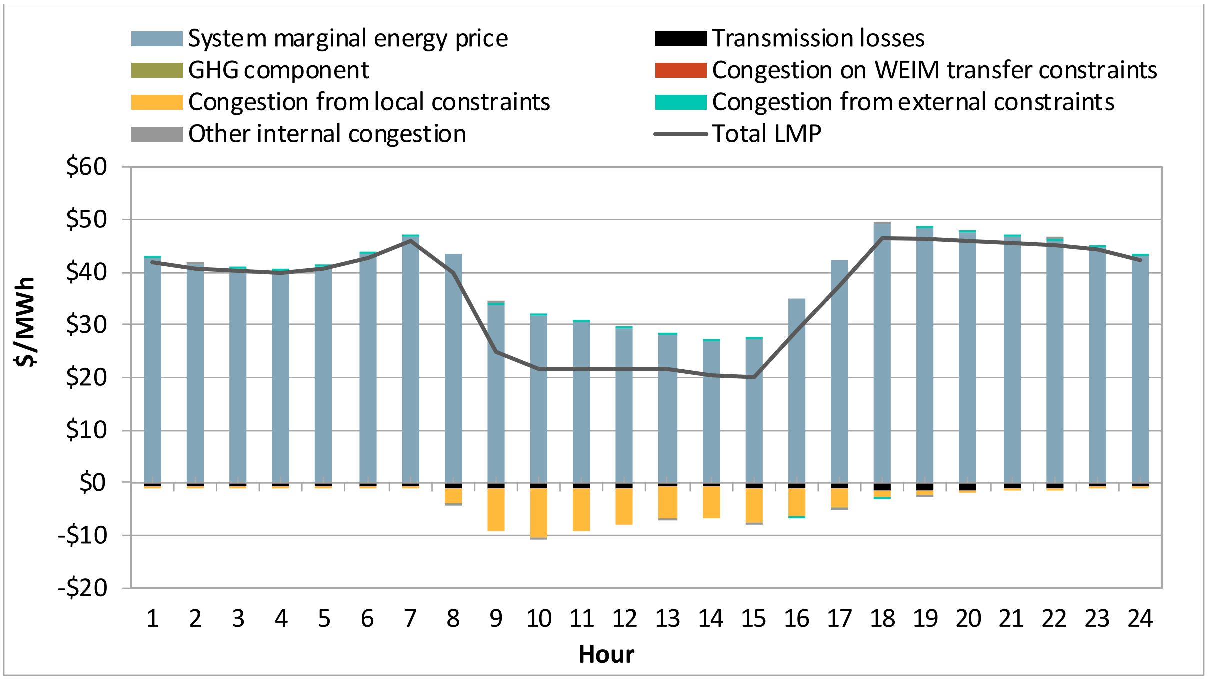


Appendix Figure A.24 Average hourly 5-minute price by component (Q4 2025)

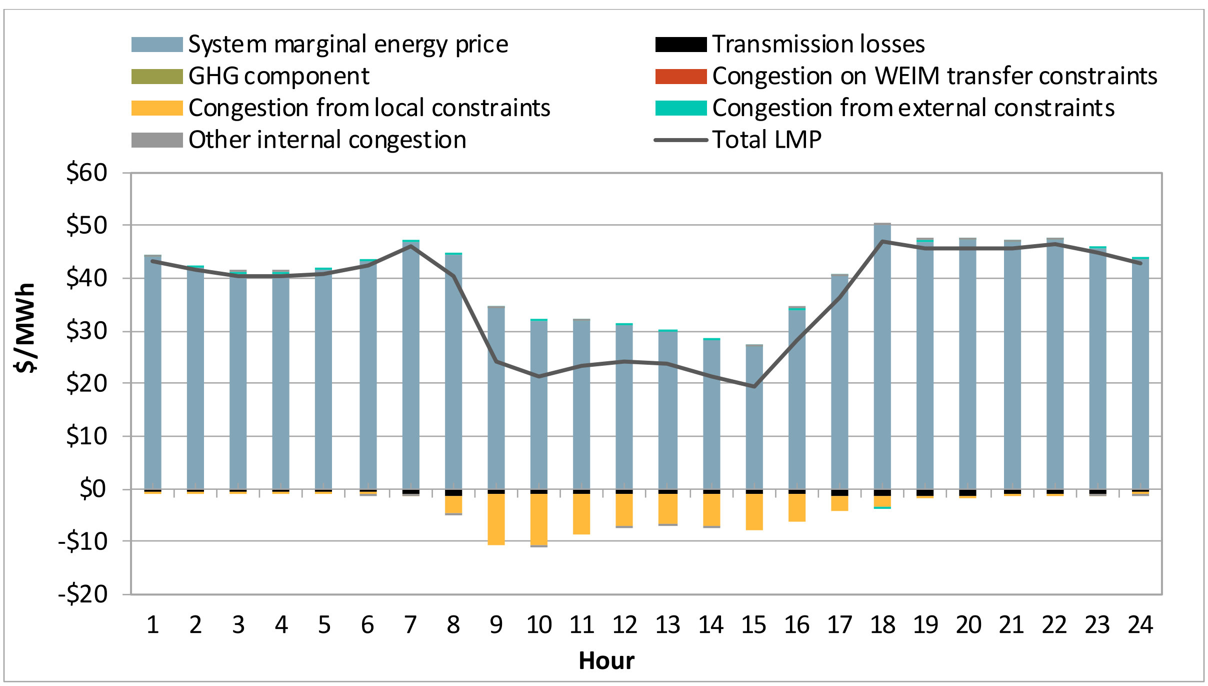


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q4 2025)

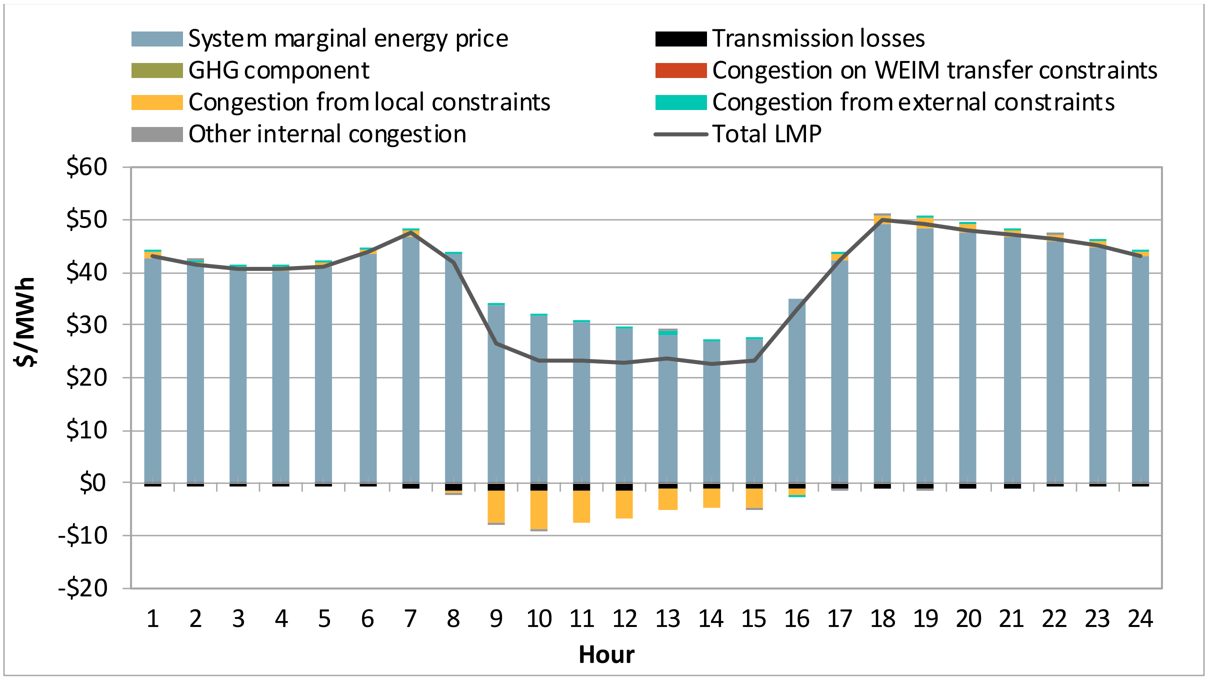


Appendix Figure A.26 Average hourly 5-minute price by component (Q4 2025)

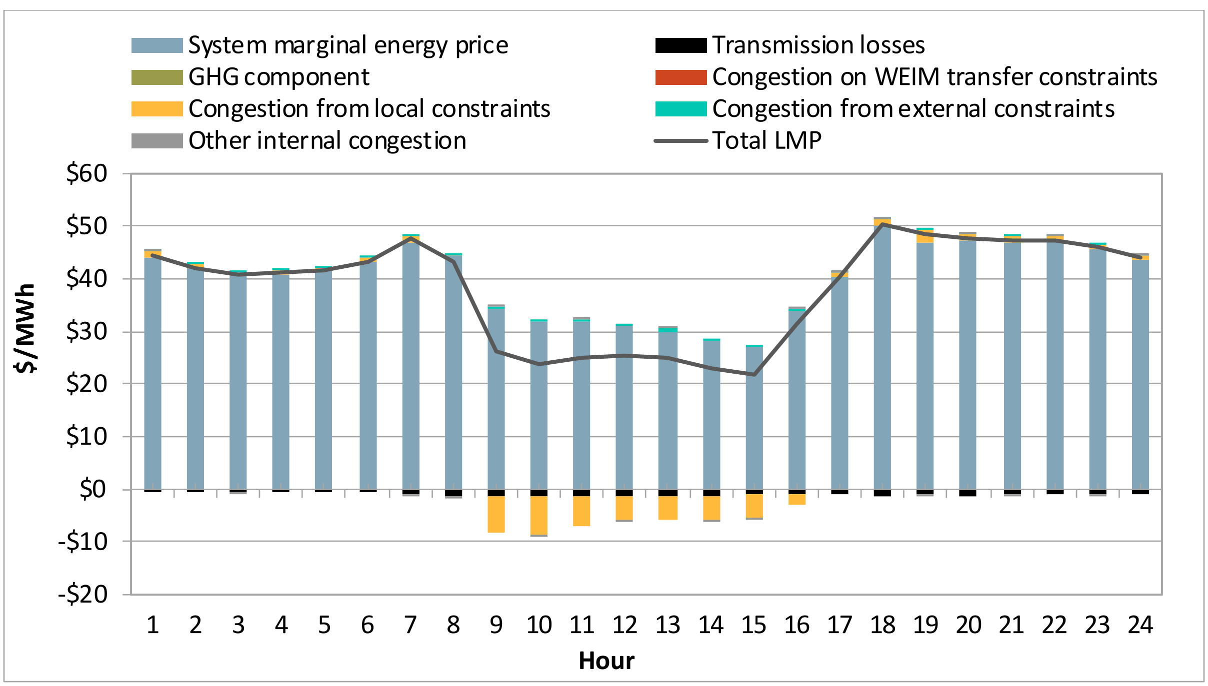


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q4 2025)

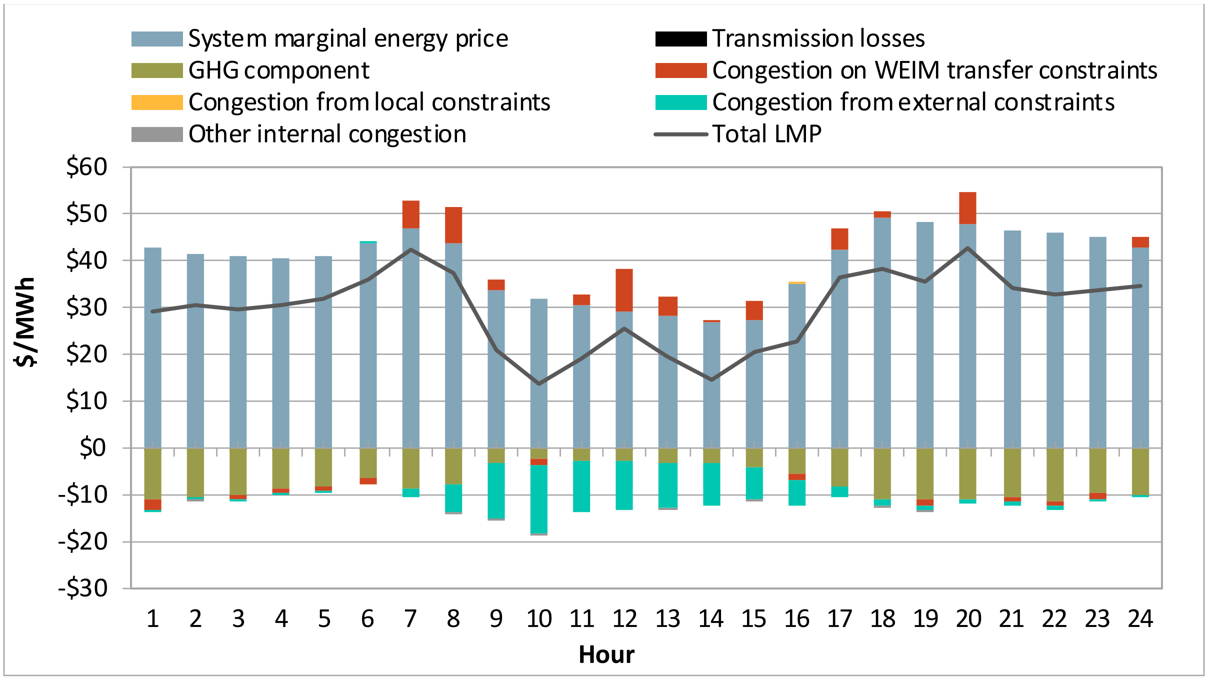


Appendix Figure A.28 Average hourly 5-minute price by component (Q4 2025)

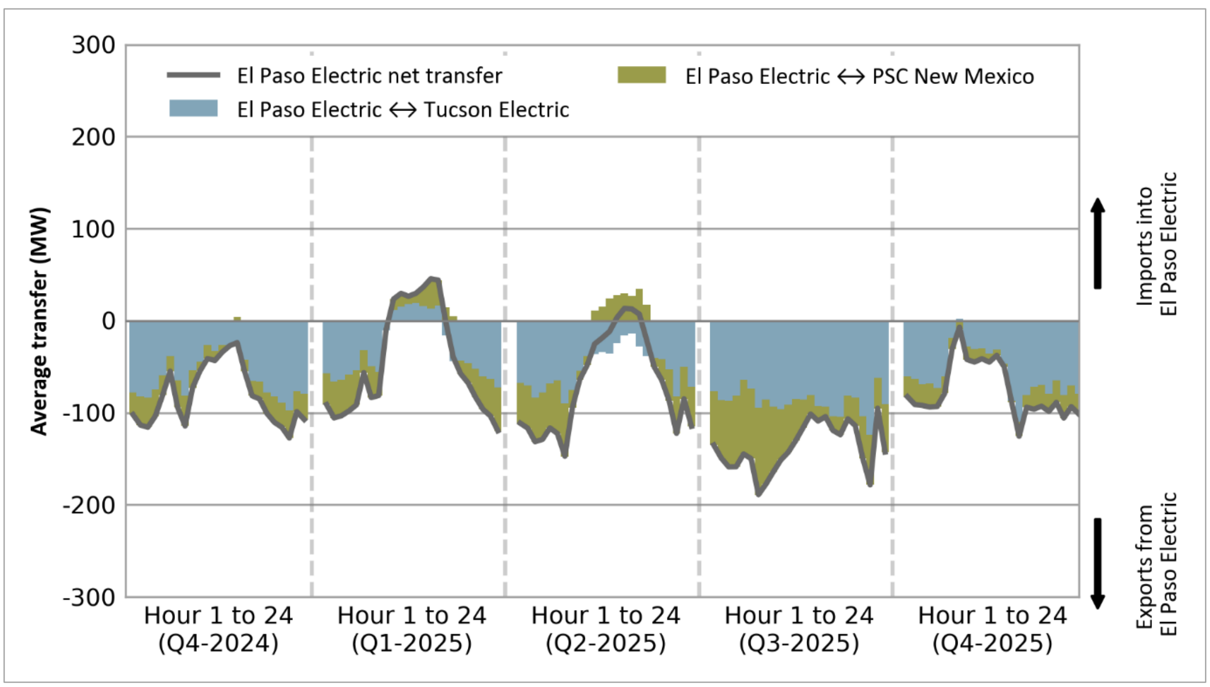


A.7 El Paso Electric

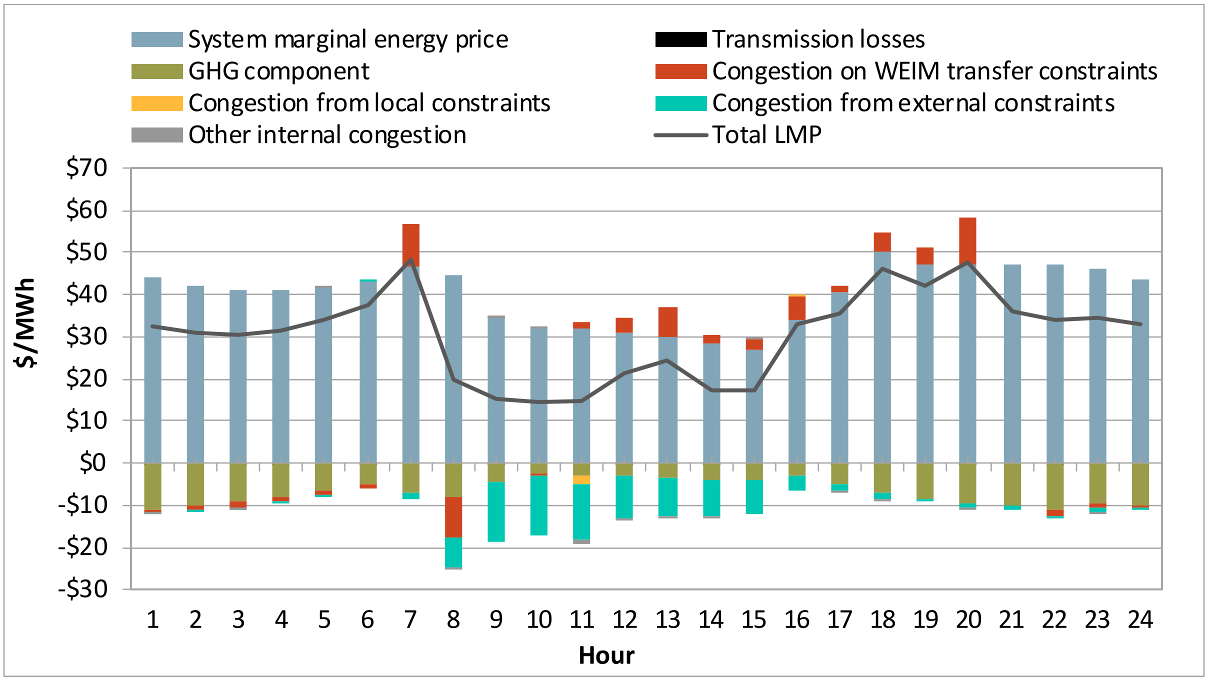
Appendix Figure A.29 Average hourly 15-minute price by component (Q4 2025)



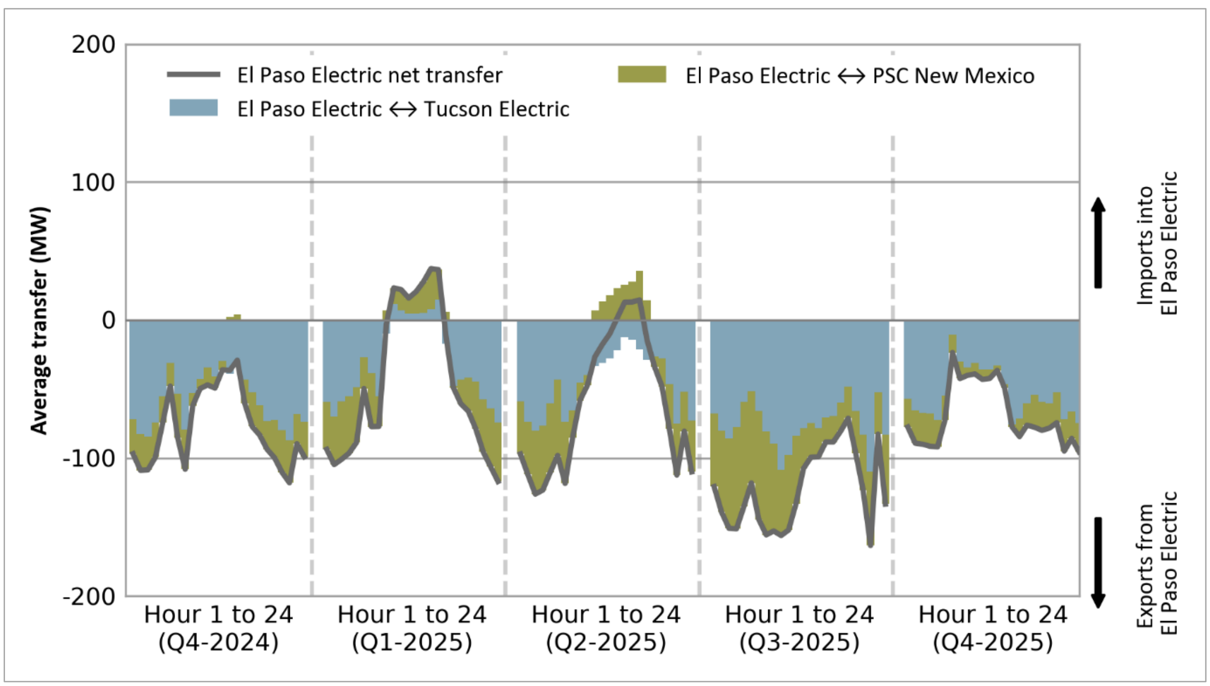
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q4 2025)

