Q1 2024 Report on Market Issues and Performance

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California Independent System Operator

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Executive summary

This report covers market performance during the first quarter of 2024 (January–March). Key highlights during this quarter include the following:

- **Prices decreased substantially compared to the same quarter of 2023** (Figure E.1). Day-ahead and real-time market prices decreased by about 53 percent, driven by significantly lower natural gas prices.
- **Natural gas prices were significantly lower.** Average gas prices at Henry Hub, the national index, decreased about 10 percent from the same quarter of 2023, while prices at both California hubs decreased more than 60 percent (Figure E.2). This was the major driver of lower system marginal energy prices across the market.
- **Average hourly battery discharge increased relative to the first quarter of 2023 by around 63 percent, while solar generation increased around 17 percent**. Hydroelectric generation decreased by around 1.4 percent while wind generation remained about the same as in Q1 2023. Average hourly generation by natural gas resources decreased around 7 percent.
- **Average hourly net imports decreased by 44 percent** compared to the first quarter of 2023. Average net interchange was in the export direction in hours-ending 10 through 16, driven by high solar output and large transfers out of the California ISO area to the rest of the Western Energy Imbalance Market (WEIM). Average net exports, including WEIM transfers, peaked at just over 2,220 MW in hour-ending 12. This was almost 1,400 MW more than the largest average net export out of CAISO in Q1 2023.
- **Average day-ahead peak energy prices at the Mid-Columbia bilateral trading hub significantly exceeded average Palo Verde and California ISO prices over the first quarter.** In January, Mid-Columbia prices averaged $250/MWh, compared to $70/MWh at Palo Verde and $72/MWh average day-ahead peak prices within the California ISO.
- **Overall congestion rents on internal and intertie constraints was $258 million, down from $280 million in the first quarter of 2023, despite congestion rents on intertie constraints increasing from $14 million to $133 million.** The average impact of congestion on price differences between load areas was greater in Q1 2024 than in the same quarter of 2023. On average, congestion was in the south-to-north direction, decreasing prices in the Desert Southwest and California compared to the Pacific Northwest and Intermountain West.
- **The average total volume of capacity procured through the residual unit commitment (RUC) process in the first quarter of 2024 was 6 percent lower than the same quarter of 2023.** Although total volumes were lower, operator adjustments to the RUC procurement target increased by about 35 percent compared to the first quarter of 2023. This was largely due to CAISO beginning to use the mosaic quantile regression method to determine RUC adjustments in the summer of 2023. CAISO has continued to use the mosaic method since July of 2023. In late December 2023, CAISO made some adjustments, significantly reducing the amount of net load uncertainty that the RUC adjustments were intended to cover in Q1 2024 compared to Q4 2023.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues received for these rights by $53 million** in the first quarter of 2024, a 76 percent increase over the losses incurred during the first quarter of 2023. 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.

