Q4 2024 Report on Market Issues and Performance

March 26, 2025

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California Independent System Operator

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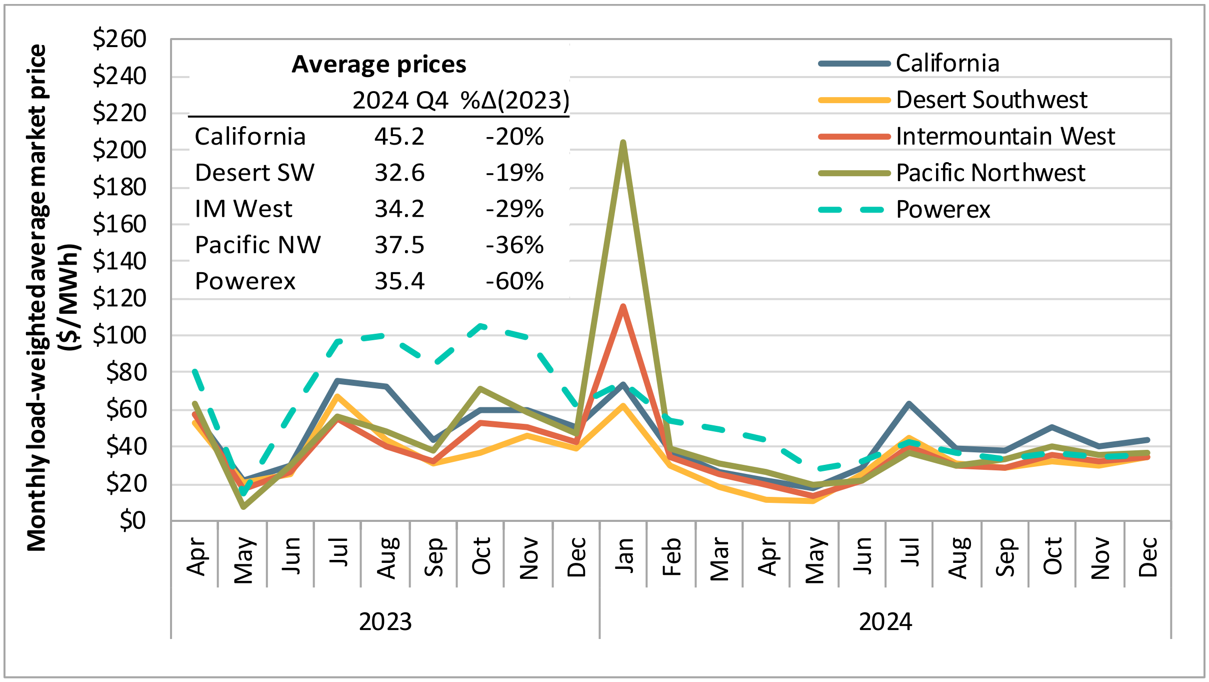
Executive summary

This report covers market performance during the fourth quarter of 2024 (October–December). Prices decreased significantly compared to the same quarter of 2023 (Figure E. 1). Prices in the 15-minute market across the Western Energy Imbalance Market (WEIM) averaged about $39/MWh, down 31 percent due mainly to lower natural gas prices. Prices in the 5-minute market were also down 31 percent and day-ahead market prices were down 22 percent compared to Q4 2023.

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



Other key highlights during this quarter include the following:

Supply and load conditions

- **Natural gas prices in the West were substantially lower.** Prices at PG&E Citygate and SoCal Citygate decreased 31 percent and 50 percent, respectively, while prices at Northwest Sumas were down 47 percent and prices at El Paso Permian decreased 26 percent compared to Q4 2023. This was the major driver of lower electricity prices across western markets.
- **Average hourly generation from renewable resources in the WEIM footprint increased by about 4,320 MW** (14 percent) compared to the fourth quarter of 2023. Over 65 percent of this growth was from wind and solar generation, both of which increased in every region.[1] Hydroelectric generation represented 87 percent of all renewable generation in the Pacific Northwest and increased by 2,040 MW (15 percent) compared to Q4 2023.

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

- **Average hourly battery discharge in the California and Desert Southwest regions increased** relative to the fourth quarter of 2023 by 490 MW (64 percent) and 300 MW (125 percent), respectively**.**
- **Average net imports into the Pacific Northwest region, excluding dynamic WEIM transfers, decreased by around 1,010 MW**. The Pacific Northwest was a net exporter overall during the fourth quarter of 2024. Coal generation in the Intermountain West region decreased by 400 MW (10 percent) while natural gas generation increased by 430 MW (17 percent).
- **WEIM transfers averaged 3,870 MW, down about 6 percent from the fourth quarter of 2023.** During mid-day solar hours, the majority of regional transfers were from the CAISO area to the Pacific Northwest and non-CAISO California areas. During morning and evening hours, the Desert Southwest was the major exporting region.
- **California ISO balancing area operators did not implement peak hour dynamic WEIM transfer restrictions into the CAISO area during any hours of the fourth quarter of 2024.** Operators had restricted most WEIM transfers into the CAISO area in the hour-ahead and 15-minute markets during peak net load hours from July 26 through November 15, 2023.
- **Generation outages in WEIM regions besides the CAISO balancing area generally decreased in the fourth quarter of 2024 compared to the fourth quarter of 2023.** The Desert Southwest region averaged about 9,400 MW of total generation outages, a 12 percent decrease from the fourth quarter of 2023. The California (non-CAISO) region averaged 4,400 MW of total generation outages, a 14 percent decrease from the fourth quarter of 2023. The Intermountain West region averaged about 2,400 MW of total generation outages, a two percent decrease from the fourth quarter of 2023. The Pacific Northwest region averaged about 3,000 MW of total generation outage, a 1 percent decrease from the fourth quarter of 2023.
- **Forced outages in the CAISO balancing area increased by 41 percent when compared to the same quarter last year**. The year-over-year increase in forced outages is consistent with a general trend of higher forced outages seen in the first and second quarters of 2024. The increase in forced outages is largely explained by the implementation of the Strategic Reliability Reserve (SRR) program, which uses outages to prevent the dispatching of SRR participating resources outside of dispatch instructions issued in the context of the SRR program.
- **Load across the WEIM averaged 75.4 GW, an increase of about 2 percent compared to the same quarter of 2023.** Q4 2024 had more hours with high system load (over 85 GW) and less hours with low system load (below 65 GW) than Q4 2023. Peak 5-minute market load for the quarter was 110.5 GW on October 2, 2024, hour-ending 18, interval 8.

Prices and congestion

- **Average prices in the ISO's day-ahead market** at the Pacific Gas and Electric load node were higher than Southern California Edison prices in every month of Q4. In October, peak day-ahead bilateral prices at Palo Verde and Mid-Columbia were similar to the Pacific Gas and Electric prices and higher than the Southern California Edison prices. This pattern shifted in November and December, when average prices at Palo Verde and Mid-Columbia dropped below Pacific Gas and Electric prices.
- **The ISO implemented enhancements to the maximum import bid price (MIBP) hourly energy shaping factor on November 16, 2024.** The ISO uses this factor to scale and shape 16-hour block prices at major bilateral trading hubs into ISO market hourly prices. If a maximum hourly price exceeds $1,000/MWh, the ISO will increase its energy bid caps to $2,000/MWh. The ISO did not raise the energy bid cap and penalty prices to $2,000/MWh in the fourth quarter.

- **Transmission congestion impact on regional prices continued to be different during mid-day solar hours than during evening hours.** During solar hours, congestion contributed to higher prices in the Pacific Northwest and Northern California relative to the Desert Southwest and Southern California. During evening hours, congestion was instead generally into California balancing areas from balancing areas in Pacific Northwest, Intermountain West, and Desert Southwest.
- **Overall day-ahead market congestion rents on internal and intertie constraints was $205 million,** down 9 percent from the fourth quarter of 2023**.**
- **Payouts to congestion revenue rights (CRRs) sold in the California ISO auction exceeded auction revenues received for these rights by about $1.7 million** in the fourth quarter of 2024. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. The Department of Market Monitoring (DMM) continues to recommend further changes to eliminate or further reduce these losses.

Resource sufficiency evaluation

- **Almost all WEIM balancing areas passed each type of the resource sufficiency evaluation test in more than 99 percent of intervals.** Public Service Company of New Mexico (PNM) failed the upward flexibility test in around 2.5 percent of intervals and the upward capacity test in about 1.2 percent of intervals.
- **Eight balancing areas opted in to the assistance energy transfer program on at least one day during the quarter.** Three of these balancing areas received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. Failures while opted in to receiving assistance energy transfers were not highly coincident across balancing areas.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in separate quarterly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[2]

Uplift costs and credits

- **Real-time imbalance offsets for balancing areas participating only in the WEIM real-time markets were an $8 million credit** to WEIM entities, compared to a $73 million credit in the fourth quarter of 2023. The congestion portion of this offset, which is largely congestion rent from WEIM transfer constraints, was a $14 million credit. PacifiCorp East received $11 million of this $14 million credit.
- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $56 million in uplift in the fourth quarter of 2024.** This was a decrease from $79 million in the same quarter of 2023. During the fourth quarter of 2024, real-time *congestion* imbalance offset costs made up $53 million of these costs.
- **Bid cost recovery payments for units in balancing areas participating in both the day-ahead and real-time markets totaled about $36 million, down about 59 percent** from the $87 million in bid

[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

cost recovery in the fourth quarter of 2023. Bid cost recovery payments associated with the residual unit commitment market were only about $6 million, a decrease of $46 million (88 percent) from the fourth quarter of 2023.

- **Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM**) totaled about $4.4 million, down about 33 percent from Q4 2023.

Operator adjustments and manual dispatch

- **Operator adjustments to load forecasts in most balancing areas were higher in the 5-minute market than in the 15-minute market.** Notable exceptions included the CAISO balancing area and Bonneville Power Administration. CAISO balancing area load adjustments in the 15-minute market during evening peak net load ramping hours were lower in the fourth quarter of 2024 compared to the fourth quarter of 2023.
- **The average total volume of capacity procured through the residual unit commitment (RUC) process in the fourth quarter of 2024 was 68 percent lower than the same quarter of 2023.** Operator adjustments to the RUC procurement target decreased by about 90 percent for the same period. This was in large part because of significant changes in the methodology for determining the adjustments on December 21, 2023 and May 7, 2024.
- **Manual dispatch energy increased in the Desert Southwest, California (non-CAISO), and Intermountain West regions** compared to the fourth quarter of 2023 by 36 percent, 27 percent, and 13 percent, respectively. Combined incremental and decremental manual dispatch energy in the Pacific Northwest region decreased by 12 percent.

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

- **Mosaic quantile regression uncertainty requirements for the flexible ramping product and resource sufficiency evaluation were on average lower than requirements would have been using the previous histogram method.** For flexible ramping products, the coverage rate was 96 percent or higher, but the regression coefficients were statistically different from zero in only 41 percent of intervals. The coverage rate for the resource sufficiency evaluation varied between 86 percent and 93 percent across balancing areas, and only 45 percent of regression coefficients were statistically significant.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty much less for intervals at the end of the hour than for intervals at the beginning of the hour.** This is because the model is designed to predict uncertainty in forecasts that are produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, produced between 47.5 and 102.5 minutes before real-time.
- **The ISO set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5th percentile of net load uncertainty on only 3 percent of days in the quarter.** The 75th percentile target was applied on 9 percent of days. The 50th percentile target was applied on 34 percent of days. During much of the quarter, no adjustment was applied (54 percent of days). Average requirements using the 97.5th percentile target were roughly double those using the 75th percentile target and more than double requirements using the 50th percentile target. The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address this same uncertainty, but the requirement will be set to cover the 97.5th percentile of

uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in the residual unit commitment (RUC) indicates that the imbalance reserve product demand curve may be much too high during most hours.

Ancillary services, available balancing capacity, and flexible ramping product

- **Upward flexible ramping product prices at the system and balancing area level for the 15-minute market were greater than zero in one or more balancing areas that passed the resource sufficiency evaluation tests in less than 1 percent of intervals in the fourth quarter.** Battery and hydro resources made up 63 percent and 26 percent of upward flexible capacity, respectively. Wind and solar combined to provide 36 percent of downward flexible capacity. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 64 percent of each. Balancing areas in the Pacific Northwest made up 21 percent of upward flexible capacity and 18 percent of downward flexible capacity.
- **Ancillary service payments in the CAISO balancing area totaled $18.3 million, a 3 percent decrease from the same quarter last year.**
- **Similar to previous quarters, available balancing capacity was dispatched for generation shortfalls in less than 1 percent of intervals for most WEIM balancing areas.**

California ISO balancing area transmission and resource adequacy capacity

- **In June 2024, the ISO implemented its new policy to issue high priority wheeling-through rights based on its estimation of CAISO area transmission capacity available for these wheels.** Schedulers reserved less priority wheel-through capacity, and on fewer interties, in the fourth quarter compared to previous quarters. Participants reserved monthly priority wheel-through capacity on the IPP and PVWEST tie points in October. Participants did not reserve monthly capacity in November or December.
- **Resource adequacy capacity bid into the real-time market was not sufficient to meet CAISO balancing area market requirements in five hours of the fourth quarter**. All of these hours were hour-ending 19 on days between October 1 and October 7, 2024.
- **Resource adequacy import bid quantity into the CAISO area increased 145 percent** compared to the fourth quarter of 2023.

1 Supply conditions

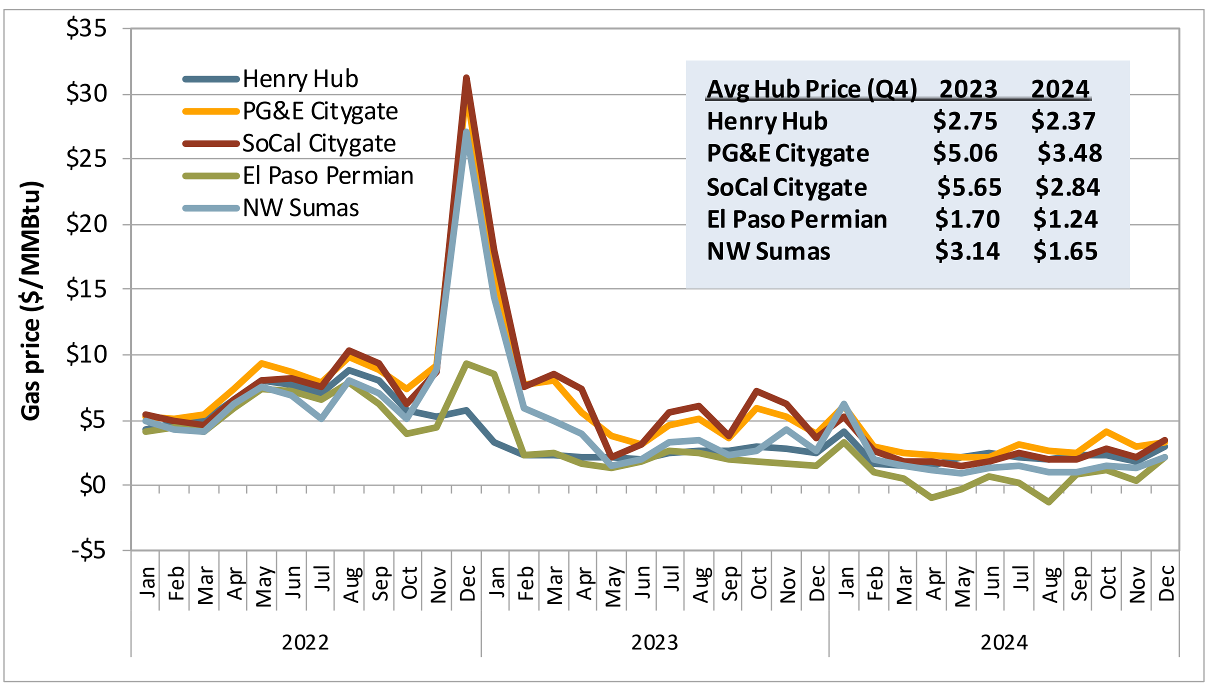
1.1 Natural gas prices

Electricity prices in Western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in Western Energy Imbalance Market (WEIM) balancing areas and other regional markets. Figure 1.1 shows monthly average natural gas prices at key delivery points across the West, as well as the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

Average natural gas prices at major Western U.S. trading hubs were down significantly in the fourth quarter of 2024 compared to the same quarter of 2023. Average fourth quarter prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) decreased by 31 percent and 50 percent compared to the same quarter of the previous year, respectively. The Henry Hub, Northwest Sumas, and El Paso Permian gas prices decreased by 14 percent, 47 percent, and 26 percent, respectively, during the same time period.

Compared to the third quarter of 2024, natural gas prices at PG&E Citygate and SoCal Citygate increased by 24 percent and 33 percent, respectively. Henry Hub and Northwest Sumas prices increased by about 13 percent and 40 percent, respectively, compared to last quarter.

Figure 1.1 Monthly average natural gas prices



1.2 Renewable generation

In the fourth quarter, the average hourly generation from renewable resources in the WEIM footprint increased by about 4,320 MW (14 percent) compared to the same quarter of 2023.[3] Wind and solar generation increased in every region.[4] The increases for wind and solar generation totaled 1,580 MW and 1,230 MW, respectively across the WEIM. The availability of variable energy resources, such as wind and solar resources, contributes to price patterns both seasonally and hourly due to their low marginal cost relative to other resources.

Figure 1.2 to Figure 1.5 show the average monthly renewable generation by fuel type.[5]

- Generation from solar resources made up 45 percent of all renewable output in the California region and increased by 447 MW (11 percent) compared to the fourth quarter of 2023.
- Solar generation represented 46 percent of the renewable fuel mix in the Desert Southwest region and increased by 650 MW (60 percent) from the fourth quarter of 2023.
- Overall, renewable generation in the Intermountain West region increased by 403 MW (11 percent) relative to the fourth quarter of 2023, with the largest increase coming from wind (270 MW).
- In the fourth quarter of 2024, hydroelectric generation represented 87 percent of all renewable generation in the Pacific Northwest and increased by 2,040 MW (15 percent) from the same quarter of the previous year. The Pacific Northwest also saw a 500 MW (32 percent) increase in wind generation.
- Average hourly generation from biogas-biomass resources decreased in all regions compared to the fourth quarter of 2023. Average hourly generation from geothermal resources in the Desert Southwest decreased by 70 MW (12 percent).

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

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

[5] Hydroelectric generation greater than 30 MW is included.

Figure 1.2 California - Average monthly renewable generation

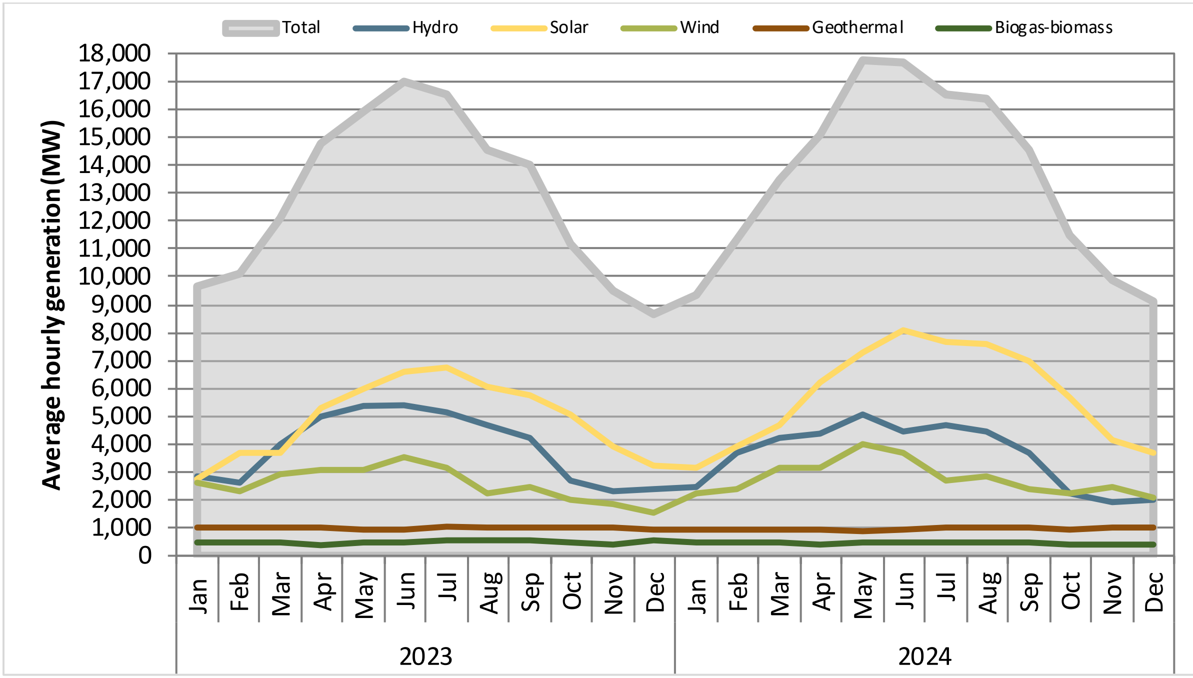


Figure 1.3 Desert Southwest - Average monthly renewable generation

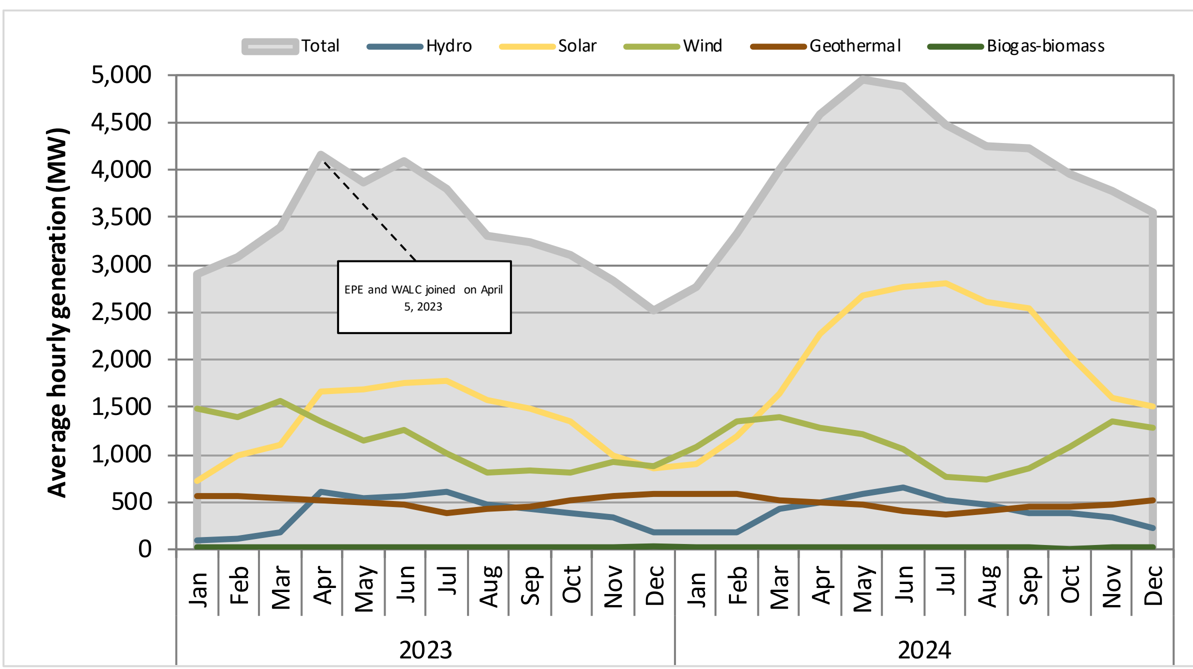


Figure 1.4 Intermountain West - Average monthly renewable generation

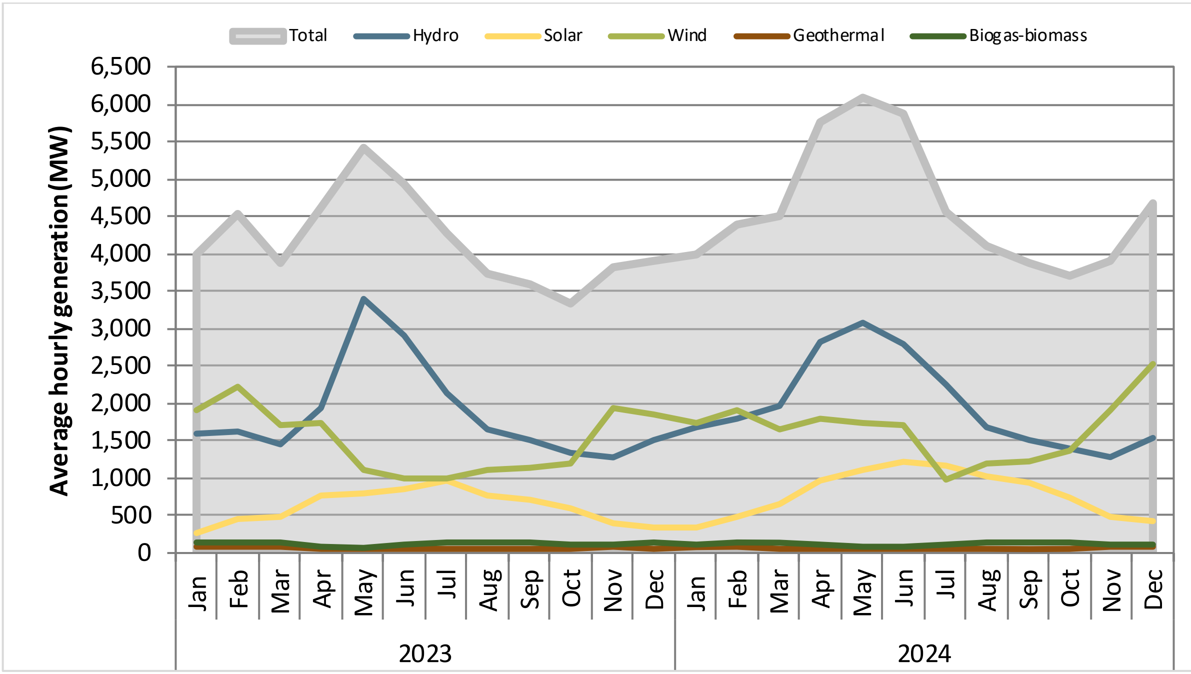
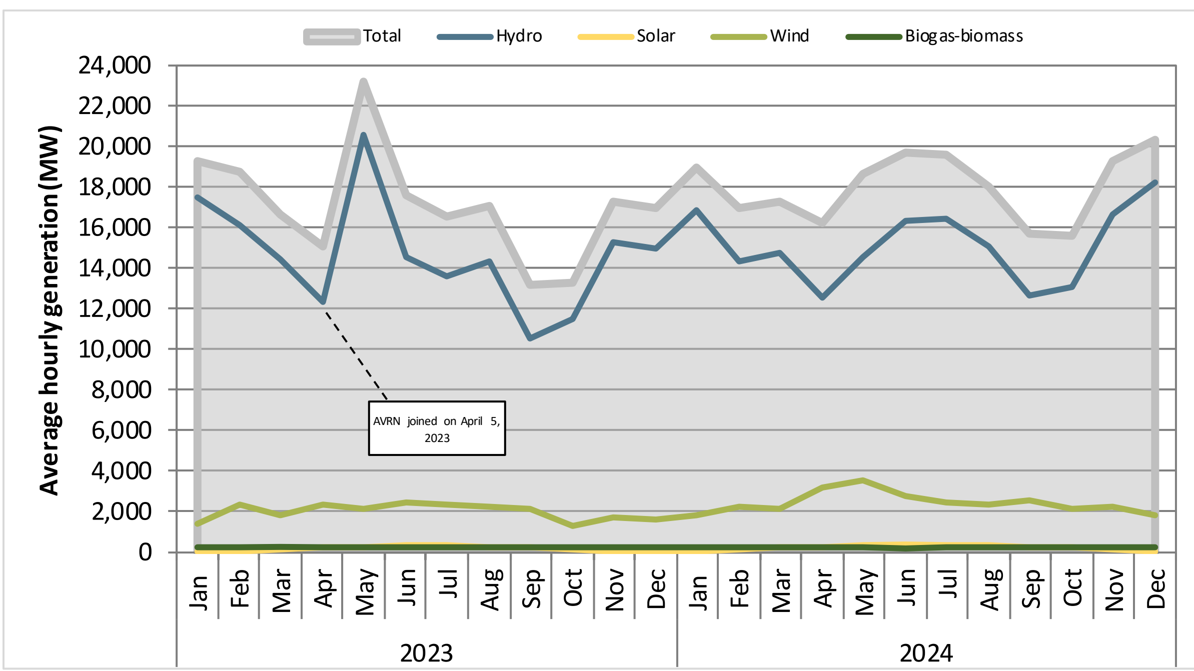


Figure 1.5 Pacific Northwest - Average monthly renewable generation



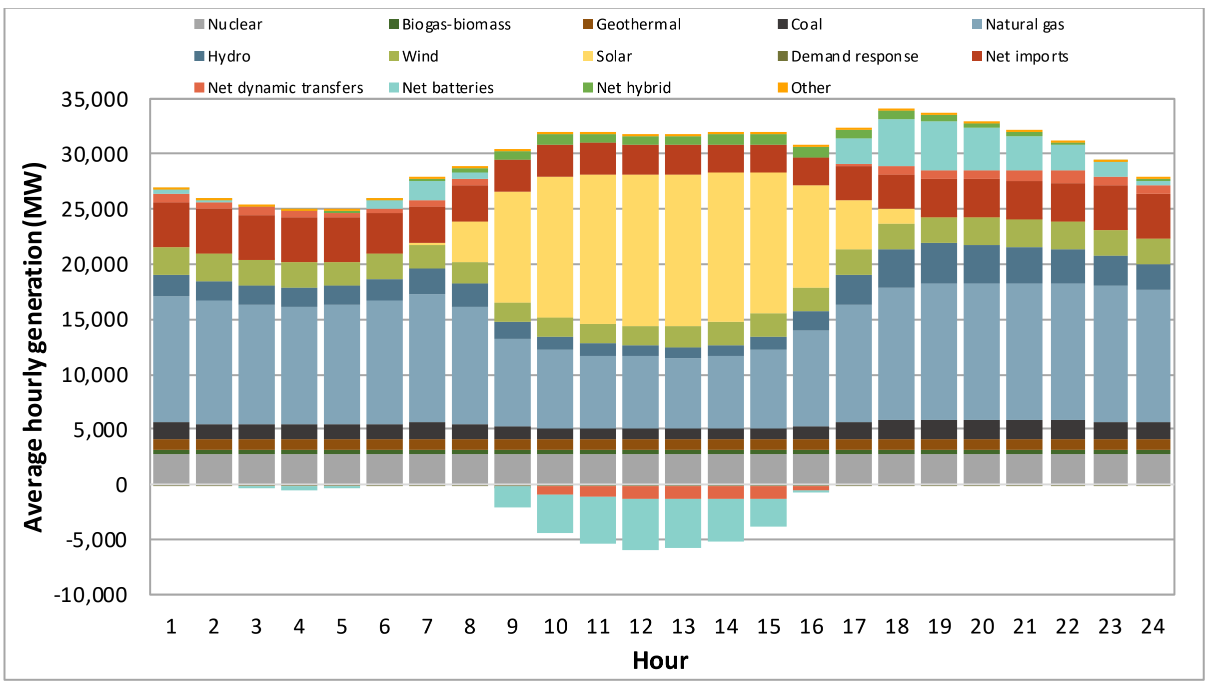
1.3 Generation by fuel type

Figure 1.6 to Figure 1.9 show the average hourly generation by fuel type during the fourth quarter of 2024 for each region in the WEIM. Total hourly average generation peaks at hour-ending 18 in all regions.

Average hourly battery discharge in the California and Desert Southwest regions increased relative to the fourth quarter of 2023 by 490 MW (64 percent) and 300 MW (125 percent), respectively.[6] Coal generation in the Intermountain West region decreased by 400 MW (10 percent) while natural gas generation increased by 430 MW (17 percent). Average hourly net imports into the Pacific Northwest region, excluding dynamic WEIM transfers, decreased by around 1,010 MW.[7] The Pacific Northwest was net exporting during the fourth quarter of 2024.

As shown in Figure 1.6 and Figure 1.7, there is significant load from batteries charging in California and the Desert Southwest during mid-day hours (represented by the aqua bars below the zero-axis). Average net battery generation across the WEIM for the fourth quarter for 2024 was lowest during hour-ending 12, at around negative 6,100 MW.

Figure 1.6 California - Average hourly generation by fuel type in the (Q4 2024)



6 This statistic refers to battery discharge only, while Figures 1.6 – 1.13 display *net* battery generation.

7 *Net imports* includes transfers scheduled ahead of the real-time market and therefore, not optimized in the market. This includes both schedules on interties between WEIM and non-WEIM balancing areas as well as bilateral base WEIM transfers.

Figure 1.7 Desert Southwest - Average hourly generation by fuel type (Q4 2024)

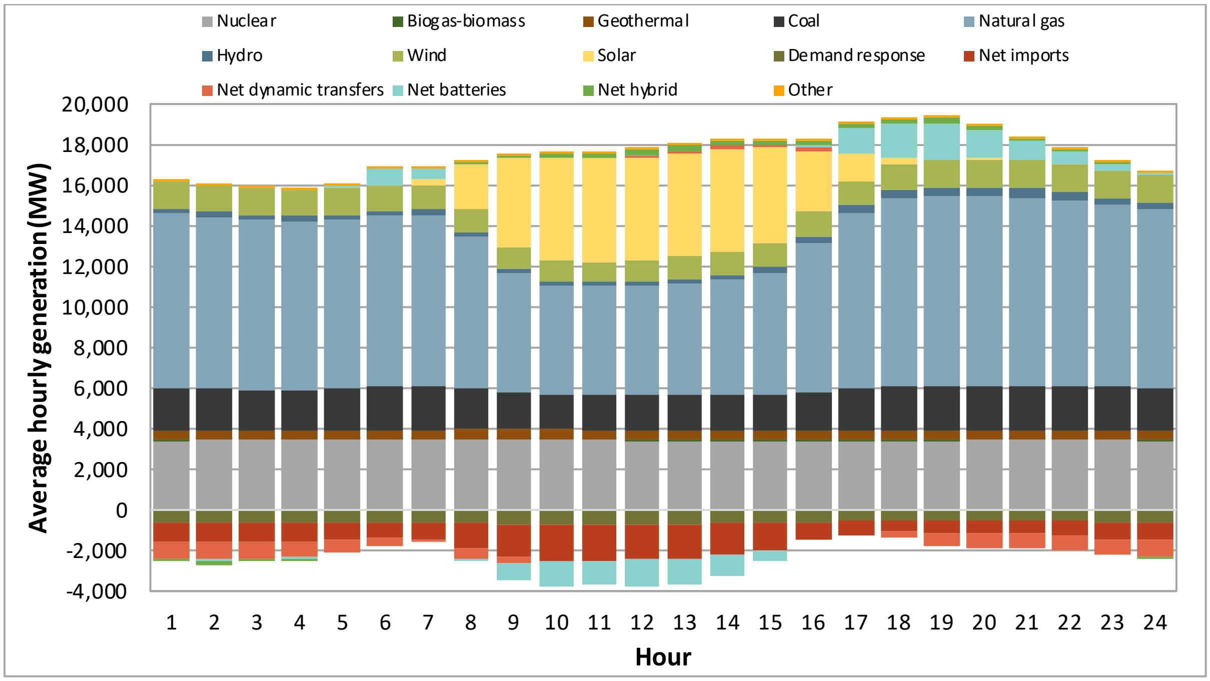


Figure 1.8 Intermountain West - Average hourly generation by fuel type (Q4 2024)

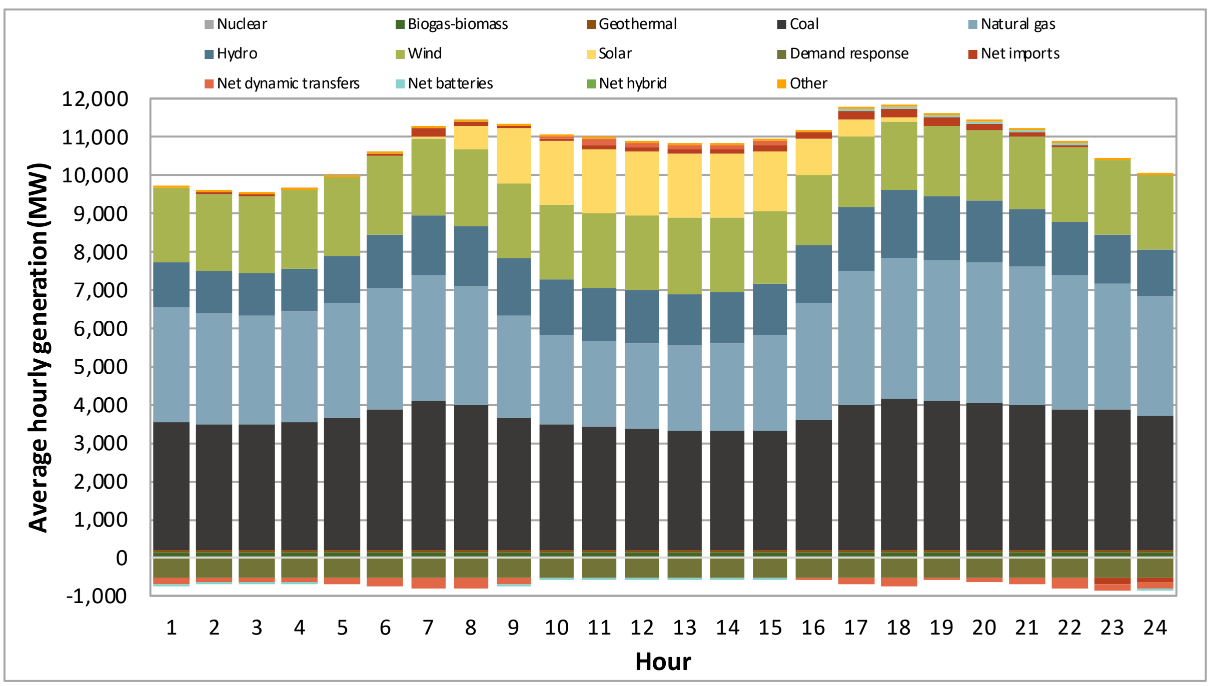


Figure 1.9 Pacific Northwest - Average hourly generation by fuel type (Q4 2024)

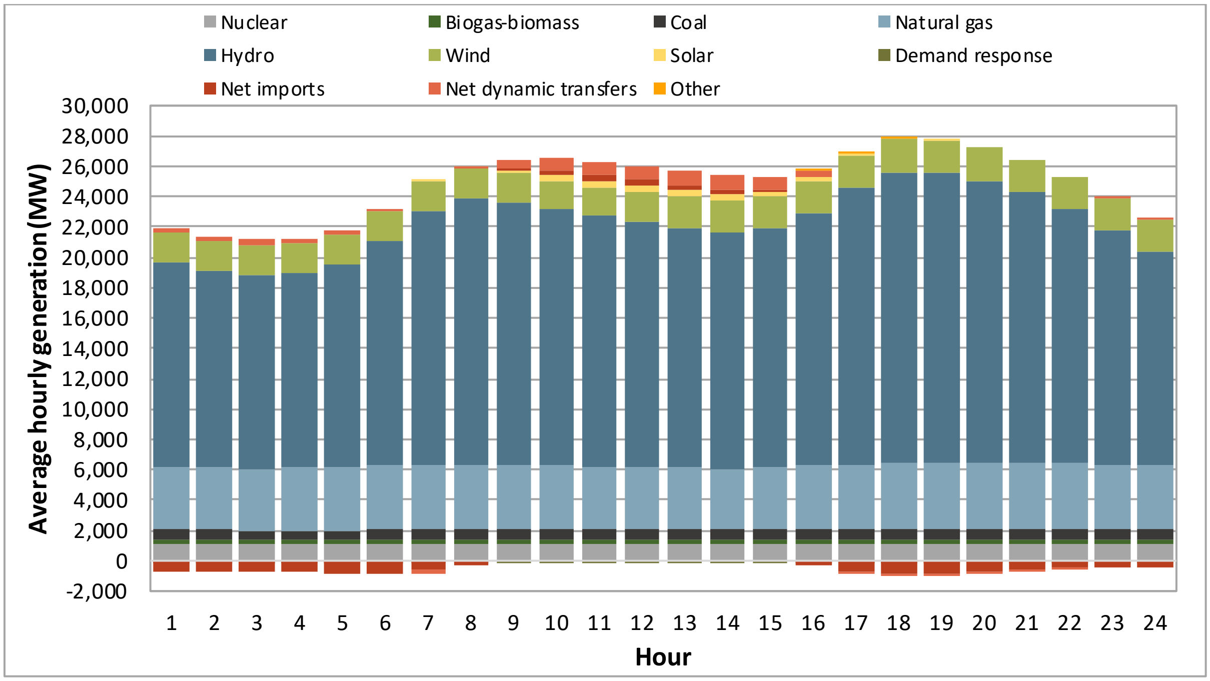


Figure 1.10 to Figure 1.13 show the change in hourly generation by fuel type between the fourth quarters of 2023 and 2024. Positive values represent increased generation relative to the same time last year, and negative values represent a decrease in generation. Change in total load is denoted by the black line.

- Natural gas generation decreased in the California, Desert Southwest, and Pacific Northwest regions while increasing in the Intermountain West region. In the Intermountain West, this can be attributed to coal-to-gas conversions of existing capacity.
- Batteries have been increasingly participating in energy arbitrage by charging during the high solar hours mid-day, and discharging during the high net load periods in the evening. Increased mid-day battery charging was met largely by greater solar and hybrid production in the California and Desert Southwest regions.
- In the Pacific Northwest, increased hydro production led to significant decreases in net imports across all hours.
- Coal generation in California increased by 710 MW (124 percent).

Figure 1.10 California - Change in average hourly generation by fuel type (Q4 2024 vs. Q4 2023)

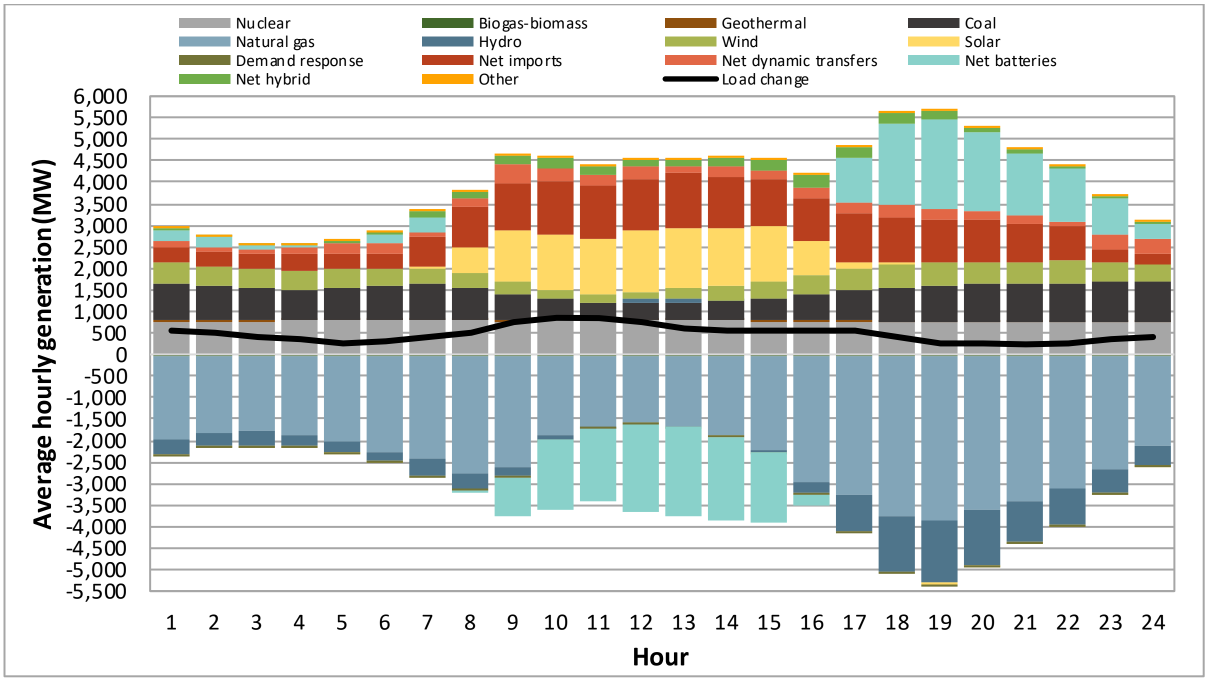


Figure 1.11 Desert Southwest - Change in average hourly generation by fuel type (Q4 2024 vs. Q4 2023)

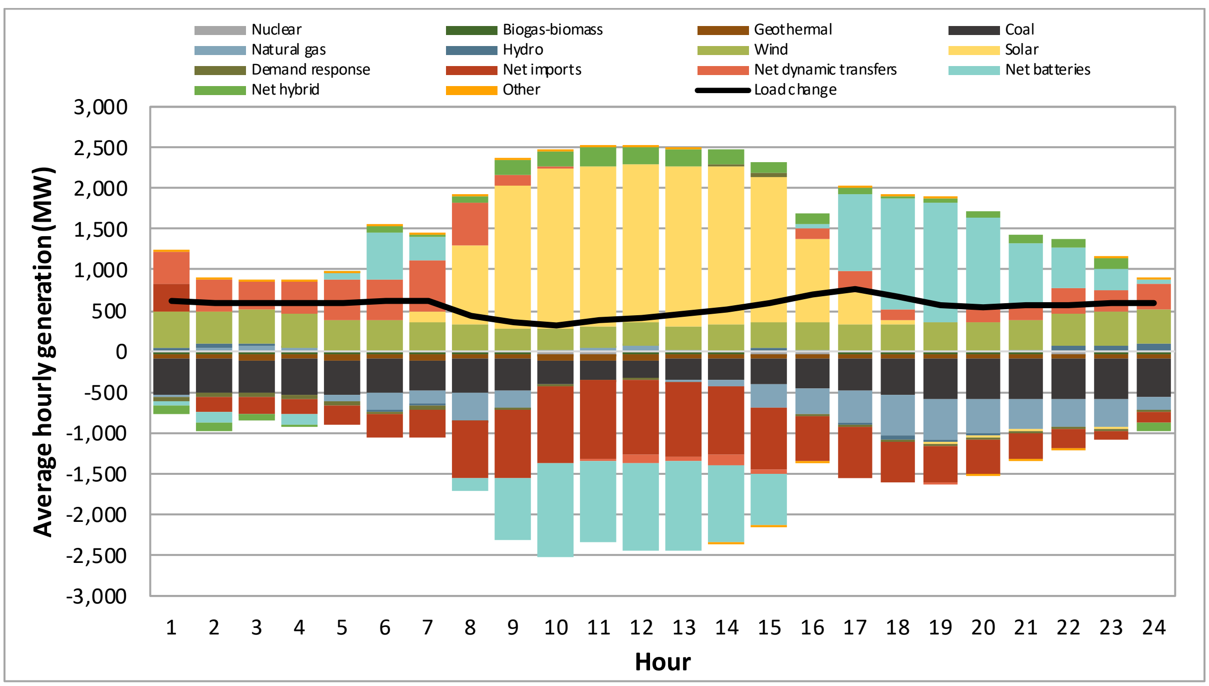


Figure 1.12 Intermountain West - Change in average hourly generation by fuel type (Q4 2024 vs. Q4 2023)

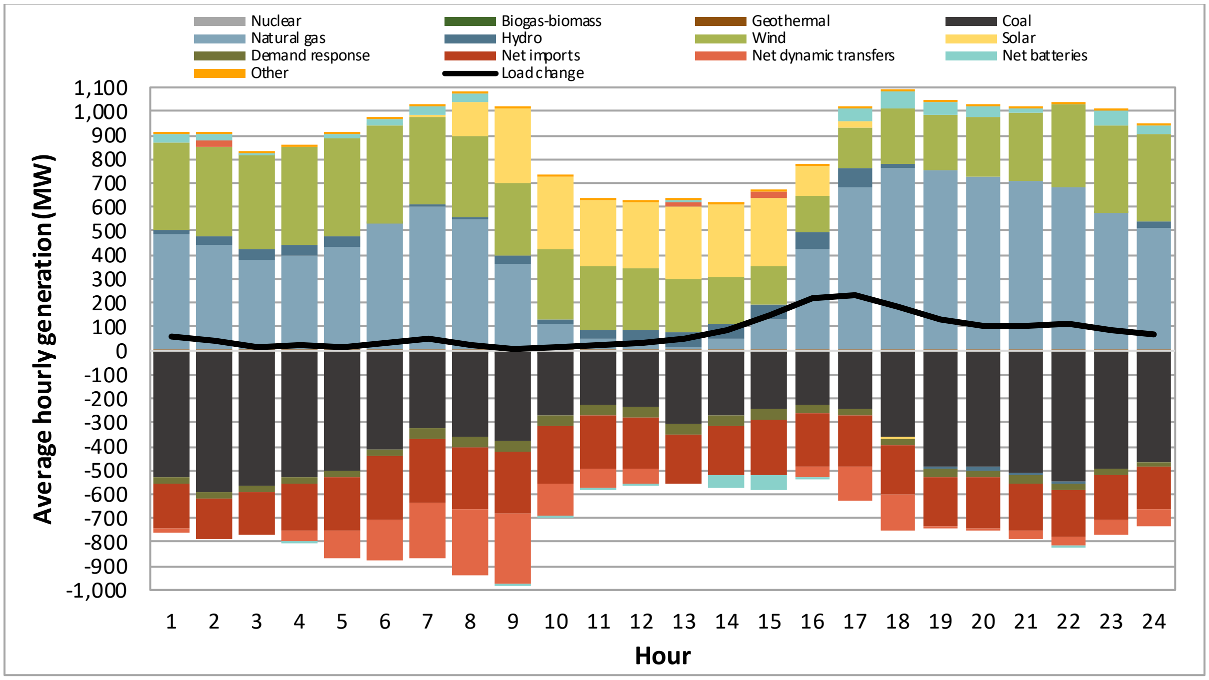


Figure 1.13 Pacific Northwest - Change in average hourly generation by fuel type (Q4 2024 vs. Q4 2023)

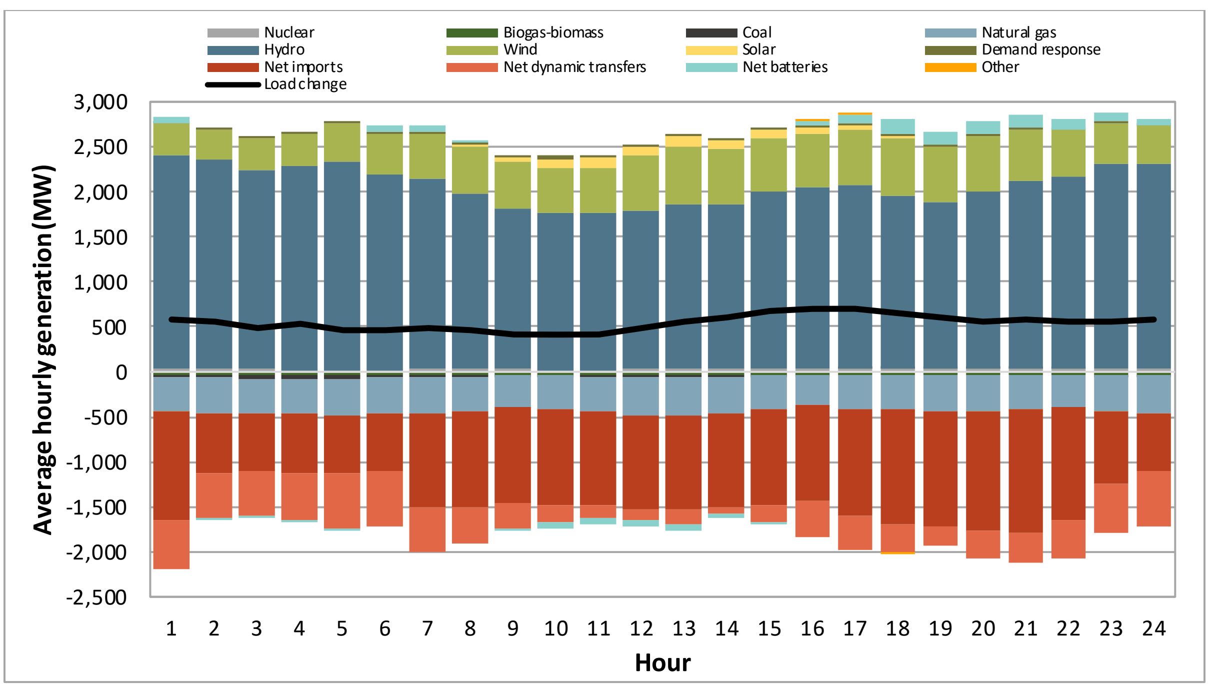
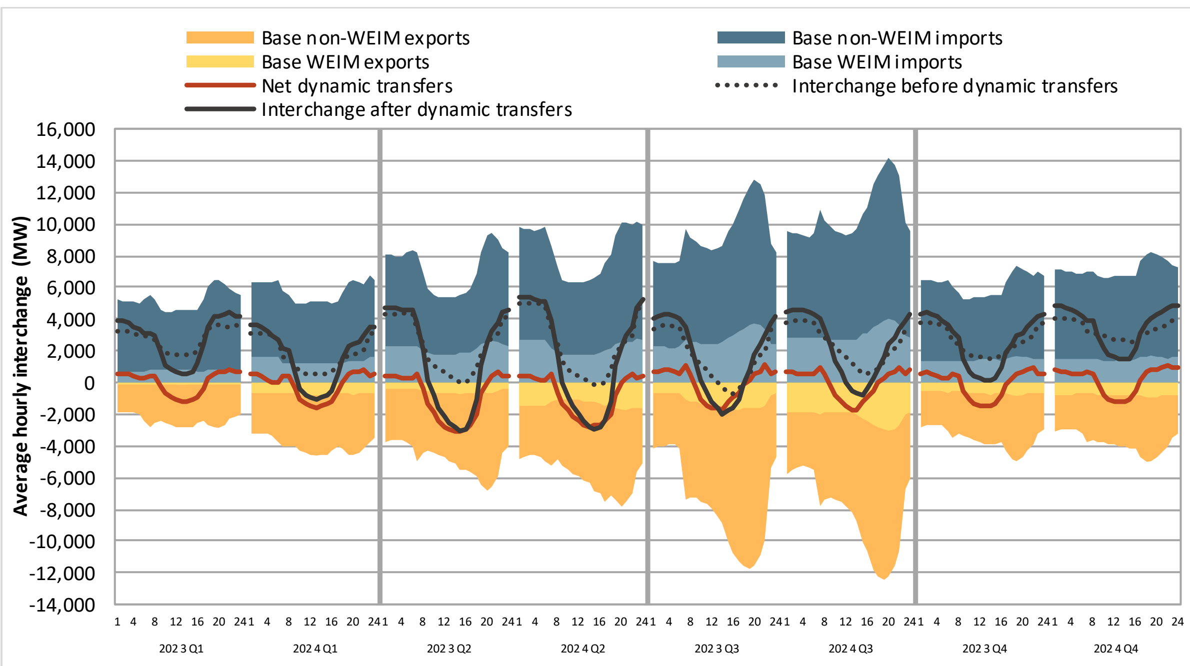


Figure 1.14 to Figure 1.17 shows imports, exports and WEIM transfers for each region in the WEIM. Power flowing into a balancing area is represented as positive while power flowing out of a balancing area is shown as negative. The dark orange and dark blue areas show fixed bilateral exports and imports between a WEIM and a non-WEIM balancing area. The legend refers to these as base non-WEIM exports or imports. Base WEIM exports and base WEIM imports (light yellow and light blue areas), on the other hand, are fixed bilateral transfers between two WEIM balancing areas that are not optimized in the market.[8]

The red line shows the net WEIM dynamic transfers into and out of all balancing areas optimized by the market software. This line also includes static transfers which are optimized in the 15-minute market but held fixed in the 5-minute market. The dotted black line nets all base non-WEIM and base WEIM exports and imports. The solid black line represents the final net interchange after adding the net dynamic transfers (red line) to the dotted black line.

In comparing the fourth quarters of 2023 and 2024, interchange after dynamic transfers (solid black line) have decreased in the Intermountain West and the Pacific Northwest regions by 350 MW and 1,660 MW, respectively. Both regions were net exporters in the fourth quarter of 2024. The California and Desert Southwest regions saw increases to their interchange after dynamic transfers by 980 MW and 140 MW respectively.

Figure 1.14 California - Average hourly net interchange by quarter



8 The export and import values in Figures 1.14 to 1.17 also include both sides of a base transfer between balancing areas in the same region. For example, base transfers from BANC into LADWP would count towards both the base WEIM exports and base WEIM imports in the figures.

Figure 1.15 Desert Southwest - Average hourly net interchange by quarter

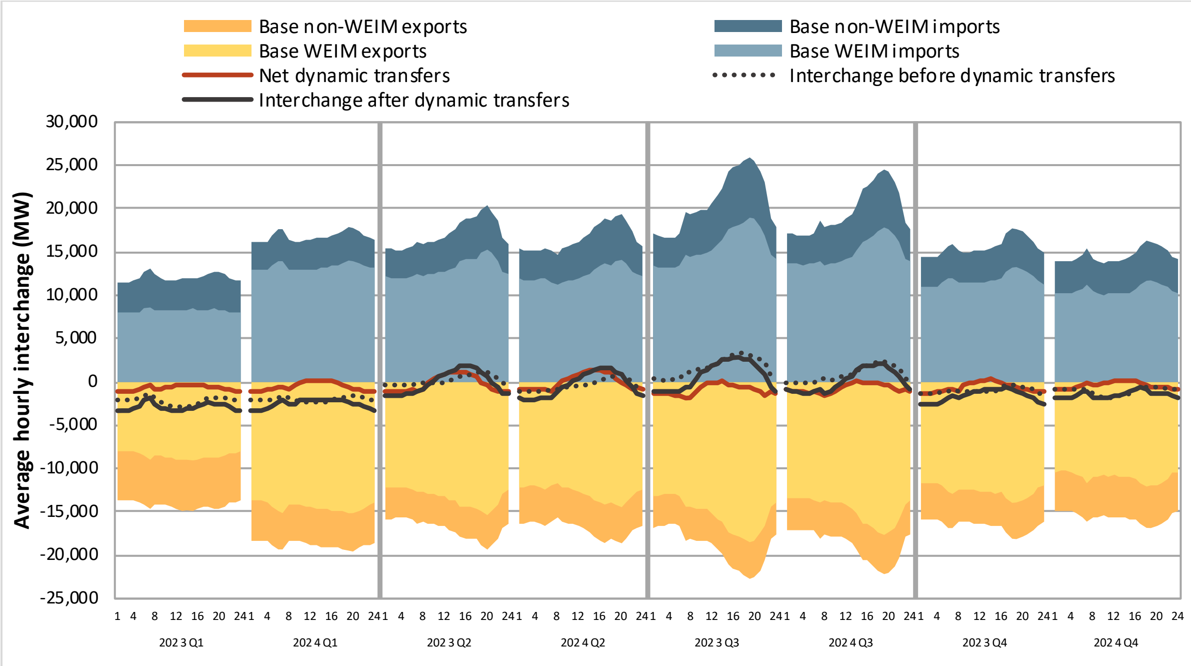


Figure 1.16 Intermountain West - Average hourly net interchange by quarter

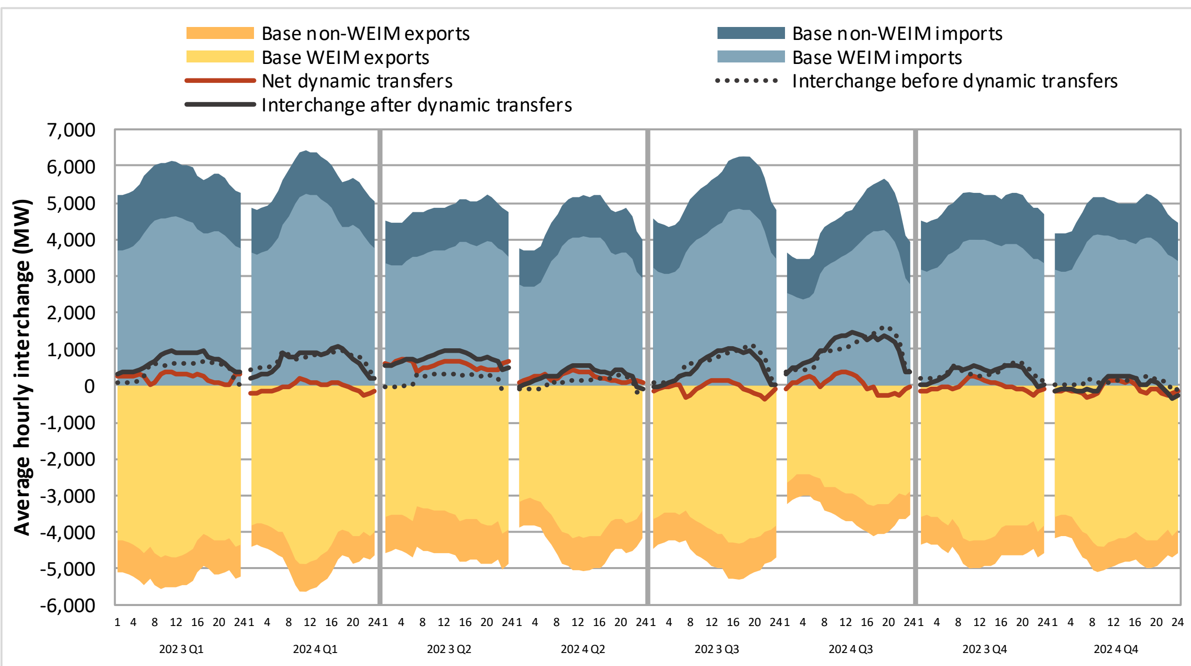


Figure 1.17 Pacific Northwest - Average hourly net interchange by quarter

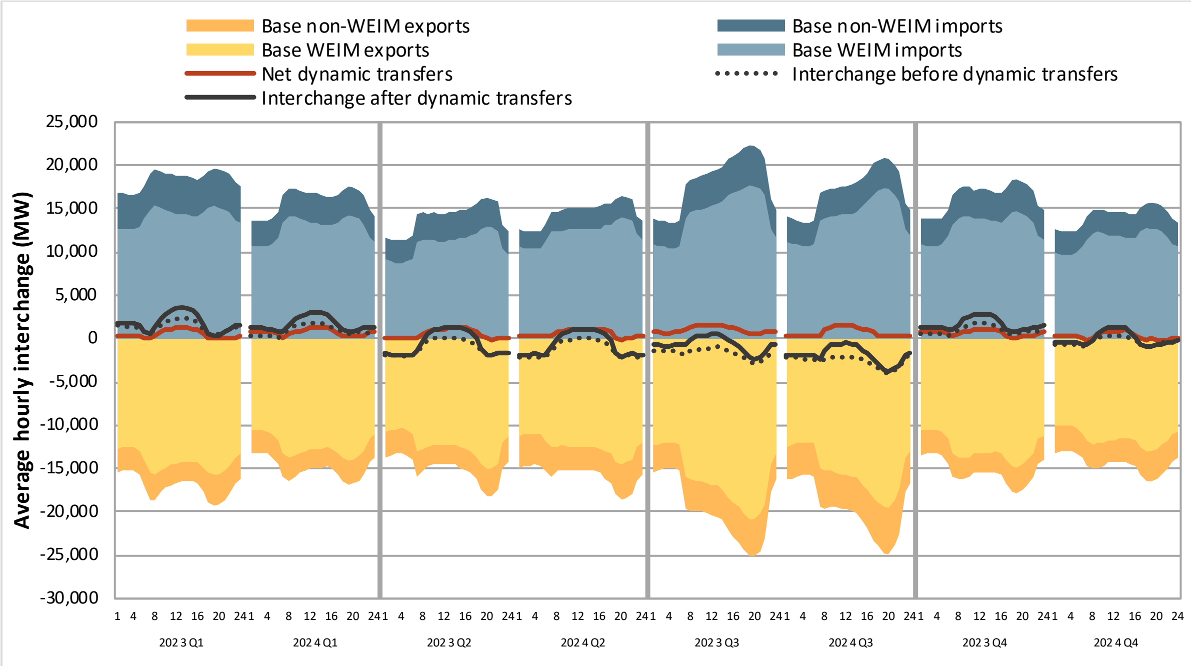
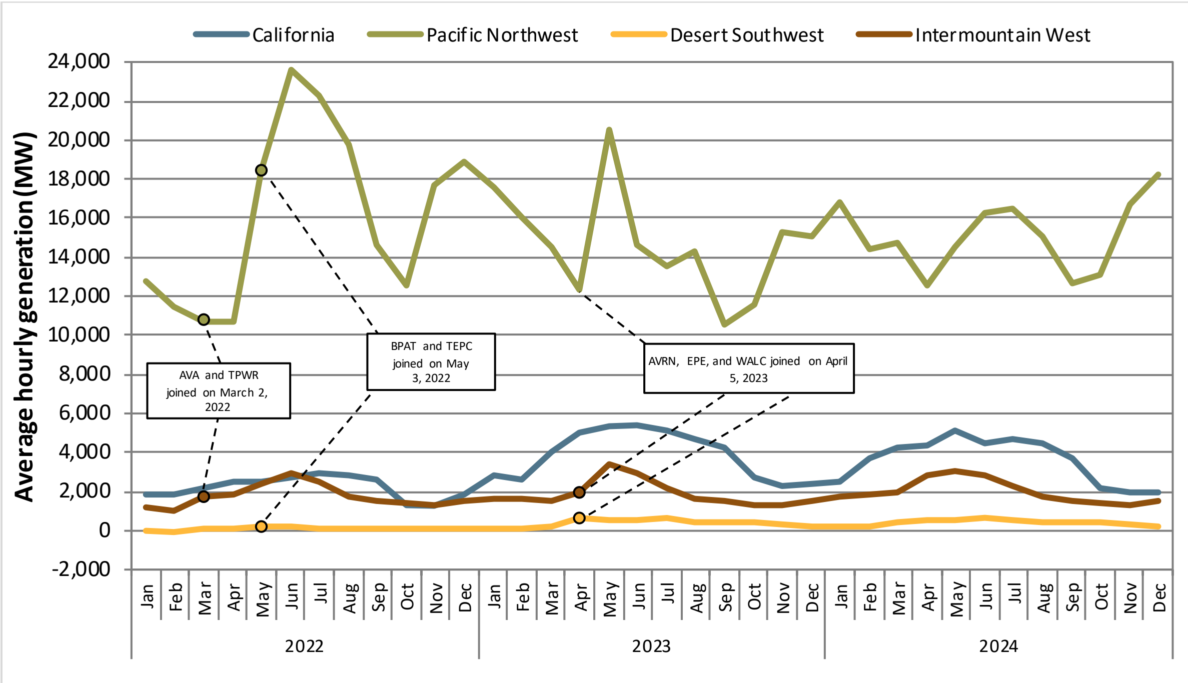


Figure 1.18 shows the monthly average hydroelectric generation from January 2022 to December 2024.

- In the Pacific Northwest, hydroelectric generation in the fourth quarter of 2024 tracked 2,040 MW (15 percent) higher than the same quarter of 2023, and tracked similarly to 2022 levels.
- In the California region, hydroelectric generation decreased by 430 MW (17 percent) relative to the fourth quarter of 2023, but increased by 570 MW (39 percent) compared to 2022.
- Hydroelectric output in the Intermountain West was similar across the fourth quarters of 2022, 2023, and 2024.
- In the Desert Southwest, hydroelectric generation increased by 10 MW (5 percent) from the fourth quarter of 2023, and has increased by 200 MW (181 percent) from 2022.

Figure 1.18 Average monthly hydroelectric generation by region



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 regions are divided into five categories:

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

2.1 Average load and load distribution

Figure 2.1 shows the total market load distribution in the 5-minute market.[9] The distribution incorporates all 5-minute load data for Q4 2024 (blue line) and Q4 2023 (grey 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.

The distribution shows how the load values are distributed. Higher points on the curve represent load levels that occurred more frequently during the quarter.[10] For instance, if the curve peaks around 70 GW, this indicates that 70 GW was a commonly observed load level.

The distribution shows more instances of high system loads—particularly above about 85 GW—in the fourth quarter of 2024, compared to the same quarter last year. The blue line is generally above the grey dashed line over 85 GW, reflecting an increased frequency of high-load intervals. Conversely, at the lower end of the load range, the blue line falls below the dashed line, indicating fewer instances of low-load intervals in Q4 2024, particularly below about 65 GW.

9 The total market load includes any load conformance.

10 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.

Figure 2.1 Quarterly system-wide total load distribution

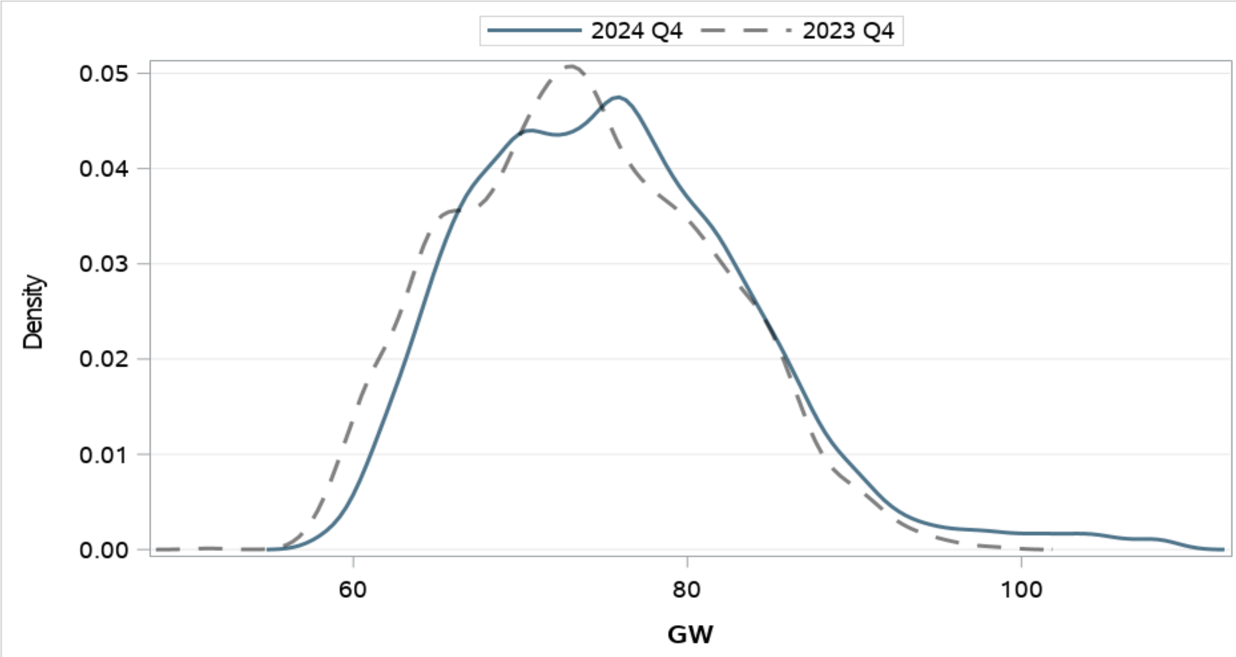


Figure 2.2 shows the monthly average 5-minute market load categorized by region from October 2022 to December 2024. The total system load for this quarter averaged 75.4 GW, representing an approximately 2 percent increase compared to the same of quarter last year. Each region's average load increased relative to the fourth quarter of 2023, ranging from 1 percent to 4 percent:

- **Pacific Northwest** (green) averaged **23.6 GW**, a 2 percent increase.
- **CAISO** (dark blue) averaged **23 GW** and rose by 1 percent.
- **Desert Southwest** (yellow) averaged **14.6 GW**, a 4 percent increase.
- **Intermountain West** (red) averaged **9.7 GW** and rose by 1 percent.
- **California** (light blue) averaged **4.5 GW**, a 3 percent increase.

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

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

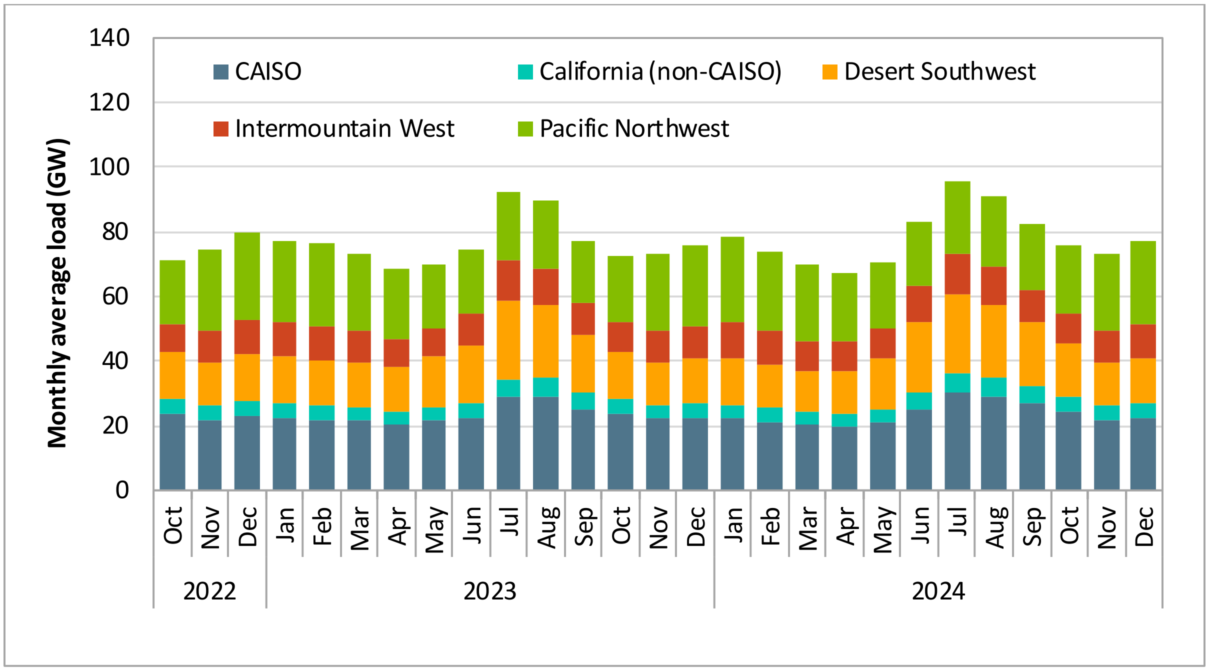


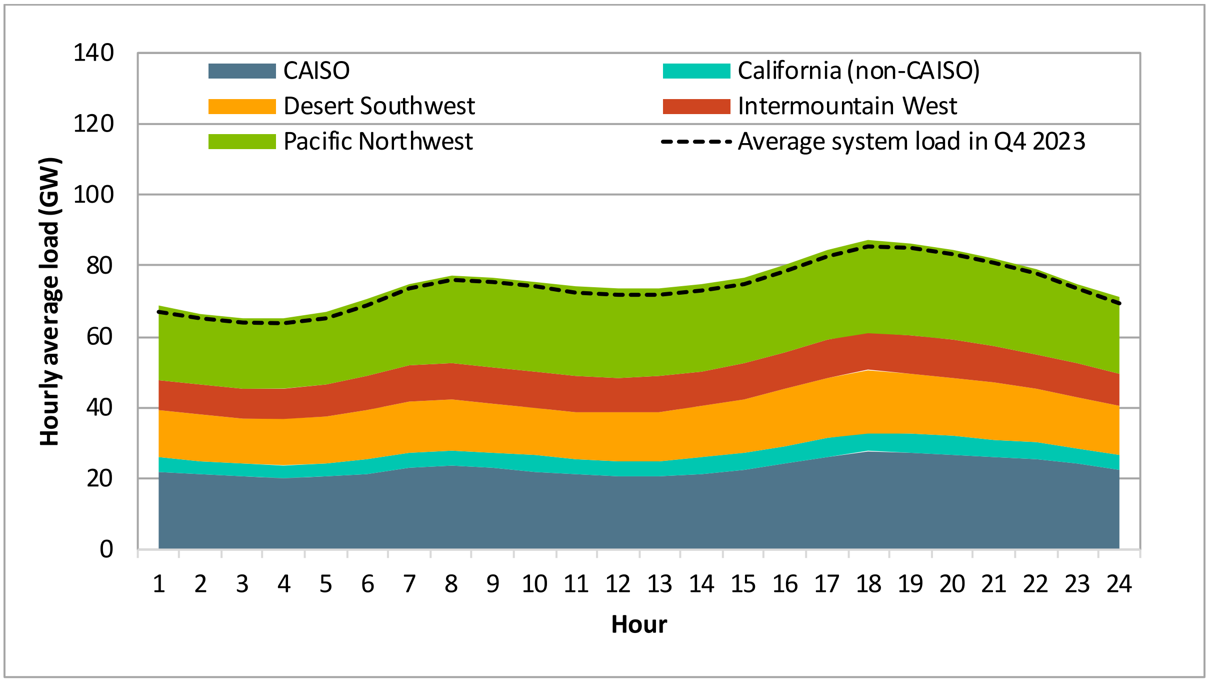
Figure 2.3 displays the hourly average 5-minute market load across different regions in Q4 2024. Each color represents a specific region, while the black dashed line indicates the average system-wide WEIM total load for the same quarter last year.

The total WEIM hourly average load peaked at hour-ending 18, reaching 87.3 GW, while the lowest load occurred at hour-ending 4, at 65.3 GW. CAISO and the Pacific Northwest consistently recorded the two largest loads across all hours. From hour-ending 6 to hour-ending 15, the Pacific Northwest had the largest regional load. During the remaining hours, CAISO recorded the highest regional load.

In Q4, the peak average hourly load for each region was:

- **CAISO:** peak load of 27.6 GW at hour-ending 18.
- **Pacific Northwest:** peak load of 26.1 GW at hour-ending 18.
- **Desert Southwest**: peak load of 17.6 GW at hour-ending 18.
- **Intermountain West**: peak load of 10.7 GW at hour-ending 18.
- **California (non-CAISO):** peak load of 5.3 GW at hour-ending 18.

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



2.2 Peak load

Figure 2.4 shows the highest 5-minute market *system* load forecast for each hour on October 2, 2024—the day with the highest system load during the quarter. The figure also shows corresponding load forecast data for each balancing area for the same 5-minute interval as the system peak for each hour. On this day, the WEIM system load peaked at 110.5 GW during hour-ending 18, interval 8. This was higher than the peak WEIM load during Q4 2023 (100 GW).

This heatmap highlights the hour with the peak load for each balancing area on this day. Red indicates the hour of highest load for each balancing area and yellow indicates hours with above-average load for that day. Peak load for balancing areas varied across hours. While the system peak occurred during hour-ending 18, many balancing areas reached their peak at different times. Even within the same region, peaking hours varied among balancing areas.

Figure 2.4 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market, October 2, 2024)

Hour	12	13	14	15	16	17	18	19	20	21	22	23	24
SYSTEM	87.3	92.0	97.6	102.9	107.8	110.1	110.5	110.0	106.6	101.9	95.9	89.1	82.0
CAISO	27.2	29.6	32.8	36.0	38.8	40.3	40.8	40.6	39.2	37.1	34.7	32.3	29.4
BANC	2.40	2.67	2.98	3.30	3.54	3.65	3.62	3.56	3.25	2.99	2.73	2.43	2.15
Turlock ID	0.45	0.50	0.55	0.58	0.61	0.62	0.62	0.61	0.57	0.54	0.50	0.46	0.42
LADWP	3.42	3.74	4.05	4.31	4.53	4.48	4.38	4.27	4.08	3.85	3.63	3.35	3.04
NV Energy	5.38	5.78	6.22	6.68	7.02	7.14	7.08	6.95	6.59	6.20	5.78	5.37	4.96
Arizona PS	5.23	5.65	6.04	6.42	6.64	6.72	6.70	6.59	6.33	6.02	5.59	5.21	4.80
Tucson Electric	1.69	1.83	1.99	2.14	2.26	2.32	2.31	2.25	2.05	1.88	1.72	1.56	1.41
Salt River Project	5.62	5.98	6.28	6.47	6.58	6.40	6.31	6.40	6.00	5.65	5.25	4.86	4.44
PSC New Mexico	1.50	1.59	1.70	1.82	1.91	1.96	1.96	1.93	1.86	1.77	1.65	1.54	1.45
WAPA - Desert SW	1.00	1.04	1.11	1.16	1.19	1.19	1.16	1.15	1.05	0.95	0.88	0.82	0.75
El Paso Electric	1.26	1.33	1.45	1.54	1.56	1.52	1.44	1.43	1.34	1.24	1.14	1.01	0.95
PacifiCorp East	5.70	5.94	6.13	6.35	6.63	6.76	6.71	6.63	6.34	6.10	5.71	5.37	5.04
Idaho Power	2.07	2.08	2.07	2.12	2.15	2.21	2.20	2.20	2.14	2.09	1.97	1.83	1.74
NorthWestern	1.15	1.16	1.16	1.18	1.19	1.19	1.20	1.21	1.23	1.18	1.11	1.04	0.99
Avista Utilities	1.14	1.13	1.12	1.12	1.12	1.13	1.15	1.16	1.18	1.16	1.11	1.02	0.95
BPA	6.07	6.03	5.99	5.97	6.01	6.14	6.22	6.27	6.31	6.32	6.12	5.73	5.45
Tacoma Power	0.47	0.47	0.47	0.46	0.47	0.47	0.47	0.48	0.50	0.50	0.48	0.45	0.41
PacifiCorp West	2.24	2.26	2.30	2.30	2.36	2.42	2.45	2.47	2.49	2.46	2.32	2.15	1.99
Portland GE	2.37	2.36	2.36	2.38	2.43	2.51	2.59	2.64	2.66	2.65	2.54	2.39	2.22
Puget Sound Energy	2.64	2.62	2.60	2.56	2.58	2.67	2.71	2.75	2.83	2.84	2.74	2.55	2.33
Seattle City Light	1.02	1.02	1.02	1.00	1.00	1.02	1.03	1.03	1.04	1.03	0.99	0.92	0.85
Powerex	7.30	7.29	7.18	7.06	7.15	7.31	7.45	7.47	7.52	7.39	7.21	6.79	6.32

Table 2.1 shows the peak 5-minute market load and date for each balancing area (or region) during the fourth quarter. The California and Desert Southwest balancing areas all experienced peak load during the first week of October (summer peaking) while the Intermountain West and Pacific Northwest balancing areas experienced peak load in December (winter peaking). The table also shows each balancing area's load during the system peak load interval on October 2, 2024 (110.5 GW).

Table 2.1 Peak WEIM load (October–November 2024)

	Peak load (October - December, 2024)		Load during WEIM system peak (2-Oct-24)	
Region/ balancing area	Date	Load (MW)	Load (MW)	Percent
WEIM system	**2-Oct-24**	**110,510**	**110,510**	
California	**2-Oct-24**	**49,373**	**49,373**	**45%**
California ISO	2-Oct-24	40,778	40,752	37%
BANC	2-Oct-24	3,659	3,619	3%
LADWP	2-Oct-24	4,553	4,384	4%
Turlock Irrig. District	3-Oct-24	633	618	0.6%
Desert Southwest	**1-Oct-24**	**28,822**	**26,965**	**24%**
Arizona Public Service	1-Oct-24	7,265	6,703	6%
El Paso Electric	3-Oct-24	1,634	1,445	1%
NV Energy	1-Oct-24	7,171	7,076	6%
PSC New Mexico	3-Oct-24	2,054	1,956	2%
Salt River Project	1-Oct-24	7,267	6,314	6%
Tucson Electric	1-Oct-24	2,468	2,307	2%
WAPA - Desert SW	1-Oct-24	1,306	1,164	1%
Intermountain West	**9-Dec-24**	**12,732**	**11,248**	**10%**
Avista Utilities	5-Dec-24	1,707	1,146	1%
Idaho Power	11-Dec-24	2,613	2,197	2%
NorthWestern Energy	16-Dec-24	1,687	1,200	1%
PacifiCorp East	9-Dec-24	6,914	6,706	6%
Pacific Northwest	**10-Dec-24**	**32,505**	**22,923**	**21%**
BPA	4-Dec-24	9,414	6,218	6%
PacifiCorp West	10-Dec-24	3,602	2,453	2%
Portland General Electric	2-Dec-24	3,632	2,590	2%
Powerex	16-Dec-24	10,478	7,446	7%
Puget Sound Energy	4-Dec-24	4,318	2,714	2%
Seattle City Light	4-Dec-24	1,567	1,028	1%
Tacoma Power	5-Dec-24	796	474	0.4%

3 Energy market performance

3.1 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.[11] Prices are calculated based on the load schedules and corresponding prices at all Aggregated Pricing Nodes (APnodes).[12]

Figure 3.1 and Figure 3.2 display the weighted average monthly electricity prices in the 15-minute and 5-minute markets by region from April 2023 to December 2024. Prices in the 15-minute market across the WEIM averaged about $39/MWh, down 31 percent due mainly to lower natural gas prices. Prices in the 5-minute market were also $39/MWh, a 31 percent decrease compared to Q4 2023.

In Q4 2024, California recorded the highest average price at $45/MWh, while other regions ranged between $32/MWh and $38/MWh. Greenhouse gas (GHG) costs contributed significantly to the higher prices in California compared to other regions. 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.

Compared to the fourth quarter of 2023, prices across the WEIM were lower despite higher loads, primarily due to significantly reduced natural gas prices. In the section of this report on natural gas above, Figure 1.1 illustrates the substantial decline in natural gas prices across major Western U.S. trading hubs in Q4 2024 compared to Q4 2023. As gas-fired units frequently set electricity market prices, lower natural gas prices lead to lower real-time prices across the WEIM.

11 The California region includes CAISO, BANC, TIDC, and LADWP. The Desert Southwest region includes NEVP, AZPS, TEPC, SRP, PNM, WALC, and EPE. The Intermountain West region includes PACE, IPCO, NWMT, and AVA. The Pacific Northwest includes AVRN, BPA, TWPR, PGE, PSEI, and SCL. Powerex is categorized separately due to transmission limitations that frequently isolate it from the rest of the WEIM system.

12 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.

Figure 3.1 Weighted average monthly 15-minute market prices by region

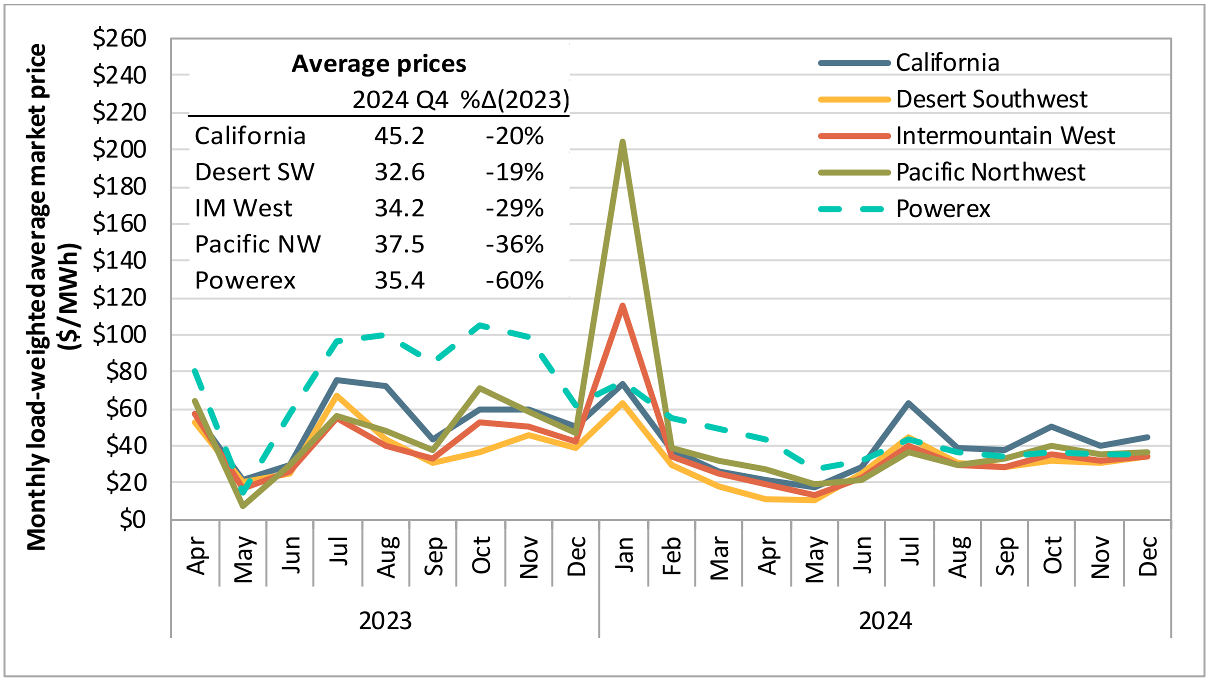


Figure 3.2 Weighted average monthly 5-minute market prices by region

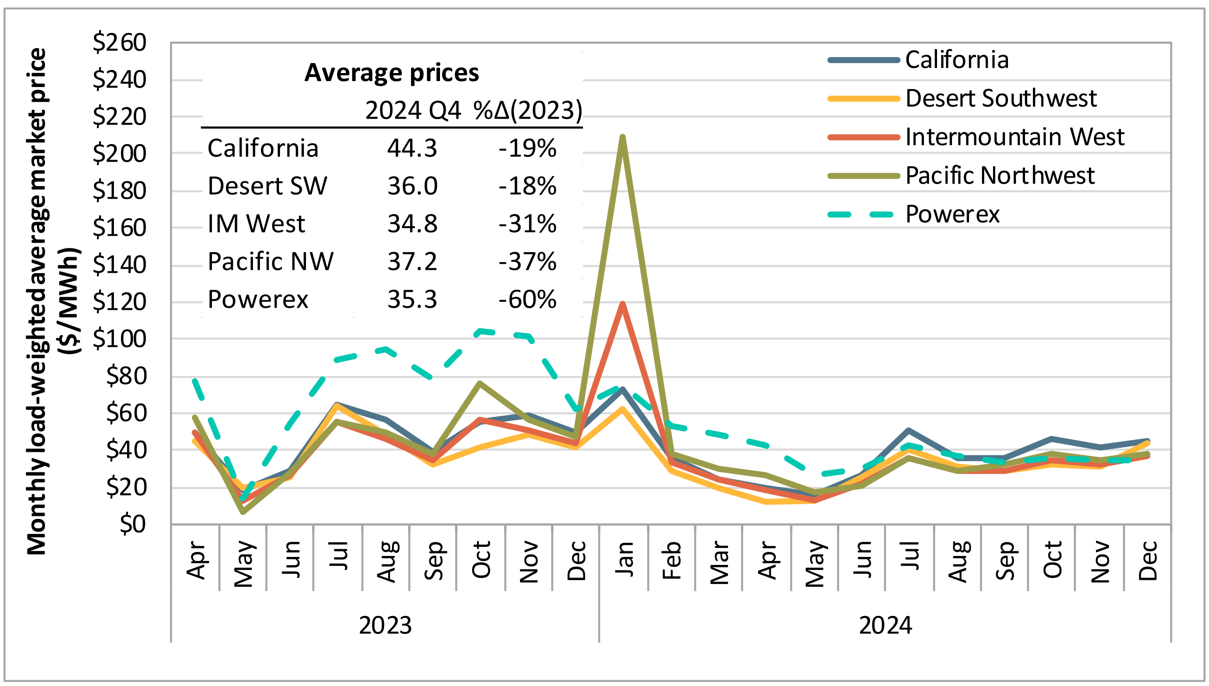


Figure 3.3 and Figure 3.4 illustrate the weighted average hourly prices for the 15-minute and 5-minute markets across regions, along with average system net-load schedules. The shape of hourly prices tended to follow the net load pattern. This trend was most prominent for prices in the California and

Desert Southwest regions, with relatively high prices during the morning and evening ramping hours, and lower prices during solar production hours.

