

California ISO

Q3 2026 Report on Market Issues and Performance

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California Independent System Operator

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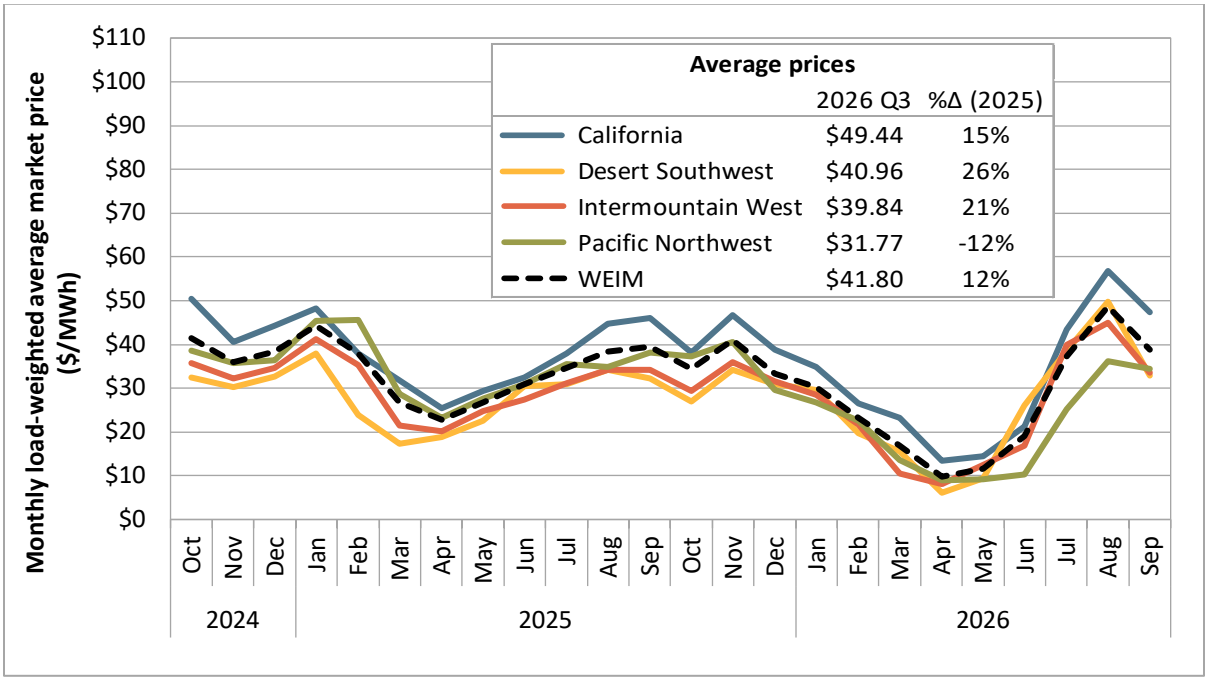
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Executive summary

This report covers market performance during the third quarter of 2026 (July–September). Overall 15-minute market prices across the Western Energy Imbalance Market (WEIM) averaged $42/MWh, up 12 percent compared to the third quarter of 2025, due mainly to higher loads across the West (Figure E. 1).

The extended day-ahead market (EDAM) launched May 1, 2026. EDAM prices averaged $46/MWh over the third quarter, just below the average 15-minute market prices of the three balancing areas participating in EDAM ($47/MWh). Prices in the day-ahead market were very competitive, averaging close to what DMM estimates under highly efficient and competitive conditions.

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

- **Changes in average natural gas prices were mixed in the third quarter of 2026 compared to the same period in 2025.** Prices were up significantly at NW Sumas (137 percent) and El Paso Permian (148 percent). Natural gas prices at other major hubs were relatively stable. Prices at SoCal Citygate increased 3 percent, while prices at Henry Hub, PG&E Citygate, and Northwest Opal Wyoming declined by about 5 percent, 8 percent, and 7 percent, respectively, compared to Q3 2025.
- **Renewable output increased significantly across the WEIM footprint, with average hourly renewable generation up 3,600 MW (8 percent)** from Q3 2025. This included increases of 1,360 MW (7 percent) in hydro, 1,140 MW (9 percent) in solar, and 1,190 MW (17 percent) in wind.
- **Solar and wind production increased in each region** compared to Q3 2025, with the largest solar increase in hourly average output occurring in the Desert Southwest (570 MW or 18 percent) and

the largest wind increase occurring in California (700 MW or 25 percent).[1] Hydro generation was up 1,430 MW in the Pacific Northwest, but hydro declined in California and the Desert Southwest and remained roughly constant in the Intermountain West compared to the third quarter of 2025.

- **Real-time net interchange into the Pacific Northwest decreased by an average of 1,300 MW** across all hours compared to Q3 2025. The region became a net exporter in each hour of the day on average.
- **The average volume of EDAM energy transfers across the system was around 930 MW** during the third quarter. PacifiCorp West was a net importer of EDAM transfers on average in all hours, at around 360 MW. PacifiCorp East was a net exporter of EDAM transfers on average in all hours, at around 410 MW. CAISO was a net exporter during the mid-day high solar production hours and was a net importer during morning and evening hours.
- **WEIM transfers averaged 4,800 MW over the third quarter, slightly higher compared to the same period of 2025.** 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 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.
- **Load across the WEIM averaged 93.4 GW, an increase of about 5.8 percent (5.1 GW) compared to the same quarter of 2025.** This represents the largest year-over-year increase in quarterly average system load over the past three years. Only a small part of this large increase in load between Q3 2025 and Q3 2026 was due to Black Hills Energy joining the WEIM system in Q2 2026. Black Hills Energy load averaged about 670 MW over the third quarter. Average load in the third quarter of 2026 increased significantly in all regions except for the Pacific Northwest.
- **Peak 5-minute market load for the third quarter was 137.0 GW on August 26, 2026**, hour-ending 18, interval 10, up significantly from the Q3 2025 peak load of about 130.1 GW.

Prices and congestion

- **Real-time prices increased slightly across the WEIM.** Prices averaged $42/MWh in the 15-minute market and $44/MWh in the 5-minute market, up 12 percent and 15 percent, respectively, from Q3 2025.
- **Prices were highest in California at $49/MWh in the 15-minute market, primarily due to greenhouse gas costs during non-solar hours.** Prices were lowest in the Pacific Northwest at $32/MWh, brought down by low prices in Powerex across all hours and transmission congestion from northern areas to southern areas, particularly during evening hours. Hourly prices followed the net-load pattern, with the highest prices during the morning and evening ramps and lower prices during solar hours.
- **Prices in the day-ahead market averaged $46/MWh.** Average 15-minute market prices were $47/MWh and 5-minute market prices were $48/MWh for balancing areas participating in the day-ahead market. Day-ahead market prices were highest in the CAISO balancing area at $48/MWh. Day-ahead prices in PACW and PACE were substantially lower, at $38/MWh and $37/MWh, respectively, due mainly to California greenhouse gas costs.

[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, PACE, Black Hills, and Power Watch. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

- **Bilateral market prices were significantly higher than ISO market prices.** Day-ahead peak prices in the Intercontinental Exchange for the Mid-Columbia trading hub averaged about $57/MWh over the quarter, $22/MWh higher than ISO 15-minute market prices in the Pacific Northwest and $18/MWh higher than ISO day-ahead market prices in PacifiCorp West. Day-ahead ICE prices for the Palo Verde trading hub averaged about $55/MWh, $12/MWh higher than ISO 15-minute market prices in the Desert Southwest and $16/MWh higher than ISO day-ahead market prices in PacifiCorp East.
- **Prices in the day-ahead market were very competitive, averaging close to what DMM estimates under highly efficient and competitive conditions.** Average price-cost markup was less than $2/MWh in each balancing area separated from the system by transfer congestion and in each group of balancing areas not separated from each other by congestion.
- **Prices in the real-time market were also very competitive.** DMM estimates that the system market price based on submitted supply bids was marked up over a competitive price by an average of less than $3/MWh across the WEIM system in Q3 2026.
- **The frequency of transfer congestion into and out of PacifiCorp East and PacifiCorp West was higher in the day-ahead market** compared to the real-time markets due to less transfer capacity with neighboring areas in the day-ahead market.
- **Transfer congestion out of Powerex separated its prices from the larger WEIM system in about 85 percent of intervals** in the 5-minute market. WEIM transfer congestion was also high for other balancing areas in the Pacific Northwest. In the 5-minute market, these balancing areas were import constrained in around 16 percent of intervals and export constrained in around 11 percent of intervals.
- **Day-ahead congestion rent totaled $144 million, up $5 million (4 percent)** from Q3 2025. The CAISO balancing area received about $145 million in congestion rent, compared with negative $0.3 million for PACE and about negative $0.9 million for PACW.
- **The initial congestion revenue allocation rules adopted for EDAM are intended to help hedge PacifiCorp transmission customers against congestion costs from CAISO balancing area transmission constraints.** However, actual congestion patterns resulted in a net payment from PacifiCorp balancing areas to the CAISO balancing area of around $540,000 in Q3 2026. PacifiCorp areas' congestion revenue allocations were about -$199,000 (charge) in July, -$757,000 (charge) in August and $415,000 (credit) in September.

Resource sufficiency evaluation

- **Day-ahead resource sufficiency evaluation failures occurred on one day in the third quarter. None of the failures resulted in exclusion from the EDAM pool for real-time resource sufficiency evaluations.** On July 13, PacifiCorp East failed the regulation up test in hours 8, 13 and 14.
- **An EDAM-participating balancing area was excluded from the EDAM pool for real-time resource sufficiency evaluations during one hour** in Q3 2026. On July 19, in hour-ending 8, PacifiCorp East was evaluated separately in the real-time downward sufficiency test.
- **Resource sufficiency test failures remained low across the WEIM** in Q3 2026, with all areas except Power Watch failing fewer than 1 percent of intervals across all test types and directions. Power Watch failed the upward flexibility test in 5.4 percent of intervals and the downward flexibility test in 6.4 percent of intervals.
- **Eleven balancing areas opted in to the assistance energy transfer program on at least one day during the quarter.** Seven of these entities received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. Public Service Company of New Mexico

received the largest amount of additional transfers in any single interval (661 MW) as well as the largest amount of additional transfer energy over the quarter (371 MWh).

- **DMM is providing additional metrics, data, and analysis on the EDAM and WEIM 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

- **The appearance of a significant day-ahead energy offset coincided with the launch of EDAM**.[3] This credit back to EDAM balancing areas can accrue if the energy portion of prices paid into the day-ahead market by demand exceeds the energy portion of prices paid out to supply. Total day-ahead energy offsets paid back to EDAM balancing areas were about $74 million during the third quarter. DMM is working with the ISO to identify the cause of this day-ahead energy revenue imbalance.
- **Real-time imbalance offsets for balancing areas participating only in the WEIM real-time markets were a net $12 million charge** to WEIM entities. On net, the energy portion of the offset was an $11 million charge. The congestion portion of the offset was a $2 million charge. Before the launch of EDAM, the congestion portion of the offset was generally a large credit to WEIM balancing areas from congestion rent that accrued on WEIM transfer constraints. The ISO has addressed some issues that may result in the energy portion of the offset decreasing in upcoming settlement runs. DMM has requested that the ISO review and correct any issues with the real-time offset calculation.
- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $88 million in uplift** in the third quarter of 2026. Real-time congestion imbalance offset costs made up the large majority of these costs at $88 million. The energy portion of the offset was a $10 million credit, and the loss portion of the offset was a $10 million cost.
- **Bid cost recovery payments for units in balancing areas participating in both the day-ahead and real-time markets totaled about $35.9 million** in the third quarter of 2026, up 5 percent from $34.3 million in the third quarter of 2025.
- **Bid cost recovery for units in areas participating only in the WEIM totaled about $3 million**, a 26 percent decrease from Q3 2025.

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 adjustments to hour-ahead and 15-minute market load in the morning and evening ramp periods were down compared to Q3 2025. The lower discrepancy between CAISO balancing area 15-minute market and 5-minute market load

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[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

[3] Data in some sections of the report, such as imbalance offsets and bid cost recovery, 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. For comparison to previous reports, see DMM annual and quarterly reports: https://www.caiso.com/market-operations/market-monitoring/market-issues-and-performance-reports

adjustments during peak morning and evening hours contributed to better overall convergence between 15-minute and 5-minute market prices.

- **There were no operator adjustments to the residual unit commitment process (RUC) procurement target in PacifiCorp East or PacifiCorp West in the third quarter of 2026.** RUC operator adjustments in the CAISO balancing area averaged about 220 MW in Q3 2026, down 77 percent from about 960 MW in Q3 2025.
- **Manual dispatch energy trends were divergent across WEIM regions.** Compared to Q3 2025, manual dispatch energy in the California (non-CAISO), Intermountain West, and Pacific Northwest regions decreased by 24 percent, 13 percent, and two percent, respectively, and increased in the Desert Southwest region by 27 percent. The average hourly total energy from exceptional dispatches in the CAISO balancing area was 72 MW in the third quarter of 2026, up from only 26 MW in the third quarter of 2025.

Imbalance reserve and flexible ramping products

- **Gas resources made up around 70 percent of upward imbalance reserve schedules**. Wind and solar resources combined made up around 62 percent of downward imbalance reserve schedules.
- **The CAISO balancing area was a net exporter of upward imbalance reserve, at around 260 MW on average across all hours, with the recipient being largely PacifiCorp East.** CAISO was also a net exporter of downward imbalance reserve, at around 50 MW on average across all hours, with the recipient being largely PacifiCorp West.
- **Prices for imbalance reserve have frequently been low or zero.** Across all balancing areas and directions, prices have been less than $5/MWh in more than 78 percent of hours and less than $10/MWh in more than 94 percent of hours.
- **Payments for upward imbalance reserve were around $11.1 million while payments for downward imbalance reserve were around $1.3 million**.
- **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 63 percent of intervals** in the third quarter of 2026, up significantly from 0.3 percent in the same quarter of 2025. The increase coincided with the implementation of EDAM in May 2026. Most of this increase occurred in the Intermountain West and Pacific Northwest regions. DMM has notified the ISO of the increase in flexible ramping product prices and will continue to work with the ISO to understand the underlying causes.
- **Payments associated with the flexible ramping product were $8.3 million during the third quarter of 2026, up significantly** from around $1.4 million in the same quarter of 2025. Much of these payments were to resources in the Pacific Northwest due to binding WEIM transfer constraints that caused higher flexible ramping product prices in this region.
- **Battery and hydro resources made up 70 percent and 20 percent of upward flexible capacity, respectively.** Wind and solar combined to provide 38 percent of downward flexible capacity, and batteries provided 29 percent of downward flexible capacity. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 58 percent in the upward direction and 55 percent in the downward direction. Balancing areas in the Pacific Northwest made up 21 percent of upward flexible capacity and 22 percent of downward flexible capacity.

Residual unit commitment

- **Average hourly residual unit commitment procurement** in Q3 2026 was 1,850 MW of reliability capacity up (RCU) and 750 MW of reliability capacity down (RCD), resulting in total procurement of 2,600 MW and net procurement of 1,100 MW. Average upward RUC procurement in the same quarter of the prior year was 1,800 MW.
- **The CAISO balancing area accounted for 95 percent of RCU and 88 percent of RCD procurement**, PACE accounted for 4 percent of RCU and 10 percent of RCD, and PACW accounted for 1 percent of RCU and 2 percent of RCD.
- **Total RUC costs were approximately $12 million per month, or $36 million overall**, in the third quarter of 2026**.** Between May 2025 and April 2026, RUC costs averaged about $10 million per month, but actual payments to non-resource adequacy resources averaged only $0.2 million per month. CAISO balancing area resources received about 99 percent of RUC payments this quarter.
- **RUC prices averaged about $6/MWh** in Q3 2026. Between May 2025 and April 2026, the average RUC price was about $9/MWh.

Ancillary services and available balancing capacity

- **Regulation up requirements increased 260 MW (58 percent) on average compared to Q3 2025.** The CAISO balancing area initiated a program in Q1 2026 to better understand why operators used load adjustments in the real-time markets. One outcome of the analysis was to replace some upward load adjustments with increased regulation up requirements.
- **Ancillary service payments totaled $29.6 million in the third quarter of 2026, up $11.6 million (65 percent) from the same quarter of the previous year.** Regulation up costs increased by about $6.5 million (201 percent) while regulation down costs decreased by about $0.6 million (6 percent).
- **Available balancing capacity was dispatched to address power balance infeasibilities in 0.2 percent or less of intervals for all areas in the 15-minute and 5-minute markets.**

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

- **Transmission ratepayers lost roughly $48 million from the congestion revenue rights (CRR) auction** in the third quarter of 2026, as payments to auctioned congestion revenue rights holders were higher than auction revenues. This was an increase from $24 million in the third quarter of 2025.
- **Scheduling coordinators secured monthly reservations for CAISO balancing area high priority wheel-through rights totaling 400 MW in July, 400 MW in August, and 209 MW in September**. The only use of that reserved capacity, via day-ahead self-schedules, was on the NOB intertie during five hours in July.
- **Real-time resource adequacy bids were not sufficient to cover the market requirements for energy and upward ancillary services in the CAISO balancing area in two intervals during peak net load hours on September 9, 2026.**
- **Resource adequacy import bids decreased 40 percent from the third quarter of 2025.** Most of this decline occurred during July and August, as September 2026 resource adequacy import bids were only 5 percent lower than September 2025.

1 Supply conditions

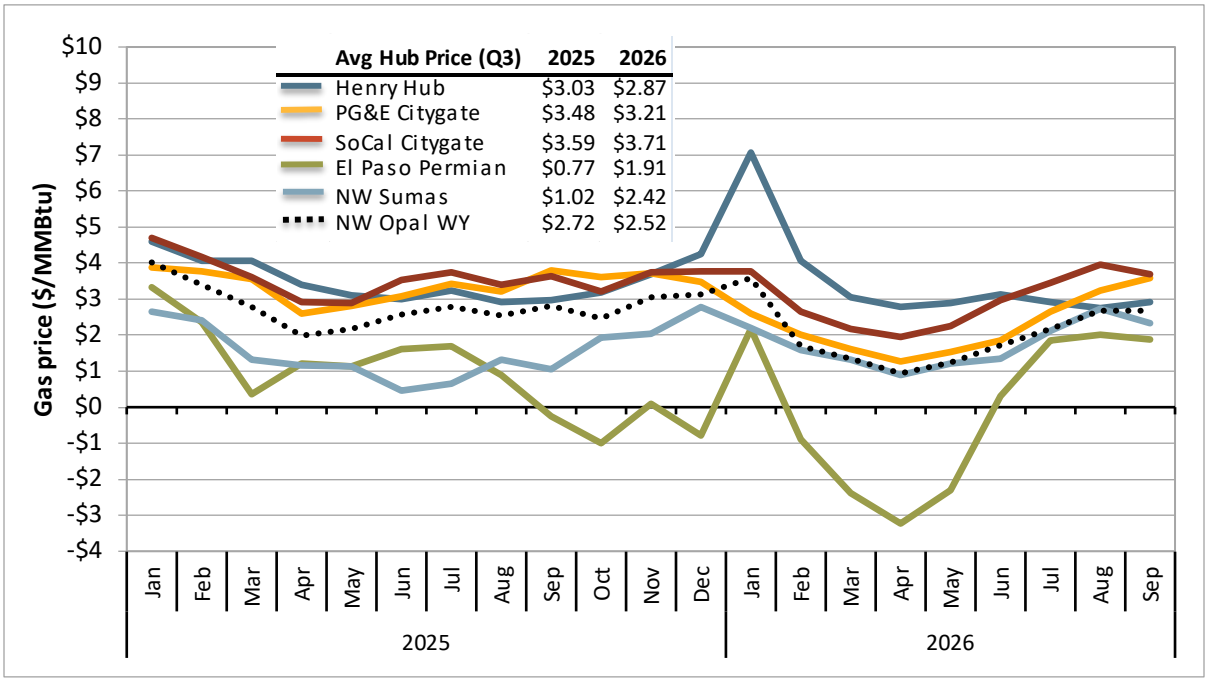
1.1 Natural gas prices

Electricity prices in Western states typically track natural gas price trends, reflecting that 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 serves as a national benchmark for natural gas prices.

Average natural gas prices were mixed in the third quarter of 2026 compared to the same period in 2025. Prices were up significantly at NW Sumas (137 percent) and El Paso Permian (148 percent). Natural gas prices at other major hubs were relatively stable. Prices at SoCal Citygate increased 3 percent, while prices at Henry Hub, PG&E Citygate, and Northwest Opal Wyoming declined by about 5 percent, 8 percent, and 7 percent, respectively, compared to Q3 2025.

Compared to the second quarter of 2026, natural gas prices at most major Western trading hubs increased in the third quarter of 2026. El Paso Permian, Northwest Sumas, PG&E Citygate, Northwest Opal Wyoming, and SoCal Citygate recorded increases of approximately 210 percent, 110 percent, 107 percent, 91 percent, and 55 percent, respectively, while Henry Hub declined by 2 percent.

Figure 1.1 Monthly average natural gas prices



1.2 Renewable generation

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. In the third quarter of 2026, the average hourly generation from renewable resources in the WEIM footprint increased by about 3,600 MW (8 percent) compared to the same quarter of 2025.[4,5] Hydroelectric, solar, and wind generation increased by approximately 1,360 MW (7 percent), 1,140 MW (9 percent), and 1,190 MW (17 percent), respectively, across the WEIM footprint. Average hourly generation from geothermal and biogas-biomass resources decreased by about 50 MW (4 percent) and 40 MW (5 percent), respectively, across the WEIM footprint compared to the third quarter of 2025.

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

- Generation from solar resources made up 50 percent of all renewable output in the California region and increased by 440 MW (6 percent) compared to the third quarter of 2025. Wind generation increased by about 700 MW (25 percent), year-over-year. Hydroelectric, geothermal, and biogas-biomass generation decreased by about 80 MW (2 percent), 40 MW (4 percent), and 20 MW (5 percent), respectively.
- The Desert Southwest region saw increases in solar (570 MW or 18 percent) and wind (80 MW or 10 percent), contributing to an overall increase in renewable generation of 610 MW (12 percent) compared to the third quarter of 2025. Hydroelectric, geothermal, and biogas-biomass generation decreased slightly year-over-year.
- Renewable generation in the Intermountain West increased by approximately 380 MW (8 percent) compared to the third quarter of 2025, with the largest increases attributed to solar and wind generation (90 MW or 6 percent, and 270 MW or 20 percent, respectively).
- In the third quarter of 2026, hydroelectric generation represented 84 percent of all renewable generation in the Pacific Northwest, with an increase of 1,430 MW (10 percent) from the same quarter of the previous year. Solar and wind generation increased by about 60 MW (14 percent) and 150 MW (6 percent), respectively.

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

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

Figure 1.2 California - Average monthly renewable generation

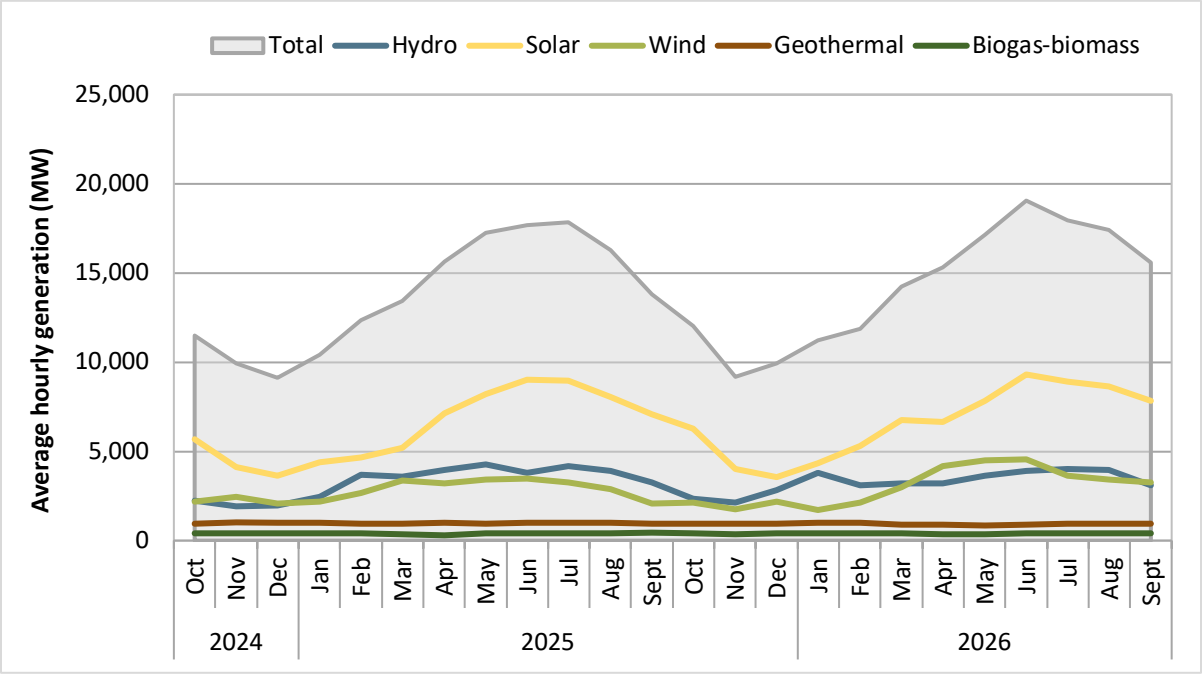


Figure 1.3 Desert Southwest - Average monthly renewable generation

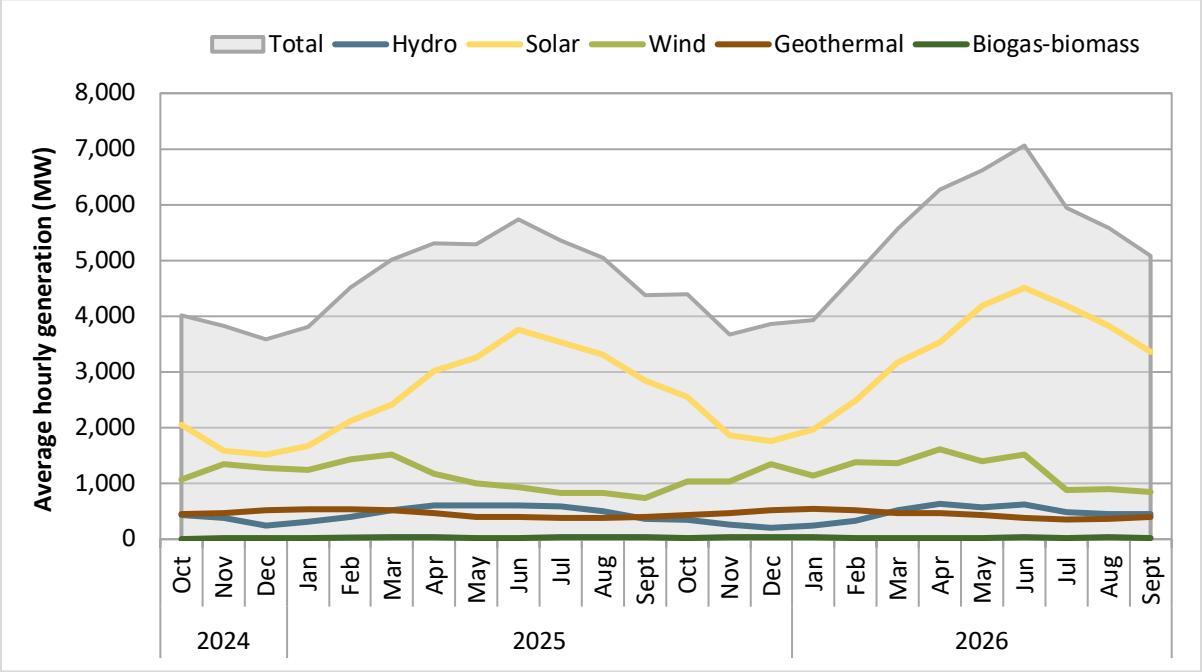


Figure 1.4 Intermountain West - Average monthly renewable generation

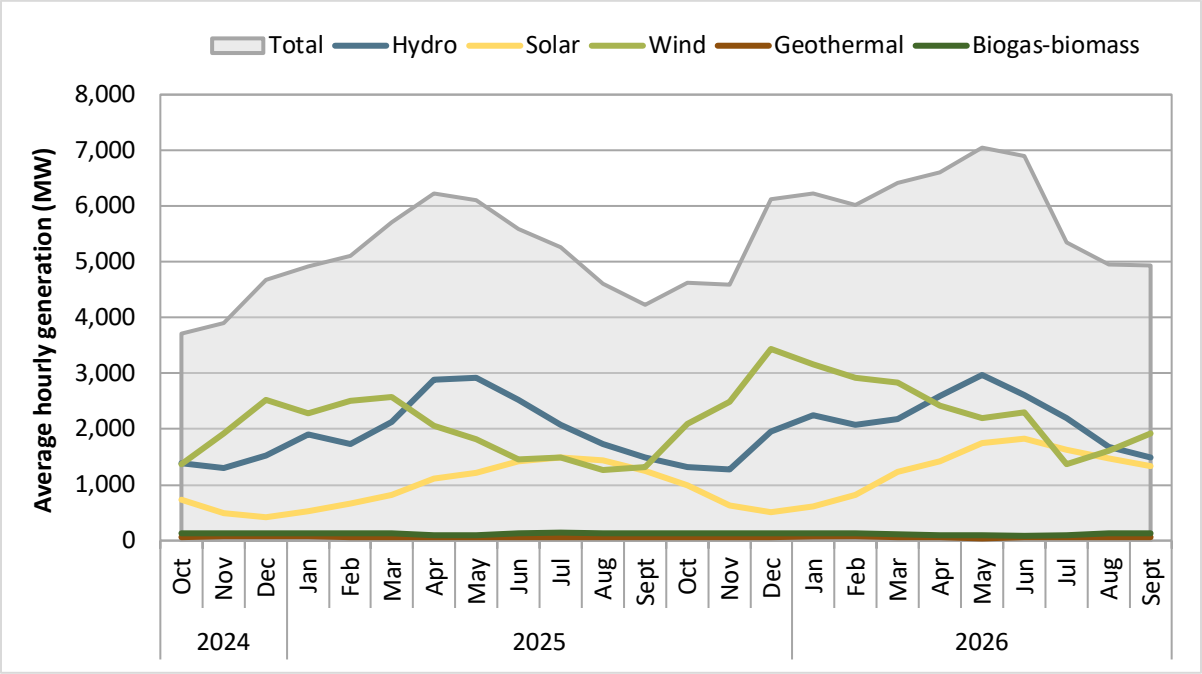


Figure 1.5 Pacific Northwest - Average monthly renewable generation

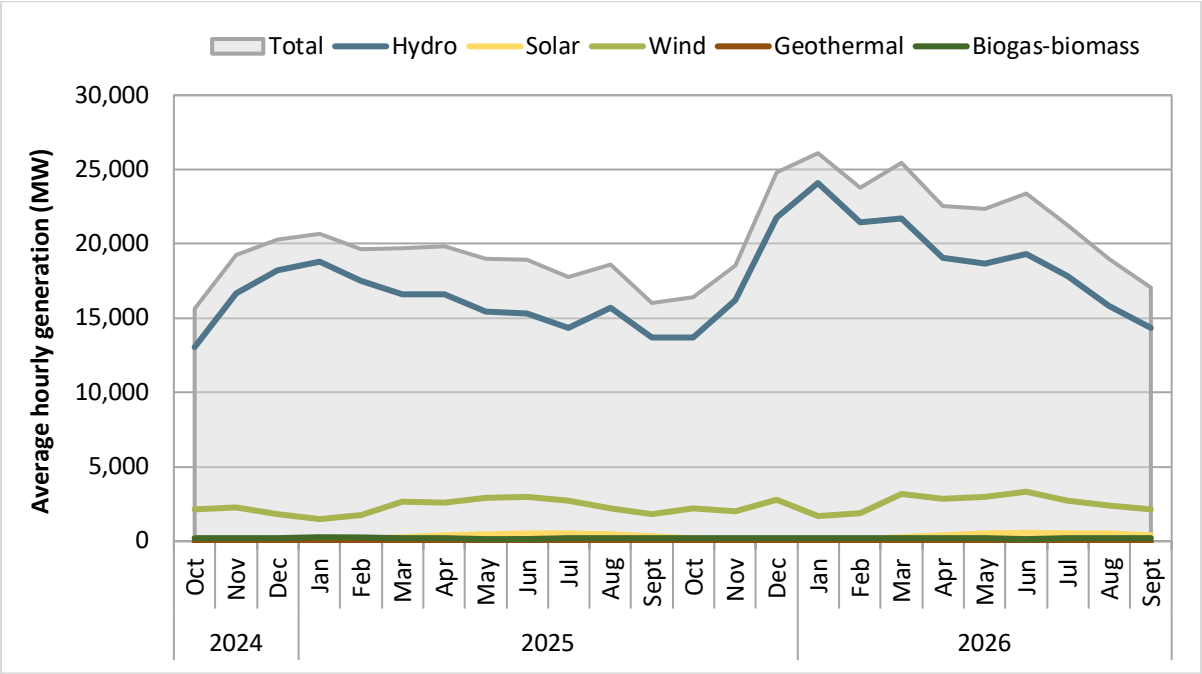
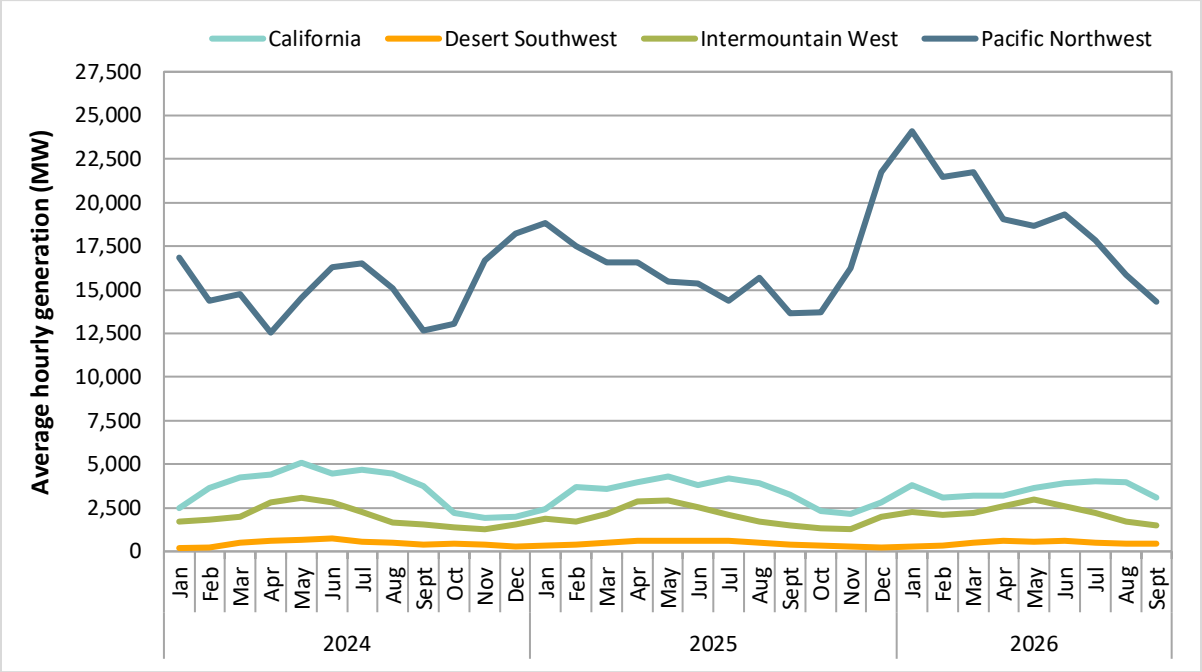


Figure 1.6 shows the monthly average hydroelectric generation from January 2024 to September 2026.

- In the California region, hydroelectric generation decreased by 80 MW (2 percent) compared to the third quarter of 2025.
- In the Desert Southwest, hydroelectric generation decreased by 20 MW (4 percent) compared to the third quarter of 2025.
- Hydroelectric output in the Intermountain West remained the same compared to the third quarter of 2025.
- In the Pacific Northwest, hydroelectric generation in the third quarter of 2026 increased 1,430 MW (10 percent) compared to the same quarter of 2025, and increased 1,260 MW (9 percent) compared to the third quarter of 2024.

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 third quarter of 2026 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 third quarters of 2025 and 2026. Positive values represent increased generation compared to the third quarter of the previous year, and negative values represent a decrease in generation. Change in total load is denoted by the black line.

Load increased in all regions: by 1,920 MW or 6 percent in California, 2,010 MW or 9 percent in the Desert Southwest, 1,160 MW or 10 percent in the Intermountain West, and 170 MW or 1 percent in the Pacific Northwest. Total hourly average generation peaked at hour-ending 19 in the California region, and peaked at hour-ending 18 in the Desert Southwest, Intermountain West, and Pacific Northwest.

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 increased in all hours in the California region, as shown in Figure 1.8. Wind generation increased in all hours, partially due to the SunZia Wind and Transmission project which added approximately 3,650 MW of wind capacity.[6] Battery discharging increased during morning and evening hours, and battery charging increased during mid-day solar hours. Net dynamic transfers, i.e., imports and exports that are optimized in the WEIM, out of California decreased during mid-day solar hours as well.

Natural gas remained the largest source of generation in the Desert Southwest in the third quarter of 2026, with increases over all hours averaging about 1,280 MW or 10 percent. The Desert Southwest also saw large increases in solar generation and corresponding battery charging in the solar hours and discharging in evening and early morning hours. Net dynamic transfers changed in the direction of decreased exports or increased imports in most hours. Net imports, i.e., energy schedules made prior to the market optimization, changed in the direction of increased exports in mid-day and evening hours. This reflected the Desert Southwest exporting more hourly schedules out of the region before the WEIM market optimization runs, but then transferring more power in during solar hours and transferring less power out during morning and evening hours via the WEIM market optimization.

The additions of new capacity following Black Hills Energy's (BHBA) entry into the WEIM in May 2026 shifted the Intermountain West generation mix more heavily toward coal and natural gas. BHBA added 800 MW and 370 MW of coal and natural gas capacity, respectively. In the third quarter of 2026, coal generation in the Intermountain West increased across all hours by an average of 510 MW (13 percent), and natural gas generation increased by an average of 870 MW (25 percent). Together, coal and gas resources represented a substantial share of the region's generation, with coal accounting for 35 percent and natural gas 33 percent. Power Watch added 400 MW of wind capacity, and wind generation across the region increased by an hourly average of 270 MW (20 percent) compared to the third quarter of 2025. Net imports decreased across all hours by an average of 440 MW (93 percent).

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 Figure 1.14, and increased by about 1,430 MW (10 percent) on average compared to the third quarter of 2025. Natural gas and coal generation decreased across all hours. Net imports and net dynamic transfers changed in the direction of more power flowing out and less power flowing in across all hours by an average of 490 MW (29 percent) and 440 MW (54 percent), respectively.

[6] See https://patternenergy.com/projects/sunzia/ for more information.

Figure 1.7 California - Average hourly generation by fuel type (Q3 2026)

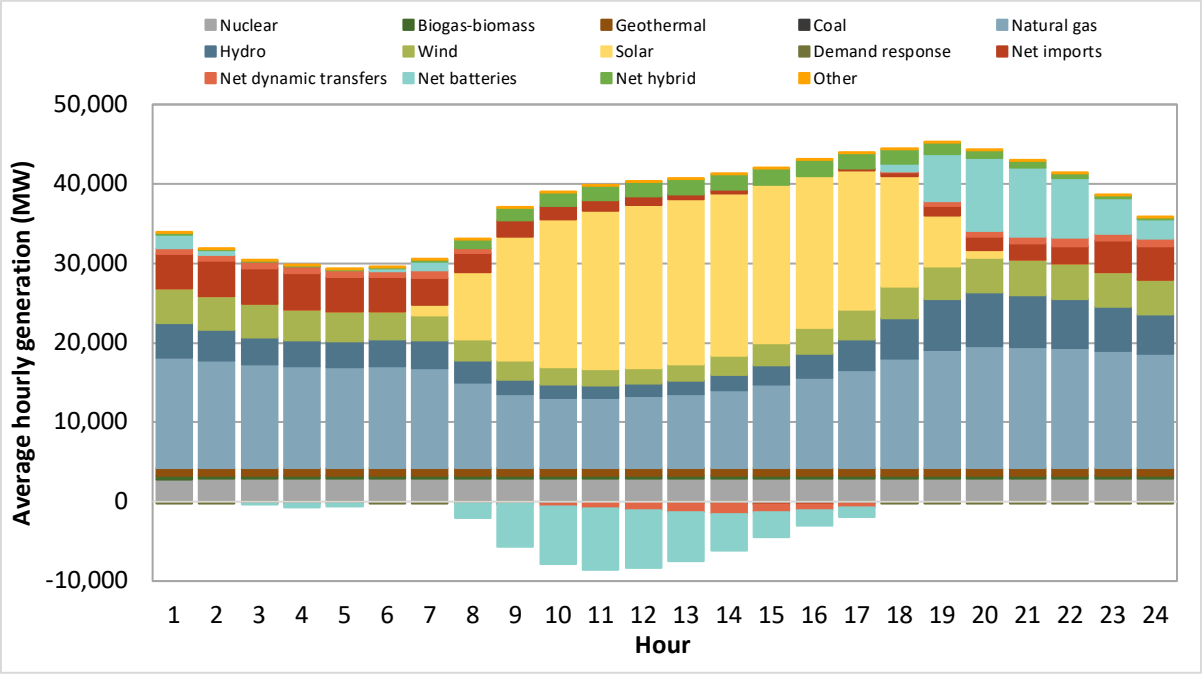


Figure 1.8 California - Change in average hourly generation by fuel type (Q3 2026 vs. Q3 2025)

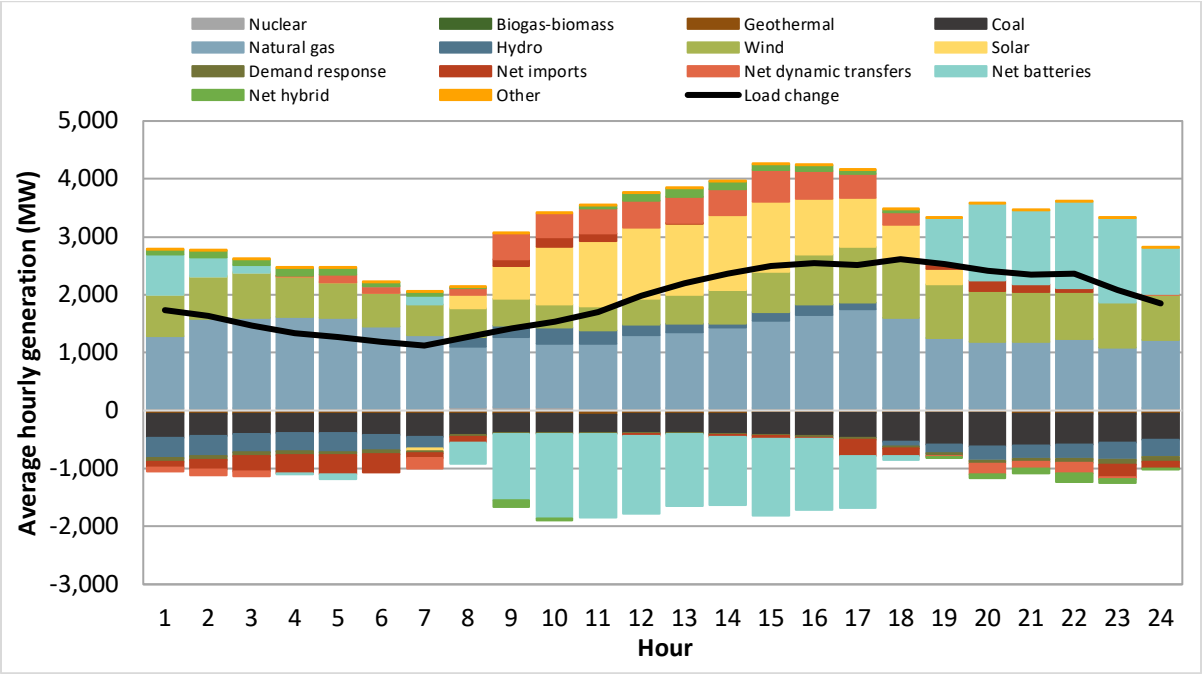


Figure 1.9 Desert Southwest - Average hourly generation by fuel type (Q3 2026)

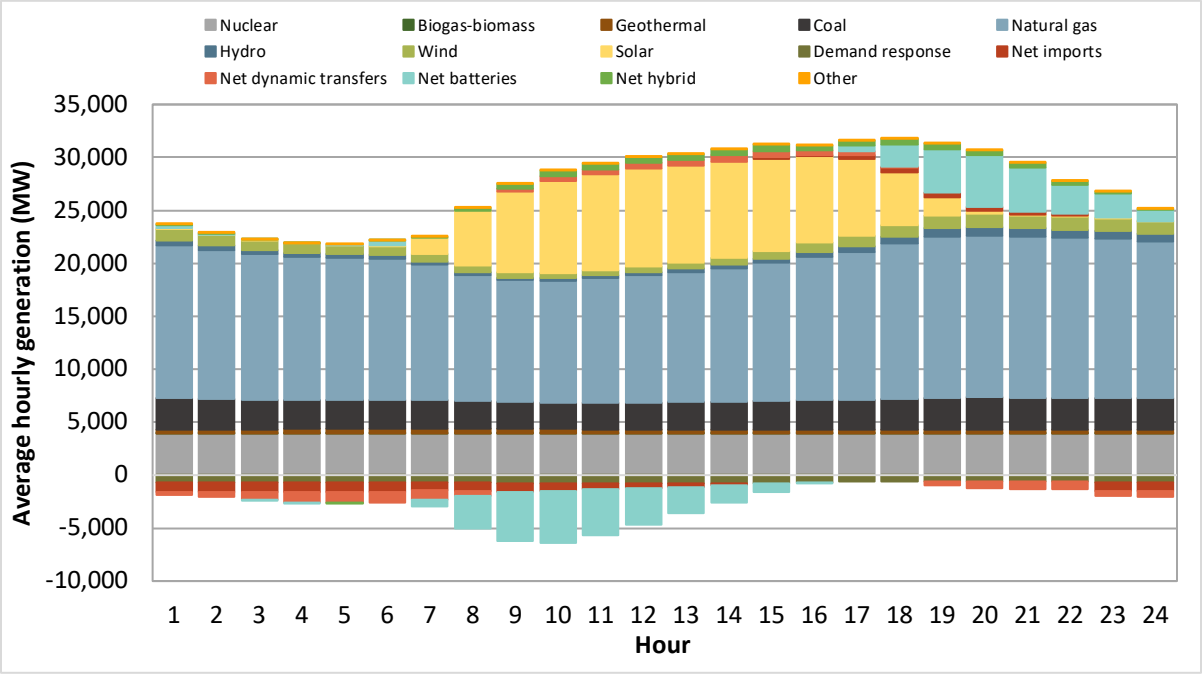


Figure 1.10 Desert Southwest - Change in average hourly generation by fuel type (Q3 2026 vs. Q3 2025)

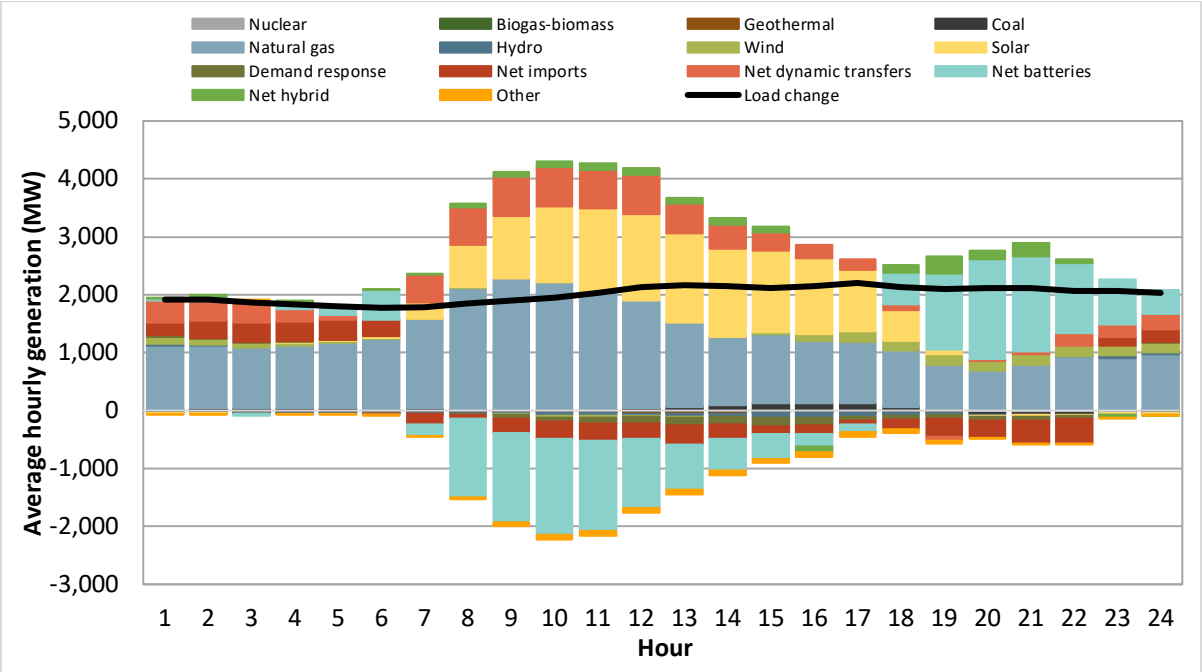


Figure 1.11 Intermountain West - Average hourly generation by fuel type (Q3 2026)

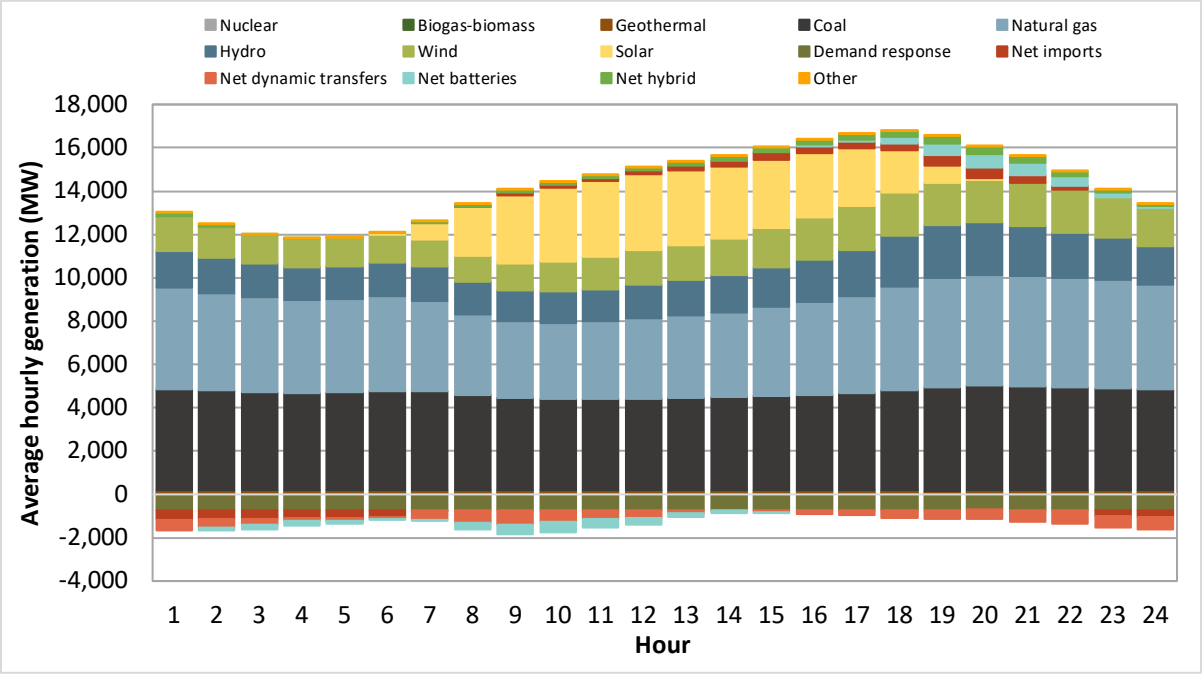


Figure 1.12 Intermountain West - Change in average hourly generation by fuel type (Q3 2026 vs. Q3 2025)

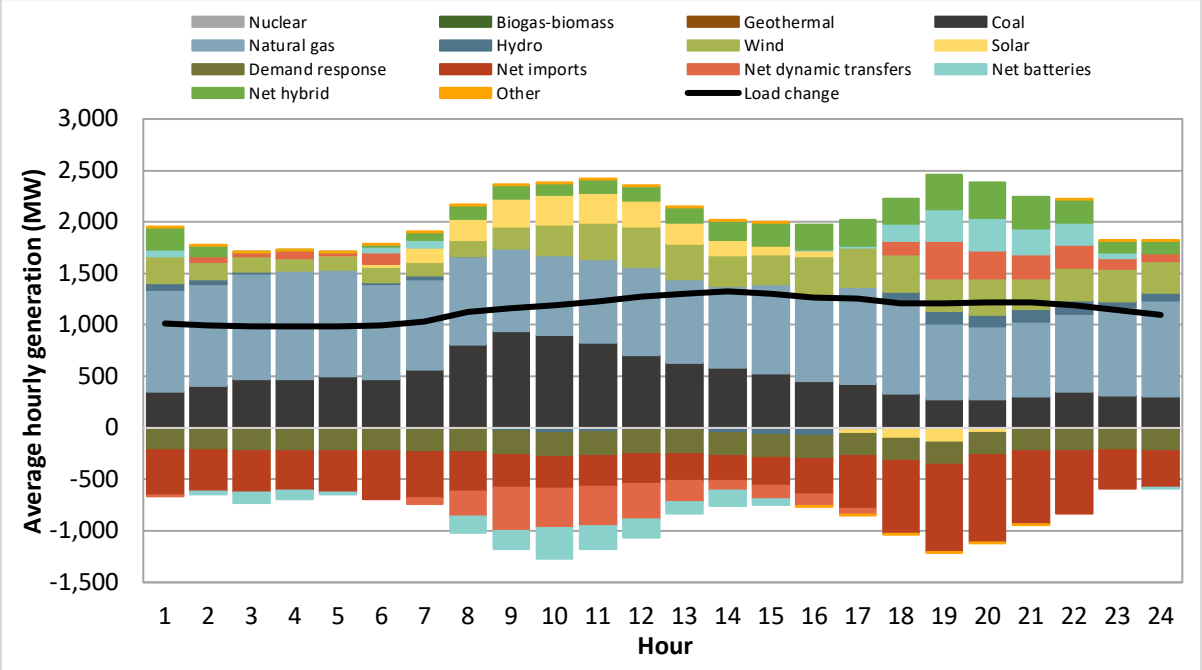


Figure 1.13 Pacific Northwest - Average hourly generation by fuel type (Q3 2026)

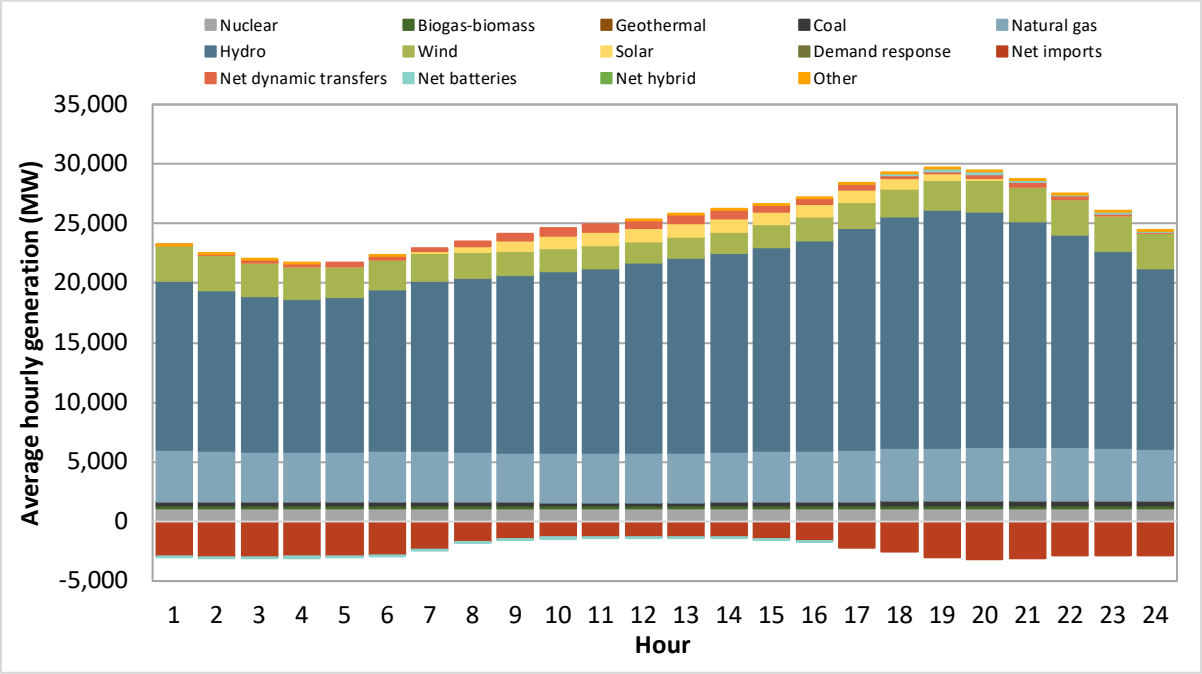
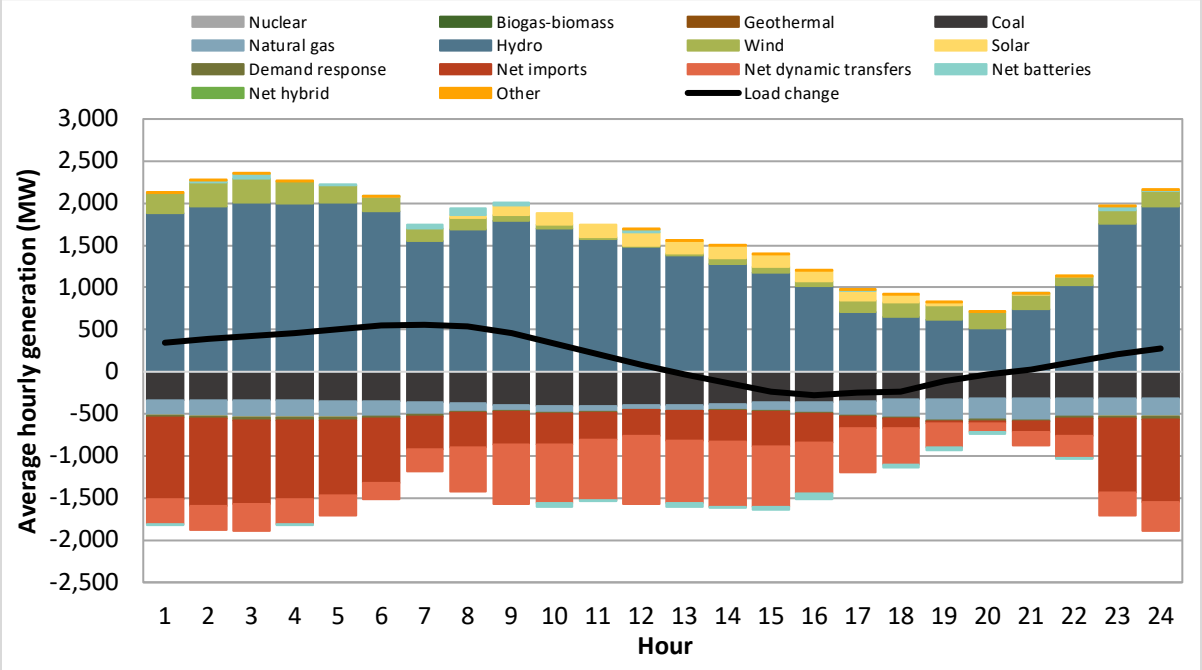


Figure 1.14 Pacific Northwest - Change in average hourly generation by fuel type (Q3 2026 vs. Q3 2025)



1.4 Interchanges between WEIM regions

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 region is represented as a positive value, while power flowing out of a region 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 third quarters of 2025 and 2026, net interchange after dynamic transfers (red line) increased in California and the Desert Southwest by approximately 30 MW (1 percent) and 250 MW (29 percent), respectively. Net interchange after dynamic transfers decreased (i.e., net exports increased) in the Intermountain West and Pacific Northwest by roughly 50 MW (38 percent) and 1,300 MW (148 percent), respectively. In the Pacific Northwest, this decrease represented a significant shift toward net

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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, with net interchange after dynamic transfers decreasing in every hour in the third quarter of 2026 compared to the same quarter of 2025. The increase in net exports was largely associated with higher hydroelectric generation, which increased during all hours in the region.

Figure 1.15 California - Average hourly interchange by quarter

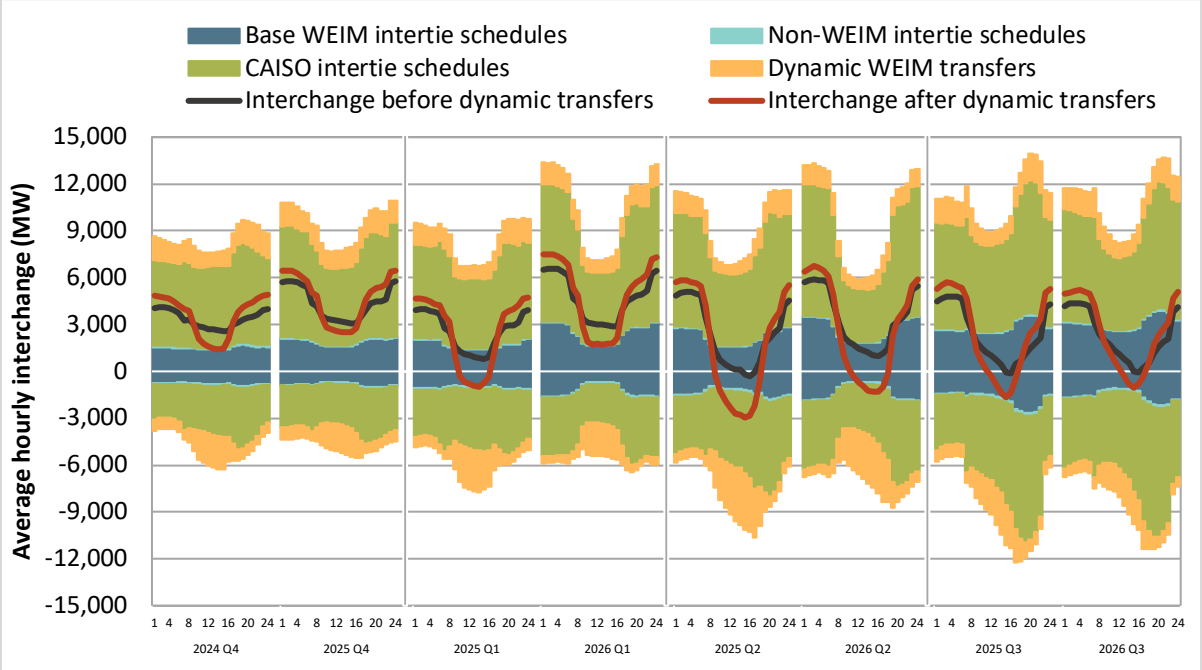


Figure 1.16 California - Average hourly net interchange by quarter

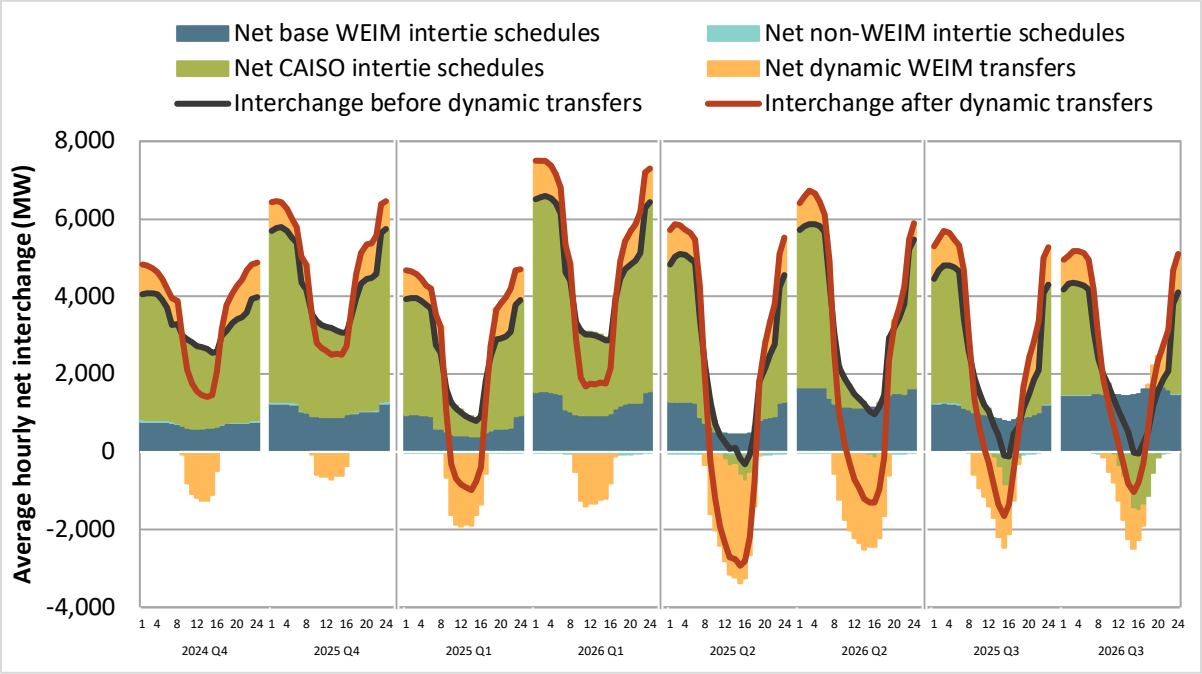


Figure 1.17 Desert Southwest - Average hourly interchange by quarter

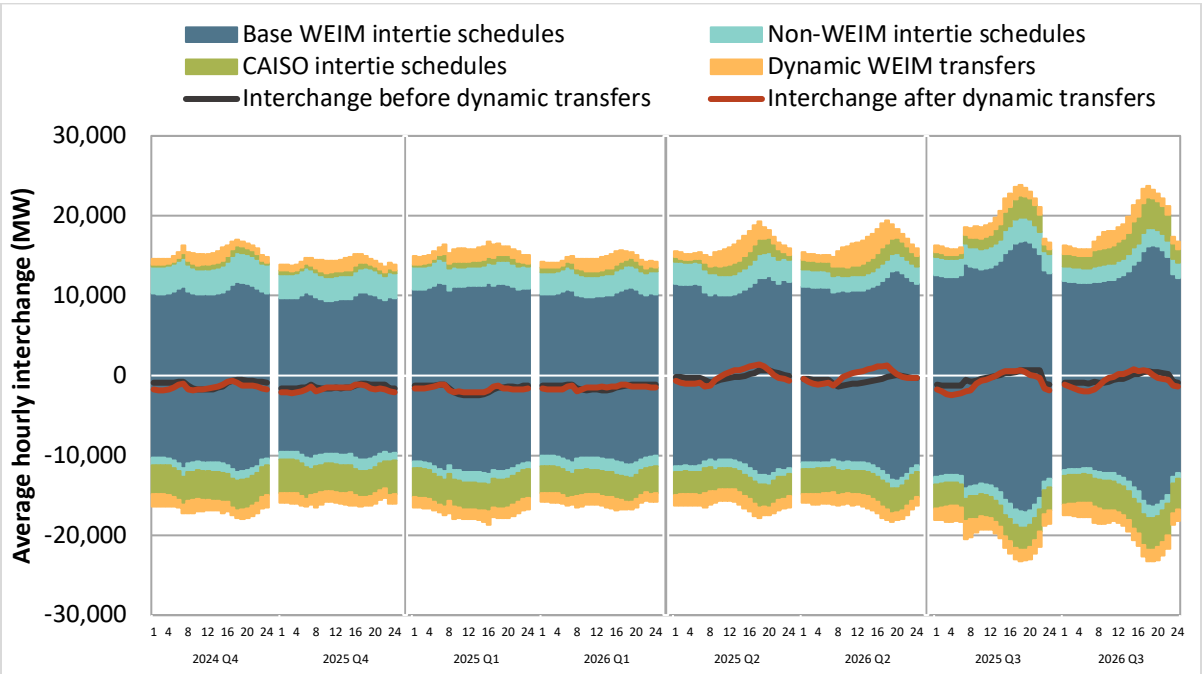


Figure 1.18 Desert Southwest - Average hourly net interchange by quarter

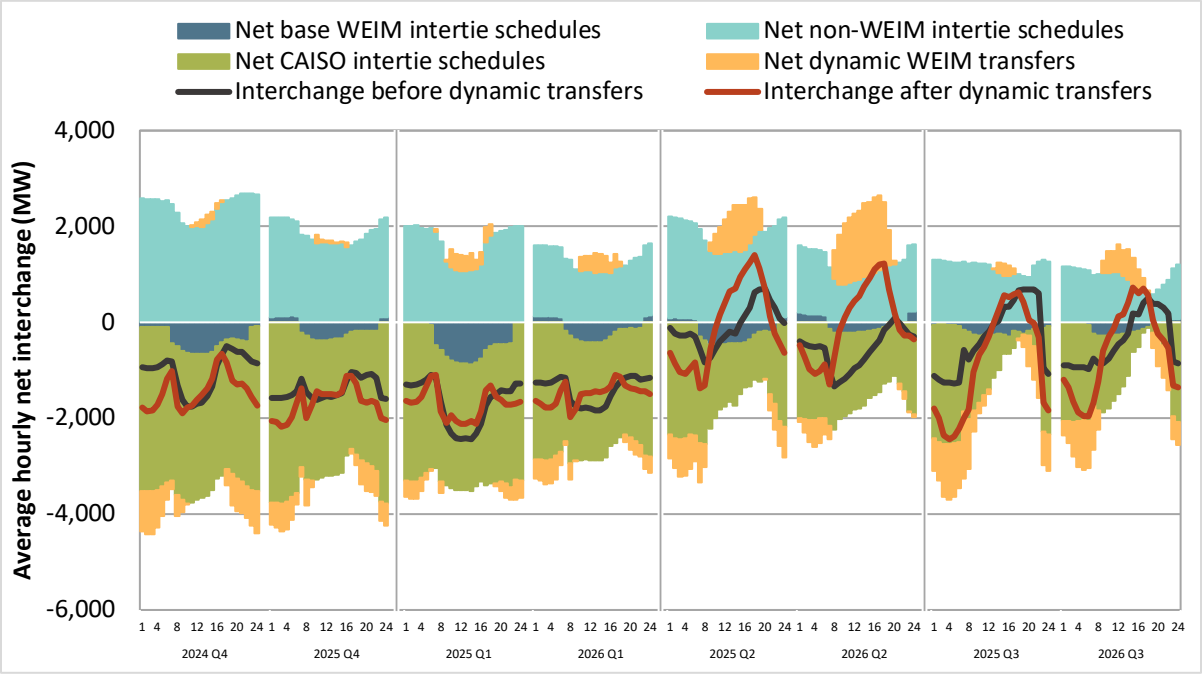


Figure 1.19 Intermountain West - Average hourly interchange by quarter

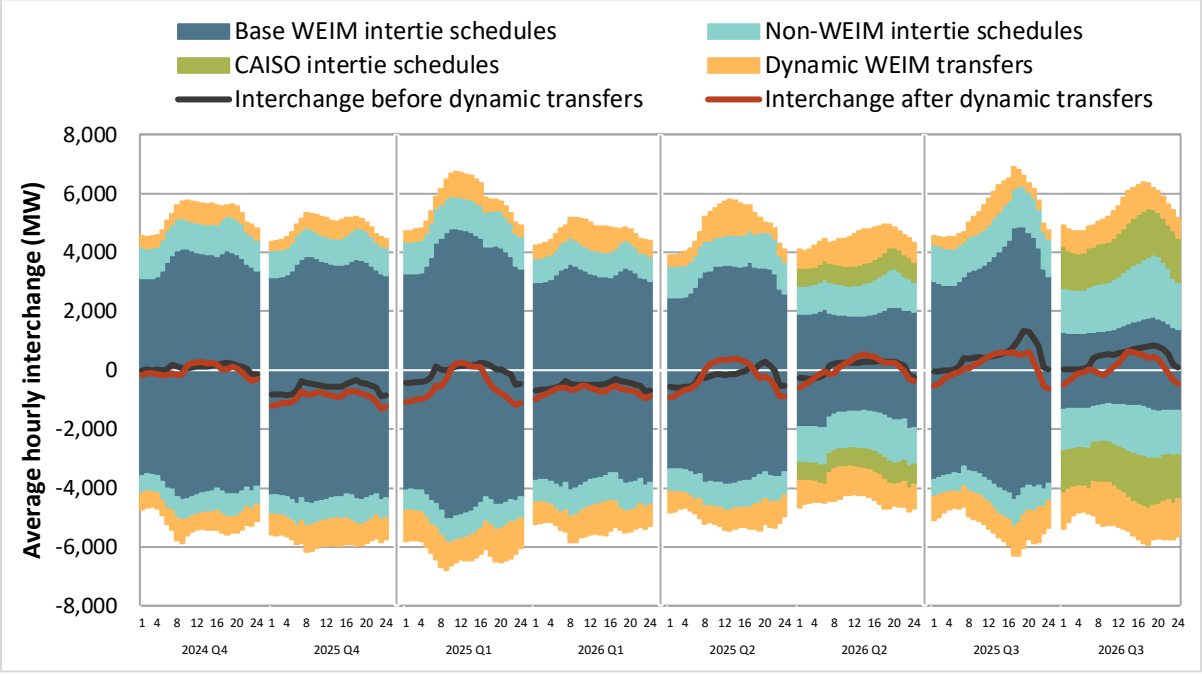


Figure 1.20 Intermountain West - Average hourly net interchange by quarter

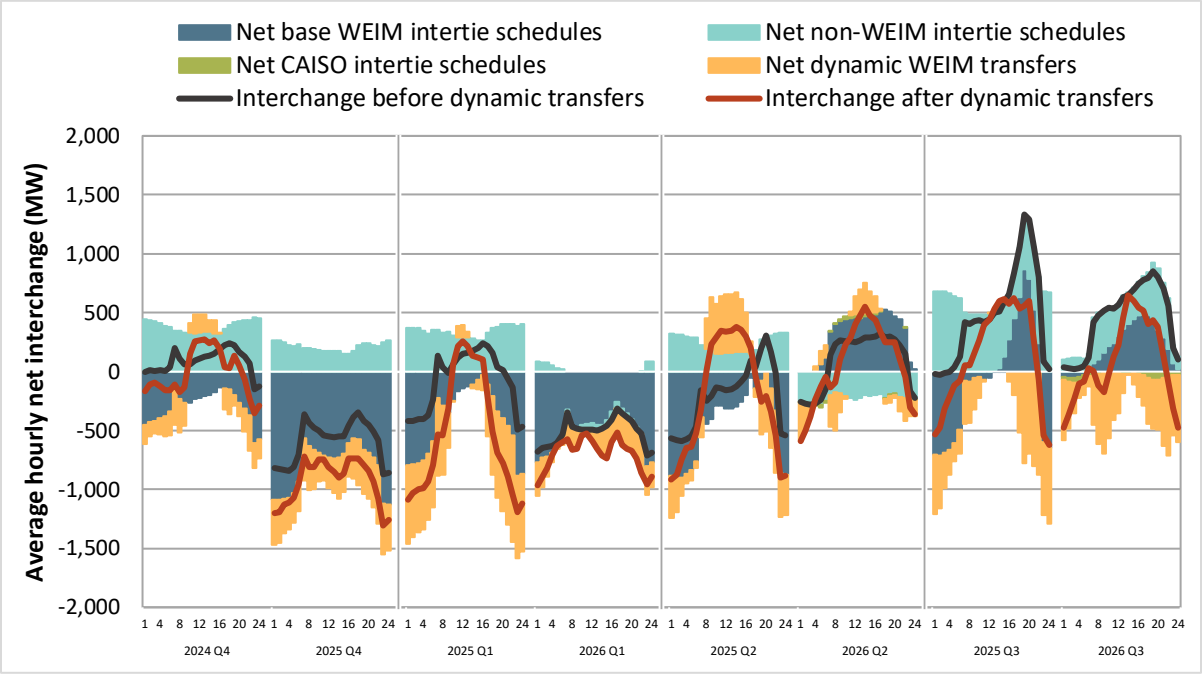


Figure 1.21 Pacific Northwest - Average hourly interchange by quarter

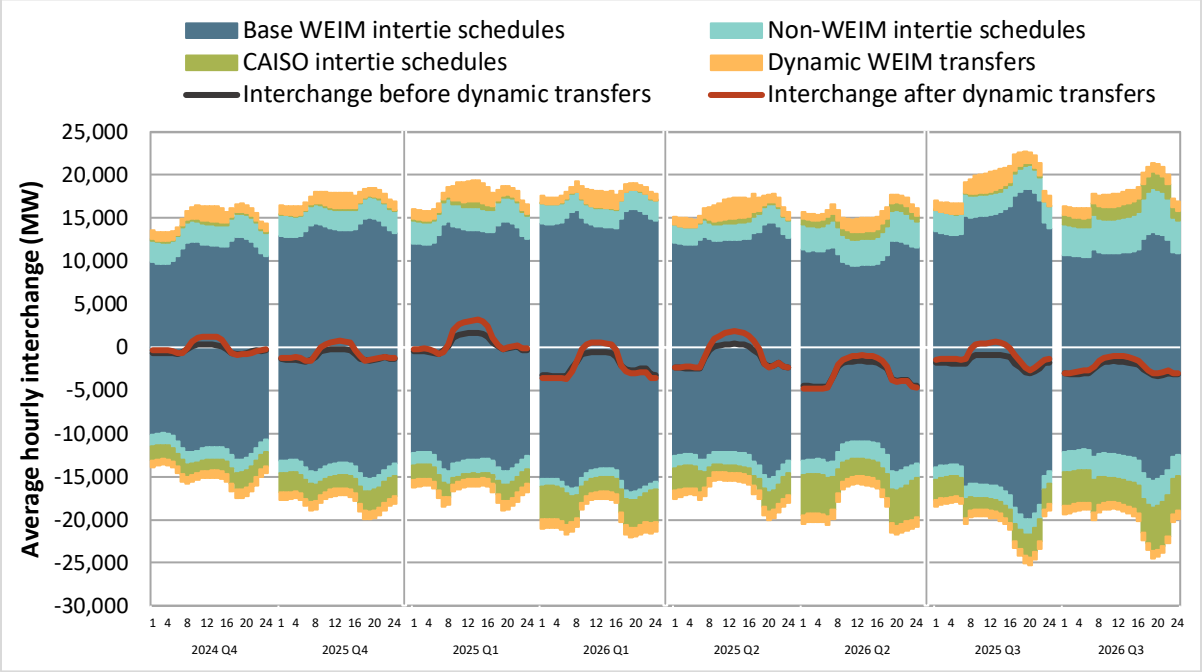
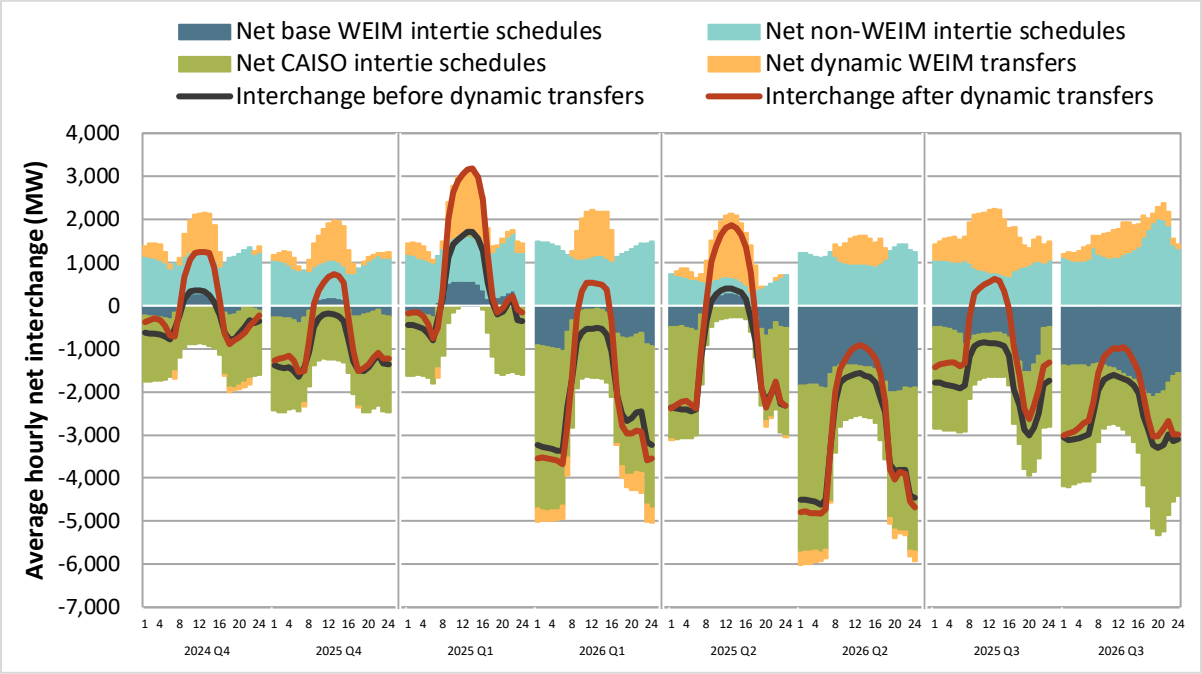


Figure 1.22 Pacific Northwest - Average hourly net interchange by quarter



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 third quarter of 2026, about a 13 percent increase compared to the third quarter of 2025.[13] In the California (non-CAISO) region of the WEIM, outages averaged about 3,200 MW, a decrease of about 450 MW from the third quarter of 2025. The Desert Southwest region averaged about 7,100 MW of total generation outages, a nine percent increase from the third quarter of 2025. The Intermountain West region averaged about 3,700 MW of total generation outages, about a 62 percent increase from the third quarter of 2025. The Pacific Northwest region averaged about 2,300 MW of total generation outages, comparable to the third quarter of 2025.

Under the ISO's current 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

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, PACE, Black Hills, and Power Watch. 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.

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 averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the third quarter of 2026 for the California ISO balancing area. 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 quarterly outages presented, there are usually more outages in the late fall, winter, and early spring than in the summer months, and this trend continued in the third quarter of 2026.

During the third quarter of 2026, the average total generation on outage in the California ISO balancing area was about 15,700 MW, which is an increase of about 13 percent compared to the third quarter of 2025, as shown in Figure 1.23. Other forced outages increased by about 12 percent, an increase of about 870 MW. Forced maintenance and plant trouble outages increased by about 10 percent when compared to the same quarter last year, an increase of about 490 MW. Compared to the third quarter of 2025, planned maintenance outages increased by 115 percent (about 725 MW) on average, and other planned outages decreased by 32 percent (about 280 MW).

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

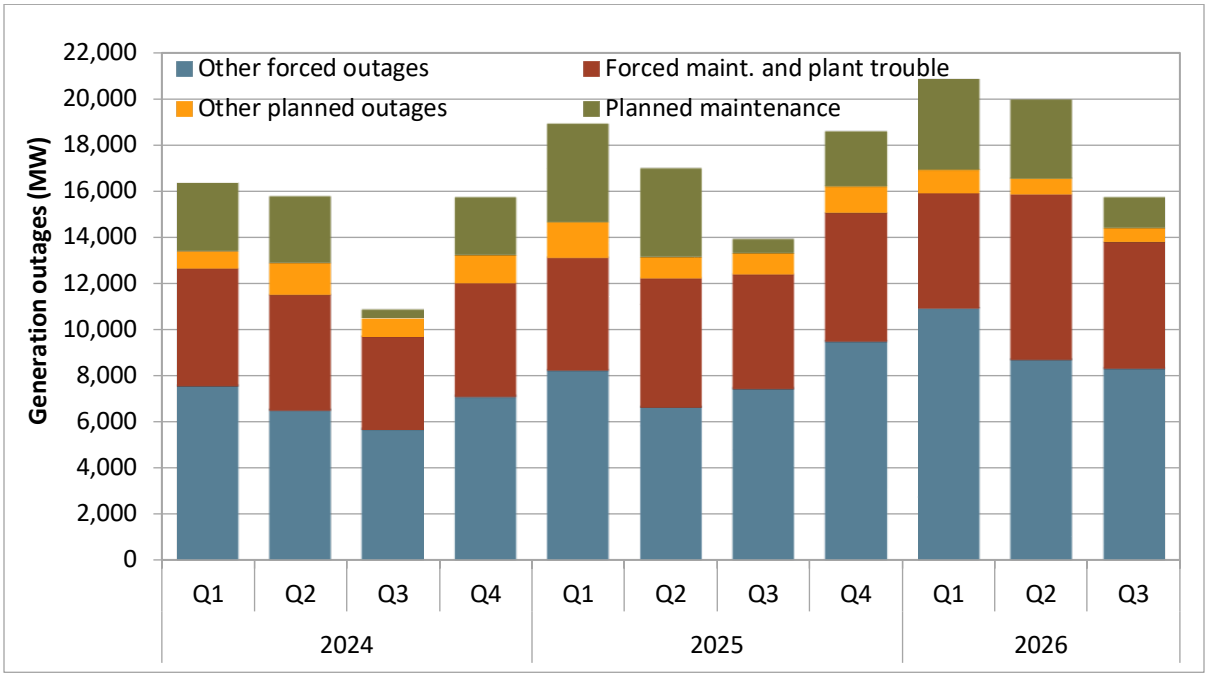
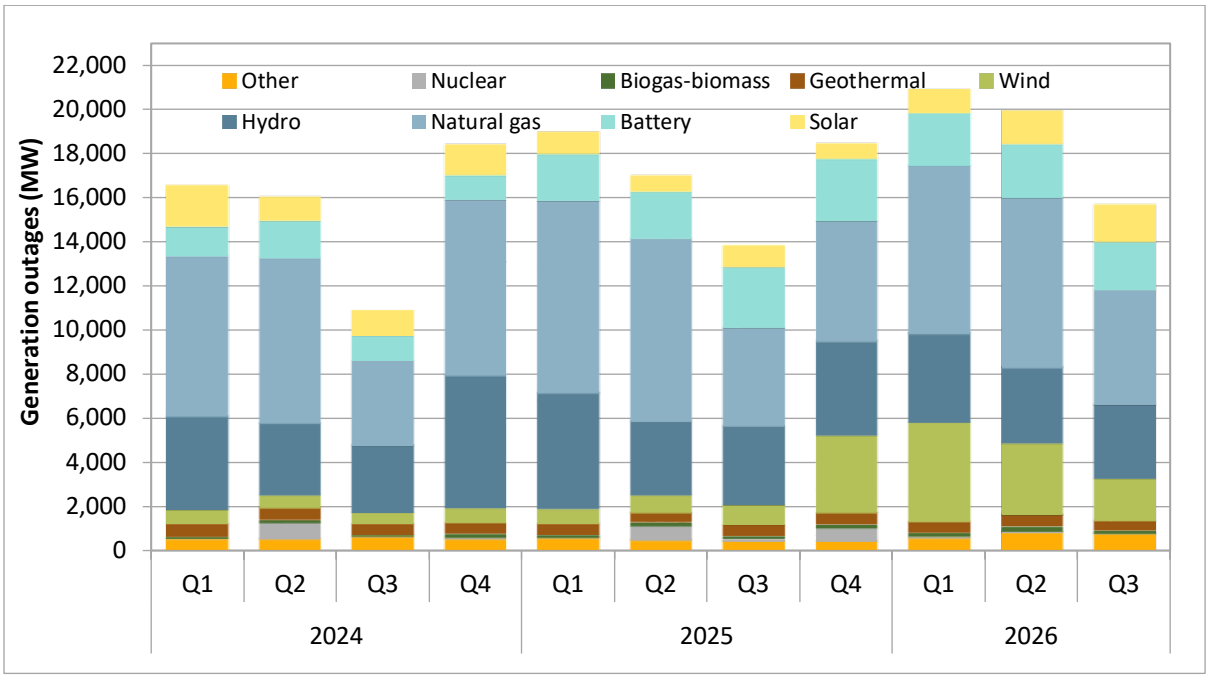


Figure 1.24 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[14] Natural gas, hydroelectric generation, battery, wind, and solar had the largest volume of outages in the third quarter of 2026 and averaged about 5,200 MW, 3,300 MW, 2,150 MW, 2,000 MW and 1,700 MW, respectively. These five fuel types accounted for a combined 91 percent of the generation outages for the quarter. The amount of wind, solar, and natural gas generation outages increased by about 110 percent, 70 percent, and 15 percent while battery and hydro fuel types decreased by about 21 percent and six percent, respectively, relative to the third quarter of 2025.

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



California (non-CAISO) region

Figure 1.25 and Figure 1.26 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the third quarter of 2026 for resources in the California WEIM region, excluding the CAISO balancing area.[15] 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 2026. Average total generation outages in the third quarter were about 3,200 MW, about a 12 percent decrease compared to the third quarter of 2025. Total forced outages decreased by about 17 percent while total planned outages increased by about 17 percent. Outages from hydro and natural gas resources decreased in the third quarter by about 32 percent and 13 percent, respectively, compared to the same period in 2025. Solar outages increased nearly 500 percent in this period.

[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.

Figure 1.25 California WEIM region quarterly average of maximum daily generation outages by type – peak hours

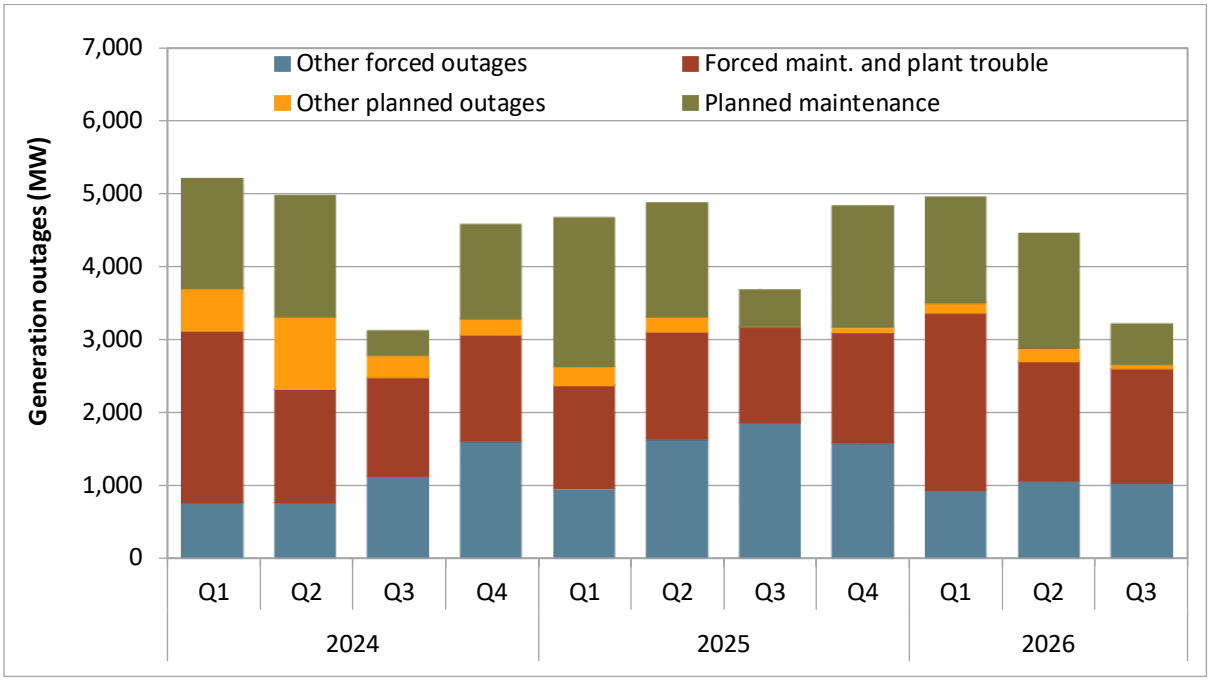
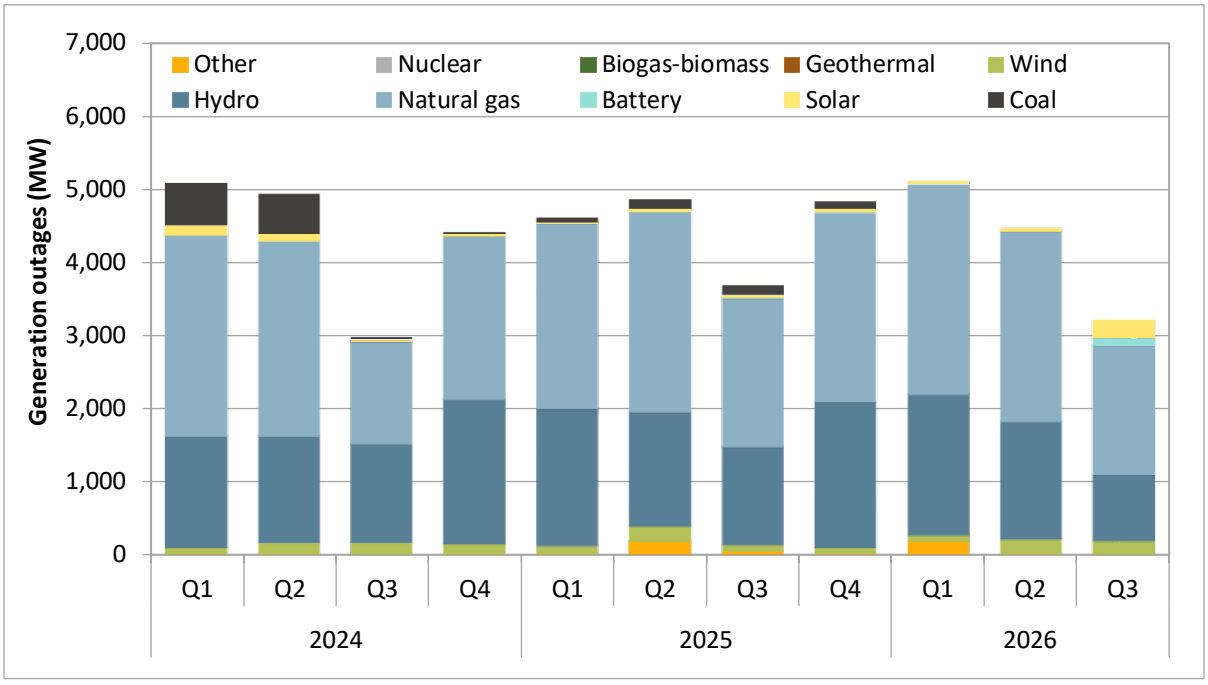


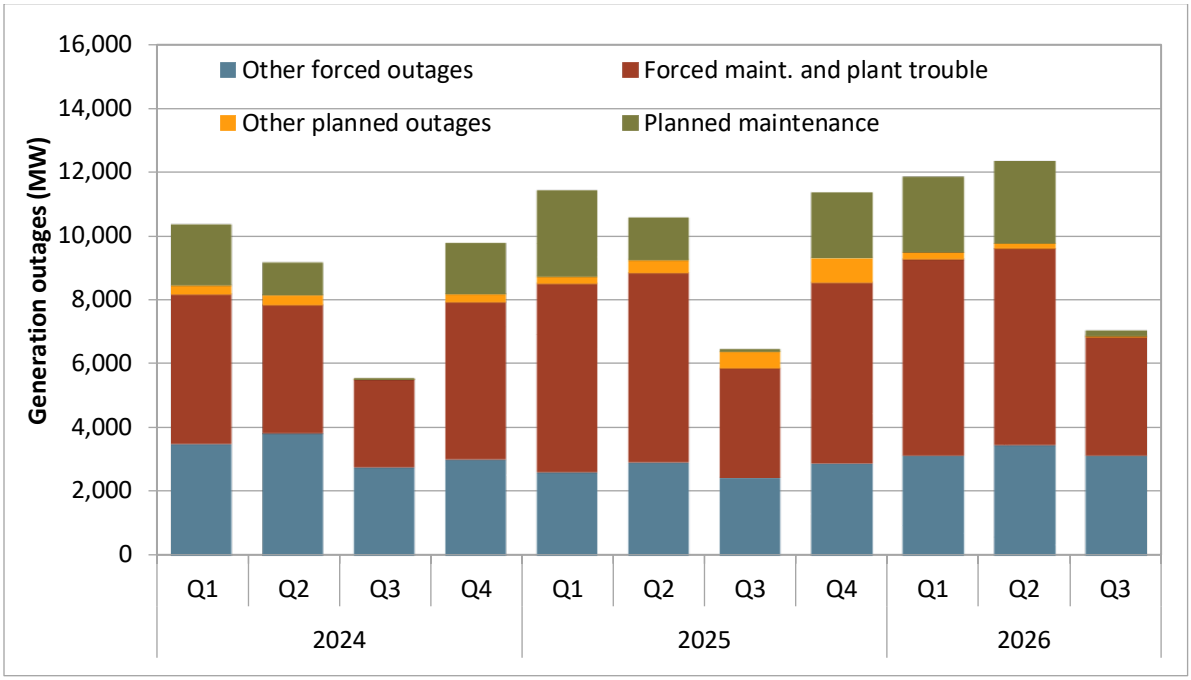
Figure 1.26 California WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Desert Southwest

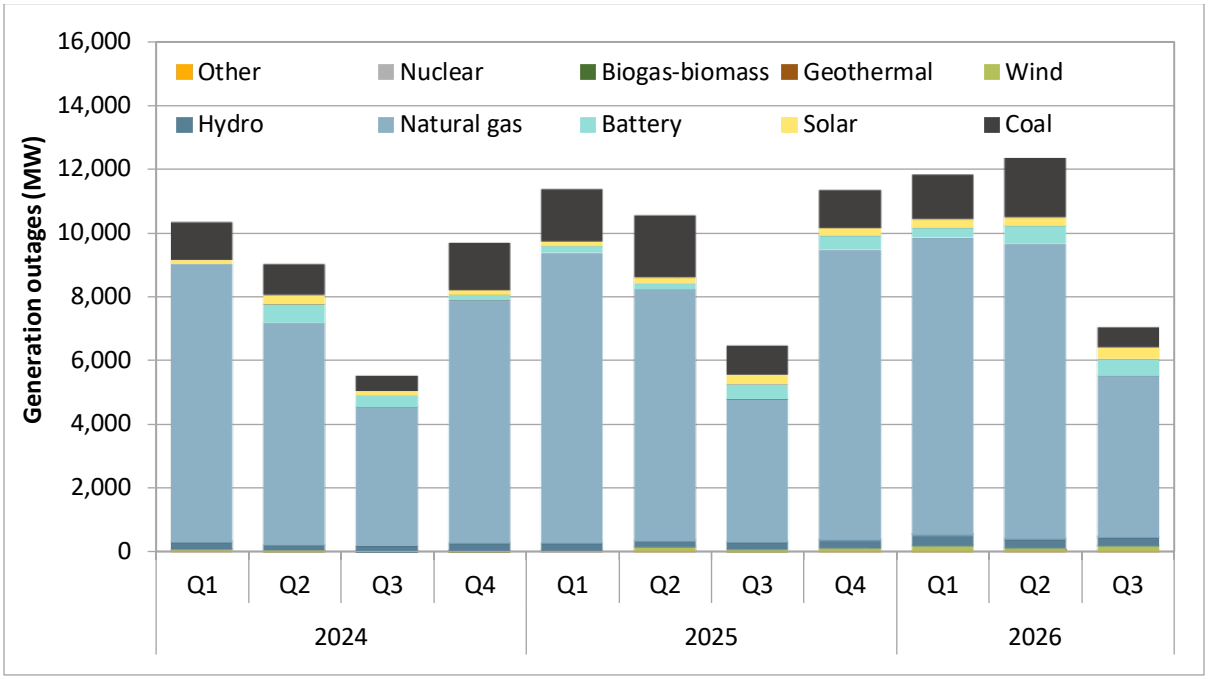
Figure 1.27 and Figure 1.28 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the third quarter of 2026 for entities in the Desert Southwest WEIM region.[16] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in the third quarter of 2026. Average total generation outages increased by about 580 MW, or approximately nine percent, compared to the third quarter of 2025. Total forced outages increased by about 17 percent while total planned outages decreased by about 60 percent. Outages from natural gas resources increased by about 12 percent while coal decreased by 30 percent.

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



[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 fuel type – peak hours



Intermountain West

Figure 1.29 and Figure 1.30 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the third quarter of 2026 for entities in the Intermountain West WEIM region.[17] Average total generation outages increased by approximately 1,400 MW, or about 62 percent, driven by increases in planned maintenance outages which more than tripled in the third quarter of 2026 compared to the third quarter of 2025.

[17] The Intermountain West region includes AVA, IPCO, NWMT, PACE, Black Hills, and Power Watch.

Figure 1.29 Intermountain West WEIM region quarterly average of maximum daily generation outages by type – peak hours

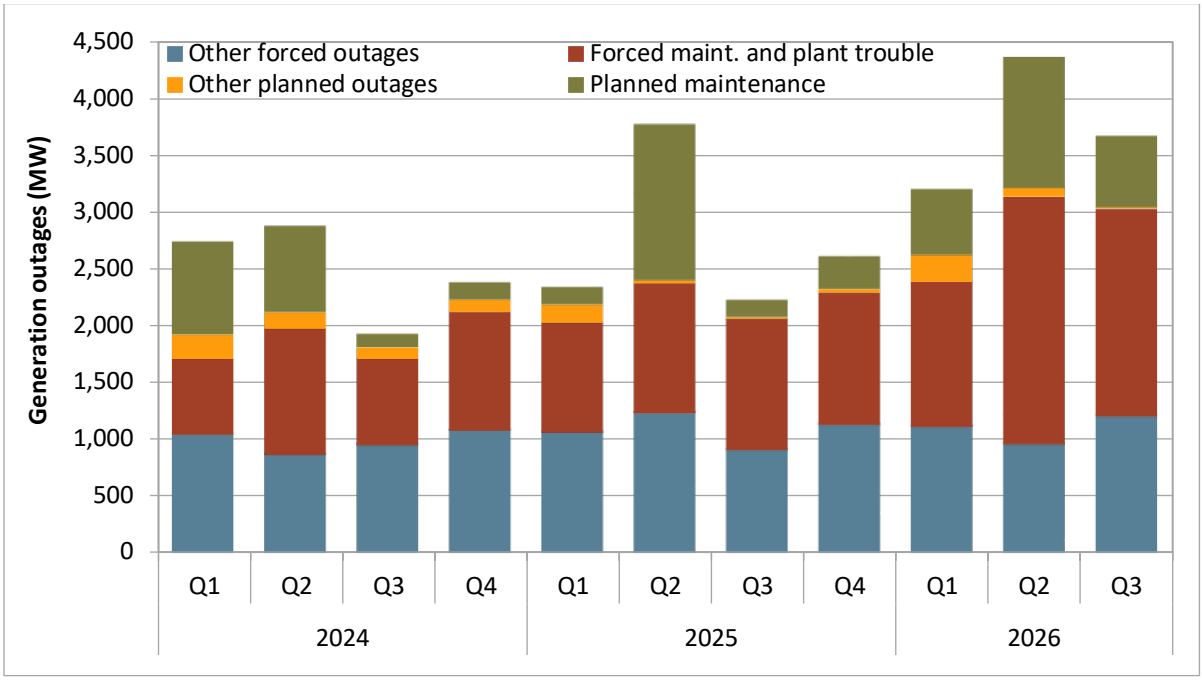
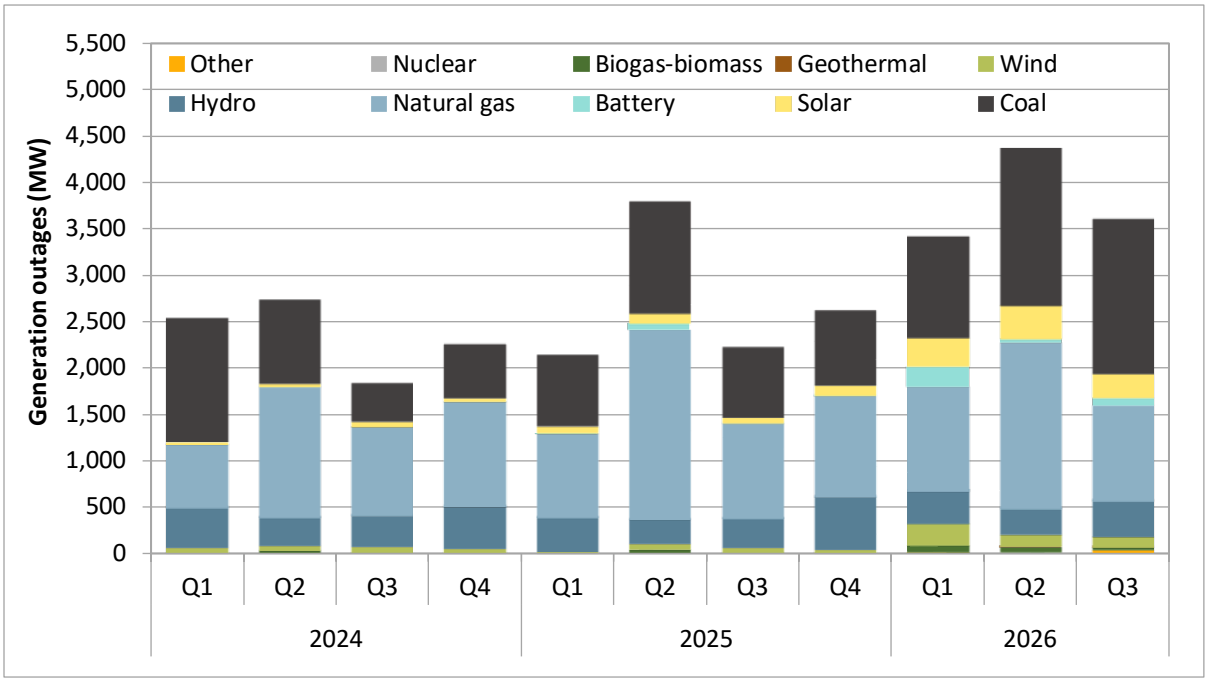


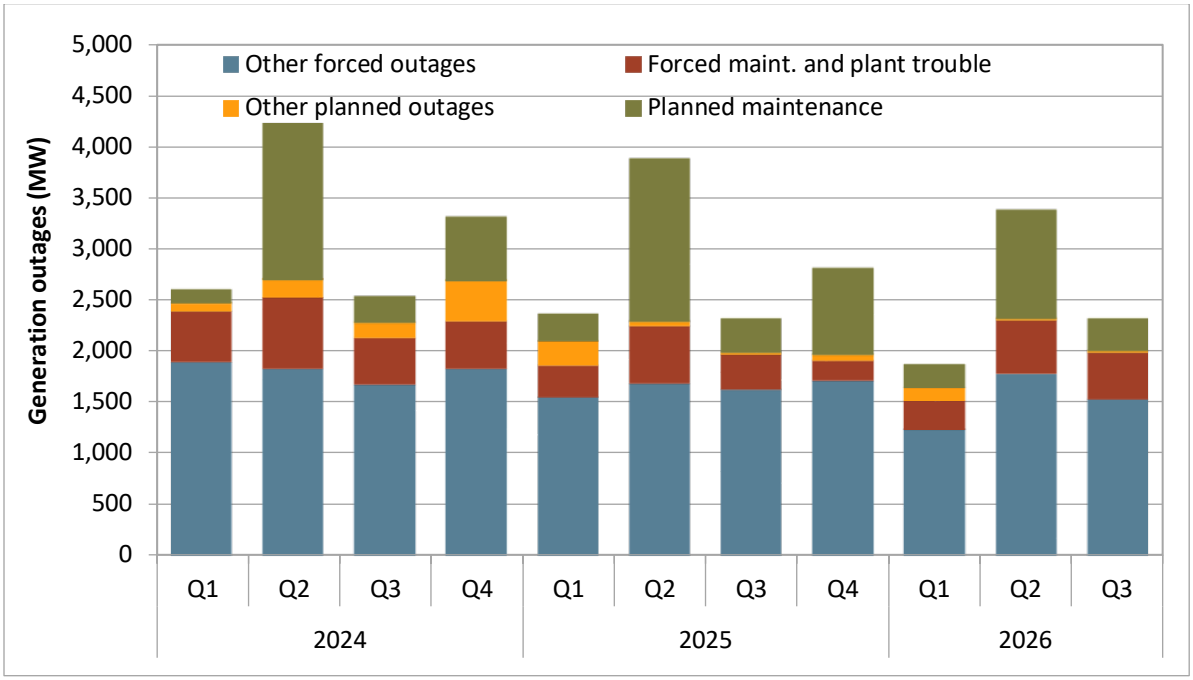
Figure 1.30 Intermountain West WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Pacific Northwest

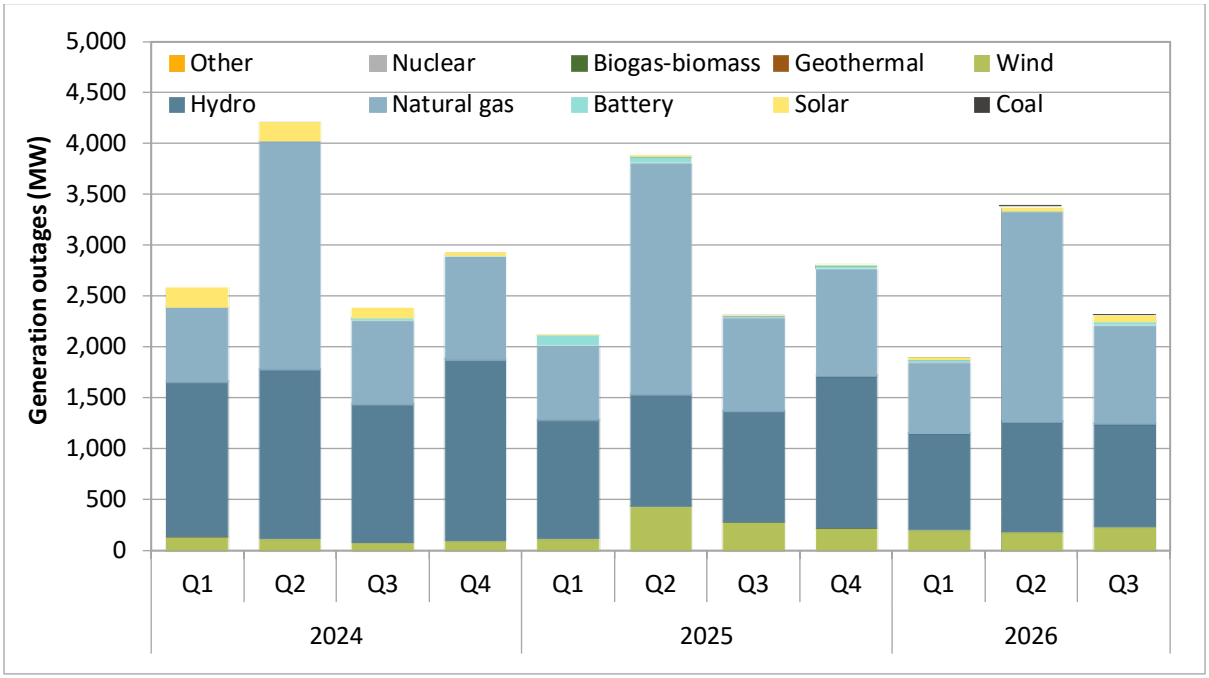
Figure 1.31 and Figure 1.32 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the third quarter of 2026 for resources in the Pacific Northwest WEIM region.[18] The typical seasonal outage pattern for the Pacific Northwest region is more outages during Q2 and Q4, and relatively lower outages during the first and third quarters. This trend is still primarily driven by planned outages for maintenance, which are generally performed outside of Q1, the Pacific Northwest's high load period, and Q3, the high load period for the West overall. Average total generation outages in the third quarter of 2026 were essentially unchanged from the same period in the prior year. However, natural gas outages increased by 5 percent, offsetting decreases in wind and hydro outages of 18 percent and 7 percent, respectively.