- **Real-time imbalance offset costs in the CAISO balancing area decreased to $51 million,** down from $90 million in the first quarter of 2023. Real-time imbalance energy offset costs made up about 16 percent of these offset costs. Much of the energy portion of these costs is caused by load settling on an average real-time price that can differ significantly from the real-time market prices that generating resources are settled on.
- **Real-time imbalance offset costs in non-CAISO WEIM balancing areas were an $81 million credit to WEIM entities**, compared to a $10 million charge in the first quarter of 2023. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was an $87 million credit. The energy and loss portions of the offset combined to be a $6 million charge.
- **Bid cost recovery payments decreased significantly** for units in the California ISO and WEIM balancing areas when compared to Q1 2023. In the California ISO, estimated payments totaled about $41.5 million compared to $80.3 million in Q1 of the prior year. Estimated bid cost recovery payments associated with the residual unit commitment market decreased by $22.3 million. In the WEIM balancing areas, estimated payments totaled about $4.8 million compared to $13.1 million in Q1 2023.
- **Ancillary service payments totaled $20.7 million, a 48 percent decrease from the same quarter last year.** These costs fell due to replacement of spinning reserves with lower cost non-spinning reserves, and a decrease in regulation costs of over $13 million.
- **Upward load adjustments in the 15-minute market remained high but decreased significantly compared to Q1 2023.** The highest hourly average adjustment was about 1,540 MW, down from around 2,350 MW in 2023. The combination of high load adjustments up in the 15-minute market and much lower adjustments in the 5-minute market contributed to the price difference between these markets during the morning and evening ramp hours.
- **Flexible ramping product system level prices were zero for over 99 percent of intervals** in the 15-minute market and in the 5-minute market. Nodal pricing and a new uncertainty calculation for the product were implemented in February 2023. Before implementation, prices were also zero in over 99 percent of intervals. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 60 percent for both directions. Balancing areas in the Pacific Northwest made up 31 percent of upward flexible capacity and 17 percent of downward flexible capacity.
- **The forecasted movement portion of flexible ramping product was settled incorrectly since the implementation of the nodal procurement enhancements on February 1, 2023.** The flexible ramping price from the wrong advisory interval was used to pay the forecasted movement. The ISO is working on correcting and resettling forecasted movement for the impacted period.
- **The mosaic quantile regression method for estimating the flexible ramping product uncertainty requirements used the wrong set of balancing areas to determine the regression coefficients during 18 percent of intervals in the first quarter.** DMM continues to recommend the ISO consider options for addressing inconsistencies between 1) the group of balancing areas used to determine the regression coefficients for the pass-group and 2) the group of balancing areas whose forecast information gets multiplied by those coefficients to determine the uncertainty requirement.
- **The mosaic quantile regression method results for determining residual unit commitment market adjustments for uncertainty did not show a meaningful correlation between the realized uncertainty and the predicted uncertainty.** A scatterplot of realized versus predicted uncertainty

shows no correlation, and the regression coefficients were statistically significant in less than 26 percent of intervals.

- **The mosaic quantile regression method results for forecasting system level flexible ramping product uncertainty did not show a meaningful correlation between the realized uncertainty and the predicted uncertainty.** A scatterplot of realized versus predicted uncertainty shows no correlation, and the regression coefficients were statistically significant in only about 20 percent of intervals. The regression method produced similarly sized uncertainty forecasts as the previous histogram method would have, and covered realized uncertainty about as often.
- **The mosaic quantile regression model coefficients for predicting resource sufficiency evaluation uncertainty were statistically significant in only 13 percent of intervals** in the first quarter of 2024. The regression method produced similarly sized uncertainty forecasts as the previous histogram method would have, and covered realized uncertainty about as often. The historical data used to create the regression coefficients is for uncertainty in the net load forecasts produced only 45-55 minutes before real-time, whereas the model should be predicting the uncertainty in forecasts from 48-102 minutes before real-time. As a result, the realized uncertainty covered by the model's predicted uncertainty was significantly lower on average for intervals at the end of the hour than for intervals at the beginning of the hour.

Figure E.1 Monthly load-weighted average energy prices California ISO (all hours)