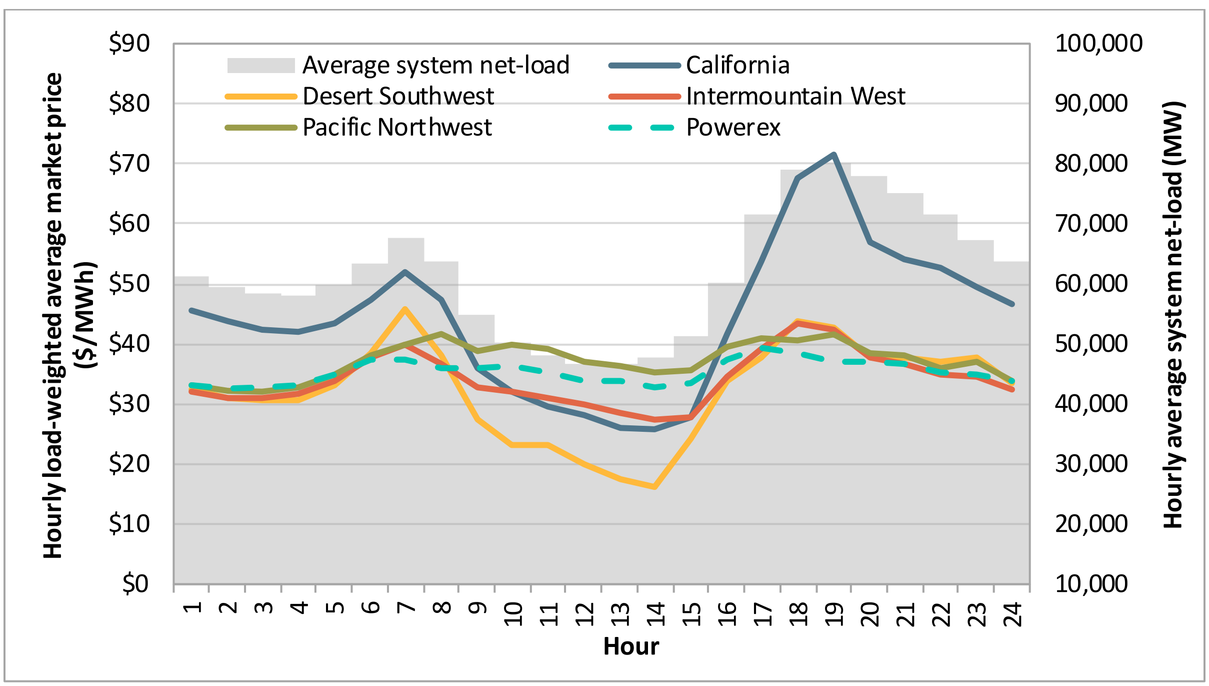
The system's peak net load occurred at hour-ending 19 in both the 15-minute and 5-minute markets, reaching around 80 GW and 79 GW, respectively. In the 15-minute market, most regions experienced peak prices around the evening ramping hours, except for the Desert Southwest, which peaked at hour-ending 7. In the 5-minute market, California and Powerex prices peaked during evening ramping hours, while the rest of the regions experienced peak prices during the morning ramping hours.

Prices in the California region were higher than prices in other regions in both markets, especially during evening peak hours. The main contributor for higher prices in California is the GHG cost, which tends to lower prices in the rest of the non-California regions.

A notable distinction occurred during mid-day solar hours when price separation was observed. The Desert Southwest experienced lower prices compared to other regions, while the Pacific Northwest saw relatively higher prices. This pattern aligned with congestion trends, where south-to-north congestion increased during high solar energy production.

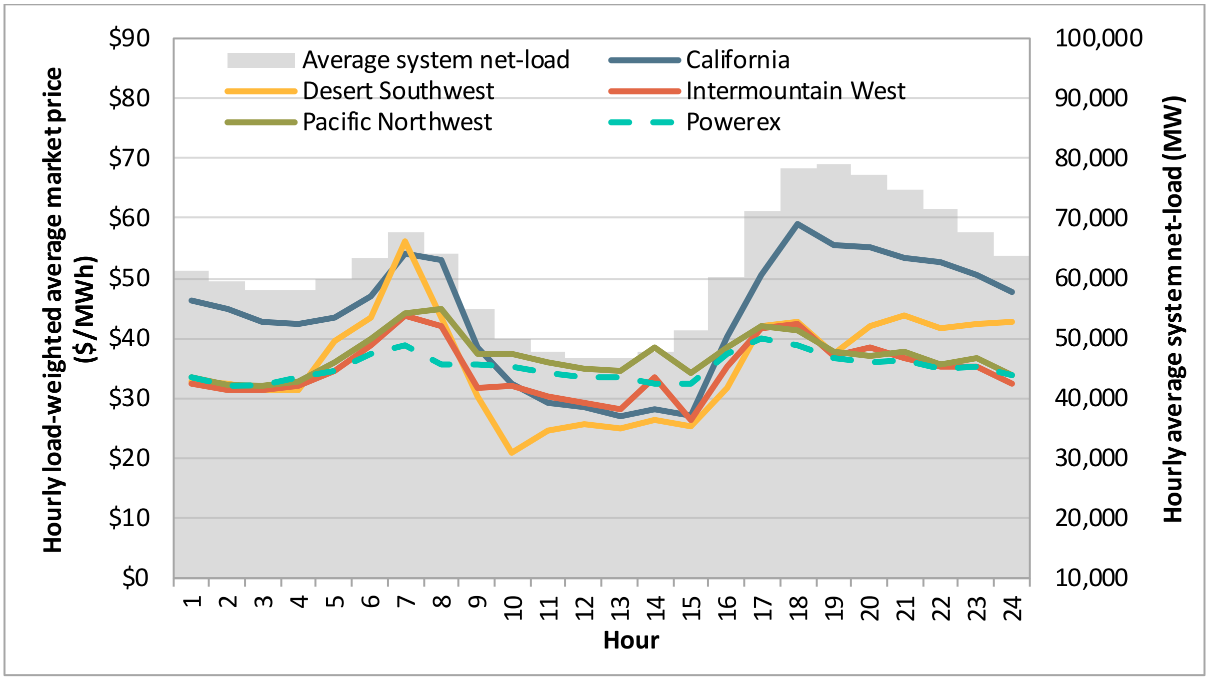
Comparing prices between the 15-minute and 5-minute markets, the 15-minute market had higher prices during peak net load hours, particularly in California. Around hour-ending 19, California's peak price in the 15-minute market reached $72/MWh, compared to $59/MWh in the 5-minute market. One factor that contributed to this price difference was the CAISO balancing area using higher load conformance in the 15-minute market than in the 5-minute market during these hours.[13]

Figure 3.3 Weighted average hourly 15-minute market prices by region (October–December 2024)



[13] For more information on load conformance, see Chapter 8.

Figure 3.4 Weighted average hourly 5-minute market prices by region (October–December 2024)



3.2 Real-time market prices by balancing area

This section summarizes prices in each Western Energy Imbalance Market (WEIM) balancing area during the fourth quarter of 2024. Figure 3.5 and Figure 3.6 show the average 15-minute and 5-minute market price by component for each balancing authority area in this quarter. These figures highlight how price differences between regions are determined by differences in transmission losses, greenhouse gas compliance costs, and congestion. These components are listed below.

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.
- **Congestion within California ISO** is the price impact from transmission constraints within the California ISO area that are restricting the flow of energy. While these constraints are located within the California ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from

individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*

- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limits WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraints (ITC) and intertie scheduling limits (ISL).

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

In both the 5-minute and 15-minute markets, internal flow-based constraints in CAISO increased prices in Northern California, the Pacific Northwest, and the Intermountain West while lowering prices in Southern California and the Desert Southwest. WEIM transfer congestion primarily affected PNM, leading to price increases, while BCHA and NWMT experienced price decreases due to this transfer congestion.

Figure 3.5 Average 15-minute market prices by balancing area (October–December 2024)

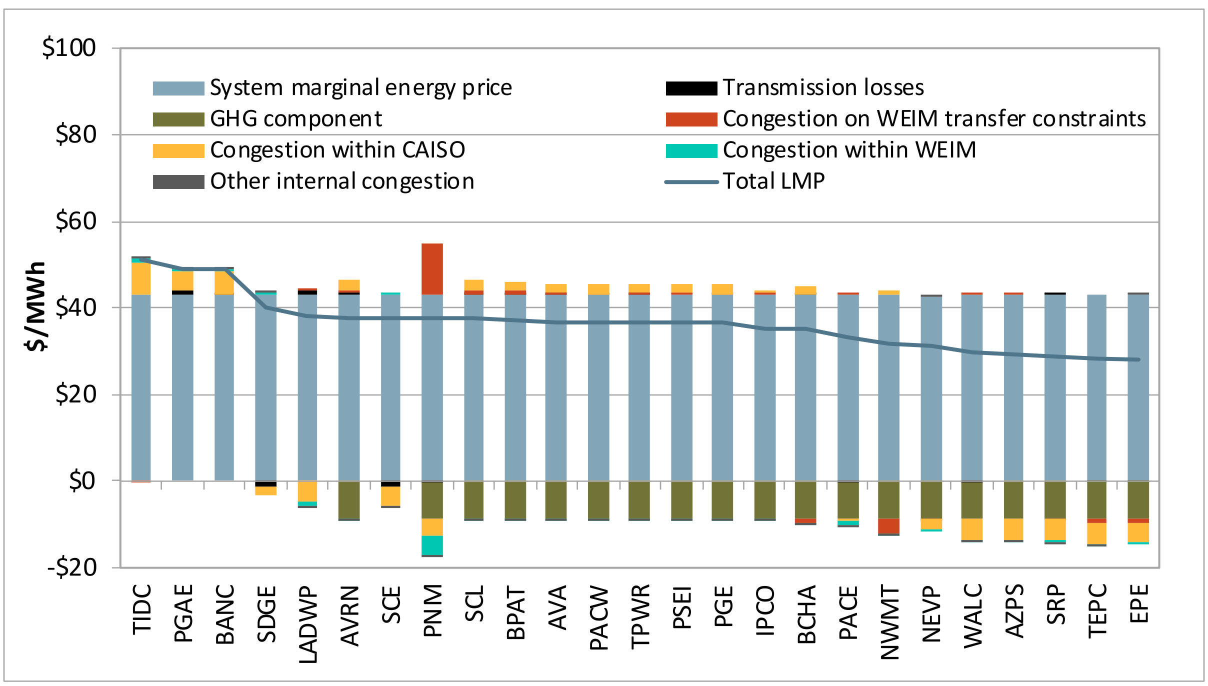


Figure 3.6 Average 5-minute market prices by balancing area (October–December 2024)

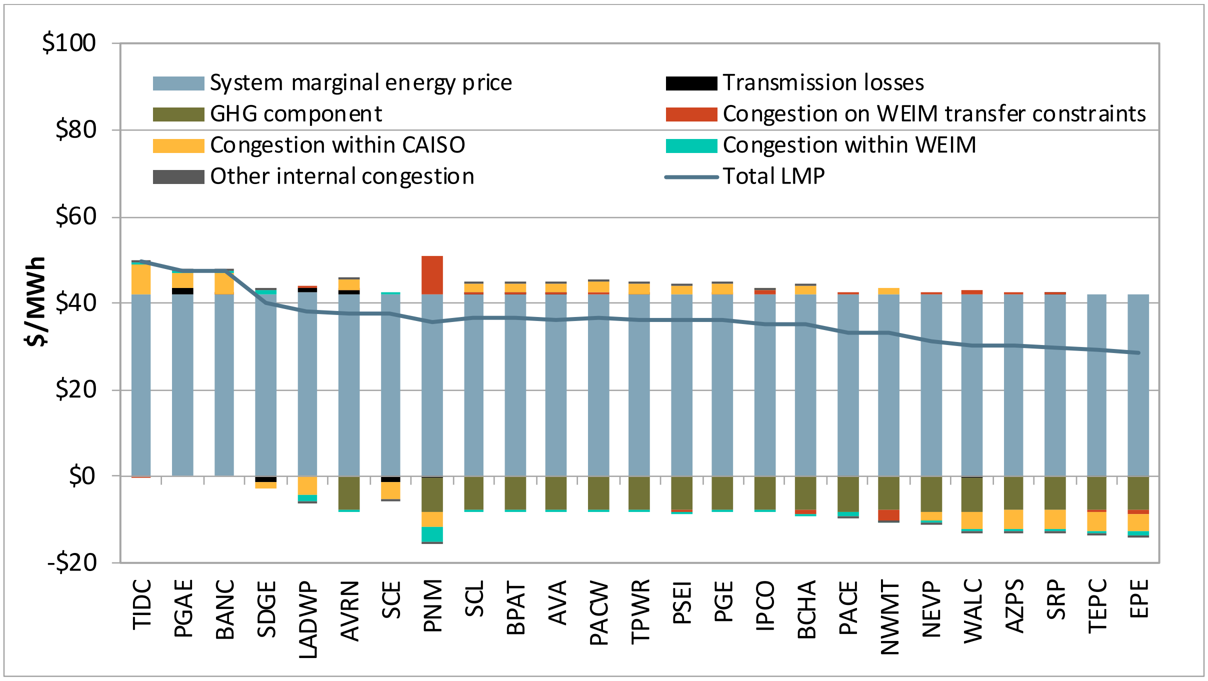


Table 3.1 and Table 3.2 show average 15-minute and 5-minute market prices by month for each balancing area. The color gradient highlights deviation from the average system marginal energy price (SMEC), shown in the top row. Blue indicates prices below that month's average system price and orange indicates prices above. As shown in these tables, average prices in California balancing areas were generally higher than those in other regions in both the 15-minute and 5-minute markets over Q4 2024. Greenhouse gas compliance costs contribute to higher prices in California relative to the rest of the system

Table 3.3 and Table 3.4 show average hourly prices in the 15-minute and 5-minute markets during the fourth quarter. In this quarter, 15-minute market prices frequently exceeded 5-minute market prices, especially during evening peak hours.

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

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

Table 3.1 Average monthly 15-minute market prices

	2023 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2024 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMEC	$140	$73	$73	$55	$19	$28	$66	$67	$42	$57	$58	$50	$89	$38	$28	$22	$16	$26	$51	$36	$35	$46	$41	$42
PG&E (CAISO)	$140	$75	$76	$57	$18	$29	$58	$65	$44	$62	$62	$54	$78	$40	$30	$28	$21	$28	$61	$36	$36	$56	$46	$46
SCE (CAISO)	$140	$68	$65	$48	$20	$27	$73	$68	$39	$51	$53	$45	$65	$31	$17	$11	$9	$24	$50	$35	$33	$38	$35	$40
BANC	$142	$75	$76	$59	$19	$30	$56	$54	$42	$59	$62	$53	$77	$41	$31	$29	$21	$27	$58	$37	$37	$56	$46	$45
Turlock ID	$142	$76	$77	$61	$19	$30	$56	$54	$43	$60	$63	$54	$78	$41	$33	$31	$21	$25	$54	$37	$39	$61	$47	$45
LADWP	$142	$73	$68	$49	$20	$27	$67	$50	$36	$45	$52	$46	$68	$32	$18	$12	$11	$27	$55	$40	$35	$40	$37	$38
NV Energy	$131	$66	$66	$50	$17	$23	$59	$40	$33	$38	$48	$42	$65	$30	$19	$13	$10	$22	$42	$29	$28	$33	$29	$31
Arizona PS	$130	$66	$65	$50	$17	$24	$63	$41	$30	$34	$45	$38	$59	$28	$18	$8	$8	$21	$45	$30	$27	$30	$26	$31
Tucson Electric	$129	$63	$60	$47	$21	$26	$58	$38	$30	$33	$45	$39	$59	$27	$15	$9	$11	$21	$39	$26	$26	$28	$27	$31
Salt River Project	$119	$52	$60	$50	$22	$24	$62	$46	$28	$34	$44	$38	$54	$25	$14	$9	$10	$25	$38	$31	$28	$30	$26	$30
PSC New Mexico	$127	$64	$65	$67	$17	$24	$59	$40	$30	$40	$50	$40	$69	$35	$18	$14	$10	$24	$43	$29	$28	$27	$57	$29
WAPA - Desert SW				$57	$20	$24	$62	$41	$30	$34	$45	$40	$60	$29	$14	$7	$10	$21	$42	$29	$27	$32	$26	$32
El Paso Electric				$33	$18	$23	$48	$37	$29	$30	$20	$20	$53	$24	$15	$9	$13	$27	$38	$25	$26	$27	$27	$30
PacifiCorp East	$120	$63	$67	$52	$18	$26	$53	$38	$31	$40	$46	$40	$76	$31	$22	$16	$12	$21	$39	$28	$27	$35	$31	$33
Idaho Power	$132	$71	$73	$59	$16	$27	$52	$39	$33	$56	$53	$45	$112	$35	$27	$20	$13	$22	$37	$28	$28	$37	$34	$35
NorthWestern	$133	$72	$75	$61	$13	$27	$53	$39	$34	$62	$54	$46	$151	$38	$29	$24	$18	$21	$36	$28	$29	$30	$33	$33
Avista Utilities	$133	$72	$74	$64	$12	$27	$49	$39	$34	$63	$55	$46	$155	$38	$30	$26	$18	$21	$33	$28	$29	$39	$36	$35
Avangrid				$61	$7	$28	$49	$40	$37	$63	$56	$48	$164	$38	$31	$25	$18	$21	$32	$28	$33	$40	$37	$36
BPA	$133	$73	$73	$62	$5	$29	$55	$49	$38	$65	$57	$47	$182	$39	$30	$27	$20	$23	$40	$31	$33	$40	$37	$35
Tacoma Power	$134	$72	$73	$62	$6	$29	$50	$43	$37	$64	$55	$47	$165	$39	$31	$26	$18	$20	$32	$27	$32	$38	$36	$36
PacifiCorp West	$132	$71	$72	$61	$6	$28	$48	$39	$35	$64	$55	$47	$170	$38	$30	$25	$17	$20	$31	$27	$32	$39	$36	$36
Portland GE	$132	$71	$72	$62	$9	$29	$50	$43	$37	$65	$55	$47	$165	$38	$32	$27	$17	$21	$32	$27	$32	$39	$36	$35
Puget Sound Energy	$133	$73	$74	$62	$8	$29	$59	$44	$37	$69	$58	$48	$167	$39	$31	$27	$18	$21	$33	$28	$32	$38	$35	$36
Seattle City Light	$133	$75	$72	$61	$6	$28	$50	$45	$37	$64	$55	$47	$167	$40	$30	$28	$18	$20	$31	$27	$32	$40	$36	$37
Powerex	$129	$79	$84	$79	$14	$55	$94	$99	$83	$102	$98	$62	$72	$54	$49	$43	$27	$32	$42	$36	$33	$36	$35	$34

Table 3.2 Average monthly 5-minute market prices

	2023 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2024 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMEC	$135	$68	$66	$47	$16	$27	$58	$53	$39	$53	$57	$49	$85	$35	$26	$20	$14	$24	$43	$34	$34	$44	$40	$43
PG&E (CAISO)	$136	$70	$68	$49	$16	$28	$52	$52	$42	$58	$62	$53	$79	$38	$28	$26	$19	$26	$49	$34	$35	$51	$45	$46
SCE (CAISO)	$133	$63	$58	$41	$16	$26	$62	$53	$35	$48	$52	$44	$63	$29	$16	$9	$8	$22	$42	$33	$32	$37	$35	$41
BANC	$138	$71	$68	$49	$16	$29	$54	$53	$42	$57	$62	$53	$79	$39	$30	$27	$20	$25	$48	$34	$36	$52	$45	$45
Turlock ID	$139	$72	$69	$52	$16	$30	$54	$53	$42	$58	$63	$54	$79	$40	$31	$29	$19	$24	$45	$35	$38	$57	$46	$46
LADWP	$134	$67	$59	$42	$16	$26	$62	$55	$37	$51	$53	$45	$66	$30	$17	$10	$10	$27	$50	$45	$35	$39	$37	$38
NV Energy	$126	$62	$60	$42	$14	$22	$56	$45	$34	$44	$50	$43	$65	$29	$19	$12	$9	$21	$37	$29	$28	$33	$30	$32
Arizona PS	$123	$66	$61	$42	$15	$24	$59	$45	$32	$40	$46	$40	$59	$26	$17	$8	$8	$21	$40	$32	$27	$30	$27	$33
Tucson Electric	$123	$60	$54	$40	$20	$26	$58	$44	$31	$38	$46	$40	$58	$28	$16	$10	$14	$24	$34	$26	$27	$27	$28	$32
Salt River Project	$109	$49	$54	$45	$23	$26	$61	$48	$27	$38	$49	$39	$53	$24	$17	$10	$13	$29	$37	$31	$29	$30	$27	$32
PSC New Mexico	$122	$60	$58	$53	$14	$24	$56	$44	$33	$46	$51	$42	$70	$34	$18	$16	$12	$25	$37	$28	$28	$27	$50	$30
WAPA - Desert SW				$40	$19	$26	$58	$44	$33	$38	$47	$40	$59	$28	$14	$6	$9	$21	$37	$29	$27	$32	$27	$32
El Paso Electric				$28	$16	$23	$47	$40	$30	$33	$23	$23	$52	$24	$15	$8	$18	$25	$36	$24	$26	$27	$27	$32
PacifiCorp East	$116	$59	$62	$45	$14	$25	$52	$43	$34	$44	$47	$40	$73	$30	$21	$15	$11	$20	$35	$27	$27	$34	$31	$34
Idaho Power	$127	$66	$68	$51	$13	$26	$52	$44	$35	$61	$54	$46	$119	$34	$25	$19	$13	$21	$34	$28	$28	$36	$34	$35
NorthWestern	$128	$67	$69	$56	$9	$27	$55	$46	$37	$67	$55	$48	$161	$37	$28	$26	$18	$20	$33	$28	$30	$31	$34	$34
Avista Utilities	$129	$67	$69	$56	$10	$27	$51	$44	$37	$68	$55	$48	$164	$37	$29	$27	$18	$20	$32	$28	$29	$37	$36	$36
Avangrid				$56	$6	$27	$51	$44	$38	$68	$55	$48	$168	$37	$29	$24	$16	$20	$33	$28	$31	$39	$37	$37
BPA	$130	$68	$68	$57	$4	$28	$53	$48	$37	$69	$56	$47	$184	$37	$28	$26	$17	$22	$38	$29	$32	$38	$35	$36
Tacoma Power	$130	$67	$69	$56	$5	$28	$50	$45	$37	$69	$54	$47	$170	$37	$29	$26	$17	$20	$32	$27	$31	$37	$35	$36
PacifiCorp West	$129	$66	$68	$56	$6	$26	$50	$42	$37	$68	$54	$47	$171	$37	$28	$24	$16	$20	$32	$27	$31	$38	$36	$36
Portland GE	$129	$66	$68	$56	$9	$27	$50	$45	$37	$69	$54	$47	$169	$37	$29	$26	$16	$20	$32	$27	$31	$38	$35	$36
Puget Sound Energy	$131	$68	$69	$56	$7	$28	$61	$47	$38	$74	$56	$47	$175	$37	$29	$27	$16	$20	$33	$27	$31	$37	$34	$36
Seattle City Light	$130	$69	$68	$56	$5	$27	$50	$46	$37	$68	$55	$47	$171	$37	$28	$26	$16	$20	$31	$27	$31	$38	$35	$36
Powerex	$127	$77	$83	$77	$14	$52	$87	$94	$77	$102	$101	$61	$72	$53	$48	$43	$27	$30	$42	$36	$33	$36	$35	$34

Table 3.3 Average hourly 15-minute market prices (October–December)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$45	$43	$42	$42	$43	$46	$51	$45	$35	$33	$31	$29	$28	$27	$29	$39	$49	$59	$61	$54	$52	$51	$49	$46
PG&E (CAISO)	$47	$45	$44	$43	$44	$48	$53	$51	$44	$42	$39	$37	$35	$35	$38	$48	$60	$74	$79	$60	$56	$54	$51	$48
SCE (CAISO)	$44	$42	$41	$41	$42	$46	$50	$42	$25	$20	$19	$19	$17	$15	$17	$31	$44	$54	$55	$51	$49	$49	$47	$45
BANC	$46	$44	$43	$42	$44	$47	$52	$50	$46	$45	$43	$40	$39	$40	$43	$51	$58	$68	$71	$57	$54	$53	$50	$47
Turlock ID	$46	$44	$43	$43	$44	$47	$52	$51	$50	$51	$49	$46	$44	$46	$50	$55	$63	$69	$72	$58	$55	$53	$50	$47
LADWP	$45	$43	$42	$41	$42	$44	$48	$37	$27	$21	$19	$19	$17	$17	$19	$38	$41	$53	$56	$52	$51	$51	$46	$46
NV Energy	$32	$31	$31	$32	$33	$37	$39	$32	$26	$24	$23	$22	$21	$20	$21	$31	$36	$42	$41	$37	$36	$35	$34	$33
Arizona PS	$32	$31	$31	$32	$34	$37	$39	$33	$21	$19	$18	$18	$16	$13	$14	$26	$35	$40	$39	$36	$35	$34	$34	$32
Tucson Electric	$30	$29	$28	$29	$31	$36	$35	$27	$19	$18	$17	$18	$16	$16	$17	$29	$36	$42	$39	$36	$35	$33	$33	$31
Salt River Project	$31	$31	$30	$31	$33	$37	$39	$31	$19	$19	$18	$18	$17	$15	$14	$26	$35	$40	$39	$36	$35	$34	$33	$32
PSC New Mexico	$35	$33	$31	$32	$38	$38	$66	$54	$26	$23	$43	$15	$2	$0	$60	$71	$35	$44	$41	$42	$50	$42	$38	$43
WAPA - Desert SW	$32	$31	$31	$32	$34	$37	$39	$31	$29	$19	$18	$18	$16	$14	$15	$27	$35	$40	$50	$36	$35	$34	$34	$32
El Paso Electric	$37	$26	$25	$26	$28	$32	$31	$23	$18	$16	$16	$16	$17	$17	$17	$35	$40	$45	$42	$38	$37	$32	$30	$27
PacifiCorp East	$32	$31	$31	$31	$33	$37	$39	$35	$30	$29	$28	$27	$26	$25	$26	$33	$38	$43	$43	$38	$36	$35	$34	$32
Idaho Power	$32	$32	$31	$32	$34	$38	$40	$37	$34	$34	$34	$33	$32	$31	$30	$36	$40	$45	$44	$39	$37	$36	$35	$33
NorthWestern	$29	$28	$29	$29	$30	$34	$37	$35	$32	$33	$32	$30	$28	$27	$28	$34	$37	$40	$37	$35	$34	$32	$31	$28
Avista Utilities	$33	$31	$31	$32	$34	$38	$40	$39	$37	$38	$37	$36	$35	$34	$34	$39	$41	$46	$44	$39	$38	$35	$35	$33
Avangrid	$33	$32	$32	$33	$35	$38	$40	$40	$39	$40	$40	$39	$38	$37	$37	$41	$43	$42	$45	$40	$38	$36	$36	$34
BPA	$33	$32	$32	$32	$35	$37	$39	$43	$40	$41	$39	$37	$37	$35	$36	$40	$41	$41	$42	$38	$39	$37	$35	$34
Tacoma Power	$32	$32	$32	$32	$34	$37	$38	$39	$37	$39	$38	$37	$40	$35	$35	$39	$41	$41	$43	$38	$36	$35	$38	$33
PacifiCorp West	$32	$32	$32	$32	$34	$37	$39	$39	$38	$39	$38	$37	$36	$36	$35	$39	$42	$41	$43	$38	$37	$36	$35	$33
Portland GE	$32	$32	$32	$32	$34	$37	$38	$39	$38	$39	$38	$37	$36	$35	$35	$39	$41	$41	$43	$39	$37	$35	$35	$33
Puget Sound Energy	$32	$32	$32	$32	$33	$36	$39	$40	$37	$38	$37	$37	$36	$36	$36	$39	$41	$41	$43	$38	$38	$35	$39	$33
Seattle City Light	$35	$32	$32	$32	$35	$37	$42	$39	$37	$39	$51	$38	$36	$35	$35	$38	$41	$41	$43	$41	$36	$35	$35	$33
Powerex	$33	$32	$32	$33	$34	$37	$37	$36	$36	$36	$35	$34	$34	$33	$33	$37	$39	$38	$37	$37	$36	$35	$34	$33

Hour

Table 3.4 Average hourly 5-minute market prices (October–December)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$46	$44	$42	$42	$43	$46	$52	$49	$36	$32	$30	$29	$28	$28	$28	$38	$46	$53	$49	$52	$51	$51	$50	$47
PG&E (CAISO)	$48	$45	$44	$43	$44	$48	$55	$55	$45	$41	$38	$37	$36	$36	$37	$46	$54	$62	$57	$59	$55	$54	$52	$49
SCE (CAISO)	$45	$43	$41	$41	$42	$46	$52	$45	$26	$20	$19	$20	$18	$16	$15	$30	$42	$50	$48	$48	$49	$50	$49	$46
BANC	$47	$44	$43	$42	$44	$47	$54	$54	$47	$44	$42	$40	$39	$41	$43	$48	$53	$58	$52	$57	$53	$52	$51	$48
Turlock ID	$47	$44	$43	$43	$44	$47	$54	$54	$50	$49	$47	$45	$44	$46	$49	$55	$57	$59	$53	$57	$53	$53	$51	$48
LADWP	$46	$43	$42	$41	$42	$43	$49	$38	$26	$19	$19	$19	$18	$18	$18	$43	$40	$54	$48	$50	$52	$52	$49	$48
NV Energy	$32	$31	$32	$32	$34	$39	$42	$32	$24	$23	$23	$24	$22	$20	$19	$32	$37	$41	$36	$37	$36	$35	$35	$33
Arizona PS	$32	$31	$31	$32	$39	$38	$43	$36	$19	$18	$18	$19	$17	$13	$13	$30	$39	$40	$36	$36	$36	$38	$35	$33
Tucson Electric	$31	$29	$29	$30	$33	$38	$38	$29	$18	$16	$18	$18	$17	$16	$20	$30	$42	$40	$35	$35	$36	$33	$34	$33
Salt River Project	$32	$31	$31	$31	$34	$38	$42	$33	$17	$18	$20	$24	$20	$16	$17	$28	$36	$39	$35	$35	$36	$34	$34	$33
PSC New Mexico	$33	$38	$31	$35	$40	$42	$73	$46	$28	$14	$30	$21	$8	$4	$32	$59	$44	$38	$33	$35	$52	$43	$41	$36
WAPA - Desert SW	$32	$31	$31	$32	$34	$38	$43	$33	$24	$18	$18	$18	$17	$15	$13	$28	$37	$40	$46	$36	$36	$35	$35	$33
El Paso Electric	$35	$27	$26	$27	$30	$34	$35	$26	$17	$16	$16	$17	$17	$17	$17	$35	$43	$46	$41	$37	$37	$31	$31	$28
PacifiCorp East	$32	$31	$31	$32	$35	$38	$42	$37	$29	$29	$28	$27	$26	$25	$24	$34	$41	$43	$36	$38	$36	$35	$35	$33
Idaho Power	$33	$32	$31	$32	$34	$39	$43	$40	$33	$33	$32	$34	$32	$29	$28	$36	$41	$42	$37	$40	$37	$36	$36	$34
NorthWestern	$29	$29	$30	$30	$30	$37	$43	$40	$33	$36	$30	$29	$27	$26	$27	$35	$39	$40	$37	$37	$35	$33	$31	$28
Avista Utilities	$32	$31	$31	$31	$34	$39	$43	$42	$36	$36	$37	$34	$35	$33	$33	$38	$42	$42	$37	$41	$37	$36	$36	$34
Avangrid	$33	$32	$32	$33	$35	$39	$43	$43	$38	$38	$37	$37	$36	$35	$35	$41	$43	$43	$38	$38	$38	$36	$37	$34
BPA	$33	$32	$32	$32	$35	$39	$42	$42	$37	$38	$36	$35	$35	$34	$35	$38	$42	$42	$38	$37	$38	$36	$36	$34
Tacoma Power	$33	$32	$32	$32	$34	$38	$42	$41	$36	$37	$36	$35	$35	$33	$33	$39	$41	$42	$37	$36	$37	$35	$38	$33
PacifiCorp West	$33	$32	$32	$32	$40	$41	$43	$41	$37	$37	$36	$35	$35	$34	$34	$39	$42	$42	$37	$37	$37	$36	$36	$33
Portland GE	$33	$32	$32	$32	$34	$39	$42	$41	$37	$37	$36	$35	$34	$34	$34	$39	$42	$42	$38	$37	$37	$35	$36	$34
Puget Sound Energy	$33	$32	$32	$32	$34	$38	$42	$41	$36	$36	$35	$35	$34	$34	$34	$39	$42	$42	$37	$36	$37	$35	$37	$33
Seattle City Light	$34	$32	$32	$31	$35	$39	$46	$41	$36	$37	$38	$35	$35	$33	$34	$38	$41	$42	$37	$36	$37	$35	$36	$34
Powerex	$33	$32	$32	$33	$34	$37	$39	$36	$35	$35	$34	$33	$34	$32	$33	$37	$40	$39	$37	$36	$36	$35	$35	$34

Hour

3.3 Day-ahead market price comparison

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

In 2024, the fourth quarter prices in the CAISO balancing area's day-ahead, 15-minute, and 5-minute markets dropped by about 22 percent compared to the fourth quarter of the previous year. The average price of the three markets this quarter decreased to $45/MWh from $57/MWh in the same quarter of 2023.

Figure 3.7 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.[14] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from January 2023 to December 2024.

Over the quarter, day-ahead prices averaged $43/MWh, 15-minute prices averaged $45/MWh, and 5-minute prices averaged $44/MWh. October had the highest prices, with an average over the three markets of about $48/MWh.

Figure 3.7 also shows monthly average gas prices at PG&E Citygate from January 2023 to December 2024. The chart shows that the monthly variation of the energy prices is highly correlated with gas prices. Over the past 24 months, both gas and energy prices exhibited similar fluctuations. The PG&E Citygate gas price has remained down after declining from January 2023, averaging about $3.5/MMBtu during the fourth quarter of 2024.

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

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

Figure 3.7 Monthly average PG&E Citygate gas price and load-weighted average electricity prices for balancing areas in day-ahead market

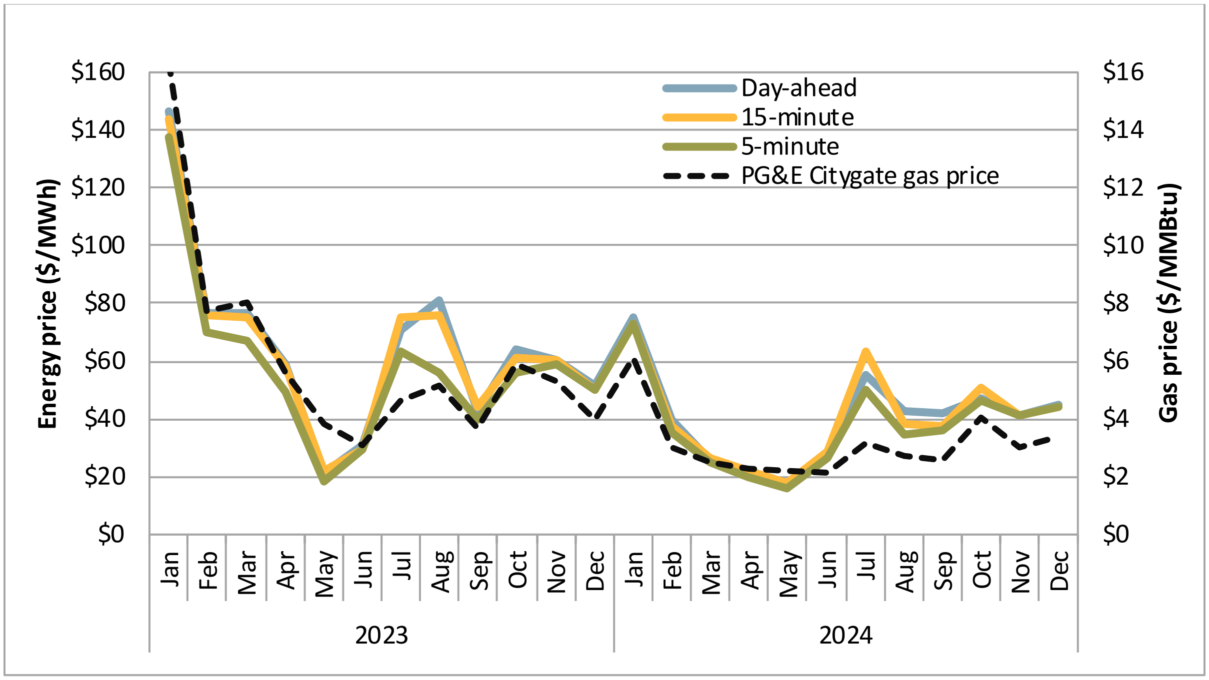


Figure 3.8 illustrates the hourly load-weighted average energy prices for the third quarter compared to the average hourly net load.[15] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

Average hourly prices continue to follow the net load pattern, with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening. Prices peaked at hour-ending 19 in the day-ahead and the 15-minute market, and at hour-ending 18 in the 5-minute market, when demand was still high but solar generation was substantially below its peak. The average net load in this quarter reached 24,944 MW at hour-ending 19.

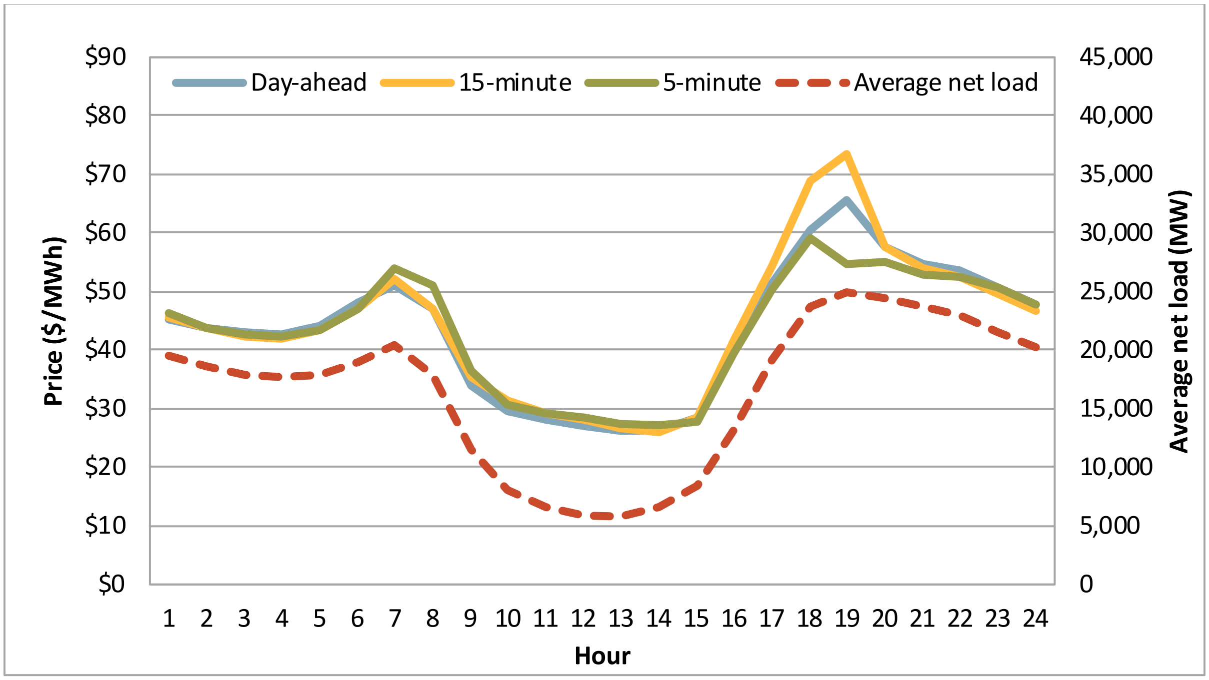
During hour-ending 19, the day-ahead load-weighted average energy price was $66/MWh, the 15-minute price was $73/MWh, and the 5-minute price was $55/MWh. Day-ahead and 15-minute market prices typically tend to converge on average due to convergence (virtual) bidding.

One major cause of price separation between the 15-minute and 5-minute markets this quarter was load conformance during evening peak net load hours. California ISO operators typically adjust the load forecast up significantly more in the 15-minute market than in the 5-minute market over these hours.[16]

[15] 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.

[16] Please see Section 8 for a detailed discussion on load conformance.

Figure 3.8 Hourly load-weighted average energy prices for balancing areas in day-ahead market (CAISO October–December)



3.4 Bilateral price comparison

Figure 3.9 and Figure 3.10 compare 15-minute prices in different regions of the WEIM during peak hours (hours-ending 7 through 22) to day-ahead prices for comparable markets. These figures show the monthly average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

As shown in these figures, in October, average peak hour prices in the 15-minute market for WEIM areas in the Pacific Northwest and Desert Southwest were significantly lower than day-ahead prices in the Intercontinental Exchange for the Mid-Columbia and Palo Verde trading hubs, respectively. These differences diminished significantly in November and December as prices converged. Similar to the previous quarter, the prices in the 15-minute market for the two main areas in the California ISO area (Pacific Gas and Electric, and Southern California Edison) tracked more closely with day-ahead prices in the California ISO integrated forward market (IFM).

Figure 3.9 Mid-C bilateral ICE vs. Pacific Northwest 15-minute market prices (peak hours)

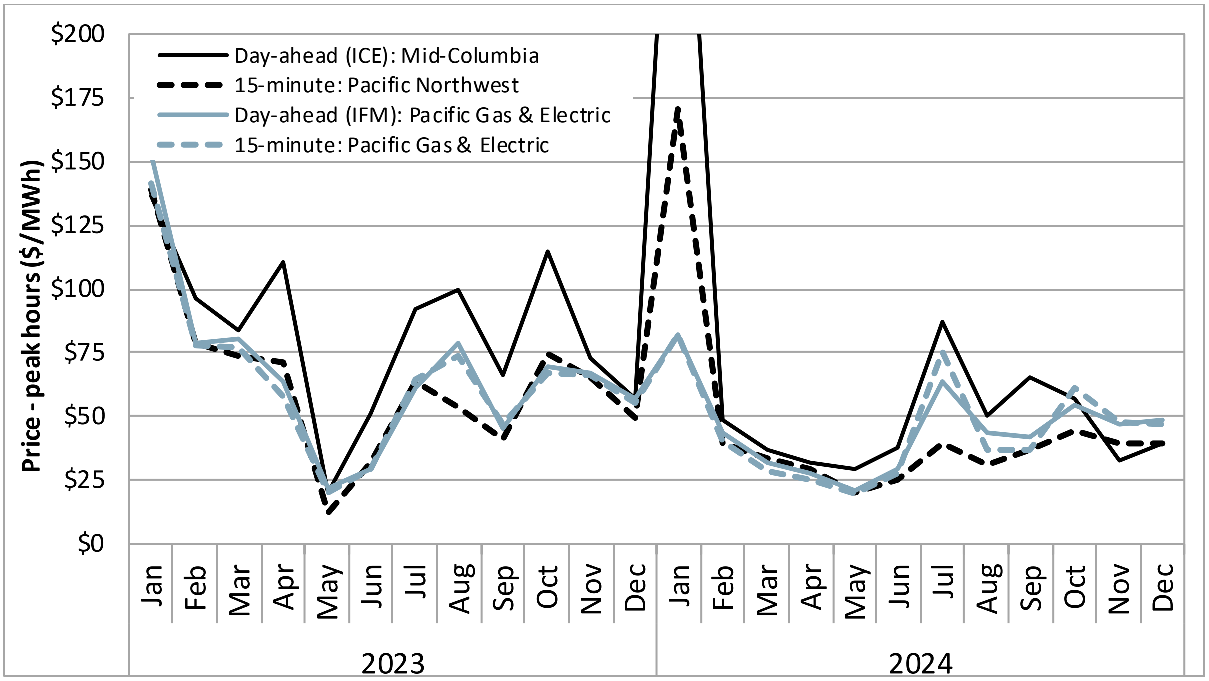


Figure 3.10 Palo Verde bilateral ICE vs. Desert Southwest 15-minute market prices (peak hours)

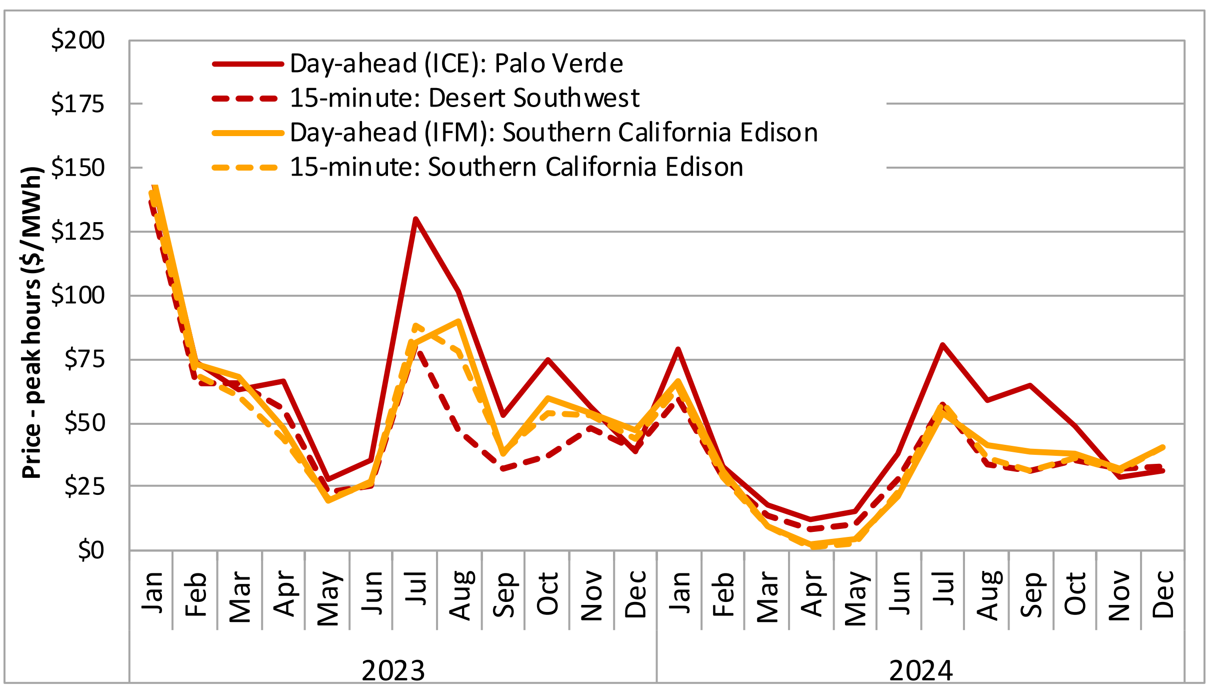


Figure 3.11 compares monthly average prices in the bilateral and ISO day-ahead market for 2023 through the fourth quarter of 2024. The California ISO market day-ahead prices are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). Average

bilateral prices for Mid-Columbia (Peak) significantly exceeded ISO market day-ahead prices in January 2024. This was a result of a large arctic air mass in mid-January,[17] which covered much of the Pacific Northwest and Intermountain West regions.

Average peak prices in the ISO day-ahead market at Pacific Gas and Electric (CAISO) were higher than Southern California Edison (CAISO) prices across all three months. In October, bilateral prices for peak hour blocks at Palo Verde and Mid-Columbia were similar to Pacific Gas and Electric prices, and higher than the Southern California Edison (CAISO) prices. This pattern shifted in November and December, when monthly average prices at Palo Verde and Mid-Columbia were lower than Pacific Gas and Electric prices.

Figure 3.11 Monthly average day-ahead and bilateral market prices

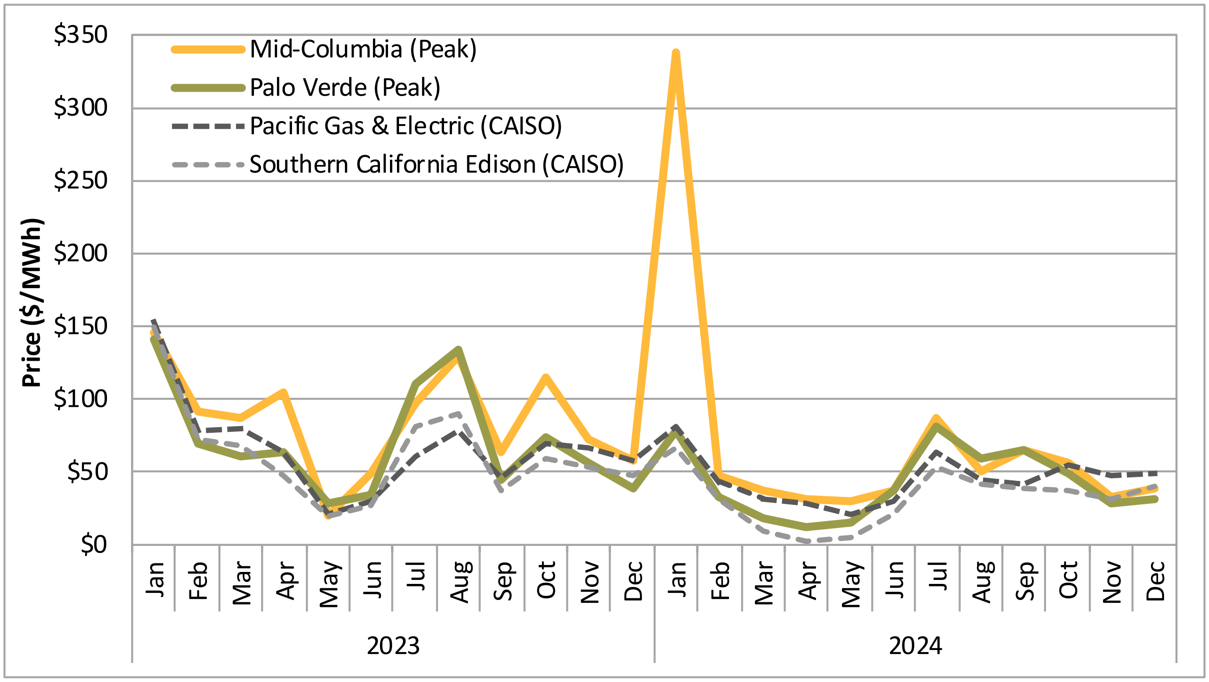


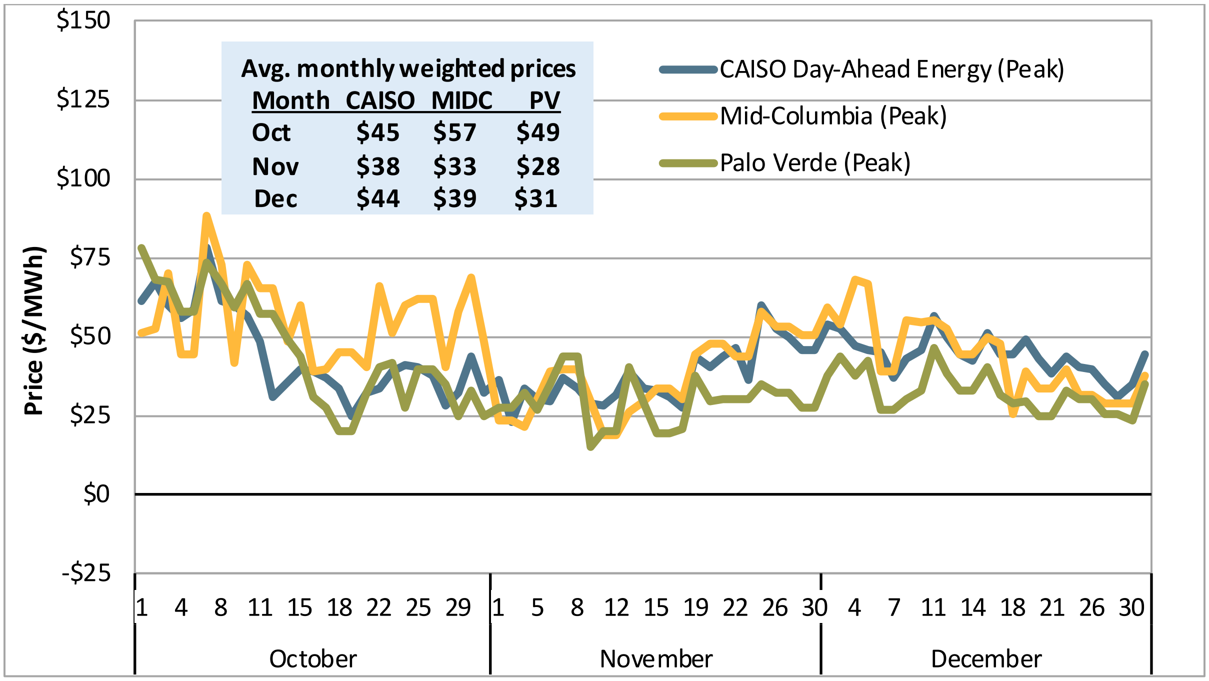
Figure 3.12 shows California ISO market day-ahead load weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as averages for the bilateral day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the ISO markets. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays. Prices at Mid-Columbia were higher than average Palo Verde market prices in October and November by about 15 percent, and December by about 26 percent.

The California ISO FERC Order 831 policy will increase the ISO market energy bid cap to $2,000/MWh if a 16-hour block peak bilateral price, scaled and shaped into hourly prices according to the shape of ISO market hourly prices, exceeds $1,000/MWh. The ISO implemented enhancements to the maximum

17 *Arctic Chill Sweeps U.S.*, NASA Earth Observatory, January 15, 2024: https://earthobservatory.nasa.gov/images/152333/%0barctic-chill-sweeps-us

import bid price (MIBP) hourly energy shaping factor on November 16, 2024.[18] The ISO did not raise the energy bid cap and penalty prices to $2,000/MWh in the fourth quarter.

Figure 3.12 Day-ahead California ISO and bilateral market prices (October–December)



Average day-ahead prices in the California ISO balancing area and bilateral hubs (from the Intercontinental Exchange—or ICE) 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. Average day-ahead hourly prices in the California ISO balancing area were greater than average real-time prices at Mid-Columbia and Palo Verde by about $4.50/MWh and $7/MWh, respectively. For the Mid-Columbia hub, average day-ahead prices were greater than the average real-time prices (from Powerdex) by about $3/MWh. For the Palo Verde hub, average day-ahead prices were lower than average real-time prices (from Powerdex) by about $3/MWh.

3.5 Price variability

This section analyzes the frequency of prices exceeding $250/MWh and the occurrence of negative prices. Two groups of balancing authority areas (BAAs) were included: the first group consists of those participating in both the day-ahead and real-time markets, which as of this quarter includes only the

18 *Modification of Maximum Import Bid Price Hourly Energy Shaping Factor effective 11/16/24* 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.[19] The second group comprises balancing areas participating exclusively in the real-time market, which includes all WEIM entities aside from the California ISO balancing area.

High prices

Figure 3.13 shows the monthly frequency of high prices across all three markets for the balancing area participating in both the day-ahead and real-time markets from October 2023 to December 2024.[20] Figure 3.14 illustrates the monthly frequency of high prices for balancing areas participating only in the real-time market during the same period.[21]

In the day-ahead market, the frequency of high prices over $250/MWh decreased compared to the same quarter of 2023. In the fourth quarter of 2024, the day-ahead market recorded zero percent of intervals with an average price exceeding $250/MWh. In the same quarter of the previous year, 0.09 percent of intervals had prices above $250/MWh.

In the 15-minute market, the frequency of high prices for the balancing area participating in the day-ahead market decreased by 29 percent, dropping from 0.21 percent in Q4 2023 to 0.15 percent in Q4 2024. Conversely, for balancing areas participating exclusively in the real-time market, the frequency of high 15-minute market prices slightly increased from 0.16 percent in Q4 2023 to 0.19 percent in Q4 2024.

In the 5-minute market, the frequency of high prices for the balancing area participating in the day-ahead market decreased by 69 percent, dropping from 0.21 percent to 0.07 percent. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market dropped by 58 percent, from 0.28 percent to 0.12 percent.

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

[20] 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.

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

Figure 3.13 Frequency of high prices in BAAs participating in the day-ahead market (CAISO)

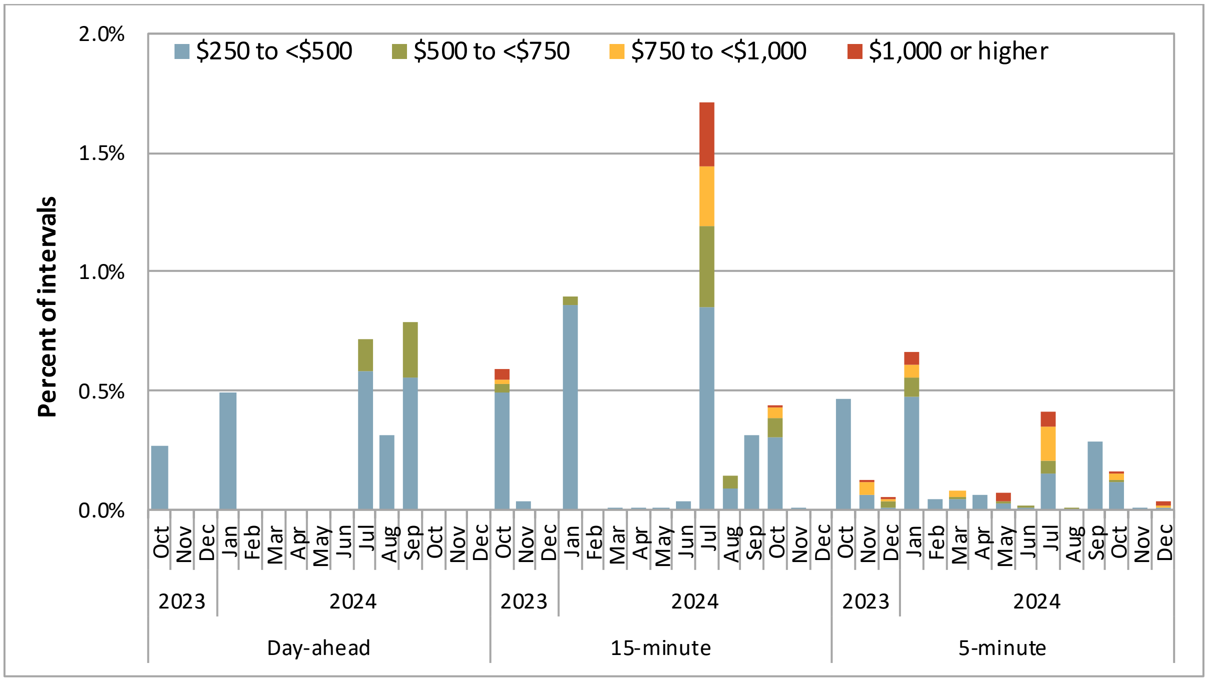
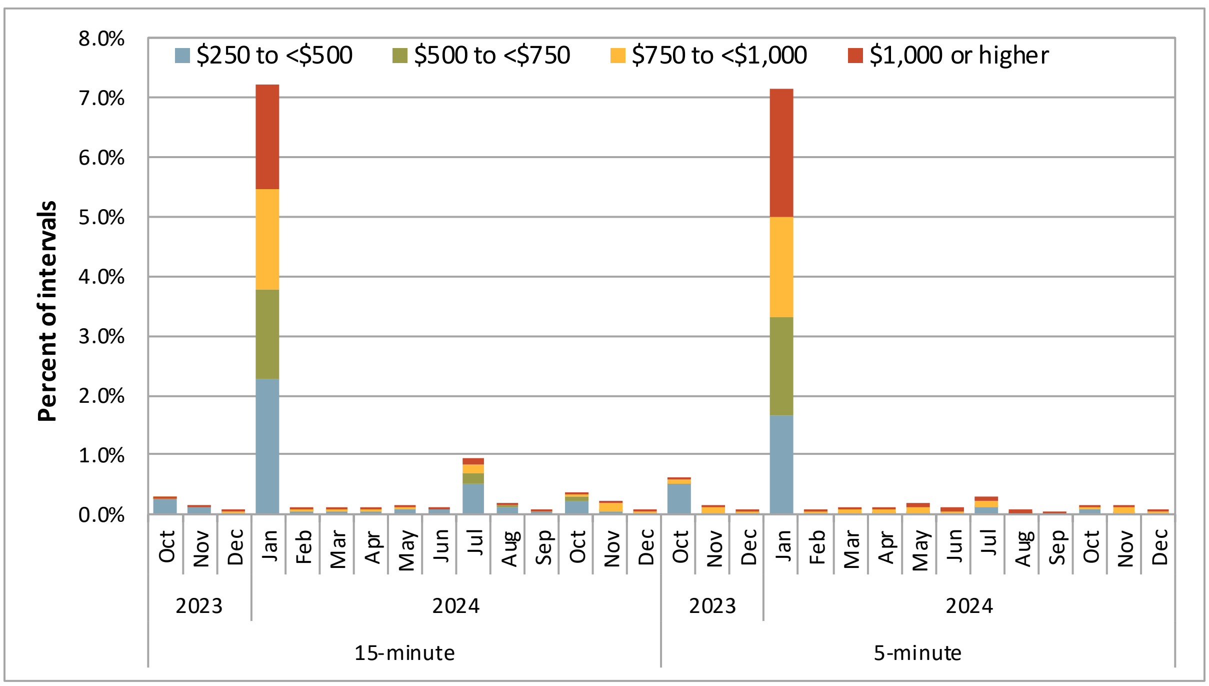


Figure 3.14 Frequency of high prices in BAAs participating only in the real-time markets



Negative prices

Figure 3.15 and Figure 3.16 show the frequency of negative prices across two groups of balancing areas: those participating in the day-ahead market and those participating only in the real-time markets, spanning the period from October 2023 to December 2024 for each market. Overall, the frequency of negative prices continued to increase for the real-time market participating group, while it showed a decline for the day-ahead market participating group.

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

For balancing areas participating in the day-ahead market—currently just the CAISO balancing area—the frequency of negative prices increased significantly in the day-ahead market but decreased in the 15-minute and 5-minute markets. In the day-ahead market, the frequency increased from 1 percent to 2.2 percent compared to the same quarter of the previous year. In the 15-minute market, it decreased from 3.7 percent to 3.1 percent, and in the 5-minute market, it decreased from 4.3 percent to 3.4 percent.

For the BAAs participating exclusively in the real-time markets—all balancing areas in WEIM besides CAISO—the frequency of negative prices showed an increase across the 15-minute and 5-minute markets, with an average rise of 16 percent compared to the same quarter of the previous year. For instance, in the 15-minute market, the frequency increased from 1.7 percent to 2 percent, while in the 5-minute market, it rose from 2 percent to 2.3 percent during this quarter.

Figure 3.15 Frequency of negative prices in BAAs participating in the day-ahead market (CAISO)

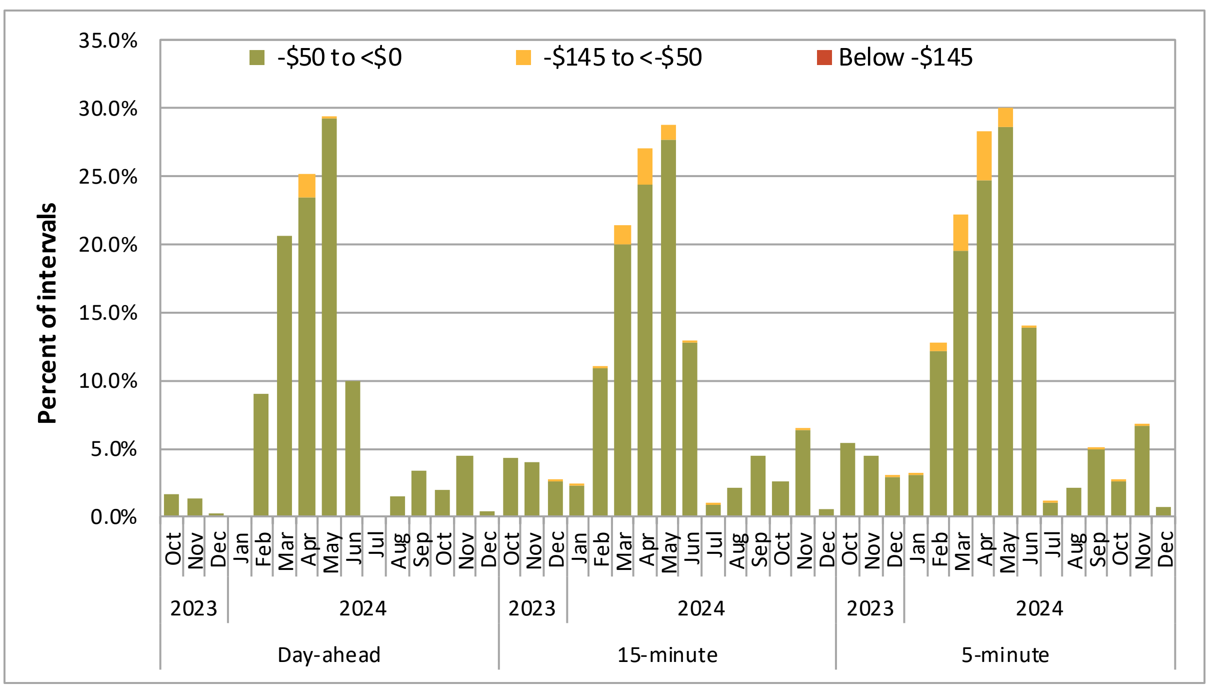
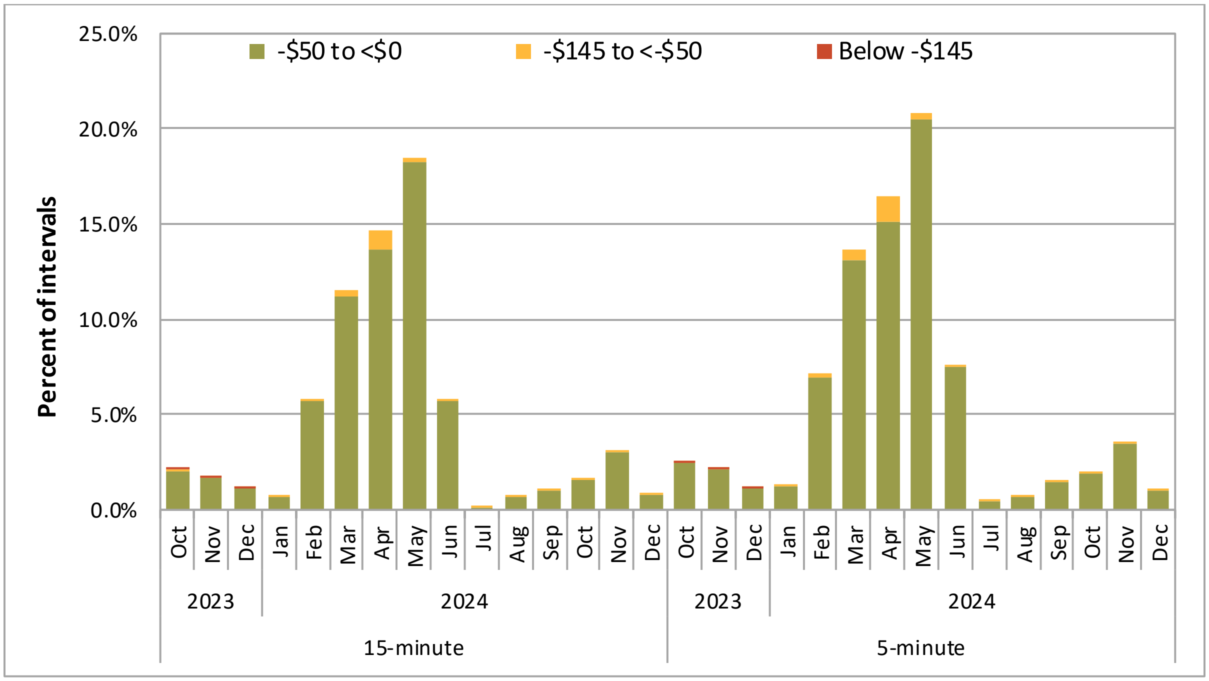


Figure 3.16 Frequency of negative prices in BAAs participating only in the real-time markets



3.6 WEIM transfers and transfer limits

Energy transfers

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

Figure 3.17 summarizes the average volume of WEIM transfers in the 5-minute market by hour during the last five quarters.[22] During the quarter, the average volume of transfers across the system was down, at around 3,870 MW, compared to around 4,560 MW in the previous quarter, and around 4,100 MW from the same quarter of the previous year.

Figure 3.18 summarizes average inter-regional transfers during the quarter. The bars show *net* WEIM transfers for each region by hour.[23] 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. Net WEIM exports for a region are shown as positive and net WEIM imports for a region are shown as negative. The figure also highlights two key periods: mid-day and peak. During the mid-day

[22] WEIM transfers in this section exclude the fixed bilateral transactions between WEIM entities (base WEIM transfer schedules) and therefore reflect only *dynamic* WEIM transfer schedules optimized in the market.

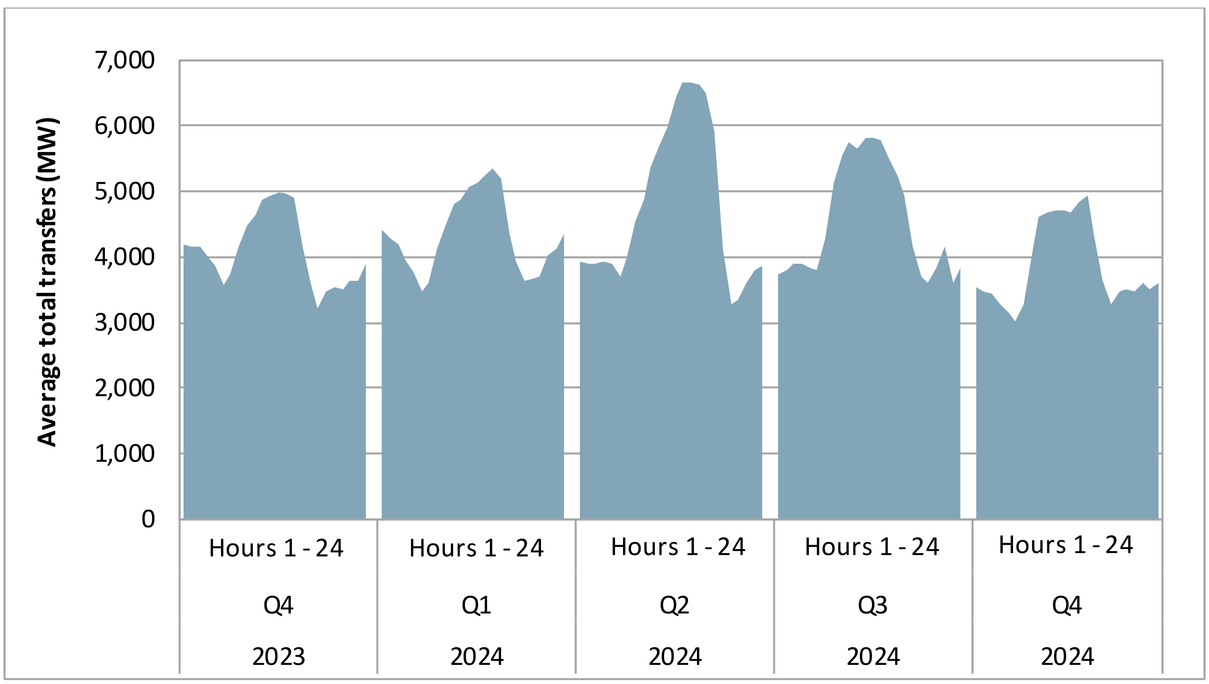
[23] See Appendix A for figures on the average hourly transfers by quarter for each WEIM balancing area.

hours, regional WEIM transfers are typically highest with significant levels of exports from the CAISO balancing area. During the peak hours—when net load in the WEIM system is highest—regional WEIM transfers were lower. Overall, balancing areas in the Desert Southwest and Intermountain West regions were exporting during this peak period, out to balancing areas in California.

Figure 3.19 and Figure 3.20 show average WEIM transfers in the 5-minute market by balancing area in the mid-day and peak periods during the quarter.[24] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area.

As shown in Figure 3.19, the CAISO balancing area exported on average over 1,300 MW 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 peak period (Figure 3.20), balancing areas in the Desert Southwest region exported on average around 710 MW to balancing areas outside the region (and 410 MW to balancing areas within the region).

Figure 3.17 Average dynamic WEIM transfer volume by hour and quarter (5-minute market)



24 In Figure 3.19 and Figure 3.20, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 3.18 Average dynamic inter-regional WEIM transfers by hour (5-minute market, October–December 2024)

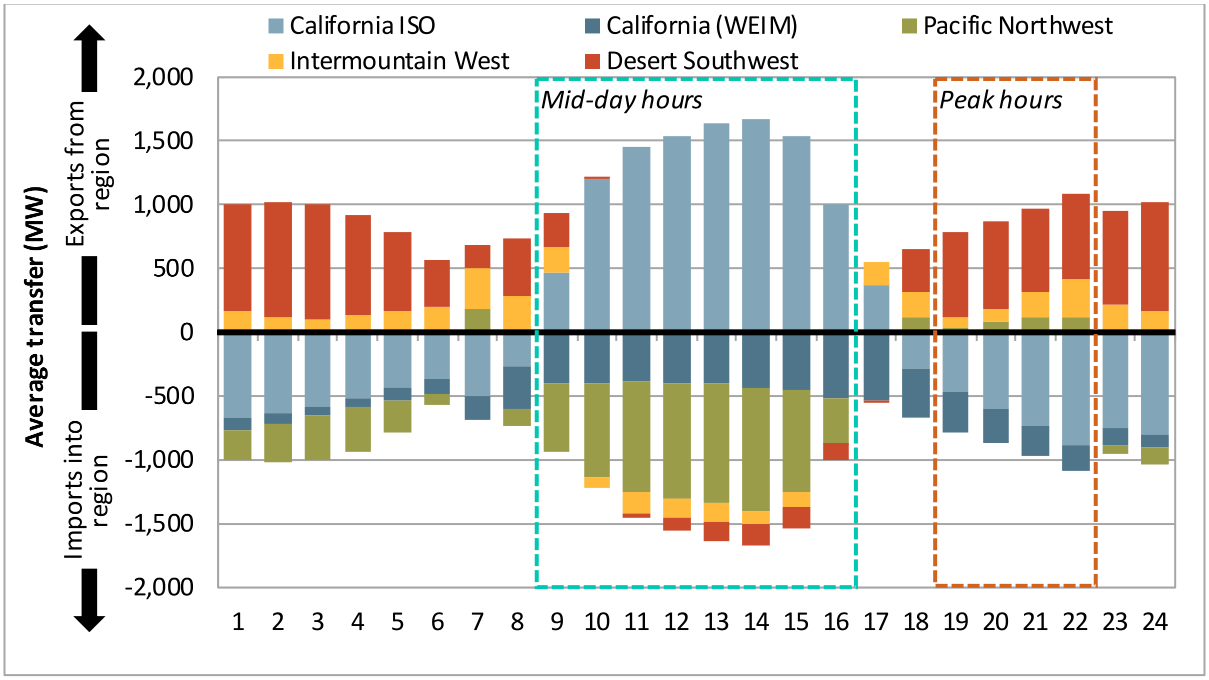


Figure 3.19 Average 5-minute market WEIM exports (mid-day hours, October–December 2024)

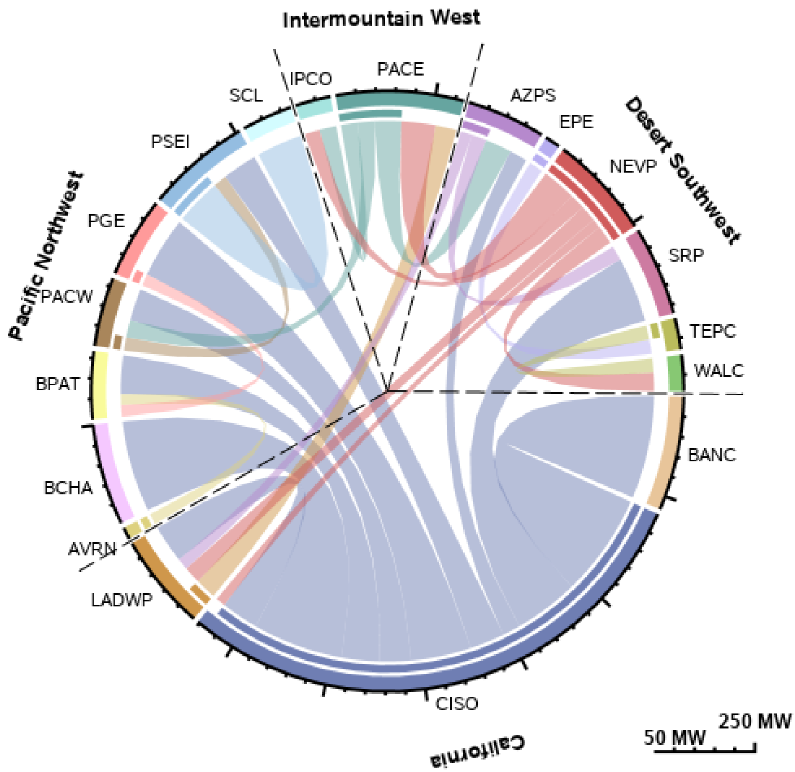
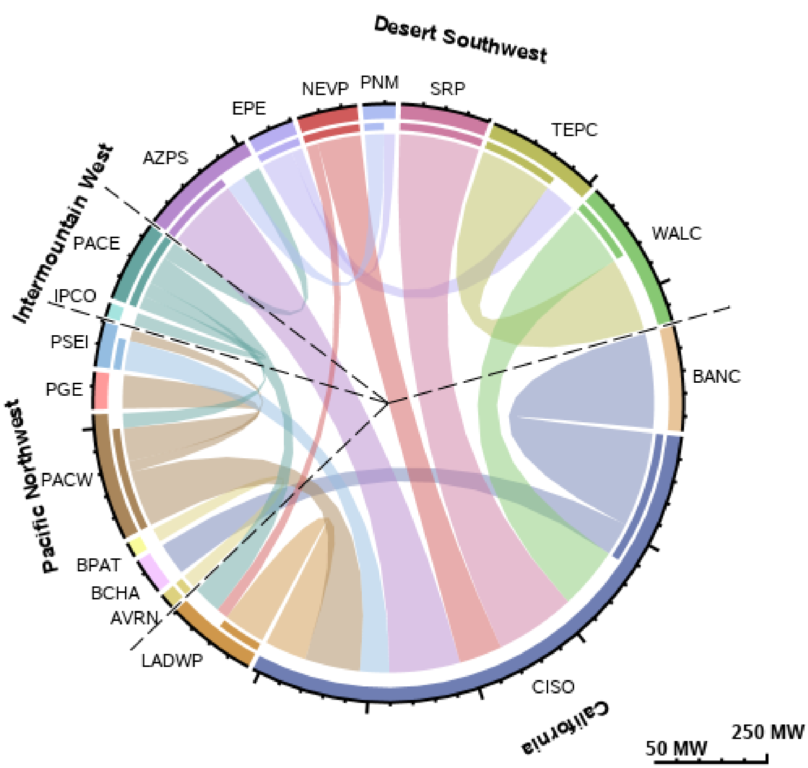


Figure 3.20 Average 5-minute market WEIM exports (peak load hours, October–December 2024)



Transfer limits

WEIM transfers between areas are constrained by transfer limits. These limits largely reflect transmission and interchange rights made available to the market by participating WEIM entities. Table 3.5 shows average 5-minute market import and export limits for each balancing area, grouped by region. These amounts exclude base WEIM transfer schedules and therefore reflect transfer capability which is made available by WEIM entities to optimally transfer energy between areas. The last two columns in Table 3.5 show WEIM transfer limits between regions (out-of-region import and export limits).

Import and export transfer capacity into or out of the Desert Southwest region was roughly 32,000 MW. For the Pacific Northwest region, there was an average of around 1,500 MW of import and 900 MW of export transfer capacity into or out of the region. The lack of transfer capability out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

Table 3.5 Average 5-minute market WEIM limits (October–December 2024)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**30,946**	**31,301**
California ISO	38,831	35,217	27,873	26,684
BANC	4,124	4,002	0	0
LADWP	7,109	11,002	3,073	4,616
Turlock Irrig. District	1,673	1,870	0	0
Desert Southwest			**32,304**	**31,925**
Arizona Public Service	47,239	43,787	23,391	22,865
El Paso Electric	713	526	0	0
NV Energy	4,176	3,620	3,581	2,641
PSC New Mexico	1,019	1,062	0	0
Salt River Project	21,915	25,103	2,186	3,146
Tucson Electric	5,465	6,756	833	1,170
WAPA - Desert SW	5,799	5,091	2,313	2,104
Intermountain West			**2,336**	**2,913**
Avista Utilities	595	997	81	97
Idaho Power	1,778	2,969	555	903
NorthWestern Energy	715	530	109	28
PacifiCorp East	3,322	2,490	1,592	1,886
Pacific Northwest			**1,478**	**926**
Avangrid	833	825	19	22
Powerex	226	50	177	0
BPA	746	785	190	146
PacifiCorp West	1,850	1,842	614	503
Portland General Electric	806	638	211	39
Puget Sound Energy	1,274	1,076	218	93
Seattle City Light	439	436	30	32
Tacoma Power	397	367	18	92

4 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.

Section 4.1 addresses congestion on the constraints limiting WEIM transfers between balancing areas in the real-time market. Section 4.2 addresses real-time market internal congestion.[25] Section 4.3 analyzes day-ahead market congestion rent and loss surpluses. Section 4.4 addresses intertie constraint congestion in the day-ahead market. Section 4.5 addresses the impact of internal congestion on the day-ahead market. Lastly, Section 4.6 addresses congestion revenue rights.

4.1 WEIM transfer constraint congestion

When limits on constraints impacting WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to prevailing system prices. Table 4.1 shows the percent of intervals and price impact of 15-minute and 5-minute market transfer constraint congestion in each WEIM area during the quarter.[26] The congestion on the WEIM transfer constraints are measured relative to a reference price in the CAISO balancing area. *Congested from area* reflects that prices are lower in the balancing area because of limited export capability out of the area or region, relative to the CAISO (and connected WEIM system). *Congestion into area* reflects that prices are higher within an area or region, because of limited import capability into the area or region.[27]

Powerex was often constrained relative to the CAISO balancing area because of WEIM transfer congestion. Powerex was congested into its area during around 19 percent of intervals in the 15-minute market and 27 percent of intervals in the 5-minute market. Powerex was also often export constrained, during around 14 percent of 15-minute market intervals and 30 percent of 5-minute market intervals.

The rest of the Pacific Northwest region was also frequently transfer constrained relative to the rest of the WEIM system. These balancing areas were *import* constrained in around 11 percent of 15-minute intervals and 7 percent of 5-minute intervals. These balancing areas were also *export* constrained in around 5 percent of 15-minute and 5-minute market intervals.

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[25] 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.

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

[27] 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.

NorthWestern Energy was also frequently export constrained during the quarter, during around 13 percent of intervals. Much of this was because of intertie constraints that the balancing area used to manage net WEIM transfers into or out of their system.

Table 4.1 Frequency and impact of transfer congestion in the WEIM (October–December 2024)

	15-minute market				5-minute market			
	Congested from area		Congested into area		Congested from area		Congested into area	
	Congestion frequency	Price impact ($/MWh)	Congestion frequency	Price impact ($/MWh)	Congestion frequency	Price impact ($/MWh)	Congestion frequency	Price impact ($/MWh)
BANC	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00
NV Energy	0.1%	-$0.01	0.0%	$0.00	0.1%	-$0.02	0.0%	$0.16
WAPA – Desert Southwest	0.0%	$0.00	0.1%	$0.77	0.0%	-$0.01	0.1%	$0.63
Turlock Irrigation District	0.1%	-$0.09	0.1%	$0.00	0.0%	-$0.02	0.1%	$0.00
Arizona Public Service	0.2%	-$0.11	0.0%	$0.11	0.2%	-$0.13	0.1%	$0.64
L.A. Dept. of Water and Power	0.9%	-$0.27	0.1%	$0.28	1%	-$0.11	0.1%	$0.58
Public Service Company of NM	0.5%	-$0.76	2%	$12.57	0.5%	-$0.54	1%	$9.44
PacifiCorp East	1%	-$0.05	2%	$0.18	2%	-$0.10	1%	$0.36
Salt River Project	4%	-$0.62	2%	$0.40	4%	-$0.73	2%	$0.85
Idaho Power	1%	-$0.03	9%	$0.89	1%	-$0.04	6%	$0.66
Avista Utilities	1%	-$0.09	9%	$0.83	1%	-$0.17	6%	$0.59
El Paso Electric Company	10%	-$1.79	2%	$0.79	9%	-$1.59	2%	$0.71
Tucson Electric Power	10%	-$1.30	2%	$0.37	10%	-$1.36	2%	$0.86
Avangrid Renewables	4%	-$0.68	10%	$0.94	4%	-$0.50	6%	$0.51
PacifiCorp West	4%	-$0.68	10%	$0.94	4%	-$0.50	6%	$0.93
Portland General Electric	4%	-$0.68	11%	$0.98	4%	-$0.51	6%	$0.57
Tacoma Power	5%	-$0.72	11%	$1.24	5%	-$0.59	6%	$0.65
Seattle City Light	4%	-$0.73	11%	$2.01	4%	-$0.67	7%	$1.02
Puget Sound Energy	5%	-$0.85	11%	$1.34	5%	-$0.78	6%	$0.66
Bonneville Power Admin.	5%	-$0.79	15%	$1.93	5%	-$0.54	11%	$0.98
NorthWestern Energy	13%	-$3.94	7%	$0.71	13%	-$3.43	5%	$1.20
Powerex	14%	-$2.06	19%	$1.17	30%	-$2.72	27%	$1.74

4.2 Internal congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across the WEIM.[28] 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 4.1.

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

28 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.

calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[29]

In this quarter, internal congestion in the real-time market was on average in the south-to-north direction. This trend was more pronounced during mid-day. This congestion contributed to increasing prices in the Northern California and Pacific Northwest regions relative to balancing areas in Southern California and the Desert Southwest.[30]

Figure 4.1 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAPs) and EIM load aggregation points (ELAPs) in the fourth quarter of 2024. The blue bars represent the 15-minute market price impact, and the yellow bars indicate the 5-minute market price impact from internal constraints.

Figure 4.1 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (October–December 2024)

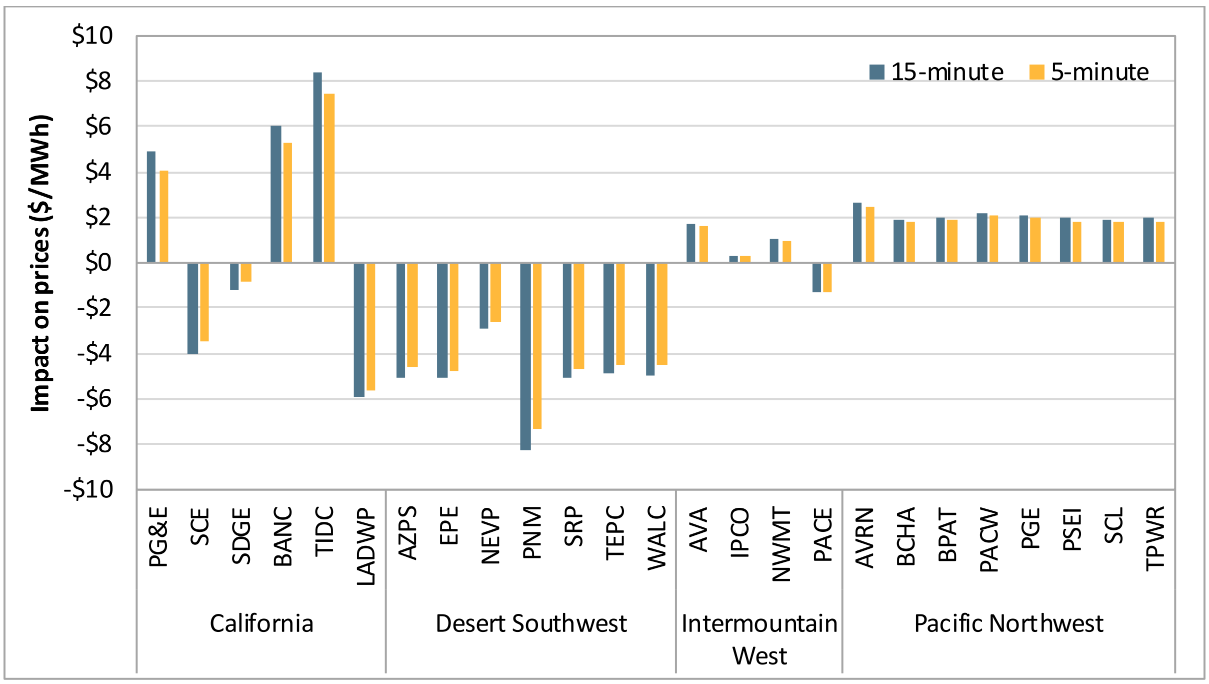


Figure 4.2 displays the average impact of internal congestion on prices in the fourth quarter of 2023 and 2024. The blue bars represent the impact for 2023, and the red bars show the impact for 2024. This

29 This approach does not include price differences that result from transmission losses.

30 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.

impact was calculated as the average of the 15-minute and 5-minute market price impacts of internal constraints for all intervals.

In both Q4 2023 and Q4 2024, internal congestion generally led to increased prices in Northern California, the Pacific Northwest, and the Intermountain West, while prices decreased in Southern California and the Desert Southwest. Notable outliers included PACE, where internal congestion in Q4 2023 and Q4 2024 was associated with a price decrease while other balancing areas in the region had increased prices due to internal congestion.