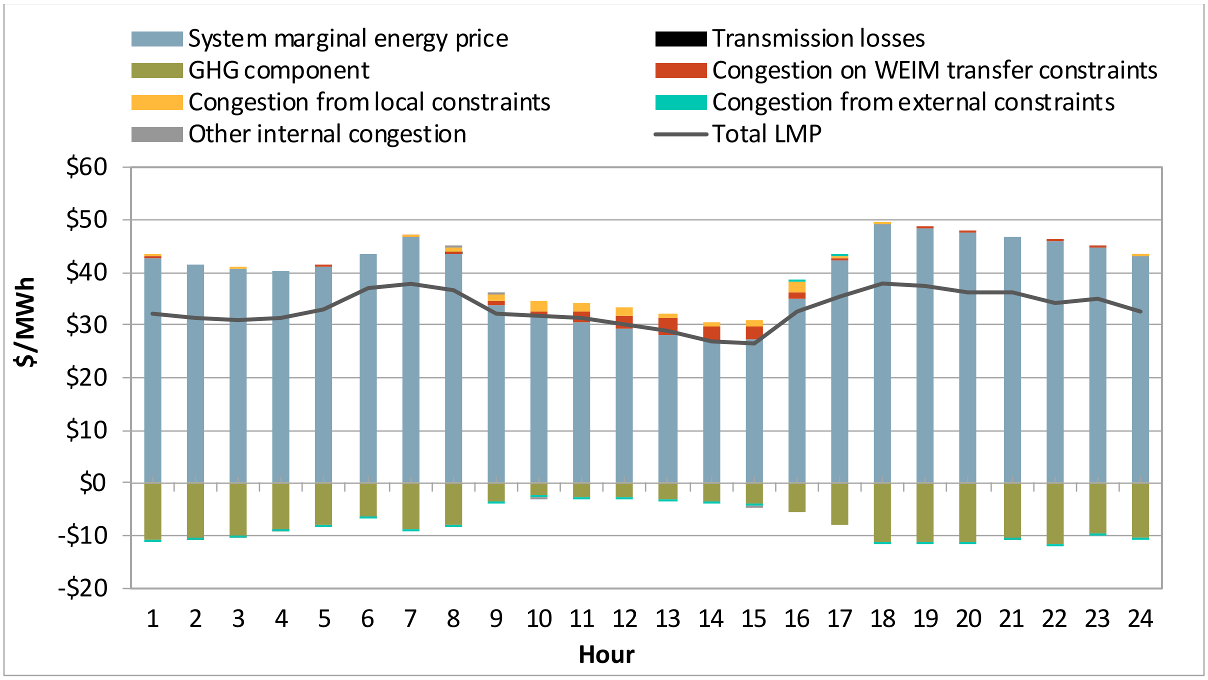


Appendix Figure A.32 Average hourly 5-minute market transfers

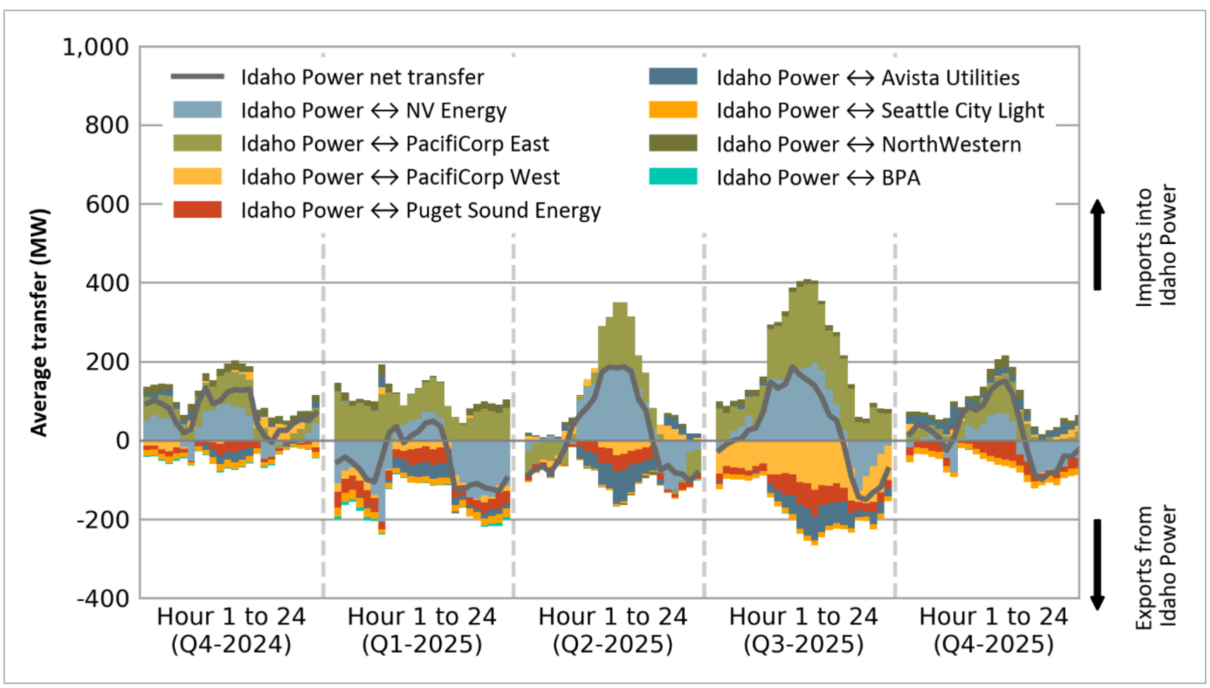


A.8 Idaho Power

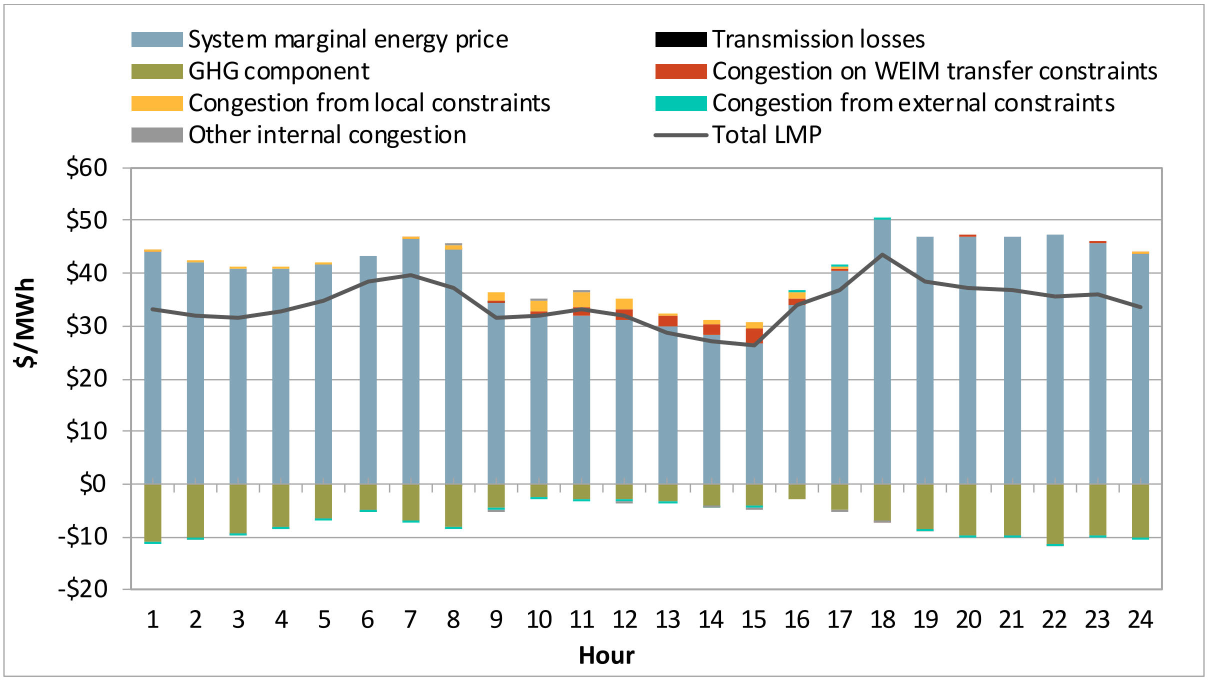
Appendix Figure A.33 Average hourly 15-minute price by component (Q4 2025)



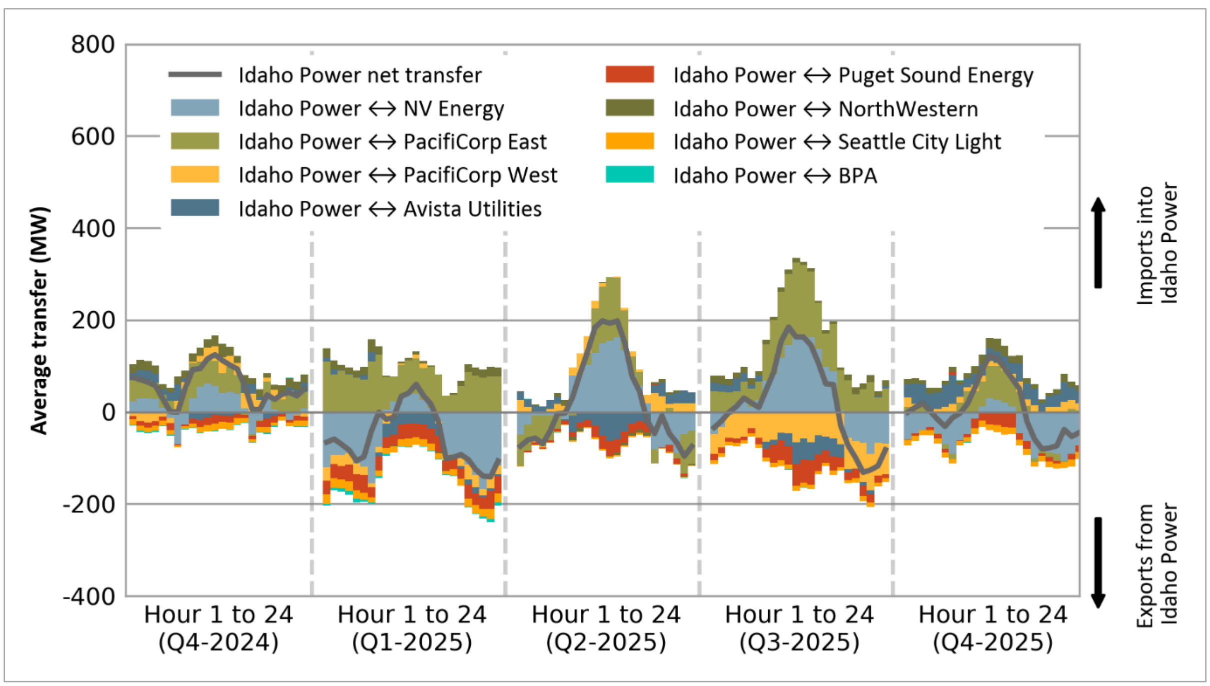
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q4 2025)

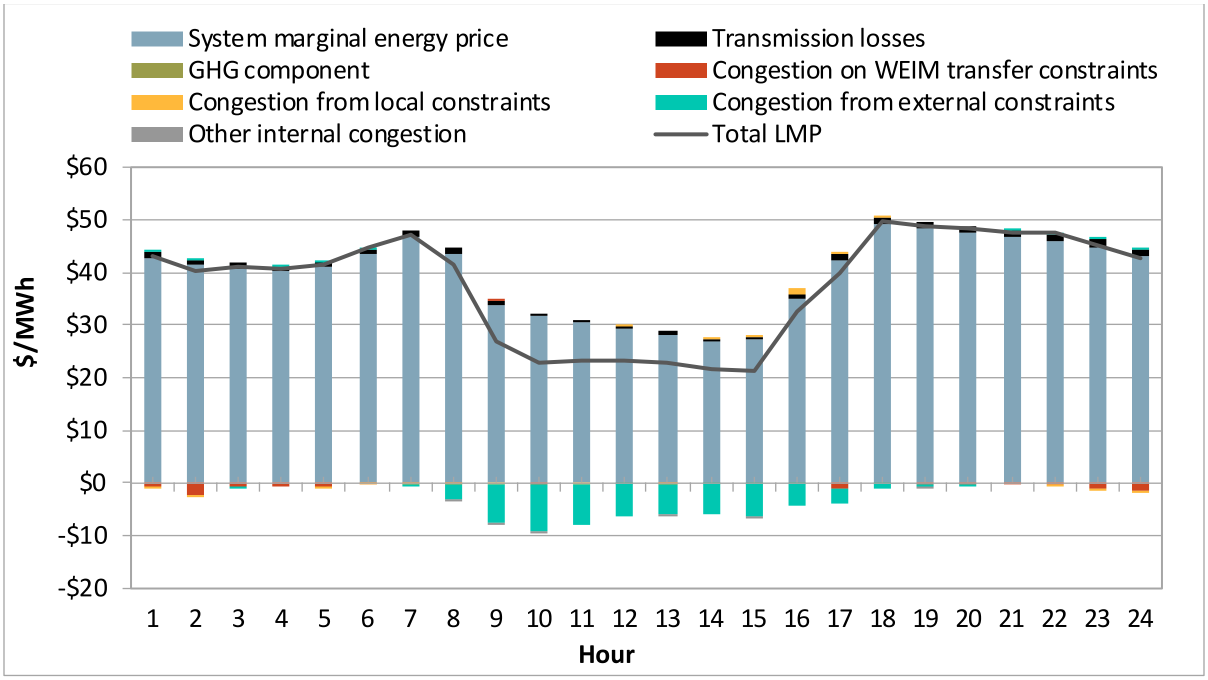


Appendix Figure A.36 Average hourly 5-minute market transfers

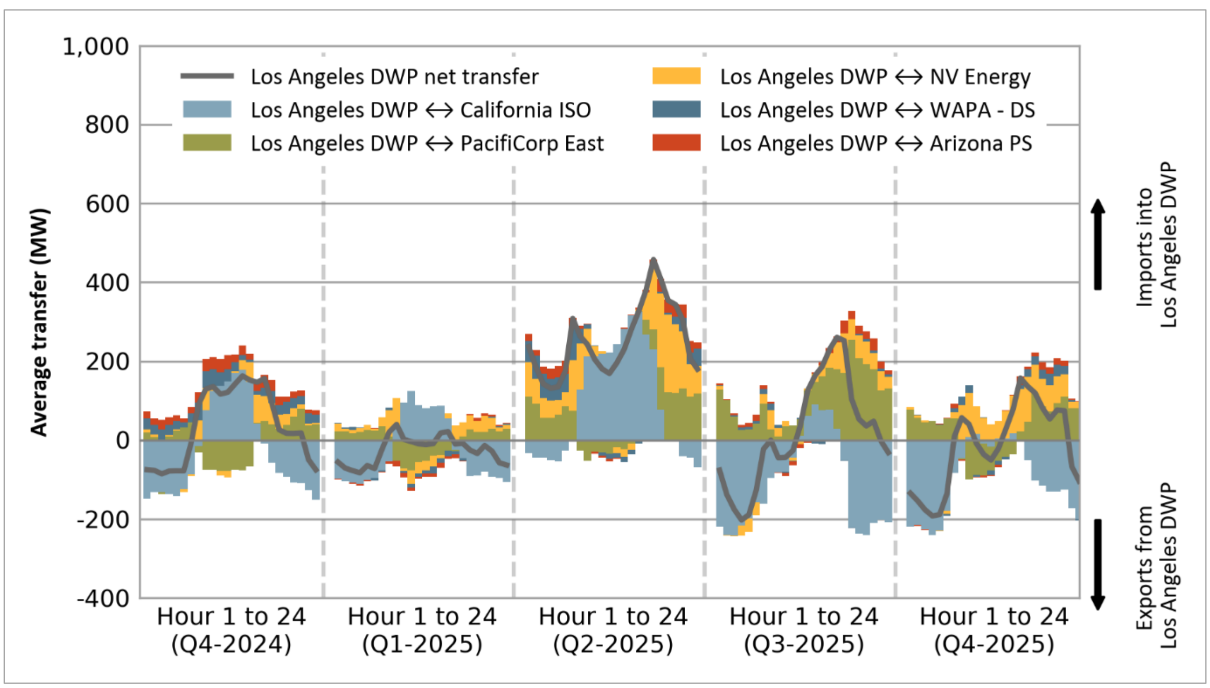


A.9 Los Angeles Department of Water and Power

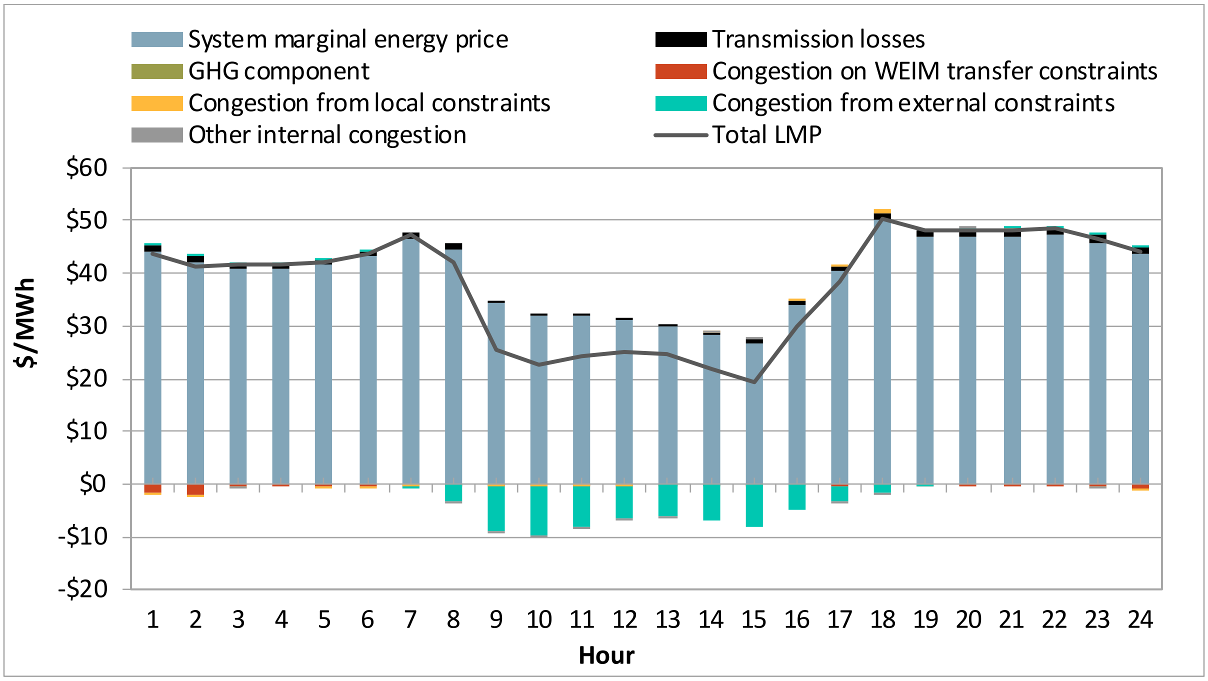
Appendix Figure A.37 Average hourly 15-minute price by component (Q4 2025)



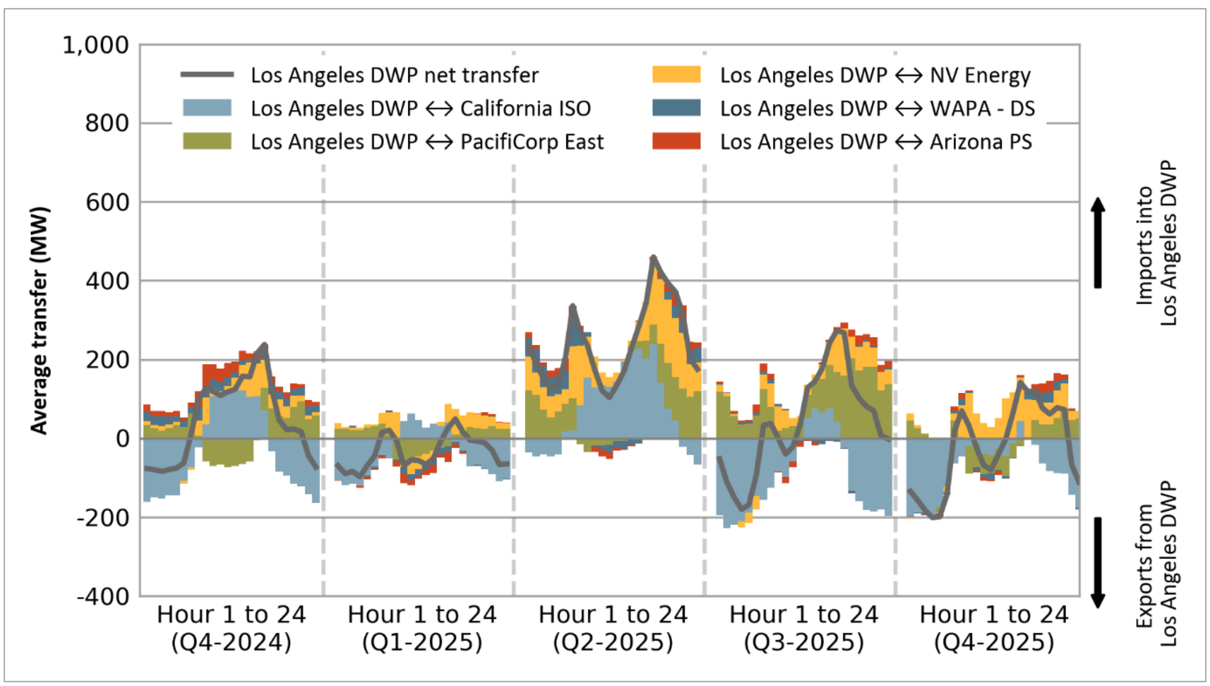
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q4 2025)

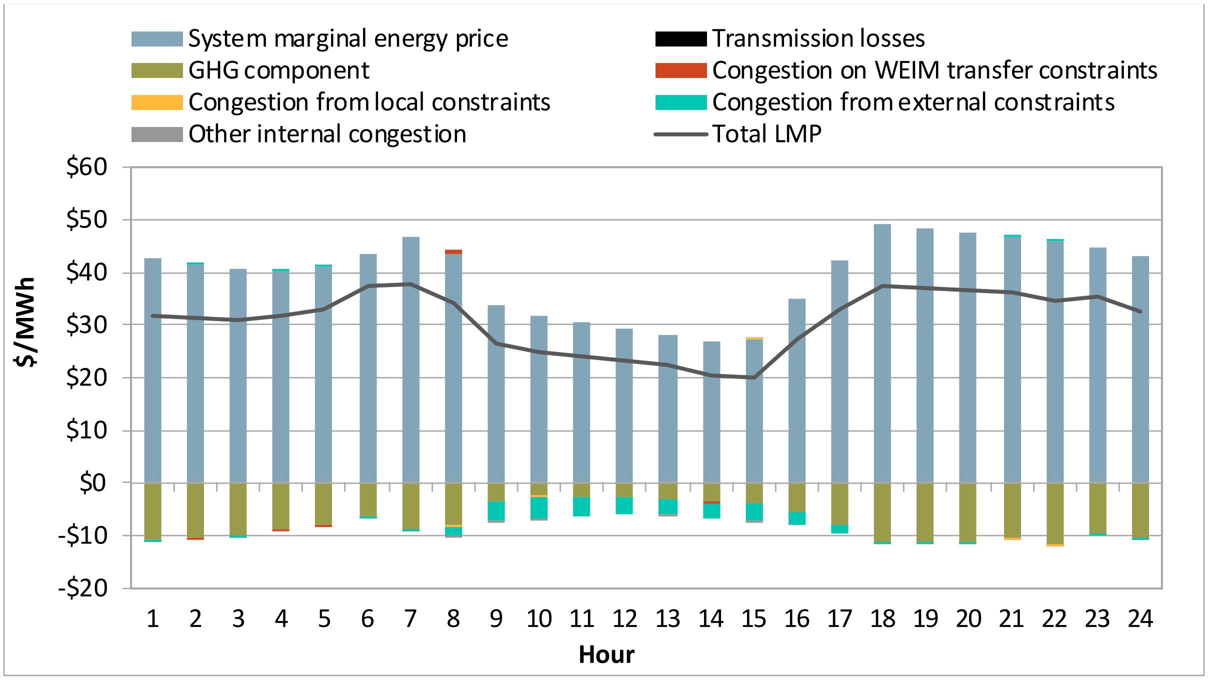


Appendix Figure A.40 Average hourly 5-minute market transfers

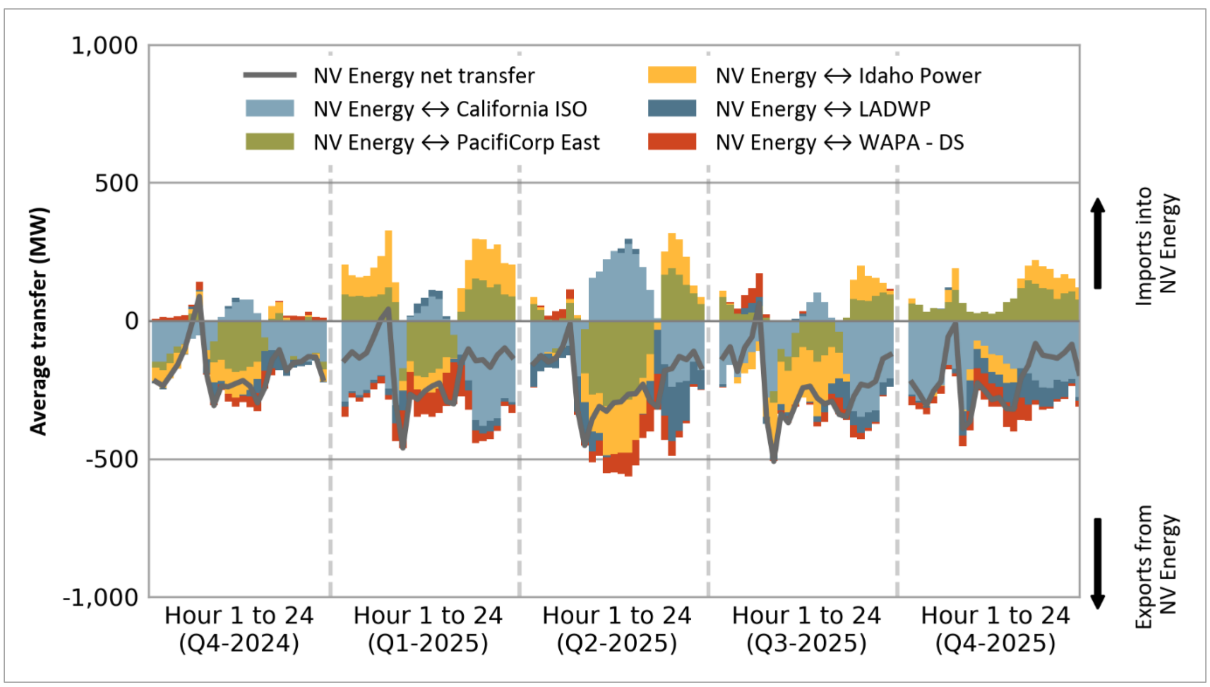


A.10 NV Energy

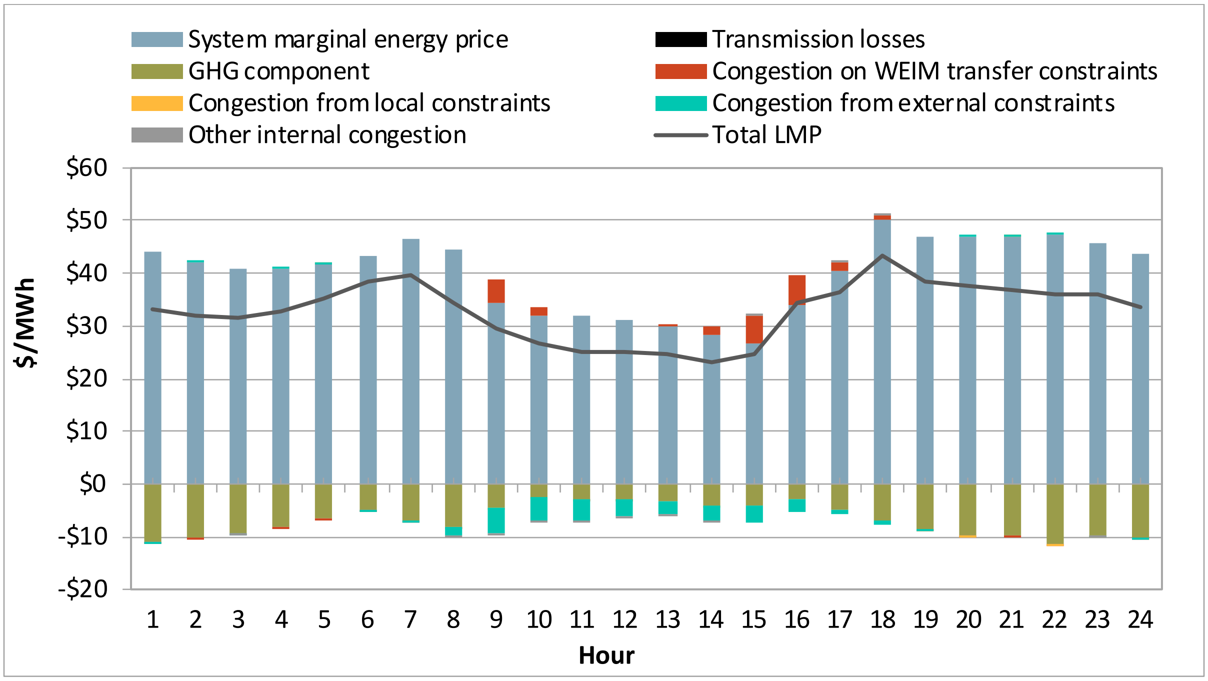
Appendix Figure A.41 Average hourly 15-minute price by component (Q4 2025)