Figure 1.31 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by type – peak hours



[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 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). On May 6, 2026, the Black Hills Energy (BHBA) balancing area, located in the Intermountain West, joined the WEIM system.
- **Pacific Northwest**: includes 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 Q3 2026 (blue line) and Q3 2025 (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 third 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 Q3 2026, the curve peaks between 80 and 85 GW, indicating that these load levels were most frequently observed.[21]

The system load distribution in the third quarter of 2026 largely resembles that of the same quarter last year. However, relative to Q3 2025, the Q3 2026 system load distribution is shifted slightly to the right, indicating higher load levels but a similar load profile.

[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

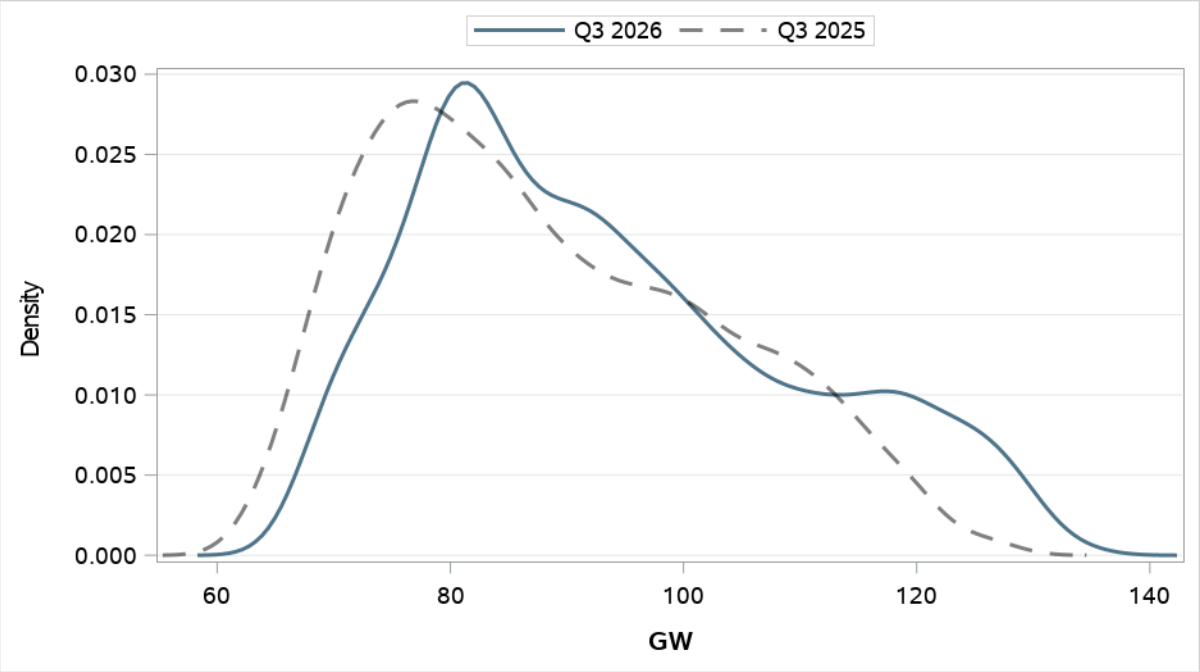


Figure 2.2 shows the monthly average 5-minute market load categorized by region from July 2024 through September 2026. The total system load for Q3 of this year averaged 93.4 GW, representing an increase of approximately 5.8 percent (5.1 GW) compared to the same quarter of 2025. This represents the largest year-over-year increase in quarterly average system load over the past three years. Only a small part of this large increase in load between Q3 2025 and Q3 2026 was due to Black Hills Energy joining the WEIM system in Q2 2026. Black Hills Energy load averaged about 670 MW over the third quarter. Average load in the third quarter of 2026 increased significantly in all regions except for the Pacific Northwest:

- **Pacific Northwest** (green) averaged **22.1 GW**, a 0.2 percent increase.
- **California** (blue) averaged **34.6 GW**, a 5.9 percent increase.
- **Desert Southwest** (yellow) averaged **24.0 GW**, a 9.0 percent increase.
- **Intermountain West** (red) averaged **12.6 GW**, a 10.0 percent increase.

The WEIM total market load tends to be lowest in April and tends to peak in July or August. Regions such as California, the Intermountain West, and the Desert Southwest closely aligned with the overall seasonal trends of the total WEIM load, recording 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)

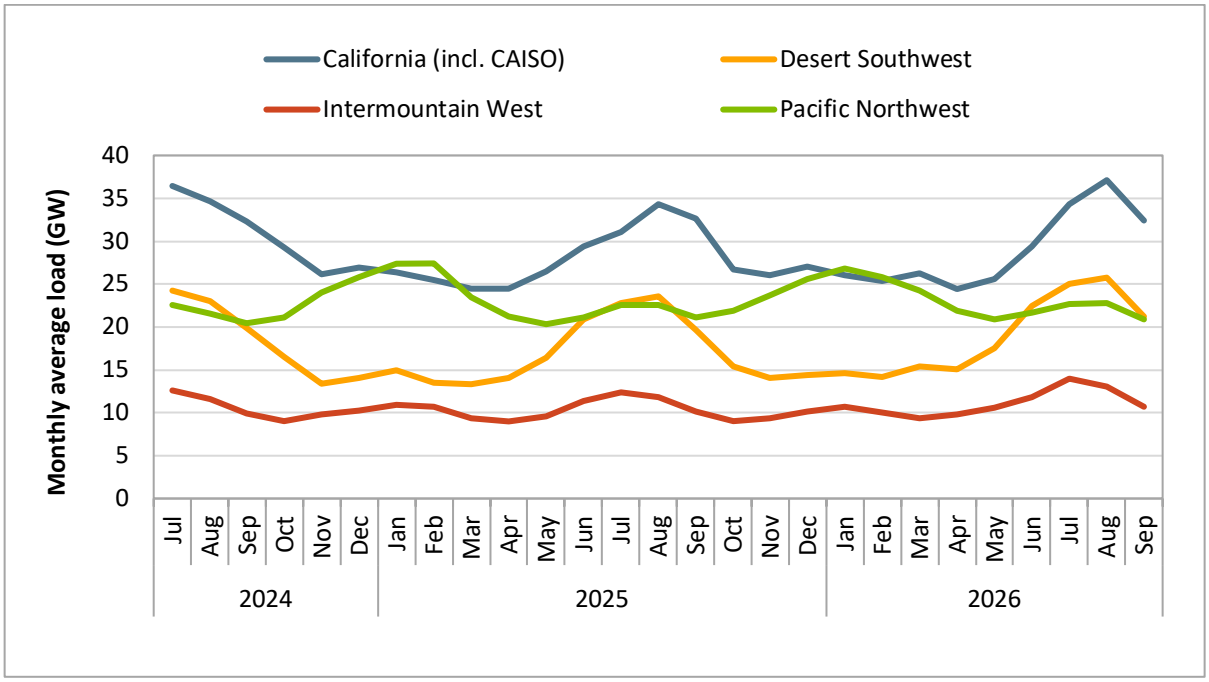
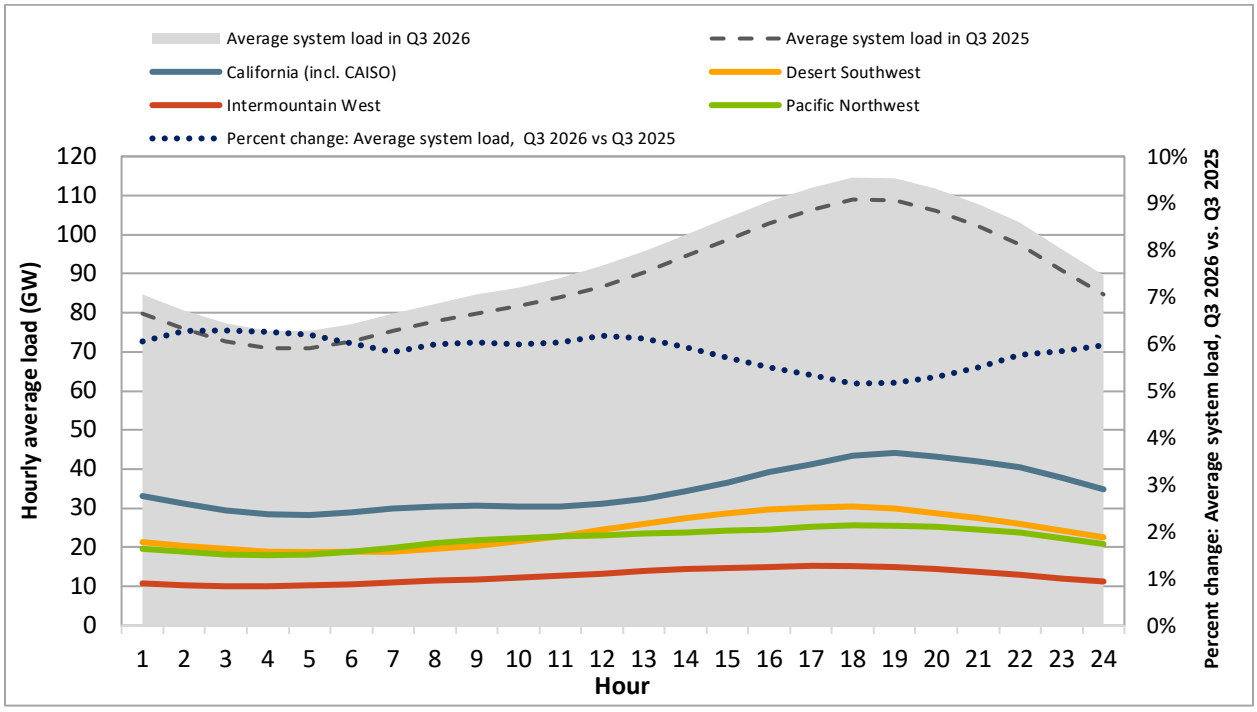


Figure 2.3 displays the hourly average 5-minute market load across different regions in Q3 2026. Each color represents a specific region. The gray area represents the average WEIM system-wide total load for the third quarter of 2026 while the gray dashed line represents the same for the third quarter of 2025. The navy blue dotted line represents the percent change of load between Q3 2025 and Q3 2026, computed for each hour by taking the difference in average system load levels between Q3 2026 and Q3 2025, and then dividing the difference by the average system load level in Q3 2025. The percent change for each hour measures how the average system load has changed in Q3 2026 relative to Q3 2025, expressed as a percentage.

The WEIM system-wide hourly average load peaked at hour-ending 18, recording a load of 114.6 GW, while the lowest load occurred at hour-ending 5, at 75.3 GW. In Q3 of 2026, all regions recorded peak hourly average loads during the evening hours, between hours-ending 17 and 19. The peak average hourly load for each region is given below:

- **Pacific Northwest:** peak load of 25.6 GW at hour-ending 18.
- **California:** peak load of 44.2 GW at hour-ending 19.
- **Desert Southwest**: peak load of 30.4 GW at hour-ending 18.
- **Intermountain West**: peak load of 15.3 GW at hour-ending 17.

Figure 2.3 Hourly average 5-minute market load by region (Q3 2026)



2.2 Peak load

On August 26, 2026, the WEIM system recorded the highest 5-minute market load forecast during the third quarter of 2026. On this day, the WEIM system load peaked at 137.0 GW during hour-ending 18, interval 10. This was significantly higher than the peak WEIM load during Q3 2025 (130.1 GW). Figure 2.4 shows the hourly average 5-minute market load forecast for each balancing authority area (BAA) on August 26, 2026.

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 of the day. The system peak occurred during hour-ending 18, and all balancing areas recorded peak loads during the evening hours, between hours-ending 15 and 19.

Figure 2.4 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market, August 26, 2026)

	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SYSTEM	99.8	104.6	110.5	116.7	123.0	128.3	133.0	136.0	137.0	136.3	132.6	128.1	123.3	115.0	106.1
CAISO	29.9	30.8	32.5	34.4	37.2	39.7	42.3	44.2	45.3	45.1	43.9	42.7	41.6	39.1	36.0
BANC	2.09	2.23	2.43	2.68	2.93	3.21	3.45	3.59	3.61	3.58	3.45	3.22	3.04	2.73	2.40
Turlock ID	.41	.44	.47	.51	.55	.58	.61	.62	.62	.62	.61	.58	.55	.50	.45
LADWP	3.98	4.32	4.71	5.00	5.26	5.45	5.62	5.67	5.70	5.64	5.34	5.14	4.88	4.53	4.16
NV Energy	6.19	6.69	7.21	7.74	8.23	8.65	9.07	9.17	9.13	8.99	8.79	8.48	8.00	7.44	6.90
Arizona PS	6.30	6.88	7.44	7.96	8.41	8.76	8.83	8.87	8.95	8.92	8.60	8.44	8.05	7.48	6.90
Tucson Electric	1.87	2.01	2.28	2.43	2.63	2.78	2.83	2.93	2.92	2.90	2.79	2.63	2.43	2.23	2.03
Salt River Project	6.41	7.05	7.70	8.27	8.61	8.87	8.90	9.07	8.66	8.76	8.40	8.08	7.71	7.16	6.61
PSC New Mexico	1.99	2.12	2.24	2.39	2.52	2.58	2.59	2.50	2.36	2.34	2.30	2.21	2.12	1.98	1.86
WAPA - Desert SW	1.12	1.22	1.33	1.41	1.49	1.53	1.55	1.57	1.54	1.54	1.48	1.41	1.31	1.23	1.15
El Paso Electric	1.58	1.75	1.91	2.06	2.16	2.25	2.30	2.31	2.24	2.21	2.08	1.94	1.78	1.63	1.49
PacifiCorp East	7.51	7.79	8.19	8.69	8.99	9.01	9.00	8.94	8.97	8.84	8.61	8.31	7.91	7.38	6.92
Idaho Power	2.85	2.99	3.15	3.37	3.56	3.65	3.73	3.67	3.74	3.73	3.71	3.47	3.25	2.99	2.73
Black Hills Energy	0.70	0.72	0.75	0.78	0.81	0.82	0.83	0.83	0.78	0.77	0.76	0.73	0.69	0.64	0.61
NorthWestern	1.44	1.48	1.54	1.61	1.70	1.75	1.79	1.78	1.76	1.75	1.70	1.63	1.53	1.41	1.34
Avista Utilities	1.40	1.49	1.58	1.68	1.77	1.79	1.84	1.86	1.86	1.84	1.77	1.66	1.54	1.38	1.23
BPA	7.19	7.38	7.54	7.76	7.94	8.16	8.35	8.52	8.62	8.64	8.53	8.29	8.07	7.61	7.09
Tacoma Power	.45	.47	.48	.49	.50	.52	.53	.54	.56	.56	.54	.54	.52	.48	.44
PacifiCorp West	2.52	2.60	2.67	2.82	2.97	3.11	3.22	3.28	3.30	3.29	3.22	3.08	2.96	2.71	2.48
Portland GE	2.75	2.76	2.69	2.81	2.92	3.06	3.22	3.37	3.46	3.46	3.46	3.40	3.31	3.10	2.88
Puget Sound Energy	2.68	2.71	2.72	2.73	2.76	2.86	2.99	3.11	3.20	3.19	3.16	3.09	3.03	2.80	2.55
Seattle City Light	1.04	1.06	1.06	1.07	1.08	1.10	1.12	1.16	1.17	1.16	1.14	1.12	1.10	1.04	0.95
Powerex	7.45	7.67	7.85	7.99	8.03	8.18	8.30	8.49	8.48	8.38	8.21	7.92	7.88	7.45	6.94

Hour

Table 2.1 shows the peak 5-minute market load and date for each balancing authority area (and region) during the third quarter of 2026. Nearly all balancing areas recorded quarterly peak load in late July or early August. California ISO and LADWP, both in the California region, recorded quarterly peak loads in early September. The right panel of the table shows each balancing area's load during the system peak load interval on August 26, 2026 (136,958 MW).

Table 2.1 Peak WEIM load (July–September 2026)

Region/balancing area	Peak load (July–September, 2026)		Load during WEIM system peak (26-Aug-2026)	
	Date	Load (MW)	Load (MW)	Percent
WEIM system	**26-Aug-26**	**136,958**	**136,958**	
California	**9-Sep-26**	**59,081**	**55,252**	**40%**
California ISO	9-Sep-26	48,927	45,318	33%
BANC	3-Aug-26	4,259	3,612	3%
LADWP	9-Sep-26	6,040	5,698	4%
Turlock Irrig. District	3-Aug-26	676	624	.5%
Desert Southwest	**24-Jul-26**	**37,361**	**35,800**	**26%**
Arizona Public Service	24-Jul-26	9,321	8,950	7%
El Paso Electric	31-Jul-26	2,551	2,237	1.6%
NV Energy	8-Aug-26	9,704	9,131	7%
PSC New Mexico	27-Jul-26	2,892	2,359	2%
Salt River Project	3-Aug-26	9,163	8,657	6%
Tucson Electric	24-Jul-26	3,067	2,924	2%
WAPA - Desert SW	1-Aug-26	1,694	1,542	1.1%
Intermountain West	**20-Jul-26**	**18,908**	**17,111**	**12%**
Avista Utilities	23-Jul-26	2,062	1,858	1%
Black Hills Energy	26-Jul-26	1,015	781	0.6%
Idaho Power	20-Jul-26	4,182	3,736	3%
NorthWestern Energy	24-Jul-26	2,043	1,762	1%
PacifiCorp East	20-Jul-26	10,464	8,974	7%
Pacific Northwest	**22-Jul-26**	**33,381**	**28,794**	**21%**
BPA	21-Jul-26	9,613	8,623	6%
PacifiCorp West	6-Aug-26	3,727	3,296	2%
Portland General Electric	21-Jul-26	4,503	3,459	3%
Powerex	22-Jul-26	9,870	8,482	6%
Puget Sound Energy	22-Jul-26	4,160	3,203	2%
Seattle City Light	22-Jul-26	1,433	1,171	0.9%
Tacoma Power	22-Jul-26	695	562	.4%

3 Operator load conformance

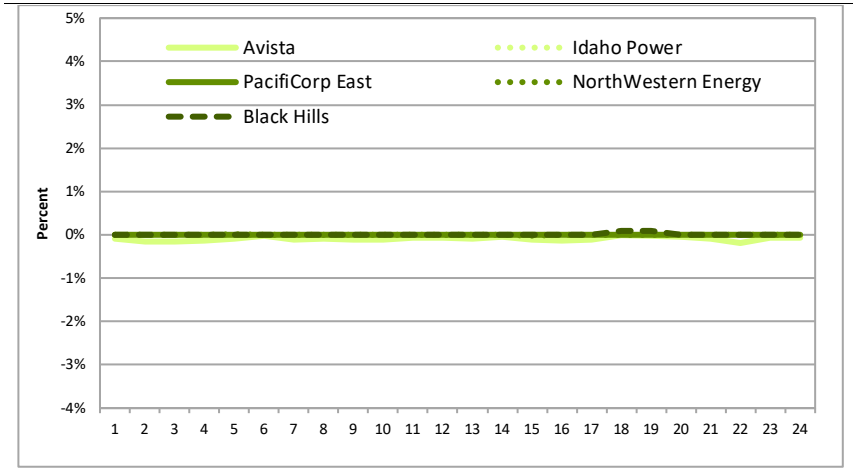
Operators in WEIM balancing areas can manually adjust the load forecasts used in the real-time markets to help maintain system reliability. The ISO refers to this as *load conformance*. These adjustments help account for potential modeling inconsistencies and inaccuracies and create additional unloaded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

3.1 Load conformance – all balancing areas

The figures below show average hourly load conformance in the 15-minute and 5-minute markets during the third quarter of 2026 for each balancing area, expressed as a percentage of average load. The magnitudes of average hourly 5-minute market load conformance adjustments were a non-negligible percentage of load forecasts in many balancing areas. The CAISO balancing area exhibited the largest average load conformance adjustments as a percentage of load in the 15-minute market, as shown by CAISO's secondary axis in Figure 3.4, while BPA also showed notable adjustments in the 15-minute market relative to most other balancing areas.

Figure 3.1 Intermountain West: Average hourly load conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q3 2026)

15-minute market



5-minute market

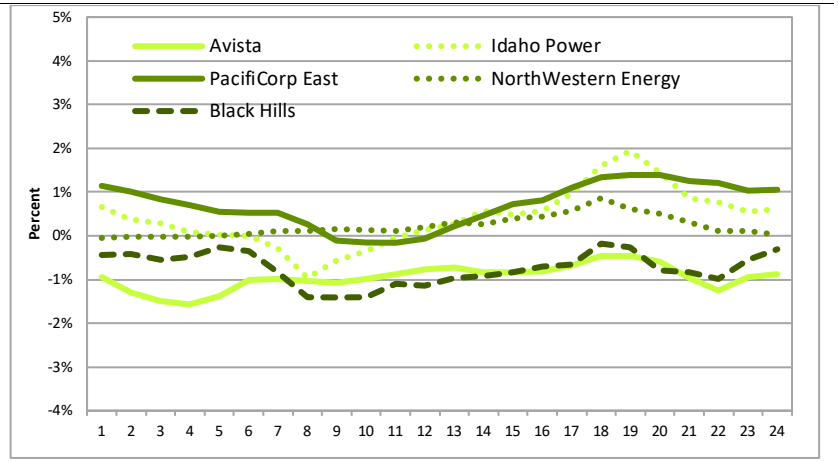
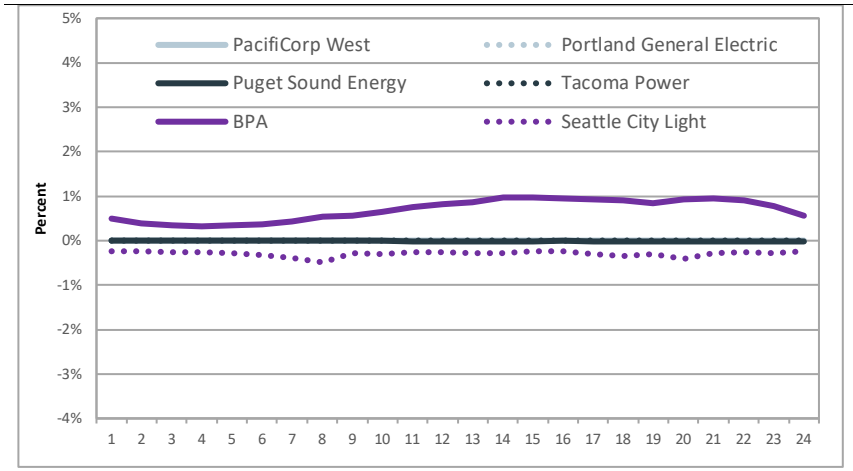


Figure 3.2 Pacific Northwest: Average hourly load conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q3 2026)

15-minute market



5-minute market

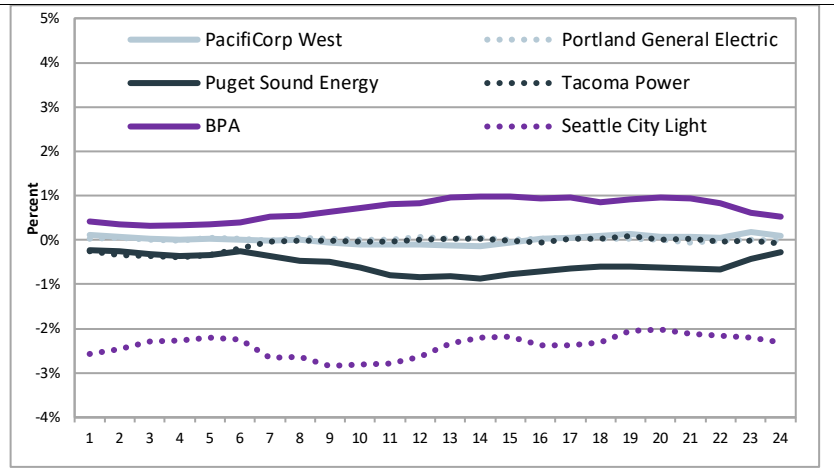
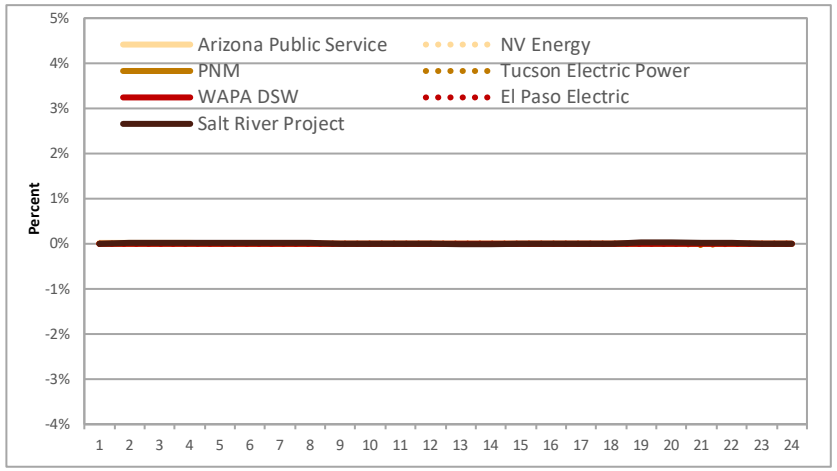


Figure 3.3 Desert Southwest: Average hourly load conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q3 2026)

15-minute market



5-minute market

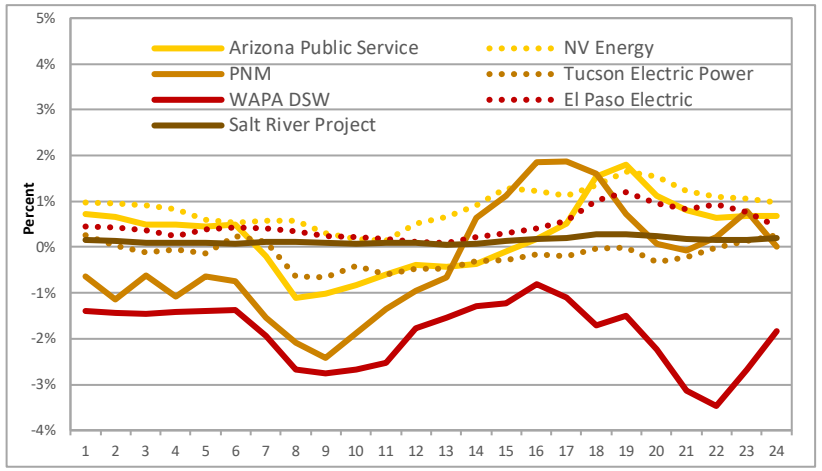
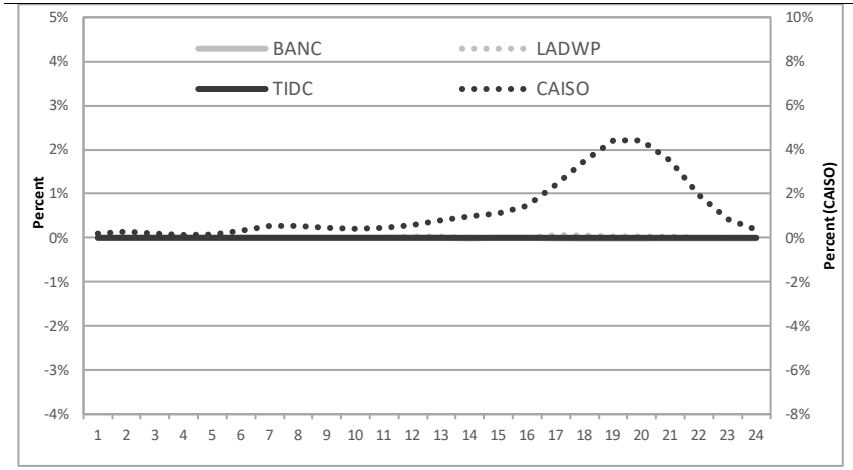
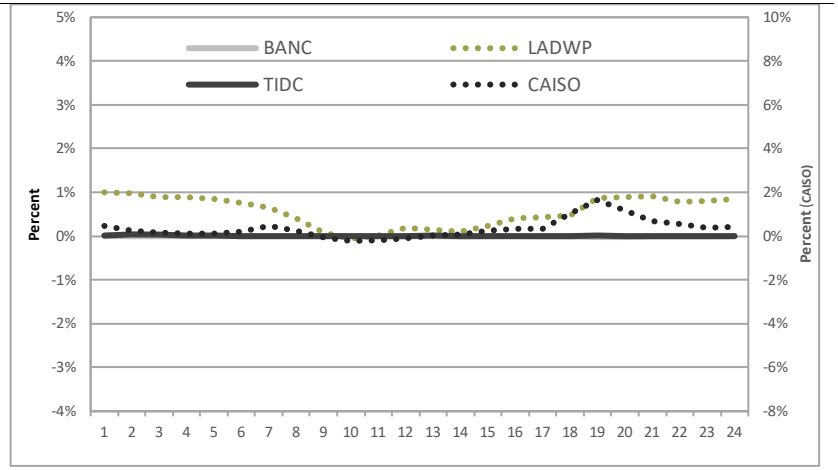


Figure 3.4 California: Average hourly load conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q3 2026)

15-minute market



5-minute market



3.2 Real-time load forecast adjustments in CAISO balancing area

Between January and early March 2026, the CAISO balancing area implemented a pilot program[22] designed to minimize the use of load conformance in the real-time markets. Practices developed during the pilot program continued into the third quarter, but high loads and fire-risk management led to increased use of load conformance compared to Q1 and Q2 2026 beginning in July.[23]

Average hourly load conformance adjustments in the hour-ahead and 15-minute markets declined significantly during the morning and evening ramp periods in the third quarter of 2026 compared to the same period in 2025. Mid-day load conformance in hour-endings 10 through 16 averaged about 240 MW, compared to approximately 0 MW in Q3 2025. The largest average morning hourly adjustment in the 15-minute market was in hour-ending 8 and was approximately 150 MW lower in Q3 2026 than in Q3 2025. The maximum average hourly 15-minute market evening adjustment occurred in hour-ending 19 and was approximately 425 MW lower than the highest average hourly evening adjustment observed in Q3 2025.

The 5-minute market adjustments were slightly higher in the morning ramp hours for the third quarter of 2026 compared to the third quarter of 2025. Evening 5-minute market adjustments peaked in hour-ending 19 at about 475 MW and were about 75 MW higher than in the third quarter of 2025.

[22] *Market Performance and Planning Forum Q2*, California ISO, April 27, 2026: caiso.com/documents/presentation-market-performance-planning-forum-q2-apr-27-2026.pdf

Market performance update, Joint ISO Board of Governors and WEM Governing Body meeting - General Session, California ISO, March 4, 2026: https://www.caiso.com/documents/market-performance-update-mar-2026.pdf

[23] *Extended Day-Ahead Market Performance July Report.* August 24, 2026*:* https://www.caiso.com/documents/monthly-extended-day-ahead-market-edam-performance-report-for-jul-2026.pdf

Figure 3.5 Average CAISO balancing area hourly imbalance conformance adjustment (Q3 2025 and Q3 2026)

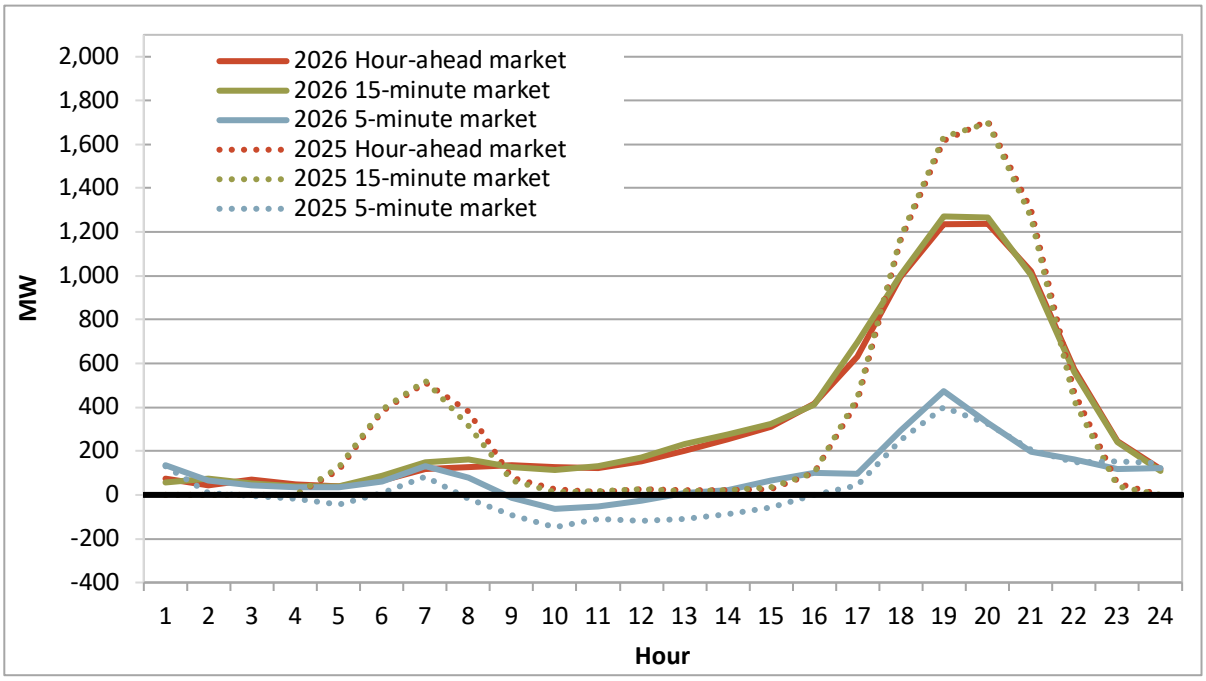


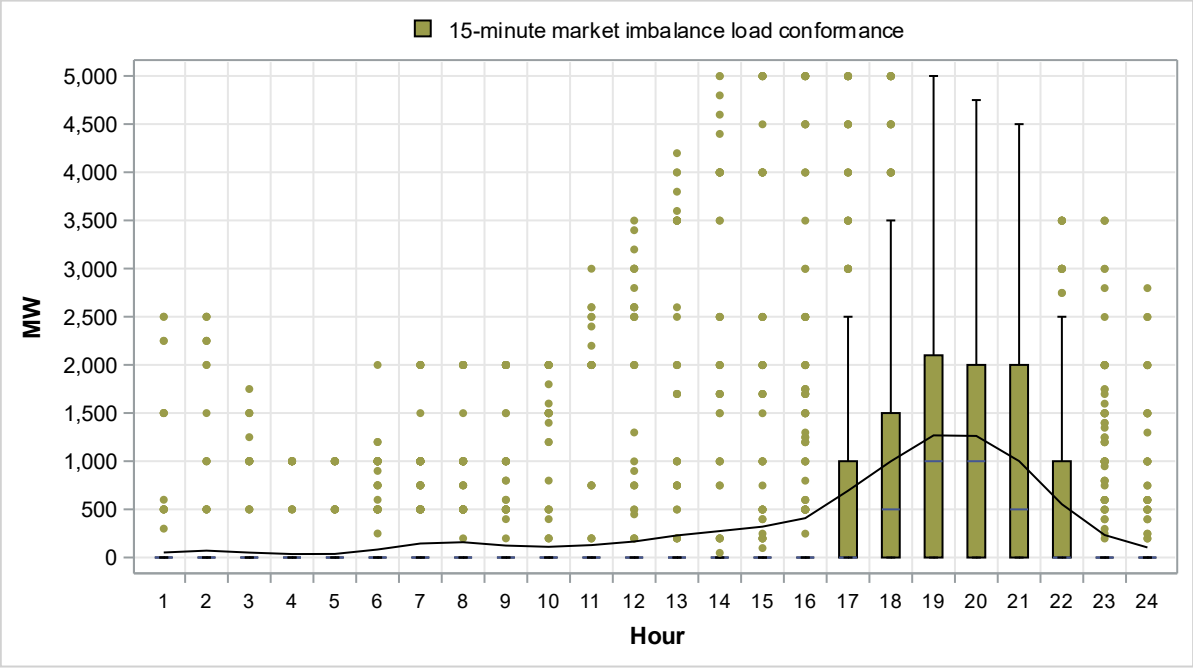
Figure 3.6 shows an hourly distribution of the 15-minute market load adjustments for the third quarter of 2026. This box and whisker graph highlights extreme outliers[24] (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well as the mean (line). The extreme outliers are represented by the filled "dots". The outside whiskers do not include these outliers. The largest outliers were observed during two[25,26] Southern California heat waves: August 25–28, 2026, and September 8–9, 2026.

[24] The upper outliers are greater than the 3rd quartile + 1.5 × Interquartile Range (IQR), while the lower outliers are less than the 1st quartile − 1.5 × IQR. The whiskers extend to the most extreme data values that are still within these limits. Observations beyond these limits are displayed individually as outliers.

[25] *Extreme Heat Warning: High Temperatures Expected Across Parts of Los Angeles County*, County of Los Angeles, California, August 24, 2026: https://lacounty.gov/2026/08/24/extreme-heat-warning-high-temperatures-expected-across-parts-of-los-angeles-county

[26] *September Heat Alert: Cal/OSHA reminds employers to protect workers from high heat with temperatures expected to reach triple digits across much of the state,* California Department of Industrial Relations, September 9, 2026: https://www.dir.ca.gov/DIRNews/2026/2026-72.html

Figure 3.6 CAISO BA 15-minute market hourly distribution of operator load adjustments (Q3 2026)



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.[27] Prices are calculated based on the load schedules and corresponding prices at all Aggregated Pricing Nodes (APnodes).[28]

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 October 2024 to September 2026. Prices in the 15-minute market across the WEIM averaged about $42/MWh in the third quarter of 2026, up 12 percent from the same quarter of last year. Prices in the 5-minute market were $44/MWh, a 15 percent increase compared to Q3 2025.

In the 15-minute market, California recorded the highest average price at $49/MWh, followed by the Desert Southwest at $41/MWh and the Intermountain West region at $40/MWh. Prices were lowest in the Pacific Northwest region ($32/MWh), brought down by low prices in Powerex across all hours. Greenhouse gas (GHG) costs during non-solar hours contributed to higher average prices in California compared to other regions.[29]

[27] 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 BHBA (Black Hills), GWA (Power Watch), PACE, IPCO, NWMT, and AVA. The Pacific Northwest includes AVRN, BPA, BCHA, TWPR, PGE, PSEI, and SCL.

[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. 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.

[29] 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

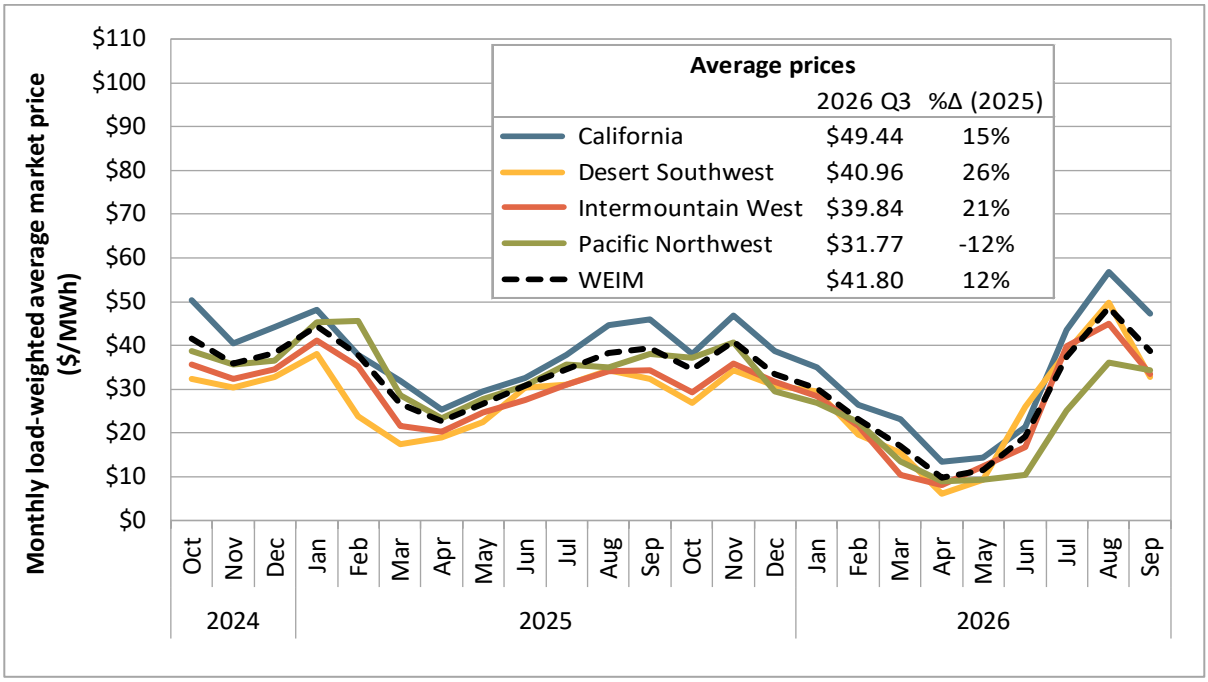


Figure 4.2 Weighted average monthly 5-minute market prices by region

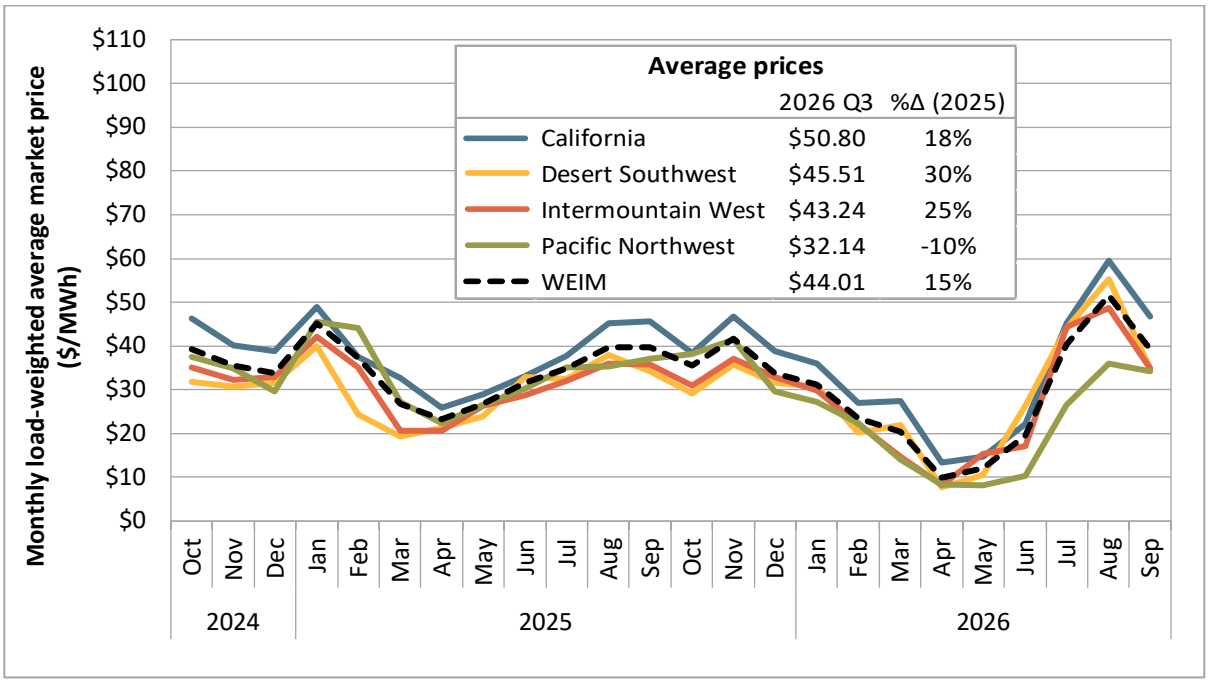


Figure 4.3 and Figure 4.4 illustrate the weighted average hourly prices for the 15-minute and 5-minute markets across regions, along with average system net-load schedules, for the third quarter of 2026. The shape of hourly prices tended to follow the net-load pattern. This trend was most prominent for prices in the California, Desert Southwest, and Intermountain West regions, with relatively high prices during the evening ramping hours, and lower prices during solar production hours.

The system's average hourly peak net load occurred at hour-ending 20 in both the 15-minute and 5-minute markets, reaching 100.6 GW and 100.3 GW, respectively. In the 15-minute and 5-minute markets, the California, Desert Southwest, and Intermountain West regions experienced peak average prices in hour-ending 20. The Pacific Northwest region experienced peak prices in hour-ending 19 in the 15-minute and 5-minute markets.

Real-time market prices in the California region were higher than prices in other regions, particularly 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. Low prices in Powerex brought down the average price of the Pacific Northwest across all hours. Transmission congestion from power flowing from northern areas to southern areas during evening hours also contributed to lower Pacific Northwest prices.

Figure 4.3 Weighted average hourly 15-minute market prices by region (July–September 2026)

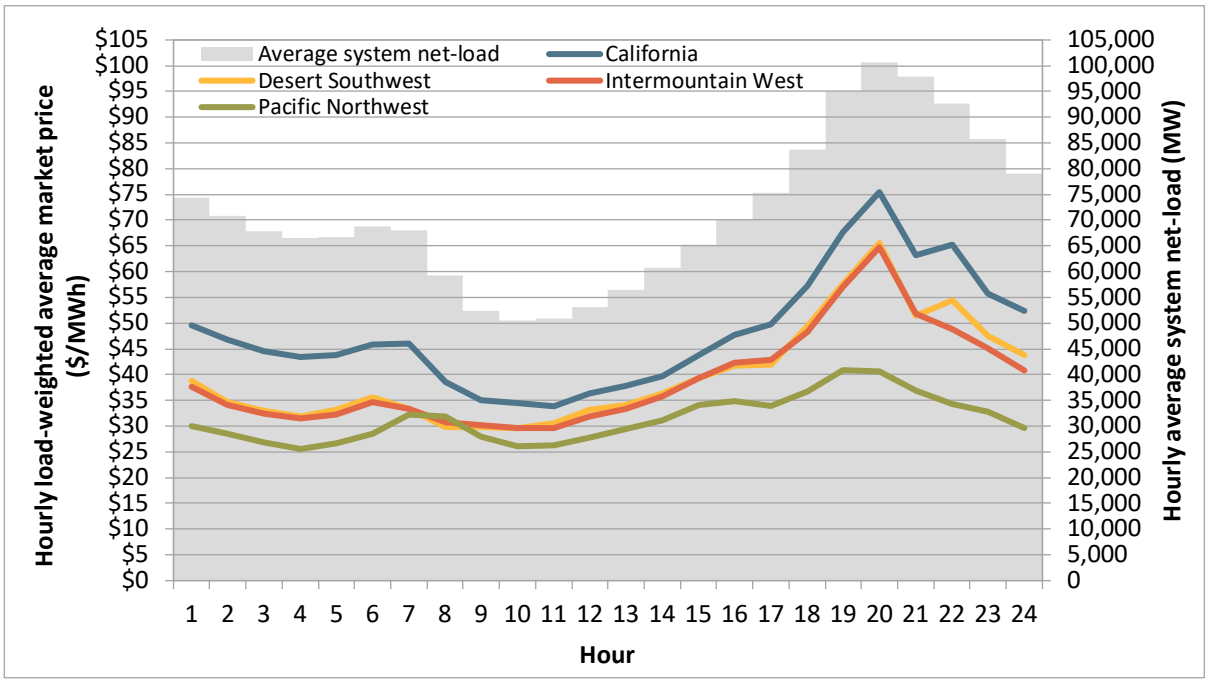
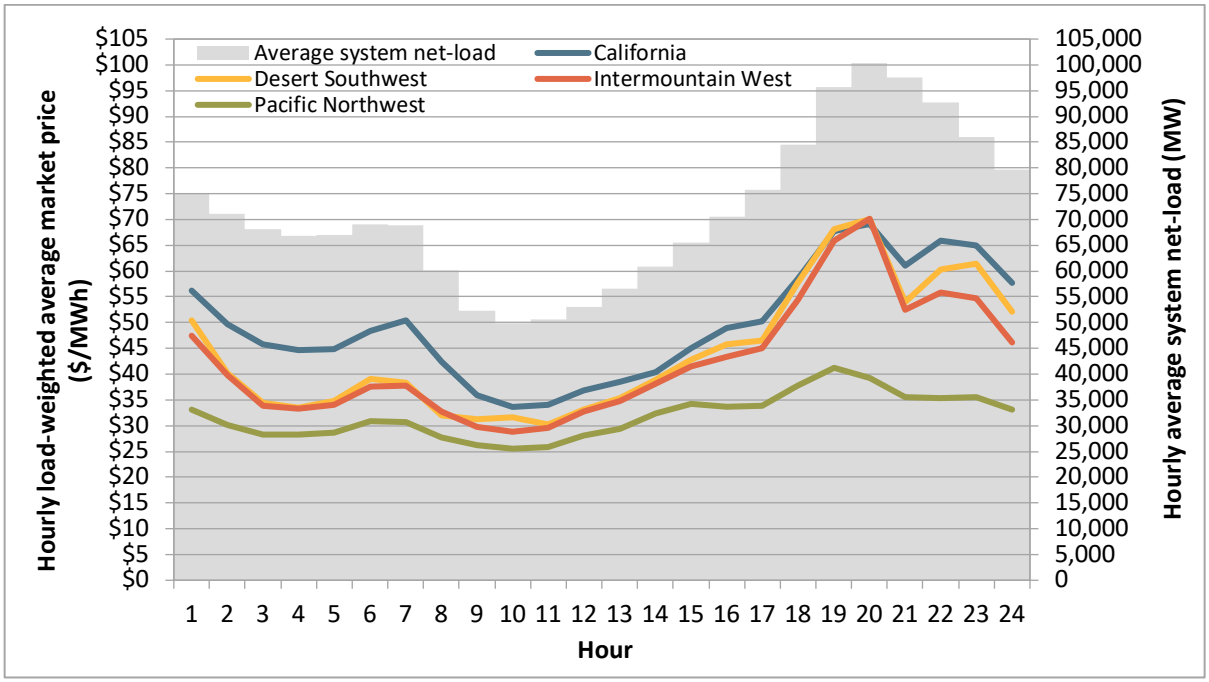


Figure 4.4 Weighted average hourly 5-minute market prices by region (July–September 2026)



4.2 Real-time market prices by balancing area

This section summarizes prices in each Western Energy Imbalance Market (WEIM) balancing area during the third quarter of 2026. 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.

- **Marginal energy cost,** referred to as MEC, is the marginal clearing price for energy in a balancing authority area (BAA). The difference in MEC between balancing areas reflects any transfer congestion between one another. These figures show the marginal energy cost for the CAISO balancing area only (light blue bars).
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the price impact from greenhouse gas (GHG) regulation. It represents the marginal cost of a net import transfer into the GHG regulation area (currently only balancing authority areas in California) determined within the optimization using the GHG bid adders of resources located outside of the GHG regulation area. This contributes to price differences between the GHG regulation area and the regions outside of it.[30]
- **Congestion from local constraints** is the price impact on a balancing area from transmission constraints within its own balancing area. While these constraints are located locally, they can

[30] Previously, the GHG component was represented as a negative price impact in all non-California balancing areas. Going forward with EDAM, GHG costs are added as a positive price impact on the GHG regulation area.

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 on a balancing area from transmission constraints in a different WEIM balancing area. 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 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 from WEIM transfer constraints** between balancing areas is represented as the difference in marginal energy cost between the CAISO balancing area and the other respective balancing areas.[31] Adding this component to the CAISO marginal energy cost in these figures results in each balancing area's MEC.

Significant factors impacting the locational marginal price (LMP) differences between balancing areas included congestion from transfer constraints out of Powerex and Power Watch, and congestion from flow-based constraints in the CAISO balancing area. GHG costs were previously embedded within the system marginal energy costs and subtracted from non-California balancing areas. These costs are now added onto the GHG regulation area which currently consists of balancing areas in California.

[31] The CAISO balancing area is selected as the reference area for a number of reasons. First, the CAISO balancing area has significant connectivity with other balancing areas and regions. Second, the CAISO balancing cannot enter market separation in the same way other balancing areas can. Last, for comparison to previous years, the system marginal energy cost was calculated prior to the launch of EDAM based on the marginal energy cost in the CAISO balancing area.

Figure 4.5 Average 15-minute market prices by balancing area (July–September 2026)

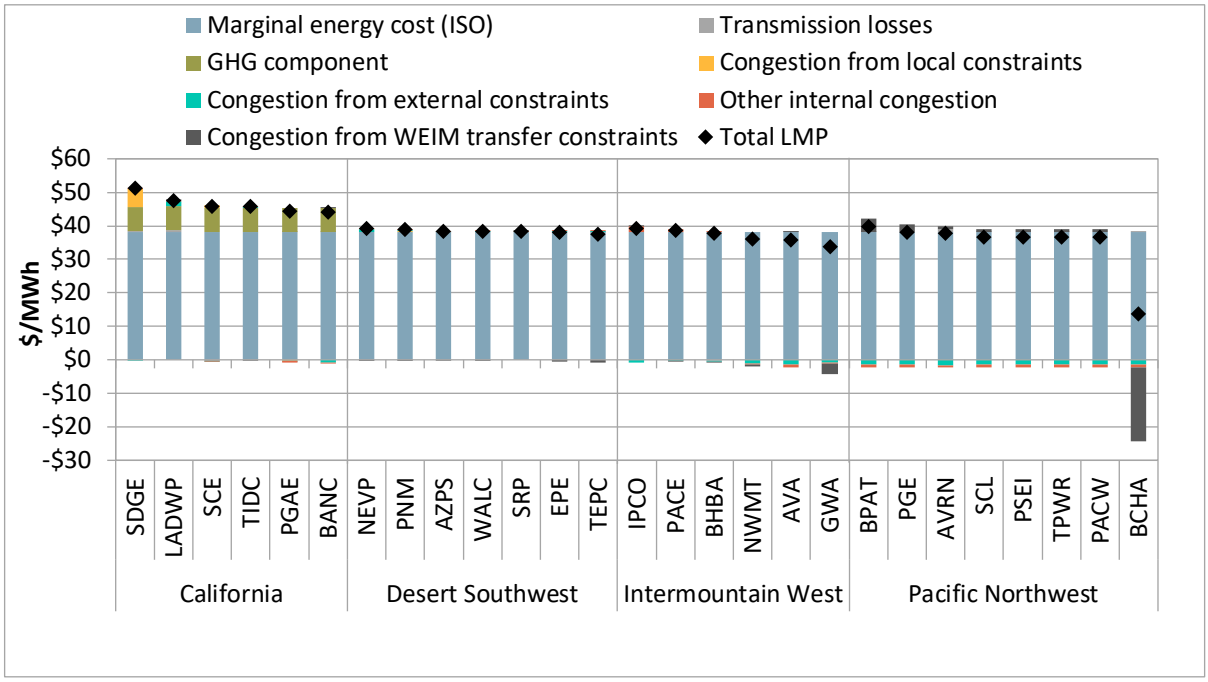


Figure 4.6 Average 5-minute market prices by balancing area (July–September2026)

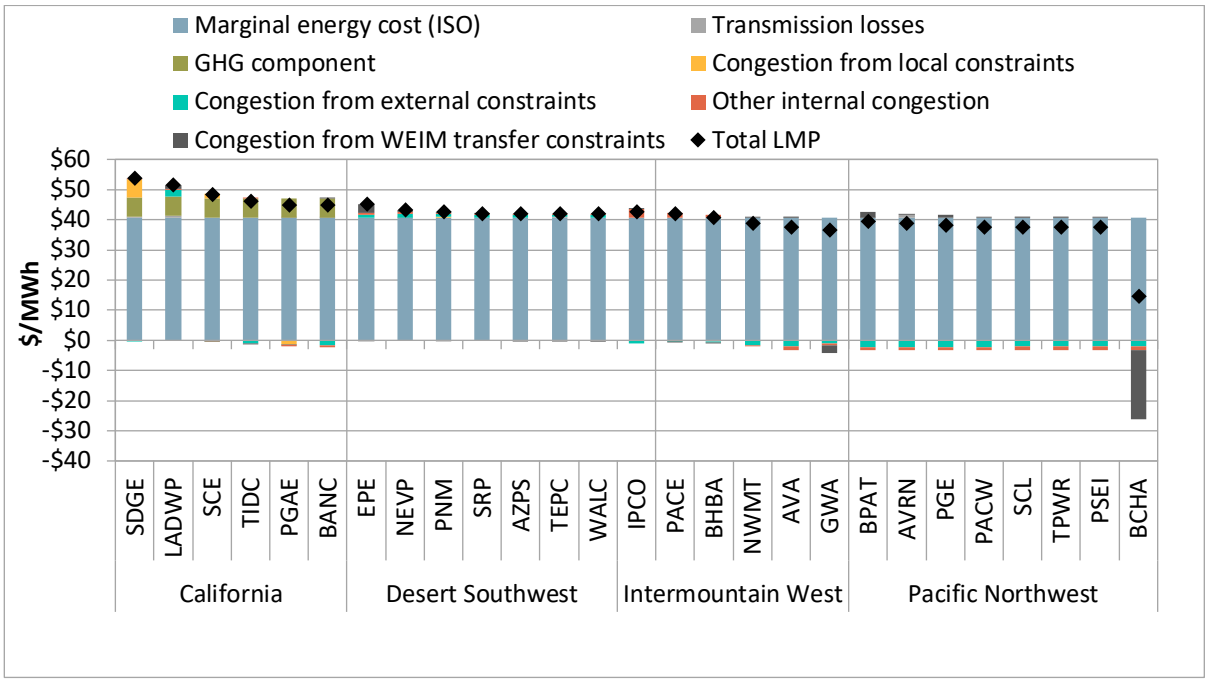


Table 4.1 and Table 4.2 show average 15-minute and 5-minute market prices by month for each balancing area. The color gradient highlights deviation from the load weighted average marginal energy cost (MEC) across all BAAs, shown in the top row. Blue indicates prices below that month's average MEC and 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 Q3 2026. 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 third quarter. 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. During evening hours, the Pacific Northwest had lower average prices due to transmission congestion from north-to-south power flows.

Table 4.1 Average monthly 15-minute market prices

	2024			2025												2026							
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Average MEC	$48	$41	$43	$47	$41	$30	$25	$29	$33	$38	$43	$44	$38	$46	$36	$34	$26	$18	$11	$11	$16	$35	$45	$35
PG&E (CAISO)	$56	$46	$46	$49	$40	$31	$27	$30	$34	$38	$43	$48	$42	$50	$37	$34	$28	$23	$15	$18	$22	$39	$49	$46
SCE (CAISO)	$38	$35	$40	$43	$30	$25	$18	$24	$28	$35	$42	$39	$32	$42	$34	$34	$23	$18	$9	$10	$17	$41	$56	$41
SDGE (CAISO)	$40	$38	$43	$49	$35	$27	$21	$25	$29	$38	$47	$45	$33	$44	$37	$37	$25	$20	$19	$17	$22	$46	$59	$48
BANC	$56	$46	$45	$49	$40	$31	$25	$29	$35	$39	$43	$48	$43	$49	$36	$33	$27	$20	$12	$17	$22	$39	$49	$45
Turlock ID	$61	$47	$45	$51	$40	$32	$28	$30	$36	$41	$44	$51	$46	$49	$36	$33	$28	$21	$13	$17	$22	$40	$50	$47
LADWP	$40	$37	$38	$45	$30	$28	$21	$27	$31	$37	$43	$42	$34	$44	$36	$34	$23	$16	$8	$5	$19	$42	$57	$43
NV Energy	$33	$29	$31	$38	$26	$20	$18	$24	$28	$31	$33	$33	$28	$35	$30	$29	$20	$14	$8	$10	$16	$37	$47	$34
Arizona PS	$30	$26	$31	$35	$22	$18	$15	$19	$25	$30	$33	$31	$26	$34	$29	$29	$19	$13	$4	$8	$15	$36	$47	$31
Tucson Electric	$28	$27	$31	$36	$22	$18	$16	$20	$26	$30	$32	$31	$27	$34	$30	$29	$20	$15	$5	$10	$17	$36	$46	$32
Salt River Project	$30	$26	$30	$35	$22	$19	$24	$20	$30	$30	$33	$32	$26	$34	$29	$28	$19	$15	$7	$10	$18	$36	$47	$31
PSC New Mexico	$27	$57	$29	$37	$14	-$1	$14	$19	$43	$31	$40	$32	$24	$31	$25	$26	$15	$11	$4	$9	$15	$37	$48	$32
WAPA - Desert SW	$32	$26	$32	$36	$22	$19	$15	$19	$25	$30	$33	$31	$28	$33	$28	$29	$23	$19	$4	$8	$15	$36	$47	$31
El Paso Electric	$27	$27	$30	$34	$19	$8	$17	$26	$32	$31	$33	$33	$26	$34	$29	$37	$19	$14	$6	$18	$20	$27	$54	$33
PacifiCorp East	$35	$31	$33	$39	$30	$19	$18	$23	$27	$30	$34	$33	$26	$34	$29	$28	$21	$11	$8	$13	$17	$39	$44	$33
Idaho Power	$37	$34	$35	$42	$35	$22	$26	$25	$28	$31	$34	$34	$33	$36	$30	$28	$21	$10	$9	$13	$16	$40	$43	$34
NorthWestern	$30	$33	$33	$41	$39	$25	$21	$24	$28	$31	$33	$34	$32	$38	$30	$28	$22	$9	$8	$13	$15	$33	$42	$33
PowerWatch																				$11	$15	$32	$36	$33
Black Hills Energy																				$12	$16	$38	$44	$32
Avista Utilities	$39	$36	$35	$43	$41	$26	$21	$24	$28	$31	$33	$35	$34	$38	$30	$28	$22	$9	$8	$13	$15	$32	$41	$35
Avangrid	$40	$37	$36	$44	$44	$26	$21	$27	$30	$33	$34	$38	$38	$40	$28	$27	$23	$13	$8	$12	$15	$34	$42	$37
BPA	$40	$37	$35	$43	$45	$26	$22	$28	$33	$36	$36	$41	$39	$40	$28	$27	$23	$13	$9	$12	$15	$36	$45	$39
Tacoma Power	$38	$36	$36	$43	$43	$26	$22	$26	$29	$35	$34	$38	$36	$39	$28	$27	$22	$12	$9	$14	$15	$33	$41	$36
PacifiCorp West	$39	$36	$36	$43	$43	$25	$20	$26	$29	$31	$33	$37	$37	$39	$27	$27	$22	$12	$9	$12	$14	$33	$41	$36
Portland GE	$39	$36	$35	$43	$43	$25	$20	$26	$29	$32	$34	$38	$37	$39	$28	$27	$22	$14	$11	$14	$14	$34	$43	$38
Puget Sound Energy	$38	$35	$36	$43	$43	$26	$23	$27	$29	$37	$34	$39	$36	$39	$28	$27	$22	$12	$10	$12	$14	$33	$41	$36
Seattle City Light	$40	$36	$37	$43	$43	$26	$22	$26	$29	$37	$34	$39	$36	$39	$29	$27	$22	$13	$9	$16	$14	$33	$41	$36
Powerex	$36	$35	$34	$48	$46	$33	$27	$29	$31	$36	$33	$34	$36	$39	$29	$25	$22	$14	$7	$2	-$1	-$1	$17	$25

Table 4.2 Average monthly 5-minute market prices

	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025	Apr 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025	Nov 2025	Dec 2025	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026
Average MEC	$45	$41	$43	$48	$40	$30	$25	$28	$33	$38	$43	$44	$38	$47	$37	$35	$27	$23	$11	$12	$17	$39	$49	$36
PG&E (CAISO)	$51	$45	$46	$50	$39	$32	$28	$29	$34	$38	$43	$48	$43	$50	$38	$35	$28	$25	$14	$18	$23	$39	$49	$47
SCE (CAISO)	$37	$35	$41	$44	$30	$26	$19	$24	$29	$35	$43	$40	$33	$42	$35	$35	$24	$23	$9	$11	$18	$44	$60	$41
SDGE (CAISO)	$38	$38	$43	$49	$35	$29	$21	$25	$30	$38	$49	$45	$33	$44	$38	$38	$25	$28	$19	$19	$23	$49	$63	$49
BANC	$52	$45	$45	$50	$39	$32	$26	$29	$35	$39	$43	$48	$44	$49	$37	$34	$28	$22	$12	$17	$22	$40	$49	$45
Turlock ID	$57	$46	$46	$51	$39	$33	$30	$30	$36	$41	$44	$51	$46	$49	$37	$34	$29	$23	$13	$17	$22	$41	$50	$47
LADWP	$39	$37	$38	$45	$30	$28	$21	$27	$32	$38	$45	$43	$34	$44	$36	$35	$24	$20	$7	$7	$20	$45	$63	$47
NV Energy	$33	$30	$32	$40	$25	$21	$22	$25	$29	$32	$35	$34	$30	$37	$32	$30	$21	$20	$8	$11	$17	$43	$52	$35
Arizona PS	$30	$27	$33	$37	$23	$19	$16	$20	$27	$32	$37	$32	$29	$35	$31	$30	$20	$19	$4	$9	$16	$40	$53	$33
Tucson Electric	$27	$28	$32	$38	$23	$21	$18	$23	$27	$32	$35	$33	$28	$35	$31	$30	$20	$19	$6	$14	$20	$40	$51	$36
Salt River Project	$30	$27	$32	$37	$23	$20	$26	$23	$34	$32	$36	$33	$28	$35	$30	$30	$20	$21	$11	$10	$19	$40	$53	$33
PSC New Mexico	$27	$50	$30	$39	$15	$3	$15	$20	$44	$32	$43	$34	$27	$32	$25	$28	$15	$16	$3	$10	$16	$41	$52	$33
WAPA - Desert SW	$32	$27	$32	$37	$22	$20	$16	$20	$27	$31	$36	$32	$29	$34	$30	$30	$21	$24	$4	$9	$16	$40	$53	$33
El Paso Electric	$27	$27	$32	$36	$19	$10	$17	$27	$33	$32	$39	$34	$27	$33	$32	$36	$20	$20	$7	$19	$26	$39	$57	$39
PacifiCorp East	$34	$31	$34	$40	$30	$18	$18	$25	$28	$32	$36	$34	$27	$36	$30	$30	$22	$15	$8	$17	$17	$43	$48	$34
Idaho Power	$36	$34	$35	$43	$34	$21	$25	$27	$29	$32	$35	$35	$35	$37	$31	$29	$22	$14	$9	$13	$16	$46	$46	$35
NorthWestern	$31	$34	$34	$42	$39	$25	$22	$25	$29	$32	$35	$35	$33	$39	$35	$29	$23	$13	$8	$14	$14	$36	$46	$35
PowerWatch																				$11	$15	$34	$40	$36
Black Hills Energy																				$17	$17	$42	$47	$33
Avista Utilities	$37	$36	$36	$43	$41	$25	$22	$25	$29	$32	$34	$36	$36	$39	$30	$29	$23	$12	$8	$13	$15	$33	$43	$36
Avangrid	$39	$37	$37	$44	$42	$24	$20	$26	$30	$33	$35	$37	$38	$40	$29	$28	$23	$14	$8	$11	$14	$35	$43	$38
BPA	$38	$35	$36	$44	$43	$24	$20	$26	$31	$35	$36	$40	$38	$40	$28	$27	$22	$14	$8	$11	$14	$35	$44	$38
Tacoma Power	$37	$35	$36	$43	$42	$24	$21	$26	$29	$34	$35	$37	$36	$39	$29	$27	$22	$13	$9	$13	$14	$33	$42	$37
PacifiCorp West	$38	$36	$36	$43	$41	$23	$19	$25	$29	$32	$34	$36	$37	$39	$29	$28	$22	$12	$8	$12	$13	$33	$42	$37
Portland GE	$38	$35	$36	$43	$41	$24	$19	$25	$29	$32	$34	$37	$37	$39	$28	$27	$22	$15	$10	$13	$14	$34	$43	$38
Puget Sound Energy	$37	$34	$36	$43	$41	$24	$22	$26	$29	$36	$35	$37	$36	$39	$28	$27	$22	$13	$9	$11	$13	$33	$43	$37
Seattle City Light	$38	$35	$36	$45	$41	$24	$21	$25	$29	$36	$35	$37	$36	$39	$29	$27	$22	$13	$9	$14	$14	$33	$43	$37
Powerex	$36	$35	$34	$47	$45	$33	$27	$28	$30	$36	$33	$34	$36	$39	$29	$25	$22	$14	$6	$2	$1	$3	$15	$26

Table 4.3 Average hourly 15-minute market prices (July–September)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Average MEC	$37	$34	$32	$31	$31	$34	$34	$31	$30	$29	$30	$32	$34	$36	$39	$42	$41	$47	$54	$58	$48	$48	$44	$40
PG&E (CAISO)	$46	$44	$42	$42	$42	$44	$44	$38	$36	$35	$32	$34	$35	$37	$40	$44	$46	$54	$62	$66	$57	$53	$50	$46
SCE (CAISO)	$50	$47	$44	$44	$44	$46	$46	$36	$31	$30	$30	$32	$33	$34	$38	$43	$44	$52	$64	$74	$62	$68	$56	$54
SDGE (CAISO)	$57	$53	$50	$47	$48	$49	$49	$42	$37	$35	$35	$37	$37	$39	$44	$48	$51	$59	$70	$81	$69	$74	$62	$59
BANC	$46	$44	$42	$42	$42	$44	$44	$38	$36	$34	$33	$35	$36	$37	$40	$44	$46	$51	$60	$63	$56	$53	$50	$46
Turlock ID	$46	$44	$42	$42	$42	$44	$44	$38	$38	$37	$38	$40	$41	$43	$46	$50	$51	$52	$59	$62	$55	$52	$50	$46
LADWP	$50	$47	$45	$43	$44	$46	$45	$37	$34	$33	$33	$35	$38	$37	$42	$46	$48	$55	$66	$76	$63	$68	$57	$54
NV Energy	$38	$35	$33	$32	$33	$35	$34	$30	$30	$30	$30	$32	$33	$35	$39	$42	$42	$48	$56	$63	$51	$53	$47	$43
Arizona PS	$38	$35	$33	$32	$33	$35	$34	$30	$29	$29	$29	$31	$32	$34	$37	$40	$39	$45	$54	$62	$50	$53	$47	$43
Tucson Electric	$38	$34	$31	$30	$31	$34	$32	$28	$27	$28	$29	$32	$32	$34	$37	$40	$39	$44	$53	$60	$50	$52	$46	$42
Salt River Project	$38	$34	$33	$32	$33	$35	$33	$29	$29	$29	$30	$32	$33	$35	$37	$39	$40	$45	$53	$61	$49	$53	$46	$43
PSC New Mexico	$38	$35	$33	$32	$33	$35	$34	$30	$29	$29	$29	$31	$33	$34	$37	$40	$42	$49	$57	$63	$50	$53	$46	$43
WAPA - Desert SW	$38	$35	$33	$32	$33	$35	$34	$30	$29	$29	$29	$31	$32	$34	$37	$39	$39	$45	$54	$62	$50	$53	$47	$43
El Paso Electric	$33	$29	$28	$29	$34	$33	$28	$27	$30	$26	$33	$40	$38	$40	$39	$38	$39	$67	$72	$52	$40	$43	$40	$36
PacifiCorp East	$37	$34	$32	$31	$32	$34	$33	$30	$30	$29	$29	$31	$32	$34	$38	$41	$42	$47	$57	$66	$52	$50	$45	$41
Idaho Power	$37	$34	$32	$31	$32	$34	$33	$31	$31	$30	$29	$32	$33	$36	$40	$42	$44	$51	$59	$64	$54	$49	$45	$40
NorthWestern	$36	$33	$32	$31	$32	$34	$33	$31	$30	$29	$28	$31	$32	$34	$36	$40	$38	$42	$50	$51	$44	$42	$42	$39
PowerWatch	$34	$31	$29	$28	$29	$30	$30	$26	$27	$26	$25	$27	$29	$31	$32	$36	$35	$40	$46	$48	$48	$44	$41	$37
Black Hills Energy	$37	$34	$32	$31	$32	$34	$33	$30	$30	$29	$29	$31	$32	$34	$37	$40	$41	$46	$55	$62	$49	$47	$43	$39
Avista Utilities	$36	$34	$32	$31	$32	$34	$33	$31	$30	$29	$29	$31	$32	$35	$37	$40	$38	$41	$47	$48	$43	$41	$42	$38
Avangrid	$36	$34	$33	$32	$32	$34	$34	$32	$32	$31	$31	$34	$36	$38	$39	$42	$41	$45	$50	$50	$46	$43	$42	$38
BPA	$38	$37	$33	$32	$33	$35	$41	$41	$39	$35	$35	$37	$38	$40	$42	$45	$43	$46	$49	$48	$45	$44	$42	$38
Tacoma Power	$36	$34	$31	$31	$32	$34	$34	$32	$31	$31	$31	$34	$36	$37	$38	$41	$40	$43	$46	$47	$44	$42	$41	$38
PacifiCorp West	$36	$34	$32	$31	$32	$34	$34	$31	$31	$30	$30	$33	$35	$37	$38	$41	$39	$43	$47	$48	$44	$42	$41	$37
Portland GE	$36	$34	$32	$32	$33	$34	$35	$33	$32	$32	$32	$34	$36	$38	$39	$42	$41	$45	$50	$54	$47	$45	$42	$38
Puget Sound Energy	$36	$33	$32	$31	$32	$34	$34	$32	$31	$31	$31	$34	$35	$37	$38	$41	$40	$43	$46	$47	$45	$42	$41	$38
Seattle City Light	$36	$34	$32	$31	$32	$34	$34	$32	$31	$31	$31	$34	$36	$37	$38	$41	$40	$43	$46	$47	$44	$42	$41	$38
Powerex	$13	$13	$13	$11	$13	$14	$20	$21	$12	$10	$11	$11	$13	$13	$13	$13	$14	$15	$21	$19	$15	$12	$10	$9

Hour

Table 4.4 Average hourly 5-minute market prices (July–September)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Average MEC	$45	$38	$33	$32	$33	$37	$37	$32	$30	$29	$29	$33	$35	$37	$40	$43	$44	$52	$60	$60	$49	$52	$53	$46
PG&E (CAISO)	$49	$46	$43	$43	$42	$45	$48	$42	$37	$34	$32	$34	$36	$37	$40	$44	$45	$53	$62	$58	$53	$53	$51	$48
SCE (CAISO)	$58	$51	$46	$45	$45	$49	$50	$40	$31	$29	$31	$32	$34	$36	$42	$44	$46	$56	$66	$71	$61	$70	$69	$61
SDGE (CAISO)	$65	$56	$50	$48	$49	$52	$54	$46	$38	$35	$35	$38	$38	$40	$46	$49	$52	$62	$72	$78	$70	$76	$75	$65
BANC	$49	$45	$43	$43	$43	$45	$48	$42	$37	$34	$33	$35	$36	$38	$41	$44	$45	$52	$60	$57	$53	$53	$52	$48
Turlock ID	$49	$46	$43	$43	$43	$45	$48	$42	$39	$36	$38	$40	$41	$43	$46	$49	$48	$52	$58	$55	$51	$52	$51	$48
LADWP	$59	$51	$48	$45	$45	$49	$50	$43	$34	$32	$33	$41	$39	$40	$45	$59	$57	$61	$68	$72	$62	$71	$70	$62
NV Energy	$48	$40	$34	$33	$35	$38	$38	$32	$36	$39	$30	$33	$34	$38	$41	$45	$43	$54	$64	$65	$53	$58	$58	$50
Arizona PS	$48	$40	$34	$33	$35	$39	$38	$32	$28	$28	$29	$32	$34	$36	$39	$41	$43	$54	$62	$64	$52	$58	$59	$51
Tucson Electric	$47	$38	$33	$32	$33	$37	$35	$28	$27	$28	$29	$32	$41	$45	$42	$43	$44	$53	$61	$63	$51	$57	$58	$50
Salt River Project	$48	$39	$34	$33	$35	$38	$37	$31	$29	$28	$30	$32	$34	$38	$41	$41	$43	$53	$61	$63	$51	$58	$59	$51
PSC New Mexico	$47	$40	$34	$33	$35	$38	$38	$32	$29	$28	$29	$32	$34	$36	$40	$43	$45	$57	$64	$65	$54	$58	$58	$50
WAPA - Desert SW	$48	$40	$34	$33	$35	$39	$38	$31	$29	$28	$29	$32	$33	$36	$39	$41	$43	$53	$62	$64	$52	$58	$59	$51
El Paso Electric	$45	$33	$29	$30	$31	$37	$40	$35	$30	$32	$30	$30	$30	$32	$49	$59	$57	$85	$98	$83	$44	$48	$53	$43
PacifiCorp East	$45	$39	$34	$33	$34	$37	$38	$32	$29	$28	$29	$32	$34	$37	$40	$42	$44	$54	$66	$71	$53	$56	$55	$46
Idaho Power	$46	$39	$34	$33	$34	$37	$38	$33	$30	$29	$30	$32	$34	$38	$41	$43	$46	$57	$66	$73	$55	$57	$54	$45
NorthWestern	$46	$43	$33	$35	$33	$36	$37	$33	$30	$28	$28	$31	$33	$35	$38	$40	$40	$47	$56	$51	$44	$45	$47	$43
PowerWatch	$40	$35	$31	$31	$32	$34	$36	$31	$27	$26	$24	$29	$30	$33	$36	$38	$39	$46	$51	$47	$46	$47	$50	$42
Black Hills Energy	$45	$38	$33	$33	$34	$37	$37	$31	$28	$28	$29	$32	$33	$36	$39	$41	$43	$53	$63	$66	$49	$52	$52	$45
Avista Utilities	$41	$36	$33	$32	$33	$36	$37	$33	$30	$28	$29	$31	$34	$35	$38	$40	$40	$46	$53	$46	$43	$42	$45	$42
Avangrid	$40	$37	$33	$33	$33	$36	$37	$33	$31	$30	$31	$34	$36	$37	$40	$42	$42	$47	$54	$50	$45	$46	$44	$40
BPA	$40	$36	$33	$34	$34	$37	$39	$36	$33	$33	$33	$36	$37	$39	$42	$43	$43	$47	$50	$49	$44	$43	$43	$39
Tacoma Power	$40	$36	$33	$33	$33	$36	$36	$33	$31	$30	$30	$34	$35	$37	$39	$40	$40	$45	$49	$46	$42	$42	$43	$39
PacifiCorp West	$39	$36	$33	$32	$33	$36	$36	$33	$30	$29	$30	$33	$35	$36	$39	$41	$40	$45	$52	$47	$43	$42	$43	$39
Portland GE	$39	$36	$33	$33	$33	$36	$36	$33	$31	$30	$31	$33	$35	$37	$40	$41	$41	$46	$53	$49	$44	$43	$43	$41
Puget Sound Energy	$40	$35	$33	$33	$33	$36	$36	$33	$31	$30	$31	$34	$35	$37	$39	$40	$40	$45	$49	$47	$43	$42	$43	$39
Seattle City Light	$40	$36	$33	$33	$33	$36	$36	$32	$31	$30	$31	$34	$36	$37	$39	$40	$40	$45	$49	$46	$42	$42	$43	$39
Powerex	$16	$16	$17	$17	$17	$17	$14	$11	$12	$12	$13	$13	$13	$13	$11	$13	$14	$16	$16	$15	$15	$16	$16	$16

Hour

4.3 Day-ahead market prices

This section analyzes day-ahead market prices for balancing areas in the day-ahead market. PacifiCorp (PACE and PACW) joined the CAISO balancing area in the day-ahead market on May 1, 2026.

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.[32] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from October 2024 to September 2026.

Over the quarter, prices in the day-ahead market averaged $46/MWh, and prices in the 15-minute and 5-minute markets averaged $47/MWh and $48/MWh, respectively, for balancing areas in the day-ahead market. August had the highest prices, with an average over the three markets of about $55/MWh.

Figure 4.7 also shows monthly average gas prices at PG&E Citygate from October 2024 to September 2026. The chart shows that the monthly variation of the electricity prices is correlated with gas prices. 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

[32] 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.

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

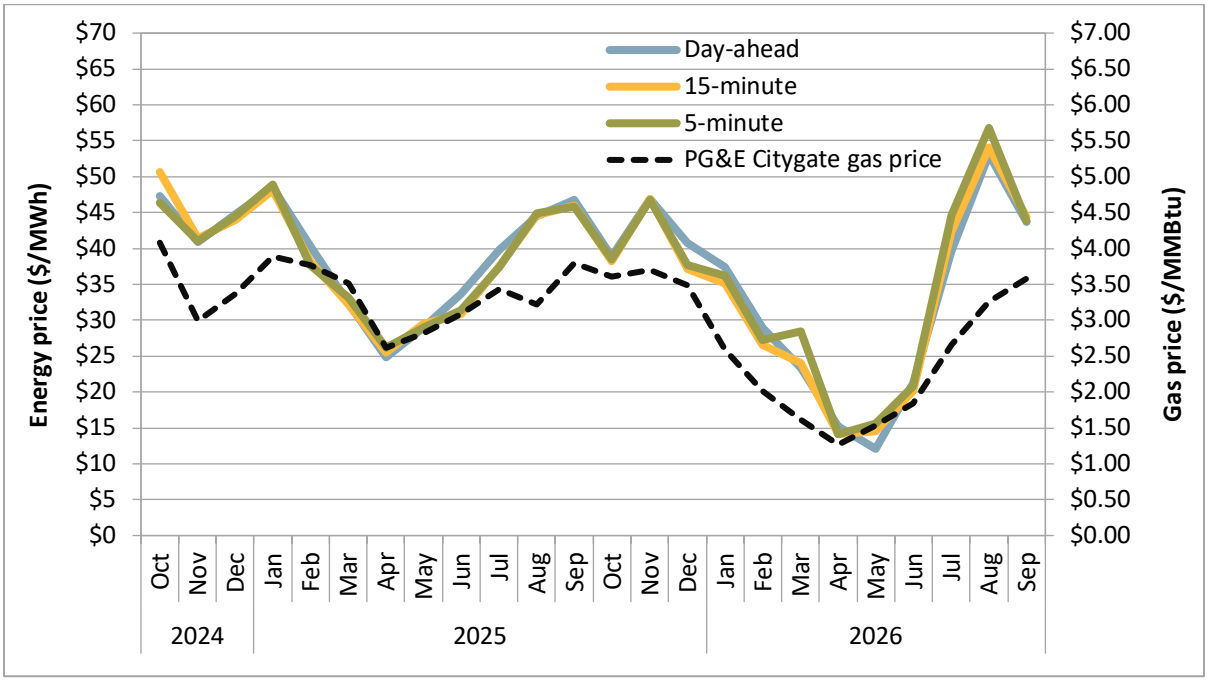


Figure 4.8 illustrates the hourly load-weighted average electricity prices for the third quarter compared to the average hourly net-load for balancing areas participating in the day-ahead market.[33] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green 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 continued 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 20, at around $70/MWh, while average net-load also peaked at hour-ending 20, reaching 40,700 MW.

During hour-ending 20, the day-ahead load-weighted average electricity price was $68/MWh, the 15-minute price was $73/MWh, and the 5-minute price was $69/MWh. Overall, prices across the three markets converged well during most hours.

[33] 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.

Figure 4.8 Hourly load-weighted average energy prices for balancing areas in day-ahead market (July–September 2026)

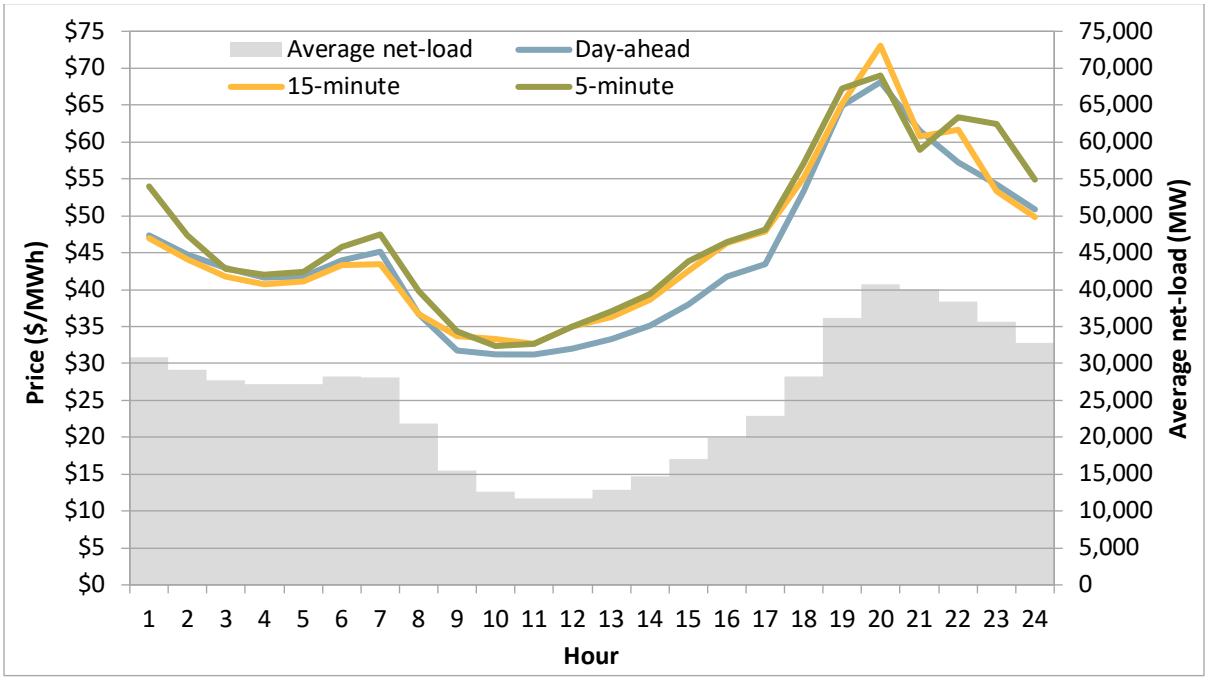


Figure 4.9 shows the hourly comparison of IFM prices between balancing areas in the day-ahead market. Prices in the CAISO balancing area were higher on average in all hours compared to the PacifiCorp balancing areas. Prices in all three balancing areas peaked during hour-ending 20. Day-ahead prices during this hour averaged $71/MWh in CAISO, $57/MWh in PACW and $59/MWh in PACE.

Figure 4.10 shows monthly day-ahead market prices by balancing area. Prices were highest in August across all balancing areas. Day-ahead prices in the third quarter of 2026 averaged $48/MWh in CAISO, $38/MWh in PACW, and $37/MWh in PACE.

Figure 4.9 Hourly load-weighted average day-ahead price comparison by BAA (July–September 2026)

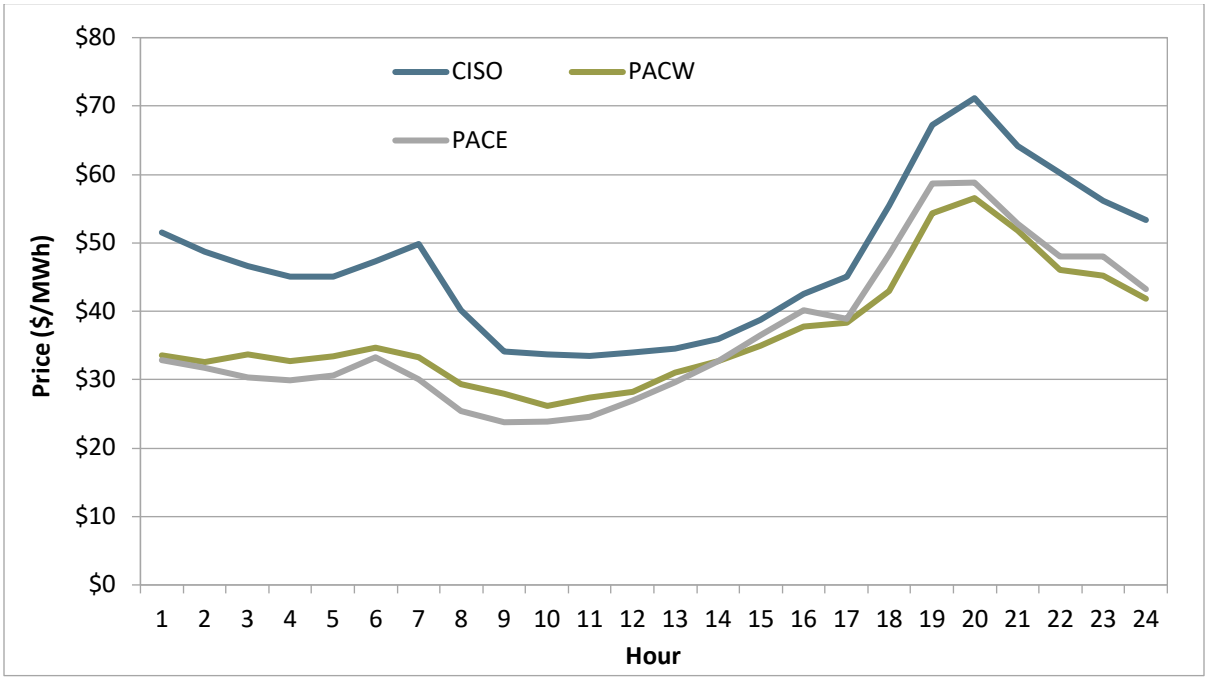


Figure 4.10 Monthly load-weighted average day-ahead price comparison by BAA

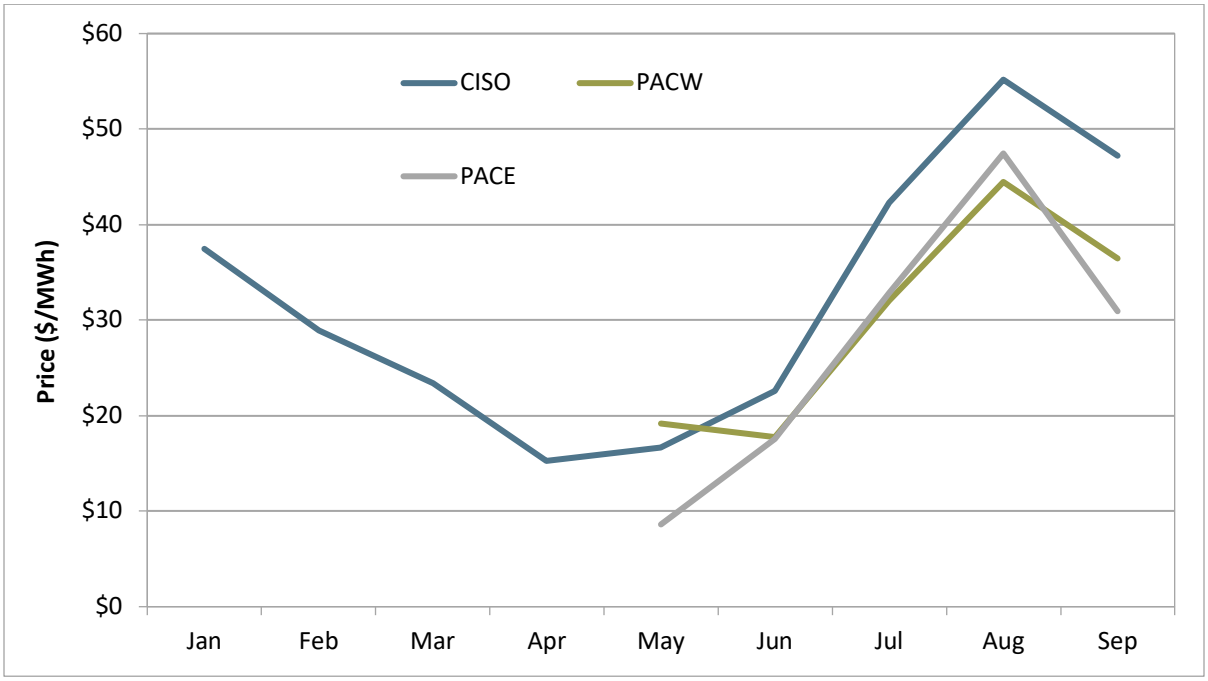
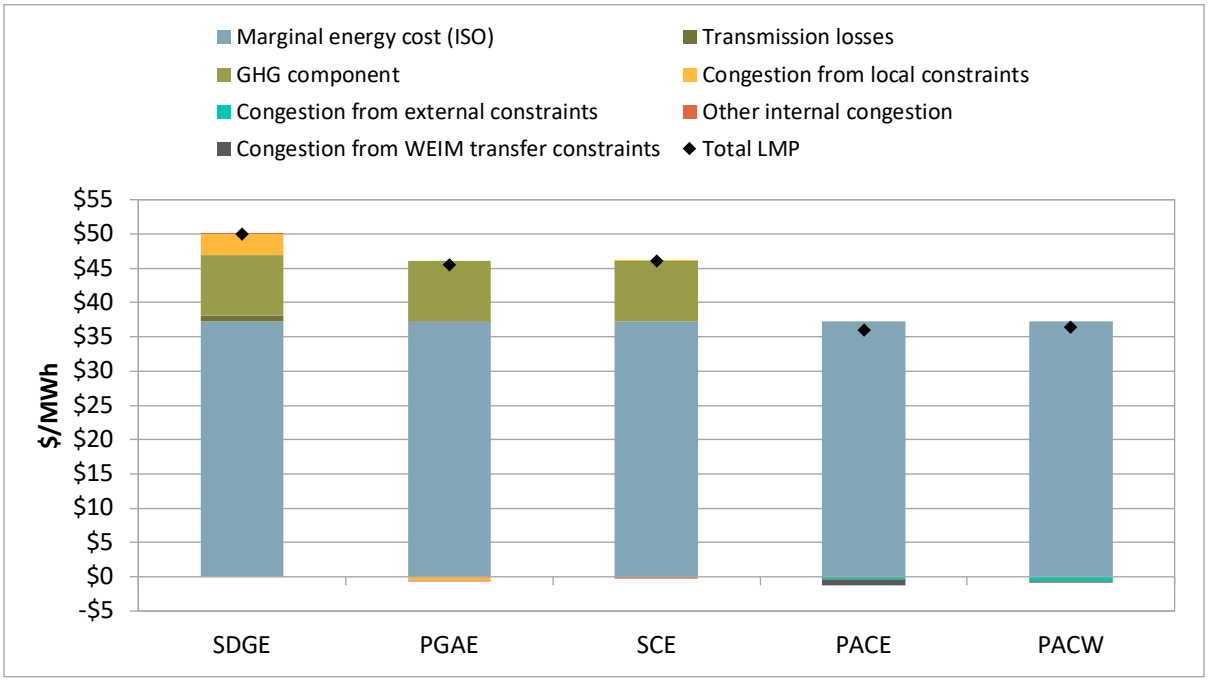


Figure 4.11 shows the average day-ahead market price by component for each balancing area participating in the day-ahead market in this quarter. The CAISO balancing area is further broken down into its three major load regions. Transfer congestion and congestion from flow-based constraints in the CAISO balancing area had a minor impact on decreasing prices in PacifiCorp areas relative to CAISO. Greenhouse gas costs in California were the main driver of day-ahead market price differences between CAISO and the rest of EDAM.

Figure 4.11 Average day-ahead market prices by load region (July–September 2026)



4.4 Bilateral price comparison

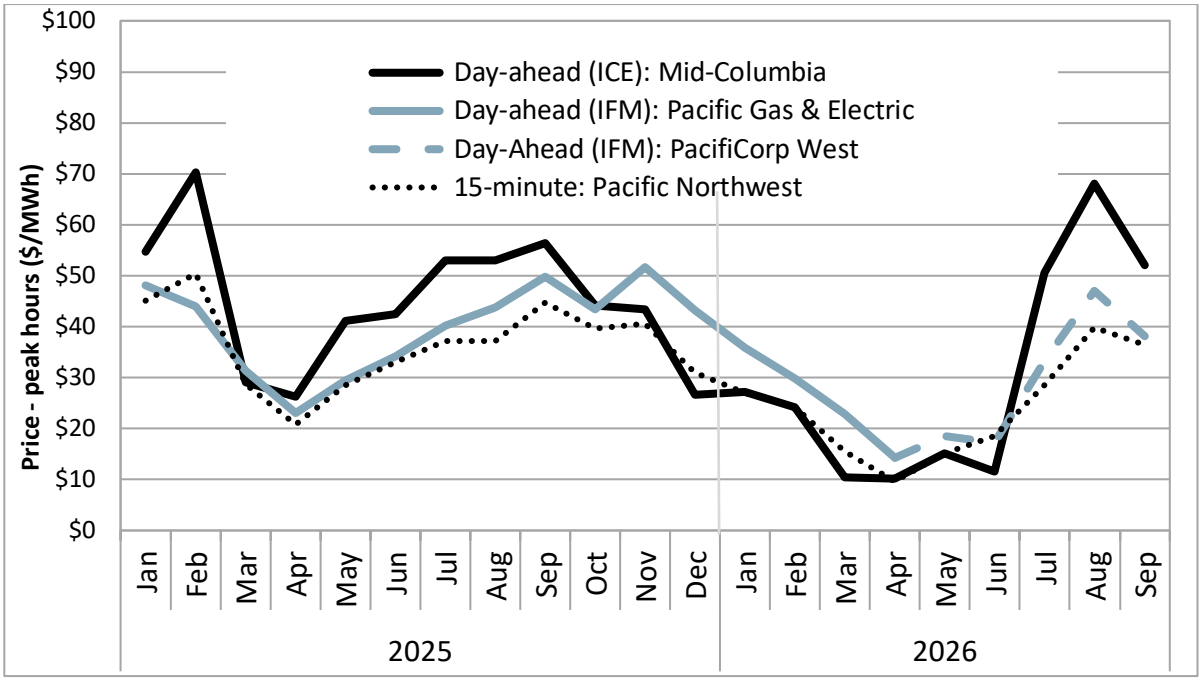
Figure 4.12 and Figure 4.13 compare ISO day-ahead and 15-minute market prices during peak hours (hours-ending 7 through 22) to bilateral day-ahead market prices. These figures show the monthly average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the ISO markets.

In the Mid-C chart, ISO day-ahead market prices prior to the EDAM launch in May 2026 are the Pacific Gas & Electric load node. ISO day-ahead market prices after the EDAM launch are the PacifiCorp West load node. 15-minute market prices are a load weighted average of Pacific Northwest balancing areas. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays. In the Palo Verde chart, ISO day-ahead market prices prior to May 2026 are for the Southern California Edison load node. ISO day-ahead market prices after the EDAM launch are the PacifiCorp East load node. 15-minute market prices are a load weighted average of Desert Southwest balancing areas. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

As shown in Figure 4.12, bilateral day-ahead prices in the Intercontinental Exchange for Mid-Columbia averaged about $57/MWh in Q3 2026. Mid-C bilateral prices were significantly higher than ISO day-ahead market prices in PacifiCorp West ($39/MWh) and ISO 15-minute market prices in the Pacific Northwest ($35/MWh).

As shown in Figure 4.13, day-ahead prices in the Intercontinental Exchange for the Palo Verde trading hub averaged about $55/MWh in Q3 2026. Palo Verde bilateral prices were significantly higher than ISO day-ahead market prices in PacifiCorp East ($39/MWh) and ISO 15-minute market prices in the Desert Southwest ($43/MWh).

Figure 4.12 Mid-C bilateral ICE vs. geographically comparable ISO day-ahead and 15-minute market prices (peak hours)[34]



[34] Data for the day-ahead (IFM) Pacific Gas & Electric ends April 30, 2026 and the day-ahead (IFM) PacifiCorp West data begin on May 1, 2026.

Figure 4.13 Palo Verde bilateral ICE vs. geographically comparable ISO day-ahead and 15-minute market prices (peak hours)[35]

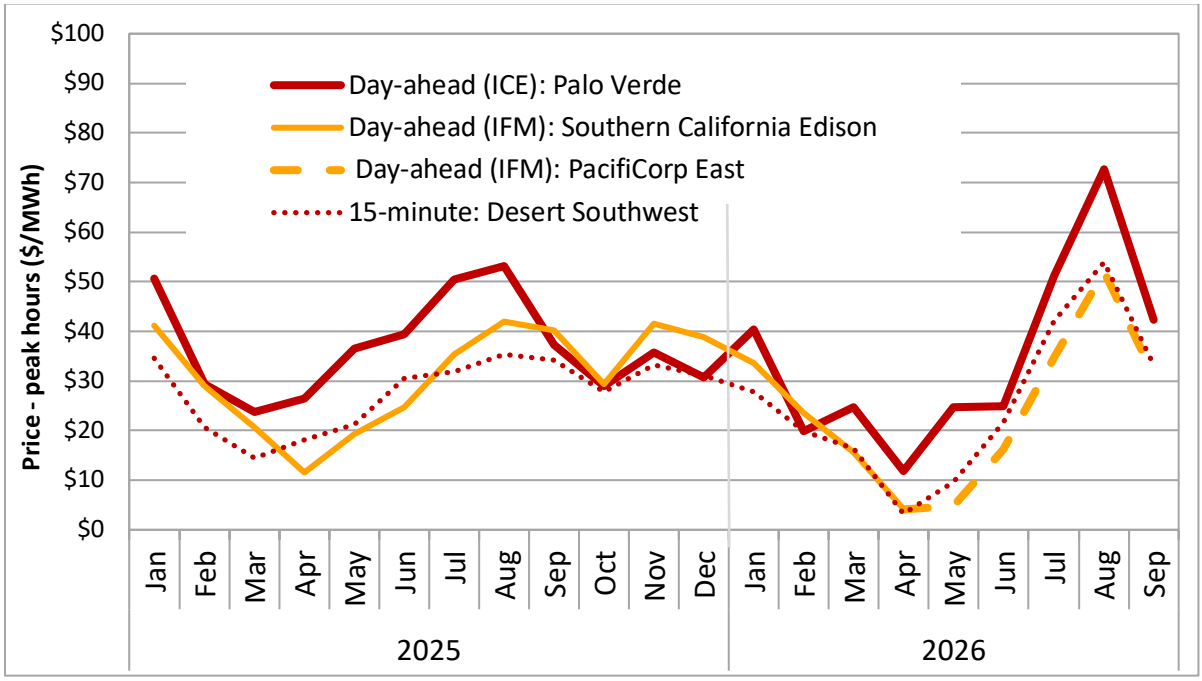


Figure 4.14 compares monthly average prices in the bilateral and ISO day-ahead markets for 2025 through the third quarter of 2026. Over the quarter, bilateral day-ahead prices at Mid-Columbia and Palo Verde averaged about $57/MWh and $55/MWh, respectively, while ISO day-ahead prices at PacifiCorp East and PacifiCorp West load nodes averaged around $39/MWh each. ISO day-ahead prices at Pacific Gas and Electric and Southern California Edison averaged around $48/MWh and $49/MWh, respectively.

[35] Data for the day-ahead (IFM) Southern California Edison ends April 30, 2026 and the day-ahead (IFM) PacifiCorp East data begin on May 1, 2026.

Figure 4.14 Monthly average day-ahead peak and bilateral market prices

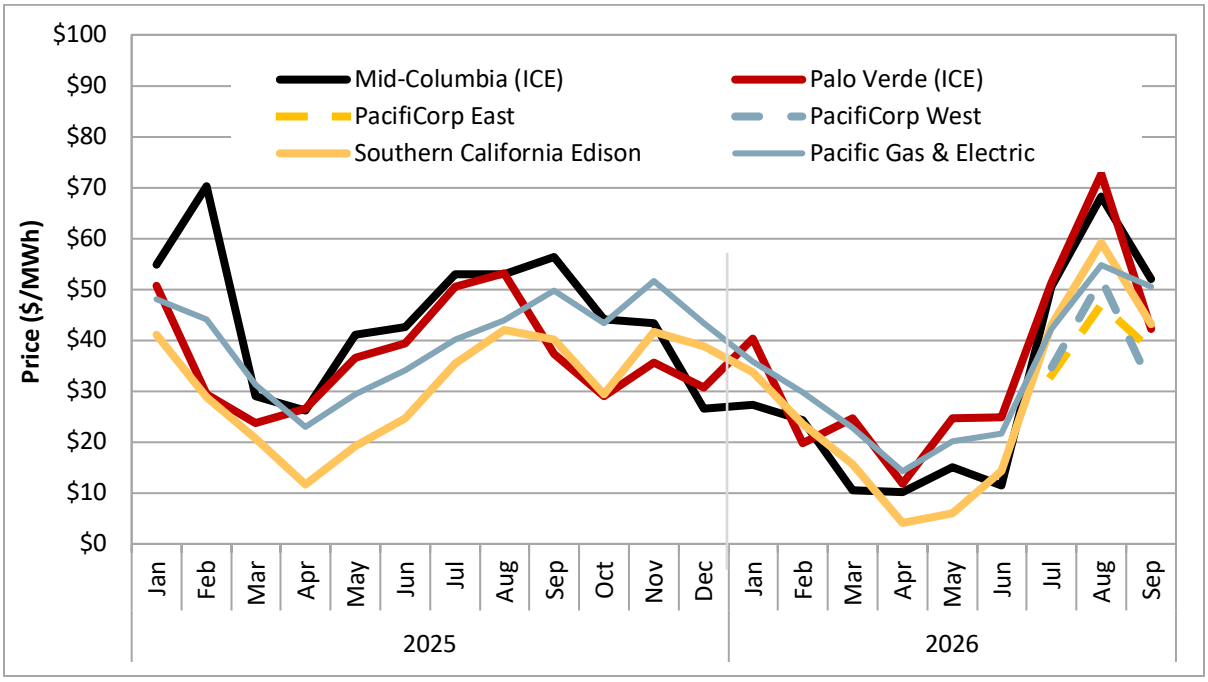
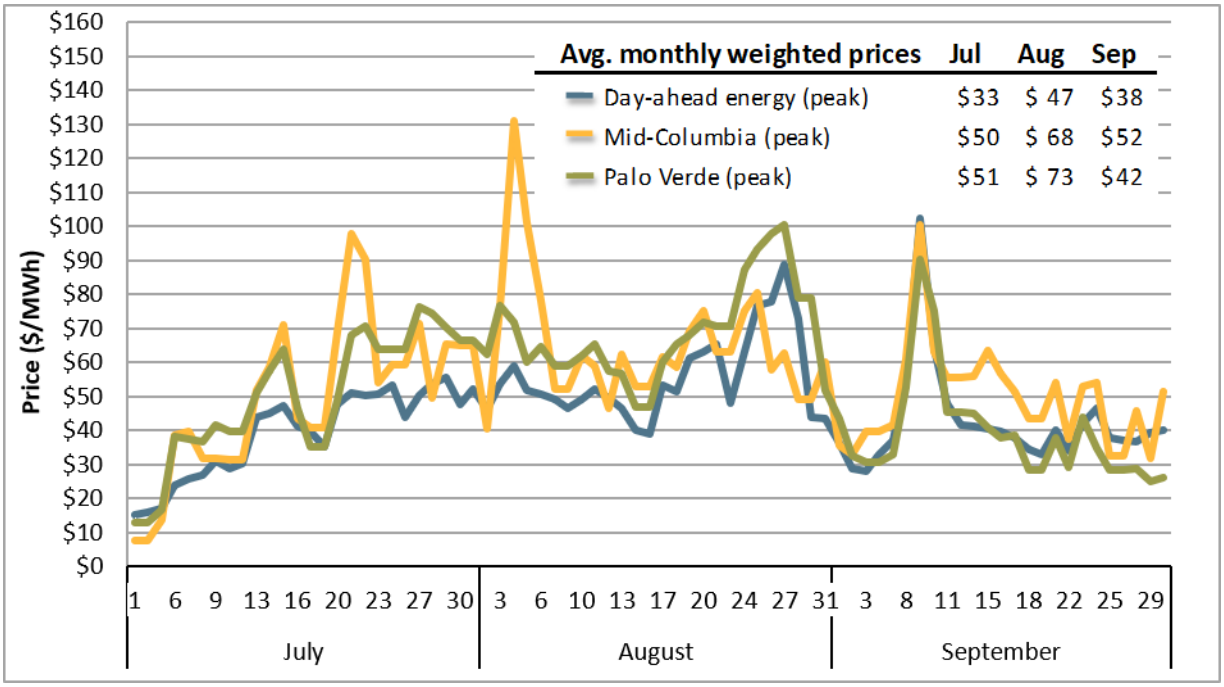


Figure 4.15 shows daily ISO market day-ahead load-weighted average peak prices across the CAISO, PacifiCorp West, and PacifiCorp East balancing areas, as well as averages for the bilateral day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the ISO markets. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

Mid-Columbia and Palo Verde bilateral prices exceeded the peak ISO day-ahead energy market prices for all three months of the quarter. The greatest premium was in August. August experienced several large price excursions exceeding $80/MWh. Mid-Columbia prices reached roughly $130/MWh on August 4, and Palo Verde prices reached $100/MWh in late August. Trading hub and ISO day-ahead prices spiked on September 8 and 9, 2026, coinciding with an extreme heat wave in Southern California.[36]

[36] California Department of Industrial Relations. September 9, 2026. *September Heat Alert: Cal/OSHA reminds employers to protect workers from high heat with temperatures expected to reach triple digits across much of the state.* https://www.dir.ca.gov/DIRNews/2026/2026-72.html

Figure 4.15 Day-ahead and bilateral market prices (July–September)



The ISO's 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.[37] The ISO did not raise the energy bid cap and penalty prices to $2,000/MWh in the third quarter of 2026.