Figure 4.2 Average impact of internal congestion on real-time market price (2023-2024)

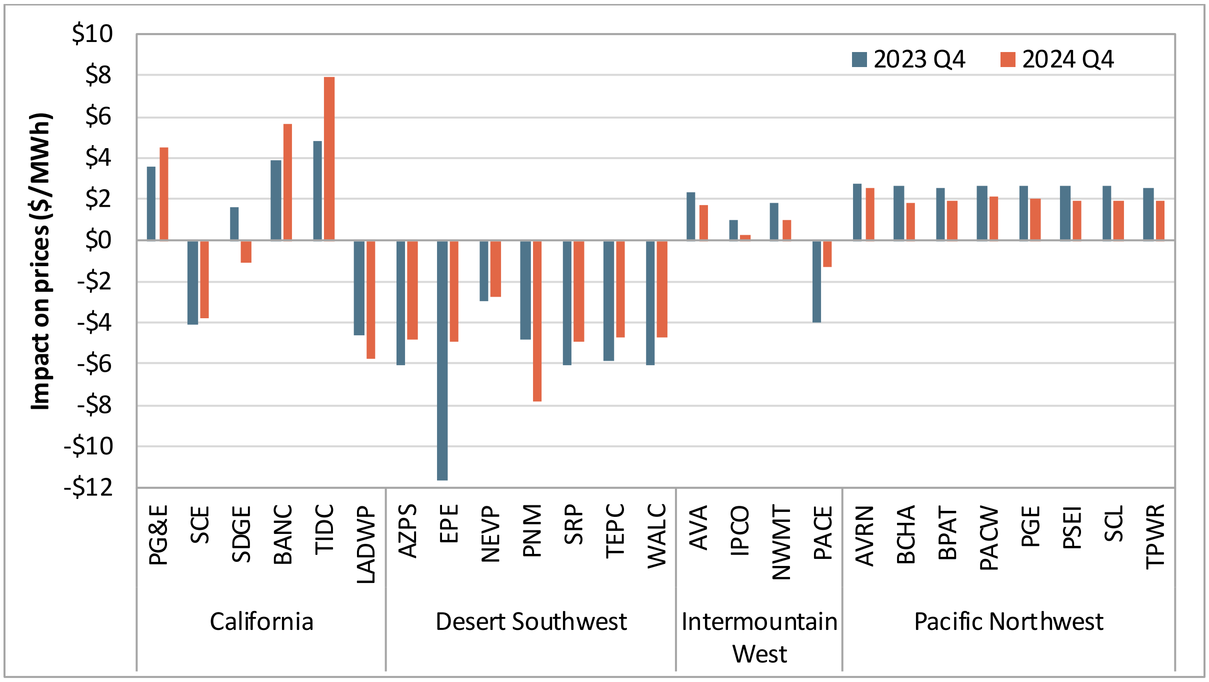


Figure 4.3 and Figure 4.4 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the fourth quarter of 2024 and 2023, respectively. Overall, in Q4 2024 and Q4 2023, the congestion pattern followed an hourly trend. Pronounced mid-day congestion resulted in south-to-north congestion that increased prices in Northern California, the Pacific Northwest, and much of the Intermountain West. In Q4 2024, the price impact on Northern California was notably stronger, especially during evening peak hours.

Figure 4.3 Overall impact of internal congestion on price separation in the 15-minute market by hour (October–December 2024)

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

Hour

Figure 4.4 Overall impact of internal congestion on price separation in the 15-minute market by hour (October–December 2023)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	0.7	0.7	0.7	0.7	0.7	0.8	0.6	3.9	8.1	9.4	8.9	8.8	8.5	8.1	8.1	5.4	4.3	2.8	2.3	0.8	0.1	0.4	0.8	0.7
BANC	0.3	0.3	0.4	0.4	0.4	0.5	0.3	3.5	10.4	12.5	11.2	10.9	10.5	10.4	10.9	6.3	3.2	0.6	1.2	0.1	-0.4	-0.2	0.2	0.3
Turlock ID	0.4	0.3	0.5	0.5	0.4	0.5	0.3	3.6	11.3	14.4	13.9	13.8	12.7	12.8	13.4	8.3	5.0	2.2	1.1	0.5	-0.2	0.0	0.2	0.3
SCE	0.3	0.3	0.1	0.3	0.3	0.1	0.2	-3.1	-11.5	-15.1	-14.3	-13.9	-12.7	-12.4	-11.4	-6.7	-3.5	-0.7	-0.2	0.6	0.3	0.4	0.7	0.5
SDG&E	5.2	5.3	5.1	4.1	4.1	5.1	3.8	2.4	-4.4	-7.8	-7.7	-6.9	-7.9	-8.2	-4.7	0.1	3.1	3.6	4.3	6.1	6.6	6.6	6.7	6.5
LADWP	-0.2	-0.4	-0.6	-1.4	-1.2	-0.8	-0.3	-3.7	-11.9	-15.2	-14.5	-13.9	-13.0	-12.7	-11.1	-6.4	-2.4	0.0	0.0	-0.1	-0.5	-0.3	0.0	-0.1
NV Energy	-0.4	-0.8	-0.6	-0.5	-0.4	-0.5	-0.3	-4.2	-7.8	-9.1	-7.9	-7.2	-7.8	-8.0	-7.6	-4.5	-2.1	0.9	0.3	-0.2	-0.5	-0.9	-1.2	-0.8
Arizona PS	-1.5	-1.5	-1.7	-1.5	-1.4	-1.7	-1.2	-5.6	-13.7	-17.4	-16.6	-16.6	-15.6	-15.5	-14.9	-7.3	-3.1	-0.7	-0.3	-1.2	-1.8	-1.7	-1.4	-1.6
Tucson Electric	-1.3	-1.3	-1.5	-1.3	-1.3	-1.5	-1.1	-5.4	-13.3	-16.8	-16.0	-15.9	-15.0	-14.9	-14.4	-7.6	-4.0	-0.8	-0.7	-1.1	-1.6	-1.6	-1.3	-1.5
Salt River Project	-1.4	-1.4	-1.5	-1.3	-1.3	-1.6	-1.2	-5.6	-13.7	-17.4	-16.6	-16.6	-15.7	-15.6	-15.2	-8.0	-4.2	-0.8	-0.7	-1.1	-1.7	-1.6	-1.3	-1.5
PSC New Mexico	-0.6	-0.6	-0.8	-0.7	-0.6	-0.8	-0.6	-4.6	-11.5	-14.2	-13.6	-13.3	-13.0	-13.0	-12.7	-6.9	-3.5	-0.4	-0.1	-0.3	-0.7	-0.8	-0.6	-0.8
WAPA - Desert SW	-1.5	-1.5	-1.7	-1.5	-1.5	-1.8	-1.3	-5.5	-13.5	-17.1	-16.2	-16.2	-15.3	-15.2	-14.7	-7.6	-4.1	-0.8	-0.8	-1.2	-1.8	-1.7	-1.4	-1.6
El Paso Electric	-10.6	-10.6	-10.6	-11.1	-10.4	-8.8	-9.3	-11.5	-16.4	-19.0	-17.7	-17.2	-16.4	-16.2	-15.9	-11.9	-10.0	-9.2	-9.2	-10.0	-10.3	-10.5	-10.4	-10.1
PacifiCorp East	-3.5	-3.5	-3.5	-3.7	-4.1	-4.2	-4.1	-4.1	-4.6	-4.8	-4.6	-4.3	-4.3	-4.3	-3.9	-3.5	-3.7	-3.4	-3.2	-3.0	-3.0	-3.1	-3.5	-3.3
Idaho Power	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.9	2.9	3.2	2.9	2.8	2.5	2.8	3.1	2.0	0.7	-0.1	-0.3	-0.2	0.2	0.1	-0.1	0.0
NorthWestern	0.1	0.2	0.3	0.2	0.2	0.3	0.1	1.7	5.3	6.1	5.6	5.4	5.2	5.4	5.4	3.3	1.3	-0.2	-0.5	-0.3	0.3	0.2	-0.1	0.0
Avista Utilities	0.1	0.2	0.3	0.2	0.2	0.3	0.2	2.1	6.8	8.0	7.1	6.8	6.6	6.7	6.7	4.0	1.5	-0.3	-0.6	-0.3	0.3	0.2	-0.2	0.0
Avangrid	-0.1	0.1	0.1	0.1	0.1	0.1	0.1	2.3	7.8	9.7	8.8	8.7	8.3	8.3	8.3	4.7	1.6	-0.4	-0.7	-0.4	0.4	0.2	-0.2	-0.1
BPA	0.1	0.2	0.3	0.3	0.3	0.3	0.2	2.3	7.3	8.7	7.7	7.4	7.2	7.4	7.6	4.5	1.6	-0.3	-0.6	-0.3	0.3	0.2	-0.2	0.0
Tacoma Power	0.1	0.2	0.3	0.3	0.3	0.3	0.2	2.3	7.3	8.6	7.6	7.3	6.9	7.1	7.7	4.6	1.6	-0.3	-0.6	-0.3	0.3	0.2	-0.2	0.0
PacifiCorp West	0.1	0.2	0.3	0.3	0.3	0.4	0.2	2.4	7.7	9.0	8.1	7.9	7.4	7.4	7.6	4.5	1.6	-0.3	-0.6	-0.3	0.4	0.2	-0.2	0.0
Portland GE	0.1	0.2	0.3	0.3	0.3	0.4	0.2	2.4	7.6	8.9	7.9	7.6	7.2	7.3	8.3	5.0	1.6	-0.3	-0.6	-0.3	0.4	0.2	-0.2	0.0
Puget Sound Energy	0.1	0.2	0.3	0.3	0.3	0.3	0.2	2.3	7.3	8.7	7.8	7.5	7.5	7.8	7.7	4.6	1.8	-0.3	-0.6	-0.3	0.3	0.2	-0.2	0.0
Seattle City Light	0.1	0.2	0.3	0.3	0.3	0.3	0.2	2.3	7.3	8.8	7.9	7.6	7.9	8.3	7.6	4.5	2.0	-0.3	-0.6	-0.3	0.3	0.2	-0.2	0.0
Powerex	0.1	0.2	0.3	0.2	0.2	0.3	0.2	2.2	7.2	8.9	7.9	7.6	8.3	8.6	7.4	4.4	2.3	-0.3	-0.6	-0.3	0.3	0.2	-0.2	0.0

Hour

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

Table 4.2 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 Los Banos-Gates #1 500kV line, Panoche-Gates #2 230kV line, and Gates-Midway #1 230kV line.

Los Banos-Gates #1 500kV line

Los Banos-Gates #1 500kV line (30050_LOSBANOS_500_30055_GATES1_500_BR_1_3) increased prices in Northern California, the Pacific Northwest, and Intermountain West, while it decreased prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar production hours, from hour-ending 9 to 15.

Panoche-Gates #2 230kV line

Panoche-Gates #2 230kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) increased prices in Northern California, the Pacific Northwest, and Intermountain West, while it decreased prices in Southern California and the Desert Southwest. This line experienced congestion during solar production hours, from hour-ending 8 to 19.

Gates-Midway #1 230kV line

Gates-Midway #1 230kV line (30900_GATES_230_30970_MIDWAY_230_BR_1_1) increased prices in Northern California, the Pacific Northwest, and Intermountain West, while it decreased prices in Southern California and the Desert Southwest. This line experienced congestion across all hours.

Table 4.2 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary constraints (WEIM, October–December 2024)[31]

BAA	Constraint	Average quarter impact ($/MWh)																								
		California						Desert Southwest							Intermountain West				Pacific Northwest							
		PG&E	BANC	TIDC	SCE	SDG&E	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	Line_OD-AR_69KV	.	.	.	0.07	0.32	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
BANC	XFMR2500.TRY	0.12	0.25	0.32	0.01	0.00	0.01	0.00	0.00	-0.02	0.00	0.00	0.00	0.00	-0.06	-0.05	-0.06	-0.03	-0.07	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
BPAT	NWACI_NS	0.10	0.11	0.10	0.06	0.05	0.06	0.04	0.04	0.03	0.03	0.04	0.04	0.04	-0.15	-0.10	-0.14	-0.05	-0.19	-0.16	-0.16	-0.16	-0.16	-0.16	-0.16	-0.16
CISO	30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	0.56	0.91	0.94	-1.16	-1.12	-1.09	-1.01	-0.94	-0.74	-0.88	-1.01	-0.99	-1.02	0.66	0.25	0.54	-0.11	0.81	0.70	0.70	0.75	0.73	0.71	0.71	0.71
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	0.90	1.19	1.45	-1.12	-1.07	-1.06	-0.94	-0.82	-0.47	-0.71	-0.94	-0.91	-0.94	0.53	.	0.14	.	0.71	0.58	0.60	0.63	0.62	0.59	0.59	0.59
	30900_GATES_230_30970_MIDWAY_230_BR_1_1	0.77	0.94	1.00	-0.79	-0.76	-0.75	-0.59	-0.56	-0.48	-0.51	-0.59	-0.58	-0.59	0.47	0.00	0.38	.	0.60	0.50	0.52	0.54	0.53	0.52	0.51	0.52
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	0.14	1.28	3.09	-0.63	-0.61	-0.41	-0.22	-0.14	-0.01	-0.10	-0.21	-0.19	-0.22	0.02	.	.	.	0.21	0.03	0.05	0.07	0.07	0.04	0.04	0.04
	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	0.32	0.38	0.39	-0.47	-0.45	-0.46	-0.41	-0.37	-0.31	-0.35	-0.41	-0.40	-0.41	0.24	0.08	0.19	-0.07	0.30	0.25	0.26	0.27	0.27	0.26	0.25	0.26
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	0.24	0.28	0.29	-0.23	-0.22	-0.23	-0.20	-0.19	-0.18	-0.17	-0.20	-0.20	-0.20	0.18	0.06	0.15	-0.03	0.22	0.19	0.19	0.20	0.20	0.19	0.19	0.19
	30797_LASAGUIL_230_30790_PANOCHE_230_BR_1_1	0.17	0.12	0.14	-0.27	-0.26	-0.26	-0.24	-0.22	-0.16	-0.20	-0.24	-0.23	-0.24	0.03	.	.	.	0.11	0.04	0.05	0.07	0.06	0.05	0.04	0.05
	30114_DELEVAN_230_30450_CORTINA_230_BR_1_1	0.22	.	0.00	0.09	0.08	.	.	.	.	.	.	.	.	-0.27	-0.08	-0.24	.	-0.30	-0.28	-0.28	-0.28	-0.28	-0.28	-0.28	-0.28
	7820_TL230S_OVERLOAD_NG	0.02	.	.	0.07	1.28	0.00	-0.25	-0.23	-0.08	-0.20	-0.27	-0.25	-0.23	.	0.00	.	-0.08	.	.	.	.	.	.	.	.
	MIGUEL_BKs_MXFLW_NG	0.03	.	.	0.11	0.94	.	-0.26	-0.24	.	-0.20	-0.27	-0.26	-0.25	.	.	.	.	.	.	.	.	.	.	.	.
	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	0.05	0.09	0.06	-0.13	-0.12	-0.13	-0.11	-0.10	-0.04	-0.10	-0.11	-0.11	-0.11	0.08	0.03	0.06	-0.02	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	0.06	0.09	0.09	-0.09	-0.09	-0.09	-0.08	-0.07	-0.06	-0.07	-0.08	-0.08	-0.08	0.07	0.03	0.06	-0.01	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07
	24801_DEVERS_500_24804_DEVERS_230_XF_2_P	0.05	0.04	0.04	0.01	0.02	0.05	-0.15	-0.14	-0.01	-0.11	-0.16	-0.14	-0.12	.	.	.	-0.03	0.00	.	.	.	.	.	.	.
	30015_TABLEMT_500_30030_VACA-DIX_500_BR_1_3	0.04	0.01	0.04	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.02	0.02	0.02	-0.07	-0.04	-0.06	-0.02	-0.08	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07
	24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	-0.06	-0.06	-0.06	0.14	0.11	0.00	.	.	.	.	.	.	.	-0.04	.	-0.01	.	-0.06	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05
	99013_CALCAPS_500_24801_DEVERS_500_BR_1_1	0.02	0.02	0.02	0.05	0.00	0.02	-0.09	-0.07	-0.02	-0.07	-0.09	-0.08	-0.07	.	.	.	-0.02	0.00	.	.	.	.	.	.	.
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	0.01	.	.	0.02	0.19	.	-0.05	-0.05	0.00	-0.04	-0.06	-0.05	-0.05	.	.	.	-0.01	.	.	.	.	.	.	.	.
	30765_LOSBANOS_230_30766_PADRFLT_230_BR_1_1	0.01	0.03	0.05	-0.03	-0.03	-0.03	-0.02	-0.02	.	-0.02	-0.02	-0.02	-0.02	0.02	.	0.01	.	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	SYLMAR-AC_BG_NG	0.02	0.02	0.02	0.04	0.00	-0.19	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	.	.	.	-0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	OMSIV-SXOUTAGE_NG	0.01	.	.	0.02	0.17	.	-0.04	-0.04	0.00	-0.03	-0.04	-0.04	-0.04	.	.	.	-0.01	.	.	.	.	.	.	.	.
	99002_MOE-ELD_500_24042_ELDORDO_500_BR_1_2	0.01	0.01	0.01	0.02	0.00	0.02	-0.05	-0.06	0.02	-0.06	-0.05	-0.05	-0.03	0.00	.	.	-0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	30885_MUSTANGS_230_30900_GATES_230_BR_2_1	0.10	0.07	0.06	-0.05	-0.05	-0.02	-0.01	-0.01	0.00	-0.01	-0.01	-0.01	-0.01	.	.	.	.	.	.	.	.	.	.	.	.
	30879_HENTAP1_230_30885_MUSTANGS_230_BR_1_1	0.05	0.03	0.03	-0.03	-0.03	-0.03	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	.	.	.	.	.	.	.	.	.	.	.	.
	30790_PANOCHE_230_30900_GATES_230_BR_1_1	0.02	0.03	0.04	-0.02	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.01	.	.	.	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	30440_TULUCAY_230_30460_VACA-DIX_230_BR_1_1	0.26	.	.	-0.03	-0.03	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	OMS_16682714_TL23055_IV_SPS_NG	0.00	.	.	0.01	0.12	.	-0.03	-0.03	.	-0.01	-0.03	-0.03	-0.03	.	.	.	.	.	.	.	.	.	.	.	.
	6310_CP7_NG	0.01	0.02	0.02	-0.02	-0.02	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	0.06	.	.	-0.07	-0.07	-0.02	0.00	.	.	.	0.00	.	0.00	.	.	.	.	.	.	.	.	.	.	.	.
	7820_TL23040_IV_SPS_NG	0.00	.	.	0.01	0.12	.	-0.01	-0.01	0.00	-0.01	-0.01	-0.01	-0.01	.	.	.	0.00	.	.	.	.	.	.	.	.
	35356_MNTAVSA_115_30705_MONTAVIS_230_XF_2	0.07	.	0.07	-0.03	-0.03	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	7760_DEV_RDB_ALIS	0.01	0.00	0.01	0.01	0.00	0.01	-0.02	-0.01	0.00	-0.01	-0.02	-0.02	-0.01	.	.	.	0.00	.	.	.	.	.	.	.	.
	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1_1	0.06	.	.	-0.03	-0.03	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	7520_Ventura_Voltage_NG	-0.01	.	.	0.08	-0.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
IPCO	BOBN-MPSN2_A	0.00	.	.	-0.02	-0.02	-0.02	-0.02	-0.02	-0.03	-0.03	-0.02	-0.02	-0.02	0.04	0.09	0.02	-0.06	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03
LADWP	WECC_Path_41	0.14	0.13	0.13	0.25	0.00	-1.49	-0.19	-0.19	-0.23	-0.19	-0.18	-0.19	-0.20	.	.	.	-0.09	0.09	.	0.00	0.05	0.03	0.00	0.00	0.00
	HWD_FARBREA	.	.	.	.	.	0.21	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
PACE	TOTAL_WYOMING_EXPORT	0.02	.	.	0.02	0.02	.	.	.	.	.	.	.	.	.	.	.	-0.26	.	.	.	.	.	.	.	.
	EAST_WYO_EXP	0.01	.	.	0.01	0.01	.	.	.	.	.	.	.	.	.	.	.	-0.18	.	.	.	.	.	.	.	.
	WINDSTAREXPORTTCOR	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	-0.11	.	.	.	.	.	.	.	.
PGE	RDMD_RDBT_V1291	.	.	.	.	.	.	.	.	.	.	.	.	.	-0.02	.	-0.02	.	.	-0.02	-0.01	0.04	-0.02	-0.02	-0.02	-0.02
PNM	CZ345kV	0.05	.	.	0.05	0.04	.	.	-0.77	.	-2.60	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvWE_So_El	.	.	.	.	.	.	.	1.03	.	-0.56	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvLK	.	.	.	.	.	.	.	-0.79	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115WTGatPEGS	.	.	.	.	.	.	.	.	.	-0.67	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	FRCE-PINT1	.	.	.	.	.	.	.	-0.10	.	-0.19	.	0.00	.	.	.	.	.	.	.	.	.	.	.	.	.
	LunaPNM345_115X	.	.	.	.	.	.	.	0.10	.	0.05	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvGYTH	.	.	.	.	.	.	.	.	.	-0.14	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Other	0.28	0.02	0.04	0.02	0.30	-0.03	-0.05	-0.03	-0.02	-0.02	-0.05	-0.05	-0.04	-0.02	-0.01	0.00	-0.05	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.01
	Total	4.94	6.01	8.39	-4.02	-1.24	-5.93	-5.05	-5.10	-2.87	-8.24	-5.08	-4.92	-4.95	1.73	0.26	1.02	-1.27	2.61	1.89	1.98	2.23	2.10	1.95	1.94	1.96

4.3 Congestion rent and loss surpluses

Figure 4.5 shows that in the fourth quarter of 2024, congestion rent and loss surpluses were $205 million and $39 million, respectively.[32] These amounts represent a decrease of 9 percent and a decrease of 13 percent relative to the same quarter of 2023. The reduction in the congestion component can be attributed to decreased congestion rent from internal constraints and intertie congestion rent. The

31 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.

32 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.

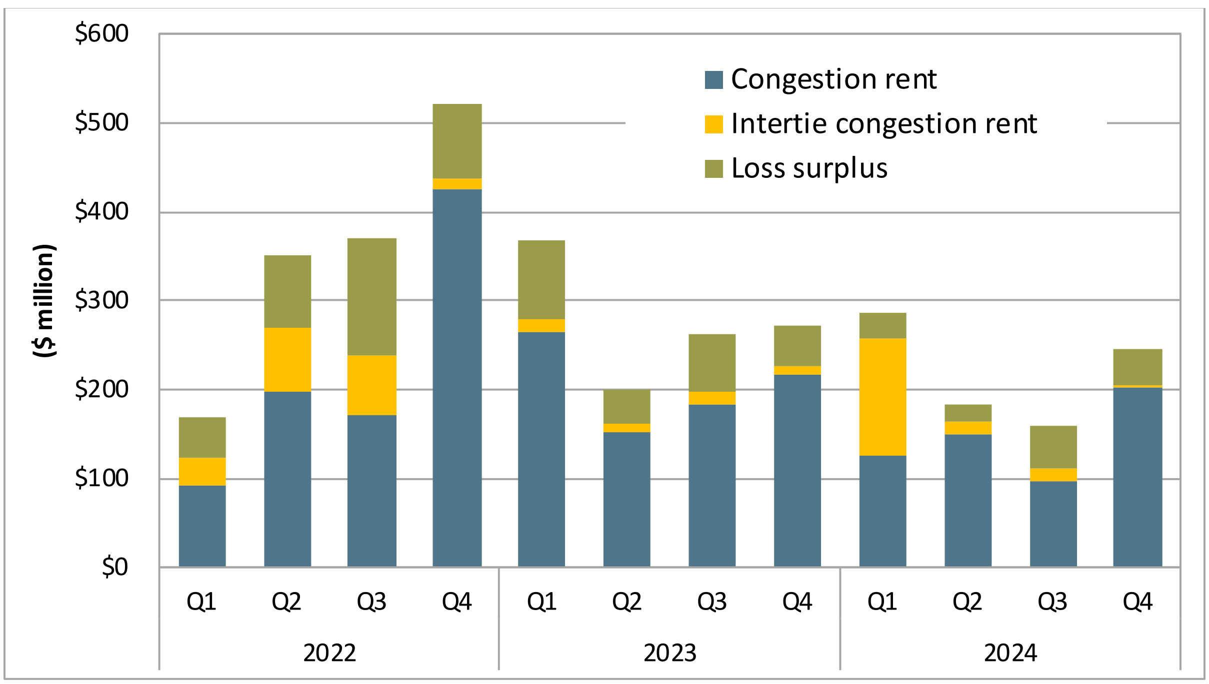
reduction in the loss component was due to lower energy prices in this quarter compared to the same period in 2023.

Congestion rent consists of rents from internal constraints and interties. Intertie congestion decreased from $8 million to $2 million this quarter compared to the same quarter in 2023.

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 13 percent decrease in the loss surplus compared to Q4 2023 can largely be attributed to lower system energy costs. The loss surplus represents the difference between what load pays for the loss component of the locational marginal price (LMP) and what generation gets paid from the loss component of LMP in the day-ahead market. The magnitude of the loss component of LMP is directly proportional to the energy component of LMP, so the loss surplus values should correlate with electricity prices and load quantities over time. In settlements, the loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[33]

Figure 4.5 Day-ahead congestion rent and loss surplus by quarter (2022-2024)



[33] For more information on marginal loss surplus allocation, refer to: *Business Practice Manual Change Management – Settlements and Billing,* CG CC6947 IFM Marginal Losses Surplus Credit Allocation, California ISO: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

4.4 Congestion on interties

Total intertie congestion rent in the day-ahead market was $2 million, down from $8 million in the third quarter of 2023. The major driver was zero export congestion on Malin. The export congestion rent on this intertie decreased from $4 million in the fourth quarter of 2023 to zero in this quarter. In addition, the total congestion rent on the NOB intertie decreased from $8.5 million in the fourth quarter of 2023 to $6.4 million in this quarter.

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

Figure 4.6 shows total intertie congestion charges in the day-ahead market from the fourth quarter of 2023 to the fourth quarter of 2024. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 4.7 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 4.3 provides a detailed summary of congestion rent and frequency over a broader set of interties distinguishing by imports and exports. As highlighted in these charts and table:

- Compared to the fourth quarter of 2023, the total intertie congestion rent decreased from $8 million to $2 million. Both import and export congestion rent dropped, with import congestion falling by 48 percent and export congestion by 88 percent.
- The majority of congestion occurred in the import direction at Malin and IPP Utah. Notably, import congestion at IPP Utah increased significantly, rising from $0.2 million to $0.8 million.
- Import congestion on IPP Utah accounted for 34 percent of the total intertie congestion rent in this quarter. The shadow prices and binding limits on this intertie remained similar between Q4 2023 and Q4 2024, but the frequency of congestion increased significantly.

Figure 4.6 Day-ahead congestion charges on major interties

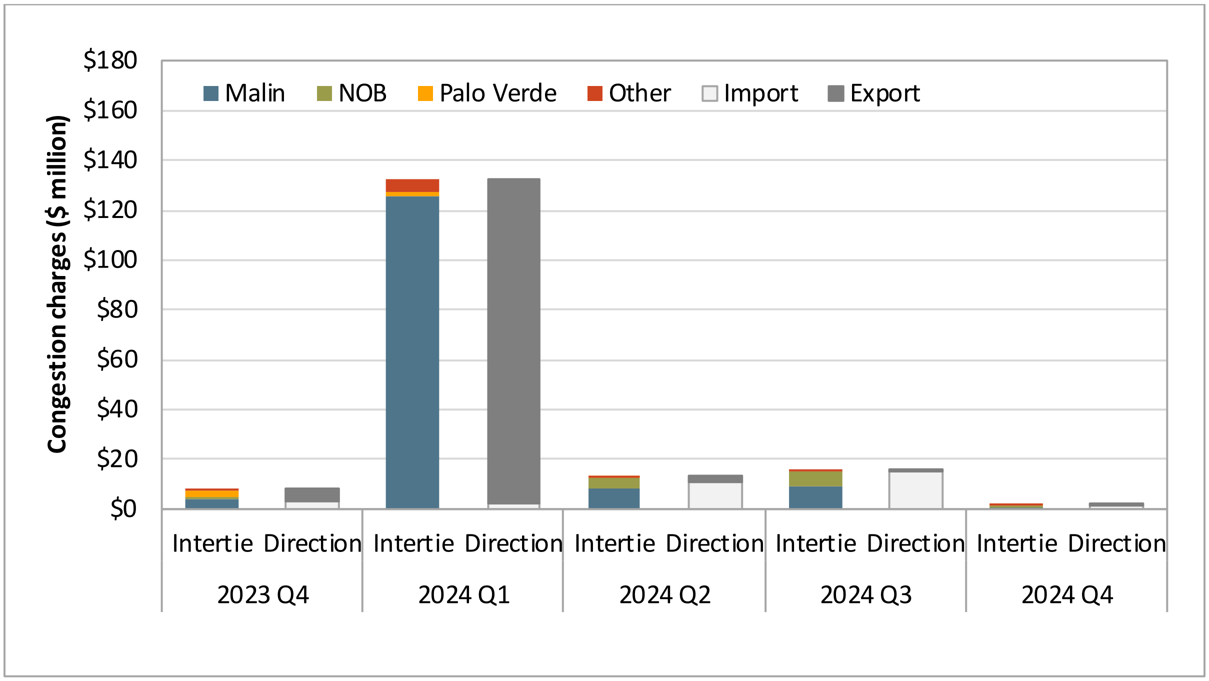


Figure 4.7 Frequency of congestion on major interties in the day-ahead market

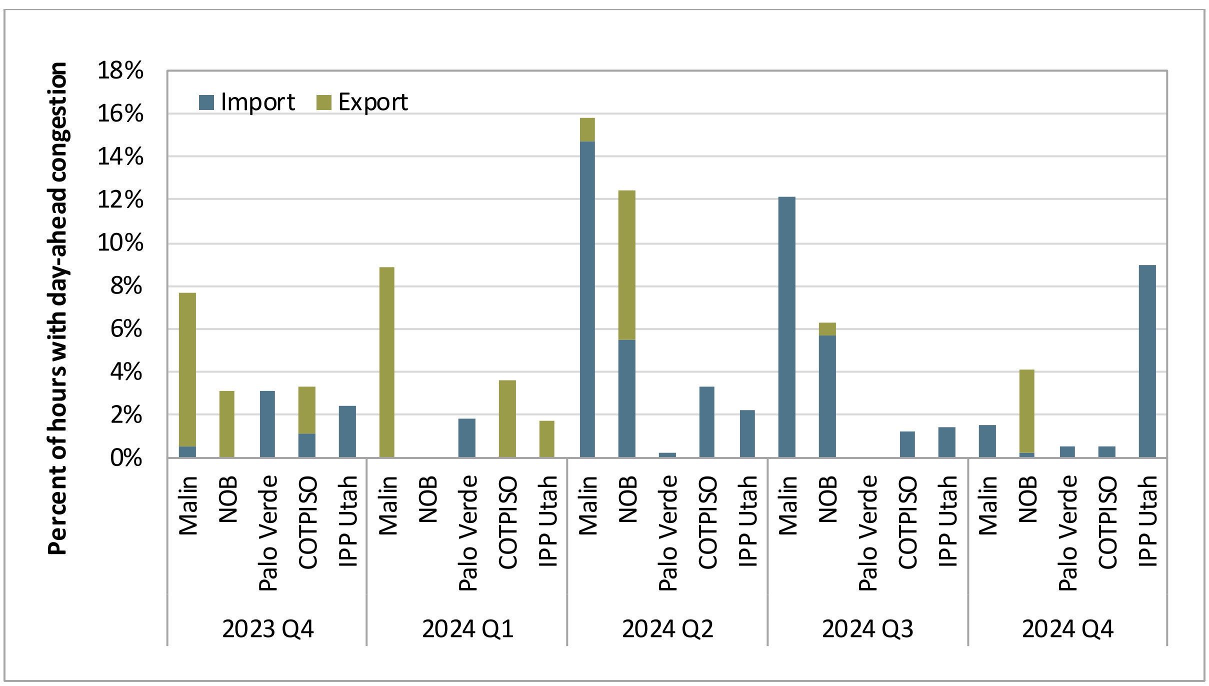


Table 4.3 Summary of intertie congestion in day-ahead market (2023-2024)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4
Northwest											
Malin	I	$243		$8,229	$8,805	$396	0.5%		14.7%	12.1%	1.5%
	E	$3,866	$125,571	$292			7.2%	8.8%	1.1%		
NOB	I			$2,608	$5,947	$76			5.5%	5.7%	0.3%
	E	$851		$1,665	$103	$573	3.1%		7.0%	0.6%	3.8%
COTPISO	I	$103	$1	$98	$14	$26	1.1%	0.0%	3.3%	1.3%	0.5%
	E	$55	$1,367				2.2%	3.5%			
Cascade	I										
	E		$2,147					8.0%			
Summit	I	$5		$14			0.2%		0.8%		
	E										
Southwest											
Palo Verde	I	$2,593	$1,909	$61		$412	3.1%	1.8%	0.3%		0.5%
	E										
IPP Utah	I	$186		$141	$115	$782	2.4%		2.2%	1.4%	9.0%
	E		$401					1.7%			
IPP DC Adelanto	I										
	E		$1,071					4.0%			
Mona	I				$19	$3				0.2%	0.0%
	E	$143	$75	$180	$712		0.7%	0.4%	2.2%	1.5%	
Mead	I		$1	$23				0.0%	0.2%		
	E										
Merchant	I										
	E										
Silver Peak	I										
	E										
Mercury	I										
	E										
Other	I	$81		$8	$0	$0					
	E		$58	$70	$0						
Import total (I)		$3,213	$1,911	$11,182	$14,900	$1,696					
Export total (E)		$4,915	$130,690	$2,207	$815	$573					
Total		$8,128	$132,601	$13,389	$15,715	$2,268					

* I: import, E: export

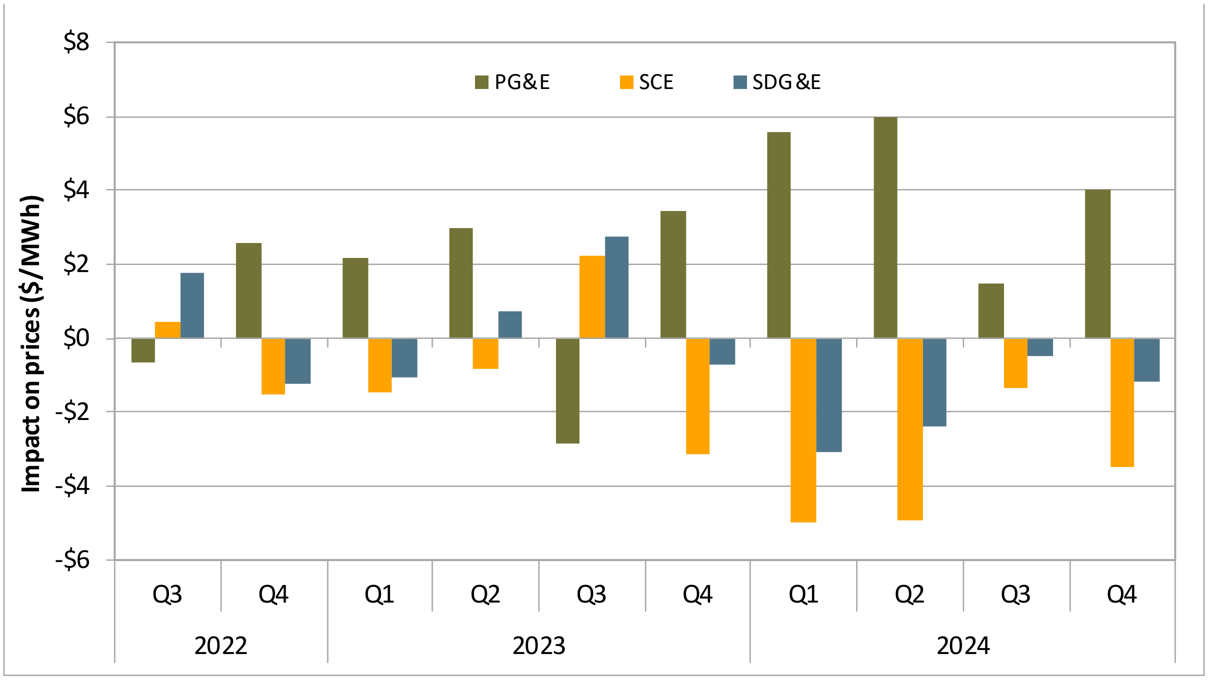
4.5 Internal congestion in the day-ahead market

Figure 4.8 shows the overall impact of congestion on day-ahead market prices in each load area from Q3 2022 to Q4 2024. Figure 4.9 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in this quarter was slightly higher compared to the same quarter in 2023, with a general trend of south-to-north congestion.

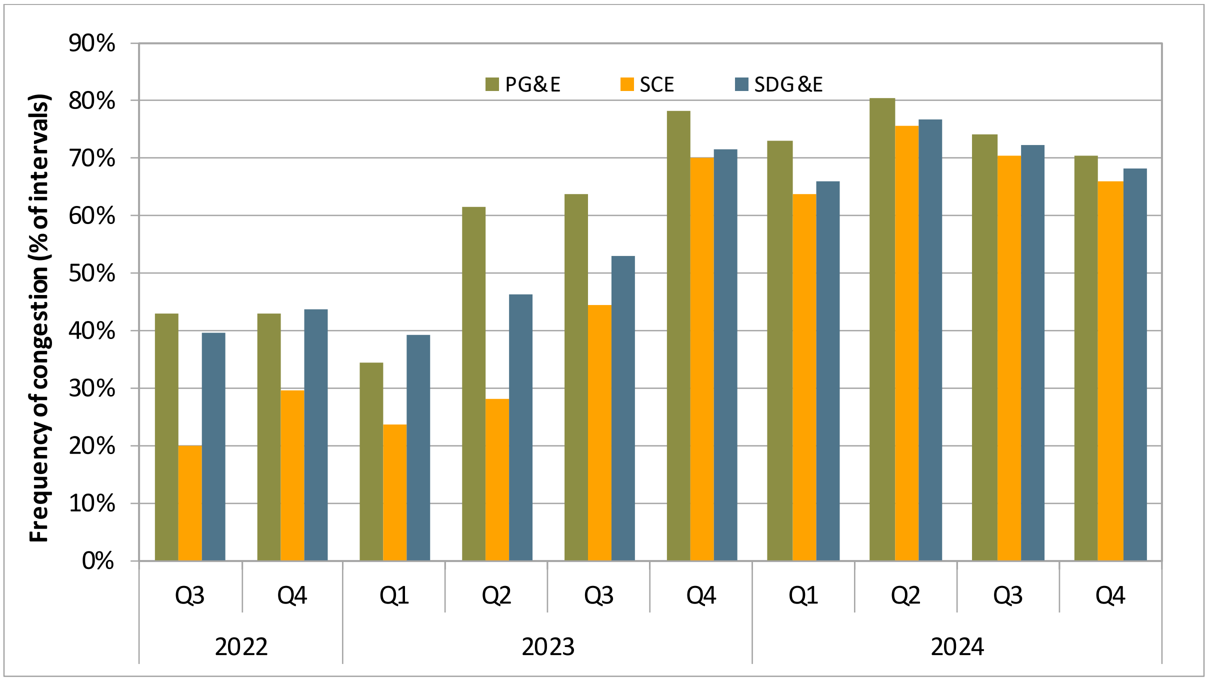
- Day-ahead congestion increased quarterly average prices in PG&E by $4/MWh, while it decreased average SCE and SDG&E prices by $3.5/MWh and $1.2/MWh, respectively.[34]
- The percentage of hours in which congestion impacted DLAP prices remained high this quarter, with PG&E experiencing congestion during an average of 70 percent of hours.
- The primary constraints affecting day-ahead market prices were the Los Banos-Gates #1 500kV, Panoche-Gates #2 230kV, and Gates-Midway #1 500kV lines.

Figure 4.8 Overall impact of congestion on price separation in the day-ahead market



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

Figure 4.9 Hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 4.4 breaks down the congestion effect on price separation during the quarter by constraint.[35] 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 tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact to prices, while blue represents a negative impact—the stronger the shading, the greater the impact in either the positive or the negative direction.

The constraints with the greatest impact on day-ahead price separation for the quarter were the Los Banos-Gates #1 500kV, Panoche-Gates #2 230kV, and Gates-Midway #1 500kV lines.

Los Banos-Gates #1 500kV line

The Los Banos-Gates #1 500kV (30050_LOSBANOS_500_30055_GATES1_500_BR_1_3) bound in 7.3 percent of hours over the quarter. For the quarter, congestion on the constraint increased average PG&E prices by $0.89/MWh and decreased average SCE and SDG&E prices by $0.73/MWh and $0.68/MWh, respectively. This transmission line was generally binding during solar generation hours, from hour-ending 10 through hour-ending 15.

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

Panoche-Gates #2 230kV line

The Panoche-Gates #2 230kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) bound in about 22 percent of hours. For the quarter, the constraint increased average PG&E prices by about $0.83/MWh, and decreased average SCE and SDG&E prices by $0.66/MWh and $0.62/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 9 through hour-ending 15.

Gates-Midway #1 500kV line

The Gates-Midway #1 500kV (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) bound in 12 percent of hours over the quarter. For the quarter, congestion on the constraint increased average PG&E prices by $0.53/MWh and decreased average SCE and SDG&E prices by $0.43/MWh and $0.41/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 8 through hour-ending 15.

Other notable constraints include transmission lines through the Imperial Valley to the metropolitan San Diego area. These constraints frequently experienced congestion, which specifically drove up prices for SDG&E.

Table 4.4 Impact of congestion on day-ahead prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	7.3%	0.89	-0.73	-0.68
30790_PANOCHE_230_30900_GATES_230_BR_2_1	21.7%	0.83	-0.66	-0.62
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	11.5%	0.53	-0.43	-0.41
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	7.5%	0.45	-0.37	-0.35
7820_TL23040_IV_SPS_NG	16.8%	-0.12	-0.03	1.00
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	15.3%	0.40	-0.32	-0.30
7820_TL230S_OVERLOAD_NG	16.2%	-0.10	-0.04	0.73
30900_GATES_230_30970_MIDWAY_230_BR_1_1	5.2%	0.19	-0.15	-0.14
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	7.2%	0.17	-0.13	-0.13
30797_LASAGUIL_230_30790_PANOCHE_230_BR_1_1	8.8%	0.17	-0.13	-0.12
MIGUEL_BKs_MXFLW_NG	2.0%	-0.05	-0.01	0.33
30056_GATES2_500_30060_MIDWAY_500_BR_2_1	2.5%	0.14	-0.11	-0.11
32056_CORTINA_60.0_30451_CRTNAM_1.0_XF_1	8.9%	0.08	-0.07	-0.08
24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	2.3%	-0.09	0.07	0.03
30440_TULUCAY_230_30460_VACA-DIX_230_BR_1_1	1.1%	0.06	-0.05	-0.05
22846_SANJCP_230-22260_ESCNDO_230-BR1	0.6%	0.00	0.01	-0.09
24074_LAFRESA_230_24065_HINSON_230_BR_1_1	1.4%	-0.02	0.04	-0.02
32214_RIOOSO_115_30330_RIOOSO_230_XF_1	5.9%	0.04	-0.02	-0.02
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	0.5%	-0.01	0.00	0.06
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	0.8%	0.02	-0.02	-0.02
OMS_16942670_IV-SXOutage_NG	0.3%	-0.01	0.00	0.05
22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	3.4%	0.00	0.00	0.05
33020_MORAGA_115_32790_STATINX_115_BR_4_1	4.4%	0.02	-0.01	-0.01
HUMBOLDT_IMP_NG	31.7%	0.02	-0.01	-0.01
34418_KINGSBRG_115_34428_CONTADNA_115_BR_1_1	2.2%	0.02	-0.01	-0.01
Other		0.39	-0.33	-0.28
Total		4.02	-3.51	-1.20

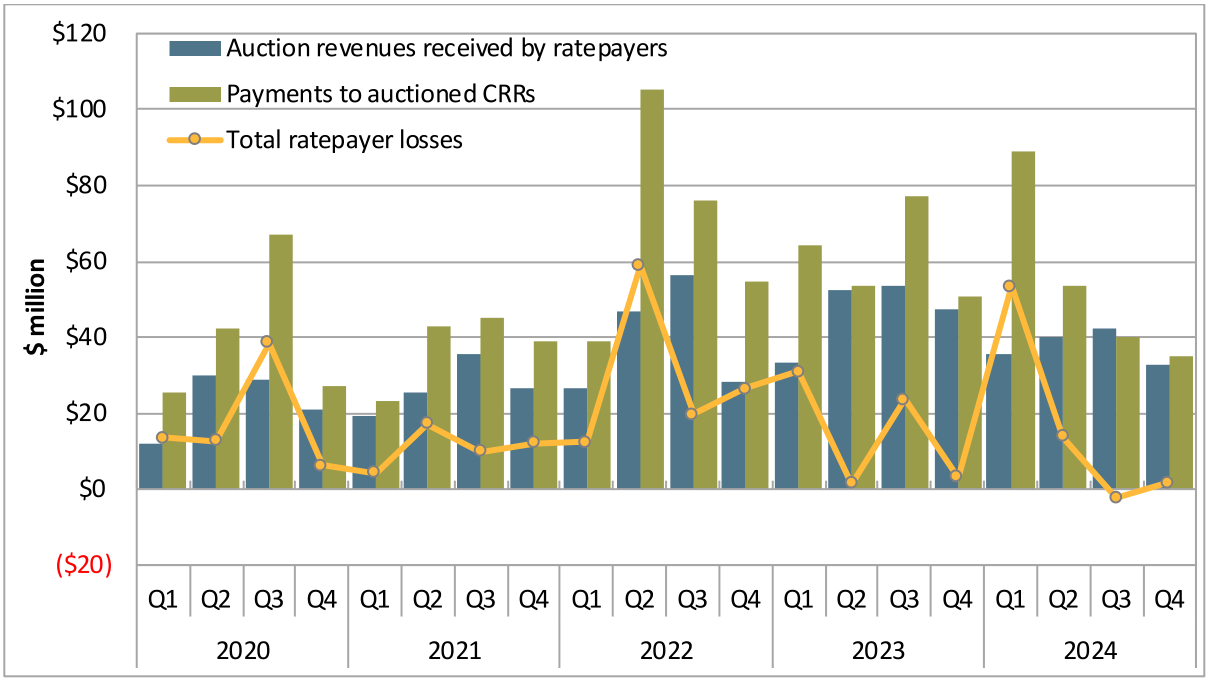
4.6 Congestion revenue rights

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.

As shown in Figure 4.10, transmission ratepayers lost $1.7 million during the fourth quarter of 2024, as payments to auctioned congestion revenue rights holders were higher than auction revenues.

Figure 4.10 Auction revenues and payments to non-load serving entities



During the fourth quarter of 2024:

- Financial entities recorded a loss of $0.4 million, in contrast to a $1.2 million profit in the same quarter of 2023. Total revenue deficit offsets were about $14 million.[36]
- Marketers had a profit of $1 million from auctioned rights, in contrast to a $0.6 million loss in the same quarter of 2023. Total revenue deficit offsets were over $6 million.
- Physical generation entities had a profit of $1.1 million from auctioned rights, down from $2.7 million in Q3 2023. Total revenue deficit offsets were $0.7 million.

The $1.7 million in fourth quarter 2024 auction loss was about 0.08 percent of day-ahead congestion rent. This is down from 0.14 percent from the previous quarter. 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).[37,38]

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

36 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.

37 *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

38 *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

estimates that changes in the settlement of congestion revenue rights made under track 1B reduced total payments to non-load serving entities by about $21 million in the fourth quarter. The track 1B effects on auction bidding behavior and reduced auction revenues are not known.

Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction consistently 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.[39]

[39] *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

5 Resource sufficiency evaluation

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

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

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

If an area that has not opted in to assistance energy transfers fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[40] If an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

5.1 Frequency of resource sufficiency evaluation failures

Figure 5.1 and Figure 5.2 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 5.3 and Figure 5.4 provide the same information for the downward direction.[41] The dash indicates the area did not fail the test during the month.

In the fourth quarter of 2024:

- Public Service Company of New Mexico (PNM) failed the upward flexibility test relatively frequently, in around 2.5 percent of intervals. This was most common during November (around 7 percent of intervals). PNM also failed the upward capacity test in around 1.2 percent of intervals.
- All other balancing areas failed each test type in less than one percent of intervals.

[40] 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.

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

Figure 5.1 Frequency of upward capacity test failures by month and area (percent of intervals)

	2023			2024											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	0.0	—	0.1	—	—	—	—	—	—	—	—	—	—	—	0.1
Avangrid	—	—	—	—	—	—	—	—	—	0.1	—	—	—	—	—
Avista	0.0	0.1	—	0.3	0.1	—	—	—	—	0.1	—	—	0.1	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	0.3	—	—	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	0.1	—	—	—	—	0.1	0.2	0.6	0.1	0.3	0.1	0.0	—	0.1	0.0
Idaho Power	—	0.1	—	0.0	—	—	—	—	—	—	—	—	—	—	—
LADWP	—	—	0.0	0.1	0.0	—	0.0	0.0	—	0.1	0.3	—	—	—	—
NorthWestern En.	—	—	—	—	0.1	—	—	—	—	—	—	0.3	—	—	0.3
NV Energy	0.0	—	—	—	—	—	—	0.1	0.0	0.1	0.0	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	0.8	0.0	—	0.1	0.0	—	—	—	—	0.1	0.3	0.0
Portland Gen. Elec.	0.0	0.6	—	—	—	—	—	0.0	0.1	0.0	—	—	—	—	—
Powerex	0.0	0.0	—	—	—	—	—	—	—	—	—	—	—	—	—
PSC of New Mexico	0.1	—	0.1	—	—	—	0.1	0.1	0.1	0.3	0.1	—	0.4	3.1	—
Puget Sound En.	0.7	1.0	0.2	0.8	0.1	0.2	0.3	0.2	—	0.2	0.1	—	0.1	—	0.1
Salt River Proj.	0.8	0.2	0.1	0.1	0.1	0.2	0.1	—	0.2	0.1	0.1	0.2	0.1	—	—
Seattle City Light	0.1	0.6	—	0.5	—	—	0.4	—	0.0	0.4	0.1	0.1	0.3	0.0	0.1
Tacoma Power	0.1	0.0	—	—	—	0.3	—	0.0	—	—	—	—	0.0	0.1	—
Tucson Elec. Pow.	0.2	—	—	—	—	—	—	—	—	0.0	—	0.0	—	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	0.3	0.4	0.1	—	—	0.1	—	0.5	0.3	0.2	0.2	—	0.1	—	—

Figure 5.2 Frequency of upward flexibility test failures by month and area (percent of intervals)

	2023			2024											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	0.2	0.1	0.2	0.1	0.5	0.1	0.3	—	0.0	0.0	—	—	—	0.1
Avangrid	0.1	0.1	0.2	0.2	0.1	0.1	0.0	0.2	0.5	0.2	—	0.1	0.5	0.1	0.4
Avista	0.1	0.1	—	0.1	—	0.1	—	—	—	0.1	—	—	0.0	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	0.1	—	—	0.4	0.0	—	0.1	0.1	0.1	0.3	0.3	0.0	—	0.1	0.1
California ISO	—	—	—	—	—	—	—	—	—	0.0	—	—	—	—	—
El Paso Electric	0.4	0.2	0.1	0.3	0.0	1.0	0.9	1.0	0.9	0.6	0.8	0.3	0.2	0.3	0.4
Idaho Power	0.1	—	—	1.1	—	0.1	0.6	0.6	0.1	0.1	—	—	0.0	—	—
LADWP	—	—	0.1	0.1	—	0.1	0.4	0.1	0.0	0.3	0.3	0.0	—	0.1	—
NorthWestern En.	0.2	0.0	0.1	0.5	0.1	0.0	0.0	0.1	0.3	0.2	—	0.4	0.1	0.2	0.2
NV Energy	—	0.1	0.0	—	0.1	0.0	—	0.1	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	0.0	0.0	—	—	0.1	—	0.1	0.0	—
PacifiCorp West	0.0	0.0	0.1	1.0	—	0.1	—	—	0.1	—	—	—	—	0.3	0.1
Portland Gen. Elec.	0.6	0.0	—	—	—	0.0	—	0.2	0.2	—	—	0.0	0.1	—	—
Powerex	—	—	—	0.2	—	—	—	—	—	0.6	—	—	—	—	—
PSC of New Mexico	1.9	1.9	0.3	2.0	2.3	0.4	1.8	1.1	1.2	1.0	1.0	0.9	0.3	7.1	0.2
Puget Sound En.	1.3	1.9	0.5	0.8	0.1	0.2	0.4	0.5	0.5	0.7	0.3	—	0.4	—	0.5
Salt River Proj.	0.6	0.4	0.2	0.2	0.1	0.7	0.4	0.1	0.3	0.3	0.4	0.5	0.2	—	—
Seattle City Light	0.0	—	—	0.3	—	0.1	0.1	0.1	—	—	—	0.0	0.1	0.1	—
Tacoma Power	0.2	0.0	—	0.1	0.0	0.4	0.0	0.0	—	—	—	—	—	0.1	0.0
Tucson Elec. Pow.	0.1	0.2	0.1	0.0	0.2	—	0.1	0.1	—	0.1	0.3	0.7	0.2	0.1	0.1
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	0.3	0.5	0.1	1.1	2.5	3.5	0.3	0.8	0.2	—	—	—	0.2	—	0.1

Figure 5.3 Frequency of downward capacity test failures by month and area (percent of intervals)

	2023			2024											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	—	0.8	0.1	0.0	0.1	0.2	—	—	—	—	0.4	—	—	—
Avangrid	—	0.3	—	—	—	—	—	—	—	—	—	—	—	—	—
Avista	—	—	—	—	—	0.1	—	—	—	—	—	—	0.0	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.1
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	—	—	—	0.2	—	0.4	0.2	0.4	0.3	0.1	0.1	0.0	0.1	0.0	—
Idaho Power	—	—	—	—	—	—	0.5	—	—	—	—	—	—	—	—
LADWP	—	—	—	—	—	—	—	—	—	—	—	0.0	—	—	—
NorthWestern En.	—	—	—	—	—	—	—	—	—	—	—	0.1	—	0.0	—
NV Energy	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	—	—	—	—	—	0.0	—	—	—	—	—	—	0.1	—
PSC of New Mexico	—	—	—	—	—	—	—	—	—	0.1	—	—	—	0.2	—
Puget Sound En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Salt River Proj.	0.1	—	—	—	0.1	0.1	0.4	0.7	—	—	0.2	—	—	—	0.3
Seattle City Light	—	0.1	0.2	0.0	—	—	—	—	—	0.3	—	—	—	0.1	0.0
Tacoma Power	—	—	—	—	—	—	—	—	0.0	0.1	0.0	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	0.2	0.2	—	—	—	—	—	—	—	0.1	—	—	—	—	—

Figure 5.4 Frequency of downward flexibility test failures by month and area (percent of intervals)

	2023			2024											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	—	0.3	0.1	0.1	0.2	0.1	—	—	—	—	—	—	0.3	0.2
Avangrid	—	—	—	0.1	—	—	—	—	—	—	—	—	—	—	—
Avista	—	0.1	—	—	0.0	—	—	—	—	0.1	—	0.0	0.6	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	0.2	—	—	0.4	0.1	—	0.0	0.1	0.1	—	—	—	—	—	0.8
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	—	0.2	0.3	0.3	0.2	0.4	0.8	0.7	0.1	—	0.1	—	0.0	—	0.2
Idaho Power	—	0.1	—	—	—	0.0	1.0	—	—	—	—	—	—	—	—
LADWP	—	—	—	—	—	—	—	—	—	—	—	0.1	—	—	—
NorthWestern En.	—	—	—	0.2	—	0.1	—	0.3	0.2	0.2	0.1	0.0	2.2	0.2	0.1
NV Energy	0.1	0.1	—	—	—	0.1	0.0	—	0.1	—	—	—	—	—	—
PacifiCorp East	0.1	—	—	—	0.2	0.0	0.5	0.2	0.0	0.0	—	0.1	—	—	—
PacifiCorp West	—	0.1	—	—	—	0.2	—	—	—	—	—	—	0.0	0.0	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.1	—	0.1	—	0.1	0.4	0.0	—	—	1.1	0.2	—	—	0.1	—
PSC of New Mexico	0.4	0.2	0.2	0.9	0.9	0.4	0.0	0.6	0.1	0.1	0.0	0.9	0.3	2.0	0.1
Puget Sound En.	—	—	—	—	—	—	—	—	—	0.1	—	—	—	—	—
Salt River Proj.	—	0.1	0.0	0.1	0.1	0.7	0.7	0.7	0.0	—	—	—	0.1	—	0.5
Seattle City Light	—	0.8	0.2	0.2	0.1	0.1	0.2	—	0.1	0.5	0.1	—	0.0	0.2	0.1
Tacoma Power	—	0.0	—	—	0.0	—	—	—	—	—	—	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	0.1	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	0.1	—	—	0.0	—	—	0.2	0.0	—	0.0	—	0.1	0.1	—
WAPA DSW	0.8	0.2	0.1	0.3	0.1	0.0	0.0	—	—	0.1	0.0	0.1	—	0.0	—

5.2 Assistance energy transfers

The assistance energy transfer (AET) option gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Without AET, a balancing area failing either the upward flexibility or upward capacity test would have net WEIM imports limited to the greater of either the base transfer or the optimal transfer from the last 15-minute market interval. Balancing areas can voluntarily opt in to the AET program to prevent their WEIM transfers from being limited during an upward resource sufficiency evaluation failure, but will be subject to an ex-post surcharge. Balancing areas must opt in or opt out of the program in advance of the trade date.[42]

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.[43] 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 5.1 shows the days in which a balancing area was opted in to receiving assistance energy transfers during the third quarter. Eight balancing areas were opted in to the program on at least one day during this period: Avangrid, CAISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, and WAPA Desert Southwest.[44] Avangrid, NorthWestern Energy, and NV Energy were opted in to AET during all days during the quarter (92 days).

[42] 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

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

[44] The CAISO balancing area can opt in to assistance energy transfers based on upcoming system conditions and operator experience. For more information, see the *Business Practice Manual for the Western Energy Imbalance Market*, section 11.3.2: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market

Table 5.1 Assistance energy transfer opt-in designations by balancing area (October–December 2024)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Oct. 1 - Dec. 31	92
California ISO	Oct. 1 - Oct. 8, Nov. 7	9
Idaho Power	Oct. 1 - Oct. 31, Nov. 6 - Dec. 31	87
NorthWestern Energy	Oct. 1 - Dec. 31	92
NV Energy	Oct. 1 - Dec. 31	92
PacifiCorp East	Oct. 24 - Dec. 31	69
PacifiCorp West	Oct. 24 - Dec. 31	69
WAPA Desert Southwest	Oct. 1 - Oct. 15	15

Table 5.2 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during the quarter and its impact following a resource sufficiency evaluation failure. First, the table shows the number of 15-minute intervals in which a balancing area failed the upward resource sufficiency evaluation after opting in to AET. These are the intervals in which the WEIM import limit following the test failure was removed—giving the WEIM entity access to WEIM supply that may not have been available otherwise. During the quarter, five balancing areas (Avangrid, Idaho Power, NorthWestern Energy, PacifiCorp East, and PacifiCorp West) failed the resource sufficiency evaluation during at least one interval while opted in to the program.

Table 5.2 also shows the percent of failure intervals in the 5-minute market in which the balancing area achieved additional WEIM imports due to opting in to AET. The table also shows the average and maximum WEIM imports added in the 5-minute market because of AET. During the quarter, Avangrid failed the resource sufficiency evaluation during 30 intervals while opted in to receiving assistance energy transfers. Avangrid achieved an additional 15 MW on average during these intervals (and a maximum of 221 MW).

Table 5.2 Resource sufficiency evaluation failures during assistance energy transfer opt-in (October–December 2024)

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	30	17%	15	221	111
California ISO	9	0	N/A	N/A	N/A	N/A
Idaho Power	87	1	0%	0	0	0
NorthWestern Energy	92	23	15%	3	43	20
NV Energy	92	0	N/A	N/A	N/A	N/A
PacifiCorp East	69	1	0%	0	0	0
PacifiCorp West	69	21	40%	29	235	151
WAPA Desert Southwest	15	0	N/A	N/A	N/A	N/A

Table 5.3 summarizes the total cost from assistance energy transfers. 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 imports.[45] The price is the real-time bid cap, typically $1,000/MWh. Table 5.3 also shows the total cost per *WEIM imports added*. WEIM imports added are measured as net WEIM imports in the 5-minute market above what the limit would have been following the resource sufficiency evaluation failure without opting in to AET.

Table 5.3 Cost of assistance energy transfers (October–December 2024)

Balancing area	RSE failures under AET (15-min. intervals)	Total WEIM imports added (MWh)	Total cost of assistance energy transfers	Total cost per added WEIM imports
Avangrid	30	111	$11,344	$102
California ISO	0	N/A	N/A	N/A
Idaho Power	1	0	$601	N/A
NorthWestern Energy	0	N/A	N/A	N/A
NV Energy	23	20	$49,958	$2,517
PacifiCorp East	1	0	$14,655	N/A
PacifiCorp West	21	151	$69,016	$456
WAPA Desert Southwest	0	N/A	N/A	N/A

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[46] 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.

45 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.

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

6 Real-time imbalance offset costs

Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $56 million in the fourth quarter of 2024.[47,48] This was a decrease from $79 million in the same quarter of 2023. During the fourth quarter of 2024, real-time *congestion* imbalance offset costs made up the majority of these costs ($53 million).

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were an $8 million credit to WEIM entities, compared to a $73 million credit in the fourth quarter of 2023. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $14 million credit. The energy portions of the offset was a $6.5 million charge.

The real-time imbalance offset cost is the difference between the total money *paid out* and the total money *collected* by the California ISO settlement process for energy in the real-time markets. This charge is calculated separately for each balancing area. Any revenue surplus or revenue shortfall within this charge is allocated to measured demand (for the California ISO balancing area) or the WEIM entity scheduling coordinator (for the WEIM balancing areas).[49]

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the congestion components of real-time energy settlement prices is collected through the *real-time congestion imbalance offset charge* (RTCIO). Similarly, any revenue imbalance from the *loss* component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge,* while any remaining revenue imbalance is *recovered* through the *real-time imbalance energy offset charge* (RTIEO). Figure 6.1 shows monthly imbalance offset costs for balancing areas participating in the day-ahead market by component since 2023.

47 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.

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

49 Measured demand is physical load plus exports.

Figure 6.1 Monthly real-time imbalance offset costs (balancing areas in day-ahead market)

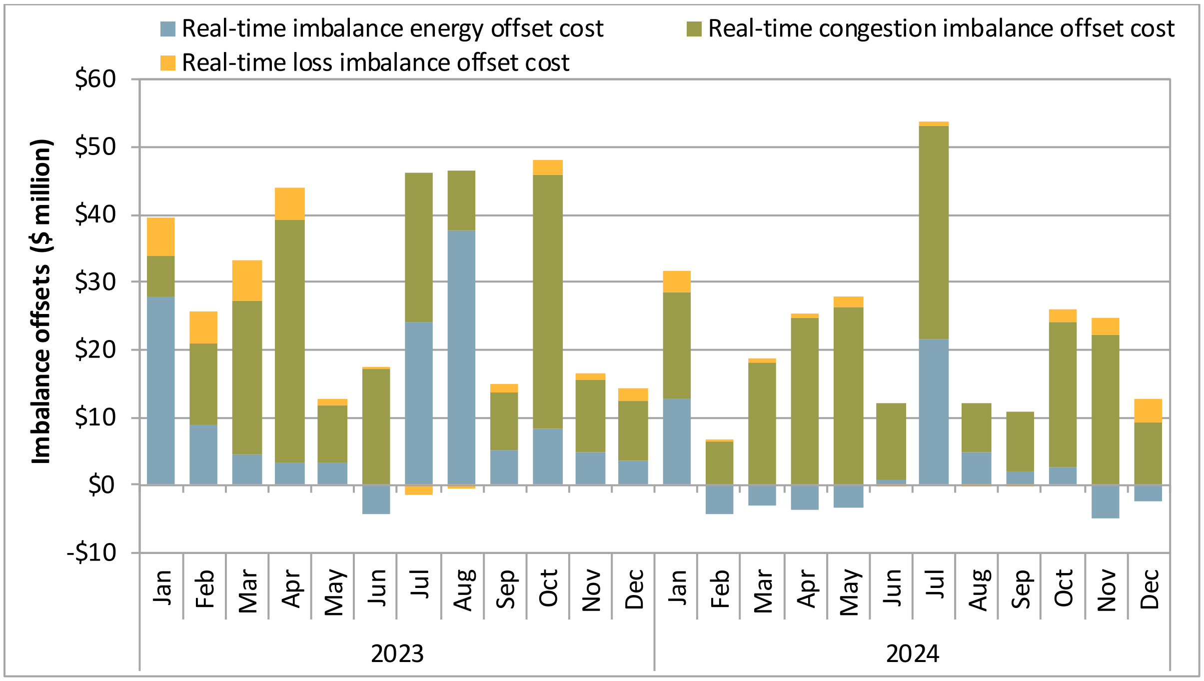


Figure 6.2 shows monthly imbalance offset costs for balancing areas only participating in the WEIM real-time markets. Offset amounts for each balancing area and charge type (energy, congestion, or losses) were assessed as positive or negative over the month, and shown collectively in the corresponding bars. The lighter-colored bars reflect positive amounts (or charges for revenue shortfall), while the darker bars reflect negative amounts (or credits for revenue surplus).

Figure 6.3 through Figure 6.5 show the quarterly real-time energy, congestion, or loss imbalance offsets for each balancing area participating only in the WEIM. Figure 6.6 shows the *total* real-time imbalance offset charges for each quarter and balancing area. Charges for revenue shortfall are shown in red, while credits for revenue surplus are shown in black. The color gradient highlights balancing areas with either greater revenue shortfall (orange) or revenue surplus (blue) over the period. Of note in the fourth quarter:

- Revenue *shortfall* from congestion imbalance offsets for LADWP was $4.9 million (charge). This was mostly from 7 million in revenue shortfall on one day, December 18, associated with congestion on the constraint, *WECC_Path_4.* Here, outages and limited capacity on the Pacific DC Intertie created significant congestion on this constraint, restricting energy flow out of the Los Angeles region.
- Revenue *surplus* from congestion imbalance offsets for PacifiCorp East was $11.4 million (credit).
- Revenue *shortfall* from imbalance energy offsets for NorthWestern Energy was $4.5 million (charge).

Figure 6.2 Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)

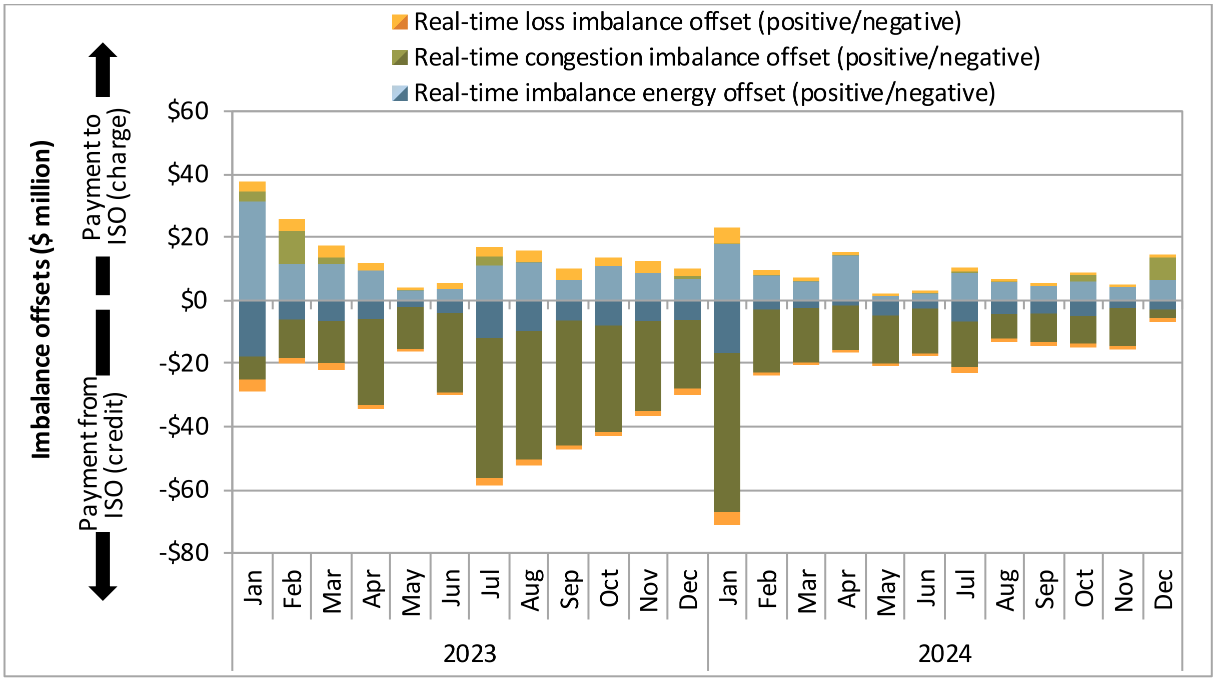


Figure 6.3 Real-time imbalance energy offsets by quarter and balancing area ($ millions)

	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4
Arizona Public Service	4	7	1	4	3
Avangrid	.1	5	8	.3	.5
Avista	.1	.1	.1	.1	.1
BANC	.3	.4	.1	1	.1
Bonneville Power Administration	.2	.6	.3	.5	.6
El Paso Electric	.2	0	0	.3	0
Idaho Power	.6	3	.1	1	.3
LADWP	.2	.2	.2	2	.2
NorthWestern Energy	6	5	1	3	4
NV Energy	2	.9	.2	.6	2
PacifiCorp East	7	3	.7	5	2
PacifiCorp West	8	10	1	6	3
Portland General Electric	.2	.1	0	.4	.1
Powerex	.7	.7	.2	.4	.1
Public Service Company of NM	4	6	1	.9	3
Puget Sound Energy	6	7	2	4	4
Salt River Project	5	4	1	3	2
Seattle City Light	.1	.4	.1	.1	.5
Tacoma Power	0	0	0	0	.1
Tucson Electric Power	.5	.4	.1	0	0
Turlock Irrigation District	.5	.3	.4	.9	.4
WAPA Desert Southwest	.1	0	.1	.3	0

Figure 6.4 Real-time congestion imbalance offsets by quarter and balancing area ($ millions)

	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4
Arizona Public Service	.3	.1	.1	.7	.1
Avangrid	.1	.9	.4	.3	.1
Avista	.4	1	.3	.4	.1
BANC	.1	0	.2	0	0
Bonneville Power Administration	1	.9	.8	2	0
El Paso Electric	1	.3	.7	.8	.1
Idaho Power	2	5	1	1	.1
LADWP	1	2	1	4	5
NorthWestern Energy	.3	1	.2	.1	.7
NV Energy	1	2	1	.2	.3
PacifiCorp East	23	22	7	7	11
PacifiCorp West	2	9	1	1	1
Portland General Electric	3	6	2	1	1
Powerex	36	25	16	6	1
Public Service Company of NM	0	1	1	.5	.7
Puget Sound Energy	4	5	2	2	1
Salt River Project	5	4	5	1	.7
Seattle City Light	.3	.3	.1	.2	.2
Tacoma Power	.1	.2	.1	.1	0
Tucson Electric Power	2	2	3	4	2
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	0	.1	0	0	0

Figure 6.5 Real-time loss imbalance offsets by quarter and balancing area ($ millions)

	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Arizona Public Service	.4	.4	.2	.8	.2
Avangrid	0	.3	.1	.2	.2
Avista	0	0	0	.1	0
BANC	0	.1	0	0	0
Bonneville Power Administration	.1	.9	0	.1	.1
El Paso Electric	.1	.1	0	.2	.1
Idaho Power	.8	.4	.2	.3	.6
LADWP	0	.5	0	0	.3
NorthWestern Energy	.1	.1	0	.1	.1
NV Energy	.3	.4	0	.3	0
PacifiCorp East	2	2	.1	1	2
PacifiCorp West	.4	0	.3	.3	.4
Portland General Electric	.1	2	0	.4	.1
Powerex	7	3	1	1	.6
Public Service Company of NM	.1	0	.1	0	.1
Puget Sound Energy	.1	.5	0	.2	0
Salt River Project	.7	.7	.1	.4	.2
Seattle City Light	.2	.4	.2	.5	.3
Tacoma Power	0	.3	0	0	0
Tucson Electric Power	.4	.3	.1	.4	.3
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	0	.2	0	0	0

Figure 6.6 Total real-time imbalance offsets by quarter and balancing area ($ millions)

	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Arizona Public Service	3	6	1	4	3
Avangrid	.1	4	8	.2	.2
Avista	.3	1	.2	.1	.1
BANC	.3	.5	0	1	.1
Bonneville Power Administration	.6	.6	.5	.9	.7
El Paso Electric	1	.4	.7	.7	.1
Idaho Power	.2	2	1	3	.8
LADWP	1	3	1	2	5
NorthWestern Energy	6	4	1	3	4
NV Energy	.5	1	1	.1	2
PacifiCorp East	18	21	6	3	11
PacifiCorp West	11	19	3	7	4
Portland General Electric	3	4	2	.3	.8
Powerex	30	20	15	4	.7
Public Service Company of NM	4	4	.1	.4	4
Puget Sound Energy	10	11	4	6	5
Salt River Project	10	8	6	4	3
Seattle City Light	0	.4	0	.2	.4
Tacoma Power	.1	.5	.1	0	.2
Tucson Electric Power	1	2	3	4	2
Turlock Irrigation District	.4	.3	.4	.8	.4
WAPA Desert Southwest	0	.1	.1	.4	.1

7 Bid cost recovery

During the fourth quarter of 2024, estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market totaled about $36 million.[50] This was a 59 percent decrease from the $87 million in bid cost recovery in the fourth quarter of 2023. Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM) totaled about $4.4 million. WEIM area bid cost recovery payments decreased about 33 percent from $6.6 million in Q4 2023.[51]

Figure 7.1 shows monthly bid cost recovery payments in the fourth quarter of 2024 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $12.7 million, up from $5 million in the fourth quarter of 2023. Bid cost recovery payments associated with residual unit commitment during the quarter totaled about $6 million, or about $46 million lower than the fourth quarter of 2023. Bid cost recovery associated with the real-time market (green bars) for areas that participate in the day-ahead market totaled about $17.4 million, which was about $12 million lower than the same quarter of 2023.

Figure 7.2 shows monthly bid cost recovery payments paid to units in areas participating only in the WEIM. Bid cost recovery payments to these units were greatest in the Desert Southwest and California[52] regions at $2.8 million and $911,000, respectively. Bid cost recovery payments to the Intermountain West and Pacific Northwest regions totaled around $179,000 and $450,000, respectively.

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. In the fourth quarter of 2024, about $31.4 million of bid cost recovery payments were made to gas resources, 90 percent of which were paid to units participating in both the day-ahead market and the WEIM. About $4.8 million and $1.2 million of payments were made to battery and hybrid resources, respectively.

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

51 The bid cost recovery payment amounts for 2022 and 2023 in this report are different than what is reported in the Q2 2023 report due to resettlements.

52 Figure 7.2 includes only non-CAISO balancing authority areas.

Figure 7.1 Monthly bid cost recovery payments for Day-Ahead Market area

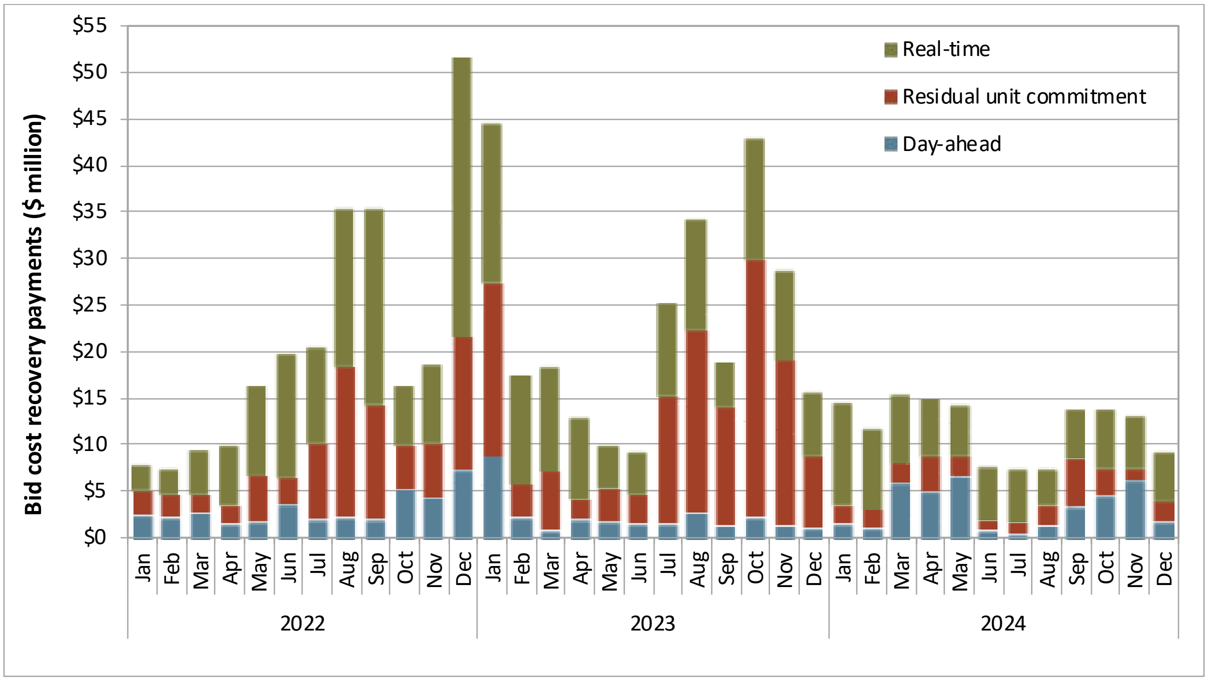
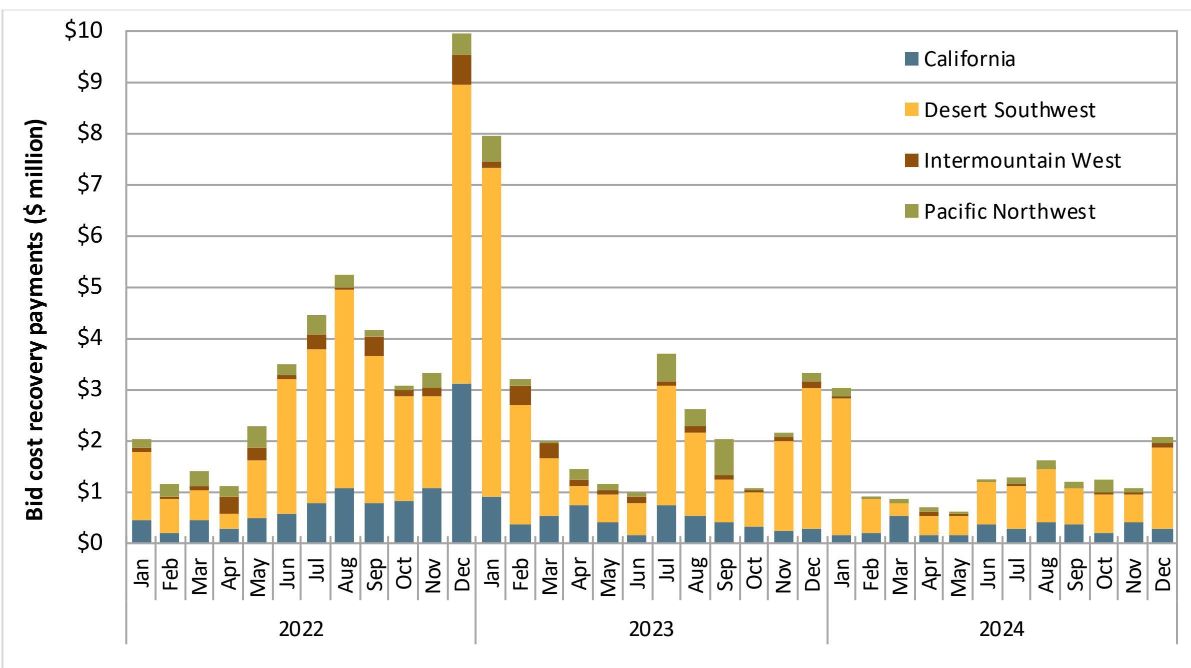


Figure 7.2 Monthly bid cost recovery payments for the WEIM



8 Imbalance conformance

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

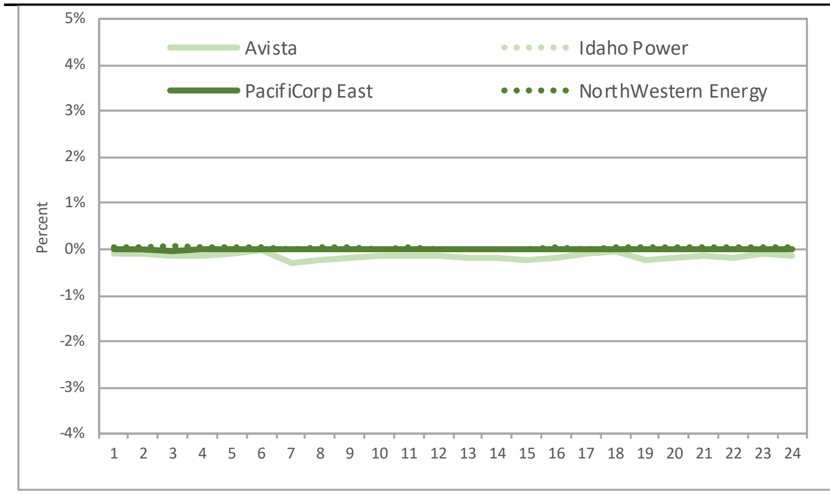
8.1 Imbalance conformance by balancing area

The figures below show fourth quarter 15-minute market and 5-minute market average hourly imbalance conformance for each balancing area as a percentage of the average load of the balancing area.[53] Generally, imbalance conformance levels were much higher in the 5-minute market than the 15-minute market, with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).

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

Figure 8.1 Intermountain West: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q4 2024)

15-minute market



5-minute market

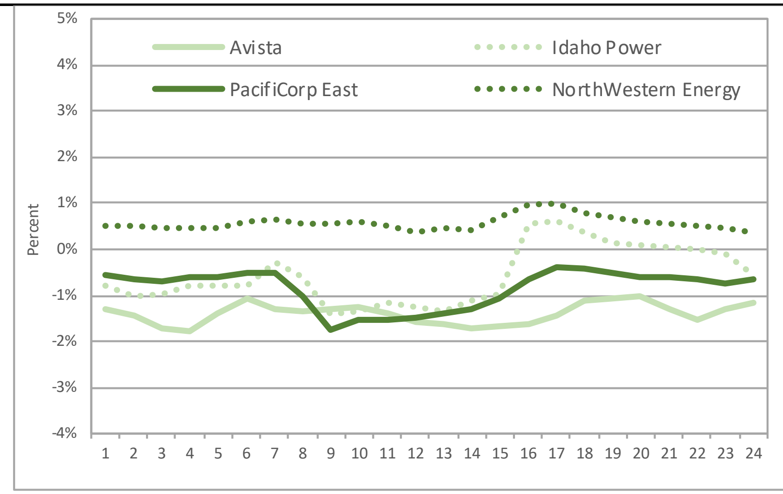
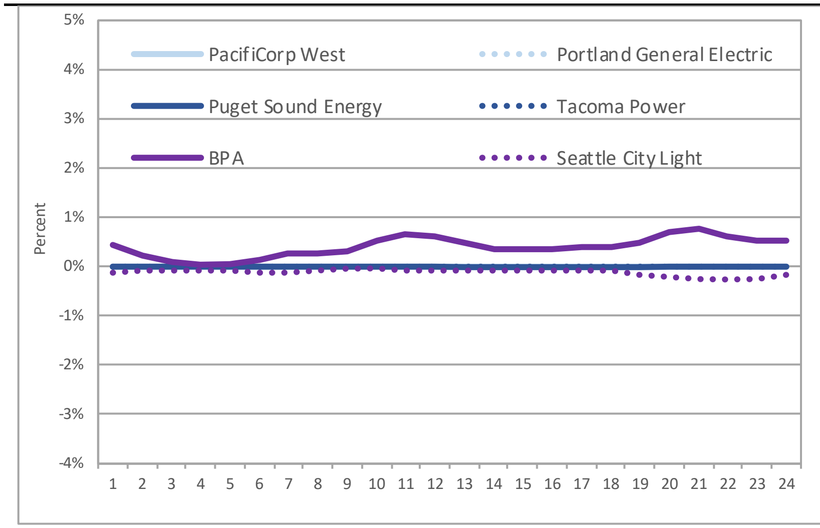


Figure 8.2 Pacific Northwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q4 2024)

15-minute market



5-minute market

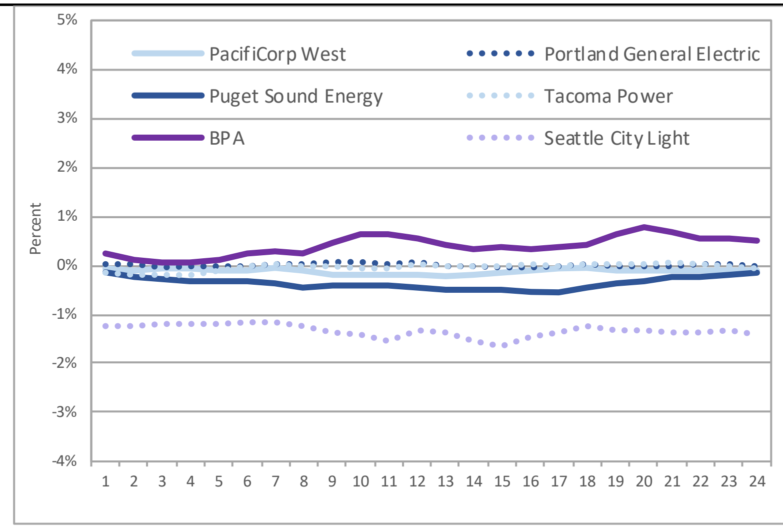
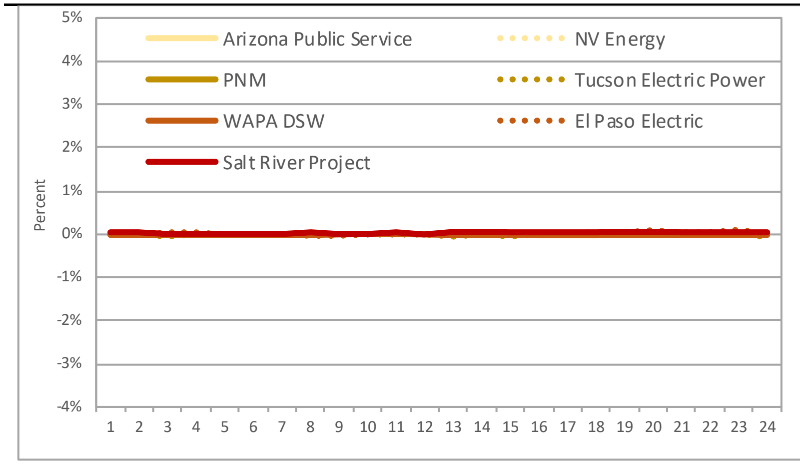


Figure 8.3 Desert Southwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q4 2024)

15-minute market



5-minute market

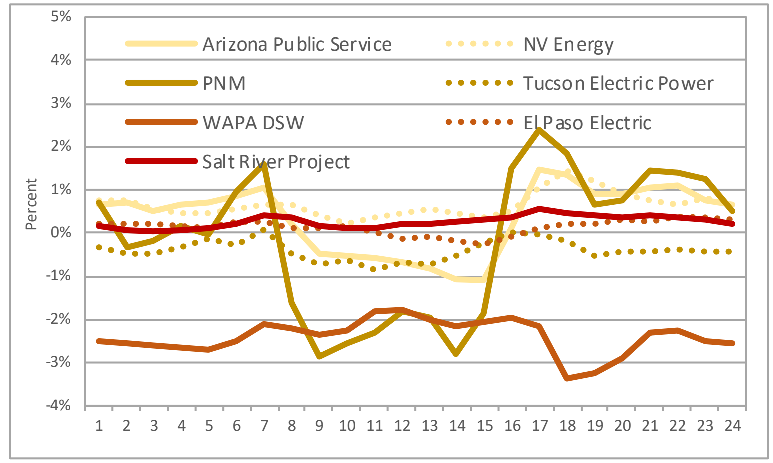
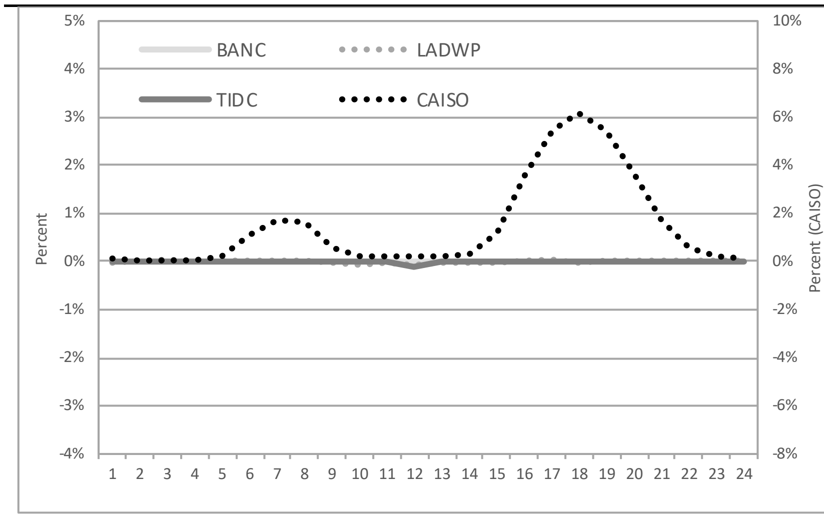
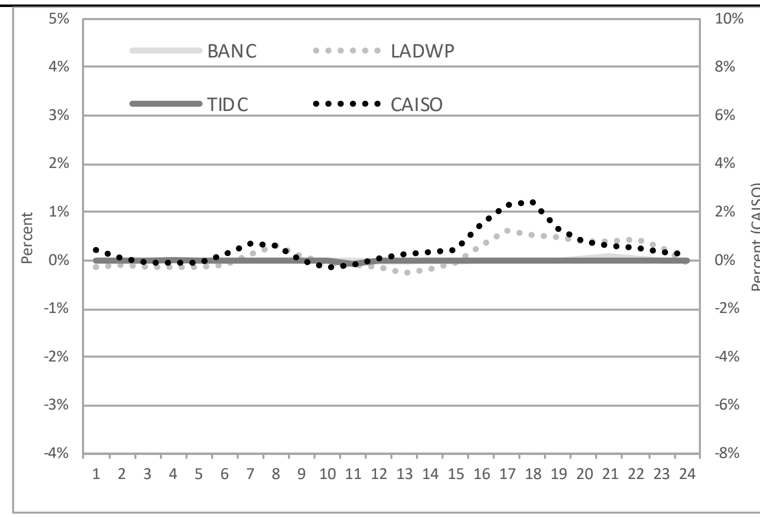


Figure 8.4 California: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q4 2024)

15-minute market



5-minute market



8.2 Imbalance conformance – special report on CAISO balancing area

The size and frequency of CAISO balancing area operators' use of imbalance conformance in the

15-minute market made it an outlier amongst WEIM areas in the fourth quarter of 2024. This section analyzes the use of imbalance conformance by CAISO balancing area operators.