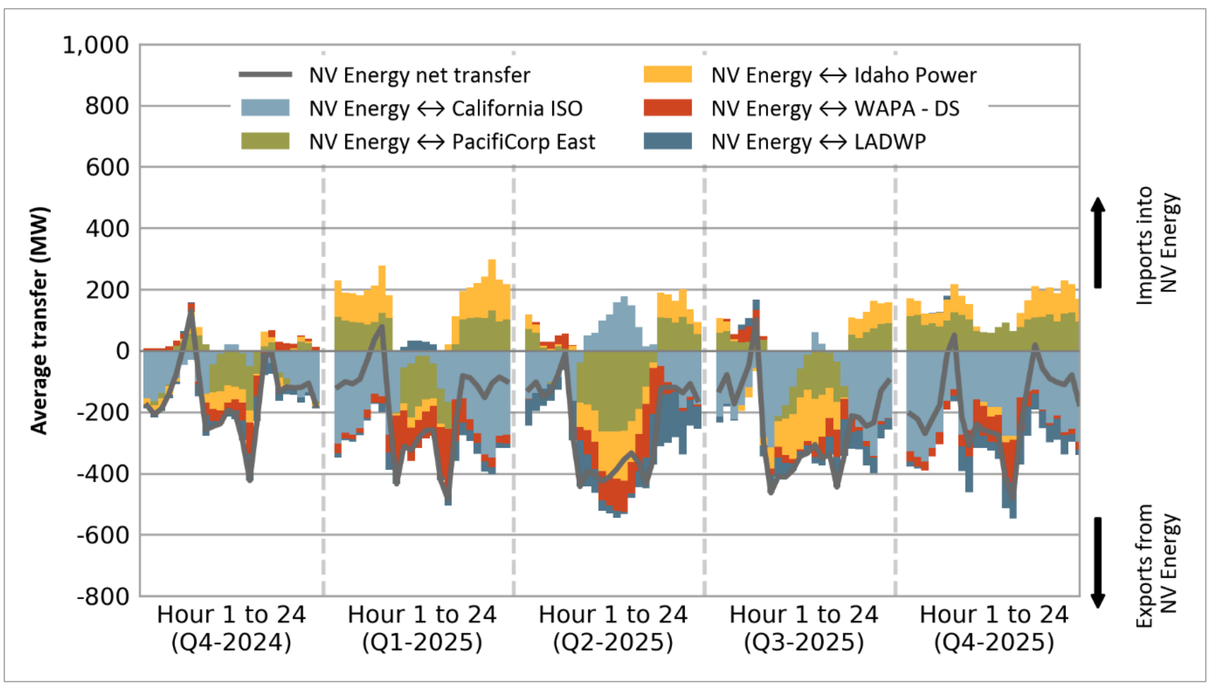
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q4 2025)

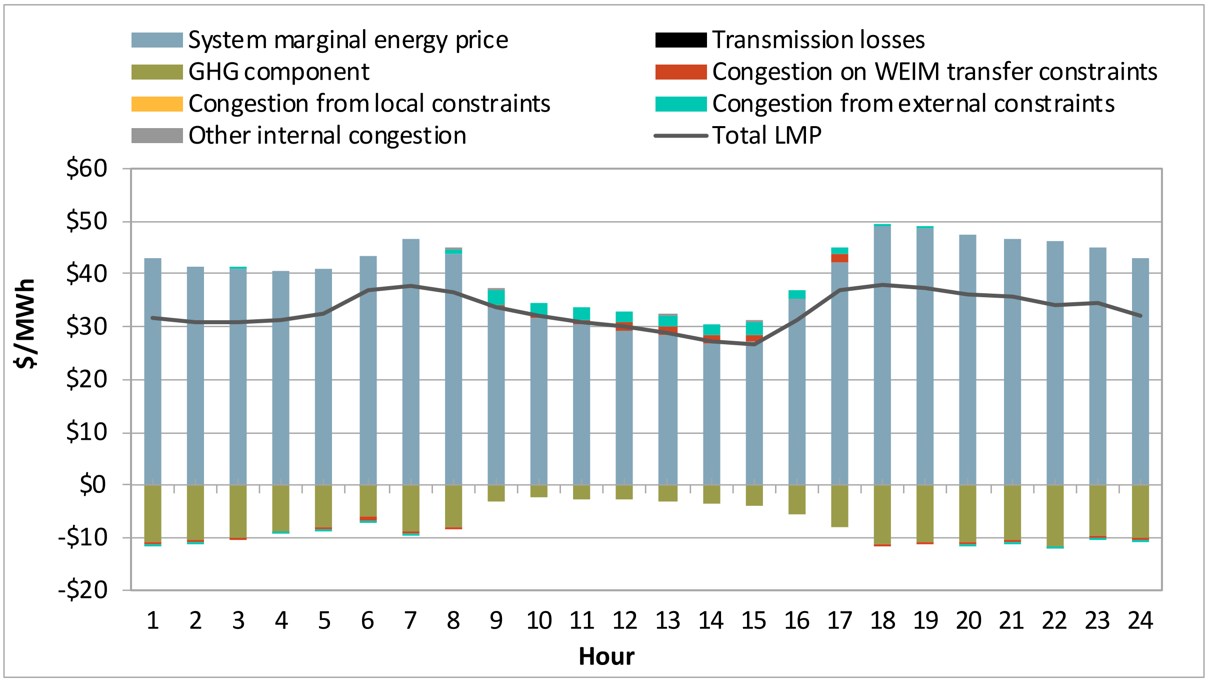


Appendix Figure A.44 Average hourly 5-minute market transfers

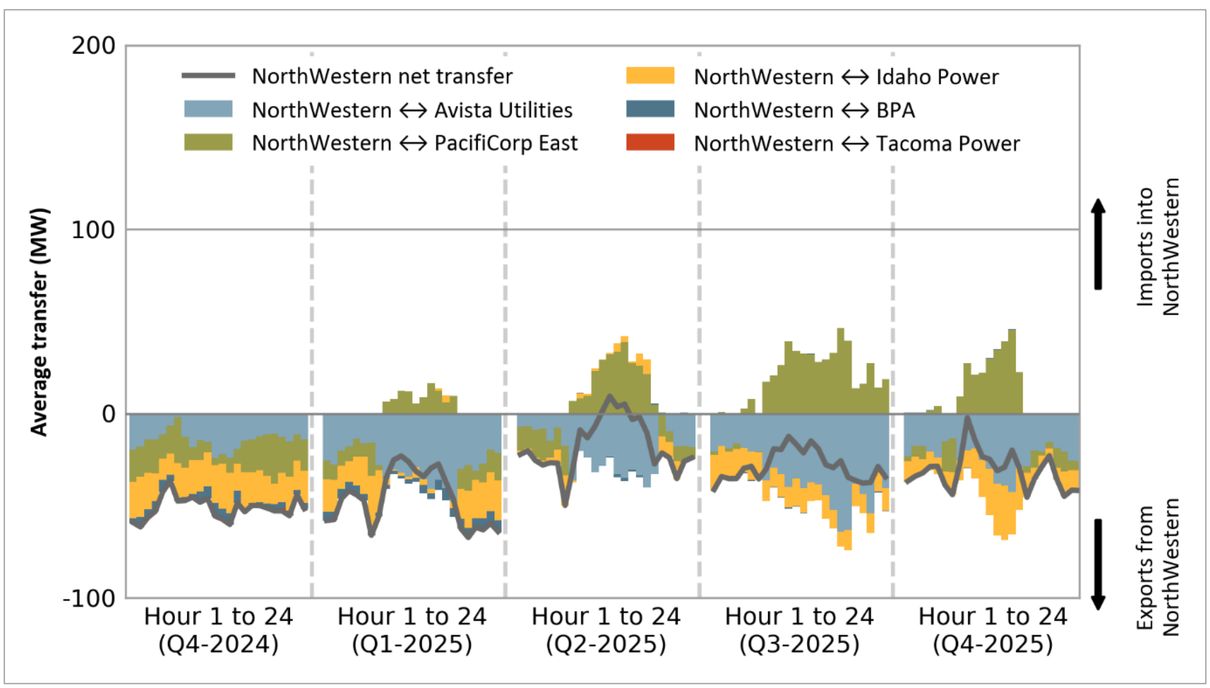


A.11 NorthWestern Energy

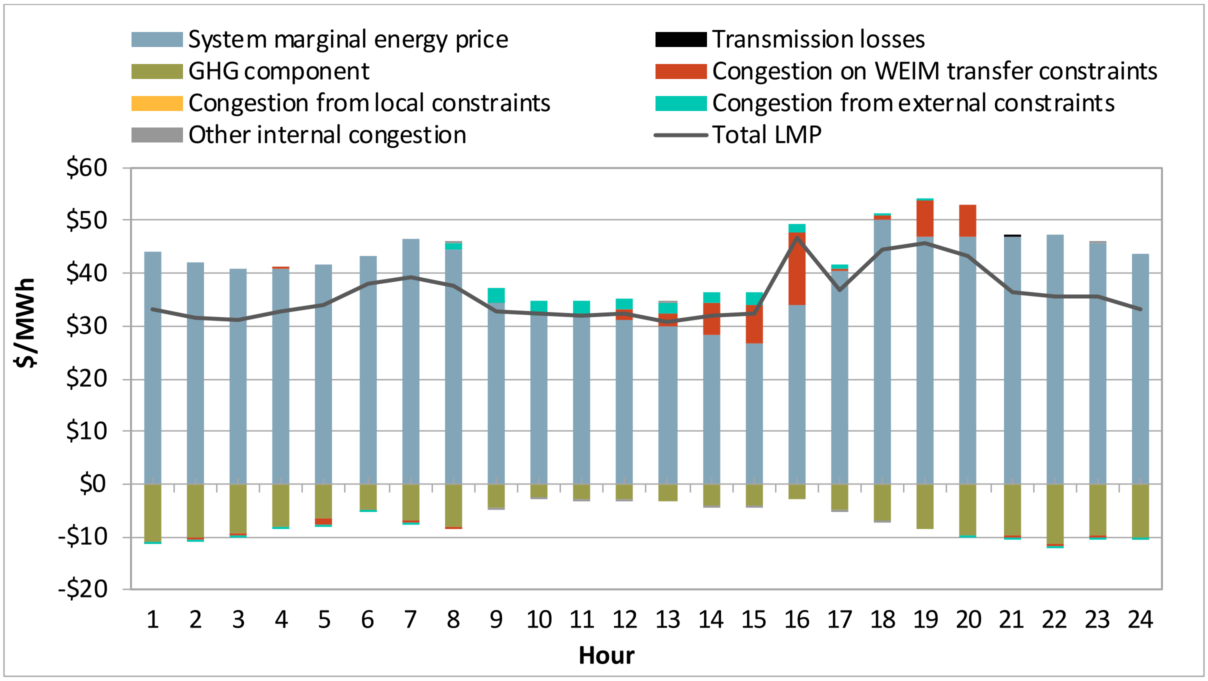
Appendix Figure A.45 Average hourly 15-minute price by component (Q4 2025)



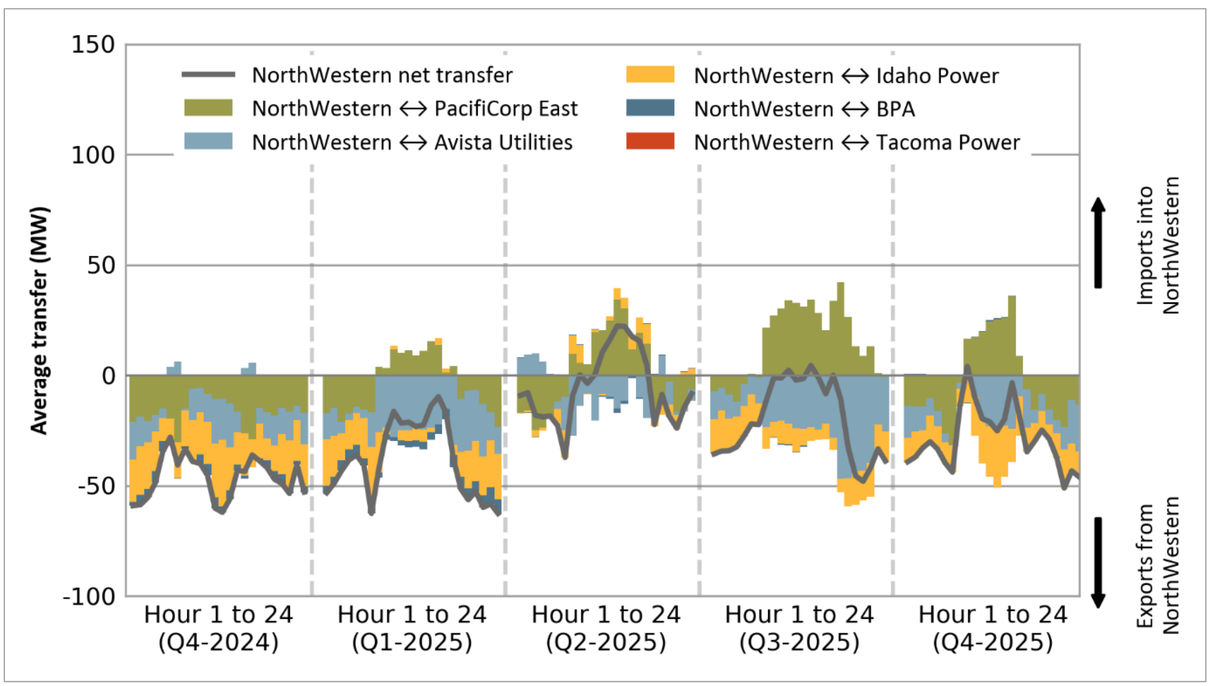
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q4 2025)

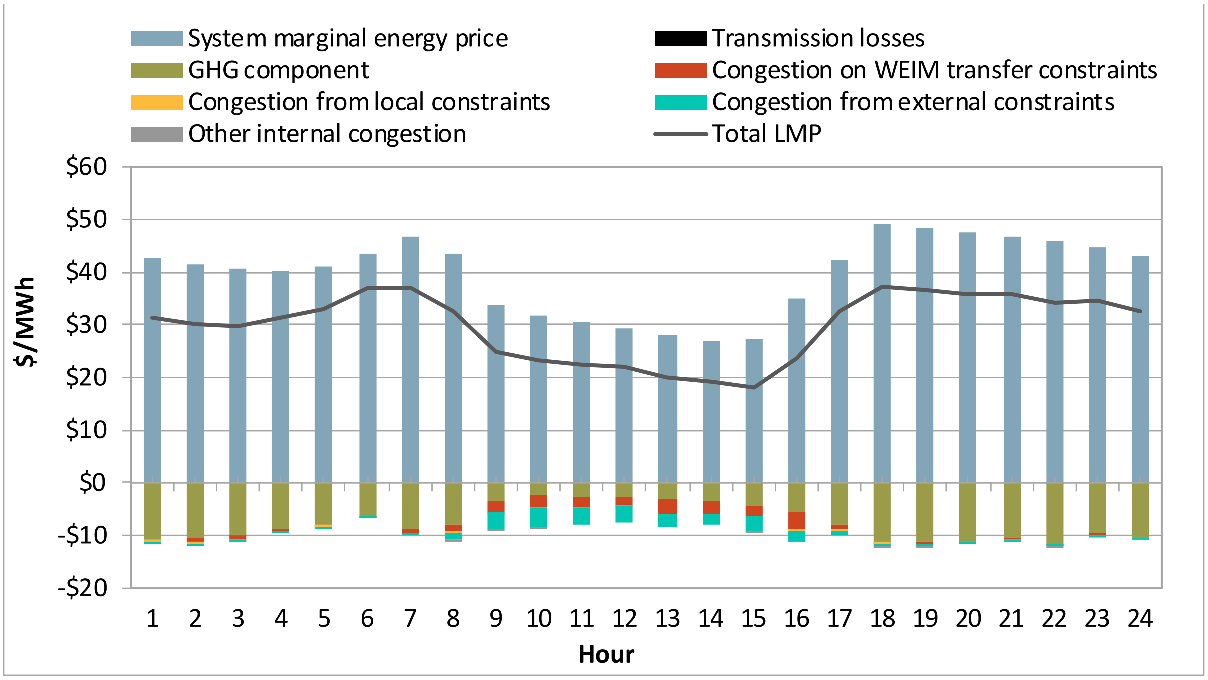


Appendix Figure A.48 Average hourly 5-minute market transfers

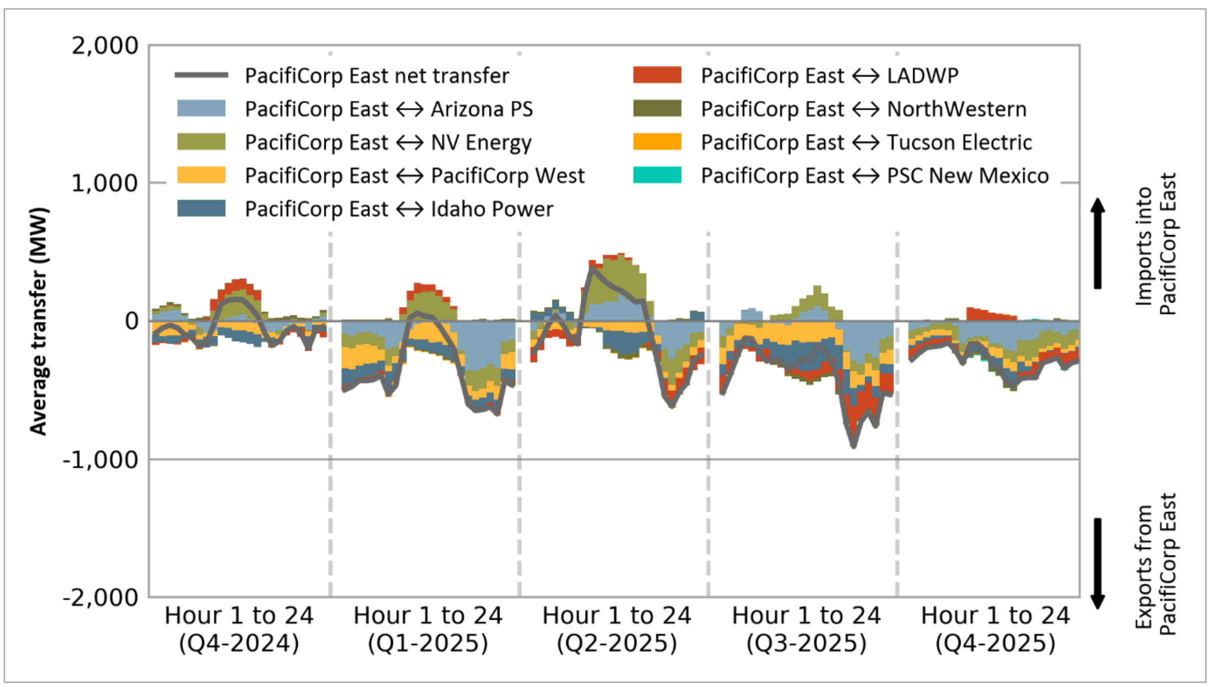


A.12 PacifiCorp East

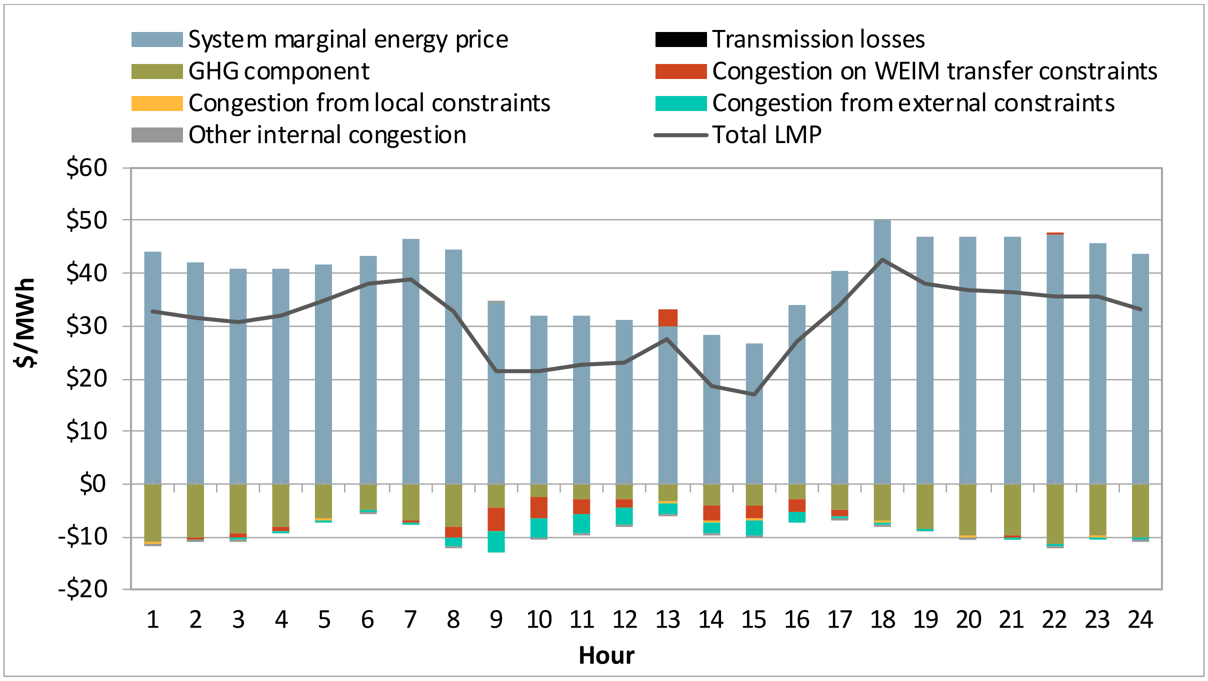
Appendix Figure A.49 Average hourly 15-minute price by component (Q4 2025)