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 higher than the average real-time prices (from Powerdex) by about $6.63/MWh. At the Palo Verde hub, average day-ahead prices were lower than average real-time prices (from Powerdex) by about $3.17/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 the

[37] *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)

California ISO balancing area, PACE and PACW.[38] The second group comprises balancing areas participating exclusively in the real-time market, which includes all WEIM entities aside from the day-ahead participating balancing authorities.

High prices

Figure 4.16 shows the monthly frequency of high prices across all three markets for balancing areas participating in both the day-ahead and real-time markets from July 2025 to September 2026.[39] Figure 4.17 illustrates the monthly frequency of high prices for balancing areas participating only in the real-time market during the same period.[40] Day-ahead market prices never reached $250/MWh in the third quarter, similar to 2025.

In the 15-minute market, the frequency of high prices for balancing areas participating in the day-ahead market increased from 0.07 percent in Q3 2025 to 0.19 percent in Q3 2026. For balancing areas participating exclusively in the real-time market, the frequency of high 15-minute market prices increased, from 0.08 percent in Q3 2025 to 0.24 percent in Q3 2026.

In the 5-minute market, the frequency of high prices for balancing areas participating in the day-ahead market increased from 0.06 percent in Q3 2025 to 0.3 percent in Q3 2026. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market increased from 0.09 percent to 0.29 percent.

[38] 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, the EIM Load Aggregation Point (ELAP) for PACE and PACW, and the ELAP for 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.

[39] 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. For PACE and PACW, the frequency was measured at their respective ELAPs.

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

Figure 4.16 Frequency of high prices in BAAs participating in the day-ahead market (EDAM)

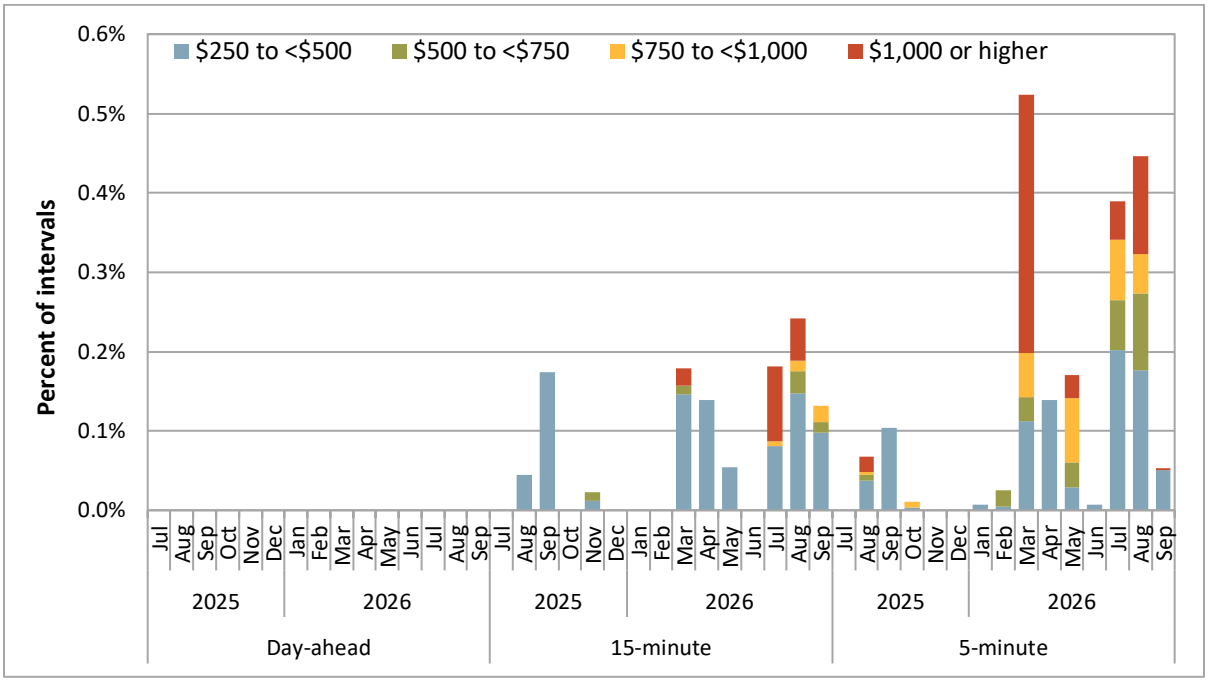
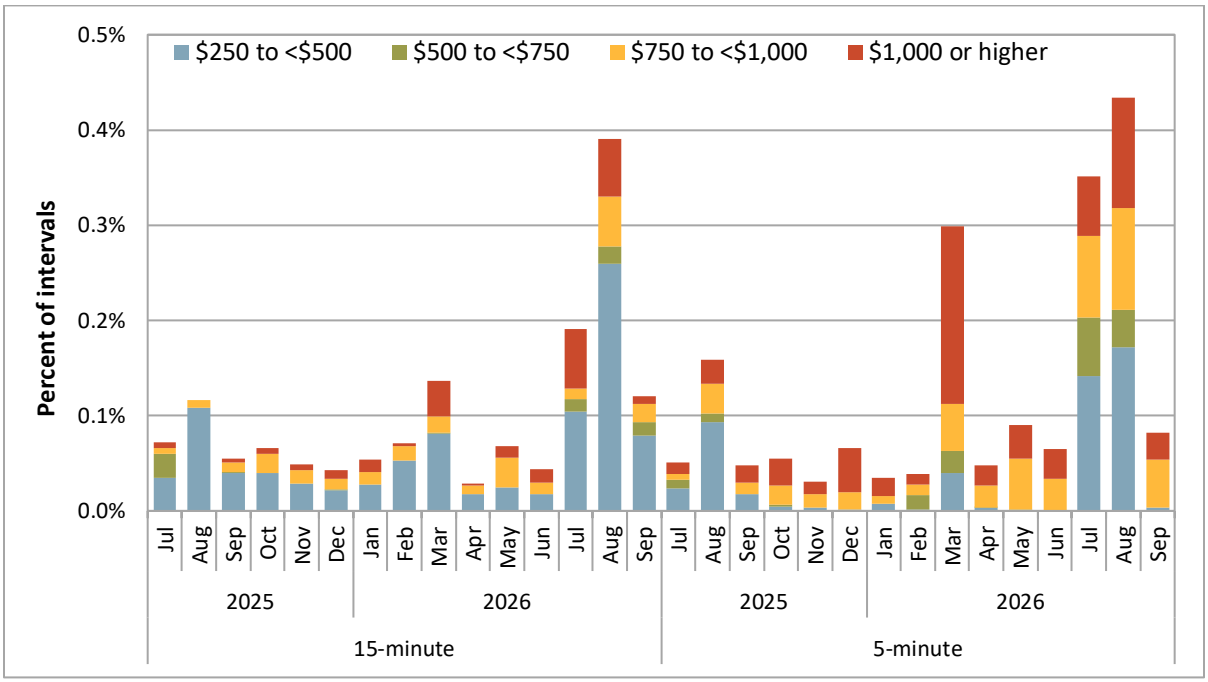


Figure 4.17 Frequency of high prices in BAAs participating only in the real-time markets



Negative prices

Figure 4.18 and Figure 4.19 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 July 2025 to September 2026.

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, the frequency of negative prices decreased in the three markets. In the day-ahead market, the frequency decreased from 0.18 percent to 0.06 percent compared to the same quarter of the previous year. In the 15-minute market, it decreased from 1.3 percent to 0.19 percent, and in the 5-minute market, it decreased from 1.2 percent to 0.3 percent.

For the BAAs participating exclusively in the real-time markets, the frequency of negative prices showed an increase across the 15-minute and 5-minute markets compared to the same quarter of the previous year. For instance, in the 15-minute market, the frequency increased from 0.3 percent to 1.3 percent. In the 5-minute market, it increased from 0.4 percent to 1.3 percent during this quarter.

Figure 4.18 Frequency of negative prices in BAAs participating in the day-ahead market (EDAM)

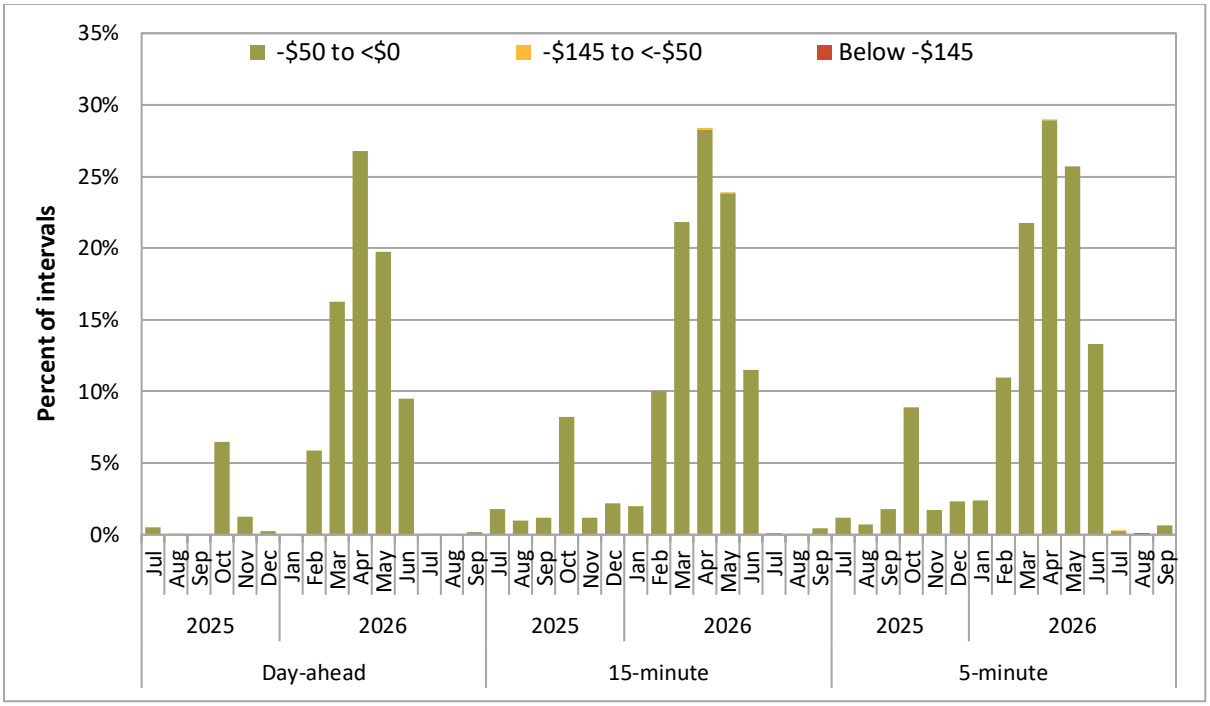
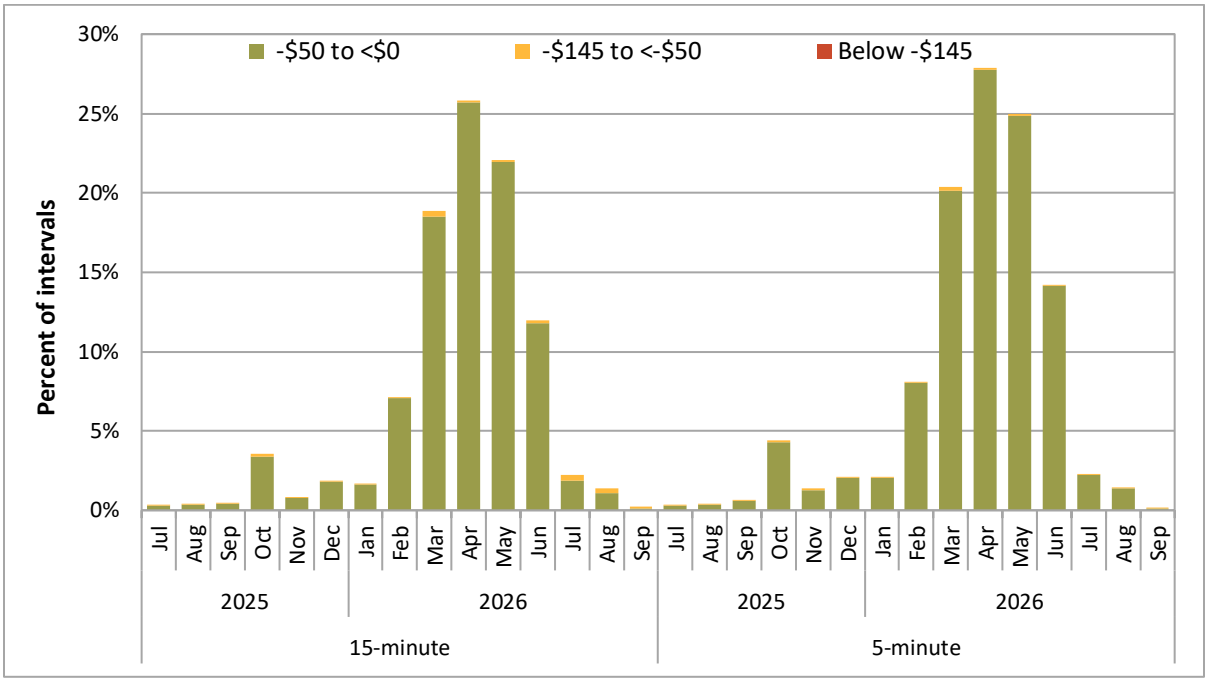


Figure 4.19 Frequency of negative prices in BAAs participating only in the real-time markets



4.6 Energy market competitiveness and bidding conduct

This section looks at competitiveness through the lens of bidding conduct—to what degree suppliers raised offers above their variable costs and what the impact was on the market price. DMM assesses this based on the price-cost markup. This measurement is a comparison between actual market prices and an estimate of prices that would result from a highly competitive market in which all suppliers bid at or below their variable costs. In this section, DMM uses the intersection of supply with demand to estimate the energy price from submitted bids. An alternate supply curve where energy is offered at or below variable costs is used to estimate a competitive price, and the difference between the energy price with submitted bids and the competitive price is the price-cost markup.

4.6.1 Day-ahead market price-cost markup

This section reviews the competitiveness of the extended day-ahead market that launched on May 1, 2026. Prices in the day-ahead market were very competitive, averaging close to what DMM estimates under highly efficient and competitive conditions.

Example interval and methodology

Starting with an example hour, Figure 4.20 shows the intersection of supply and demand in the day-ahead market.[41,42] In this hour, there was no EDAM transfer congestion separating the California ISO, PacifiCorp East, and PacifiCorp West balancing areas such that the supply and demand here reflects the entire EDAM system. The marginal energy cost is therefore the same for each balancing area. In this hour, the market marginal energy cost for these balancing areas equaled the intersection of the curves shown in this figure, at $64/MWh.

Figure 4.21 shows a zoomed-in section of the supply and demand curves, including a "competitive" supply curve with all supply set to the lower of their submitted market bid, or their *default energy bid* (DEB). The default energy bid is designed to reflect a generator's variable cost.[43] As shown in the figure, much of the supply was bid near or below these reference levels such that the supply set to the minimum of bid or DEB was similar to the market bids. Further, virtuals in the day-ahead market provide additional elasticity to the supply and demand curves, and can reduce the ability of suppliers to raise costs and exercise market power. In this hour, moving all generation to competitive levels would have had a relatively small impact on the market clearing price ($2/MWh lower).

41 The supply curve here considers all energy that balances against demand. For illustrative purposes, generation associated with the minimum operating level of on-line resources are shown at -$250/MWh and self-scheduled supply is shown at -$200/MWh. The economic segments include generation and imports that either cleared the market, or were bid above locational price and did not clear the market. Segments that were bid below locational price and did not clear the market (because of ancillary service obligation, resource constraint, etc.) are not included. Conversely, bid segments that were bid above locational price and cleared the market regardless (because of ancillary service obligation, resource constraint, etc.) are moved to the bottom of the supply stack and treated as a self-schedule.

42 The demand curve here considers all energy that balances against supply. This includes load, pump-load, losses, and exports. For illustrative purposes, self-scheduled load, pump-load, and exports as well as losses are shown at $1,100/MWh. For battery resources, the maximum charging amount is counted on the demand curve and all incremental energy (reduced charging or discharging) is counted on the supply side.

43 Default energy bids are used in local market power mitigation.

Figure 4.20 Day-ahead market supply and demand (July 21, 2026, 22:00–23:00)

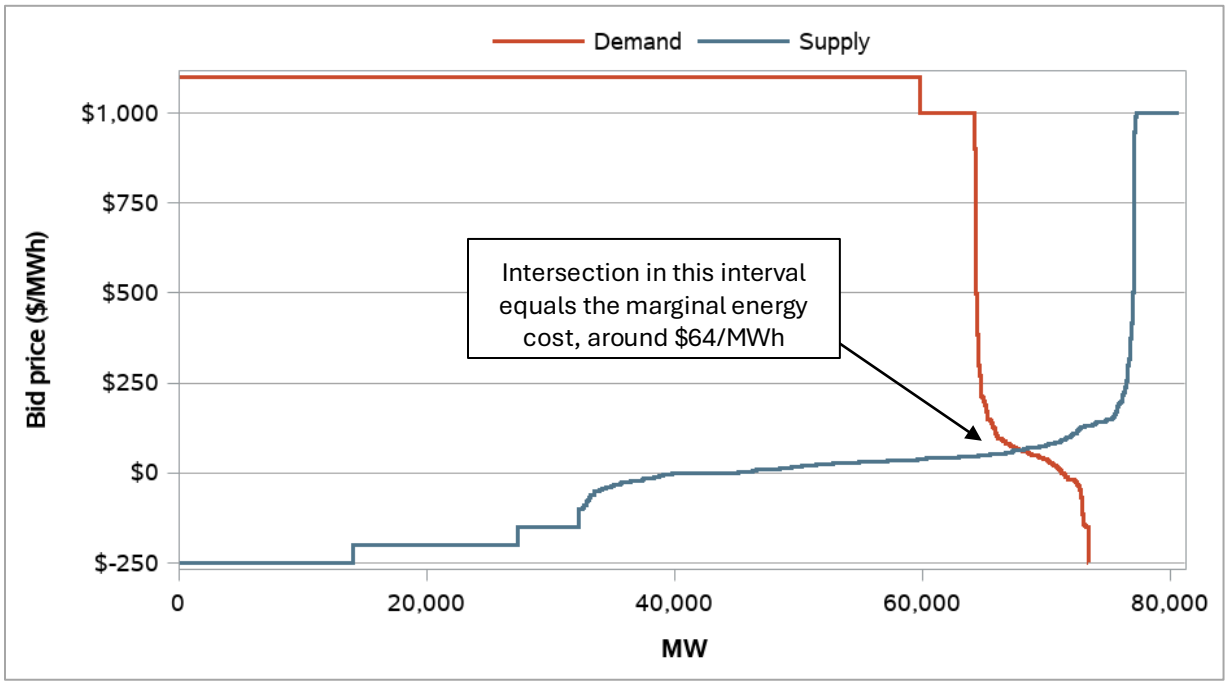
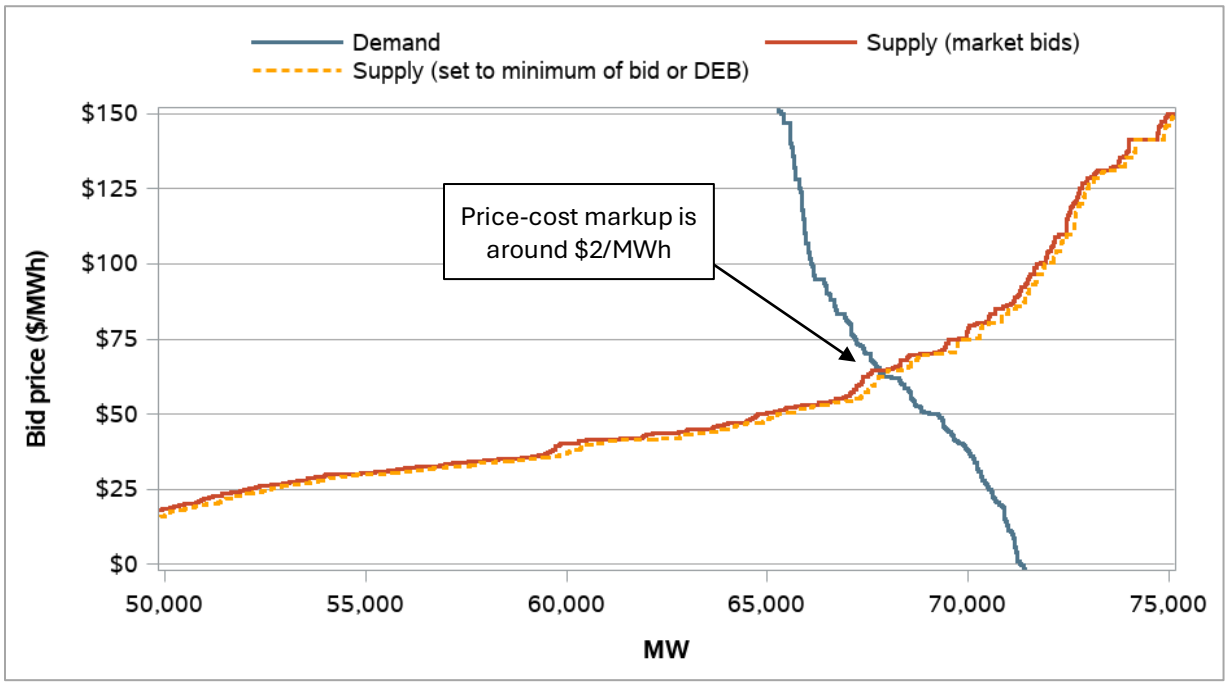


Figure 4.21 Day-ahead market with generation at competitive reference levels (July 21, 2026, 22:00–23:00)



Day-ahead price-cost markup

The price-cost markup summarizes the impact of using suppliers' actual offers relative to a scenario in which supply is offered at or below cost-based offers. Here, DMM calculates the prices by creating supply curves as shown in the example above. The "baseline" price—which is an estimate of the actual marginal energy cost—is calculated from the intersection of demand and available supply at market bids.[44] The "competitive" price is calculated from the intersection of demand and available supply set instead to the lower of its submitted market bid or default energy bid.

In the day-ahead market, congestion on EDAM transfers between participating balancing areas can create separation, resulting in differences in marginal energy cost and available supply across the balancing areas. Therefore, DMM assesses the markup for each grouping for each hour in the day-ahead market. For example, if the California ISO, PacifiCorp East, and PacifiCorp West balancing areas were *not* transfer constrained, then the marginal energy cost (MEC) for each of these balancing areas would also be the same—and the supply, demand, and markup is assessed for this entire group. If just PacifiCorp West was transfer constrained, then we separately assess both the combined California ISO and PacifiCorp East balancing areas on their own as well as the PacifiCorp West balancing area on its own.[45]

Figure 4.22 shows the average markup for each group during the third quarter.[46] The grouping indicates that the balancing area(s) were not transfer constrained and had the same marginal energy cost for that hour. The parentheses below each markup amount shows the percent of hours that grouping occurred. For example, during the third quarter, PacifiCorp West and the California ISO balancing areas were combined—with only transfer congestion with PacifiCorp East—in 41 percent of hours with an average markup of $1.05.

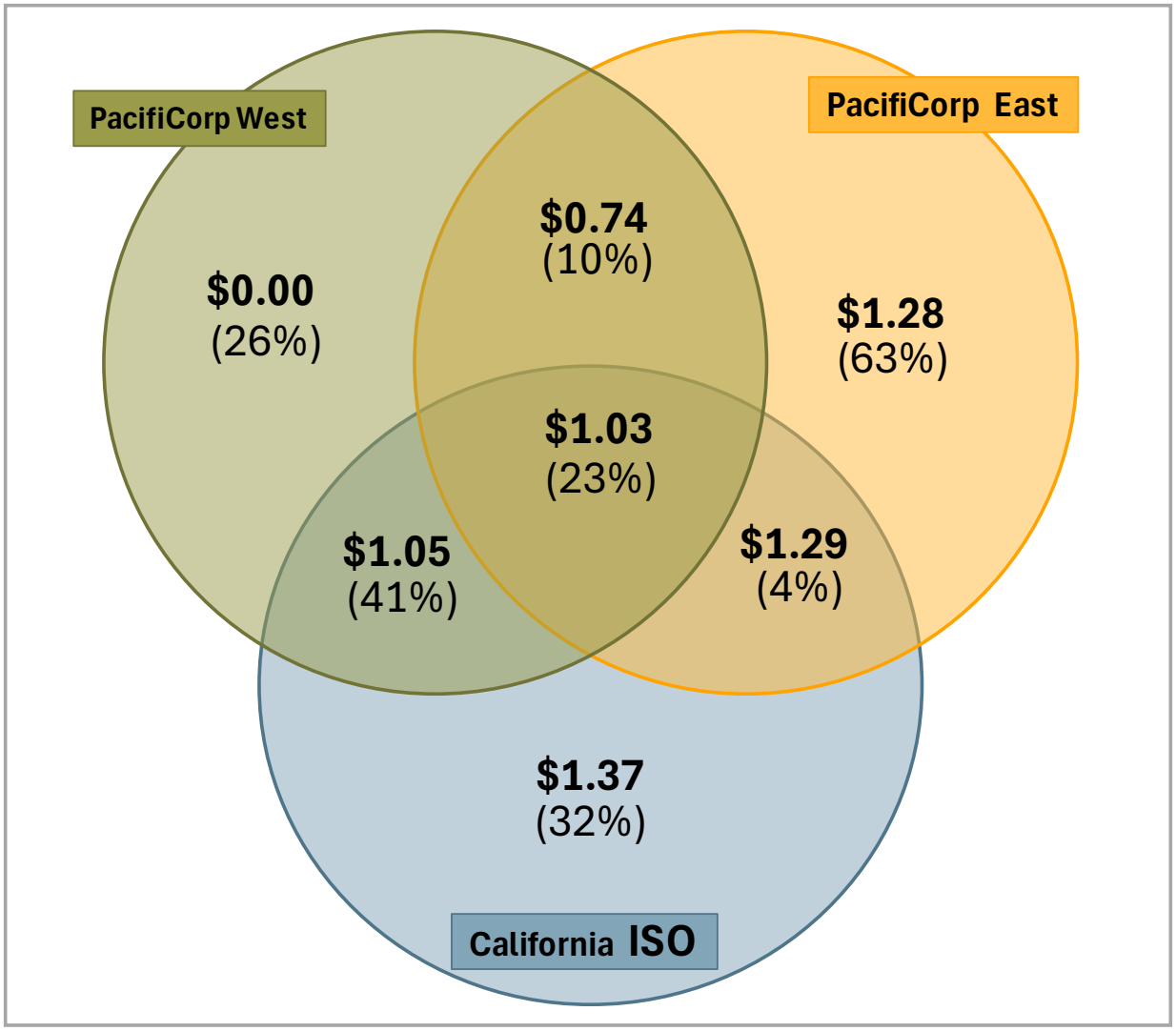
Prices in the day-ahead market were very competitive, averaging close to what DMM estimates under highly efficient and competitive conditions. Average price-cost markup was less than $2/MWh in each balancing area or grouping.

[44] The market bids here *includes* any mitigation that may have already set the bid to the default energy bids because of local market power mitigation. The markup relative to this baseline therefore measures the incremental effect at the system level.

[45] Any EDAM imports or exports with a constrained EDAM balancing area is considered fixed and counted as supply or demand accordingly.

[46] The average prices are weighted by load in each hour.

Figure 4.22 Day-ahead market price-cost markup (Q3 2026)



4.6.2 Real-time market price-cost markup

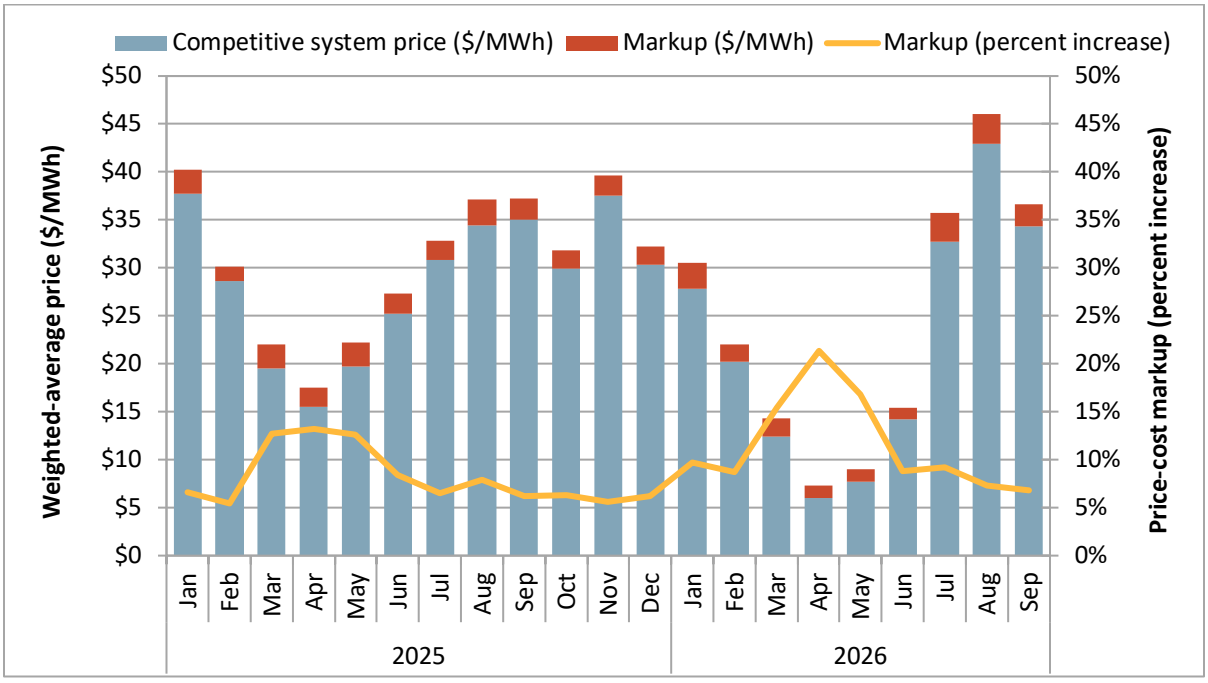
This section assesses bidding conduct instead in the real-time market by looking at the composition of supply and demand in the greater Western Energy Imbalance Market (WEIM) footprint. In the real-time market, there are many more combinations of groupings that can exist because of WEIM transfer congestion between balancing areas. Balancing areas are also generally less congested because of more participating balancing areas and thus more transfer capacity that is made available to optimally transfer energy in the real-time market. As a result, DMM's real-time price-cost markup assessment only looks at the balancing areas that are part of the greater WEIM system. This system is defined as the group of

balancing areas that have the same marginal energy cost (no transfer congestion) and includes the CAISO balancing area.[47]

Elsewise, the price-cost markup calculated for the real-time market is the same approach described above for the day-ahead market, using the intersection of supply and demand to calculate prices and markup. Again, DMM constructs system-wide supply curves based on available resources and market bids in each interval and uses a "competitive" version based on cost-based offers to calculate the markup.

Figure 4.23 shows the price-cost markup in the real-time market, using average prices weighted by system load from each interval. The figure also shows the price-cost markup as a percent increase relative to the competitive price which was calculated using the cost-based offers. The markup above the competitive price was less than $3/MWh during the third quarter, indicating that real-time market outcomes were generally close to competitive levels.

Figure 4.23 Real-time market price-cost markup



[47] The CAISO balancing area is selected as the reference area for a number of reasons. First, the CAISO balancing area has significant connectivity with other balancing areas and regions. Second, the CAISO balancing area cannot enter market separation in the same way other balancing areas can. Last, for comparison to previous years, the system marginal energy cost was calculated prior to the launch of EDAM based on the marginal energy cost in the CAISO balancing area.

5 EDAM and WEIM transfers

This section provides an overview of transfers between EDAM or WEIM balancing areas as well as constraints impacting those transfers. Key observations from the quarter include the following:

The average volume of EDAM transfers across the system was around 930 MW during the third quarter. This was slightly higher compared to the first two months of EDAM operation in May and June.

The average volume of WEIM transfers was 4,800 MW during the third quarter, slightly higher compared to 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.

The Pacific Northwest region continued to have the lowest transfer capacity into and out of the region. The lack of transfer capacity into or out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

Net WEIM exports for El Paso Electric were regularly constrained by intertie constraints that each balancing area can use to manage total or net transfers into or out of their system. Net exports for El Paso Electric were constrained in around 6 percent of intervals at 100 MW on average because of this constraint.

5.1 Energy transfers

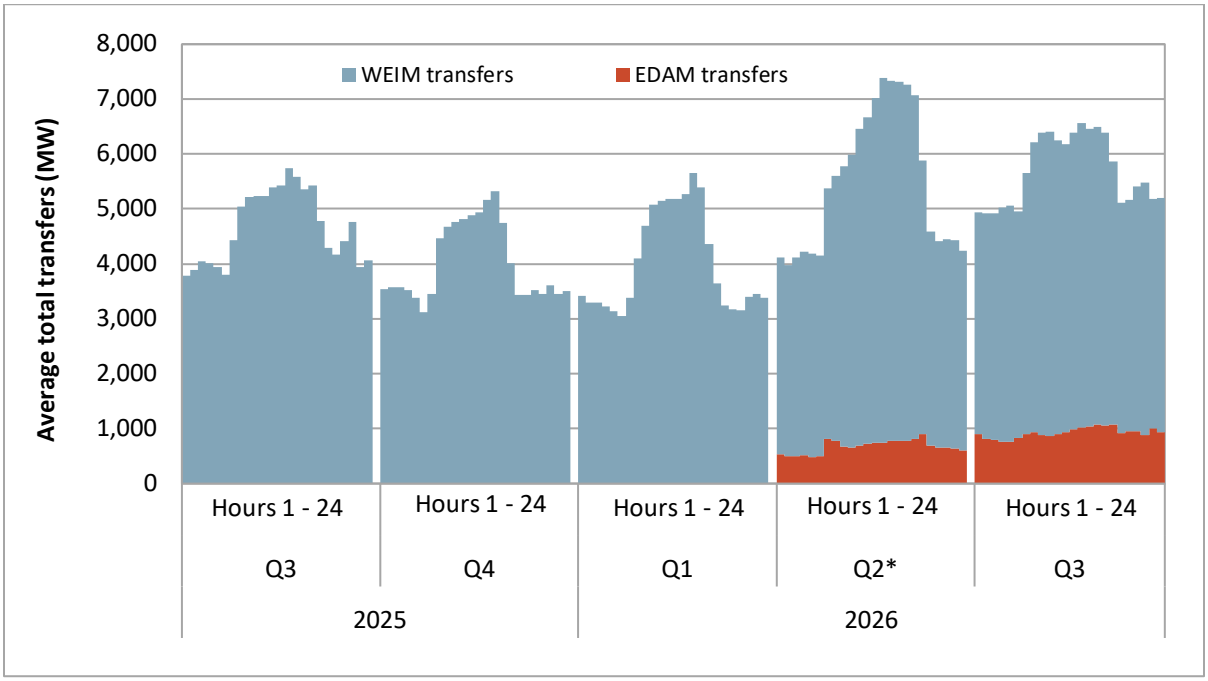
One of the key benefits of the Western Energy Imbalance Market (WEIM) is the ability to transfer energy between balancing areas in the real-time markets. These transfers reflect regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint. The extended day-ahead market (EDAM) was launched on May 1, 2026, extending this benefit to participating balancing areas in the longer timeframe of the day-ahead market.

WEIM transfers for the real-time markets 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 EDAM and WEIM transfers—as optimized in the day-ahead and 5-minute markets, respectively—during the last five quarters. The transfer volume summarizes how much transfer activity there is in each period, by looking at only exports in the system. The average volume of EDAM transfers across the system was around 930 MW during the third quarter, slightly higher compared to the first two months of EDAM in May and June. The average volume of WEIM transfers was around 4,800 MW during the third quarter, slightly higher compared to the same

quarter of the previous year. These transfers helped to displace expensive generation and meet load across the footprint.

Figure 5.1 Average EDAM and 5-minute market WEIM transfer volume by hour and quarter (Day-ahead and 5-minute market, Q3 2025 – Q3 2026)



*WEIM transfers for Q2 2026 are May and June only for comparison to EDAM

Figure 5.2 summarizes *net* EDAM transfers as optimized in the day-ahead market during the first two quarters of EDAM operation. At the time of the launch on May 1, the EDAM included participation from the California ISO, PacifiCorp East, and PacifiCorp West balancing areas. EDAM transfers leverage resource diversity and transfer capability between these balancing areas. During the third quarter, PacifiCorp West was a net importer on average in all hours, at around 360 MW. PacifiCorp East was a net exporter on average in all hours, at around 410 MW. These amounts were up considerably from the previous quarter. EDAM transfers out of the CAISO balancing area decreased during the mid-day solar hours from the previous quarter, in part due to higher loads in the third quarter.

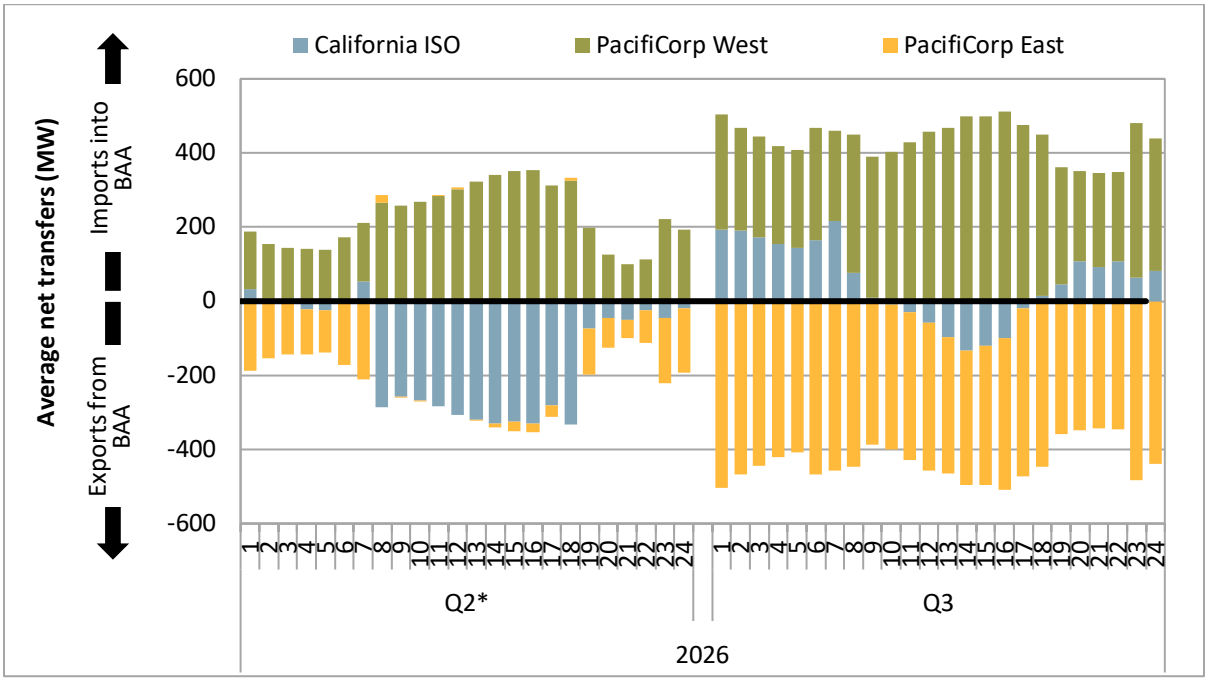
Figure 5.3 summarizes average inter-regional transfers by hour during the last five quarters in the Western Energy Imbalance Market (WEIM).[48] The bars show net WEIM transfers for each *region* by hour and do not include EDAM transfers that were scheduled in the day-ahead market.[49] WEIM transfers 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

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

[49] 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.

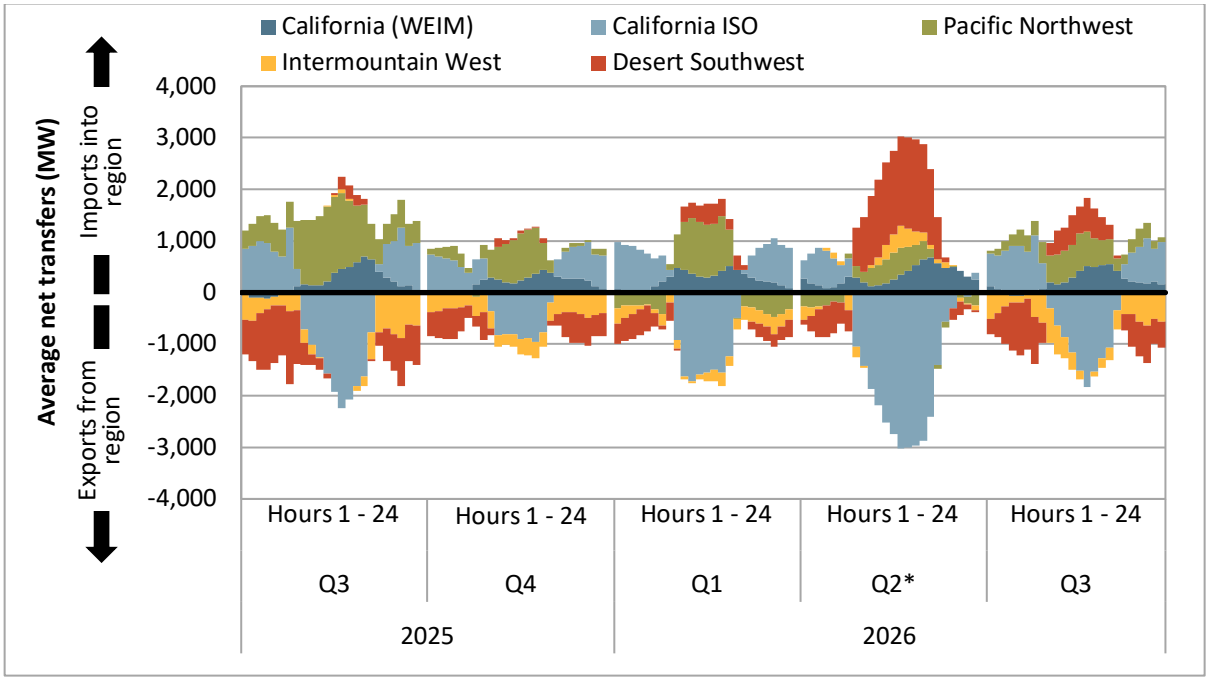
largely from the Desert Southwest and Intermountain West regions to California and the Pacific Northwest.

Figure 5.2 Average day-ahead market EDAM transfers by hour (Q2 2026 – Q3 2026)



*Q2 2026 is May and June only

Figure 5.3 Average 5-minute market inter-regional WEIM transfers by hour (Q3 2025 – Q3 2026)



*WEIM transfers for Q2 2026 are May and June only for comparison to EDAM

Figure 5.4 shows average WEIM transfers in the 5-minute market by balancing area in the mid-day hours when solar generation is highest.[50] Figure 5.5 shows the same information except in the remaining off-solar hours. The curves show the path and size of exports where the color corresponds to the area the transfer is coming from.[51] 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 970 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. During the remaining non-solar hours (Figure 5.5), balancing areas in the Intermountain West and Desert Southwest regions exported *on net* around 1,080 MW on average out to balancing areas outside this combined region (mostly to California).

[50] Mid-day solar hours in this figure are the twelve hours in the middle of the day when solar generation is highest, while the off-solar hours are the remaining twelve hours in the early morning and late evening.

[51] In the first figure, each small tick is 100 MW, each large tick is 500 MW, and average WEIM transfer paths less than 50 MW are excluded. In the second figure, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 5.4 Average 5-minute market WEIM exports in mid-day solar hours (Q3 2026)

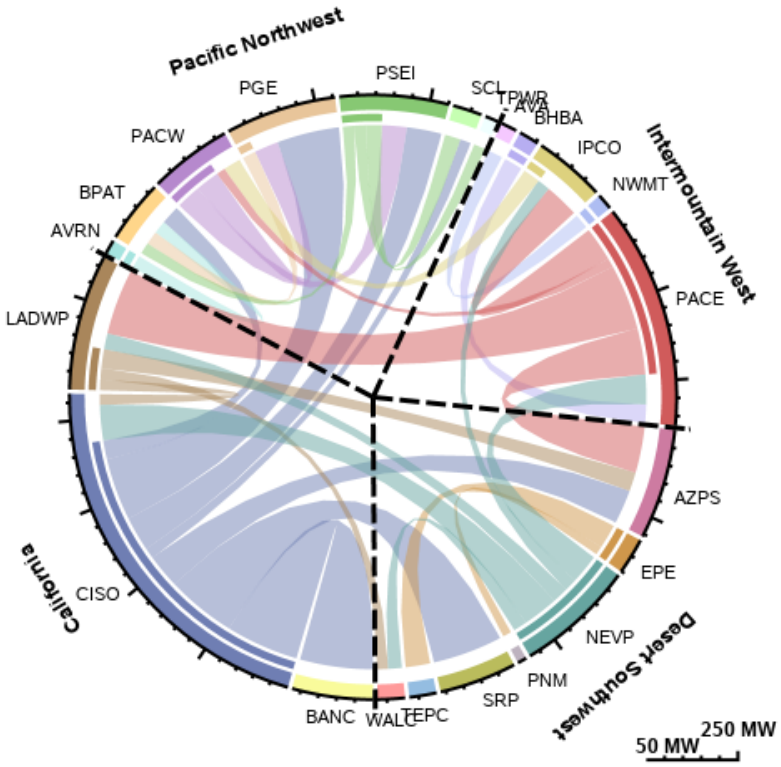
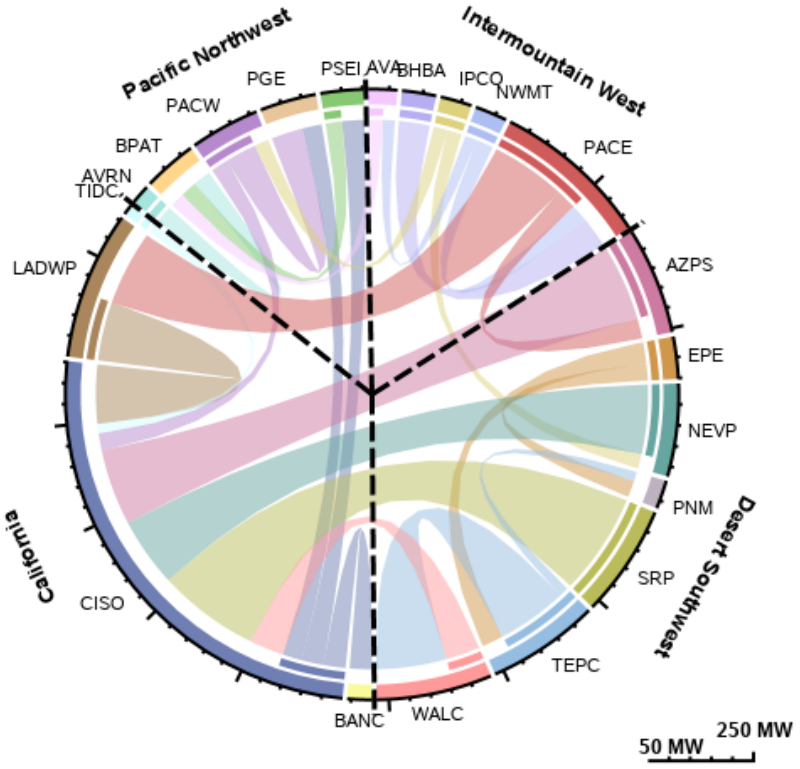


Figure 5.5 Average 5-minute market WEIM exports in off-solar hours (Q3 2026)



5.2 EDAM and WEIM transfer limits

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

Figure 5.6 summarizes average transfer limits (or transfer capacity) made available to transfer energy between participating EDAM balancing areas in the day-ahead market during the third quarter. Average transfer limits made available in EDAM were higher between all balancing areas compared to the first two months of EDAM operation in May and June.

Figure 5.6 Average day-ahead market EDAM transfer limits between balancing areas (Q3 2026)

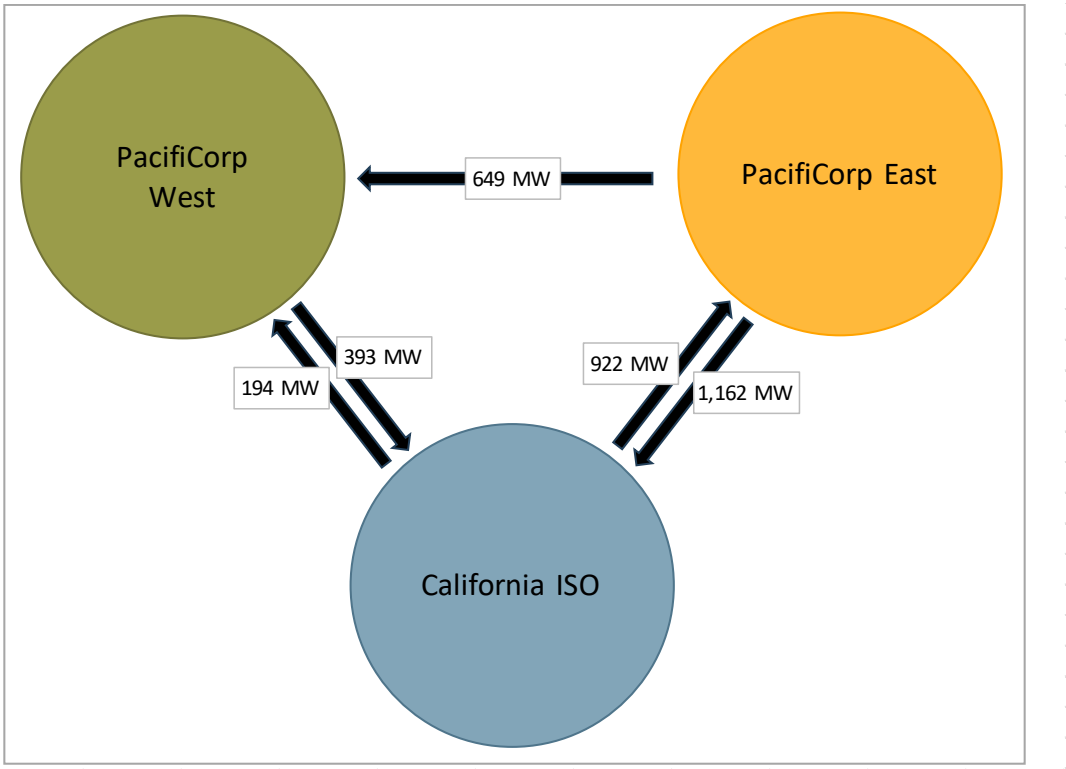


Figure 5.7 shows WEIM transfer capacity (or transfer limits) available in the 5-minute market to support the transfer of energy between balancing areas and regions in the Western Energy Imbalance Market.[52] The width of each path reflects the size of the WEIM transfer capacity. WEIM transfer capacity 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. Of note, much more transfer capacity between balancing areas is available in the real-time market relative to the day-ahead market. This can contribute to different pricing outcomes for each EDAM balancing area between the day-ahead and real-time markets.

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

Figure 5.7 Average 5-minute market WEIM transfer limits by balancing area (Q3 2026)

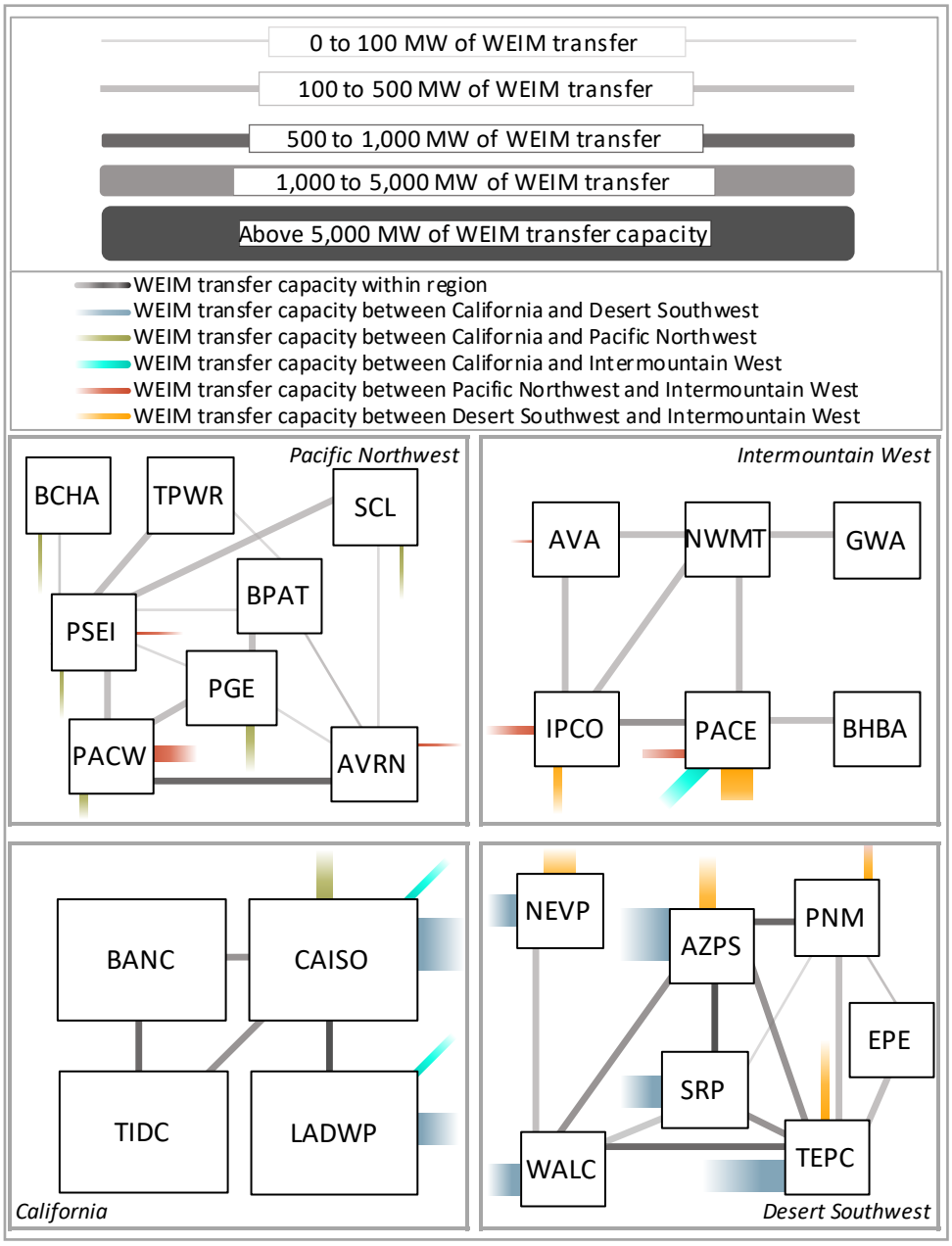


Table 5.1 summarizes average regional transfer capacity in the WEIM.[53] Total WEIM transfer capacity between balancing areas *within a region* is shown in the gray cells. Transfer capacity *between regions* is shown in the remaining cells. The sum of each column reflects the average total import capacity into the region, while the sum of each row reflects the average total export capacity out of the region.

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 1,287 MW of import transfer capacity and 752 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 (Q3 2026)

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	24,693	31,601	305	758 / 338	32,775 / 338
Desert Southwest	31,981	60,290	2,019		34,000
Intermountain Wes	481	2,405	5,891	529	3,462
Pacific Northwest	432 / 173		320	4,427	752 / 173
Total out-of-region import limit	32,942 / 173	34,006	2,756	1,287 / 338	

EDAM transfer system resource types

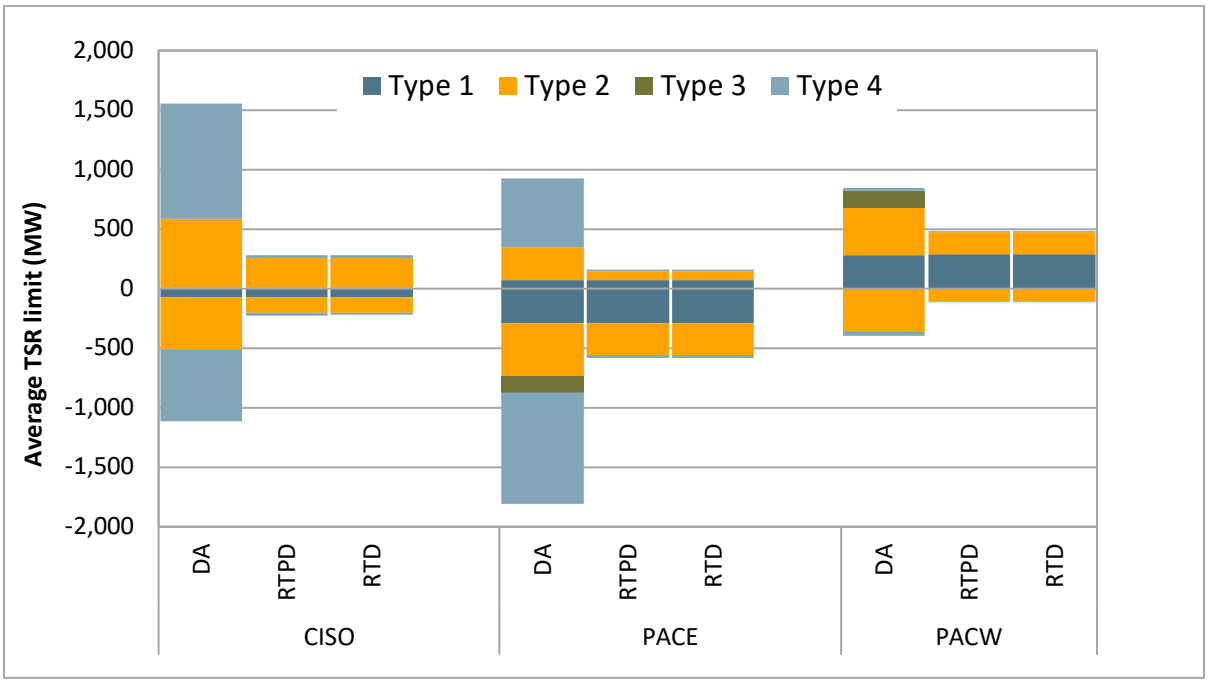
Day-ahead transfers between EDAM balancing areas are modeled using one of four categories of transfer system resource (TSR). Type 1 TSRs represent bilateral transfers between EDAM balancing areas, excluding those that use transmission from a non-EDAM area. Type 1 TSRs are self-scheduled into the day-ahead market and are the only TSR type that may re-bid capacity into the real-time market. Type 2 and type 4 TSRs are similar to each other in that they represent released transmission rights that are available to the day-ahead market to optimize transfers. For type 2 TSRs, the transmission customer (the EDAM scheduling coordinator) releases the transmission capacity for optimization, whereas for type 4 TSRs, the capacity is released by the EDAM BA. Type 3 TSRs represent resource-specific capacity

[53] 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.

used to support balancing area load. Type 1 and type 3 TSRs are eligible to be counted in the day-ahead resource sufficiency evaluation.

Besides type 1 TSRs rebidding into the real-time market, changes to day-ahead TSR schedules in real-time may only be caused by derates in the TSRs' maximum capacity. Figure 5.8 shows average EDAM TSR limits by type and market for the third quarter. Most decreases in TSR limits from the day-ahead to the real-time market are for type 2 and type 4 resources, which are ineligible to be counted towards the day-ahead RSE. On average, type 1 limits either increased or stayed near day-ahead levels going into the real-time market across all EDAM balancing areas. Similar to trends in the second quarter, type 3 day-ahead import limits in PACW consistently decreased to 0 in the real-time market. However, no type 3 transfers were cleared in the day-ahead market in Q3.

Figure 5.8 EDAM transfer system resource limits by type and market (2026 Q3)



EDAM historical revenue recovery

By making transmission capacity available to EDAM, participating transmission providers may forgo revenues they otherwise could have earned from short-term transmission sales. The ISO compensates transmission providers for these forgone revenues. To determine the eligible compensation for forgone transmission sales, the ISO collects forecasts from EDAM entities for their transmission service providers' recoverable revenues from three categories:

1. The historical sale of certain eligible transmission products to third parties, including short-term firm and non-firm point-to-point transmission and wheeling (historical recovery);
2. The cost associated with forgone transmission sales on certain new network upgrades or resulting from the expiration of EDAM legacy contracts (new transmission recovery); and

3. Projected revenue shortfalls associated with wheeling through an EDAM Entity Balancing Authority Area or the CAISO Balancing Authority Area (wheeling recovery).

The ISO publicly reports on each category of recovery paid to EDAM entities and CAISO participating transmission owners.[54] As of October 2026, all transmission recovery falls under the historical recovery category.

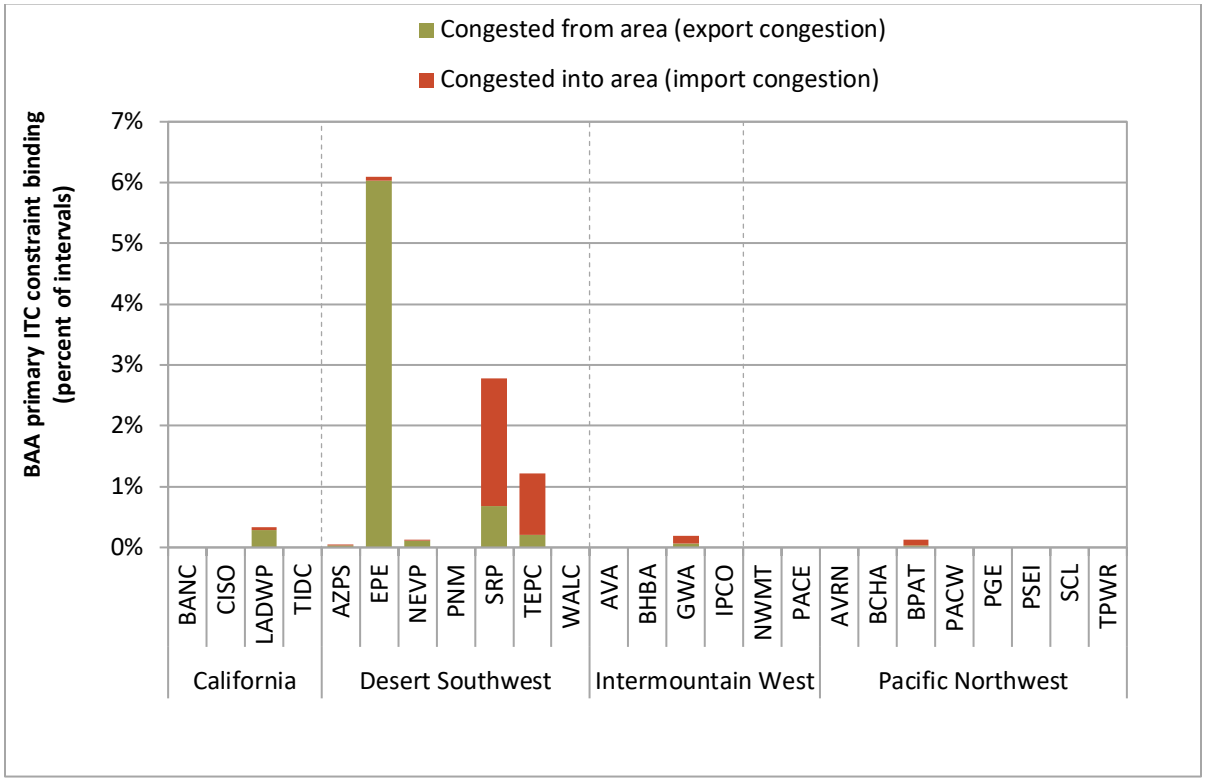
5.3 WEIM intertie constraints

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 EDAM or WEIM, these can also be used to manage EDAM or WEIM transfers in a balancing area. Here, a *primary* intertie constraint is modeled for each balancing area that is mapped to all of their EDAM transfers or non-base WEIM transfers. A WEIM entity can use this constraint to effectively manage all these transfers into or out of their system, on net, without needing to adjust individual transfer limits. In the EDAM, the primary intertie constraint that can limit all EDAM transfers on net for a balancing area was not binding for any balancing area during the quarter.

Figure 5.9 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 6 percent of intervals because of this constraint. When this constraint was binding in the export direction, net exports were limited to around 100 MW on average.

[54] https://www.caiso.com/library/extended-day-ahead-market-edam-access-charge-rates

Figure 5.9 Frequency of primary ITC constraint binding for net WEIM transfers (5-minute market, Q3 2026)



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 exports in around 8 percent of intervals and for total WEIM imports in around 4 percent of intervals. The limit was around 500 MW on average in both directions when these constraints were binding.

5.4 Intertie transactions for EDAM entities

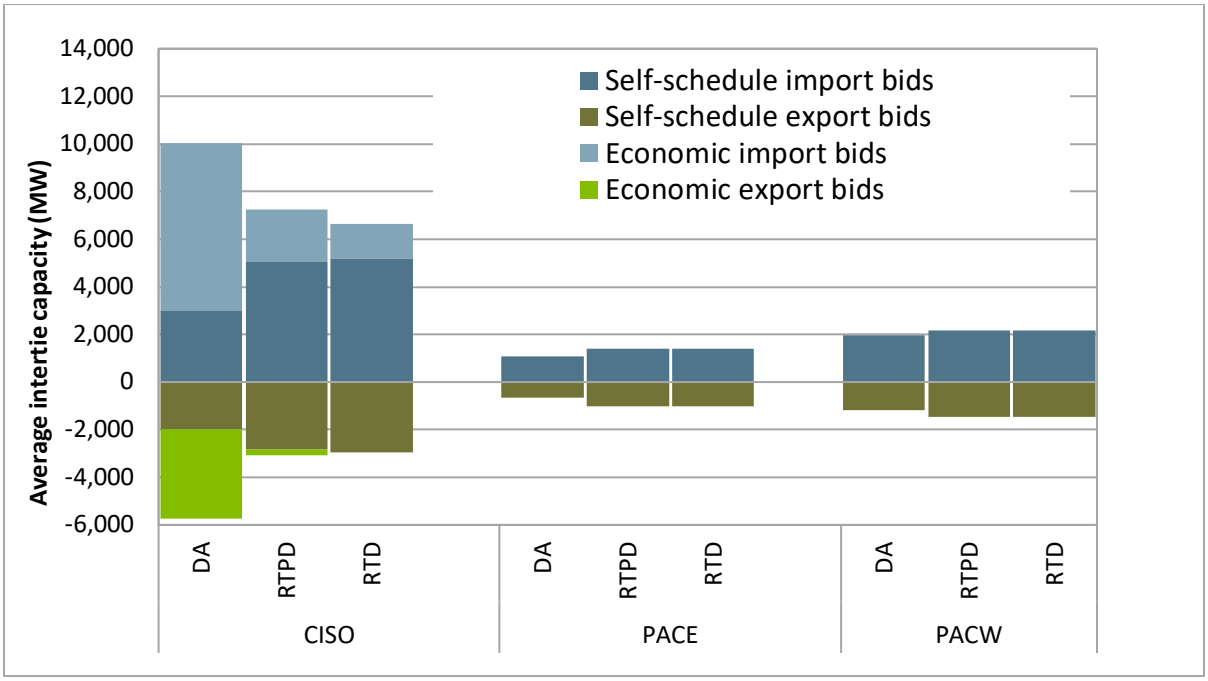
In the extended day-ahead market (EDAM), the ISO's market software continues to support intertie transactions at EDAM external interties, i.e., interties using transmission from both EDAM balancing areas and non-EDAM balancing areas. CAISO interties continue to support intertie resources' ability to submit self-schedules or economic bids. However, at non-CAISO external interties, entities may submit self-schedules for imports and exports but economic bids are limited to imports from designated network resources specified in the terms of the EDAM entity Open Access Transmission Tariff (OATT).

The market software does not support day-ahead intertie bidding to facilitate bilateral transactions between two EDAM balancing areas, except at the Mona and Crag View interties or when the transaction uses transmission through a non-EDAM area. The ISO made exceptions for Mona and Crag

on an interim basis to support imports into the CAISO balancing area related to either resource adequacy or Renewable Portfolio Standard contracts. Besides the exceptions noted previously, bilateral transactions between two EDAM areas are modeled as TSR type 1, described in more detail in Section 5.2 of this report.

Figure 5.10 shows average intertie resource capacity bid into the market for day-ahead balancing areas in the third quarter, broken out by whether capacity was self-scheduled or bid in economically. The majority of intertie bids for the CAISO balancing area were economic bids, with 65 percent of exports and 70 percent of imports being bid economically. There were no economically bid day-ahead imports into PacifiCorp areas in the third quarter.

Figure 5.10 Average bid-in intertie resource capacity for day-ahead balancing areas (Q3 2026)



Intertie transactions are considered in the new day-ahead market resource sufficiency evaluation (RSE), with imports counting towards additional supply for a balancing area and exports counting towards additional demand. Figure 5.11 shows average cleared intertie resource capacity by balancing area for the day-ahead RSE and all market runs for the third quarter. In the third quarter, CAISO was the only day-ahead balancing area that cleared less intertie capacity (both imports and exports) in the day-ahead RSE compared to the day-ahead market. Intertie bids are not counted towards the day-ahead RSE for the CAISO balancing area unless they meet the deliverability requirements outlined under the CAISO tariff.[55]

[55] California ISO Tariff Section 33.30.8.2
https://www.caiso.com/documents/section-33-extended-day-ahead-market-as-of-may-1-2026.pdf

Figure 5.12 compares average intertie import capacity that counted towards the day-ahead RSE, with day-ahead market awards and 5-minute market bids from those same resources. On average, slightly less capacity was bid into the real-time market, compared to what was awarded in day-ahead, for PACE in July, and both PACE and CAISO in September.

Figure 5.13 highlights this difference between 5-minute market bids and day-ahead awards for resources counted in the day-ahead RSE. In addition to changes in supply shown by the blue bars (with negative values indicating real-time supply shortfalls resulting from lower import bid quantities), Figure 5.13 also shows changes in demand, represented by the yellow bars (with negative values indicating increased export bids). The red diamonds indicate the net shortfall resulting from changes in either real-time import bids, export bids, or both, relative to day-ahead market awards.

Figure 5.11 Average cleared intertie resource capacity for day-ahead balancing areas (Q3 2026)

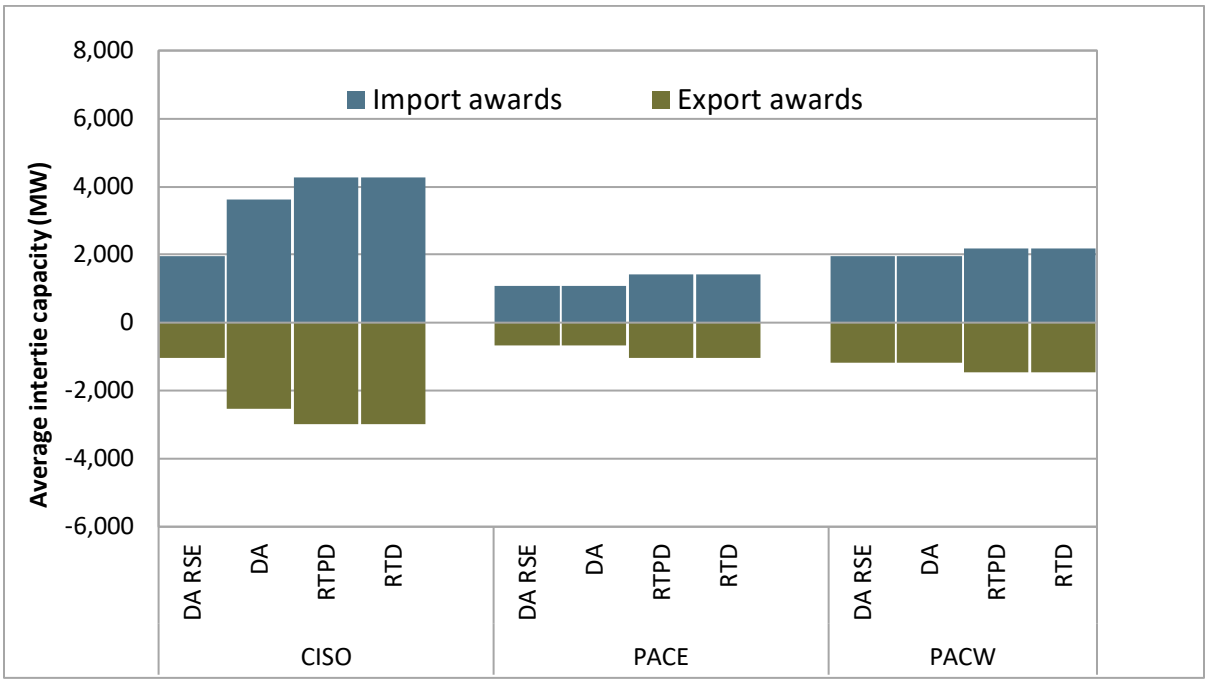


Figure 5.12 Day-ahead and real-time market comparison of intertie import capacity (Q3 2026)

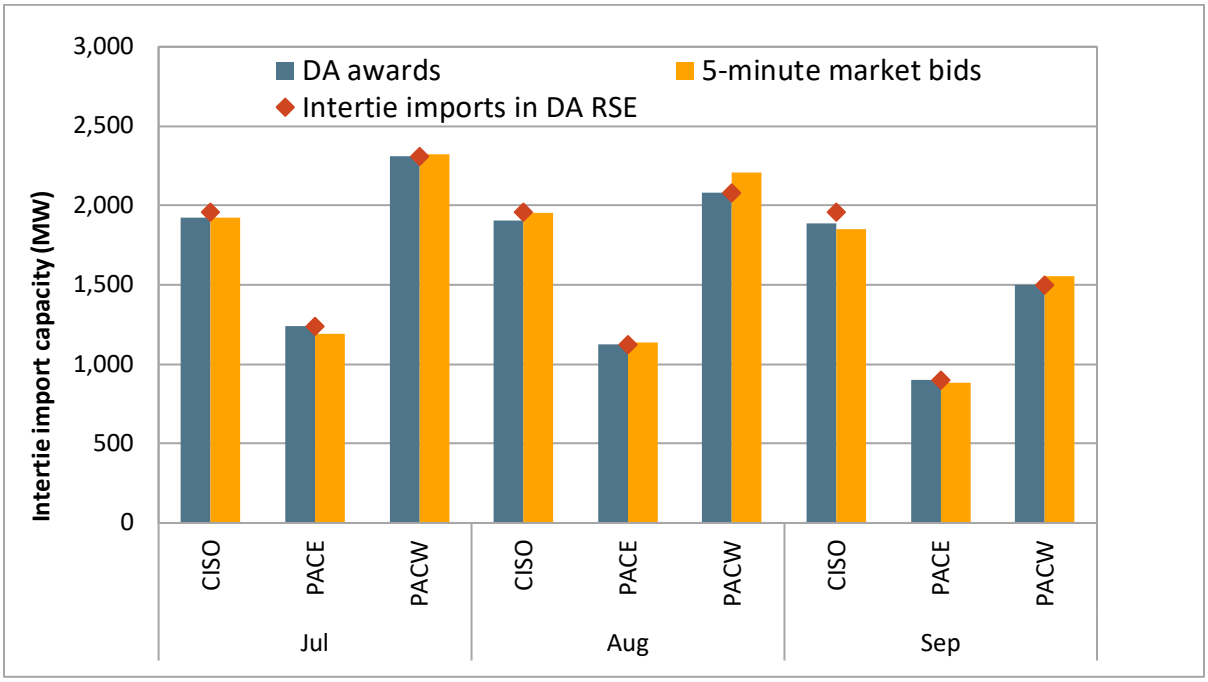
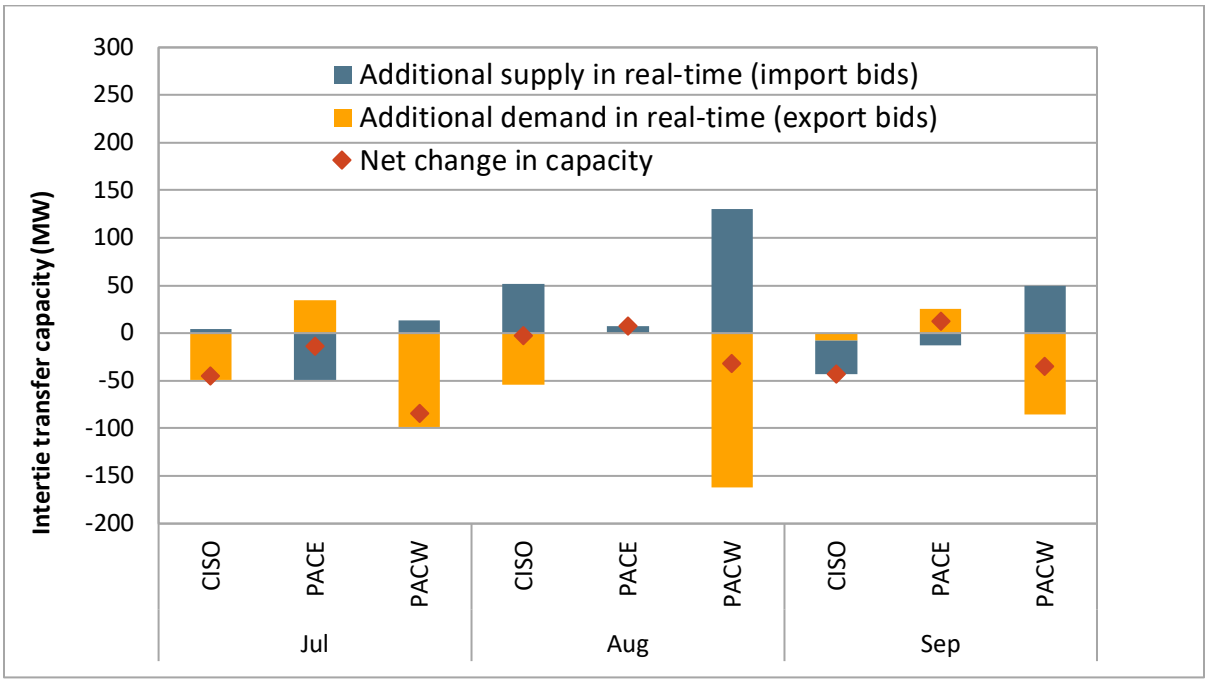


Figure 5.13 Real-time bid changes for resources counted toward the day-ahead RSE (Q3 2026)



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 6.4 show the average impact of congestion on day-ahead and real-time market prices, respectively, in Q3 of 2025 and 2026. Blue bars represent the 2026 impact, while gray bars represent the 2025 values. The congestion impact in real-time was calculated as the average price impact across both the 15-minute and 5-minute markets for all intervals during the quarter.

The total congestion shown in these figures includes both internal and transfer congestion. Internal congestion reflects the impact of flow-based constraints, while transfer congestion reflects the difference between each balancing authority area's marginal energy component (MEC) and that of the CAISO balancing area.

In the day-ahead market this quarter, prices in SCE and SDG&E were higher due to congestion, while prices in PG&E, PACE, and PACW were lower.

In the real-time market as well, the north-to-south congestion pattern was predominant in this quarter. Prices in Northern California, the Pacific Northwest, and the Intermountain West were generally lower, while prices in Southern California and Desert Southwest were higher.

Compared with the same quarter last year, congestion impacts shifted notably across the WEIM. Congestion generally followed a north-to-south pattern this quarter, compared with a south-to-north pattern last year. The most notable impact was observed in Powerex (BCHA), where prices were $23/MWh lower than CAISO balancing area prices due to transfer congestion.

Figure 6.1 Average impact of congestion on day-ahead market price (Q3 2026)

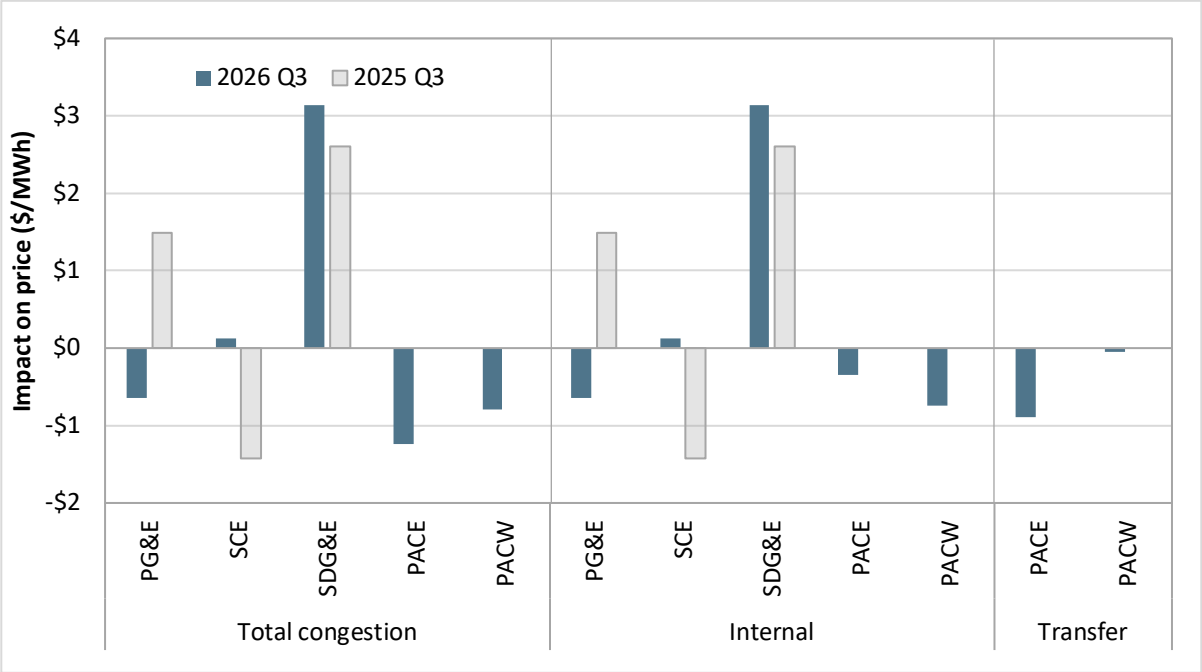


Figure 6.2 Average impact of total congestion on real-time market price (2025–2026)

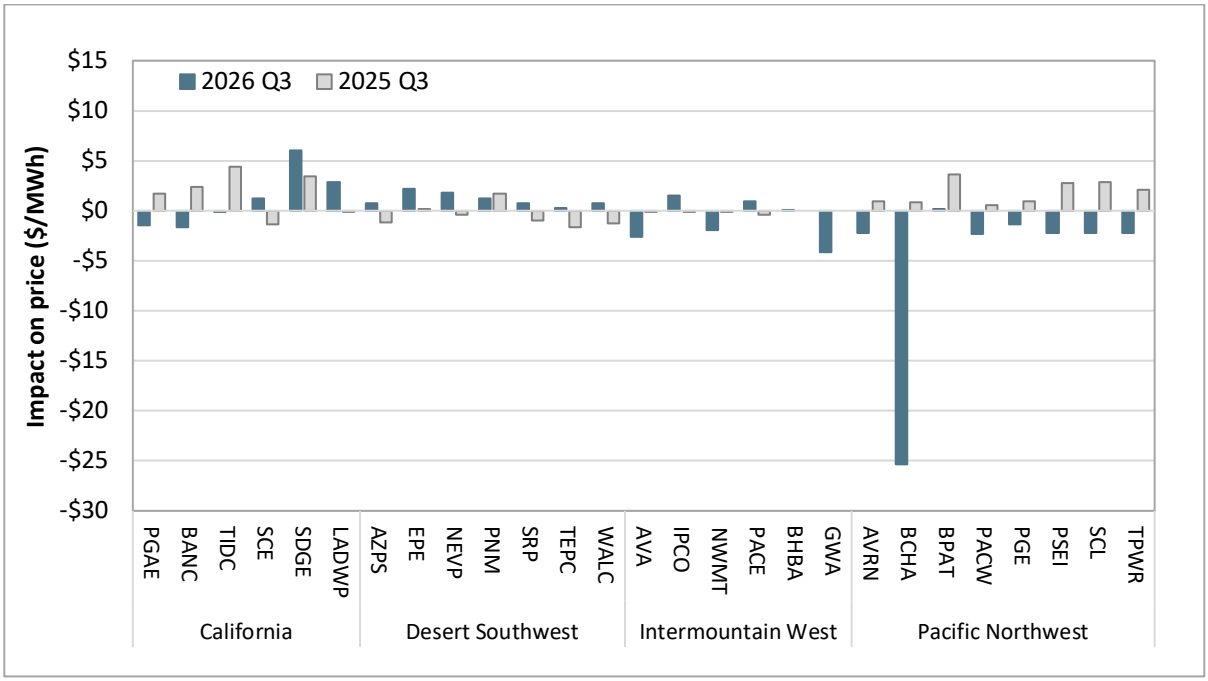


Figure 6.3 Average impact of transfer congestion on real-time market price (2025–2026)

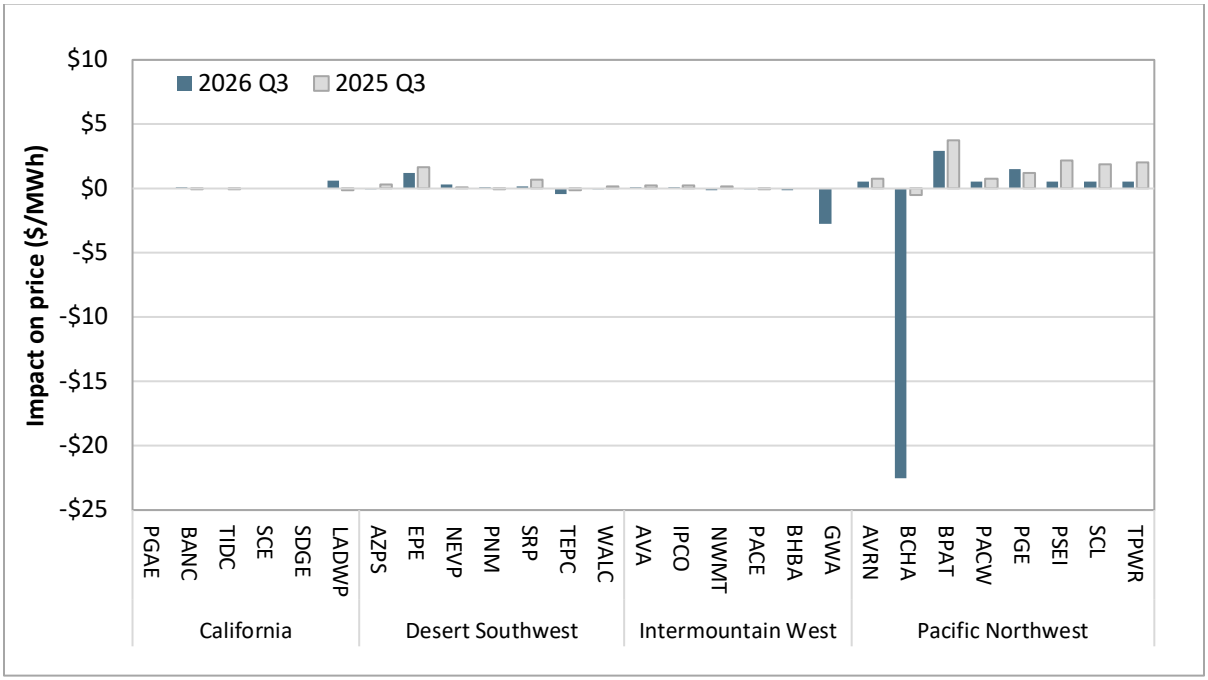
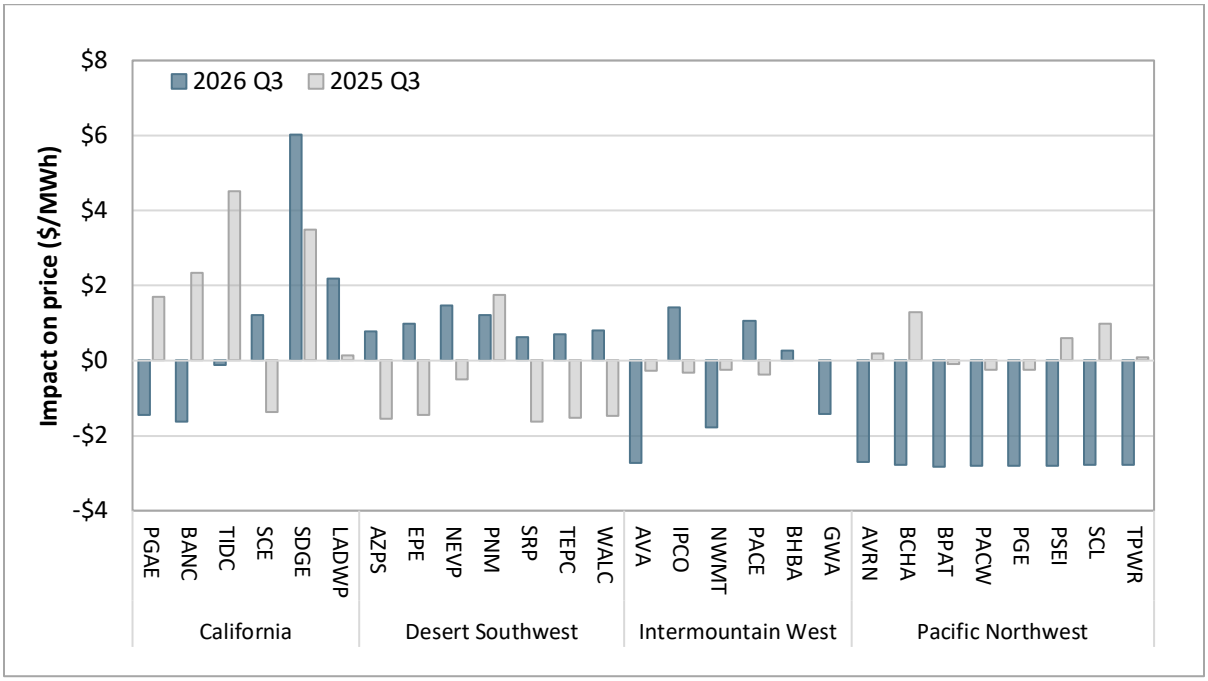


Figure 6.4 Average impact of internal congestion on real-time market price (2025–2026)



The following sections present further details on price impacts from different sources of congestion. Section 6.1 addresses congestion on the constraints limiting EDAM and WEIM transfers between balancing areas. Section 6.2 addresses real-time market internal congestion.[56] Section 6.3 analyzes day-ahead market congestion rent and loss surpluses. Section 6.4 addresses congestion revenue allocation between day-ahead market balancing areas. Section 6.5 addresses intertie constraint congestion in the day-ahead market. Lastly, Section 6.6 addresses the impact of internal congestion on the day-ahead market.

6.1 EDAM and WEIM transfer constraint congestion

When limits on constraints impacting EDAM or WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to the rest of the system. With the launch of the EDAM on May 1, the marginal energy cost (MEC) is now calculated separately for each balancing area and differences in the MEC between balancing areas reflects any EDAM or WEIM transfer congestion. Figure 6.5 shows the percent of intervals and overall price difference for EDAM participating balancing areas in each market during the third quarter. The EDAM or WEIM transfer congestion is measured as the difference in the marginal energy cost (MEC) for each balancing area relative to the CAISO balancing area.[57] *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 wider WEIM or EDAM system. *Congestion into area* reflects that prices are higher within an area or region because of limited import capability into the area or region.[58]

Much more transfer capacity between balancing areas is available in the real-time markets relative to the day-ahead market. This can contribute to different price outcomes for each EDAM balancing area between the day-ahead and real-time markets. PacifiCorp East was transfer constrained (either direction) in 73 percent of intervals in the day-ahead market, compared to just 5 percent of intervals in the 5-minute market. PacifiCorp West was transfer constrained in 36 percent of intervals in the day-ahead market, compared to 21 percent of intervals in the 5-minute market.

For the CAISO balancing area, convergence bidding helps to align day-ahead and 15-minute market prices by allowing financial bids on internal nodes to arbitrage price differences between the two markets. At the launch of the extended day-ahead market, PacifiCorp East and PacifiCorp West have opted *not* to enable convergence bidding in their balancing areas.[59] Substantial differences in transfer

[56] 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.

[57] Differences in the marginal energy cost between balancing areas accounts for any constraint that can limit EDAM or WEIM transfers between balancing areas, including (1) scheduling limits on individual EDAM or WEIM transfers, (2) total scheduling limits, or (3) intertie constraint and intertie scheduling limits.

[58] 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.

[59] EDAM participating balancing areas can choose to enable convergence bidding or not in their balancing area at the onset of participation. The ISO intends to derive a more permanent EDAM convergence bidding policy after two years of EDAM operation.

capacity between the day-ahead and real-time markets can contribute to different price outcomes in these balancing areas.

Figure 6.5 Frequency and impact of EDAM or WEIM transfer congestion – EDAM balancing areas (Q3 2026)

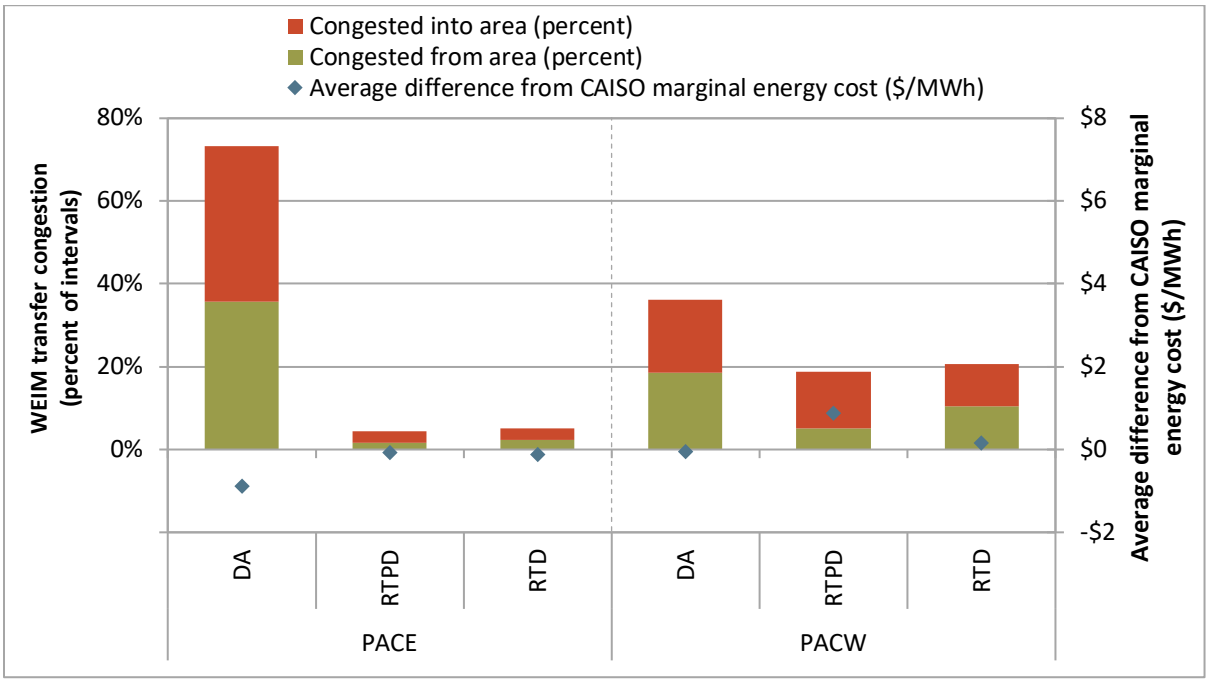


Figure 6.6 and Figure 6.7 show the same information for all WEIM participating balancing areas in the 15-minute and 5-minute markets.

Powerex (BCHA) was frequently export constrained relative to the CAISO balancing area because of WEIM transfer congestion in the third quarter. In the 5-minute market, Powerex was export constrained during around 85 percent of intervals. On average for the quarter, Powerex prices were $22.15/MWh lower because of WEIM transfer congestion in the 15-minute market, and $22.96/MWh lower in the 5-minute market.

WEIM transfer congestion was also high for other balancing areas in the Pacific Northwest. In the 5-minute market, these balancing areas were import constrained in around 16 percent of intervals and export constrained in around 11 percent of intervals.

El Paso Electric was frequently export constrained. This transfer congestion was often the result of intertie constraints that balancing areas can use to manage total or net WEIM transfers into or out of their system. El Paso Electric was export constrained in 24 percent of intervals in the 5-minute market.

Figure 6.6 Frequency and impact of WEIM transfer congestion in the 15-minute market (Q3 2026)

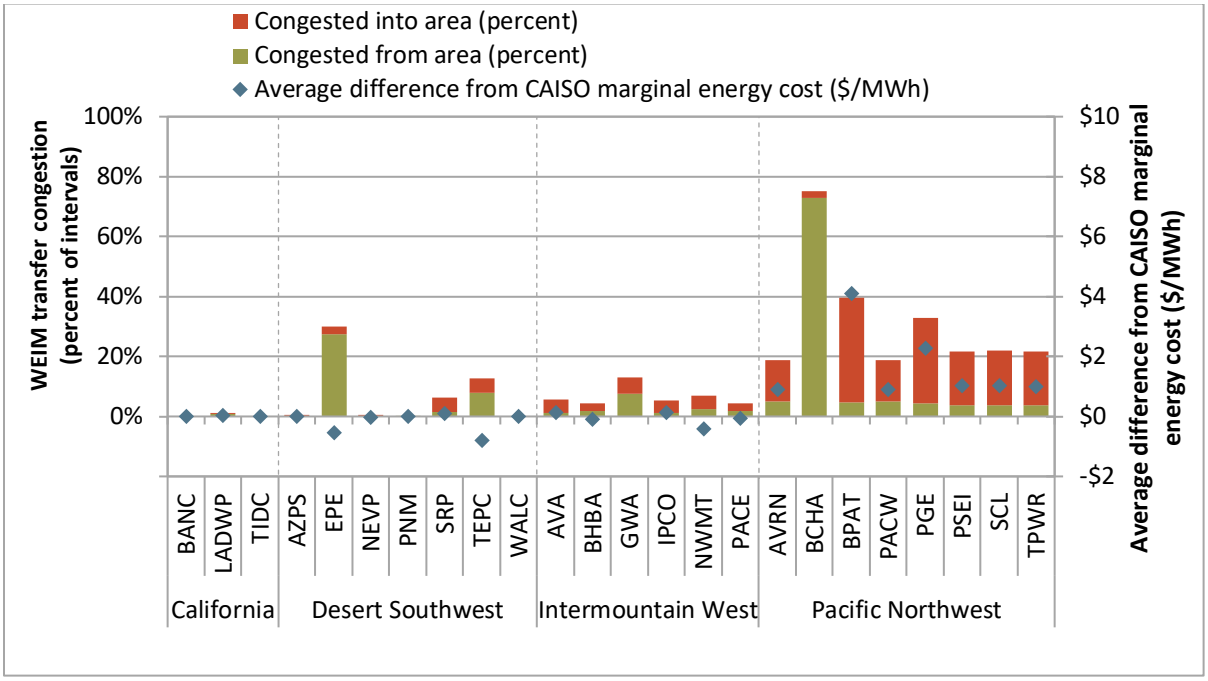
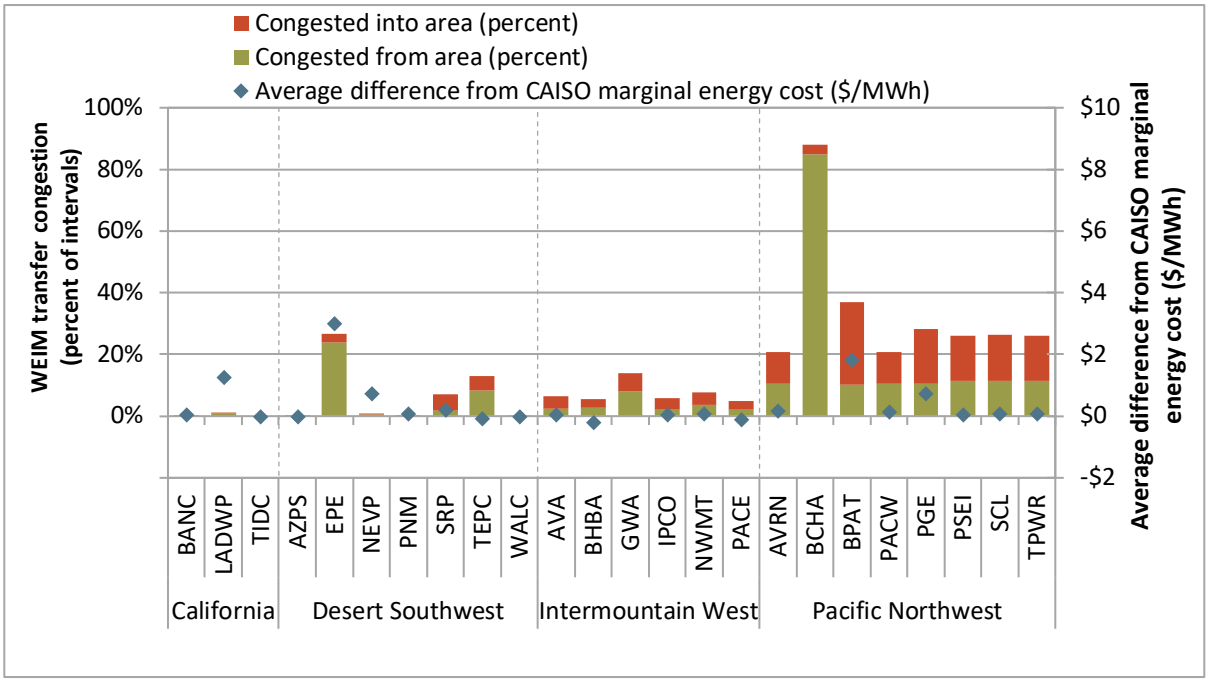


Figure 6.7 Frequency and impact of WEIM transfer congestion in the 5-minute market (Q3 2026)



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.[60] 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.[61]

Figure 6.8 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAPs) and EIM load aggregation points (ELAPs) in the third quarter of 2026. The blue bars represent the 15-minute market price impact, and the yellow bars indicate the 5-minute market price impact from internal constraints.

In this quarter, prices were elevated in Southern California and the Desert Southwest relative to prices in the Northern California and the Pacific Northwest regions. In the Intermountain West, prices in some balancing areas were higher and prices in other balancing areas were lower due to congestion. SDG&E experienced the largest price increase due to internal congestion.

Overall, congestion impact was greater in the 5-minute market than in the 15-minute market, although the general direction of the price impact from internal congestion remained consistent.

[60] 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.

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

Figure 6.8 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (July–September 2026)

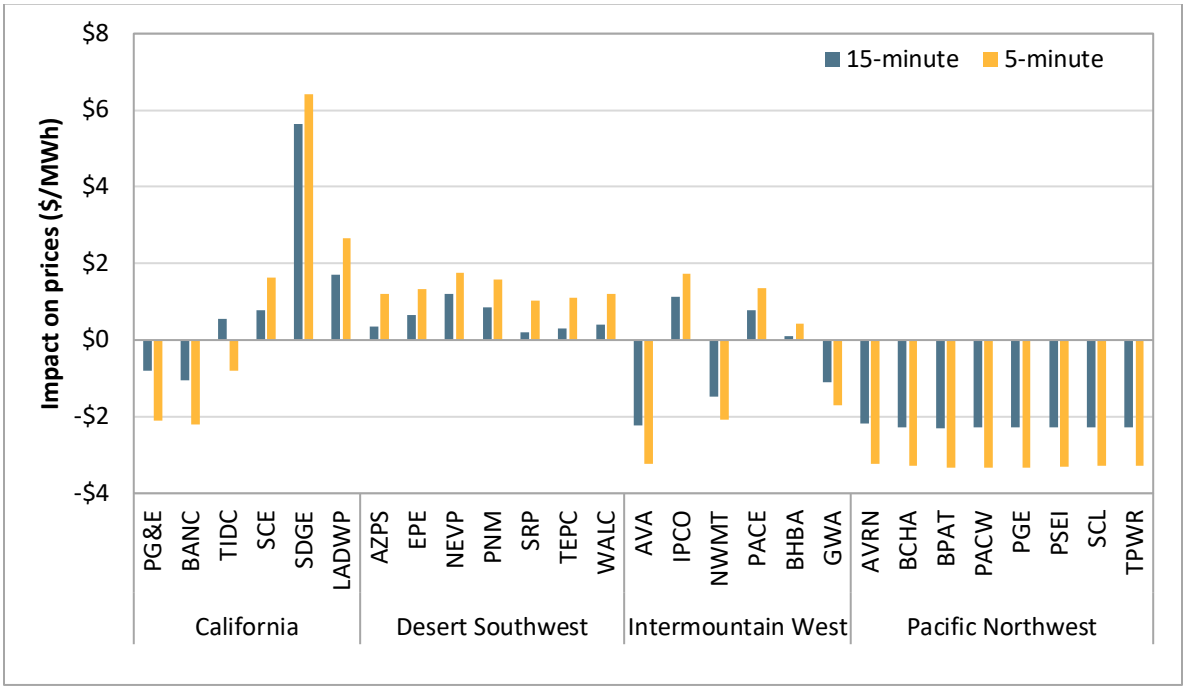


Figure 6.9 and Figure 6.10 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the third quarter of 2026 and 2025, respectively. A notable change from the same quarter last year was heavy north-to-south congestion during evening peak and overnight hours. During these hours, prices were elevated in the Southern California and the Desert Southwest relative to the rest of the WEIM. In addition, the typical south-to-north congestion pattern during solar hours was much less pronounced this quarter compared to Q3 2025.