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO balancing area hour-ahead and 15-minute markets. Figure 8.5 shows CAISO area imbalance conformance adjustments in real-time markets for the fourth quarter of 2023 and 2024. Imbalance conformance over the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. This contributes to higher prices in the 15-minute market than in the 5-minute market over these hours.

Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets increased during morning ramp hours and decreased during evening ramp hours in the fourth quarter of 2024 relative to the same quarter of 2023. During the morning hours, the highest average hourly adjustments were around 400 MW. This was an increase from a maximum average of about 125 MW over the morning hours of Q4 2023. Imbalance conformance over the evening peak hours reached about 1,450 MW, about 200 MW lower than the largest average hourly evening adjustments over Q4 2023.

The 5-minute market adjustments were very similar in the fourth quarter of 2024 in all hours compared to the fourth quarter of 2023. These adjustments peaked in hour-ending 18 at about 550 MW.

Figure 8.5 Average CAISO balancing area hourly imbalance conformance adjustment (Q4 2023 and Q4 2024)

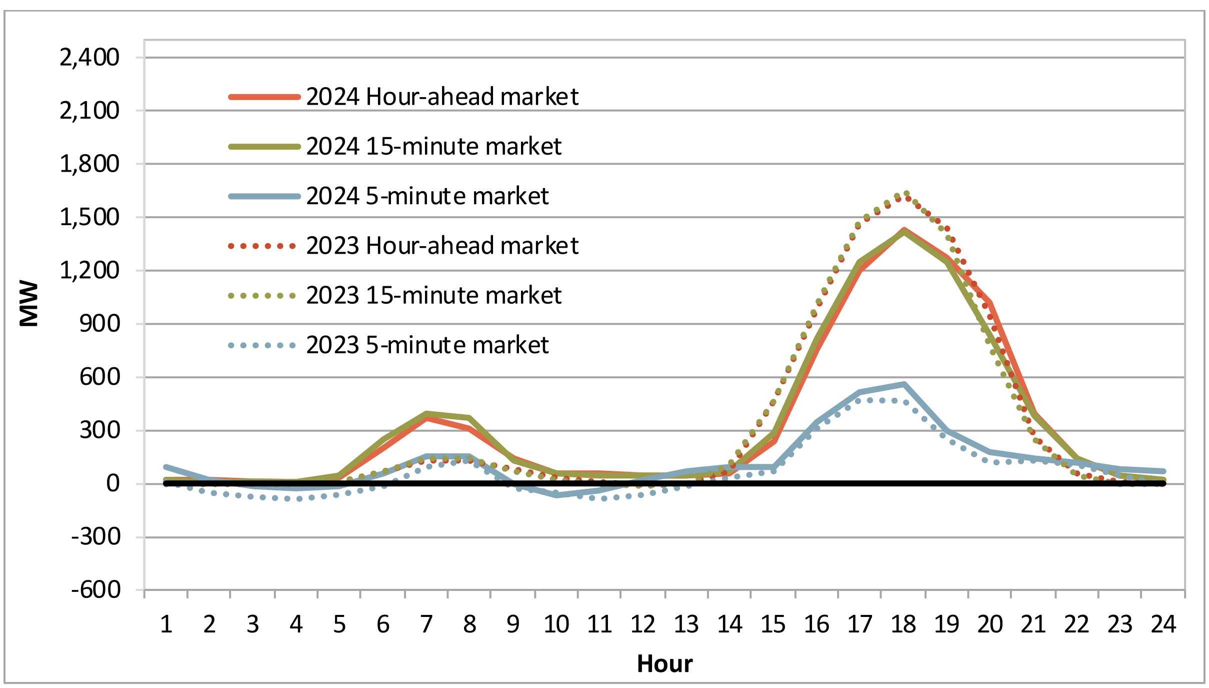
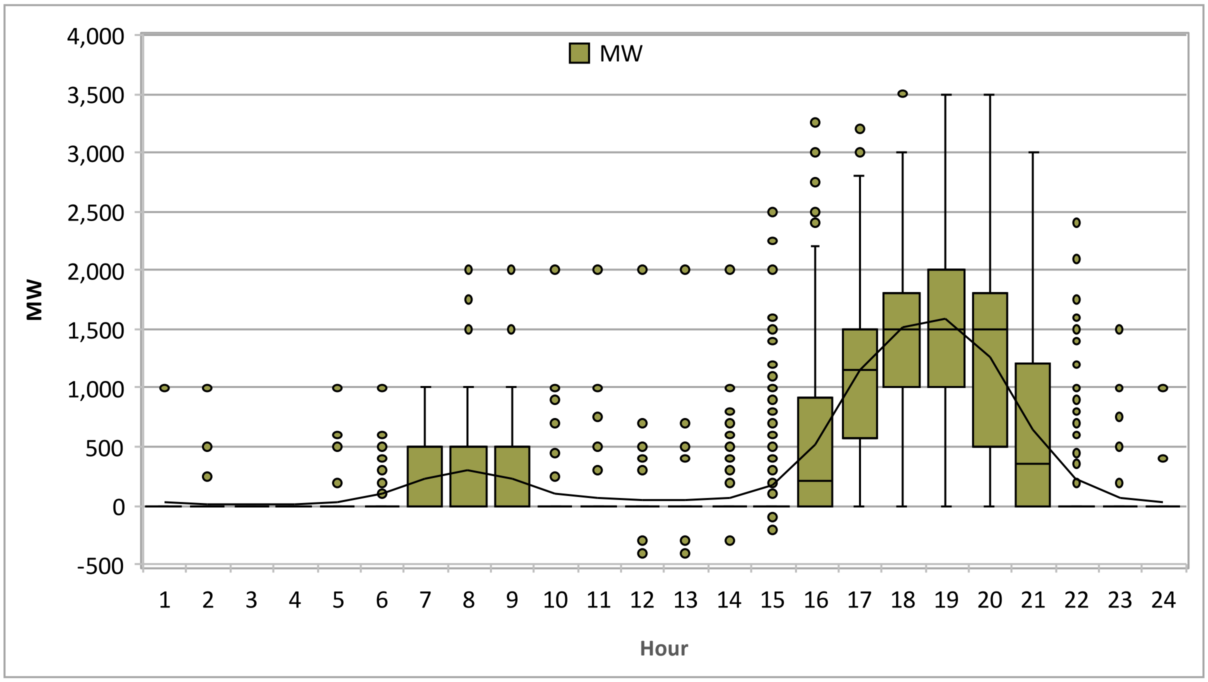


Figure 8.6 shows an hourly distribution of the 15-minute market load adjustments for the fourth quarter of 2024. This box and whisker graph highlights extreme outliers[54] (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well as the mean (line). The extreme outliers are represented by the filled "dots". The outside whiskers do not include these outliers. For the quarter, the maximums and major outliers in hours-ending 17 to 22, e.g., greater than 2,400 MW, primarily occurred between October 1 and October 10,[55] associated with record setting heat in the West and the rapid solar ramp down period. The negative mid-day minimum outliers, -400 MW, occurred on two days, October 27 and November 27, while the positive 2,000 MW mid-day outliers occurred on October 8.

Figure 8.6 CAISO BA 15-minute market hourly distribution of operator load adjustments (Q4 2024)



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

[55] California Governor's Office of Emergency Services (Cal OES) *California Takes Action During October Heat Wave* https://news.caloes.ca.gov/california-takes-action-during-october-heat-wave/

9 Flexible ramping product

The flexible ramping product is designed to enhance reliability and market performance by procuring upward and downward flexible ramping capacity in the real-time market, to help manage volatility and uncertainty surrounding net load forecasts.[56] The amount of flexible capacity the product procures is derived from a demand curve, which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs. Flexible capacity is procured and priced at a nodal level to better ensure that sufficient transmission is available for the capacity to be utilized.

The flexible ramping product demand curves are implemented in the ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This "requirement" for rampable capacity reflects the upper end of uncertainty in each direction that might materialize.[57] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for the group of balancing areas that instead pass the resource sufficiency evaluation are pooled together to meet the uncertainty requirement for the rest of the system. Both the requirement for the pass-group and the requirement for balancing areas that fail the resource sufficiency valuation are calculated using a method called *mosaic quantile regression*. This method applies regression techniques on historical data to produce a series of coefficients that define the relationship between forecast information (load, solar, or wind) and the extreme percentile of uncertainty that might materialize (95 percent confidence interval). These coefficients are then combined with current forecast information for each interval to determine the uncertainty requirement.

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

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

57 Based on a 95 percent confidence interval.

9.1 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.[58] 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.[59] 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 base-case flow based constraints were modeled in the deployment scenarios at implementation of the enhancements on February 1, 2023. Nomogram constraints were later enforced for flexible ramping product procurement on September 7, 2023. Contingency flowgate constraints were activated on June 4, 2024, and de-activated on June 12 due to performance issues with the solution run-times.[60] 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.[61] 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.[62] 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

58 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

59 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.

60 *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

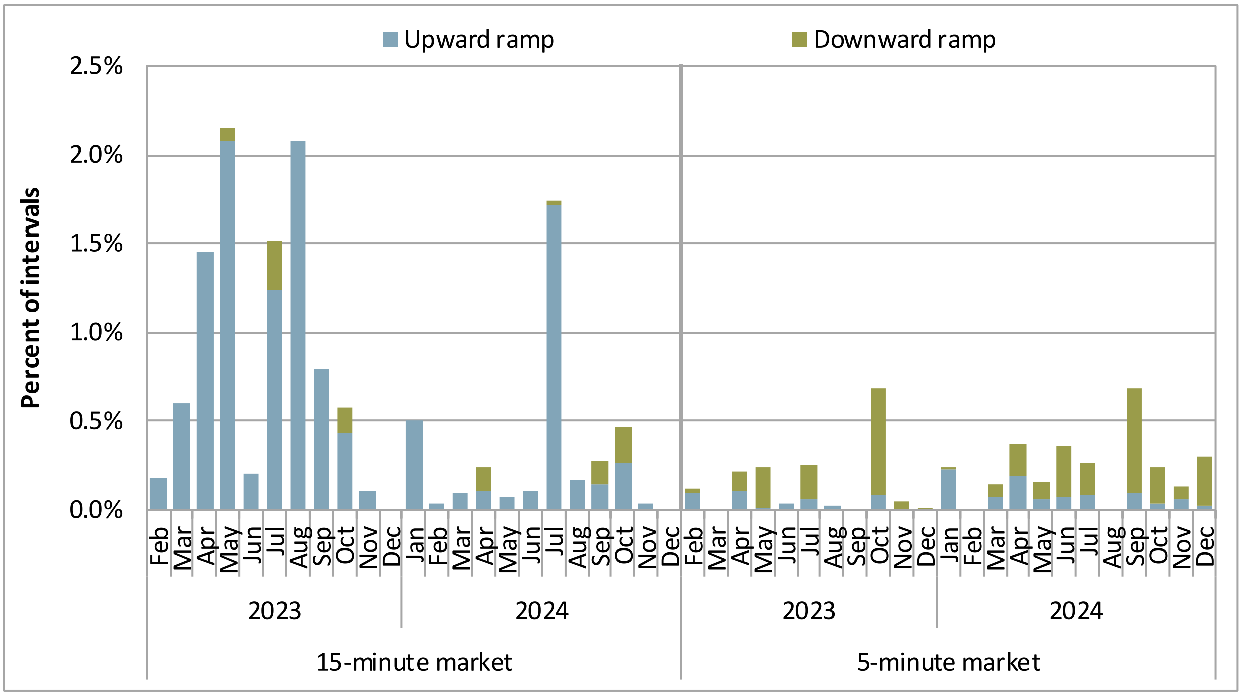
61 Or for each surplus zone in the case of the CAISO balancing area (by TAC area) and BANC (by custom load aggregation point).

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

available.[63] 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 9.1 shows the percent of intervals in which the shadow price on the pass-group constraint was non-zero (constraint binding) for upward and downward flexible capacity. This reflects more widespread prices for flexible capacity within the group of balancing areas that passed the resource sufficiency evaluation, but does not account for any congestion that may affect the price of flexible capacity at the nodal level.[64] The pass-group constraint for procuring *upward* flexible capacity in the 15-minute market was binding in around 0.1 percent of intervals during the quarter. In the 5-minute market, the constraint for procuring flexible capacity within the pass-group was also binding very infrequently.

Figure 9.1 Frequency of flexible ramping product prices from pass-group constraint



The price of flexible capacity for a node in a balancing area that passed the resource sufficiency evaluation can still be positive even when the shadow price on the constraint for procuring pass-group-level flexible capacity is zero (e.g., not binding). This can occur because of congestion on

63 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.

64 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.

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 9.2 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 9.1, summarizing the frequency in which the constraint for meeting pass-group flexible capacity requirements was binding. The figure adds the percent of intervals in which the constraint that reflects WEIM transfer congestion in the deployment scenario was binding for one or more balancing areas in the pass-group—*and the pass-group constraint was not also binding*. This reflects additional flexible ramping product prices within at least one balancing area. In most cases, these prices were within one isolated balancing area in the pass-group that was not able to meet its share of pass-group uncertainty. Localized flexible ramping product prices within the pass-group that are entirely driven by congestion on transmission constraints are not reflected in this figure.

Figure 9.2 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

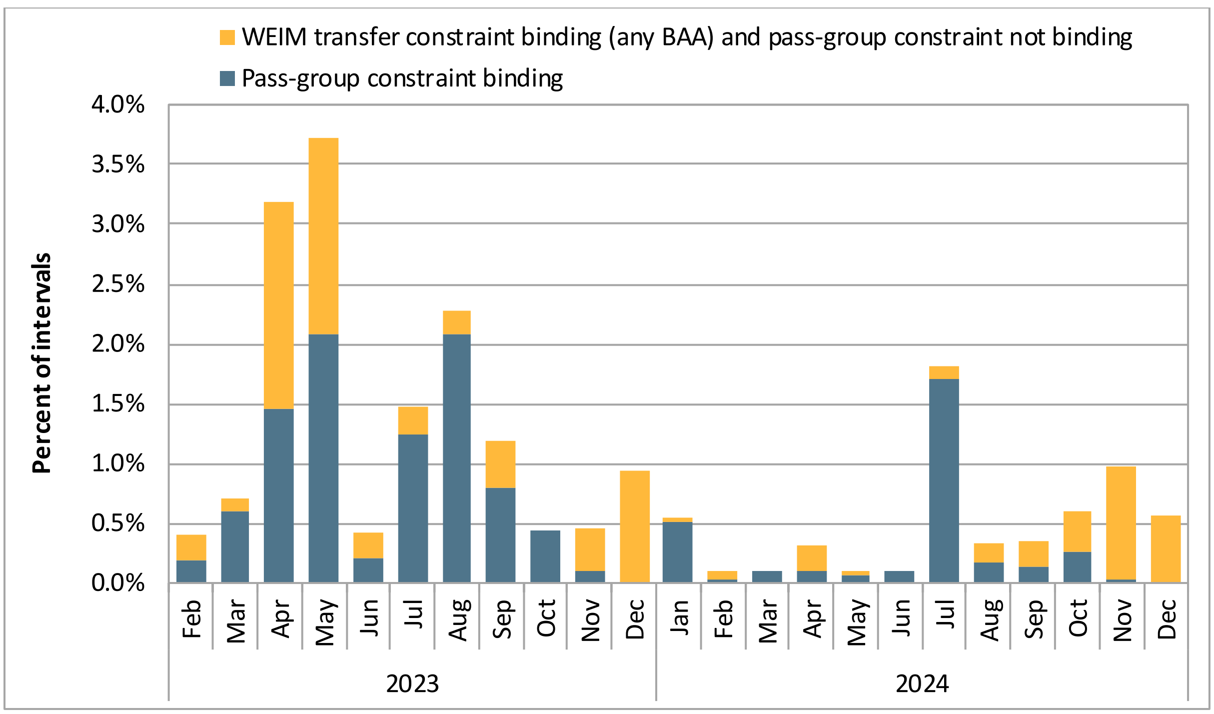


Figure 9.3 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the quarter. These results are shown separately by the constraint contributing to that price:

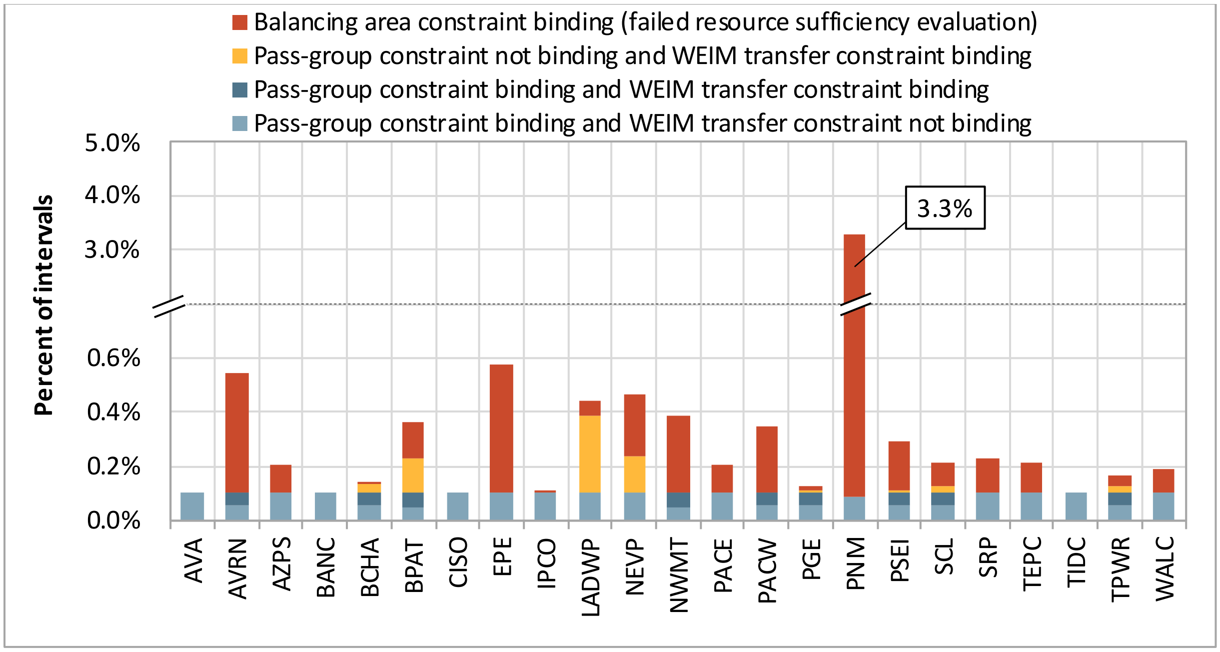
- **Pass-group constraint binding and WEIM transfer constraint not binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group.
- **Pass-group constraint binding and WEIM transfer constraint binding** 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.
- **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.
- **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.

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. In some of these intervals, balancing areas in the Pacific Northwest region had sufficient flexible capacity, but because of congestion on WEIM transfer constraints out of the balancing area in the deployment scenario, flex ramp prices here were typically zero.

Figure 9.3 also summarizes flexible capacity prices that can exist following a resource sufficiency evaluation failure (red bars). 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. The Public Service Company of New Mexico (PNM) had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 3 percent of intervals. Most of these were 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.[65]

[65] 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 9.3 Frequency of upward flexible ramping product prices by balancing area and constraint (15-minute market, October–December 2024)



9.2 Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the group of WEIM balancing areas that pass the resource sufficiency evaluation. Figure 9.4 and Figure 9.5 show the percent of upward or downward flexible capacity that was procured from various fuel types.

The share of flexible capacity from various fuel types has been relatively stable in 2024. During the quarter, battery resources continued contributing to much of the upward and downward flexible capacity. Battery resources made up almost 63 percent of upward flexible capacity and 34 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (26 percent). Wind and solar resources combined made up around 36 percent of downward flexible capacity.

Figure 9.6 and Figure 9.7 show the percent of upward or downward flexible capacity that was procured in various regions.[66] 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 64 percent for both directions. Balancing areas in the

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

Pacific Northwest made up 21 percent of upward flexible capacity and 18 percent of downward flexible capacity.

Figure 9.4 Percent of upward system or pass-group flexible ramp procurement by fuel type

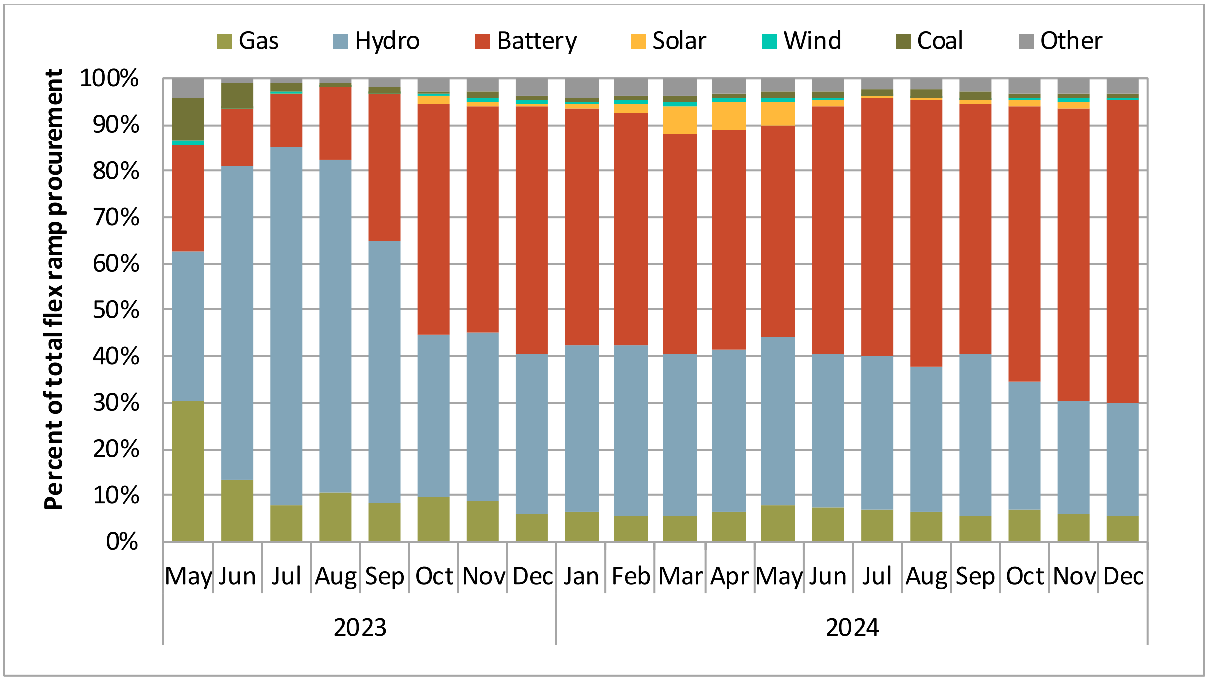


Figure 9.5 Percent of downward system or pass-group flexible ramp procurement by fuel type

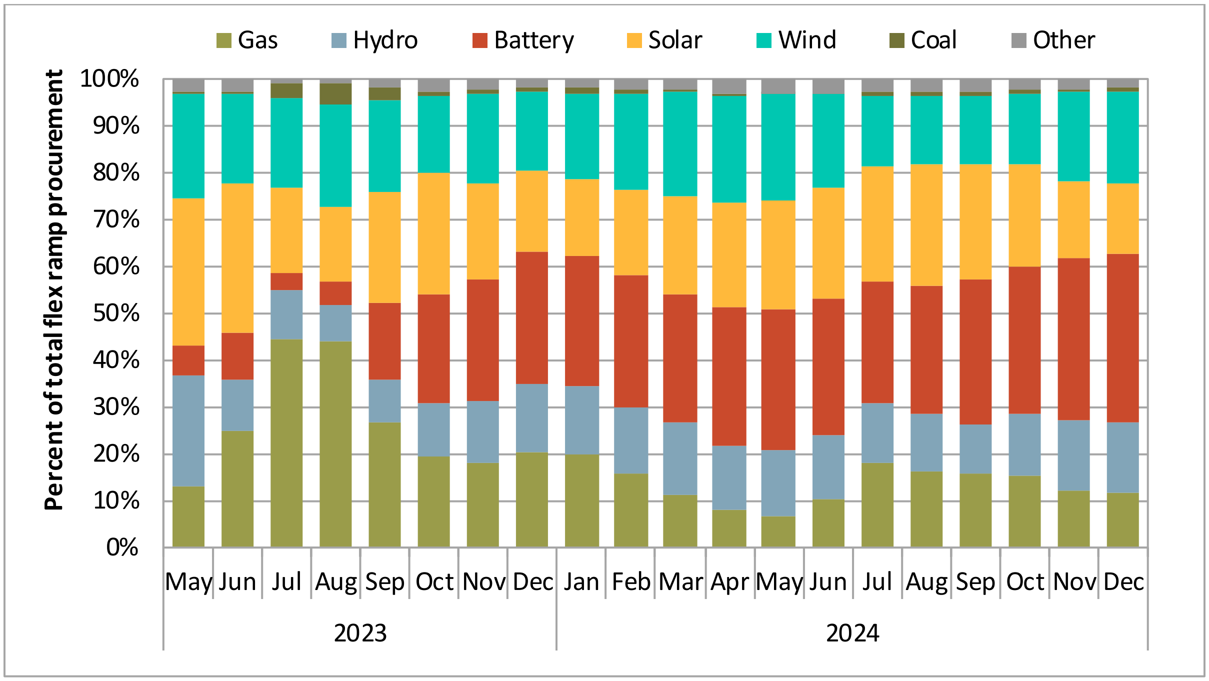


Figure 9.6 Percent of upward system or pass-group flexible ramp procurement by region

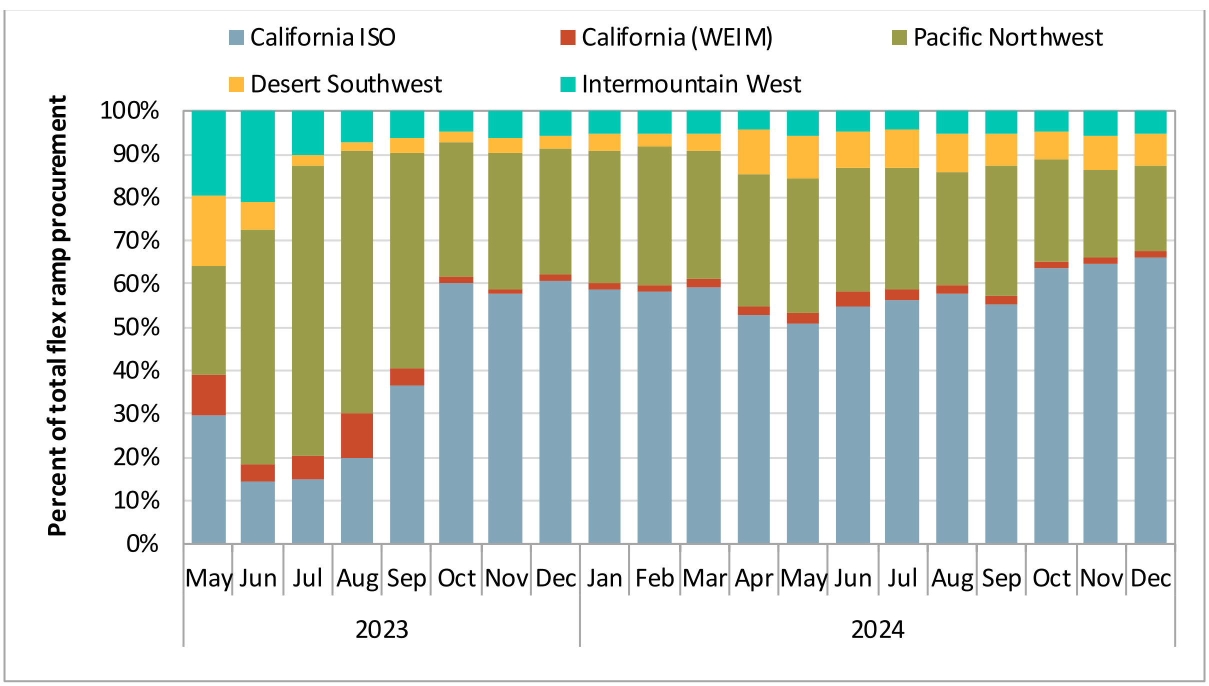
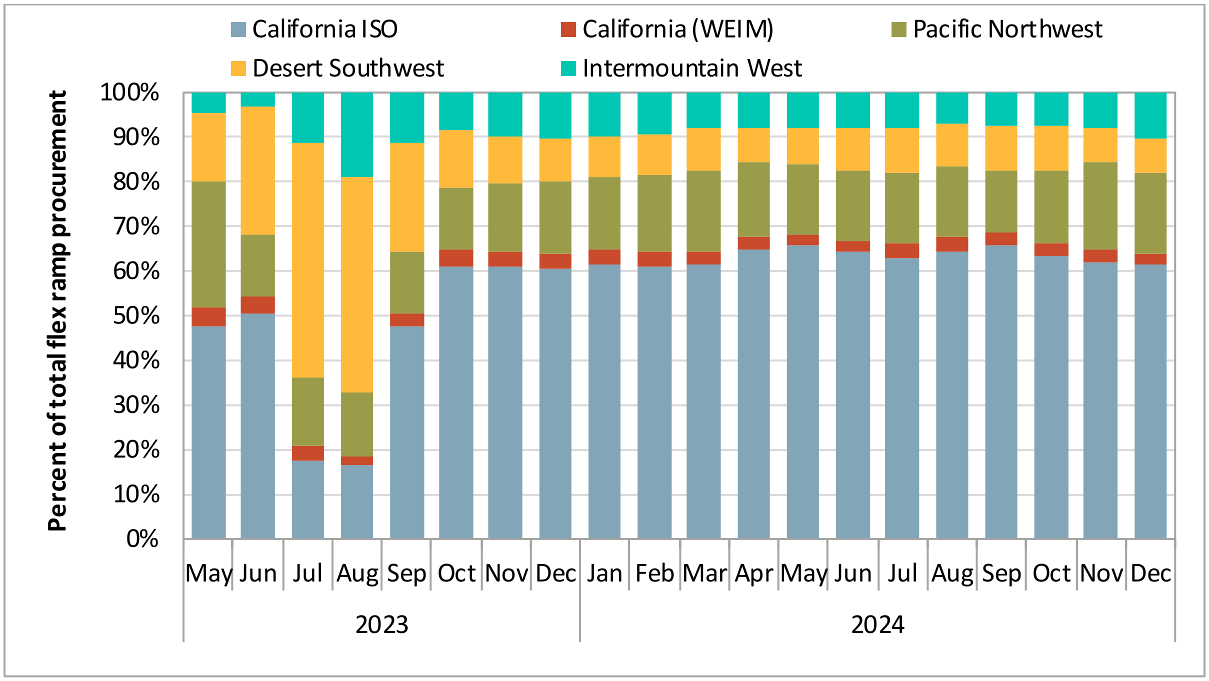


Figure 9.7 Percent of downward system or pass-group flexible ramp procurement by region



10 Uncertainty

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

Background defining the uncertainty analyzed in this section

The California ISO introduced a regression method to calculate uncertainty on February 1, 2023.[67] This methodology is a forecasting approach to manage uncertainty. Uncertainty in the market is defined as forecasting error. For example, the 15-minute and 5-minute markets utilize available forecasts for load, wind, and solar at the time when the market runs. If the target is hour-ending 18, both markets run for the same target hour, but calculations are made at different times. The 15-minute market runs earlier than the 5-minute markets, leading to differences in forecast data due to updates in weather and other variables in the interim period. This difference in forecast data is the uncertainty.

67 Before the February changes, uncertainty was calculated by selecting the 2.5th and 97.5th percentile of observations from a distribution of historical net load errors. This is known as the *histogram method*. For the 15-minute market product and the resource sufficiency evaluation, the historical net load error observations in the distribution are defined as the difference between binding 5-minute market net load forecasts and corresponding advisory 15-minute market net load forecasts.

Uncertainty in the market can take many forms. When discussing uncertainty in this section, we are specifically referring to net load uncertainty. This is the net load forecasting error between different market runs for the same ultimate interval of power flow. This section focuses on uncertainty across two different markets. One is the forecasting error from the day-ahead market to the 15-minute market, which is the uncertainty considered in the residual unit commitment adjustment. The other is the forecast difference from the 15-minute market to the 5-minute market that is used for the flexible ramping product and the resource sufficiency evaluation.

Uncertainty for an upcoming interval cannot be known in advance. For example, for the 15-minute market flexible ramping product, uncertainty is defined as the difference between the first advisory 15-minute forecast and the binding 5-minute forecasts.[68] At the start time of the advisory 15-minute market run, the 15-minute market uses a forecast of what net load is expected to be. However, at that time, the net load that the corresponding 5-minute markets will use when those market runs start 45-55 minutes later is not known. The uncertainty calculation uses historical data to forecast what the uncertainty might be. This allows for better preparation and adjustment in the market operations.

Background on calculating net load uncertainty

In calculating uncertainty, the ISO has employed two different methods. The first method involved estimating future uncertainty by analyzing the historical distribution of uncertainty. By examining past data, the method identified lower and upper extremes of uncertainty and used these to predict future uncertainty. This approach assumes that future uncertainty will fall within the historical range, with uncertainty fluctuating between the observed high and low extremes. This histogram method was used in the market until February 1, 2023.

On February 1, 2023, the ISO began using a second method to calculate uncertainty. This was the mosaic quantile regression method. The regression approach adds another layer to the uncertainty calculation by incorporating the mosaic variable—a predictor constructed by the ISO. Unlike the first method that only considers historical uncertainty, this approach looks for patterns between uncertainty and the mosaic variable, and uses it for forecasting. For example, if uncertainty was high when the mosaic variable was high in the past, it suggests that high uncertainty might occur in future periods when the mosaic variable is also high. The regression method quantifies the patterns observed in the past, providing exact numbers rather than just indicating high or low. Once the pattern is known, it can be applied to future scenarios. The variable is derived from a combination of load, solar, and wind forecasts.[69]

For a regression methodology to produce better forecasting results than a histogram methodology, there must be a strong pattern between the uncertainty and the mosaic variable. Also, this pattern should persist in the future period being forecasted. If the pattern does not persist over time, it may suggest the pattern is driven by noise in the past data, providing incorrect information for forecasting uncertainty. This could result in less accurate and potentially erroneous forecasts. If the pattern is weak

68 In comparing the 15-minute observation to the three corresponding 5-minute observations for the 15-minute market product, the minimum and maximum net load errors were each used as a separate observation in the distribution. The 5-minute market product instead used the difference between a binding 5-minute market net load forecast and advisory 5-minute market net load forecast.

69 For a more detailed description of the mosaic quantile regression method, see the DMM special report, *Review of the Mosaic Quantile Regression*, Nov 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

or nonexistent, the regression method essentially reverts to the histogram method, which relies solely on past uncertainty distributions without the added insight from the mosaic variable.[70]

Patterns in regression are essentially a formula. This formula shows the historical level of uncertainty for any given mosaic variable value. In simple terms, regression answers the question: if the mosaic variable was, for example, 1,000 MW, what was the level of uncertainty in the past? Plugging mosaic variable values for upcoming intervals into the historical pattern can forecast uncertainty.

Quantile regression focuses on specific parts of the data pattern. Instead of analyzing the overall pattern between uncertainty and the mosaic variable, it targets specific percentiles. For example, if the target percentile is 97.5, the regression mainly focuses on the top 2.5th percent of uncertainty. It puts the most weight on finding patterns between this extreme uncertainty and the mosaic variable.

The ISO uses quantile regression with target percentiles of 97.5 and 2.5. Therefore, the regression method aims to find patterns at the extreme ends of historical data samples. The regression method produces a forecast as its output. This forecast is interpreted as a prediction range. The realized net load uncertainty between a current and upcoming market run is expected to fall within the upper and lower bounds of the prediction range with 95 percent probability.

Background on assessing performance of the mosaic quantile regression forecast

One important criteria for assessing the performance of the quantile regression forecast method is its *accuracy*. A useful metric for evaluating the accuracy of the forecast is called the coverage rate. The coverage rate indicates the percentage of realized uncertainty that falls within the forecasted prediction range described above. For the flexible ramping product and resource sufficiency evaluation, the target coverage rate is 95 percent. This means that for an accurate regression model, we would expect that 95 percent of the realized uncertainty will be within the model's predicted range.

Another important criteria for assessing the regression model is *efficiency*. An efficient model would produce a narrow prediction range while maintaining this 95 percent coverage rate. The efficiency is often measured by the average upward and downward requirement. These requirements represent the prediction range for uncertainty, with the upward requirement corresponding to the 97.5th percentile and the downward requirement corresponding to the 2.5th percentile of uncertainty.

Accuracy and efficiency are critical metrics for evaluating the performance of a forecasting model, but assessing them can be more complex. Accuracy has an absolute benchmark, such as achieving 95 percent coverage. In contrast, efficiency lacks a clear standard. A model might achieve 95 percent accuracy, but this could come at the expense of very high upward and very low downward requirements. Efficiency can be meaningful when compared to other models. Since the current forecast method relies on a single regression model, evaluating the performance can be less insightful.

In addition to accuracy and efficiency, this section evaluates the model's validity by examining the statistical significance of its coefficients. These coefficients reflect patterns in historical data, and their statistical significance confirms whether these patterns are strong enough for forecasting. For example, in load forecasting, if temperature and load have a significant historical relationship, this can be useful

[70] For further information on the weak pattern and its implication, details can be found in the DMM special report, *Review of the Mosaic Quantile Regression,* Nov 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

for future prediction, assuming the pattern holds. However, if the relationship is non-significant, the forecast is likely based on unreliable patterns, making the prediction questionable.

In uncertainty forecasting, the relationships between variables are not always as intuitive as those between load and temperature, making actual testing crucial. Statistical significance alone does not guarantee good forecasts, especially when historical and future conditions are different. However, it can serve as a reliable indicator for forecasting, particularly when only a single predictor is used to estimate uncertainty.

Statistical testing determines whether the historical patterns represented by regression coefficients are actually different from zero. Simply comparing the size of the coefficient to zero is not always helpful, as coefficients can be very small yet still meaningfully different from zero. This section uses tests on these coefficients to determine their significance. If the coefficient is significantly different from zero, it indicates a pattern in the historical data. While this does not guarantee that the pattern will be useful for forecasting, it at least suggests some relationship exists. However, if the coefficient is not significantly different from zero, it may imply either no pattern at all or that the quantified pattern is unreliable or irrelevant, potentially leading to erroneous forecasts.

If in a larger percentage of intervals, the regression method produces statistically significant coefficients, the regression forecast results should have greater divergence from the histogram method results. This is because the regression incorporates the histogram method. When the pattern detected by regression is not statistically significant, one possibility is that the coefficient may be zero, causing the regression results to resemble the histogram.[71] Another possibility is that the coefficient is non-zero but unreliable, potentially leading to erroneous forecasts. In practice, mosaic regression often encounters a combination of these two issues.

In the following subsections, this report presents performance metrics for the mosaic quantile regression performed for the flexible ramping product, resource sufficiency evaluation, and the residual unit commitment market adjustment. Measurements of the uncertainty requirements and coverage in this section are based on actual market results. The statistical significance metrics are based on DMM's replication of the ISO's mosaic quantile regression method.[72]

10.1 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.

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71 For further information about the statistical significance test and its implementation, details can be found in the DMM special report, *Review of the Mosaic Quantile Regression*, Nov 20, 2023 (p 5, section 3): https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

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

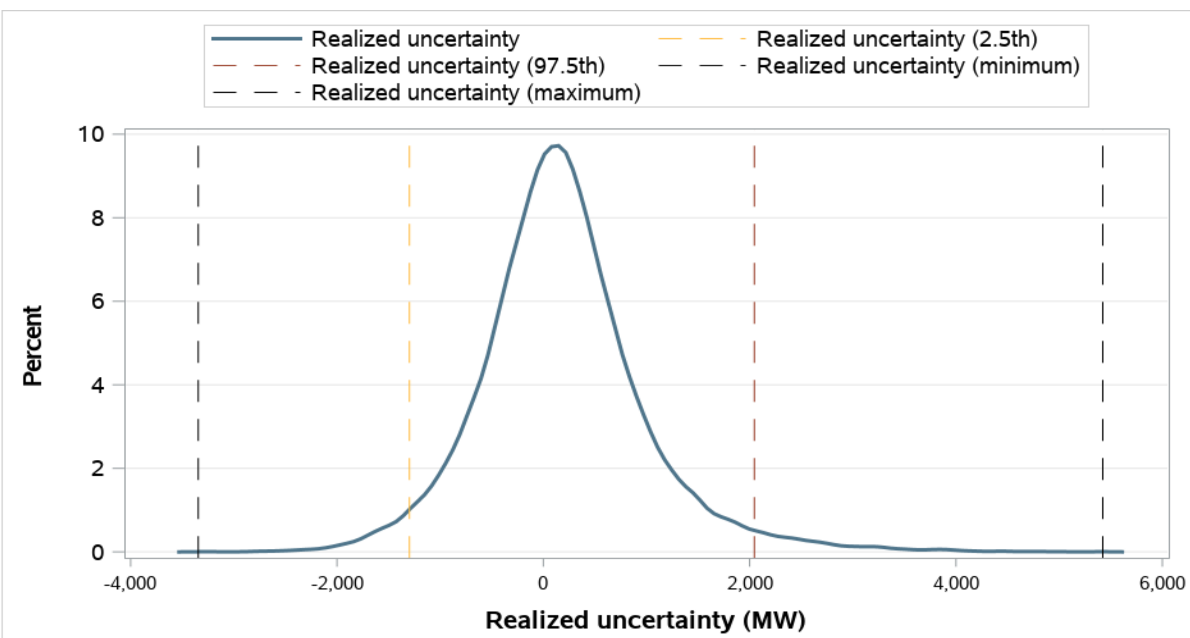
The flexible ramping product uses an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for instead the group of balancing areas that pass the resource sufficiency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

Figure 10.1 illustrates the distribution of realized uncertainty in the flexible ramping product (FRP) for the group of balancing areas that passed the resource sufficiency evaluation (RSE) for the fourth quarter of 2024. The distribution is depicted as a blue line, with the extreme percentiles highlighted: the lowest 2.5th percentile in yellow, the 97.5th percentile in red, and the black dashed lines indicating the minimum and maximum values.

The range from the upper 2.5 percent of uncertainty to its maximum spans from 2,000 MW to over 5,500 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 distribution was skewed upward, resulting in a longer tail on the upper end. This may indicate the influence of systematic patterns, rather than purely random variations. These factors may provide valuable information for forecasting uncertainty.

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 10.1 Distribution of realized uncertainty in FRP (pass-group, October-December 2024)



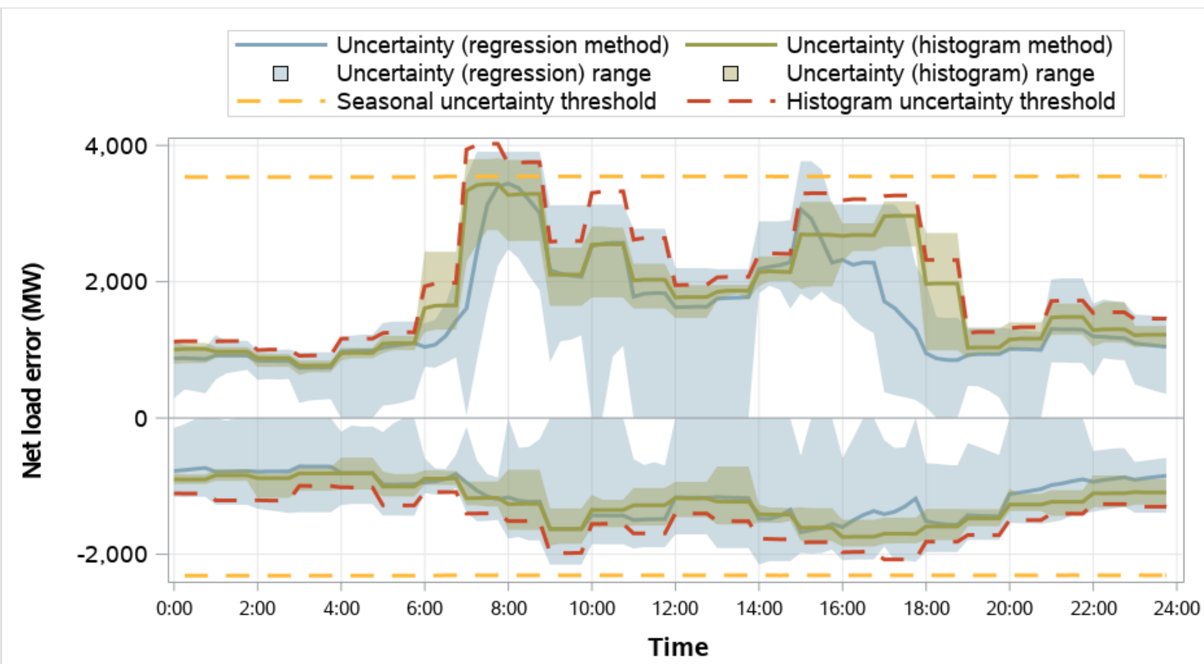
10.1.1 Results of flexible ramping product uncertainty calculation

Figure 10.2 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation (RSE), both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the historical 180-day period) and with the mosaic quantile regression method. The green and blue lines show the average upward and downward uncertainty from each method while the areas around the lines show the minimum and maximum amount over the quarter. The dashed red and yellow lines show the average histogram and seasonal thresholds, respectively, during the period.[73]

Figure 10.3 shows the same information for 5-minute market uncertainty, which reflects the difference between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the quantile regression approach was typically lower or comparable to uncertainty calculated with the histogram approach. Of note, between 16:00 and 18:00, the regression-based uncertainty was much lower on average, in comparison to the histogram-based uncertainty. However, results of the regression-based approach vary more widely, including periods with much lower (or zero) uncertainty.

Figure 10.2 15-minute market pass-group uncertainty requirements (October–December 2024)



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

Figure 10.3 5-minute market pass-group uncertainty requirements (October–December 2024)

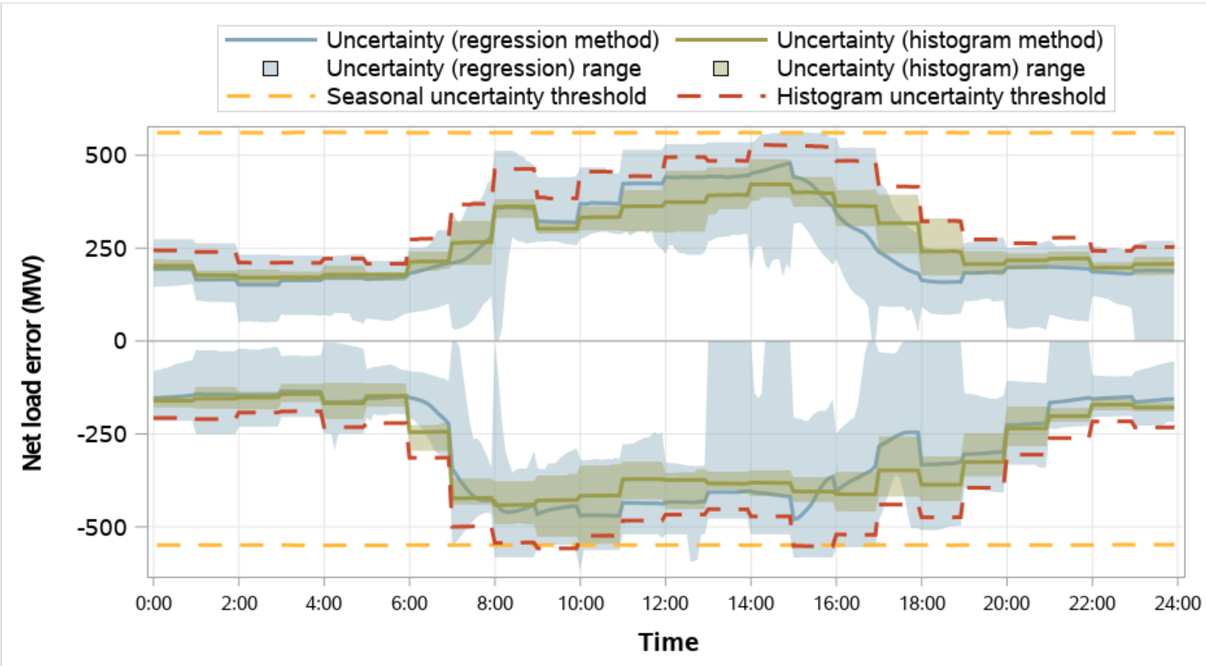


Table 10.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the 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.[74]

In 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.[75] In the 15-minute market, uncertainty forecasted by mosaic regression generally had lower coverage and lower requirements, whereas the histogram method showed slightly higher coverage and higher requirements. In the 5-minute market, the difference between the two methods was minimal.

74 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.

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

Table 10.1 Average pass-group uncertainty requirements (October–December 2024)

		Requirement			Coverage		
Market	Direction	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference
15-minute market	Up	1,784	1,564	-220	98.0%	96.5%	-1.4%
	Down	1,227	1,146	-81	97.2%	96.2%	-1.1%
5-minute market	Up	270	262	-7	97.6%	97.3%	-0.3%
	Down	293	287	-6	97.3%	96.9%	-0.4%

Table 10.2 presents the percentage of statistically significant coefficients across various quantile regressions for the 15-minute market calculation of pass-group uncertainty. The results are based on DMM's replication.

The mosaic regression is primarily designed to forecast net load uncertainty, with the mosaic variable serving as the main predictor in this regression. The three additional quantile regressions—load, solar, and wind—function as intermediate regressions used to construct the mosaic variable.[76]

The percentages in the table indicate the proportion of estimated coefficients that were statistically different from zero among all regression estimation in this quarter. Each regression includes two primary coefficients: a quadratic term and a linear term.[77] The percentages represent the proportion of regression where at least one of these coefficients was statistically significant. The significance level was set at 10 percent.

Table 10.2 Statistical significant test for mosaic quantile regression in FRP (October–December 2024)

Regression type	All hours	Peak hours(1)
Mosaic	41%	45%
Load	26%	41%
Solar	72%	91%
Wind	51%	61%

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

The coefficient for the mosaic variable was statistically significant during only 41 percent of intervals. This means that in 59 percent of cases, the mosaic variable does not show a strong pattern with historical uncertainty.[78] Whether the mosaic variable is high or low, the uncertainty does not

76 For a more detailed description of how the three other quantile regressions are used to construct the mosaic variable, see the DMM special report, *Review of the Mosaic Quantile Regression*, Nov 20, 2023, pp 6-10: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

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

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

consistently respond with similarly high or low levels of uncertainty. Consequently, when looking at future data, even if the mosaic variable is high, it is unclear whether the uncertainty will be high or low.

Low statistical significance suggests that the regression often fails to identify a meaningful relationship. This failure could stem from either no relationship or inconsistent relationship. While it is difficult to quantify the proportion of cases due to no relationship versus inconsistency, mathematically, if no relationship exists, the quantile regression outcomes will converge to the histogram results.[79] Intuitively, this occurs because a no relationship implies that the mosaic variable provides no additional information for forecasting. As a result, the forecast relies solely on the historical net load uncertainty data, which is the histogram method.

In Figure 10.2 and Table 10.1, the average hourly requirement and performance metrics show a high degree of similarity between the histogram and mosaic regression method. This resemblance can be explained by the low percentage of statistically significant coefficients.

10.1.2 Threshold for capping flexible ramping product uncertainty

Flexible ramping product and resource sufficiency evaluation uncertainty calculated from the quantile regressions is capped by the lesser of two ceiling thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from a 180 day period.[80] The seasonal threshold is updated each quarter and is calculated based on the 1st and 99th percentile using observations over the previous 90 days. For the upward seasonal threshold, the 99th percentile is calculated separately for each of the 24 hours in a day. The maximum value out of these 24 hours is used as the threshold for all hours.[81]

During the quarter, the ceiling thresholds capped *upward* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 13 percent of intervals in the 15-minute market and 9 percent of intervals in the 5-minute market. *Downward uncertainty* was capped by the ceiling thresholds in around 11 percent of intervals in the 15-minute market and 13 percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the seasonal threshold.

The ceiling threshold implies that the requirement is set at the highest 1 percent of uncertainty over the past 90 or 180 days. The expected frequency of reaching this threshold is around 1 percent of the time. However, the observed frequency of over 10 percent in the 15-minute market significantly exceeded this expectation.

[79] For a detailed discussion on the theoretical background and empirical findings regarding the resemblance between the mosaic quantile regression and the histogram method, see the DMM special report, *Review of the Mosaic Quantile Regression*, Nov 20, 2023, p 5 and pp 31-33: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

[80] As of August 14, 2024, the histogram threshold uses symmetric sampling, from historical observations from the previous 90 days as well as the next 90 days minus one year.

[81] For the downward seasonal threshold, the 1st percentile is calculated separately for each of the 24 hours in a day. The minimum value out of these 24 is used as the threshold for all hours.

A floor threshold is also in place that sets the floor for uncertainty at 0.1 MW in both directions. The upward and downward uncertainty is therefore set near zero when the uncertainty calculated from the quantile regression would be negative. During the quarter, uncertainty calculated for the group of balancing areas that passed the resource sufficiency evaluation was set near zero by this threshold in less than 1 percent of intervals in both directions and in both the 15-minute and 5-minute markets.

10.2 Resource sufficiency evaluation uncertainty

Uncertainty is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the resource sufficiency evaluation (RSE). Here, balancing areas must show enough upward and downward ramping flexibility over an hour to meet both the forecasted change in demand *as well as uncertainty*.[82] This additional requirement in the flexibility test is also based on a 95 percent confidence interval for uncertainty that might materialize. This section analyzes the performance of the mosaic quantile regression in the resource sufficiency evaluation.

Figure 10.4 shows the distribution of realized 15-minute uncertainty in the RSE for each balancing authority area (BAA) for the fourth quarter of 2024. Here, realized uncertainty is defined as the net load forecast difference between the forecasts used in the resource sufficiency evaluation and those in the binding 5-minute market runs. To facilitate comparison across different BAAs, the realized uncertainty has been standardized by its mean and standard deviation.[83] This eliminates scale issues and allows for a clear assessment of relative volatility in realized uncertainty among BAAs. Additionally, the figure displays the standardized average upward and downward requirement imposed in the market, enabling a comparison of each BAA's requirement relative to its own uncertainty, as well as in relation to other areas.

82 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.

83 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 10.4 Standardized realized uncertainty and requirement for RSE (October–December 2024)

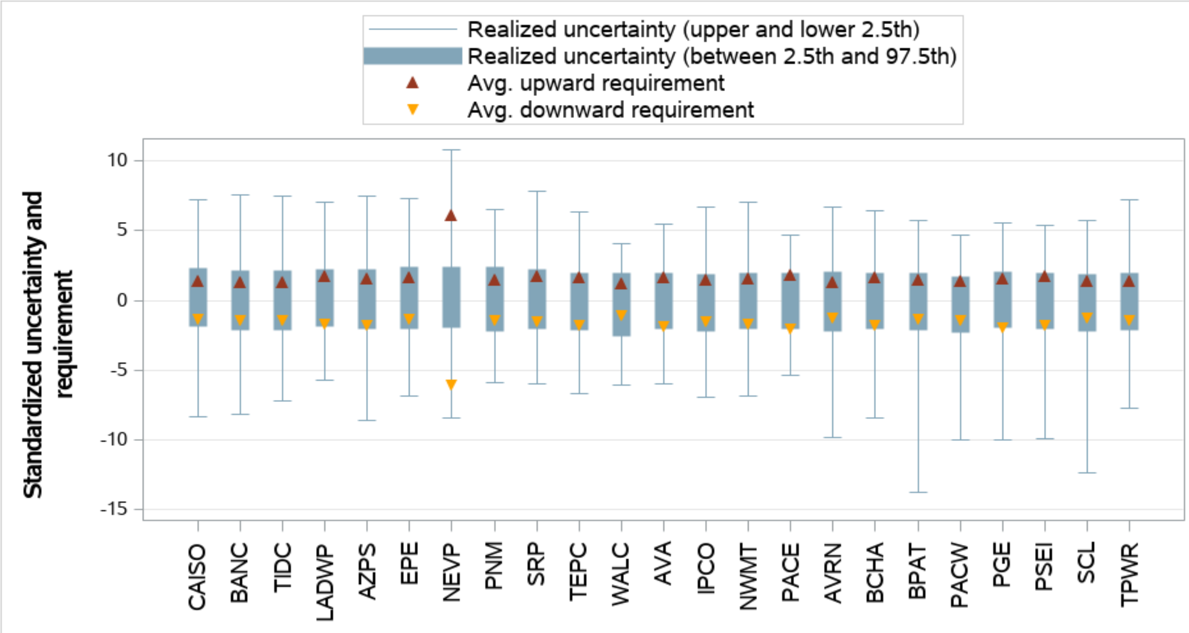


Figure 10.4 provides a comparison of the realized uncertainty across different BAAs for this quarter. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 2.5th percentile to the minimum value of realized uncertainty. The triangle markers show the average upward and downward requirement applied in the market, based on the ISO estimates.

Key observations include:

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

10.2.1 Results of resource sufficiency evaluation uncertainty calculation

Table 10.3 summarizes the average requirements and coverage for uncertainty in the resource sufficiency evaluation using both the histogram and mosaic quantile regression methods. In this table, *requirement* shows the average uncertainty component considered in the upward and downward flexibility test requirements. *Coverage* measures how frequently realized uncertainty—as measured by the difference between binding 5-minute market net load forecasts and net load forecasts in the resource sufficiency evaluation (RSE)—fell within the calculated uncertainty requirements for the same interval.

In the RSE, both the histogram and mosaic regression showed overall coverage levels significantly below the 95 percent target. Although the histogram method nearly reached 95 percent for some balancing areas, mosaic regression mostly remained below 90 percent coverage. This is largely due to a disparity with the underlying data used to estimate resource sufficiency evaluation uncertainty, as discussed in the following section. On average across all hours, the uncertainty calculated from the regression method was less than the histogram method for almost all of the WEIM entities. The resource sufficiency evaluation uncertainty calculated from the regression method covered between 86 and 93 percent of realized uncertainty across all balancing areas.

Table 10.3 Average resource sufficiency evaluation uncertainty requirements and coverage (October–December 2024)

	Upward requirement			Downward requirement			Coverage		
Balancing area	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference
Arizona Public Service	234	205	-29	198	184	-14	93%	90%	-3%
Avangrid	235	157	-79	178	112	-66	93%	87%	-5%
Avista	63	58	-5	68	63	-6	93%	90%	-3%
BANC	42	37	-5	43	38	-5	92%	89%	-3%
Bonneville Power	233	185	-48	242	186	-57	92%	87%	-5%
California ISO	1,178	1,025	-153	705	656	-48	92%	89%	-3%
El Paso Electric	39	33	-6	32	26	-6	95%	90%	-5%
Idaho Power	128	105	-23	138	117	-21	93%	88%	-5%
LADWP	168	156	-12	144	131	-13	93%	90%	-3%
NorthWestern Energy	73	67	-6	85	77	-8	92%	90%	-2%
NV Energy	261	217	-45	216	196	-20	95%	92%	-3%
PacifiCorp East	366	346	-21	526	496	-30	95%	93%	-2%
PacifiCorp West	92	80	-12	138	109	-29	91%	88%	-3%
Portland General Electric	143	121	-22	132	125	-7	93%	91%	-2%
Powerex	149	140	-8	150	150	1	91%	89%	-2%
PNM	178	145	-34	158	142	-16	93%	90%	-3%
Puget Sound Energy	144	134	-11	136	130	-6	93%	91%	-2%
Salt River Project	159	132	-27	121	100	-21	94%	89%	-5%
Seattle City Light	16	16	0	18	19	1	87%	86%	0%
Tacoma Power	10	10	0	11	11	0	87%	86%	-2%
Tucson Electric Power	97	89	-8	101	90	-11	93%	89%	-4%
Turlock Irrigation District	7	6	-1	8	6	-2	93%	87%	-6%
WAPA Desert Southwest	26	23	-3	24	21	-3	91%	87%	-4%

Table 10.4 summarizes the percentage of statistically significant coefficients during all hours and peak hours, based on DMM's replication of the regression. The balancing areas are listed in descending order, starting with those with the highest percentage of significant coefficients. Overall, 45 percent of regression coefficients were significant in Q4 2024, indicating that 55 percent of the regression estimations were based on either weak or inconsistent patterns.

Table 10.4 Statistical significant test for mosaic quantile regression in RSE (October-December 2024)

BAA	Percent of significant coefficients	
	All hours	Peak hours(1)
Avangrid	93%	98%
PacifiCorp West	68%	66%
BPA	68%	62%
Arizona PS	57%	51%
NorthWestern	53%	56%
Idaho Power	51%	64%
CAISO	48%	61%
Salt River Project	46%	43%
NV Energy	46%	61%
Avista Utilities	46%	45%
Seattle City Light	46%	49%
LADWP	42%	40%
PSC New Mexico	41%	44%
Portland GE	40%	35%
Puget Sound Energy	38%	40%
Tucson Electric	38%	34%
PacifiCorp East	35%	37%
BANC	33%	40%
El Paso Electric	31%	32%
Tacoma Power	30%	30%
Turlock ID	27%	33%
WAPA - Desert SW	25%	31%
Powerex	24%	33%
Average	45%	47%

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

10.2.2 RSE uncertainty special issue — time horizon for predicting uncertainty

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

The resource sufficiency evaluation uses exactly the same underlying historical data to perform the regressions and calculate uncertainty as the flexible ramping product in the 15-minute market.[84] This data is based on the difference from advisory forecasts in the 15-minute market to the corresponding binding forecasts in the 5-minute market. The regressions use this data to produce hourly coefficients that define the relationship between the forecasts and uncertainty. This calculation reflects 45 to 55 minutes in which uncertainty may materialize between the applicable 15-minute and 5-minute market runs.

However, the resource sufficiency evaluation occurs over a different timeframe than what is considered for procuring 15-minute market flexible capacity. Figure 10.5 illustrates the timeframe of uncertainty considered for the flexible ramping product in the 15-minute market, and how it compares with the timeframe of the resource sufficiency evaluation.[85] For the flexible ramping product, the calculation is designed to capture uncertainty that may materialize around a single upcoming (advisory) interval. However, the resource sufficiency evaluation considers forecast information from *four* 15-minute intervals within an hour. When comparing the forecast values used in each interval of the resource sufficiency evaluation to corresponding 5-minute market intervals, there exists a larger gap of time for uncertainty to materialize.

In comparing the first 15-minute test interval of the RSE to corresponding 5-minute market intervals, the timeframe and potential for net load uncertainty to materialize is similar to the timeframe of the 15-minute market flexible ramping product uncertainty calculation. However, in the later test intervals, the gap between the predicted forecasts at the time of the resource sufficiency evaluation and the real-time forecasts widens, reaching above 100 minutes. The current determination of the regression coefficients for predicting net load uncertainty for the resource sufficiency evaluation (based on short-term historical data) does not capture the increased net load uncertainty associated with the longer-term horizon of this market process.[86]

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the resource sufficiency evaluation. Figure 10.6 shows the average coverage rate across all balancing areas by interval. Here, coverage is measured as the percent of intervals when realized uncertainty from the forecasts considered in the resource sufficiency evaluation to the 5-minute market forecasts fell within the calculated uncertainty requirement for the same interval. The calculated uncertainty covered the realized uncertainty much less for intervals at the end of the hour compared to the beginning of the hour because the current calculation is not designed to capture uncertainty that can realize over a longer-term horizon.

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

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

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

Figure 10.5 Comparison of timeframe considered for the flexible ramping product and resource sufficiency evaluation

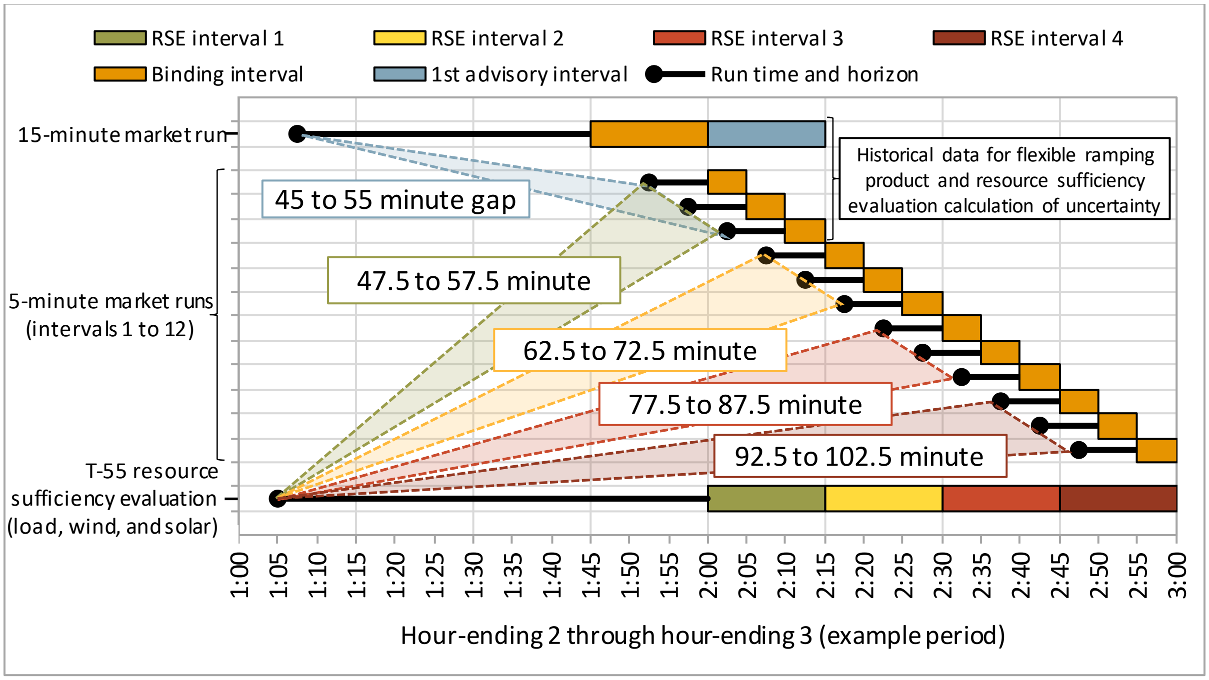
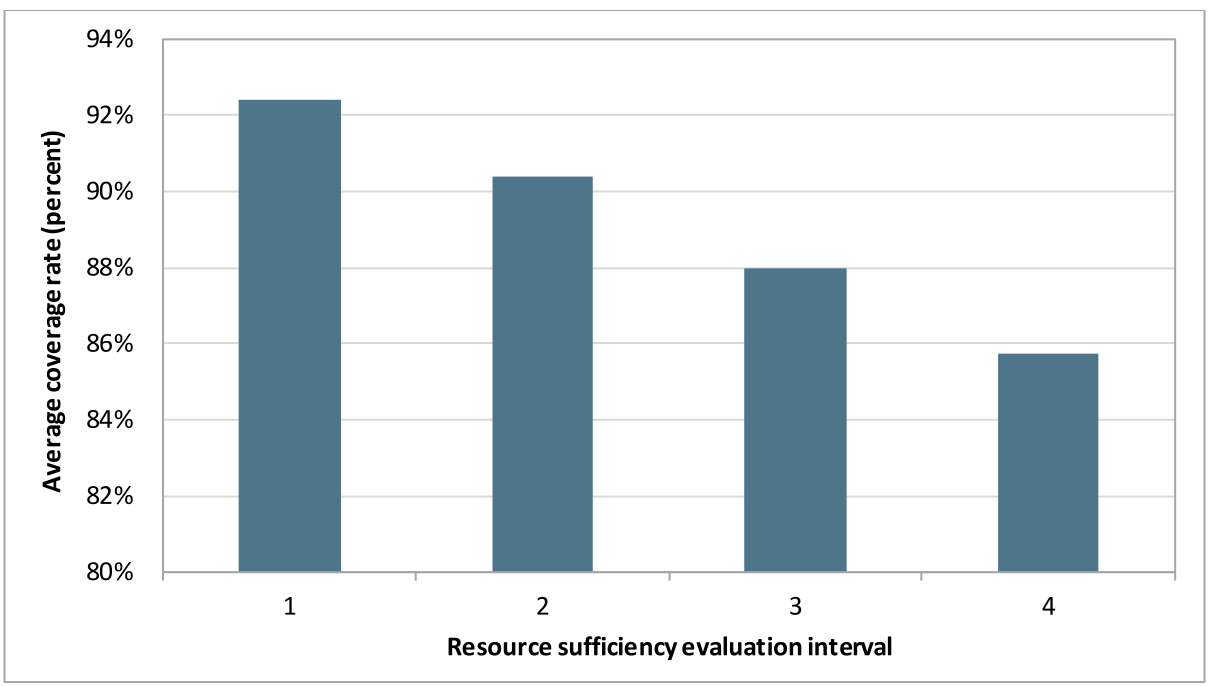


Figure 10.6 Average coverage rate by resource sufficiency evaluation interval (October–December 2024)



10.3 Residual unit commitment uncertainty

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

Figure 10.7 shows the average residual unit commitment adjustment on each day of 2023 (red) and 2024 (blue). The arrows highlight key changes that occurred in 2023 and 2024.

1. On June 30, 2023, the ISO began using the *mosaic quantile regression* method to calculate the RUC adjustments. Between June 30 and December 20, 2023, this calculation was applied to all hours based on the 97.5th percentile of net load uncertainty that might materialize in real-time.

2. On December 21, 2023, the ISO implemented a new operating procedure that changed the methodology for calculating the RUC adjustments, effectively lowering the amounts. The procedure calls for selecting the percentile target for calculating the adjustment based on conditions in the system. Under periods with moderate operational uncertainty, the operating procedure calls for using an adjustment that will procure enough capacity 50 percent of the time (i.e., the 50th percentile of upward uncertainty). The ISO can adjust the calculation on any day to instead use the 75th or 97.5th percentile during periods of higher forecast uncertainty or in extreme conditions.

3. On May 7, 2024, the ISO made changes to the operating procedure that allowed the uncertainty adjustment to be applied to only select hours.[87] During periods with moderate uncertainty, the adjustment is typically applied only to the peak morning and peak evening hours (around six hours). During periods with more operational uncertainty, the adjustment is generally applied to either mid-day hours (around 16 hours) or all hours. During periods with low operational uncertainty, *no adjustment* can also be applied.[88]

[87] See CAISO Operating Procedure 1210, May 7, 2024, pp 12-13: https://www.caiso.com/Documents/1210.pdf

[88] As noted in the day-ahead market operating procedure, dispatchable resources in the market, WEIM transfers, or regulating resources can instead manage uncertainty during periods with lower uncertainty.

Figure 10.7 Average residual unit commitment adjustment by day (2023 vs. 2024)

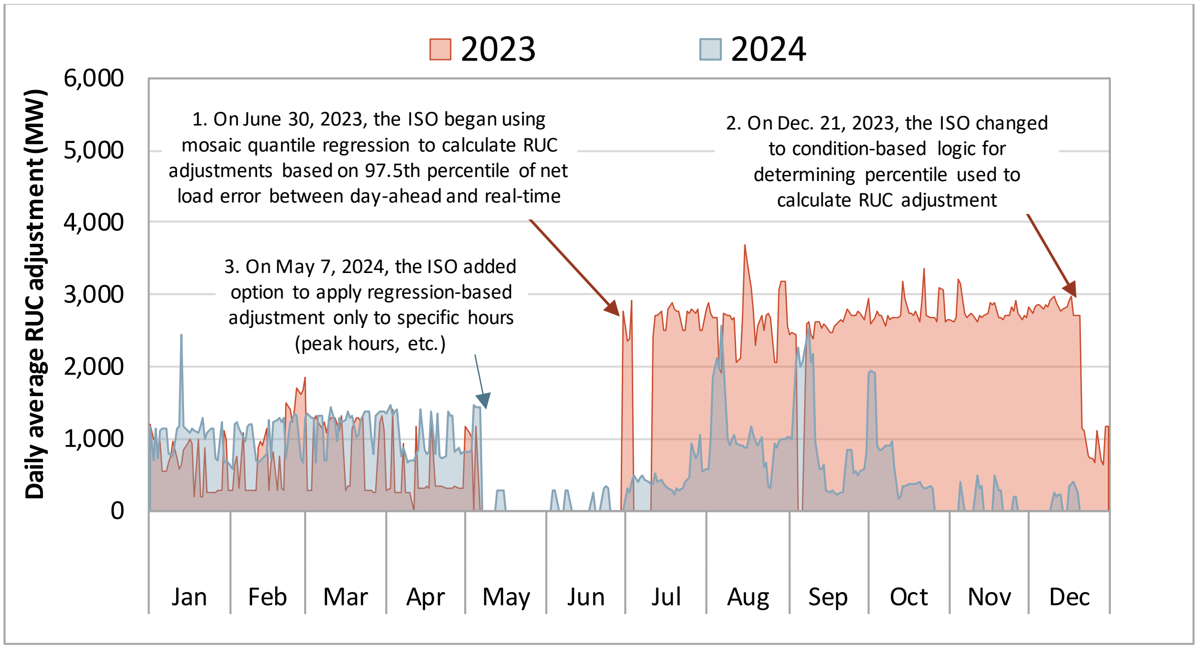
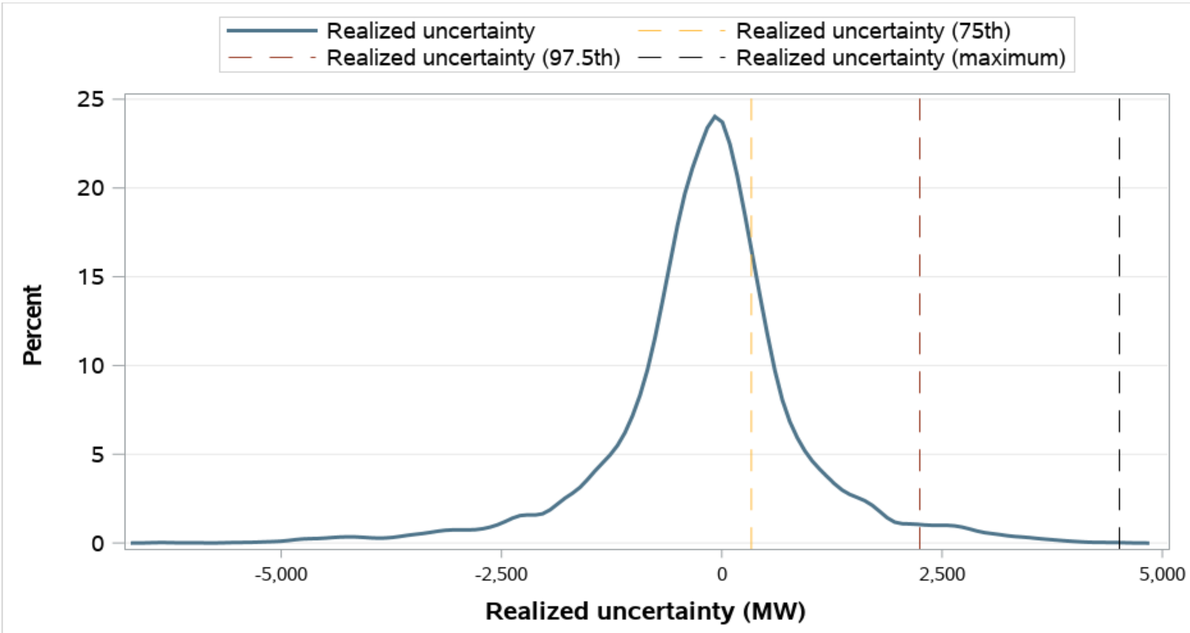


Figure 10.8 shows this quarter's distribution of realized uncertainty between the net load forecasts of the day-ahead market and the 15-minute market. This distribution represents all uncertainties observed in the 15-minute market intervals for this quarter and serves as the forecasting target. The first notable feature is that net load uncertainty in the day-ahead time horizon ranged from -6,400 MW to 4,500 MW. The distribution shows a long tail, with the area between the red dashed line and the black dashed line highlighting the range from the 97.5th percentile of uncertainty up to the maximum value. This area ranged from 2,200 MW to 4,500 MW. A long tail could indicate rare but impactful events, such as unexpected weather changes or some other cause of a sudden shift in demand or renewable resource output.

Figure 10.8 Distribution of realized uncertainty between RUC and 15-minute market net load forecasts (October–December 2024)



10.3.1 Results of uncertainty calculation for residual unit commitment

Figure 10.9 shows the average RUC adjustment on each day since May 7, 2024 during the peak morning and evening hours (hours 7 to 9 and 19 to 21). The figure also shows the estimated percentile that was used to determine the additional requirements for the peak hours of each day.[89] During the fourth quarter, the 97.5th percentile target was applied on 3 percent of days while the 75th percentile target was applied on 9 percent of days. The 50th percentile target was applied on 34 percent of days. During much of the quarter, no adjustment was applied (54 percent of days). Figure 10.10 instead shows the average RUC adjustment for each day *across all hours*.[90] The dotted black line (right axis) shows the number of hours in which the adjustment was applied. At the start of October, the ISO applied an operator adjustment to the mid-day hours, but otherwise restricted the adjustment to either the peak hours or no hours the rest of the quarter.

The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty as this RUC adjustment, but the imbalance reserve up requirement will be set to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in RUC indicates that the imbalance reserve product demand curve may be much too high during most hours.

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

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

Figure 10.9 Average residual unit commitment adjustment by day (peak morning and evening hours, May 7–December 31, 2024)

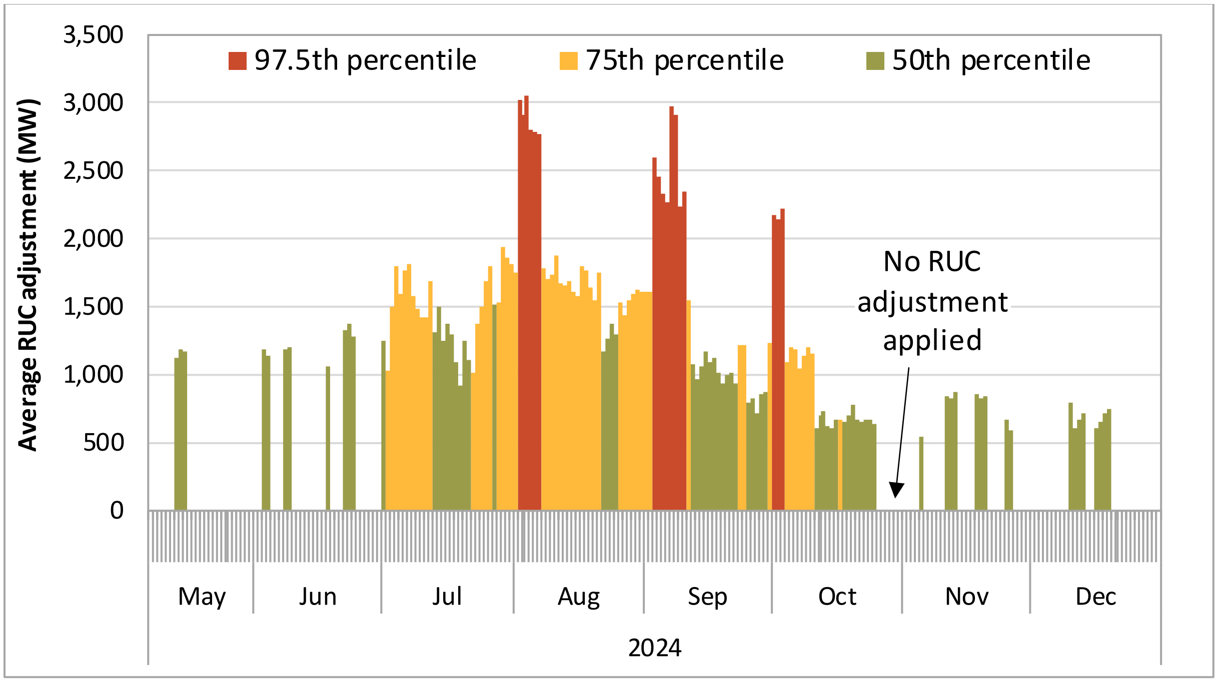


Figure 10.10 Average residual unit commitment adjustment by day (all hours, May 7–December 31, 2024)

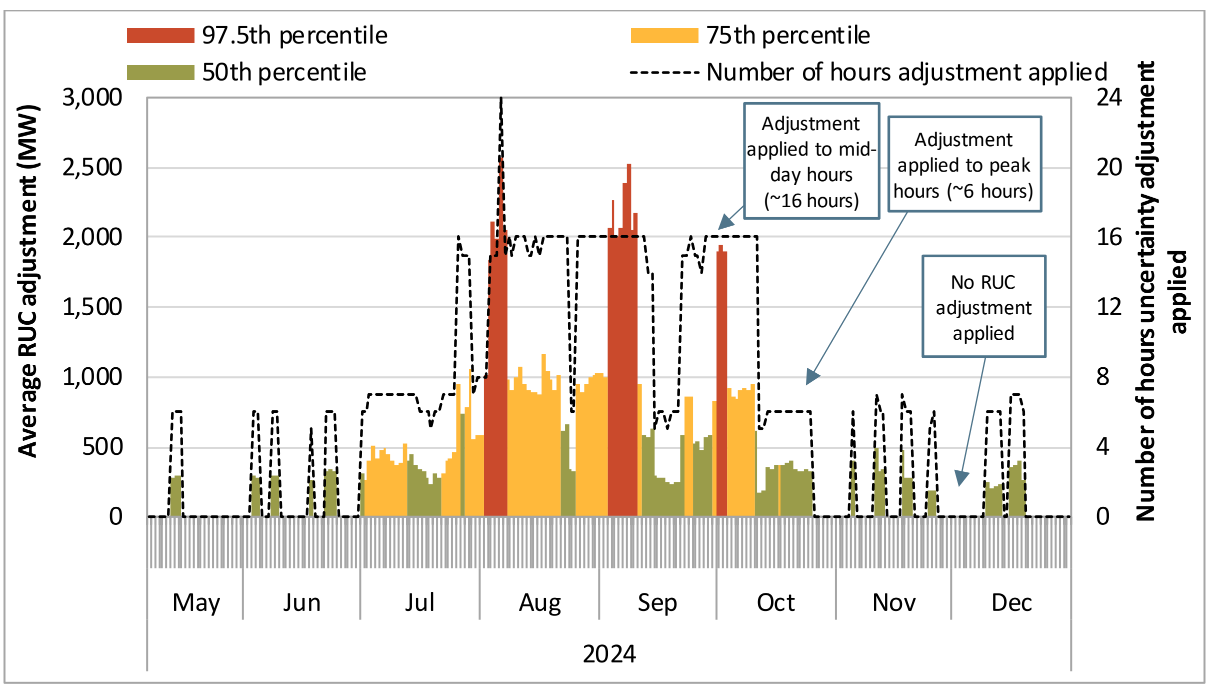


Table 10.5 summarizes the average requirement and coverage based on the percentile target that was selected and the hours it was applied (either mid-day hours or peak hours). Coverage shows the percent of 15-minute market intervals in which realized uncertainty from the day-ahead market to the real-time market was below the RUC adjustment quantity. The average requirement and coverage were assessed only in hours the uncertainty adjustment was applied. Average requirements using the 97.5th percentile target were roughly double those using the 75th percentile target while coverage was higher (100 percent compared to 91 percent for adjustments applied during mid-day hours).

Table 10.5 Average residual unit commitment uncertainty adjustment and coverage (October–December 2024)

Percentile target	Hours applied	Percent of days	Average requirement	Coverage
97.5th percentile	Mid-day hours	3%	2,879	100%
75th percentile	Mid-day hours	8%	1,352	91%
	Peak hours	1%	1,471	88%
50th percentile	Mid-day hours	1%	913	75%
	Peak hours	33%	1,255	82%

Table 10.6 represents DMM's simulation of the RUC adjustment using the mosaic quantile regression. It provides insight into the different percentiles used in the market and illustrates the likely outcomes if a specific percentile were applied to forecast the RUC adjustment.

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

The 97.5th percentile regression showed a zero rate of statistical significance, likely due to sample size. This specific percentile regression focuses on only 4 to 5 observations.[91] While an underlying pattern may exist, the small sample size of 4 to 5 observations is insufficient to find such a pattern, resulting in zero statistical significance.

The coverage rates for regression were notably inflated. For example, the 50th percentile regression, designed to capture 50 percent of realized uncertainty, showed coverage rates of 76 percent and 82 percent during peak hours.

This inflation arises from two key factors. First, while the realized uncertainty represents the difference between day-ahead and 15-minute net load forecasts, available as four uncertainty realizations per hour, the regression model forecasts the maximum uncertainty for each hour. This discrepancy inflated the result. As shown in Figure 10.8, the realized uncertainty distribution indicated the 50th percentile value was around -100 MW, meaning that a -100 MW requirement would effectively achieve 50 percent

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

coverage. However, the 50th percentile regression averaged around 590 MW (as shown in Table 10.6). This means that the regression is producing over 700 MW more than ideal, due to the practice of forecasting the maximum uncertainty per hour. Second, the regression in RUC estimates only the upper bound of uncertainty, meaning any negative uncertainty is automatically covered, contributing to the inflated coverage rate.

Table 10.6 DMM simulation for RUC adjustment using mosaic quantile regression (October–December 2024)

	Requirement (MW)		Percent of significant coefficients		Coverage	
	All hours	Peak hours(1)	All hours	Peak hours	All hours	Peak hours
Replication (97.5th)	2,123	2,291	0%	0%	100%	100%
Replication (75th)	1,082	1,414	24%	40%	91%	93%
Replication (50th)	591	957	40%	50%	76%	82%
Replication (25th)	125	488	38%	49%	53%	62%

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

11 Wheeling rights

The ISO began developing a framework that establishes high-priority wheeling through scheduling priorities in the CAISO balancing area following the power outages in the summer of 2020. In July 2021, the ISO started the Transmission Service and Market Scheduling Priorities (TSMSP) initiative that had two phases: an interim phase to establish wheeling-through priorities for the challenging system conditions in the summer of 2022, and a longer-term framework that started in 2024. External suppliers and load serving entities can now reserve the capacity to self-schedule wheel-through transactions that have the same scheduling priority as CAISO demand in advance of the market runs on rolling monthly and daily timeframes.[92]

11.1 Transmission capacity reservations and usage

The following analysis shows the reserved priority wheel-through (PWT) capacity and native load need estimates on interties that experienced demand for reservations.

Table 11.1 shows all of the monthly priority wheel-through reservations made in the second, third, and fourth quarters by CAISO market tie point. Schedulers reserved less priority wheel-through capacity, and on fewer interties, in the fourth quarter compared to previous quarters. Participants reserved monthly priority wheel-through capacity on the IPP and PVWEST tie points in October. Participants did not reserve monthly capacity in November or December.

92 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

Table 11.1 2024 monthly high priority wheel-through reservations by CAISO market tie point[93]

Quarter	Month	CAISO market tie point	Monthly PWT
Q2	Jun	MALIN500	72
		NOB	378
		RDM230	225
Q3	Jul	MALIN500	77
		NOB	378
		PVWEST	10
		RDM230	225
	Aug	IPP	25
		MALIN500	97
		NOB	378
		PVWEST	10
		RDM230	225
	Sep	IPP	25
		NOB	250
		PVWEST	10
		RDM230	225
Q4	Oct	IPP	25
		PVWEST	10

Figure 11.1 to Figure 11.2 show the four categories of capacity on the interties with any priority wheel-through reservations in the quarter. Scheduling coordinators can reserve available priority wheel-through capacity (green bars) at interties if there is leftover available transmission capacity after accounting for (1) native load need (blue bars), (2) any previously reserved priority wheel-through capacity (turquoise bars), and a transmission reliability margin (yellow bars), The thick horizontal red lines in these figures show the available transmission capacity (ATC), which is the total transmission capacity leftover after accounting for outages and existing transmission rights (TTC – outages – ETC/TORs).

The total volume of capacity in these four categories (shown by the stacked bars) can total more than the available capacity of an intertie if outage conditions or native load need values change between reservation windows. For example, the final capacity values for June could total more than the final available transmission capacity if the ISO underestimates the native load need before the final resource

93 Table 11.1 reports priority wheel-through reservations for the CAISO market tie point of the wheel import leg. 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 the most limiting 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

adequacy (RA) showings, or if new intertie outages lower intertie availability below values the ISO assumed would be available for the month in previous reservation windows.

Figure 11.1 shows the monthly transmission capacity reservations at the IPP intertie.[94] Priority wheel-through reservations in October (25 MW) remained the same from the previous quarter. There were no priority wheel-through reservations on IPP for November and December. Native loads required the most amount of capacity over the intertie in October (about 400 MW) compared to the other months (about 300 MW), however the total available capacity sufficiently covered the native load need along with the priority wheel-through reservations and the transmission reliability margin (TRM).

Figure 11.1 Monthly transmission capacity values at IPP market tie point

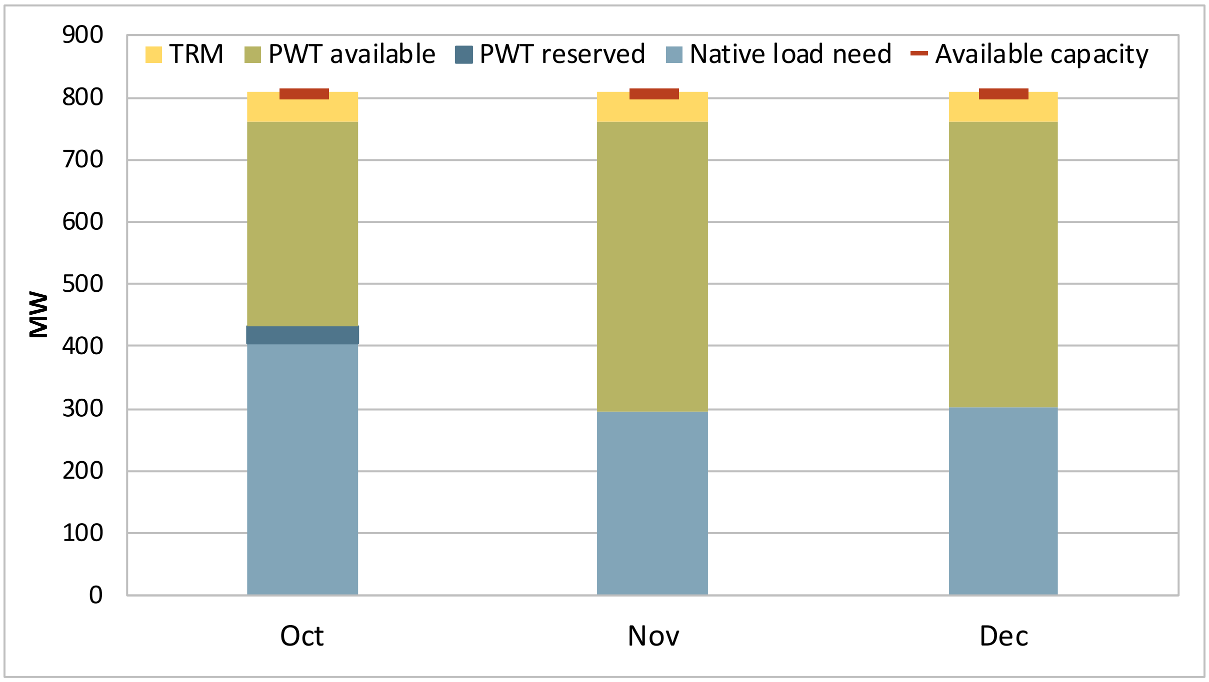


Figure 11.2 shows the monthly transmission capacity reservations at PVWEST.[95] Priority wheel-through reservations in October (10 MW) remained the same from the previous quarter. There were no priority wheel-through reservations on PVWEST for November and December. Native loads required the most amount of capacity over the intertie in October (about 1,300 MW) compared to the other months (about 1,100 MW). PVWEST was oversubscribed relative to the anticipated transmission availability in October.