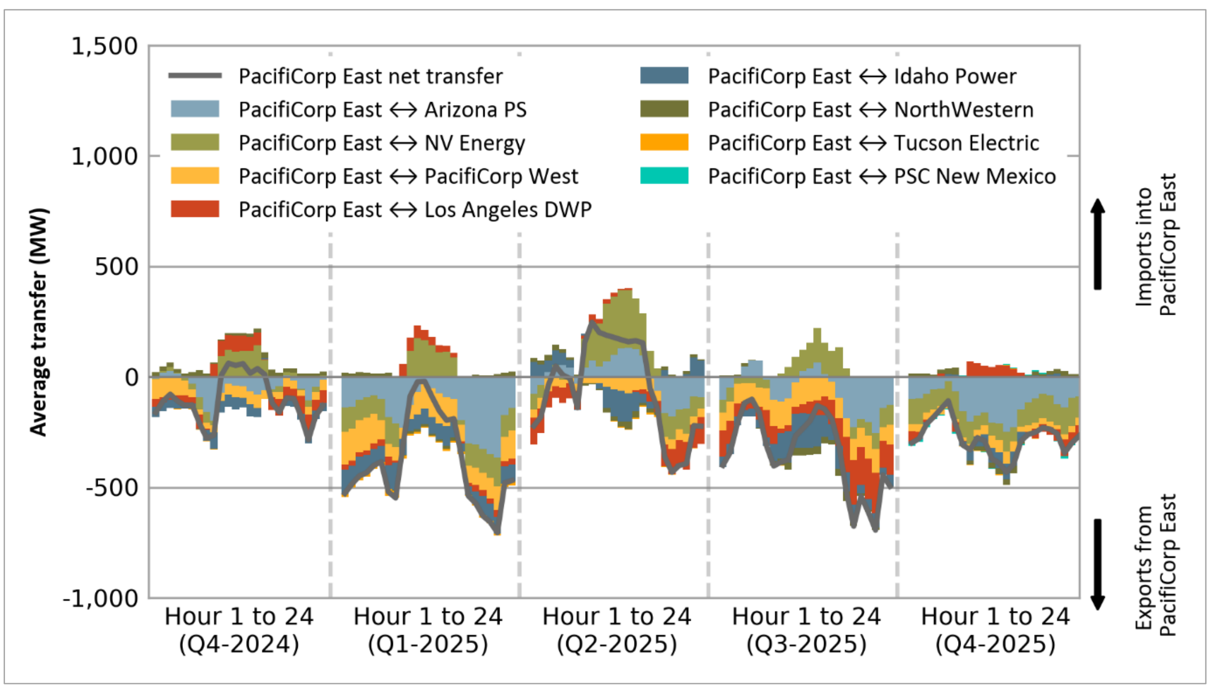
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q4 2025)

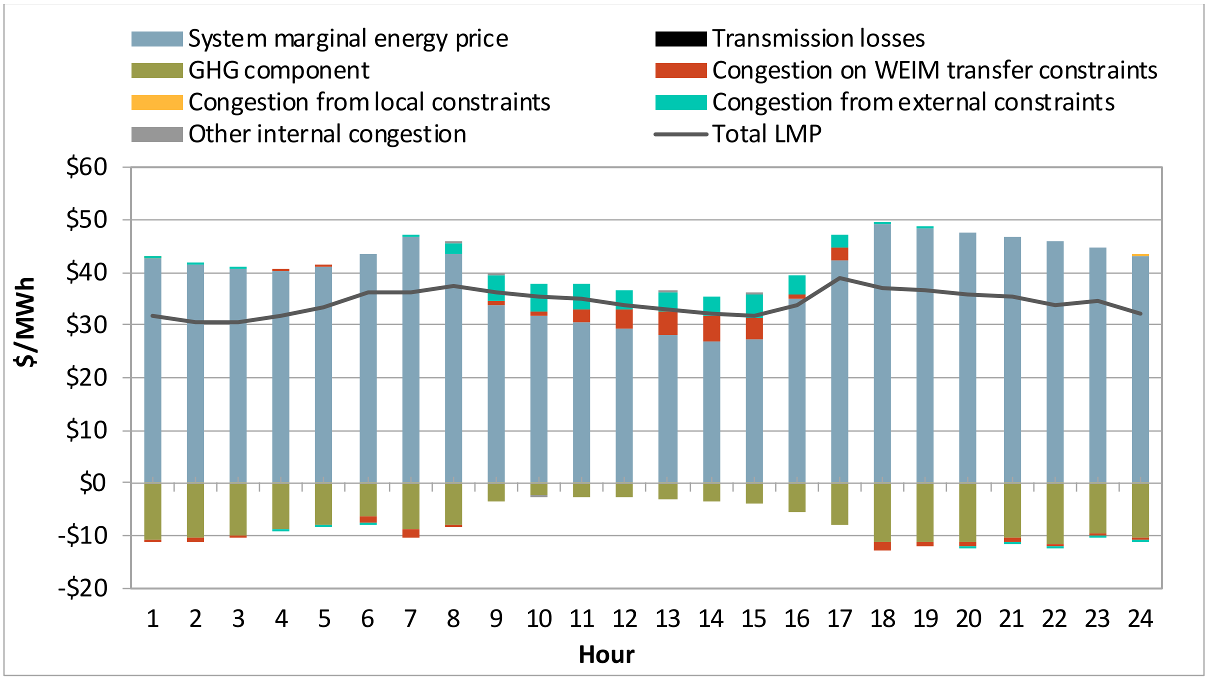


Appendix Figure A.52 Average hourly 5-minute market transfers

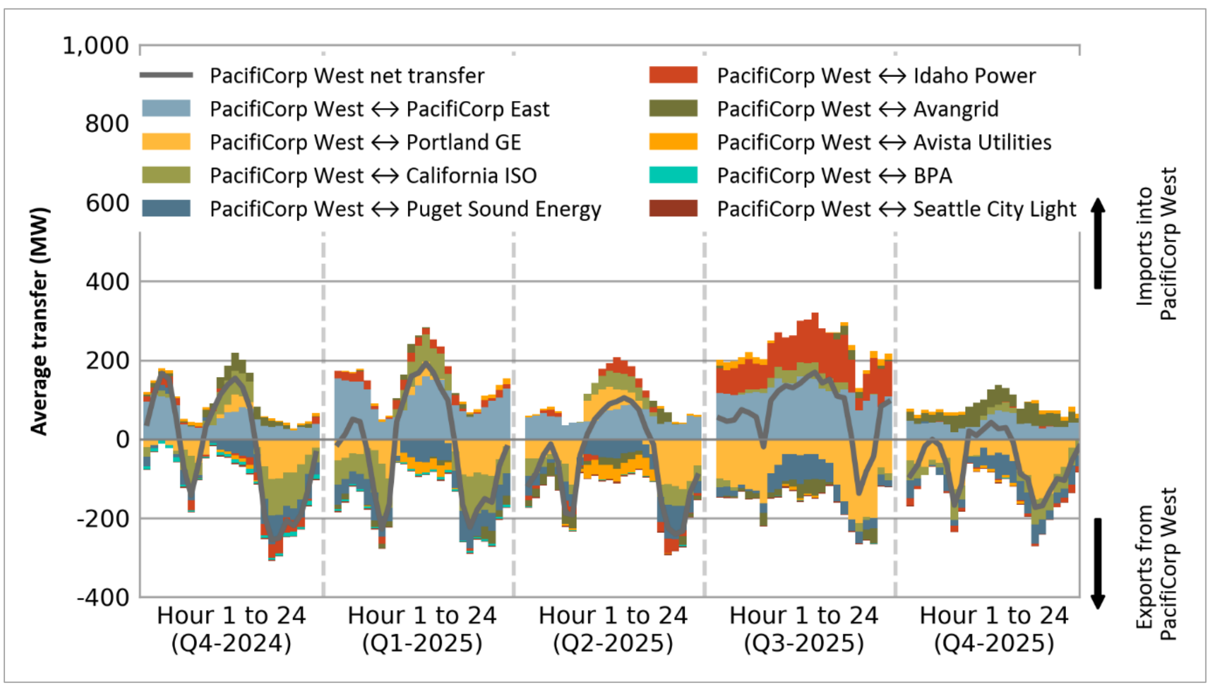


A.13 PacifiCorp West

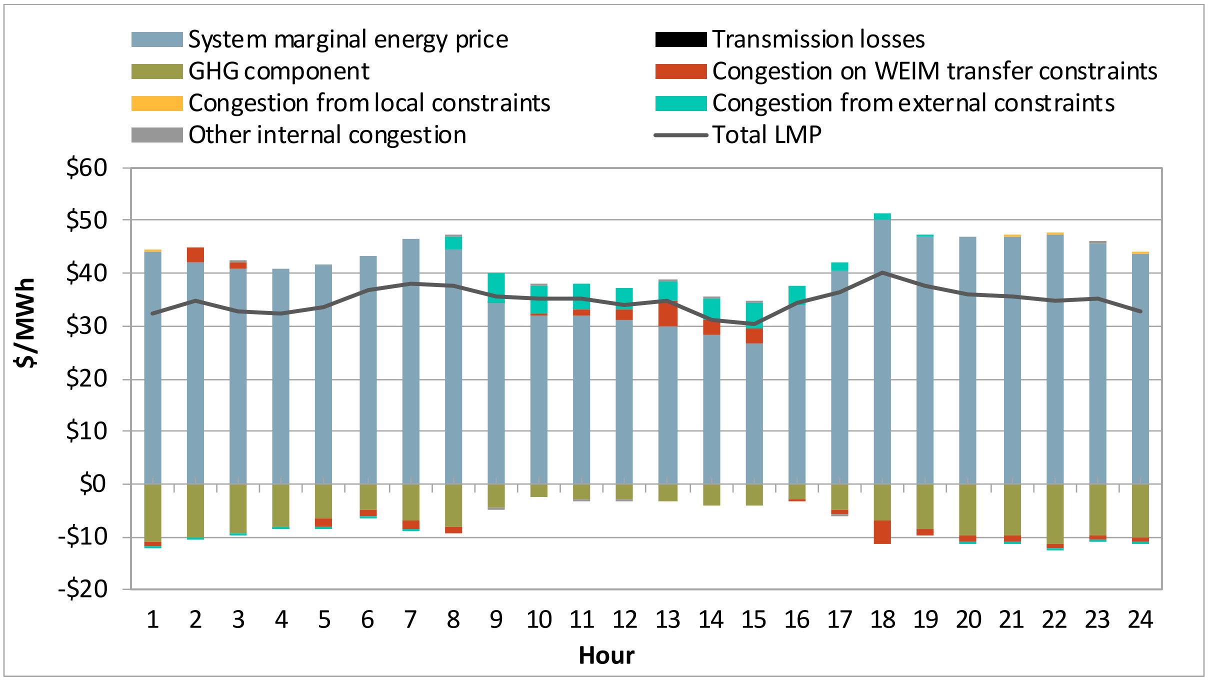
Appendix Figure A.53 Average hourly 15-minute price by component (Q4 2025)



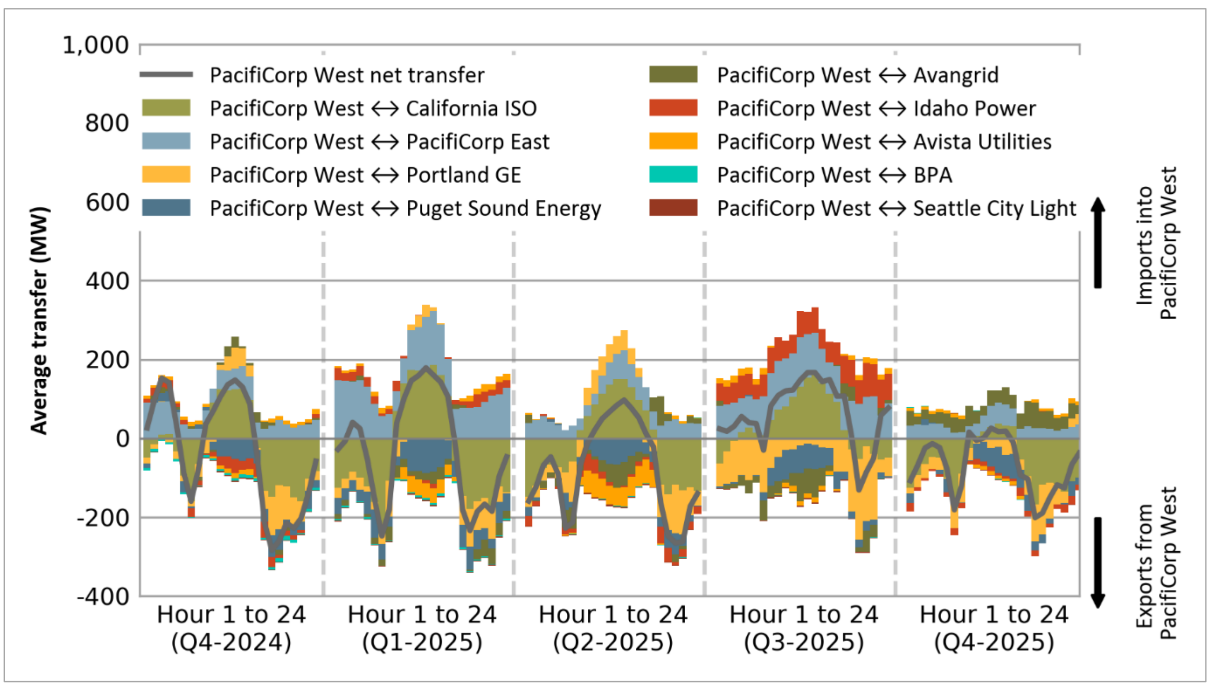
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q4 2025)

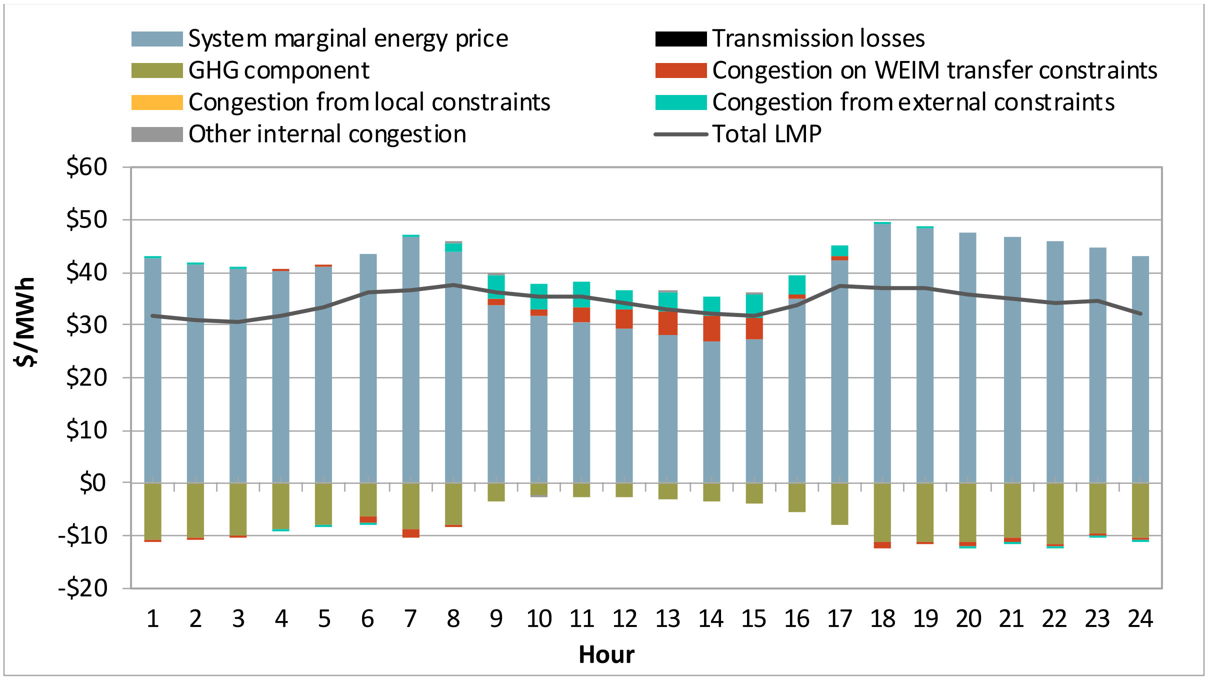


Appendix Figure A.56 Average hourly 5-minute market transfers

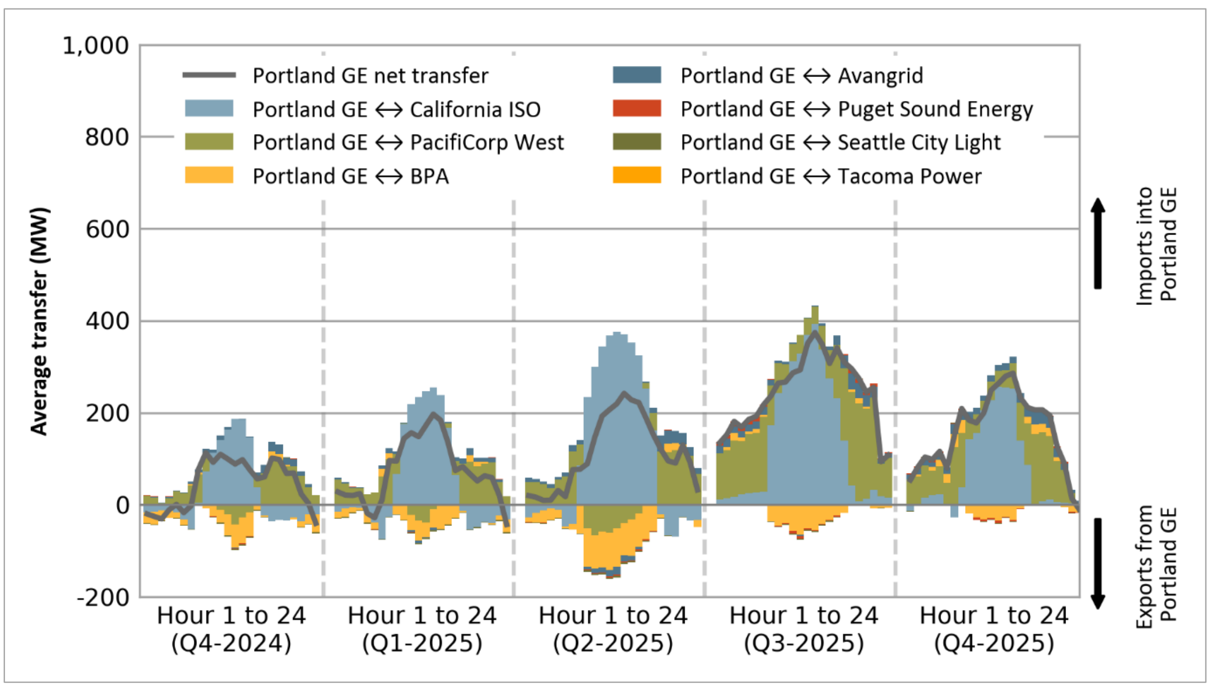


A.14 Portland General Electric

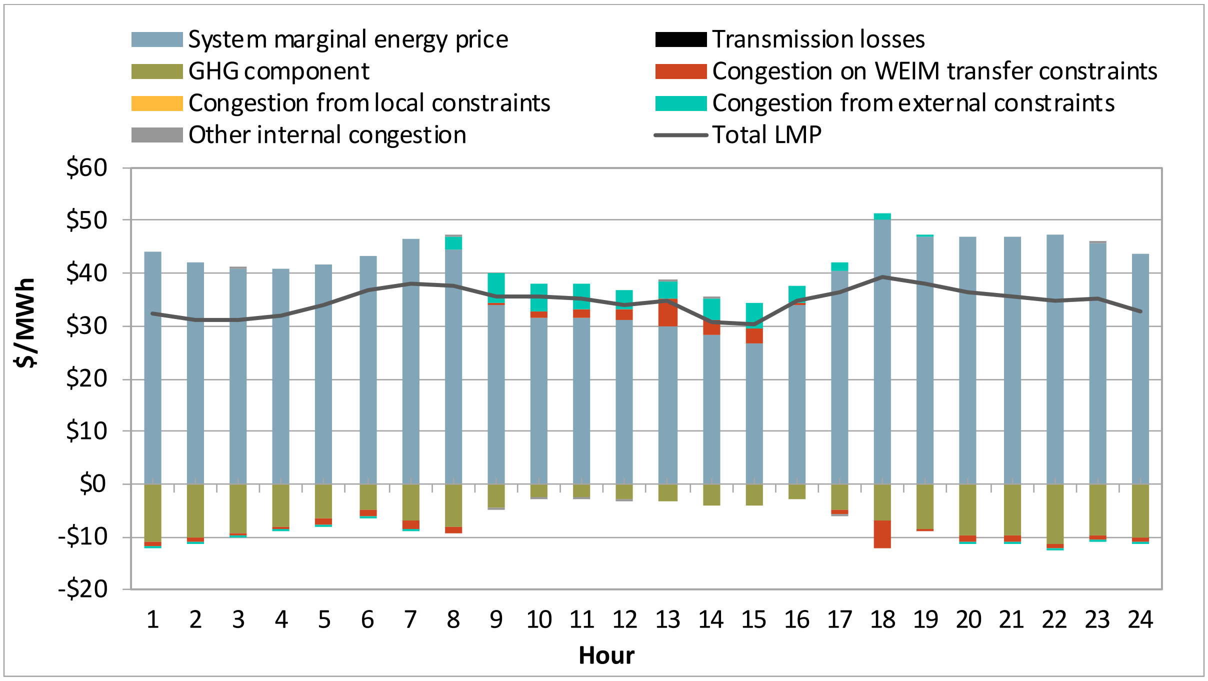
Appendix Figure A.57 Average hourly 15-minute price by component (Q4 2025)



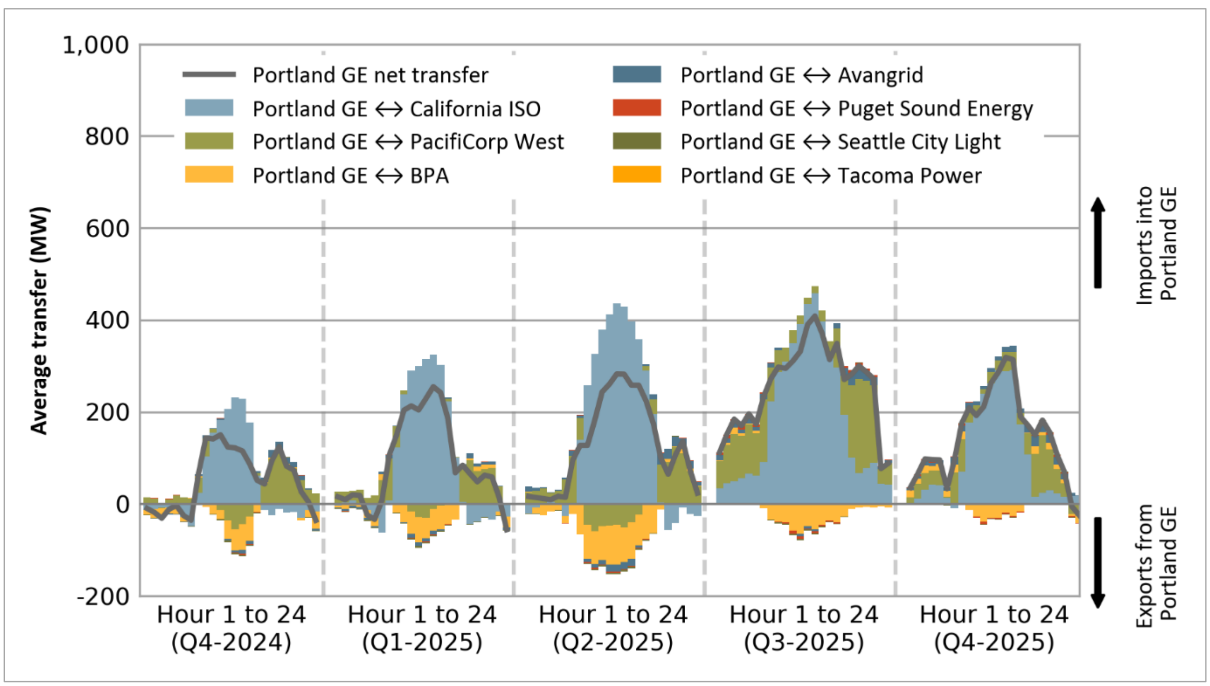
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q4 2025)