Figure 6.9 Overall impact of internal congestion on price separation in the 15-minute market by hour (July–September 2026)

	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	-1.8	-0.8	-0.8	-0.7	-1.0	-1.0	-0.8	0.7	1.9	1.9	-0.2	0.2	0.5	0.9	0.1	0.9	1.3	1.9	-0.4	-4.6	-2.2	-8.1	-3.8	-3.6
BANC	-2.3	-1.5	-1.5	-0.9	-1.3	-1.3	-0.7	1.2	2.0	1.4	0.9	1.3	1.4	1.4	0.8	1.5	1.7	-0.8	-2.3	-6.9	-3.5	-8.0	-3.7	-4.0
Turlock ID	-2.2	-1.5	-1.4	-0.9	-1.2	-1.3	-0.8	1.1	4.1	4.5	5.6	6.3	6.7	6.7	6.6	7.0	6.4	0.9	-3.3	-8.4	-4.6	-8.9	-3.9	-4.0
SCE	2.0	1.1	1.0	0.7	0.9	1.1	0.9	-0.8	-2.5	-2.6	-1.5	-1.6	-1.6	-1.5	-0.8	-0.1	0.3	1.0	2.2	5.0	2.8	6.9	2.9	3.2
SDG&E	8.2	6.6	5.6	3.5	4.0	3.2	3.5	4.4	3.2	2.3	3.0	3.4	2.8	3.2	4.2	4.9	6.4	6.9	7.7	10.8	9.9	12.3	8.0	7.5
LADWP	1.4	0.9	0.8	0.5	0.7	0.4	-0.1	-0.6	-0.4	0.2	0.7	0.7	0.8	0.9	2.1	2.1	2.4	3.3	3.5	5.6	3.0	6.2	2.9	2.9
NV Energy	0.7	0.3	0.4	0.1	0.4	0.3	0.3	-0.2	0.0	0.3	0.6	0.5	0.5	0.5	1.0	0.9	1.6	1.9	2.8	5.4	2.7	4.4	2.1	1.8
Arizona PS	0.6	0.1	0.2	0.2	0.4	0.6	0.2	-1.0	-1.3	-0.7	-0.1	-0.7	-0.6	-0.6	-0.8	-1.3	-1.7	-0.6	0.7	4.0	1.6	5.1	2.1	2.1
Tucson Electric	0.5	0.0	0.2	0.2	0.3	0.6	0.1	-1.0	-1.2	-0.7	-0.1	-0.7	-0.6	-0.7	-0.8	-1.8	-1.9	-0.7	0.6	4.1	1.7	5.0	2.0	2.0
Salt River Project	0.5	0.0	0.1	0.1	0.3	0.6	0.2	-1.1	-1.3	-0.8	-0.1	-0.8	-0.7	-0.7	-0.9	-2.1	-2.2	-1.1	0.3	3.9	1.5	5.0	2.0	2.1
PSC New Mexico	0.5	0.1	0.2	0.2	0.3	0.5	0.2	-0.8	-0.9	-0.5	0.0	-0.4	-0.2	-0.5	-0.5	-1.2	0.9	3.3	3.8	5.6	2.0	4.5	1.8	1.7
WAPA - Desert SW	0.6	0.1	0.2	0.2	0.4	0.6	0.2	-1.0	-1.2	-0.6	0.0	-0.5	-0.4	-0.6	-0.7	-1.6	-1.7	-0.4	0.8	4.2	1.8	5.2	2.1	2.1
El Paso Electric	0.4	0.0	0.2	0.1	0.3	0.5	0.1	-0.9	-1.0	-0.6	-0.1	-0.6	-0.4	-0.7	-0.8	-1.7	0.2	2.5	3.1	5.2	1.8	4.7	1.9	1.7
PacifiCorp East	-0.3	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.1	0.1	-0.5	-0.1	-0.3	0.7	2.2	4.1	7.8	3.6	1.7	0.5	-0.1
Idaho Power	-0.6	-0.4	-0.2	-0.2	-0.3	-0.3	-0.2	0.3	0.2	0.1	-0.3	-0.1	0.0	-0.2	0.9	0.7	3.3	5.4	6.5	6.1	5.6	1.1	0.4	-0.8
NorthWestern	-1.1	-0.6	-0.6	-0.4	-0.5	-0.6	-0.4	0.1	-0.1	-0.3	-0.7	-0.7	-0.7	-0.7	-1.4	-1.3	-2.0	-2.5	-2.8	-5.4	-3.4	-5.1	-2.2	-2.0
Avista Utilities	-1.4	-0.8	-0.7	-0.5	-0.7	-0.8	-0.5	0.1	-0.1	-0.5	-0.9	-0.8	-0.9	-0.9	-2.0	-1.8	-2.9	-4.2	-5.3	-9.5	-5.6	-7.1	-3.0	-2.6
Black Hills Corp	-0.5	-0.3	-0.2	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.3	-0.1	0.0	-0.1	-0.8	-0.8	-1.0	-0.2	1.0	2.2	4.9	1.5	-0.7	-0.6	-0.6
Power Watch	-0.8	-0.4	-0.3	-0.2	-0.3	-0.3	-0.2	0.3	0.1	-0.2	-0.5	-0.5	-0.7	-0.6	-1.1	-0.9	-1.7	-2.6	-3.2	-6.3	-2.5	-1.5	-1.1	-0.9
Avangrid	-1.8	-1.0	-0.9	-0.7	-0.9	-1.0	-0.7	0.2	0.2	-0.1	-0.6	-0.6	-0.7	-0.8	-1.7	-1.5	-2.2	-3.7	-5.1	-9.4	-5.3	-7.8	-3.4	-3.2
BPA	-1.6	-0.9	-0.8	-0.6	-0.8	-0.8	-0.6	0.1	0.0	-0.3	-0.9	-0.8	-0.9	-0.9	-2.0	-1.9	-3.0	-4.3	-5.5	-9.9	-5.7	-7.5	-3.2	-2.8
Tacoma Power	-1.6	-0.9	-0.8	-0.6	-0.8	-0.8	-0.6	0.1	0.0	-0.3	-0.9	-0.8	-0.9	-0.9	-2.0	-1.9	-2.9	-4.2	-5.3	-9.7	-5.6	-7.4	-3.2	-2.8
PacifiCorp West	-1.7	-0.9	-0.8	-0.6	-0.8	-0.9	-0.6	0.2	0.0	-0.3	-0.9	-0.8	-0.9	-0.9	-1.9	-1.7	-2.7	-4.1	-5.4	-9.8	-5.6	-7.6	-3.3	-2.9
Portland GE	-1.7	-0.9	-0.8	-0.6	-0.8	-0.9	-0.6	0.1	0.0	-0.3	-0.9	-0.8	-0.9	-0.9	-2.0	-1.8	-2.8	-4.2	-5.4	-9.8	-5.6	-7.5	-3.2	-2.9
Puget Sound Energy	-1.6	-0.9	-0.8	-0.6	-0.7	-0.8	-0.6	0.1	0.0	-0.3	-0.9	-0.8	-1.1	-1.0	-2.0	-1.9	-2.9	-4.2	-5.3	-9.7	-5.6	-7.4	-3.2	-2.8
Seattle City Light	-1.6	-0.9	-0.8	-0.5	-0.7	-0.8	-0.6	0.1	0.0	-0.3	-0.9	-0.8	-0.8	-0.9	-2.0	-1.9	-2.9	-4.2	-5.3	-9.7	-5.6	-7.4	-3.2	-2.8
Powerex	-1.6	-0.9	-0.8	-0.5	-0.7	-0.8	-0.6	0.1	-0.1	-0.3	-0.9	-0.8	-1.3	-1.2	-1.9	-1.9	-2.9	-4.2	-5.3	-9.5	-5.5	-7.3	-3.1	-2.8

Hour

Figure 6.10 Overall impact of internal congestion on price separation in the 15-minute market by hour (July–September 2025)

	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	-0.2	0.1	0.0	0.0	-0.1	0.1	1.2	2.0	3.3	1.9	2.0	1.6	2.3	2.8	4.9	4.9	3.4	4.1	8.3	4.8	0.7	-0.4	-0.8
BANC	-0.6	-0.5	-0.1	-0.1	-0.1	-0.1	-0.3	0.9	2.0	2.2	4.9	5.6	6.1	7.5	8.8	9.2	7.4	2.1	1.6	5.4	2.3	-0.4	-0.5	-0.9
Turlock ID	-0.8	-0.4	-0.1	-0.1	-0.1	-0.1	-0.3	0.4	4.1	5.5	10.7	12.1	14.2	16.9	18.8	17.9	14.3	4.0	-0.4	1.4	0.4	-0.9	-0.9	-1.0
SCE	0.6	0.1	0.0	0.0	0.0	0.1	0.0	-1.3	-4.0	-5.8	-2.4	-2.3	-2.4	-3.0	-3.5	-3.5	-2.4	-1.0	-1.0	-4.1	-2.6	0.0	0.5	0.8
SDG&E	1.7	1.1	0.5	0.2	0.3	0.3	0.9	2.9	2.0	2.9	5.1	4.2	4.8	6.6	6.6	7.5	9.3	9.8	5.9	1.6	2.9	2.7	3.1	1.8
LADWP	0.6	0.2	0.1	0.0	0.1	0.1	0.2	-1.1	-2.0	-2.1	-0.6	-0.4	-0.5	-0.5	0.5	0.9	2.9	1.0	1.8	-1.0	-1.5	0.2	0.5	0.6
NV Energy	0.2	0.0	-0.4	0.0	-0.1	0.0	-0.7	-3.5	-2.6	-3.0	-0.8	-0.7	-0.6	-0.3	0.5	-0.1	-0.1	0.3	0.2	-0.1	-0.3	0.1	-0.1	0.2
Arizona PS	0.5	0.1	0.1	0.1	0.1	0.1	0.1	-1.9	-3.6	-4.1	-2.0	-2.1	-2.5	-3.7	-4.3	-5.2	-4.9	-2.5	-0.7	-2.4	-2.1	-0.2	0.1	0.4
Tucson Electric	0.5	0.1	0.1	0.1	0.1	0.0	0.1	-1.8	-3.5	-4.0	-2.0	-2.0	-2.4	-3.7	-4.4	-5.1	-4.7	-2.5	-0.7	-2.4	-2.1	-0.2	0.0	0.4
Salt River Project	0.5	0.1	0.1	0.1	0.1	0.1	0.1	-1.9	-3.7	-4.2	-2.1	-2.2	-2.6	-3.9	-4.7	-5.5	-5.2	-2.6	-0.7	-2.4	-2.2	-0.2	0.0	0.4
PSC New Mexico	0.4	0.1	0.1	0.1	0.1	0.1	0.1	-1.5	-2.9	-3.3	-1.4	-1.5	-1.8	-2.9	-3.1	-4.0	-3.7	-0.1	0.9	6.8	12.8	12.4	20.2	5.8
WAPA - Desert SW	0.5	0.1	0.1	0.1	0.1	0.1	0.1	-1.8	-3.5	-3.9	-1.9	-2.0	-2.4	-3.6	-4.2	-4.8	-4.5	-2.3	-0.6	-2.3	-2.1	-0.1	0.1	0.4
El Paso Electric	0.5	0.1	0.1	0.1	0.1	0.1	0.1	-1.7	-3.2	-3.4	-1.7	-1.8	-2.2	-3.2	-2.8	-3.3	-3.1	-2.0	-0.2	-1.6	-3.3	-1.8	-2.5	-0.3
PacifiCorp East	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	-0.8	-1.4	-1.6	-0.3	-0.2	-0.4	-0.6	-0.5	-0.6	-0.5	-0.4	-0.1	-0.2	-0.4	-0.3	-0.3	-0.2
Idaho Power	-0.2	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.7	-1.2	-1.3	-0.1	-0.2	-0.3	-0.1	-0.1	0.1	0.0	-0.5	-0.4	-0.1	-0.3	-0.4	-0.3	-0.4
NorthWestern	-0.4	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.1	0.0	-0.2	-0.2	-0.3	0.0	0.1	0.3	-0.1	-0.5	-0.6	-0.2	-0.2	-0.5	-0.5	-0.5
Avista Utilities	-0.5	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.3	-0.5	-0.1	-0.1	-0.3	0.2	0.4	0.7	0.2	-0.5	-0.7	-0.2	-0.3	-0.5	-0.6	-0.6
Black Hills Corp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Watch	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avangrid	-0.7	-0.2	-0.1	-0.1	-0.1	-0.1	-0.2	-0.6	-0.6	-0.7	0.8	1.2	1.2	2.3	3.0	3.7	2.7	0.1	-0.8	-0.3	-0.7	-0.8	-0.8	-0.9
BPA	-0.6	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	0.1	0.2	0.3	0.1	0.2	0.0	0.7	0.9	1.2	0.8	-0.2	-0.8	-0.2	-0.2	-0.5	-0.6	-0.7
Tacoma Power	-0.6	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.9	1.5	1.5	0.0	0.2	0.3	0.9	1.0	1.2	0.6	0.0	-0.8	-0.2	0.2	-0.3	-0.5	-0.5
PacifiCorp West	-0.6	-0.2	-0.1	-0.1	-0.1	-0.1	-0.2	-0.7	-1.1	-1.1	0.1	0.2	0.0	0.7	1.1	1.9	1.2	-0.4	-0.8	-0.3	-0.6	-0.8	-0.7	-0.8
Portland GE	-0.6	-0.2	-0.1	-0.1	-0.1	-0.1	-0.2	-0.6	-1.0	-1.1	0.1	0.1	0.0	0.7	1.0	1.7	1.1	-0.4	-0.8	-0.3	-0.6	-0.8	-0.7	-0.8
Puget Sound Energy	-0.6	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	2.7	4.6	4.8	0.1	0.4	0.9	1.5	1.5	1.4	0.6	0.8	-0.8	-0.1	1.0	0.2	-0.2	-0.2
Seattle City Light	-0.6	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	4.0	6.8	7.2	0.1	0.5	1.2	1.8	1.7	1.4	0.6	1.3	-0.7	-0.1	1.8	0.6	-0.1	0.1
Powerex	-0.6	-0.1	-0.1	-0.1	-0.1	-0.1	0.1	5.1	8.8	9.2	0.2	0.5	1.7	2.2	2.0	1.4	0.6	1.7	-0.7	0.0	2.3	1.0	0.1	0.3

Hour

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 Midway-Vincent #2 500 kV line, San Diego Area nomogram, and Devers Eastern Area nomogram.

Midway-Vincent #2 500 kV

The Midway-Vincent #2 500 kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) contributed to north-to-south congestion. As a result, prices in Southern California and the Desert Southwest were elevated relative to prices in Northern California, the Intermountain West, and the Pacific Northwest. This line typically experienced congestion from hour-ending 10 through hour-ending 24.

San Diego Area nomogram

The San Diego Area nomogram (7820_TL230S_OVERLOAD_NG) was a transmission bottleneck into SDG&E, contributing to congestion on power flows from the Desert Southwest and parts of the

Intermountain West. Congestion frequency on this line increased between hour-ending 8 and hour-ending 13, with another increase during hour-ending 21 and hour-ending 24.

Devers Eastern Area nomogram

The Devers Eastern Area nomogram (7760_DEV_RDB_ALIS) contributed to congestion on power flows into California from the Desert Southwest and a part of the Intermountain West. As a result, prices in California were elevated relative to prices in the Desert Southwest and the Intermountain West. Congestion frequency on this line increased between hour-ending 15 and hour-ending 21.

A notable trend this quarter was north-to-south congestion on several Path 26 transmission lines, including those around Midway, Vincent, Whirlwind, and Antelope. As a result, prices were elevated in Southern California and the Desert Southwest.

Table 6.1 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary constraints (WEIM, July–September)[62]

BAA	Constraint	Average quarter impact ($/MWh)																													
		California						Desert Southwest							Intermountain West						Pacific Northwest										
		PGE	BANC	TIDC	SCE	SDGE	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	BHBA	GWA	AVRN	BCHA	BPAT	PACW	PGE	PSB	SCL	TPWR			
CISO	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-1.74	-1.66	-1.72	1.32	1.26	1.30	1.13	1.01	.79	.93	1.12	1.09	1.12	-1.16	-.57	-.94	-.02	-.07	-.37	-1.38	-1.21	-1.23	-1.28	-1.27	-1.23	-1.23	-1.23			
	7820_TL230S_OVERLOAD_NG	.04	.00	.00	.12	2.32	.01	-.38	-.37	-.09	-.31	-.42	-.40	-.35	-	-.01	-	-.12	-.13	-	-	-	-	-	-	-	-	-			
	7760_DEV_RDB_ALIS	.18	.16	.18	.39	.02	.19	-.63	-.54	-.01	-.48	-.66	-.57	-.51	-	.00	-	-.11	-.13	-	.01	-	-	.00	.00	-	-	-			
	30060_MIDWAY_500_24156_VINCENT_500_BR_1_1	-.17	-.16	-.17	.13	.13	.13	.12	.10	.09	.10	.11	.11	.12	-.11	-.05	-.09	.00	.00	-.10	-.13	-.11	-.12	-.12	-.12	-.12	-.12	-.12			
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1_1	-.16	-.16	-.16	.13	.13	.14	.11	.10	.09	.10	.11	.11	.11	-.11	-.05	-.09	-	-	-.10	-.13	-.11	-.11	-.12	-.12	-.11	-.11	-.11			
	30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	-.13	-.12	-.13	.11	.10	.11	.09	.08	.07	.08	.09	.09	.09	-.08	-.04	-.07	-	.00	-.07	-.09	-.09	-.09	-.09	-.09	-.09	-.09	-.09			
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	.05	.51	1.14	-.22	-.21	.00	-	-	-	-	-	-	-	.00	-	-	-	-	.00	.03	.01	.01	.01	.01	.01	.01	.01			
	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	.11	.12	.13	-.10	-.10	-.10	-.09	-.08	-.06	-.07	-.09	-.09	-.09	.08	.04	.07	.00	.00	.08	.10	.09	.09	.09	.09	.09	.09	.09			
	6410_CP1_NG	-.09	-.09	-.09	.07	.07	.07	.06	.06	.04	.05	.06	.06	.06	-.06	-.03	-.05	.00	.00	-.04	-.08	-.07	-.07	-.07	-.07	-.07	-.07	-.07			
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	.49	.01	-	-.42	-.40	-.03	-.01	-	-	-	-.01	.00	-.01	.01	-	-	-	-	.00	.03	.02	.02	.02	.02	.02	.02	.02			
	22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	-	-	-	-	1.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	.06	.08	.08	-.07	-.06	-.07	-.06	-.05	-.04	-.05	-.06	-.05	-.06	.05	.02	.04	-	.00	.05	.06	.06	.06	.06	.06	.06	.06	.06			
	38615_DSAMIGO_230_30790_PANOCHE_230_BR_1_1	-.02	.09	.72	-.21	-.20	-.01	-	-	-	-	-	-	-	.01	-	-	-	-	-	.01	.01	.01	.01	.01	.01	.01	.01			
	30790_PANOCHE_230_30900_GATES_230_BR_1_1	.12	.15	.19	-.11	-.10	-.10	-.04	-.03	.00	-.02	-.03	-.03	-.04	.01	-	.00	-	-	.00	.09	.01	.01	.03	.02	.01	.01	.01			
	24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	-.05	-.05	-.05	.12	.04	.10	-	-	-	-	-	-	-	-.04	-.01	-.04	-	-	-.04	-.05	-.04	-.04	-.05	-.05	-.04	-.04	-.04			
	7430_CP6_NG	.13	.39	-	-.15	-.14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
PNM	115kvML	.00	-	-	.00	-.02	-	-	.35	-	.39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
CISO	30790_PANOCHE_230_30900_GATES_230_BR_2_1	.06	.08	.10	-.06	-.06	-.05	-.02	-.01	-.01	-.01	-.02	-.01	-.02	.01	-	.00	-	-	.01	.05	.02	.02	.04	.04	.02	.02	.02			
	6410_CP5_NG	-.04	-.04	-.04	.03	.03	.03	.03	.02	.02	.02	.03	.03	.03	-.03	-.01	-.02	.00	.00	-.02	-.03	-.03	-.03	-.03	-.03	-.03	-.03	-.03			
	MIGUEL_BKs_MXFLW_NG	.01	-	-	.03	.26	-	-.06	-.05	-	-.04	-.06	-.06	-.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	8610_SylmarBNK_N-S_Import_NG	.02	.02	.02	.03	.00	-.16	-.02	-.02	-.02	-.02	-.02	-.02	-.02	.01	-	.00	-.01	.00	.01	.01	.01	.01	.01	.01	.01	.01	.01			
	30060_MIDWAY_500_24156_VINCENT_500_BR_1_3	-.03	-.03	-.03	.02	.02	.02	.02	.02	.01	.02	.02	.02	.02	-.02	-.01	-.01	.00	-	-.01	-.02	-.02	-.02	-.02	-.02	-.02	-.02	-.02			
	6110_COI_N-S	.02	.02	.02	.01	.01	.01	.01	.01	.00	.01	.01	.01	.01	-.02	-.01	-.02	-.01	-.01	-.02	-.02	-.03	-.03	-.03	-.03	-.03	-.03	-.03			
	7820_TL23040_IV_SPS_NG	.01	-	-	.02	.27	-	-.03	-.02	-	-.02	-.03	-.03	-.03	-	-	-	.00	.00	-	-	-	-	-	-	-	-	-			
	39536_FINKSS_230_38402_WSTLYTID_230_BR_1_1	.01	.03	.05	-.02	-.01	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.02	.01	.01	-	-	.01	.02	.02	.02	.02	.02	.02	.02	.02			
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	.01	-	-	.02	.15	-	-.03	-.03	-	-.03	-.04	-.04	-.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	30515_WARNERVL_230_30800_WILSON_230_BR_1_1	.02	-.11	-.08	.02	.02	-	-	-	-	-	-	-	-	.00	-	-	-	-	.00	-.02	-.01	-.01	-.02	-.02	-.01	-.01	-.01			
	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1_1	.18	-	-	-.07	-.07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	OMS_20387484MG-BK81_NG	.01	-	-	.01	.11	-	-.02	-.02	-	-.02	-.02	-.02	-.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	OMS_20420463_DEV-RDB_NG	.01	.01	.01	.02	.00	.01	-.03	-.03	-	-.02	-.03	-.03	-.03	-	-	-	-	.00	-	-	-	-	-	-	-	-	-			
	OMS_20788970MG-BK81_NG	.00	-	-	.01	.09	-	-.02	-.02	-	-.02	-.02	-.02	-.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	30879_HENTAP1_230_30885_MUSTANGS_230_BR_1_1	.03	.02	.02	-.02	-.02	-.02	-.01	-.01	-	-.01	-.01	-.01	-.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	29400_ANTELOPE_500_24156_VINCENT_500_BR_1_1	-.02	-.01	-.01	.00	.02	-.01	.02	.02	.02	.02	.02	.02	.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	22886_SUNCREST_230_92861_SUNCTP2_230_BR_2_1	.00	-	-	.01	.08	-	-.02	-.02	-	-.02	-.02	-.02	-.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	35618_SNJSEA_115_35616_SNJOSEB_115_BR_1_1	.10	-	-	-.05	-.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7820_TL649A_OVERLOAD_NG	-	-	-	-	.18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7690-CONTRL-INYOKN_EXP_NG	-	-	-	-.16	.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	35658_LSESTRS_115_35659_NORTECH_115_BR_1_1	.08	-	-	-.04	-.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	29400_ANTELOPE_500_24156_VINCENT_500_BR_2_1	-.01	-.01	-.01	.00	.02	-.02	.01	.01	-	.01	.01	.01	.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	30765_LOSBANOS_230_30766_PADRFLT_230_BR_1_1	-.03	-	.05	-.01	-.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1	.02	-	-	.04	-.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	22640_PENDLETN_69.0_22708_SANLUSRY_69.0_BR_1_1	-	-	-	-	.10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	30733_VASONA_230_30735_METCALF_230_BR_1_1	.06	-	-	-.02	-.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	35120_NEWARKD_115_36851_NORTHERN_115_BR_1_1	.03	-	-.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	24701_KRAMER_230_24601_VICTOR_230_BR_2_1	-	-	-	-.08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	35122_NWARKEF_115_30630_NEWARK_230_XF_11	.07	-	-	.00	.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	34366_SANGER_115_34370_MCCALL_115_BR_3_1	.04	-	-	-.01	-.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	99254_J.HINDS2_230_24806_MIRAGE_230_BR_1_1	.01	-	-	.04	.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7690-COOLWATER_KRAMER_IM_NG	-	-	-	.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	.00	-	-	.00	.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	Other	-.29	-.30	.40	-.16	.24	.18	.23	.19	.31	.27	.18	.16	.15	-.80	1.85	-.26	1.04	.44	-.50	-.65	-.81	-.81	-.75	-.75	-.79	-.77	-.77			
	TOTAL	-0.80	-1.05	0.56	0.78	5.64	1.71	0.35	.66	1.20	0.85	0.21	0.30	0.41	-2.23	1.13	-1.47	.77	.10	-1.11	-2.19	-2.28	-2.31	-2.29	-2.29	-2.29	-2.27	-2.27			

62 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 6.11 shows that in the third quarter of 2026, EDAM congestion rent and loss surpluses were $144 million and $74 million, respectively.[63] The congestion rent surplus was up $5 million, or 4 percent, compared to the third quarter of 2025. The loss surplus was up about $28 million, or 62 percent, compared to Q3 2025.

Total EDAM congestion rent was concentrated in CAISO, which accounted for about $145 million, compared with *negative* $0.3 million in PACE and about *negative* $0.9 million in PACW.[64] The congestion revenue allocation (CRA) credit allocated to non-CAISO BAAs totaled negative $0.5 million and is discussed further in the next section. The congestion rent reported here is net of credits, but the amount was already negative before credit deductions.

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.

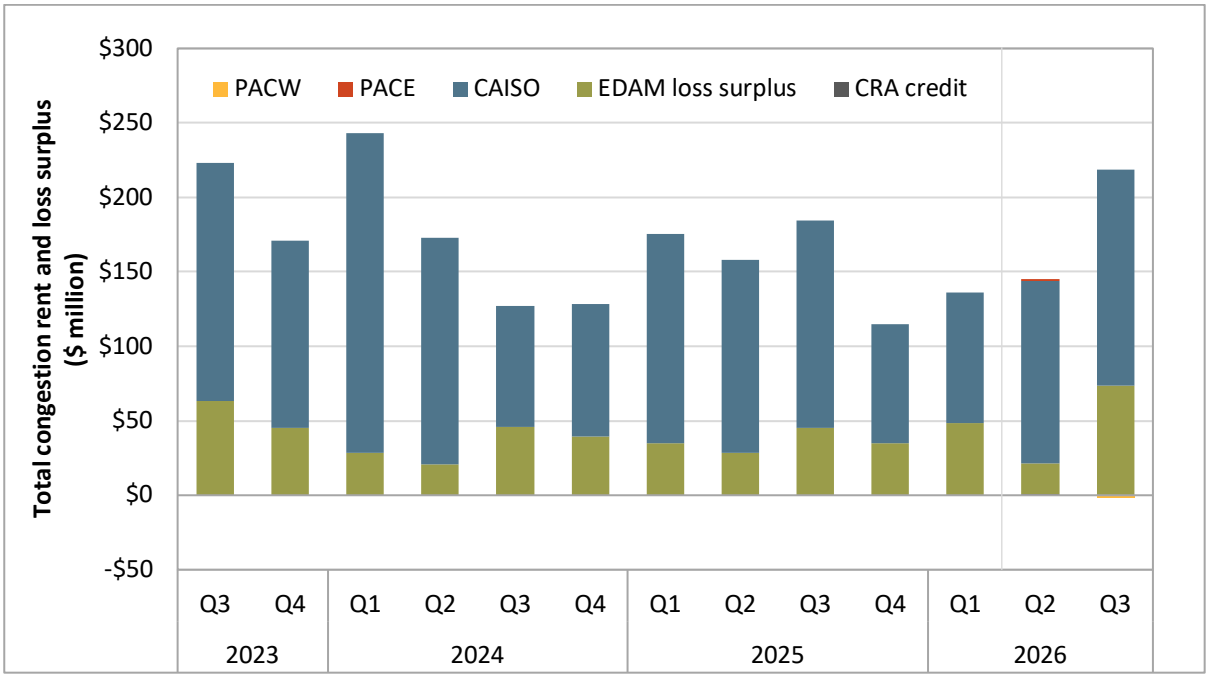
The loss surplus represents the net excess of loss charges collected from demand over loss credits paid to supply. The marginal cost of losses at each node is determined by the product of BAA-specific marginal energy cost (MEC) and the marginal loss factor, which measures the sensitivity of total system losses to an incremental injection at that location.[65] Changes in the total loss surplus can be driven by changes in BAA-specific MEC or by changes in marginal loss factors due to shifts in generation and load patterns, transmission outages, or increased electrical distance between supply and demand.

[63] 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.

[64] These values reflect each balancing area's day-ahead congestion rent net of ETC, TOR, and OATT credits, including CRA-related deductions. DMM separately calculates total EDAM CRA credit received by non-CAISO balancing areas, shown in dark gray in Figure 6.11.

[65] See CAISO Tariff, Appendix C, Section A.4, Marginal Losses Component Calculation: https://www.caiso.com/library/current-tariff-appendices-a-z

Figure 6.11 Day-ahead congestion rent and loss surplus by quarter (2023–2026)



6.4 Extended day-ahead market congestion revenue allocation

Under the EDAM design initially approved by the Federal Energy Regulatory Commission (FERC), the ISO would allocate congestion revenue to the balancing authority area (BAA) where the binding transmission constraint causing congestion is located. After stakeholders raised concerns that this design would limit EDAM BAAs' ability to hedge congestion costs by exercising transmission rights, FERC approved an amended design that would return congestion revenues resulting from binding external constraints to balancing areas with eligible self-scheduled transmission rights. Eligible transmission rights, also referred to as open access transmission tariff (OATT) rights, include point-to-point (PTP) service and network integration transmission service (NITS). The CAISO balancing area does not offer PTP nor NITS, so this congestion revenue allocation (CRA) credit is currently only settled with PacifiCorp areas.

Figure 6.12 compares DMM's estimate of each PacifiCorp balancing area's congestion revenue allocation credit with all other congestion revenue paid to entities within the balancing area. Throughout Q3 2026, DMM estimates that congestion revenue allocation credits represented nearly all the congestion revenues for PacifiCorp areas. Figure 6.12 also includes congestion revenue related to OATT self-schedules where, due to missing data, the location of the binding transmission constraint could not be determined. This "unknown constraint OATT revenue" category represented less than one percent of congestion revenue in the third quarter.

Figure 6.12 EDAM congestion revenue allocation credit and total congestion revenue

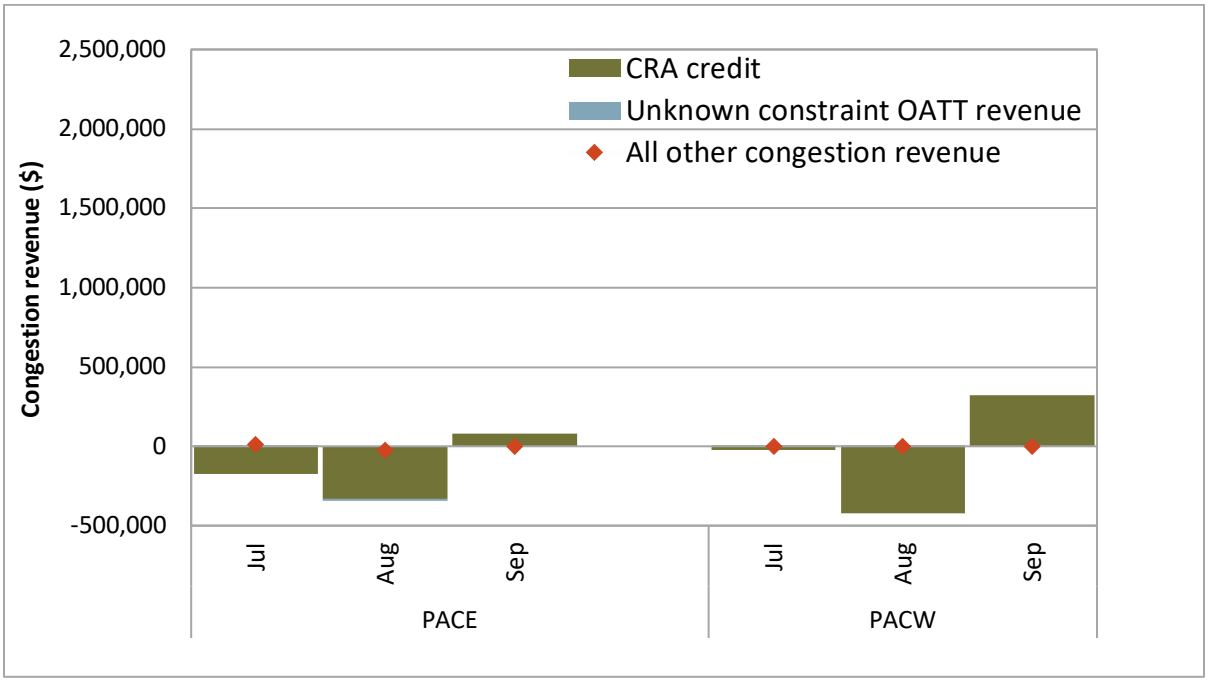


Figure 6.13 breaks out the congestion revenue allocation credit paid (or charged in the case of negative values) to a balancing area by the external balancing area whose binding constraints resulted in the credit. In Q3, all congestion revenue allocation credits were a result of binding constraints in the CAISO balancing area.

Initially, an error in the ISO's settlements process resulted in congestion revenue allocation credit overpayments. Incorrect congestion revenue allocation credits for past months are currently being resettled according to the ISO's typical 70-business-day timeline. Figure 6.14 compares the settled congestion revenue allocation credit with DMM's estimate by month, as of mid-October 2026. Following resettlement, July congestion revenue allocation credits are expected to shift from a net payment to PacifiCorp areas to a net charge. DMM estimates the congestion revenue allocation credit for PacifiCorp entities at approximately -$199,000 in July, -$757,000 in August, and $415,000 in September. As a result of the congestion revenue allocation policy, PacifiCorp balancing areas paid the CAISO balancing area a total of $541,000 in the third quarter of 2026.

Figure 6.13 EDAM congestion revenue allocation credit by balancing area

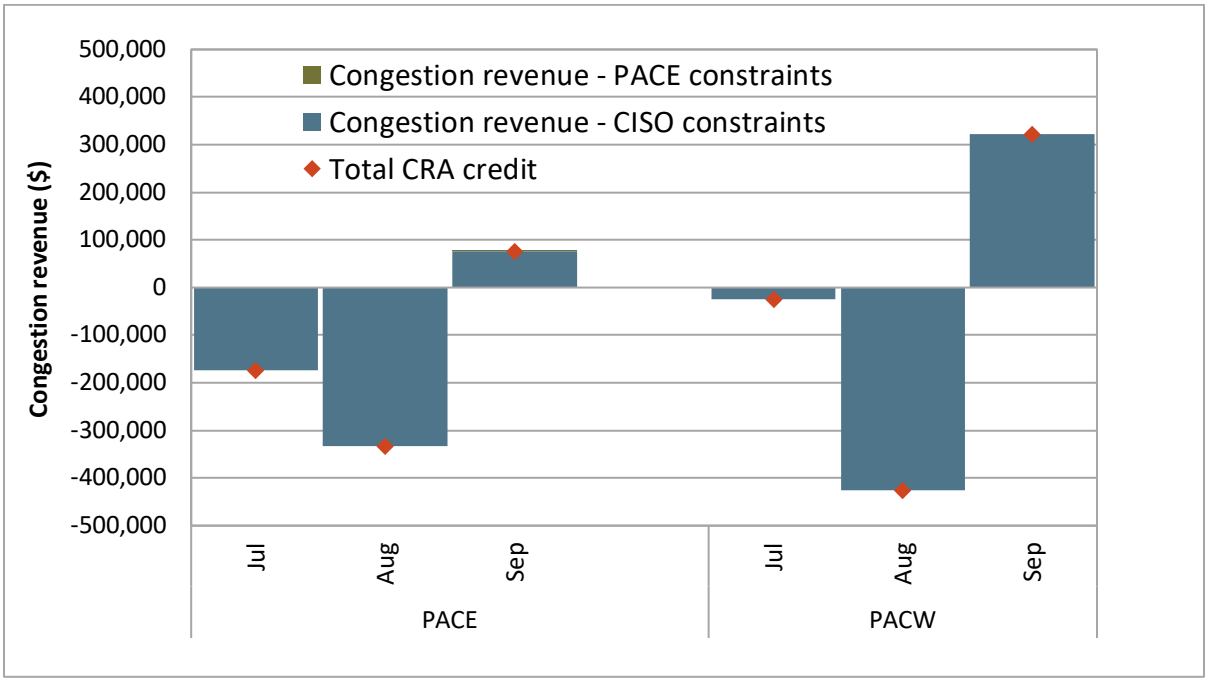
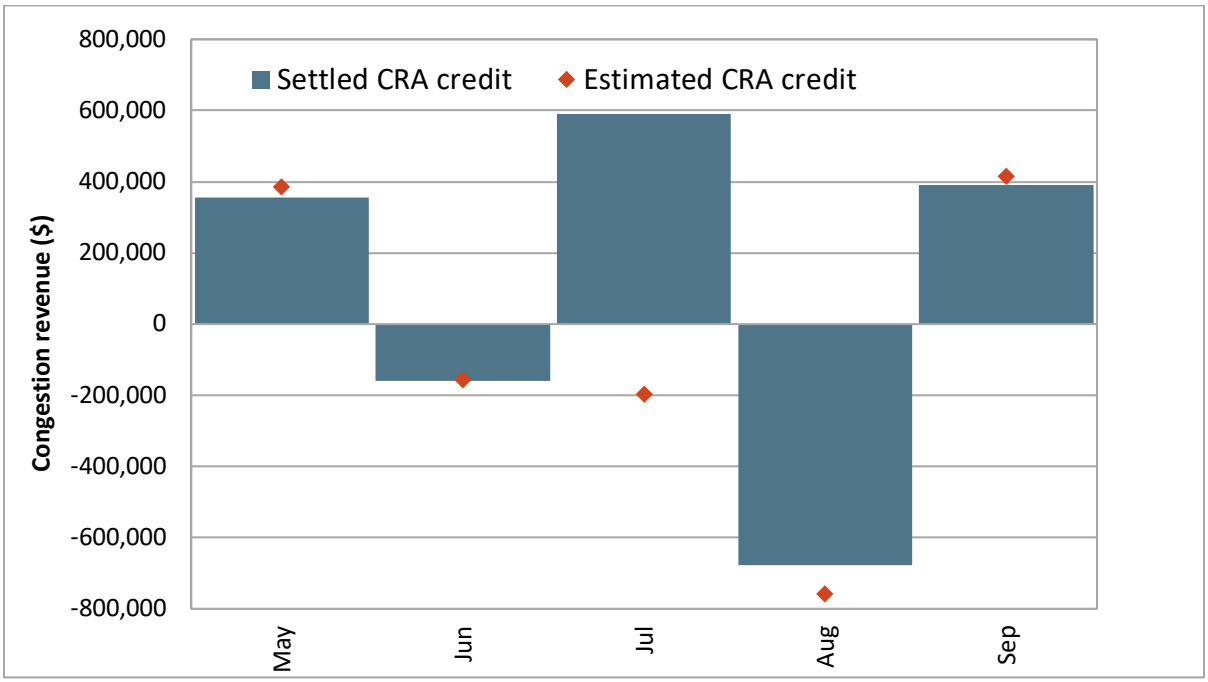


Figure 6.14 Comparison of settled CRA credit with DMM's estimate



6.5 Congestion on interties

Total intertie congestion rent in the day-ahead market was $7.8 million, up from $7.5 million in the third quarter of 2025. The major driver was import congestion rent on IPP Utah, which was $1.2 million higher in this quarter compared to the same quarter of 2025. The increase was partly offset by lower congestion on Malin and NOB. No congestion rent was collected on PACE intertie constraints. Congestion rent collected on PACW's constraint totaled $17,000.

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 EDAM side of the intertie and the lower price of import bids outside of the EDAM area. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO balancing area at points corresponding to interties.

Figure 6.15 shows total intertie congestion charges in the day-ahead market from the third quarter of 2025 to the third quarter of 2026. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 6.16 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 third quarter of 2025, the total intertie congestion rent increased from $7.5 million to $7.8 million.
- Congestion was spread across several interties. In the Northwest, Malin and NOB accounted for 40 percent of total congestion rent, while IPP Utah, Mona, Mead, and Palo Verde in the Southwest accounted for 47 percent.
- A notable change this quarter was higher congestion rent on Southwest interties and relatively lower congestion rent on Northwest interties compared with previous quarters.

Figure 6.15 Day-ahead congestion charges on major interties

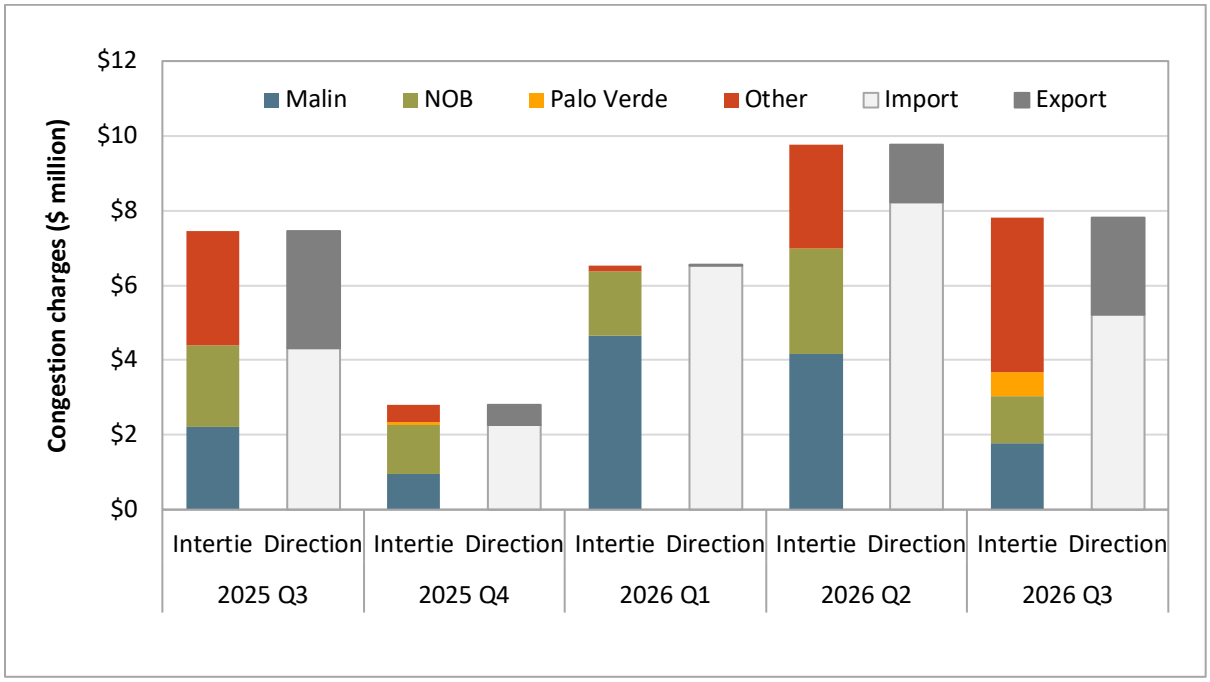


Figure 6.16 Frequency of congestion on major interties in the day-ahead market

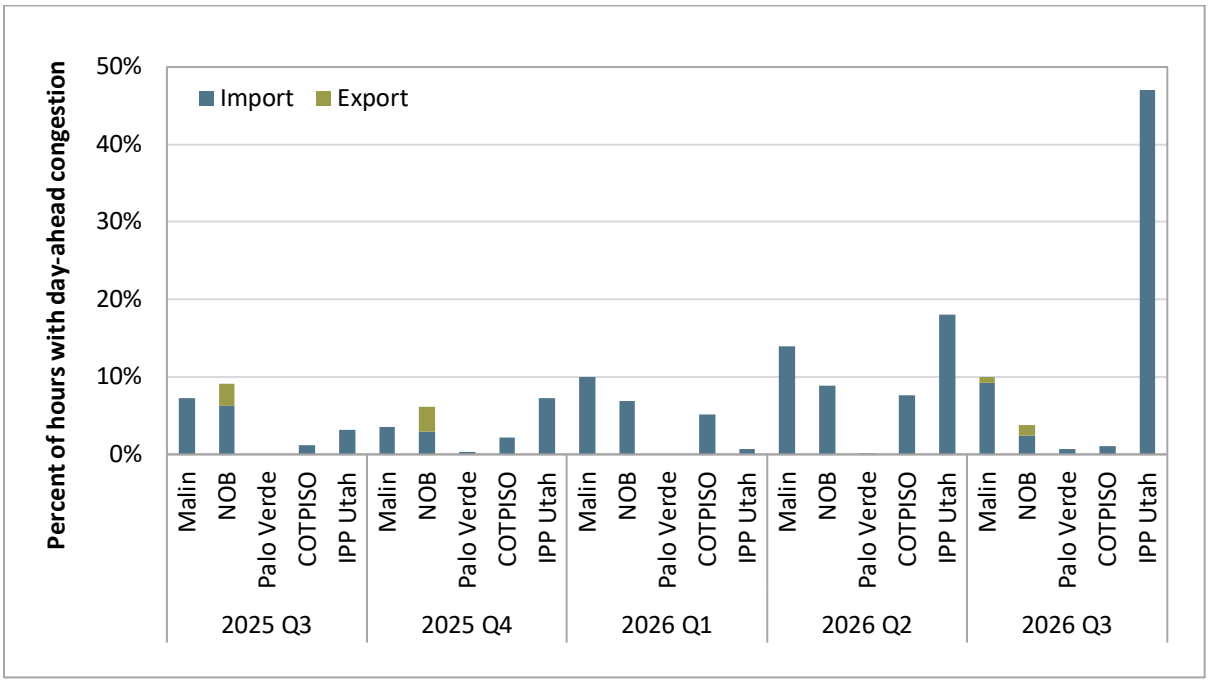


Table 6.2 Summary of intertie congestion in day-ahead market (2025–2026)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3
Northwest											
Malin	I	$2,223	$949	$4,650	$4,178	$1,612	7.3%	3.5%	10.0%	14.0%	9.2%
	E					$153					0.8%
NOB	I	$1,983	$781	$1,725	$2,802	$1,057	6.3%	2.9%	6.9%	8.9%	2.4%
	E	$180	$530			$211	2.8%	3.2%			1.4%
COTPISO	I	$11	$92	$122	$311	$28	1.2%	2.2%	5.2%	7.6%	1.1%
	E										
Cascade	I										
	E					$0					12.0%
Summit	I	$11					0.1%				
	E										
Southwest											
Palo Verde	I		$92		$12	$636		.3%		.%	.7%
	E										
IPP Utah	I	$103	$354	$33	$915	$1,330	3.2%	7.3%	0.7%	18.0%	47.0%
	E										
IPP DC Adelanto	I				$9					0.3%	
	E	$92			$1,420	$144	0.8%			21.0%	3.4%
Mona	I										
	E	$2,856			$29	$832	3.7%			1.1%	11.%
Mead	I										
	E				$2	$862				0.1%	2.5%
Merchant	I										
	E										
Silver Peak	I										
	E	$1		$0	$0		0.5%		0.3%	0.0%	
Mercury	I										
	E										
EDAM											
PACE interties	I										
	E										
PACW interties	I					$0	$1				3.8%	5.3%
	E					$9	$16				0.3%	1.5%
Other	I						$554					
	E					$78	$370					
Import total (I)		$4,332	$2,268	$6,530	$8,226	$5,219					
Export total (E)		$3,128	$530	$0	$1,538	$2,587					
Total		$7,460	$2,798	$6,531	$9,764	$7,806					

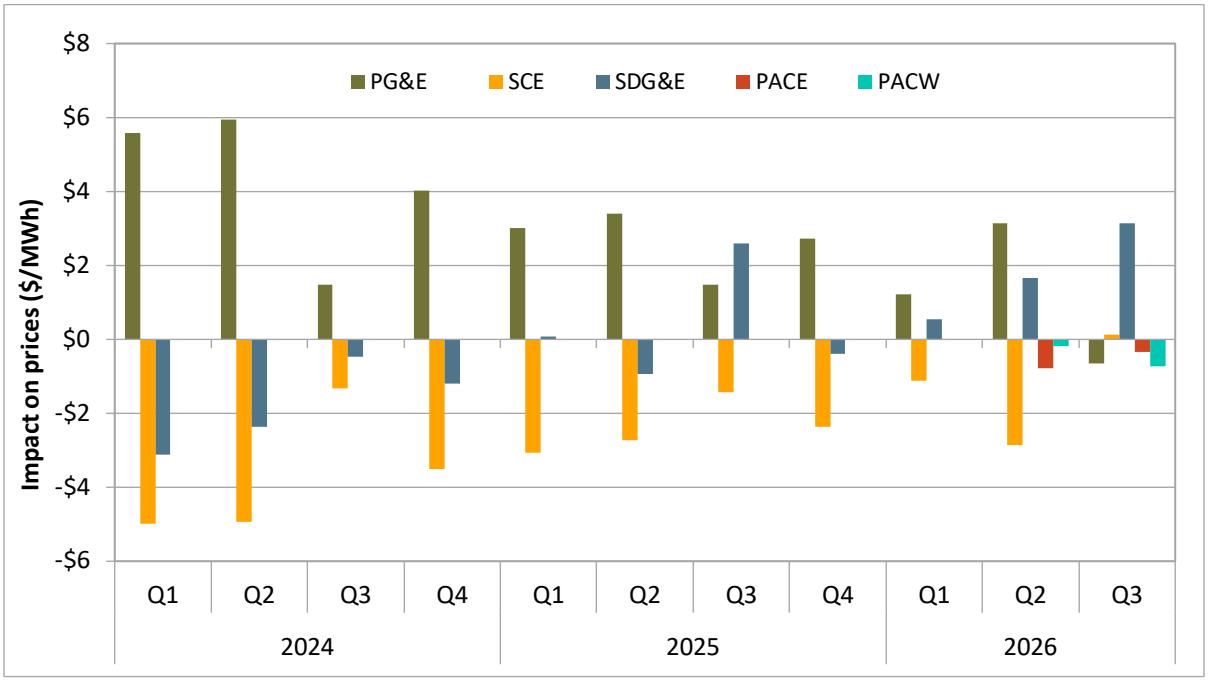
* I: import, E: export

6.6 Internal congestion in the day-ahead market

Figure 6.17 shows the overall impact of congestion on day-ahead market prices in each load area from Q1 2024 to Q3 2026. Figure 6.18 shows the frequency of congestion. Highlights for this quarter include:

- Prices in SDG&E and SCE were elevated by $3/MWh and $0.1/MWh, respectively, while prices in PG&E, PACE, and PACW were reduced by $0.6/MWh, $0.4/MWh, and $0.7/MWh, respectively, due to internal congestion.[66]
- The percentage of hours in which congestion impacted DLAP prices remained high this quarter, with SDG&E experiencing congestion during 95 percent of hours on average. For PACE and PACW, the congestion frequency averaged about 41 percent in this quarter.

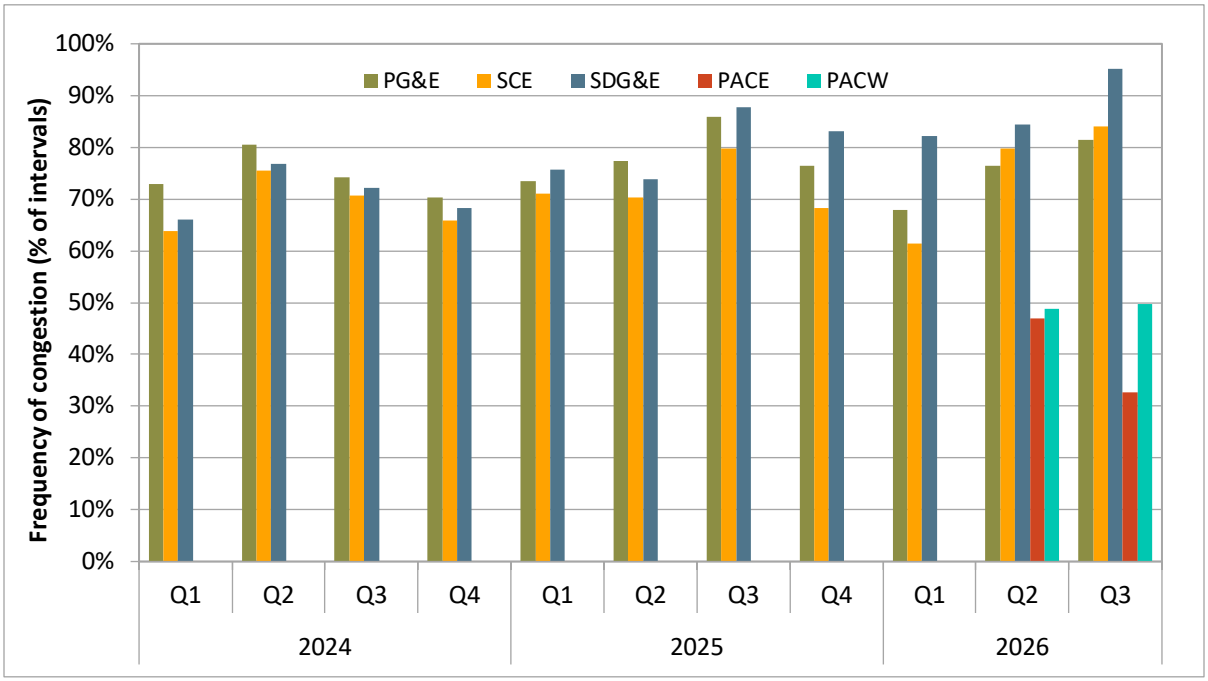
Figure 6.17 Overall impact of congestion on price separation in the day-ahead market[67]



[66] 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.

[67] Data for PACE and PACW reflect May and June after the EDAM launch, while the remaining data cover the full second quarter.

Figure 6.18 Hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)[68]



Impact of congestion from individual constraints

Table 6.3 breaks down the congestion effect on price separation during the quarter by constraint.[69] 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 Midway-Vincent #2 500 kV, El Cajon-Los Coches #1 69 kV, and Moss Landing-Las Aguilas #1 230 kV lines.

Midway-Vincent #2 500 kV

Midway-Vincent #2 500 kV (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) line bound in 17 percent of hours over the quarter. Prices in SCE and SDG&E were elevated, while prices in PG&E and PACW were lowered. The constraint is generally bound across all hours.

[68] Data for PACE and PACW reflect May and June after the EDAM launch, while the remaining data cover the full second quarter.

[69] 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*".

El Cajon-Los Coches #1 69 kV

El Cajon-Los Coches #1 69 kV line (22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1) bound in 87 percent of hours over this quarter. Prices in SDG&E were elevated due to this constraint. This line generally bound across all hours.

Moss Landing-Las Aguilas #1 230 kV

The Moss Landing-Las Aguilas #1 230 kV (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) line bound in 24 percent of hours over the quarter. For the quarter, on average, prices in PG&E and PACW were pushed upward, while prices in SCE and SDG&E were pushed downward.

In this quarter, SDG&E prices were elevated due to multiple constraints, each primarily affecting the SDG&E area. PACW and PG&E showed similar congestion patterns across most constraints.

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

BAA	Constraint	Frequency	Average quarter impact ($/MWh)				
			PG&E	SCE	SDG&E	PACE	PACW
CISO	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	17%	-.78	.58	.56	.00	-.57
	22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	87%	-	-	1.22	-	-
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	24%	.48	-.35	-.33	-	.05
	30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	3%	-.32	.24	.23	.0	-.24
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	20%	.13	-.17	-.15	-	.30
	30060_MIDWAY_500_24156_VINCENT_500_BR_1_1	2%	-.17	.14	.13	.0	-.12
	7820_TL230S_OVERLOAD_NG	16%	-.03	-.01	.40	-.06	-.03
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1_1	3%	-.14	.1	.1	.0	-.10
	22604_OTAY_69.0_22616_OTAYLKTP_69.0_BR_1_1	2%	.	.	.22	-	-
	7820_TL23040_IV_SPS_NG	10%	-.01	.	.18	-.01	.0
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	3%	.07	-.05	-.05	-	.05
	MIGUEL_BKs_MXFLW_NG	1%	-.01	.01	.17	-.02	-
	7820_TL649A_OVERLOAD_NG	49%	-	-	.18	-	-
	OMS_TL23054_OUTAGE_NG	1%	-.01	.	.13	-.02	.0
	38615_DSAMIGO_230_30790_PANOCHE_230_BR_1_1	13%	.02	-.06	-.06	-	.02
	7430_CP6_NG	15%	.05	-.05	-.05	-	-
	7760_DEV_RDB_ALIS	3%	.	.04	-.03	-.07	-
	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1_1	13%	.07	-.03	-.03	-	-
	OMS_20788970MG-BK81_NG	1%	-.01	.00	.1	-.02	-
	35618_SNJSEA_115_35616_SNJOSEB_115_BR_1_1	9%	.05	-.04	-.04	-	-
	24701_KRAMER_230_24601_VICTOR_230_BR_2_1	29%	.03	-.06	.03	-	-
	24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	1%	-.03	.03	.	-.02	-.03
	30790_PANOCHE_230_30900_GATES_230_BR_1_1	3%	.04	-.03	-.02	-	.02
	6410_CP5_NG	1%	-.03	.02	.02	.0	-.02
	22468_MIGUEL_500_22472_MIGUELMP_1.0_XF_80	1%	.	.	.07	-.01	-
	Other		-.04	-.19	.16	-.12	-.07
	Total		-0.64	0.12	3.14	-.35	-.74

7 Resource sufficiency evaluation

Beginning on May 1, 2026, all extended day-ahead market (EDAM) participants became subject to an EDAM resource sufficiency evaluation (EDAM RSE). Before engaging in economic transfers with other EDAM balancing areas in the day-ahead market, the EDAM RSE tests if each EDAM-participating balancing area has procured sufficient supply and reserves to meet their own forecasted demand, ancillary services, and uncertainty. The EDAM RSE considers whether a unit commitment optimization problem can be solved without relaxing (1) the power balance constraint, (2) the imbalance reserve up/down procurement constraints, or (3) the ancillary services procurement constraints. Each condition is assessed independently, and an entity passes the test only if all three can be satisfied without relaxation. The evaluation is performed hourly for both upward and downward directions.

Any balancing area that fails any test has the opportunity to cure the insufficiency in the integrated forward market with appropriate surcharges assessed on the procurement, and if the insufficiency is appropriately cured, the balancing area will remain on track to be in the EDAM pool for the real-time resource sufficiency evaluation on the trade day. If the balancing area fails to cure the insufficiency, the balancing area will be ejected from, or evaluated separately from, the EDAM pool in real-time.

In the real-time, as part of the WEIM design, each 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 real-time market 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.[70] If an area fails either test in the downward direction, transfers out of that area cannot be increased.

7.1 Frequency of EDAM resource sufficiency evaluation failures

Day-ahead or EDAM resource sufficiency evaluation failures occurred on one day in the third quarter. On July 13, PacifiCorp East failed the regulation up test in hours-ending 8, 13, and 14. No other EDAM

[70] 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.

resource sufficiency evaluation failures occurred in Q3 2026. Table 7.1 provides a full summary of EDAM resource sufficiency evaluation failure rates.

Table 7.1 Frequency of EDAM resource sufficiency evaluation failures (July–September 2026)

	Imbalance Reserve Up	Imbalance Reserve Down	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve
CAISO	0%	0%	0%	0%	0%	0%
PacifiCorp East	0%	0%	.1%	0%	0%	0%
PacifiCorp West	0%	0%	0%	0%	0%	0%

7.2 Exclusion from the EDAM pool in real-time resource sufficiency evaluations

During one hour in the third quarter, an EDAM-participating balancing area was excluded from the EDAM pool for real-time resource sufficiency evaluations. On July 19, in hour-ending 8, PacifiCorp East was evaluated separately in the real-time downward sufficiency test. This is potentially because the balancing area was found to have not adequately complied with e-tagging requirements; specifically, EDAM-participating balancing areas are required to tag, by the start of the short-term unit commitment (STUC) run, all imports used to pass the EDAM resource sufficiency evaluation.

7.3 Frequency of real-time 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 in real-time, while Figure 7.3 and Figure 7.4 provide the same information for the downward direction.[71] The dash indicates the area did not fail the test during the month. A gray-shaded cell indicates that the given test was not applicable to the WEIM area during that month. For example, both Power Watch and Black Hills Energy joined the WEIM in May 2026. Accordingly, all months preceding their participation are shown as gray-shaded cells for each test in Figures 7.1-7.4.

Each row in Figures 7.1-7.4 represents a WEIM area, and areas are grouped by geographical region. The first four rows represent EDAM-participating balancing areas. As part of the market design, beginning on May 1, 2026, the EDAM balancing areas are jointly evaluated in the real-time resource sufficiency evaluation. EDAM balancing areas may be excluded from this "EDAM pool" if they fail the day-ahead resource sufficiency evaluation or if an EDAM area is found to not adequately comply with e-tagging protocols. For this reason, Figures 7.1-7.4 include separate rows for the EDAM pool and for each EDAM-participating balancing area. Gray cells indicate that an EDAM-participating balancing area was evaluated as part of the EDAM pool in all hours during a month and therefore was not tested separately in the real-time resource sufficiency evaluations. However, in Q3 2026, PacifiCorp East was removed from the EDAM pool and evaluated separately on July 19, 2026 for the real-time downward flexibility test. In that instance, PacifiCorp East passed the resource sufficiency evaluation, and the corresponding month is denoted by a blue-shaded cell and a dashed line.

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

EDAM balancing areas are no longer subject to the real-time capacity test, either jointly, as a pool, or individually, when excluded from the pool, and so the EDAM pool is not represented in the capacity test in Figure 7.1 and Figure 7.3.[72]

In the third quarter, the frequency of real-time resource sufficiency evaluations failures was low, with few exceptions. During the third quarter of 2026:

- Power Watch failed the flexibility test in the upward direction in 5.4 percent of intervals. Power Watch failed the flexibility test in the downward direction in 6.4 percent of intervals. Power Watch failed the capacity tests in either direction in under one percent of intervals.
- All other balancing areas failed the capacity and flexibility tests in less than one percent of intervals.

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

	Jul 2025	Aug	Sep	Oct	Nov	Dec	Jan 2026	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
CAISO	—	—	—	—	—	—	—	—	—	—					
PacifiCorp East	—	—	.0	.0	—	—	—	—	—	—					
Pacificorp West	.1	.1	.7	.4	.2	.7	.1	.4	.2	.5					
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock ID	—	—	—	.1	—	—	—	—	—	—	—	—	—	—	—
LADWP	—	—	—	—	—	—	—	—	.1	.0	—	—	—	.1	.3
NV Energy	.0	.1	—	—	—	—	—	—	—	—	—	.7	.0	.0	—
Arizona PS	—	—	—	—	—	—	—	—	—	.1	—	—	—	—	—
Tucson Electric	—	.0	—	—	—	—	—	—	.2	—	.1	—	.0	—	—
Salt River Project	—	.2	.0	.1	.0	—	—	—	.1	—	—	—	.1	.1	—
PSC New Mexico	—	—	—	.1	—	.1	—	—	—	—	—	—	—	—	—
WAPA - Desert SW	.0	.1	1.1	—	—	—	.1	.1	1.8	2.4	.1	.0	.3	.7	.1
El Paso Electric	.1	.0	—	.1	.1	—	—	.0	.1	.1	1.1	.1	—	.1	—
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PowerWatch											.7	—	—	.4	.1
Black Hills Energy											.1	—	.1	—	—
NorthWestern	—	—	.2	.0	—	.1	—	—	—	—	—	—	.3	—	—
Avista Utilities	—	—	.1	—	—	—	—	—	—	—	.1	—	—	—	—
Avangrid	—	.3	—	—	—	—	—	.0	—	—	—	—	.2	—	—
BPA	—	.0	—	—	—	—	—	—	—	—	—	.1	.1	—	—
Tacoma Power	.2	—	—	—	—	—	—	—	—	—	—	.1	—	—	—
Portland GE	—	.1	—	—	—	—	—	.1	.1	—	—	.0	—	—	—
Puget Sound Energy	.1	.0	—	.1	—	—	—	.2	—	—	—	—	—	—	—
Seattle City Light	.0	—	—	.0	—	.2	.1	.1	.2	.3	.2	.1	—	—	—
Powerex	—	—	.0	—	—	—	—	—	.1	—	—	—	.2	—	—

[72] *Business Requirements Specification, Extended Day-Ahead Market*, California ISO, version dated March 26, 2026, p 128: https://www.caiso.com/documents/business-requirements-specification-extended-day-ahead-market.pdf. Feasibility or capacity real-time tests will no longer run for EDAM-participating balancing areas, either jointly, in the pool, or individually, when excluded from the pool. Further, the real-time balancing test will no longer apply to *any* balancing area in the WEIM system.

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

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
	2025										2026				
EDAM Pool											—	—	—	—	—
CAISO	—	—	—	—	—	—	—	—	—	—					
PacifiCorp East	.0	.2	.2	.4	.1	.1	.0	.1	.1	.1	—				
Pacificorp West	—	.0	.5	.2	.3	.5	.5	.1	.3	.0					
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock ID	—	—	.0	—	—	—	—	—	—	—	—	—	—	—	—
LADWP	—	.0	—	—	—	—	—	—	—	—	—	—	—	—	.1
NV Energy	—	.1	.0	—	—	—	.1	—	—	—	—	1.1	—	.0	.0
Arizona PS	—	—	—	—	.0	—	—	.1	—	.1	—	—	—	—	—
Tucson Electric	—	—	.0	.1	.2	.1	—	.3	.7	.1	.1	.1	.3	.2	—
Salt River Project	—	.2	.3	.0	.1	—	—	—	.2	.1	—	—	—	.0	—
PSC New Mexico	.1	—	.0	.7	.3	.4	.3	.1	.2	.2	.0	—	.1	.1	—
WAPA - Desert SW	.0	—	—	—	—	—	.0	1.7	2.3	3.5	.6	.1	.1	.0	.0
El Paso Electric	.4	.1	.0	.6	1.2	.6	.4	1.0	.8	.7	1.6	.5	.6	.7	.8
Idaho Power	—	.1	—	.1	—	—	—	.0	—	.3	.2	—	.5	.3	.0
PowerWatch											4.4	2.4	3.3	8.2	4.8
Black Hills Energy											.3	—	.3	.0	—
NorthWestern	—	—	.0	.0	—	—	—	—	—	—	.1	—	.4	.1	—
Avista Utilities	—	—	—	—	—	—	—	—	.2	.1	.4	.0	—	—	—
Avangrid	.2	—	.0	—	.1	.1	.1	.4	.2	.1	.1	.1	.1	.2	.1
BPA	—	—	—	.1	.1	.3	.3	.2	.4	.3	.1	.1	.3	.1	—
Tacoma Power	—	—	—	—	.1	.0	—	—	—	—	.1	.2	—	—	—
Portland GE	—	—	—	—	.0	.1	—	.1	.1	—	.0	—	.2	.0	—
Puget Sound Energy	.1	.0	.1	—	—	—	.0	.1	.1	.0	.1	—	—	—	—
Seattle City Light	—	—	—	—	—	.1	—	.0	.1	.2	.3	—	—	—	—
Powerex	—	—	.0	—	—	.0	—	.1	.3	.1	.0	.0	.6	.1	—

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

	Jul 2025	Aug 2025	Sep 2025	Oct 2025	Nov 2025	Dec 2025	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026
CAISO	—	—	—	—	—	—	—	—	—	—					
PacifiCorp East	—	.1	—	—	—	—	—	—	—	—					
Pacificorp West	.0	—	.2	—	.6	.0	.2	.1	—	—					
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock ID	—	—	—	—	—	—	—	—	—	—	.1	.0	—	—	—
LADWP	—	—	.1	—	—	—	—	—	—	—	—	—	—	—	—
NV Energy	—	—	—	—	—	—	—	—	—	—	—	.4	—	—	—
Arizona PS	—	—	—	—	—	—	—	—	—	.1	—	—	—	—	—
Tucson Electric	—	—	—	—	—	—	—	—	—	—	.0	—	—	—	—
Salt River Project	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PSC New Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA - Desert SW	—	—	—	—	—	—	—	—	—	—	—	—	.0	—	—
El Paso Electric	.3	.1	.2	.2	.4	.3	.0	.1	.1	.1	.4	.5	.1	.1	.6
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PowerWatch											.5	.3	.3	.1	—
Black Hills Energy											.2	—	—	—	—
NorthWestern	—	—	.1	—	—	—	—	—	.4	.1	.3	—	—	—	—
Avista Utilities	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avangrid	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	—	—	—	—	—	—	—	.1	—	—	—	.1
Tacoma Power	.1	—	—	—	—	—	—	—	—	—	—	.0	.2	—	—
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Puget Sound Energy	—	—	—	—	—	—	—	—	.3	—	—	—	.1	—	—
Seattle City Light	—	—	—	—	—	—	—	—	.0	—	.2	—	—	—	—
Powerex	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

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

	Jul 2025	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May 2026	Jun	Jul	Aug	Sep
EDAM Pool											—	—	—	—	—
CAISO	—	—	—	—	—	—	—	—	—	—					
PacifiCorp East	.0	.4	—	—	—	—	—	—	—	.0					
Pacificorp West	.1	.1	.0	—	.5	—	.1	—	—	.2		—	—		
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock ID	.3	.1	—	—	—	.0	—	—	.2	—	.2	.1	—	—	—
LADWP	—	—	—	.2	.0	.1	.1	.4	—	—	.1	—	—	—	—
NV Energy	—	—	—	—	—	—	—	—	—	—	—	1.1	—	—	—
Arizona PS	—	—	—	.1	.0	.1	.0	—	—	.2	—	—	—	—	—
Tucson Electric	—	—	—	—	—	—	.2	—	.2	.0	.1	—	—	—	—
Salt River Project	—	.0	—	—	.0	.0	.3	—	—	—	—	—	—	—	—
PSC New Mexico	.0	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA - Desert SW	—	—	—	—	.7	1.5	.3	.1	—	.0	—	—	.1	—	—
El Paso Electric	—	—	.0	.8	1.0	2.2	1.0	1.1	.6	.7	2.5	.6	.1	.4	1.5
Idaho Power	—	—	—	.0	—	—	—	.6	.2	.2	—	.9	—	—	.2
PowerWatch											1.1	—	5.5	13.4	.4
Black Hills Energy											.3	—	.1	.0	—
NorthWestern	.0	—	.1	.2	—	.8	.1	—	.8	.0	.4	.6	.3	.0	—
Avista Utilities	—	.1	—	—	—	—	—	—	—	—	—	—	—	—	—
Avangrid	—	—	—	—	—	—	.2	—	.0	—	.6	—	—	—	—
BPA	—	—	.3	.1	—	.2	.0	.0	—	.1	.4	—	.0	.0	.2
Tacoma Power	.3	—	—	—	.1	—	—	—	—	—	.0	.1	.2	—	.0
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Puget Sound Energy	—	—	—	—	—	—	—	—	.1	—	—	—	.1	—	—
Seattle City Light	.3	—	—	.1	.0	—	—	—	.0	.1	.2	—	.0	.1	—
Powerex	—	—	—	—	—	—	.1	—	.1	—	—	.0	.7	.1	—

7.4 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 in real-time. 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.[73]

[73] 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

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.[74] 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 7.2 shows the days in which a balancing area was opted in to receiving assistance energy transfers during the quarter. Eleven balancing areas were opted in to the program on at least one day during this period: Avangrid, the Balancing Area of Northern California, Black Hills Energy, California ISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, PSC of New Mexico, and WAPA Desert Southwest. Avangrid, the Balancing Area of Northern California, California ISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, and WAPA Desert Southwest were opted in to AET on all days during the quarter.

Table 7.2 Assistance energy transfer opt-in designations by balancing area (July–September 2026)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Jul. 1 - Sep. 30	92
Balancing Area of Northern California	Jul. 1 - Sep. 30	92
Black Hills Energy	Jul. 26 - Sep. 30	67
California ISO	Jul. 1 - Sep. 30	92
Idaho Power	Jul. 1 - Sep. 30	92
NorthWestern Energy	Jul. 1 - Sep. 30	92
NV Energy	Jul. 1 - Sep. 30	92
PacifiCorp East	Jul. 1 - Sep. 30	92
PacifiCorp West	Jul. 1 - Sep. 30	92
PSC of New Mexico	Jul. 1 - Aug. 1, Aug. 10 - Sep. 30	84
WAPA Desert Southwest	Jul. 1 - Sep. 30	92

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

Table 7.3 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during the quarter and the resulting 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, seven balancing areas (Avangrid, Black Hills Energy, Idaho Power, NorthWestern Energy, NV Energy, PSC of New Mexico, and WAPA Desert Southwest) failed the resource sufficiency evaluation during at least one interval while opted in to the program. All seven of these balancing areas received additional imports due to assistance energy transfer opt-in.

Table 7.3 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. During the quarter, WAPA Desert Southwest failed the resource sufficiency evaluation in the most intervals while opted in to receiving assistance energy transfers (36 intervals). WAPA Desert Southwest achieved an additional 36 MW on average during these intervals (and a maximum of 257 MW). WAPA Desert Southwest achieved the most additional imports from assistance energy transfers during the quarter (327 MWh).

Table 7.3 Resource sufficiency evaluation failures during assistance energy transfer opt-in (July–September 2026)

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	13	28%	24	301	80
Balancing Area of Northern California	92	0	N/A	N/A	N/A	N/A
Black Hills Energy	67	3	22%	3	13	2
California ISO	92	0	N/A	N/A	N/A	N/A
Idaho Power	92	24	25%	41	296	248
NorthWestern Energy	92	19	51%	33	321	156
NV Energy	92	4	50%	117	272	117
PacifiCorp East	92	0	N/A	N/A	N/A	N/A
PacifiCorp West	92	0	N/A	N/A	N/A	N/A
PSC of New Mexico	84	8	71%	185	661	371
WAPA Desert Southwest	92	36	33%	36	257	327

Table 7.4 summarizes the total cost from assistance energy transfers.[75] 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 the resource sufficiency evaluation insufficiency or the WEIM import transfers.[76] The price is the real-time bid cap, typically $1,000/MWh. Table 7.4 also shows the total cost per *WEIM imports added*. WEIM

[75] 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.

[76] 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.

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 7.4 Cost of assistance energy transfers (July–September 2026)

Balancing area	RSE failures under AET (15-min. intervals)	Total WEIM imports added (MWh)	Total cost of assistance energy transfers ($)	Total cost per added WEIM import ($/MWh)
Avangrid	13	80	$49,641	$624
Balancing Area of Northern California	0	N/A	N/A	N/A
Black Hills Energy	3	2	$2,403	$1,205
California ISO	0	N/A	N/A	N/A
Idaho Power	24	248	$98,369	$397
NorthWestern Energy	19	156	$184,563	$1,185
NV Energy	4	117	$11,727	$100
PacifiCorp East	0	N/A	N/A	N/A
PacifiCorp West	0	N/A	N/A	N/A
PSC of New Mexico	8	371	$100,211	$270
WAPA Desert Southwest	36	327	$216,049	$661

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[77] 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.

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

8 Offset costs

The day-ahead and real-time offset costs are the difference between the total money *paid out* and the total money *collected by* the California ISO settlement process for energy in the day-ahead and real-time markets, respectively. The difference is balanced through these settlements to maintain revenue neutrality.

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 EDAM or WEIM entity scheduling coordinator (for the non-CAISO balancing areas).[78]

Key findings in this section include:

- Total day-ahead energy offset credits paid back to EDAM balancing areas were about $74 million during the third quarter.
- Total real-time offset costs for balancing areas participating in the day-ahead market were $88 million in the third quarter of 2026.[79,80] The congestion portion of the offset made up the large majority of the cost at around $88 million. The energy portion of the offset was a $10 million credit while the loss portion was a $10 million charge.
- Real-time offset costs for balancing areas participating only in the WEIM real-time markets were a net $12 million charge to WEIM entities. On net, the energy portion of the offset was around an $11 million charge. The congestion portion of the offset was a $2 million charge. The loss portion was a $1 million credit.

8.1 Day-ahead offsets

The day-ahead offset settlement includes a component for the energy portion of prices that is applicable to all EDAM participating balancing areas.[81] Figure 8.1 shows monthly day-ahead energy offsets since the launch of EDAM in May. Total day-ahead energy offset credits paid back to EDAM balancing areas were about $74 million during the third quarter. This credit back to EDAM balancing areas can accrue if the energy portion of prices paid into the day-ahead market by demand exceeds the energy portion of prices paid out to supply. DMM is working with the ISO to identify the cause of this day-ahead energy revenue imbalance.

[78] Measured demand is physical load plus exports.

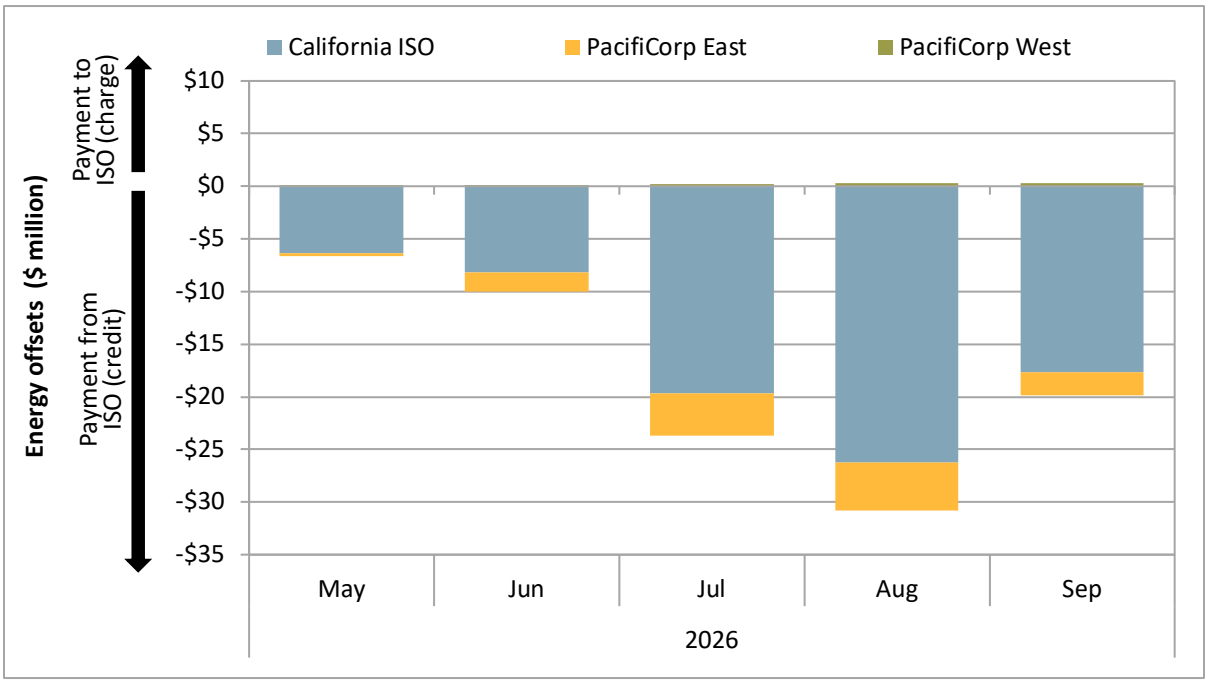
[79] Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date. For comparison to previous reports, see DMM annual and quarterly reports: https://www.caiso.com/market-operations/market-monitoring/market-issues-and-performance-reports

[80] This includes PacifiCorp East and PacifiCorp West since May, following the launch of the extended day-ahead market (EDAM) on May 1. Prior to May, CAISO was the only balancing area participating in the day-ahead market.

[81] This "energy" offset component in the day-ahead offset calculation also includes any loss offsets.

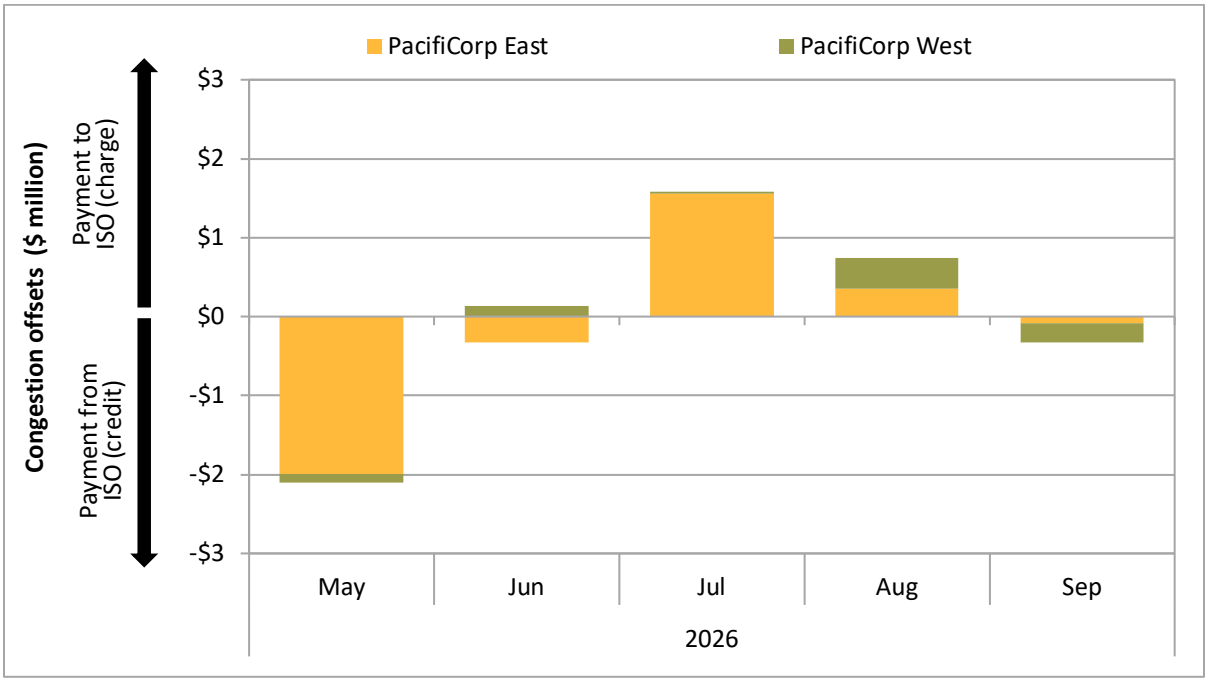
With the launch of the extended day-ahead market, the day-ahead offsets also include a congestion component that is applicable to the non-CAISO balancing areas.[82] Figure 8.2 shows monthly day-ahead congestion offsets. Total congestion offsets for PacifiCorp East and PacifiCorp West in the third quarter equaled a charge of around $2 million.

Figure 8.1 Monthly day-ahead energy offset costs



[82] The CAISO balancing area instead uses congestion revenue rights (CRR) to manage imbalances.

Figure 8.2 Monthly day-ahead congestion offsets



8.2 Real-time offsets

The real-time 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 offset charge* (RTCO). Similarly, any revenue imbalance from the loss component of real-time energy prices is collected through the *real-time loss offset charge*, while any remaining revenue imbalance is recovered through the *real-time imbalance energy offset charge* (RTIEO).

Figure 8.3 shows monthly imbalance offset costs since the third quarter of 2024 for balancing areas participating in the day-ahead market. 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). The majority of real-time offset costs for balancing areas participating in the day-ahead market were for the CAISO balancing area. In the third quarter, the CAISO balancing area received a charge of $89 million for the congestion portion of the offset and a credit of $8 million for the energy portion of the offset.

Figure 8.4 shows the same information for balancing areas only participating in the WEIM real-time markets. In the third quarter, charges (positive) to balancing areas for the energy portion of the offset (light blue bars) were $25 million.

Figure 8.3 Monthly real-time offset costs (balancing areas in day-ahead market)

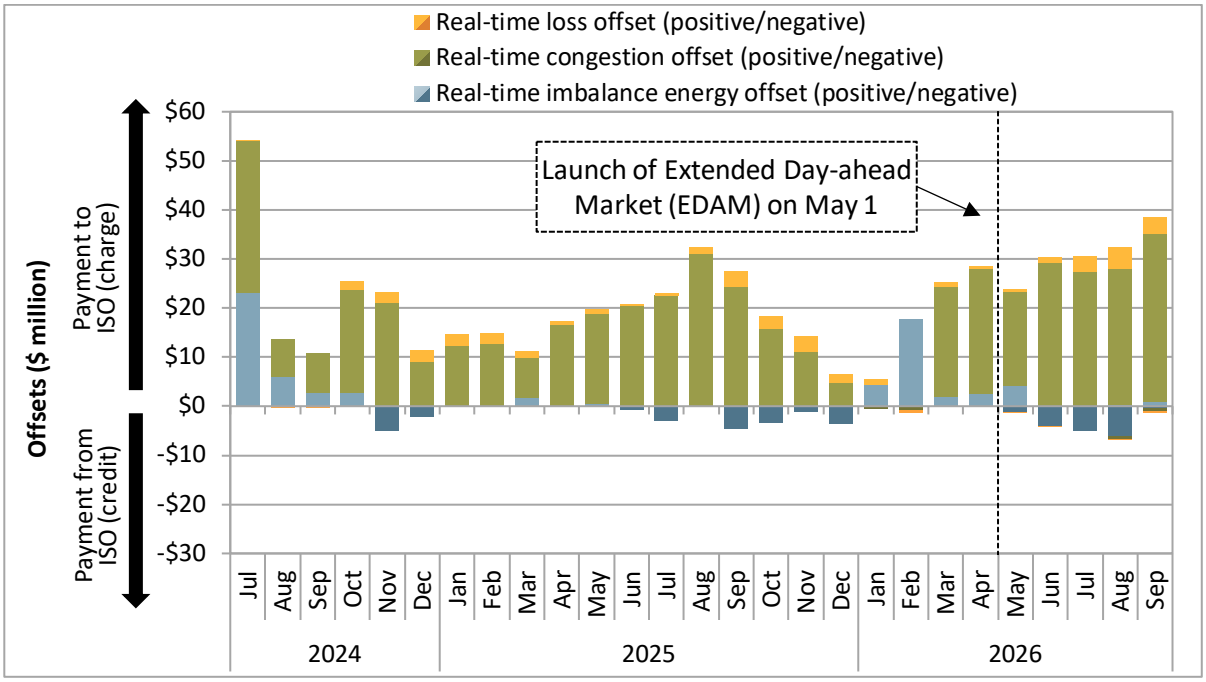


Figure 8.4 Monthly real-time offset costs (balancing areas participating only in WEIM)

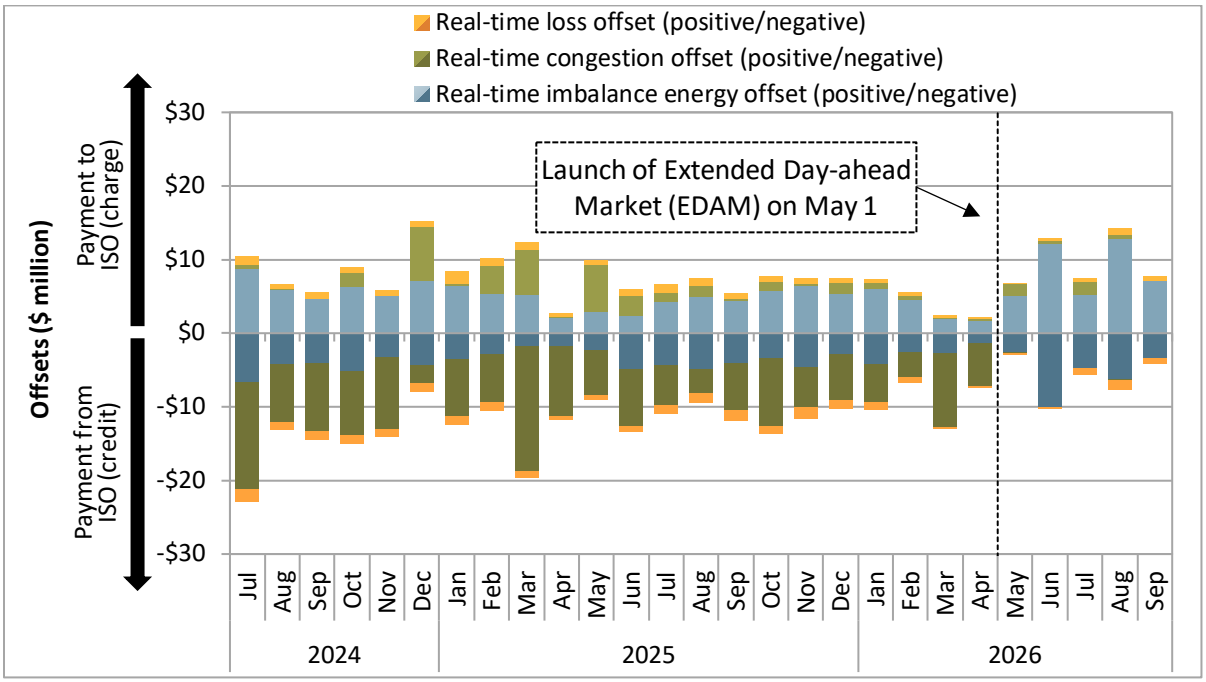


Figure 8.5 through Figure 8.7 show the quarterly real-time energy, congestion, or loss components of the offsets from Q3 2025 through Q3 2026 for each balancing area.[83] Figure 8.8 shows the *total* real-time offset costs for each quarter and balancing area during the same period. Charges for revenue shortfall are shown in orange, while credits for revenue surplus are shown in blue. Of note in the third quarter:

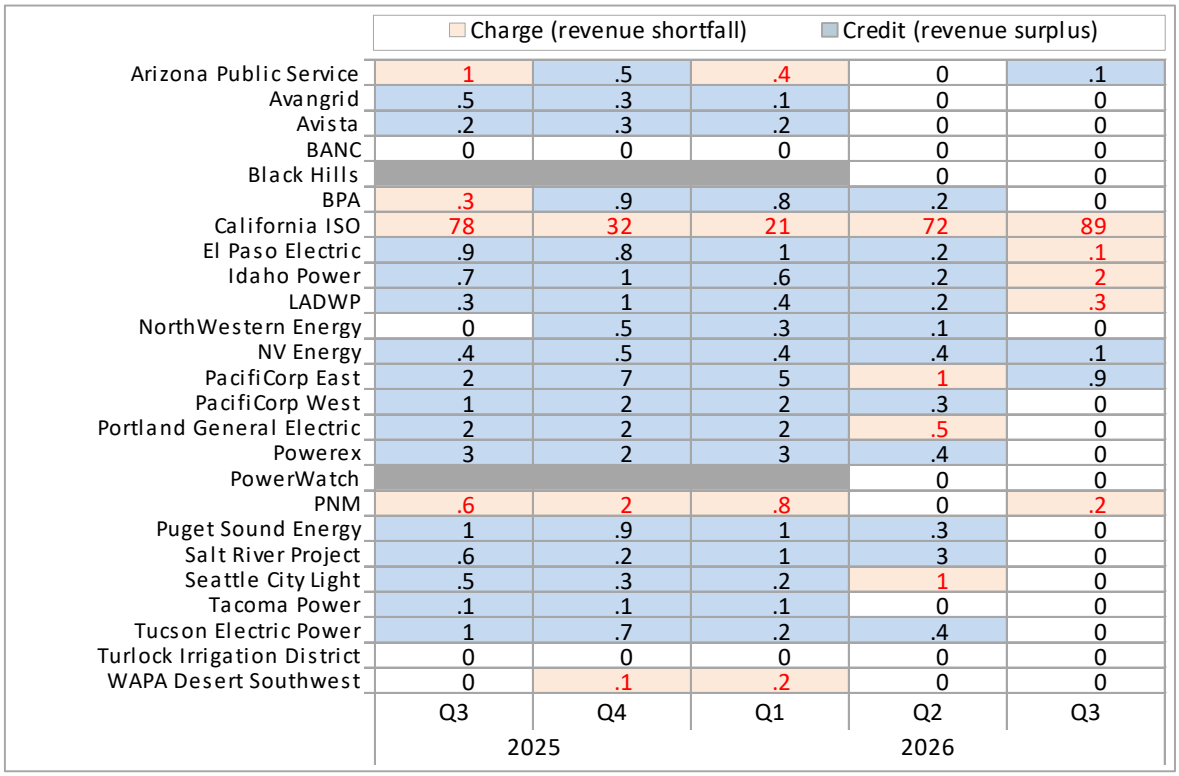
- Credits for the congestion portion of the offset—which were historically tied to congestion rent from WEIM transfer constraints—have been relatively low since the launch of EDAM. With the launch of EDAM, congestion on WEIM transfer constraints is no longer reflected in the congestion component of the locational marginal price.
- Revenue *shortfall* from imbalance energy offsets was relatively high for NV Energy and Black Hills. This was $8.2 million (charge) for NV Energy and $5.4 million (charge) for Black Hills.
- Revenue *surplus* from imbalance energy offsets for Puget Sound Energy was $4.5 million (credit).
- Revenue *surplus* from imbalance energy offsets for Salt River Project was $4.2 million (credit).

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

	Charge (revenue shortfall)			Credit (revenue surplus)	
Arizona Public Service	4	3	1	6	3
Avangrid	.1	.3	.2	0	.1
Avista	0	0	0	.5	1
BANC	.6	.8	.1	.8	0
Black Hills				4	5
BPA	.4	.2	.1	.1	.9
California ISO	7	8	24	3	8
El Paso Electric	.1	.1	.1	.5	.8
Idaho Power	.9	.8	1	.6	1
LADWP	.1	.1	.2	2	.1
NorthWestern Energy	3	5	2	.5	3
NV Energy	3	4	3	3	8
PacifiCorp East	.9	.3	1	.8	.2
PacifiCorp West	3	2	2	.2	2
Portland General Electric	0	0	0	.3	.3
Powerex	.2	.2	.3	.8	2
PowerWatch				0	.3
PNM	1	2	2	.3	.3
Puget Sound Energy	4	4	3	1	5
Salt River Project	3	2	2	4	4
Seattle City Light	1	1	1	.5	1
Tacoma Power	0	0	0	0	0
Tucson Electric Power	0	.1	.3	2	.6
Turlock Irrigation District	.7	.7	.2	.2	.6
WAPA Desert Southwest	.7	.2	.6	3	.3
	Q3	Q4	Q1	Q2	Q3
	2025			2026	

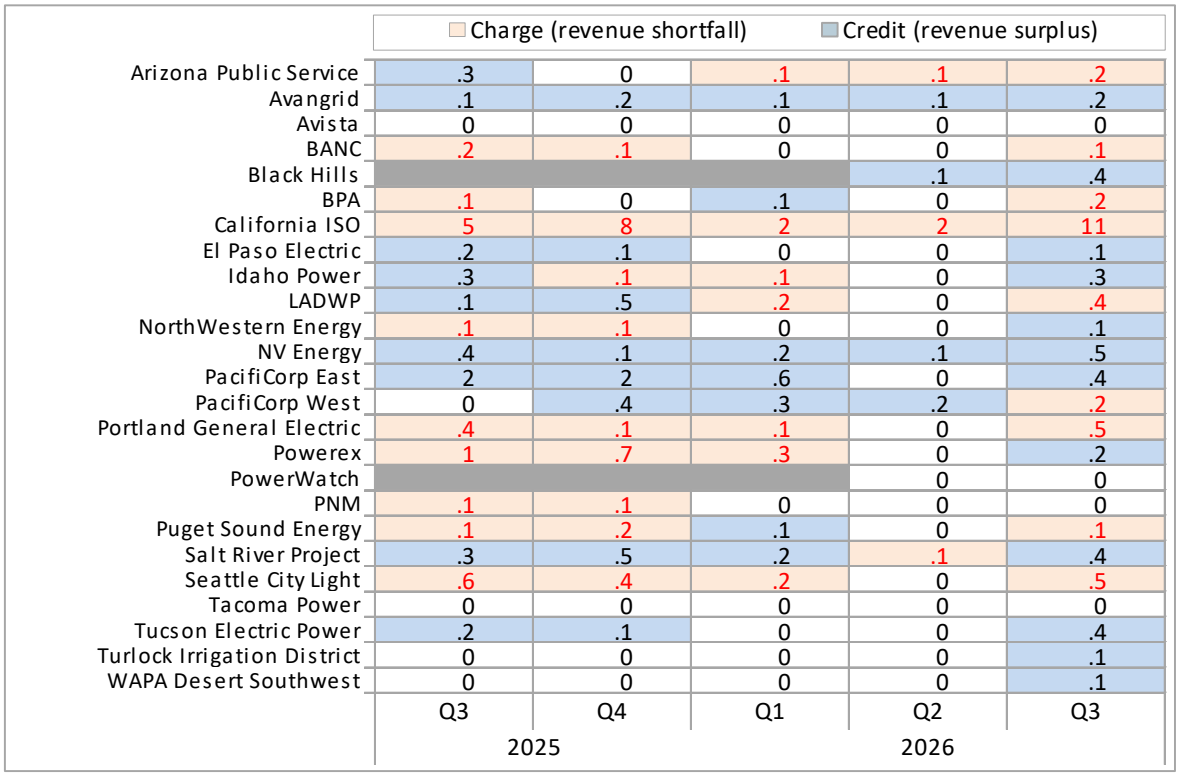
[83] The nature of real-time imbalance offset costs differs between balancing areas in the day-ahead market and balancing areas participating in only the Western Energy Imbalance Market (WEIM). PacifiCorp East and PacifiCorp West joined the extended day-ahead market (EDAM) on May 1. Black Hills and Power Watch joined the WEIM on May 6.

Figure 8.6 Real-time congestion offsets by quarter and balancing area ($ millions)



	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026
Arizona Public Service	1	.5	.4	0	.1
Avangrid	.5	.3	.1	0	0
Avista	.2	.3	.2	0	0
BANC	0	0	0	0	0
Black Hills				0	0
BPA	.3	.9	.8	.2	0
California ISO	78	32	21	72	89
El Paso Electric	.9	.8	1	.2	.1
Idaho Power	.7	1	.6	.2	2
LADWP	.3	1	.4	.2	.3
NorthWestern Energy	0	.5	.3	.1	0
NV Energy	.4	.5	.4	.4	.1
PacifiCorp East	2	7	5	1	.9
PacifiCorp West	1	2	2	.3	0
Portland General Electric	2	2	2	.5	0
Powerex	3	2	3	.4	0
PowerWatch				0	0
PNM	.6	2	.8	0	.2
Puget Sound Energy	1	.9	1	.3	0
Salt River Project	.6	.2	1	3	0
Seattle City Light	.5	.3	.2	1	0
Tacoma Power	.1	.1	.1	0	0
Tucson Electric Power	1	.7	.2	.4	0
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	0	.1	.2	0	0

Figure 8.7 Real-time loss offsets by quarter and balancing area ($ millions)



	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026
Arizona Public Service	.3	0	.1	.1	.2
Avangrid	.1	.2	.1	.1	.2
Avista	0	0	0	0	0
BANC	.2	.1	0	0	.1
Black Hills				.1	.4
BPA	.1	0	.1	0	.2
California ISO	5	8	2	2	11
El Paso Electric	.2	.1	0	0	.1
Idaho Power	.3	.1	.1	0	.3
LADWP	.1	.5	.2	0	.4
NorthWestern Energy	.1	.1	0	0	.1
NV Energy	.4	.1	.2	.1	.5
PacifiCorp East	2	2	.6	0	.4
PacifiCorp West	0	.4	.3	.2	.2
Portland General Electric	.4	.1	.1	0	.5
Powerex	1	.7	.3	0	.2
PowerWatch				0	0
PNM	.1	.1	0	0	0
Puget Sound Energy	.1	.2	.1	0	.1
Salt River Project	.3	.5	.2	.1	.4
Seattle City Light	.6	.4	.2	0	.5
Tacoma Power	0	0	0	0	0
Tucson Electric Power	.2	.1	0	0	.4
Turlock Irrigation District	0	0	0	0	.1
WAPA Desert Southwest	0	0	0	0	.1

Figure 8.8 Total real-time offsets by quarter and balancing area ($ millions)

	Charge (revenue shortfall)			Credit (revenue surplus)	
Arizona Public Service	4	3	2	7	3
Avangrid	.6	.3	0	.1	.3
Avista	.2	.3	.2	.5	1
BANC	.5	.7	.1	.8	.1
Black Hills				4	5
BPA	.8	.7	1	.2	1
California ISO	75	31	47	78	91
El Paso Electric	1	.8	.9	.8	.8
Idaho Power	2	.2	.7	.5	.2
LADWP	.5	1	.4	2	.7
NorthWestern Energy	3	4	2	.4	2
NV Energy	2	3	3	4	8
PacifiCorp East	3	9	4	.4	1
PacifiCorp West	4	4	4	.6	2
Portland General Electric	2	1	2	.8	.7
Powerex	1	.8	2	.3	2
PowerWatch				0	.3
PNM	2	5	2	.4	.1
Puget Sound Energy	5	5	4	1	4
Salt River Project	4	3	3	1	5
Seattle City Light	1	1	1	.8	1
Tacoma Power	.1	.1	.1	0	0
Tucson Electric Power	1	.8	.1	2	.9
Turlock Irrigation District	.7	.7	.1	.2	.6
WAPA Desert Southwest	.7	.1	.4	3	.4
	Q3	Q4	Q1	Q2	Q3
	2025			2026	

9 Bid cost recovery

During the third quarter of 2026, estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market totaled about $35.9 million.[84] This was a 5 percent increase from the $34.3 million in bid cost recovery in the third quarter of 2025. Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM) totaled about $3 million. WEIM area bid cost recovery payments decreased 26 percent from Q3 2025.[85]

Figure 9.1 shows monthly bid cost recovery payments in the third quarter of 2026 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market (blue bars) totaled about $13.1 million, up from $6.2 million in the third quarter of 2025. Bid cost recovery payments associated with residual unit commitment (red bars) during the quarter totaled about $2.6 million, or about $14.1 million lower than the third quarter of 2025. Bid cost recovery associated with the real-time market (green bars) for areas that participate in the day-ahead market totaled about $20.2 million, which was about $8.8 million higher than the same quarter of 2025.

Figure 9.2 shows monthly bid cost recovery payments paid to units in areas participating only in the WEIM.[86] Bid cost recovery payments to these units were greatest in the Desert Southwest and California regions at $1.5 million and $1.1 million, respectively. Bid cost recovery payments to the Intermountain West and Pacific Northwest regions totaled around $168,000 and $170,000, 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 third quarter of 2026, about $22 million of bid cost recovery payments were made to gas resources. About $8.2 million and $4.6 million of payments were made to demand response and battery resources, respectively. Hydroelectric resources were paid $1.2 million in bid cost recovery payments.

[84] CAISO was the only balancing area participating in the day-ahead market until PacifiCorp (PACW and PACE) joined on May 1, 2026.

[85] The values in this section are preliminary based on settlements data retrieved on October 27, 2026 and may change significantly in upcoming reports.

[86] Figure 9.2 only shows non-EDAM balancing authority areas.

Figure 9.1 Monthly bid cost recovery payments for balancing areas participating in EDAM

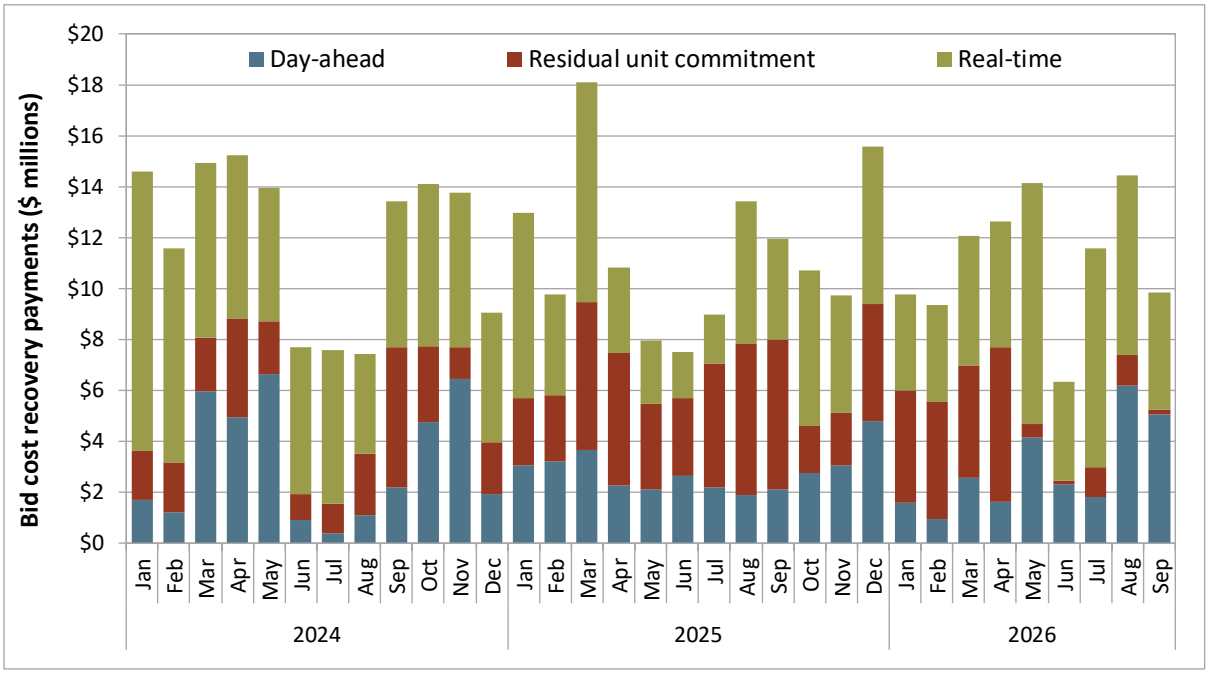
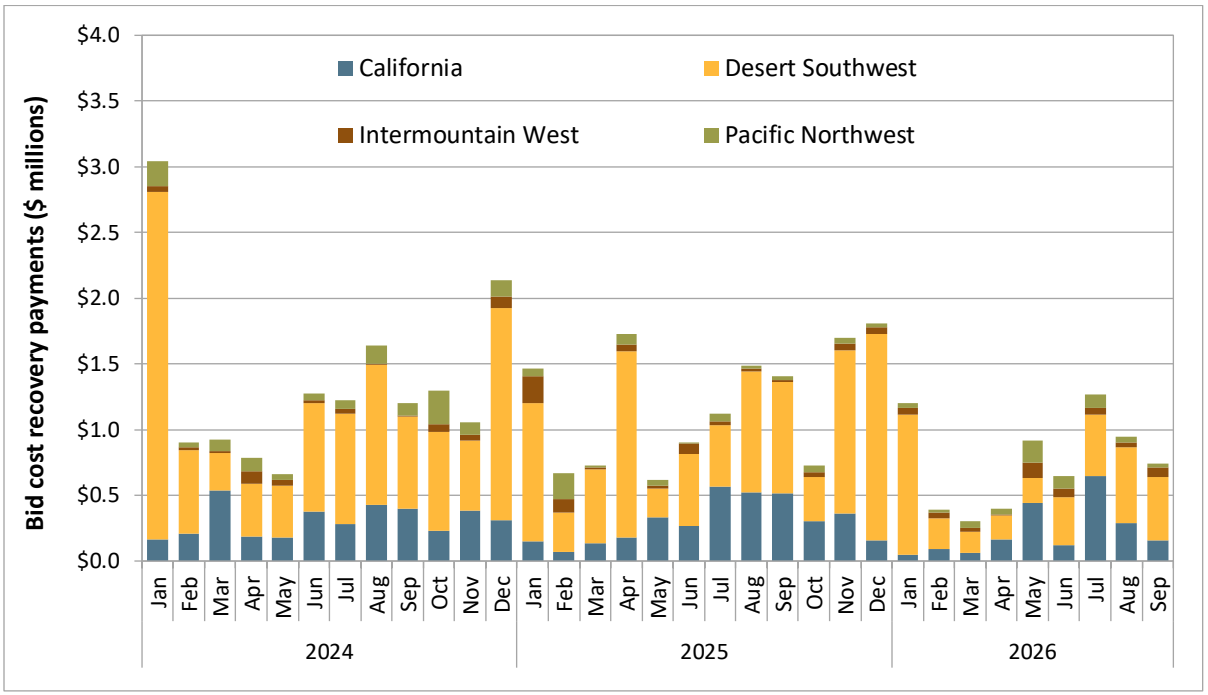


Figure 9.2 Monthly bid cost recovery payments for balancing areas only participating in WEIM



10 Residual unit commitment

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.

The average total volume of capacity procured through the residual unit commitment (RUC) process in the third quarter of 2026 was about 55 percent lower than the same quarter of 2025. A main driver of this was a 77 percent decrease in operator adjustments to the RUC procurement target.

10.1 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 10.1 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 10.1 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 ISO's day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). On average, this factor contributed to reducing the residual unit commitment requirements by about 165 MW per hour in the third quarter of 2026.

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 10.1. The magnitude of downward eligible intermittent resource adjustments averaged about 1,600 MW in Q3 2026, an increase of 21 percent from about 1,325 MW in Q3 2025.

Lastly, operators can 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 10.1 show the average adjustment to the residual unit commitment requirement. Figure 10.2 shows the hourly distribution of these operator adjustments during the third quarter of 2026. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour. Average operator adjustments to the residual unit commitment load forecast were about 220 MW in Q3 2026, down 77 percent from about 960 MW in Q3 2025. The operator adjustments and changes to the methodology are described in more detail in the following section.