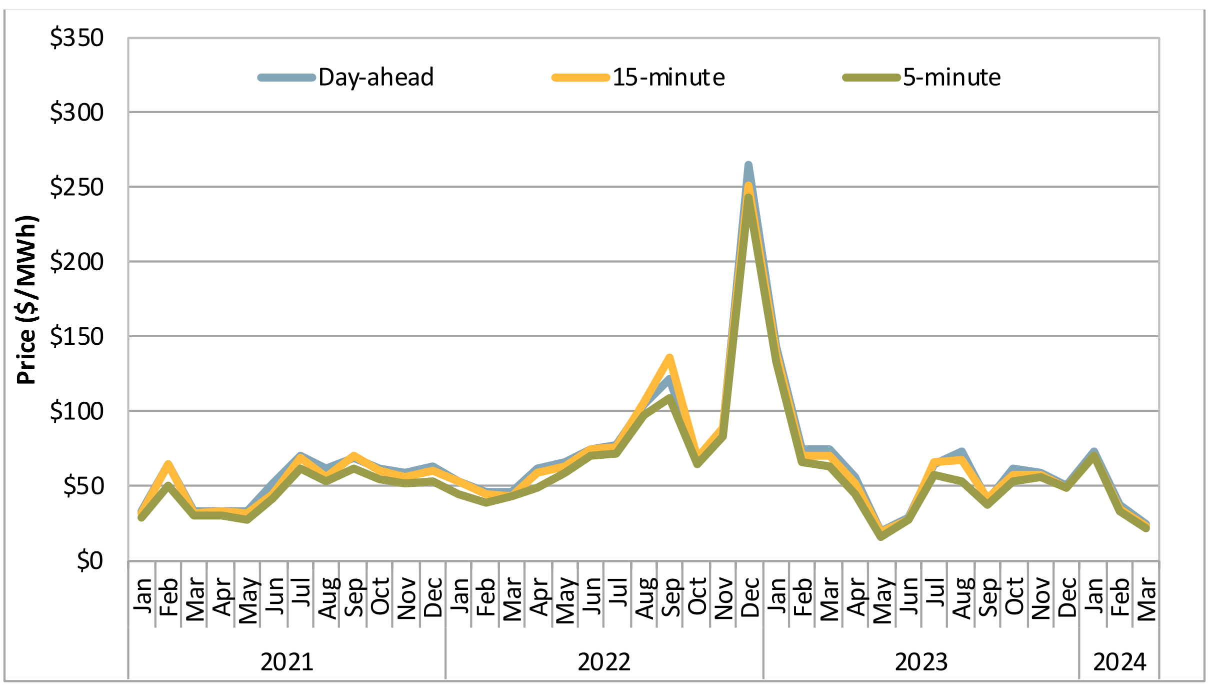
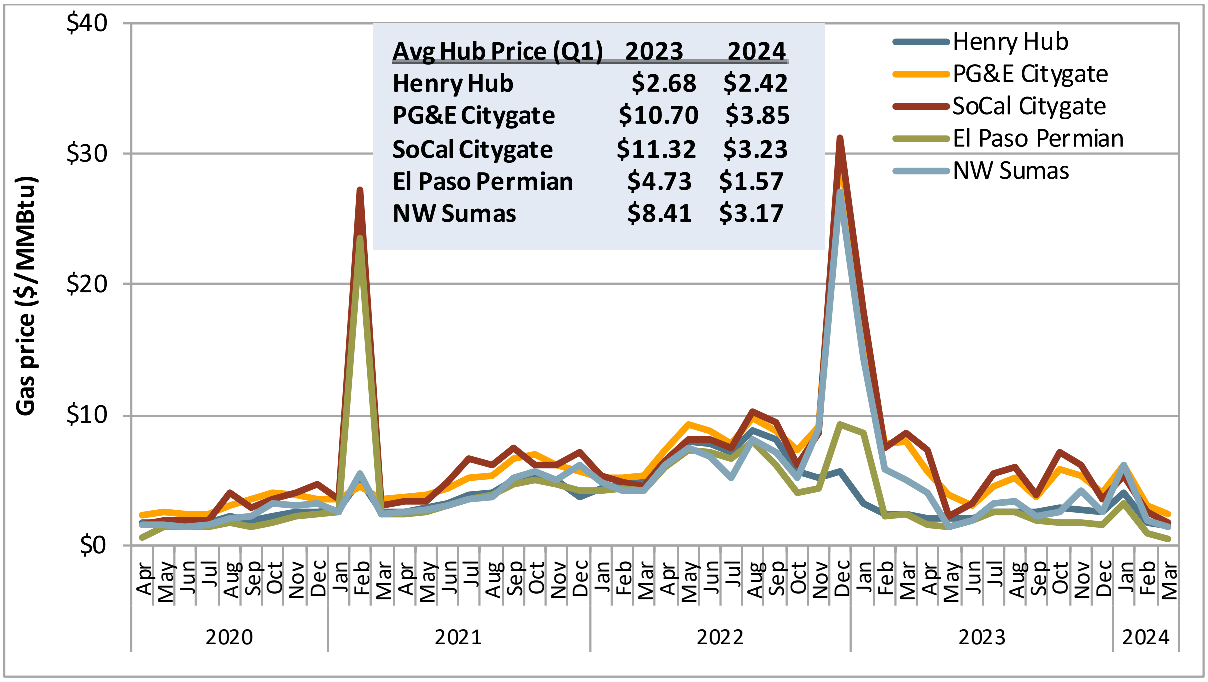