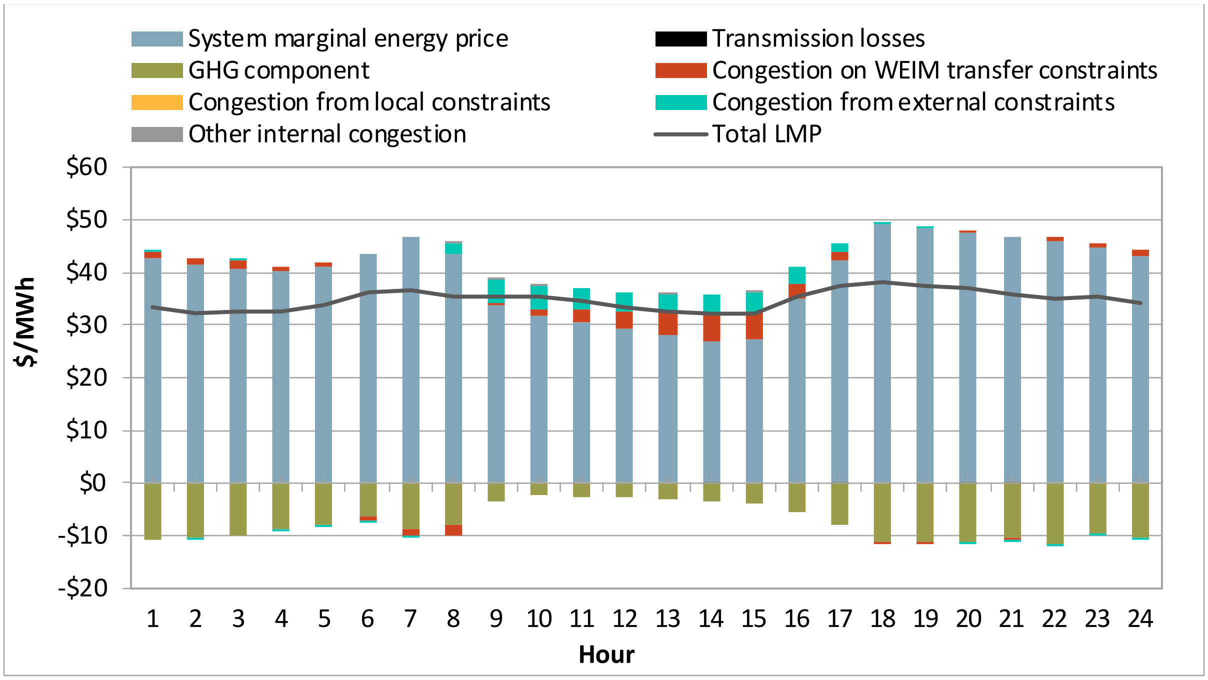


Appendix Figure A.60 Average hourly 5-minute market transfers

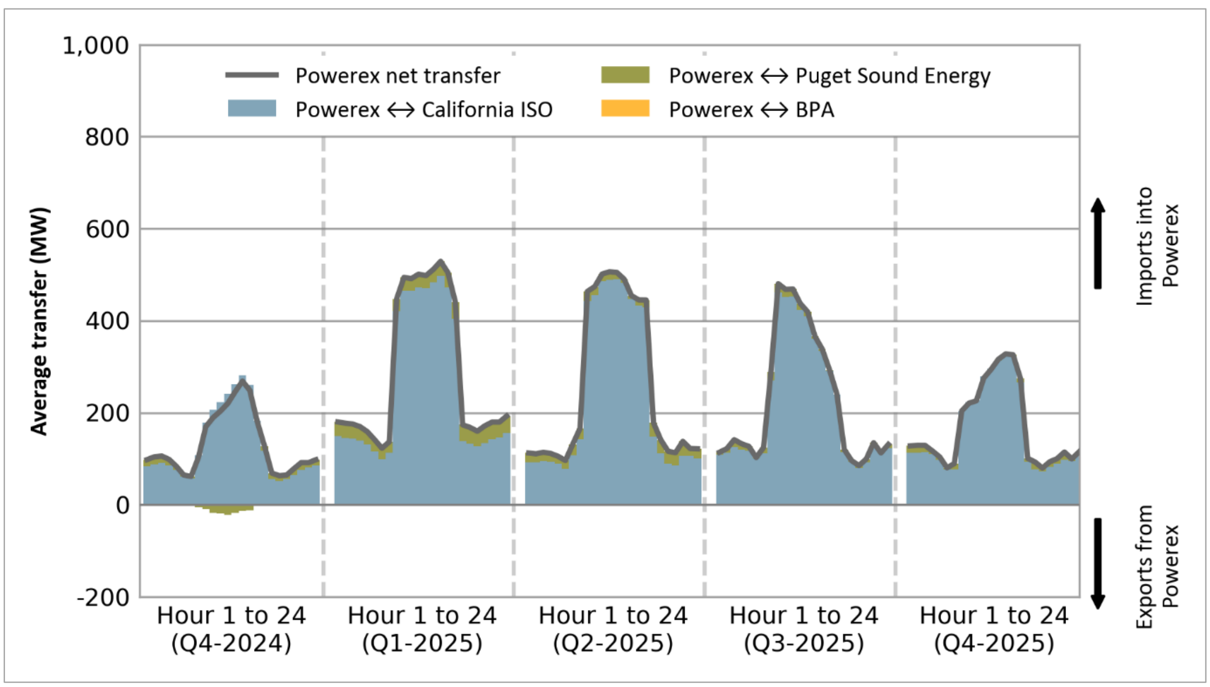


A.15 Powerex

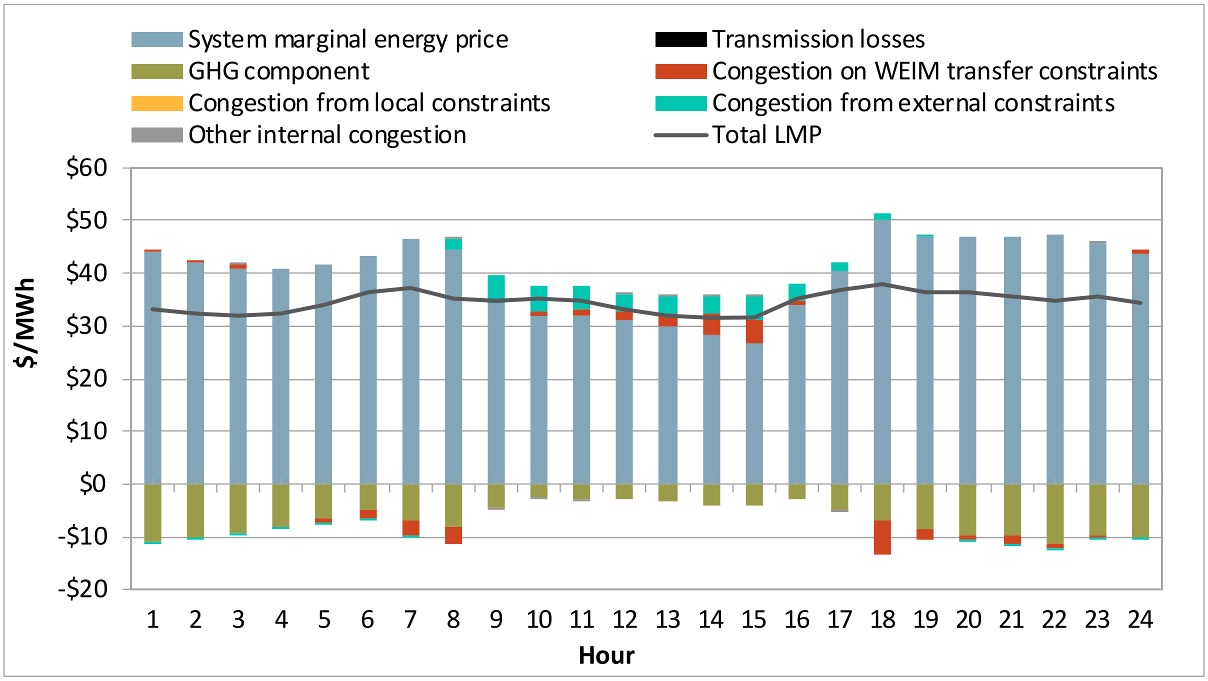
Appendix Figure A.61 Average hourly 15-minute price by component (Q4 2025)



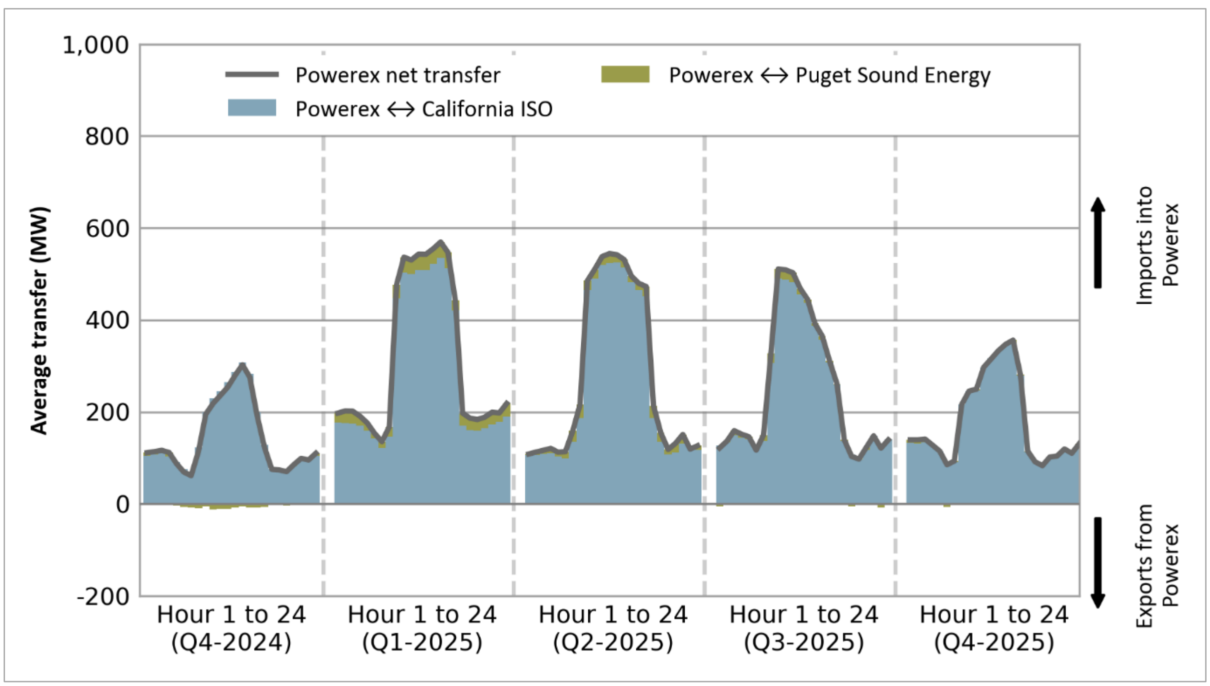
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q4 2025)

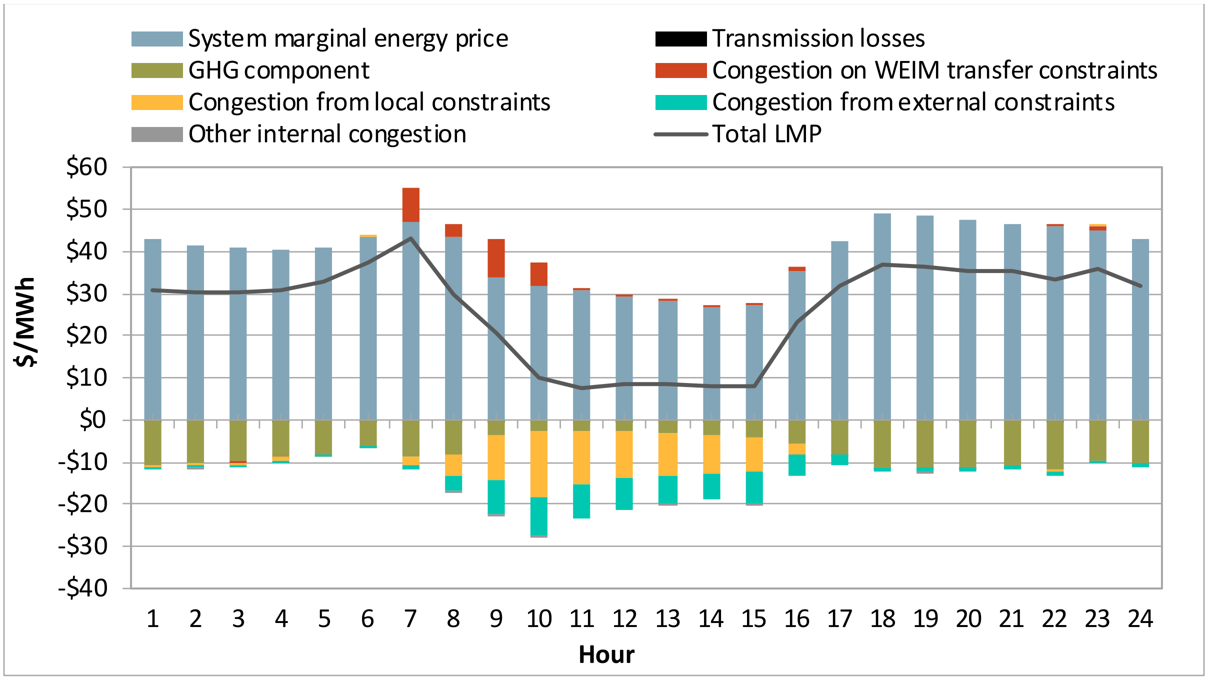


Appendix Figure A.64 Average hourly 5-minute market transfers

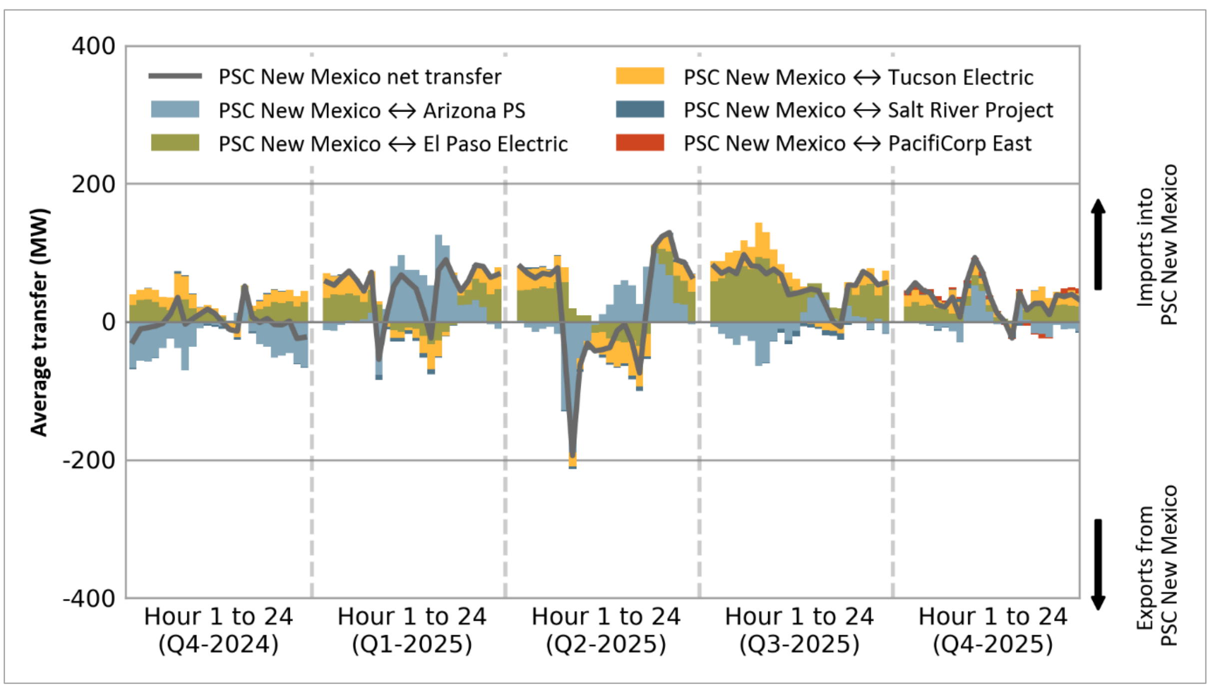


A.16 Public Service Company of New Mexico

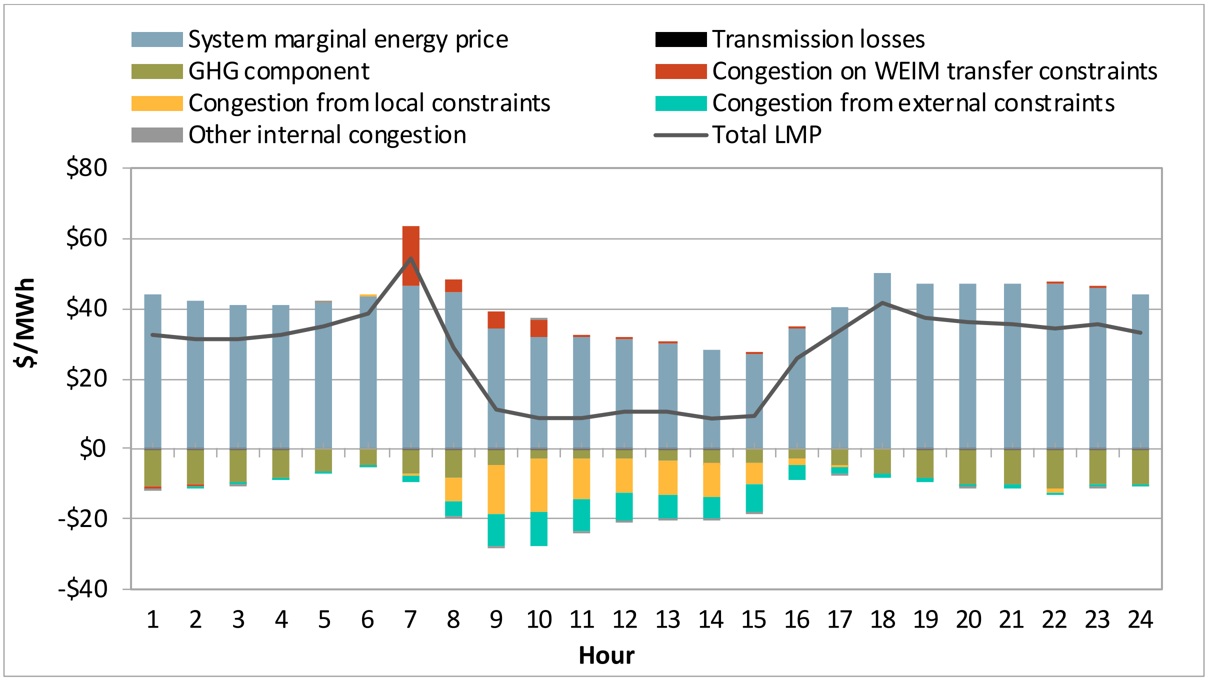
Appendix Figure A.65 Average hourly 15-minute price by component (Q4 2025)



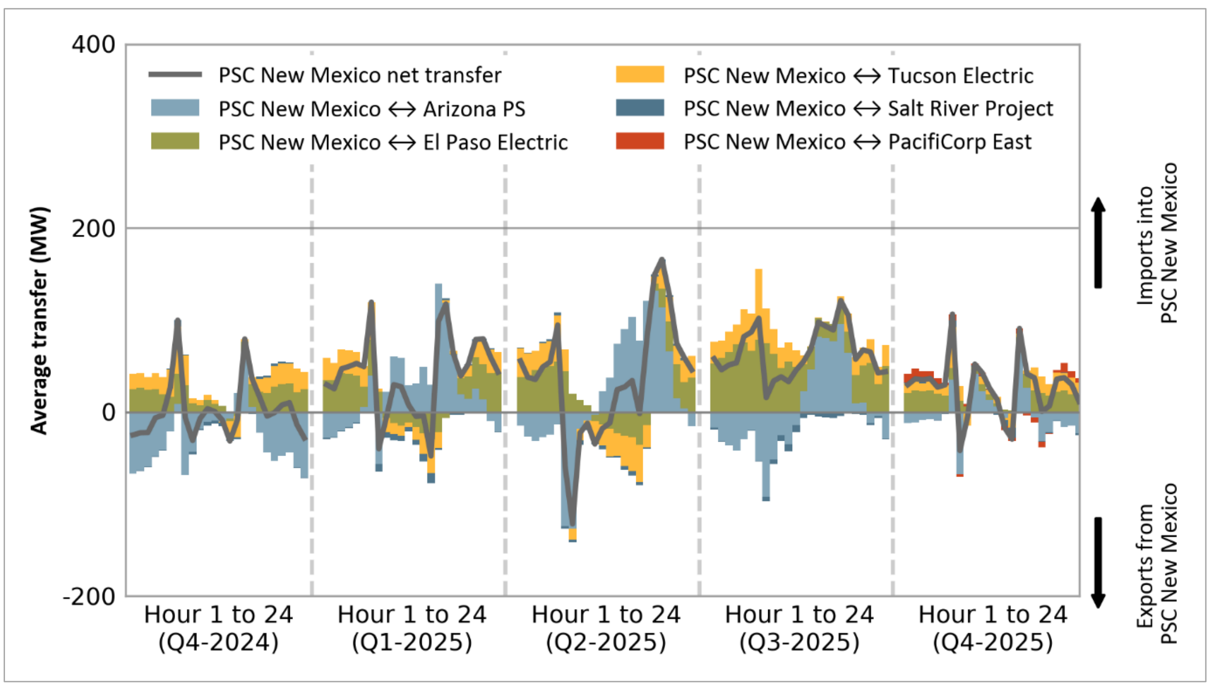
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q4 2025)