Figure 10.1 Average incremental residual unit commitment requirement by component

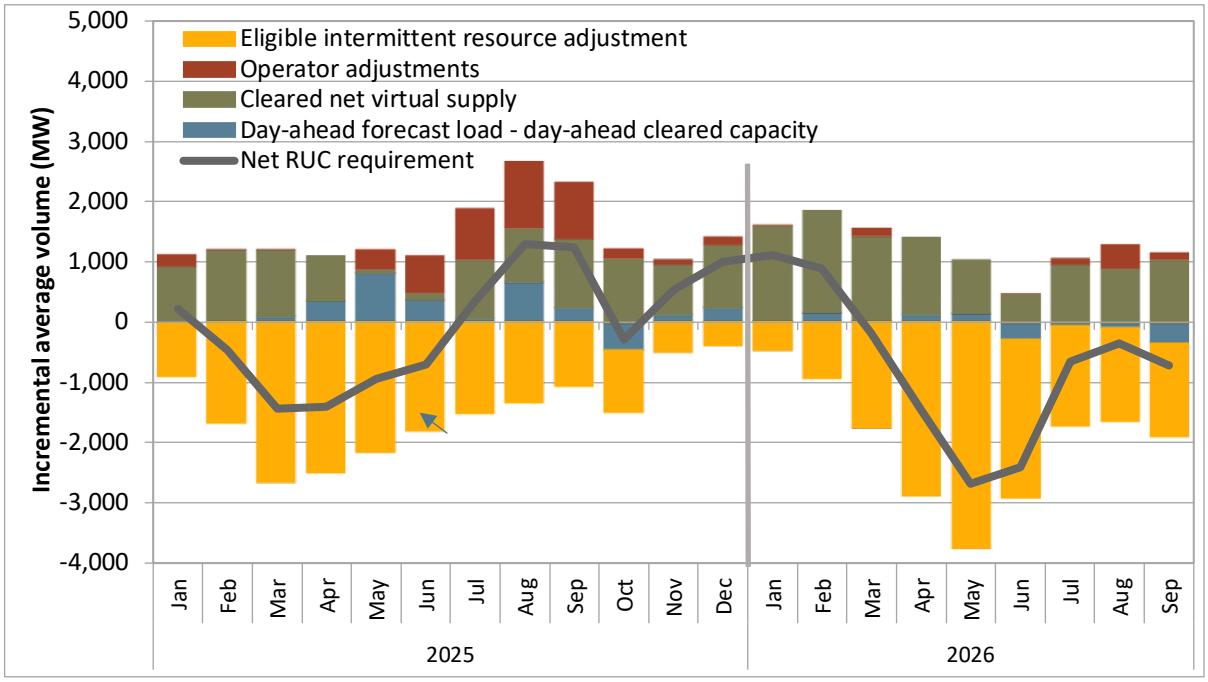
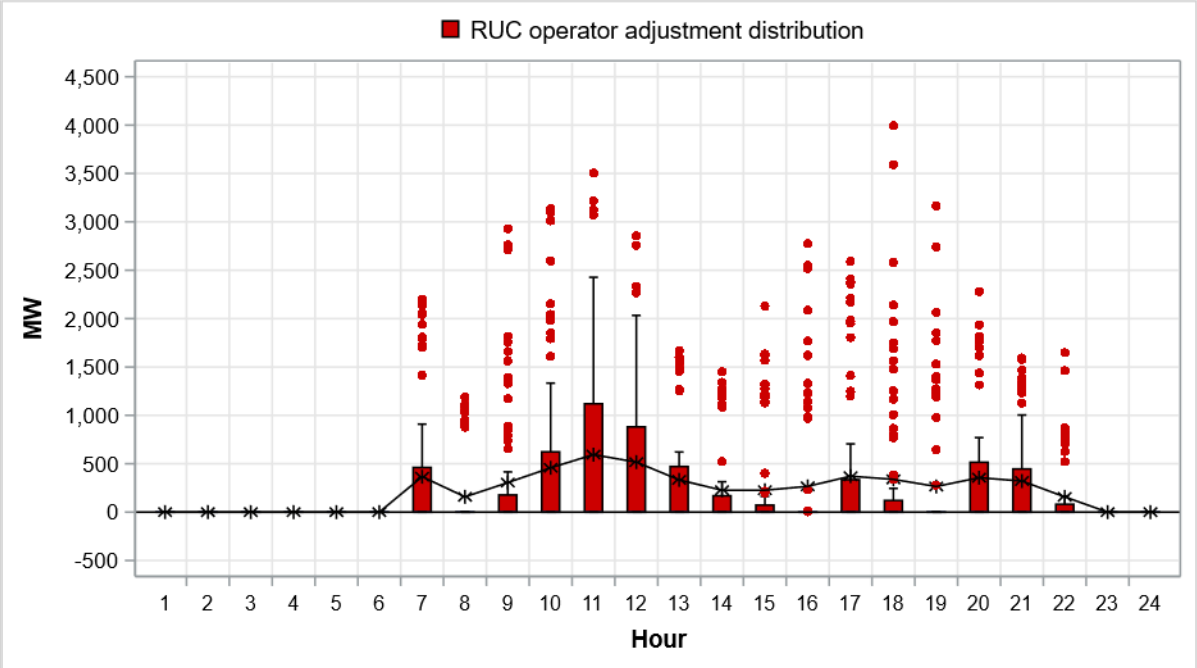


Figure 10.2 Hourly distribution of residual unit commitment operator adjustments (July–September 2026)



Residual unit commitment operator adjustments

The residual unit commitment (RUC) adjustments are added to the forecasted load in the RUC process and are intended to address uncertainty and provide extra capacity for a balancing area beyond what is accounted for in the integrated forward market.

Day-ahead market enhancements (DAME) and the extended day-ahead market (EDAM) were launched on May 1, 2026. This included the implementation of the *imbalance reserve product.* Imbalance reserves are bid into the market, co-optimized with energy and ancillary services, and are intended to address much of the same net load uncertainty as the former RUC adjustments. However, there are several key differences with imbalance reserve. The imbalance reserve requirement is 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 flexibility. The imbalance reserve product was also implemented at launch with the requirement set to cover all hours at the 90th percentile of uncertainty.

With the implementation of the imbalance reserve product, RUC adjustments can still be entered to address any uncertainty not covered by imbalance reserve, but the amount is now *incremental* and tied to the 97.5th percentile of uncertainty.[87] RUC adjustments may be entered in addition to procurement of imbalance reserve for a number of reasons. First, the imbalance reserve requirement is based on the 90th percentile instead of the 97.5th percentile. Next, there can be relaxation of the imbalance reserve requirement. Last, there can be additional sources of operational uncertainty not covered by the imbalance reserve product (outages, fire risk, weather events, etc.). Any RUC adjustment is calculated minus upward imbalance reserve procured in the day-ahead market to capture only incremental uncertainty that may need to be accounted for to be sufficient between the day-ahead and real-time markets.[88]

The CAISO operating procedure for setting the RUC adjustments within the CAISO balancing area recommends using a particular percent of the 97.5th percentile of uncertainty, considering the level of operational uncertainty or load.[89,90] During days with moderate operational uncertainty or load, the operating procedure recommends to use 4 percent of this uncertainty for either the peak morning and evening hours or the mid-day hours. During days with higher operational uncertainty or load, the procedure recommends using 50 percent for the mid-day hours. Last, during the days with the highest operational uncertainty or load, the procedure recommends using 100 percent for the mid-day hours.

As an example, Figure 10.3 shows the calculation of these RUC adjustments on September 7, 8, and 9. Here, the load forecast significantly increased over the three days. On September 7, the RUC adjustment was calculated based on 4 percent of the 97.5th percentile of uncertainty, resulting in no RUC adjustment above imbalance reserve. On September 8, the RUC adjustment was calculated based on 50

[87] The RUC uncertainty is calculated using the same mosaic quantile regression method as the imbalance reserve product, except using the 97.5th percentile. 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 high percentile of uncertainty that might materialize. These coefficients are then combined with RUC forecast information at the time of each market run to determine the uncertainty.

[88] The imbalance reserve procured here also accounts for imports and exports of imbalance reserve for the balancing area.

[89] See CAISO Operating Procedure 1210, July 1, 2026, pp 12-13: https://www.caiso.com/Documents/1210.pdf

[90] Prior to the implementation of Day-Ahead Market Enhancements, the percentile target of uncertainty for the RUC adjustments was selected at either the 50th percentile, 75th percentile, or 97.5th percentile, based on conditions in the system.

percent of the 97.5th percentile of uncertainty resulting in 180 MW on average of additional RUC adjustments in the applied mid-day hours (or a maximum of around 910 MW). On September 9, the RUC adjustment was calculated based on 100 percent of the 97.5th percentile of uncertainty, resulting in over 1,600 MW on average in the applied mid-day hours (or a maximum of around 2,740 MW).

Figure 10.4 shows the average residual unit commitment adjustment on each day during the first three quarters of the year, comparing 2025 (red) and 2026 (blue). There were no RUC adjustments applied for PacifiCorp East or PacifiCorp West such that these amounts are for the CAISO balancing area only. Average RUC adjustments were about 220 MW in Q3 2026, down 77 percent from about 960 MW in Q3 2025.

Figure 10.3 CAISO residual unit commitment adjustment calculation (September 7–9, 2026)

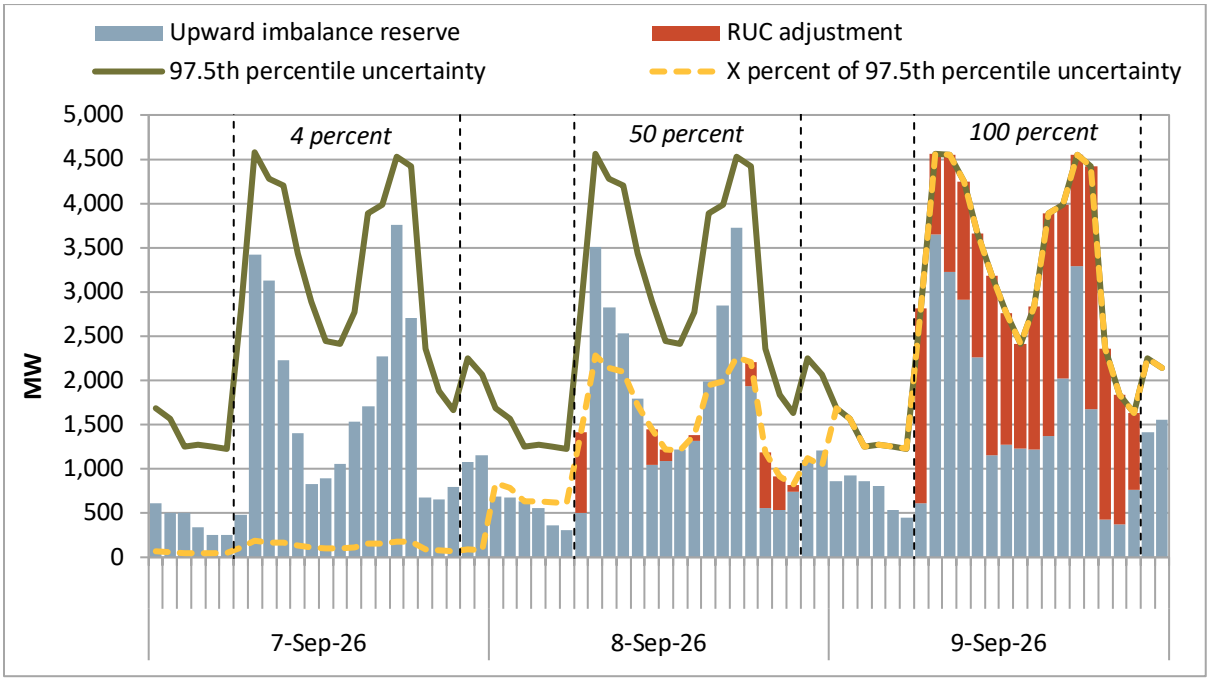
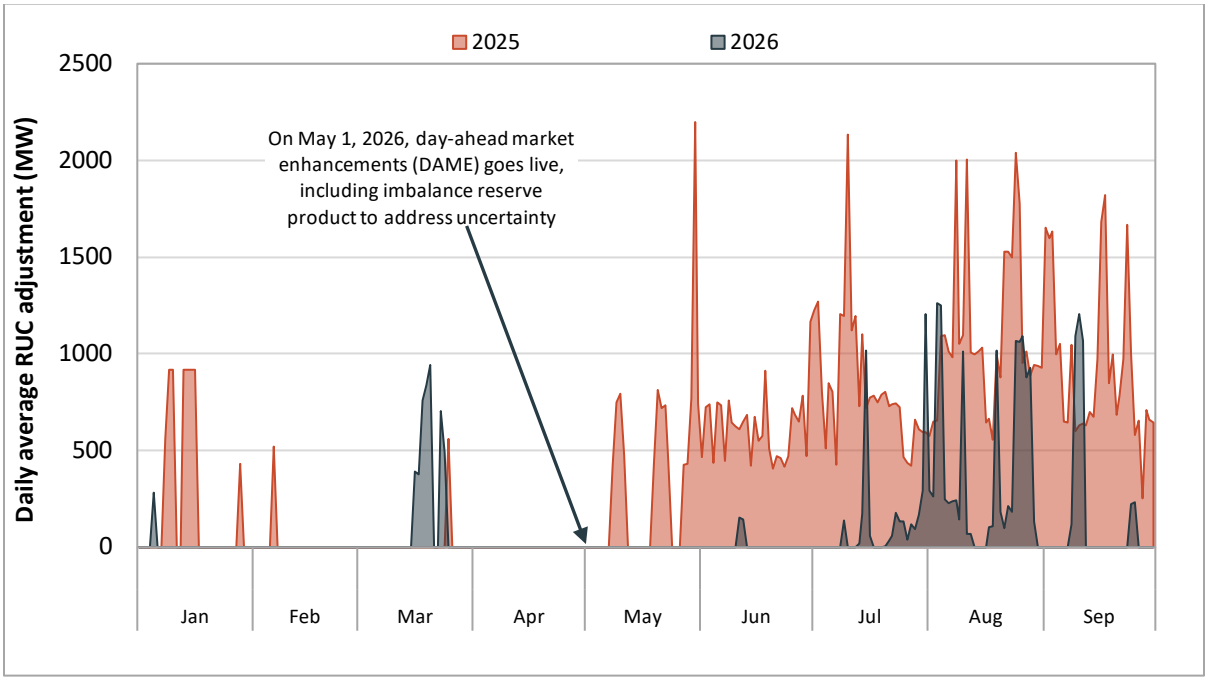


Figure 10.4 Average residual unit commitment adjustment by day (January – September 2025 vs. 2026)



10.2 Residual unit commitment procurement and costs

In May 2026, the ISO implemented day-ahead market enhancements (DAME) and the extended day-ahead market (EDAM), which introduced significant changes to the residual unit commitment (RUC) process. Under the prior design, RUC procured capacity in the upward direction only. Under DAME, RUC procures both upward capacity (reliability capacity up, or RCU) and downward capacity (reliability capacity down, or RCD), with separate locational prices for each. Resources submit RCU and RCD availability bids as part of the day-ahead market submission, with bid prices between $0/MWh and $250/MWh. A resource can only receive an RCU or RCD award in a given hour. Under EDAM, the RUC process extends to EDAM entity balancing authority areas, each with its own procurement target. Reliability capacity can transfer between balancing authority areas.

DAME transitional measures and resource adequacy revenue allocation

A significant financial change is to resource adequacy (RA) resource compensation. Under the prior design, RA resources were required to bid $0/MWh into RUC and were excluded from RUC availability payments. The RUC settlement system only compensated non-RA capacity, while RA resources received no market payment for their RUC awards. Starting with DAME/EDAM, resources with RCU or RCD awards—including RA resources—receive availability payment at the market clearing price. This change created new market revenue for RA resources that did not exist under the prior design. The tariff includes optional DAME transitional measures under tariff section 11.2.6, through which resource and load serving entity (LSE) scheduling coordinators can mutually elect to have the RA capacity portion of

RCU and RCD revenue credited back to the LSE. If neither party elects, the resource retains all revenue.[91, 92]

The tariff specifies that the overlapping RA capacity—the portion used to determine how much revenue flows back to the LSE—is based on the higher of generic RA capacity or flexible RA capacity on the monthly supply plan (tariff section 11.2.6.2).

In this quarter, approximately 3,000 MW of RA capacity per month was subject to transitional measures, representing about 4 percent of total RA capacity.

Residual unit commitment costs and procurement under DAME and EDAM

As discussed above, DAME introduced RCU and RCD as separate products, replacing the prior single upward RUC schedules, with RA resources now receiving revenues at the market clearing price. Under EDAM, PacificCorp East (PACE) and PacificCorp West (PACW) participate in the RUC process with their own procurement targets, and reliability capacity can transfer between balancing areas.

Figure 10.5 shows average hourly RUC megawatts from May 2025 through September 2026, calculated as total monthly RUC megawatts divided by the number of hours in each month. Prior to May 2026, bars show only CAISO RUC megawatts, of which 98 percent on average came from RA resources. Beginning in May 2026, bars show RCU as positive values and RCD as negative values for each EDAM BAA.

Average hourly procurement in this quarter was 1,850 MW of RCU and 750 MW of RCD, resulting in total procurement of 2,600 MW and net procurement of 1,100 MW.

The CAISO balancing area accounted for 95 percent of RCU and 88 percent of RCD procurement, PACE accounted for 4 percent of RCU and 10 percent of RCD, and PACW accounted for 1 percent of RCU and 2 percent of RCD.

Total RUC procurement this quarter was higher than the pre-EDAM level of 1,800 MW in the third quarter of 2025.

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91 For additional tariff detail, see *California ISO Settlement and Billing, Section 11, effective May 1, 2026,* available at: https://www.caiso.com/library/tariff-sections. DAME transitional measures are specified in Section 11.2.6.

92 For RCU, if the day-ahead energy schedule plus upward ancillary service awards and imbalance reserve up award is below the RA capacity, part of the upward awards falls within the RA capacity range. That portion is credited to the LSE. Any RCU award above the RA capacity level stays with the resource. For RCD, if the day-ahead energy schedule minus regulation down and imbalance reserve down awards is above the RA capacity, part of the downward award brings the resource back down to the RA capacity level. That portion is credited to the LSE. Any award that takes the resource below the RA capacity level stays with the resource (tariff section 11.2.6.2)

Figure 10.5 Monthly hourly average RUC procurement (May 2025 – September 2026)

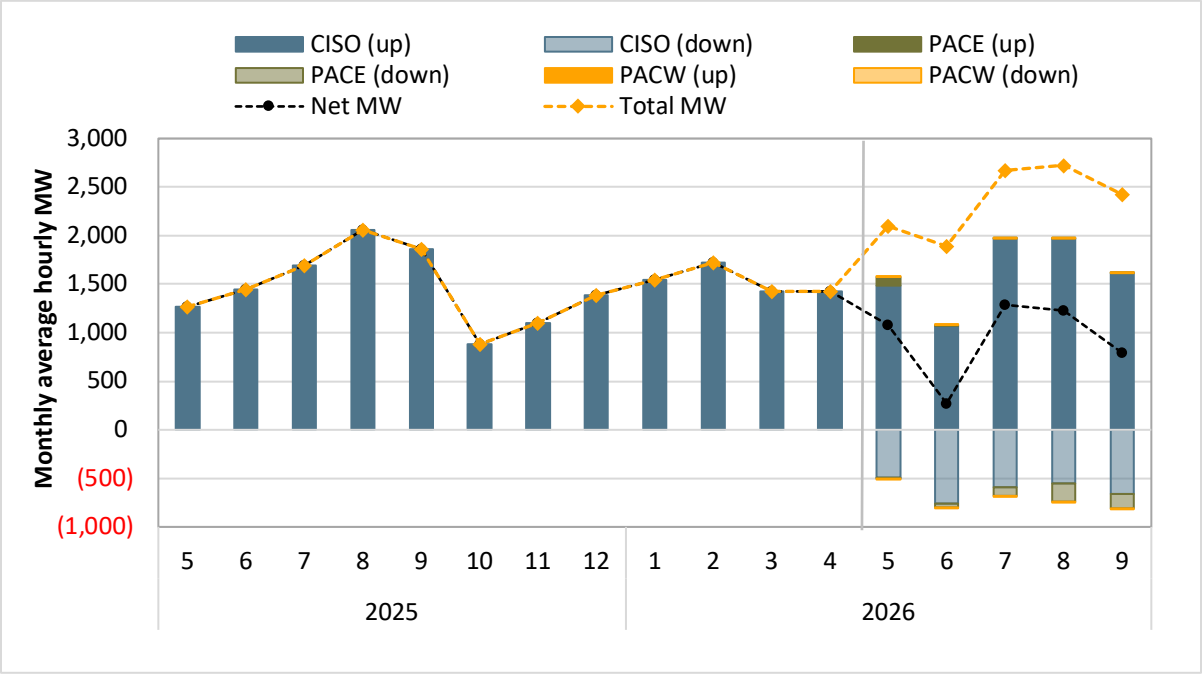
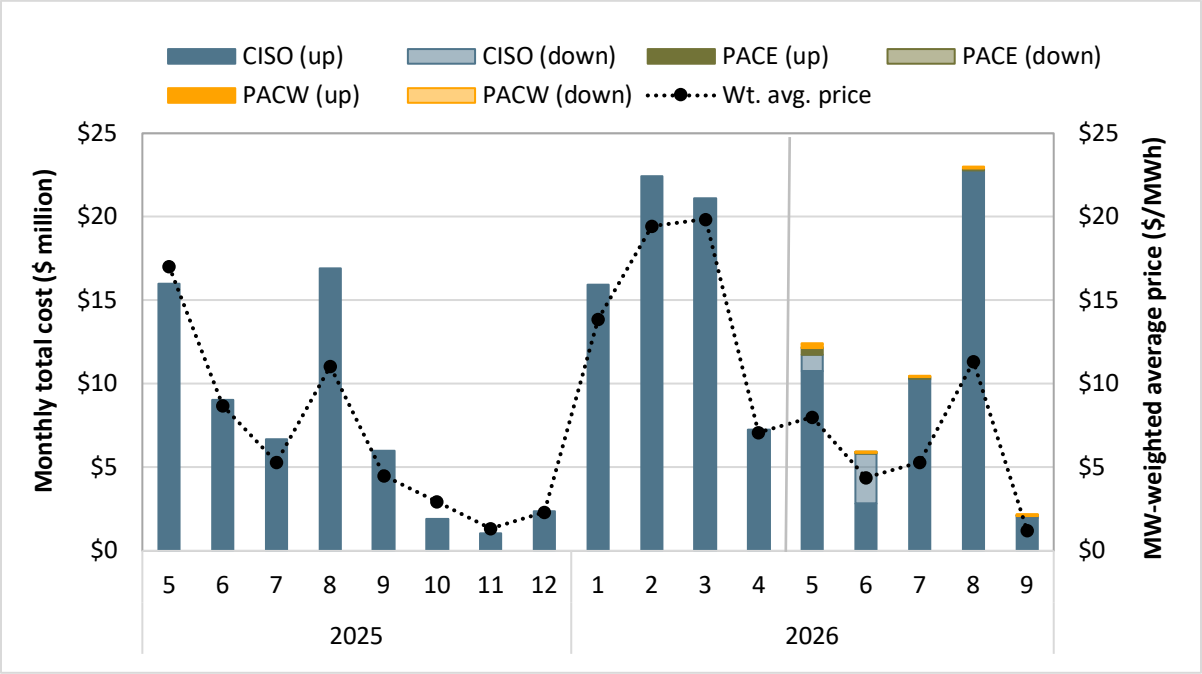


Figure 10.6 shows monthly total RUC payment costs and megawatt-weighted average RUC prices from May 2025 through September 2026. Prior to May 2026, the bars (blue) represent the imputed cost of RA and non-RA capacity in RUC, calculated as RA and non-RA resource schedules multiplied by their locational RUC prices. This amount was not an actual market payment—under the prior design, RA resources were excluded from RUC payments and received no compensation. The imputed value reflects the cost that would have been incurred if the market had to procure this capacity at market prices rather than through bilateral RA contracts. Beginning in May 2026 under DAME, RA capacity could be scheduled for both upward and downward reliability capacity and receive settlement payments. About 4 percent of RA capacity was subjected to the transitional measure election. Costs for this capacity are included in the chart and averaged about $0.1 million per month in this quarter.

The secondary axis displays the megawatt-weighted average RUC price, calculated across all resource RUC schedules weighted by their locational RUC prices.

Figure 10.6 Monthly RUC costs and weighted average price (May 2025 – September 2026)



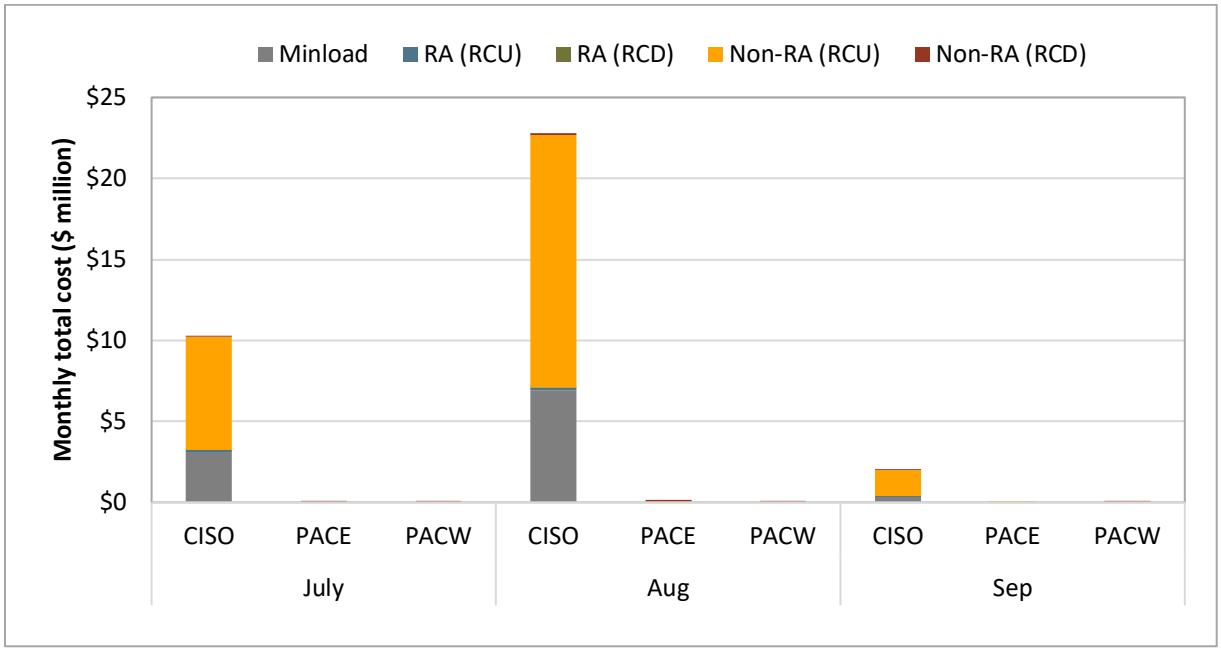
Total RUC costs were approximately $12 million per month, totaling $36 million for this quarter, compared to an average of $10 million per month between May 2025 and April 2026, of which actual payments to non-RA resources averaged only $0.2 million per month. The MW-weighted average RUC price fluctuated over the period. Between May 2025 and April 2026, the average price was about $9/MWh. It decreased to $5/MWh in July 2026, increased to $11/MWh in August, and sharply fell to $1/MWh in September.

The sharp decline in RUC costs in September was driven by lower prices, averaging $1/MWh, while hourly average procurement remained high at 2,400 MW.

Figure 10.7 shows the total RUC cost breakdown for this quarter by balancing area and category: minimum load, RA RCU, RA RCD, non-RA RCU, and non-RA RCD. The RA designation reflects resources with DAME transitional measures elections, where the RA capacity portion of RCU and RCD revenue is credited back to the LSE. Non-RA includes both non-RA resources and RA resources without elections.

Of the total $36 million in this quarter, about $24 million reflected RCU payments to non-RA resources and RA resources not subject to the transitional measure in the CAISO balancing area, while approximately $10 million reflected CAISO minimum-load payments. Of the resource adequacy resource payments, about $0.4 million was subject to the transitional measure and credited back to LSEs in this quarter. Total RUC payments were about $0.3 million for PACE and $0.2 million for PACW.

Figure 10.7 Monthly RUC cost breakdown (July–September 2026)



11 Uncertainty products

This chapter analyzes the imbalance reserve product in the day-ahead market and the flexible ramping product in the real-time market. These products are designed to enhance reliability and market performance as well as support renewable integration by procuring upward and downward flexibility to meet net load uncertainty. Key findings in this chapter for the third quarter include:

Imbalance reserve

- Gas resources made up around 70 percent of upward imbalance reserve schedules. Wind and solar resources combined made up around 62 percent of downward imbalance reserve schedules.
- The California ISO balancing area was a net exporter of upward imbalance reserve, at around 260 MW on average across all hours, with the recipient being largely PacifiCorp East. The California ISO was also a net exporter of downward imbalance reserve, at around 50 MW on average across all hours, with the recipient being largely PacifiCorp West.
- Prices for imbalance reserve have frequently been low or zero. Across all balancing areas and directions, prices have been less than $5/MWh in more than 78 percent of hours and less than $10/MWh in more than 94 percent of hours.
- Payments for upward imbalance reserve were around $11.1 million while payments for downward imbalance reserve were around $1.3 million—or around $12.3 million combined.

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 63 percent of intervals in the third quarter of 2026, up significantly from 0.3 percent in the same quarter of 2025. The increase coincided with the implementation of EDAM in May 2026. Most of this increase occurred in the Intermountain West and Pacific Northwest regions. DMM has notified the ISO of the increase in flexible ramping product prices and will continue to work with the ISO to understand the underlying causes.
- Payments associated with the flexible ramping product were $8.3 million during the third quarter of 2026, up significantly from around $1.4 million in the same quarter of 2025. Much of these payments were to resources in the Pacific Northwest due to binding WEIM transfer constraints that caused higher flexible ramping product prices in this region.
- Battery and hydro resources made up 70 percent and 20 percent of upward flexible capacity, respectively. Wind and solar combined to provide 38 percent of downward flexible capacity, and batteries provided 29 percent of downward flexible capacity. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 58 percent in the upward direction and 55 percent in the downward direction. Balancing areas in the Pacific Northwest made up 21 percent of upward flexible capacity and 22 percent of downward flexible capacity.

The imbalance reserve product is procured in the day-ahead market—reserving flexible ramping capacity to cover uncertainty that may materialize between the day-ahead and real-time markets. The flexible ramping product is procured in the real-time market—covering uncertainty that may materialize within the next real-time market interval.

The amount of flexibility the imbalance reserve and flexible ramping product procures are each derived from a demand curve which reflects a calculation of the optimal willingness-to-pay for that flexibility. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexibility and the expected reduction in cost associated with power balance constraint infeasibilities.

The imbalance reserve and 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 flexibility. This "requirement" reflects the upper end of uncertainty in each direction that might materialize.[93] This is sometimes referred to as the uncertainty requirement.

The uncertainty is 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 high percentile of uncertainty that might materialize. These coefficients are then combined with current forecast information for each interval to determine the uncertainty requirement.

11.1 Imbalance reserve

The imbalance reserve product was implemented on May 1, 2026 as part of day-ahead market enhancements (DAME) alongside the launch of the extended day-ahead market (EDAM). These reserves are bid into the market and co-optimized with energy and ancillary services in the day-ahead market to cover net load uncertainty that may materialize. This allows the market to optimally position and compensate resources that are able to provide flexibility to cover variation in load, wind, or solar forecasts.

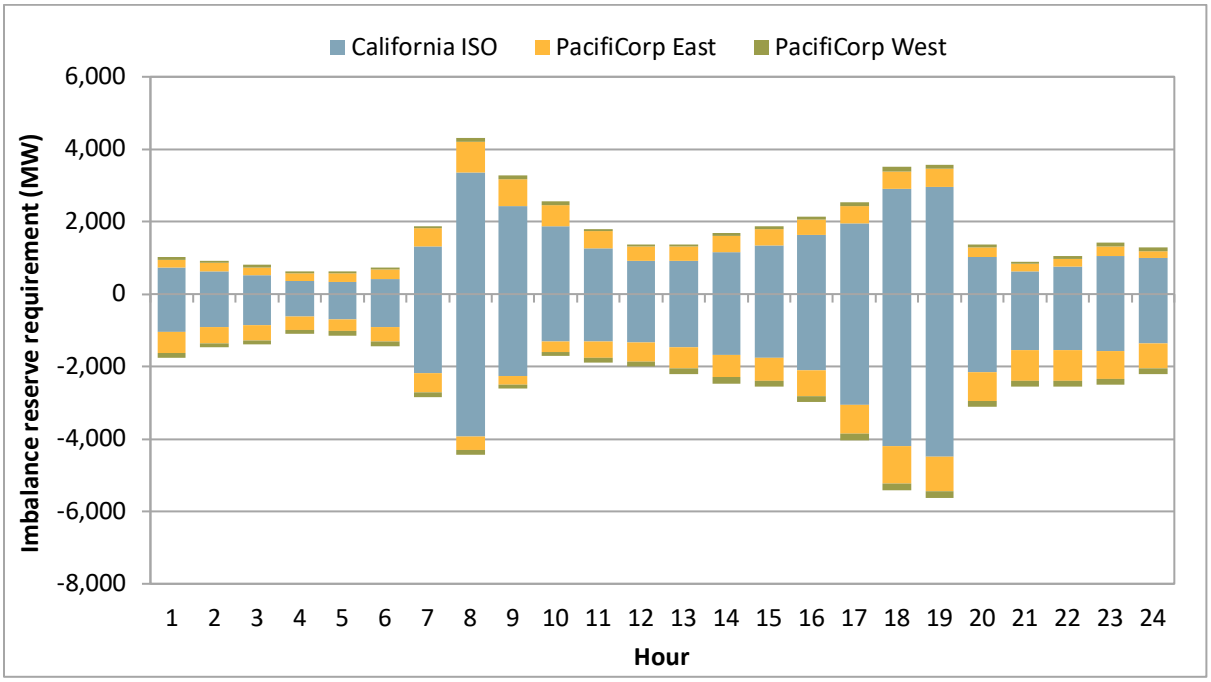
11.1.1 Imbalance reserve requirements

Figure 11.1 shows average imbalance reserve requirements for each balancing area participating in the day-ahead market. These requirements are calculated based on the 10th and 90th percentile of net load uncertainty that may materialize between the day-ahead market and real-time markets.[94] During the third quarter, the California ISO balancing area accounted for roughly 72 percent of total imbalance reserve requirements. Total imbalance reserve requirements were highest in hours 8, 18, and 19. These hours include the morning and evening solar ramp, which typically has the highest levels of uncertainty.

[93] For imbalance reserve, the requirement is calculated based on the 10th and 90th percentile of net load uncertainty. For the flexible ramping product, the requirement is calculated based on the 2.5th and 97.5th percentile of net load uncertainty.

[94] The 10th and 90th percentile for the uncertainty requirements were set as a transitionary measure for the launch of the extended day-ahead market (EDAM) and implementation of day-ahead market enhancements (DAME). These levels may be adjusted at a later date.

Figure 11.1 Imbalance reserve requirements by hour and balancing area (Q3 2026)



11.1.2 Imbalance reserve procurement

Figure 11.2 and Figure 11.3 summarize schedules for upward and downward imbalance reserve by fuel type across all EDAM participating balancing areas. The black line shows the combined California ISO, PacifiCorp East, and PacifiCorp West imbalance reserve requirement. For *upward* imbalance reserves, gas resources made up around 70 percent of the schedules. Battery and hybrid resources combined made up around 12 percent of upward imbalance reserve schedules. For *downward* imbalance reserves, wind and solar resources combined made up around 62 percent of schedules.

Figure 11.4 shows average transfers of upward and downward imbalance reserve between EDAM participating balancing areas. Net import of imbalance reserve is shown as positive and net export of imbalance reserve is shown as negative. The California ISO balancing area was a net exporter of upward imbalance reserve, at around 260 MW on average across all hours, with the recipient being largely PacifiCorp East. The California ISO was also a net exporter of downward imbalance reserve, at around 50 MW on average across all hours, with the recipient being largely PacifiCorp West.

Figure 11.2 Average upward imbalance reserve procurement by fuel type (Q3 2026)

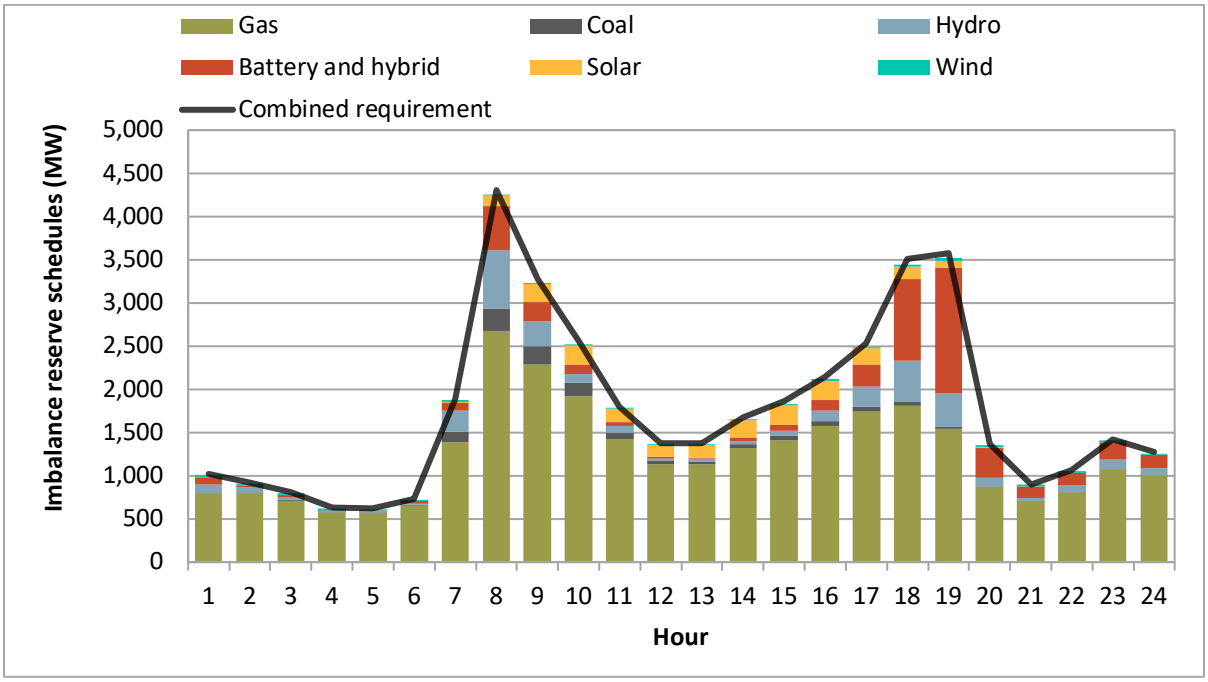


Figure 11.3 Average downward imbalance reserve procurement by fuel type (Q3 2026)

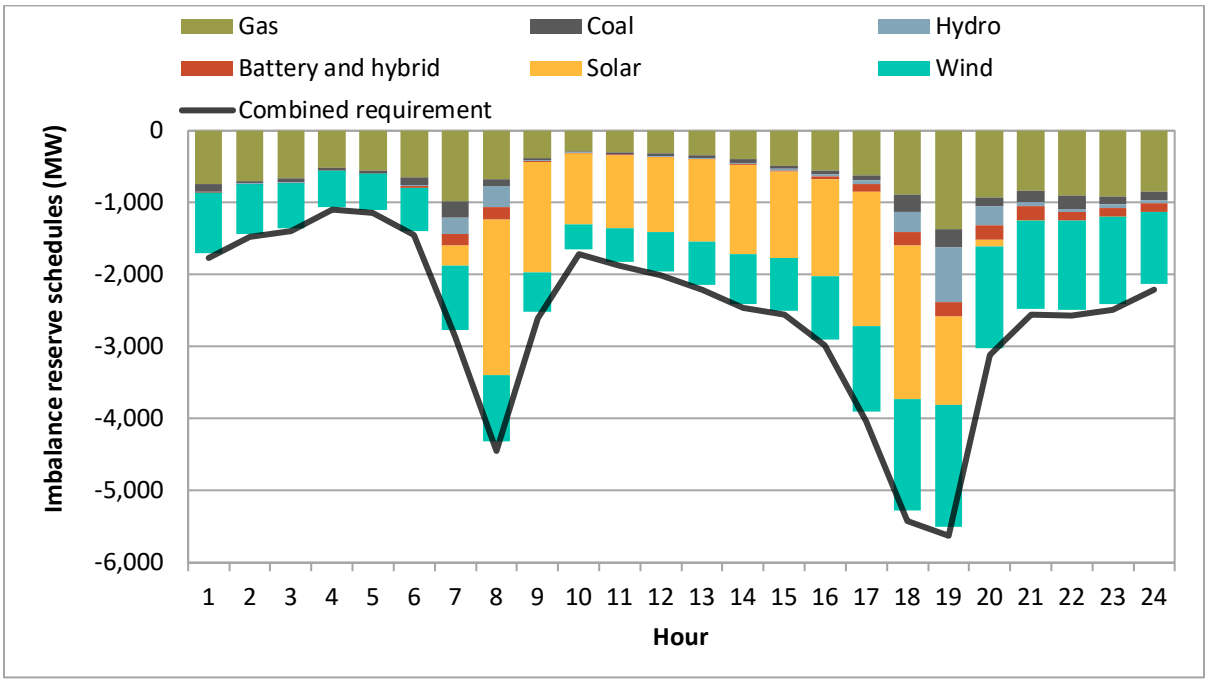
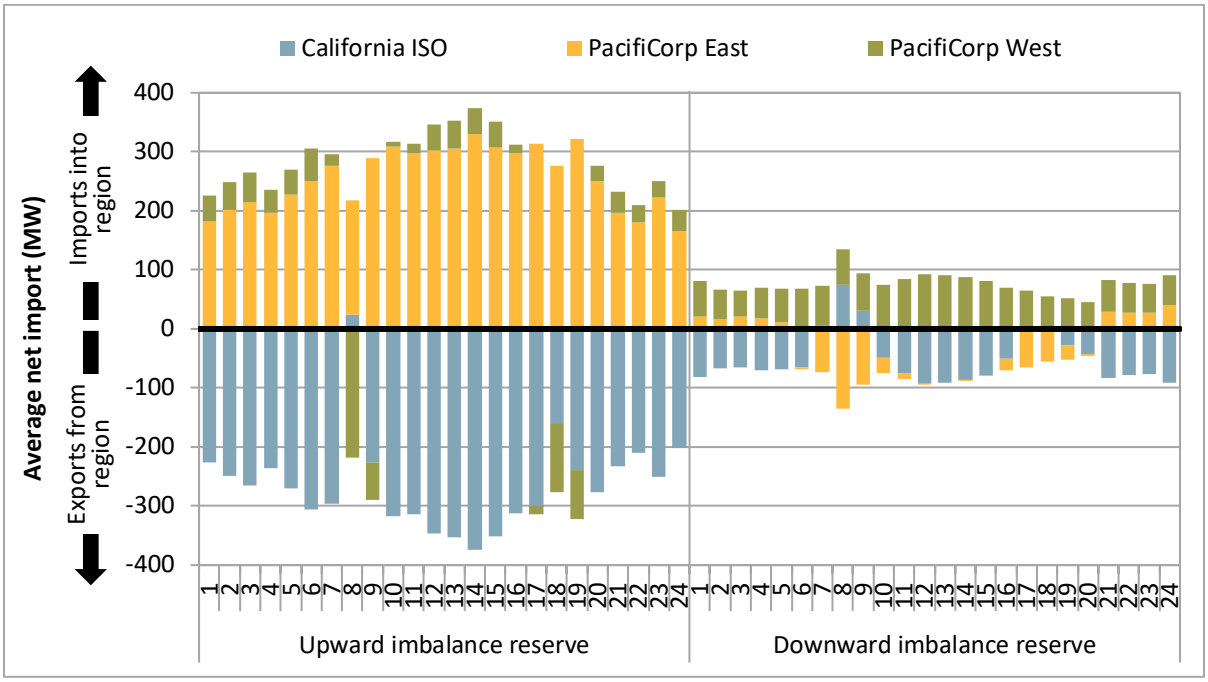


Figure 11.4 Average imbalance reserve transfers by balancing area (Q3 2026)

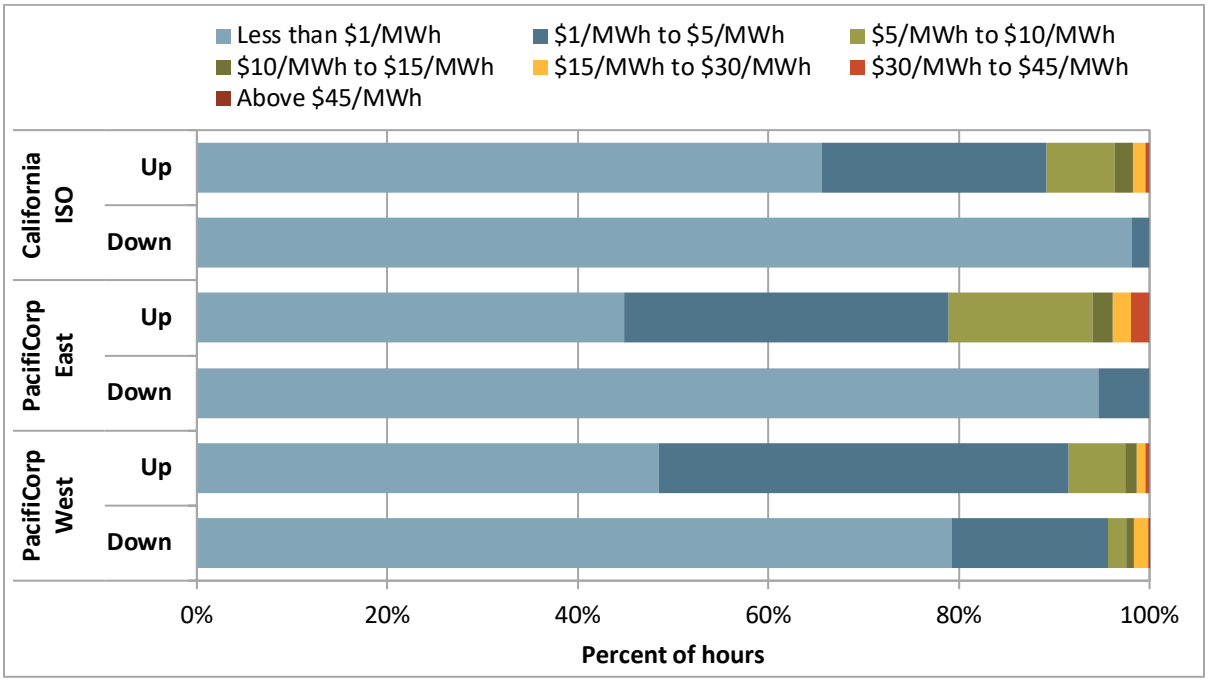


11.1.3 Imbalance reserve prices

For imbalance reserves, the offer cap and demand curve (for any relaxation of the uncertainty requirement) are both capped at $55/MWh. Figure 11.5 summarizes the frequency of imbalance reserve prices by price range for each balancing area.[95] Prices for imbalance reserve have frequently been low or zero. Across all balancing areas and directions, prices have been less than $5/MWh in more than 78 percent of hours and less than $10/MWh in more than 94 percent of hours.

[95] This figure summarizes the shadow price on each balancing area's constraint for procuring imbalance reserve up or down, and does not consider prices that may exist at the nodal level that are the result of internal congestion.

Figure 11.5 Frequency of imbalance reserve prices by price range (Q3 2026)

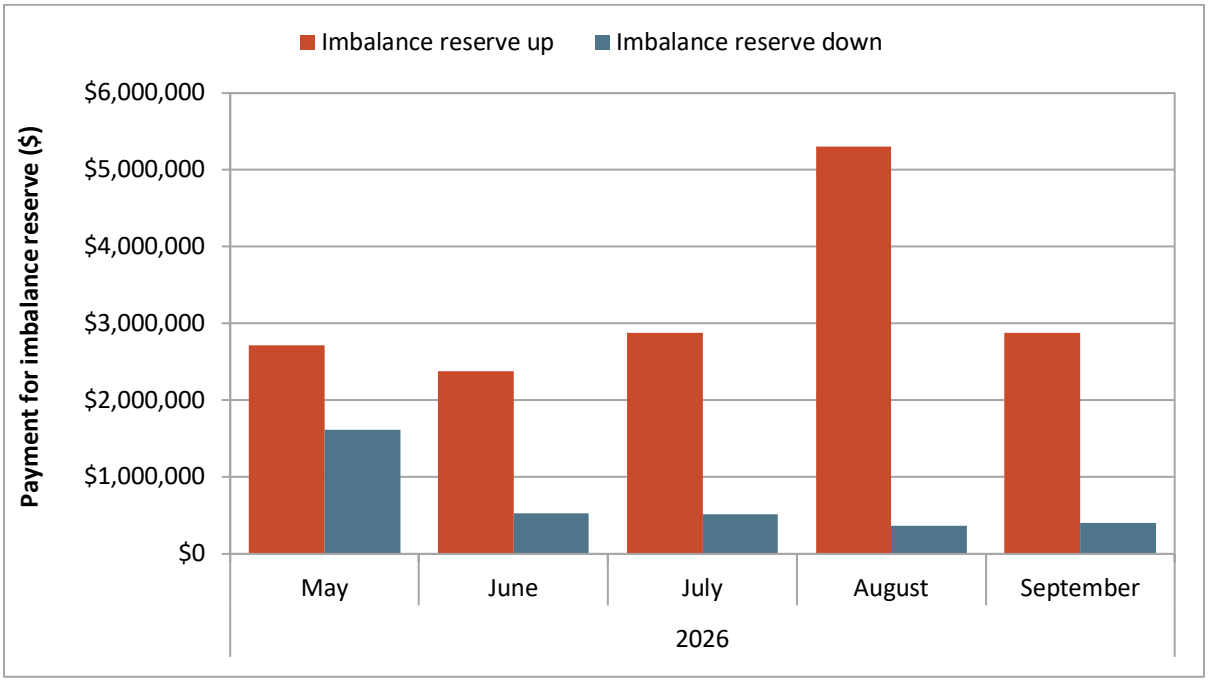


11.1.4 Imbalance reserve settlement

Figure 11.6 shows total monthly payments for imbalance reserve.[96] During the third quarter, payments for upward imbalance reserve were around $11.1 million while payments for downward imbalance reserve were around $1.3 million—or around $12.3 million combined. Upward imbalance reserve payments were highest in August, at around $5.3 million.

[96] This information is based on settlement values available at the time of drafting. Settlement information is subject to updates that can occur within the settlements timeline.

Figure 11.6 Total monthly payments for imbalance reserve by direction



11.2 Flexible ramping product

The flexible ramping product procures and prices flexible capacity in the real-time market. 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.

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.

11.2.1 Flexible ramping product requirements

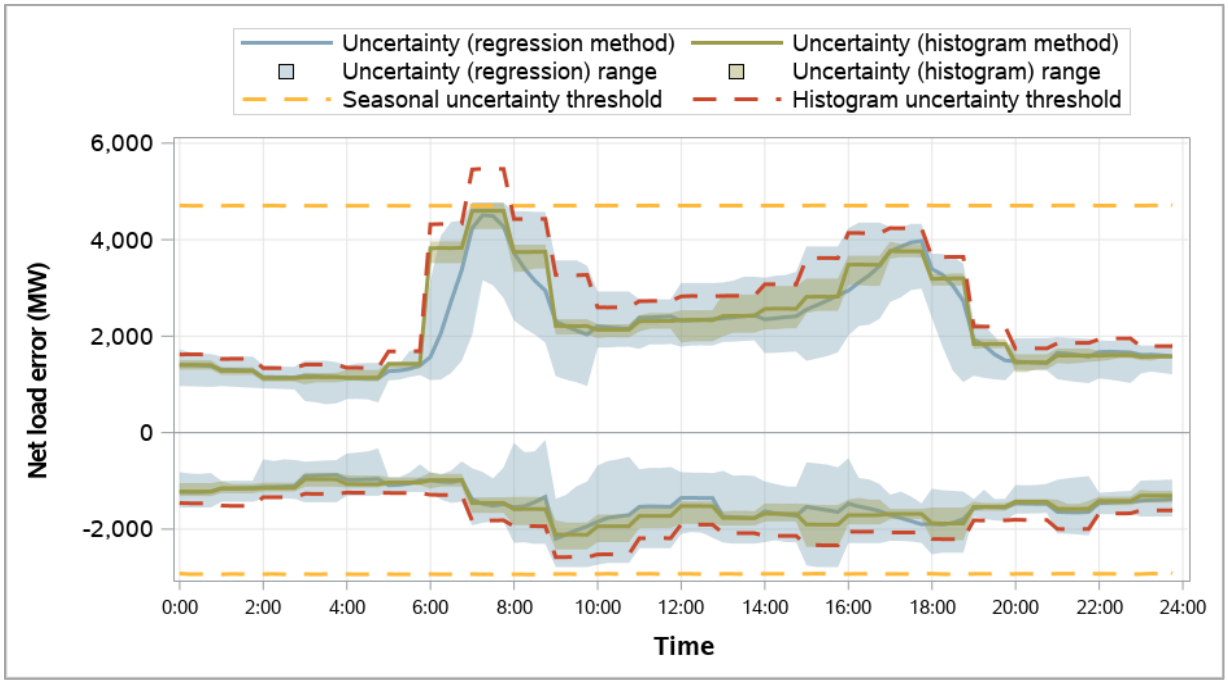
Figure 11.7 shows 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation (RSE), comparing the *mosaic quantile regression* method that is used currently and a simpler *histogram* method (pulled from the 2.5th and 97.5th percentile of observations in

the hour from the historical 180-day period).[97] 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.[98]

Figure 11.8 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.

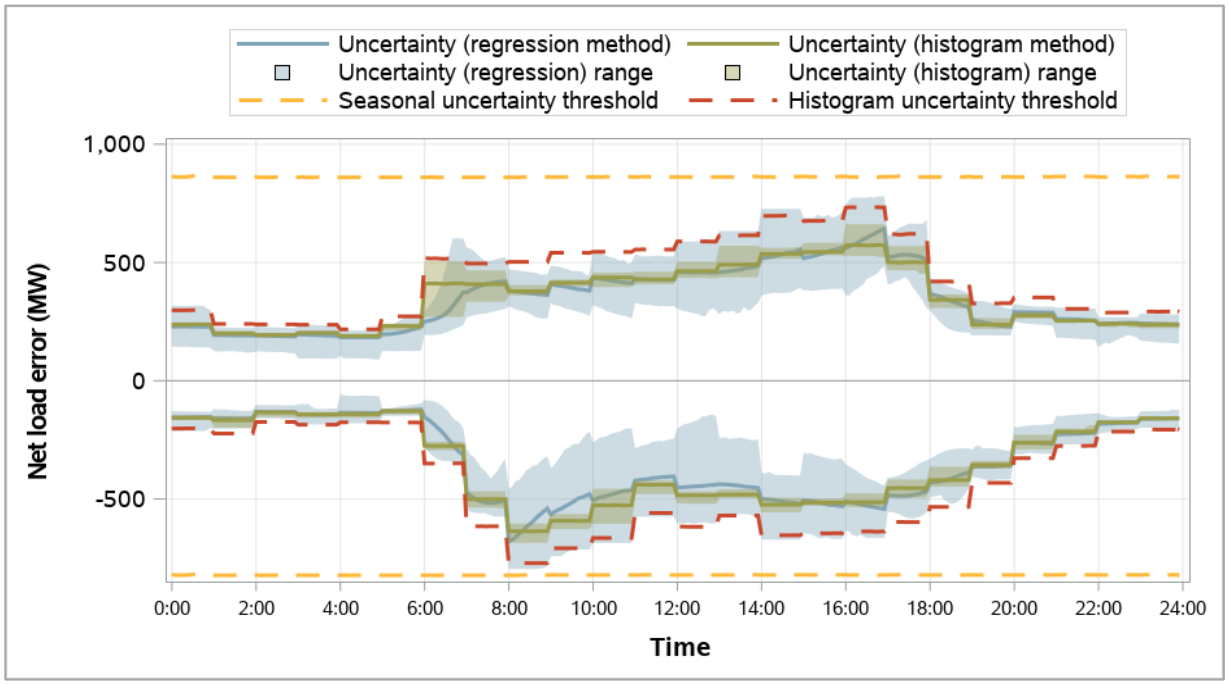
Figure 11.7 15-minute market pass-group uncertainty requirements (Q3 2026)



[97] The ISO uses *mosaic quantile regression* to calculate uncertainty. This applies regression techniques on historical data to produce outputs that are dependent on current forecast conditions. This is compared against the *histogram* method which simply selects the 2.5th and 97.5th percentile observations from the historical data. The histogram method was used prior to the implementation of the regression-based method.

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

Figure 11.8 5-minute market pass-group uncertainty requirements (Q3 2026)



11.2.2 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.[99] 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.[100] 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-

[99] 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

[100] 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.

activated on June 12 due to performance issues with the solution run-times.[101] 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).

The slack variables are implemented for each balancing area.[102] 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.[103] 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.[104] 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 11.9 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.[105] The pass-group constraint for procuring *upward* flexible capacity in both the 15-minute and 5-minute markets was binding in about 0.2 percent or less of intervals on average during the

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101 *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

102 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).

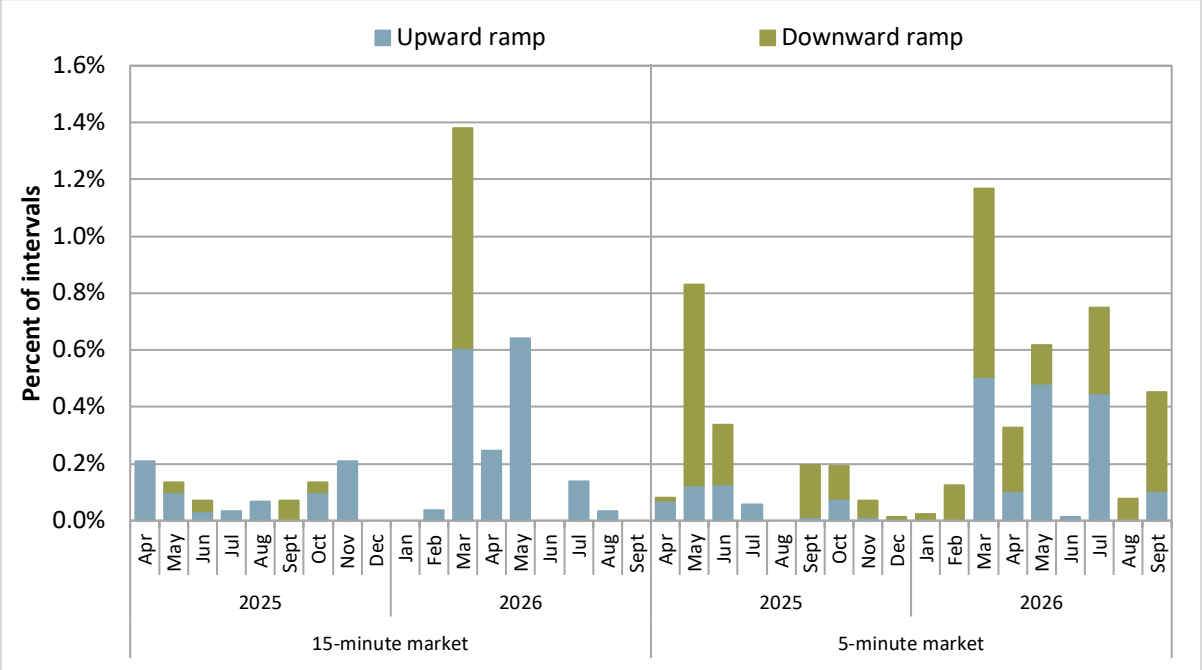
103 For upward flexible capacity, the demand curves are capped at $247/MWh.

104 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.

105 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.

quarter. The pass-group constraint for procuring *downward* flexibility in the 15- and 5-minute markets was also binding very infrequently, in less than 0.3 percent of intervals on average.

Figure 11.9 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 11.10[106] 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 11.9, 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.

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

The frequency of upward flexible ramping product prices has been very low across the pass-group until May of this year. 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 pass-group during about 48 percent of intervals in July 2026, 70 percent of intervals in August 2026, and 70 percent in September 2026. This represents an average of 63 percent of intervals in the third quarter of 2026, up from 0.3 percent in the same quarter of 2025. DMM has notified the ISO of the increase in flexible ramping product prices and will continue to work with the ISO to understand the underlying causes.

Figure 11.10 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

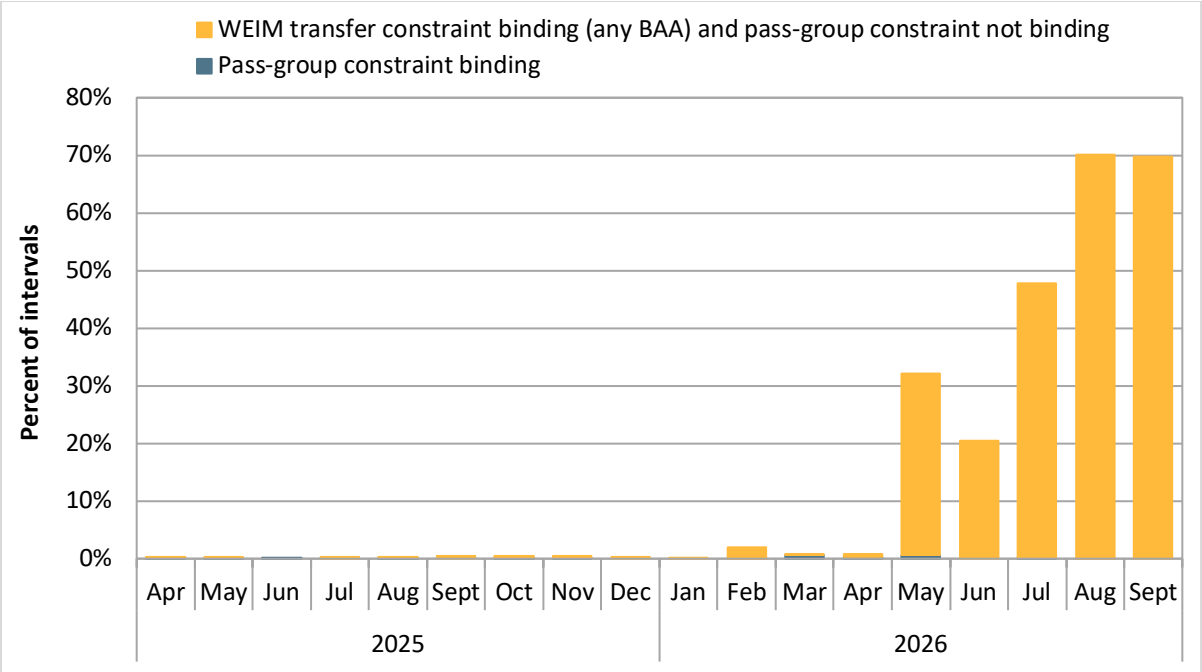


Figure 11.11 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the quarter. These results are shown separately by the constraint contributing to that price:

- **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 11.11.
- **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.

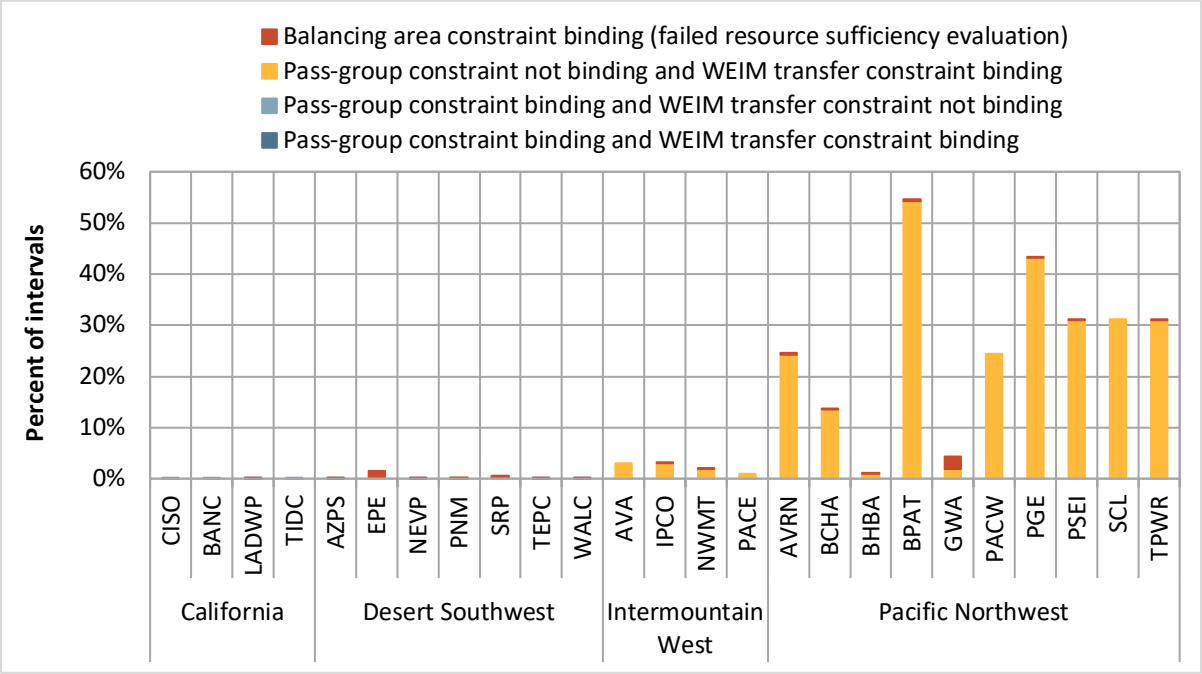
- **Pass-group constraint binding and WEIM transfer constraint not binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group. This is shown in light blue below.
- **Pass-group constraint binding 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 0.1 percent of intervals. Balancing areas across the WEIM failed the resource sufficiency evaluation during around 0.2 percent of intervals overall. 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.[107]

Compared with the third quarter of 2025, balancing areas in the Intermountain West and Pacific Northwest experienced an increase in the frequency of flexible ramping product prices associated with binding WEIM transfer constraints. Balancing areas in the Intermountain West had prices for flexible capacity due to the WEIM transfer constraint binding in about 2 percent of intervals in the third quarter of 2026, up from 0.0 percent of intervals in the same quarter in 2025. Balancing areas in the Pacific Northwest had prices for flexible capacity due to the WEIM transfer constraint binding in about 25 percent of intervals in the third quarter of 2026, up from 0.02 percent of intervals in the same quarter in 2025.

[107] 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.

Figure 11.11 Frequency of upward flexible ramping product prices by balancing area and constraint



11.2.3 Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the group of WEIM balancing areas that passed the resource sufficiency evaluation. Figure 11.12 and Figure 11.13 show the average upward and 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 70 percent of upward flexible capacity and 29 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 11.12 Average upward pass-group flexible ramp procurement by fuel type (15-minute market, Q3 2026)

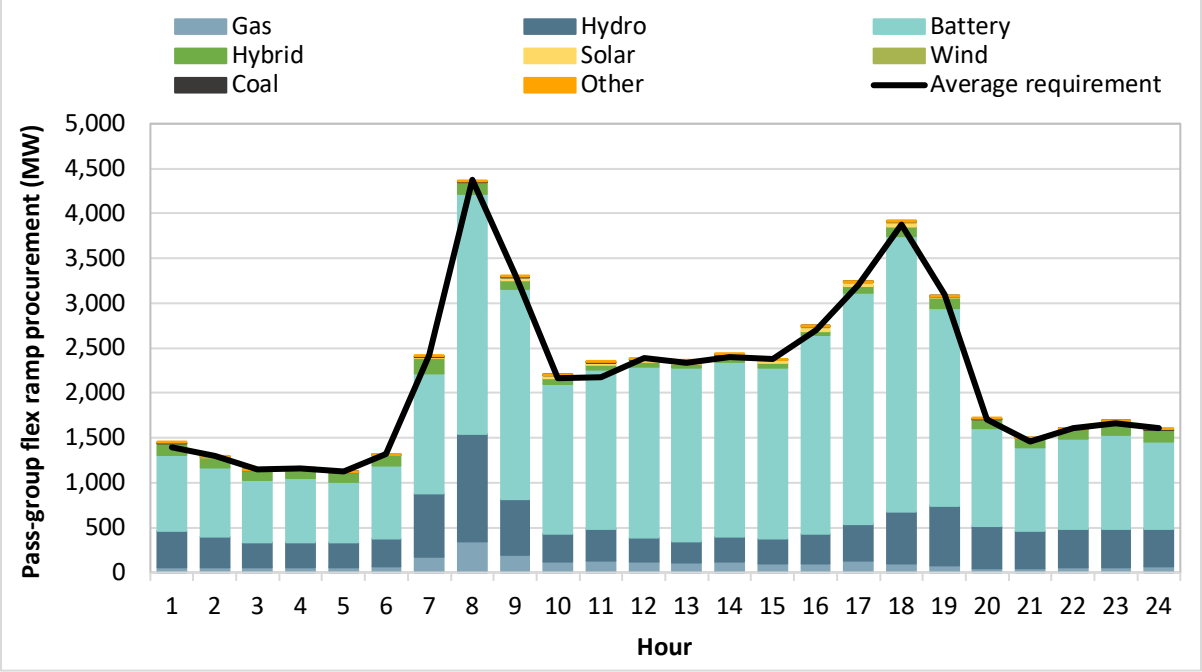


Figure 11.13 Average downward pass-group flexible ramp procurement by fuel type (15-minute market, Q3 2026)

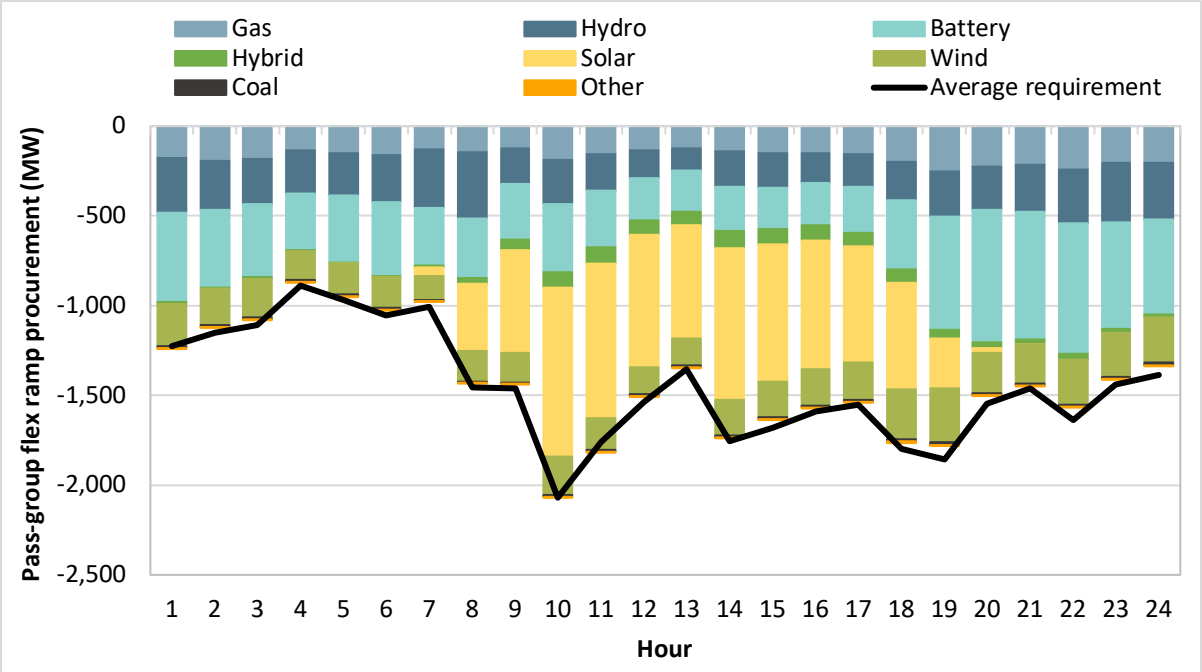
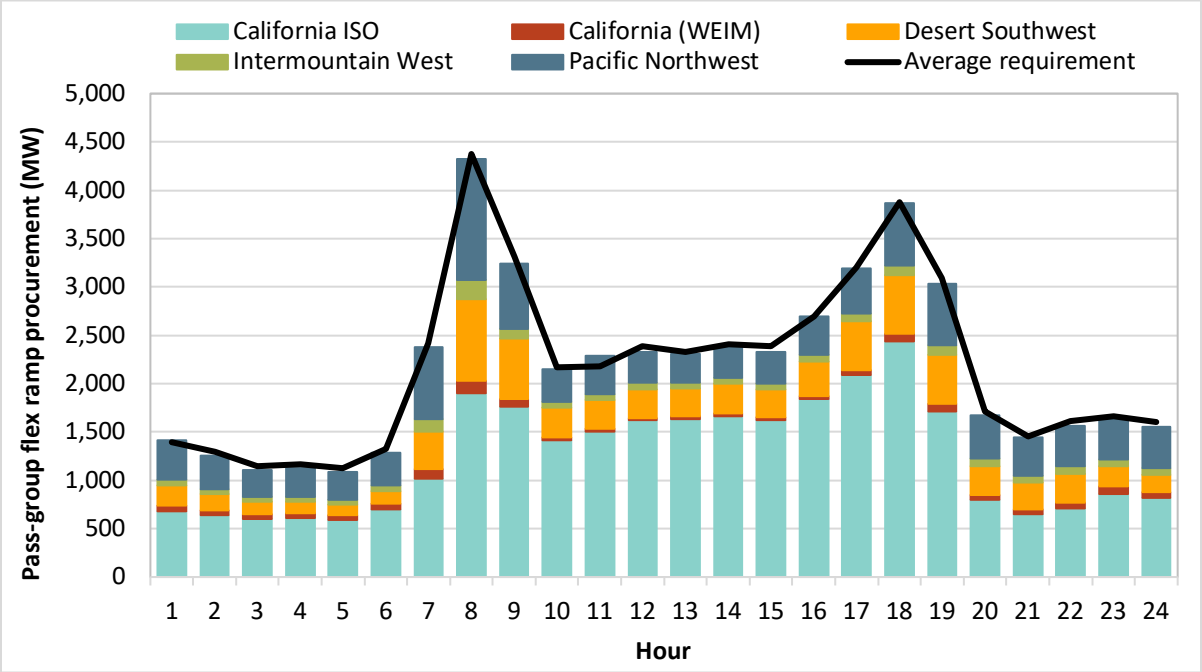


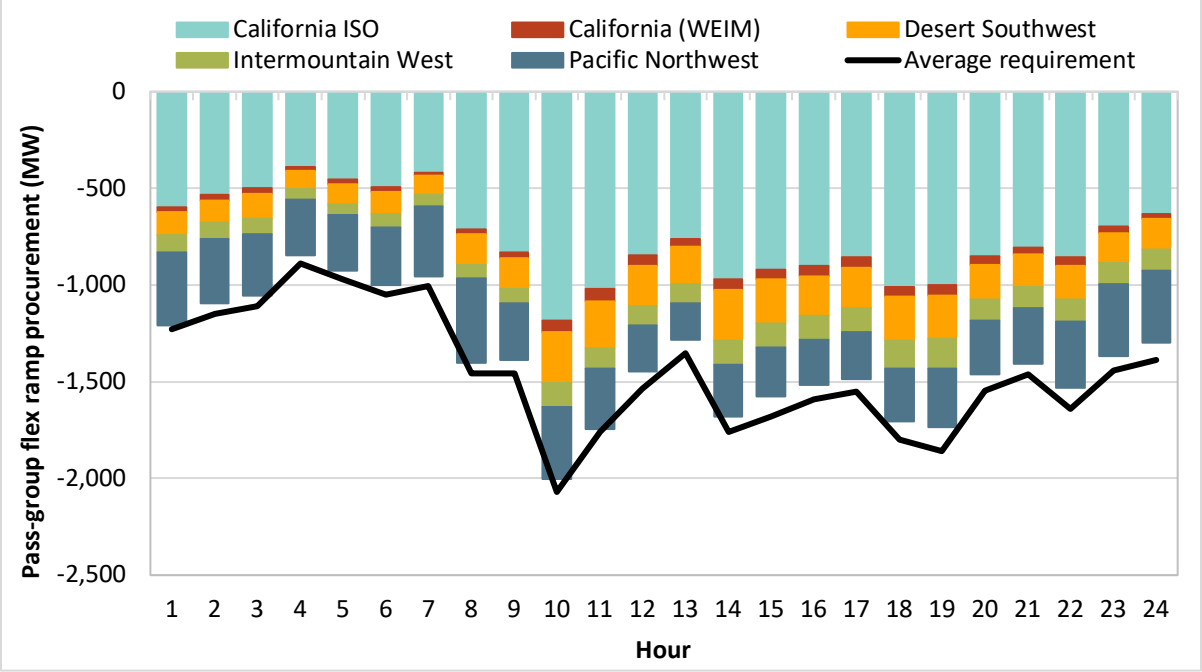
Figure 11.14 and Figure 11.15 show average upward and downward pass-group flexible ramp procurement across the various regions.[108] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import 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 58 percent in the upward direction and 55 percent in the downward direction. Balancing areas in the Desert Southwest made up 15 percent of upward flexible capacity and 13 percent of downward flexible capacity. Balancing areas in the Intermountain West made up 4 percent of upward flexible capacity and 7 percent in the downward direction. The Pacific Northwest made up about 21 percent and 22 percent of upward and downward flexible capacity, respectively.

Figure 11.14 Average upward pass-group flexible ramp procurement by region (15-minute market, Q3 2026)



[108] 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, Avista, Black Hills, and Power Watch. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power.

Figure 11.15 Average downward pass-group flexible ramp procurement by region (15-minute market, Q3 2026)



11.2.4 Flexible ramping product settlement

Variation in net load forecasts creates a demand for real-time ramp. This can be split up into two components: (1) the amount of ramp needed to meet the expected net load forecast in the next interval of the same market run ("forecasted movement") and (2) additional ramping capability that may be needed if the net load forecast materializes higher or lower in a subsequent market run ("uncertainty"). The flexible ramping product pays resources for both.

Flexible ramping capacity awards reflect the ability for a resource to ramp above or below their expected schedule in the next interval to address uncertainty that might materialize. Flexible ramping capacity that satisfies the demand for upward or downward flexibility receives payments based on the price for flexible capacity at that node. In addition, the flexible ramping product price is used to pay or charge for forecasted movements. Forecasted movement is a resource's expected change in schedule in the next interval.[109] A payment indicates that the resource was given an advisory dispatch by the market in the same direction as the demand for flexibility (i.e., supporting flexibility). A charge indicates that the resource was given an advisory dispatch by the market in the opposite direction as the demand for flexibility (i.e., consuming flexibility).

[109] Base WEIM transfers (fixed bilateral transactions between two WEIM entities) are excluded from the forecasted movement settlement. All other generation and intertie schedules (non-WEIM) are paid or charged for forecasted movement based on their expected change in schedule in the next interval. For more information, see DMM's 2025 First Quarter Report on Market Issues and Performance: https://www.caiso.com/documents/2025-first-quarter-report-on market-issues-and-performance-jun-23-2025.pdf

Figure 11.16 shows the total monthly net payments to resources from the flexible ramping product, including both payments for flexible ramping capacity to meet upward and downward uncertainty as well as payments for forecasted movements. Payments associated with the flexible ramping product were $8.3 million during the third quarter of 2026 after accounting for forecasted movement, up significantly from around $1.4 million in the same quarter of 2025. Much of this increase was from upward uncertainty ($5.2 million in Q3 2026 compared to $0.6 million in Q3 2025).

Figure 11.17 shows the same information, except without the payments for forecasted movement and split out by WEIM region. This therefore only shows the payments to generators for upward and downward ramping capacity to meet uncertainty needs. Most of the payments for uncertainty in the third quarter were to resources in the Pacific Northwest region. As shown in the previous sections, flexible ramping product prices were highest in the Pacific Northwest because of binding WEIM transfer constraints, resulting in higher prices in this region, relative to the rest of the WEIM system.

Figure 11.16 Monthly flexible ramping product payments by type

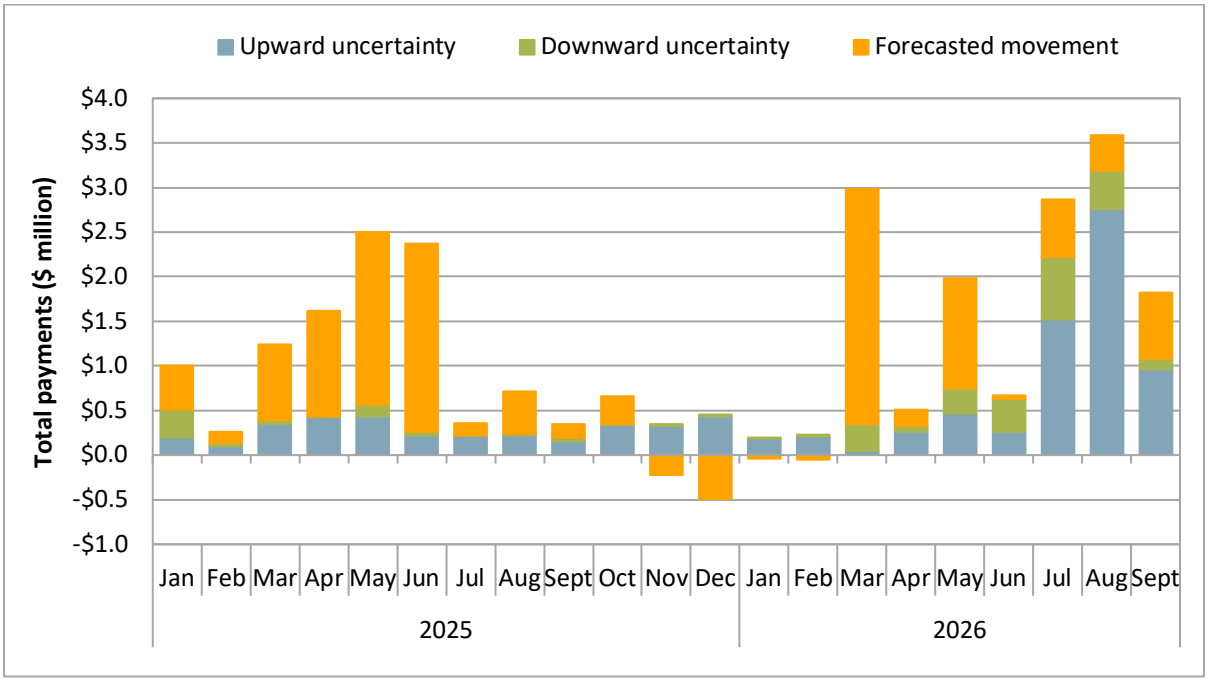
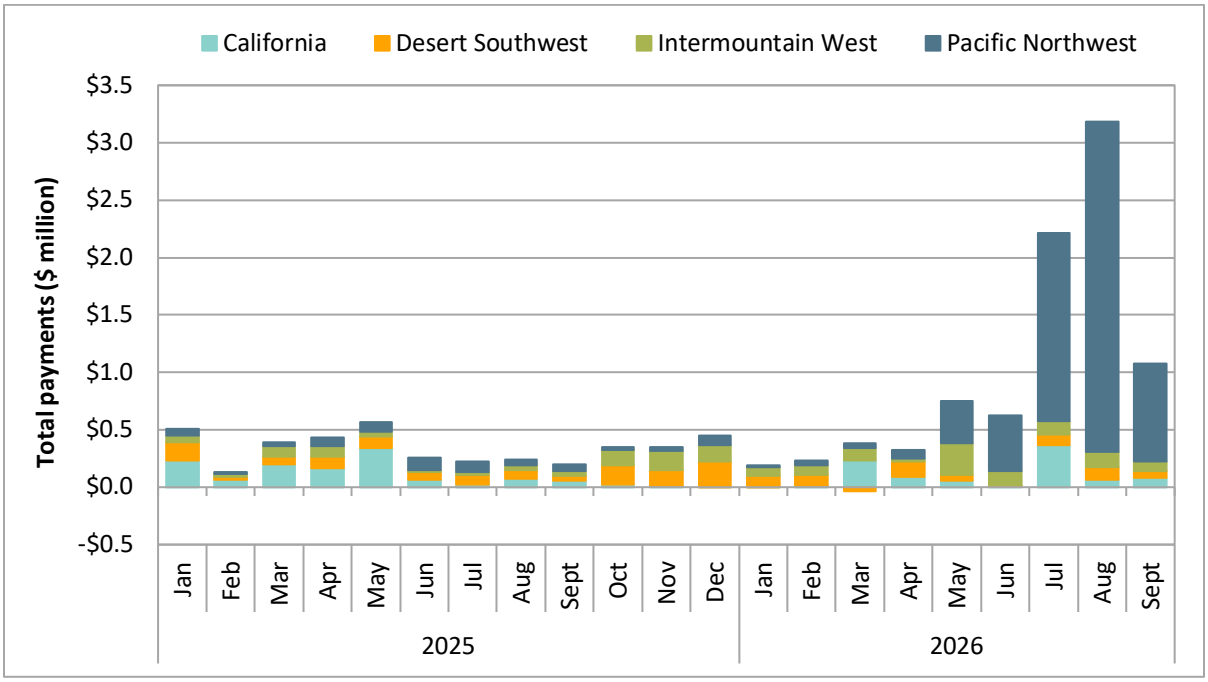


Figure 11.17 Monthly flexible ramping product uncertainty payments by region



11.3 Uncertainty calculation and assessments

This section discusses uncertainty considered in different applications of the market. This includes the EDAM resource sufficiency evaluation (EDAM RSE) and imbalance reserve product in the day-ahead market, and the WEIM resource sufficiency evaluation (WEIM RSE) and flexible ramping products (FRP) in the real-time markets. Because net load uncertainty can be highly variable and difficult to interpret directly, this section presents basic statistics and distributions to provide context for the characteristics of uncertainty observed in the market.[110]

11.3.1 Imbalance reserve and EDAM resource sufficiency evaluation uncertainty

The imbalance reserve product procures flexible capacity in the day-ahead market to cover net-load uncertainty that may materialize in the real-time market. Uncertainty is measured as the difference between the 15-minute market net-load forecast and the corresponding day-ahead net-load forecast,

[110] Uncertainty represents conditions that are not known at the time of the market run and only materialize in future operating intervals. To account for this uncertainty, the ISO uses Mosaic Quantile regression to estimate the range of uncertainty that may materialize.

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 load uncertainty*, November 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

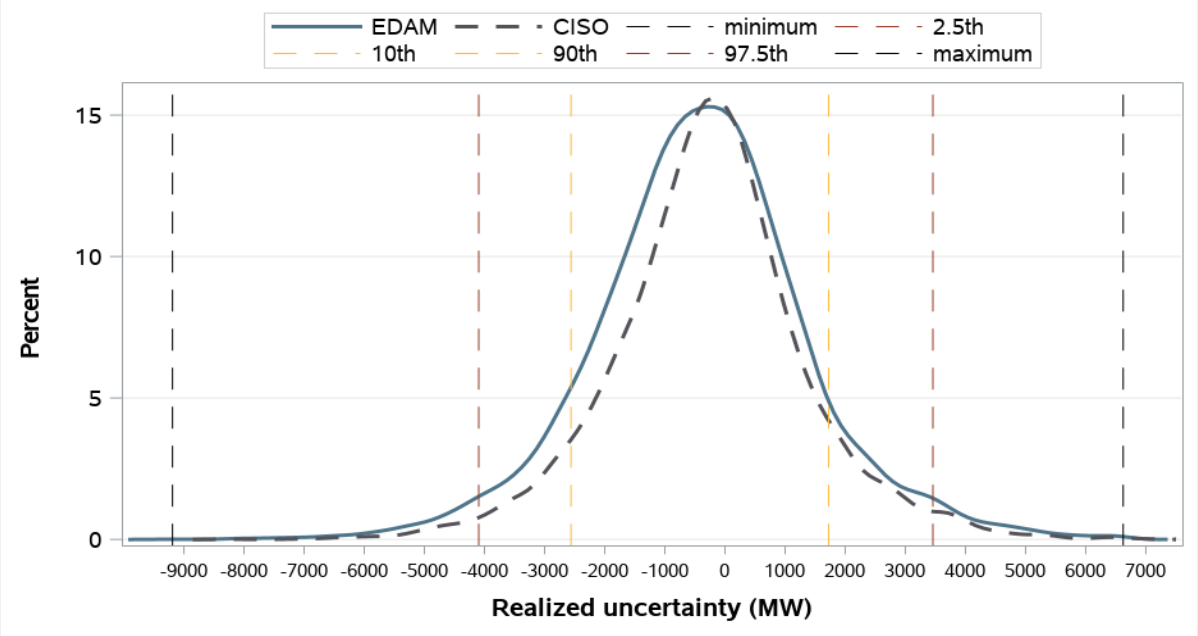
where net load is demand minus wind and solar generation. Upward and downward requirements reflect the upper and lower portions of the forecast-error: imbalance reserve up addresses the higher-end of the uncertainty while imbalance reserve down addresses the lower-end of the uncertainty. The CAISO balancing area uses the same definition of uncertainty to determine the additional reliability capacity that may need to be procured through the residual unit commitment process.

Because the actual uncertainty is not known at the time of the market run, the ISO uses the mosaic quantile regression to estimate the uncertainty in advance and establish the imbalance reserve requirement. The EDAM resource sufficiency evaluation requirement includes an uncertainty component in addition to each balancing area's load forecast. The ISO uses the same definition of uncertainty and regression method to determine both the EDAM RSE uncertainty component and the upward imbalance reserve product uncertainty. Figure 11.18 shows the uncertainty that ultimately materialized in the market, which is the uncertainty the imbalance reserve and EDAM RSE requirement is intended to cover.

Figure 11.18 shows the distribution of realized uncertainty between the net-load forecasts of the day-ahead market and the 15-minute market in this quarter. This distribution represents all uncertainties observed in the 15-minute market intervals for this quarter and serves as the forecasting target. The blue line represents aggregate uncertainty across all EDAM entities. Vertical reference lines indicate the minimum, maximum, and selected percentiles of EDAM uncertainty.

The EDAM net-load uncertainty in the day-ahead time horizon ranged from -9,200 MW to 6,600 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 and from the 2.5th percentile to the minimum value. These areas ranged from 3,500 MW to 6,600 MW on the positive side and from about -4,100 MW to -9,200 MW on the negative side. The distribution is strongly skewed downward. This indicates that 15-minute net-load came in below the day-ahead forecast. 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.

Figure 11.18 Distribution of realized uncertainty between RUC and 15-minute market net-load forecasts (July–September 2026)



11.3.2 Flexible ramping product uncertainty

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.

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 11.19 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 third quarter of 2026. 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 3,000 MW to over 8,300 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.

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 11.19 Distribution of realized uncertainty in FRP (pass-group, July-September 2026)

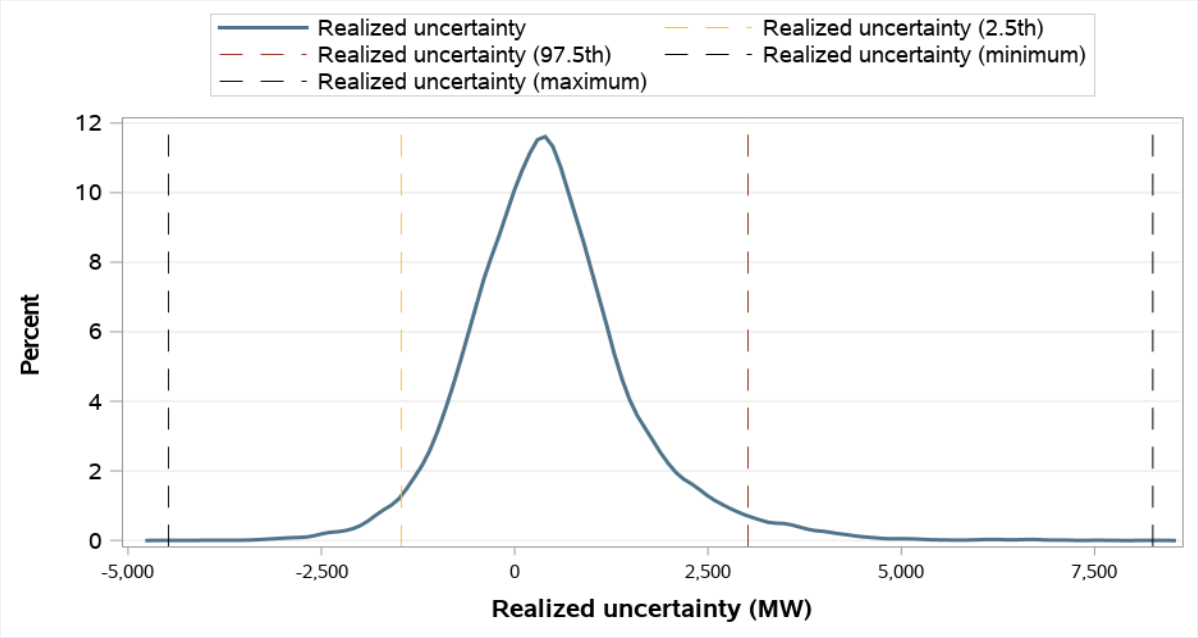


Table 11.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the 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.[111]

[111] 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.

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.[112] Uncertainty forecasted by mosaic regression method generally had lower requirements. Coverage was about the same.

Table 11.1 Average pass-group uncertainty requirements (Q3 2026)

		Requirement			Coverage		
Market	**Direction**	**Histogram**	**Mosaic**	***Difference***	**Histogram**	**Mosaic**	***Difference***
15-minute market	Up	2,294	2,186	-109	96.6%	96.6%	0.0%
	Down	1,491	1,449	-41	97.8%	98.0%	0.1%
5-minute market	Up	351	344	-8	97.2%	97.1%	-0.1%
	Down	350	339	-11	97.2%	97.3%	0.1%

11.3.3 WEIM resource sufficiency evaluation uncertainty

Uncertainty is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the WEIM 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.[113] 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 WEIM resource sufficiency evaluation.

Figure 11.20 shows the distribution of realized 15-minute uncertainty in the WEIM RSE for each balancing authority area (BAA) for the third quarter of 2026. Here, realized uncertainty is defined as the net-load forecast difference between the forecasts used in the WEIM 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.[114] This eliminates scale issues and allows for a clear assessment of relative volatility in realized uncertainty among BAAs.

[112] 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 25 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.

[113] 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.

[114] 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.

Figure 11.20 Standardized realized uncertainty for RSE (July–September 2026)

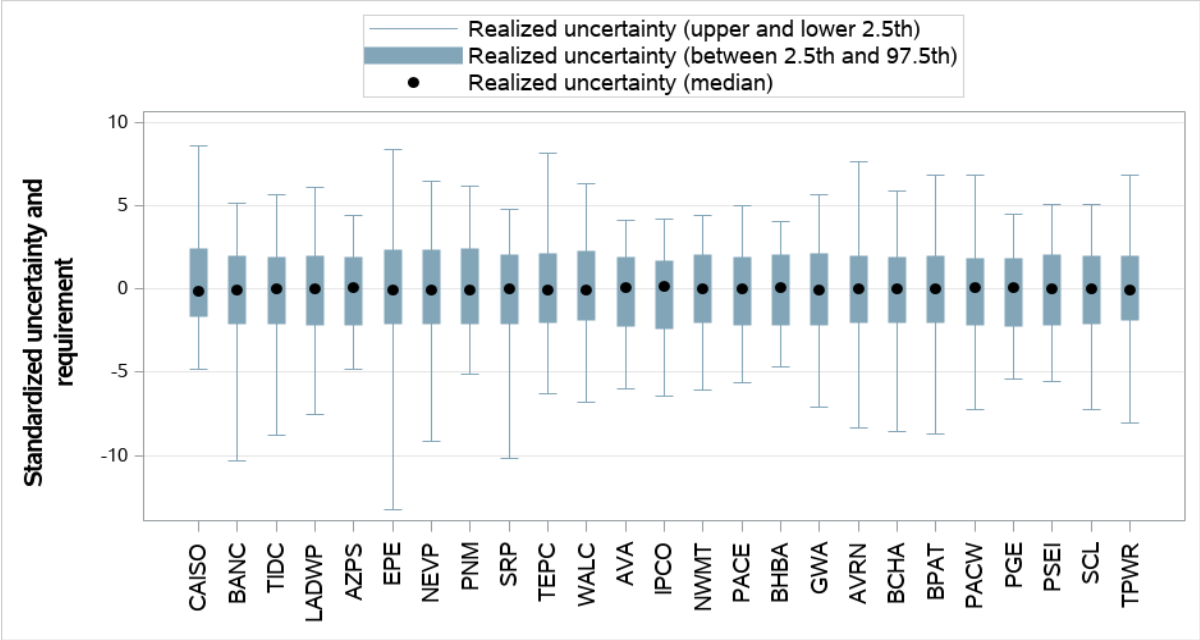


Figure 11.20 provides a comparison of the realized uncertainty across different BAAs for this quarter. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 2.5th percentile to the minimum value of realized uncertainty. The circle markers show the median realized uncertainty.

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.

Table 11.2 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 uncertainty requirements for the same interval.[115]

In the WEIM RSE, the mosaic regression method resulted in coverage levels for individual balancing areas largely below the 95 percent target. This is mostly due to a disparity with the underlying data used

[115] The EDAM up and EDAM down groups are only assessed in one direction. Coverage for the EDAM up group is instead measured as the percent of intervals in which the realized uncertainty was below the upward uncertainty requirement; or above the downward uncertainty requirement for the EDAM down group (97.5 percent target).

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 all of the WEIM entities. The WEIM RSE uncertainty calculated from the regression method covered between 87 and 94 percent of realized uncertainty across individual balancing areas. The upward EDAM group was covered in 91 percent of intervals using the regression method while the downward EDAM group was covered in 97 percent of intervals.

Table 11.2 Average resource sufficiency evaluation uncertainty requirements and coverage (Q3 2026)

	Upward uncertainty			Downward uncertainty			Coverage		
Balancing area or group	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference
EDAM up group	1,822	1,683	-140				93%	91%	-2%
EDAM down group				1,034	1,019	-16	97%	97%	0%
Arizona Public Service	365	326	-39	460	380	-80	94%	91%	-3%
Avangrid	203	188	-14	187	162	-25	94%	94%	0%
Avista	59	55	-4	66	63	-3	91%	90%	-1%
BANC	54	57	3	53	55	2	93%	93%	0%
Black Hills	76	67	-9	95	94	-1	93%	91%	-2%
Bonneville Power Admin.	233	220	-13	254	236	-17	95%	94%	-1%
El Paso Electric	69	69	0	57	55	-2	87%	87%	0%
Idaho Power	157	148	-9	217	192	-25	92%	92%	-1%
LADWP	172	154	-18	152	150	-3	94%	93%	-1%
NorthWestern Energy	76	73	-3	86	76	-10	93%	91%	-2%
NV Energy	313	292	-21	252	248	-3	92%	93%	1%
Portland General Electric	119	116	-3	134	132	-3	93%	92%	-1%
Powerex	143	137	-6	153	147	-6	93%	92%	-1%
Power Watch	70	37	-33	70	69	-1	91%	89%	-2%
PNM	235	218	-17	226	212	-15	92%	91%	0%
Puget Sound Energy	158	136	-23	156	151	-5	92%	91%	-1%
Salt River Project	188	178	-9	160	153	-6	89%	88%	0%
Seattle City Light	17	15	-1	16	15	-1	93%	91%	-2%
Tacoma Power	10	10	0	10	9	-1	93%	91%	-2%
Tucson Electric Power	137	123	-14	94	85	-9	92%	91%	-2%
Turlock Irrigation District	7	7	0	9	9	0	90%	90%	0%
WAPA Desert Southwest	60	64	4	42	46	4	85%	87%	3%

WEIM RSE uncertainty special issue — time horizon for predicting uncertainty

The regression model used for the WEIM 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 WEIM resource sufficiency evaluation includes four intervals, typically produced between 47.5 and 102.5 minutes before real-time.

The WEIM 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.[116] This data is based on the difference from advisory forecasts in the 15-minute market to the

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

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 WEIM resource sufficiency evaluation occurs over a different timeframe than what is considered for procuring 15-minute market flexible capacity. Figure 11.21 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 WEIM resource sufficiency evaluation.[117] For the flexible ramping product, the calculation is designed to capture uncertainty that may materialize around a single upcoming (advisory) interval. However, the WEIM 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 WEIM 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 WEIM 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 WEIM 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.[118]

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the WEIM resource sufficiency evaluation. Figure 11.22 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 WEIM 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.

[117] The figure shows the time horizon for the WEIM 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.

[118] The WEIM 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 WEIM resource sufficiency evaluation is combined with the short-term regression coefficients.

Figure 11.21 Comparison of timeframe considered for the flexible ramping product and WEIM resource sufficiency evaluation

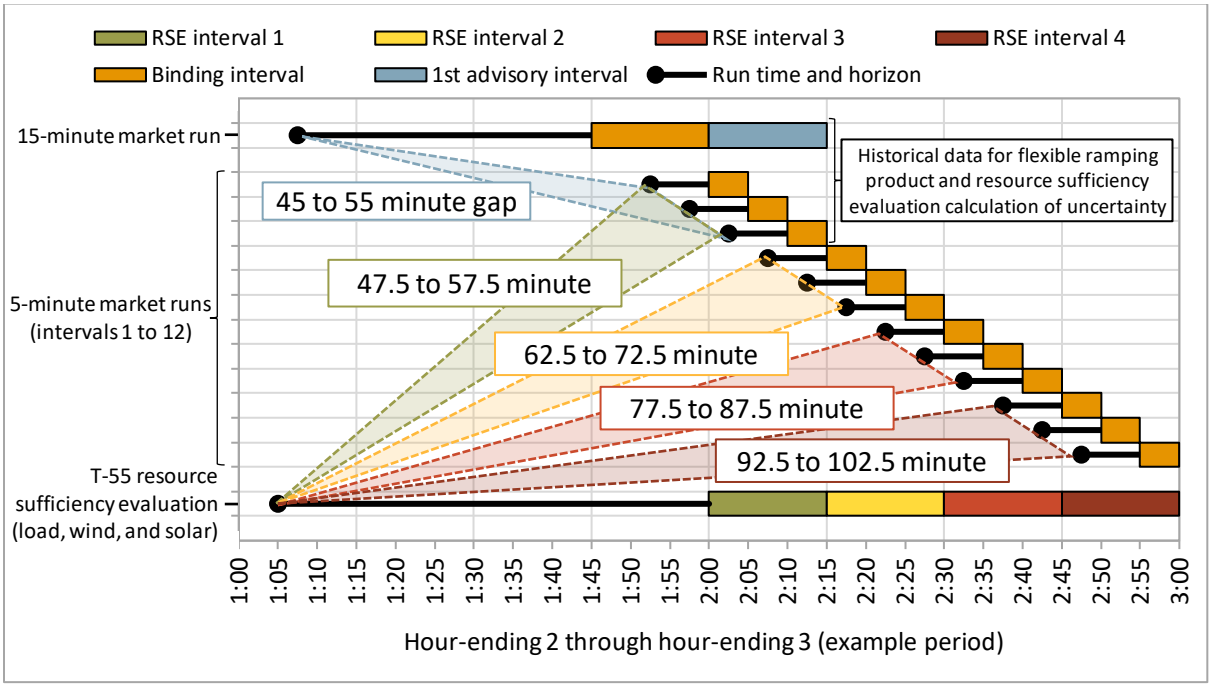
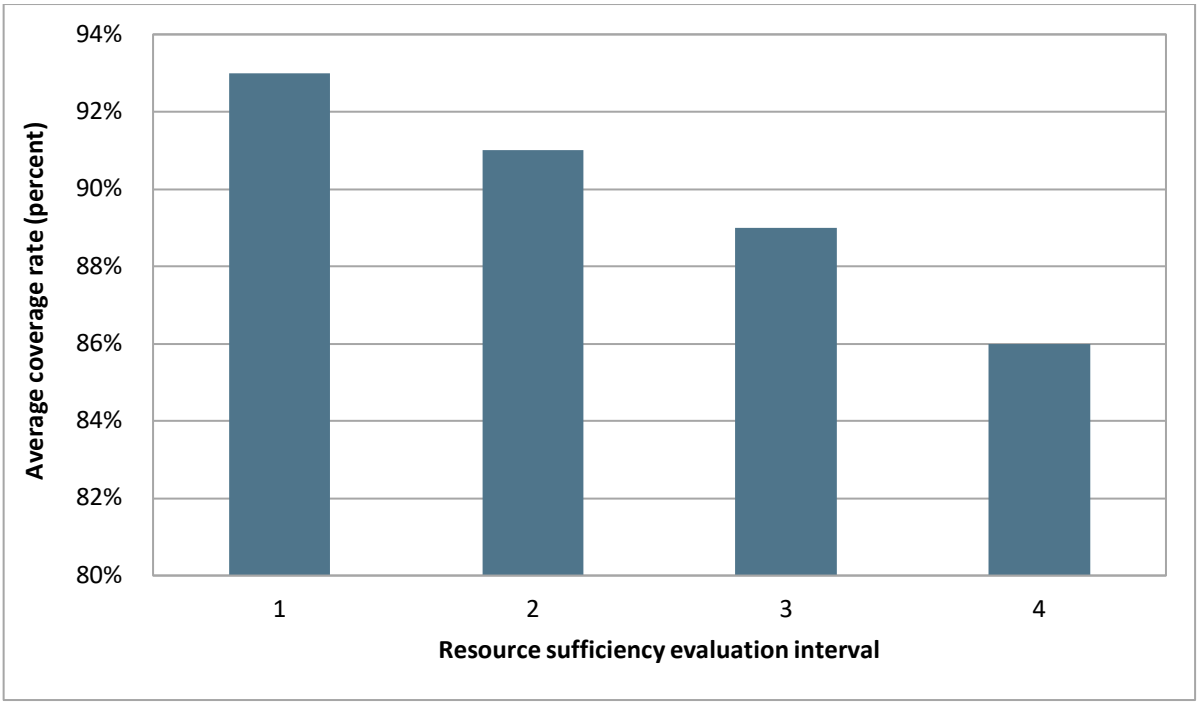


Figure 11.22 Average coverage rate by WEIM resource sufficiency evaluation interval (Q3 2026)



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 third quarter of 2026 to the third quarter of 2025, incremental manual dispatch energy from participating resources (yellow bars) showed mixed trends, increasing in the Pacific Northwest and Desert Southwest by 37 percent and 8 percent, respectively, while decreasing in the Intermountain West and California regions by 45 percent and 42 percent, respectively. Similarly, when comparing the third quarter to the same quarter in 2025, incremental manual dispatch energy from non-participating resources (red bars) decreased in the Desert Southwest and Pacific Northwest regions by 10 percent and 5 percent, respectively, while the Intermountain West region increased by nearly 200 percent.

From the third quarter of 2025 to the third quarter of 2026, decremental manual dispatch energy from participating resources (green bars) increased in both the Desert Southwest and California regions by 55 percent and 10 percent, respectively. The Intermountain West and Pacific Northwest regions decreased by 38 percent and 26 percent, respectively. When comparing the third quarter of 2026 to the same quarter in 2025, decremental manual dispatch energy from non-participating resources (blue bars) decreased in the Desert Southwest by 37 percent, remained unchanged in the Pacific Northwest, and increased in the Intermountain West by about 190 percent.

Overall, combined incremental and decremental manual dispatch energy increased by 27 percent in the Desert Southwest region. Combined manual dispatch energy in the California (non-CAISO), Intermountain West, and Pacific Northwest regions decreased by 24 percent, 13 percent, and two percent, respectively.