Figure E.2 Average monthly natural gas prices by hub



Western Energy Imbalance Market

- **Each balancing area in the Pacific Northwest and Intermountain West regions experienced peak load during an extreme cold weather event between January 12 and January 16, 2024.** Prices in the 15-minute market for most of these balancing areas were between $780/MWh and $940/MWh on average across all hours from January 13th to 15th.[1] Western Energy Imbalance Market (WEIM) transfer capacity and other transmission constraints into these northern regions were frequently constrained, preventing lower priced marginal energy in southern areas from setting lower prices in the north.
- **Natural gas prices fell significantly across the WEIM** compared to the first quarter of 2023, resulting in large decreases in average electricity prices in all regions despite the severe cold weather event in northern regions in mid-January.
- **Prices in the Pacific Northwest and Intermountain West were significantly higher than the rest of the WEIM during Q1 2024,** particularly in January, when average prices in these regions were around $150/MWh due to the severe cold weather event in the middle of the month. In contrast, January prices across other WEIM areas averaged around $65/MWh. This large price premium in northern areas did not continue into February or March. Desert Southwest areas generally had relatively lower prices than the rest of WEIM, consistent with the trend observed in the first quarter of 2023.

[1] Including NorthWestern Energy, Avista, Avangrid, Portland General Electric, Tacoma Power, Seattle City Light, Puget Sound Energy, PacifiCorp West, and BPA.

- **Powerex continued to have significantly higher prices than other WEIM areas, except for January.** This was due to transfer congestion into the area during most intervals in February and March.
- **California ISO balancing area operators did not implement peak hour dynamic WEIM transfer restrictions into the CAISO area during any hours of the first quarter of 2024.** Operators had restricted most Western Energy Imbalance Market (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.
- **The major net exporters of WEIM transfers shifted significantly** between the mid-day hours—when solar generation is typically at its highest—and the peak net load hours.
- **During the peak solar mid-day hours, the CAISO balancing area was the major net exporter of WEIM transfers,** exporting an average of over 1,600 MW between hours 10 and 17 to areas in the Pacific Northwest, California, and Desert Southwest. Nevada Power was also a significant net exporter during solar hours. Powerex was the major net importer of WEIM transfers during these hours.
- **During peak net-load hours, major net exporters were Salt River Project, Arizona Public Service, and PacifiCorp West.** CAISO and Powerex were the major net importers during these hours.
- **Six balancing areas opted in to the assistance energy transfer program on at least one day during the quarter.** Four of these balancing areas received additional WEIM transfers during resource sufficiency evaluation failures as a result of the program.
- **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]
- **Appendix A includes hourly price and transfer figures for each WEIM area.**

[2] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx

1 Market Performance

This section covers performance of the California ISO balancing area wholesale energy markets and resource adequacy program during the first quarter of 2024.