94 Represented by the capacity values of the IPPDCADLN_ITC intertie constraint, as the most limiting intertie constraint applicable to this market tie point.

95 Represented by the capacity values of the PALOVRDE_ITC constraint, as the only intertie constraint applicable to this market tie point.

Figure 11.2 Monthly transmission capacity values at PVWEST market tie point

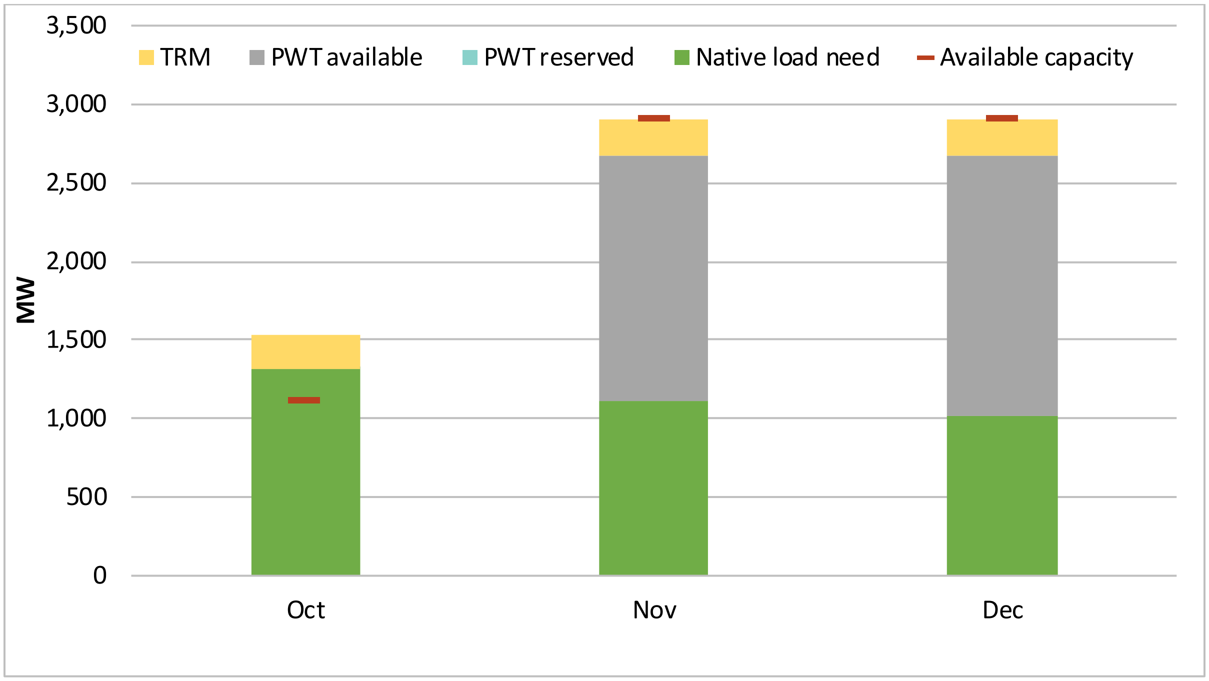


Figure 11.3 shows the daily transmission capacity reservations at PVWEST. The figure shows the oversubscription in October was due to an intertie derate for one day on the 29th, when the available capacity dropped from 2,897 MW to 1,107 MW. On the other days, the higher daily available transmission capacity values allowed for more priority wheel-through reservations (1,359 MW); however, there were no incremental priority wheel-through reservations between the monthly and daily timeframes.

Figure 11.3 Daily transmission capacity values at PVWEST market tie point

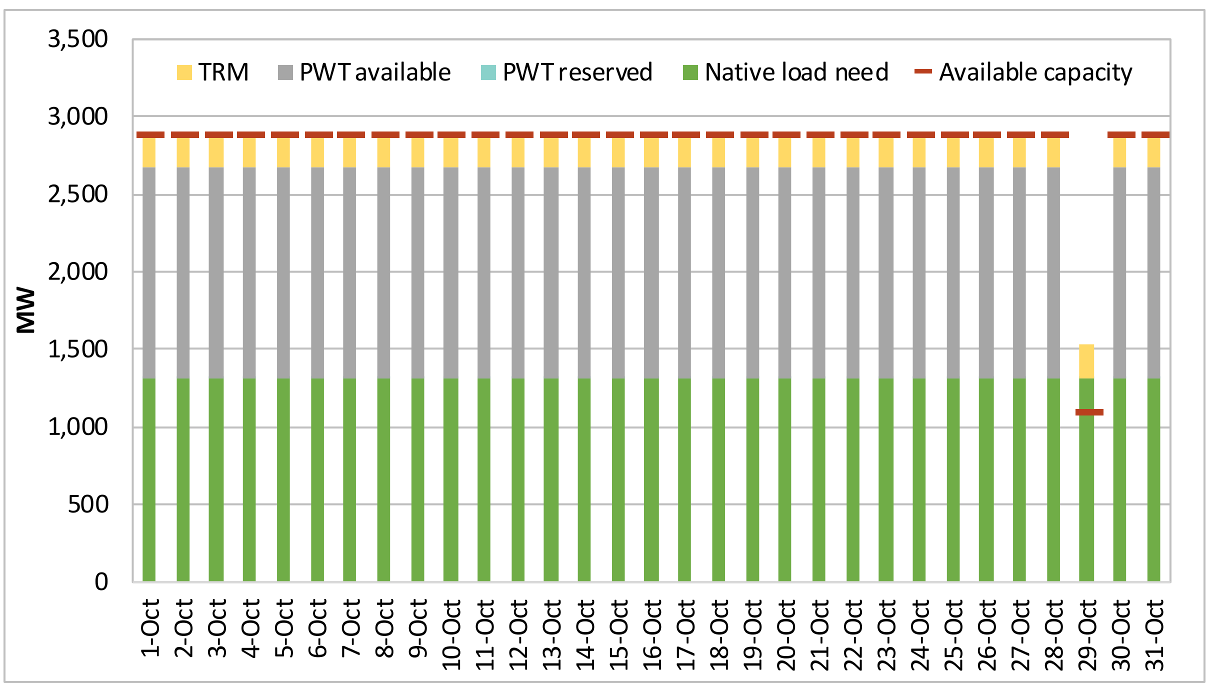


Figure 11.4 to Figure 11.5 show how native load need estimates compare to final import showings from load serving entities. In calculating available transmission capacity for priority wheel-throughs for future months, the ISO sets aside transmission capacity by estimating what native load needs will be. Ultimately, the amount of 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 ISO.

Final resource adequacy plans are due 30 days prior to the relevant month. Before T-30, the ISO estimates how much intertie transmission capacity native loads will need by taking the maximum amount of shown import RA and non-RA contracted imports delivered on that intertie for the same month over the previous two years.

In addition, the ISO accounts for the impact that load growth may have on native load needs by calculating a load growth value from the California Energy Commission load forecast. This is because loads may have increased over the value that determined maximum resource adequacy obligations over the past two years. The ISO updates these native load need numbers after load serving entities submit their final resource adequacy plans.

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

Figure 11.4 shows the native load need estimate and final value for IPP.[96] The ISO estimated native loads would need about 414 MW of transmission capacity in October, 294 MW in November, and 223 MW in December. This overestimated actual native load needs by 8 MW (or 2 percent) in October, overestimated November native load need by less than a megawatt, and underestimated December native load need by 79 MW (26 percent).

[96] Represented by the capacity values of the IPPDCADLN_ITC intertie constraint, as the most limiting intertie constraint applicable to this market tie point. These values do not necessarily represent the native load need at this specific tie point, but reflect the impacts of native load need on this intertie constraint, from all tie points impacted by this intertie constraint.

Figure 11.4 Native load need estimate vs. final import RA impacting IPP market tie point

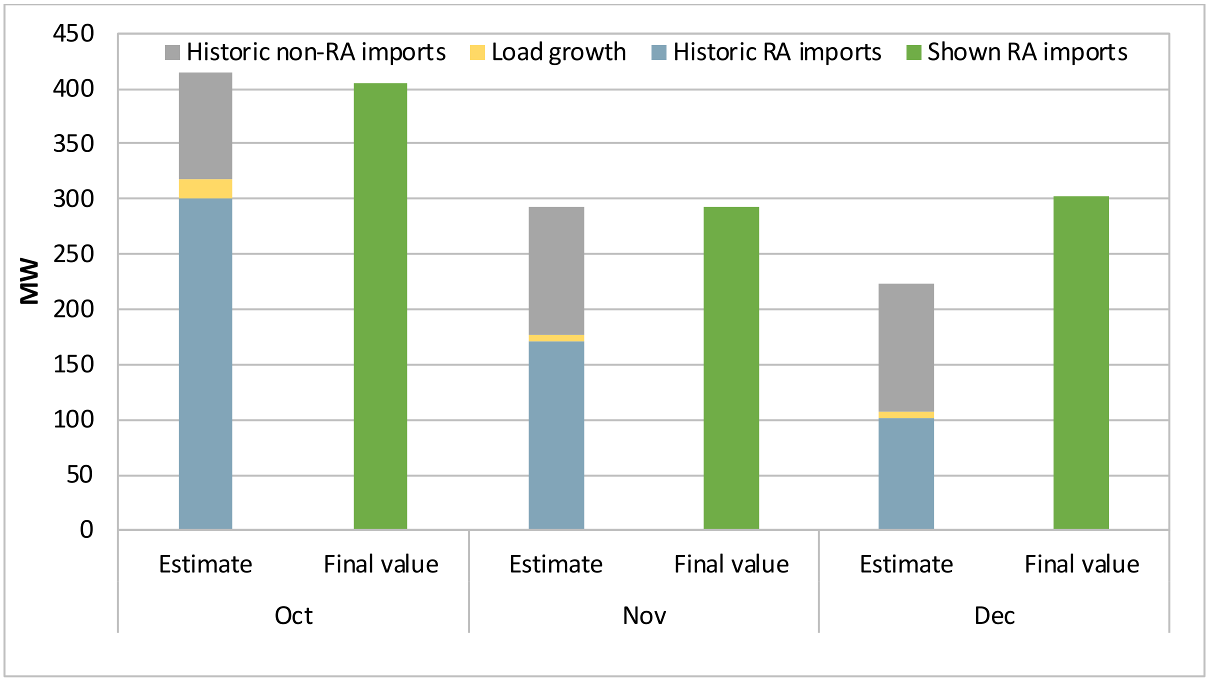


Figure 11.5 shows the native load need estimates and final values for the PVWEST market tie point.[97] The ISO estimated native loads would need 940 MW in October, 620 MW in November, and 991 MW in December. This underestimated actual native load needs by 370 MW (or 28 percent) in October, 497 MW (45 percent) in November, and 31 MW (3 percent) in December.

[97] Represented by the capacity values of the PALOVRDE_ITC intertie constraint, as the only intertie constraint applicable to this market tie point.

Figure 11.5 Native load need estimate vs. final import RA at PVWEST market tie point

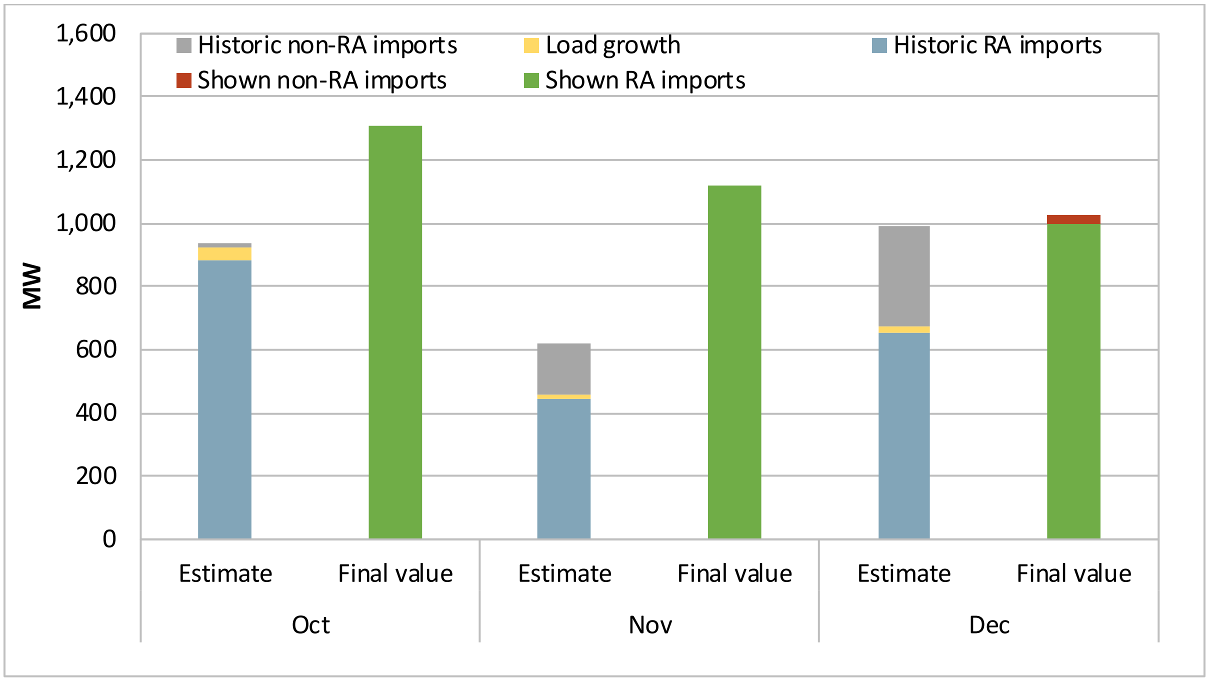
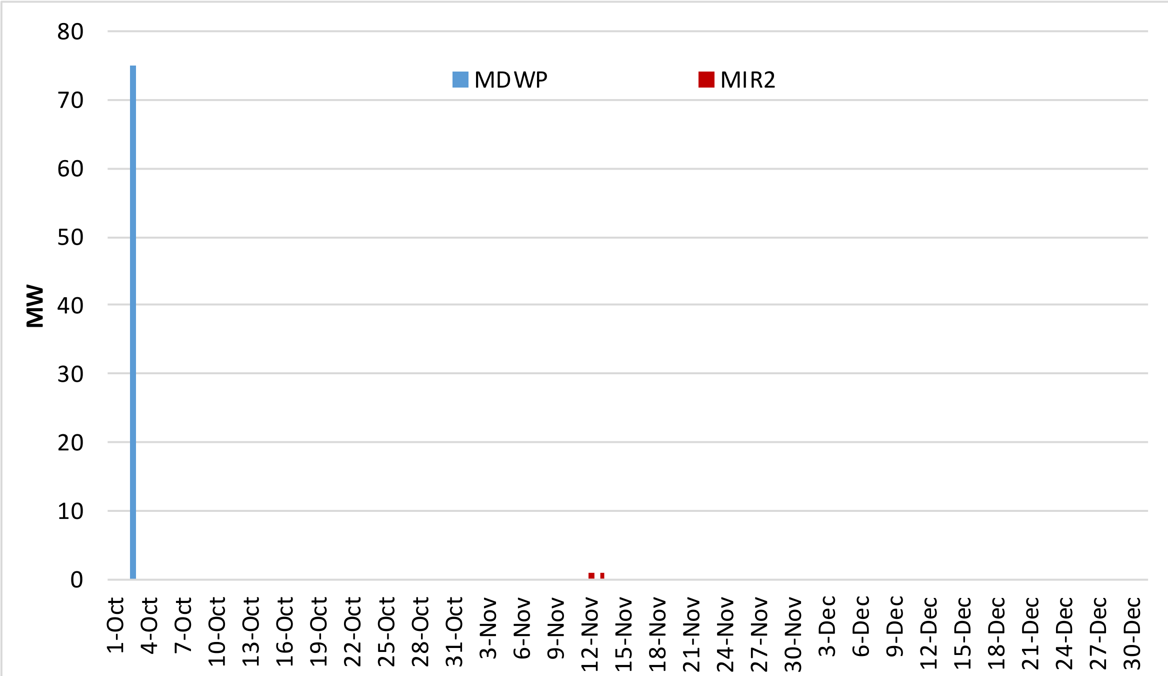


Figure 11.6 shows incremental priority wheel-through reservations on the daily timeframe. Participants can reserve additional priority wheel-through capacity for specific days if priority wheel-through capacity remains after the monthly reservation process or if the available capacity of the intertie increases from expected levels during previous reservation windows. Participants reserved incremental priority wheel-through capacity on the MDWP tie point (75 MW on October 3) and MIR2 tie point (1 MW on November 12 and November 13).[98] Of all the priority wheel-through reservations in the quarter, both on the monthly and daily horizons, the capacity on the MIR2 intertie is the only reservation to use the high priority self-schedules in the market.

98 Represented by the capacity values of the MONAIPPDC_ITC and IID-SCE_ITC constraints, respectively.

Figure 11.6 Incremental daily PWT reservations by CAISO market tie point



12 Resource adequacy

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

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

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

However, 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 there to be insufficient resource adequacy capacity in real-time to cover market requirements, rather than a shortcoming in the resource adequacy program design.

Table 12.1 shows the hours during the fourth quarter of 2024 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 market requirements for energy and upward ancillary services. Available resource adequacy capacity was not sufficient to meet CAISO balancing area market requirements in five hours of the fourth quarter. All of these hours were hour-ending 19 on days between October 1 and October 7, 2024.

Table 12.1 Resource adequacy bids vs. market requirement

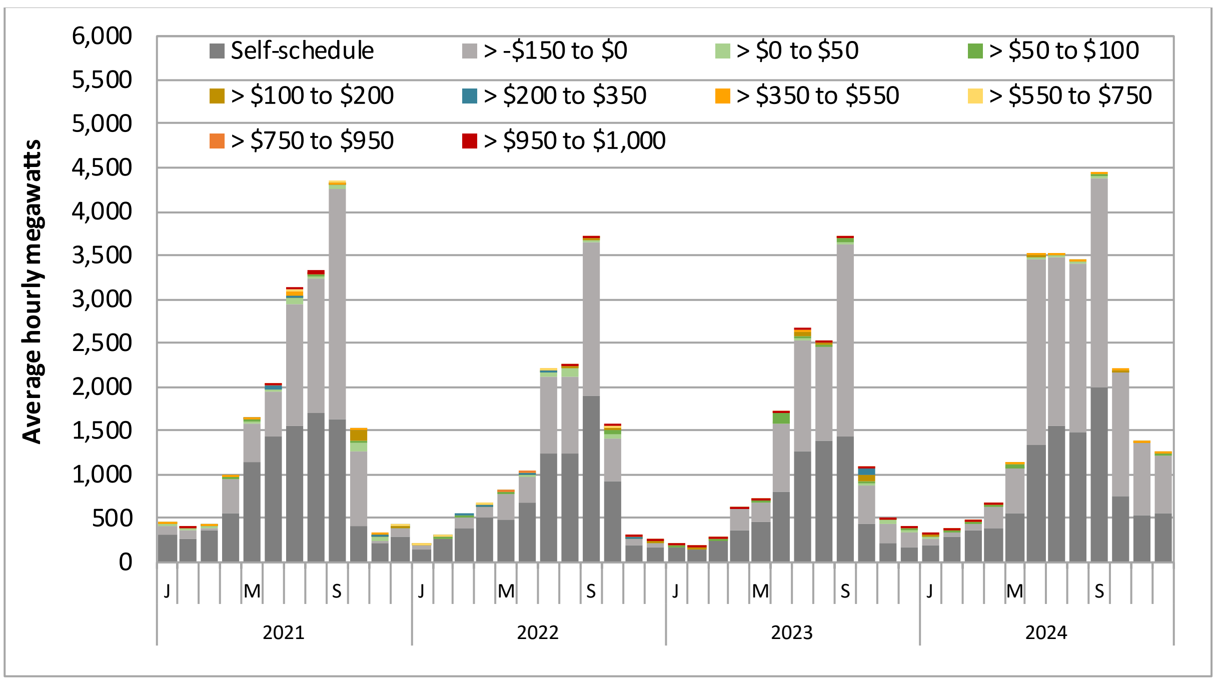
Date	Hour	Real-time requirement			Real-time resource adequacy bids			Total available RA - Total requirement
		Market requirement + losses	+ Regulation	+ Reserves	Resource adequacy + Above RA VERs	RA bids	Above RA VERs	
10/1/2024	19	39,340	39,870	42,129	40,893	40,681	211	-1,236
10/2/2024	19	41,066	41,596	44,001	42,641	41,283	1,358	-1,360
10/3/2024	19	39,808	40,338	42,662	42,194	41,095	1,099	-468
10/6/2024	19	37,207	37,737	39,930	38,508	37,956	552	-1,422
10/7/2024	19	39,858	40,388	42,743	41,469	40,722	746	-1,274

12.2 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.[99] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices of imports. An overall decline in volumes began in late 2020 and continued throughout 2021, but appear to have stabilized since then. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

Figure 12.1 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[100] The dark grey bars reflect import capacity that was self-scheduled. The light grey bars show imports bid at or below $0/MWh. The remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market bid above $0/MWh. Overall bid-in levels of resource adequacy imports increased in October, November, and December compared to the same months of 2023, by 103 percent, 181 percent, and 213 percent, respectively. Overall, resource adequacy import bids in Q4 2024 increased 145 percent over Q4 2023.

Figure 12.1 Average hourly resource adequacy imports by price bin



[99] 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.

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

13 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the fourth quarter of 2024 was 68 percent lower than the same quarter of 2023. Operator adjustments to the RUC procurement target decreased by about 90 percent for the same period. This was in large part because of changes in the methodology for determining the adjustments on December 21, 2023 and May 7, 2024. CAISO balancing area methods for determining operator adjustments are discussed in detail in Section 10 above on uncertainty.

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

13.1 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 13.1 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 13.1 depict the day-ahead forecasted load versus cleared day-ahead capacity, which includes both physical supply and net virtual supply. This represents the difference between the California ISO day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). On average, this factor contributed towards increasing residual unit commitment requirements by about 290 MW per hour in the fourth quarter of 2024, down from about 530 MW in Q4 2023.

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 13.1.

Lastly, operators will often increase the residual unit commitment market's target load requirement to a value above the day-ahead market load forecast. This allows the residual unit commitment market to procure extra capacity to account for uncertainty that may materialize in the load forecast and scheduled physical supply. The red bars in Figure 13.1 show the average adjustment to the residual unit commitment requirement. During 2023 and 2024, there were significant changes to how these amounts were determined. The operator adjustments and the changes in the methodology are described in Section 10 above on uncertainty.

Figure 13.2 shows the hourly distribution of these operator adjustments during the fourth quarter of 2024. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour.

Figure 13.1 Average incremental residual unit commitment requirement by component

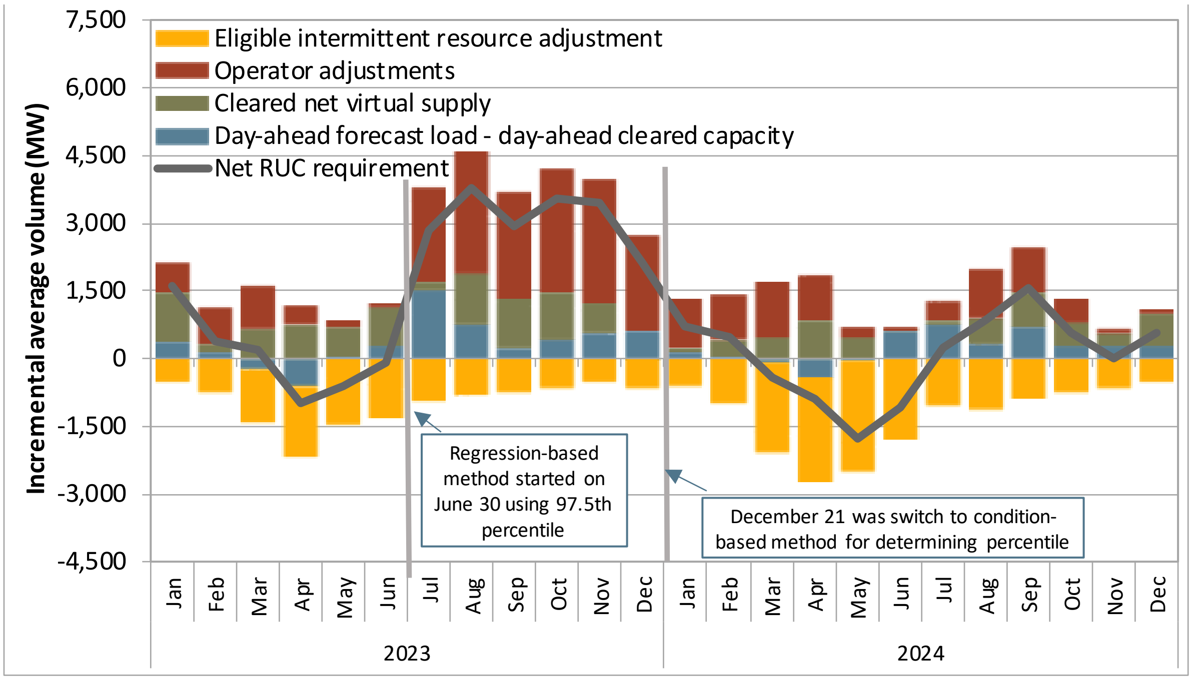
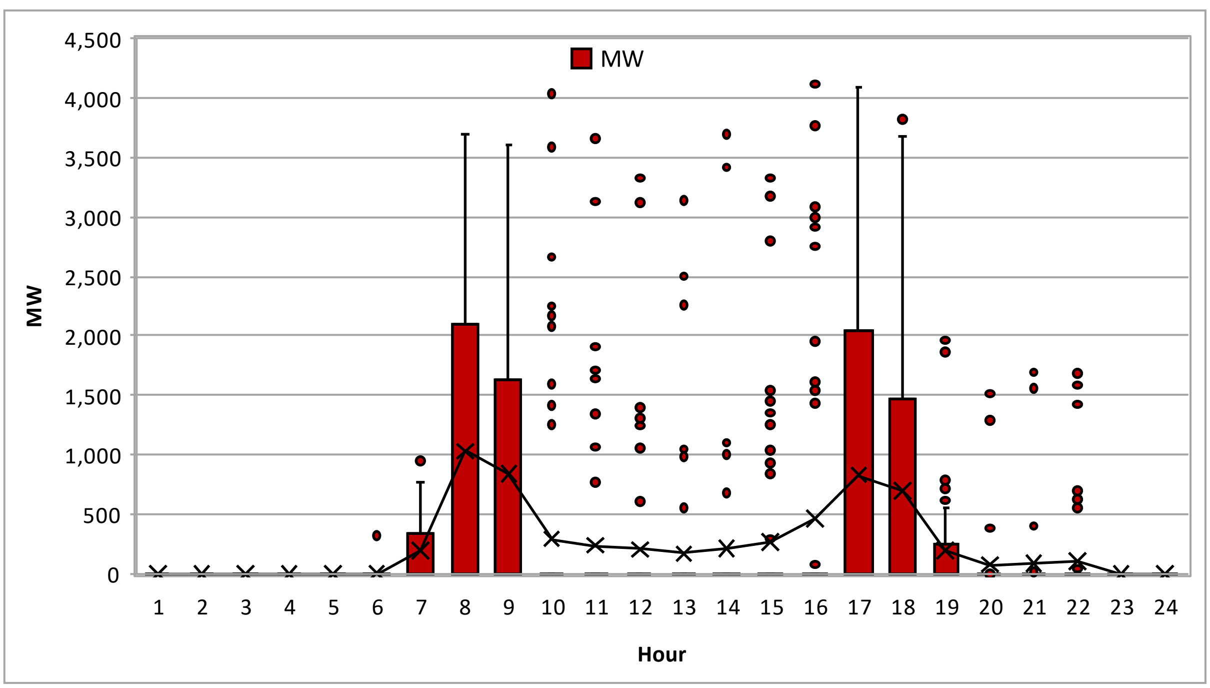


Figure 13.2 Hourly distribution of residual unit commitment operator adjustments (October–December 2024)

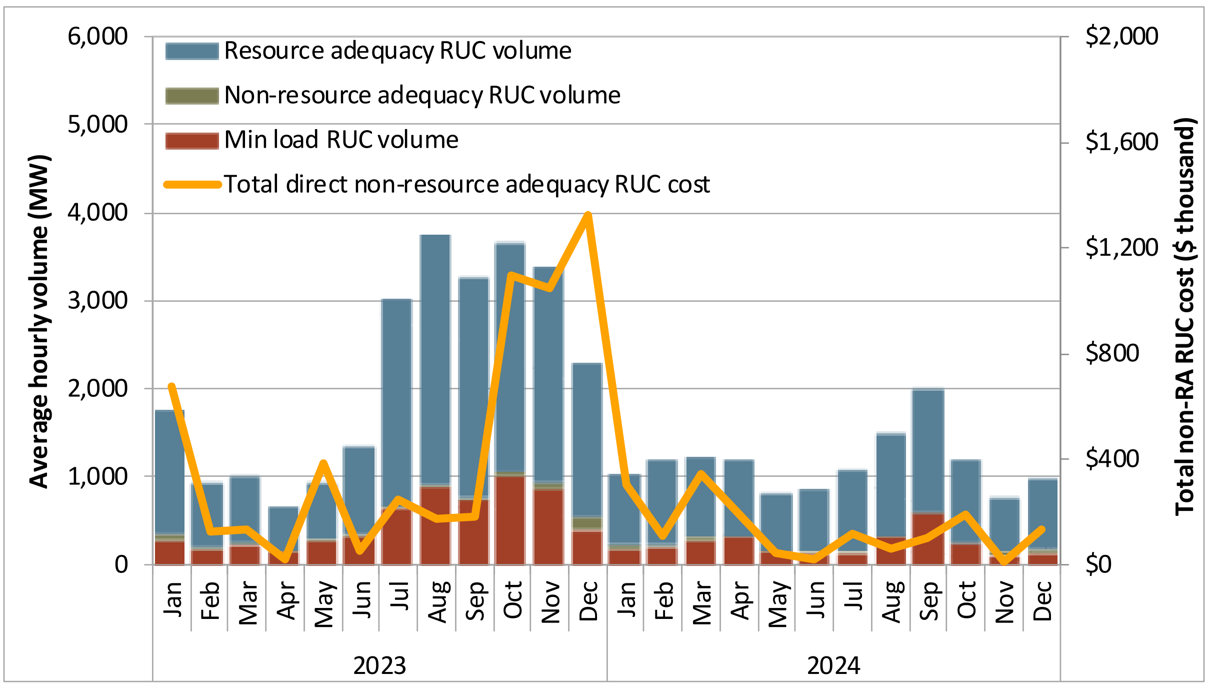


13.2 Residual unit commitment procurement and costs

Figure 13.3 shows the monthly average hourly residual unit commitment (RUC) procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The average residual unit commitment procurement for the fourth quarter of 2024 decreased by 68 percent to about 1,000 MW, from an average of about 3,100 MW in the same quarter of 2023. Of the 1,000 MW capacity, the capacity committed to operate at minimum load averaged about 170 MW.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units receiving awards in this process receive RUC capacity payments.[101] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 13.3. In the fourth quarter of 2024, these costs were about $337,000, or about 10 percent of the costs in the same quarter of 2023.

Figure 13.3 Residual unit commitment costs and volume



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

14 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. In the fourth quarter, financial entities received the vast majority of profits from convergence bidding, while marketers were the only others to profit.

14.1 Convergence bidding revenues

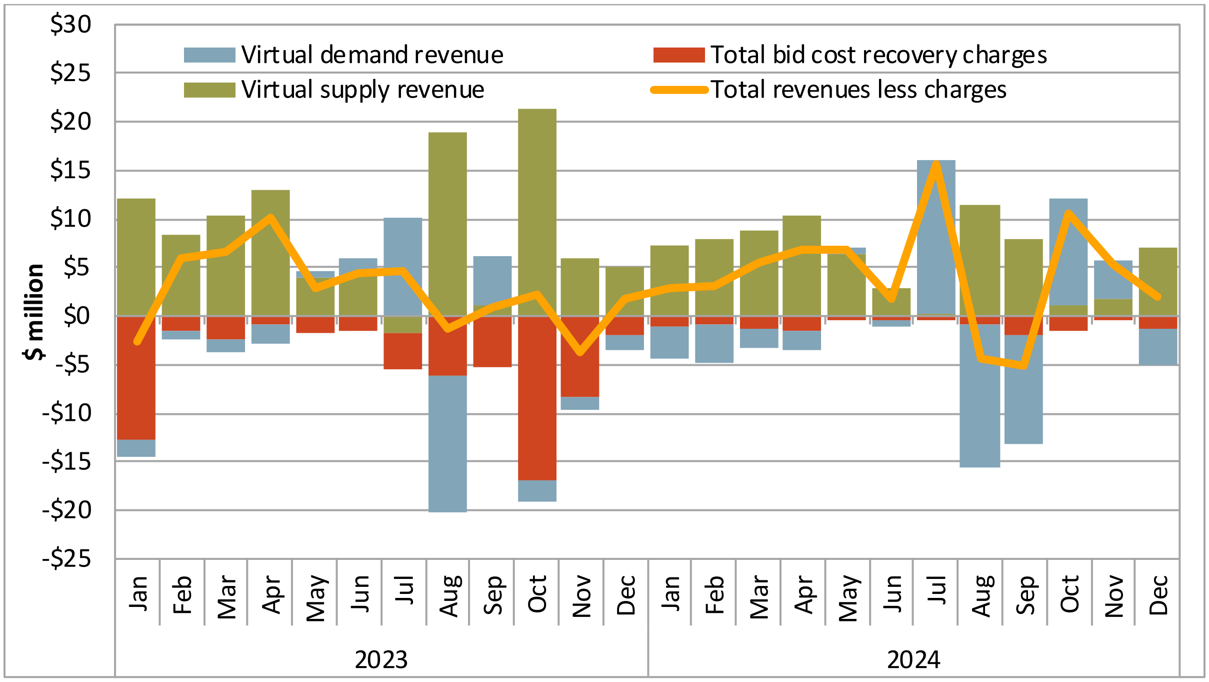
Net revenues for convergence bidders were about $17.8 million for the fourth quarter, after inclusion of about $3.2 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply.[102] Figure 14.1 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). Before accounting for bid cost recovery charges:

- Convergence bidding revenues were positive during all months of the quarter, totaling $17.8 million. In comparison, total market revenues were around $330,000 in the fourth quarter of 2023.
- Virtual demand revenues were about $10.8 million, $4.1 million, and -$3.9 million for October, November, and December, respectively.
- Before accounting for bid cost recovery, virtual supply revenues were about $1.2 million, $1.7 million, and $7.1 million for October, November, and December, respectively.

Bid cost recovery charges allocated to virtual bids were about $1.5 million, $470,000, and $1.2 million for October, November, and December, respectively. The majority of bid cost recovery allocated to virtual bidding participants in this quarter was charged to the residual unit commitment (RUC) tier 1 allocation, which helps offset costs related to periods with net virtual supply. Virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in RUC. When market revenues do not cover the commitment costs of resources committed in RUC, the resources receive bid cost recovery payments, and some of this bid cost recovery is allocated to virtual supply during periods with net virtual supply.

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

Figure 14.1 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 14.1 compares the distribution of convergence bidding cleared volumes and revenues, before and after taking into account bid cost recovery, in millions of dollars, among different groups of convergence bidding participants.[103,104]

After accounting for bid cost recovery, financial entities received nearly 87 percent of the total revenue earned from convergence bidding. Financial entities and marketers accounted for about 85 percent and 15 percent, respectively, of the cleared volume of virtual trades in the fourth quarter.

103 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

104 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, and participants whose portfolios are not primarily focused on physical or financial participation in the California ISO market.

Table 14.1 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2024 Q4								
Financial	3,412	3,736	7,149	$9.83	$8.02	-$2.15	$5.87	$15.71
Marketer	640	660	1,301	$1.22	$1.58	-$0.55	$1.02	$2.25
Physical load	5	39	44	-$0.01	$0.06	-$0.09	-$0.03	-$0.04
Physical generation	52	177	229	-$0.03	$0.28	-$0.37	-$0.09	-$0.12
Total	**4,109**	**4,612**	**8,723**	**$11.01**	**$9.94**	**-$3.16**	**$6.77**	**$17.80**

15 Ancillary services and available balancing capacity

Ancillary service payments totaled $18.3 million, a 3 percent decrease from the same quarter last year. Average requirements for regulation up and regulation down increased compared to the fourth quarter of 2023. Average operating reserve requirements remained the same compared to the fourth quarter of 2023.

Similar to previous quarters, available balancing capacity was dispatched for generation shortfalls in less than 1 percent of intervals for most WEIM balancing areas.

15.1 Ancillary service requirements

The California ISO procures four ancillary services for the CAISO balancing area in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. 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.[105] 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.[106] 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.

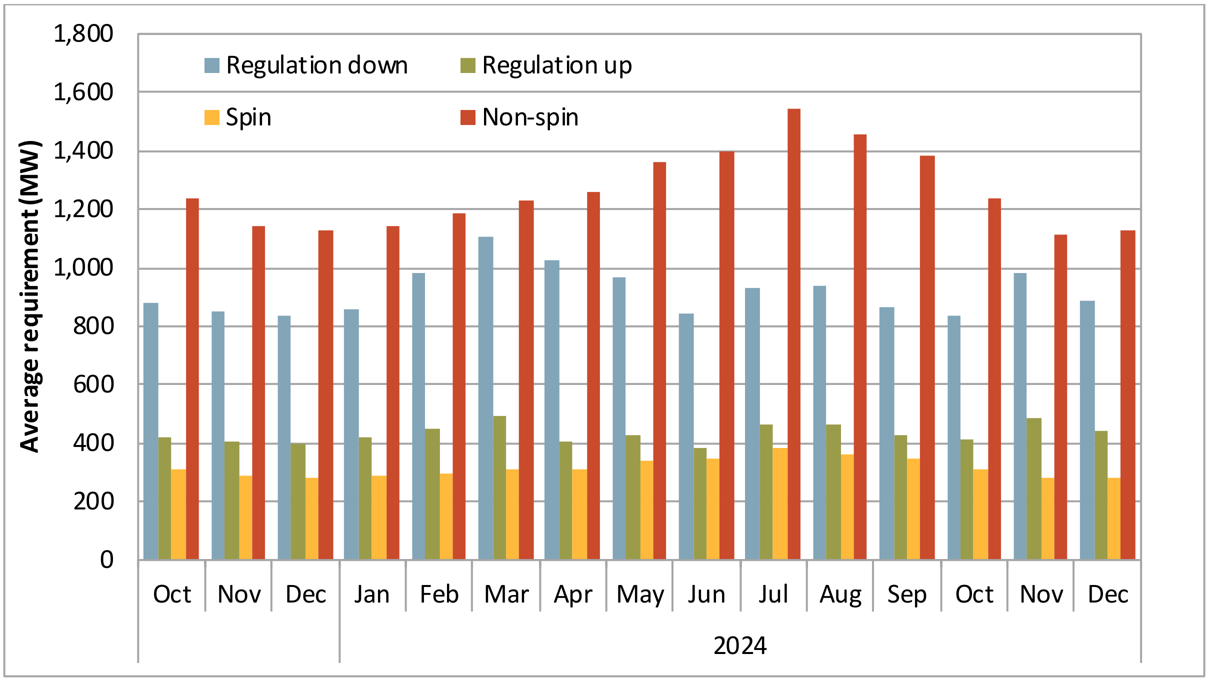
Starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. Since the second quarter of 2023, CAISO operators have procured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

Figure 15.1 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation up and regulation down requirements increased 10 percent and 5 percent, respectively, compared to the fourth quarter of 2023. Average requirements for operating reserves did not change significantly year-over-year.

105 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

106 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 15.1 Average monthly day-ahead ancillary service requirements



15.2 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 fourth quarter of 2024.

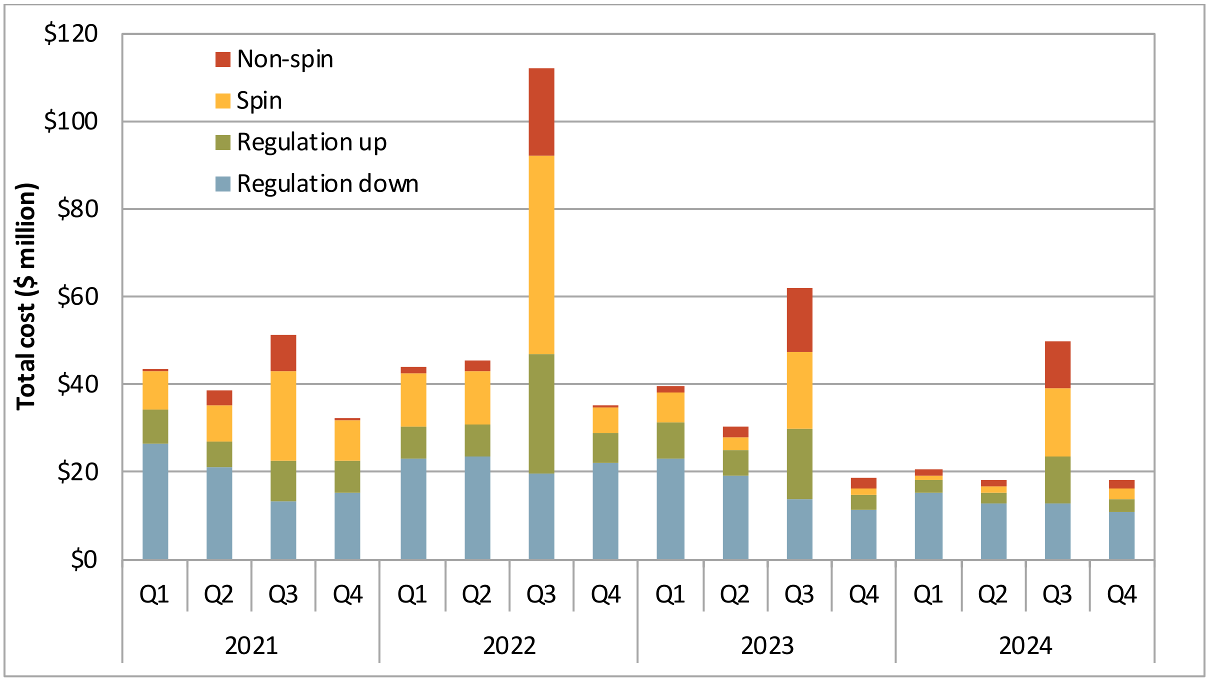
15.3 Ancillary service costs

Ancillary service payments totaled $18.3 million in the fourth quarter of 2024, around $576 thousand less than the same quarter of the previous year.

Figure 15.2 shows the total cost of procuring ancillary service products by quarter.[107] Payments for regulation down, regulation up, and non-spinning reserve decreased 4 percent, 8 percent, and 26 percent, respectively, compared to the fourth quarter of 2023. Spinning reserve costs increased $854 thousand, or around 57 percent, compared to the fourth quarter of 2023.

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

Figure 15.2 Ancillary service cost by product



15.4 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 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 15.1 summarizes the frequency of upward and downward available balancing capacity offered in each area in the fourth quarter. Available balancing capacity was dispatched in less than 1 percent of intervals for all areas except for NV Energy, which had both products dispatched in 3 percent of intervals in the 15-minute and 5-minute markets.

Table 15.1 Frequency of available balancing capacity offered (Q4)

	ABC Up Offered		ABC Down Offered	
	Percent of Hours	Average MW	Percent of Hours	Average MW
BANC	100%	82	100.0%	92
Bonneville Power Admin.	100%	317	100.0%	600
Turlock Irrigation District	100%	15	100.0%	333
Avista Utilities	100%	10	100.0%	5
Powerex	100%	1,139	100.0%	10
Tucson Electric	100%	30	100.0%	30
Salt River Project	100%	99	96.0%	15
WAPA - Desert Southwest	96%	15	98.0%	5
NV Energy	100%	70	96.0%	50
Portland General Electric	99%	30	93.0%	3
Tacoma Power	87%	2	100.0%	61
NorthWestern Energy	98%	5	97.0%	70
Arizona Public Service	99%	61	28.0%	33
LADWP	83%	61	95.0%	176
PacifiCorp East	35%	76	5.0%	105
Seattle City Light	0%	N/A	0.0%	N/A
PacifiCorp West	1%	112	1.0%	50
PSC New Mexico	0%	N/A	0.0%	N/A
El Paso Electric	0%	N/A	0.0%	N/A
Puget Sound Energy	0%	N/A	0.0%	N/A
Avangrid	100%	38	0.0%	N/A
Idaho Power	0%	N/A	0.0%	N/A

16 Generation outages

This section covers information on generation outages in the California ISO balancing area and the WEIM by region.[108] The average generation on outage in the California ISO balancing area averaged about 18,400 MW in the fourth quarter of 2024, a 36 percent increase from the fourth quarter of 2023.[109] In the WEIM, the California region, excluding the CAISO balancing area, averaged 4,400 MW of total generation outages, a 14 percent decrease from the fourth quarter of 2023. The Desert Southwest region averaged about 9,400 MW of total generation outages, a 12 percent decrease from the fourth quarter of 2023. The Intermountain West region averaged about 2,400 MW of total generation outages, a two percent decrease from the fourth quarter of 2023. The Pacific Northwest region averaged about 3,000 MW of total generation outage, a 1 percent decrease from the fourth quarter of 2023.

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

109 This is calculated as the average of the daily maximum level of outages, excluding off-peak hours.

Under the current California ISO outage management system, known as WebOMS, all outages are categorized as either “planned” or “forced”. An outage is considered *planned* if a participant submitted it more than 7 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.

16.1 California ISO balancing area

Figure 16.1 and Figure 16.2 show the quarterly and monthly averages, respectively, of maximum daily outages during peak hours by type from the first quarter of 2023 through the fourth quarter of 2024.[110] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period. Looking at the monthly outages, there are usually a higher number of outages in the fall, winter, and early spring than in the summer months, and this trend continued in 2024.

During the fourth quarter of 2024, the average total generation on outage in the California ISO balancing area was 18,400 MW, about 4,800 MW greater than the fourth quarter of 2023, as shown in Figure 16.2. Forced outages increased by 41 percent when compared to the same quarter last year, while planned outages increased by 21 percent. The increase in forced outages is partly explained by the implementation of the Strategic Reliability Reserve (SRR) program which uses outages to prevent the dispatching of the greater than 2,800 MW of SRR participating resource capacity outside of dispatch instructions issued in the context of the SRR program. The remaining portion of increased forced outages is primarily driven by several large gas generators being out for a significant portion of the fourth quarter, as well as increased hydroelectric forced generation outages.

[110] Values reported here only reflect generators in the California ISO balancing area and do not include outages in the Western Energy Imbalance Market.

Figure 16.1 CAISO balancing area quarterly average of maximum daily generation outages by type – peak hours

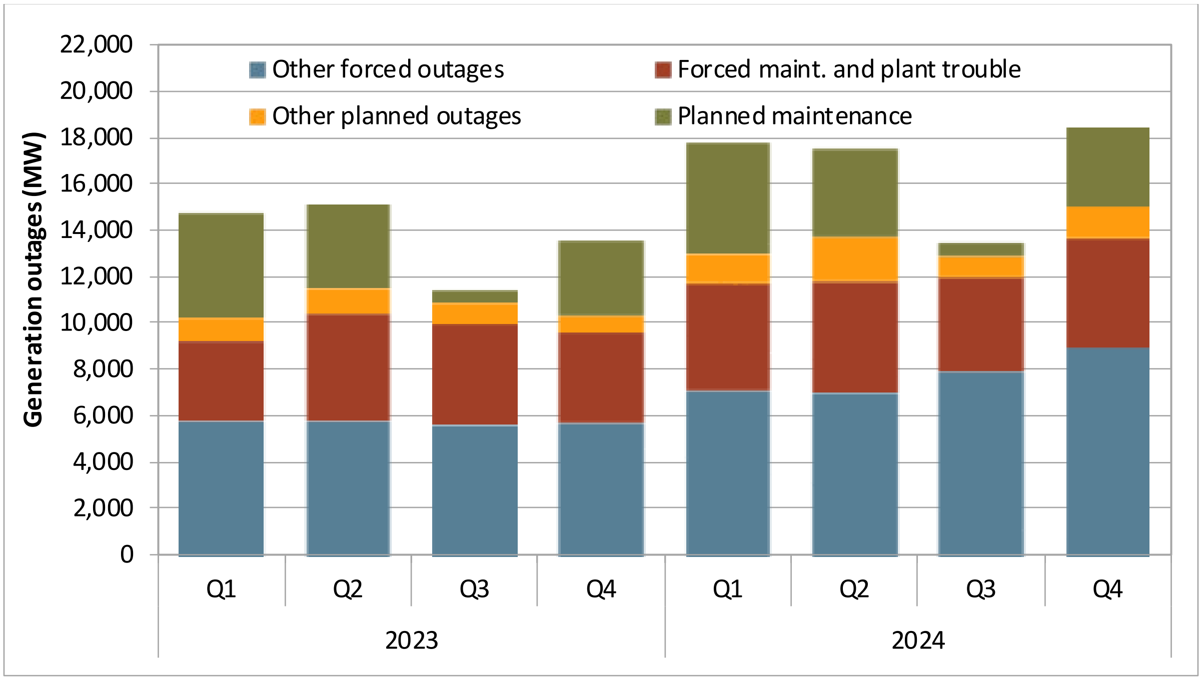
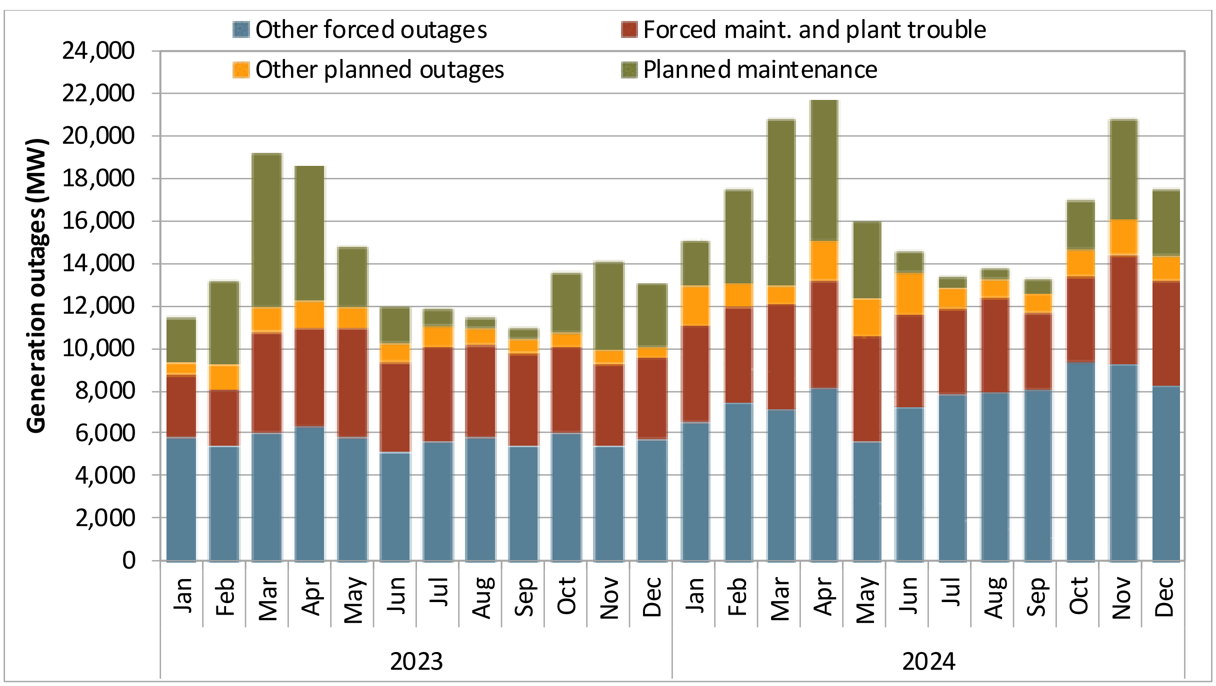


Figure 16.2 CAISO balancing area monthly average of maximum daily generation outages by type – peak hours



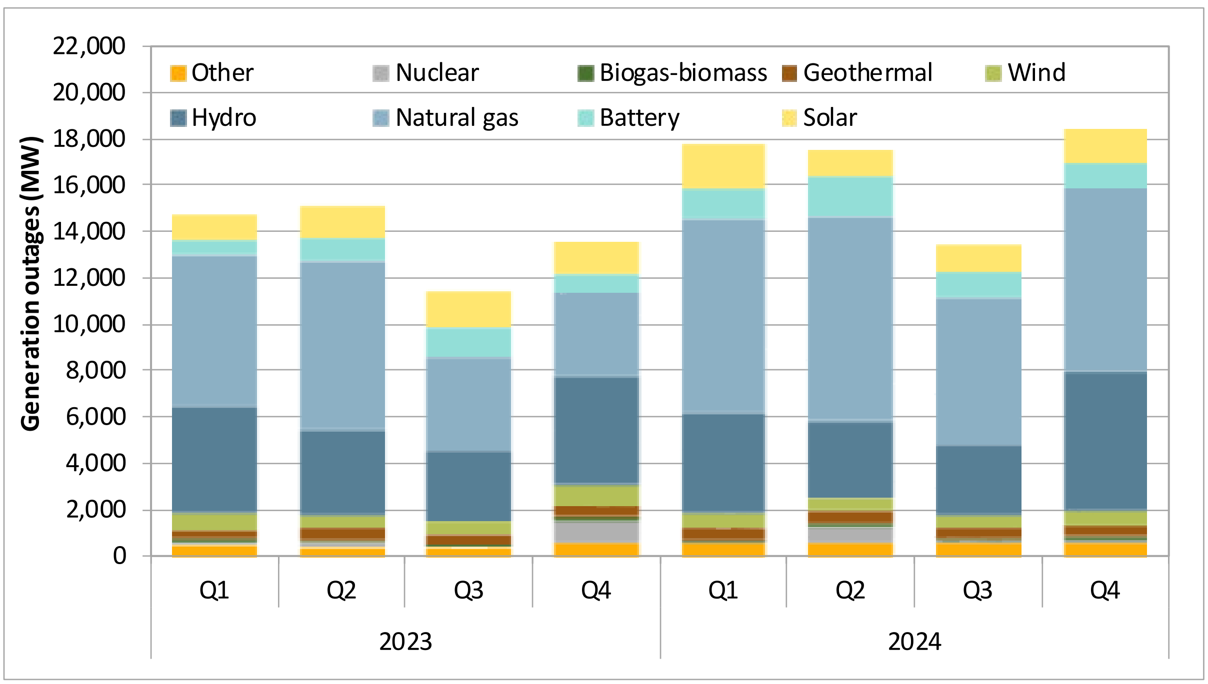
Generation outages by fuel type

Natural gas and hydroelectric generation had the largest volume of outages in the fourth quarter of 2024 and averaged about 7,900 MW and 5,900 MW, respectively. These two fuel types accounted for a combined 75 percent of the generation outages for the quarter. The amount of natural gas generation outages increased 120 percent relative to the fourth quarter of 2023. As noted earlier, this increase is driven by the increase in outages caused by how the Strategic Reliability Reserve is managed, and a few large natural gas plants taking long duration outages.

The quarterly average megawatts of battery storage resources on outage increased by 26 percent in the fourth quarter of 2024 when compared to the fourth quarter of 2023. The year-over-year increase corresponds to the continued growth of battery storage capacity in the CAISO footprint.

Figure 16.3 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[111] Natural gas, hydroelectric, solar, biogas-biomass, and battery storage outages increased compared to the fourth quarter of 2023, while outages for all other resource types decreased.

Figure 16.3 CAISO balancing area quarterly average of maximum daily generation outages by fuel type – peak hours



16.2 California WEIM region

Figure 16.4 and Figure 16.5 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of

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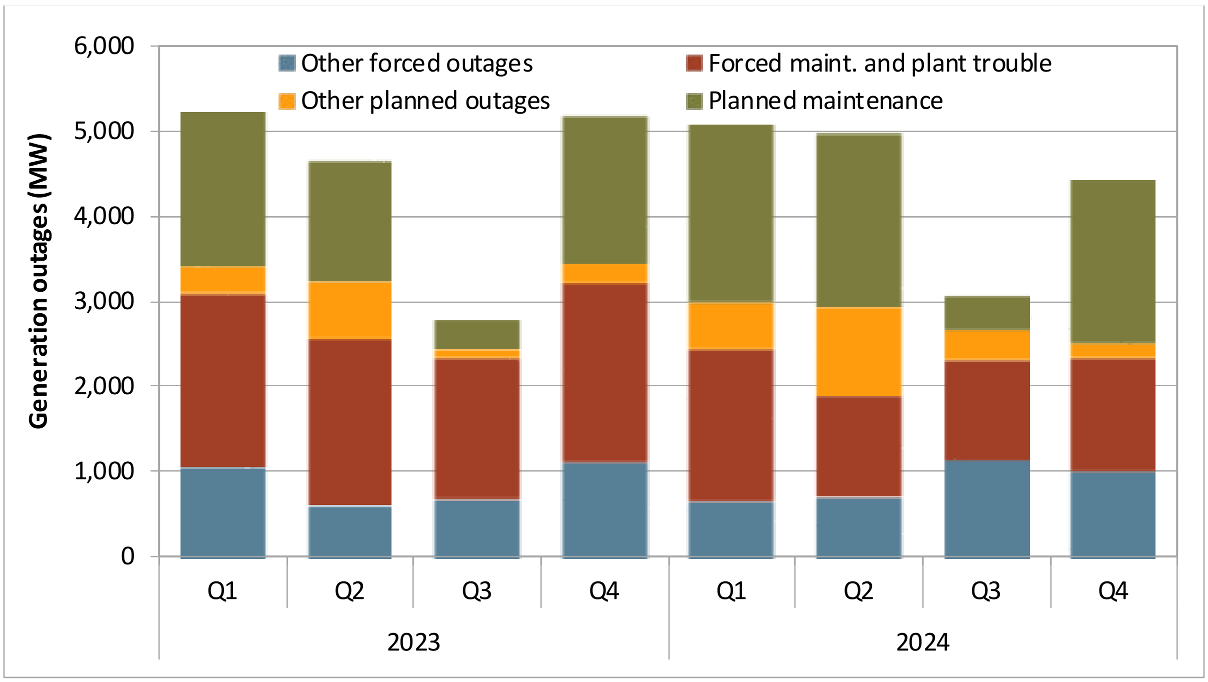
111 In this figure, the "Other" category contains demand response, coal, and additional resources of unique technologies.

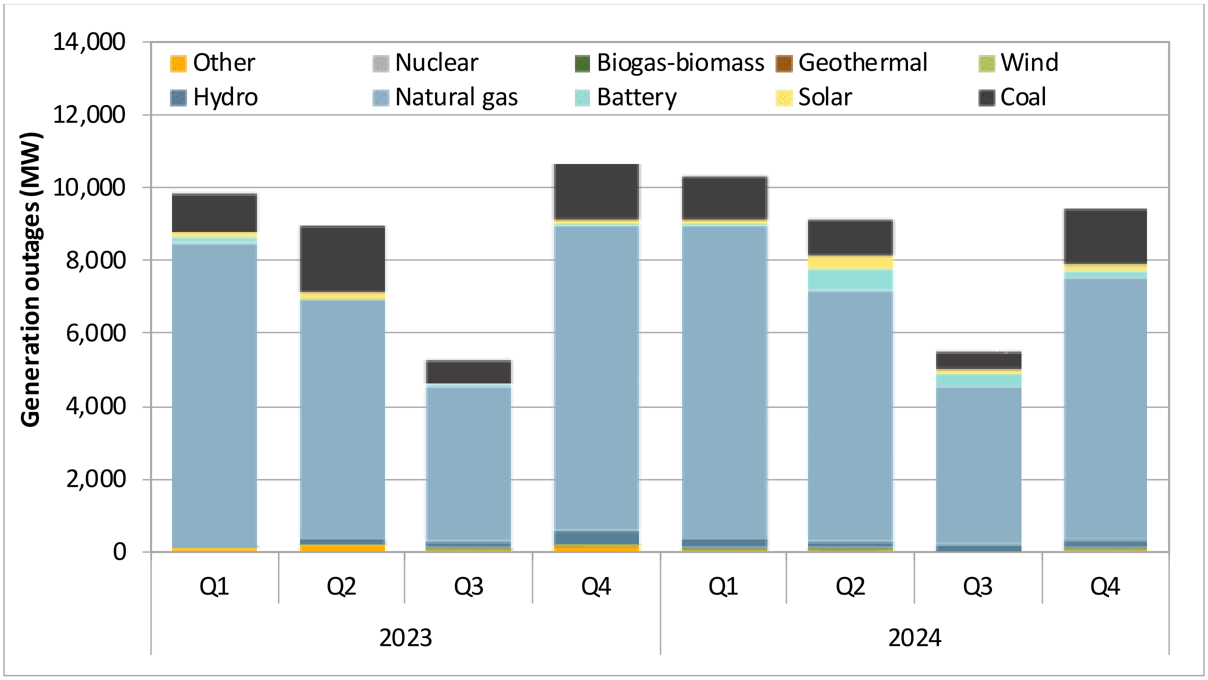
2024 for entities in the California WEIM region, excluding the CAISO balancing area.[112] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2024. Average total outages decreased by approximately 750 MW or 14 percent. The year-over-year decrease was primarily driven by reduced natural gas, solar, and coal outages in the fourth quarter of 2024 when compared to the fourth quarter of 2023.

Figure 16.4 California WEIM region quarterly average of maximum daily generation outages by type – peak hours



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

Figure 16.5 California WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



16.3 Desert Southwest WEIM region

Figure 16.6 and Figure 16.7 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2024 for entities in the Desert Southwest WEIM region.[113] 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 2024. Average total outages decreased by approximately 1,260 MW or 12 percent. The year-over-year decrease was primarily driven by a 14 percent decrease in natural gas outages in the fourth quarter of 2024 when compared to the fourth quarter of 2023.

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

Figure 16.6 Desert Southwest WEIM region quarterly average of maximum daily generation outages by type – peak hours

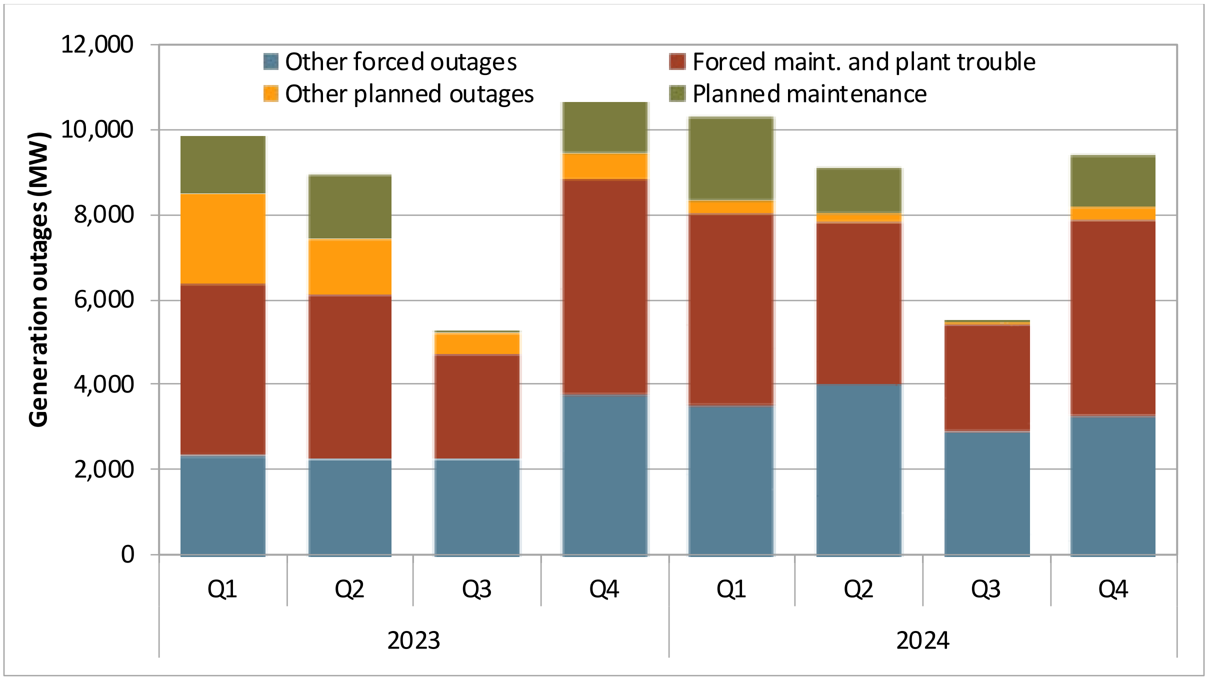
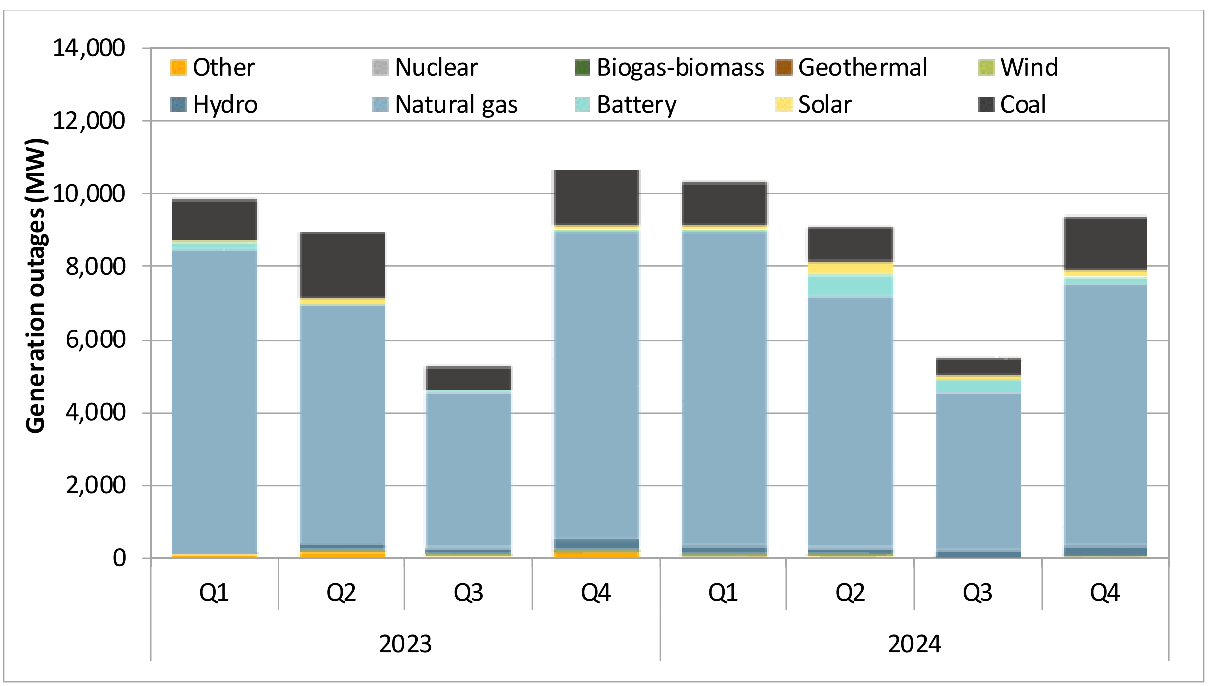


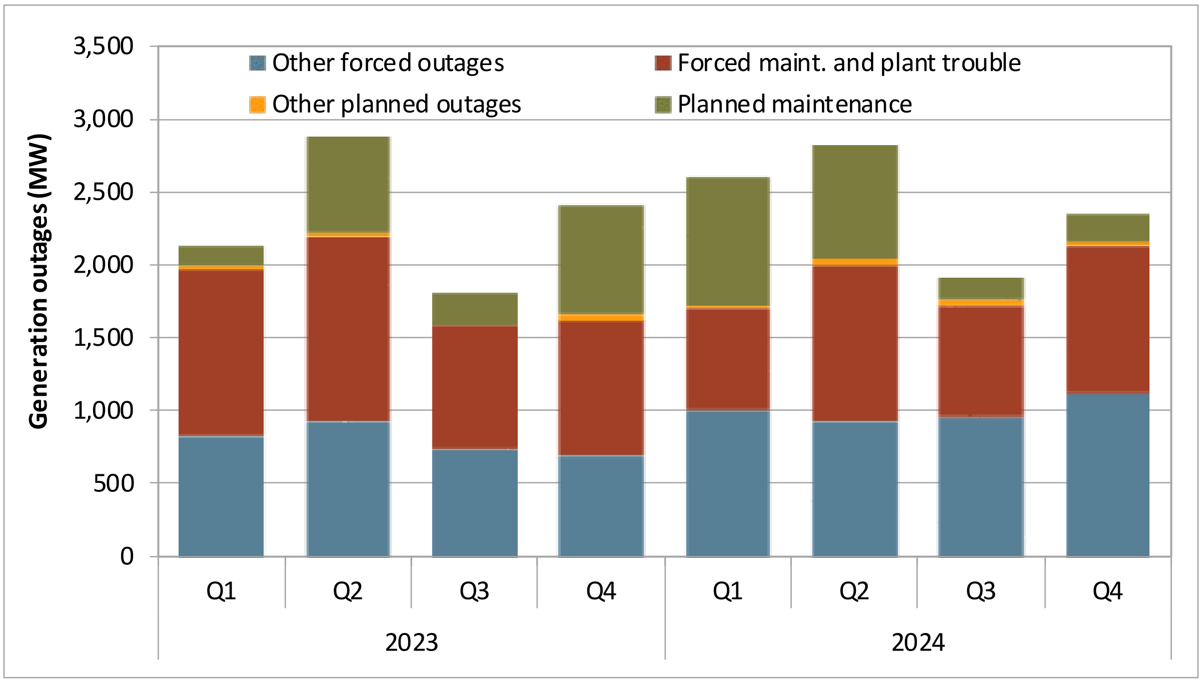
Figure 16.7 Desert Southwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



16.4 Intermountain West WEIM Region

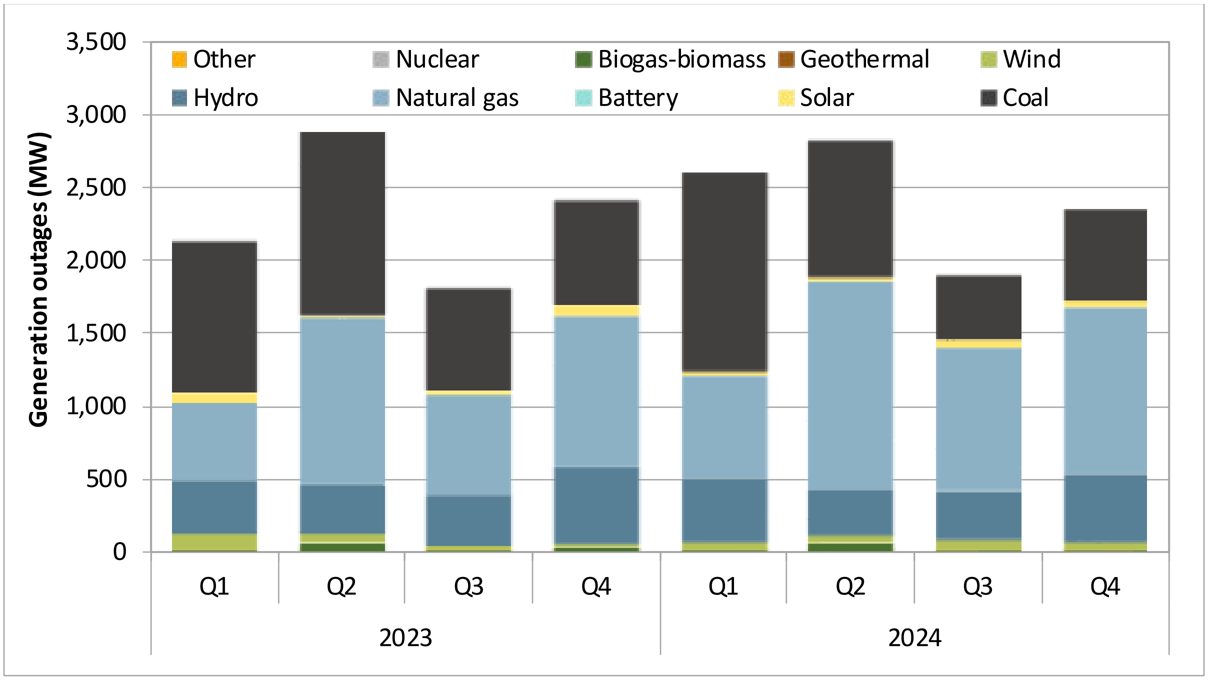
Figure 16.8 and Figure 16.9 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2024 for entities in the Intermountain West WEIM region.[114] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2024. Average total outages decreased by approximately 50 MW or 2 percent.

Figure 16.8 Intermountain West WEIM region quarterly average of maximum daily generation outages by type – peak hours



[114] Intermountain West region includes AVA, IPCO, NWMT, and PACE.

Figure 16.9 Intermountain West WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



16.5 Pacific Northwest WEIM region

Figure 16.10 and Figure 16.11 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2024 for entities in the Pacific Northwest WEIM region.[115] The typical seasonal outage pattern for the Pacific Northwest region diverges from the others, with outages typically peaking in the second quarter while outages in all other quarters remain low. The trend is still primarily driven by planned outages for maintenance, which are generally performed outside of the higher load periods. Average total outages decreased by approximately 40 MW or 1 percent.

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

Figure 16.10 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by type – peak hours

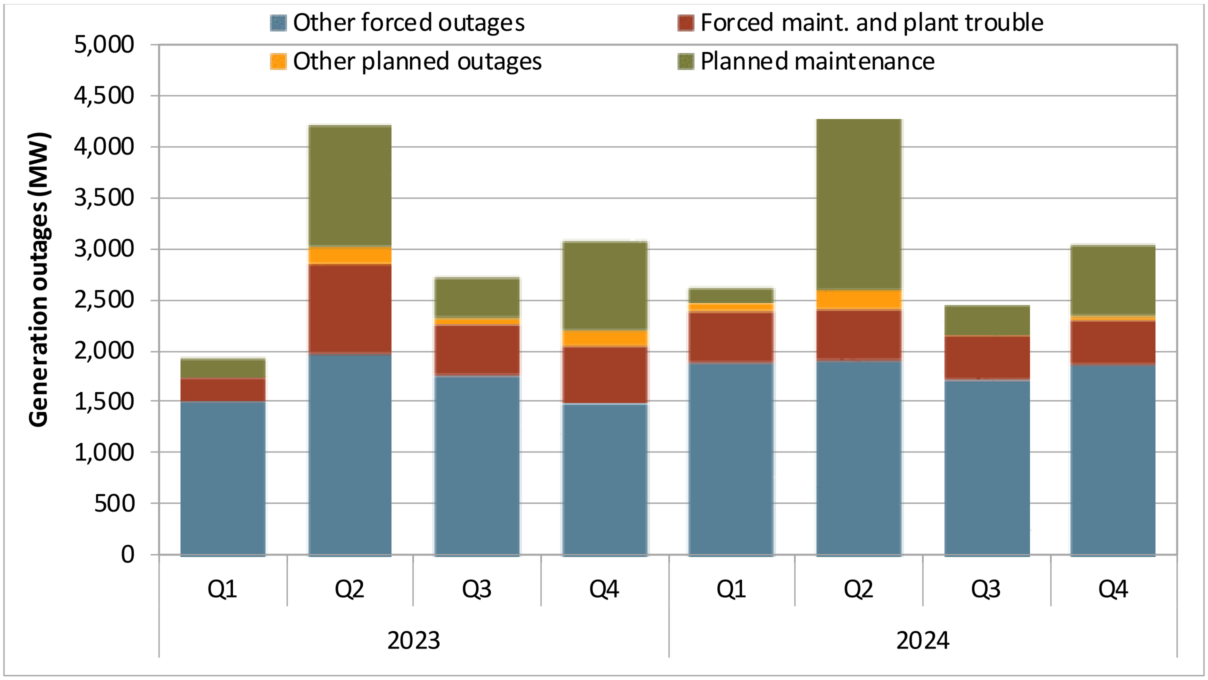
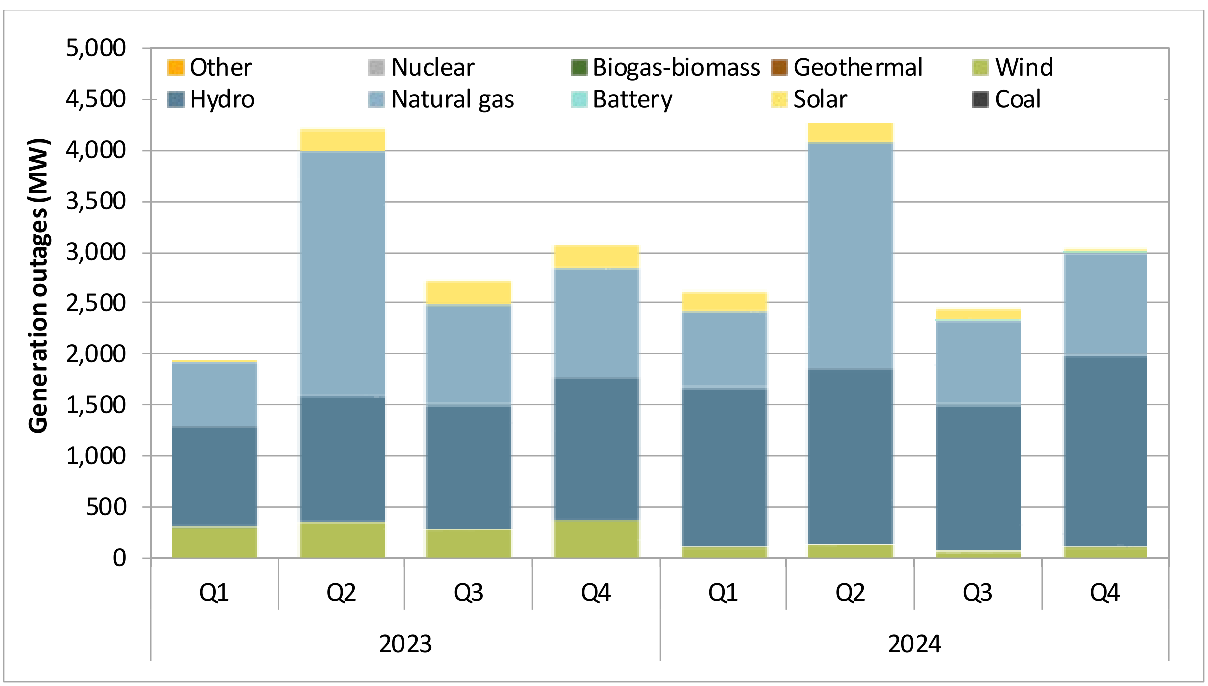


Figure 16.11 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



17 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. CAISO balancing area exceptional dispatches are covered in a separate subsection from the rest of the WEIM because of significant differences in how manual dispatches are settled in the CAISO balancing area relative to other balancing areas in the WEIM.

17.1 California ISO exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.

- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would have likely cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as in-sequence real-time energy.

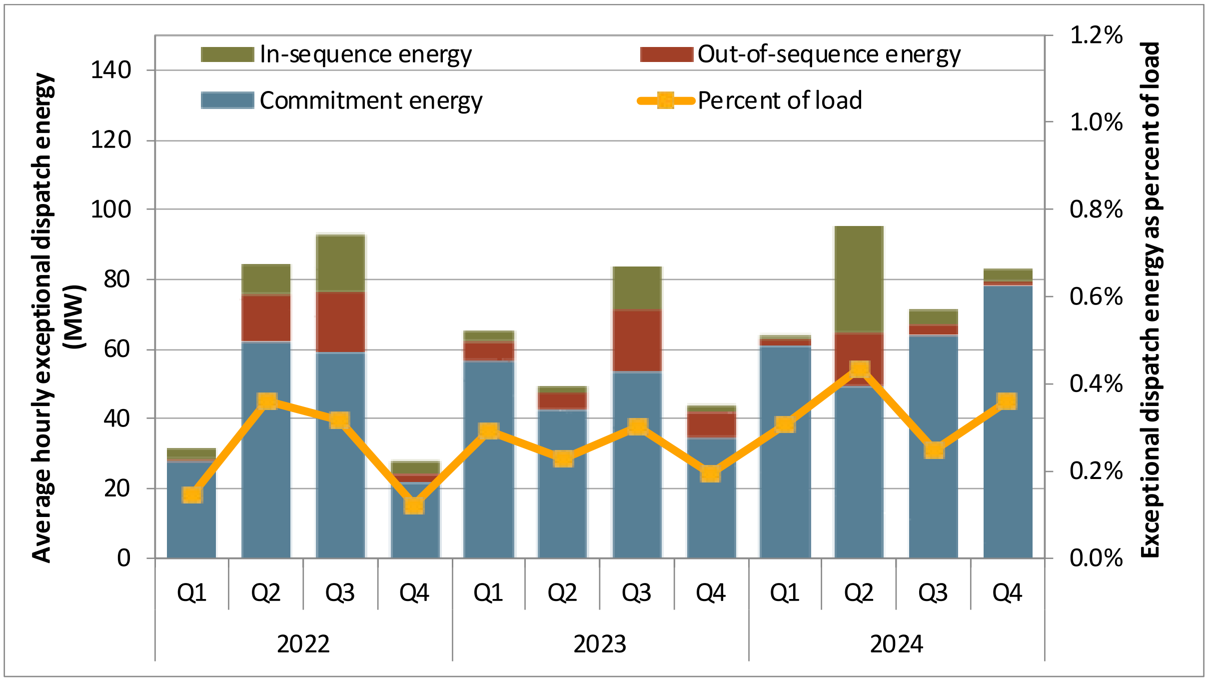
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in out-of-sequence real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market-clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to the local market power mitigation provisions in the California ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

Energy from exceptional dispatch

Energy from exceptional dispatches continued to account for under 1 percent of total load in the California ISO balancing area, represented by the yellow line in Figure 17.1. As shown in Figure 17.1, the average hourly total energy from exceptional dispatches—including minimum load energy from unit commitments—was 83 MW in the fourth quarter of 2024, which is an 89 percent increase from the fourth quarter of 2023.[116]

In the fourth quarter of 2024, exceptional dispatches for unit commitments (blue) accounted for about 94 percent of all exceptional dispatch energy—about 2 percent was from out-of-sequence energy (red), and the remaining 4 percent was from in-sequence energy (green), as shown in Figure 17.1.

Figure 17.1 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

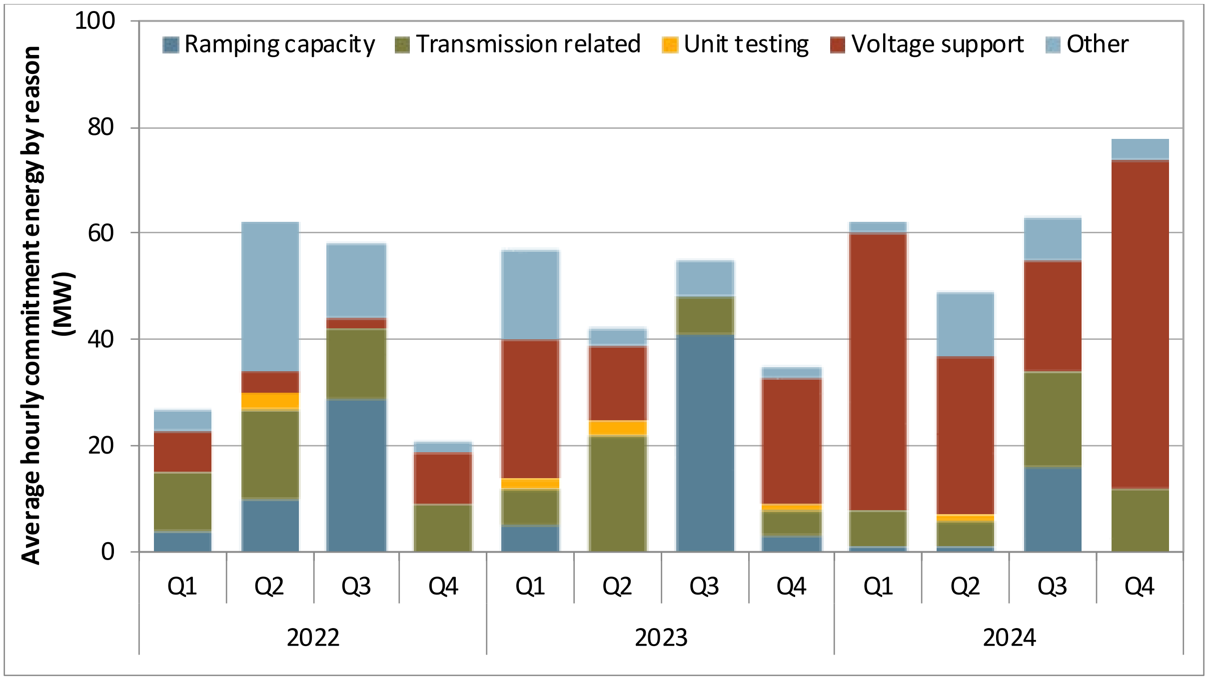
The California ISO balancing area operators occasionally find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. In these instances, the California ISO may commit additional 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 17.2 shows the reasons for minimum load energy exceptional dispatches: ramping capacity (dark blue), transmission related (green), unit testing (yellow), voltage support (red), and other (light blue). The total average minimum load energy from unit commitment exceptional dispatches in the fourth quarter of 2024 was 78 MW, which was above the 35 MW of average minimum load energy from unit commitment in the fourth quarter of 2023.

[116] 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.

Minimum load energy from unit commitment exceptional dispatches to provide voltage support (red bars) in the fourth quarter of 2024 increased by 158 percent from the same quarter of 2023. Meanwhile, minimum load energy from transmission related unit commitment exceptional dispatches (green bars) in the fourth quarter of 2024 increased by 140 percent from the same quarter in 2023.

Figure 17.2 Average minimum load energy from exceptional dispatch unit commitments

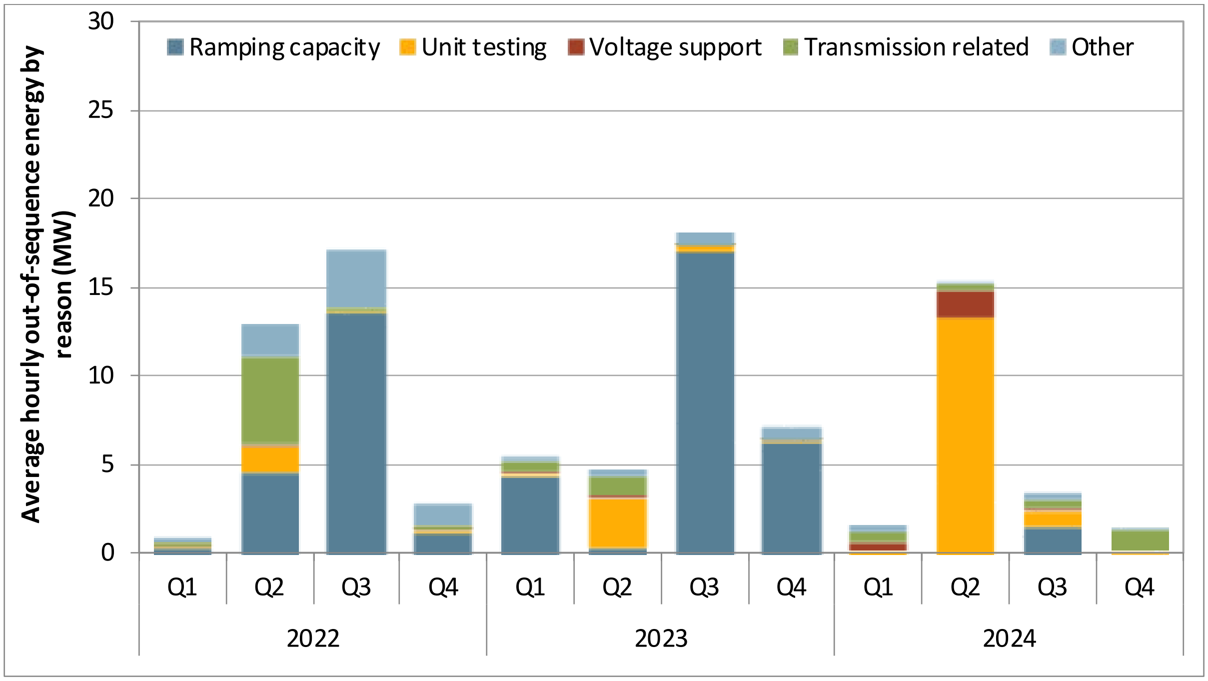


Exceptional dispatches for energy

Figure 17.3 shows the average hourly out-of-sequence exceptional dispatch energy by quarter for 2022, 2023, and 2024. The primary reason logged for out-of-sequence energy in the fourth quarter of 2024 was transmission-related. Transmission-related exceptional dispatches are issued for any transmission-related modeling limitations that may arise from transmission maintenance, lack of voltage support at proper levels, and incomplete or inaccurate information about the transmission network.

Average hourly out-of-sequence energy from transmission-related exceptional dispatches (green bars) increased by 15 percent in the fourth quarter of 2024 when compared to the fourth quarter of 2023. Meanwhile, the total average hourly out-of-sequence energy from exceptional dispatch decreased by 79 percent in the fourth quarter of 2024 when compared to the fourth quarter of 2023.