Figure 12.1 WEIM manual dispatches – California

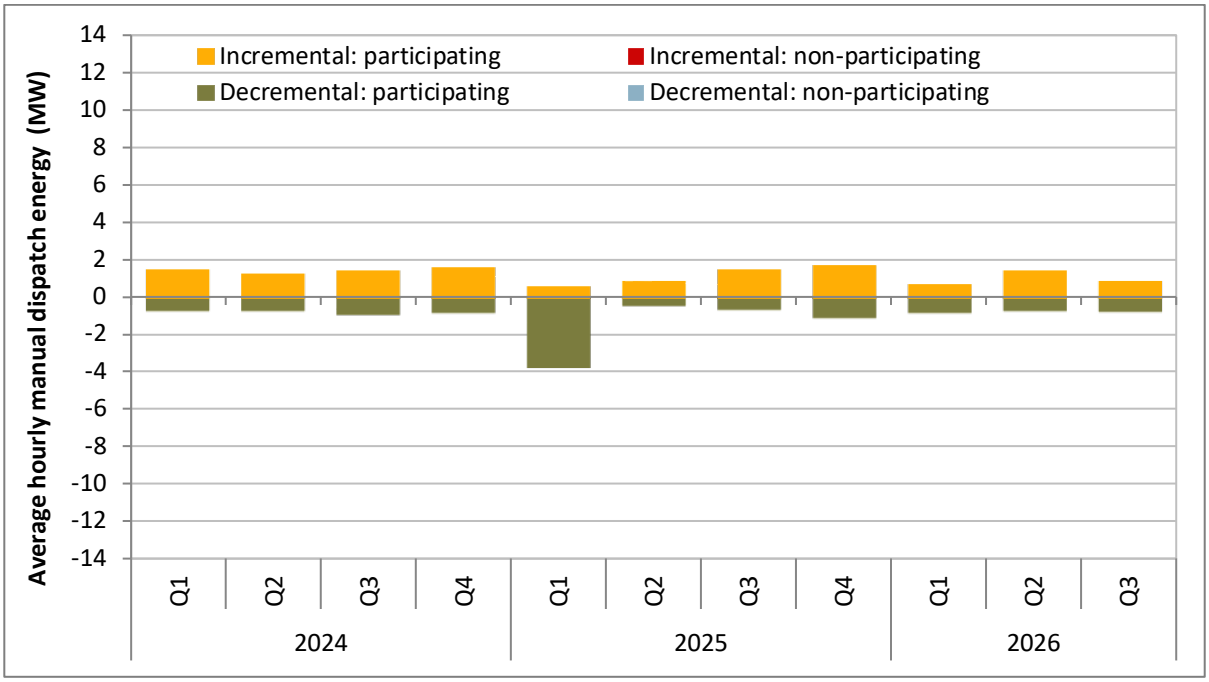


Figure 12.2 WEIM manual dispatches – Desert Southwest

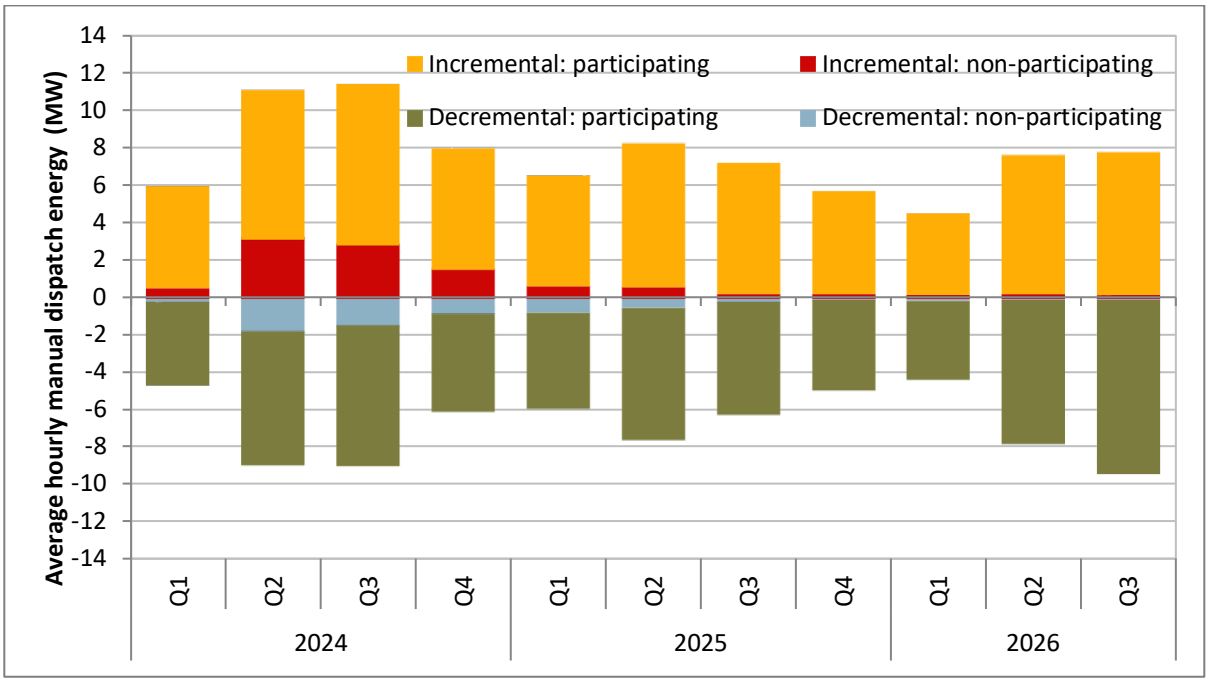


Figure 12.3 WEIM manual dispatches – Intermountain West

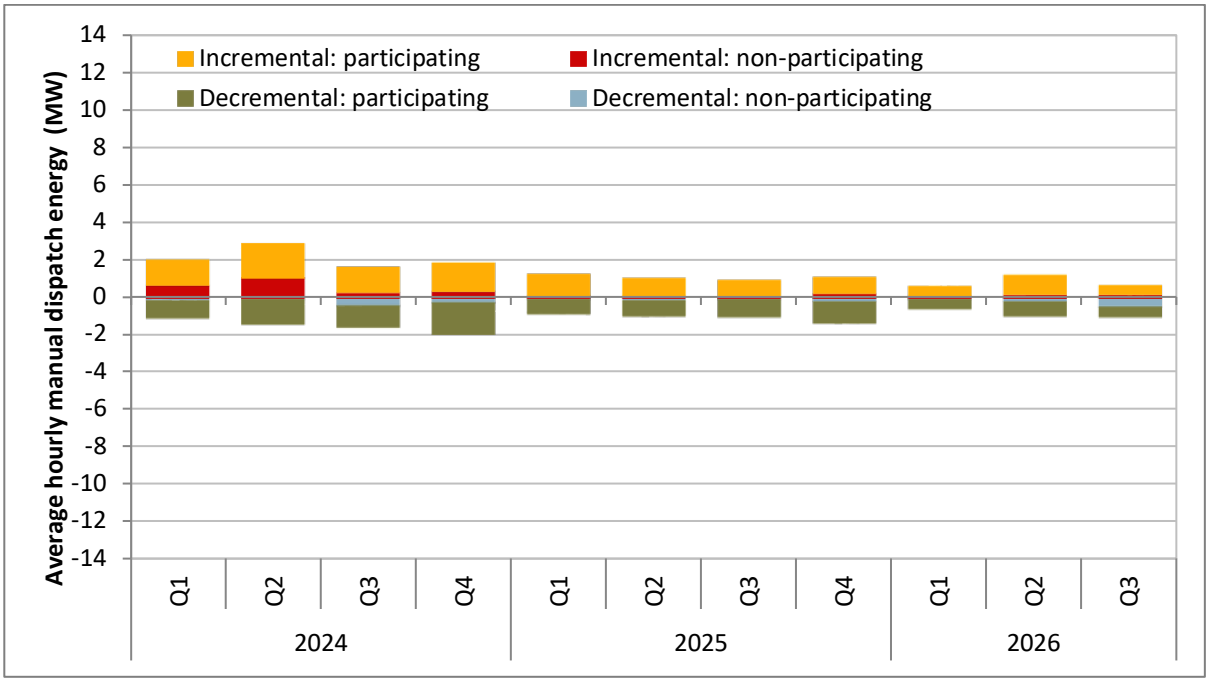
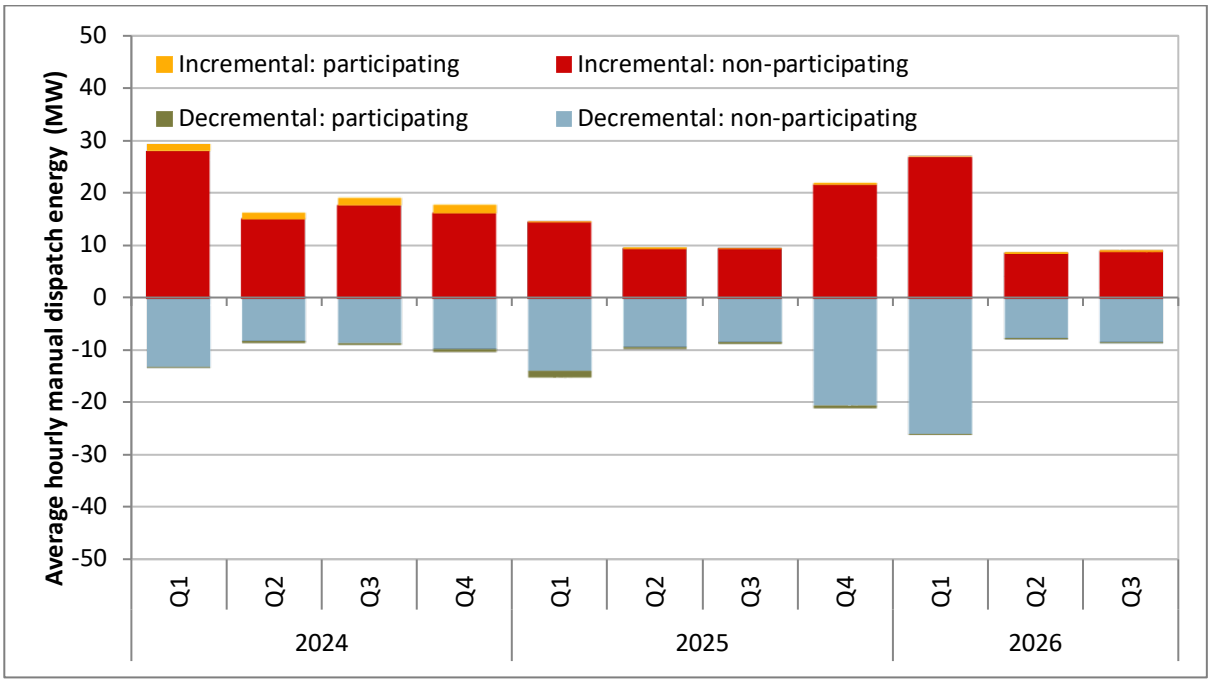


Figure 12.4 WEIM manual dispatches – Pacific Northwest



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.

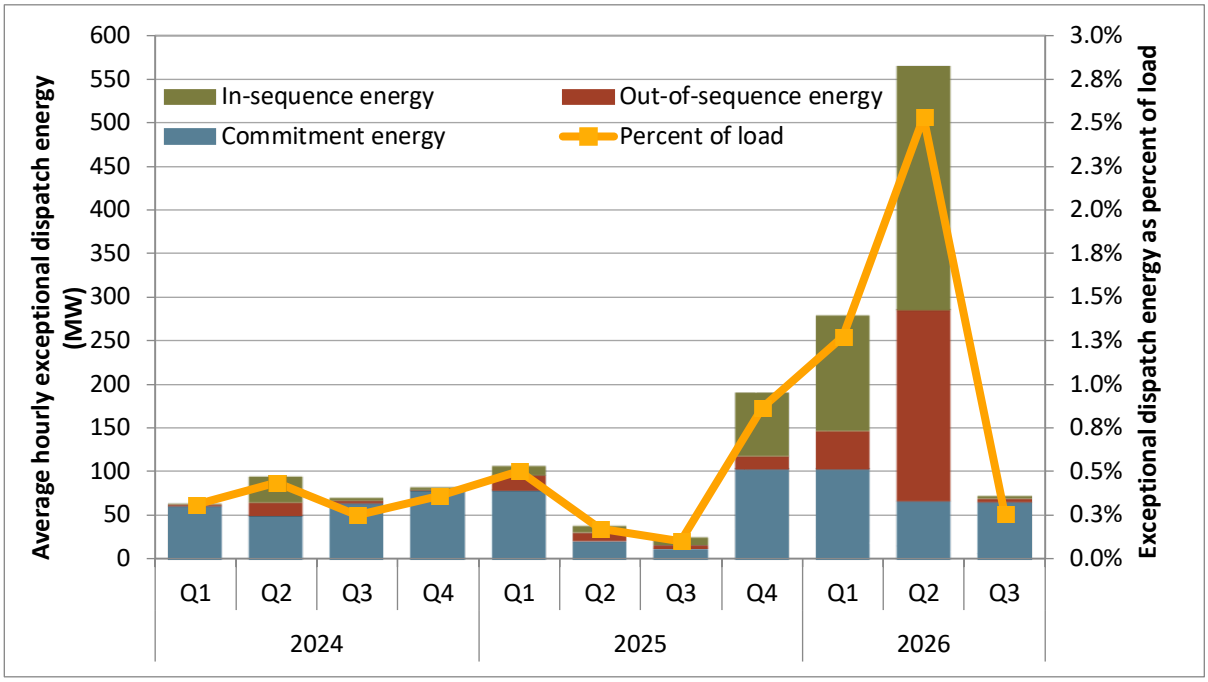
Energy from exceptional dispatch

Energy from exceptional dispatch declined in the third quarter from a three-year high in the second quarter of 2026, but remained above levels in the third quarter of prior years. It accounted for about 0.25 percent of total load in the California ISO balancing area, as shown 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 about 72 MW in the third quarter of 2026, which is an increase from about 26 MW in the third quarter of 2025.[119]

In the third quarter of 2026, exceptional dispatches for unit commitments (blue) accounted for about 90 percent of all exceptional dispatch energy; about six percent was from out-of-sequence energy (red), and the remaining four percent was from in-sequence energy (green), as shown in Figure 12.5.

[119] 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

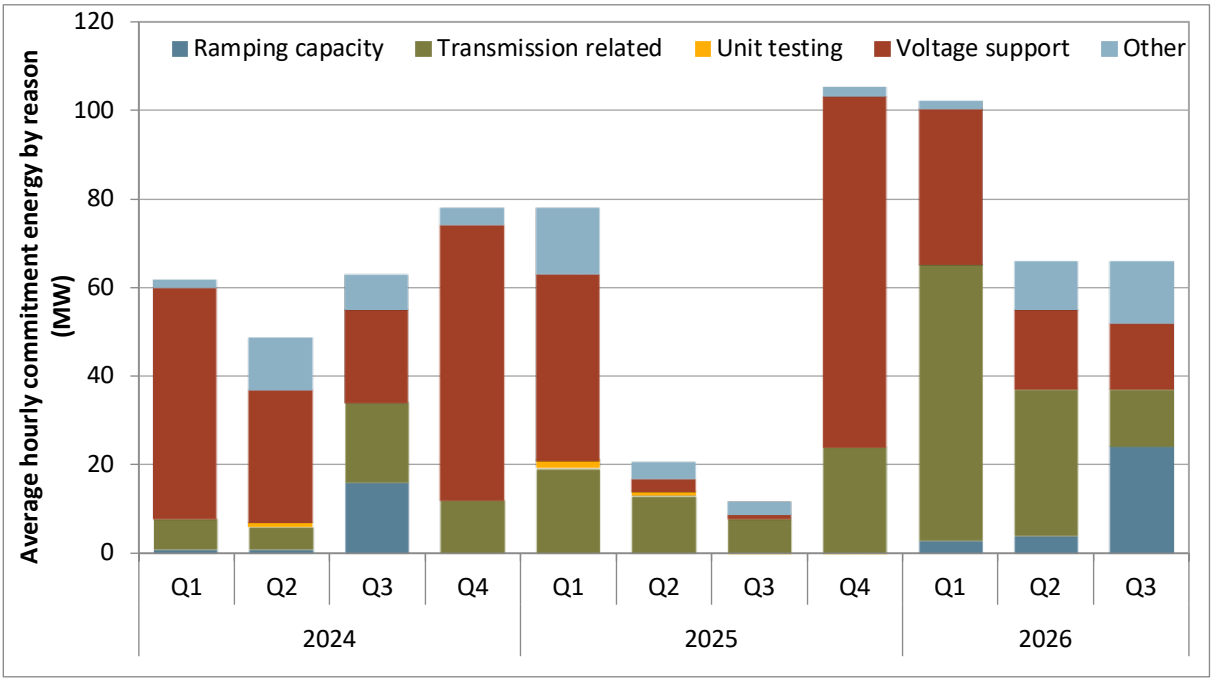


Exceptional dispatches for unit commitment

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 third quarter of 2026 was 65 MW, above the 11 MW average minimum load energy from unit commitment in the third quarter of 2025.

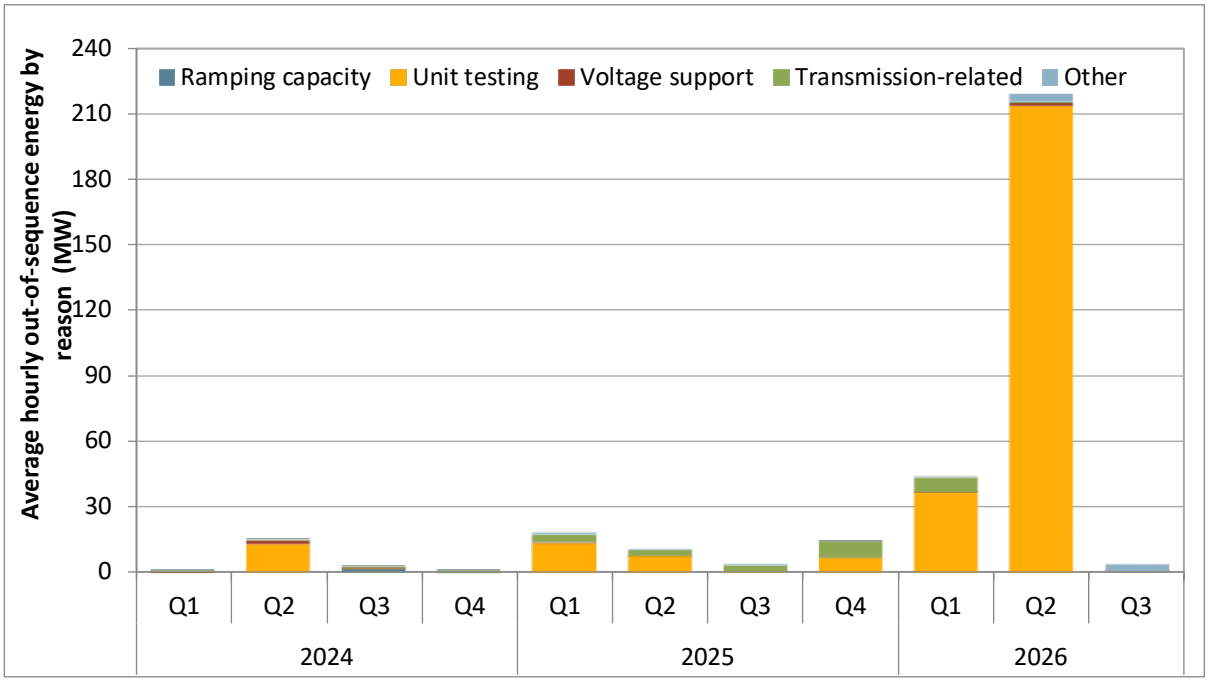
Figure 12.6 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Figure 12.7 shows the average hourly out-of-sequence exceptional dispatch energy by reason for each quarter from Q1 2024 through Q3 2026. Out-of-sequence energy declined in the third quarter from a three-year high in the second quarter to levels more consistent with recent years.

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



Exceptional dispatch costs

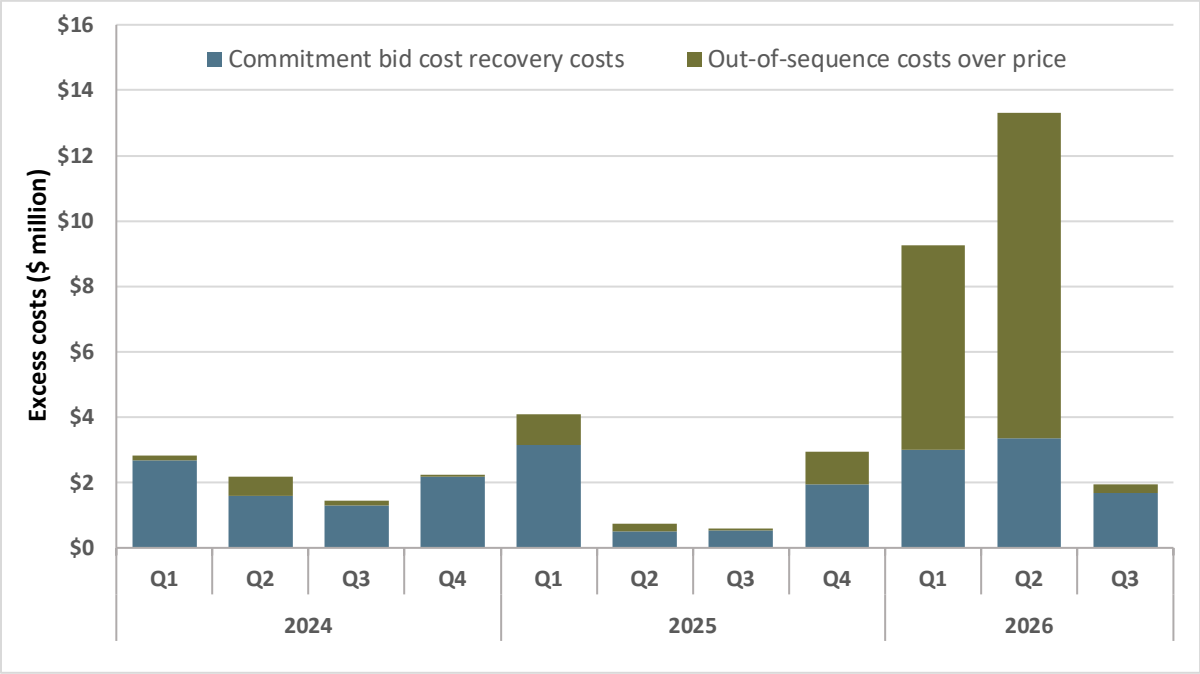
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

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 out-of-sequence real-time energy 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 associated with unit commitment and exceptional dispatch for energy above minimum load when the resource's bid price exceeds its locational marginal price. In the third quarter of 2026, out-of-sequence energy costs were about $260,000, up from about $60,000 in the third quarter of 2025. Bid cost recovery payments awarded to resources committed through exceptional dispatch were $1.7 million in the third quarter, up from about $540,000 in the third quarter of 2025. The higher costs were primarily attributable to unit commitments associated with ramping and other requirements.

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 $11.5 million for the third quarter, after accounting for about $13.7 million in virtual bidding bid cost recovery charges.[120]

Of note, the day-ahead market ran without virtual bids on July 29, 2026 due to a technical problem with Scheduling Infrastructure and Business Rules (SIBR). The issue was resolved that day and the day-ahead market has run with virtual bids since then.

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 -$1.3 million, $4.7 million, and $11.3 million for July, August, and September, respectively. Virtual demand revenues were about $7.1 million, $1.9 million, and $1.5 million for July, August, and September, respectively.

Bid cost recovery charges allocated to virtual bids were about -$6.2 million, -$7.4 million, and -$0.2 million for July, August, and September, respectively.

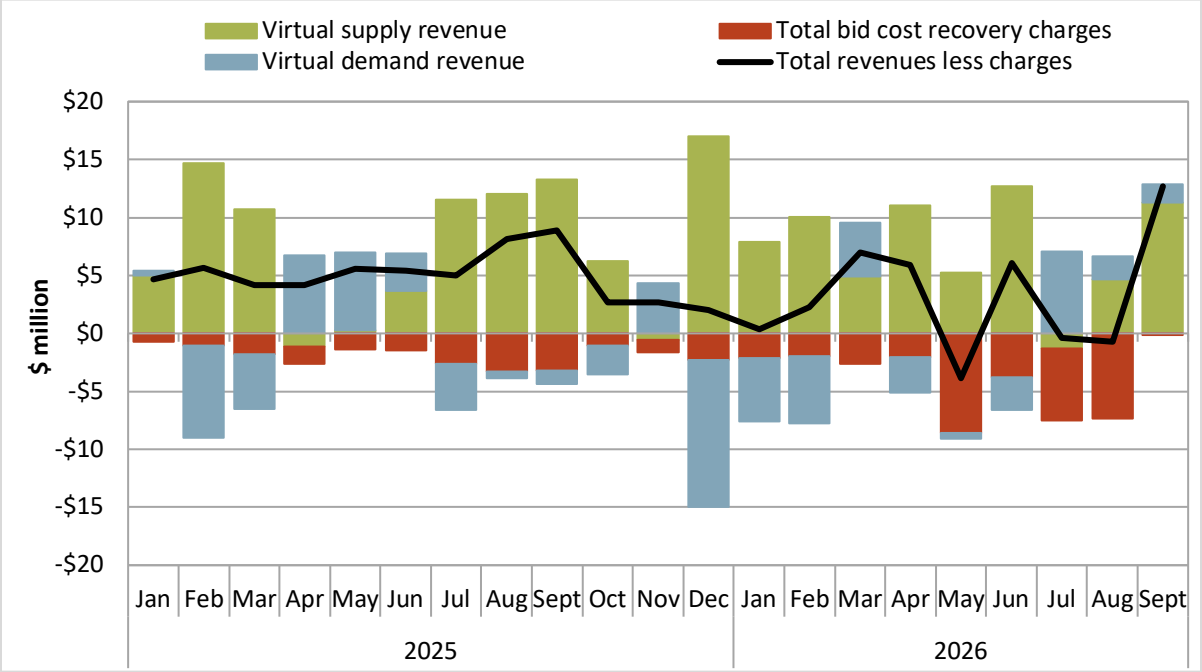
Much of the bid cost recovery allocated to virtual bidding participants during the quarter was associated with reliability commitment costs. These charges were primarily through the reliability capacity up (RCU) and reliability capacity down (RCD) tier 1 allocations.

These allocations help offset reliability commitment costs associated with virtual bids clearing in the day-ahead market. Virtual supply leads to decreased unit commitment in the day-ahead market while increasing 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. During periods of net virtual supply, a portion of this bid cost recovery is allocated to virtual supply. Since the launch of EDAM, virtual demand also receives a surcharge to help offset the costs of RCD related to periods with net virtual demand.

Net convergence bidding revenues totaled $11.5 million in the third quarter of 2026. In comparison, net revenues were around $22.0 million in the third quarter of 2025.

[120] 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 cleared convergence bidding volumes and revenues before and after accounting for bid cost recovery among different groups of convergence bidding participants. Revenues are reported in millions of dollars.[121,122,123]

After accounting for bid cost recovery, financial and marketing entities were the only participants with positive convergence bidding revenues overall. Before accounting for bid cost recovery, nearly all virtual bidding revenue was split between financial entities and marketers, at around 81 percent and 12

[121] 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

[122] 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.

[123] BCR allocated to virtual supply includes the virtual-allocated portion of charge codes 6636 and 6806 before EDAM implementation, and the virtual-allocated portion of charge codes 6636 and 8806 after EDAM implementation. BCR allocated to virtual demand includes the virtual-allocated portion of charge code 8816, which was introduced with the implementation of EDAM.

percent, respectively. Financial entities and marketers accounted for about 81 percent and 11 percent, respectively, of the cleared volume of virtual trades in the third quarter.

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 before BCR	Virtual supply before BCR	Virtual demand BCR	Virtual supply BCR	
2026 Q3								
Financial	3,522	4,050	7,571	$9.6	$10.8	-$0.1	-$9.9	$10.5
Marketer	472	520	992	$0.9	$2.2	$0.0	-$0.8	$2.2
Physical load	10	24	35	-$0.1	$0.1	$0.0	-$0.2	-$0.1
Physical generation	205	608	813	$0.2	$1.6	$0.0	-$2.8	-$1.0
BAA	3	0	3	$0.0	$0.0	$0.0	$0.0	$0.0
Total	**4,212**	**5,203**	**9,414**	**$10.6**	**$14.7**	**-$0.1**	**-$13.6**	**$11.5**

Trading entities	Total hourly megawatts			Revenues/losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand before BCR	Virtual supply before BCR	Virtual demand BCR	Virtual supply BCR	
2025 Q3								
Financial	4,686	5,196	9,881	-$4.5	$30.0	$0.0	-$5.7	$19.7
Marketer	492	553	1,045	-$0.6	$3.3	$0.0	-$0.5	$2.2
Physical load	85	179	264	-$0.3	$0.9	$0.0	-$0.6	$0.0
Physical generation	215	471	686	-$0.4	$2.2	$0.0	-$1.8	$0.0
BAA	0	84	84	$0.0	$0.4	$0.0	-$0.4	$0.0
Total	**5,478**	**6,482**	**11,961**	**-$5.7**	**$36.8**	**$0.0**	**-$9.1**	**$22.0**

14 Ancillary services and available balancing capacity

Ancillary service requirements and payments increased in the third quarter of 2026 compared with the third quarter of 2025. Average requirements for regulation up, regulation down, and operating reserves increased about 260 MW (58 percent), 60 MW (7 percent), and 160 MW (9 percent), respectively. Ancillary service payments totaled $29.6 million in the third quarter of 2026, around $11.6 million (65 percent) more than the same quarter of the previous year. Available balancing capacity was dispatched to address power balance infeasibilities in 0.2 percent or less of intervals for all areas in the 15-minute and 5-minute markets.[124]

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.[125] 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.[126] 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.

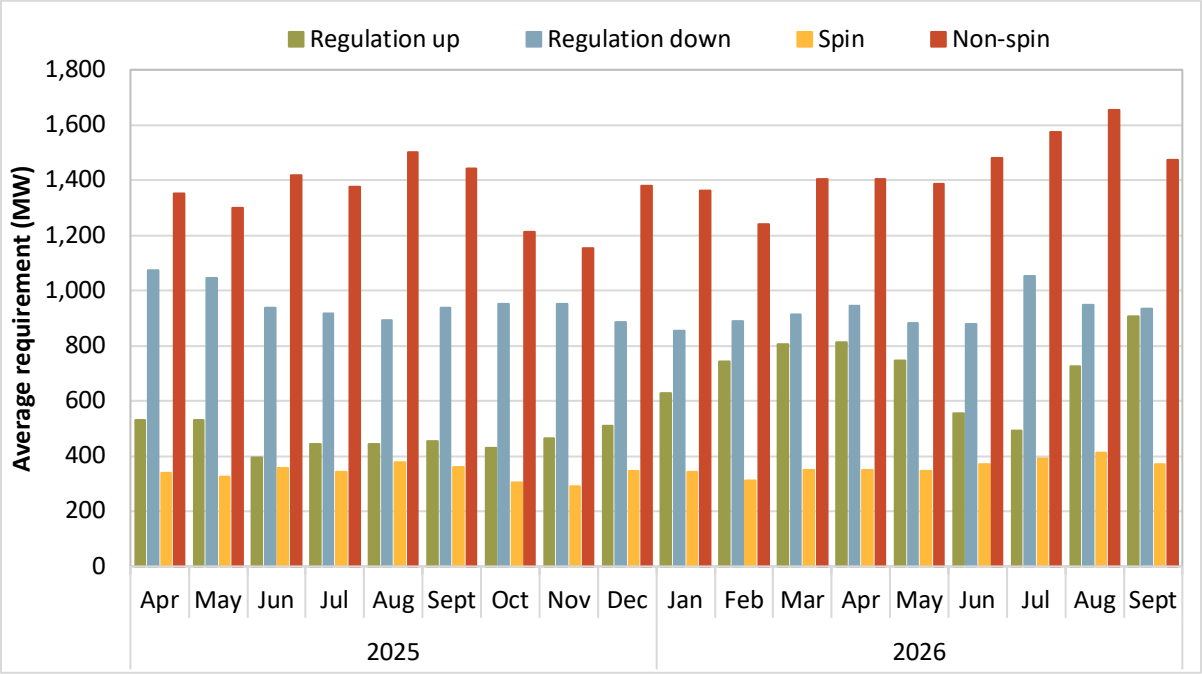
Figure 14.1 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation up and down requirements increased about 260 MW (58 percent) and 60 MW (7 percent), respectively, compared to the third quarter of 2025. Average operating reserve requirements increased about 160 MW (9 percent) compared to the third quarter of 2025.

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

[125] 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

[126] 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. 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.

No scarcity events occurred in the third quarter of 2026.

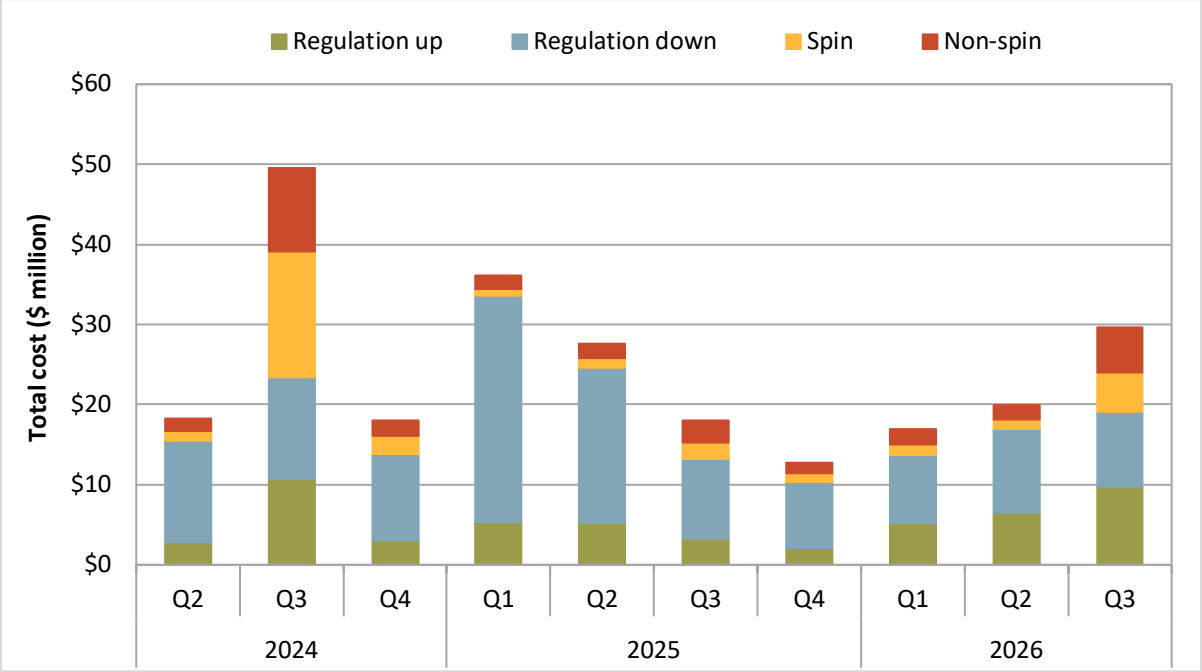
14.3 Ancillary service costs

Ancillary service payments totaled $29.6 million in the third quarter of 2026, around $11.6 million (65 percent) more than the same quarter of the previous year due in part to higher ancillary service requirements and higher load.[127]

[127] See Section 2.

Figure 14.2 shows the total cost of procuring ancillary service products by quarter.[128] Payments for regulation up, spinning reserves, and non-spinning reserves increased by 201, 137, and 110 percent, respectively, and decreased for regulation down by 6 percent, compared to the third quarter of 2025.

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 summarizes the frequency and average quantity of upward and downward available balancing capacity offered in each area, as well as the frequency with which available balancing capacity was scheduled in the 15-minute and 5-minute markets during the third quarter. Available balancing capacity was scheduled in 0.2 percent or less of intervals for all areas in the 15-minute and 5-minute markets.

[128] 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.

Table 14.1 Frequency of available balancing capacity offered (Q3 2026)

		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	98.6%	92	.0%	.0%	98.6%	93	.0%	.0%
	LADWP	46.5%	61	.0%	.0%	.0%	N/A	.0%	.0%
	Turlock Irrigation District	98.6%	15	.0%	.0%	98.6%	5	.0%	.0%
Desert Southwest	Arizona Public Service	98.5%	87	.1%	.0%	98.6%	87	.0%	.0%
	El Paso Electric	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	NV Energy	98.3%	71	.0%	.1%	91.3%	67	.1%	.0%
	PSC New Mexico	.0%	N/A	.0%	.0%	.3%	50	.0%	.0%
	Salt River Project	98.3%	99	.0%	.0%	97.5%	50	.0%	.0%
	Tucson Electric	98.6%	53	.2%	.2%	98.6%	53	.0%	.0%
	WAPA - Desert Southwest	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
Intermountain West	Avista Utilities	98.6%	10	.0%	.0%	98.6%	10	.0%	.0%
	Black Hills	98.5%	37	.0%	.0%	98.5%	25	.0%	.0%
	Idaho Power	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	NorthWestern Energy	96.8%	5	.1%	.1%	96.8%	5	.0%	.0%
	PacifiCorp East	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	PowerWatch	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
Pacific Northwest	Avangrid	98.6%	47	.0%	.0%	.0%	N/A	.0%	.0%
	Powerex	97.9%	1,084	.0%	.0%	98.6%	600	.0%	.0%
	Bonneville Power Admin.	98.6%	331	.0%	.0%	98.6%	341	.0%	.0%
	PacifiCorp West	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	Portland General Electric	97.4%	30	.0%	.0%	.0%	N/A	.0%	.0%
	Puget Sound Energy	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	Seattle City Light	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	Tacoma Power	78.4%	2	.0%	.0%	93.9%	2	.0%	.0%

15 Congestion revenue rights

Congestion revenue right auction returns

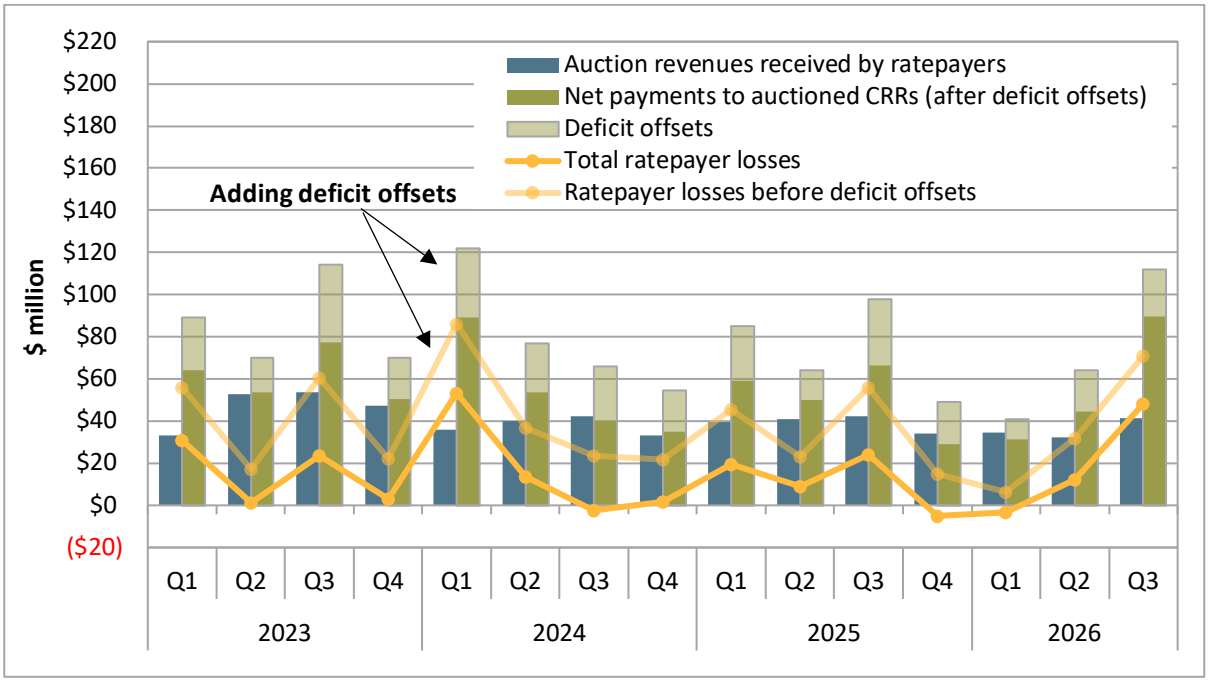
Profits from the congestion revenue rights (CRR) auction by non-load serving entities are calculated by summing revenue paid out to congestion revenue rights purchased by these entities, and then subtracting the auction price paid for these rights. While this represents a profit to entities purchasing rights in the auction, it represents a loss to transmission ratepayers. Figure 15.1 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).[129]
- 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 lost $48 million during the third quarter of 2026, as payments to auctioned congestion revenue rights holders were higher than auction revenues. This was an increase from ratepayer losses of $24 million in the third quarter of 2025.

[129] 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 15.1 Auction revenues and payments to non-load serving entities



During the third quarter of 2026:

- Financial entities earned a $44 million profit from auction rights, up from about $22 million during the same quarter of 2025. Total revenue deficit offsets were about $19 million.[130]
- Marketers earned $3.5 million from auctioned rights, up from a $1.6 million profit in the same quarter of 2025. Total revenue deficit offsets were over $3.7 million.
- Physical generation entities earned $0.6 million from auctioned rights, a decline from $0.7 million in profit in Q3 2025. Total revenue deficit offsets were $3,000.

The $48 million auction loss in the third quarter of 2026 was about 33 percent of CAISO day-ahead congestion rent. This was an increase from 18 percent of CAISO total congestion rent in the third quarter of 2025. 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).[131,132]

130 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.

131 *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

132 *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

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 $23 million in this 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.[133]

[133] *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

16 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. This allows external suppliers and load serving entities to 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.[134] Table 16.1 shows the import portion of all monthly high priority wheel-through reservations made in the third quarter by constraint.

Table 16.1 2026 Q3 monthly high priority wheel-through reservations by constraint[135]

Month	Constraint	Monthly PWT (MW)
Jul	ADLANTOVICTVL-SP_ITC	25
	NOB_ITC	300
	PALOVRDE_ITC	75
Aug	ADLANTOVICTVL-SP_ITC	25
	NOB_ITC	300
	PALOVRDE_ITC	75
Sep	ADLANTOVICTVL-SP_ITC	25
	NOB_ITC	109
	PALOVRDE_ITC	75

Figure 16.1 shows available transmission capacity (ATC) in the red diamonds. This is the total transmission capacity left after accounting for outages and existing transmission rights for the NOB intertie. NOB, along with Malin, is one of the primary interties used to wheel power from north to south across the CAISO system. Scheduling coordinators can reserve available priority wheel-through (PWT) capacity (yellow bars) at interties if there is leftover available transmission capacity after accounting for native load need (dark blue bars), a transmission reliability margin (TRM, light blue bars), and any previously reserved priority wheel-through capacity (green bars).

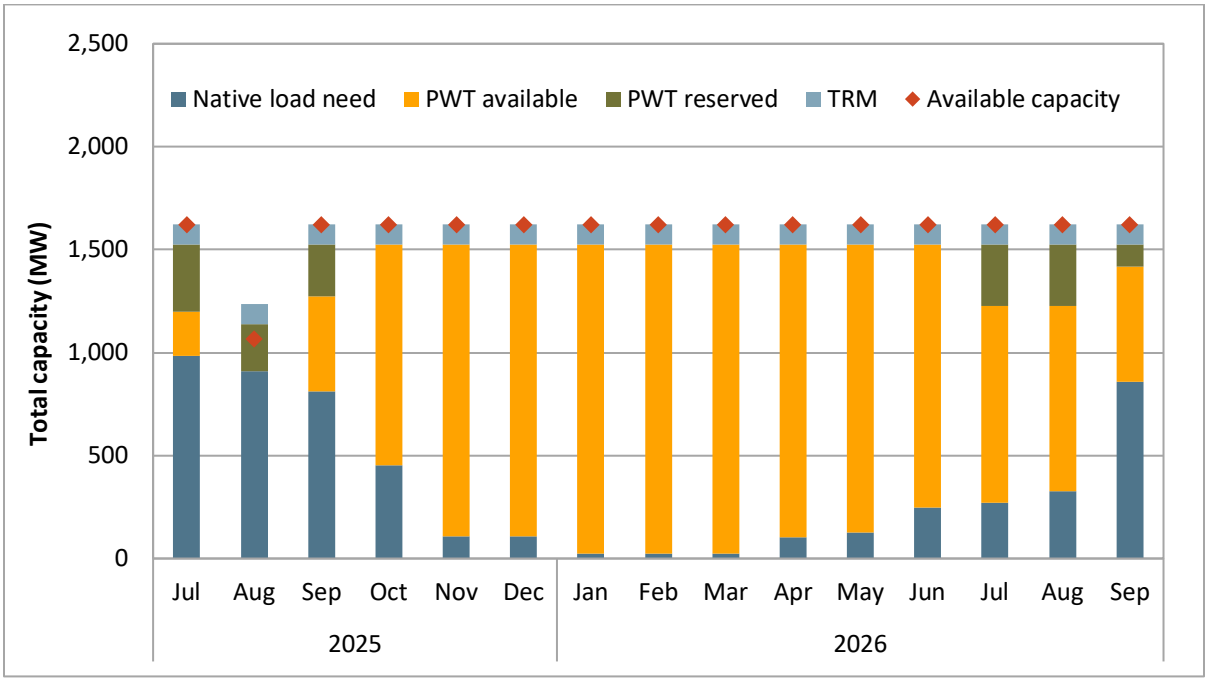
The stacked capacity bars in Figure 16.1 can exceed the available capacity of an intertie if intertie transmission outages or native load need values increase between reservation windows, as occurred at

[134] 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

[135] OASIS reports priority wheel-through reservations by the relevant intertie constraints that can limit intertie capacity. Multiple intertie constraints can affect the flows over different tie points and, therefore, OASIS reports the same priority wheel-through reservation amount for each related intertie constraint. This section reports transmission and priority wheel-through capacity for a single intertie constraint related to the CAISO market tie point of the wheel import legs to avoid double counting. See CAISO Operating Procedure 2510A for additional detail on the relationship between CAISO market tie points and intertie constraints: https://www.caiso.com/documents/2510a.pdf

NOB in August 2025. In contrast, in Q3 2026, there was excess capacity at NOB for priority wheels in all months.

Figure 16.1 Monthly transmission capacity at NOB intertie

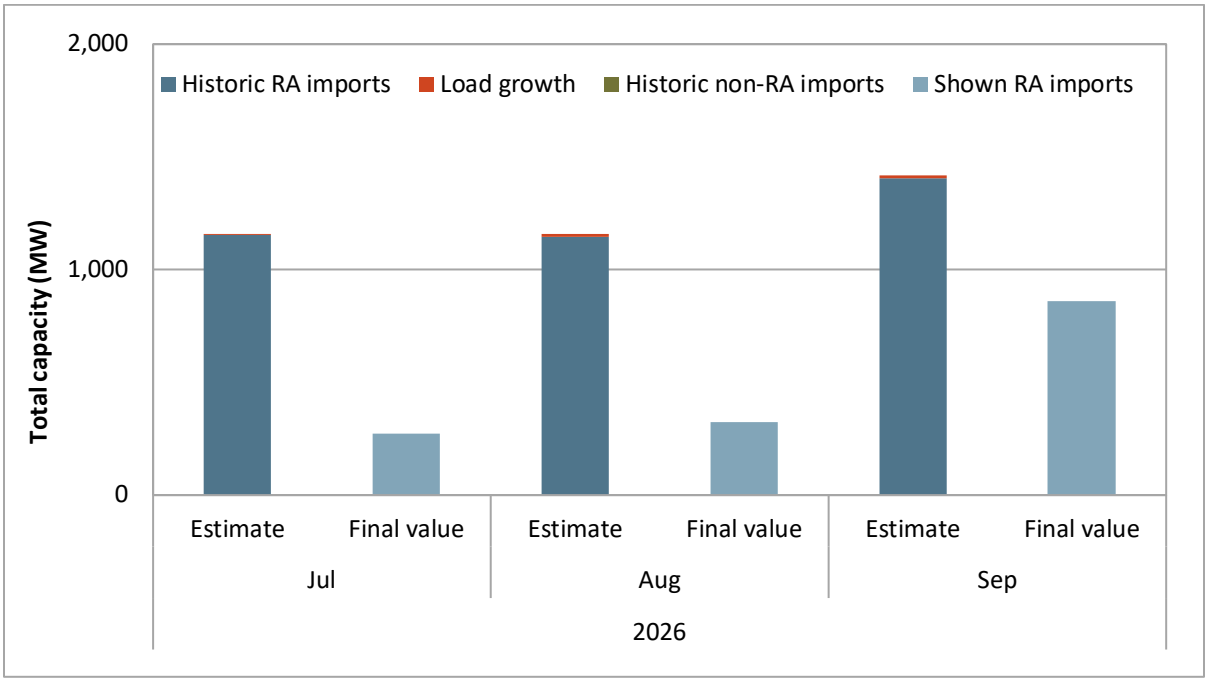


In calculating available transmission capacity for priority wheel-throughs for future months, the ISO sets aside transmission capacity by estimating what is needed to serve CAISO balancing area load. Ultimately, this "native load need" capacity on interties is the sum of shown import resource adequacy, as well as non-resource adequacy contracts that load serving entities may show the CAISO. Final resource adequacy plans are due 30 days prior to the relevant month (T-30). Before T-30, CAISO estimates how much intertie transmission capacity native loads will need by taking the maximum amount of shown import resource adequacy and non-resource adequacy contracted imports delivered on that intertie for the same month over the previous two years. To account for potential load growth beyond historical resource adequacy obligations, CAISO adjusts these estimates using load growth projections from the California Energy Commission. CAISO updates these native load need numbers after load serving entities submit their final resource adequacy plans.

If CAISO overestimates actual native load needs, and the final resource adequacy and non-resource adequacy import showings are below the estimate based on historic data, CAISO will release excess transmission as available capacity that scheduling coordinators can reserve for priority wheel-throughs. Conversely, if CAISO underestimates native load needs, CAISO will reduce any previously unreserved available transmission capacity. However, if there is not any remaining available transmission capacity, then CAISO will revert to the originally calculated native load need estimate and will honor all of the previously reserved priority wheel-through capacity.

Figure 16.2 compares the CAISO balancing area's native load need estimate and the final shown resource adequacy import value at NOB. CAISO overestimated native load needs on NOB by 325 percent in July, 257 percent in August, and 65 percent in September 2026.

Figure 16.2 Native load need estimate vs. final import RA at NOB intertie



Priority wheel-through reservation values, or awards, are dependent on the supply contract parameters that scheduling coordinators submit to the CAISO balancing area. Scheduling coordinators may reserve available transmission capacity for priority wheel-throughs for hourly blocks that correspond to the service hours in these contracts. In the third quarter, scheduling coordinators with priority wheel-through reservations only used that reserved capacity, via day-ahead self-schedules, on NOB intertie during five hours in July.

17 Resource adequacy

17.1 Available resource adequacy bids

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.

Table 17.1 shows the hours during the third quarter of 2026 where real-time bids from resource adequacy resources, including bids from variable energy resources (VERs) above their resource adequacy capacity, were not sufficient to cover the load forecast for energy and upward ancillary service awards. Available resource adequacy capacity was not sufficient to meet CAISO balancing area load requirements in 2 intervals during peak load hours on September 9, 2026.

Table 17.1 Resource adequacy bids vs. market requirement

Date	Hour	Interval	Real-time requirement			Real-time resource adequacy bids			Total available RA - Total requirement
			Fifteen-minute load forecast	+ Regulation	+ Reserves	Resource adequacy + Above RA VERs	RA bids	Above RA VERs	
9/9/2026	19	4	48,591	50,171	53,006	51,954	51,644	310	-1,052
9/9/2026	20	1	47,794	49,064	51,850	51,639	51,353	286	-210

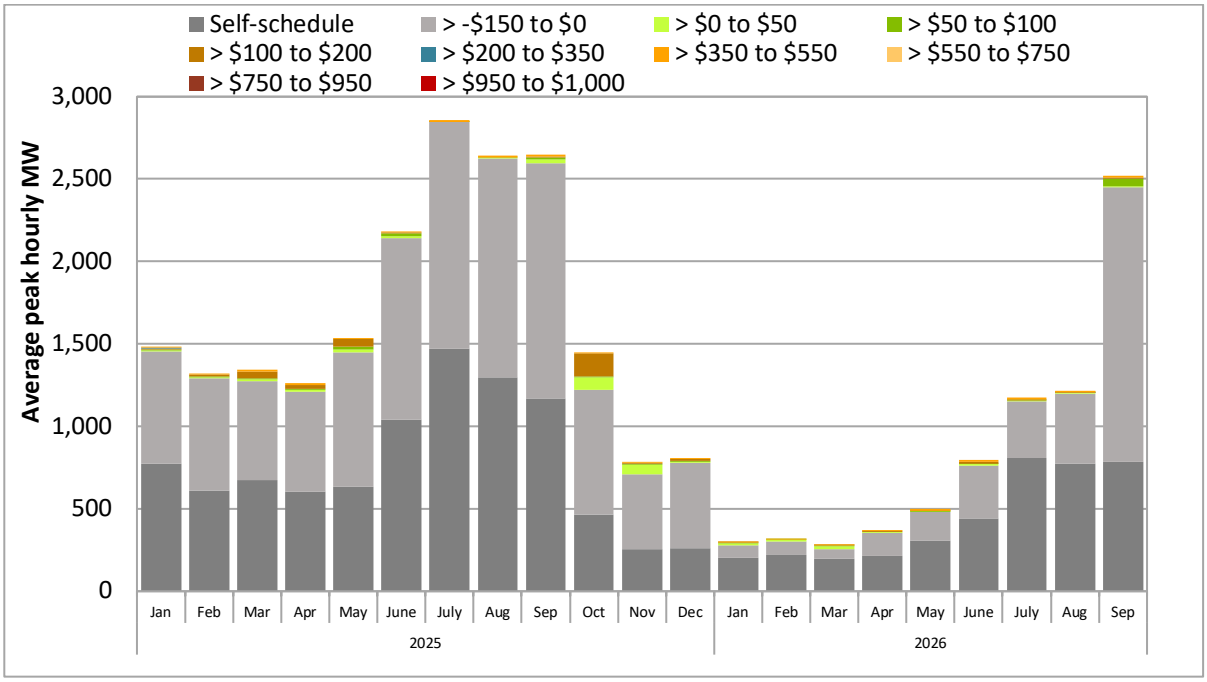
17.2 Resource adequacy import bids

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.[136] These rules became effective at the beginning of 2021.

Figure 17.1 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market during peak hours.[137] The dark gray bars reflect import capacity that was self-scheduled. The light gray 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 by 59 percent in July, 54 percent in August, and 5 percent in September, compared to the same months of 2025. Volumes remained substantially below prior-year levels in July and August but increased sharply in September, returning close to the September 2025 level. Resource adequacy import bids in Q3 2026 decreased 40 percent from Q3 2025.

Figure 17.1 Average hourly resource adequacy imports by price bin



[136] 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.

[137] 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.25 include figures for each WEIM area showing hourly locational marginal price (LMP) and dynamic transfers.[138] 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.

- **Marginal energy cost**, referred to as MEC, is the marginal clearing price for energy in a balancing authority area (BAA). The difference in MEC between balancing areas reflects any transfer congestion between one another. These figures show the marginal energy cost for the CAISO balancing area (light blue bars), which serves as the reference balancing area for assessing transfer constraint congestion discussed below.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the price impact from greenhouse gas (GHG) regulation. It represents the marginal cost of a net import transfer into the GHG regulation area (currently only balancing authority areas in California) determined within the optimization using the GHG bid adders of resources located outside of the GHG regulation area. This contributes to price differences between the GHG regulation area and the regions outside of it.[139]
- **Congestion from local constraints** is the price impact on a balancing area from transmission constraints within its own balancing area. While these constraints are located locally, they can create price impacts across the WEIM and show up as external constraints to other balancing areas
- **Congestion from external constraints** is the price impact on a balancing area from transmission constraints in a different WEIM balancing area. 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 from WEIM transfer constraints** between balancing areas is represented as the difference in marginal energy cost between the CAISO balancing area and the respective balancing

[138] 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.

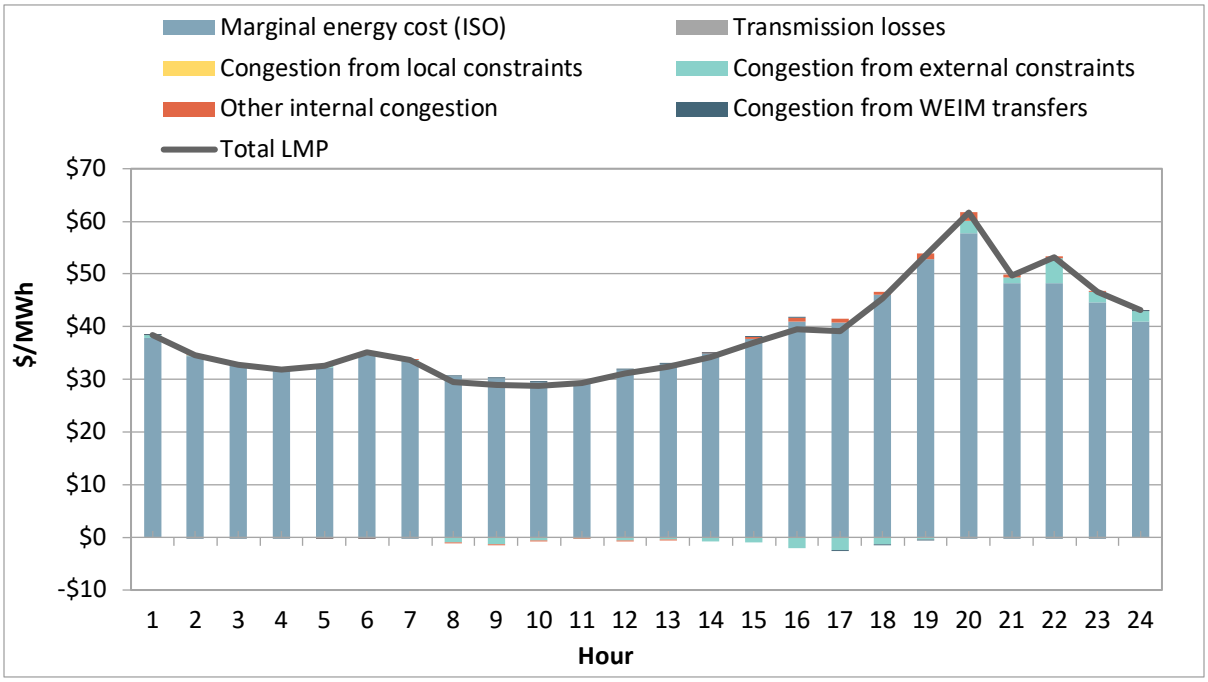
[139] Previously, the GHG component was represented as a negative price impact in all non-California balancing areas. Going forward with EDAM, GHG costs are added as a positive impact on the GHG regulation area.

area.[140] Adding this component to the CAISO marginal energy cost in these figures results in the balancing area's MEC.

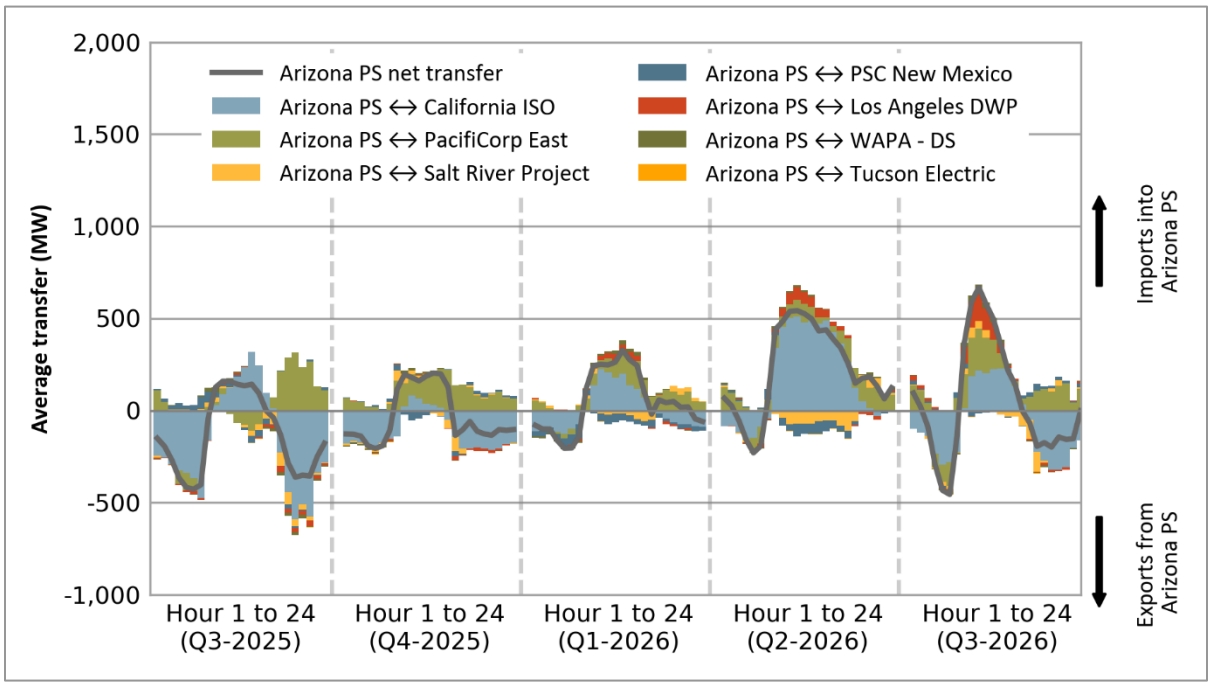
[140] The CAISO balancing area is selected as the reference area for a number of reasons. First, the CAISO balancing area has significant connectivity with other balancing areas and regions. Second, the CAISO balancing cannot enter market separation in the same way other balancing areas can. Last, for comparison to previous years, the system marginal energy cost was calculated prior to the launch of EDAM based on the marginal energy cost in the CAISO balancing area.

A.1 Arizona Public Service

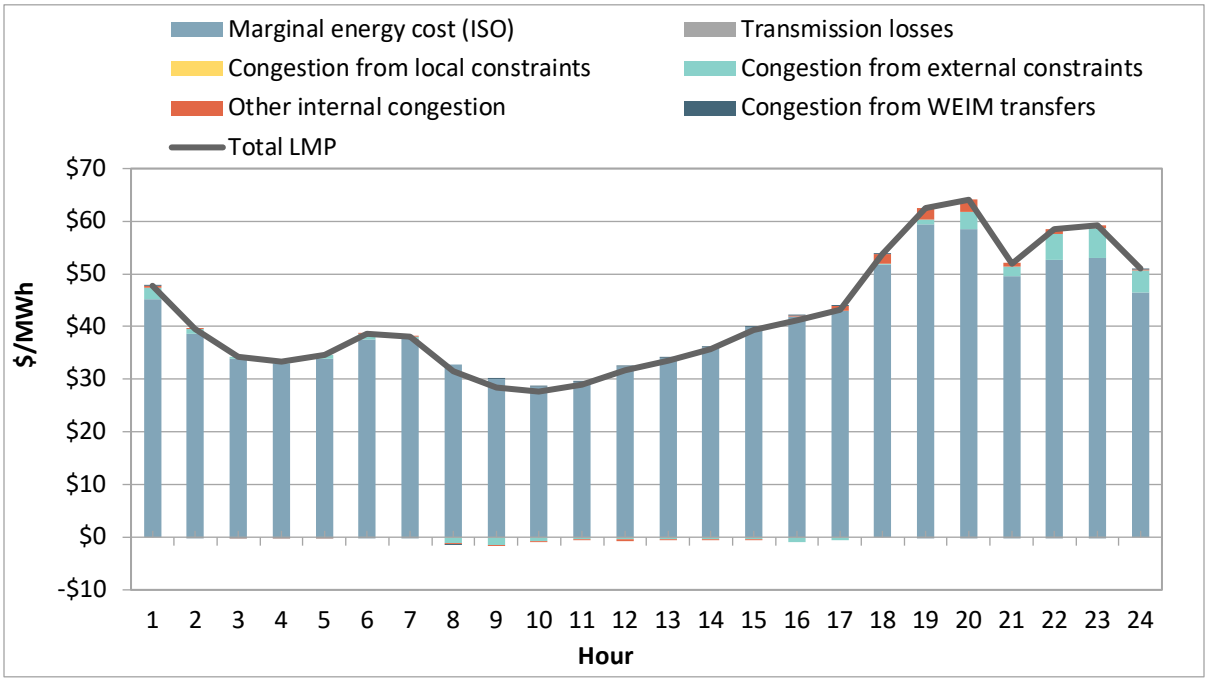
Appendix Figure A.1 Average hourly 15-minute price by component (July – September 2026)



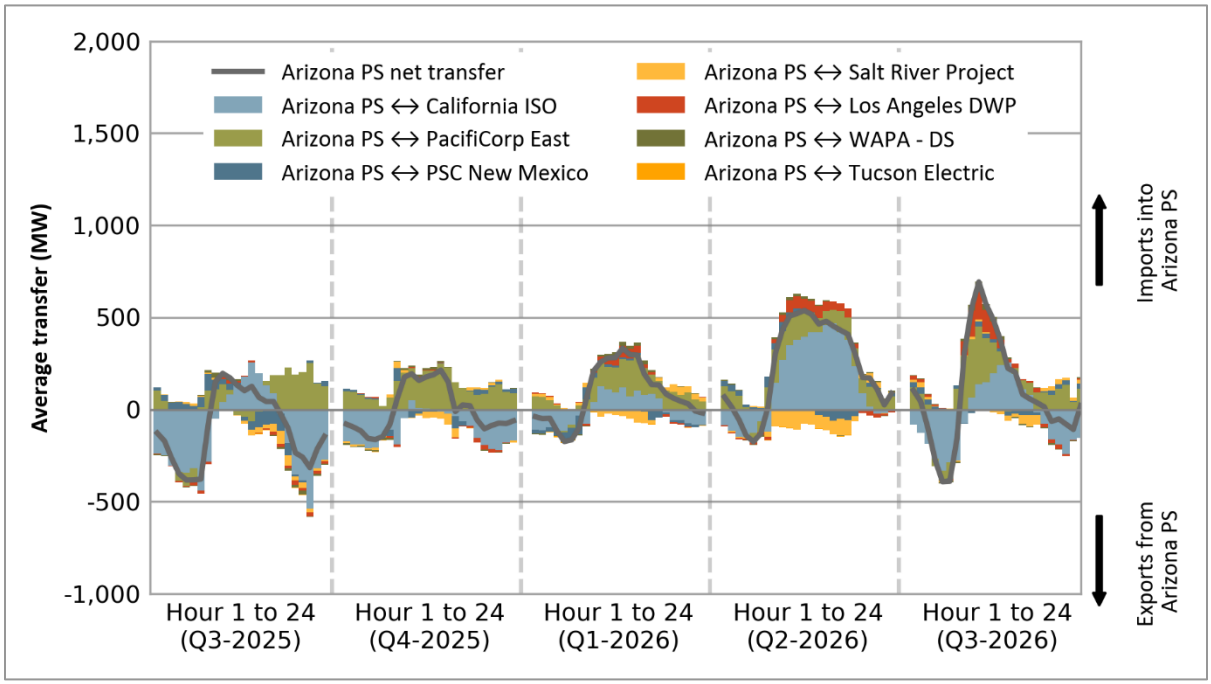
Appendix Figure A.3 Average hourly 15-minute market transfers



Appendix Figure A.4 Average hourly 5-minute price by component (July – September 2026)

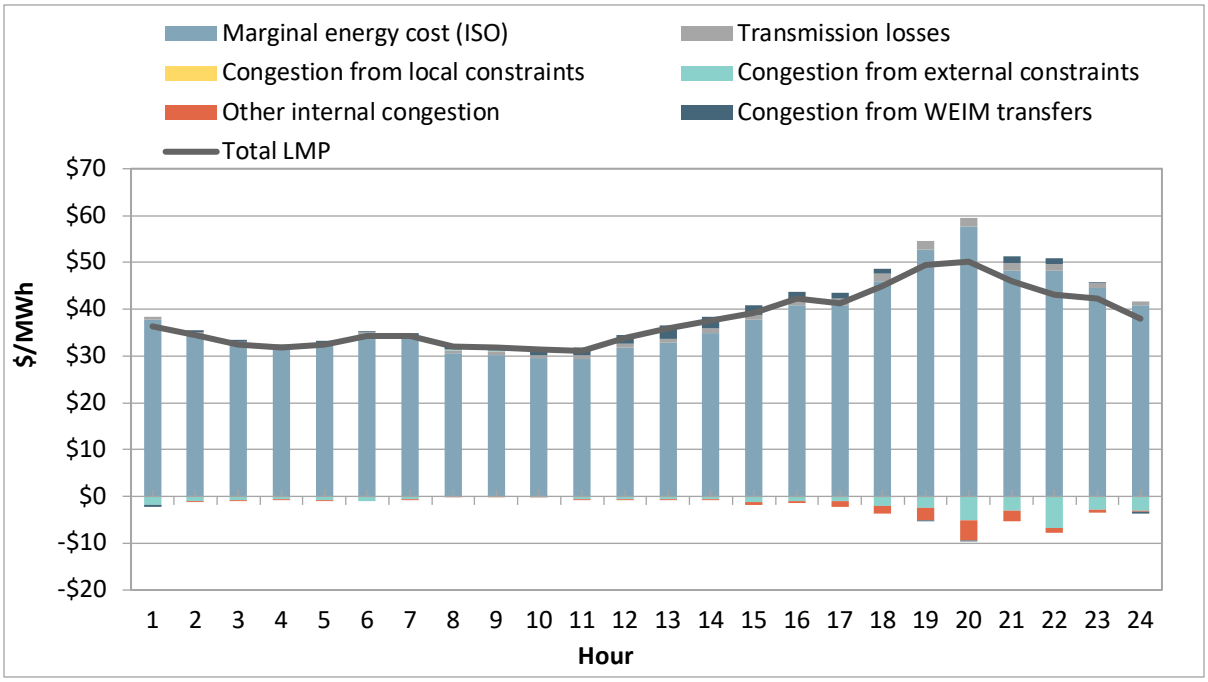


Appendix Figure A.6 Average hourly 5-minute market transfers

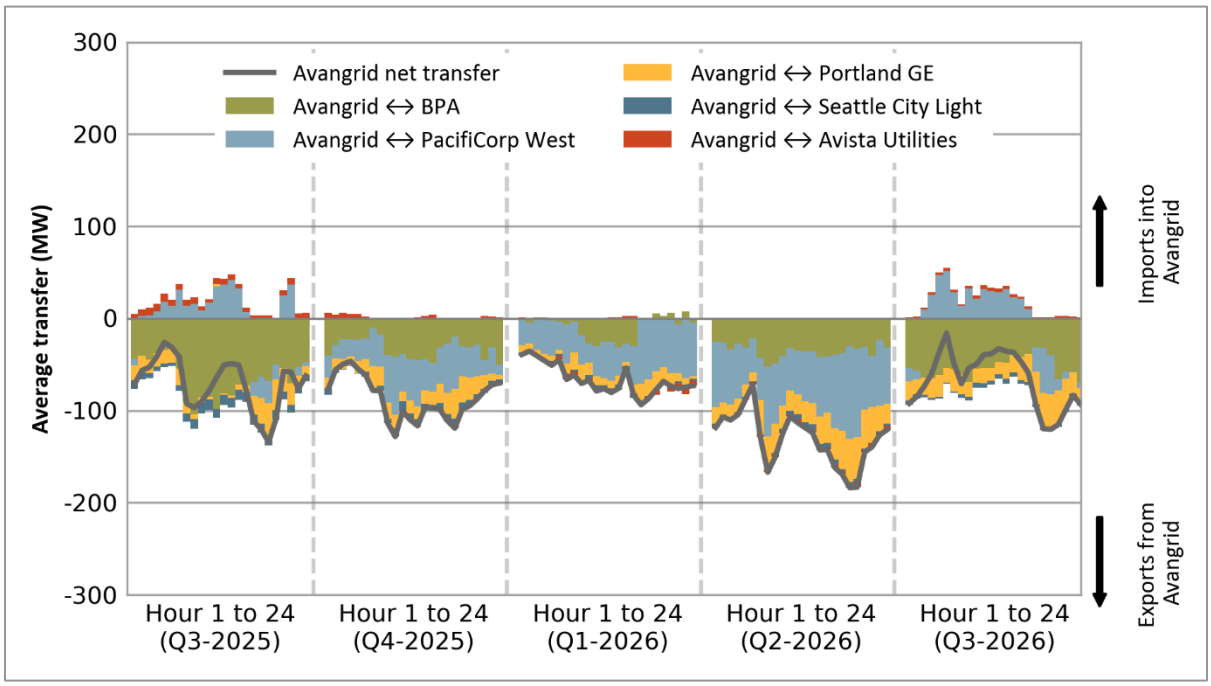


A.2 Avangrid

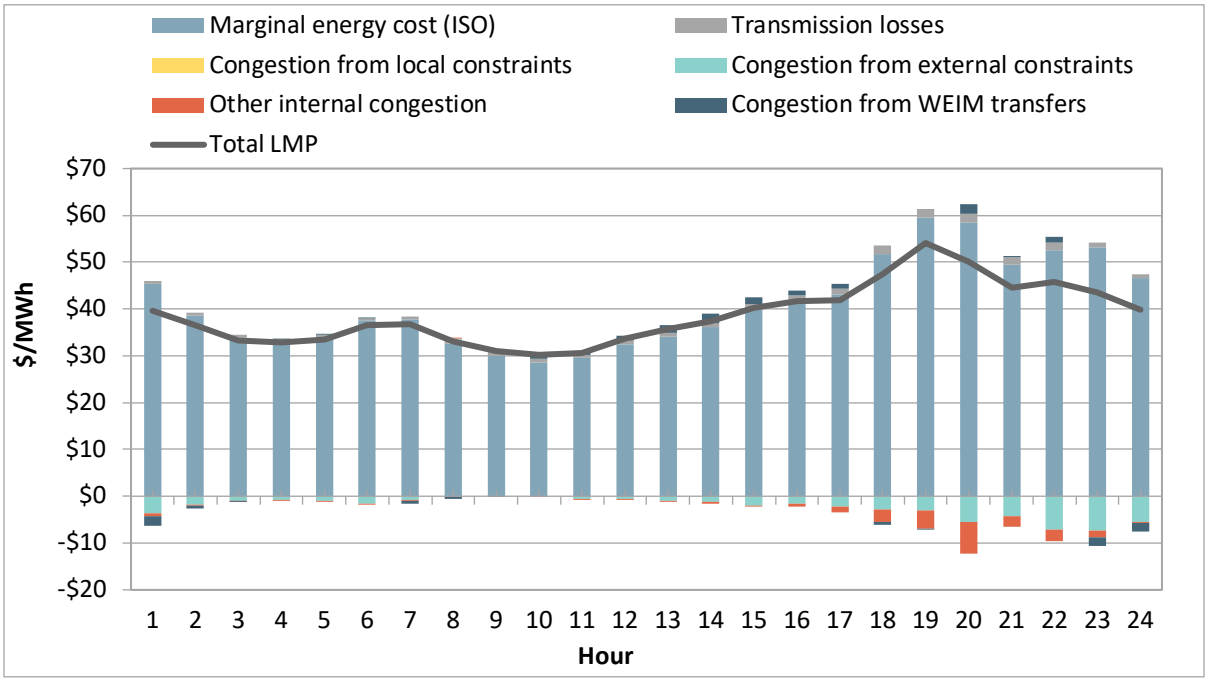
Appendix Figure A.7 Average hourly 15-minute price by component (July – September 2026)



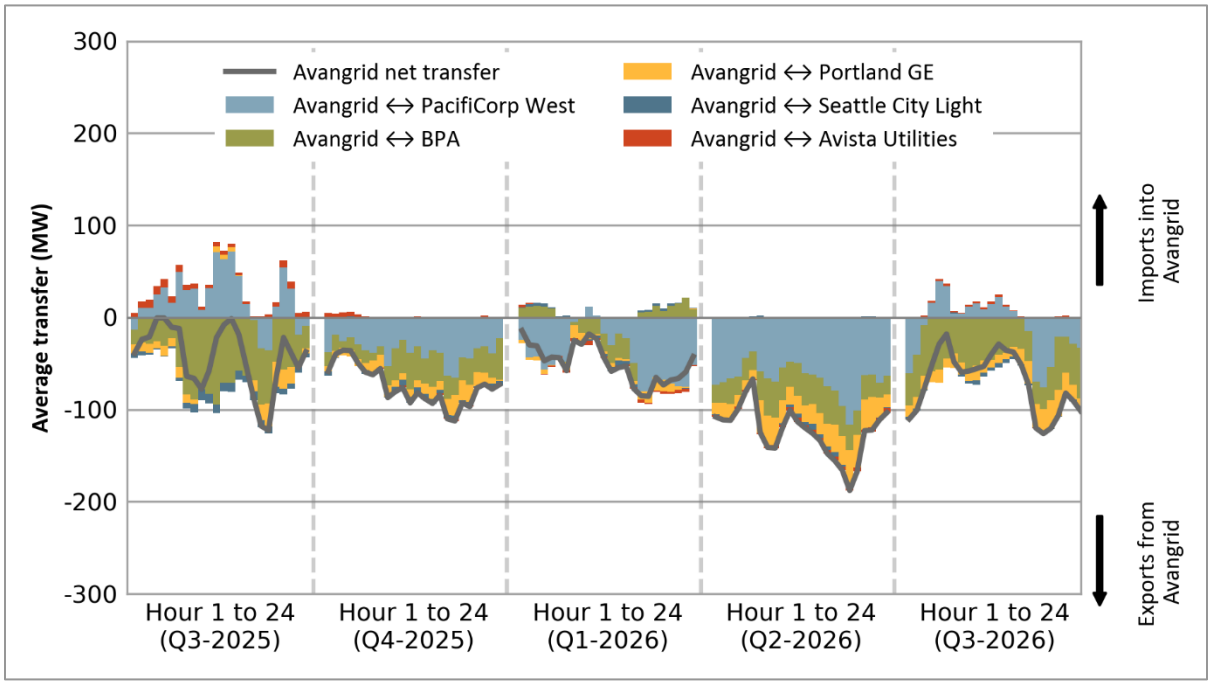
Appendix Figure A.9 Average hourly 15-minute market transfers



Appendix Figure A.10 Average hourly 5-minute price by component (July – September 2026)

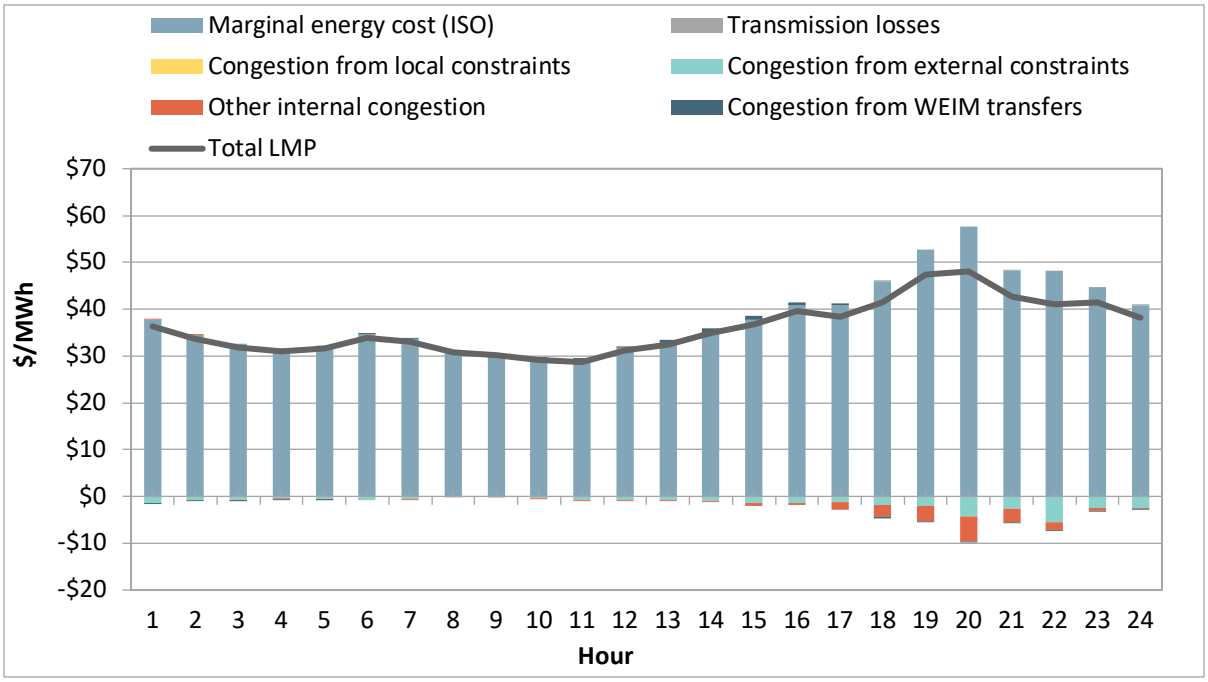


Appendix Figure A.12 Average hourly 5-minute market transfers

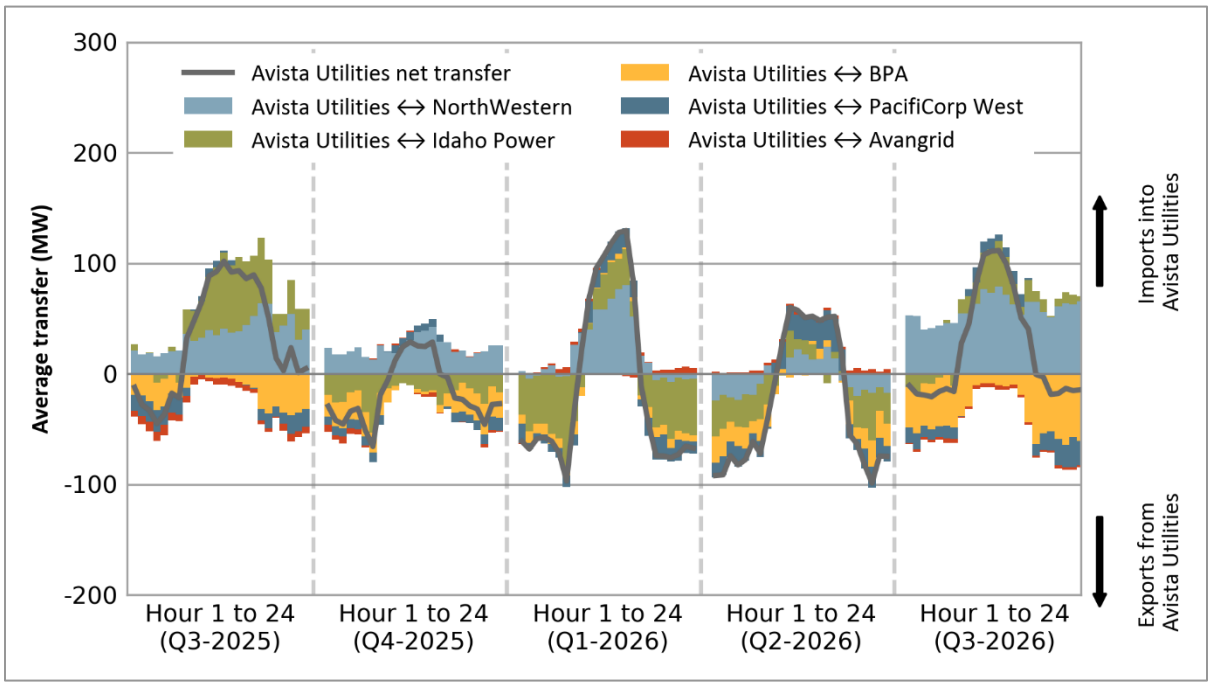


A.3 Avista Utilities

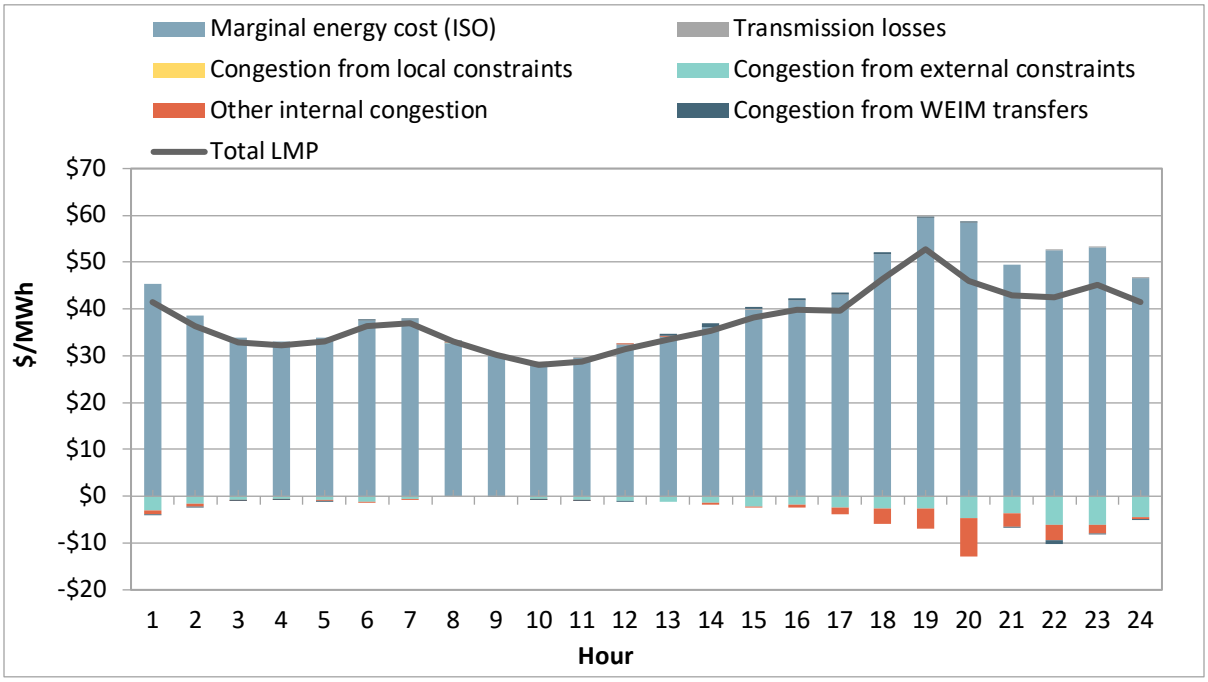
Appendix Figure A.13 Average hourly 15-minute price by component (July – September 2026)



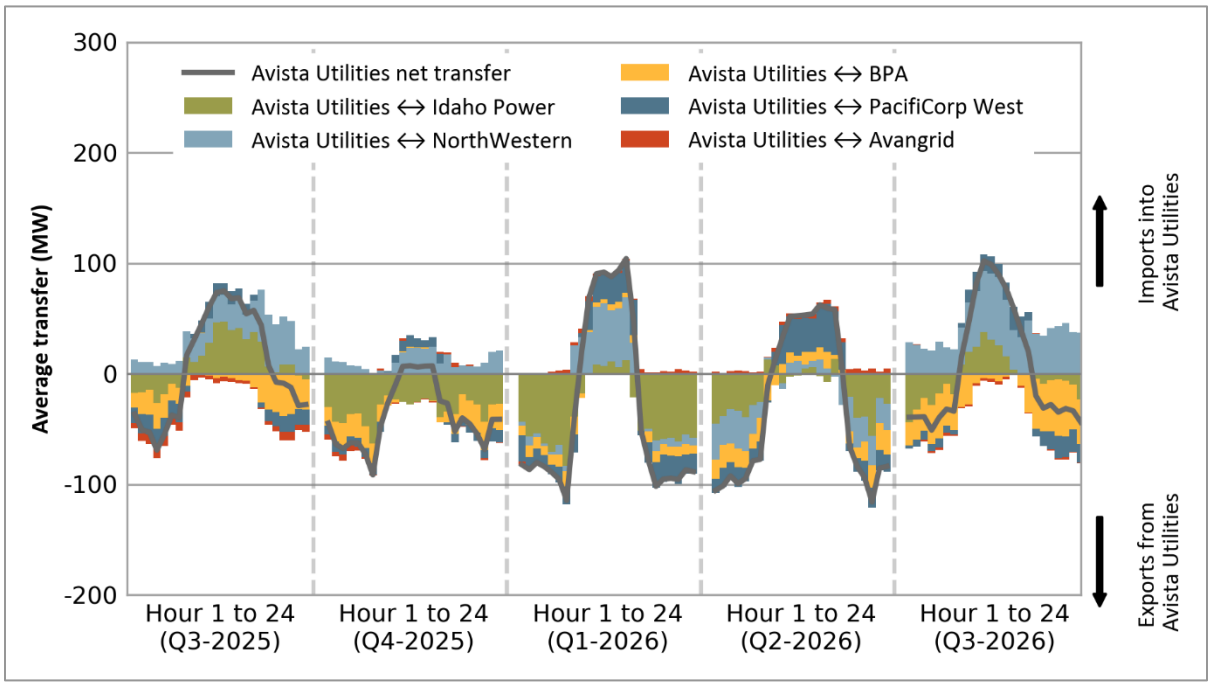
Appendix Figure A.15 Average hourly 15-minute market transfers



Appendix Figure A.16 Average hourly 5-minute price by component (July – September 2026)

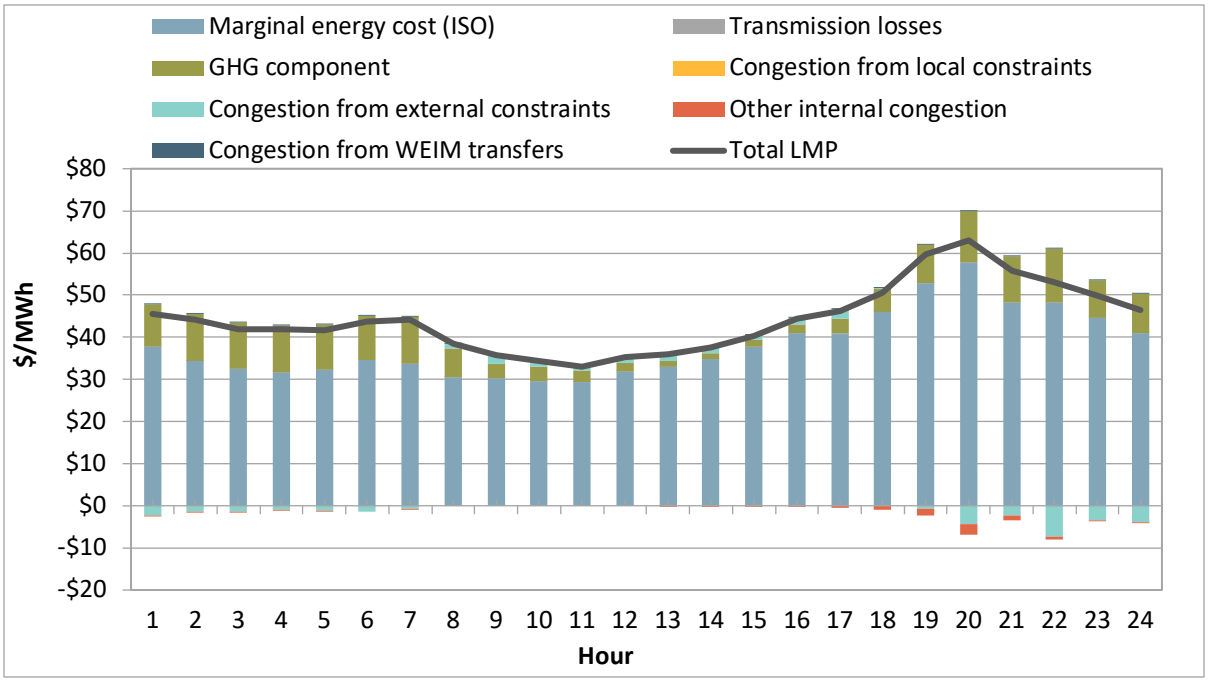


Appendix Figure A.18 Average hourly 5-minute market transfers

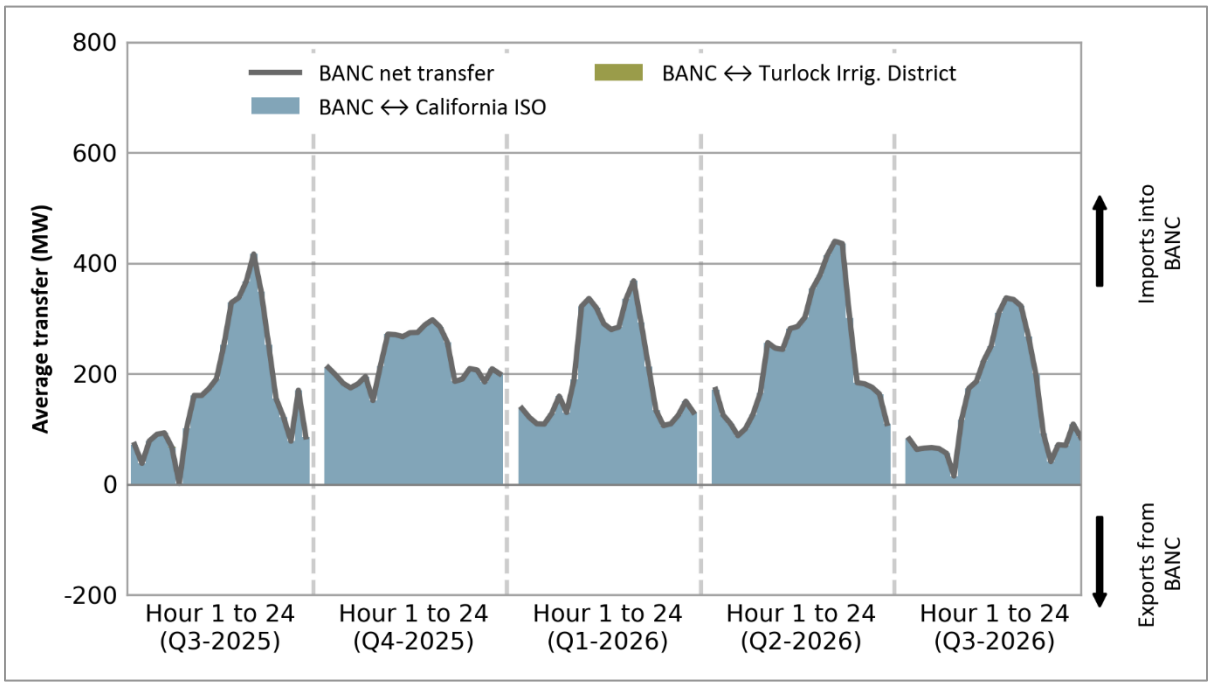


A.4 Balancing Authority of Northern California

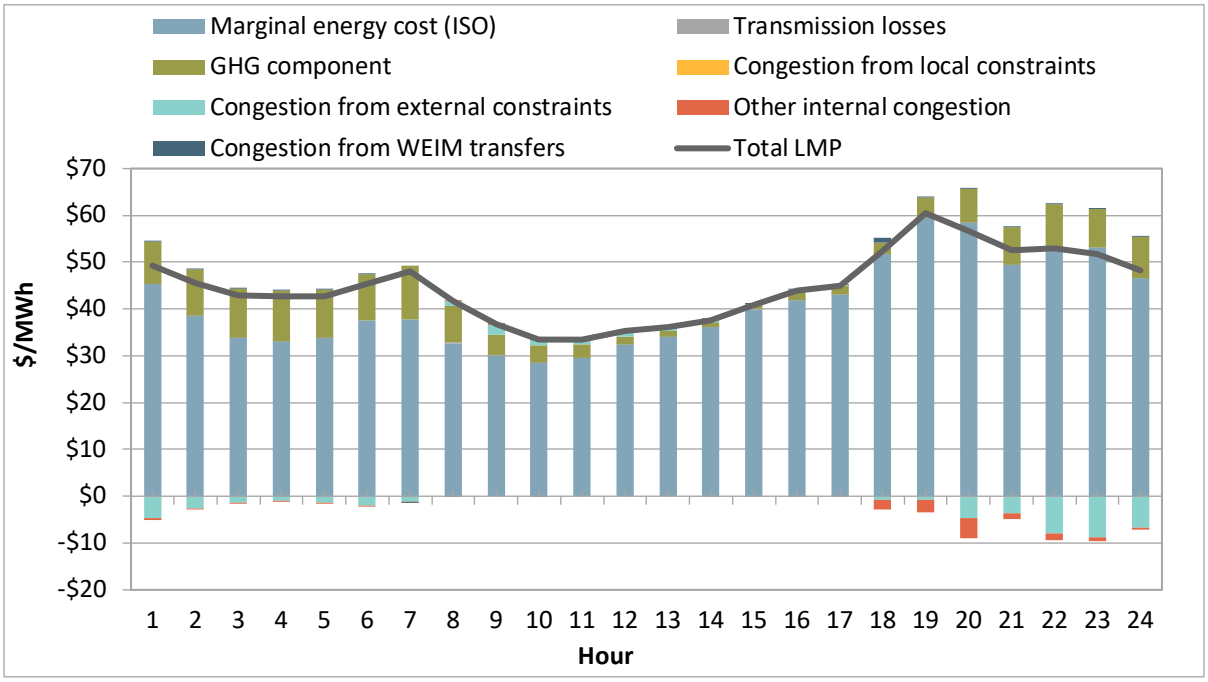
Appendix Figure A.19 Average hourly 15-minute price by component (July – September 2026)



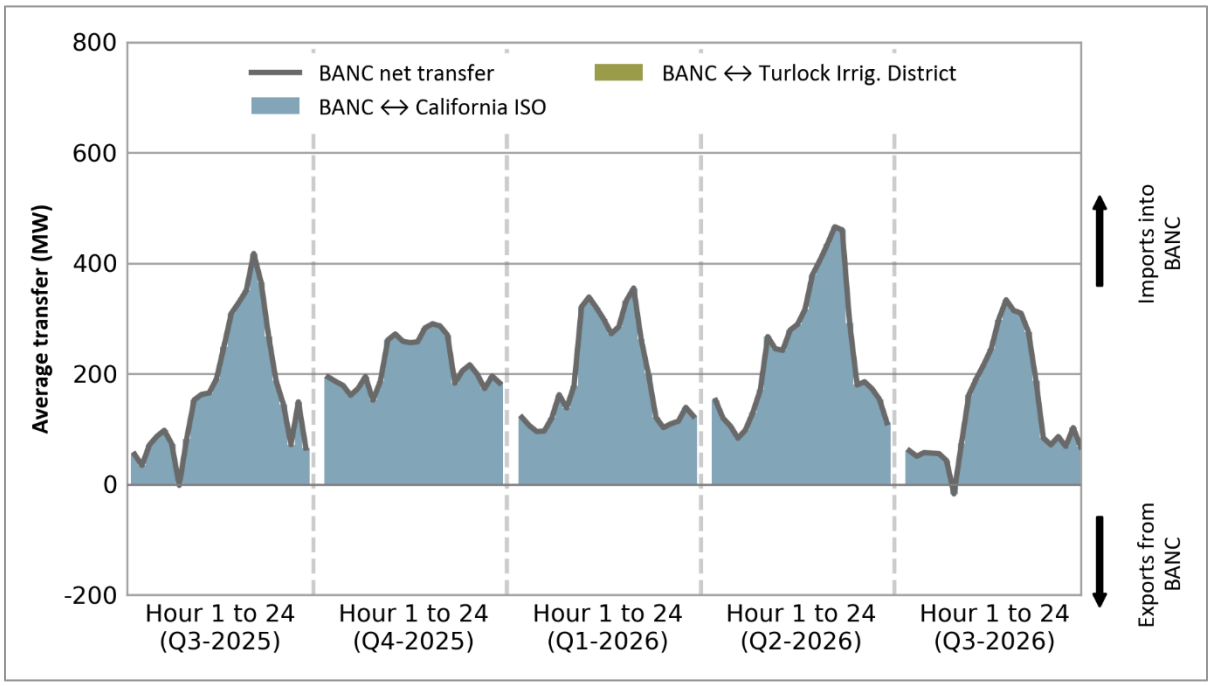
Appendix Figure A.21 Average hourly 15-minute market transfers



Appendix Figure A.22 Average hourly 5-minute price by component (July – September 2026)

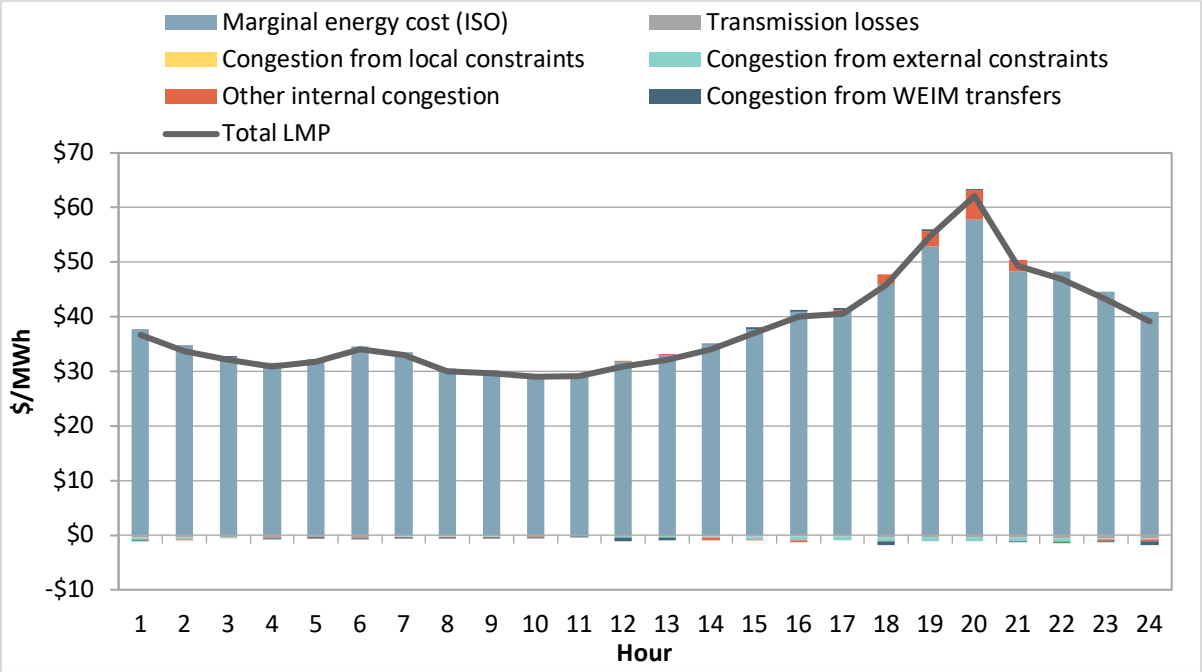


Appendix Figure A.24 Average hourly 5-minute market transfers

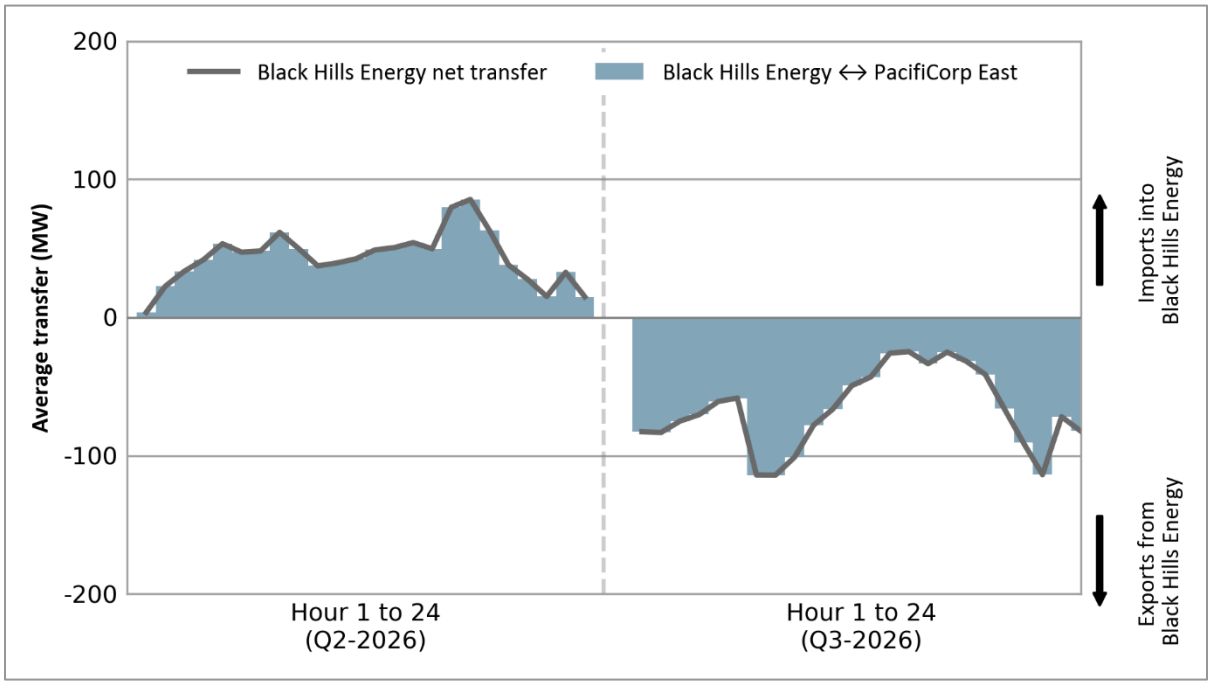


A.5 Black Hills Energy

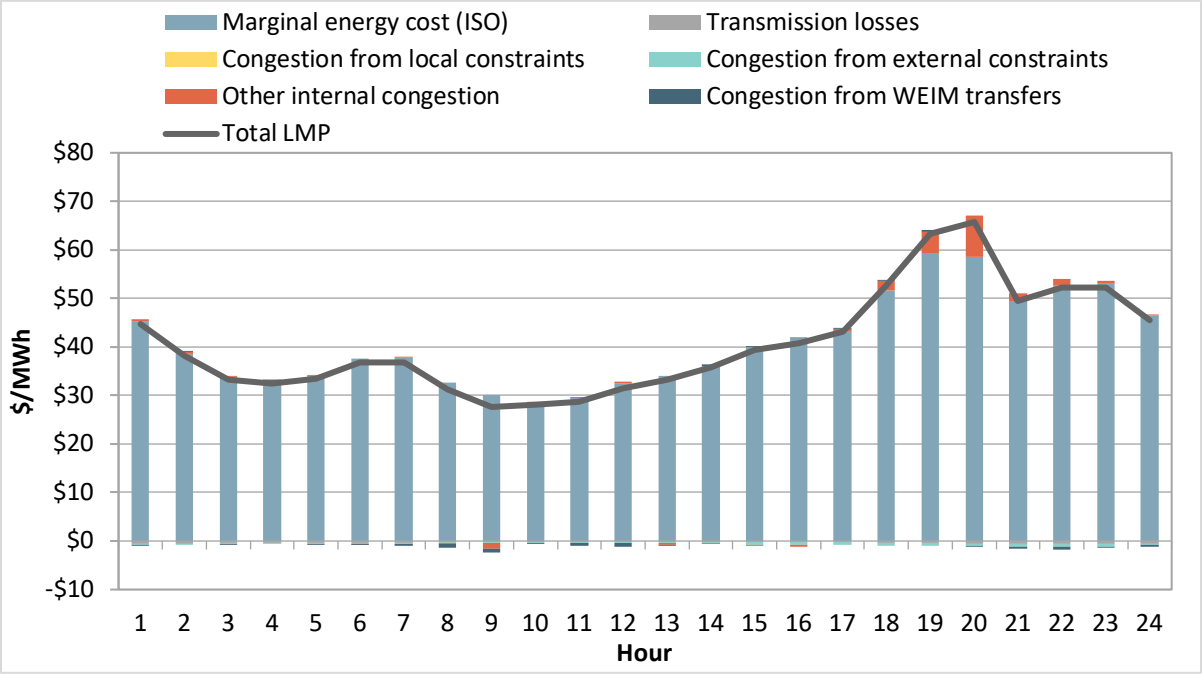
Appendix Figure A.25 Average hourly 15-minute price by component (July – September2026)



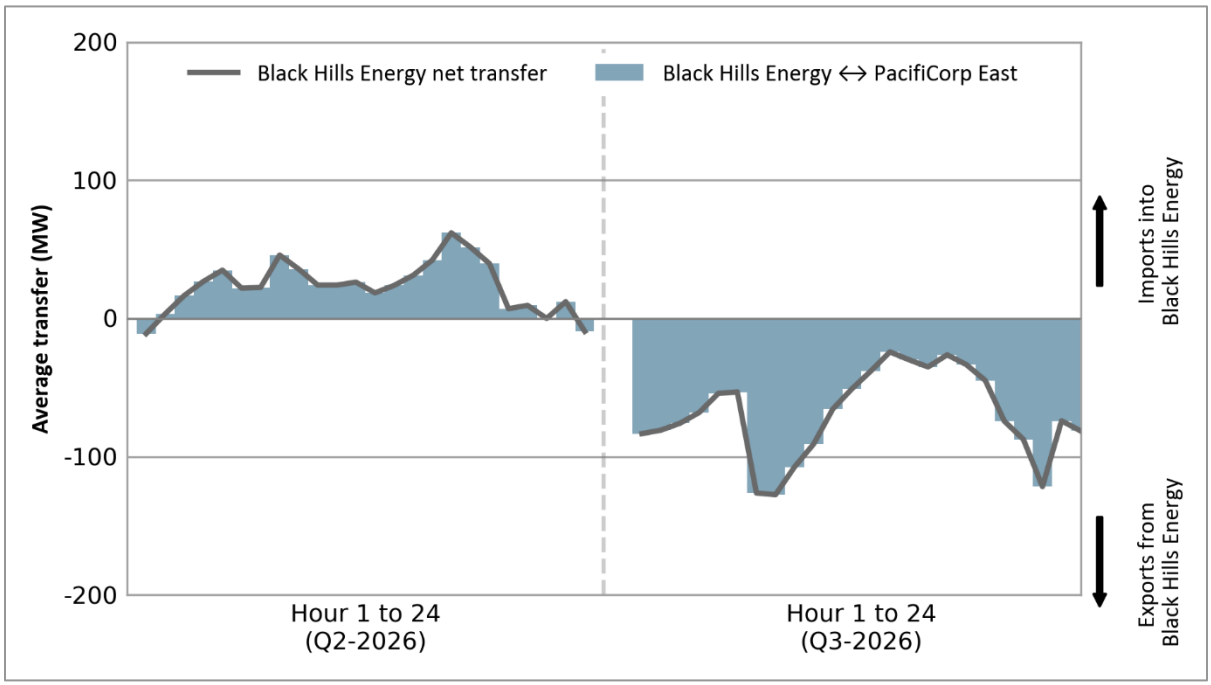
Appendix Figure A.26 Average hourly 15-minute market transfers



Appendix Figure A.27 Average hourly 5-minute price by component (July – September 2026)