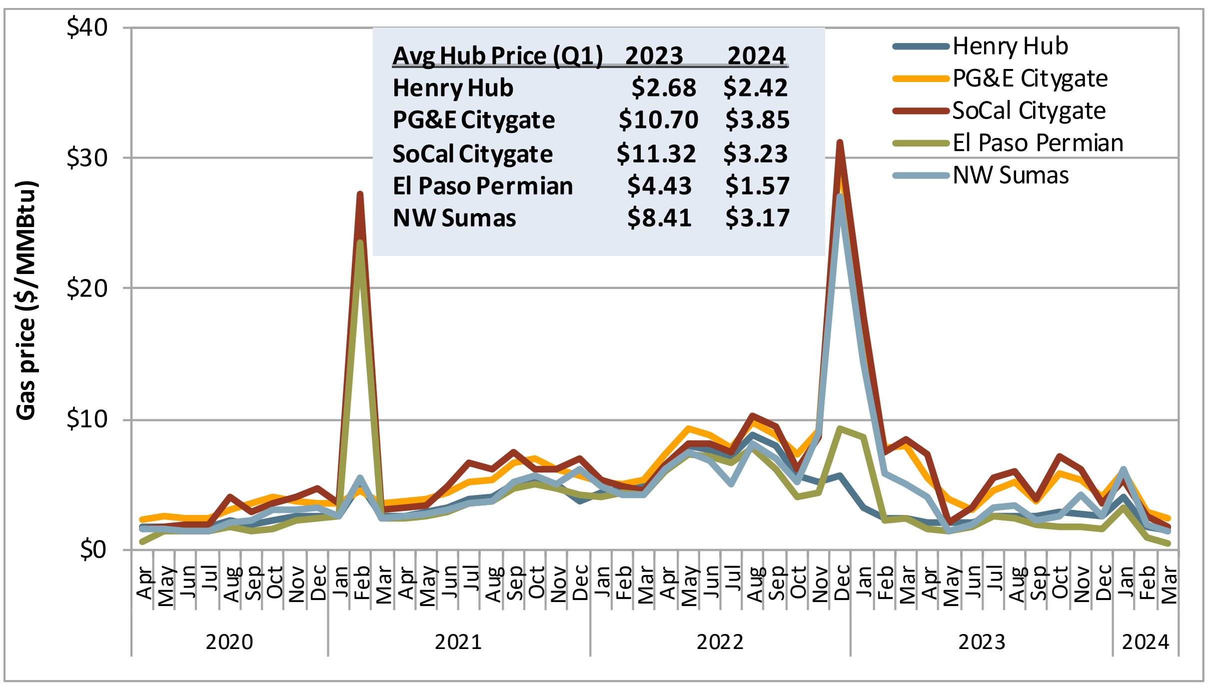
1.1 Supply conditions

1.1.1 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 the California ISO balancing area (CAISO) and other regional markets. In January 2024, the average gas prices at major Western U.S. gas trading hubs rose above December 2023 prices before decreasing in February and March. The rise in January was associated with an unseasonably cold mid-month storm. Natural gas prices in the first quarter of 2024, however, were down significantly compared to the same quarter of 2023.

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.

Figure 1.1 Monthly average natural gas prices



Avg Hub Price (Q1)	2023	2024
Henry Hub	$2.68	$2.42
PG&E Citygate	$10.70	$3.85
SoCal Citygate	$11.32	$3.23
El Paso Permian	$4.43	$1.57
NW Sumas	$8.41	$3.17

Average first quarter prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) decreased by 24 percent and 43 percent compared to the previous quarter, respectively. The Northwest Sumas prices remained about the same from the previous quarter. The Henry Hub and El Paso Permian gas prices decreased by 12 percent and 6 percent, respectively, during the same time period. Likewise, all delivery point prices decreased substantially when compared to the first quarter of

2023: SoCal Citygate (-71 percent), El Paso Permian and PG&E Citygate (-64 percent), Northwest Sumas (-62 percent), and Henry Hub (-10 percent).

On August 31, 2023, the CPUC issued an order increasing the inventory limit for the Aliso Canyon storage facility from 41.16 Bcf to 68.6 Bcf, which builds on the storage level set in 2021 of about 34 Bcf.[3] This action contributed to increasing SoCalGas total authorized storage inventory capacity to 119.5 Bcf.[4] First quarter 2024 storage inventory for SoCalGas steadily decreased from about 105 Bcf on January 2, 2024 to about 86 Bcf on March 31, 2024. This is in contrast to the first quarter 2023 storage levels, which fell from around 62 Bcf in January 2023 to about 37 Bcf by March 31, 2023.[5]

1.1.2 Renewable generation

In the first quarter, the average hourly generation from renewable resources increased by about 370 MW (3.8 percent) compared to the same quarter of 2023.[6] The availability of variable energy resources contributes to price patterns, both seasonally and hourly, due to their low marginal cost relative to other resources.

Figure 1.2 shows the average monthly renewable generation by fuel type.[7] Generation from solar resources increased 16.9 percent compared to the first quarter of 2023. Hydroelectric generation decreased by around 1.4 percent while wind generation stayed around the same. Generation from geothermal and biogas-biomass resources decreased by about 8.8 percent and 4.7 percent, respectively.