Figure 17.3 Out-of-sequence exceptional dispatch energy by reason



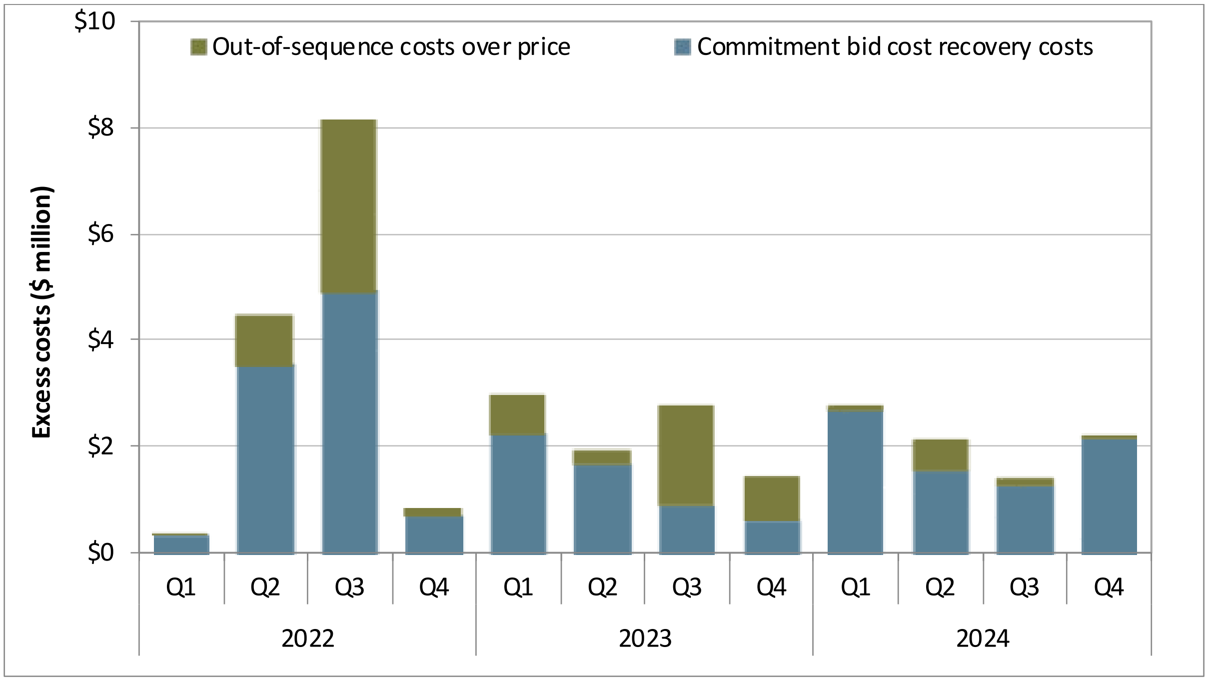
Exceptional dispatch costs

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

- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for these costs.
- Units exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

Figure 17.4 shows the estimated costs for unit commitment and exceptional dispatch for energy above minimum load whose bid price exceeded the resource's locational marginal price. In the fourth quarter of 2024, out-of-sequence energy costs were $0.05 million, a 94 percent decrease from the fourth quarter of 2023. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the fourth quarter were $2.2 million, a 235 percent increase from the fourth quarter of 2023. Overall, the additional costs associated with the exceptional dispatches in the fourth quarter of 2024 increased by 51 percent when compared to the fourth quarter of 2023.

Figure 17.4 Excess exceptional dispatch cost by type



17.2 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 not issued by the CAISO and can only be issued by a WEIM entity for their respective balancing authority area. 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 17.5 through Figure 17.8 summarize average hourly incremental and decremental manual dispatch activity of participating and non-participating resources for each WEIM region. The California region, however, has no manual dispatch energy from non-participating resources.

When comparing the fourth quarter of 2024 to the fourth quarter of 2023, incremental manual dispatch energy from participating resources (yellow bars) increased in the California and Desert Southwest regions by 35 percent and 23 percent, respectively, but decreased in the Intermountain West and Pacific Northwest regions by 30 percent and 18 percent, respectively. Similarly, when comparing the fourth quarter of 2024 to the same quarter in 2023, incremental manual dispatch energy from non-participating resources (red bars) increased by 74 percent for the Desert Southwest region but decreased for the Intermountain West and Pacific Northwest regions by 3 percent and 18 percent, respectively.

Decremental manual dispatch energy from participating resources (green bars) increased in all four WEIM regions—most notably a 117 percent increase in the Pacific Northwest—from the fourth quarter of 2023 to the fourth quarter of 2024. Meanwhile, when comparing the fourth quarter of 2024 to the same quarter in 2023, decremental manual dispatch energy from non-participating resources (blue bars) increased in the Desert Southwest and Intermountain West regions by 226 percent and 193 percent, respectively, but decreased in the Pacific Northwest by 3 percent.

Overall, combined incremental and decremental manual dispatch energy increased in the Desert Southwest, California (non-CAISO), and Intermountain West regions compared to the fourth quarter of 2023 by 36 percent, 27 percent, and 13 percent, respectively. Total manual dispatch energy in the Pacific Northwest region decreased by 12 percent.

Figure 17.5 WEIM manual dispatches – California

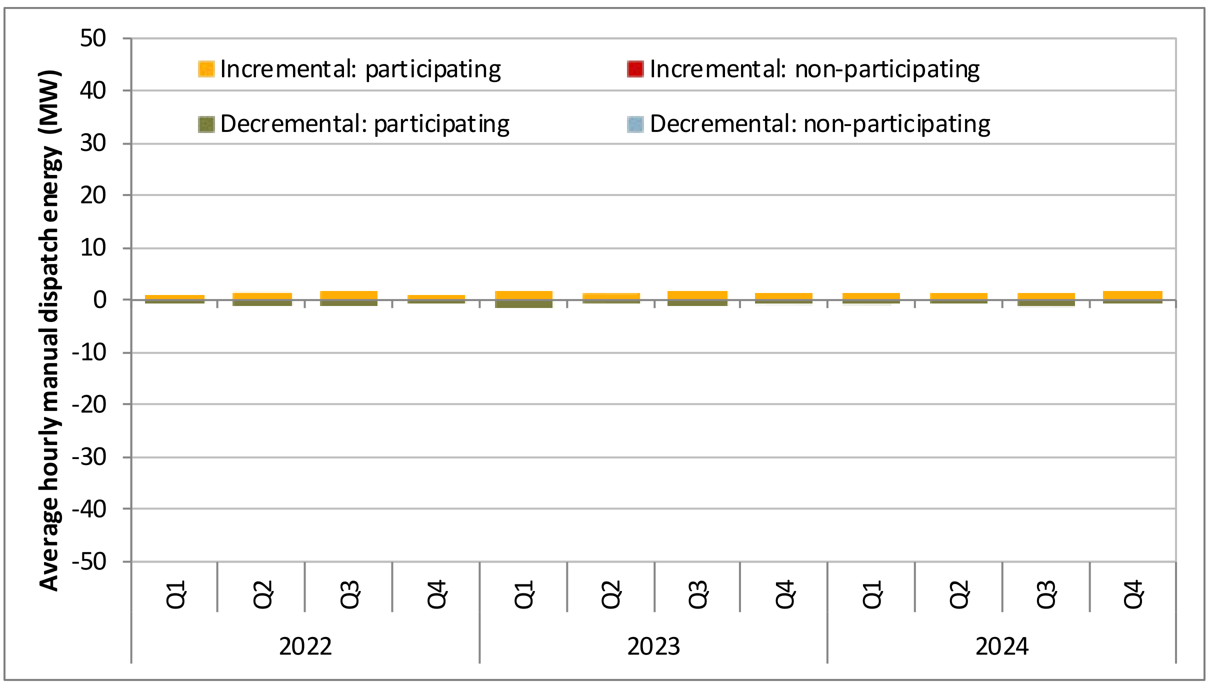


Figure 17.6 WEIM manual dispatches – Desert Southwest

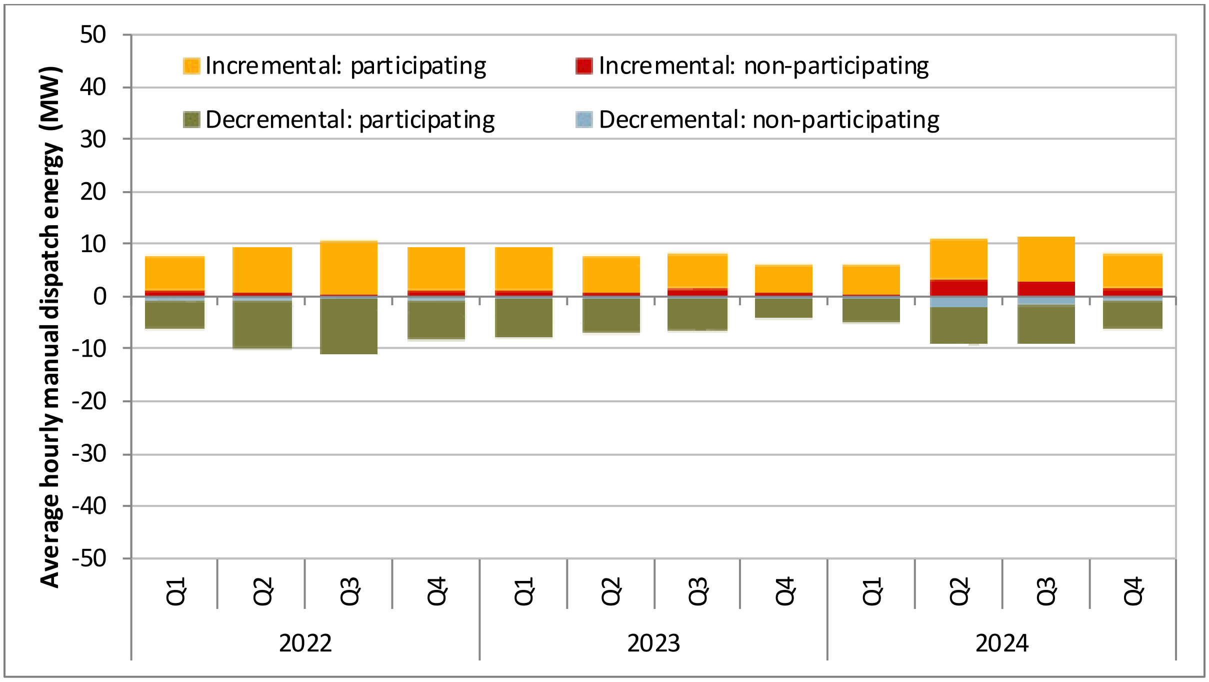


Figure 17.7 WEIM manual dispatches – Intermountain West

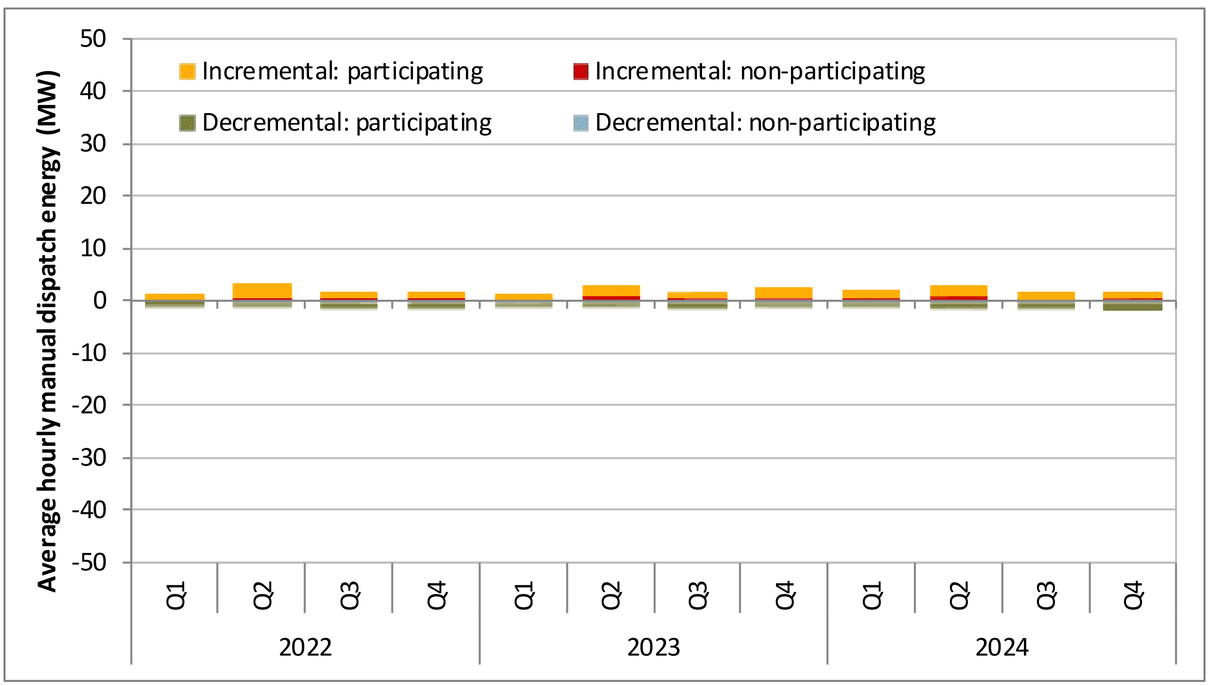
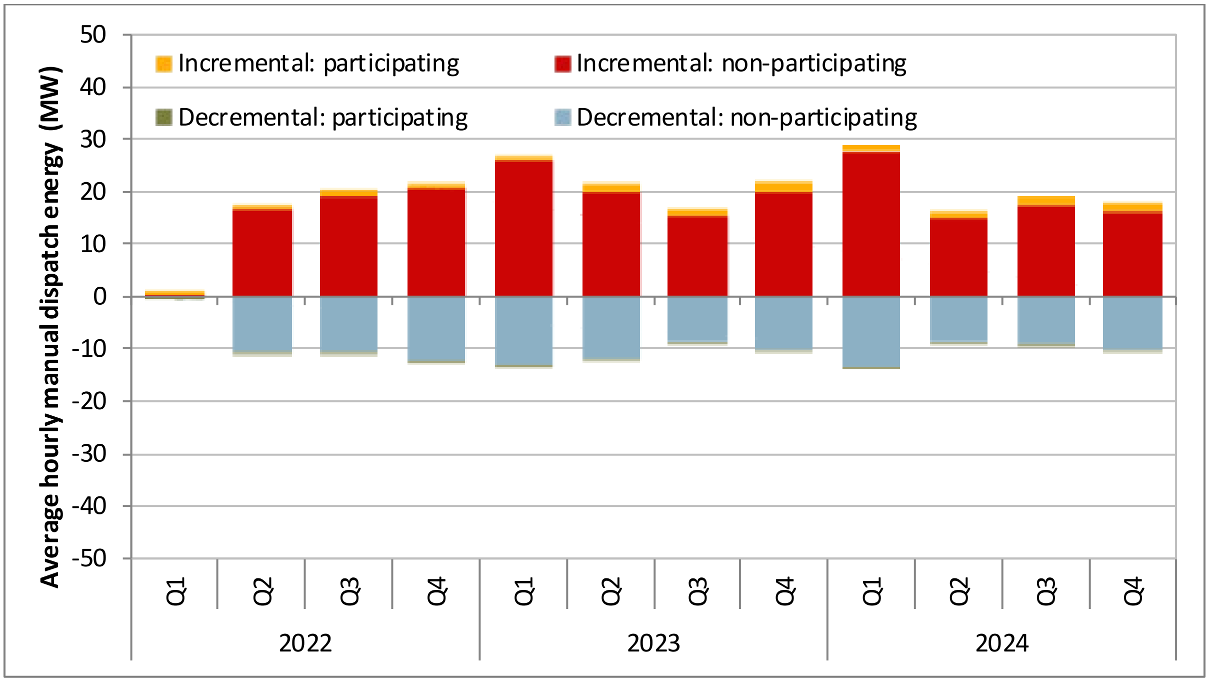


Figure 17.8 WEIM manual dispatches – Pacific Northwest



APPENDIX

Appendix A | Western Energy Imbalance Market area specific metrics

Sections A.1 to A.23 include figures by WEIM area on the hourly locational marginal price (LMP) and dynamic transfers.[117] These figures are included for both the 15-minute and 5-minute markets. Key highlights of the quarter include:

- In this quarter, the overall hourly LMP trend across all balancing areas followed a similar pattern, with higher prices during morning ramping and evening peak hours and lower prices midday during solar production. The primary factors driving price separation among BAAs were internal congestion within CAISO and the GHG component, which generally lowered prices in balancing areas outside California relative to balancing areas in California. Additionally, WEIM transfer congestion had a significant impact, particularly on LADWP and PNM.
- In this quarter, WEIM dynamic transfers exhibited distinct patterns both across regions and BAAs. Within the California region, CAISO typically exported during the day and imported during non-solar hours, while non-CAISO California BAAs showed the opposite trend, importing midday and exporting during non-solar hours, with most energy flowing to CAISO. A similar pattern was observed in the Desert Southwest, where most BAAs exported throughout the day, with exports more pronounced during morning and evening peak hours. In the Intermountain West, AVA and IPCO exhibited a mix of imports and exports throughout the day. The Pacific Northwest tended to import, with the exception of AVRN, PACW, and TPWR.

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

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.
- **Congestion within California ISO** is the price impact from transmission constraints within the California ISO area that are restricting the flow of energy. While these constraints are located within the California ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from

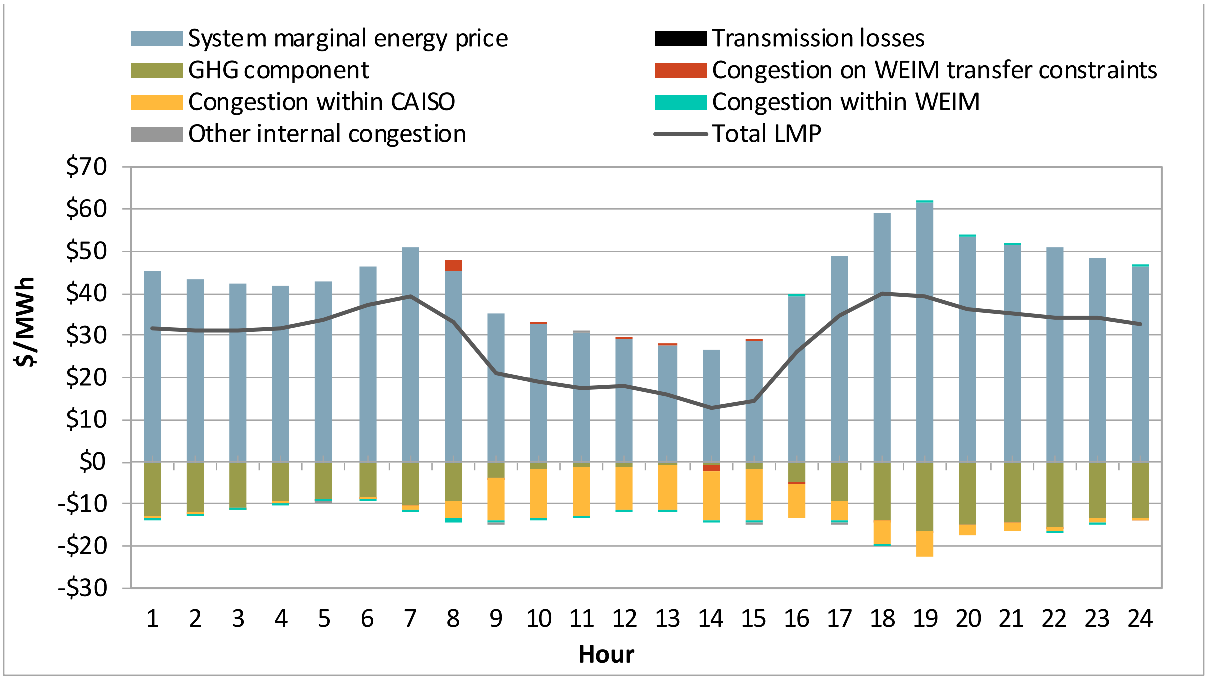
[117] These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will not appear in the figures.

individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*

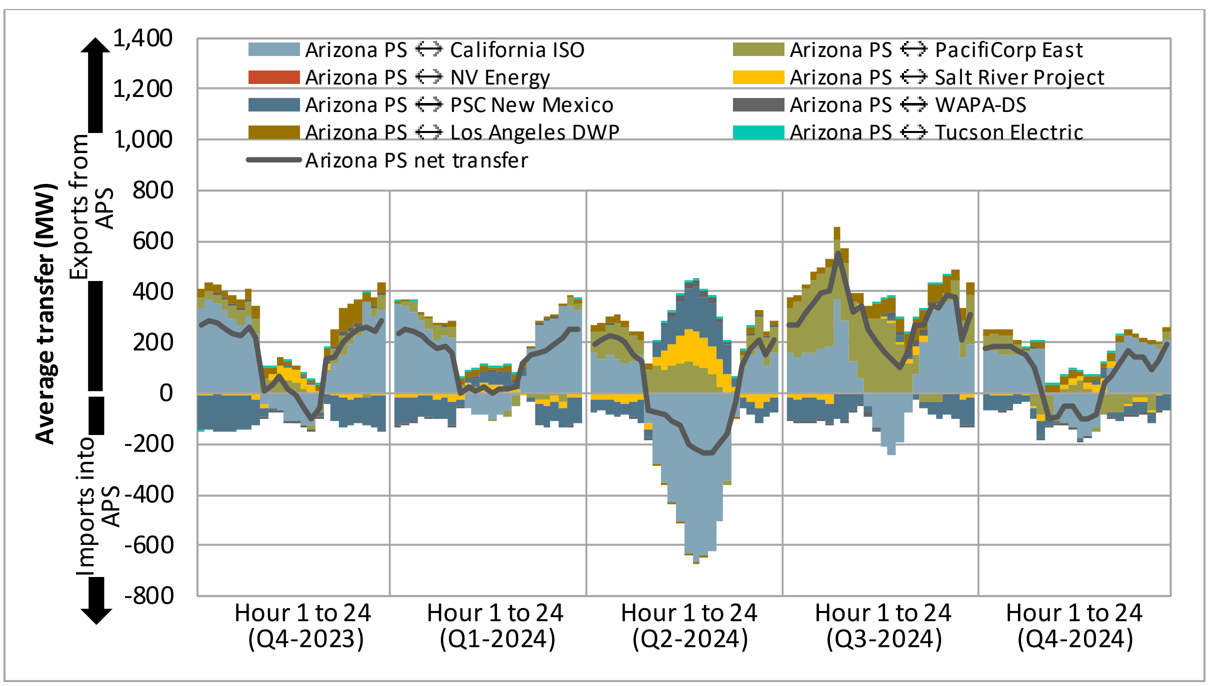
- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limit WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits following a resource sufficiency evaluation failure, or (3) intertie constraint (ITC) and intertie scheduling limit (ISL).

A.1 Arizona Public Service

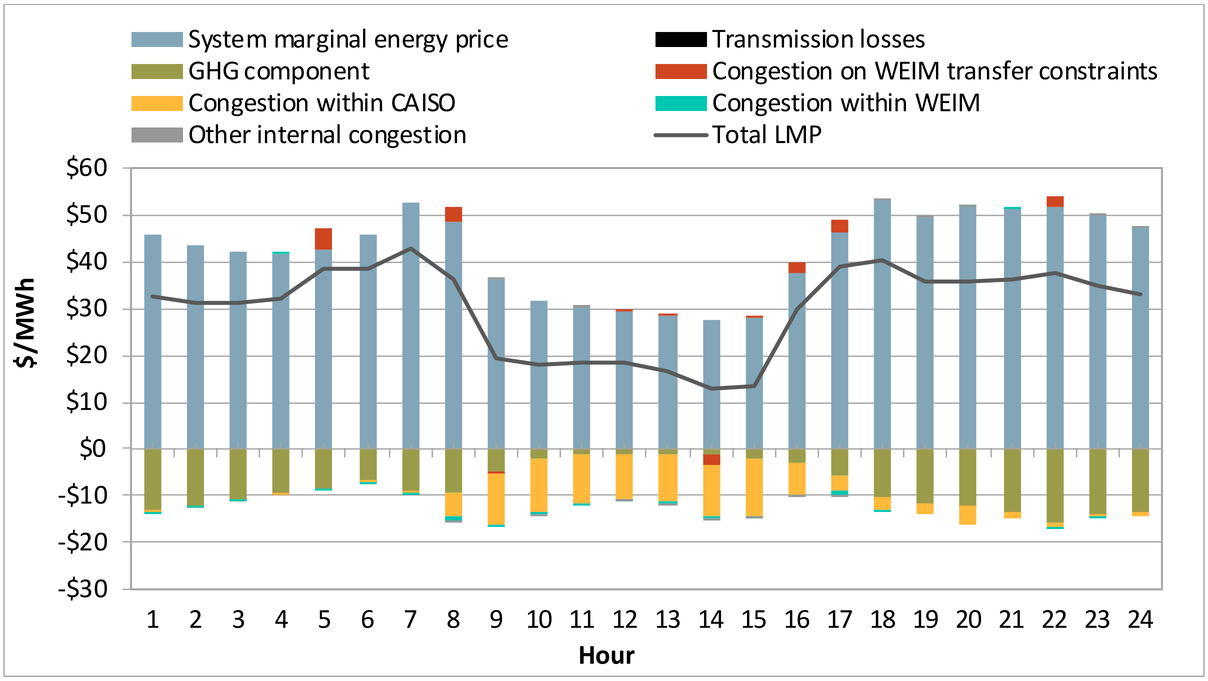
Appendix Figure A.1 Average hourly 15-minute price by component (Q4 2024)



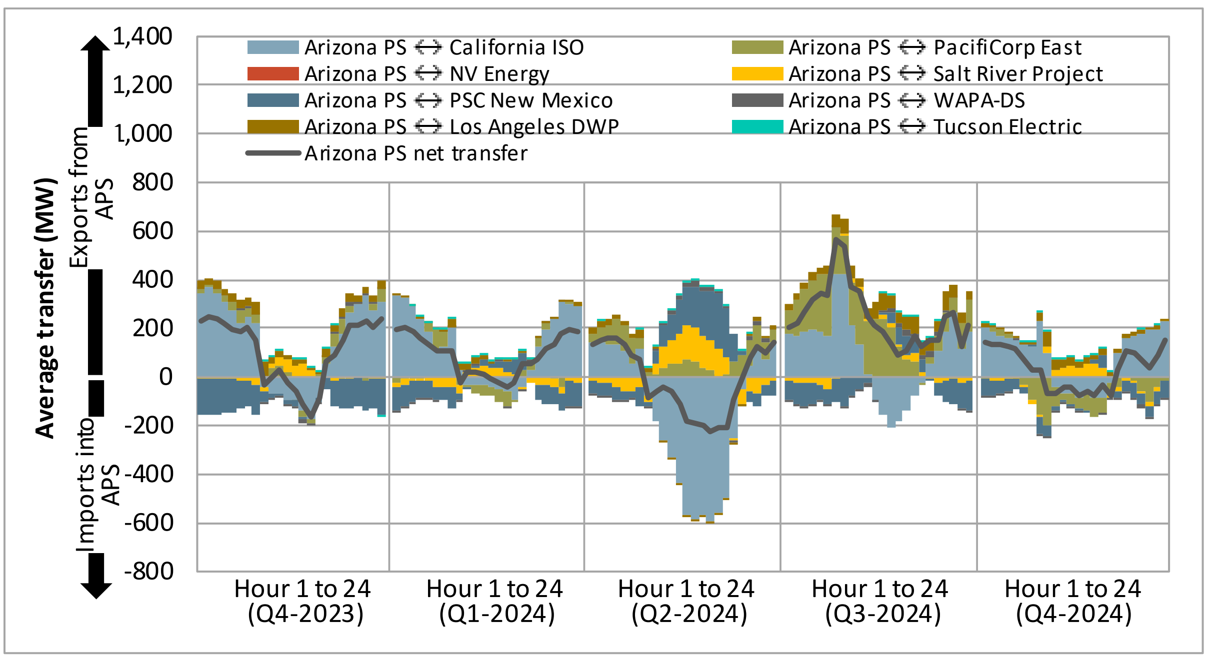
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q4 2024)

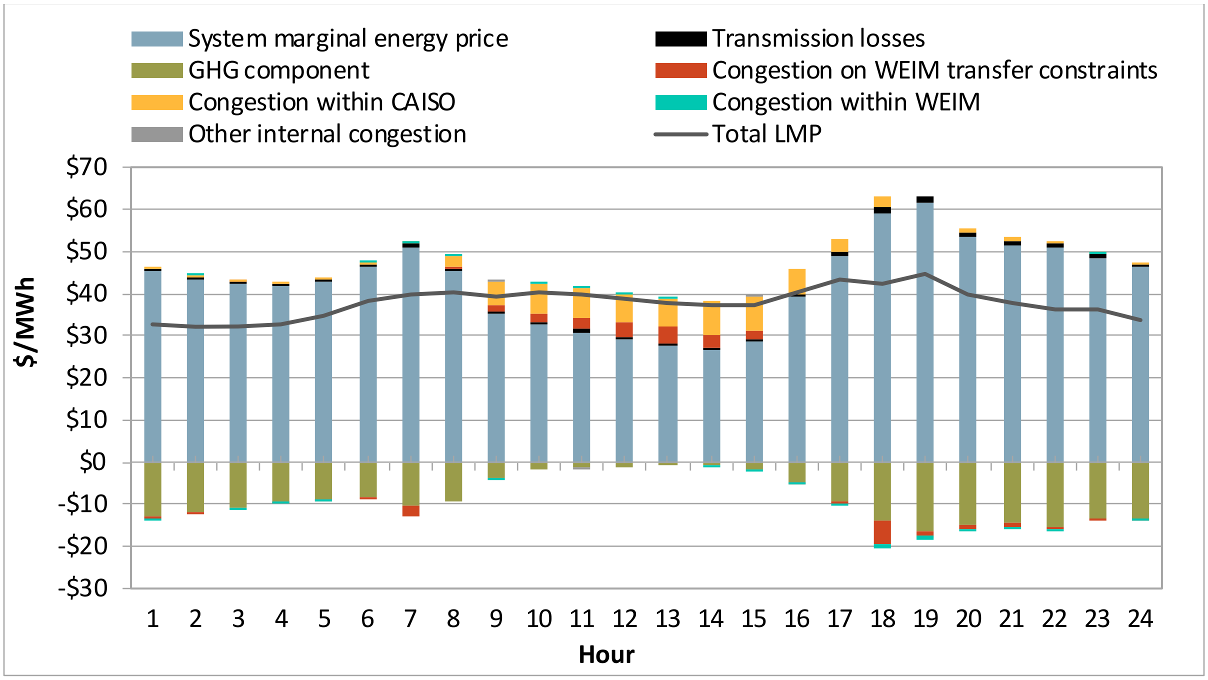


Appendix Figure A.4 Average hourly 5-minute market transfers

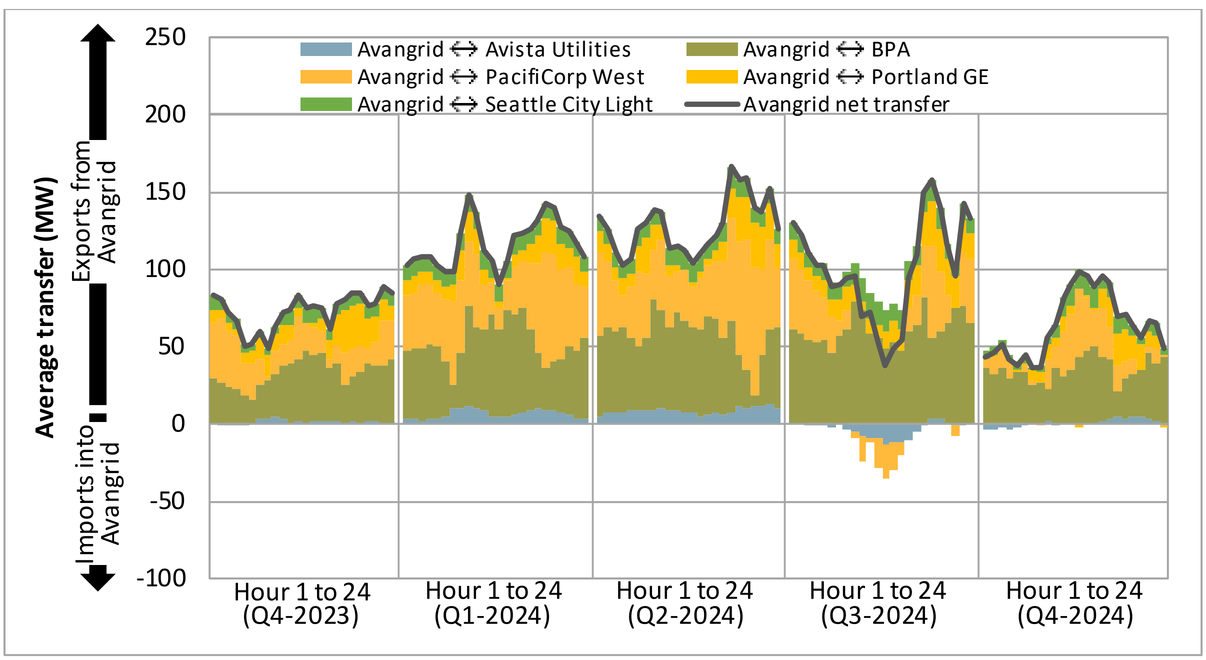


A.2 Avangrid

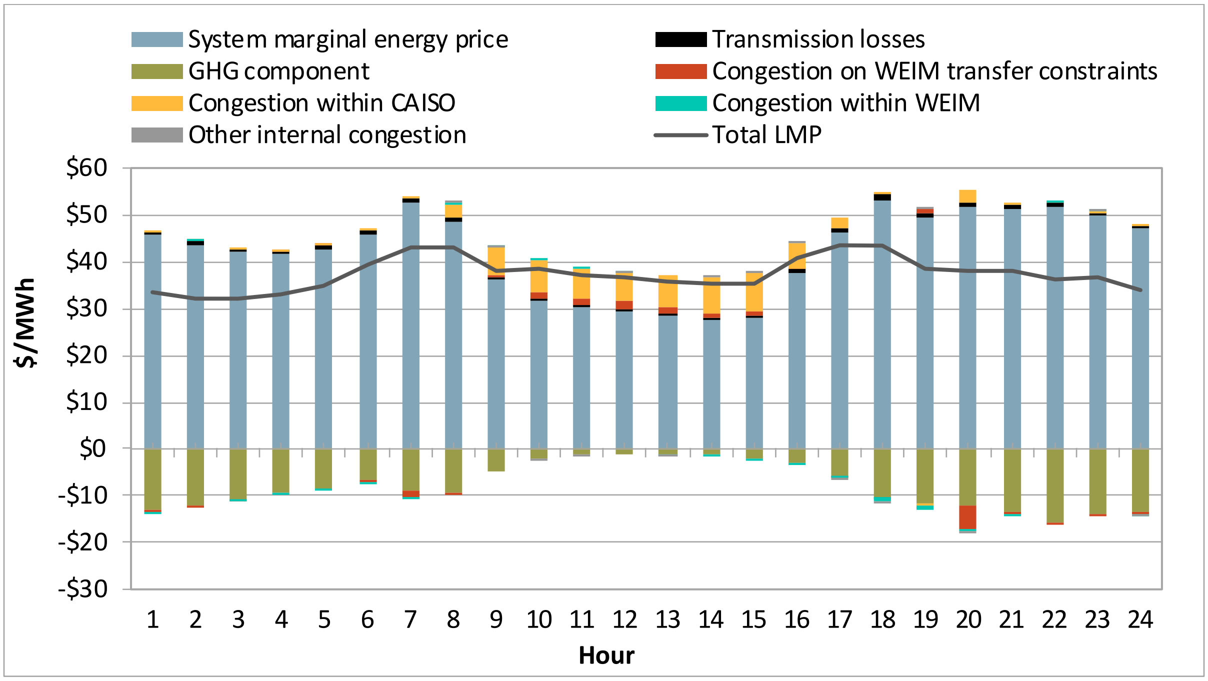
Appendix Figure A.5 Average hourly 15-minute price by component (Q4 2024)



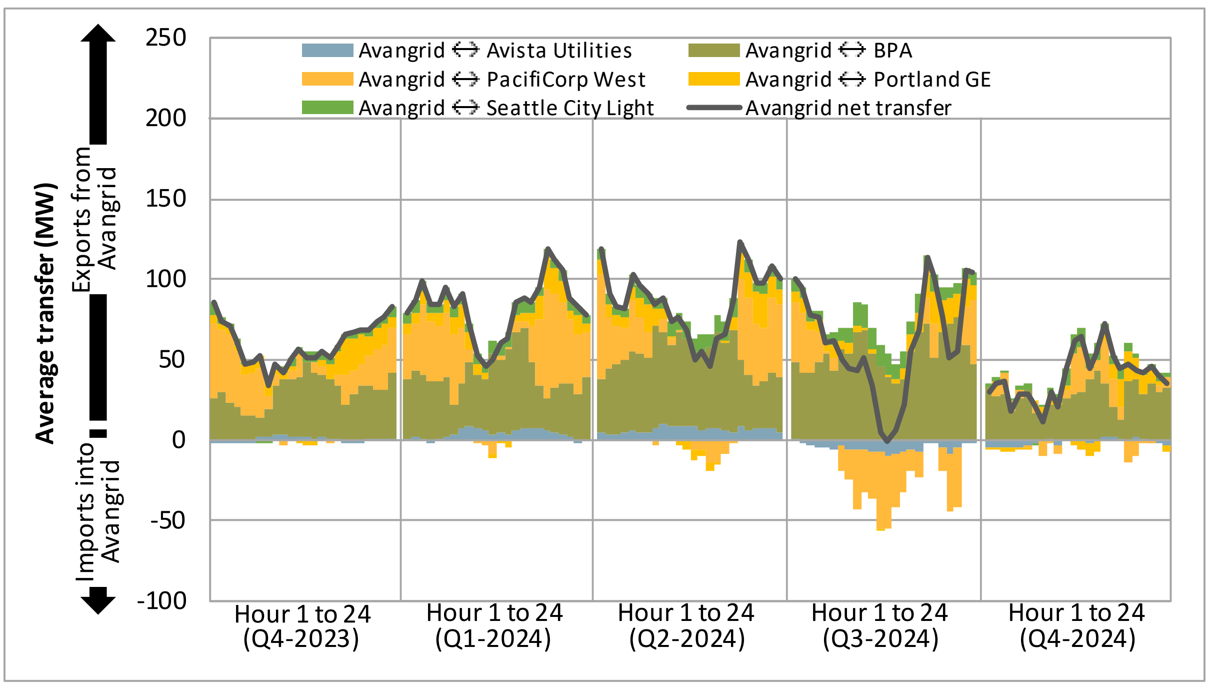
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q4 2024)

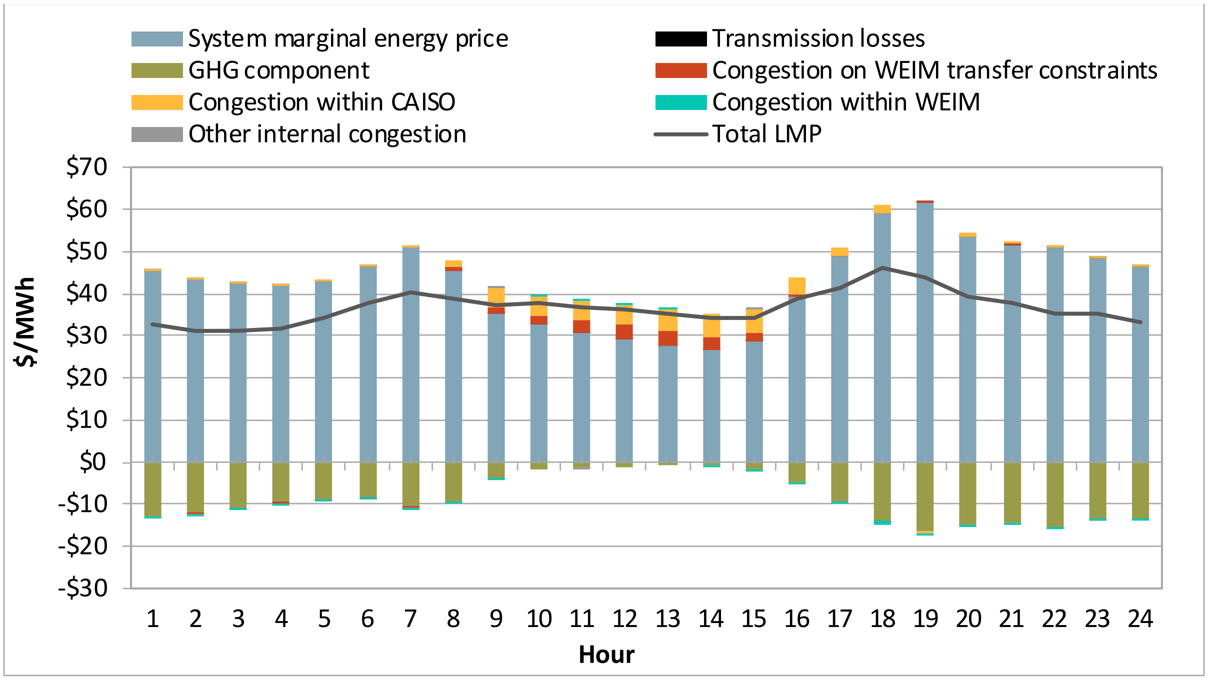


Appendix Figure A.8 Average hourly 5-minute market transfers

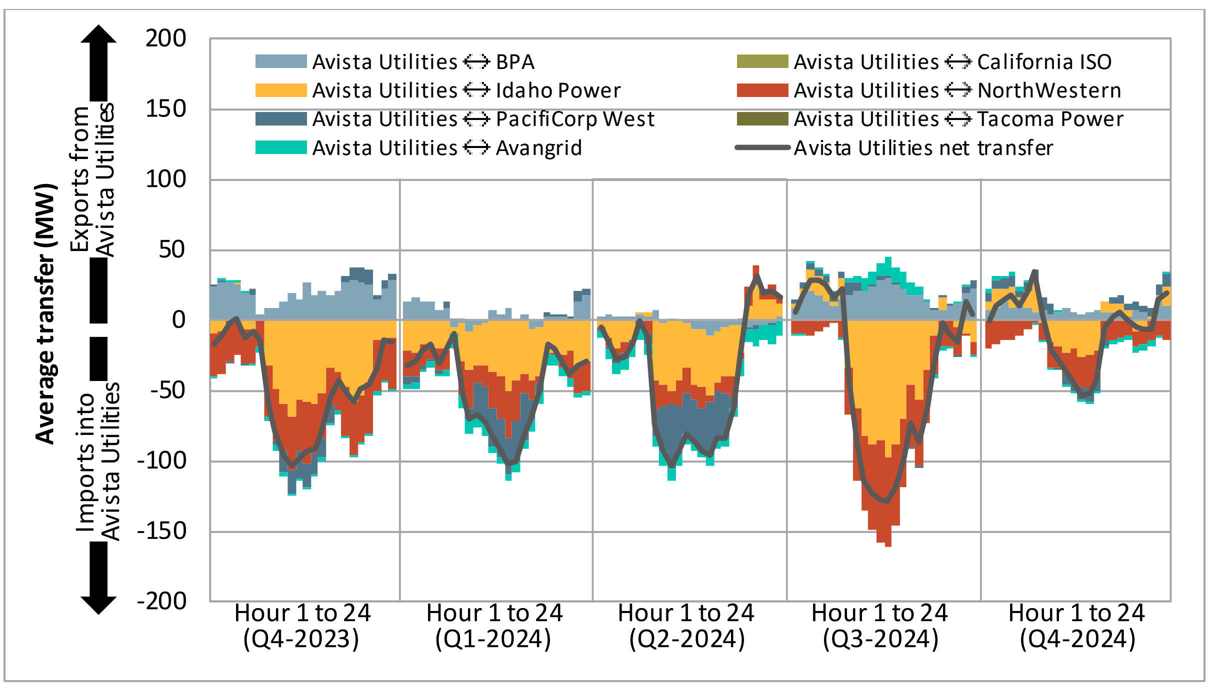


A.3 Avista Utilities

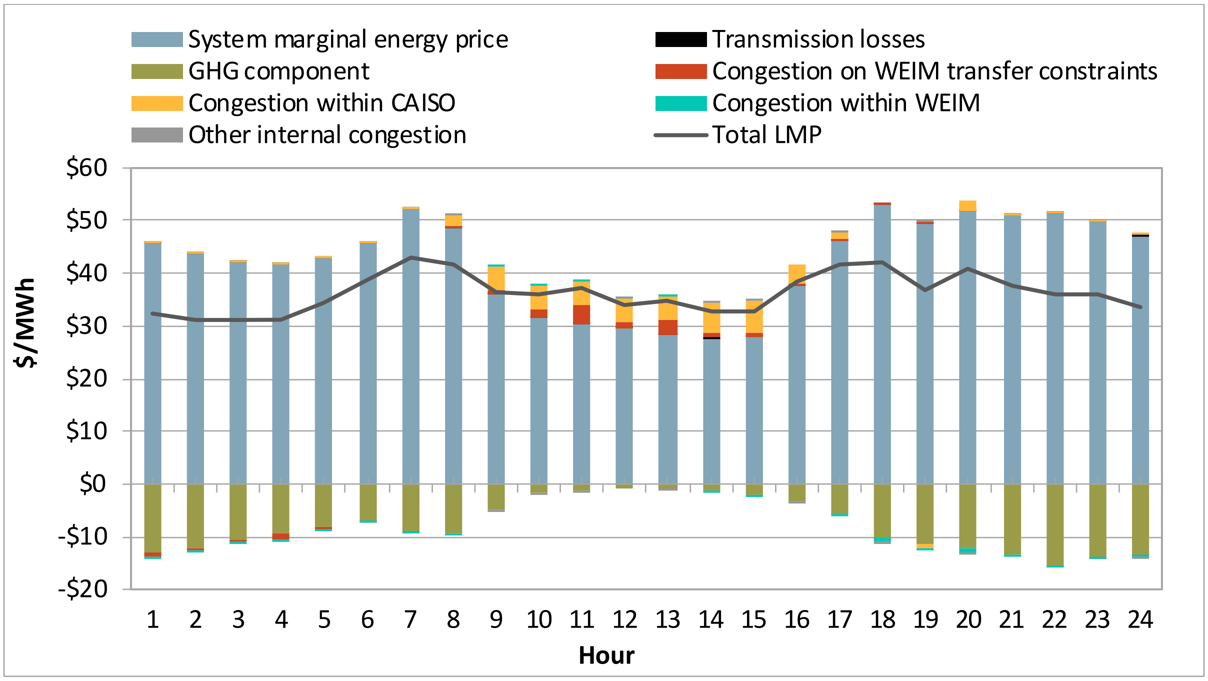
Appendix Figure A.9 Average hourly 15-minute price by component (Q4 2024)



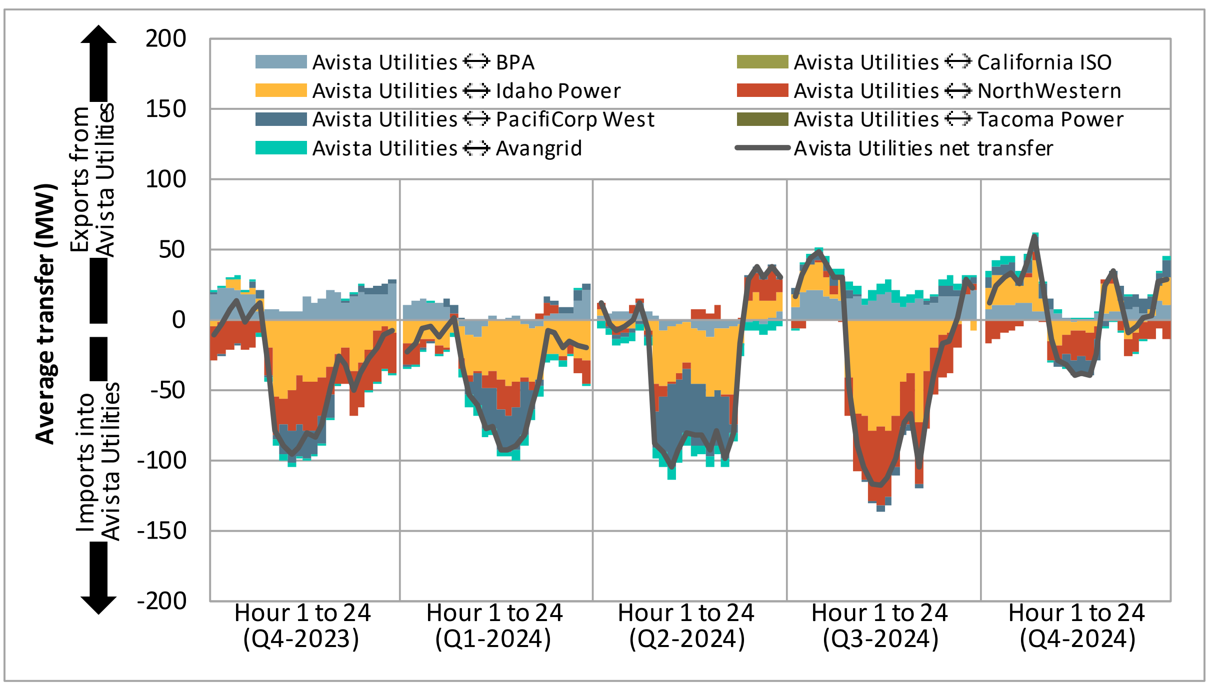
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q4 2024)

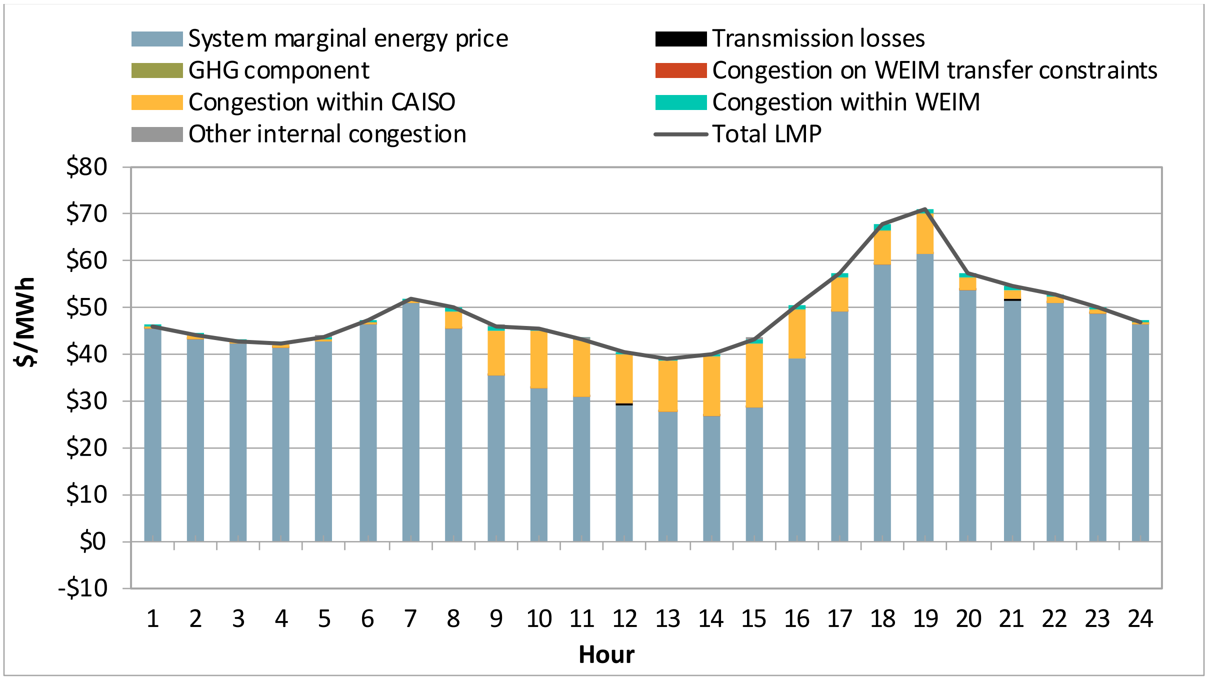


Appendix Figure A.12 Average hourly 5-minute market transfers

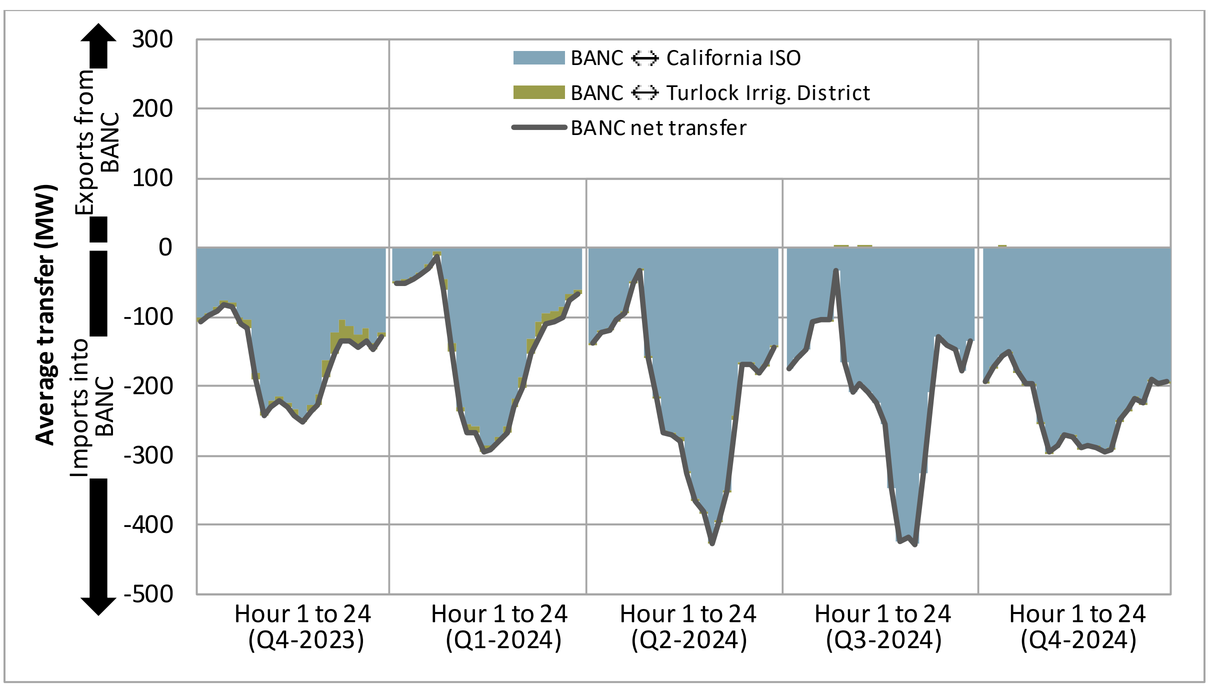


A.4 Balancing Authority of Northern California

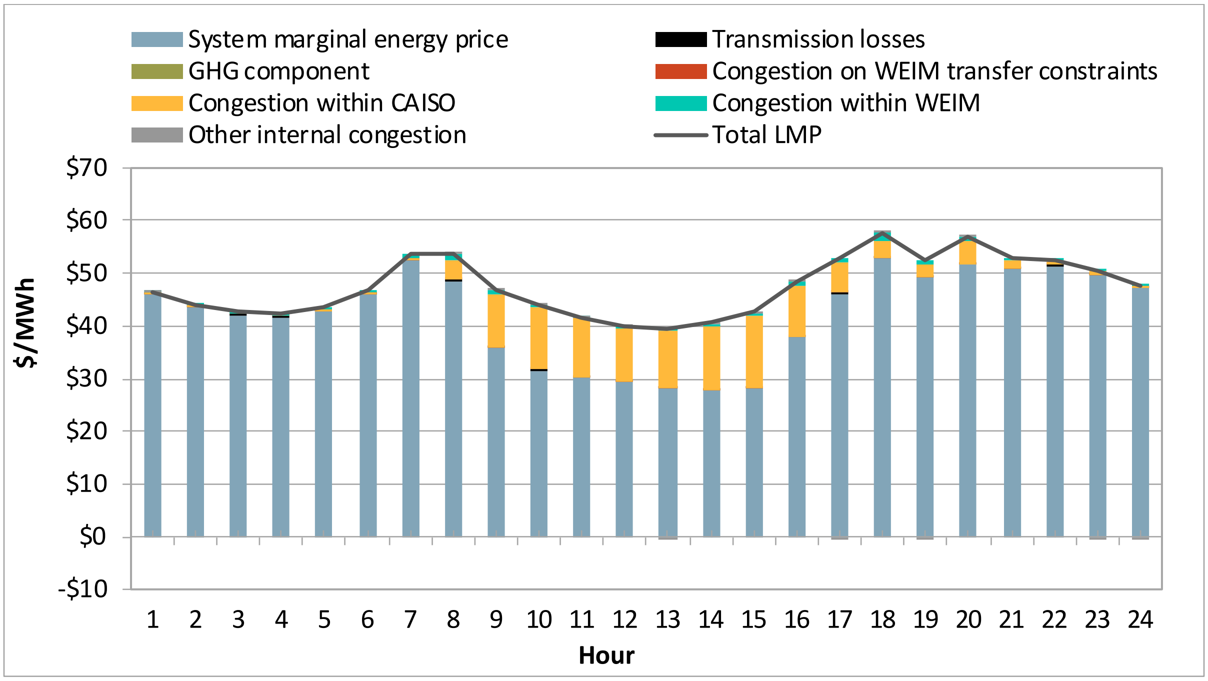
Appendix Figure A.13 Average hourly 15-minute price by component (Q4 2024)



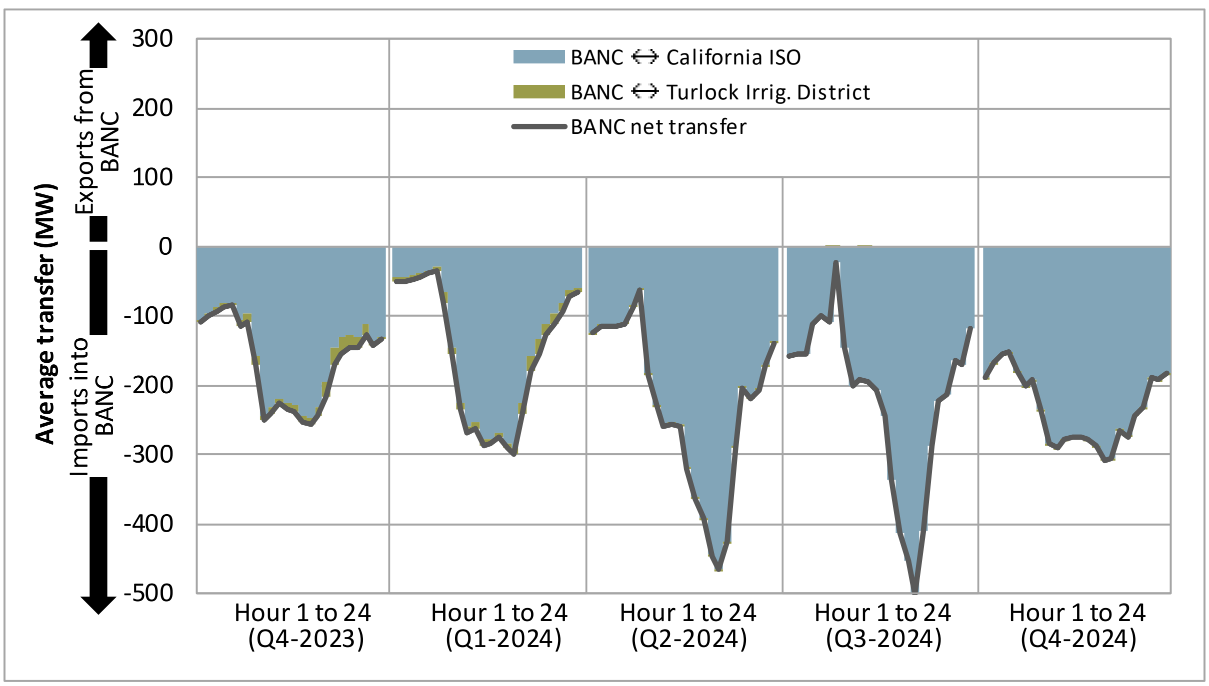
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q4 2024)

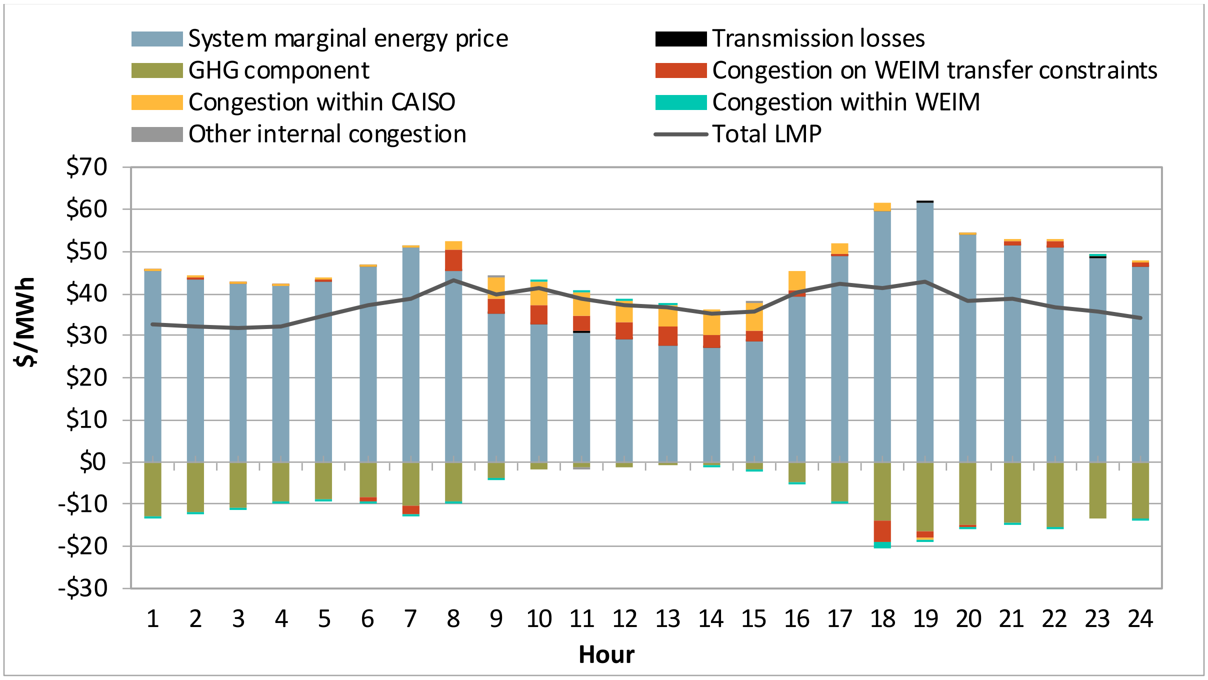


Appendix Figure A.16 Average hourly 5-minute market transfers

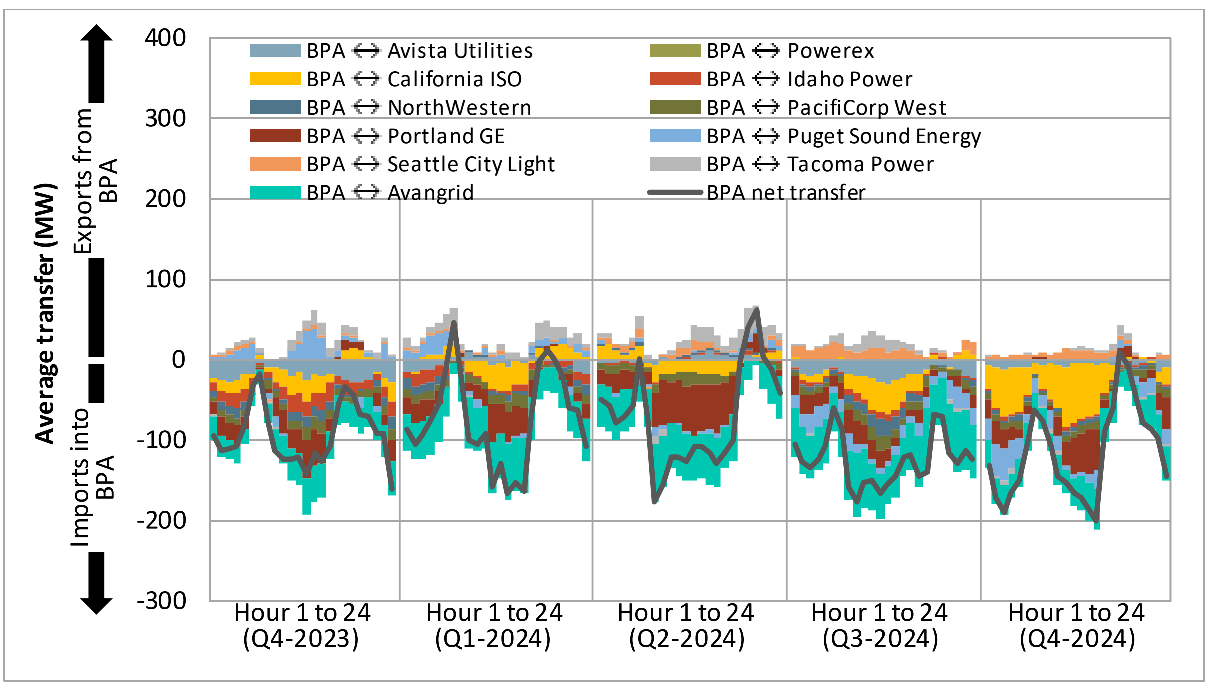


A.5 Bonneville Power Administration

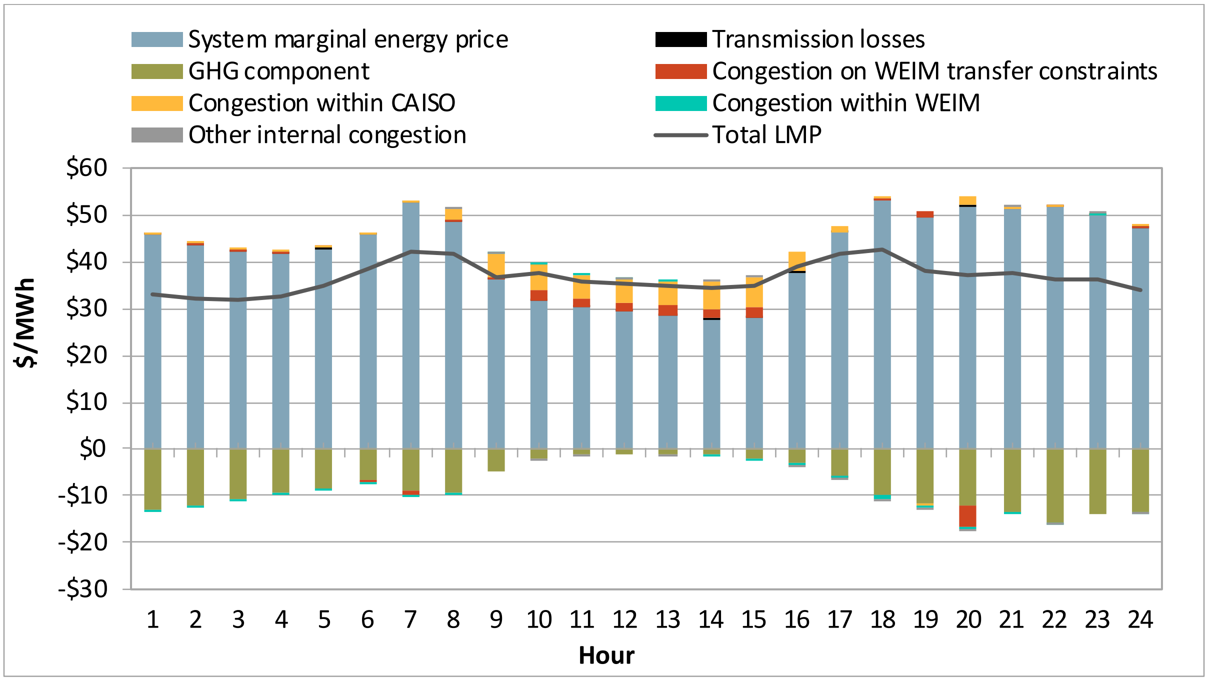
Appendix Figure A.17 Average hourly 15-minute price by component (Q4 2024)



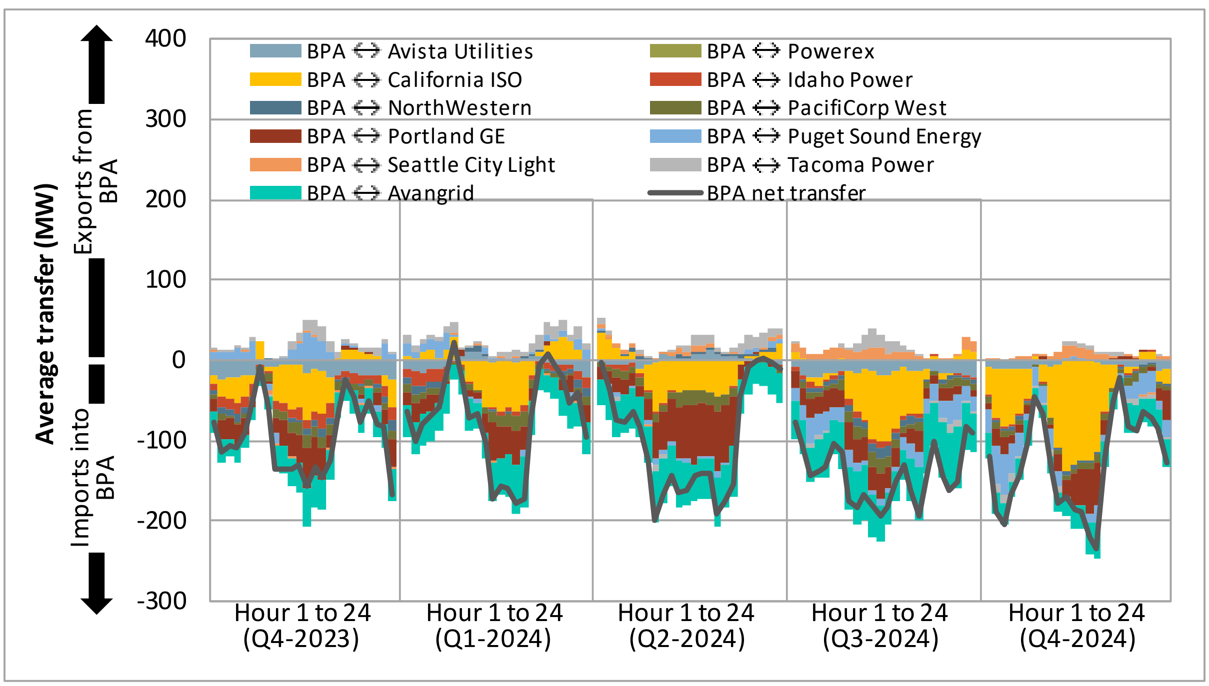
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q4 2024)

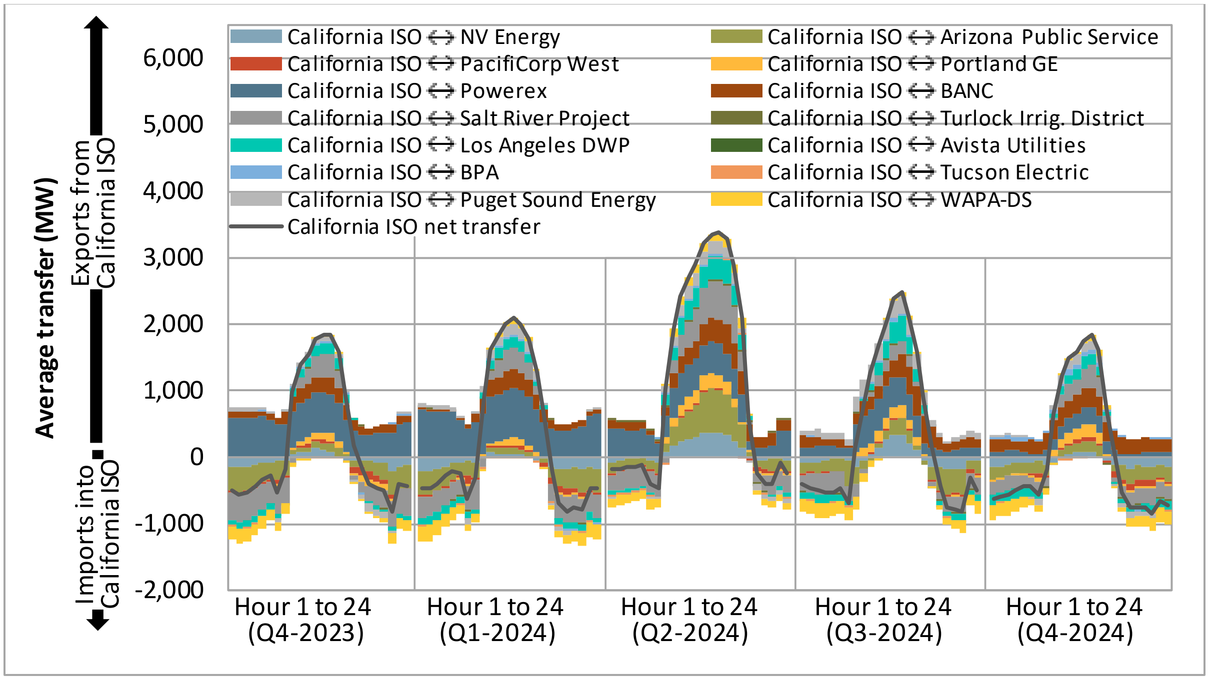


Appendix Figure A.20 Average hourly 5-minute market transfers

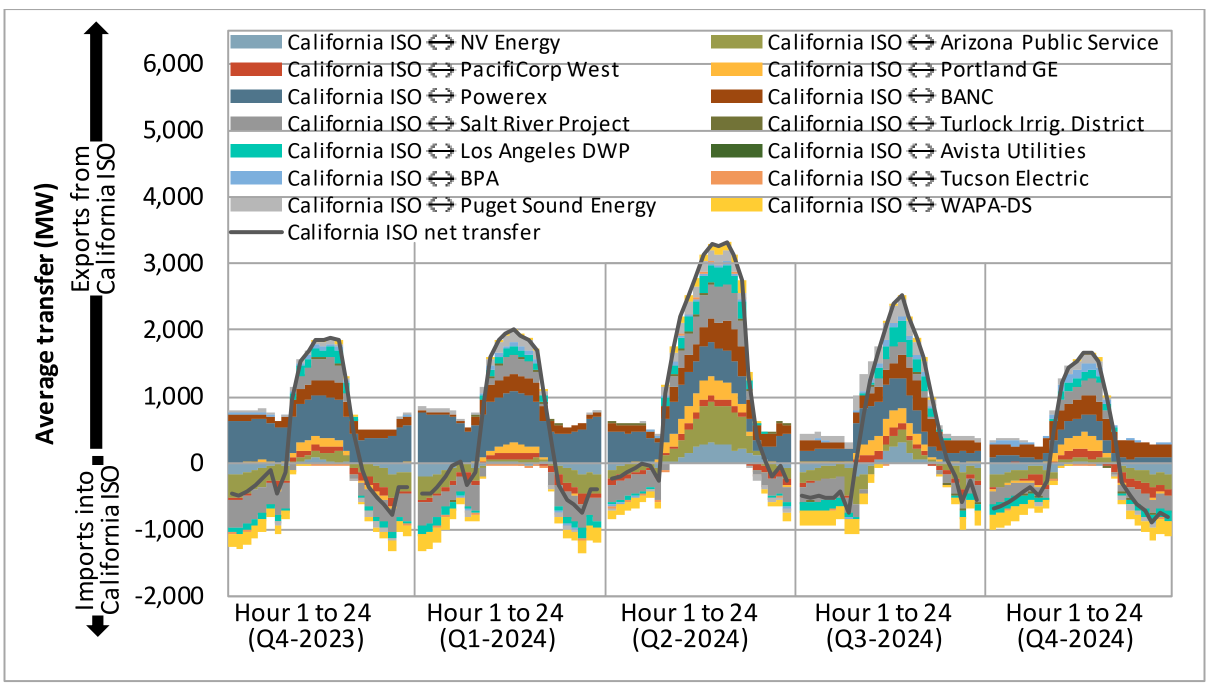


A.6 California ISO

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

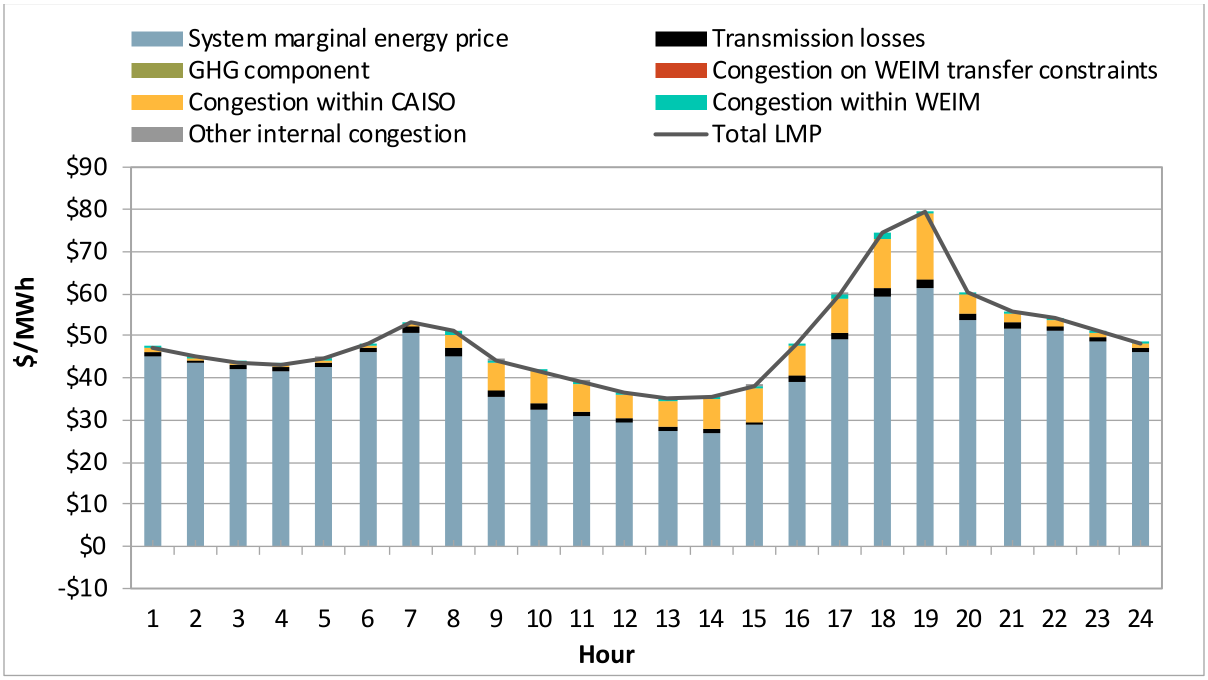


Appendix Figure A.22 Average hourly 5-minute market transfers

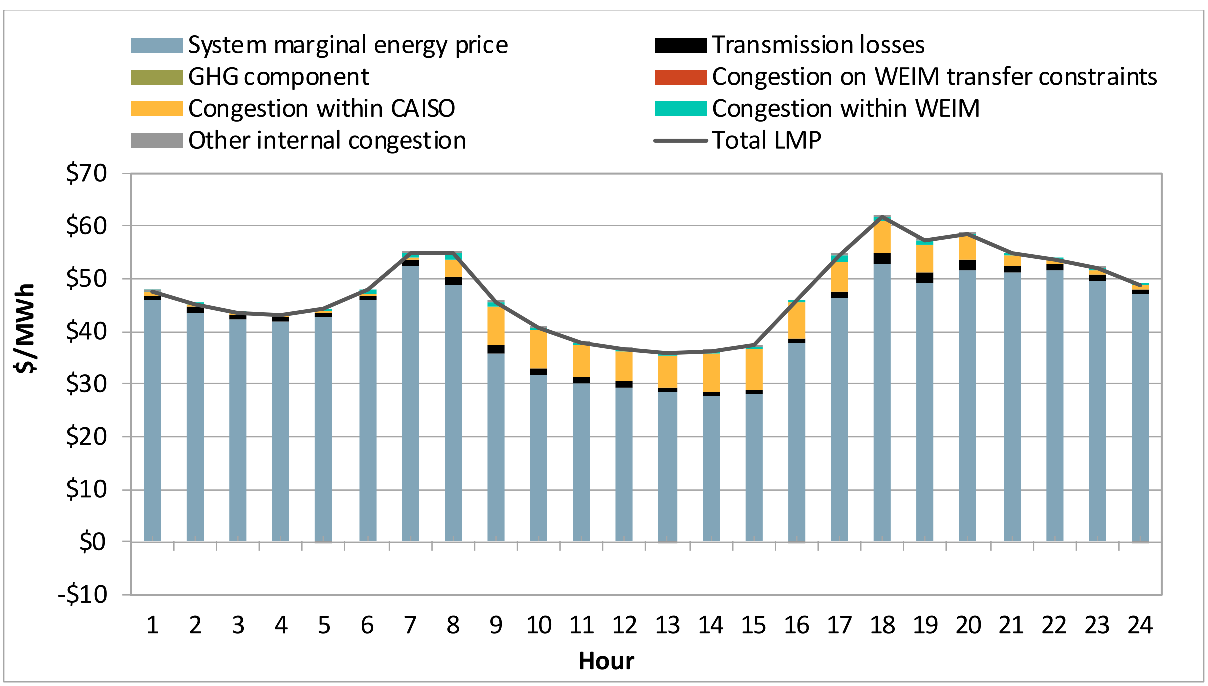


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q4 2024)

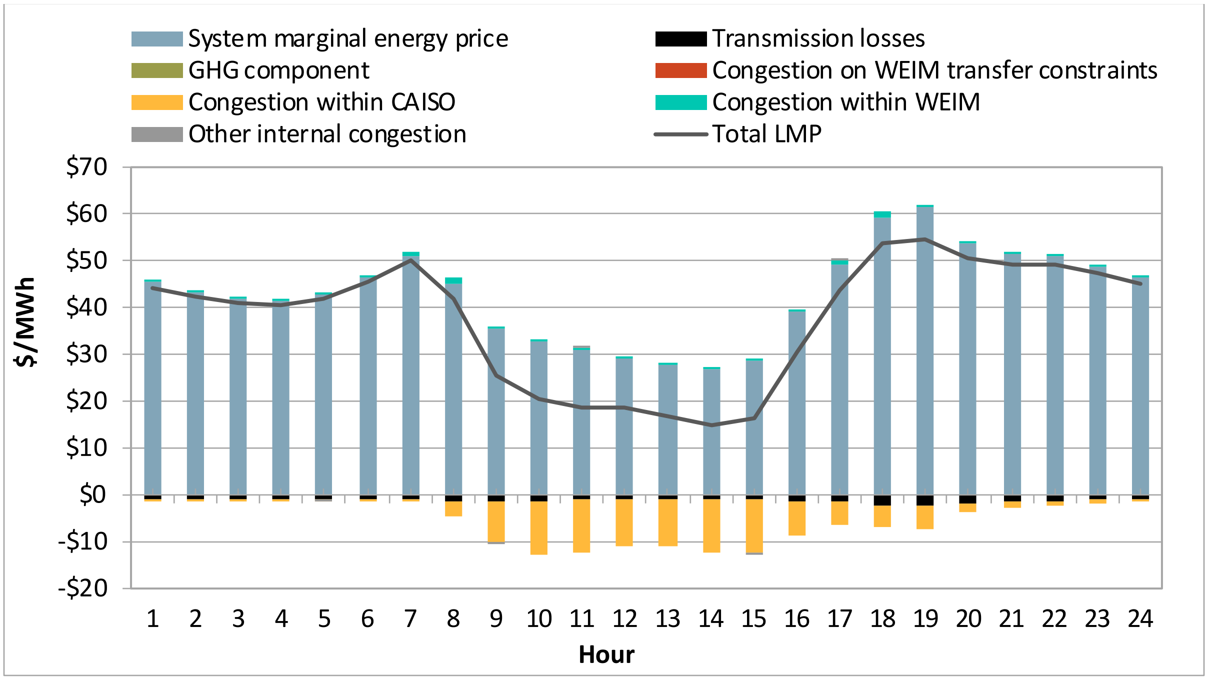


Appendix Figure A.24 Average hourly 5-minute price by component (Q4 2024)

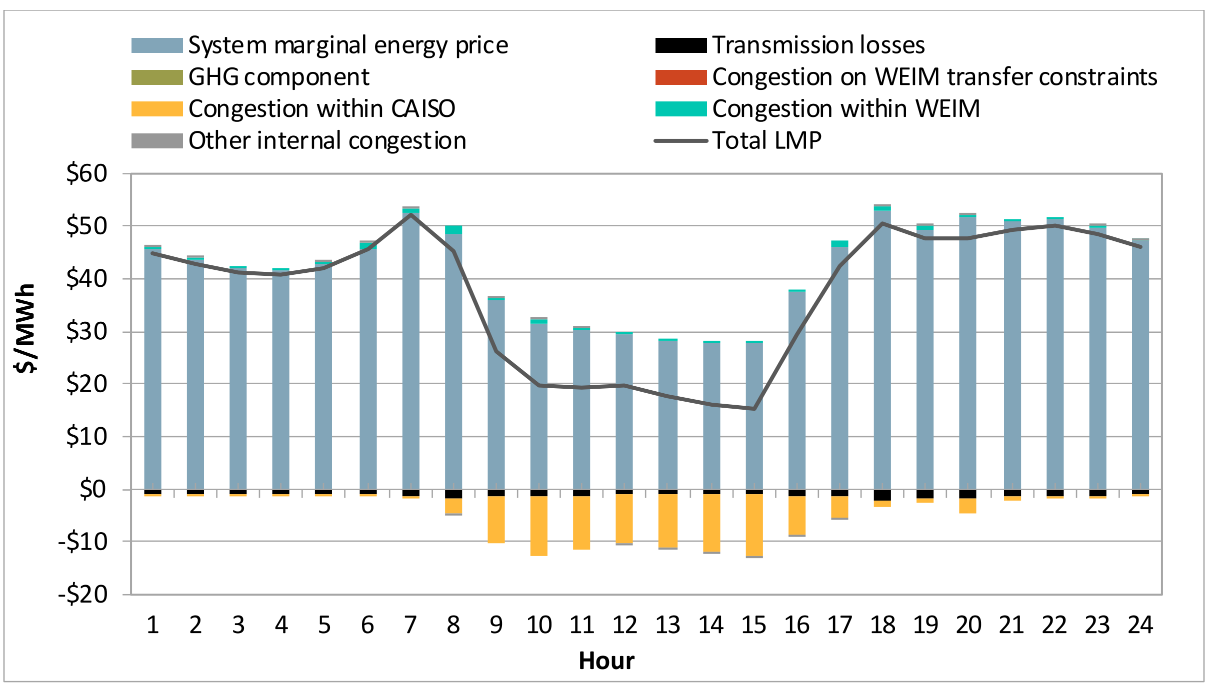


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q4 2024)

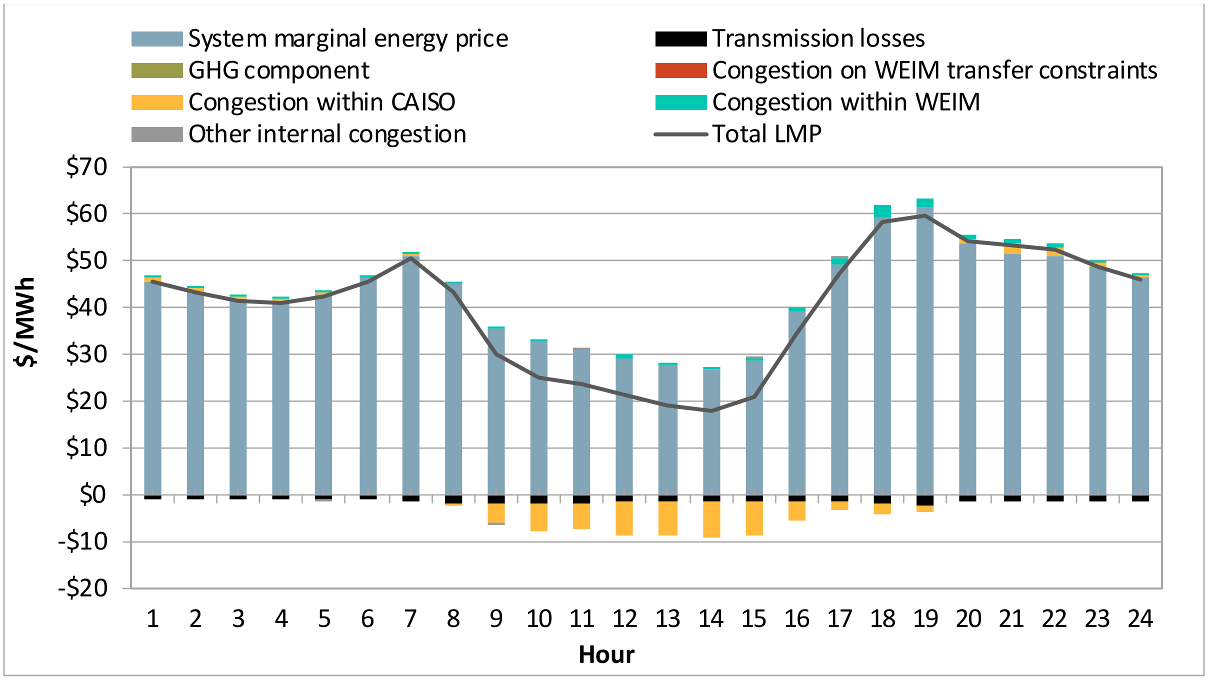


Appendix Figure A.26 Average hourly 5-minute price by component (Q4 2024)

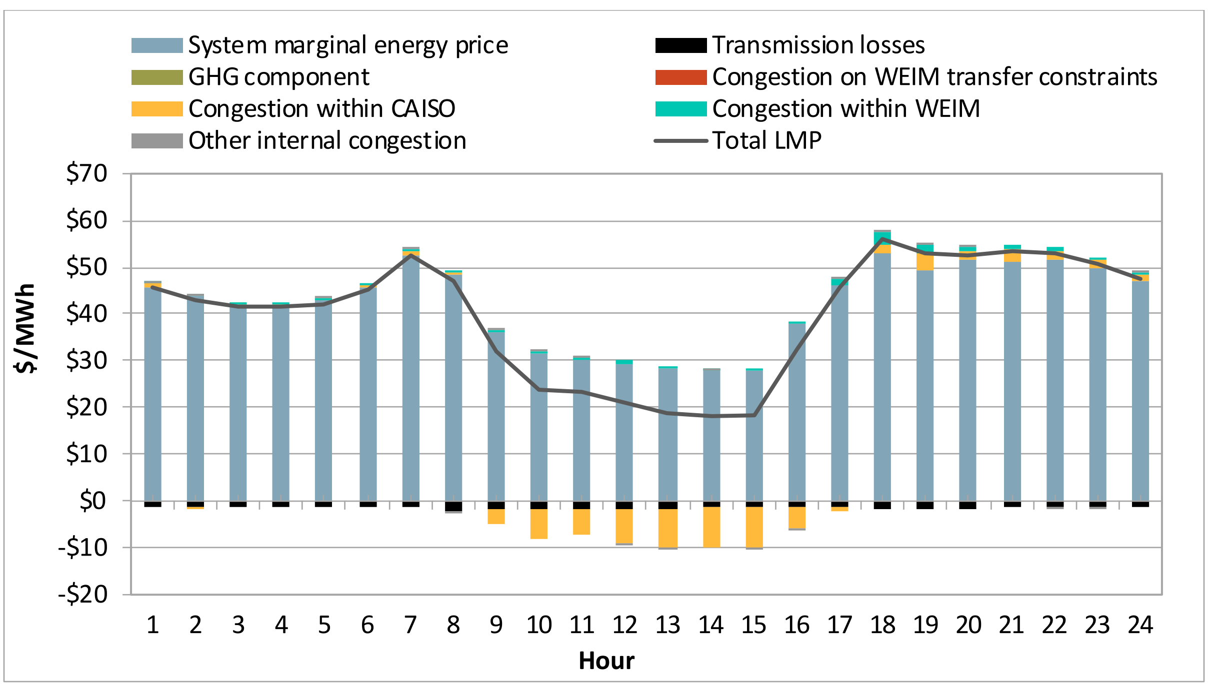


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q4 2024)