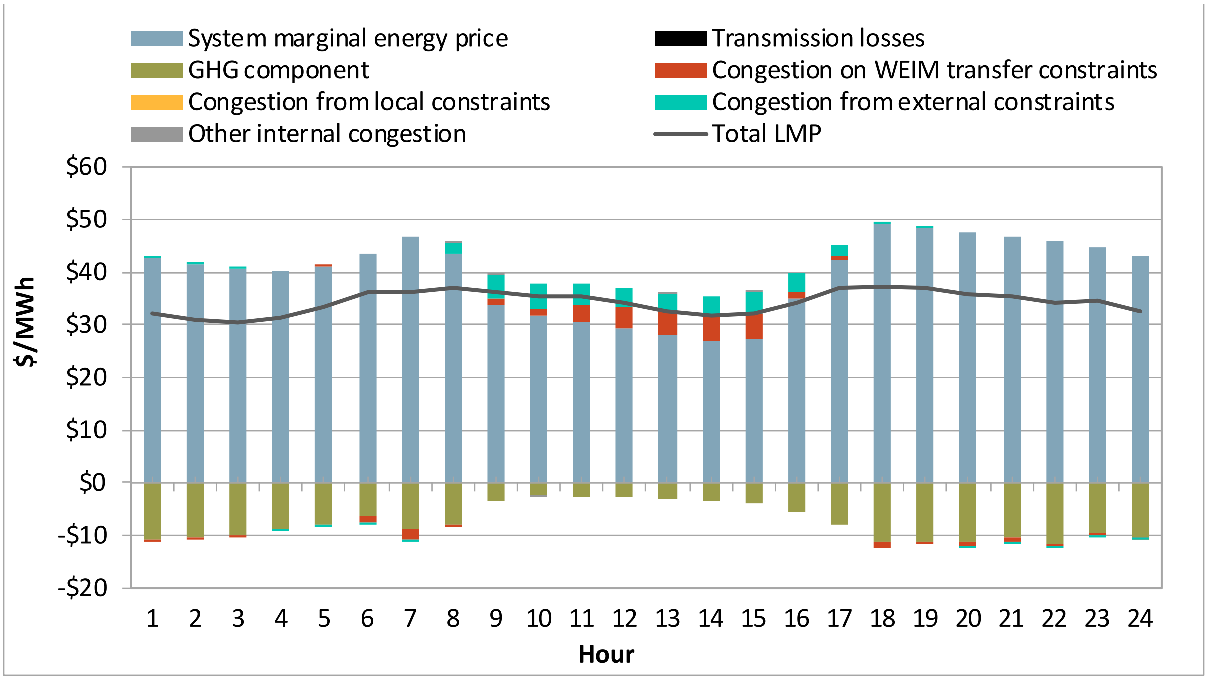


Appendix Figure A.68 Average hourly 5-minute market transfers

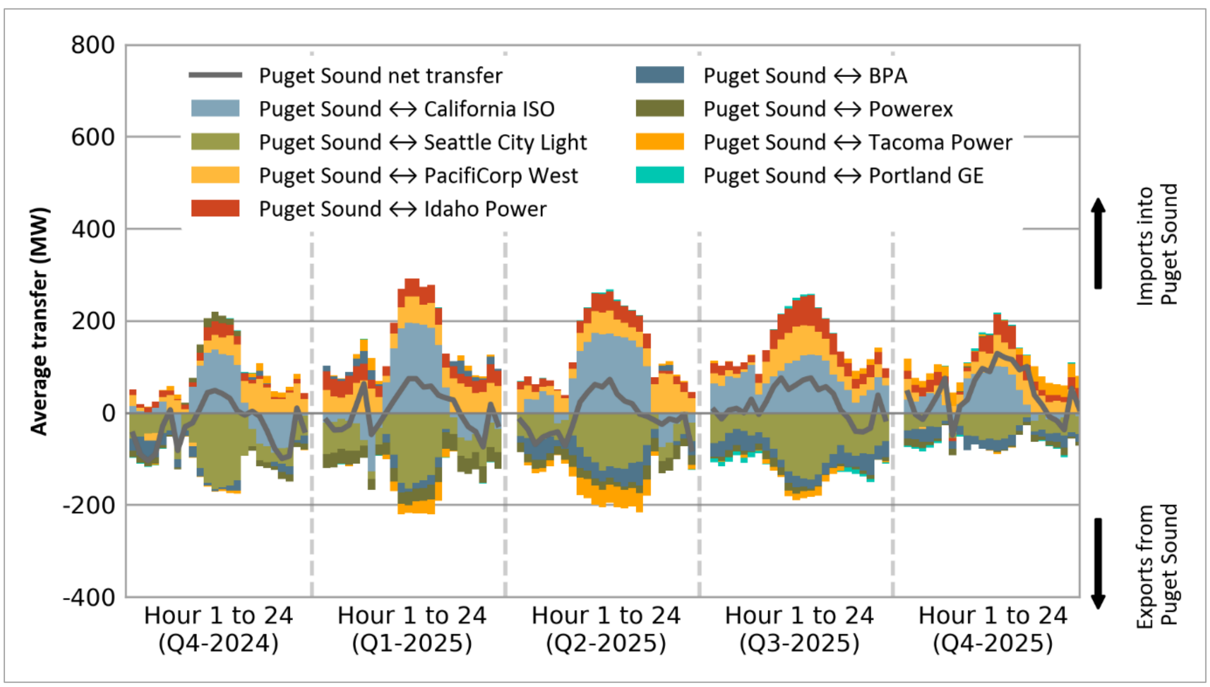


A.17 Puget Sound Energy

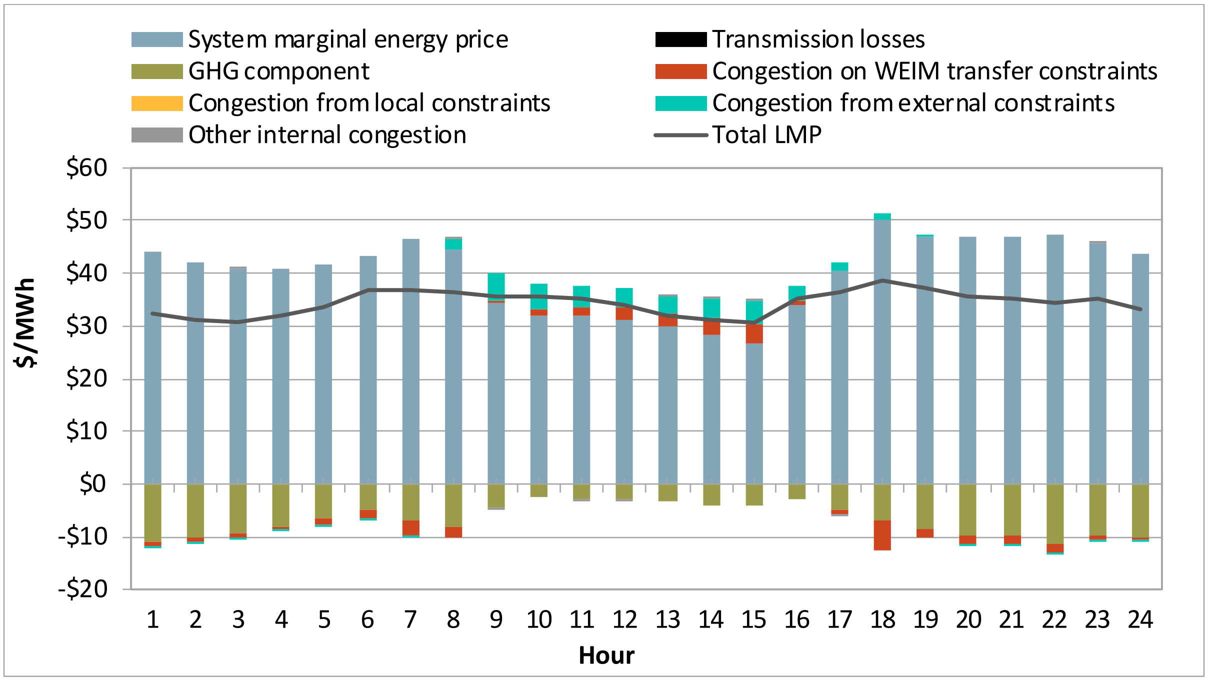
Appendix Figure A.69 Average hourly 15-minute price by component (Q4 2025)



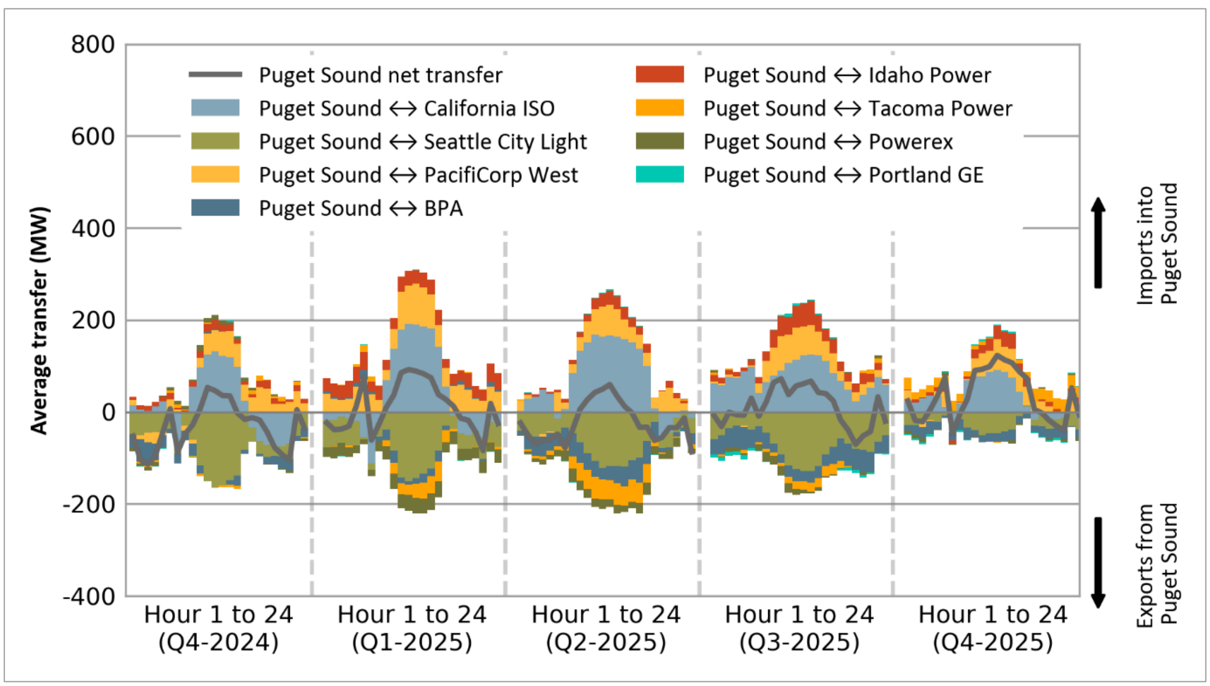
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q4 2025)

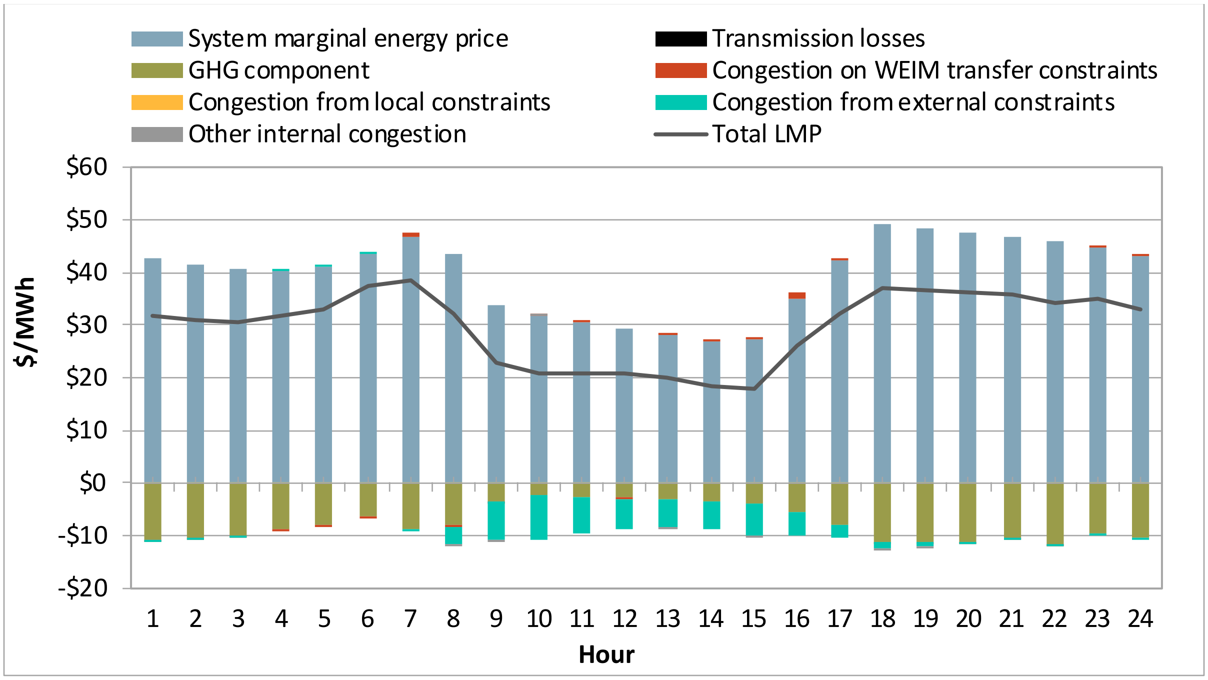


Appendix Figure A.72 Average hourly 5-minute market transfers

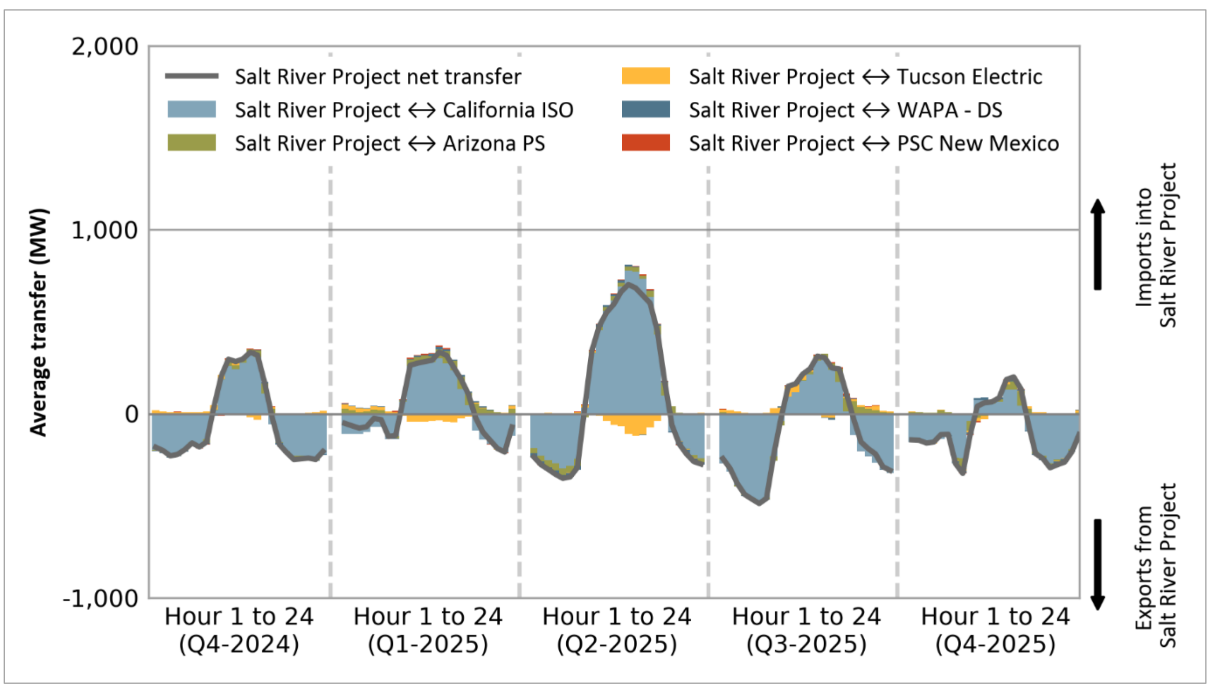


A.18 Salt River Project

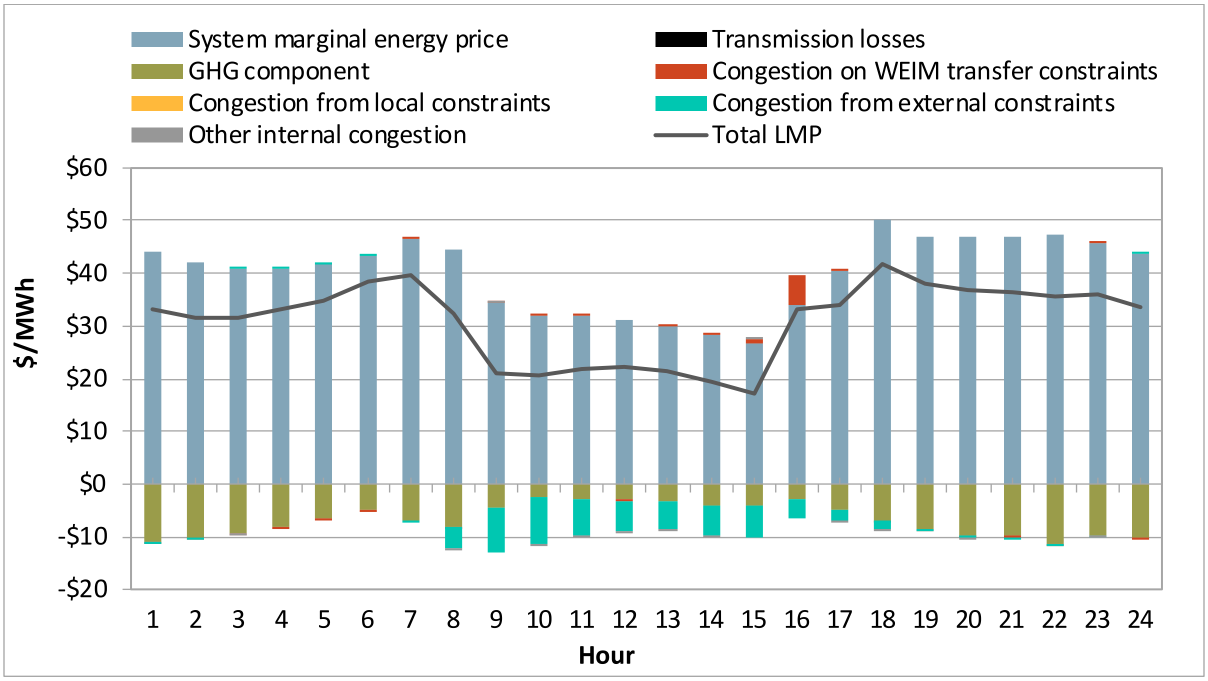
Appendix Figure A.73 Average hourly 15-minute price by component (Q4 2025)



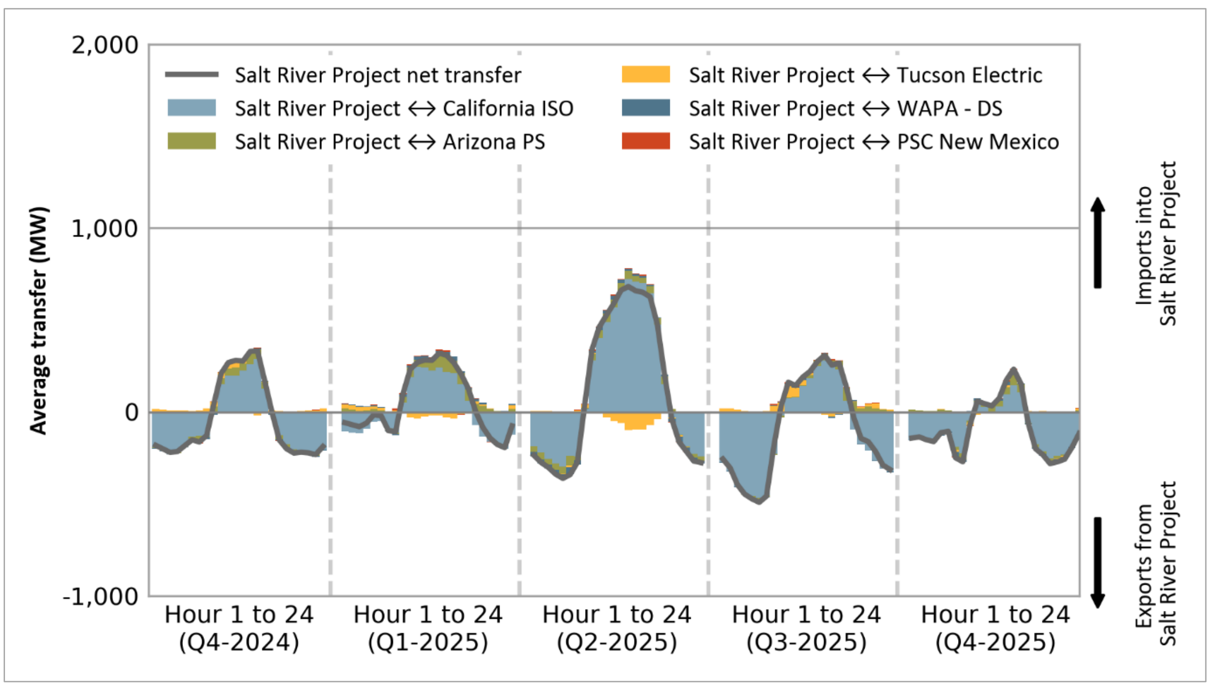
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q4 2025)