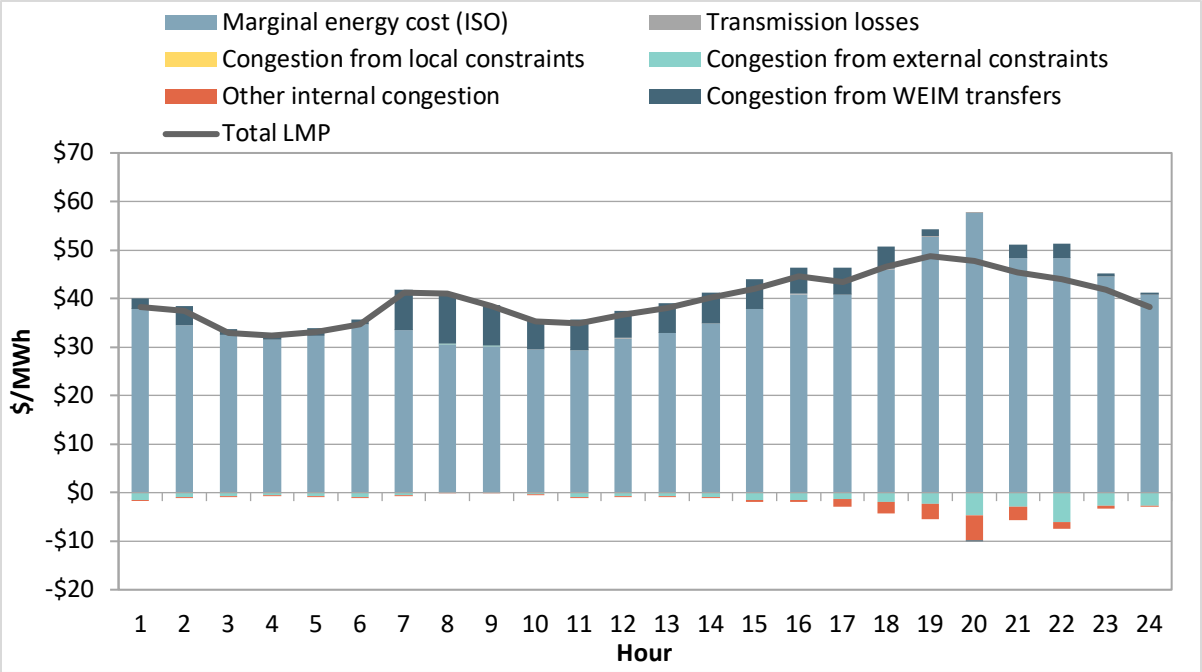


Appendix Figure A.28 Average hourly 5-minute market transfers

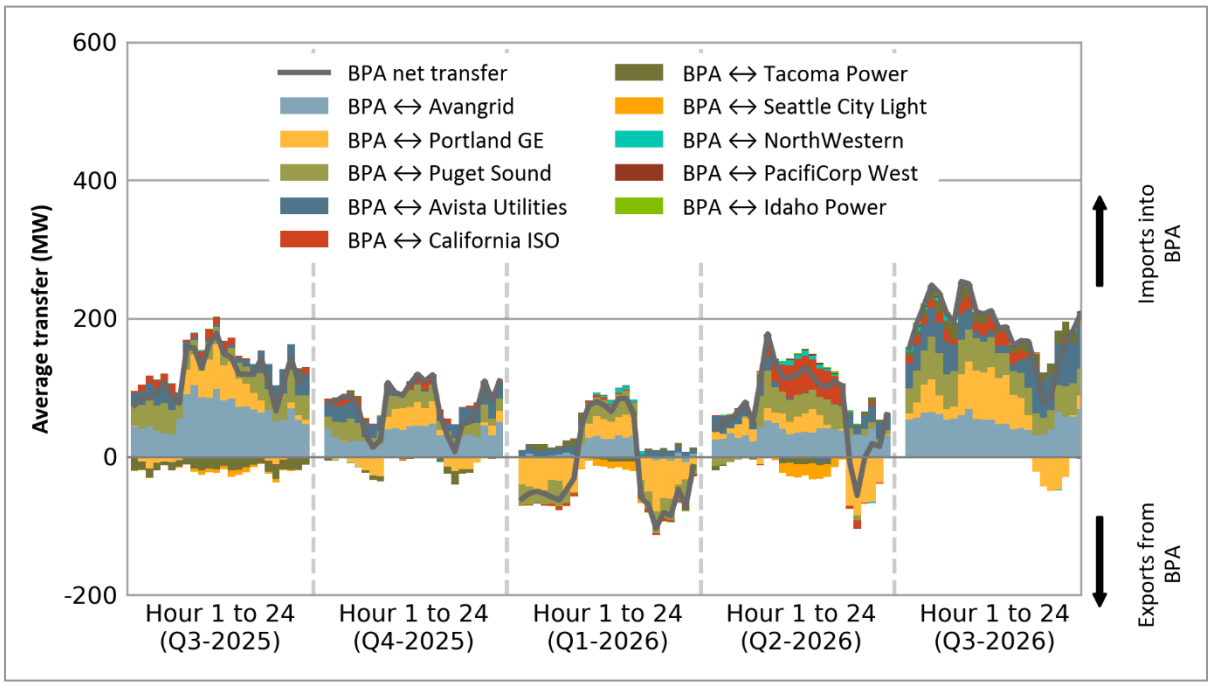


A.6 Bonneville Power Administration

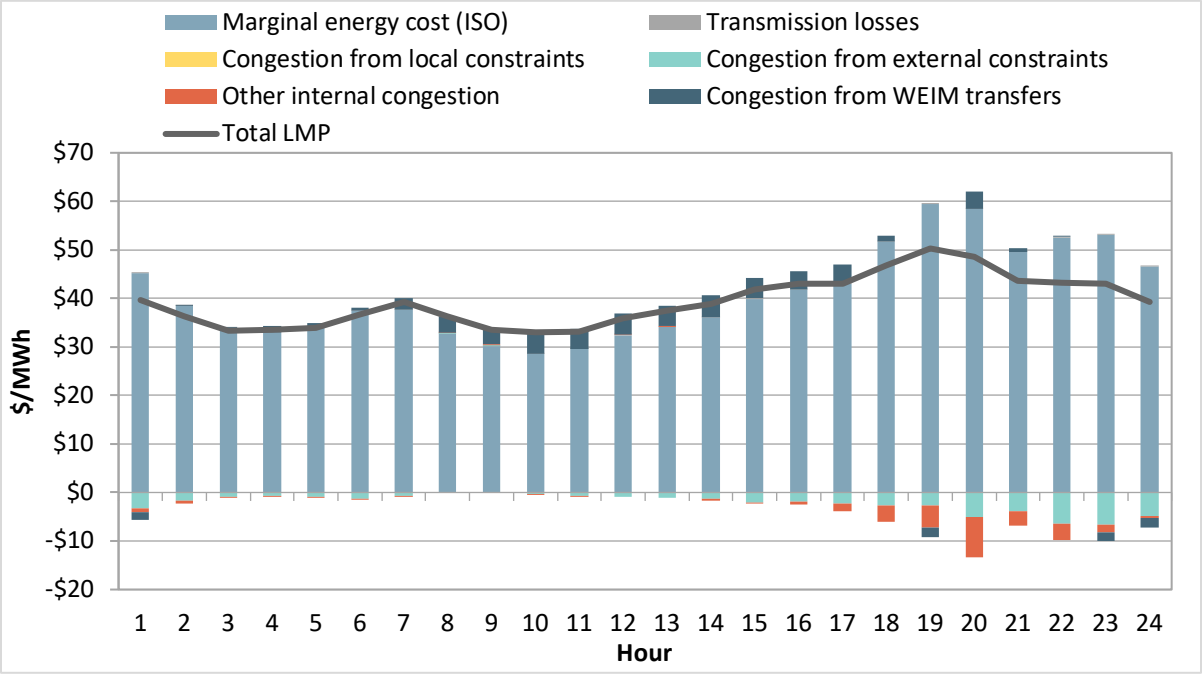
Appendix Figure A.29 Average hourly 15-minute price by component (July – September 2026)



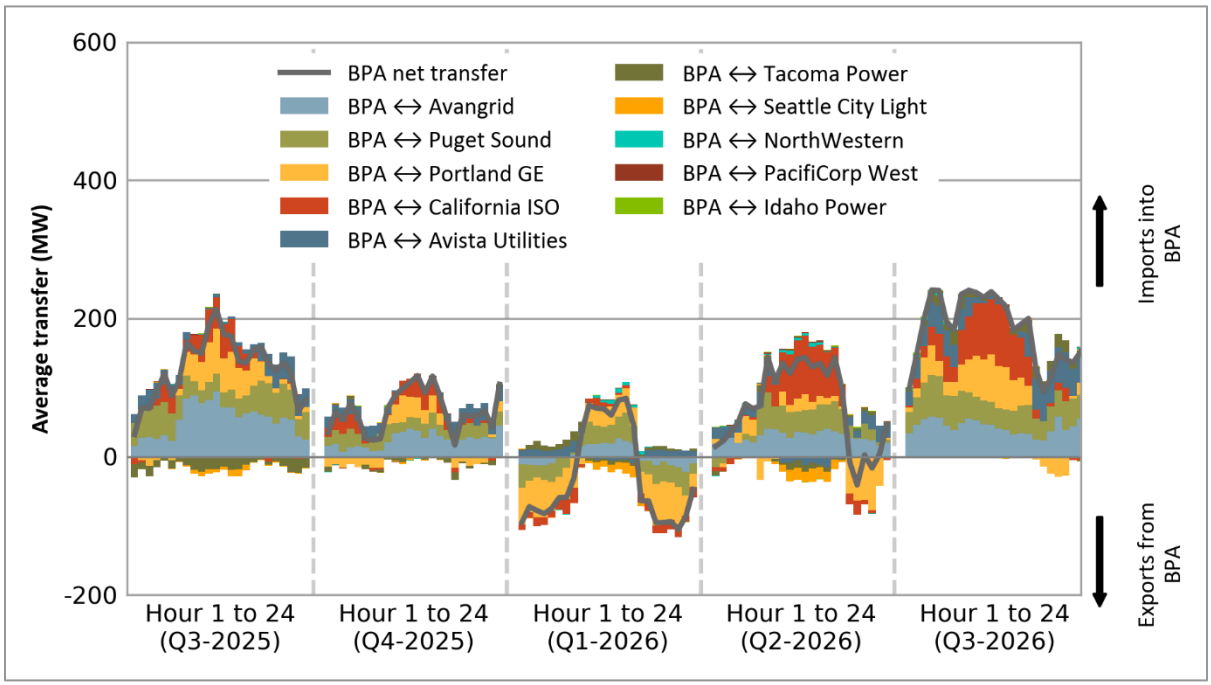
Appendix Figure A.31 Average hourly 15-minute market transfers



Appendix Figure A.32 Average hourly 5-minute price by component (July – September 2026)

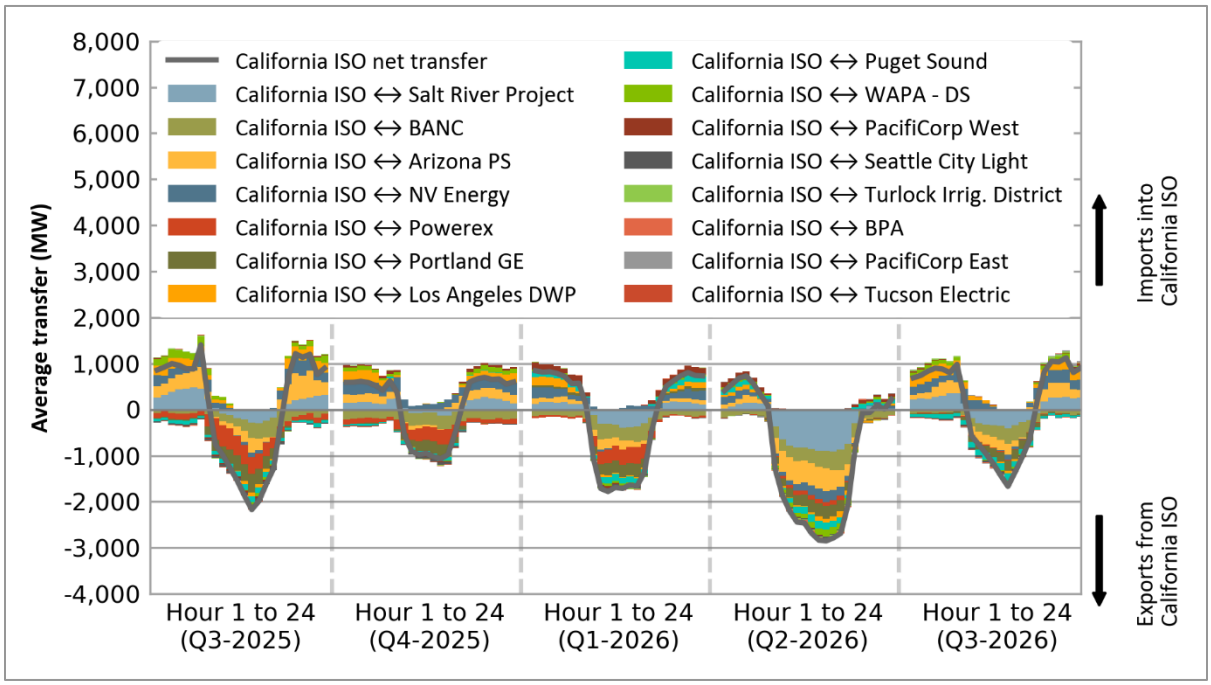


Appendix Figure A.34 Average hourly 5-minute market transfers

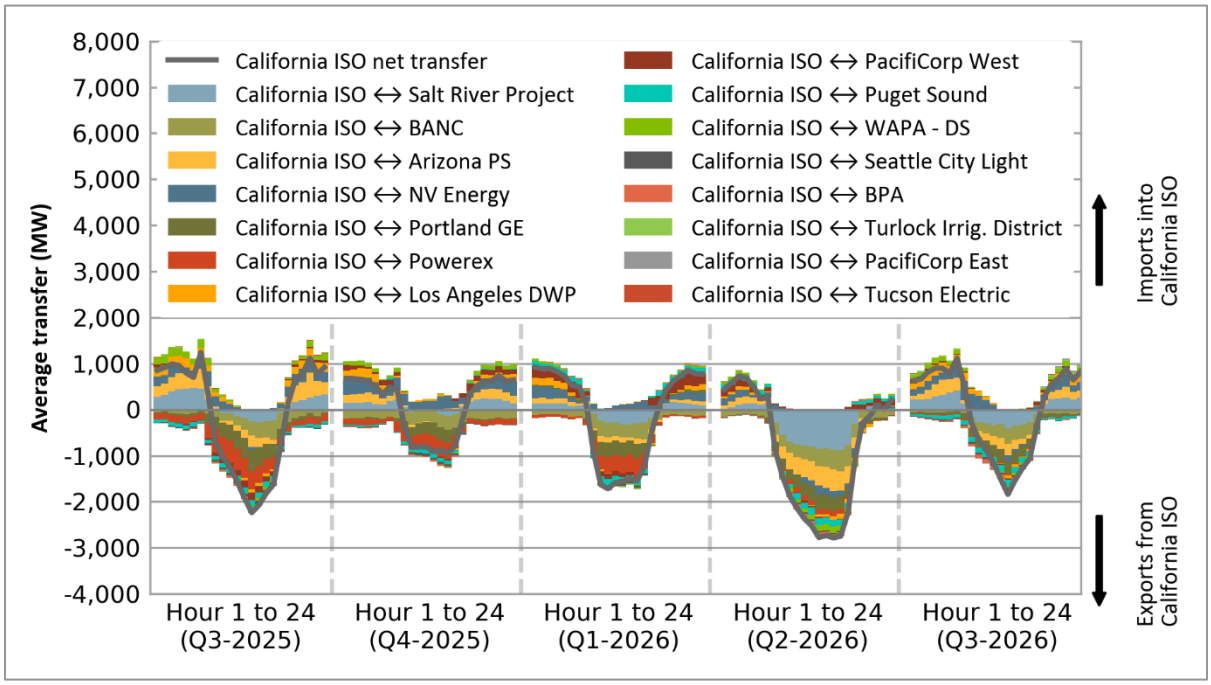


A.7 California ISO

Appendix Figure A.35 Average hourly 15-minute market transfers

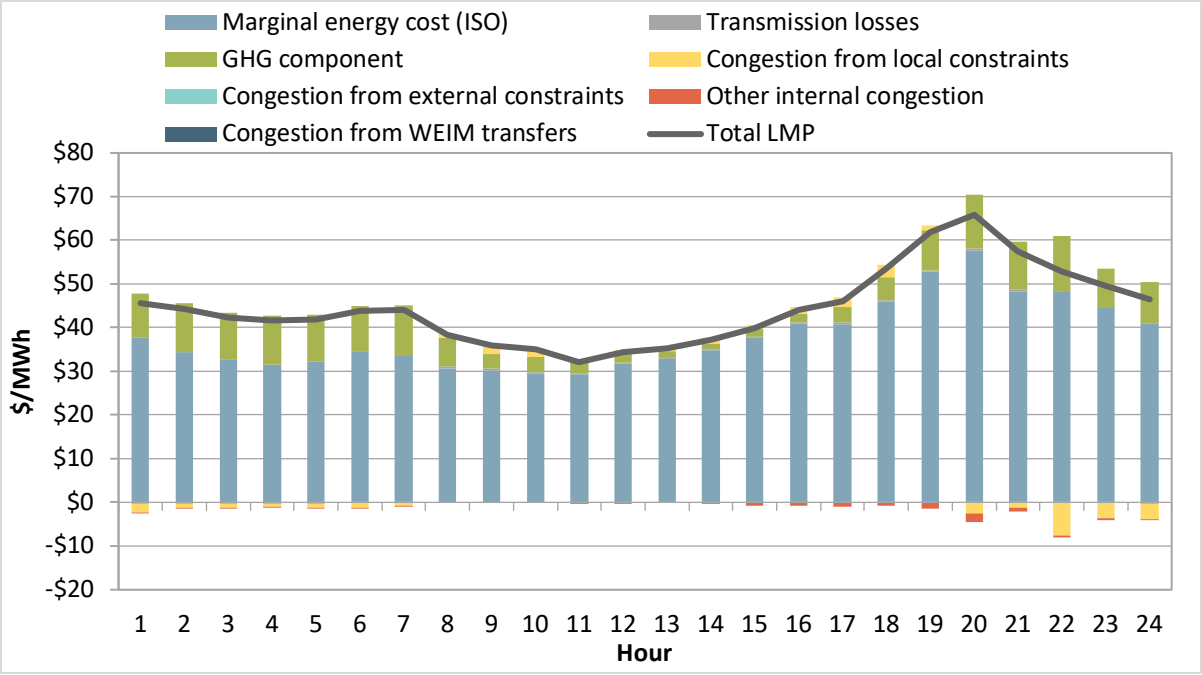


Appendix Figure A.36 Average hourly 5-minute market transfers

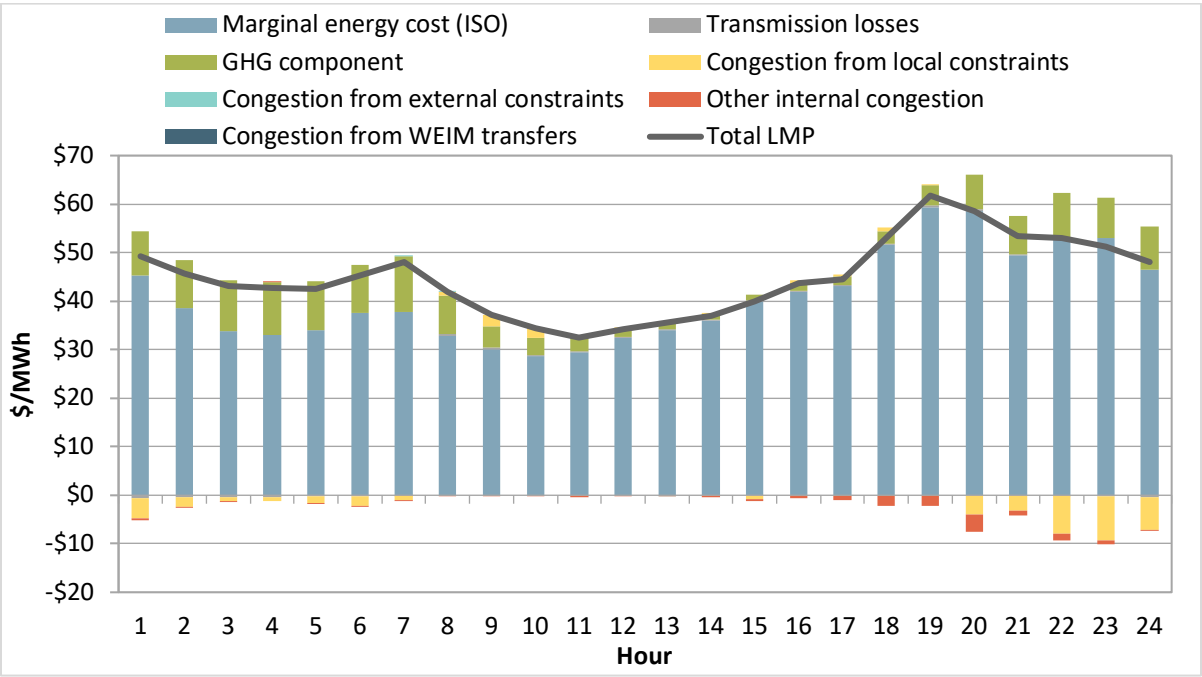


A.7.1 Pacific Gas and Electric

Appendix Figure A.37 Average hourly 15-minute price by component (July – September 2026)

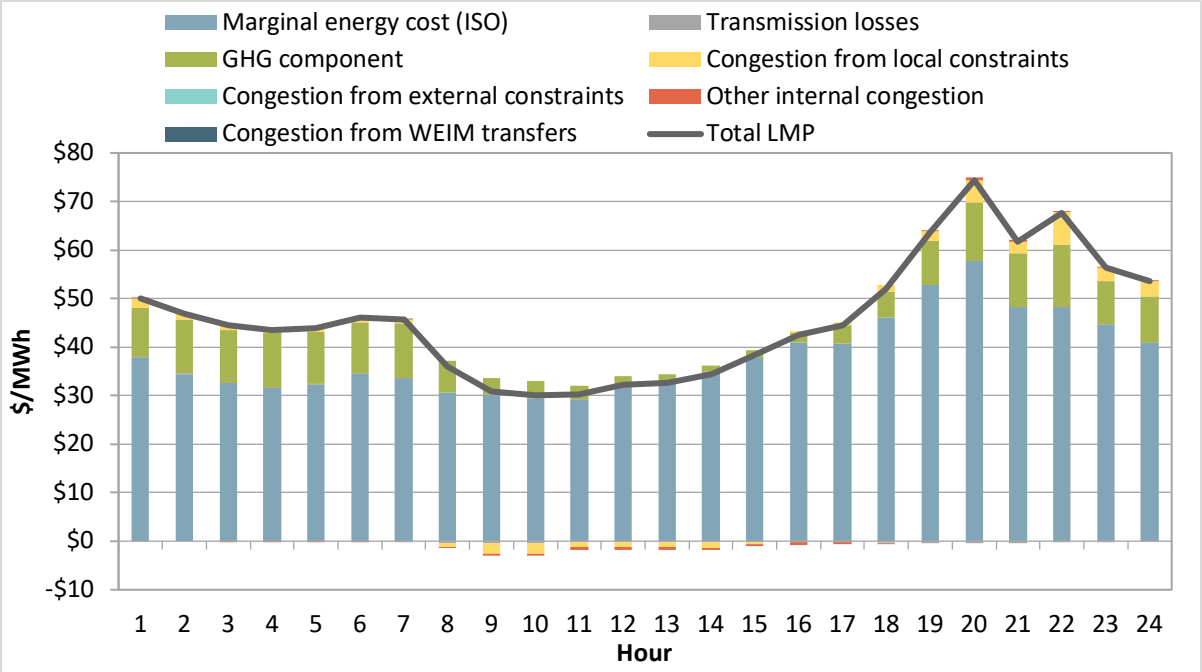


Appendix Figure A.39 Average hourly 5-minute price by component (July – September 2026)

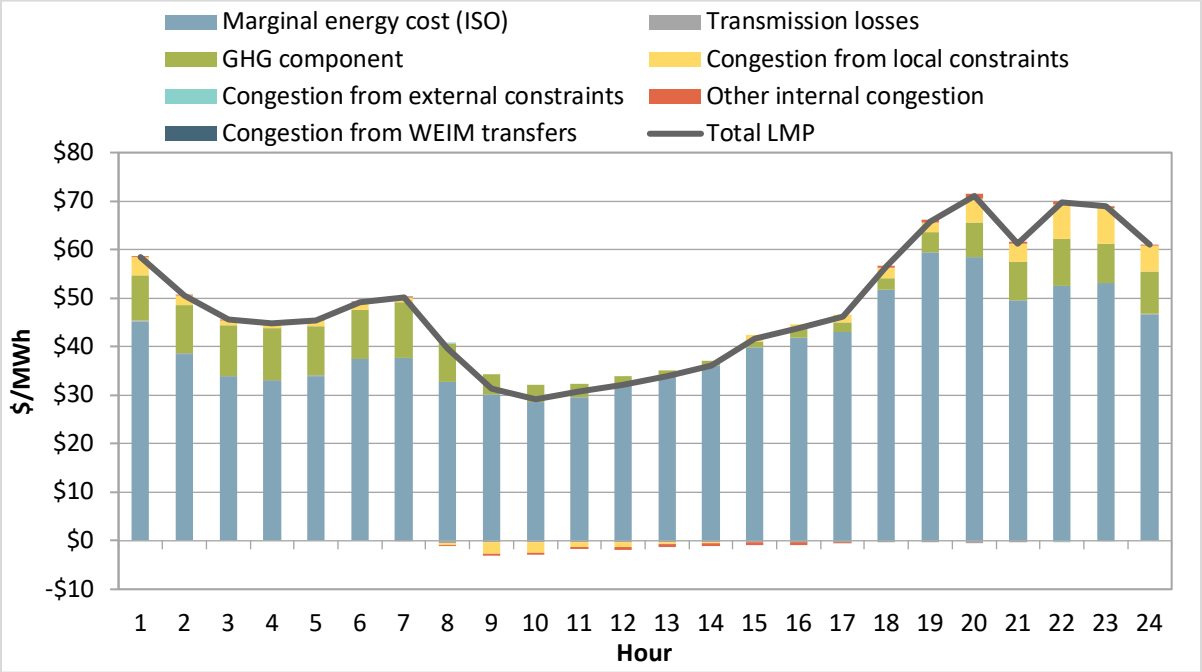


A.7.2 Southern California Edison

Appendix Figure A.41 Average hourly 15-minute price by component (July – September 2026)

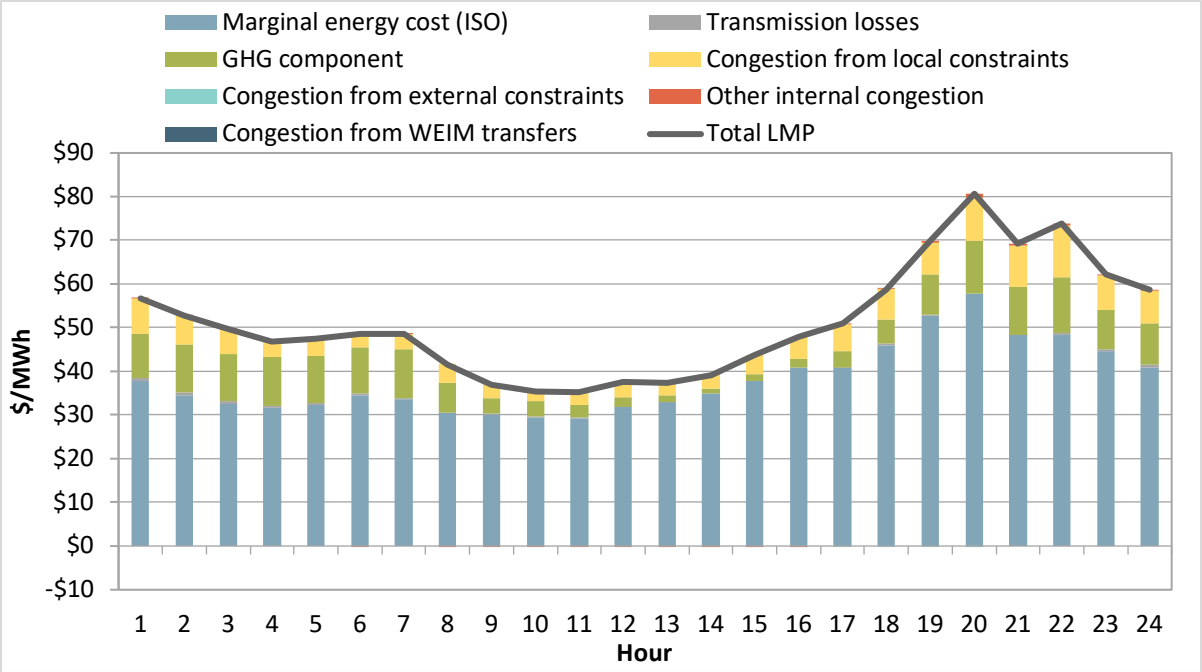


Appendix Figure A.43 Average hourly 5-minute price by component (July – September 2026)

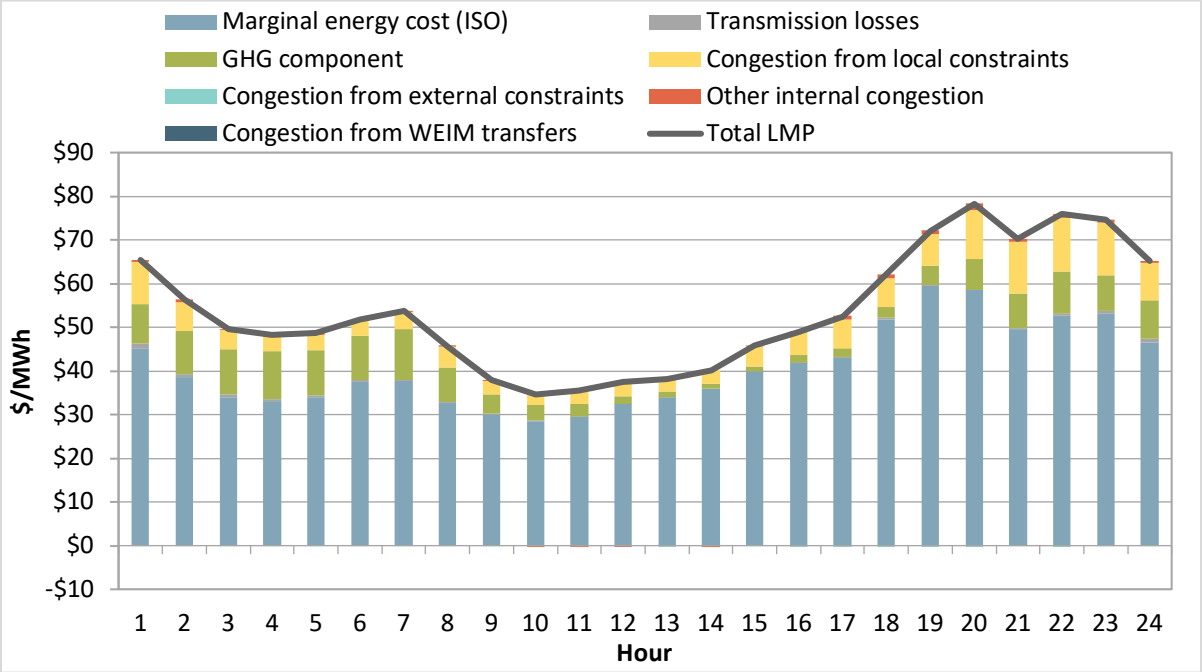


A.7.3 San Diego Gas & Electric

Appendix Figure A.45 Average hourly 15-minute price by component (July – September 2026)

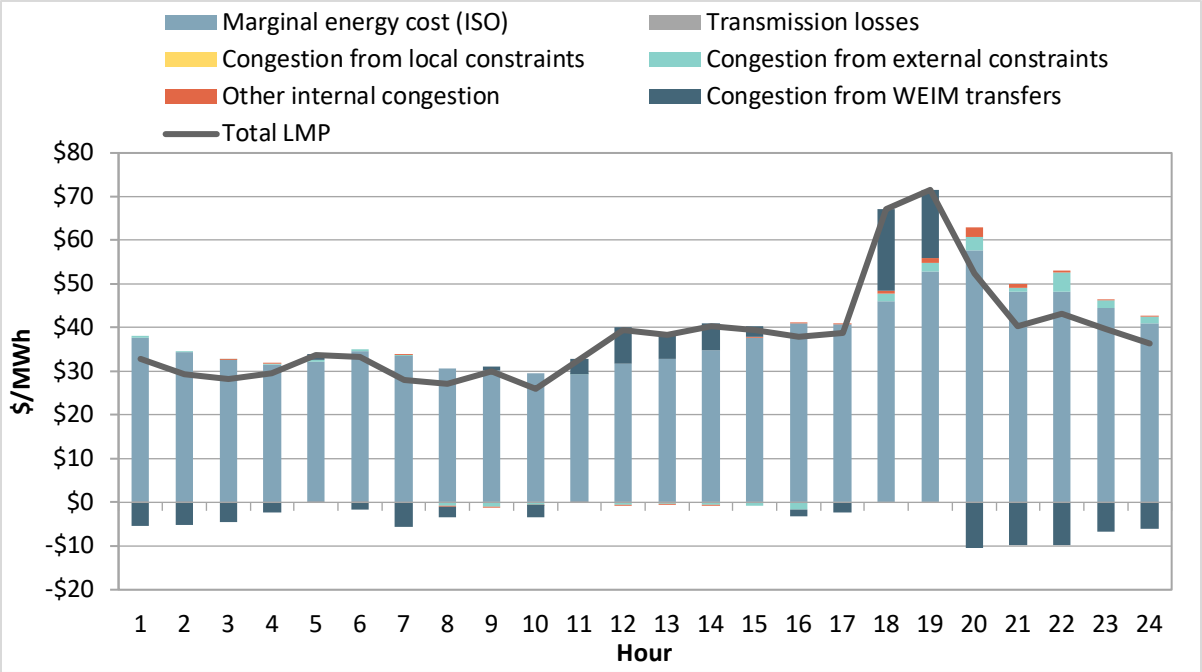


Appendix Figure A.47 Average hourly 5-minute price by component (July – September 2026)

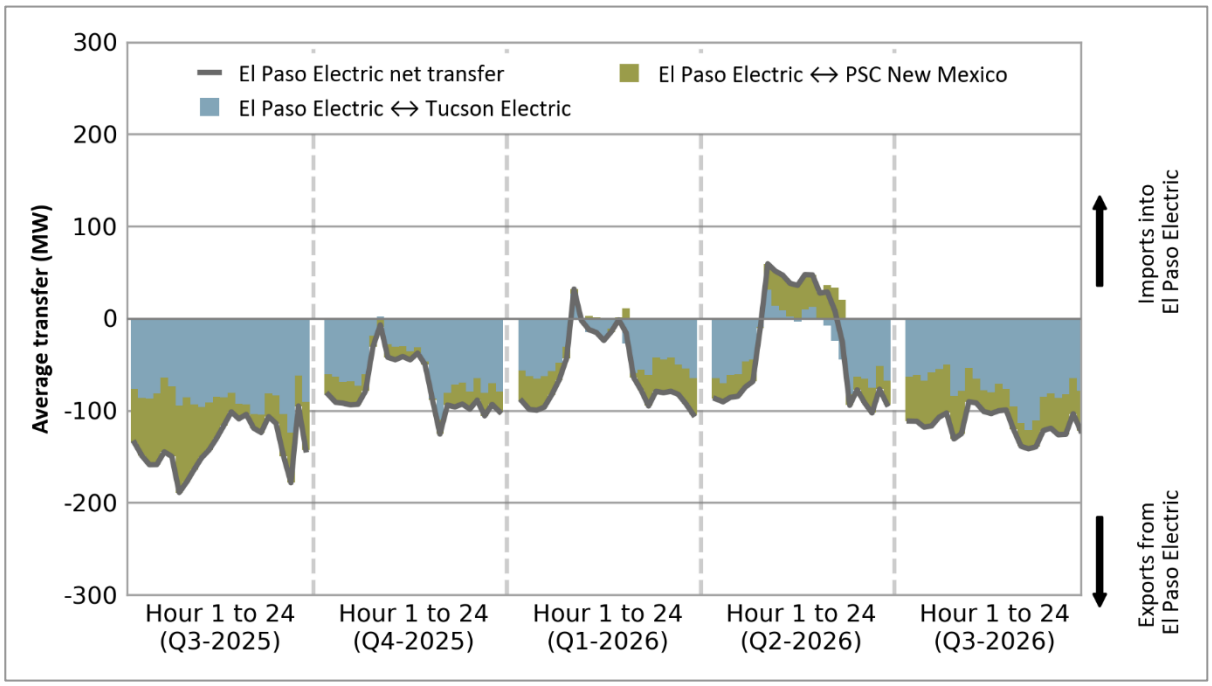


A.8 El Paso Electric

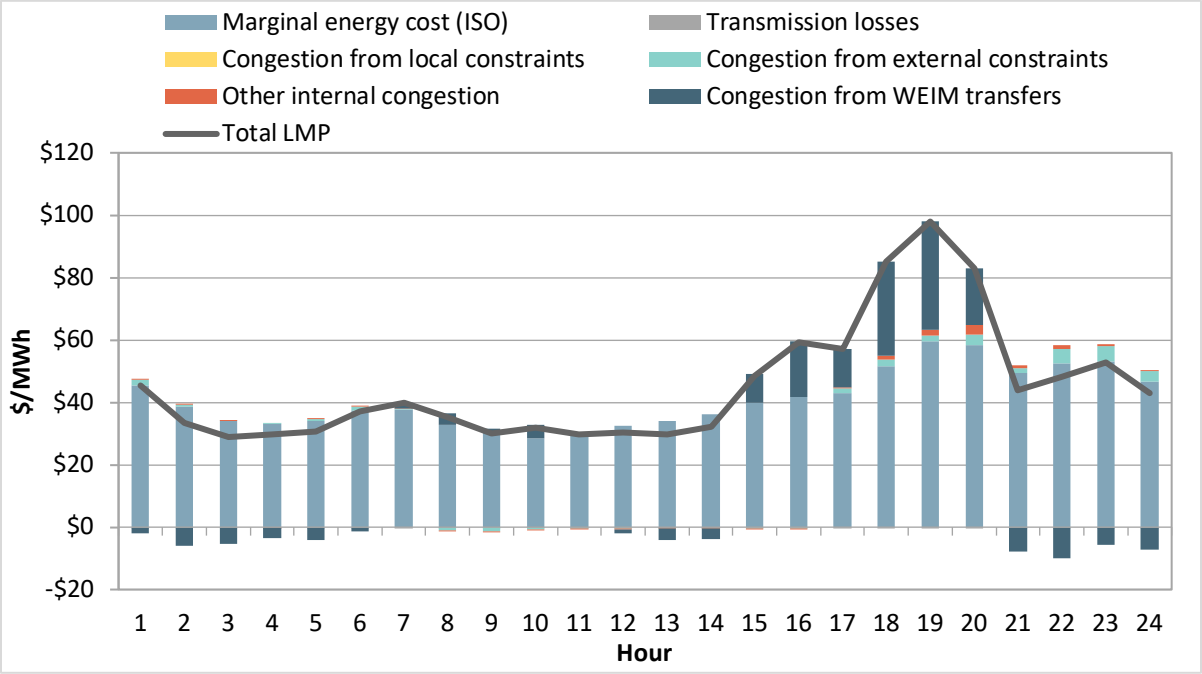
Appendix Figure A.49 Average hourly 15-minute price by component (July – September 2026)



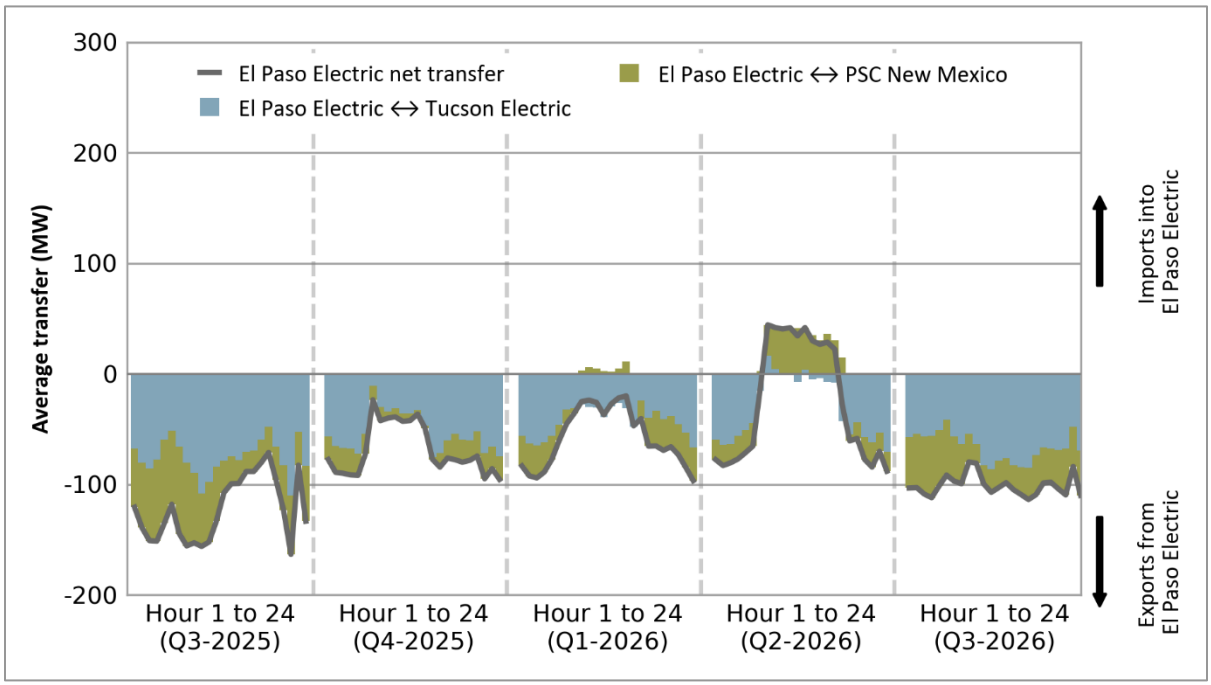
Appendix Figure A.51 Average hourly 15-minute market transfers



Appendix Figure A.52 Average hourly 5-minute price by component (July – September 2026)

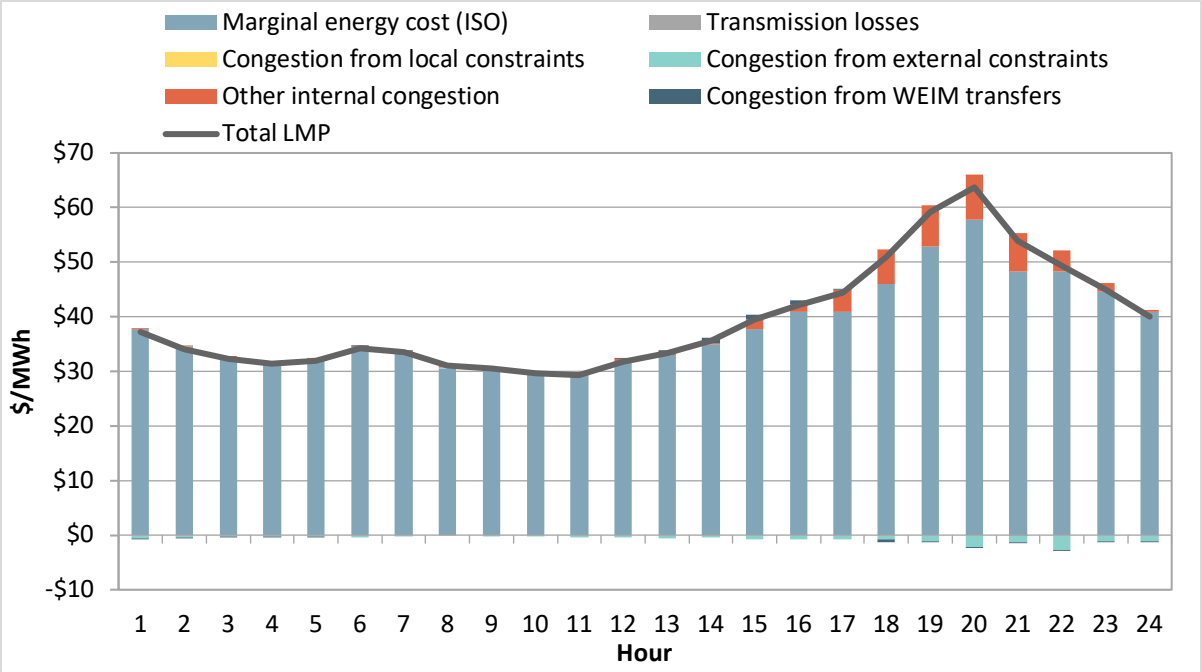


Appendix Figure A.54 Average hourly 5-minute market transfers

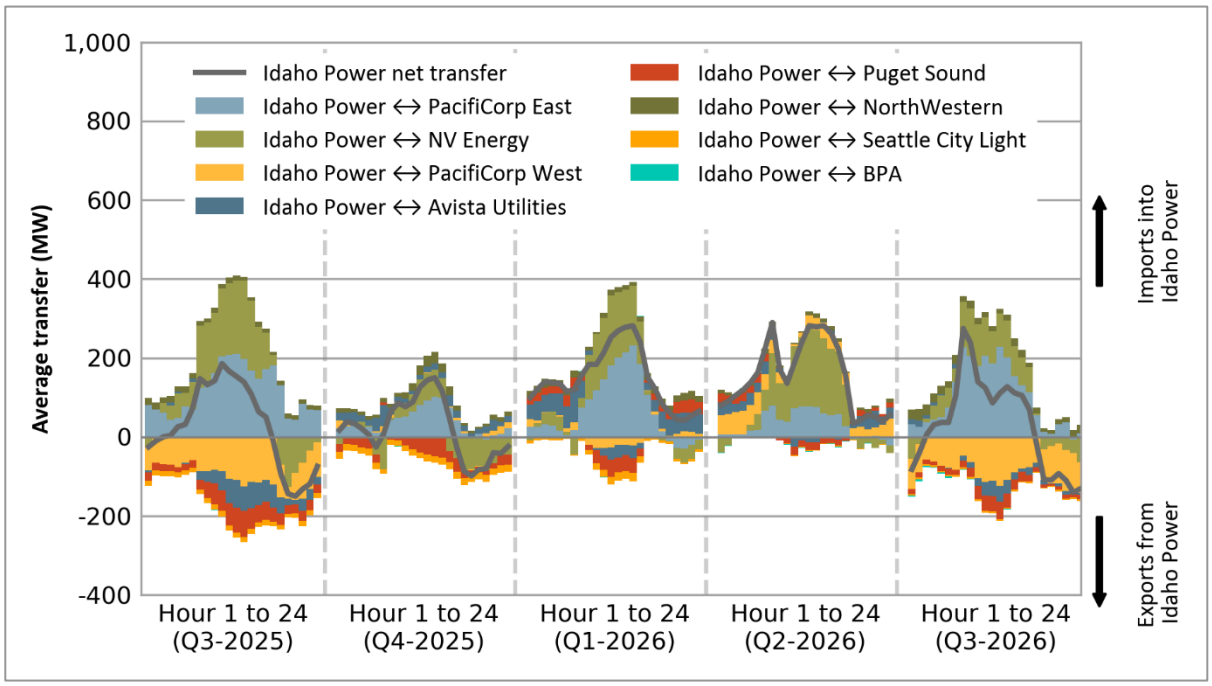


A.9 Idaho Power

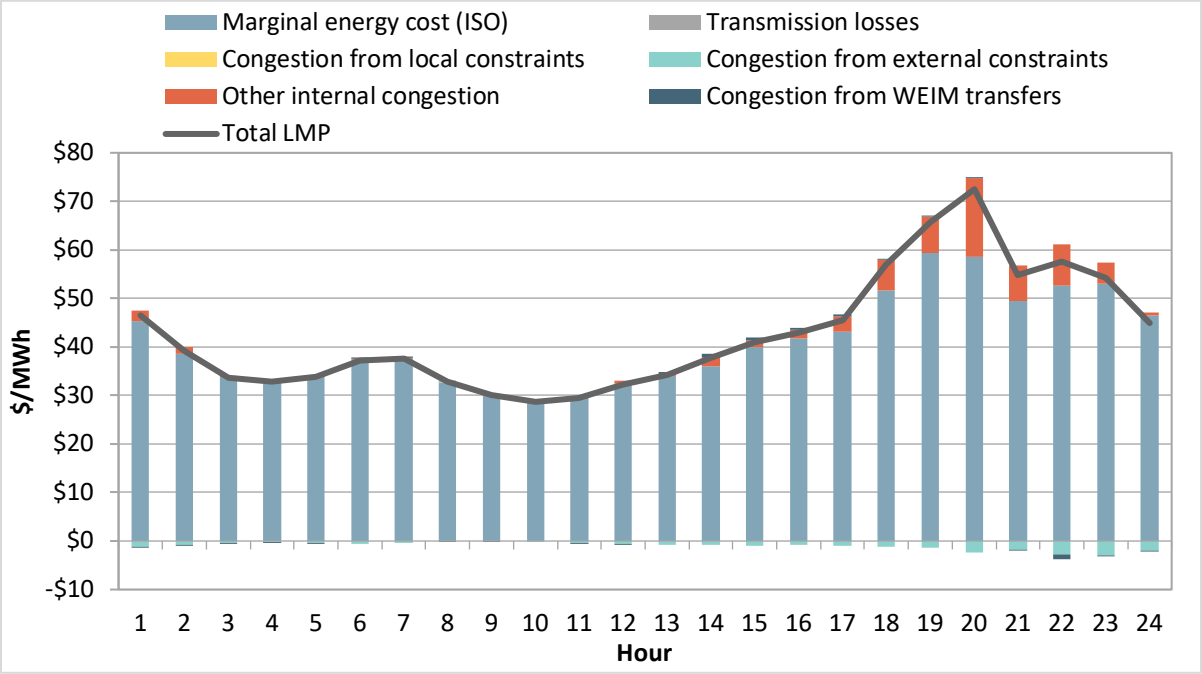
Appendix Figure A.55 Average hourly 15-minute price by component (July – September 2026)



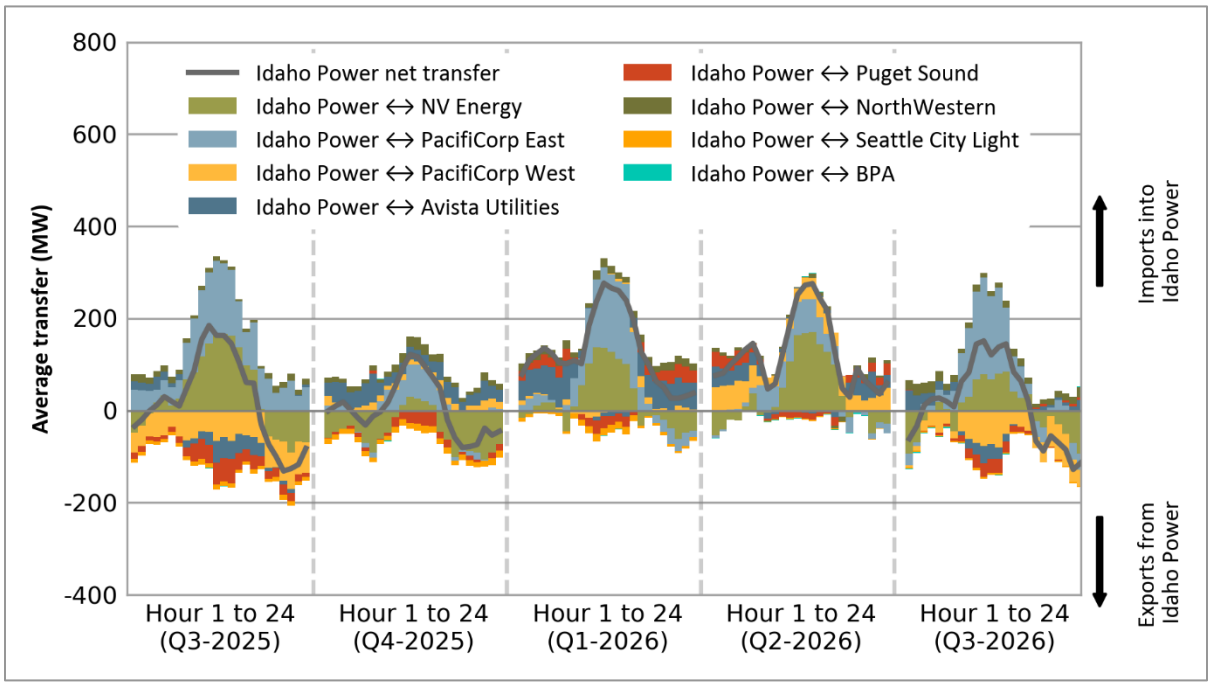
Appendix Figure A.57 Average hourly 15-minute market transfers



Appendix Figure A.58 Average hourly 5-minute price by component (July – September 2026)

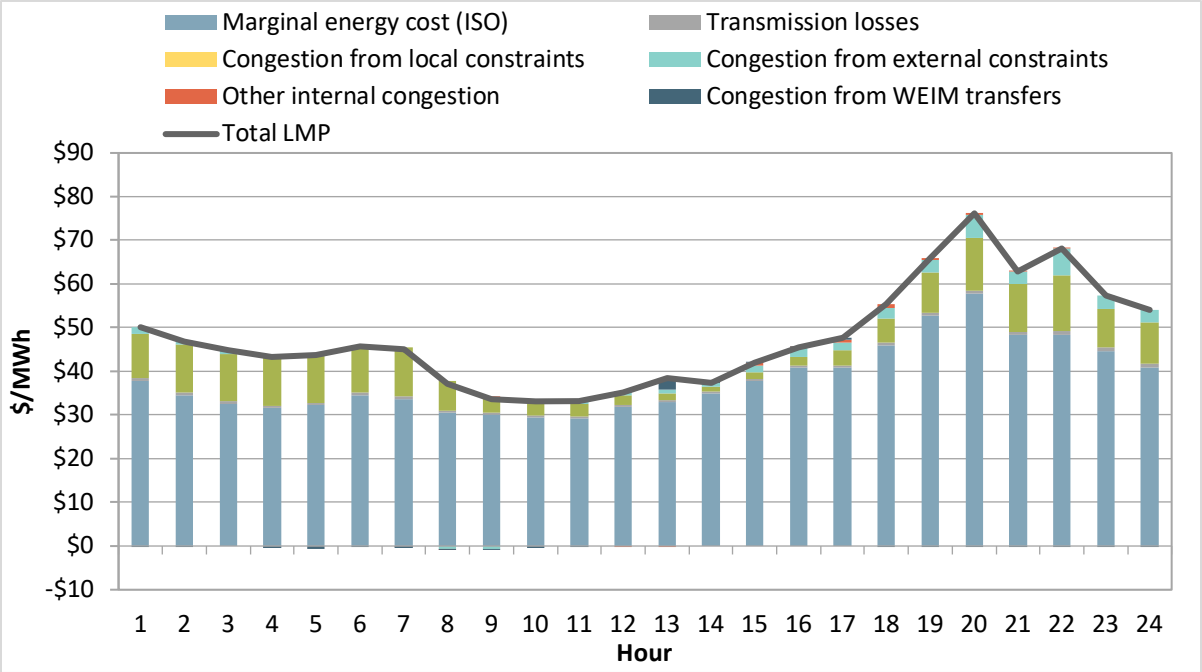


Appendix Figure A.60 Average hourly 5-minute market transfers

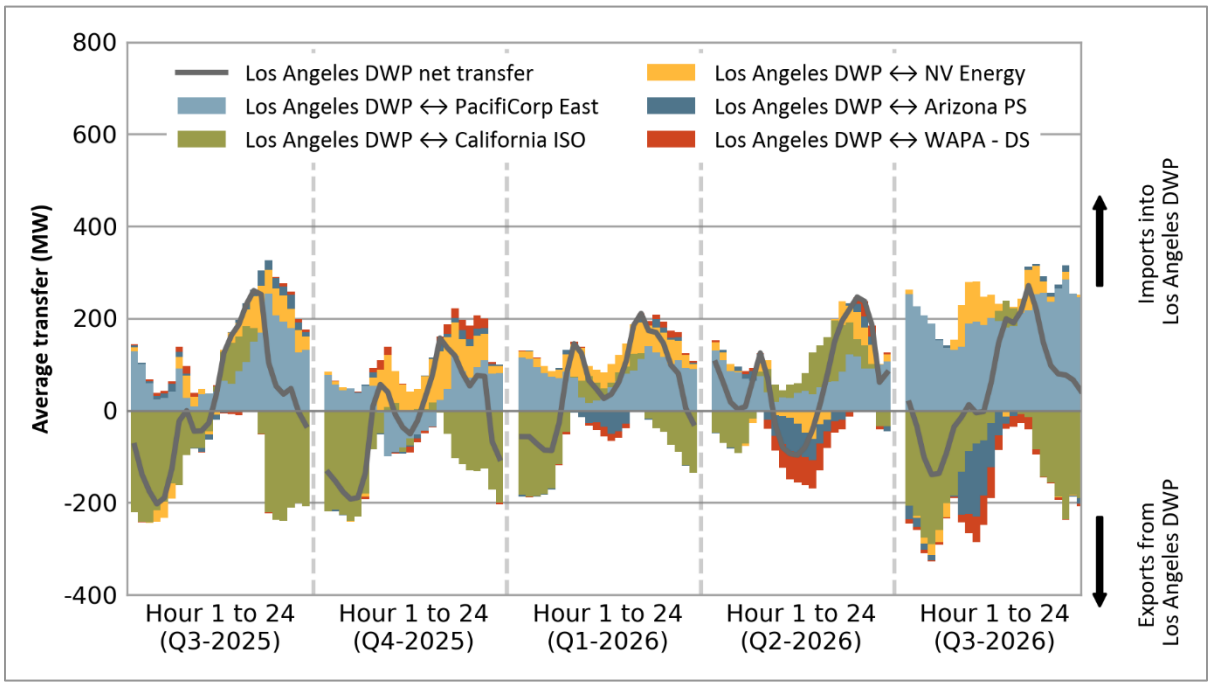


A.10 Los Angeles Department of Water and Power

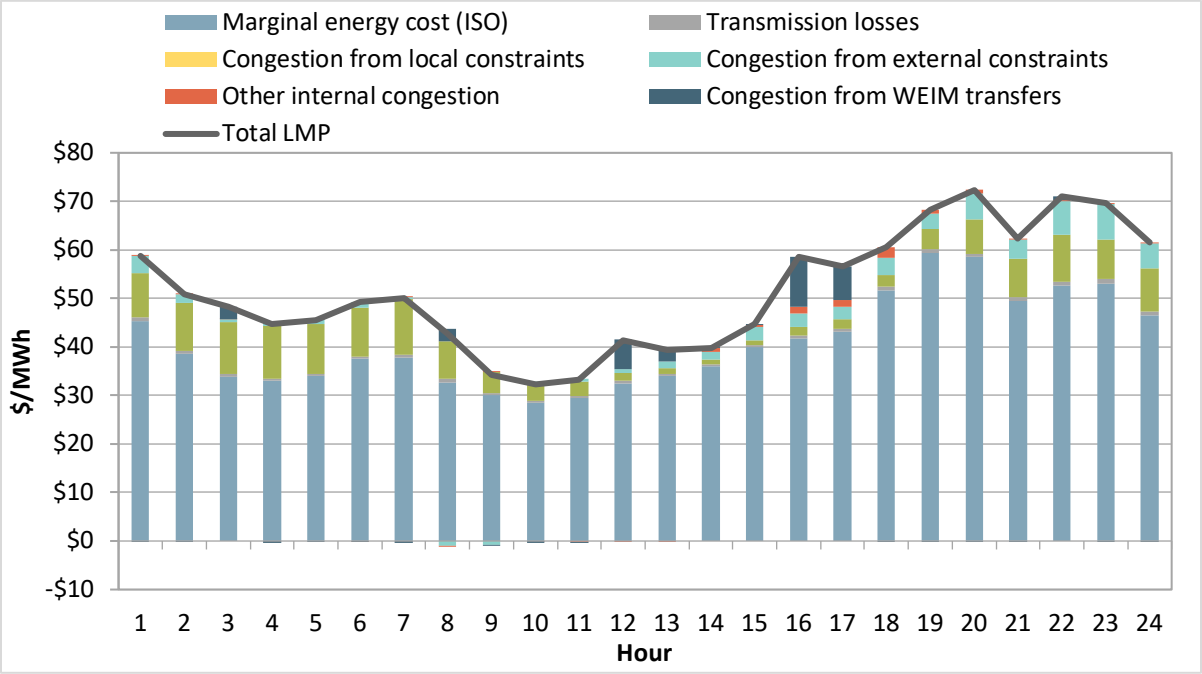
Appendix Figure A.61 Average hourly 15-minute price by component (July – September 2026)



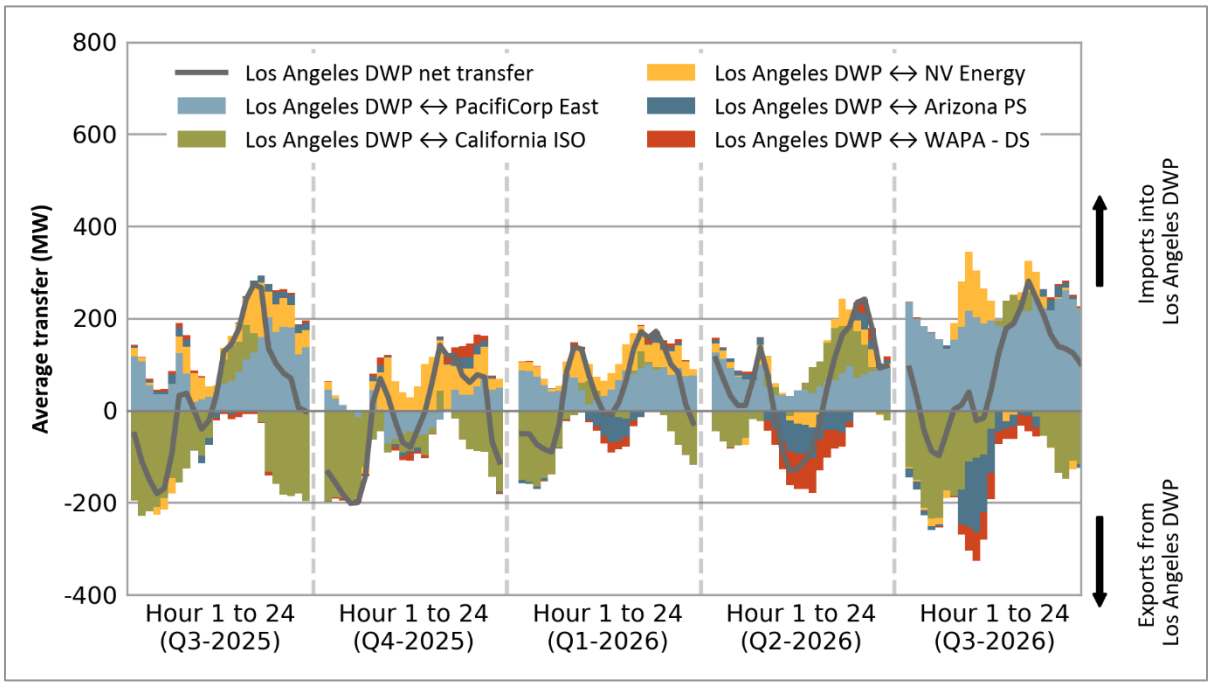
Appendix Figure A.63 Average hourly 15-minute market transfers



Appendix Figure A.64 Average hourly 5-minute price by component (July – September 2026)

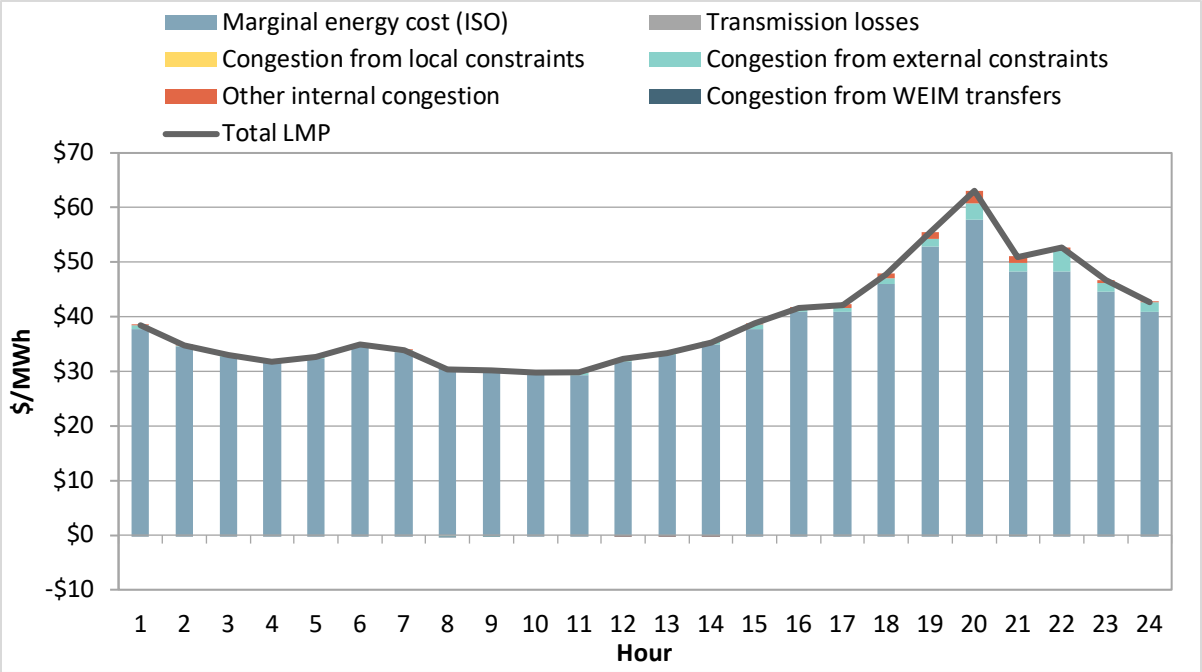


Appendix Figure A.66 Average hourly 5-minute market transfers

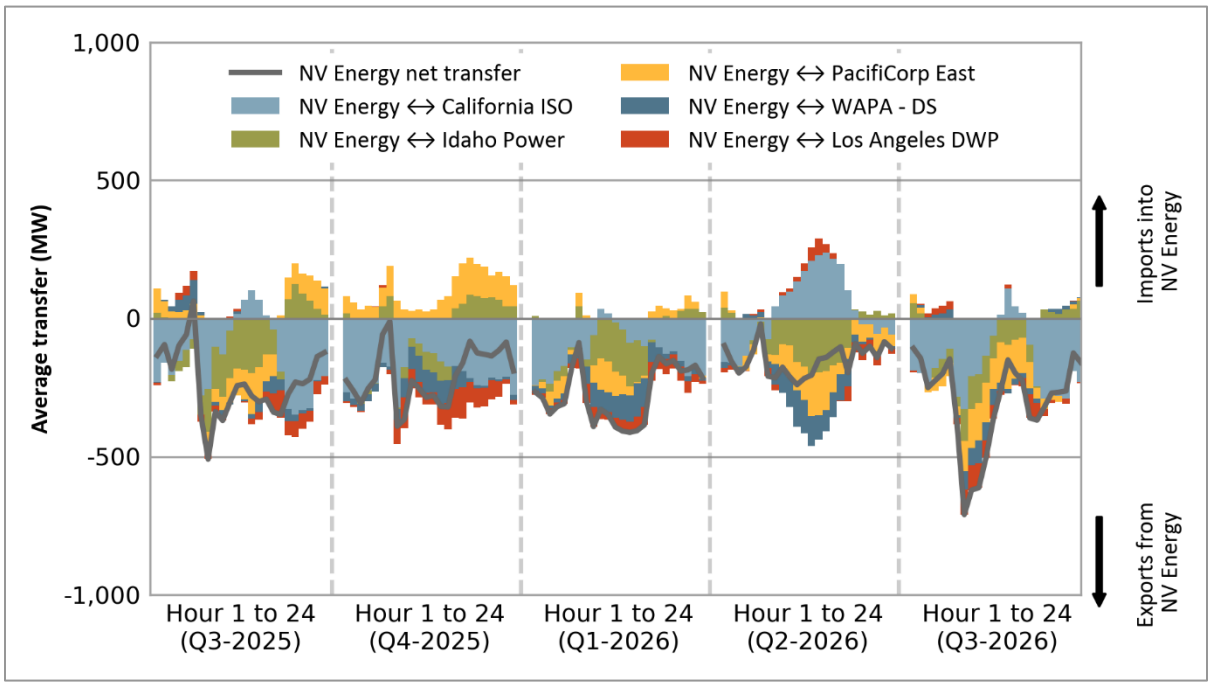


A.11 NV Energy

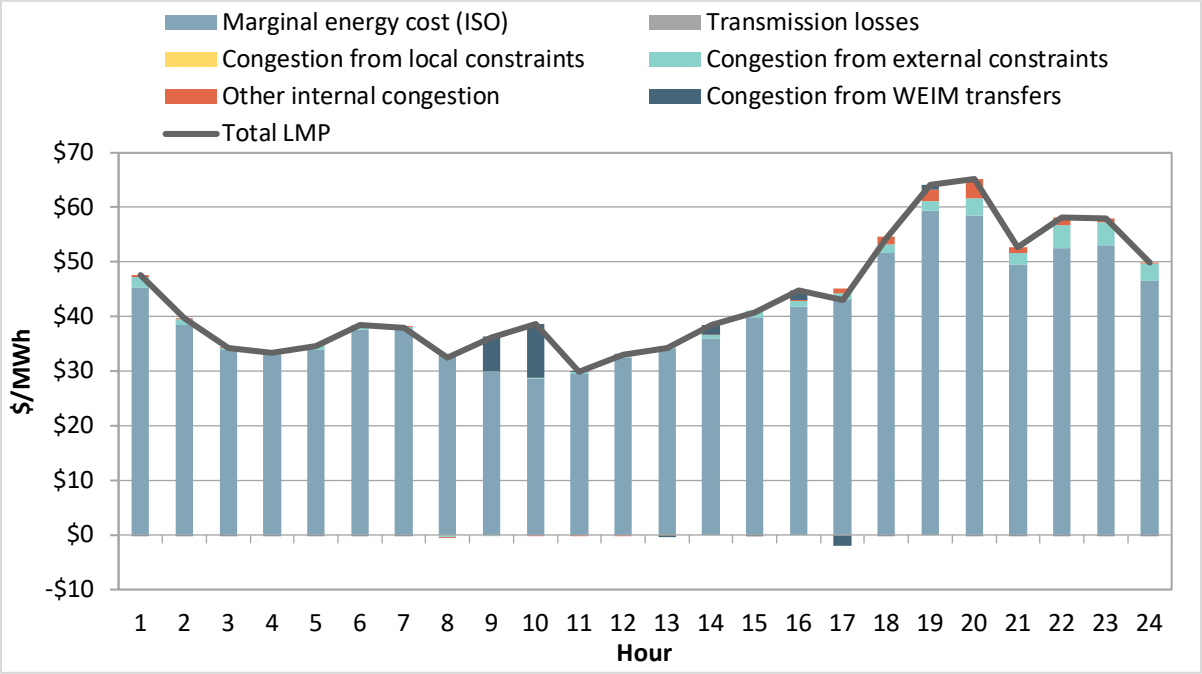
Appendix Figure A.67 Average hourly 15-minute price by component (July – September 2026)



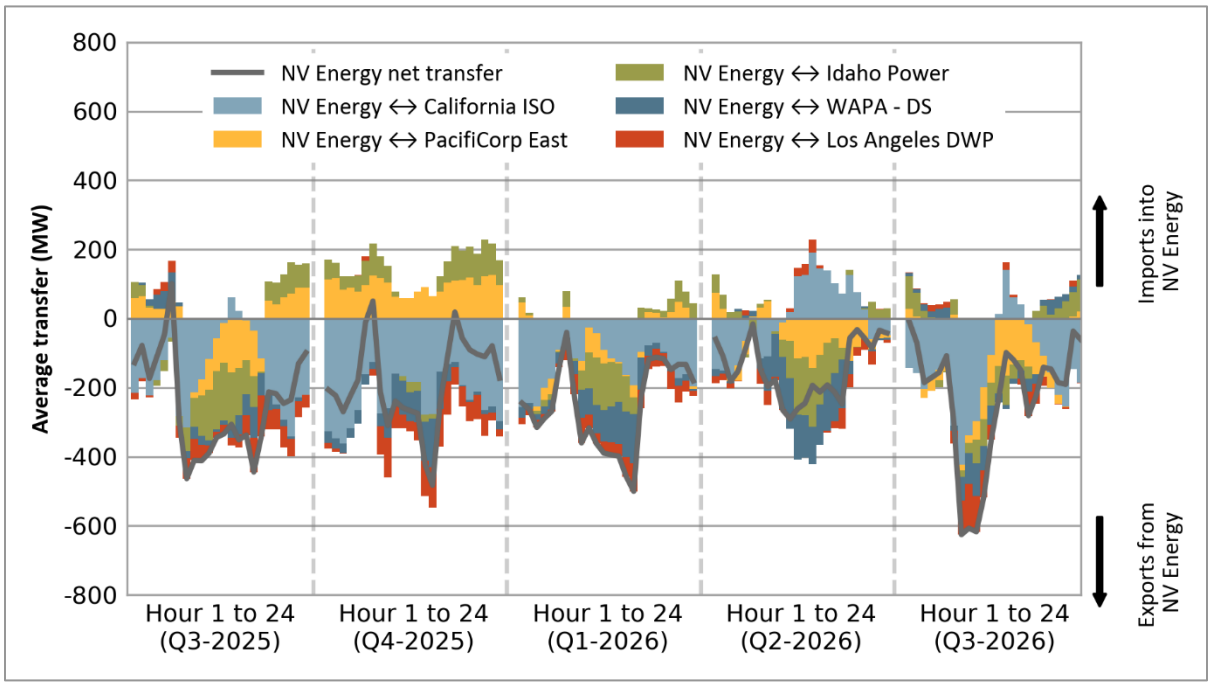
Appendix Figure A.69 Average hourly 15-minute market transfers



Appendix Figure A.70 Average hourly 5-minute price by component (July – September 2026)

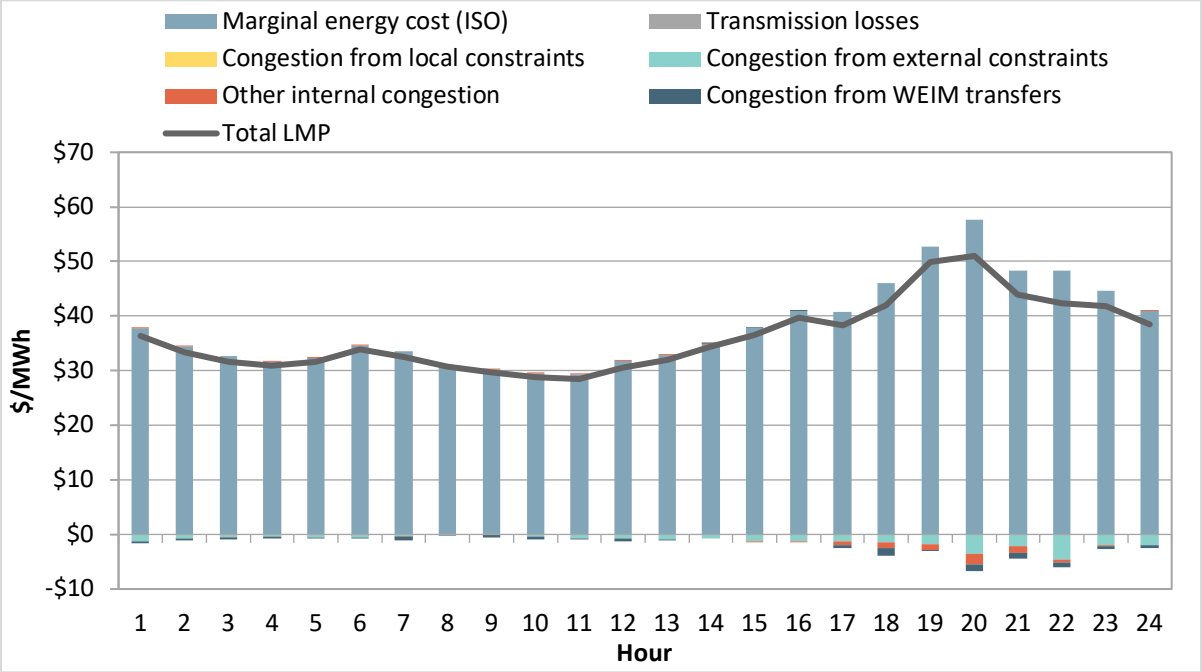


Appendix Figure A.72 Average hourly 5-minute market transfers

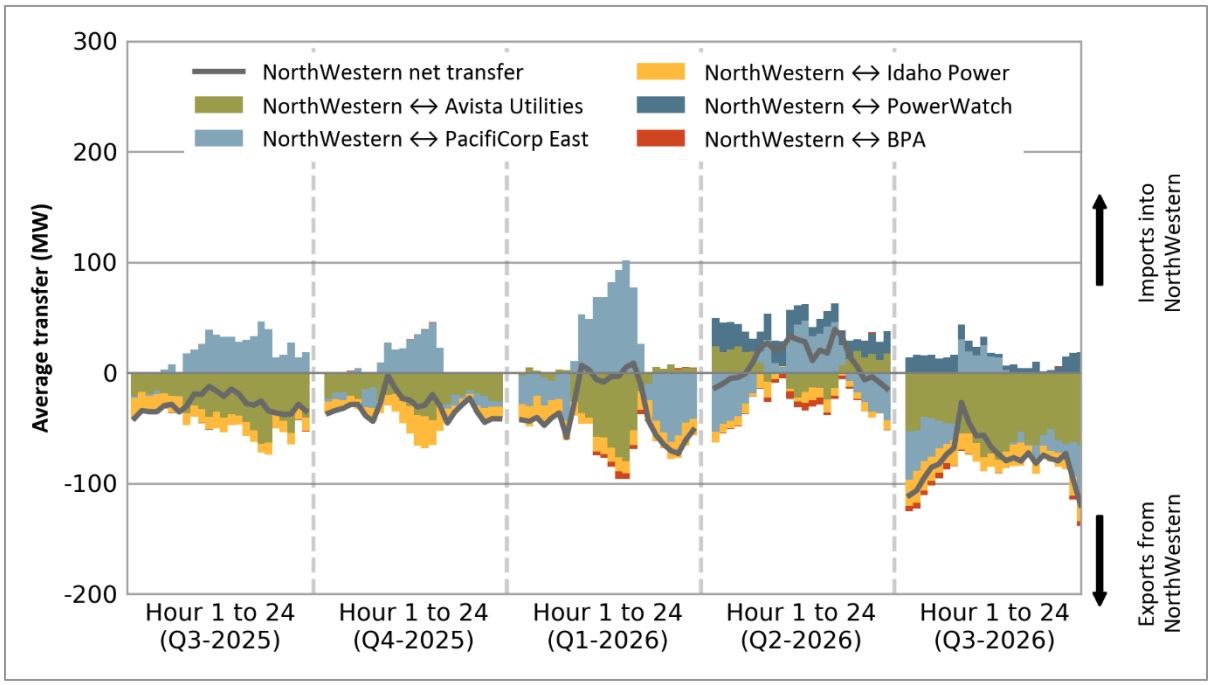


A.12 NorthWestern Energy

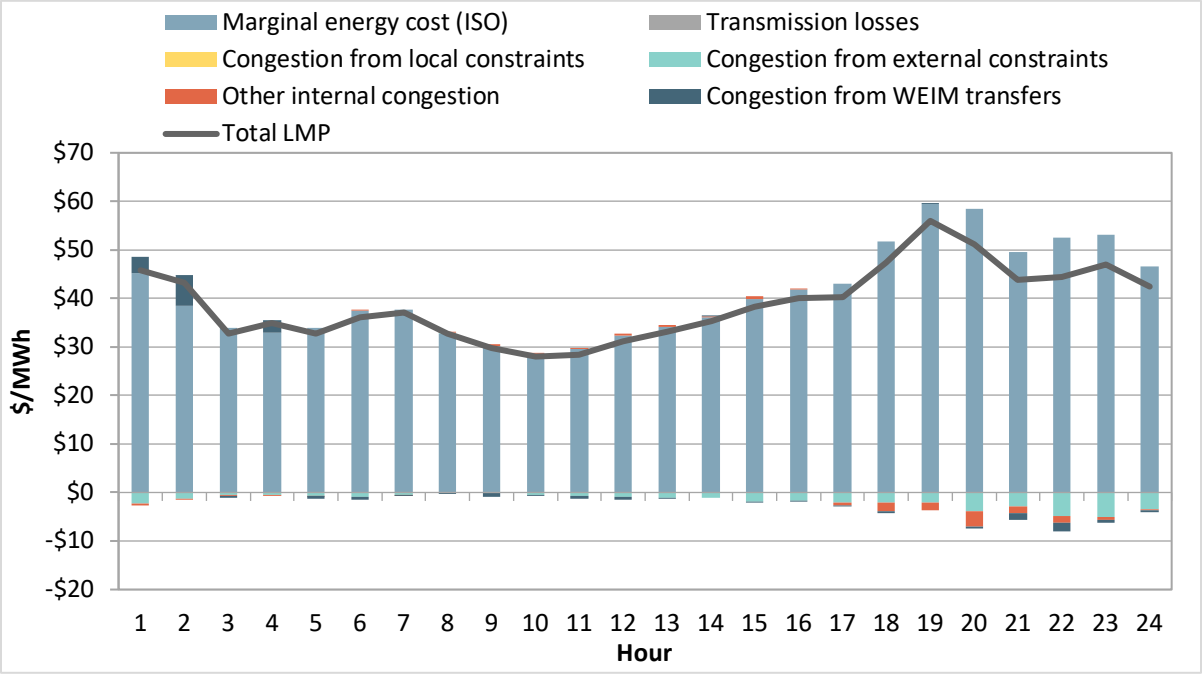
Appendix Figure A.73 Average hourly 15-minute price by component (July – September 2026)



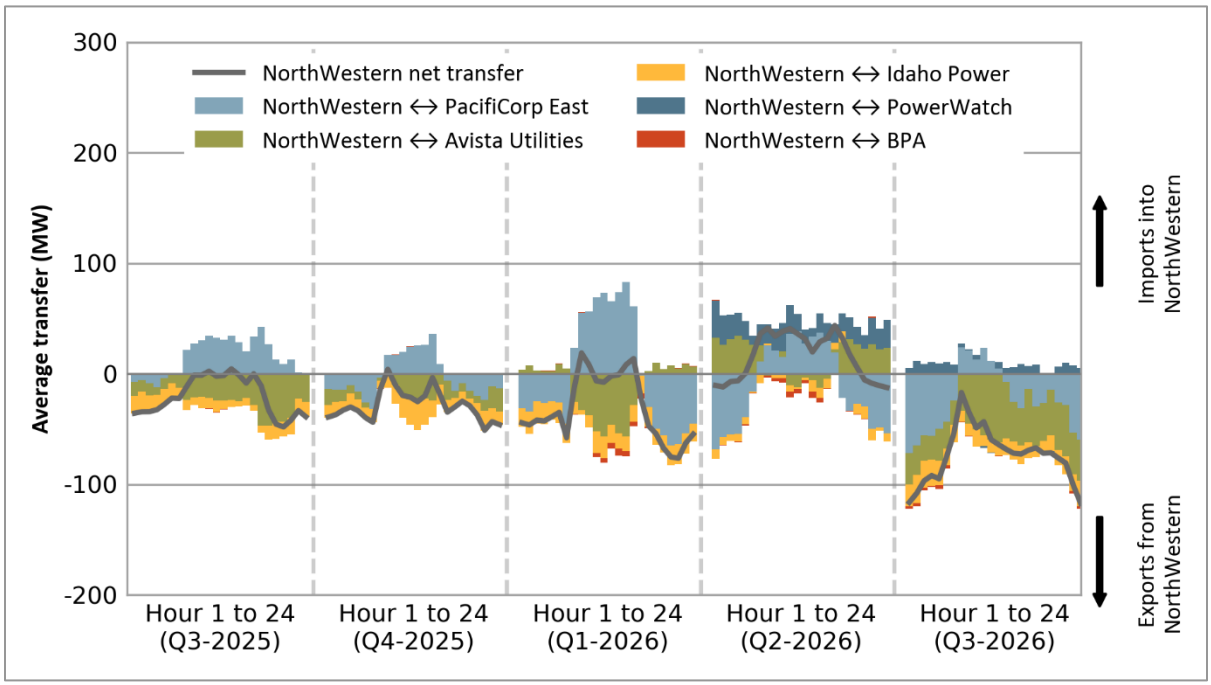
Appendix Figure A.75 Average hourly 15-minute market transfers



Appendix Figure A.76 Average hourly 5-minute price by component (July – September 2026)

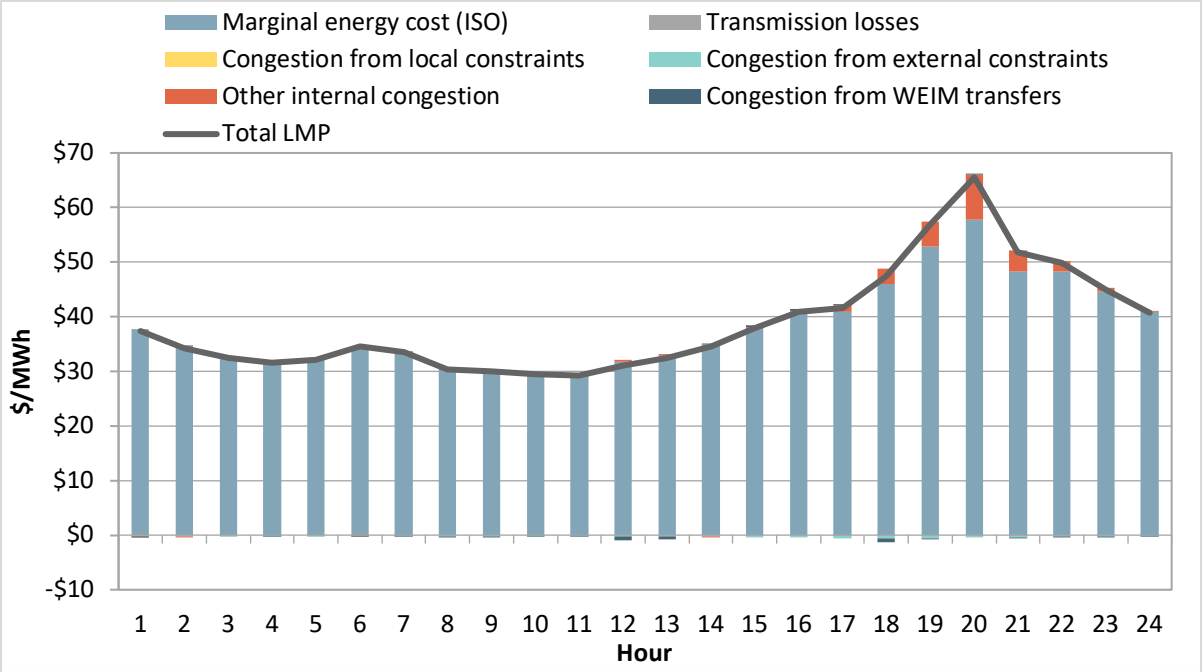


Appendix Figure A.78 Average hourly 5-minute market transfers

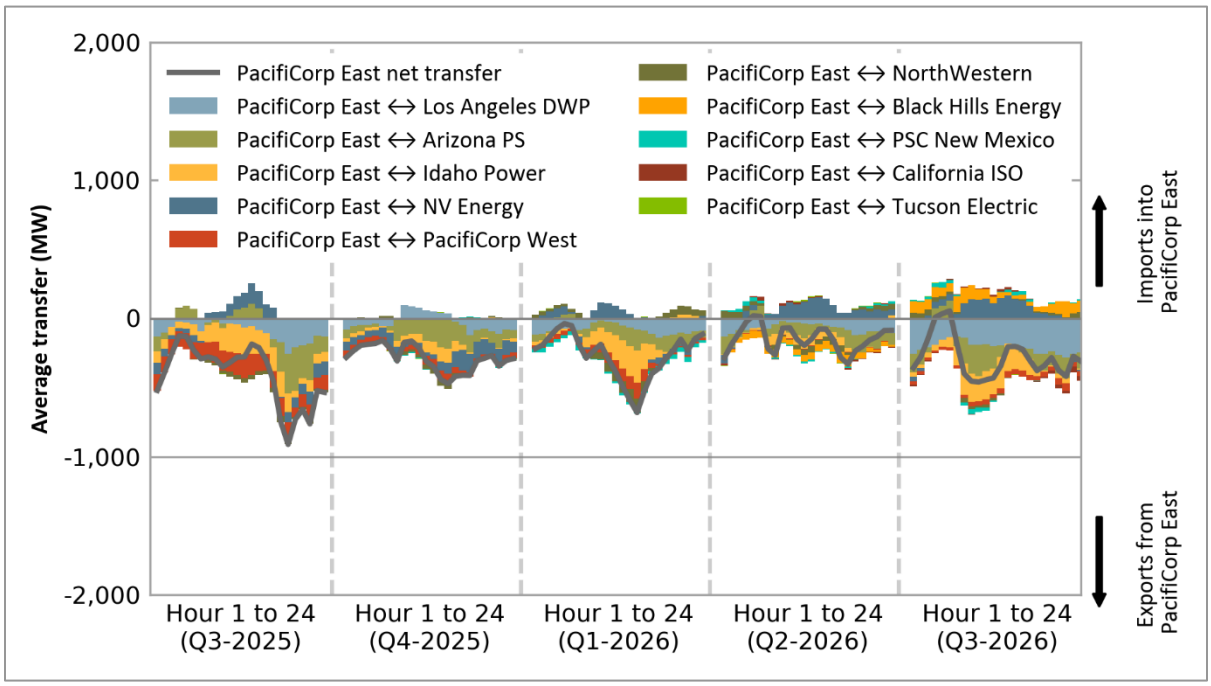


A.13 PacifiCorp East

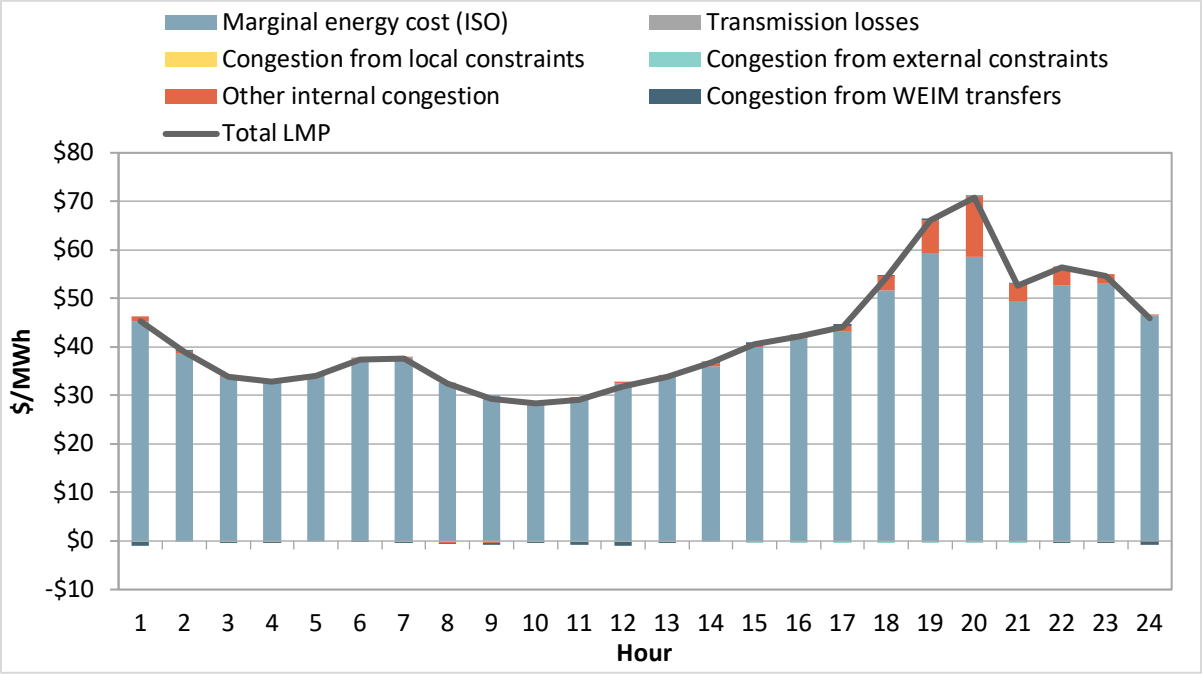
Appendix Figure A.79 Average hourly 15-minute price by component (July – September 2026)



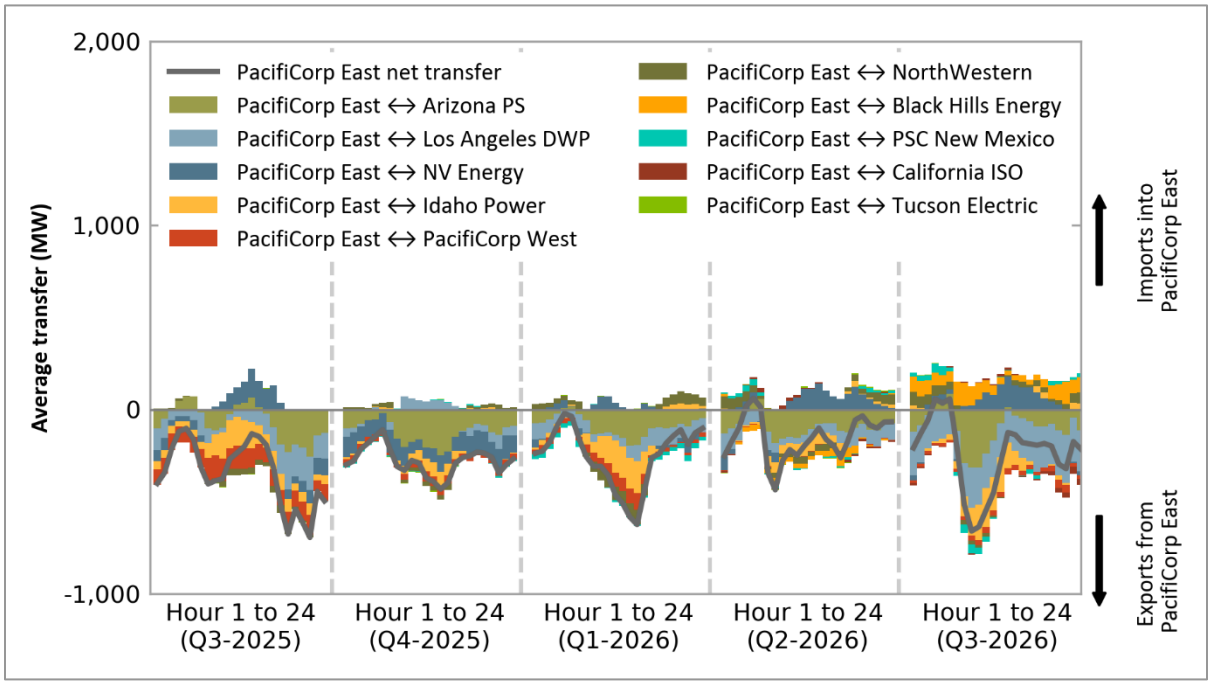
Appendix Figure A.81 Average hourly 15-minute market transfers



Appendix Figure A.82 Average hourly 5-minute price by component (July – September 2026)

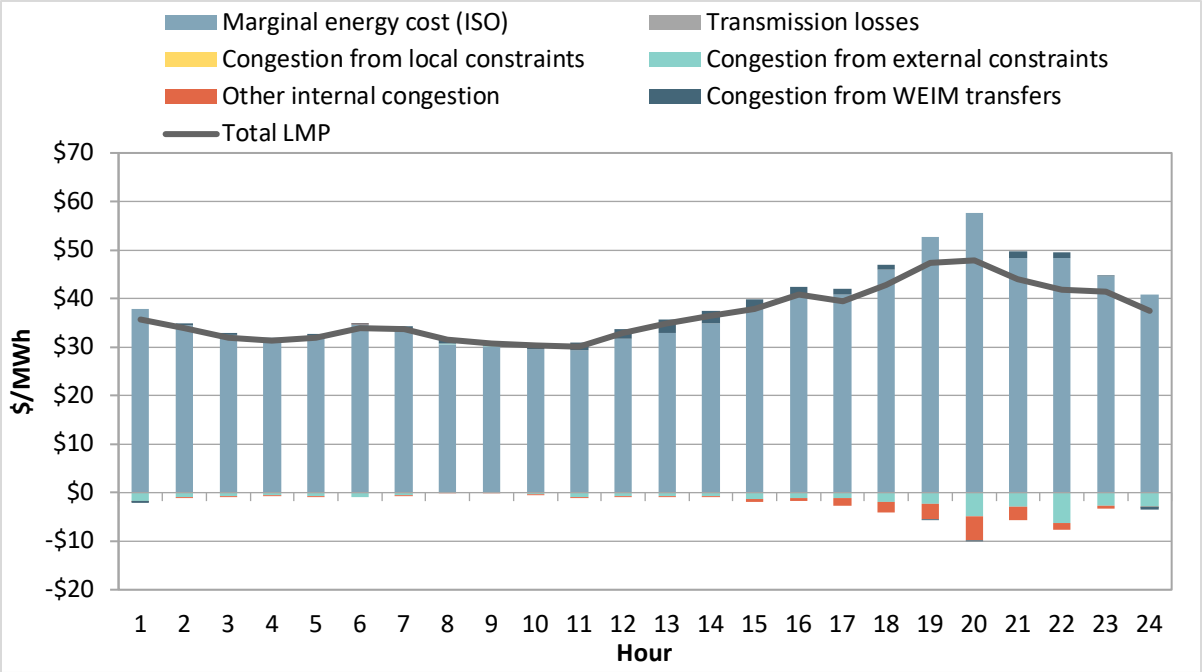


Appendix Figure A.84 Average hourly 5-minute market transfers

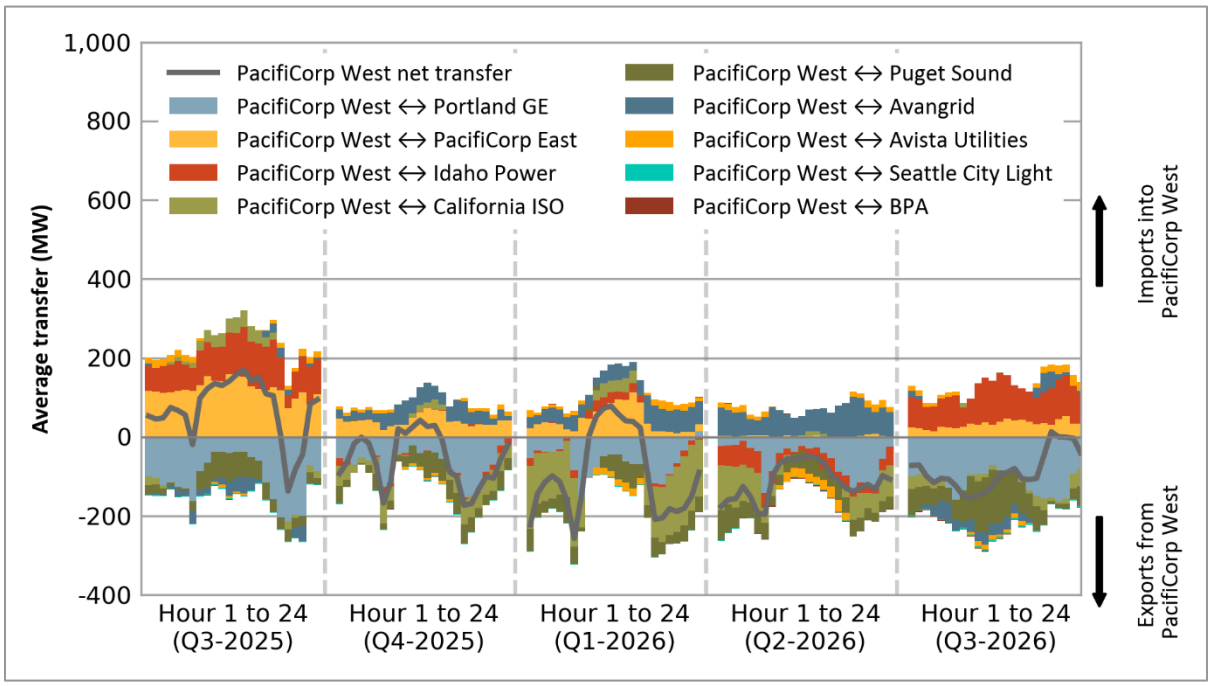


A.14 PacifiCorp West

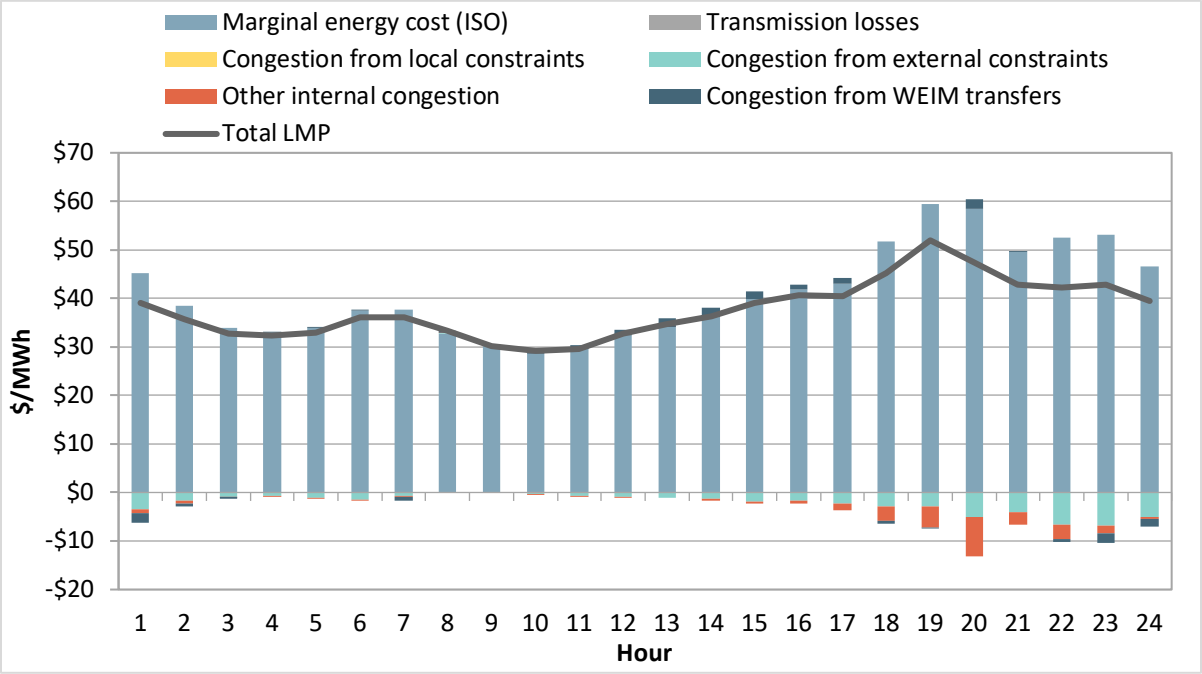
Appendix Figure A.85 Average hourly 15-minute price by component (July – September 2026)



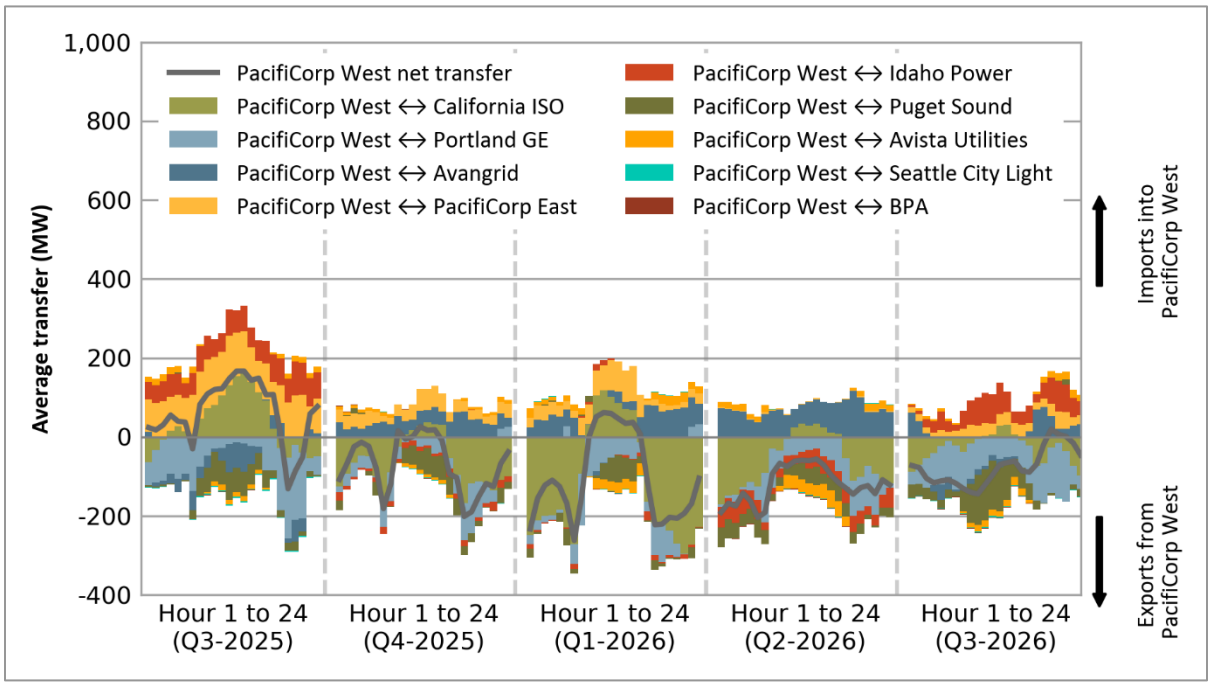
Appendix Figure A.87 Average hourly 15-minute market transfers



Appendix Figure A.88 Average hourly 5-minute price by component (July – September 2026)

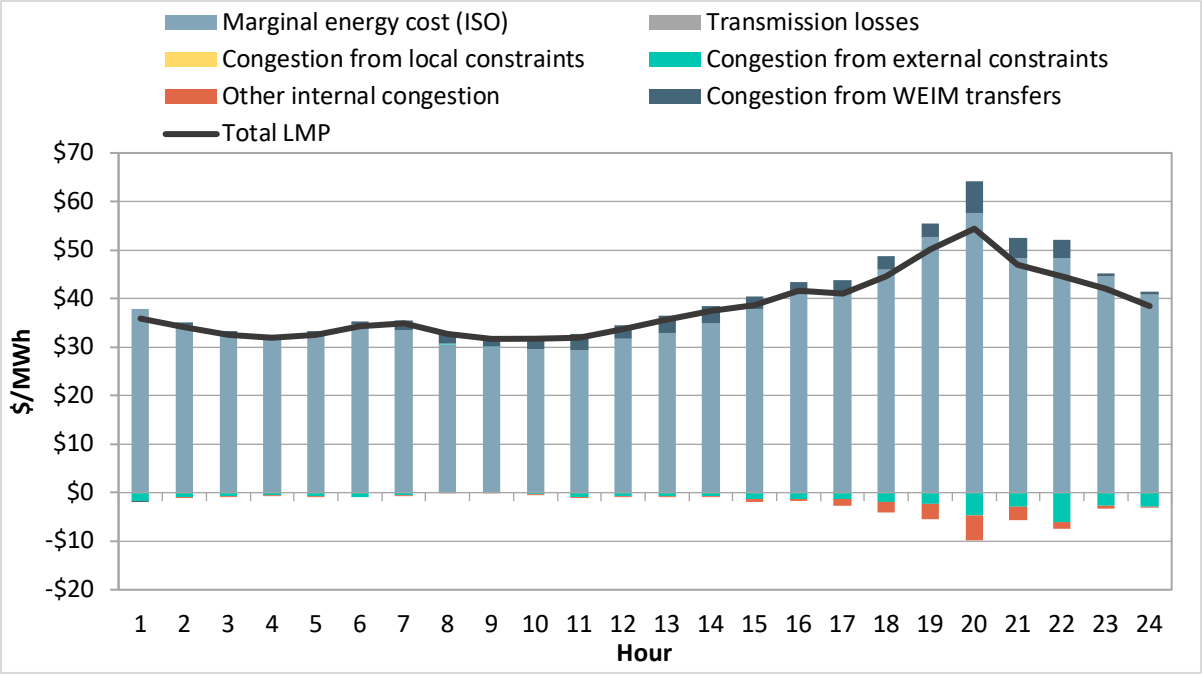


Appendix Figure A.90 Average hourly 5-minute market transfers

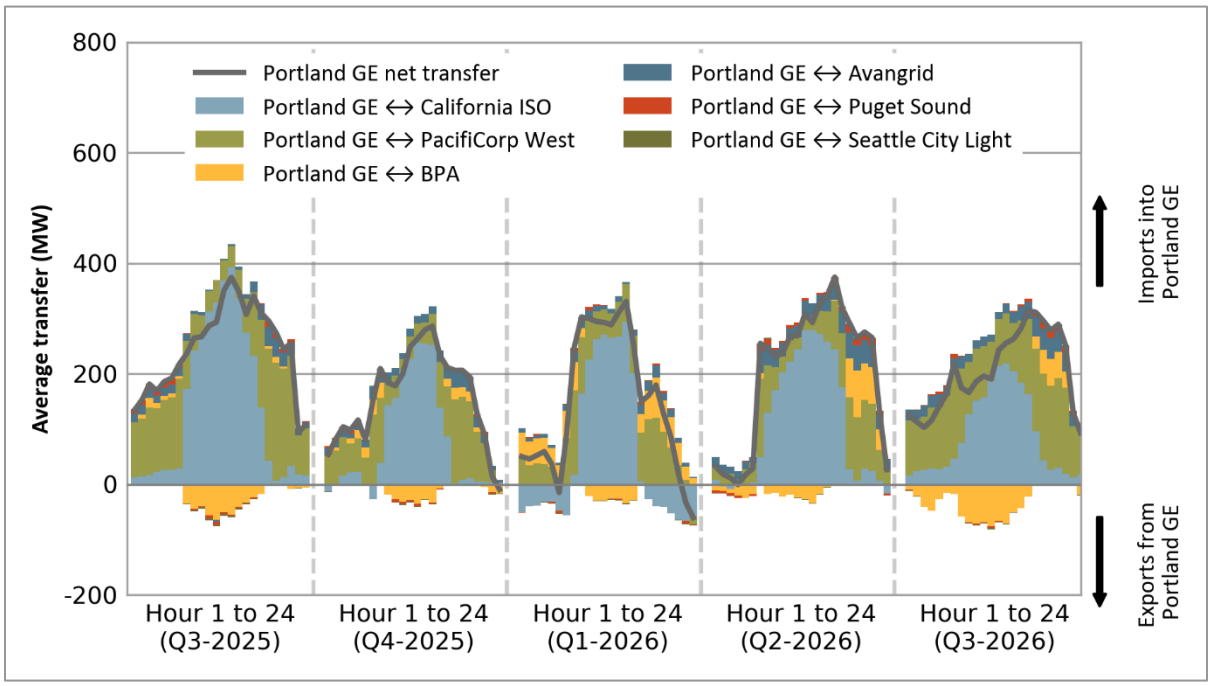


A.15 Portland General Electric

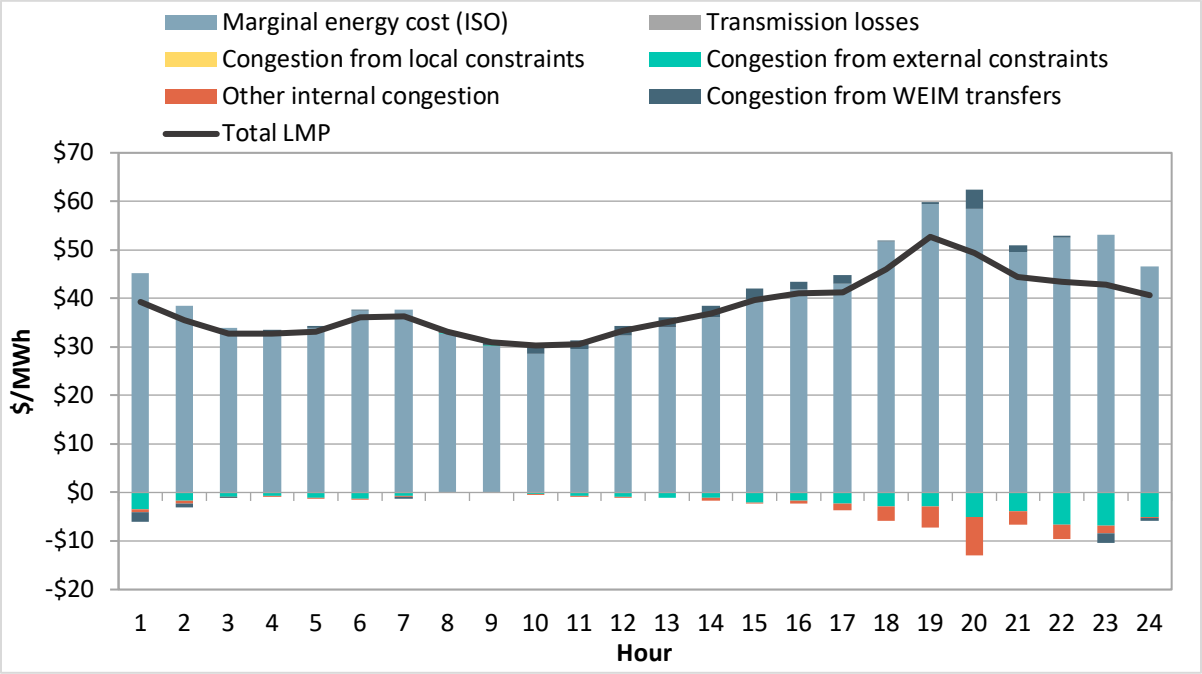
Appendix Figure A.91 Average hourly 15-minute price by component (July – September 2026)