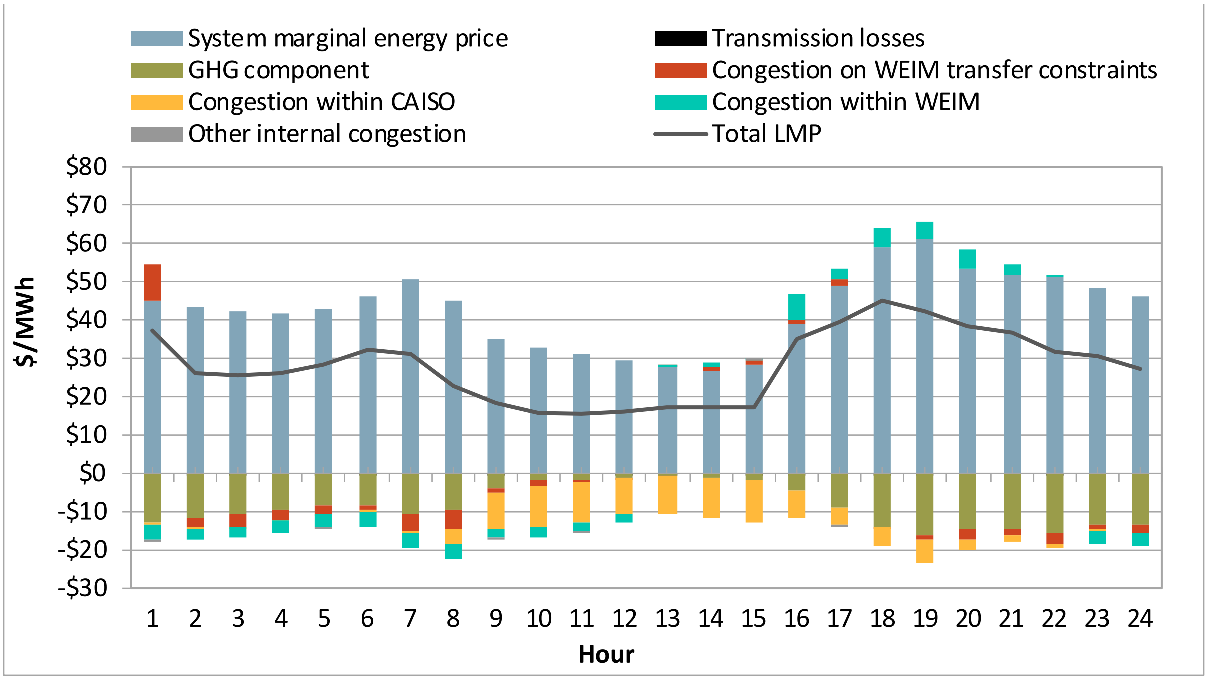


Appendix Figure A.28 Average hourly 5-minute price by component (Q4 2024)

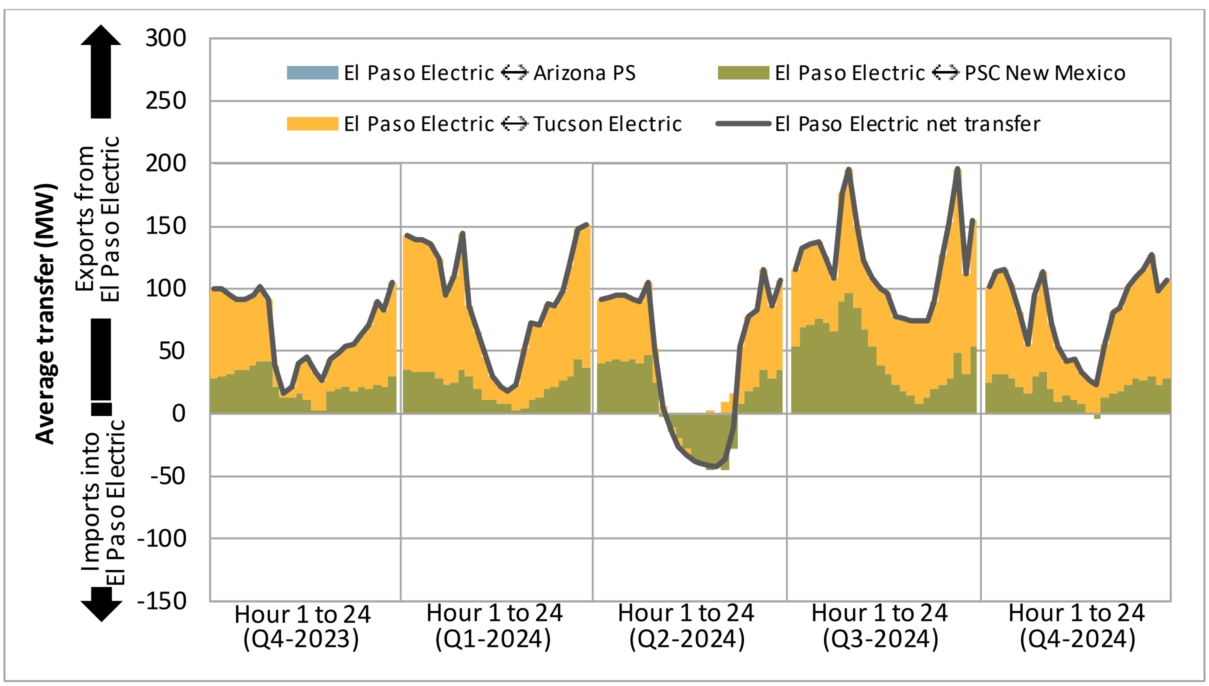


A.7 El Paso Electric

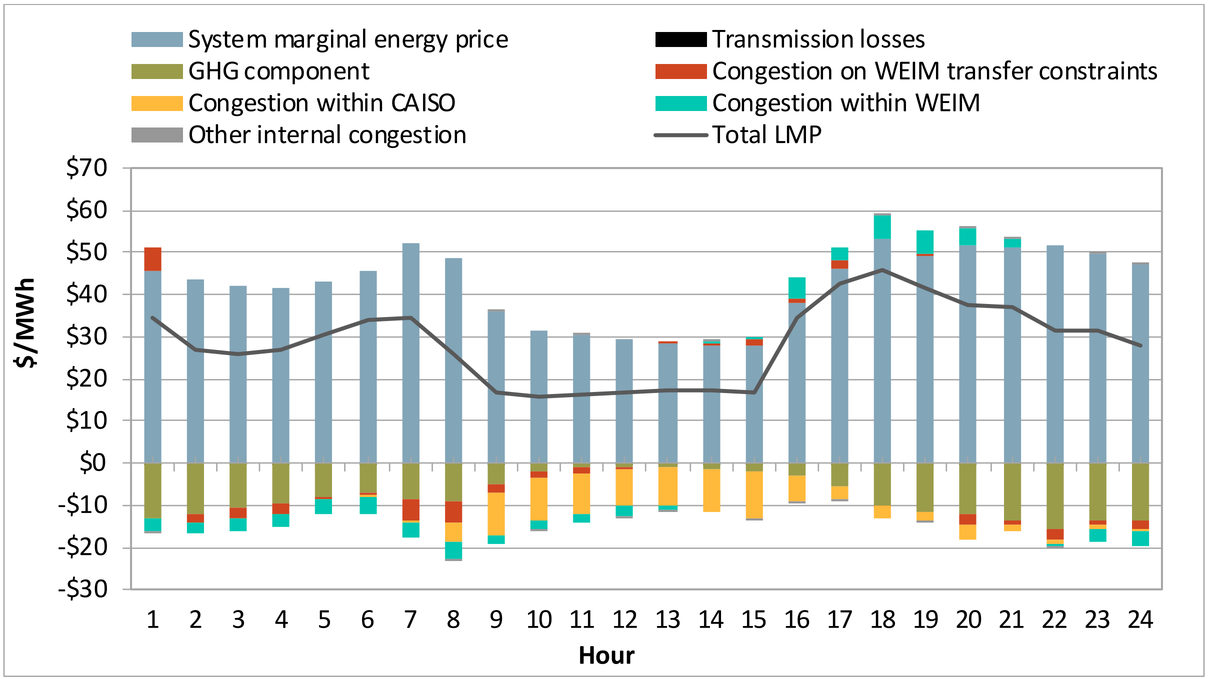
Appendix Figure A.29 Average hourly 15-minute price by component (Q4 2024)



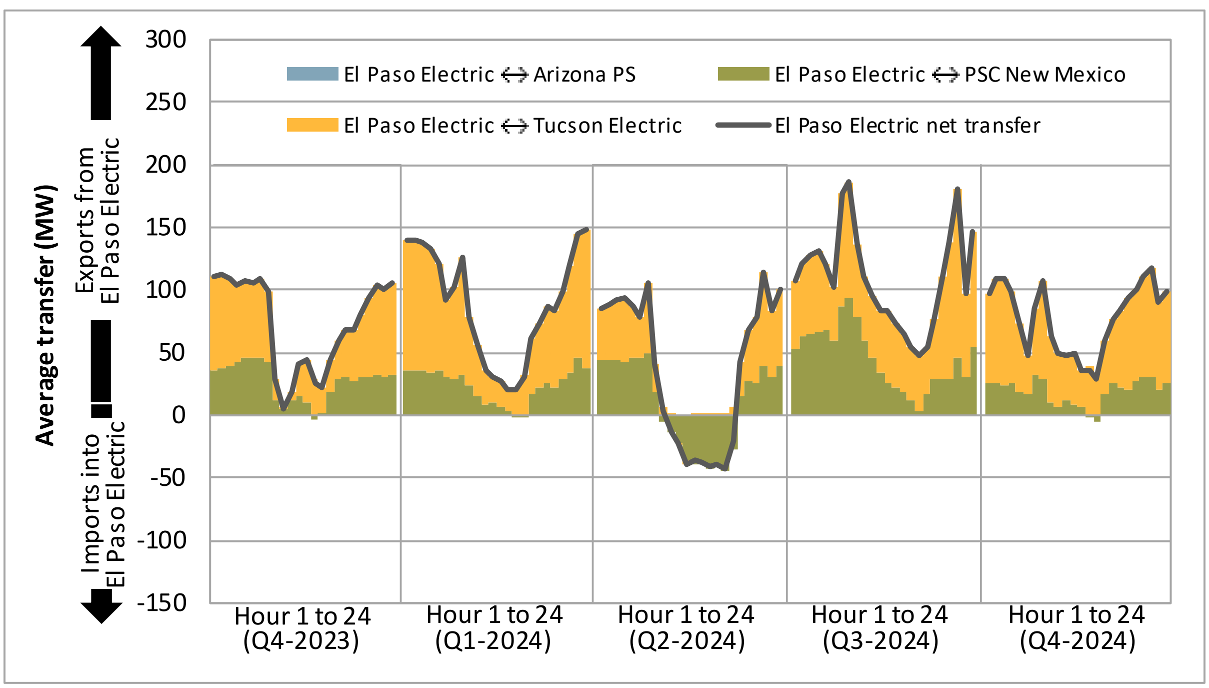
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q4 2024)

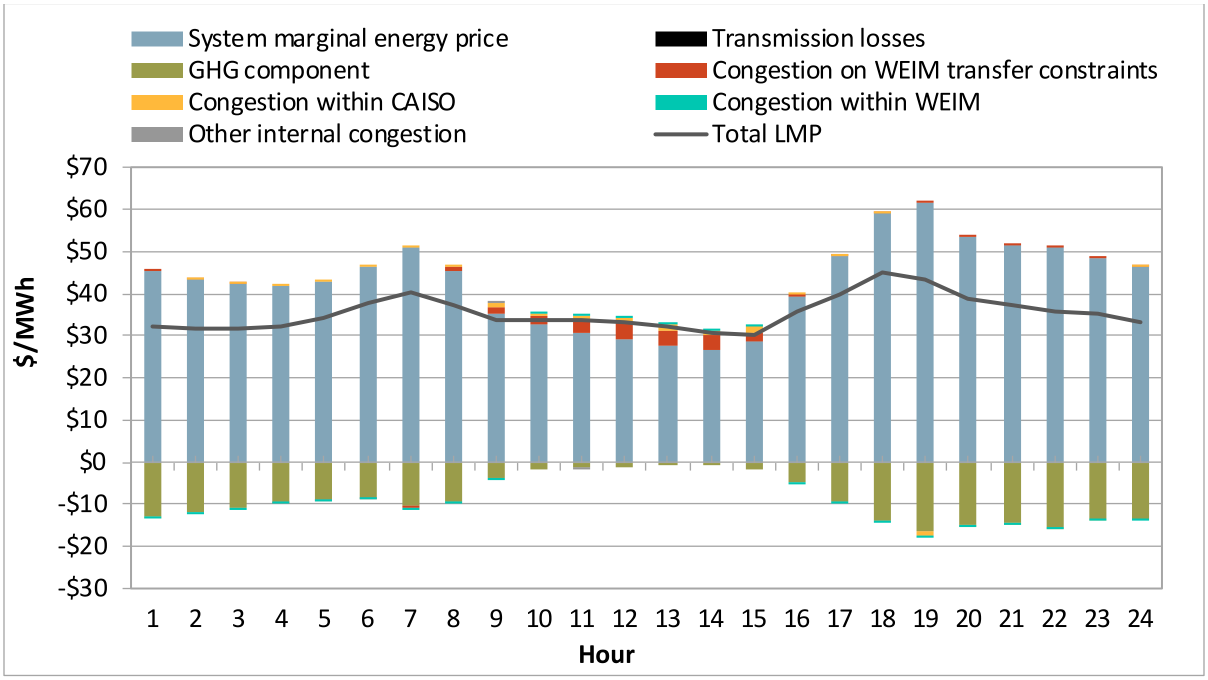


Appendix Figure A.32 Average hourly 5-minute market transfers

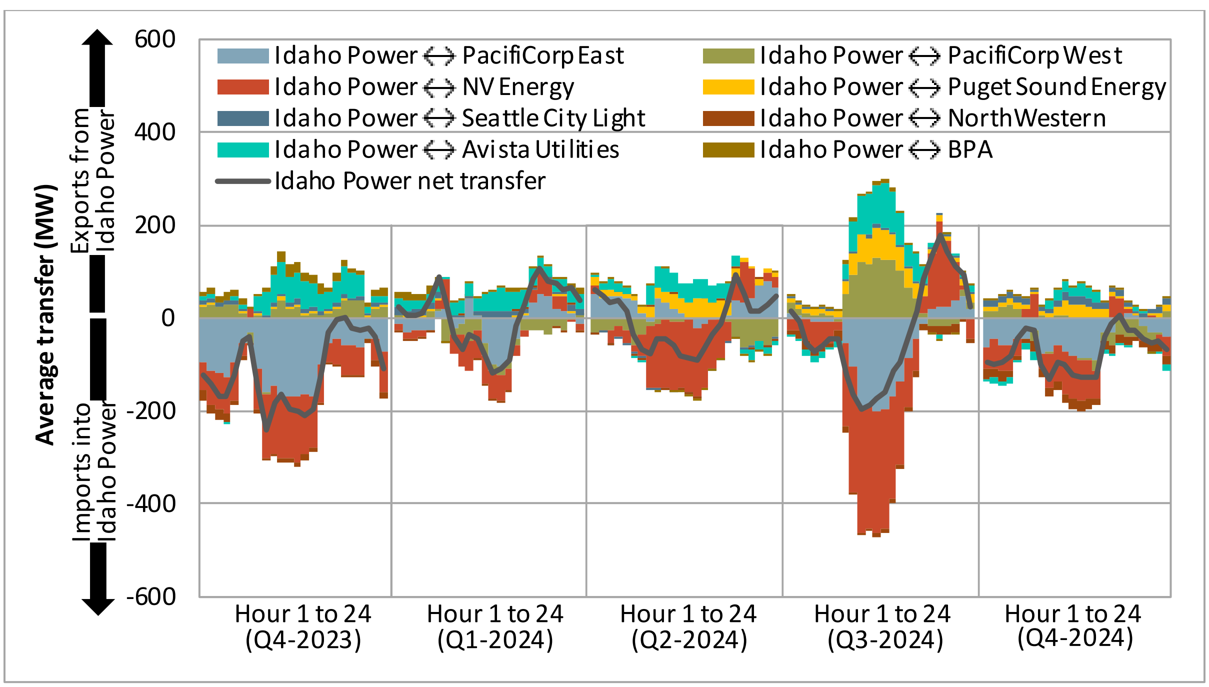


A.8 Idaho Power

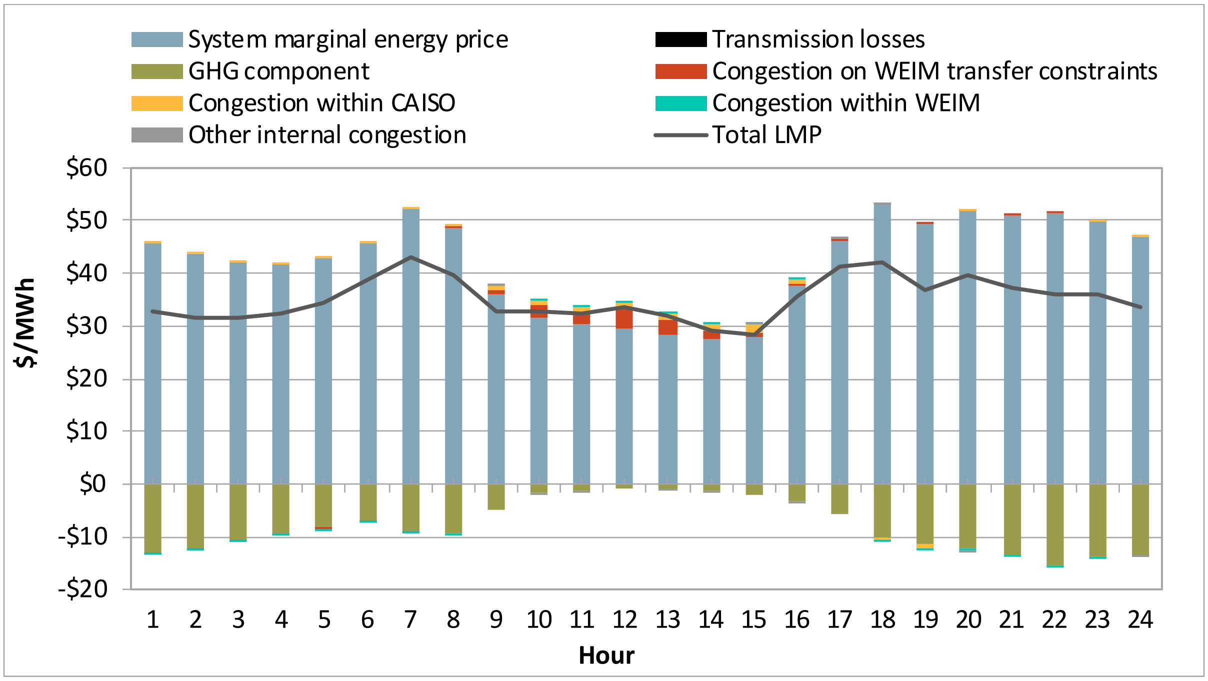
Appendix Figure A.33 Average hourly 15-minute price by component (Q4 2024)



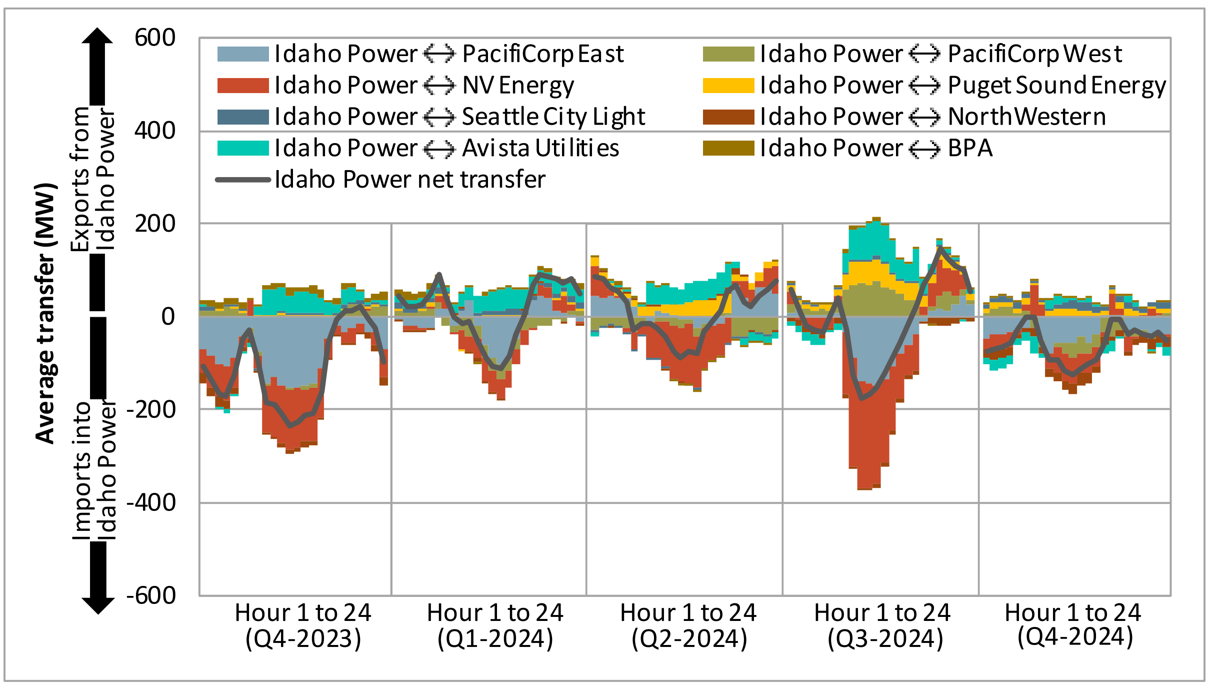
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q4 2024)

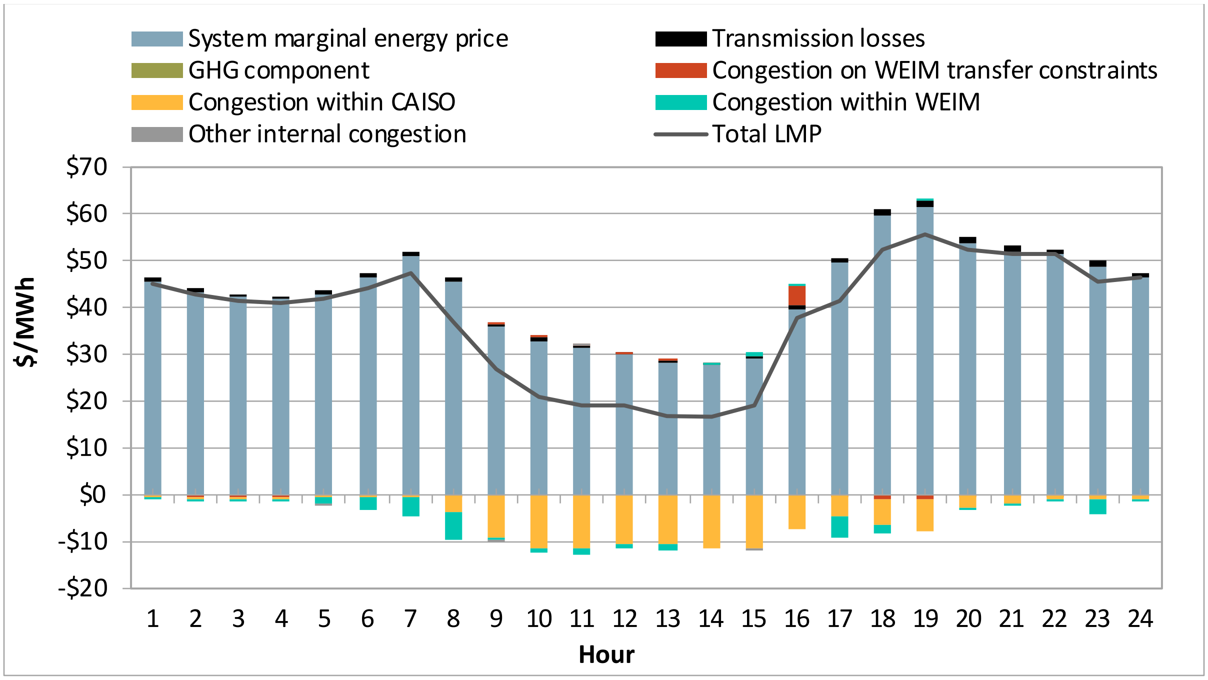


Appendix Figure A.36 Average hourly 5-minute market transfers

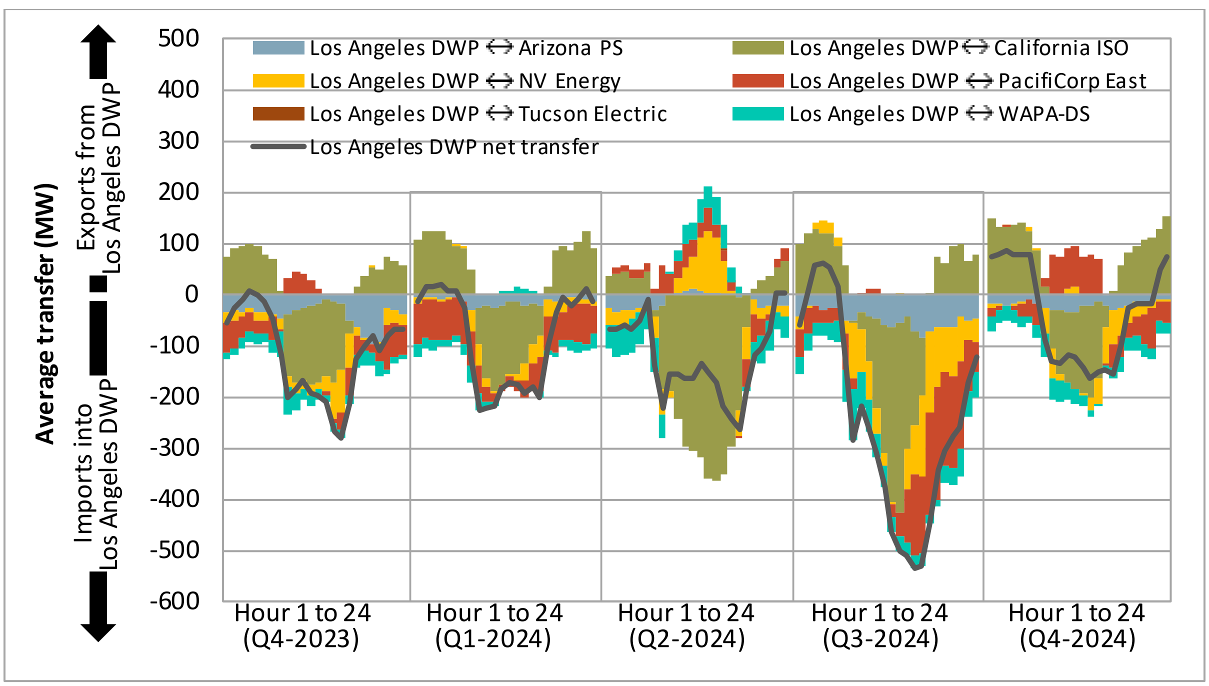


A.9 Los Angeles Department of Water and Power

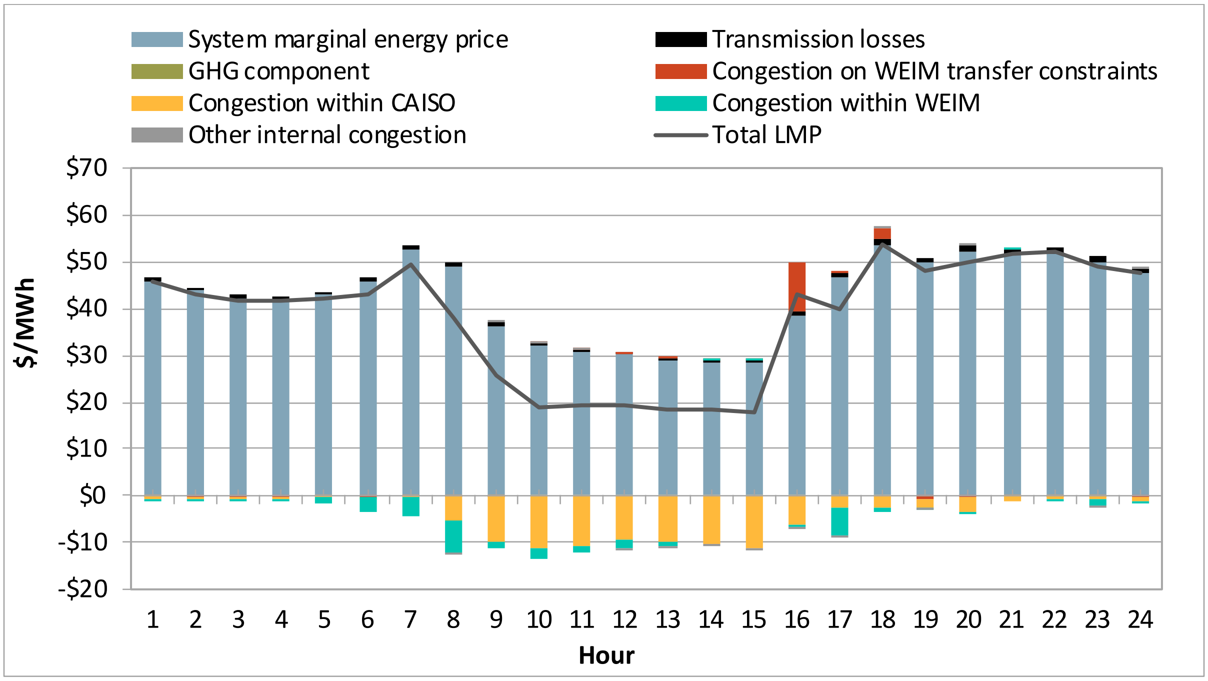
Appendix Figure A.37 Average hourly 15-minute price by component (Q4 2024)



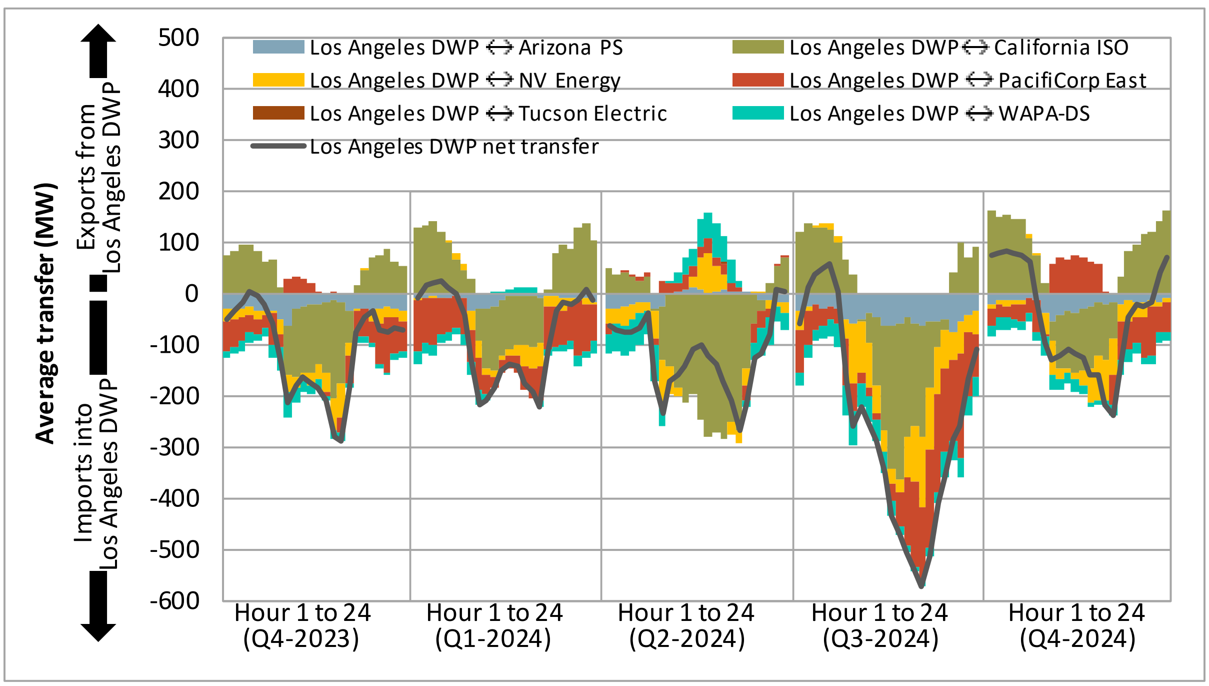
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q4 2024)

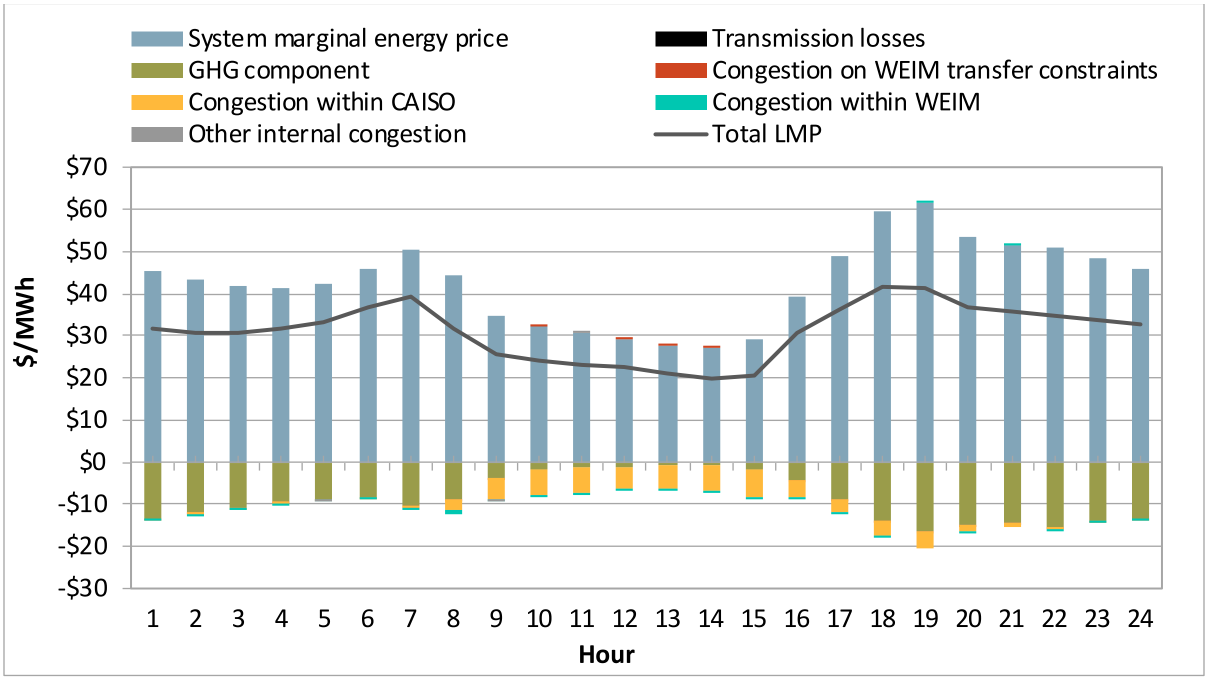


Appendix Figure A.40 Average hourly 5-minute market transfers

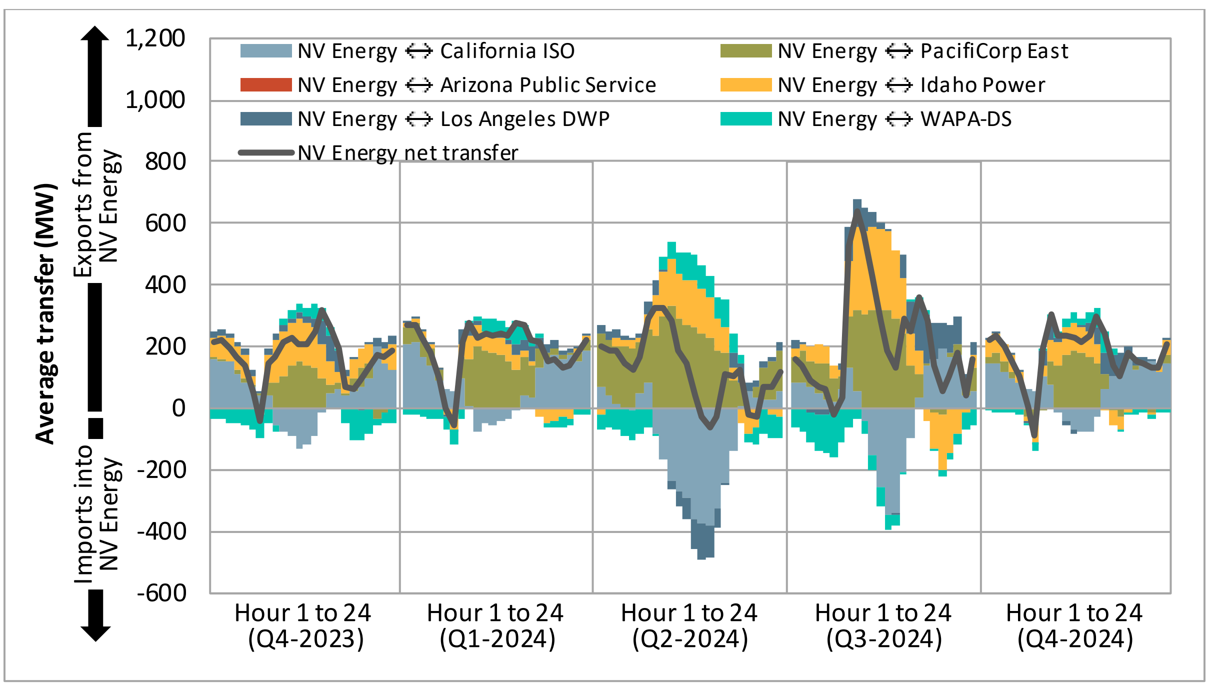


A.10 NV Energy

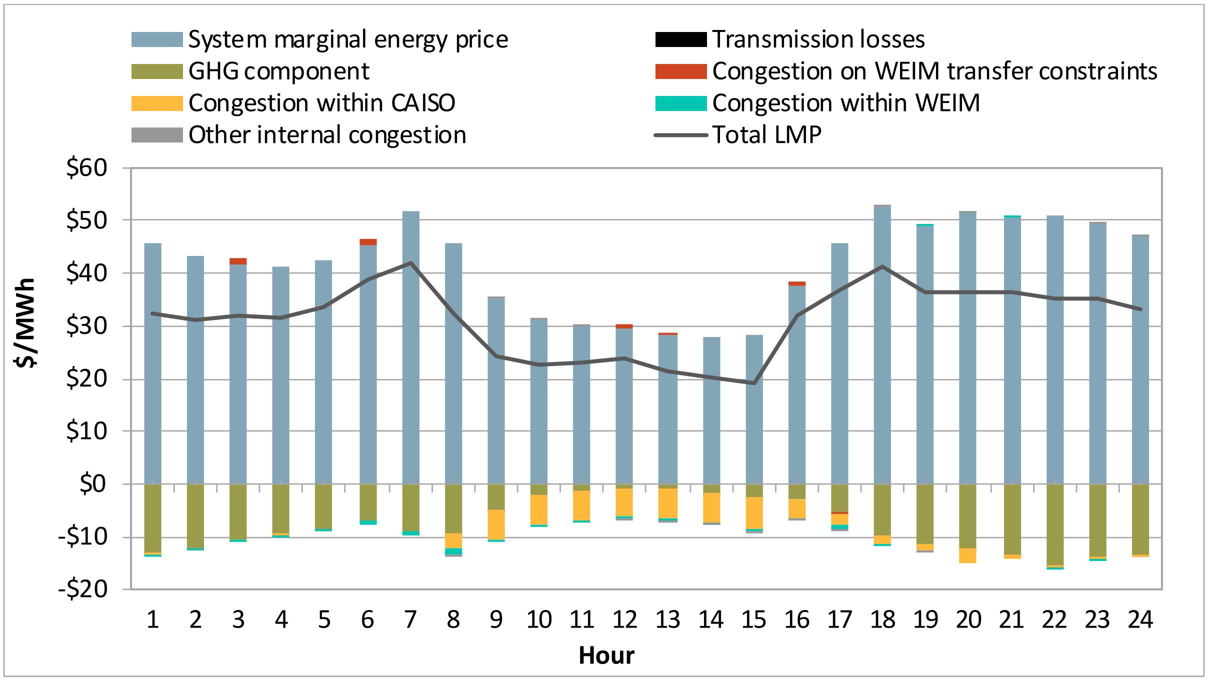
Appendix Figure A.41 Average hourly 15-minute price by component (Q4 2024)



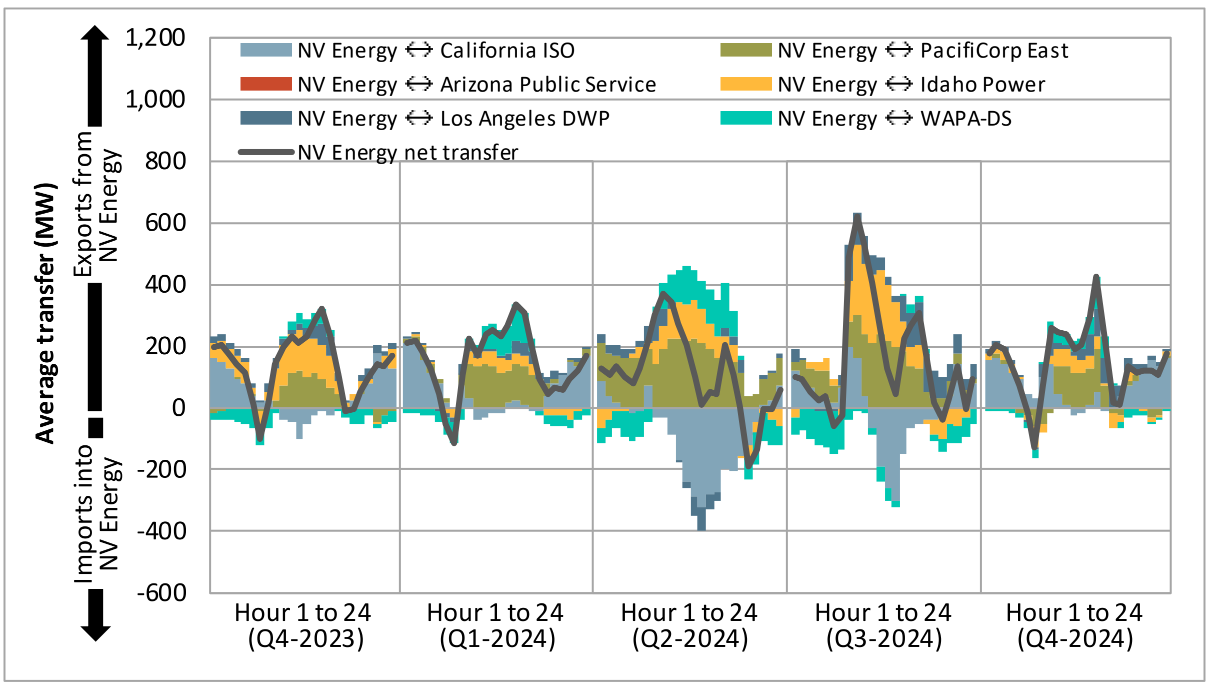
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q4 2024)

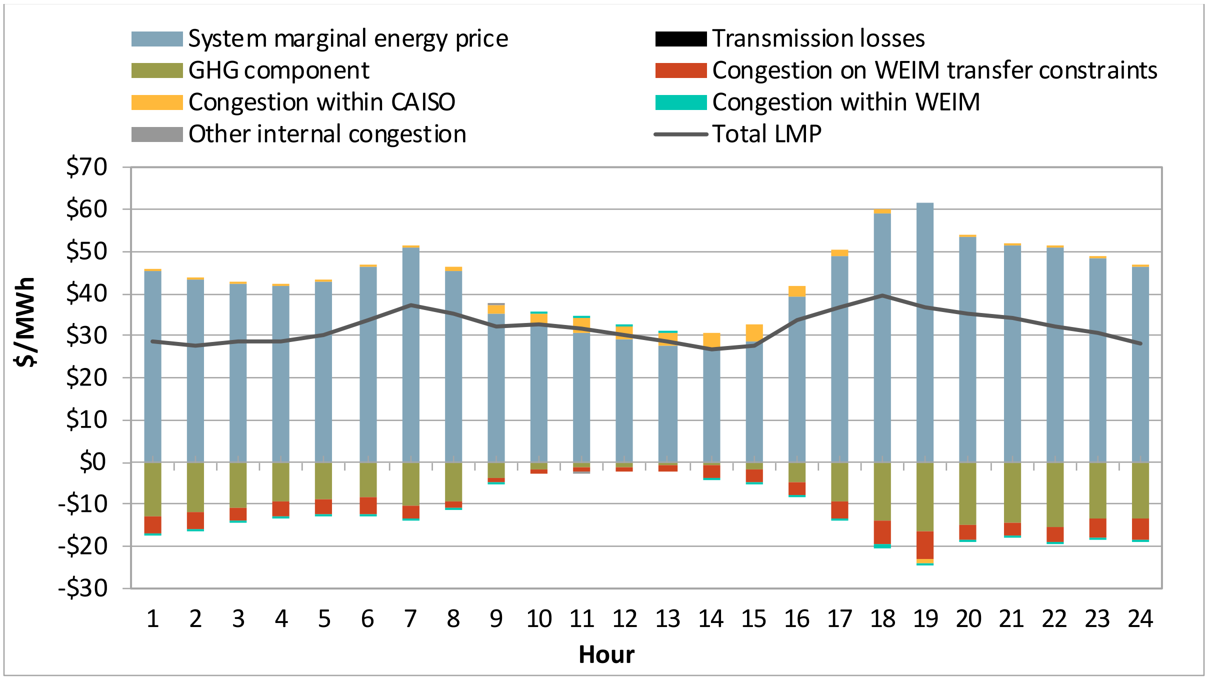


Appendix Figure A.44 Average hourly 5-minute market transfers

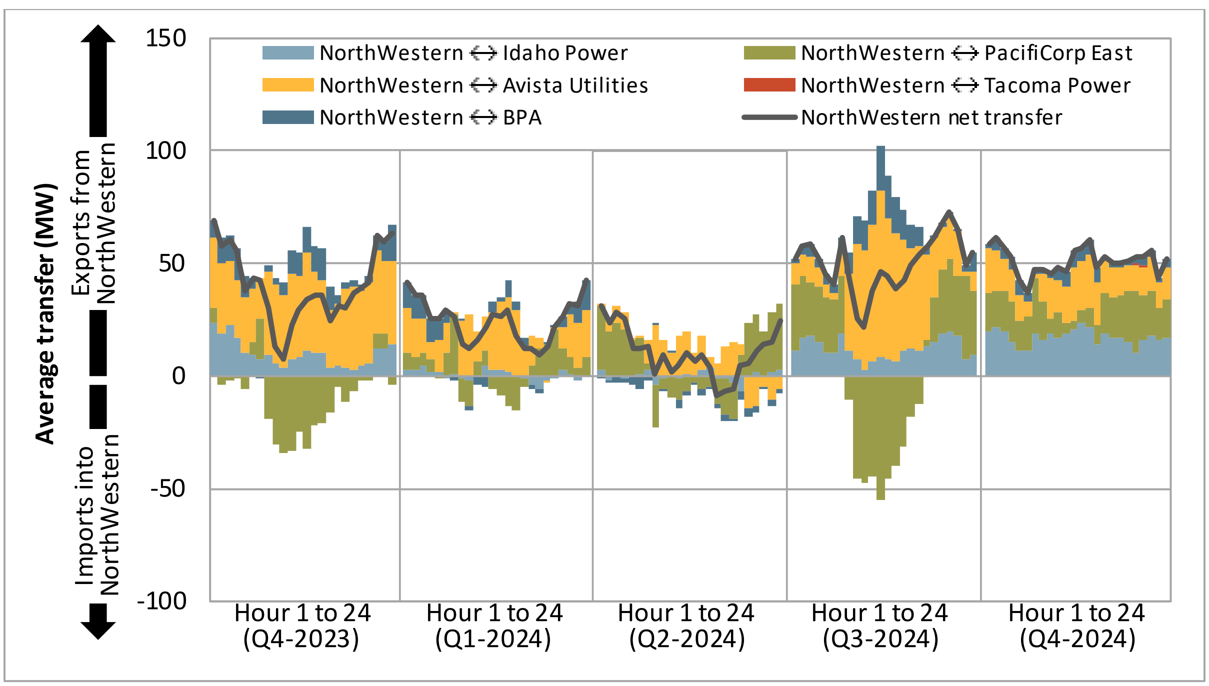


A.11 NorthWestern Energy

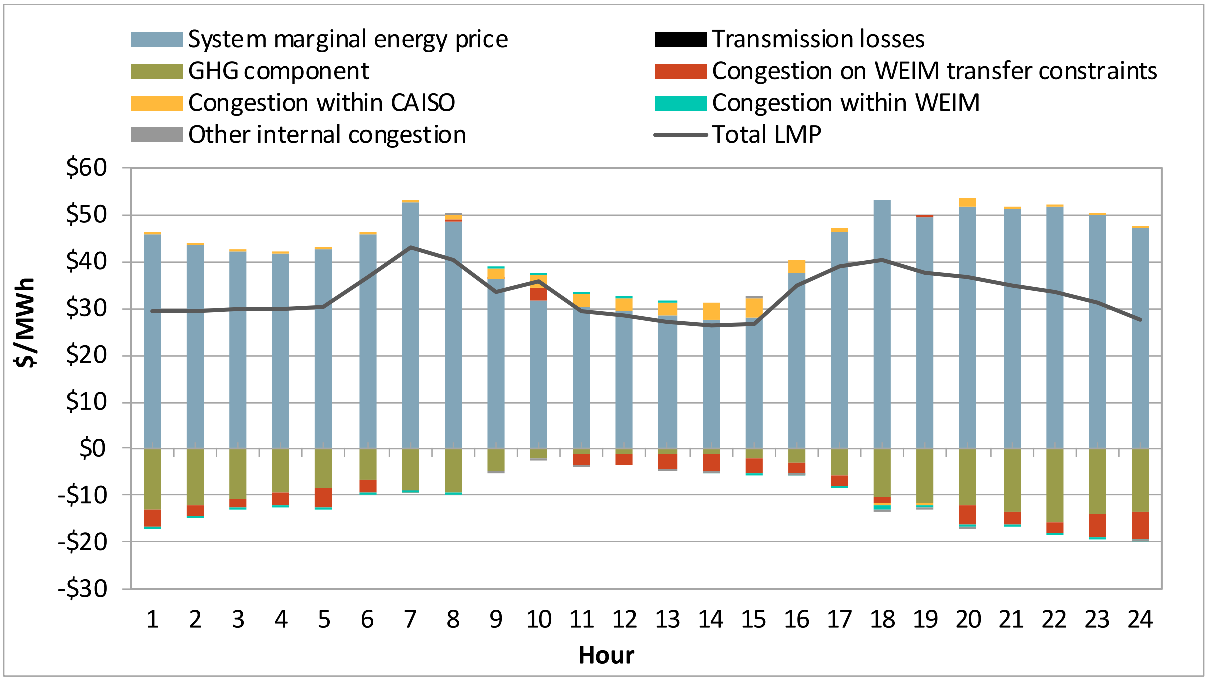
Appendix Figure A.45 Average hourly 15-minute price by component (Q4 2024)



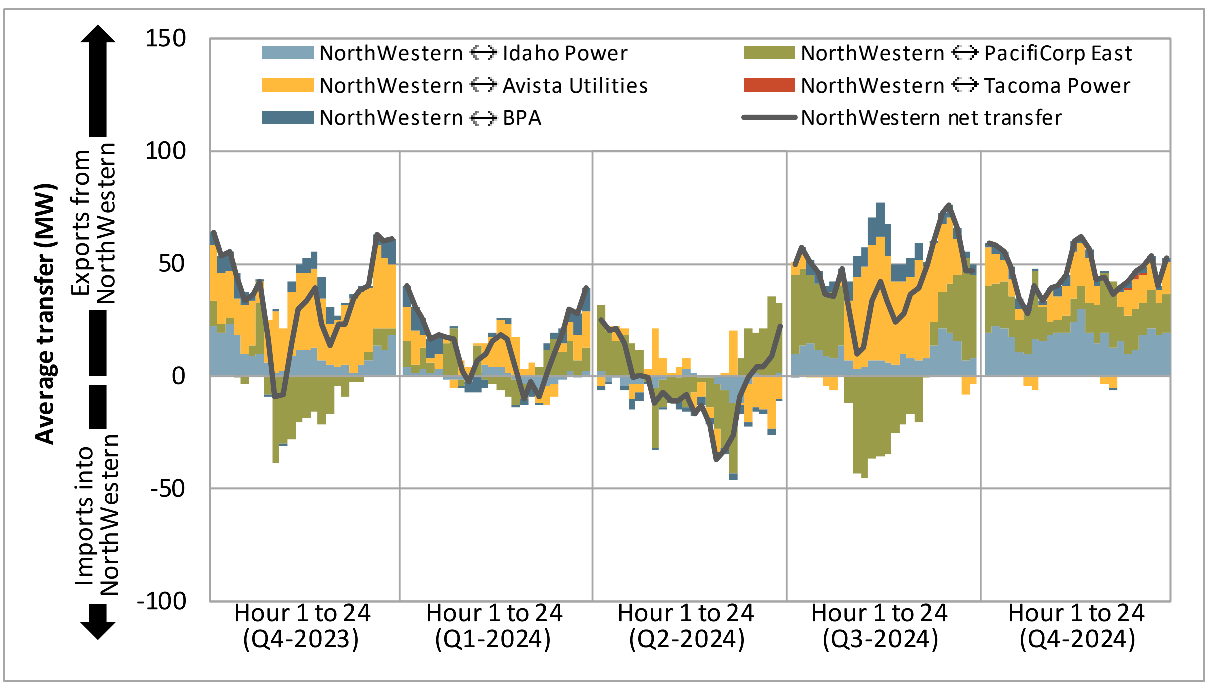
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q4 2024)

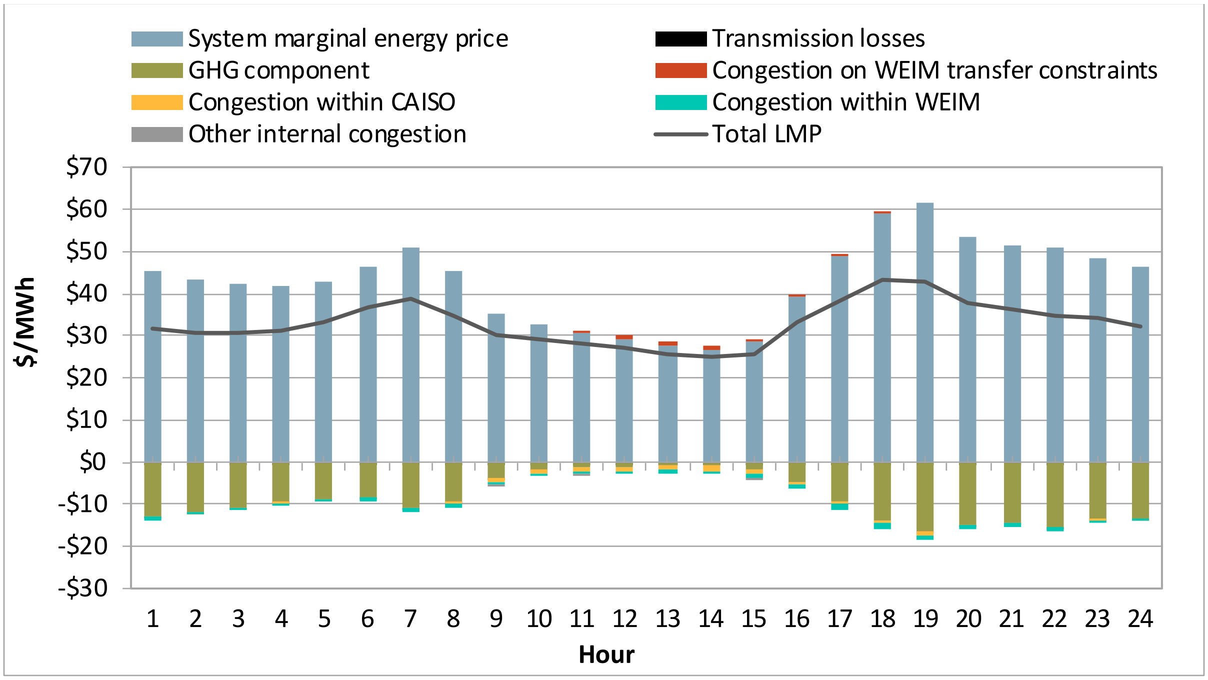


Appendix Figure A.48 Average hourly 5-minute market transfers

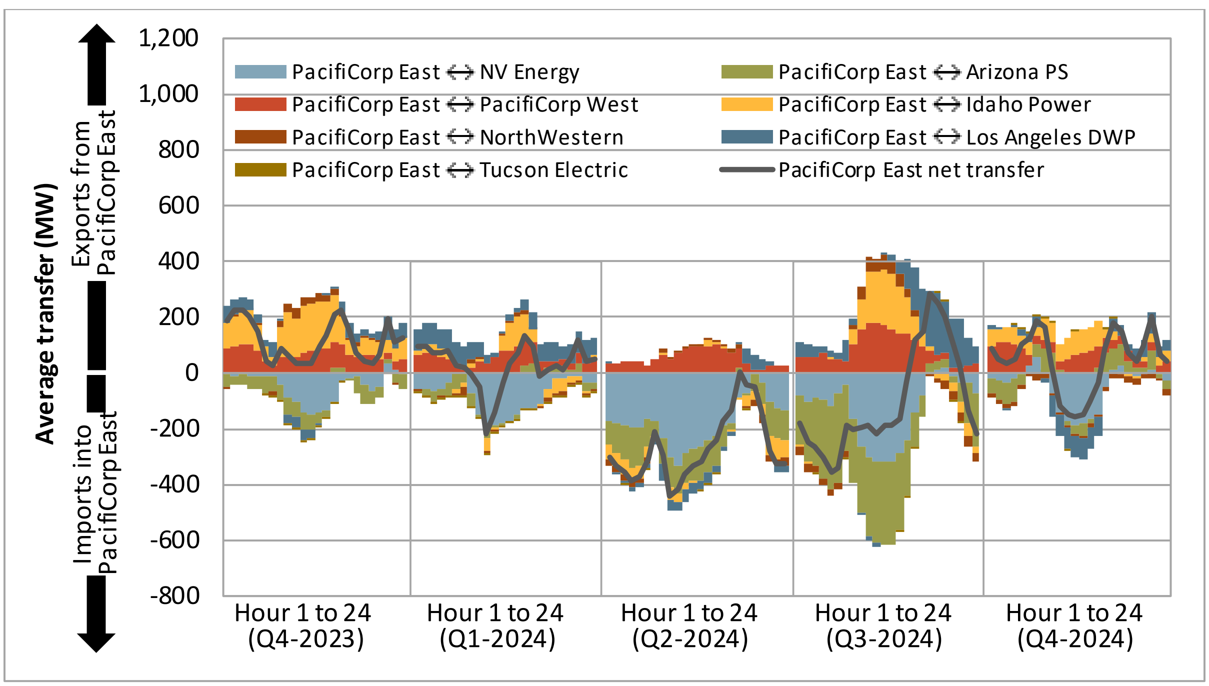


A.12 PacifiCorp East

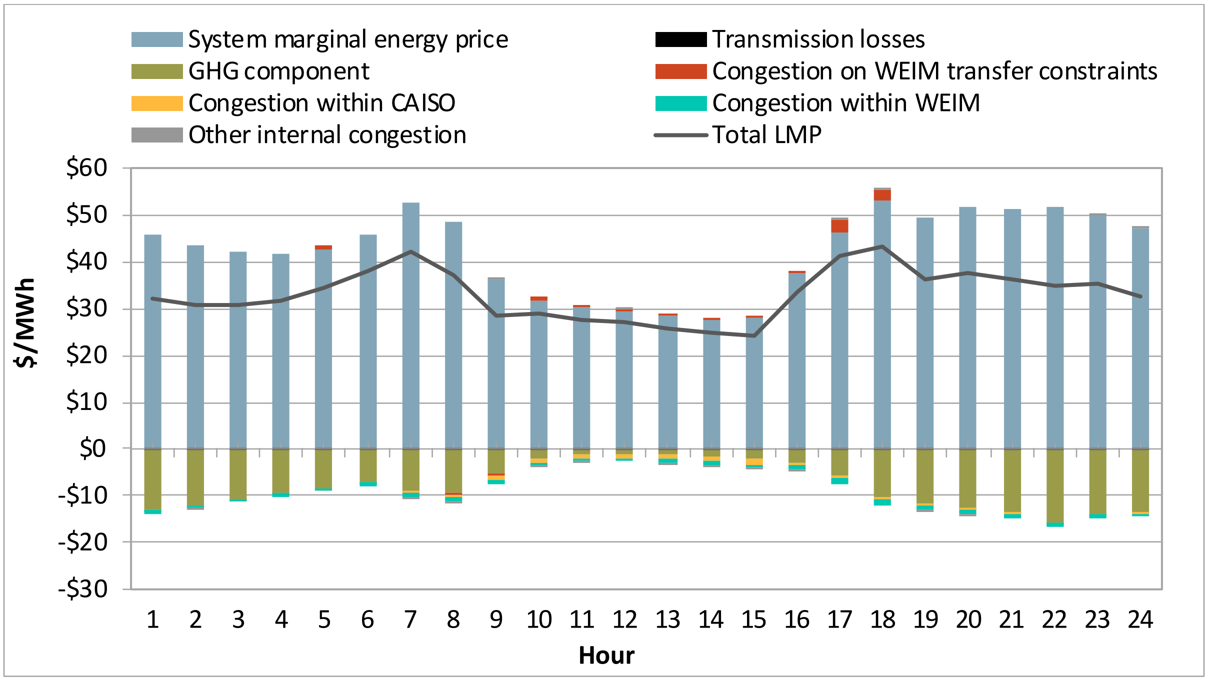
Appendix Figure A.49 Average hourly 15-minute price by component (Q4 2024)



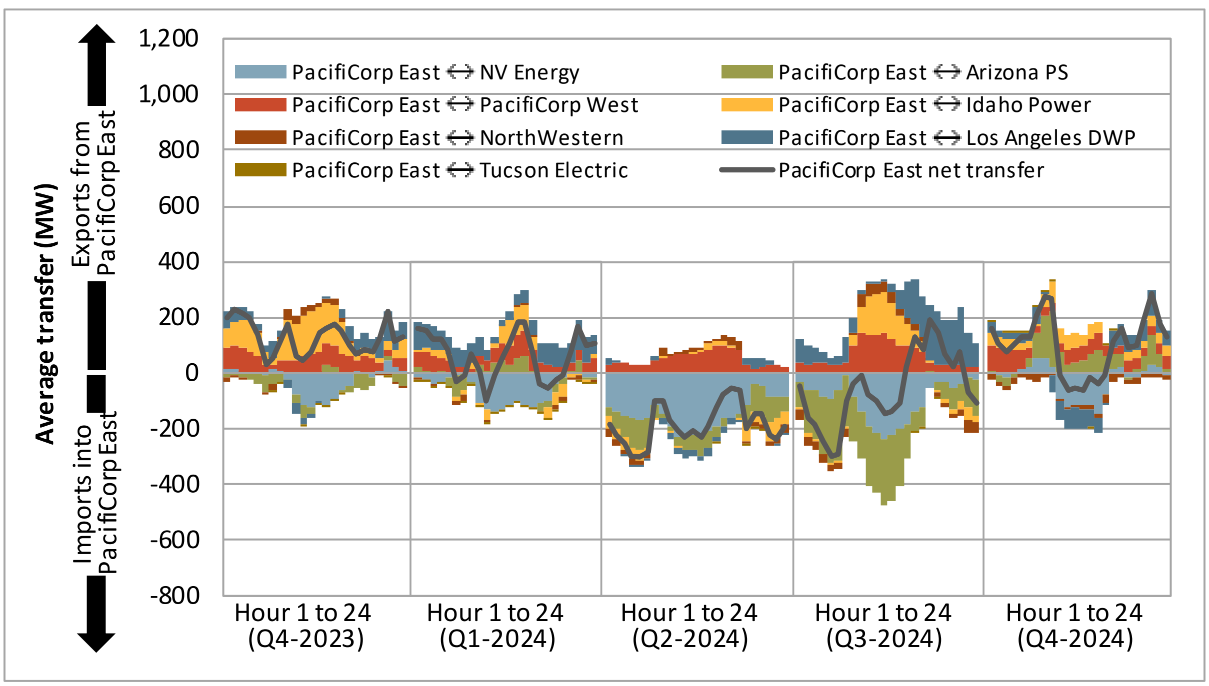
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q4 2024)

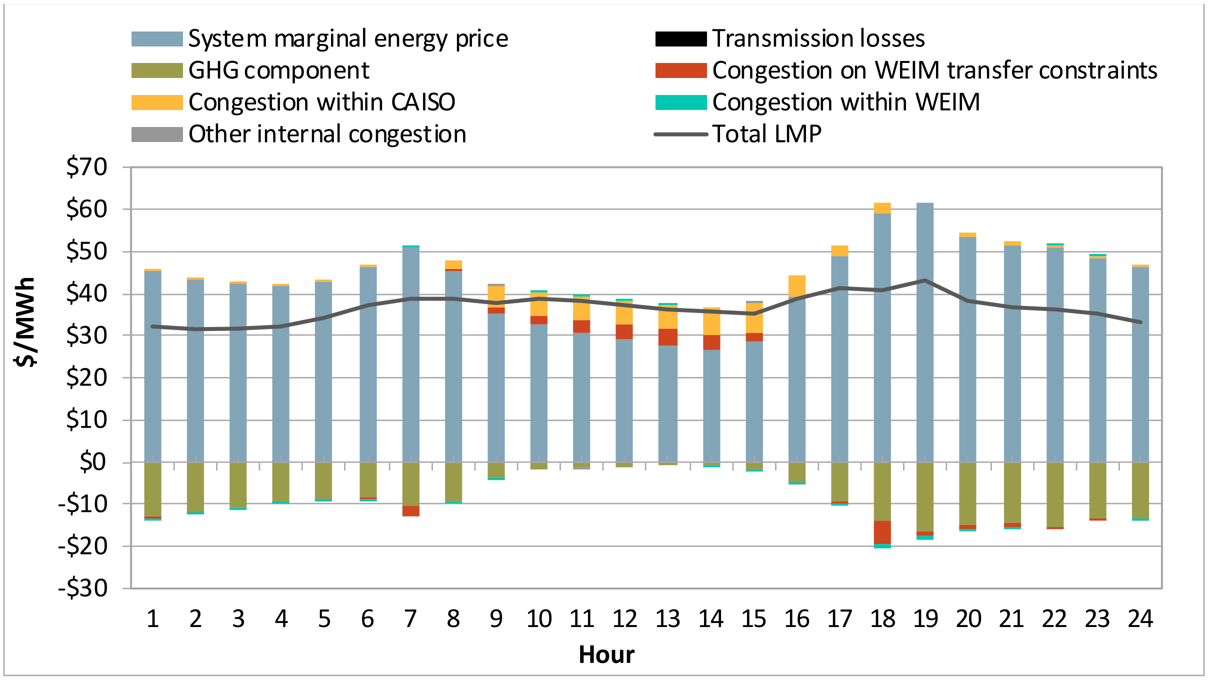


Appendix Figure A.52 Average hourly 5-minute market transfers

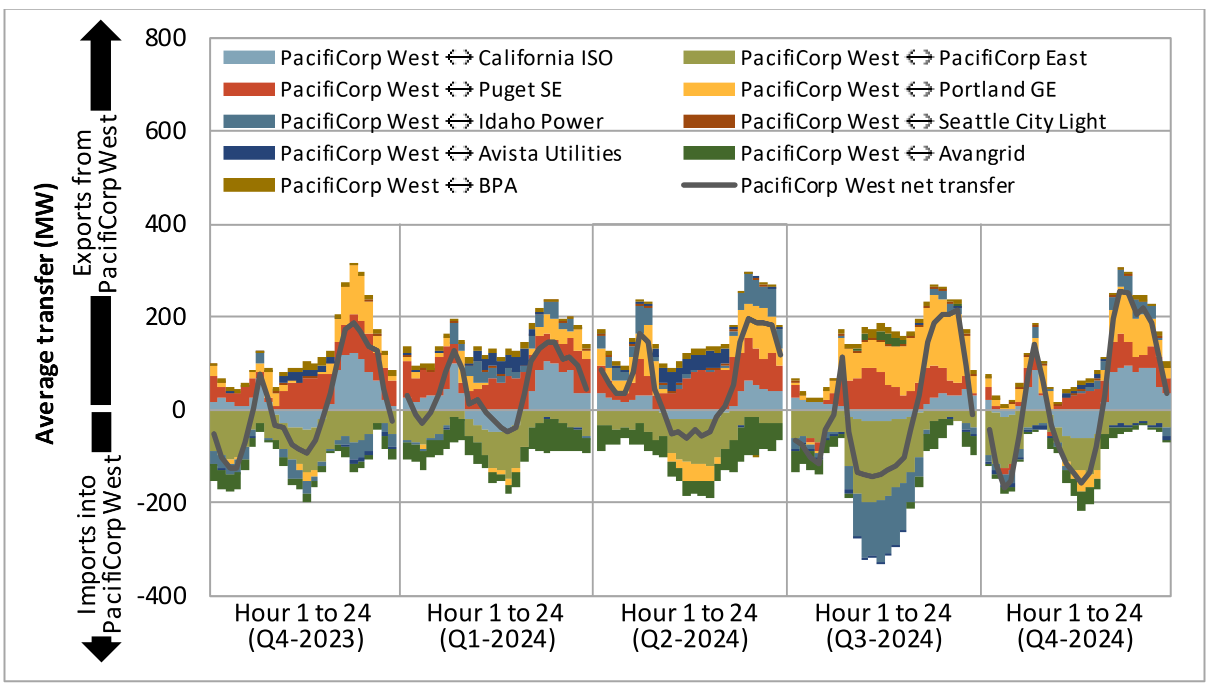


A.13 PacifiCorp West

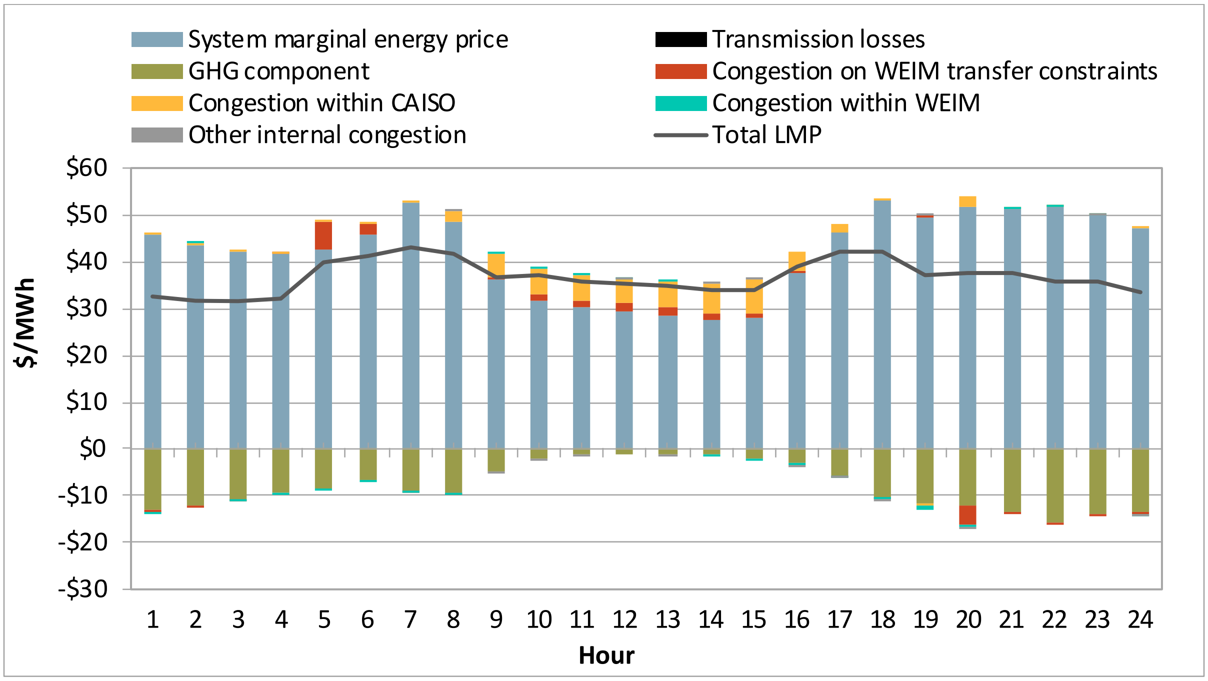
Appendix Figure A.53 Average hourly 15-minute price by component (Q4 2024)



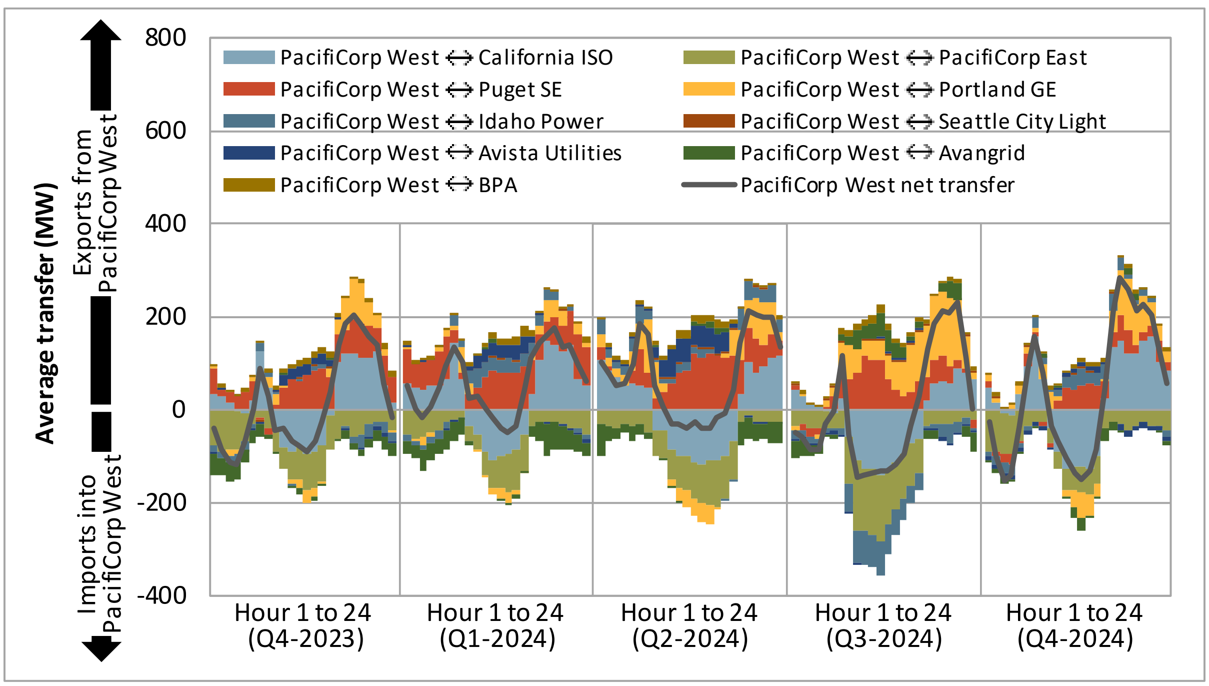
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q4 2024)

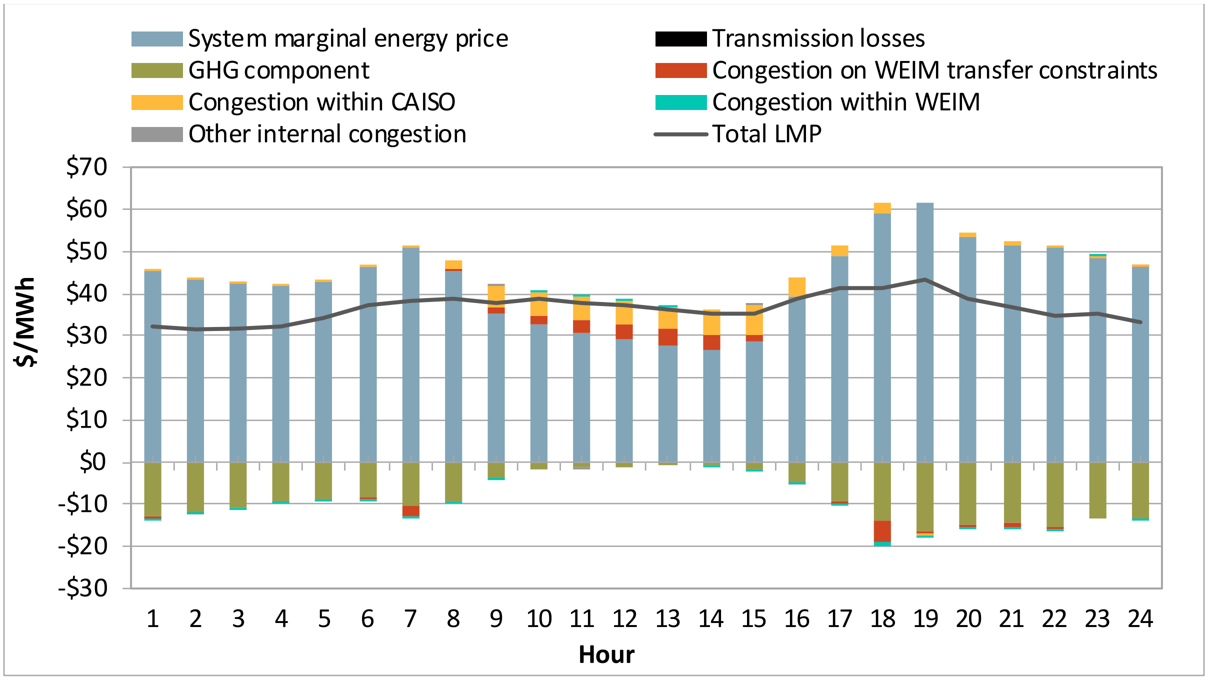


Appendix Figure A.56 Average hourly 5-minute market transfers

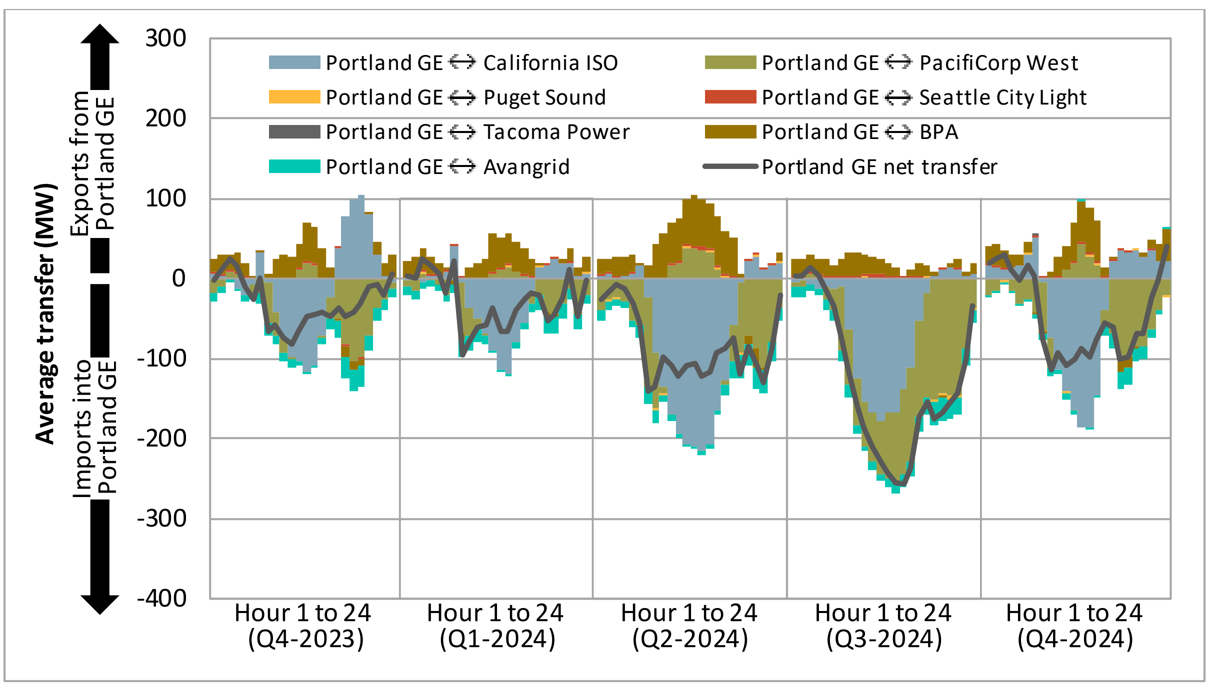


A.14 Portland General Electric

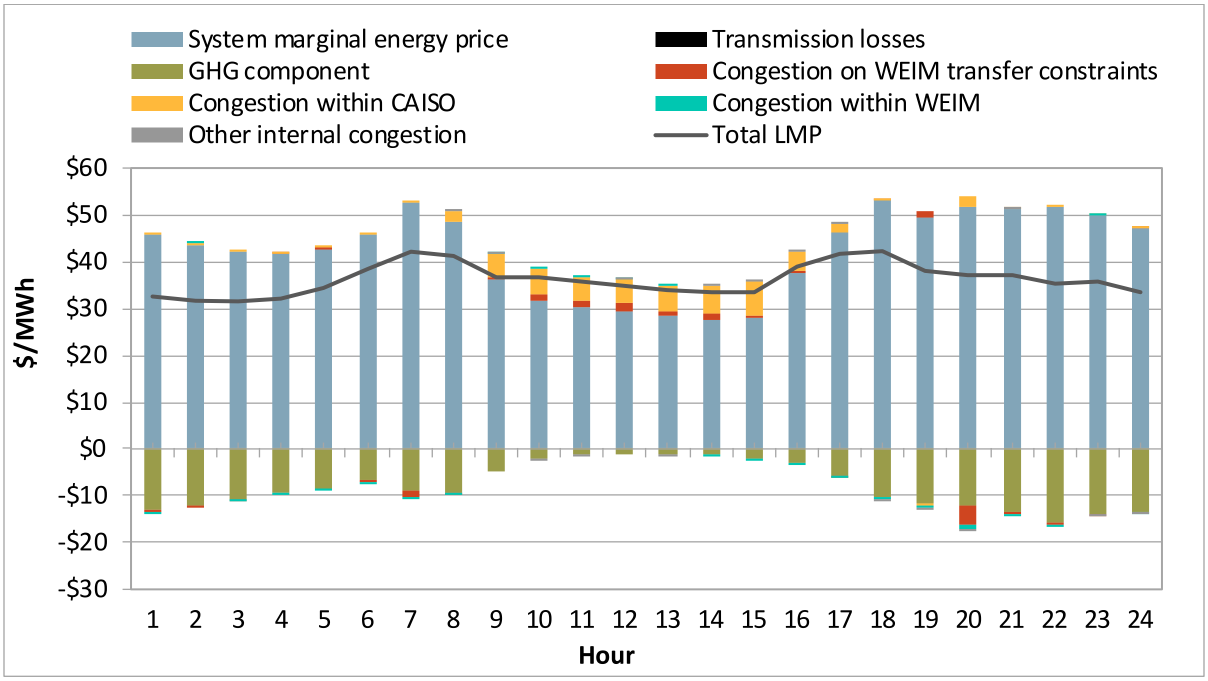
Appendix Figure A.57 Average hourly 15-minute price by component (Q4 2024)



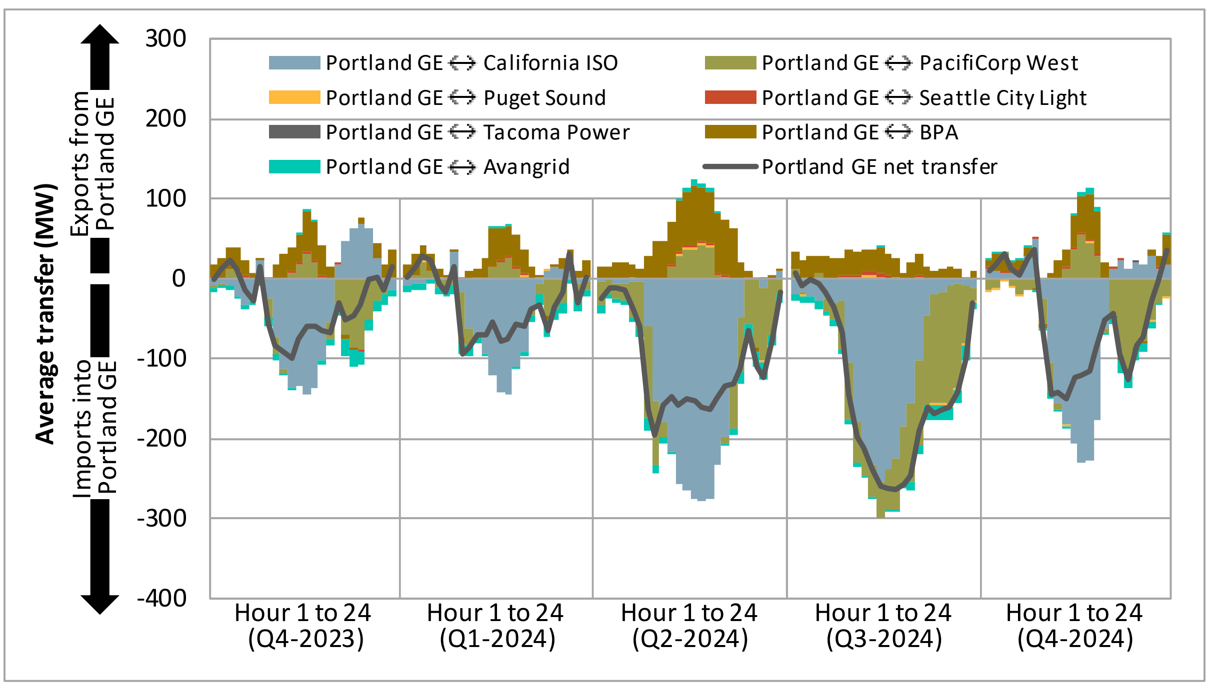
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q4 2024)