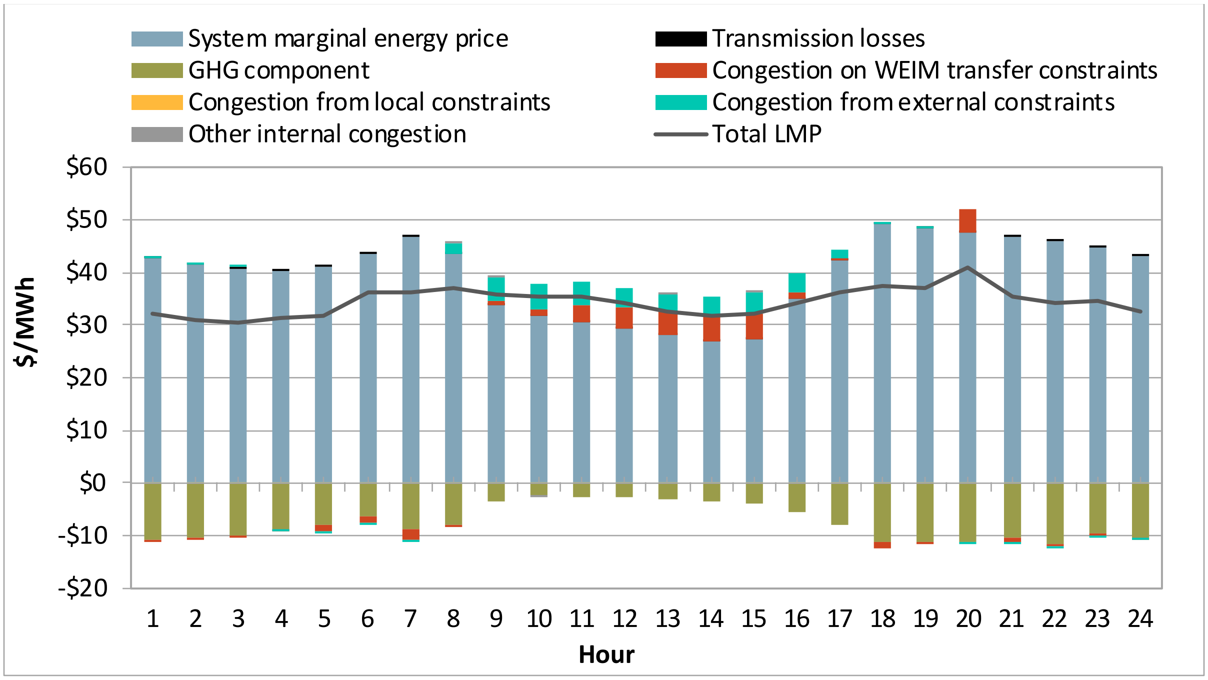


Appendix Figure A.76 Average hourly 5-minute market transfers

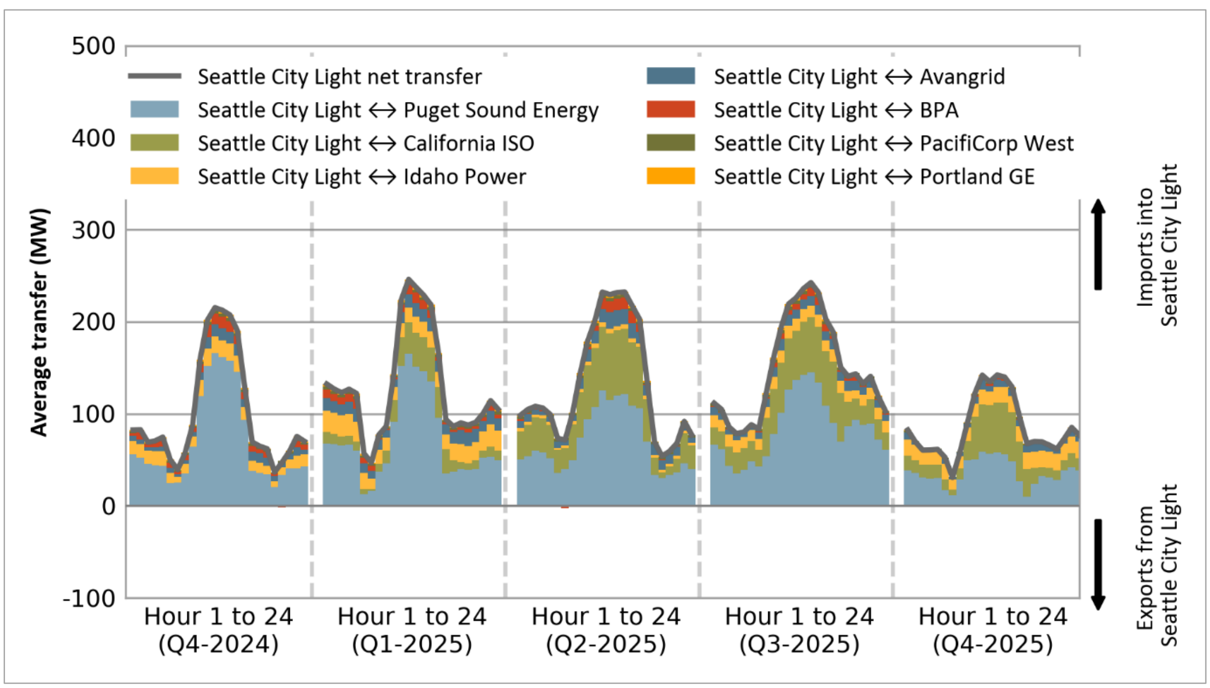


A.19 Seattle City Light

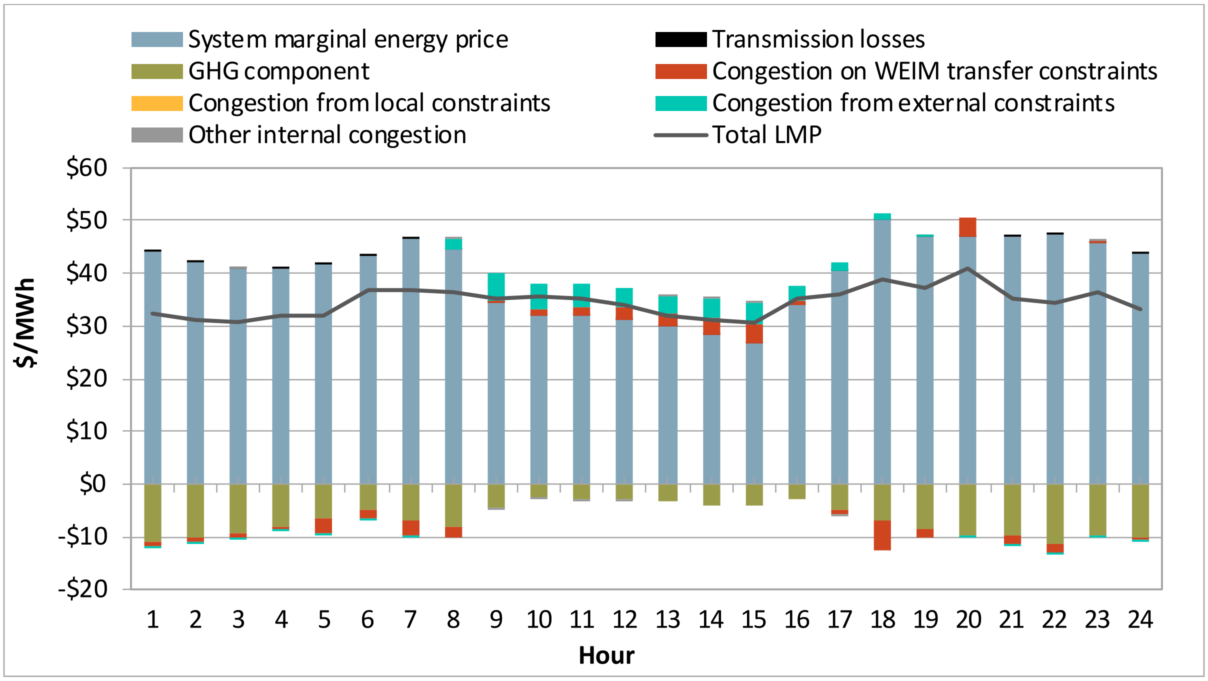
Appendix Figure A.77 Average hourly 15-minute price by component (Q4 2025)



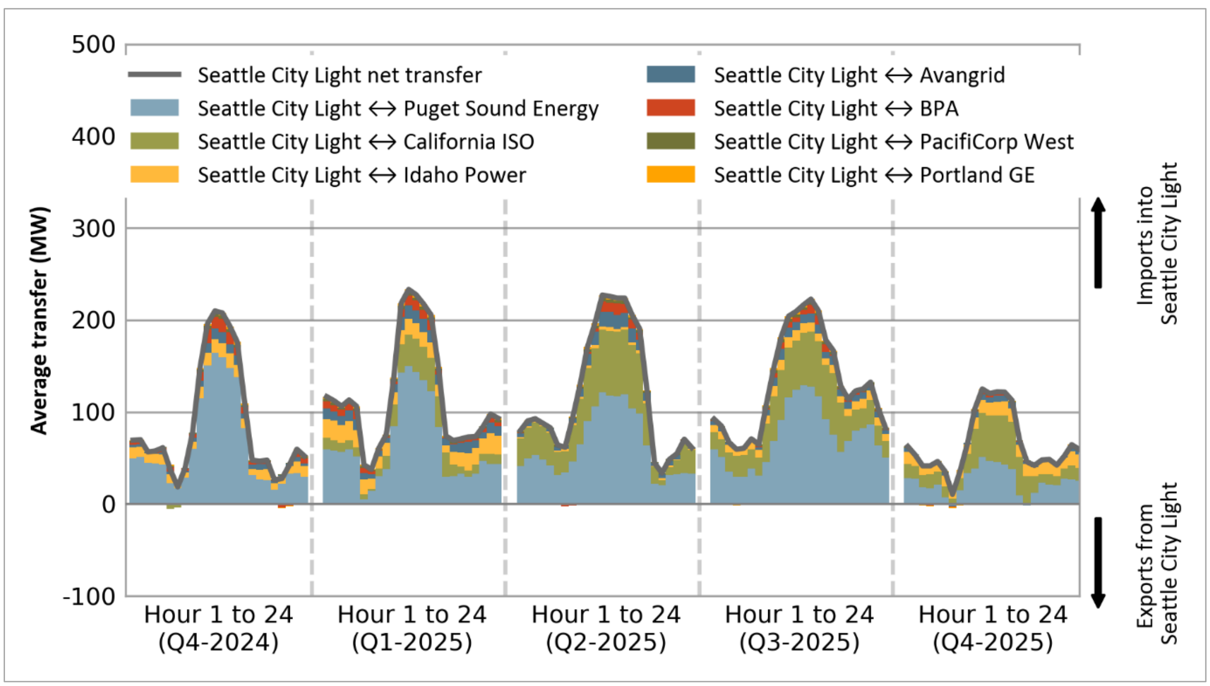
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q4 2025)

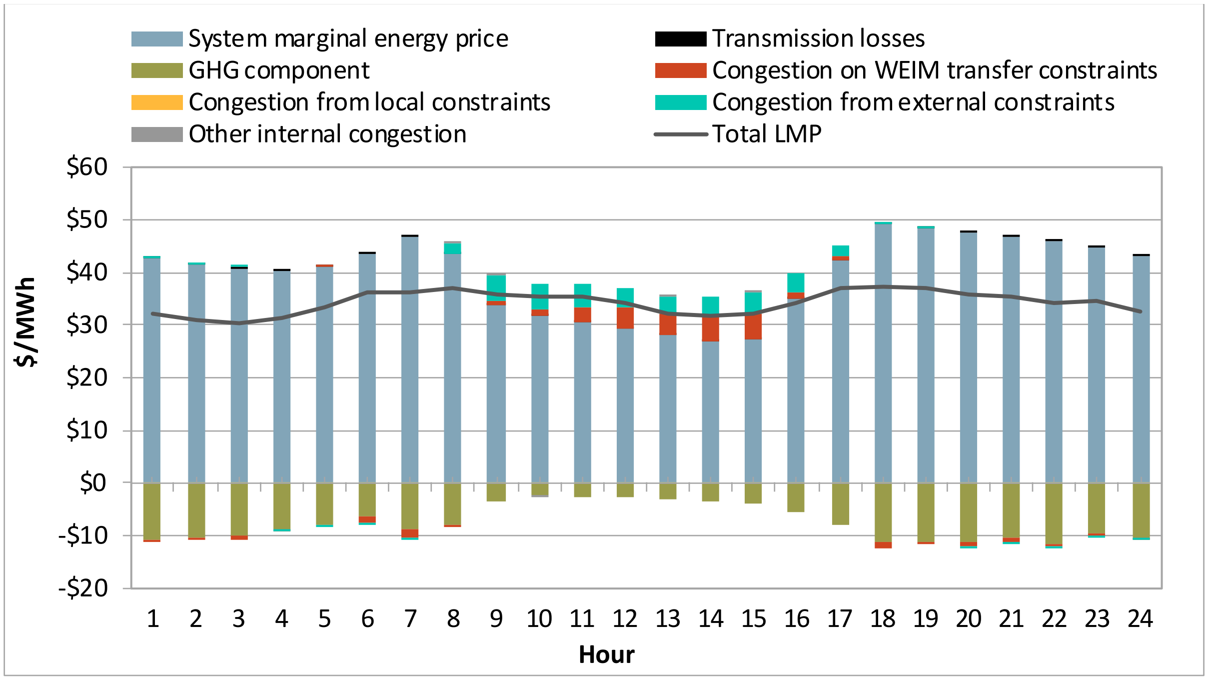


Appendix Figure A.80 Average hourly 5-minute market transfers

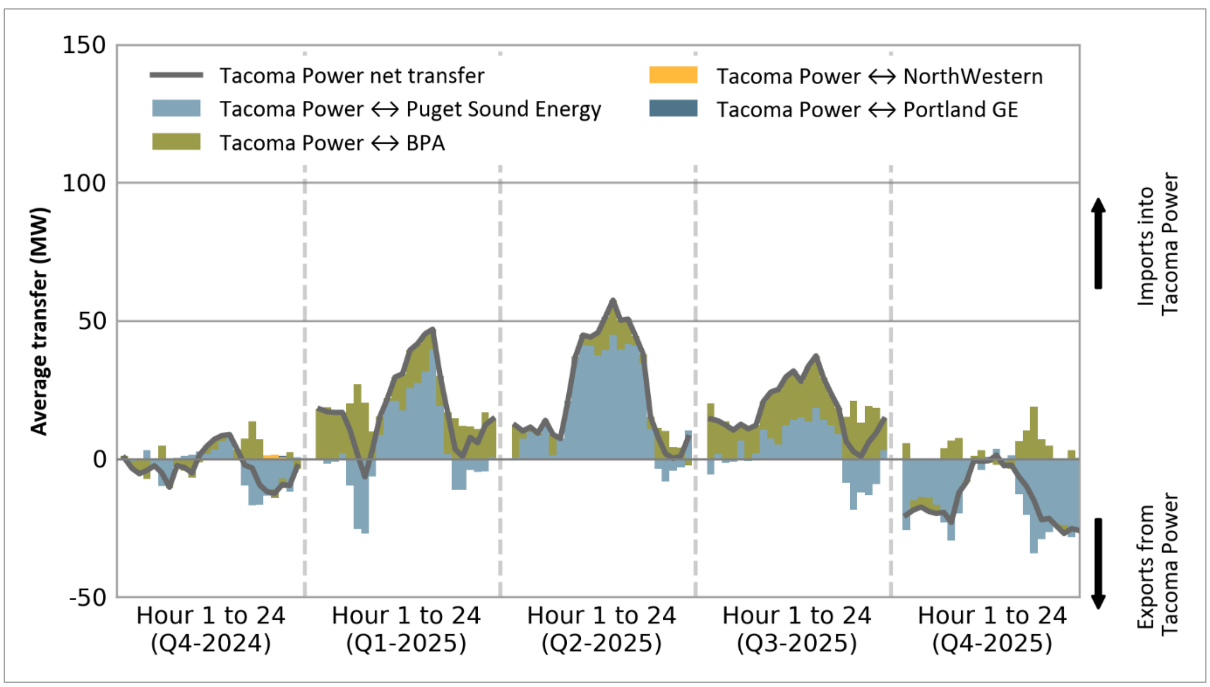


A.20 Tacoma Power

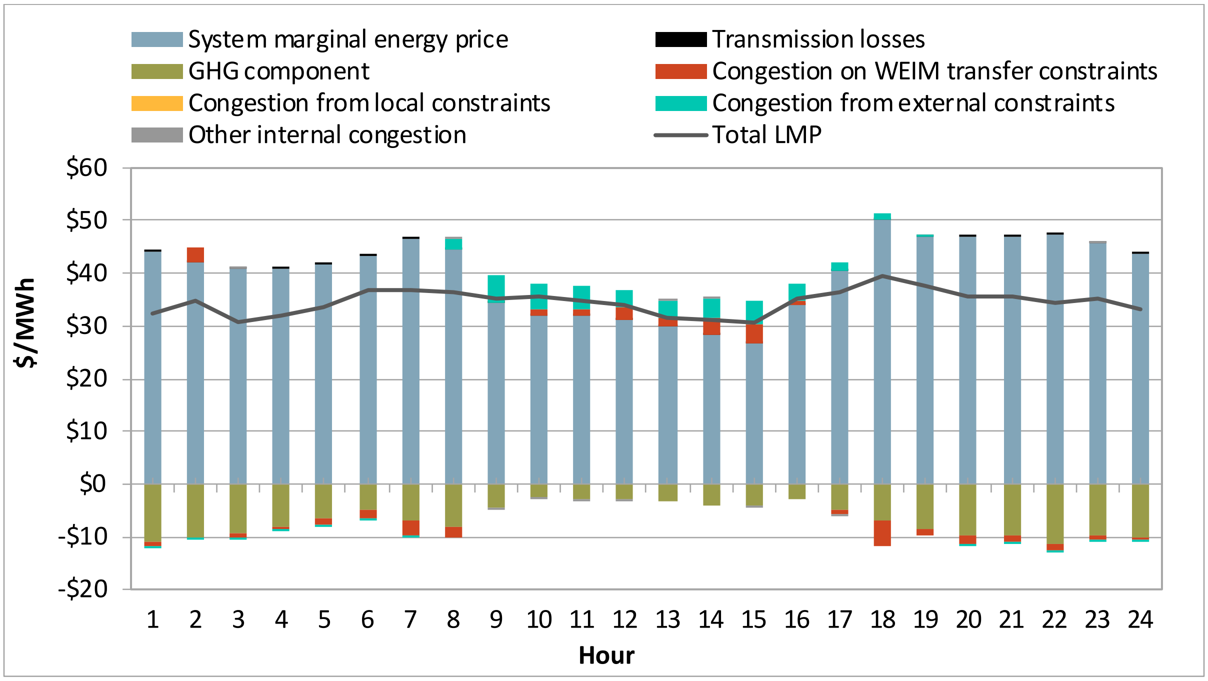
Appendix Figure A.81 Average hourly 15-minute price by component (Q4 2025)



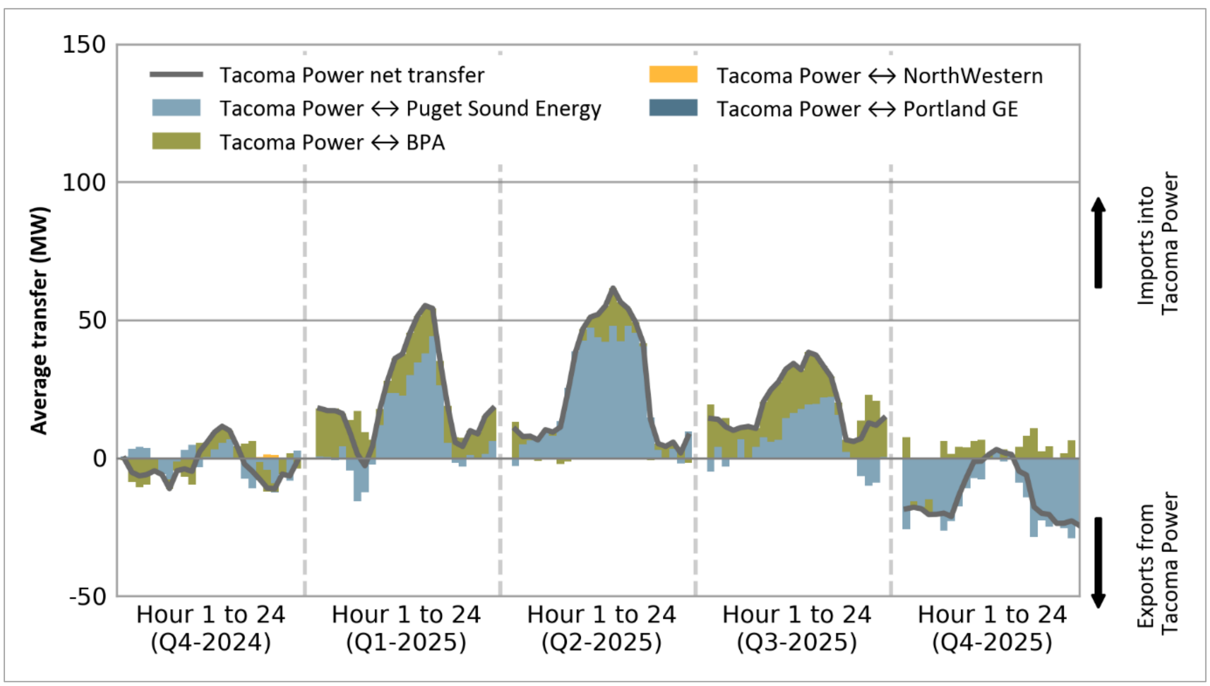
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q4 2025)

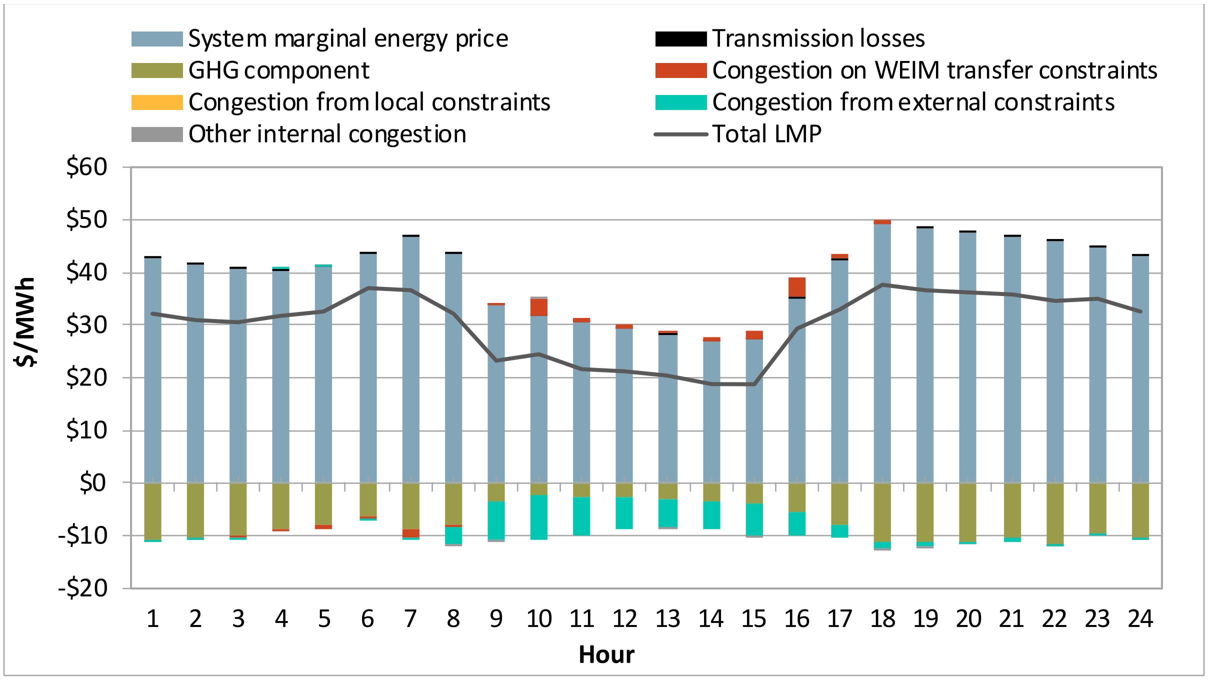


Appendix Figure A.84 Average hourly 5-minute market transfers

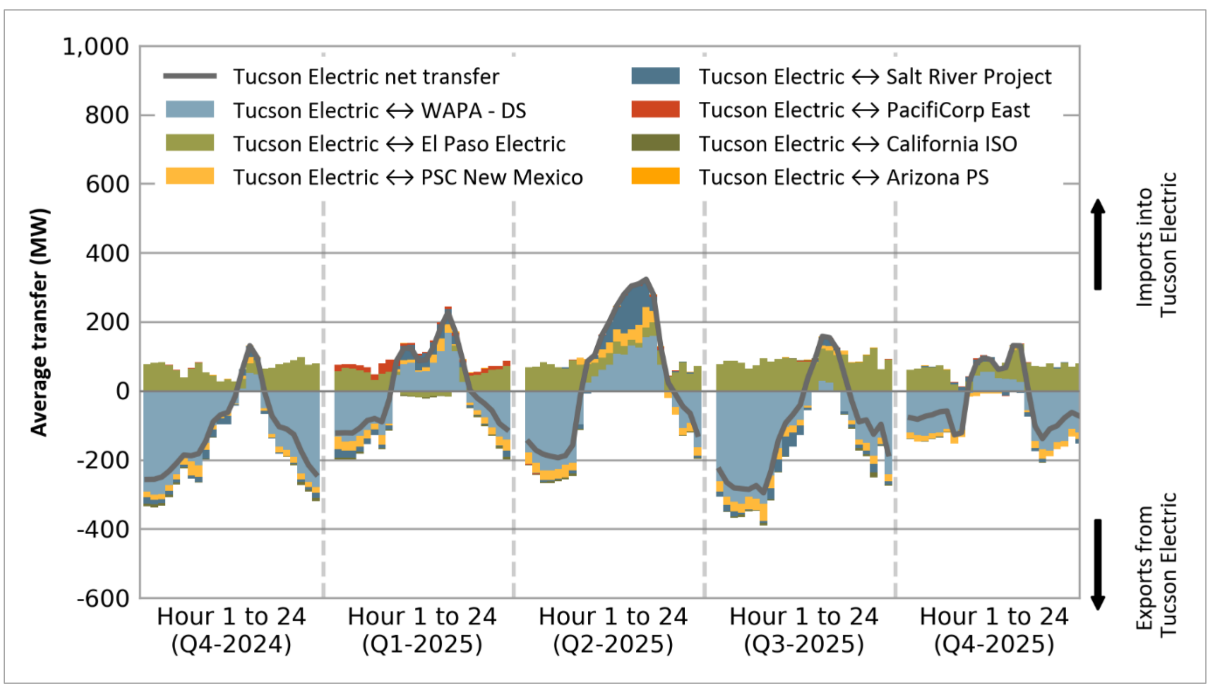


A.21 Tucson Electric Power

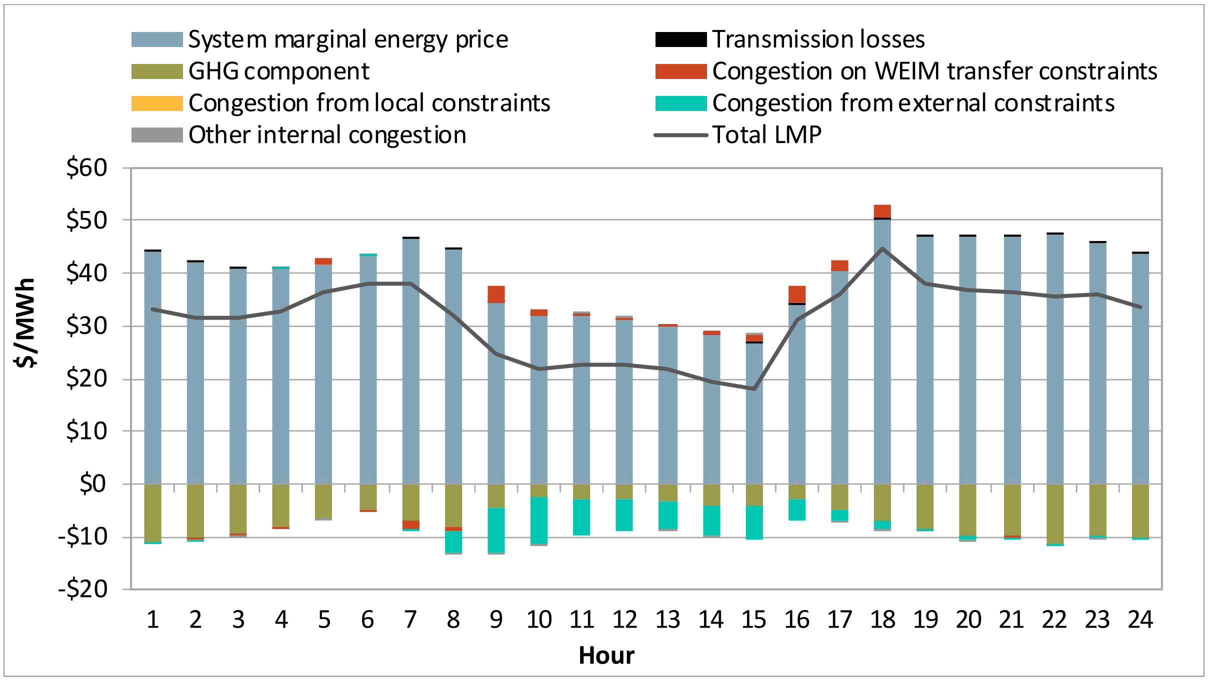
Appendix Figure A.85 Average hourly 15-minute price by component (Q4 2025)