3 CPUC Proposed Decision to Protect Against Natural Gas Price Spikes in Southern California (I.17-02-002): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/ac-storage-level-pd-0722823.pdf

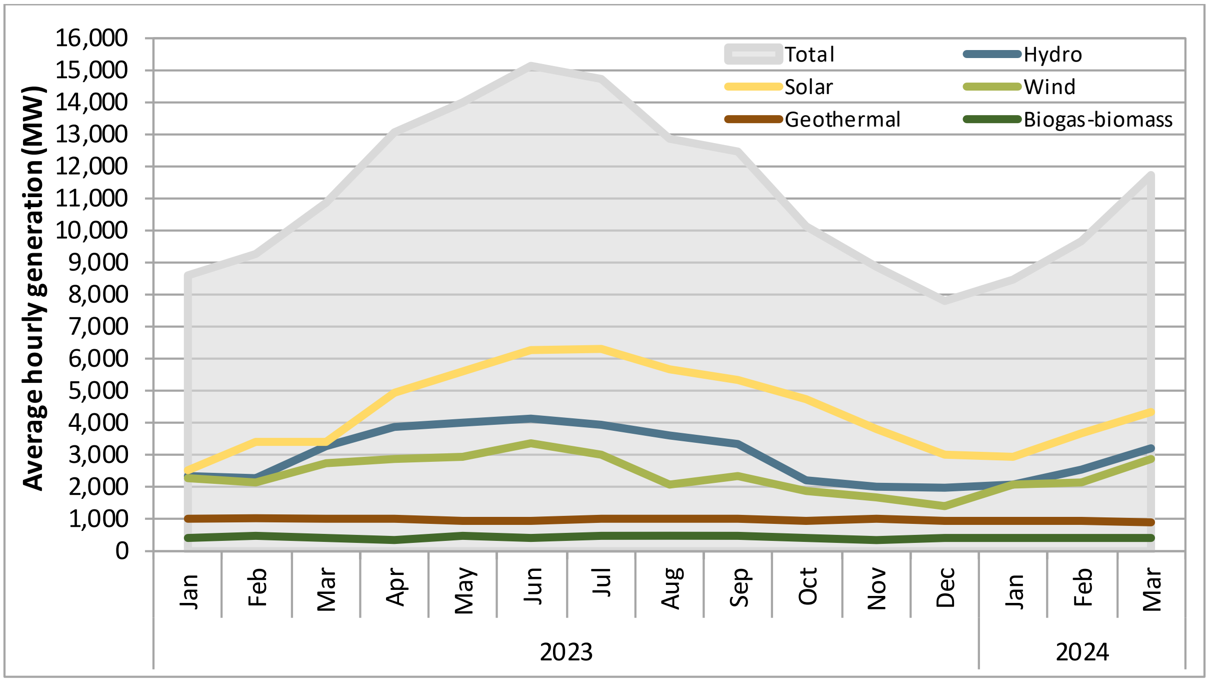
4 SoCalGas owns and operates four underground storage facilities: Aliso, Honor Rancho, La Goleta, and Playa Del Rey: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M328/K289/328289863.PDF

5 SoCalGas ENVOY Storage Inventory (Bcf): https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome

6 Figures and data provided in this section are preliminary and may be subject to change.

7 Hydroelectric generation greater than 30 MW is included.

Figure 1.2 Average monthly renewable generation



1.1.3 Generation by fuel type

Average hourly battery discharge increased relative to the first quarter of 2023 by around 63 percent,[8] while solar generation increased by around 17 percent. Average hourly generation by natural gas resources decreased by around 7 percent. Average hourly net imports have decreased by around 44 percent, primarily driven by significant increases in exports out of the CAISO balancing area. The California ISO was a net exporter from hours-ending 10 through 16.[9]

Figure 1.3 shows the average hourly generation by fuel type during the first quarter of 2024, as measured by preliminary meter data. Total hourly average generation from California ISO resources peaked at about 25,500 MW during hour-ending 19. Net battery discharge also peaked during the same hour at about 2,400 MW. Non-hydroelectric renewable generation, which includes geothermal, biogas-biomass, wind, and solar resources, contributed to 21 percent of total generation during the peak net load hours,[10] up from 19 percent during the same time last year.[11]

Figure 1.3 also shows net battery generation across all hours. Note that during mid-day hours, there is significant load from batteries charging, represented by the net negative points below the zero-axis. On

[8] This statistic refers to battery discharge only, while Figure 1.3 and Figure 1.4 display *net* battery generation.

[9] Figures and data provided in this section are preliminary and may be subject to change as final meter data is submitted.

[10] Hours-ending 17 through 21.