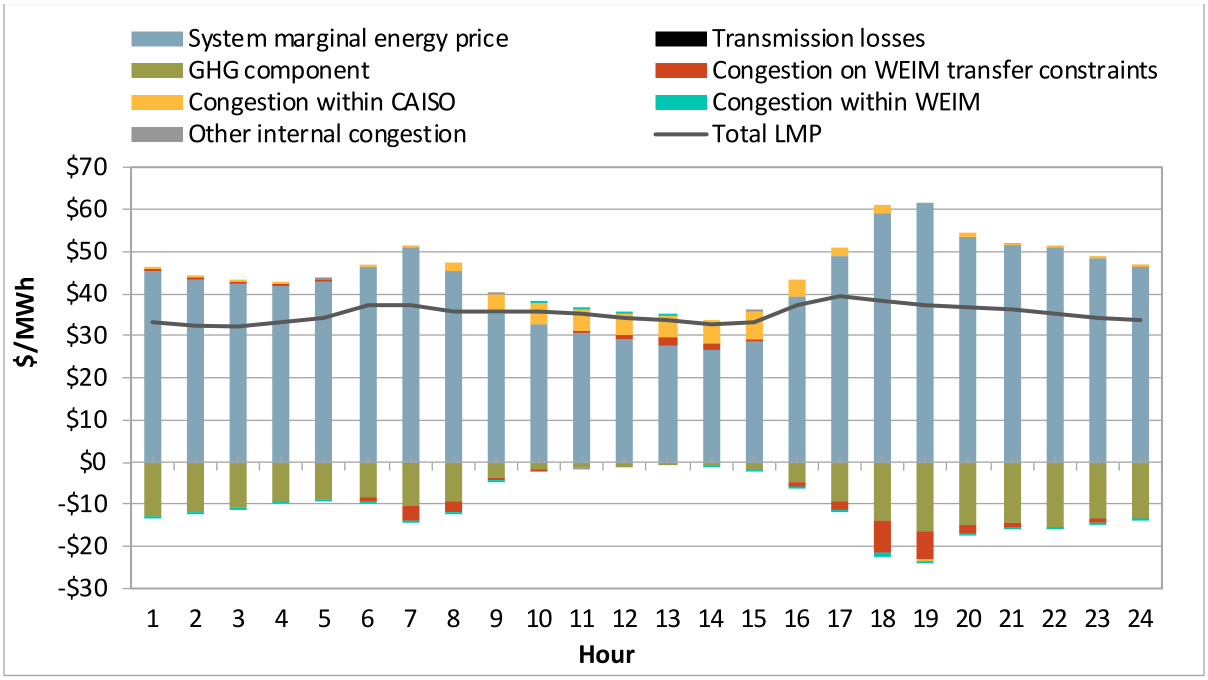


Appendix Figure A.60 Average hourly 5-minute market transfers

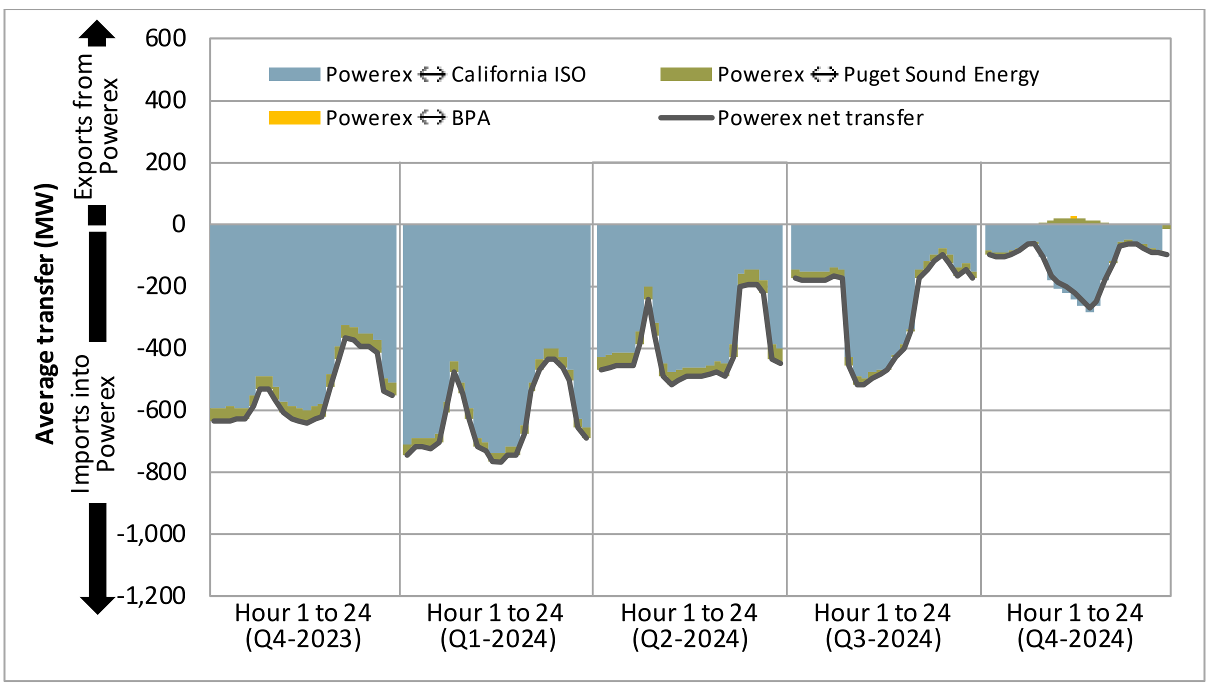


A.15 Powerex

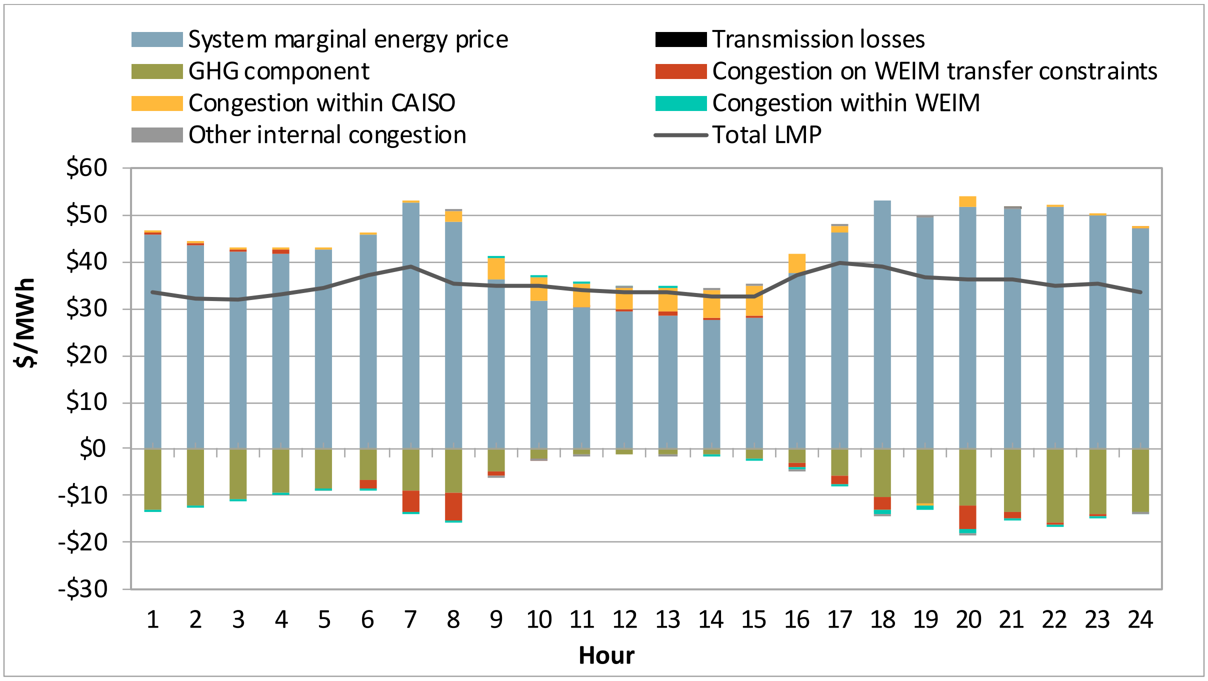
Appendix Figure A.61 Average hourly 15-minute price by component (Q4 2024)



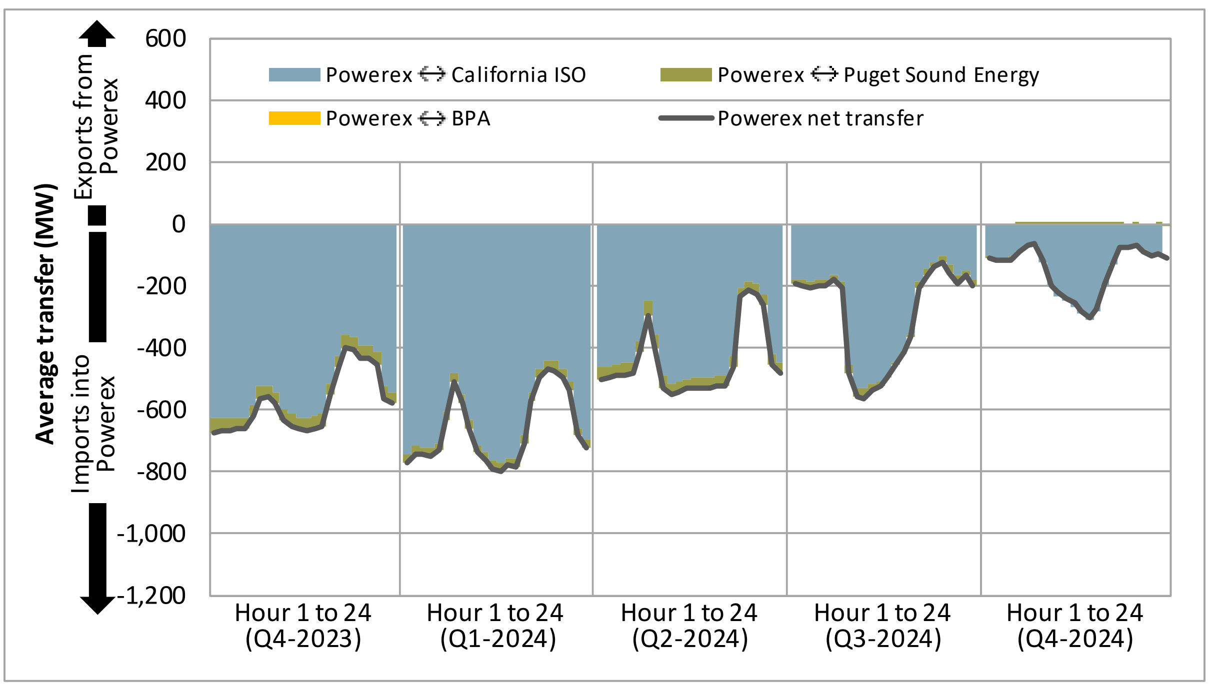
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q4 2024)

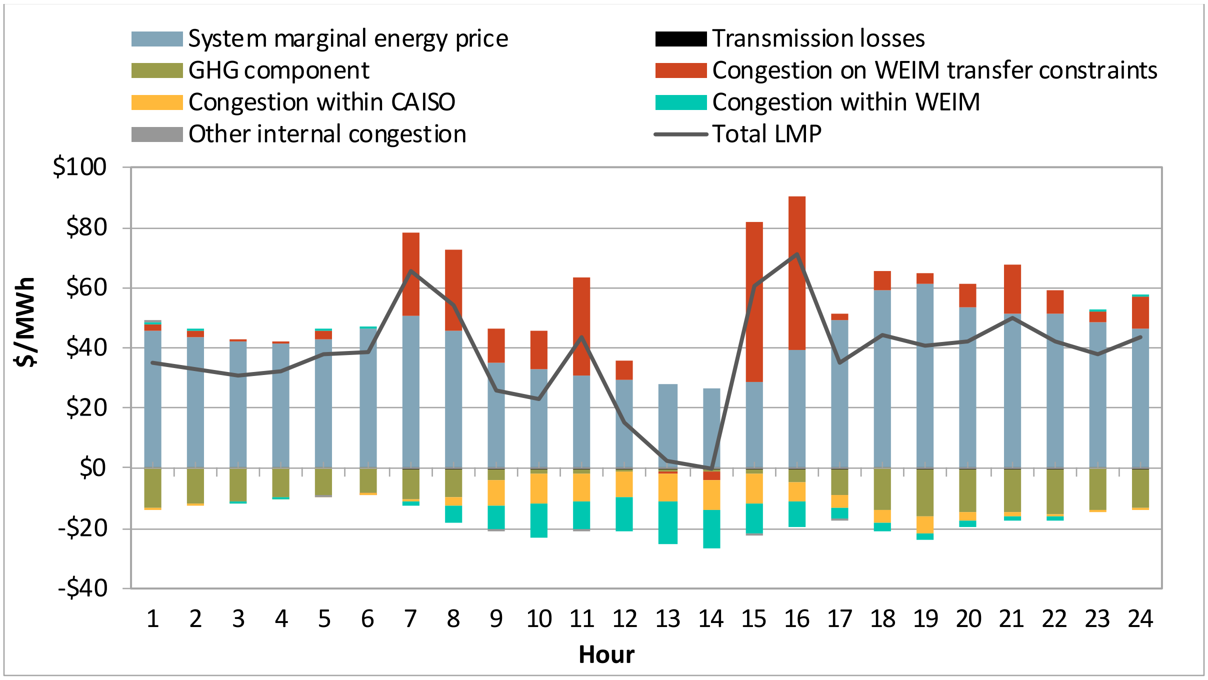


Appendix Figure A.64 Average hourly 5-minute market transfers

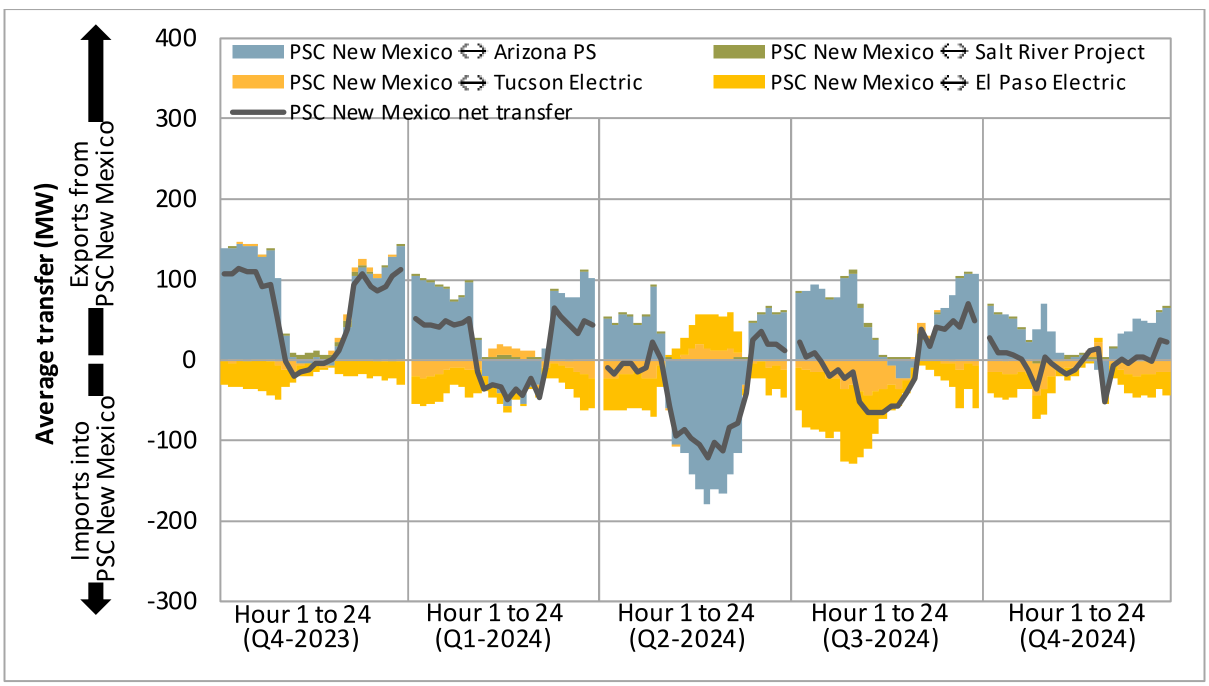


A.16 Public Service Company of New Mexico

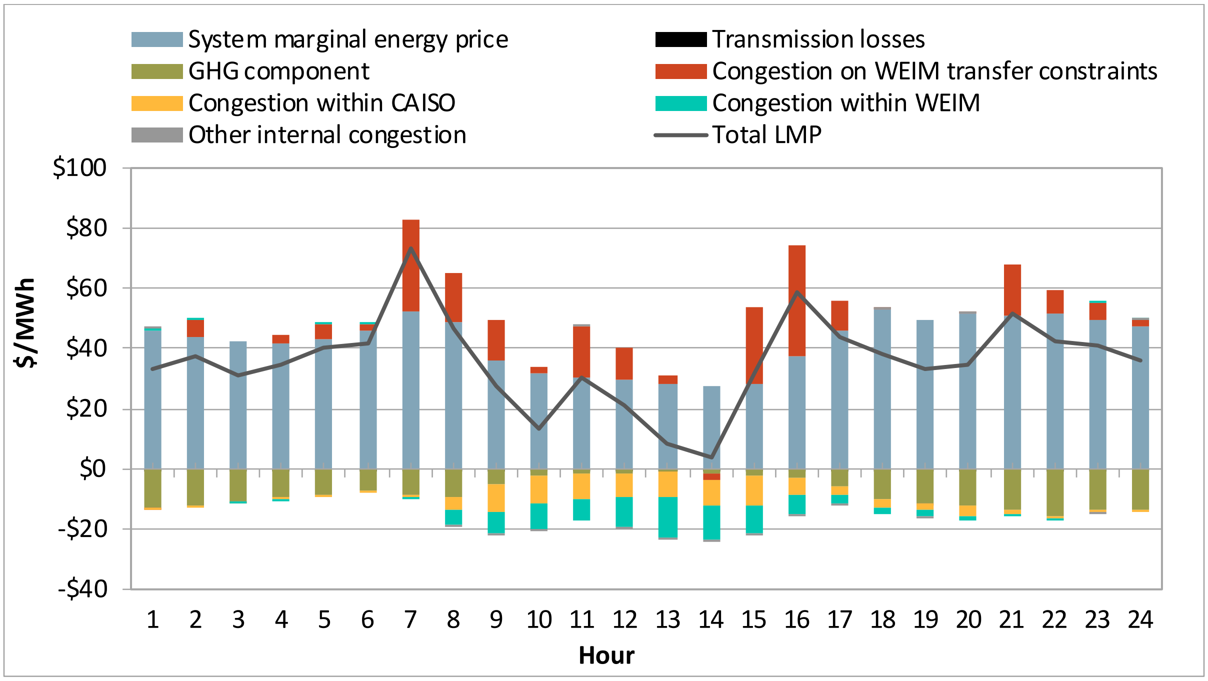
Appendix Figure A.65 Average hourly 15-minute price by component (Q4 2024)



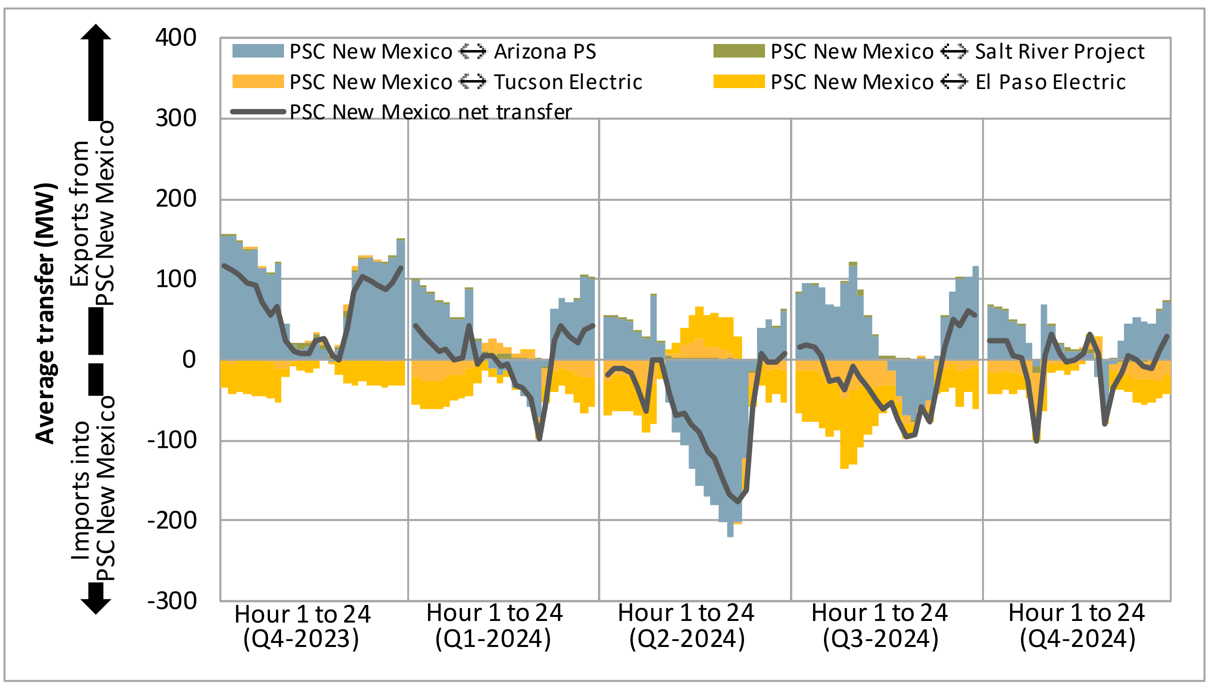
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q4 2024)

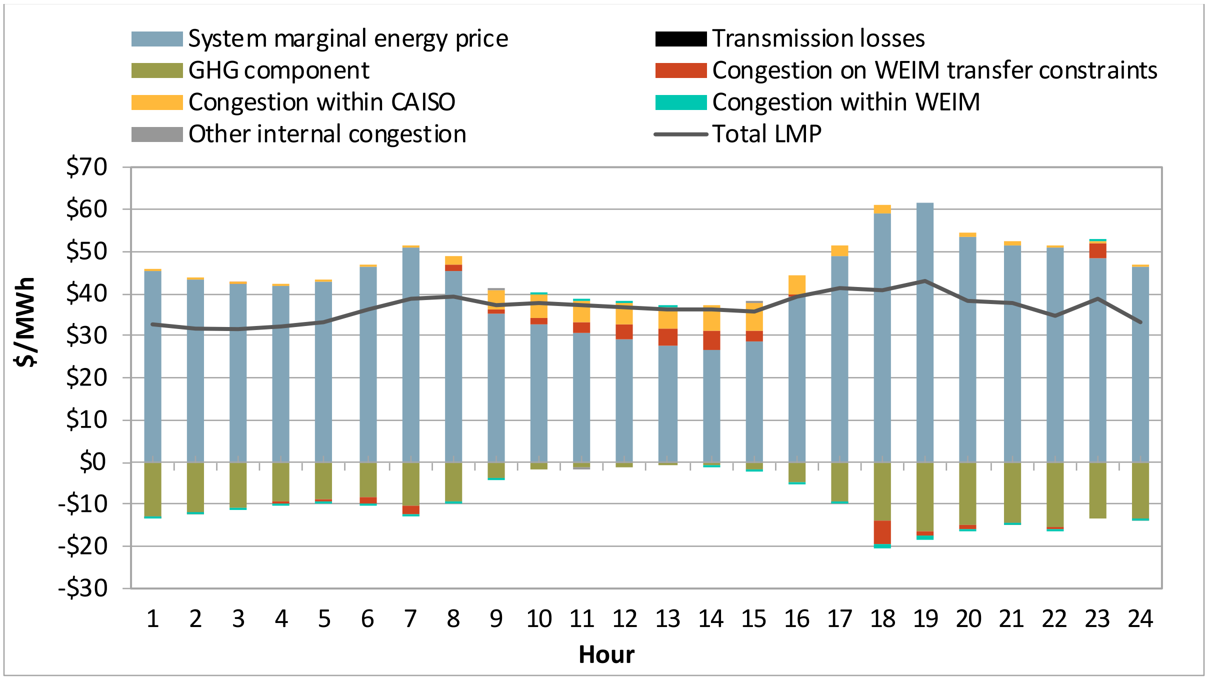


Appendix Figure A.68 Average hourly 5-minute market transfers

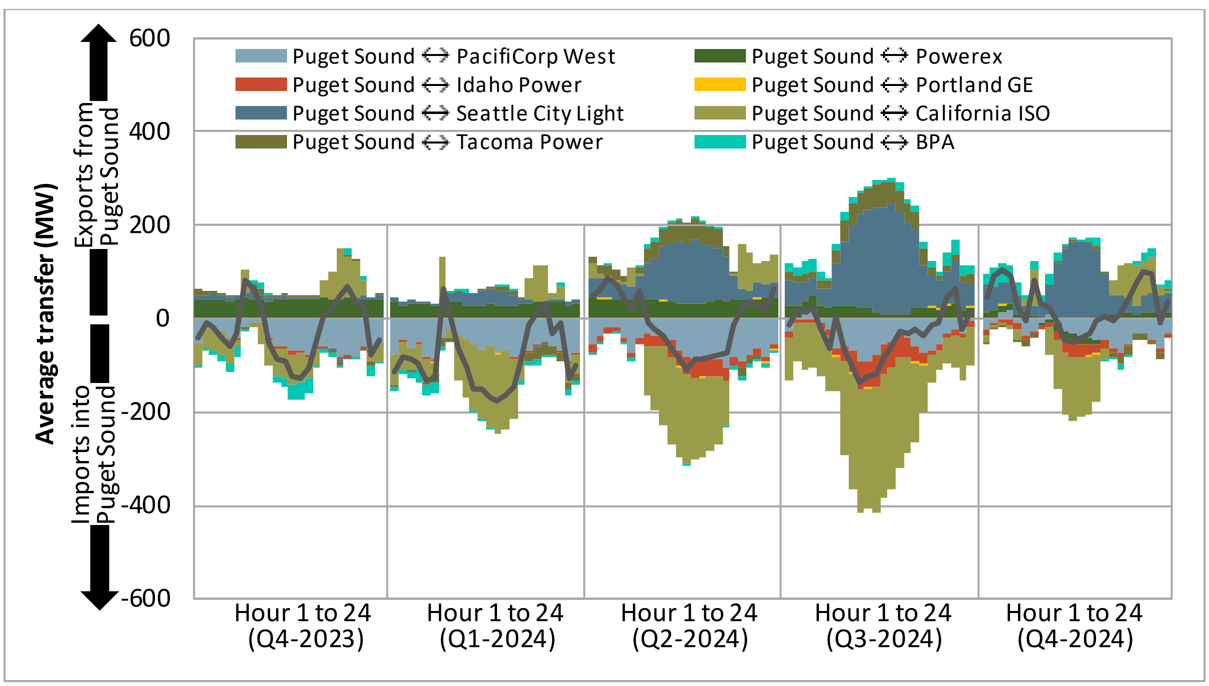


A.17 Puget Sound Energy

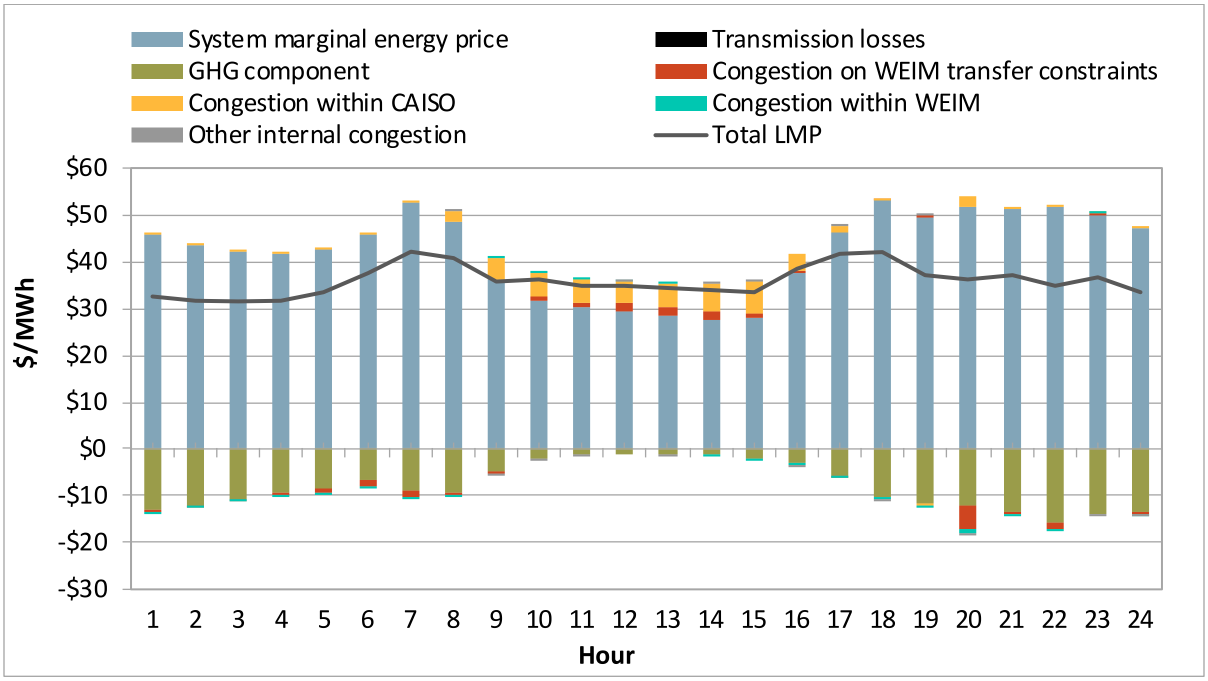
Appendix Figure A.69 Average hourly 15-minute price by component (Q4 2024)



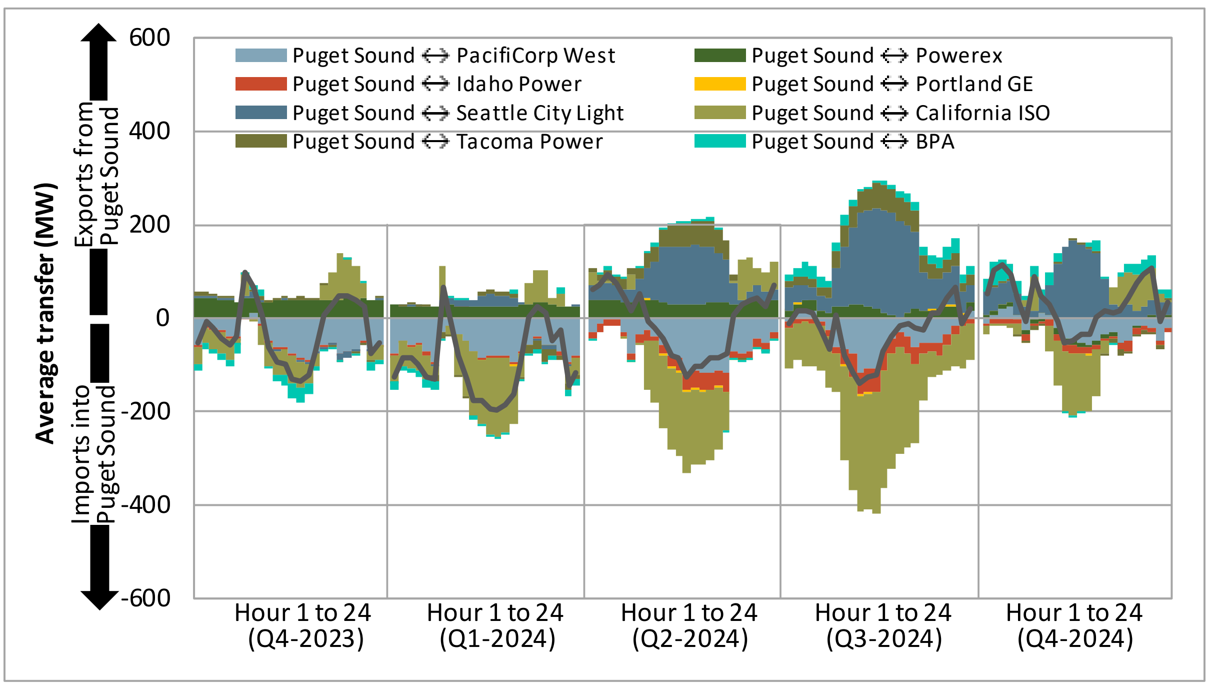
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q4 2024)

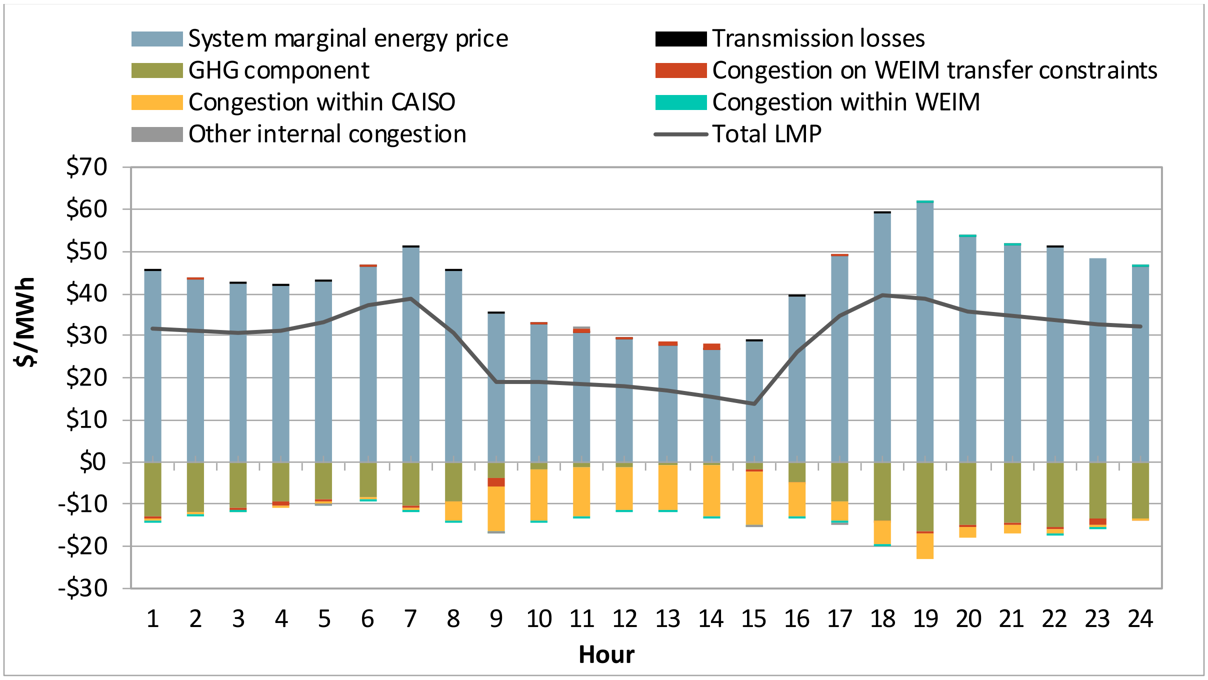


Appendix Figure A.72 Average hourly 5-minute market transfers

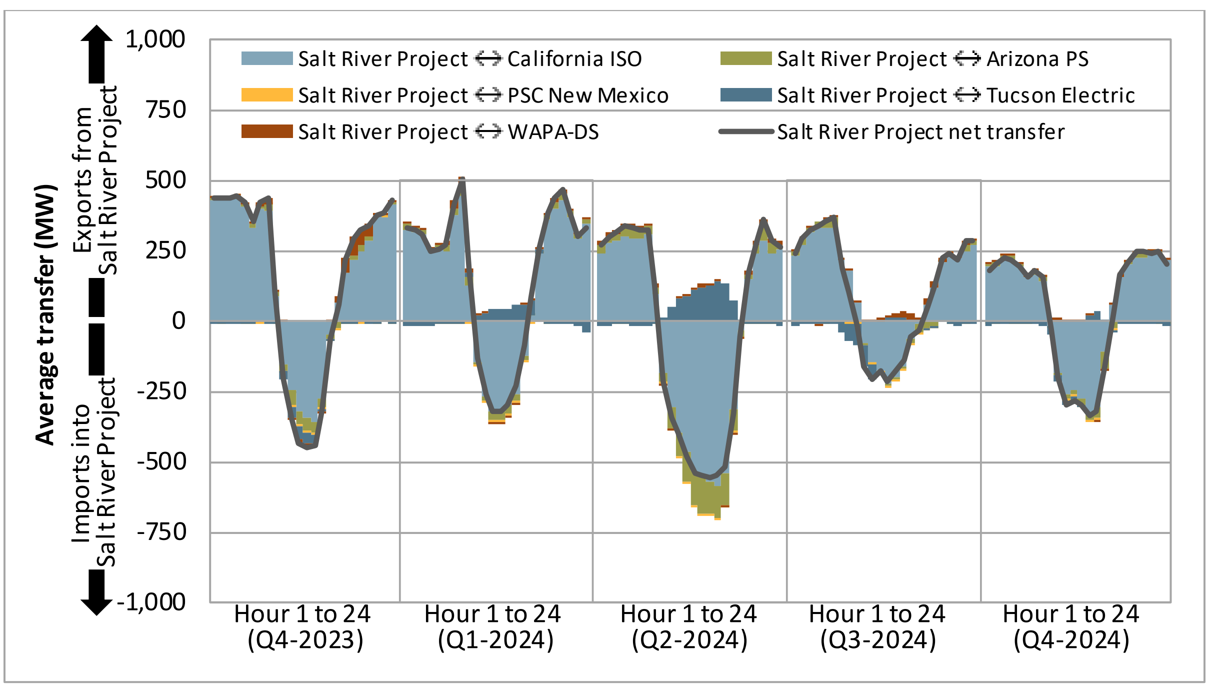


A.18 Salt River Project

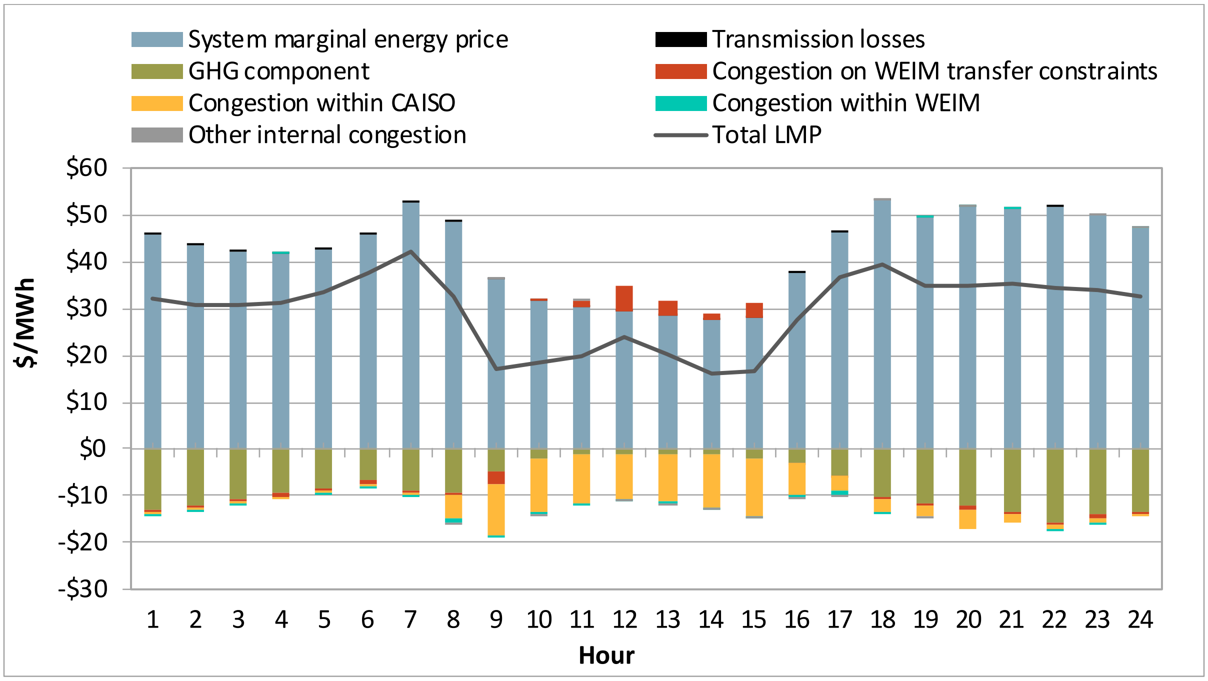
Appendix Figure A.73 Average hourly 15-minute price by component (Q4 2024)



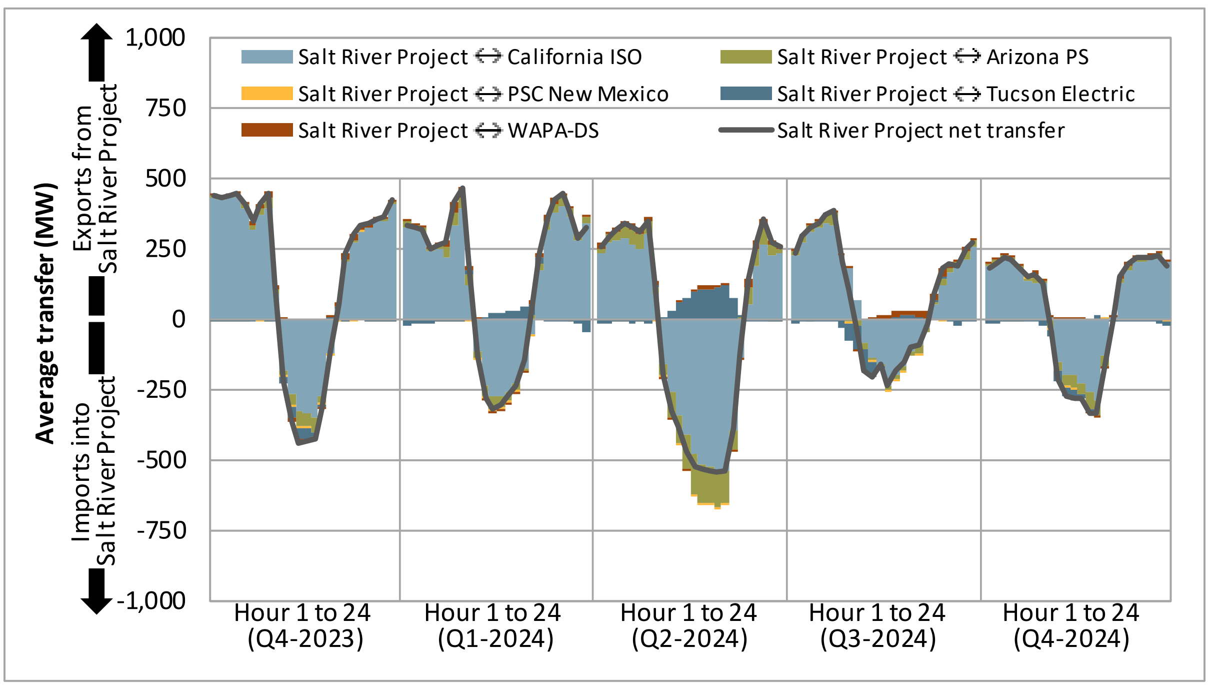
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q4 2024)

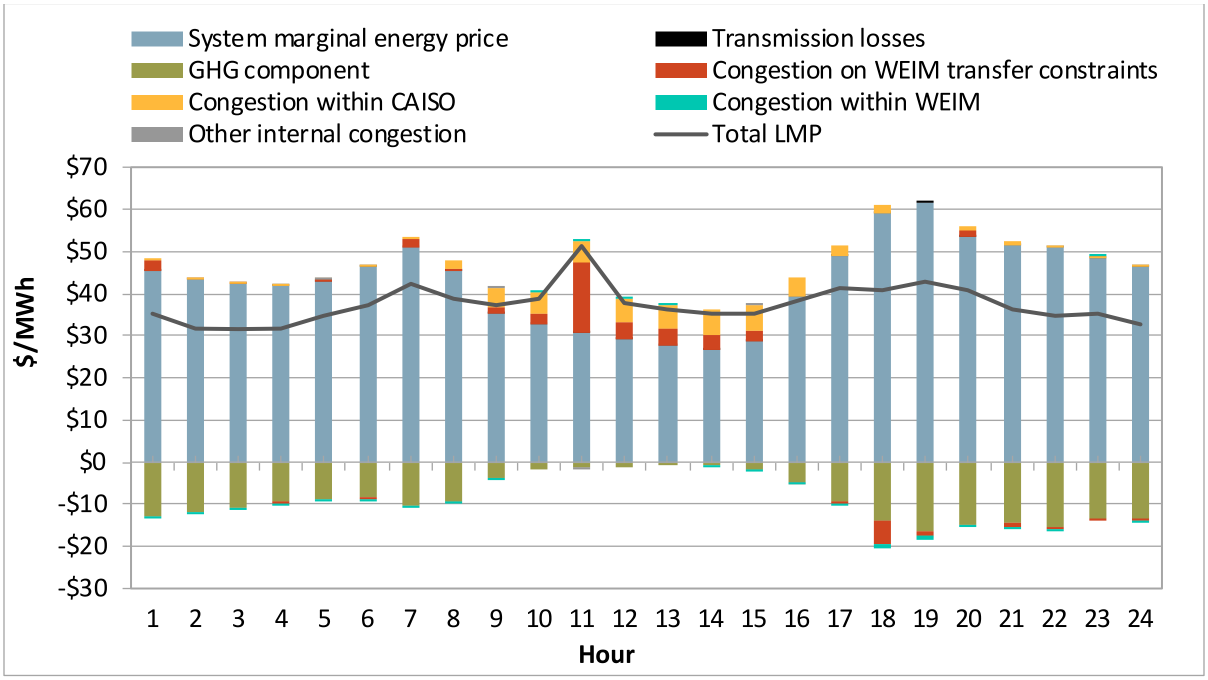


Appendix Figure A.76 Average hourly 5-minute market transfers

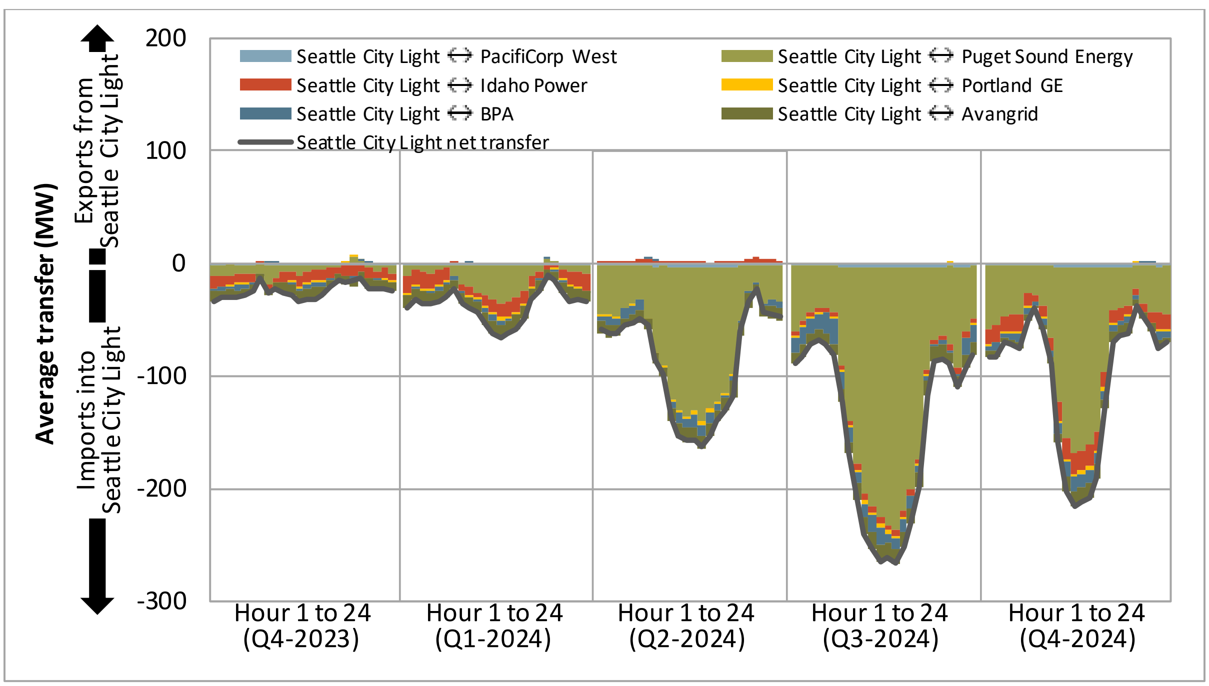


A.19 Seattle City Light

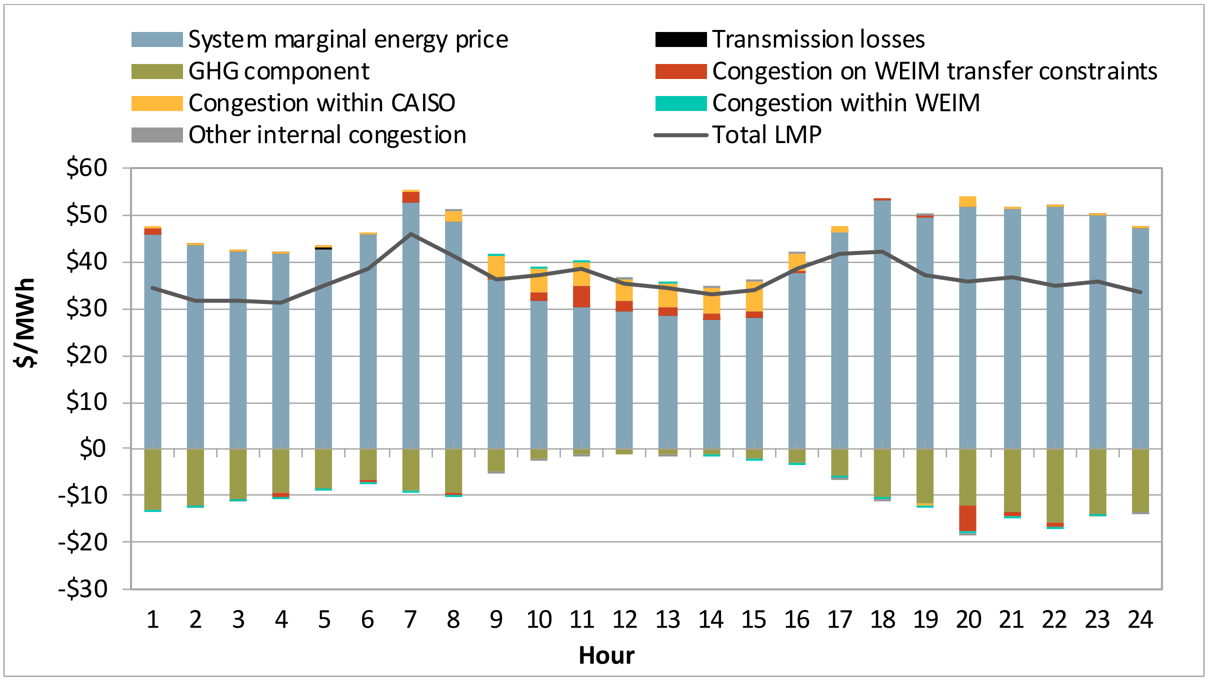
Appendix Figure A.77 Average hourly 15-minute price by component (Q4 2024)



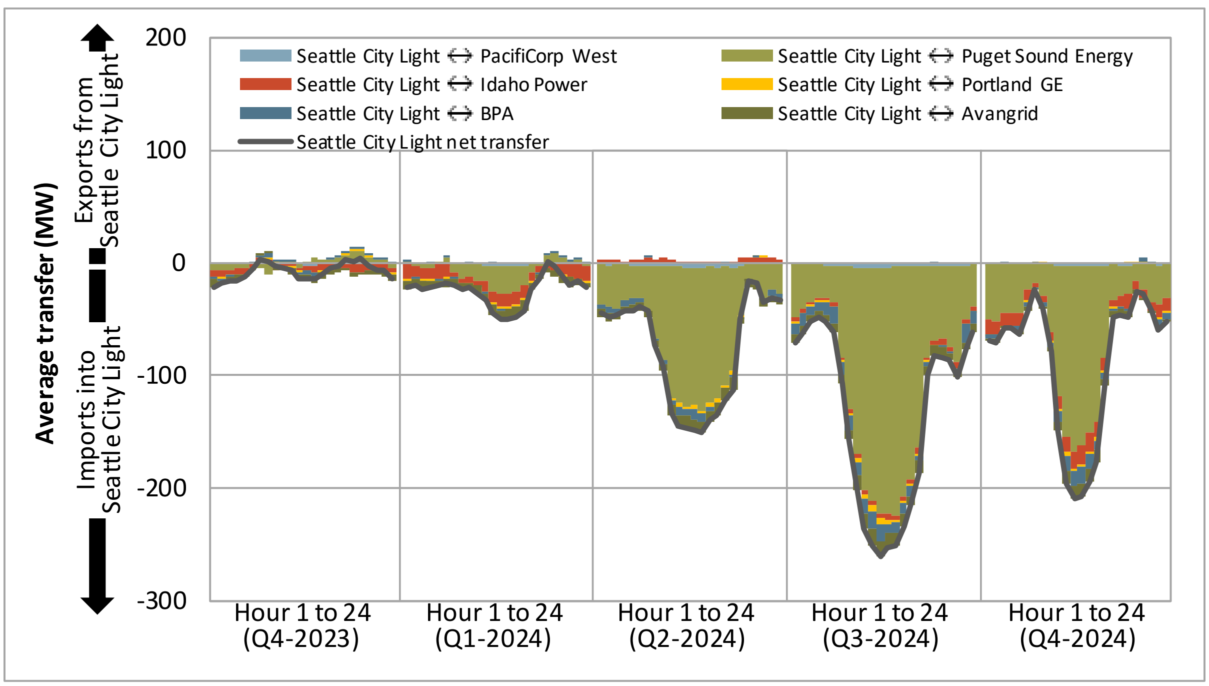
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q4 2024)

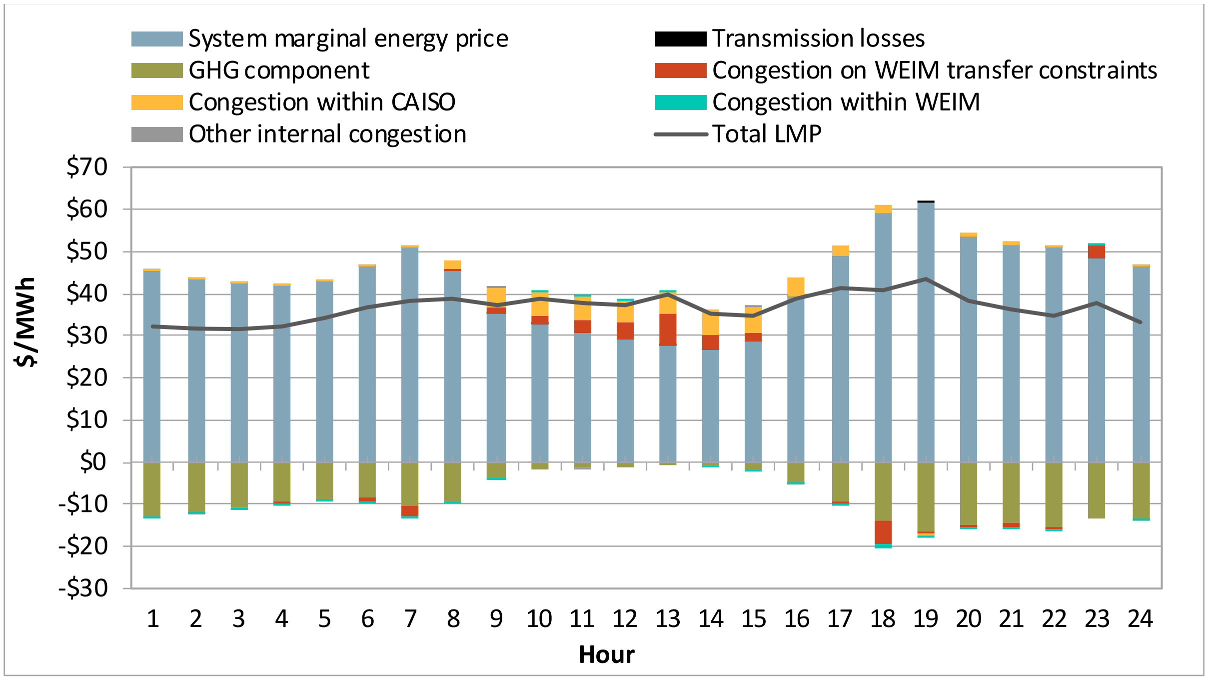


Appendix Figure A.80 Average hourly 5-minute market transfers

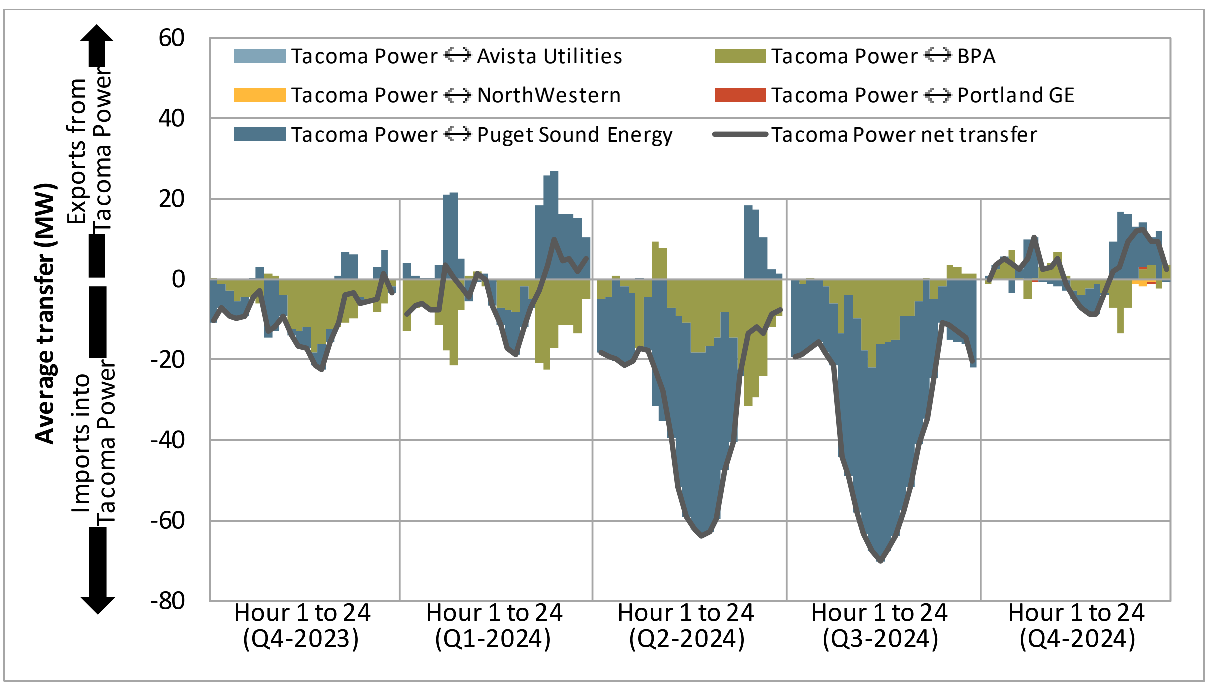


A.20 Tacoma Power

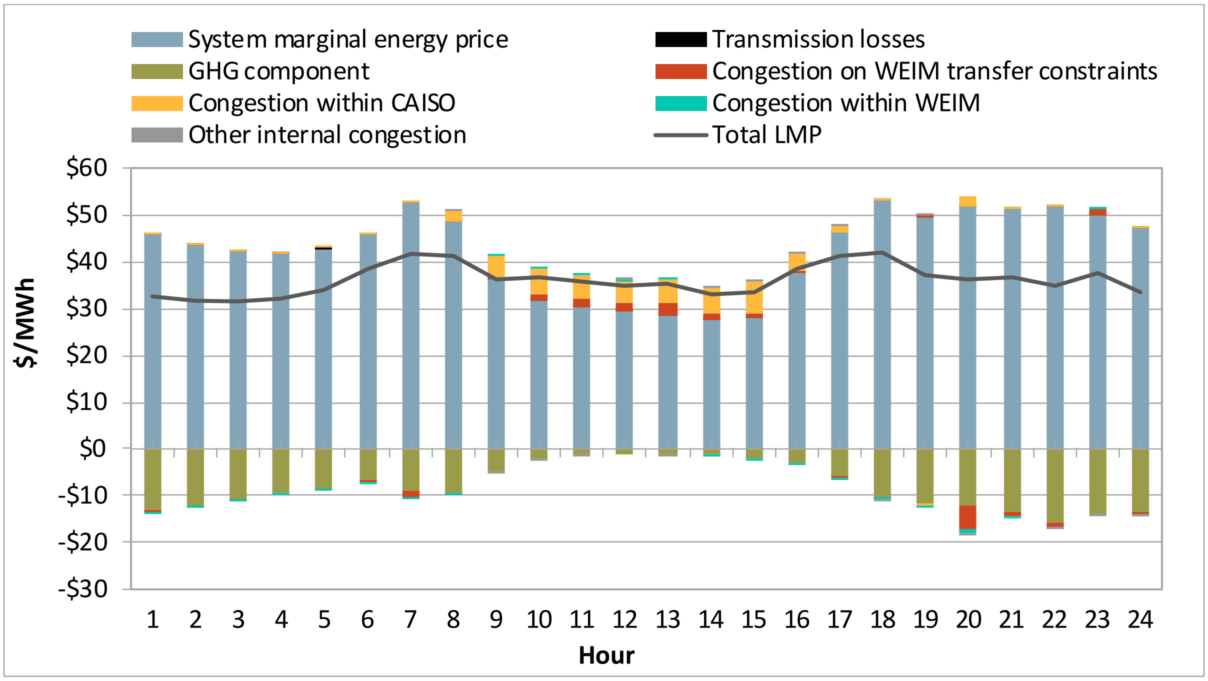
Appendix Figure A.81 Average hourly 15-minute price by component (Q4 2024)



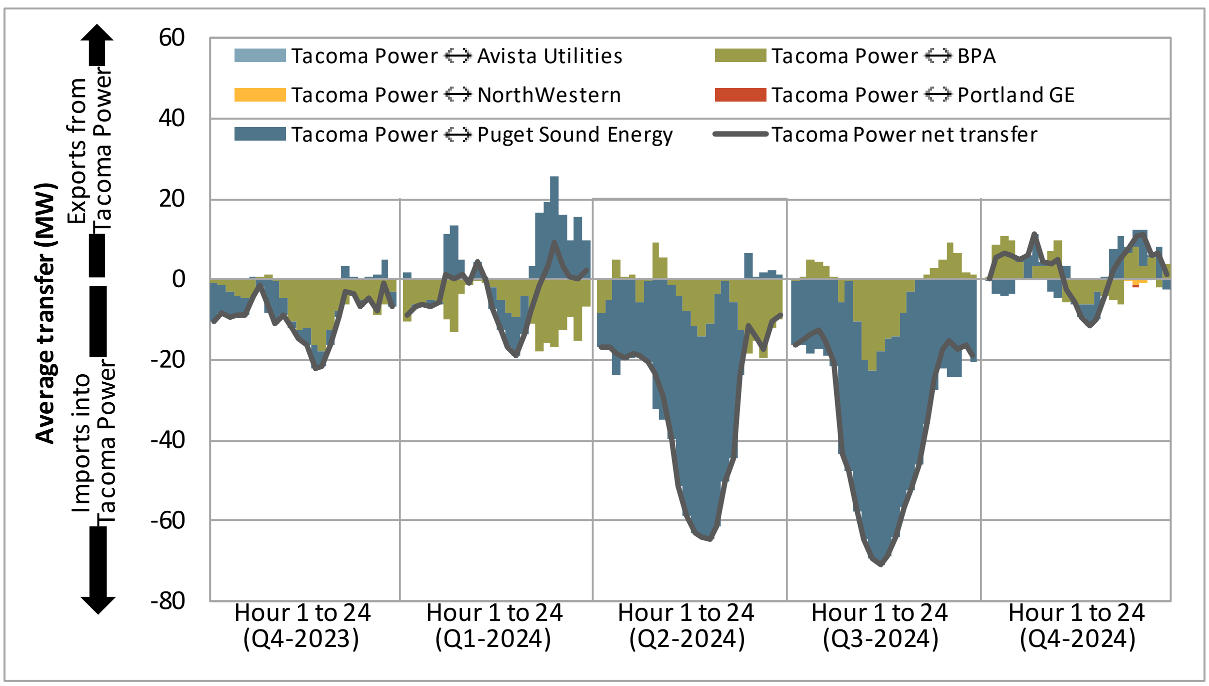
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q4 2024)

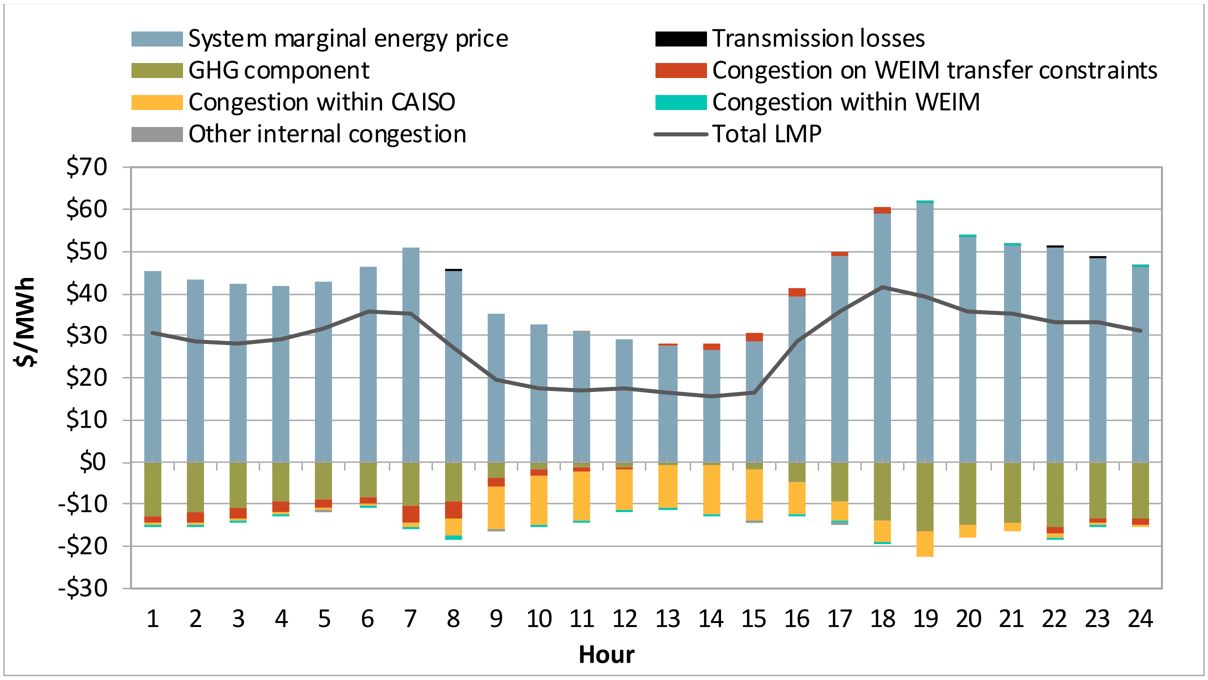


Appendix Figure A.84 Average hourly 5-minute market transfers

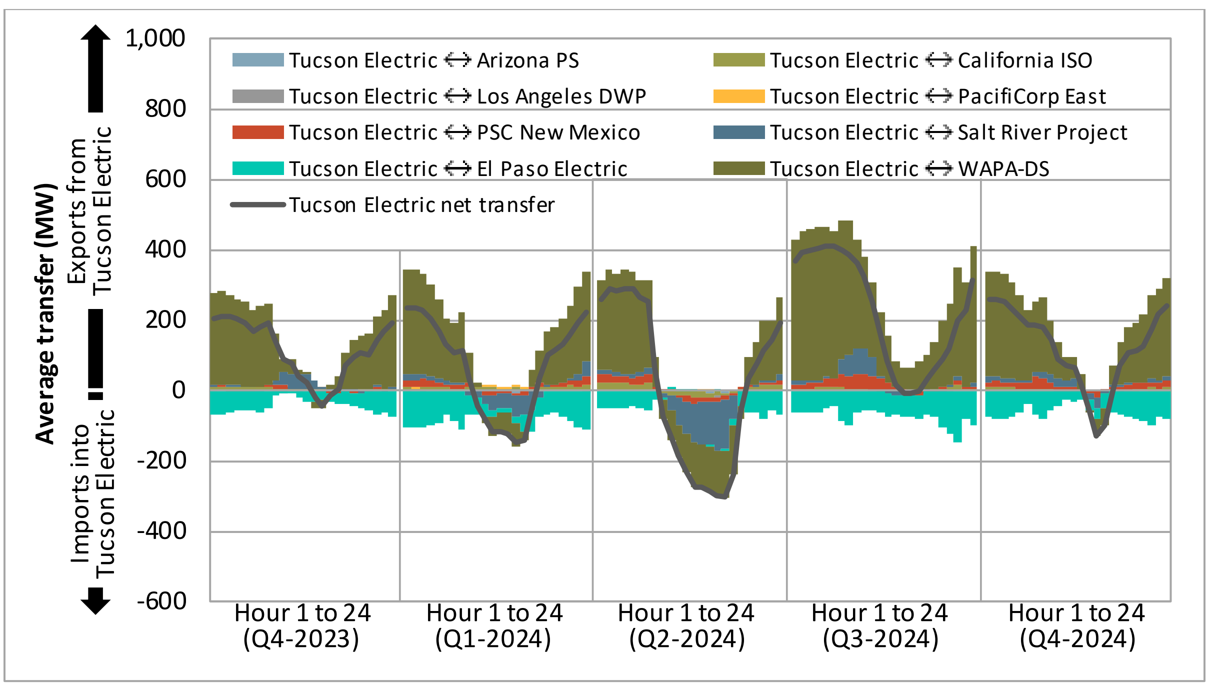


A.21 Tucson Electric Power

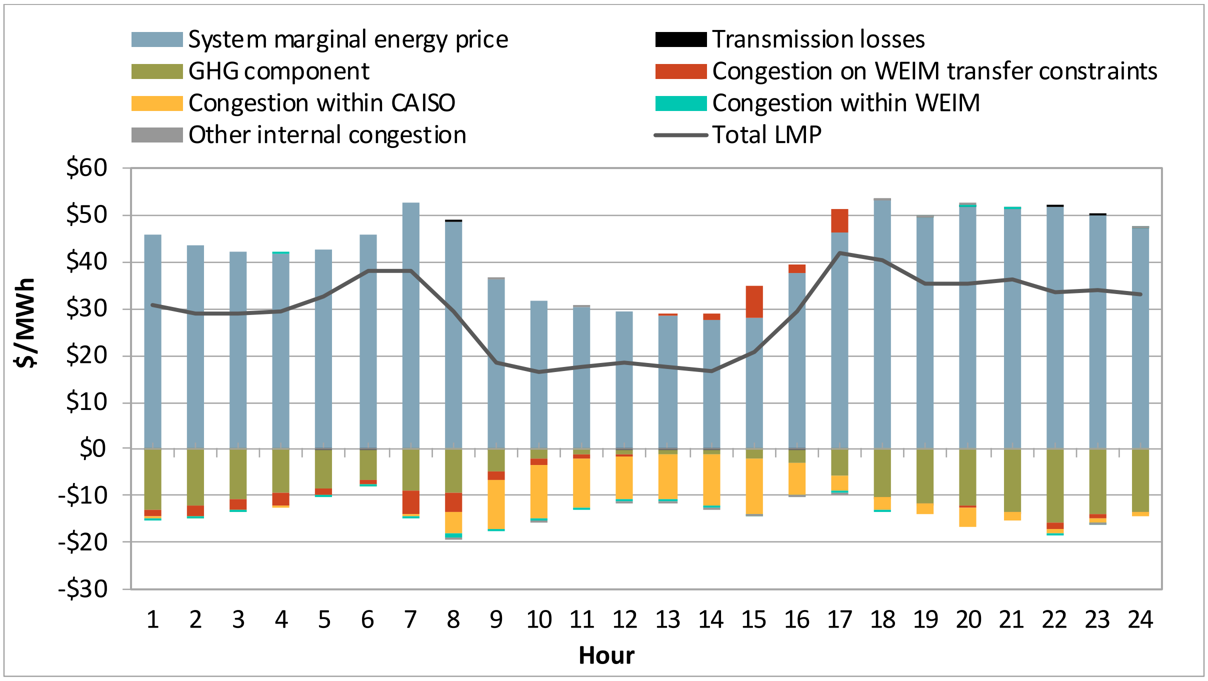
Appendix Figure A.85 Average hourly 15-minute price by component (Q4 2024)



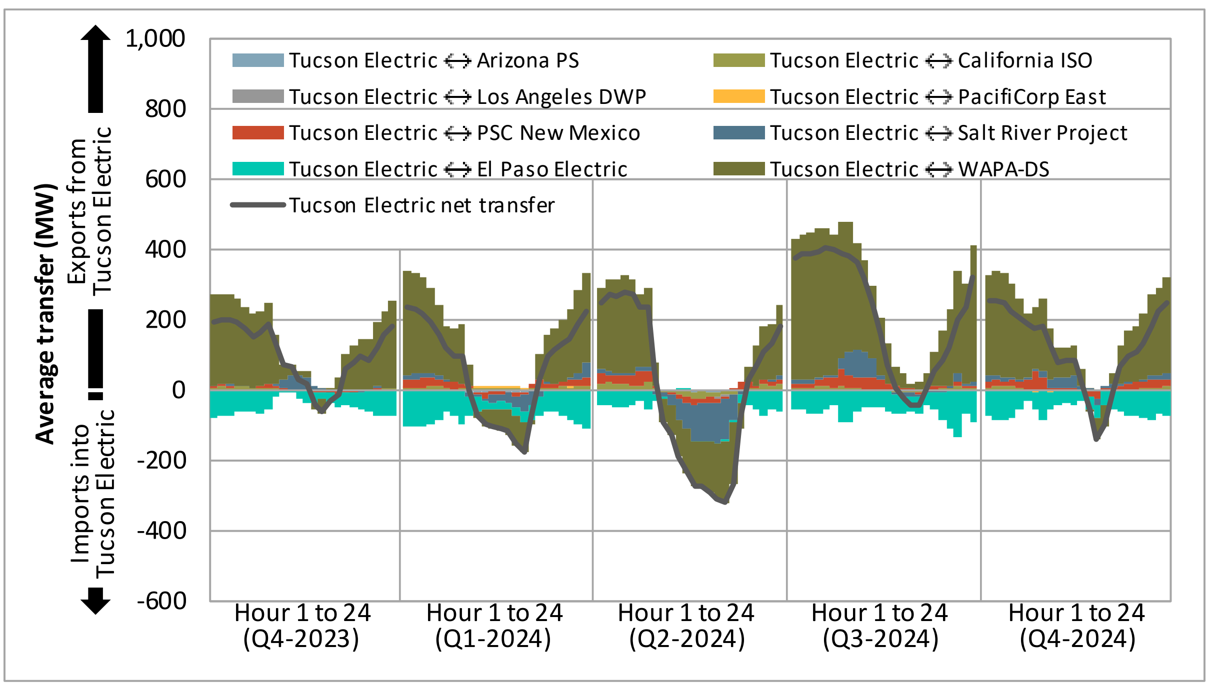
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q4 2024)

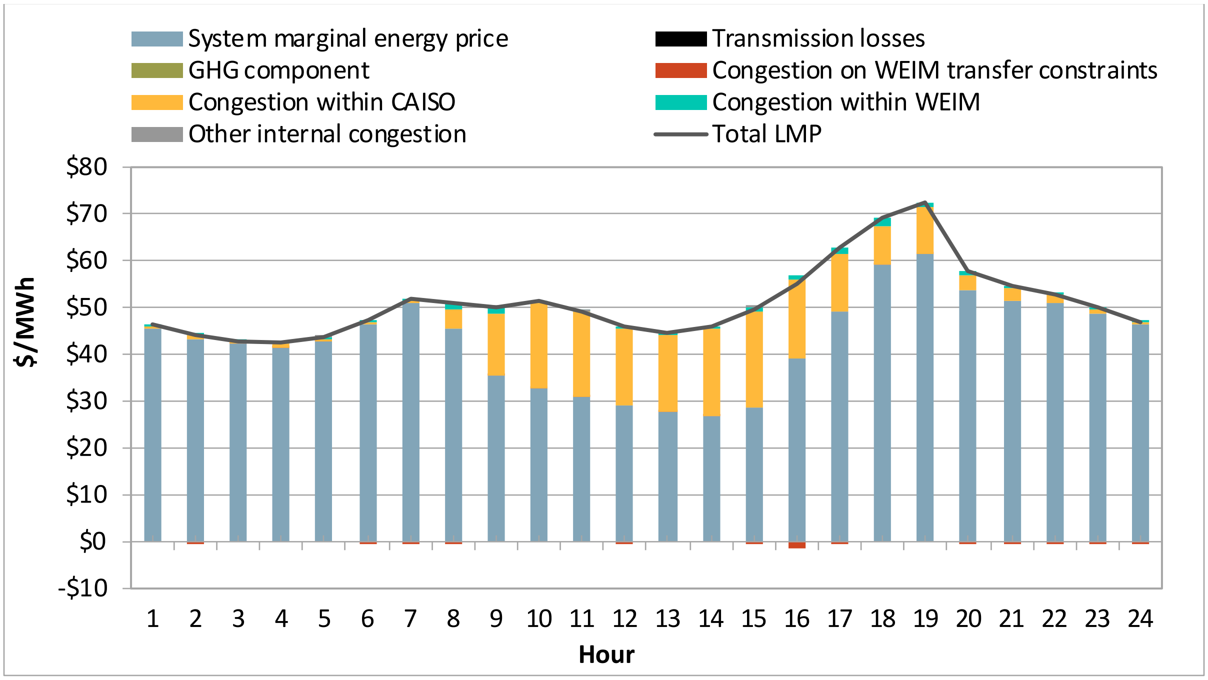


Appendix Figure A.88 Average hourly 5-minute market transfers

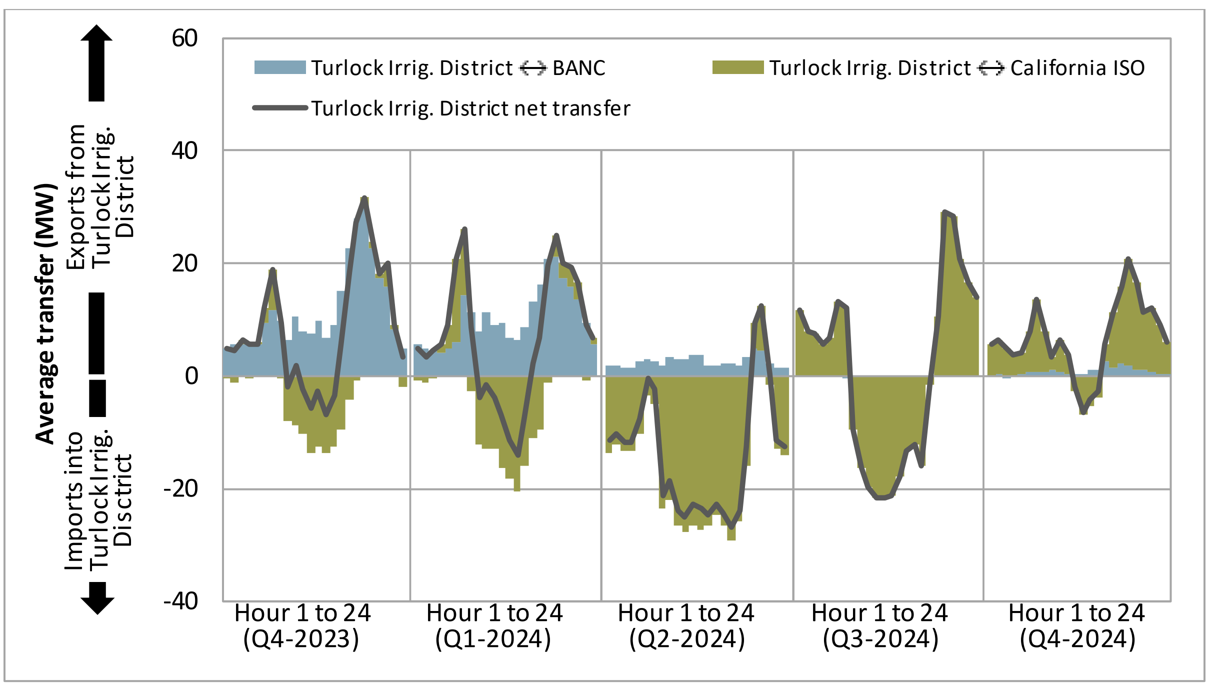


A.22 Turlock Irrigation District

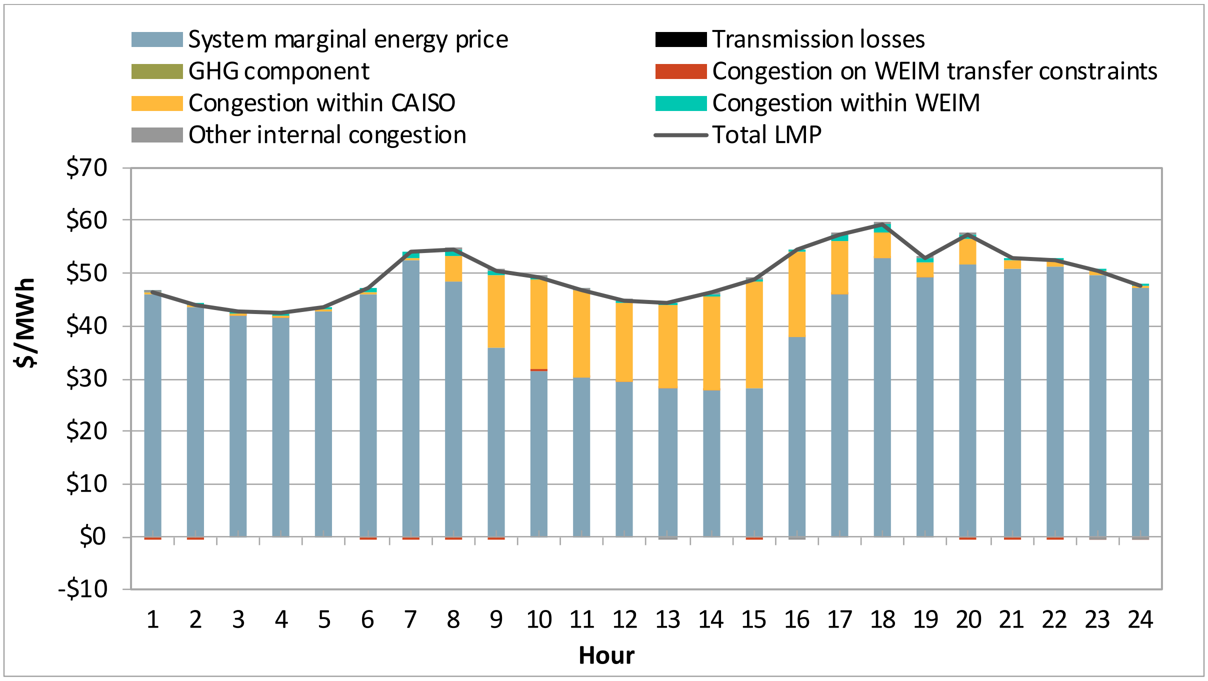
Appendix Figure A.89 Average hourly 15-minute price by component (Q4 2024)



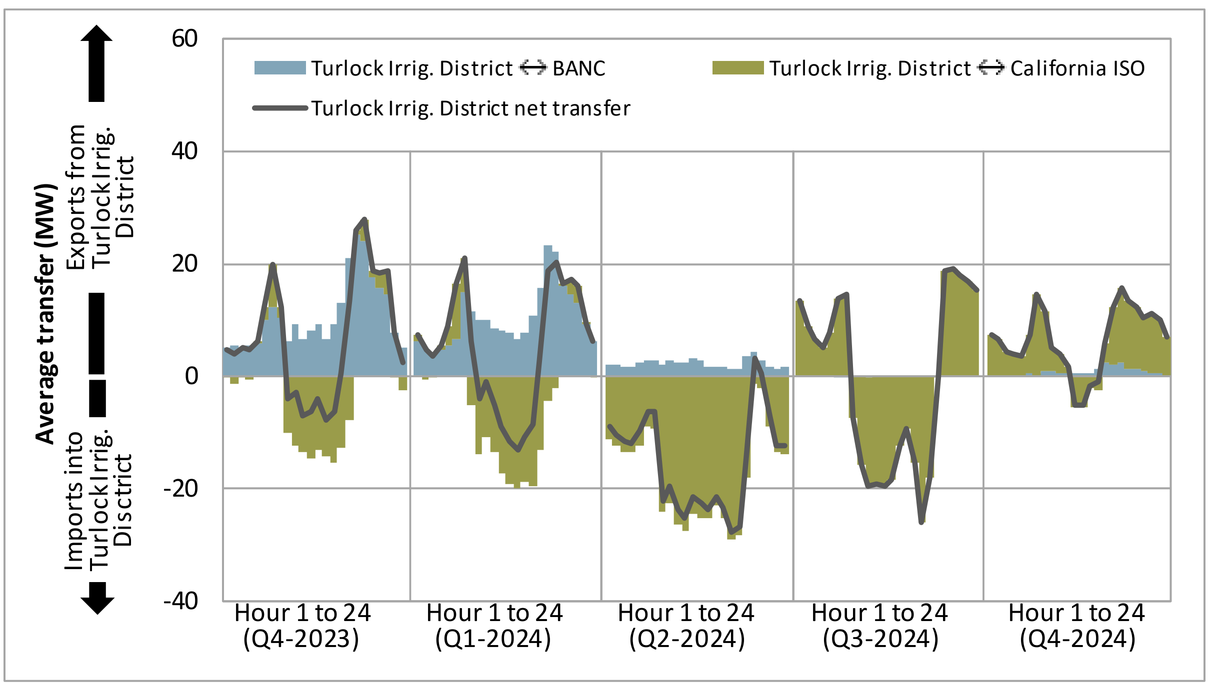
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q4 2024)

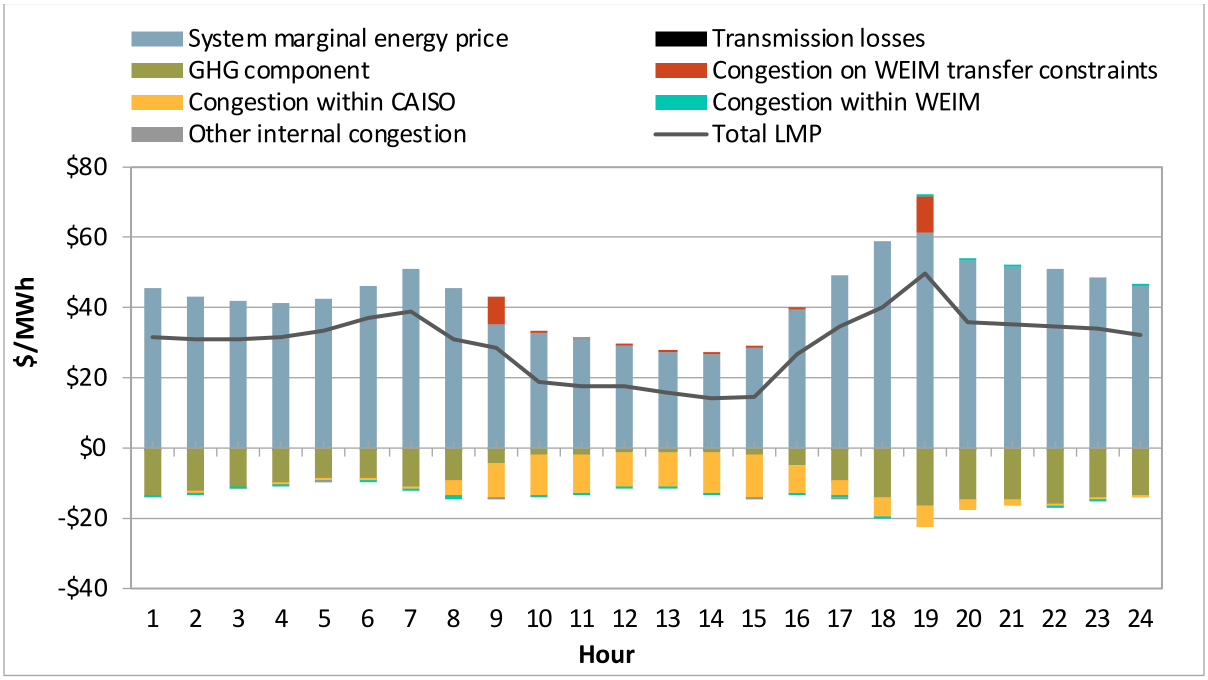


Appendix Figure A.92 Average hourly 5-minute market transfers

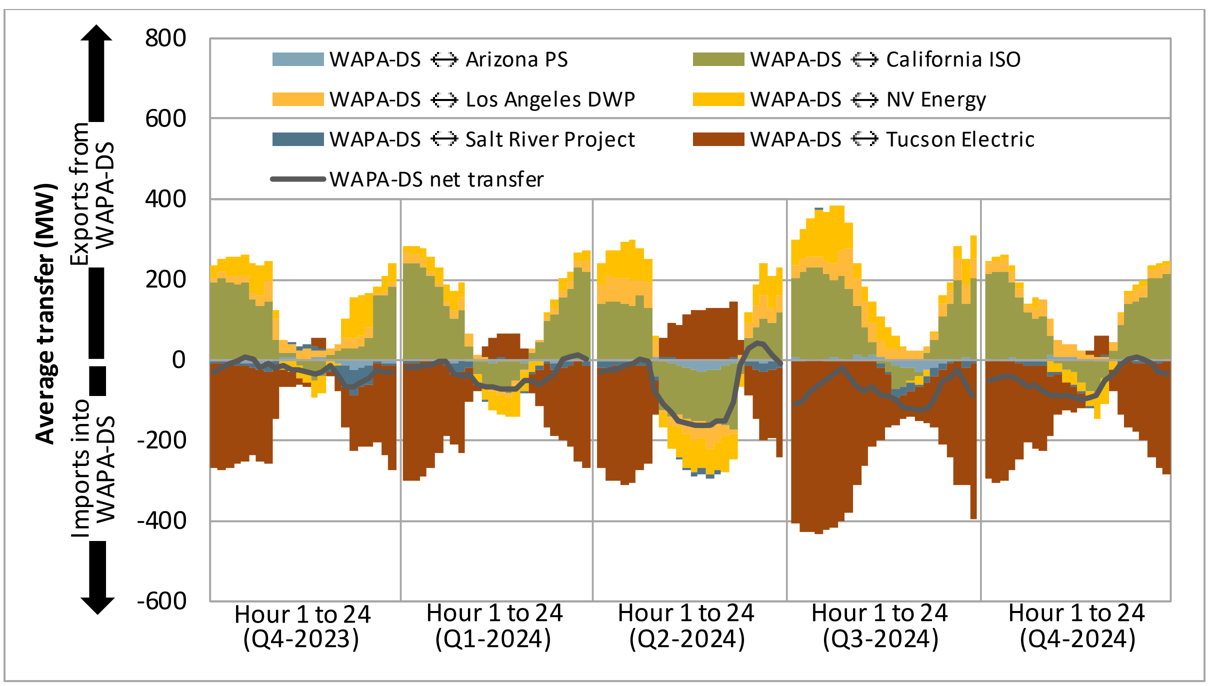


A.23 Western Area Power Administration Desert Southwest

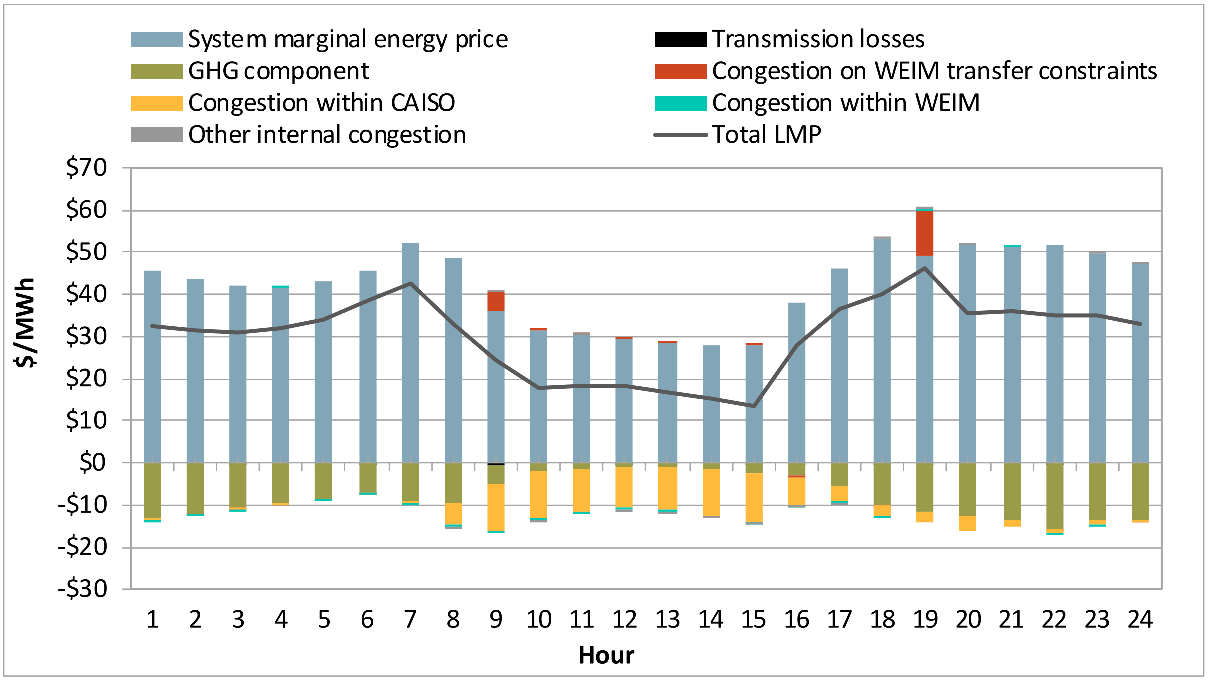
Appendix Figure A.93 Average hourly 15-minute price by component (Q4 2024)



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



Appendix Figure A.95 Average hourly 5-minute price by component (Q4 2024)



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