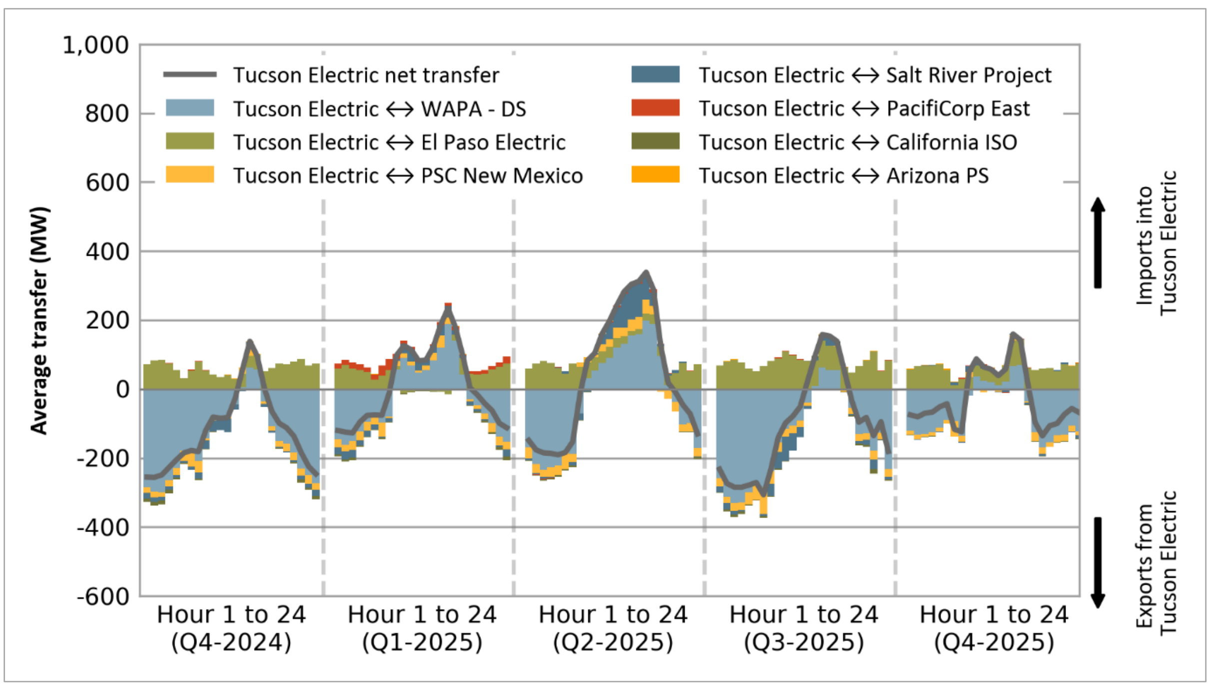
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q4 2025)

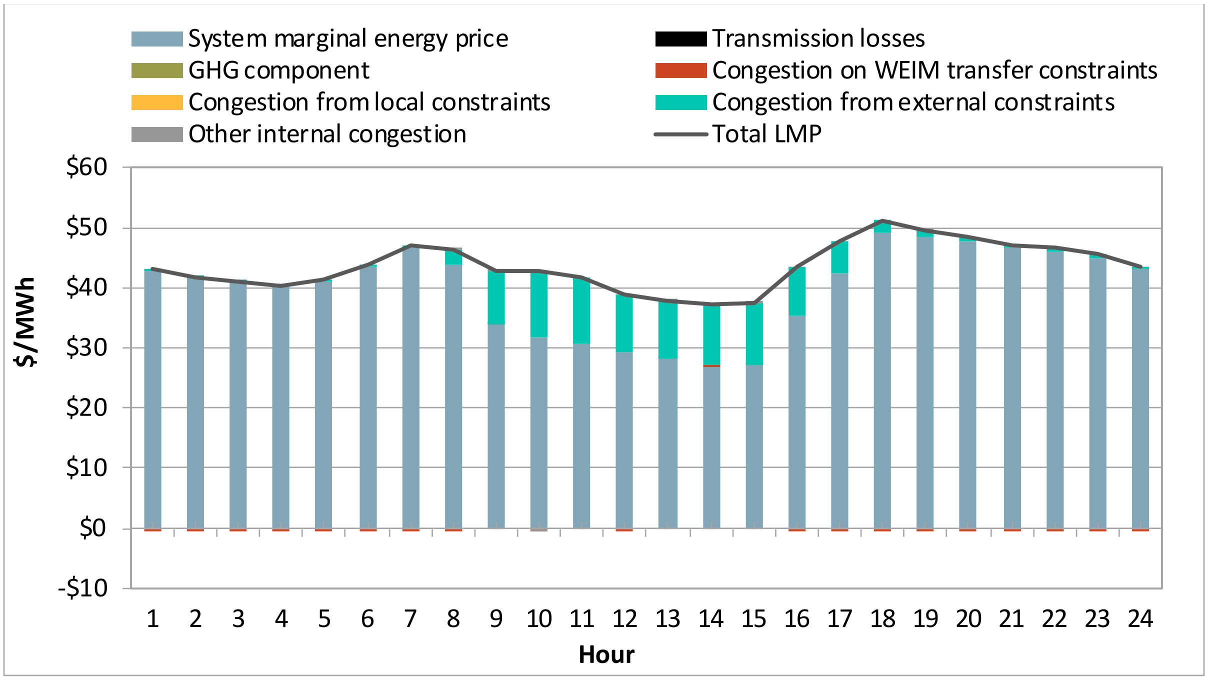


Appendix Figure A.88 Average hourly 5-minute market transfers

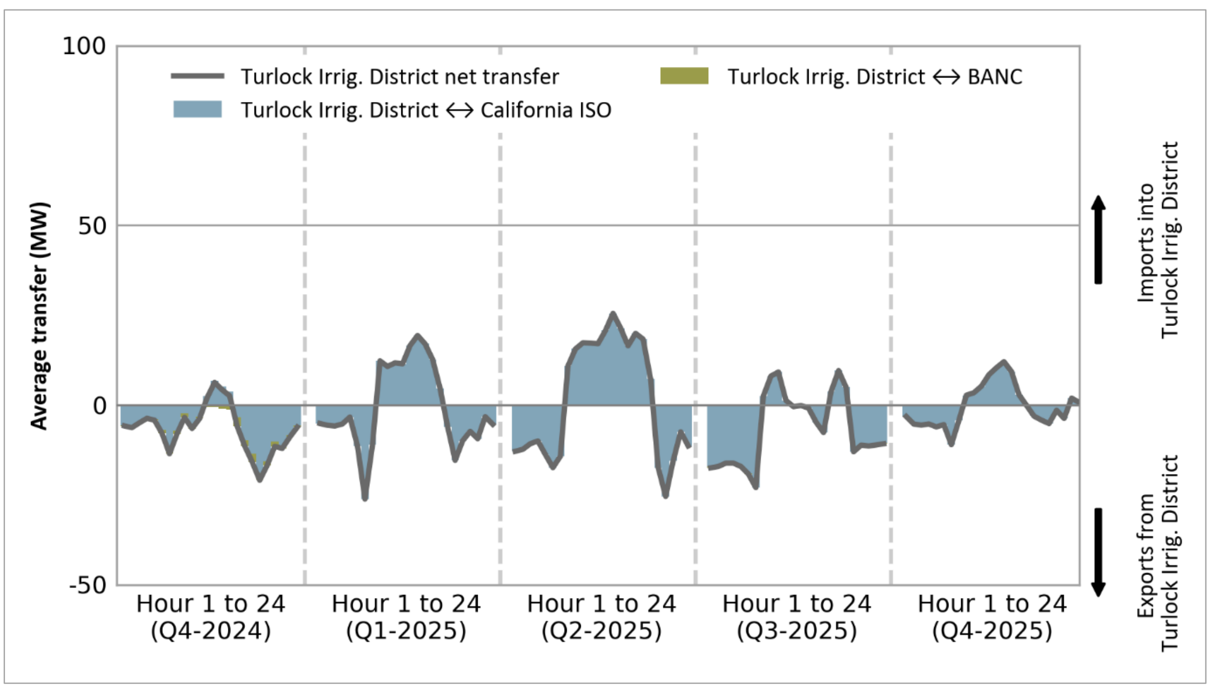


A.22 Turlock Irrigation District

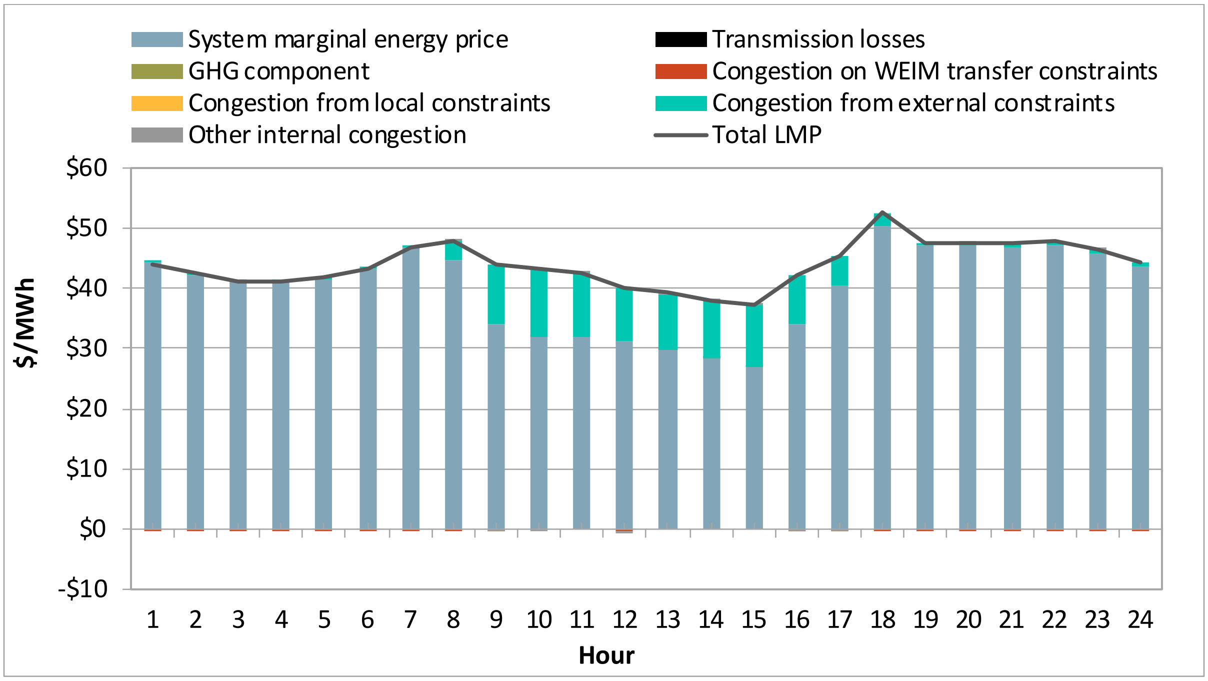
Appendix Figure A.89 Average hourly 15-minute price by component (Q4 2025)



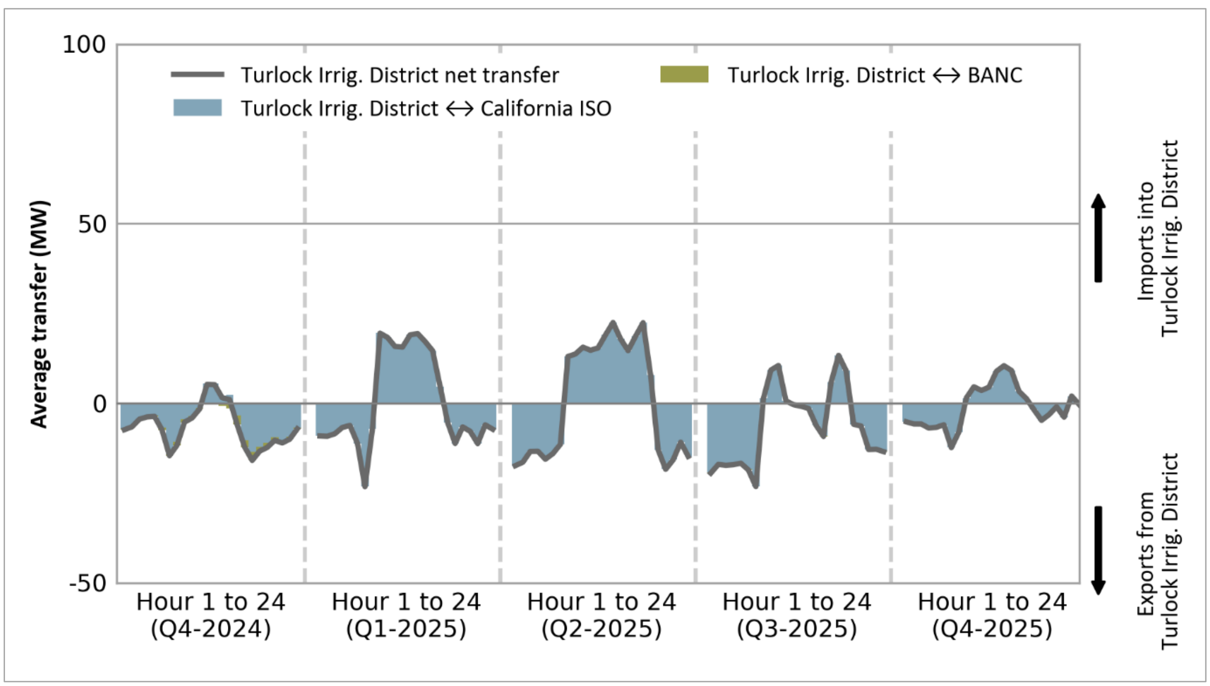
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q4 2025)

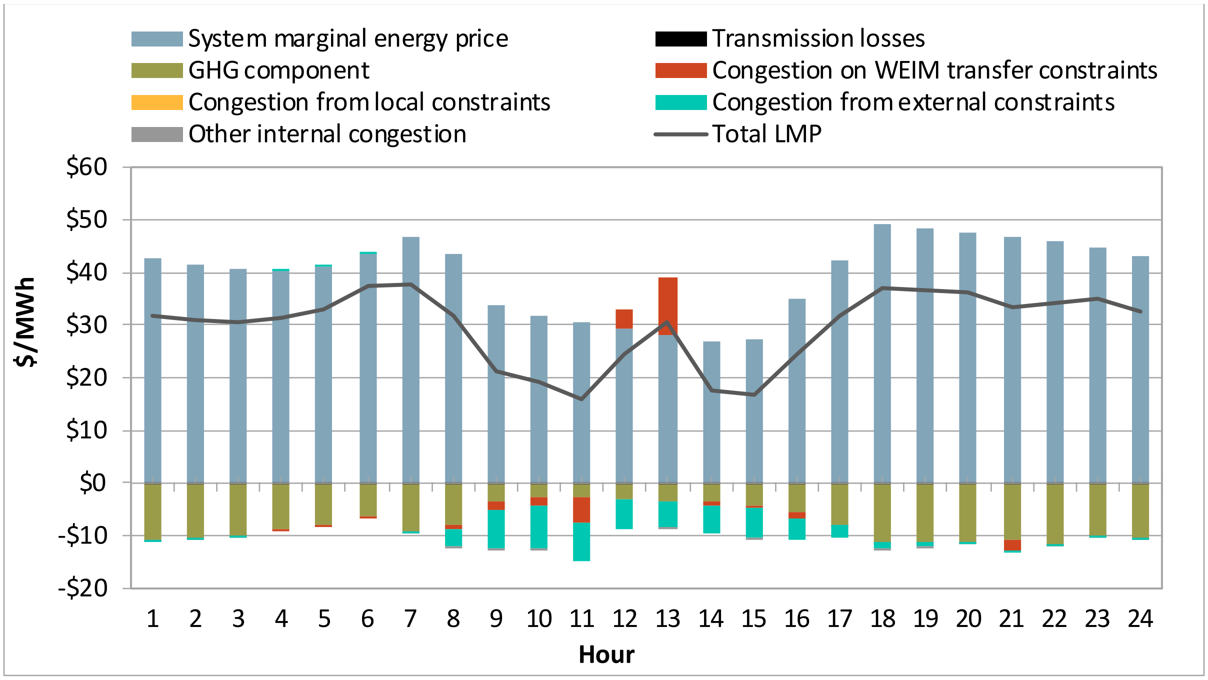


Appendix Figure A.92 Average hourly 5-minute market transfers

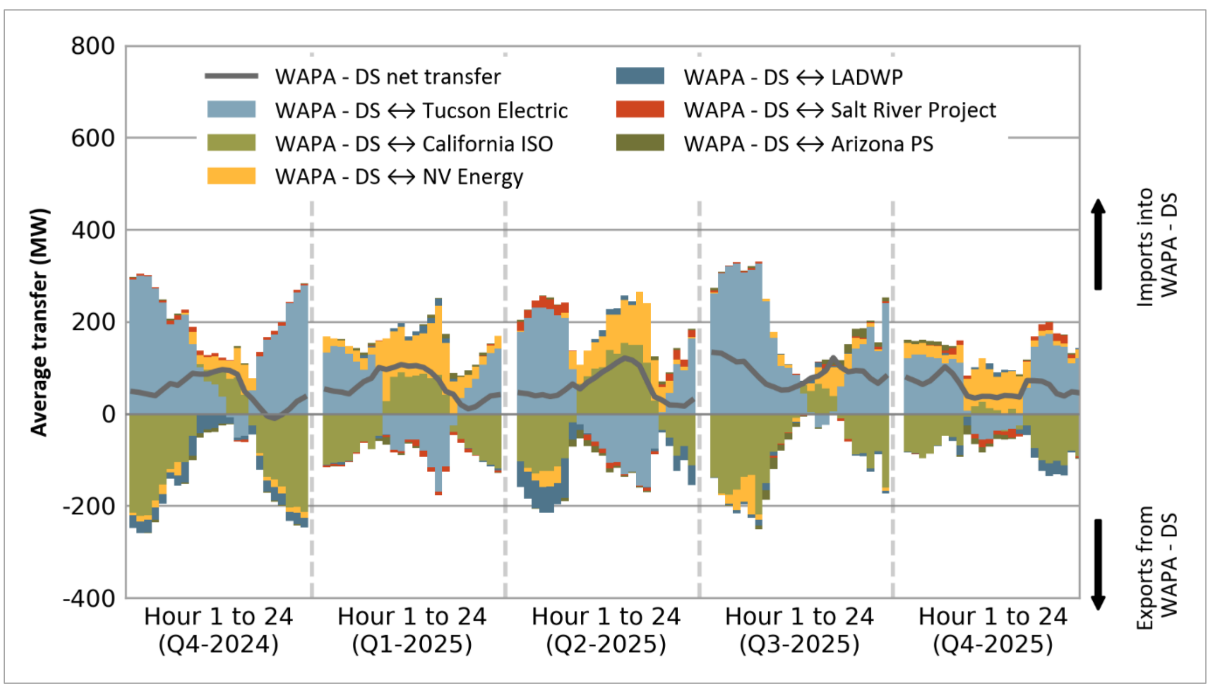


A.23 Western Area Power Administration Desert Southwest

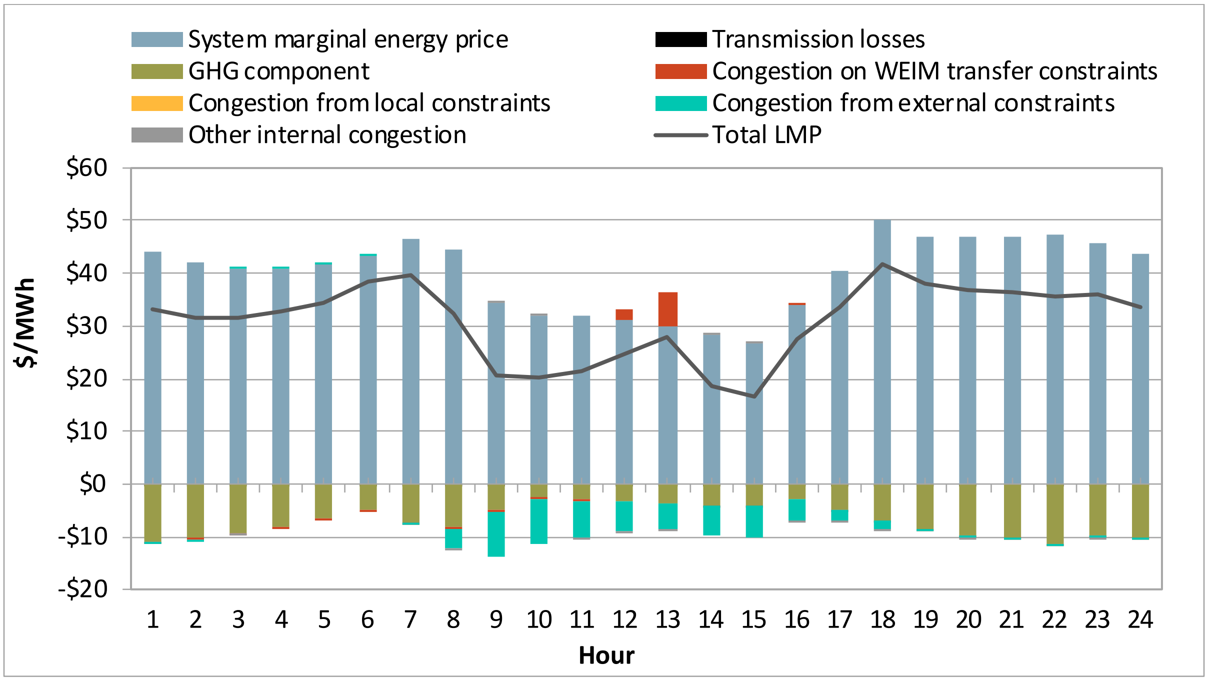
Appendix Figure A.93 Average hourly 15-minute price by component (Q4 2025)



Appendix Figure A.94 Average hourly 15-minute market transfers



Appendix Figure A.95 Average hourly 5-minute price by component (Q4 2025)



Appendix Figure A.96 Average hourly 5-minute market transfers