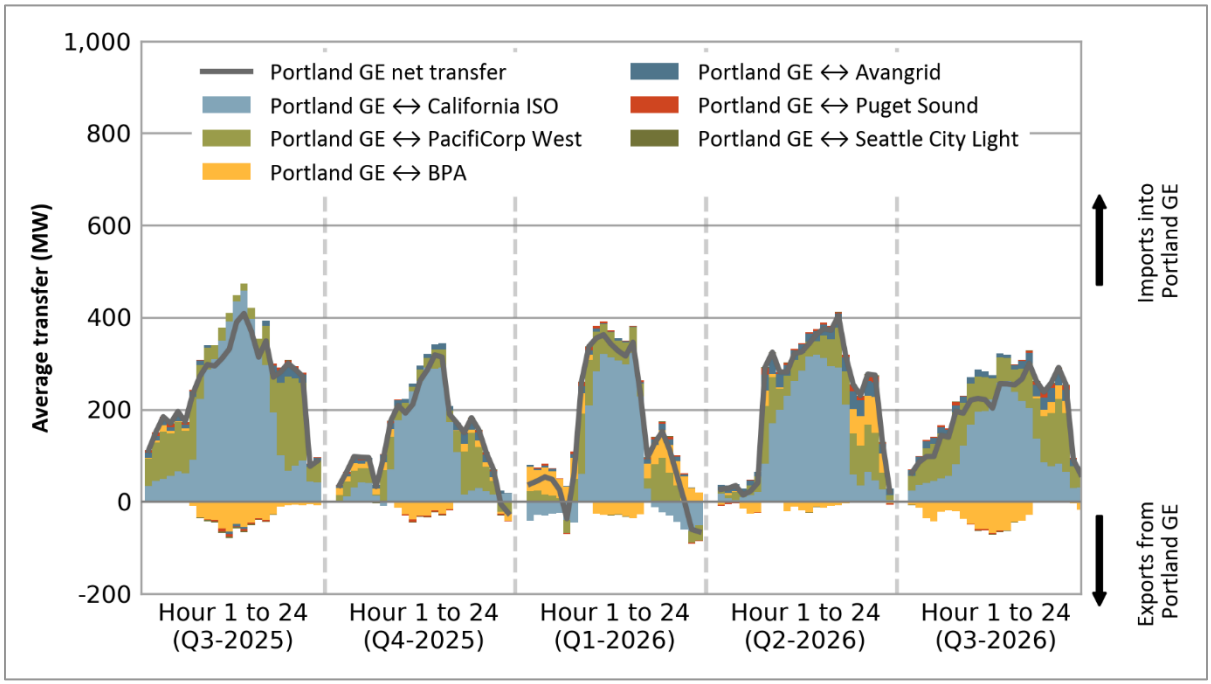
Appendix Figure A.93 Average hourly 15-minute market transfers



Appendix Figure A.94 Average hourly 5-minute price by component (July – September 2026)

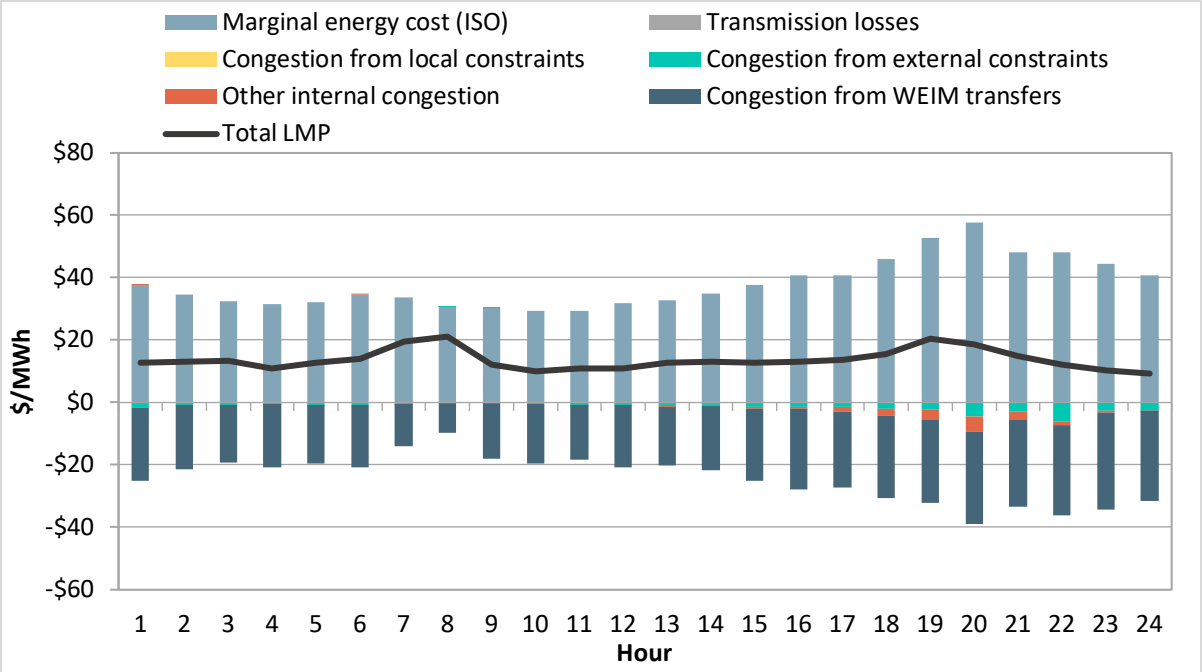


Appendix Figure A.96 Average hourly 5-minute market transfers

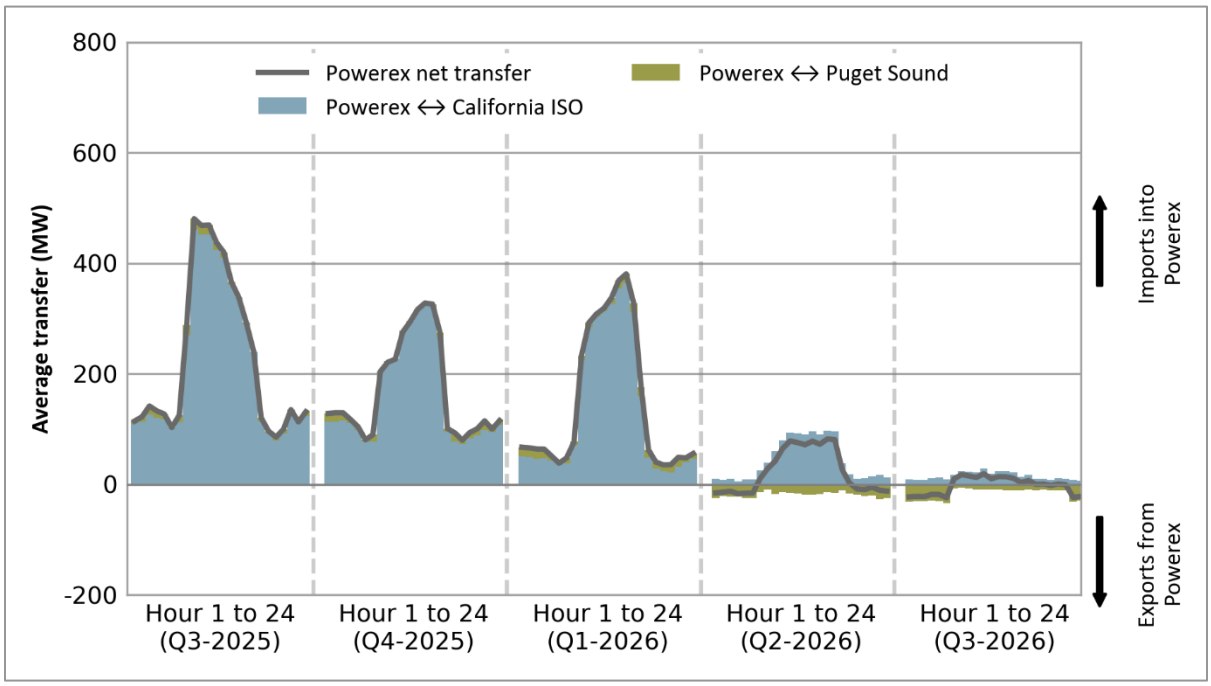


A.16 Powerex

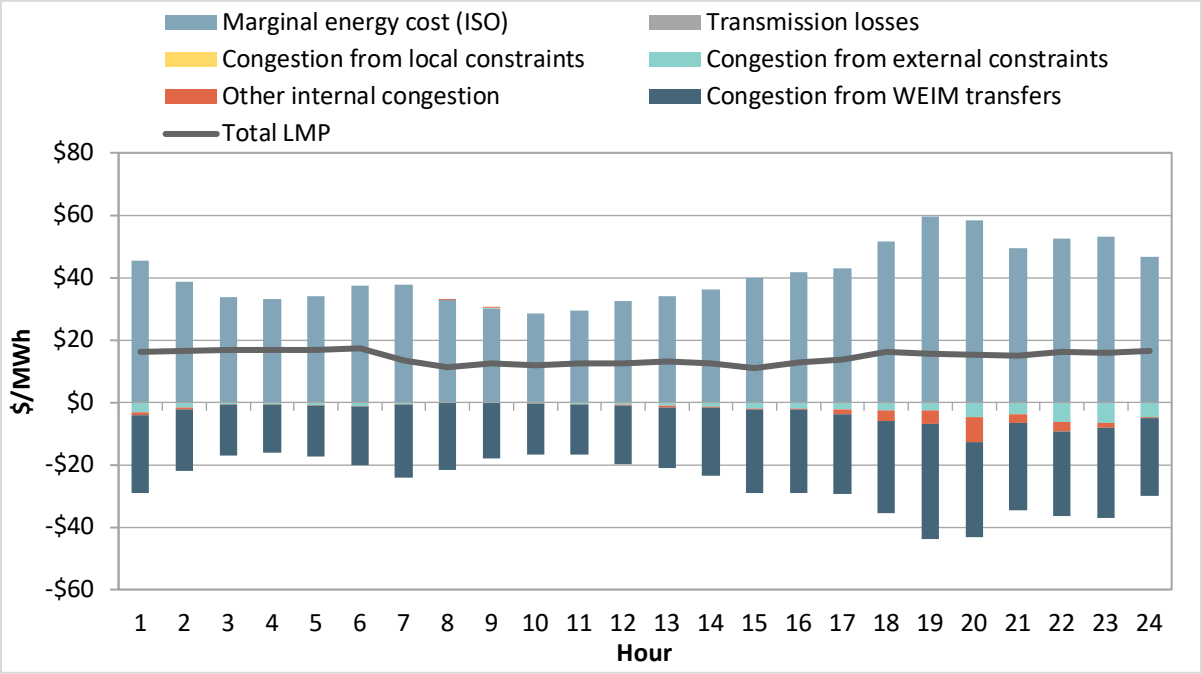
Appendix Figure A.97 Average hourly 15-minute price by component (July – September 2026)



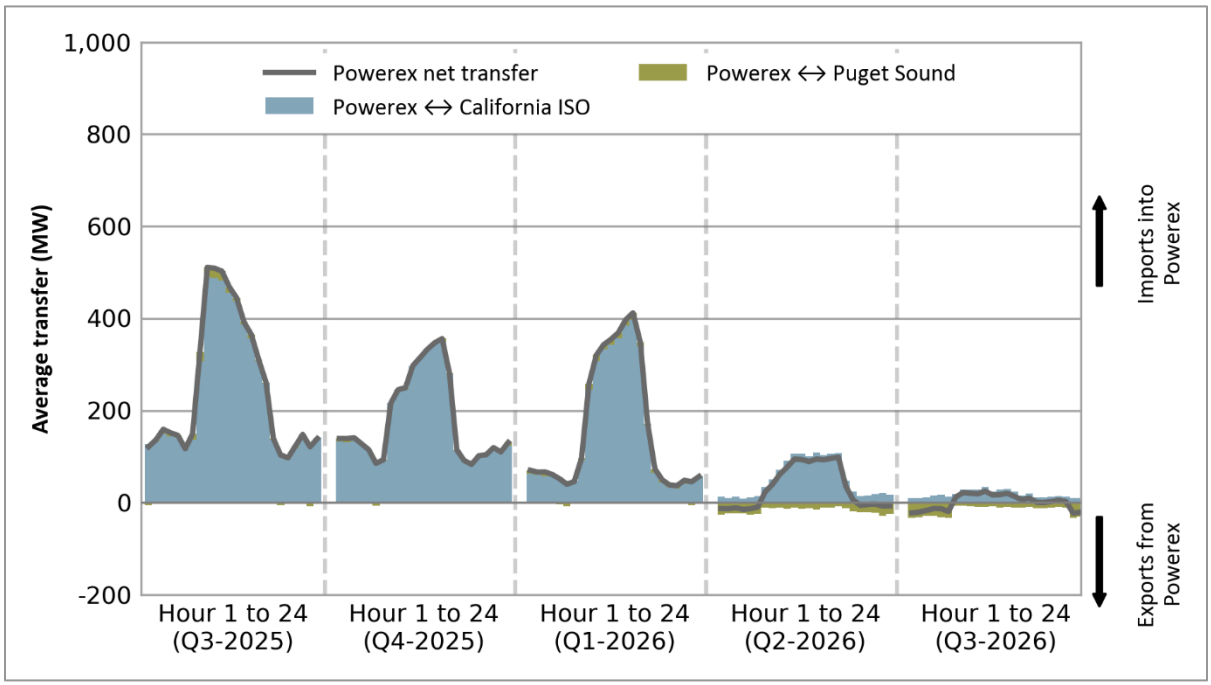
Appendix Figure A.99 Average hourly 15-minute market transfers



Appendix Figure A.100 Average hourly 5-minute price by component (July – September 2026)

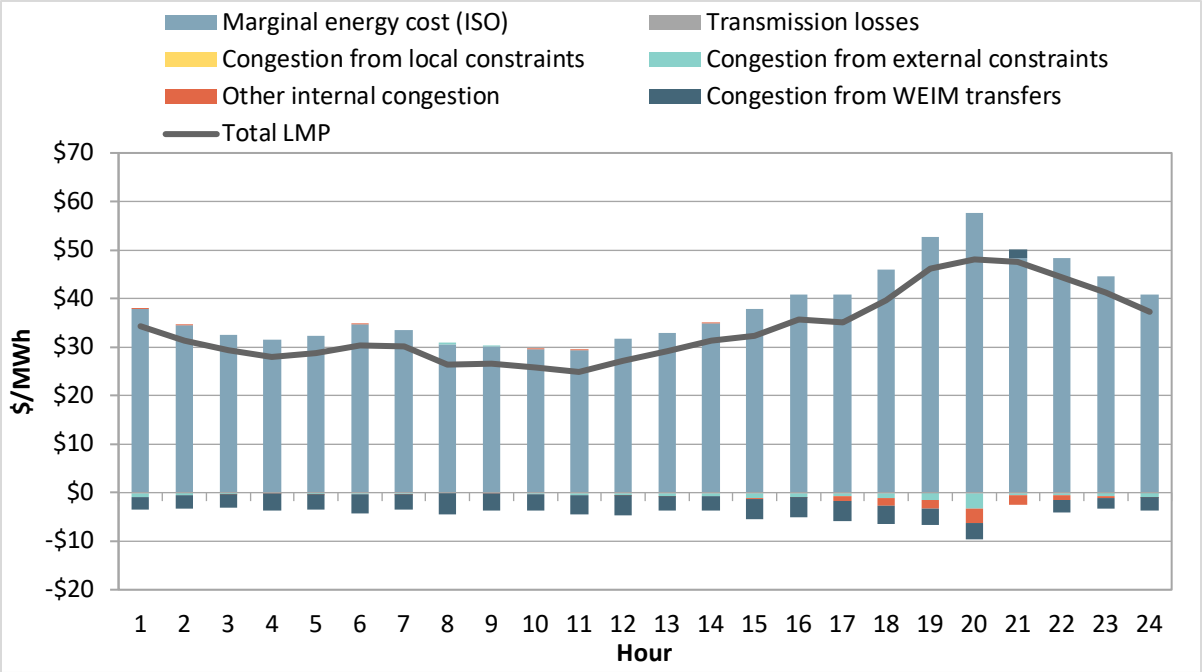


Appendix Figure A.102 Average hourly 5-minute market transfers

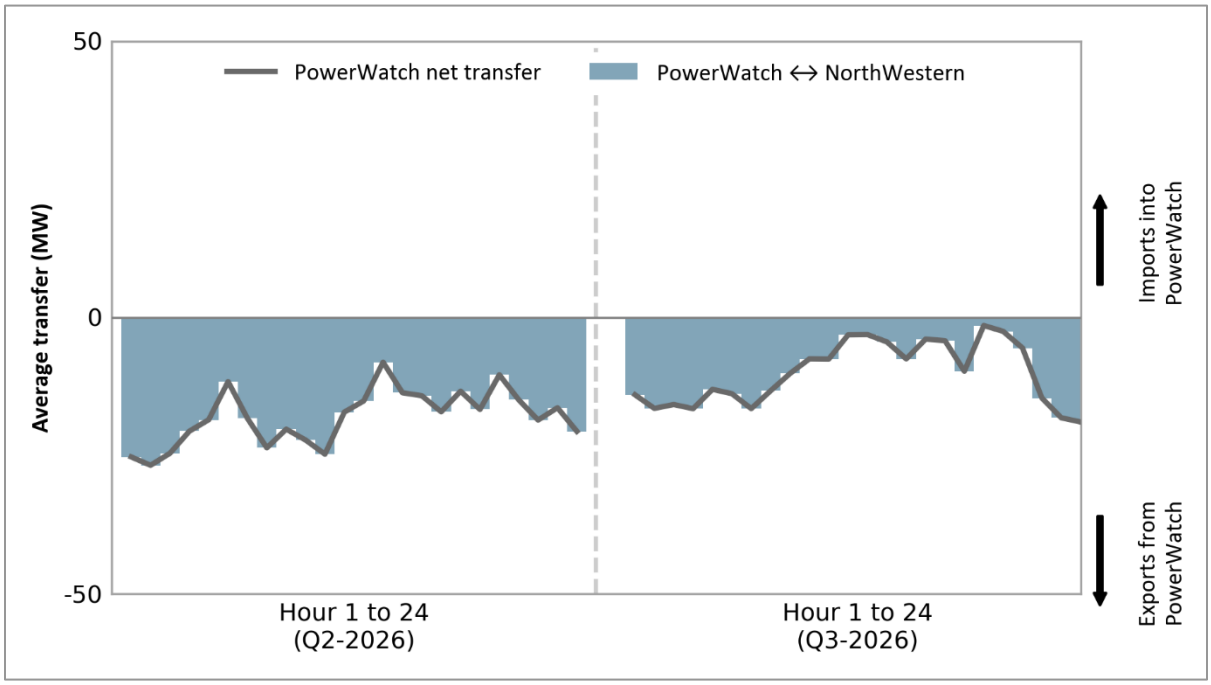


A.17 Power Watch

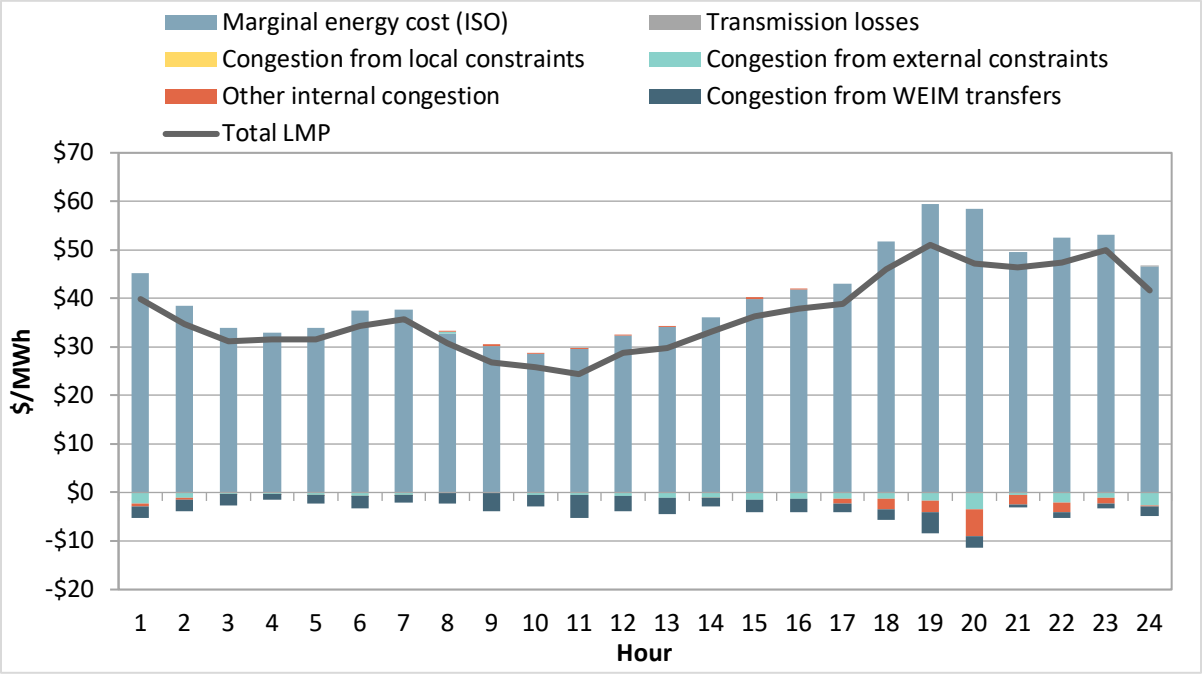
Appendix Figure A.103 Average hourly 15-minute price by component (July – September2026)



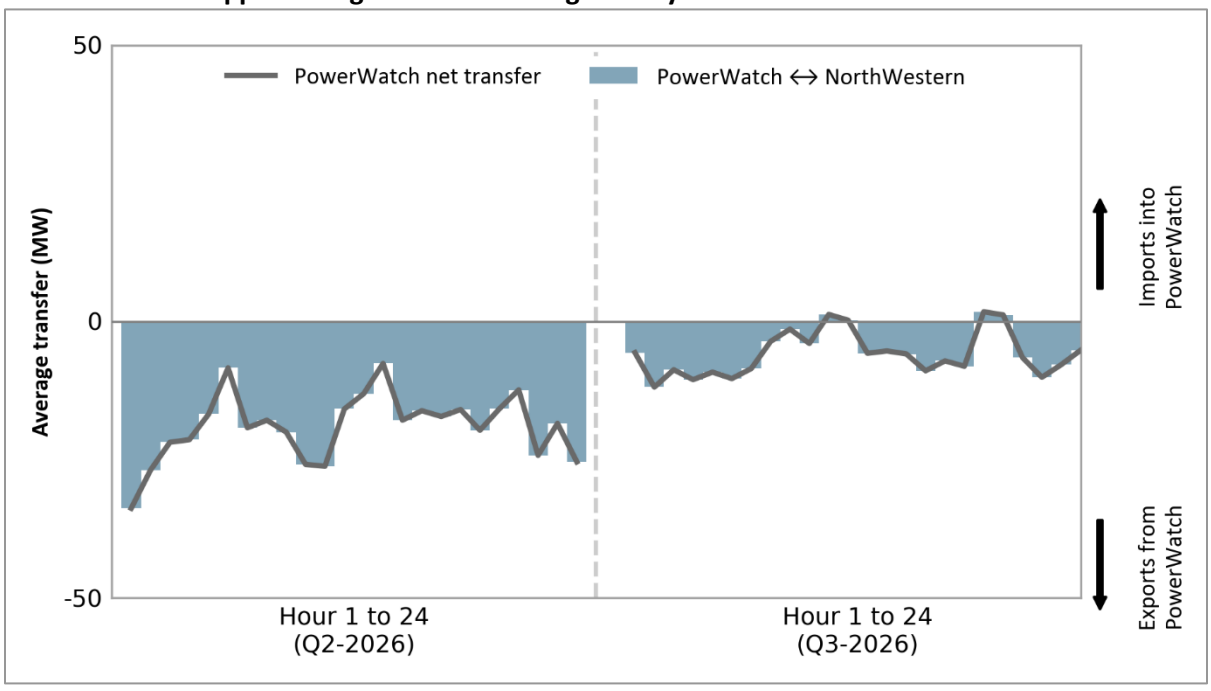
Appendix Figure A.104 Average hourly 15-minute market transfers



Appendix Figure A.105 Average hourly 5-minute price by component (July – September 2026)

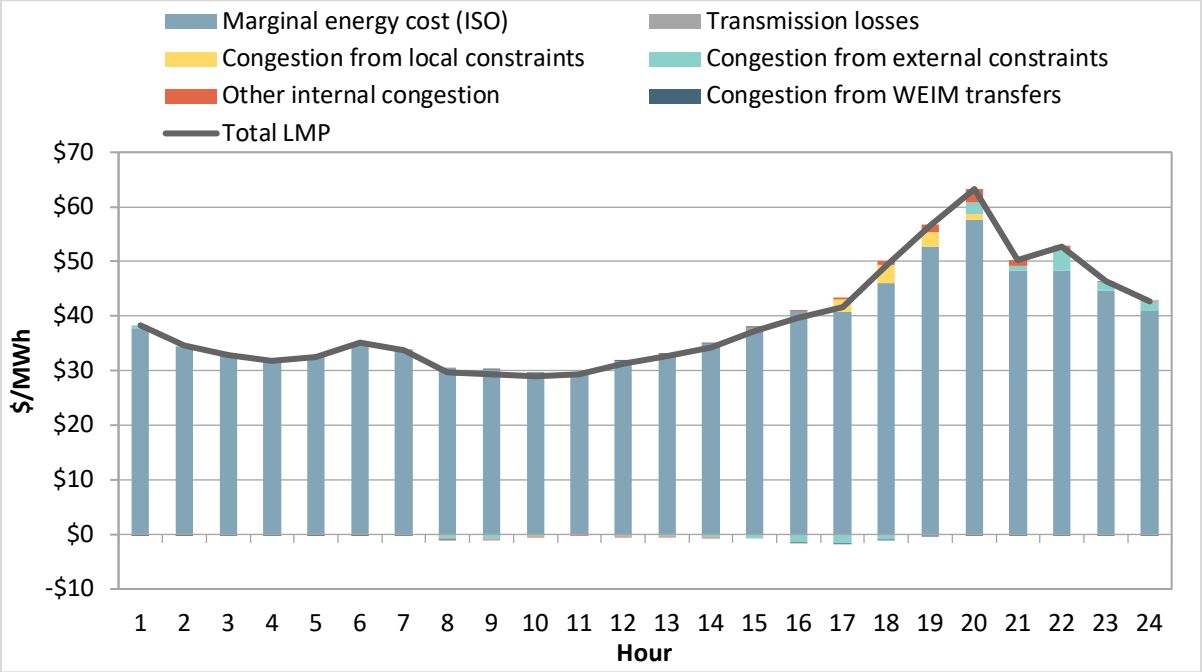


Appendix Figure A.106 Average hourly 5-minute market transfers

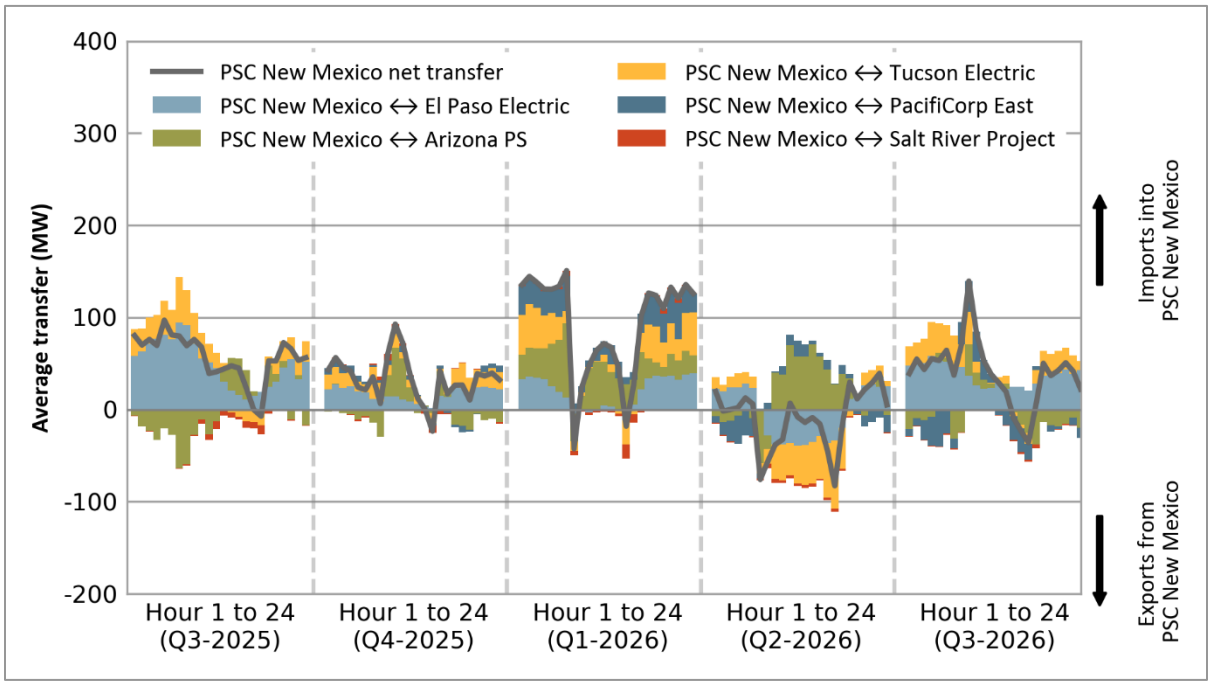


A.18 Public Service Company of New Mexico

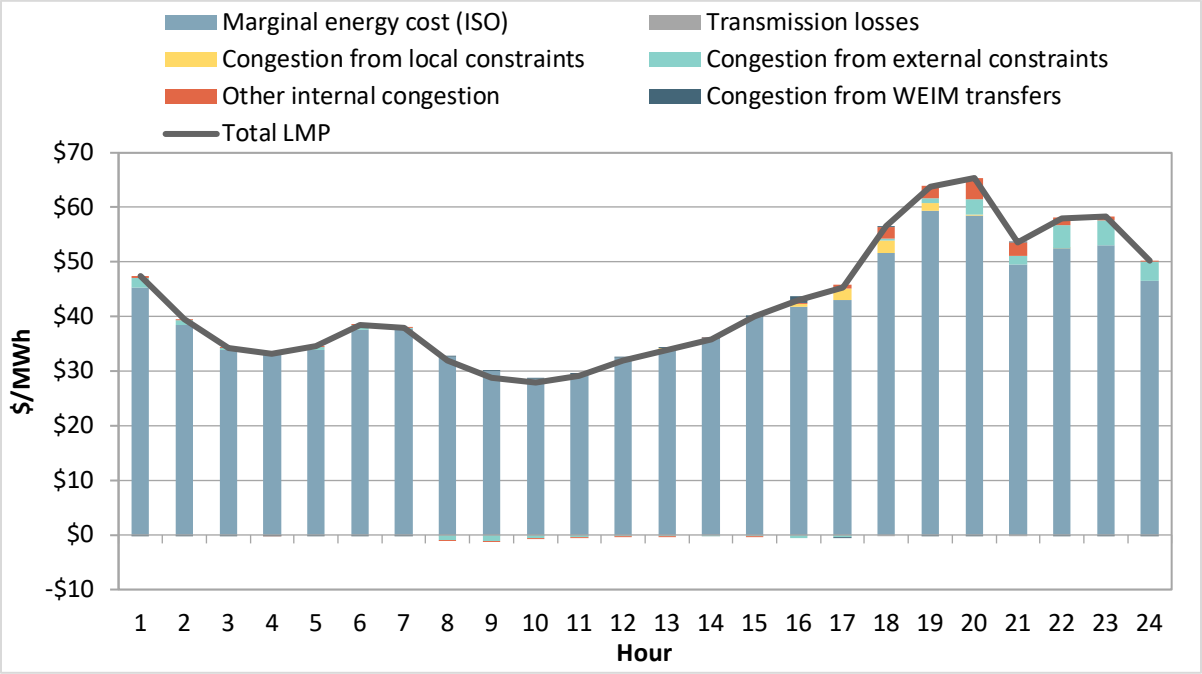
Appendix Figure A.107 Average hourly 15-minute price by component (July – September 2026)



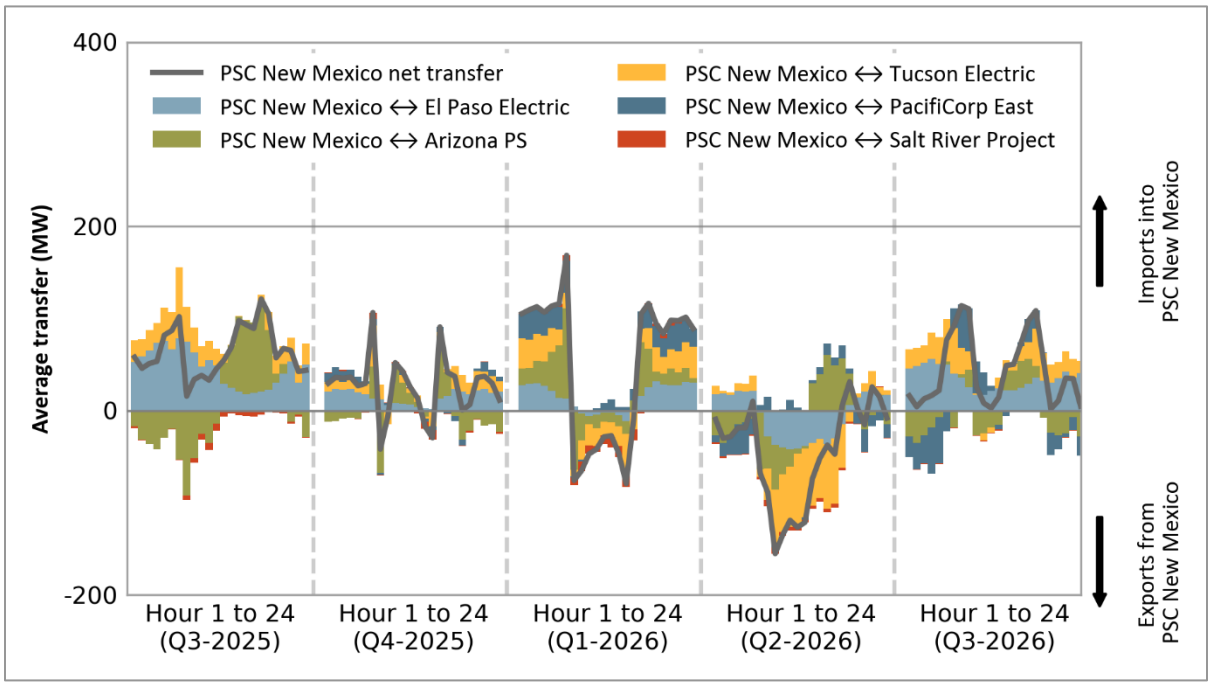
Appendix Figure A.109 Average hourly 15-minute market transfers



Appendix Figure A.110 Average hourly 5-minute price by component (July – September 2026)

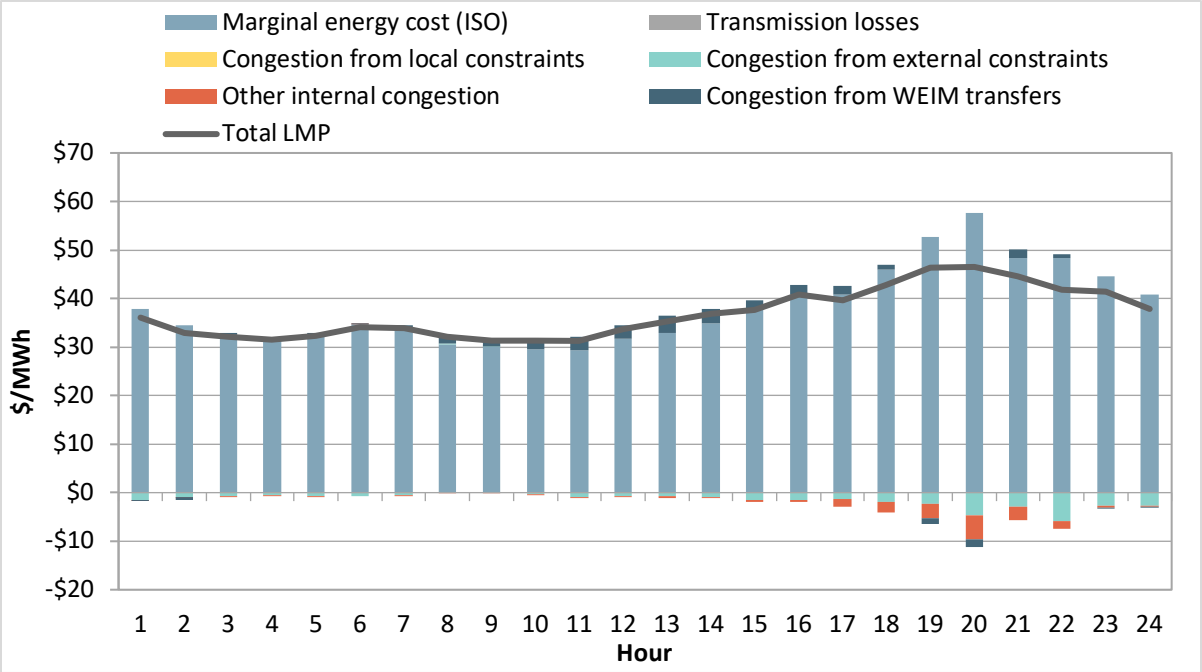


Appendix Figure A.112 Average hourly 5-minute market transfers

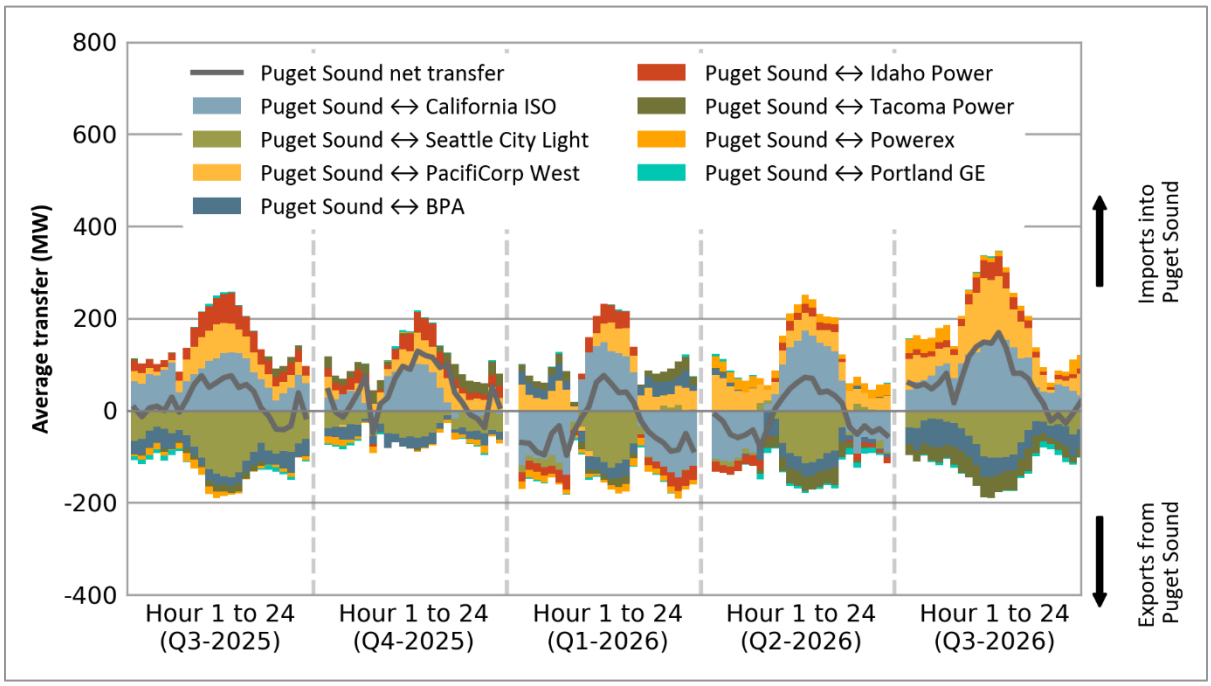


A.19 Puget Sound Energy

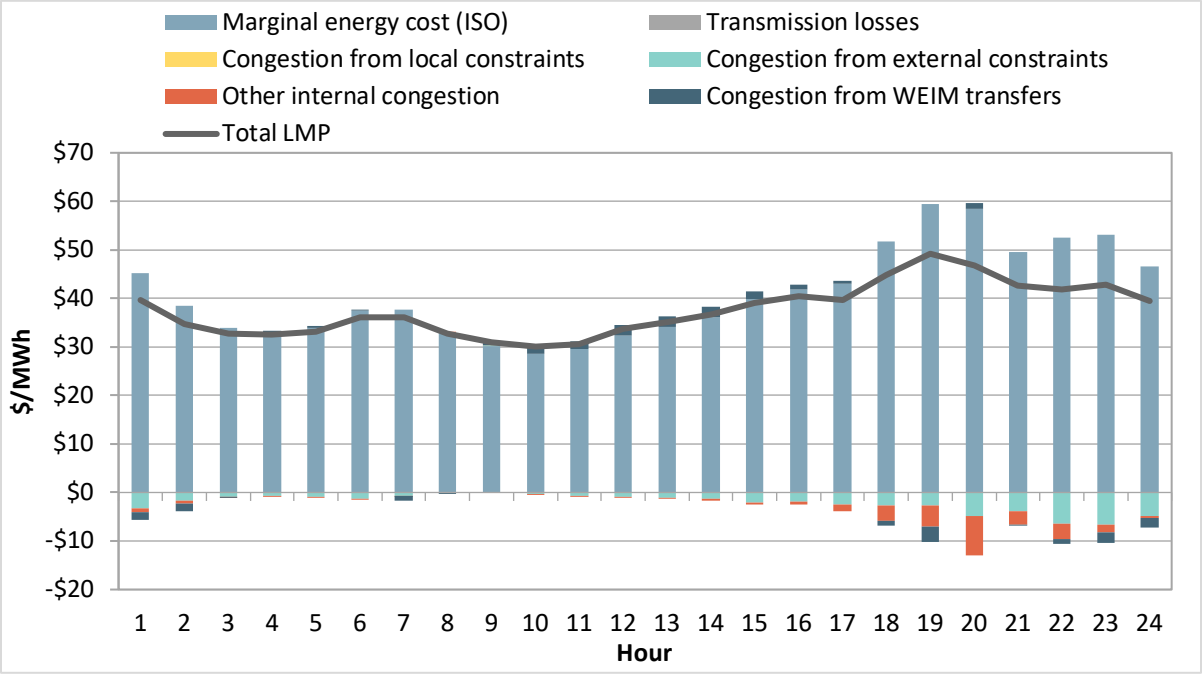
Appendix Figure A.113 Average hourly 15-minute price by component (July – September 2026)



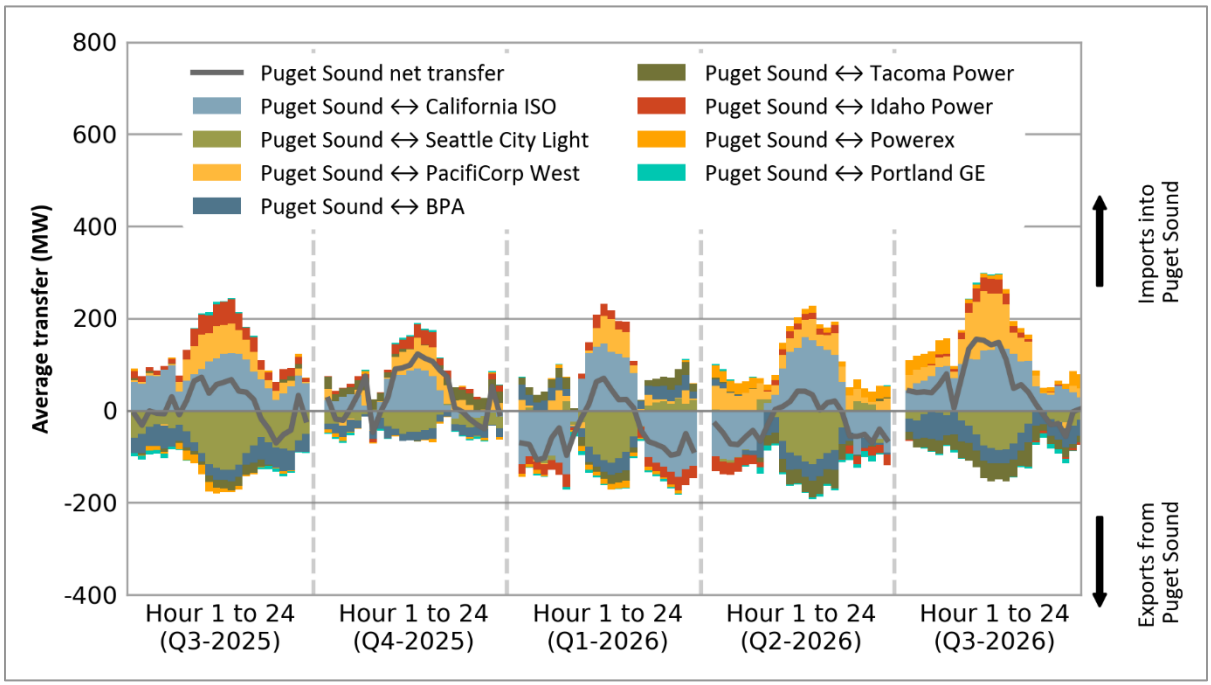
Appendix Figure A.115 Average hourly 15-minute market transfers



Appendix Figure A.116 Average hourly 5-minute price by component (July – September 2026)

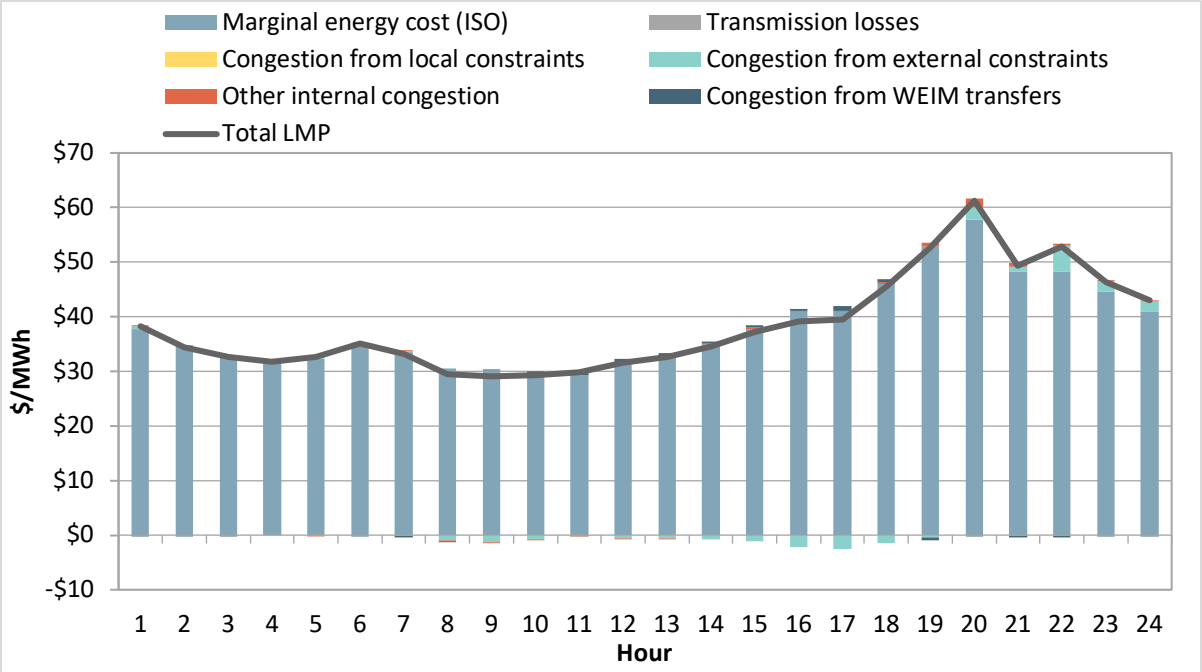


Appendix Figure A.118 Average hourly 5-minute market transfers

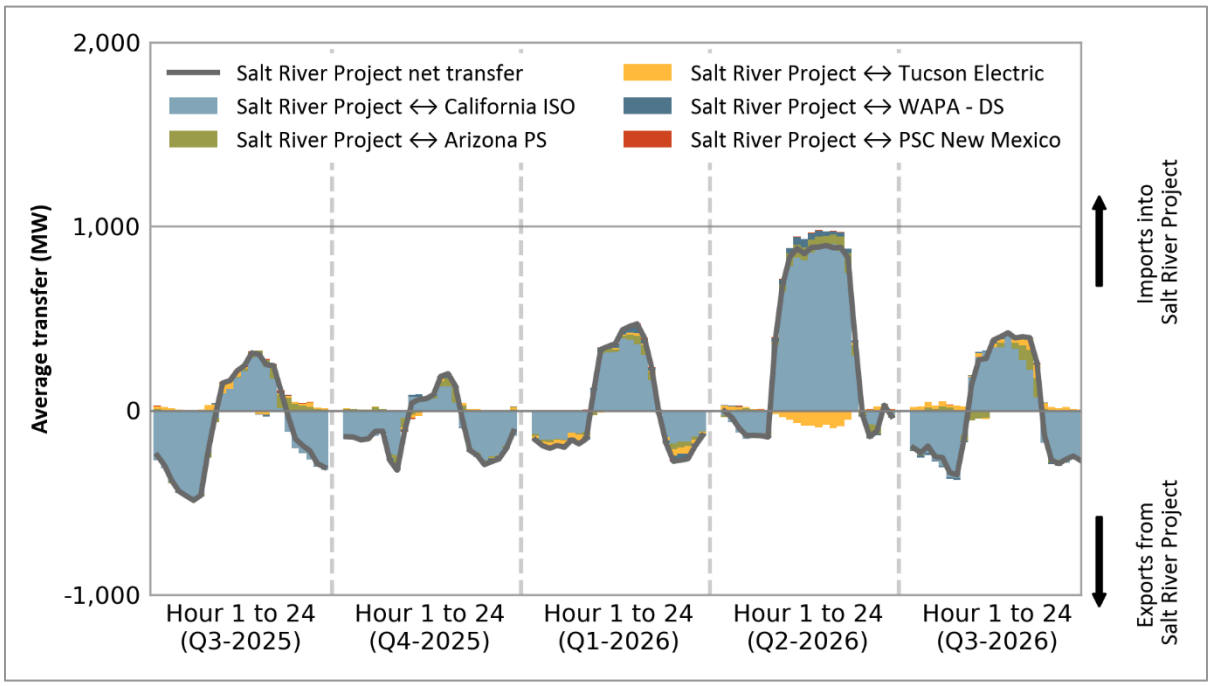


A.20 Salt River Project

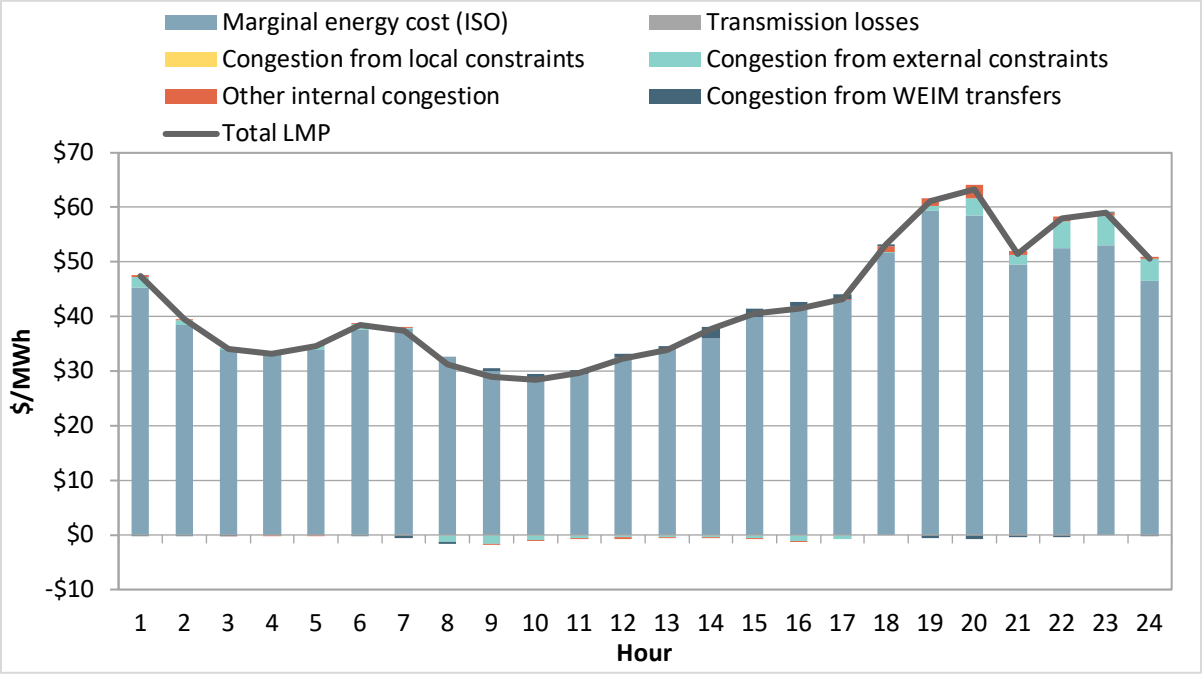
Appendix Figure A.119 Average hourly 15-minute price by component (July – September 2026)



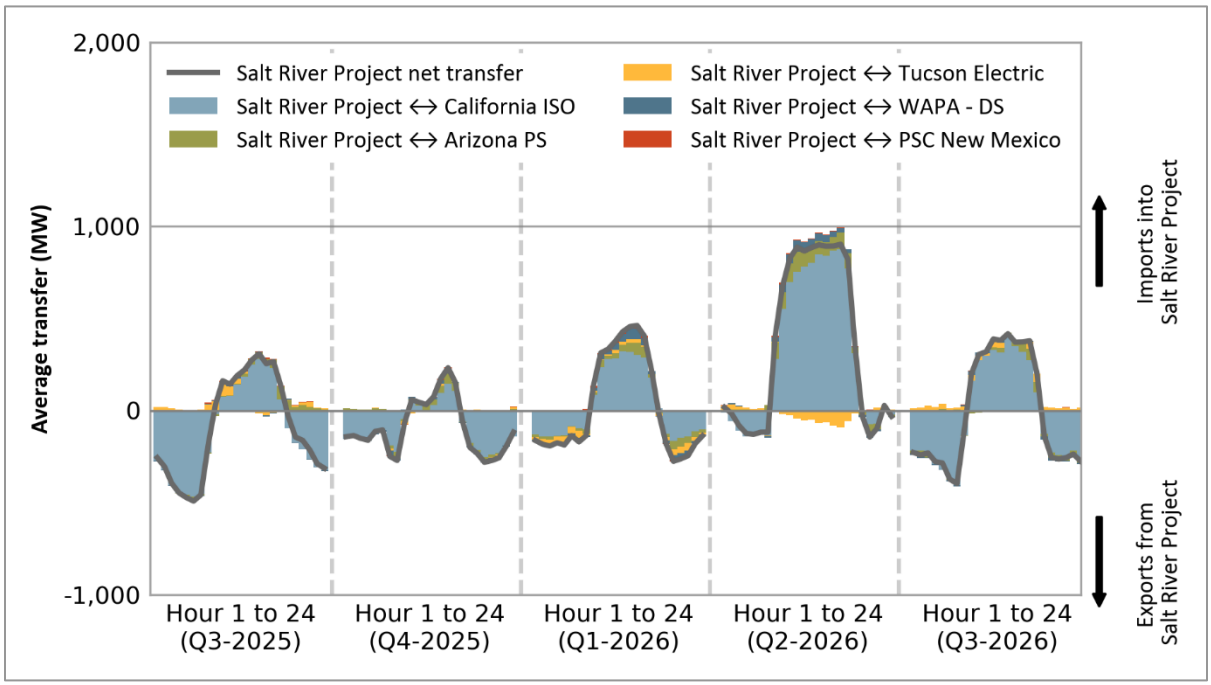
Appendix Figure A.121 Average hourly 15-minute market transfers



Appendix Figure A.122 Average hourly 5-minute price by component (July – September 2026)

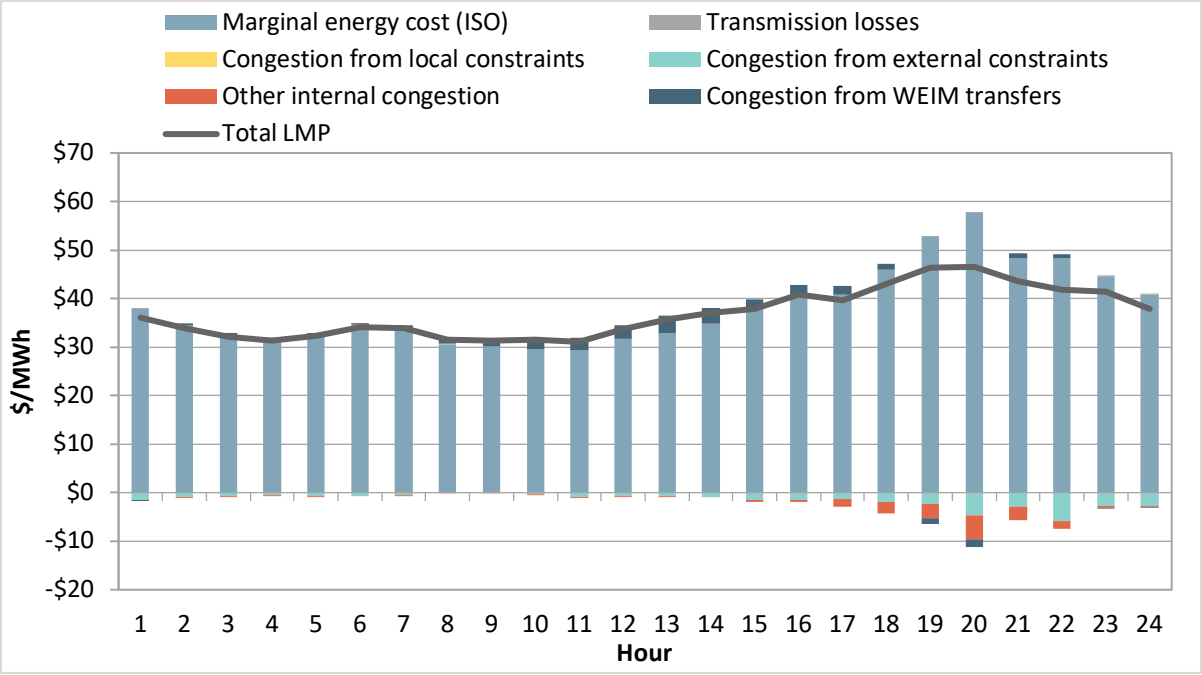


Appendix Figure A.124 Average hourly 5-minute market transfers

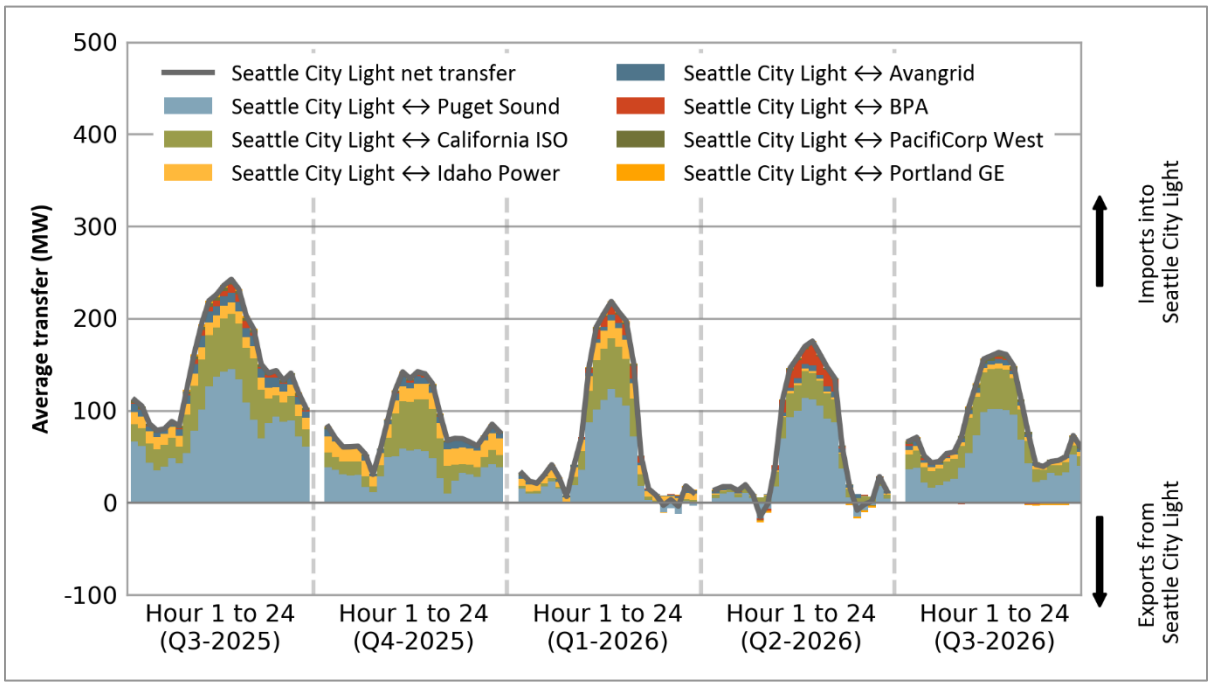


A.21 Seattle City Light

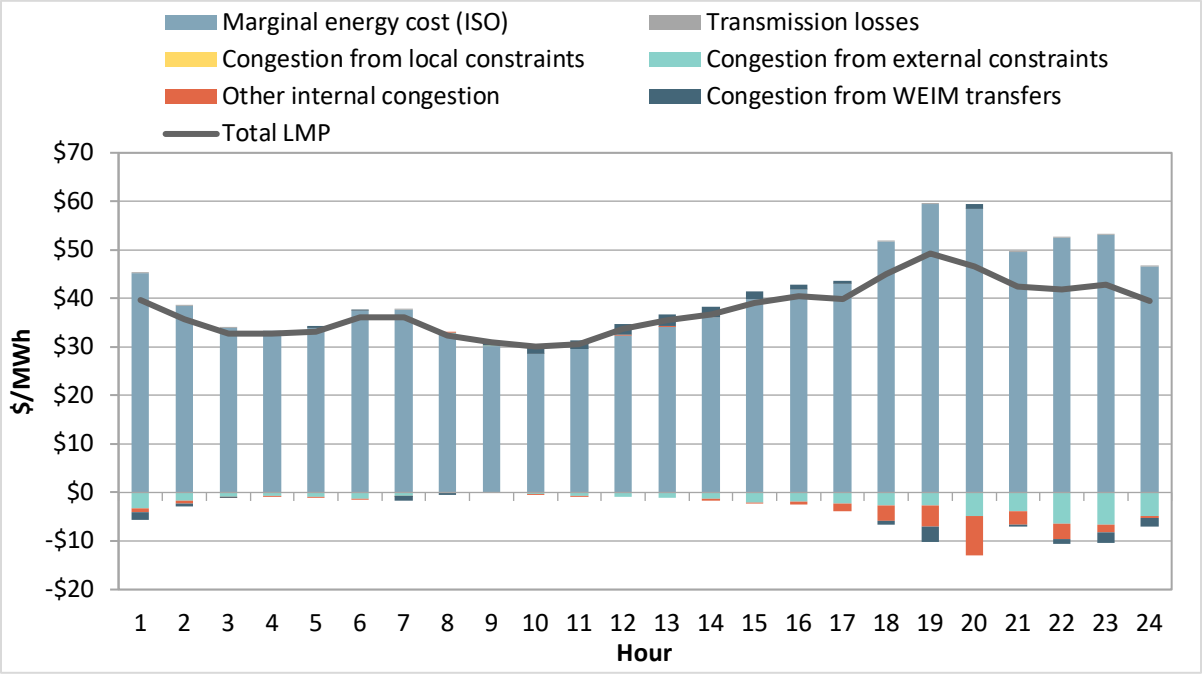
Appendix Figure A.125 Average hourly 15-minute price by component (July – September 2026)



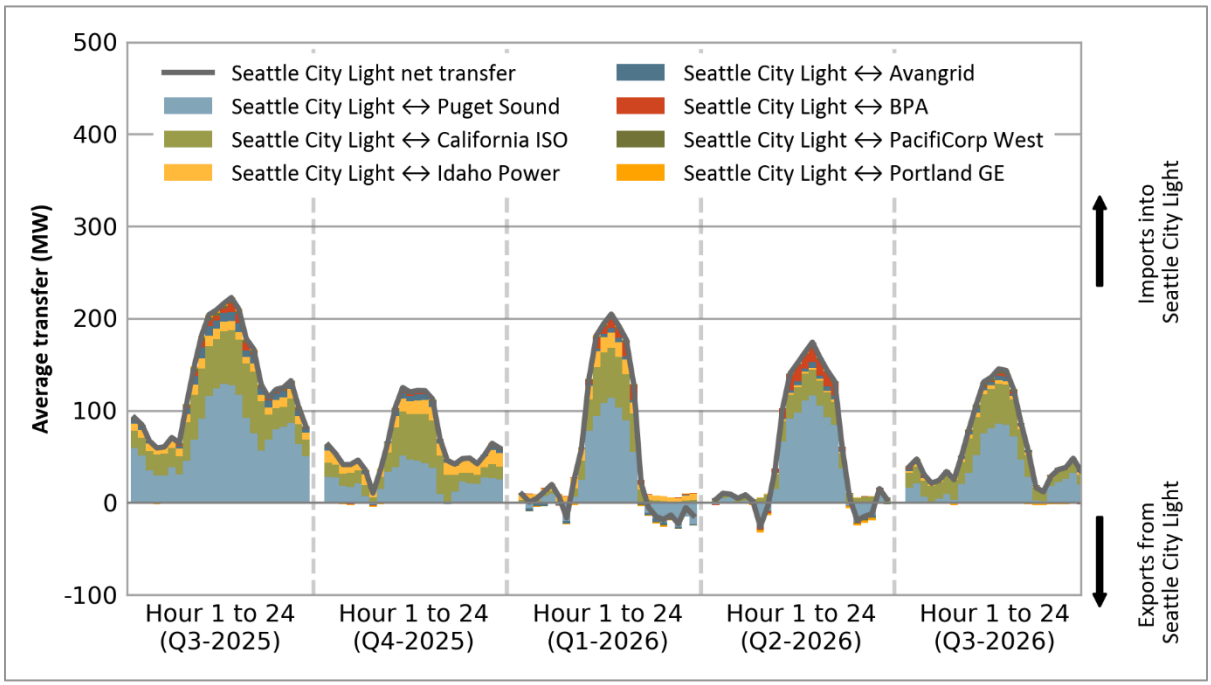
Appendix Figure A.127 Average hourly 15-minute market transfers



Appendix Figure A.128 Average hourly 5-minute price by component (July – September 2026)

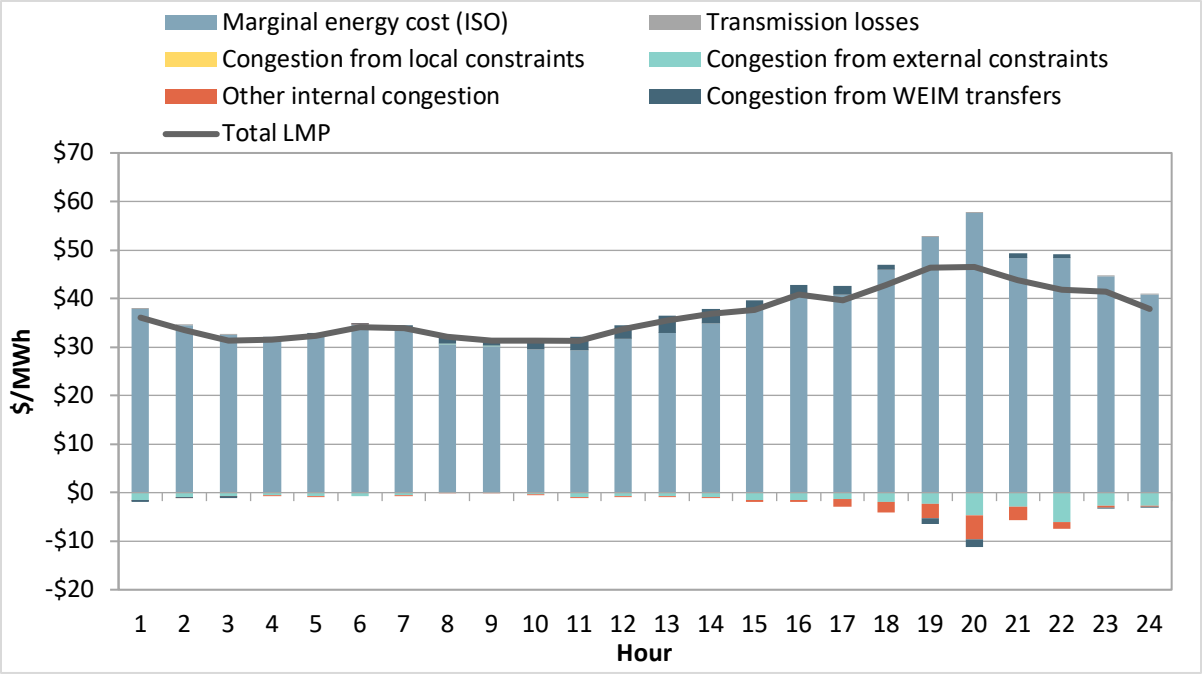


Appendix Figure A.130 Average hourly 5-minute market transfers

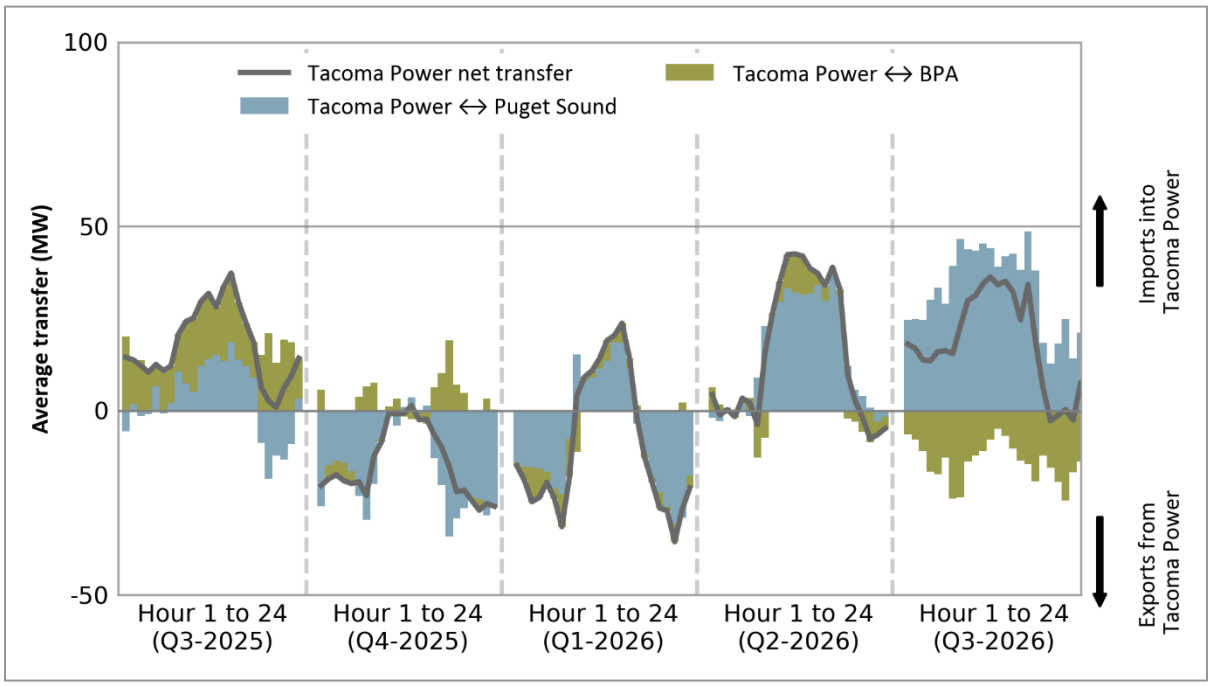


A.22 Tacoma Power

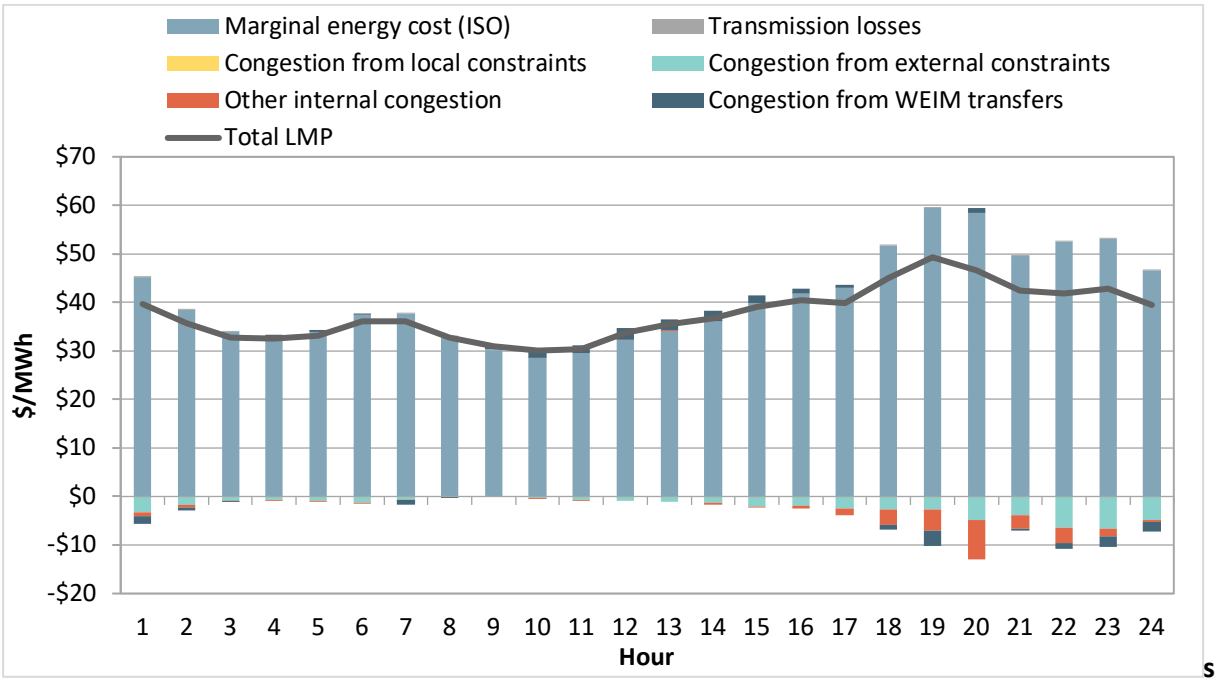
Appendix Figure A.131 Average hourly 15-minute price by component (July – September 2026)



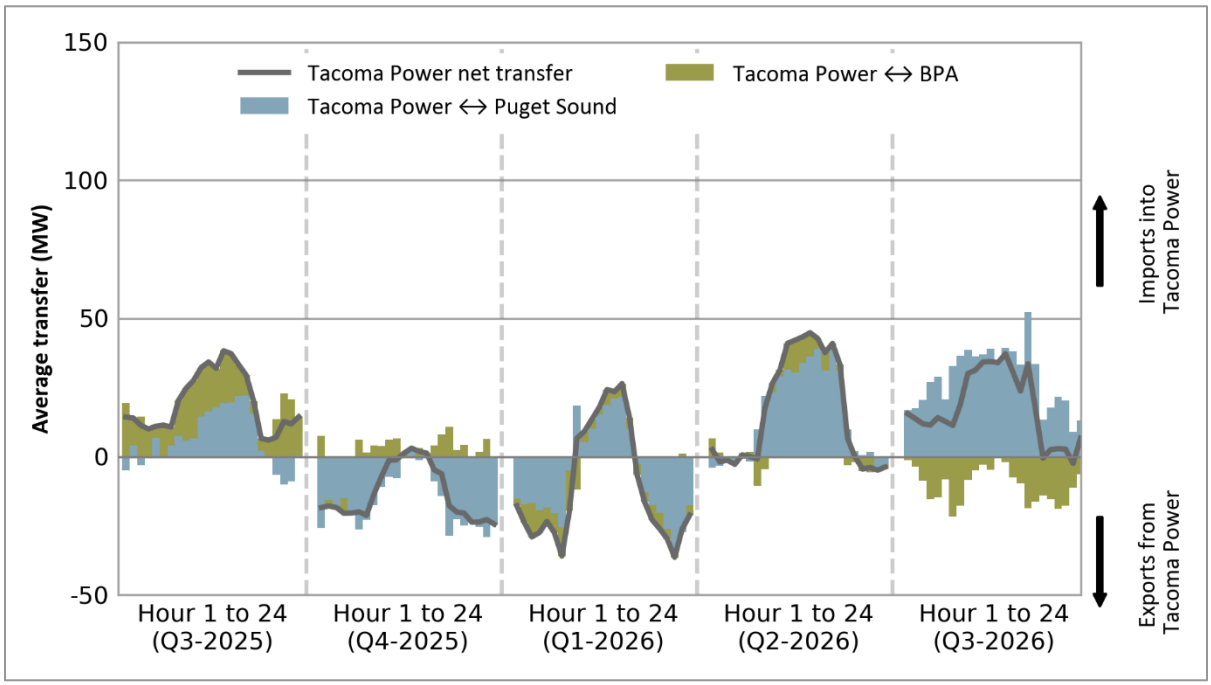
Appendix Figure A.133 Average hourly 15-minute market transfers



Appendix Figure A.134 Average hourly 5-minute price by component (July – September 2026)

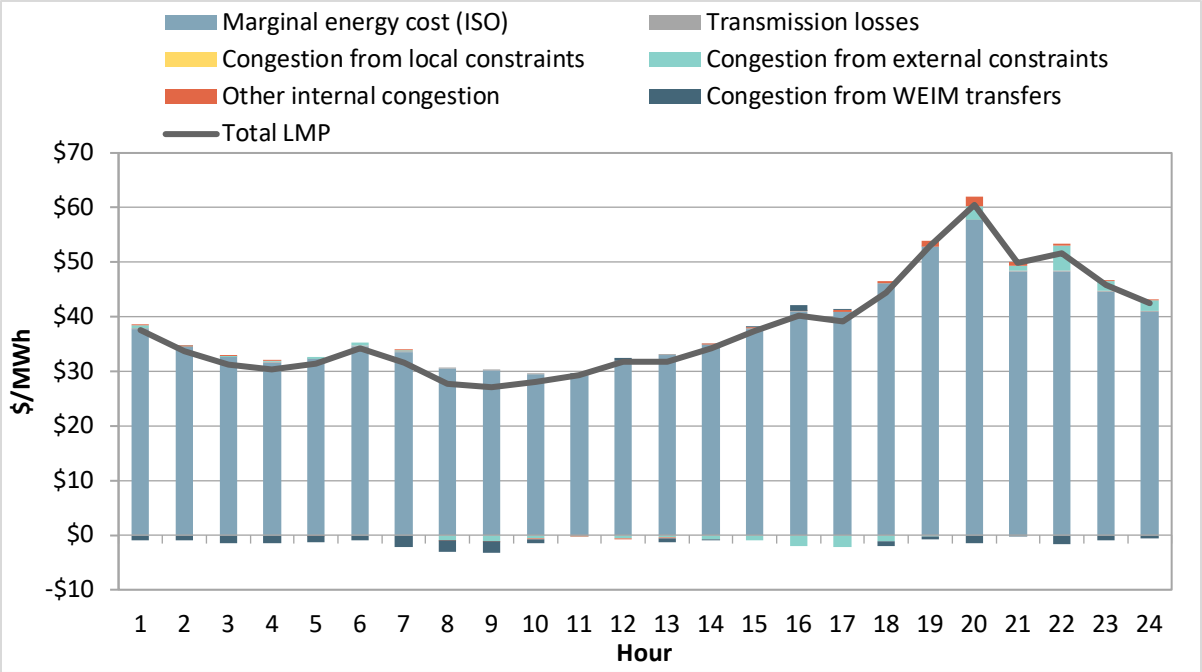


Appendix Figure A.136 Average hourly 5-minute market transfers

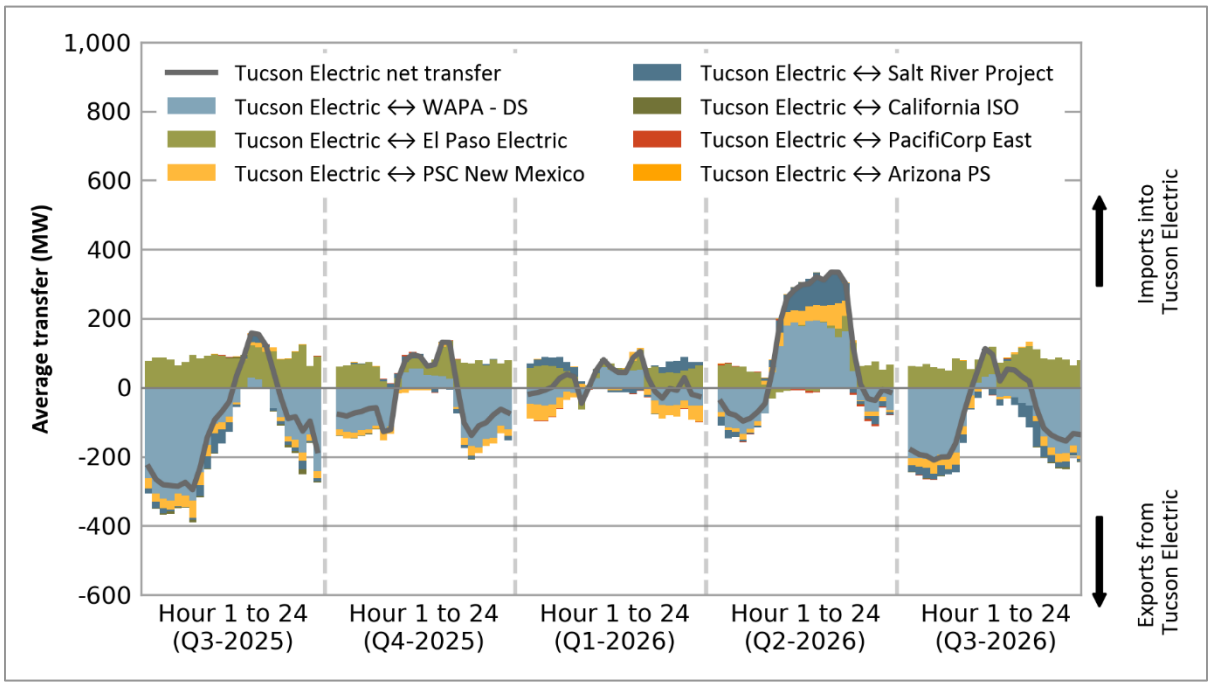


A.23 Tucson Electric Power

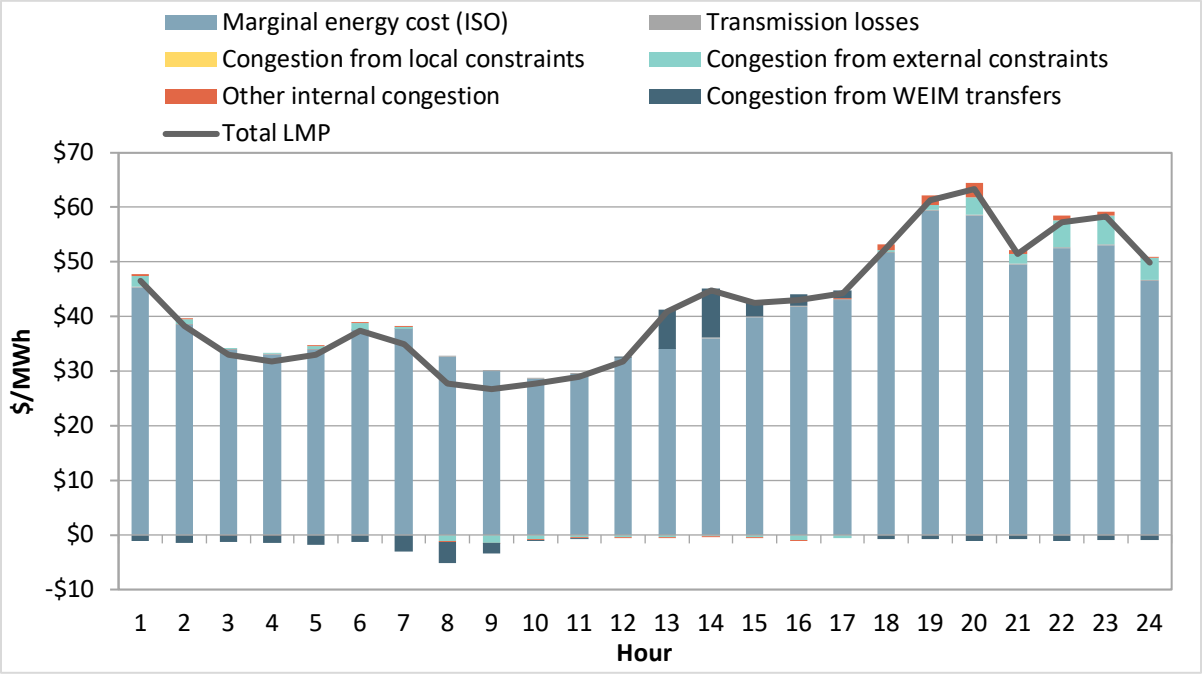
Appendix Figure A.137 Average hourly 15-minute price by component (July – September 2026)



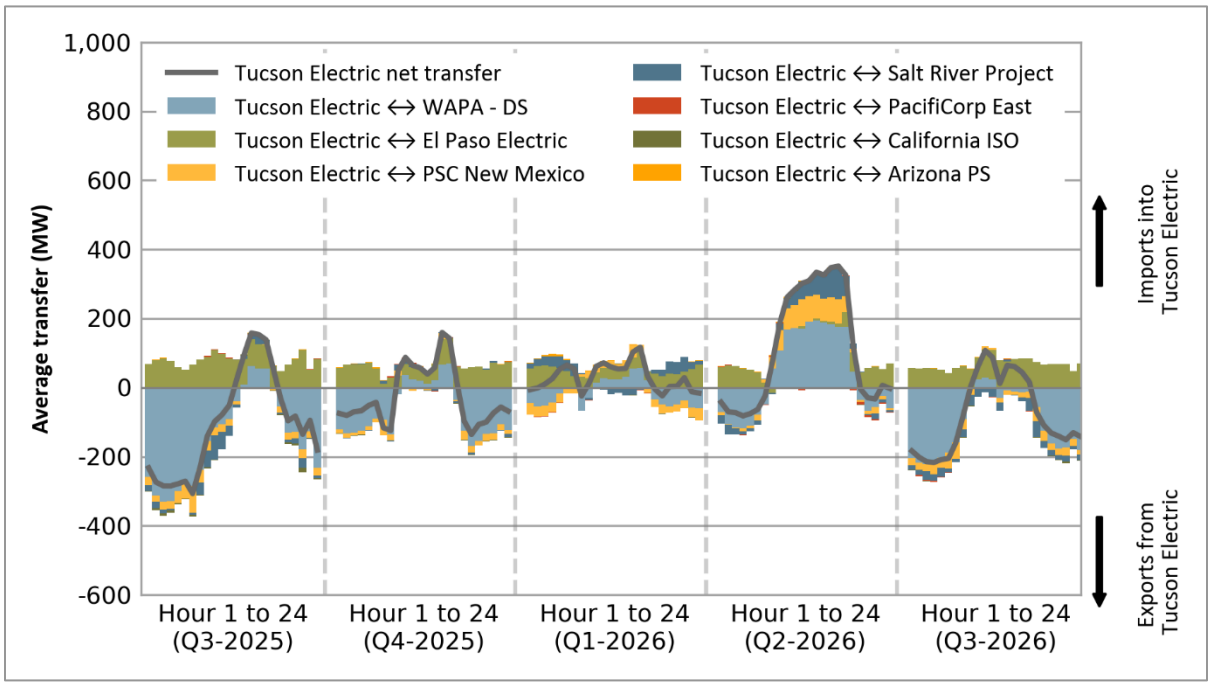
Appendix Figure A.139 Average hourly 15-minute market transfers



Appendix Figure A.140 Average hourly 5-minute price by component (July – September 2026)

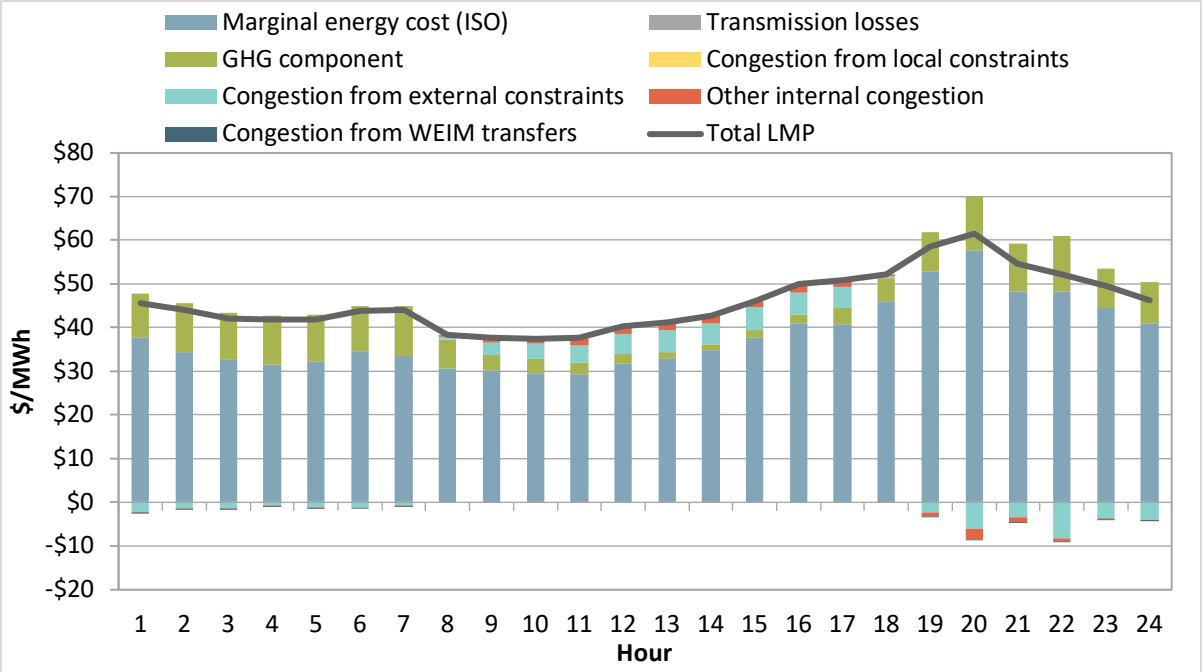


Appendix Figure A.142 Average hourly 5-minute market transfers

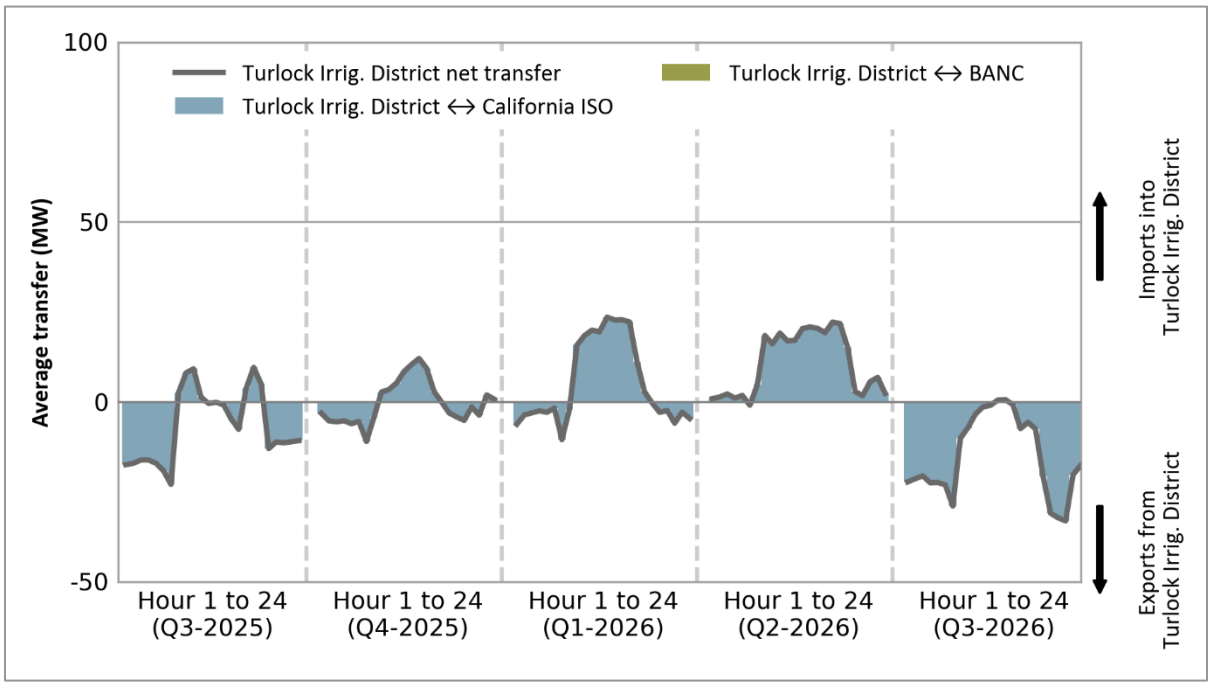


A.24 Turlock Irrigation District

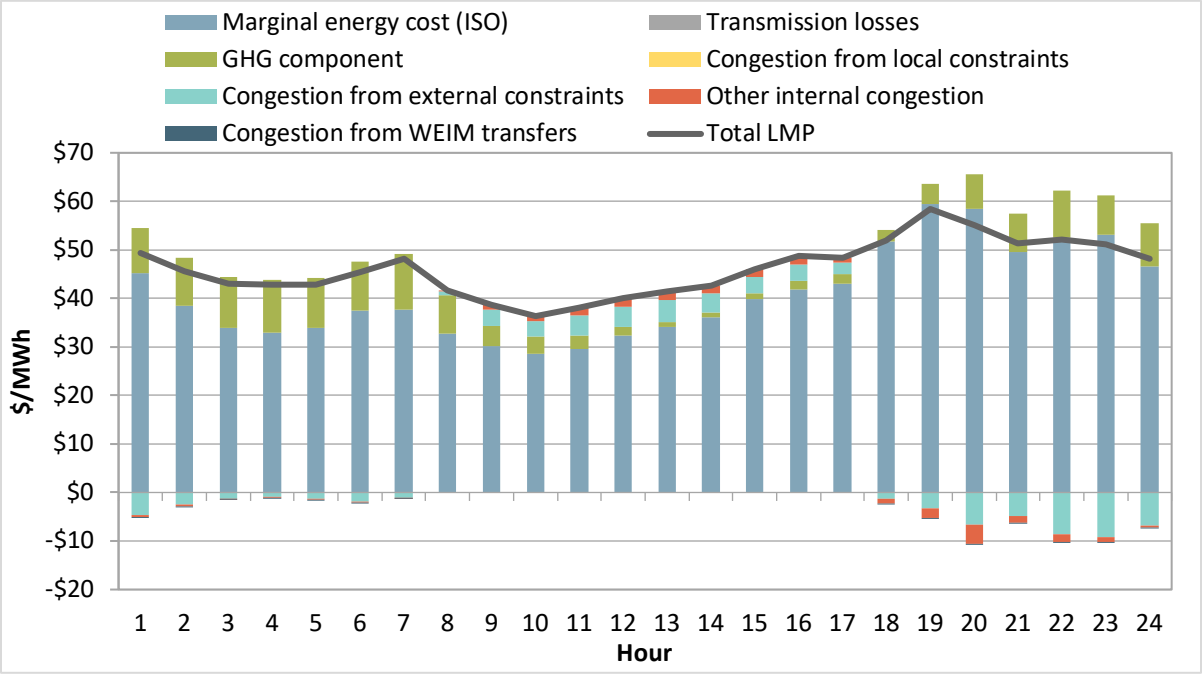
Appendix Figure A.143 Average hourly 15-minute price by component (July – September 2026)



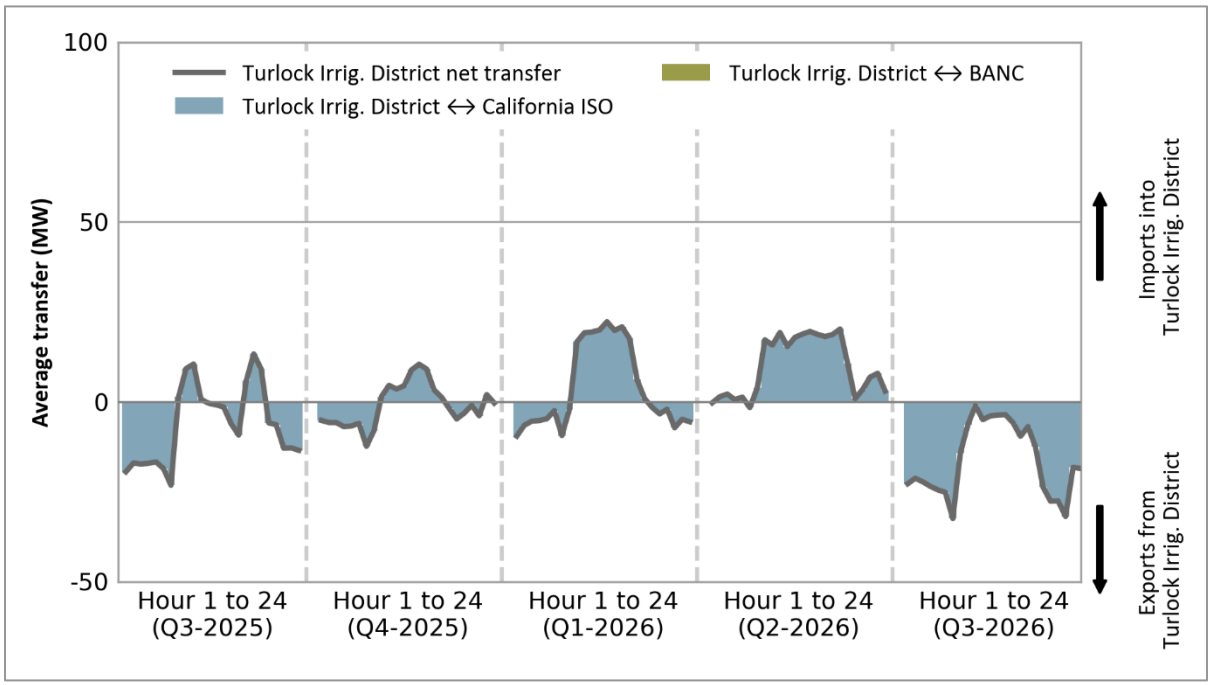
Appendix Figure A.145 Average hourly 15-minute market transfers



Appendix Figure A.146 Average hourly 5-minute price by component (July – September 2026)

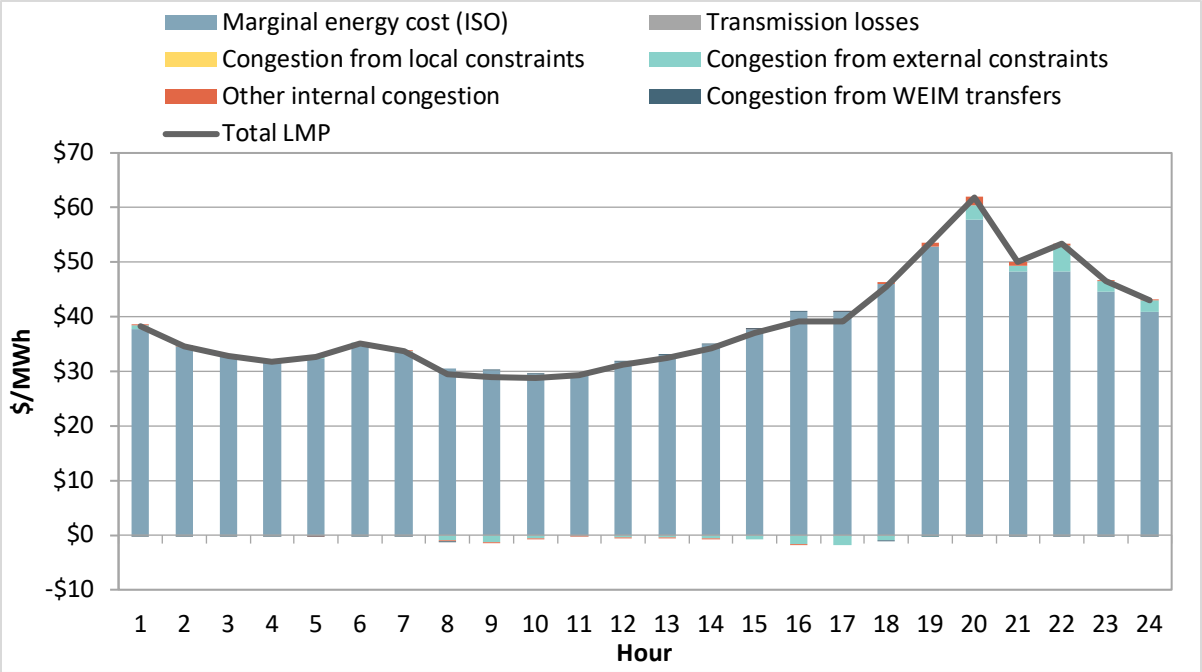


Appendix Figure A.148 Average hourly 5-minute market transfers

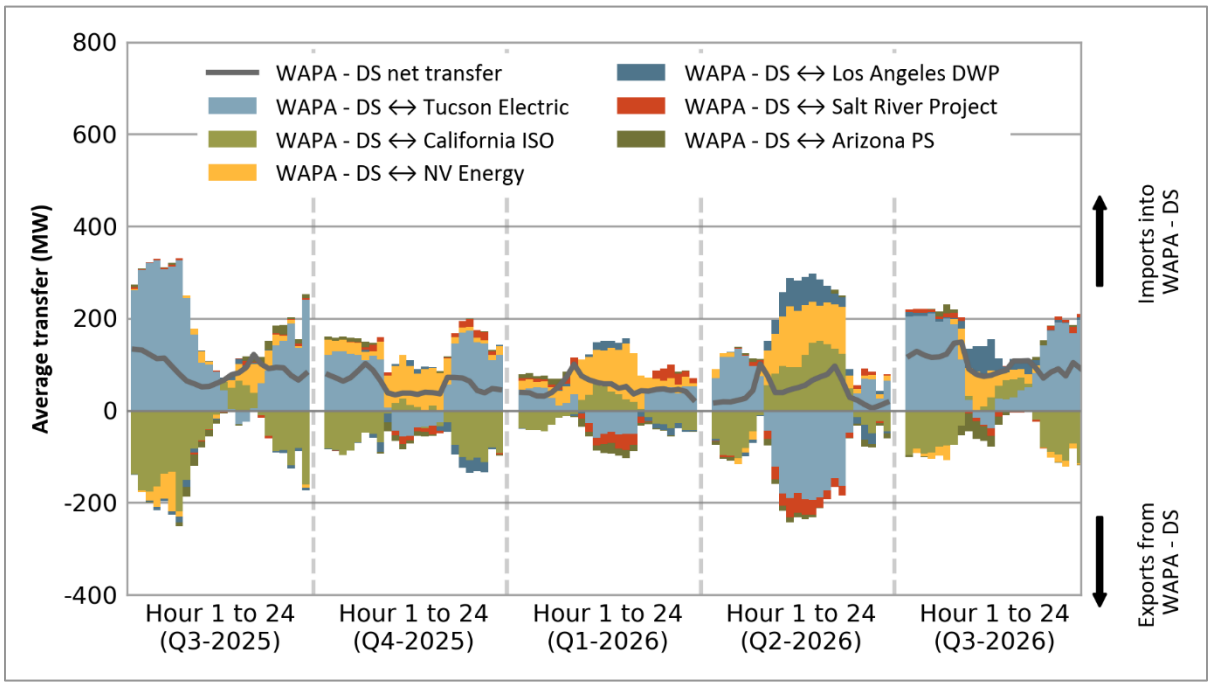


A.25 Western Area Power Administration Desert Southwest

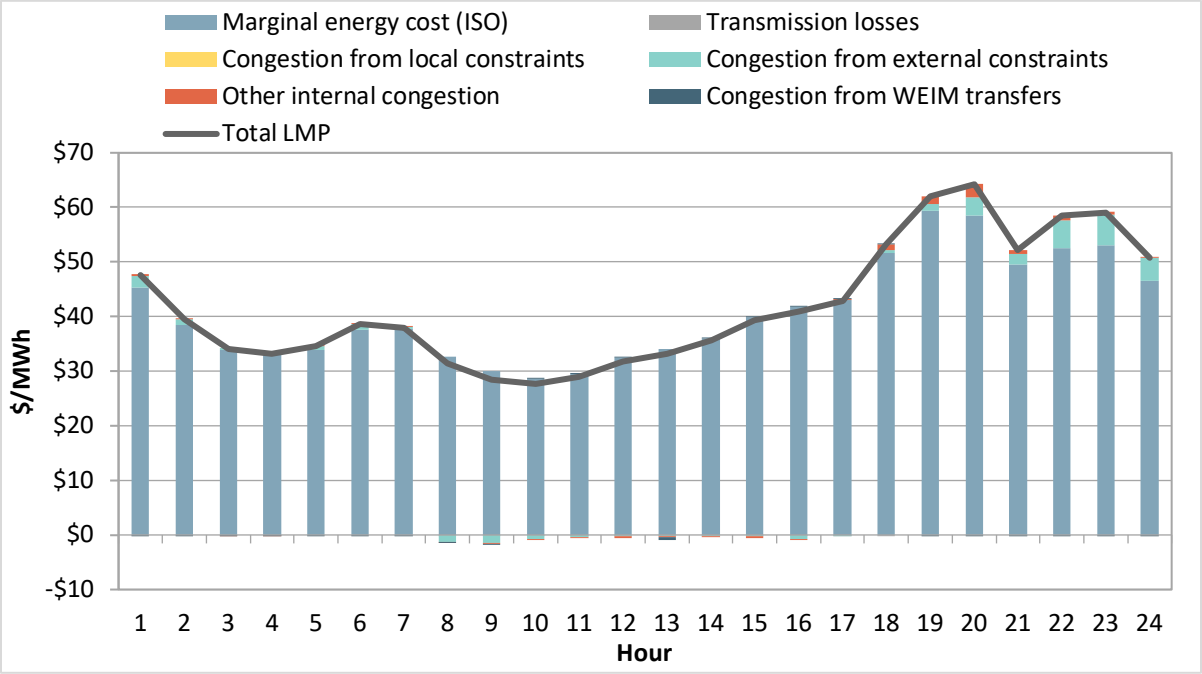
Appendix Figure A.149 Average hourly 15-minute price by component (July – September 2026)



Appendix Figure A.151 Average hourly 15-minute market transfers



Appendix Figure A.152 Average hourly 5-minute price by component (July – September 2026)



Appendix Figure A.154 Average hourly 5-minute market transfers