[11] The percent is slightly different than what is reported in the Q1 2023 report due to changes in how total generation is measured. The calculation now uses net battery and net hybrid generation instead of only discharge meter data. Net WEIM transfer data has also been added to the total.

average, net battery generation for the first quarter of 2024 was lowest during hour-ending 13, at around -2,900 MW.

Figure 1.3 Average hourly generation by fuel type (Q1 2024)

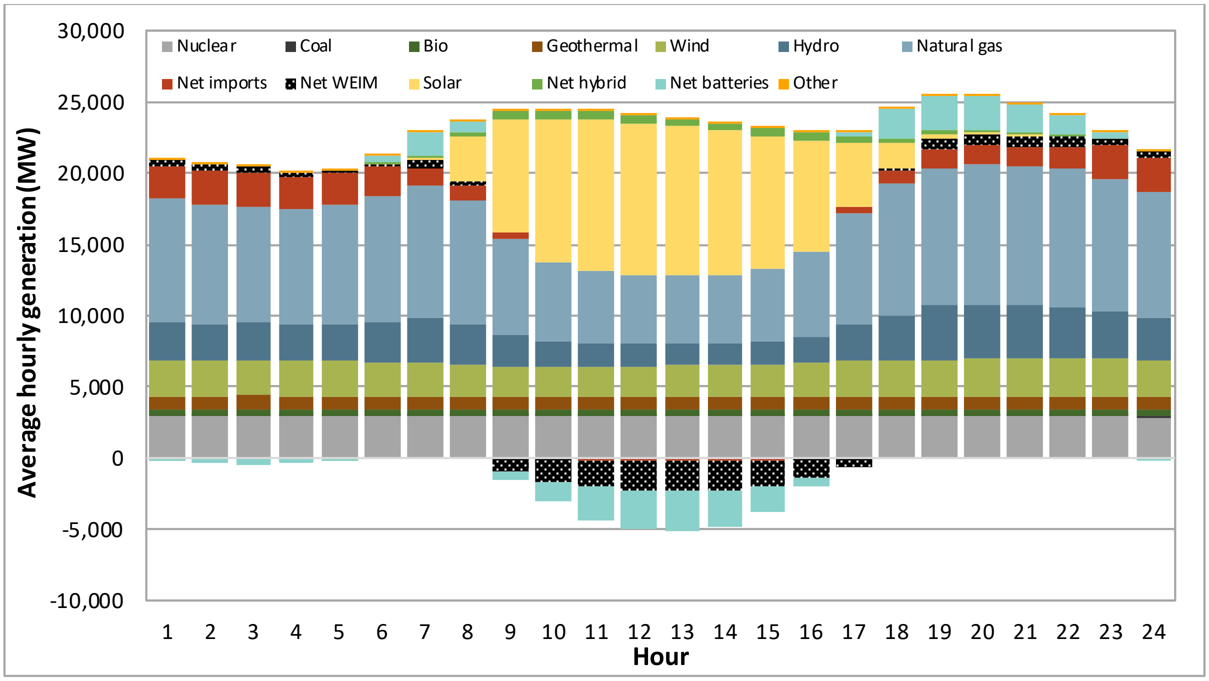


Figure 1.4 shows the change in hourly generation by fuel type between the first quarters of 2023 and 2024.[12] In the chart, positive values represent increased generation relative to the same time last year, and negative values represent a decrease in generation.

There was a decrease in overall average hourly generation in all hours compared to the first quarter of 2023, as shown by the net change line. This is primarily driven by significant decreases in net imports and natural gas generation. Batteries have been increasingly participating in energy arbitrage by charging during high solar hours mid-day, and discharging during the high net-load periods in both the morning and evening. Average net battery generation increased in both the morning—from hours-ending 6 to 8—and in the evening, from hours-ending 17 through 23.

Figure 1.5 shows the monthly average hydroelectric generation from 2020 to 2024. Hydroelectric generation in the first quarter of 2024 tracked similarly to the start of 2023, and higher than the three prior years.

[12] Hybrid generation was included in the “Other” category in Q1 2023 but is identified as “Hybrid” in Q1 2024. Therefore, reductions in “Other” generation are offset by the additional “Hybrid” generation.

Figure 1.4 Change in average hourly generation by fuel type (Q1 2023 to Q1 2024)

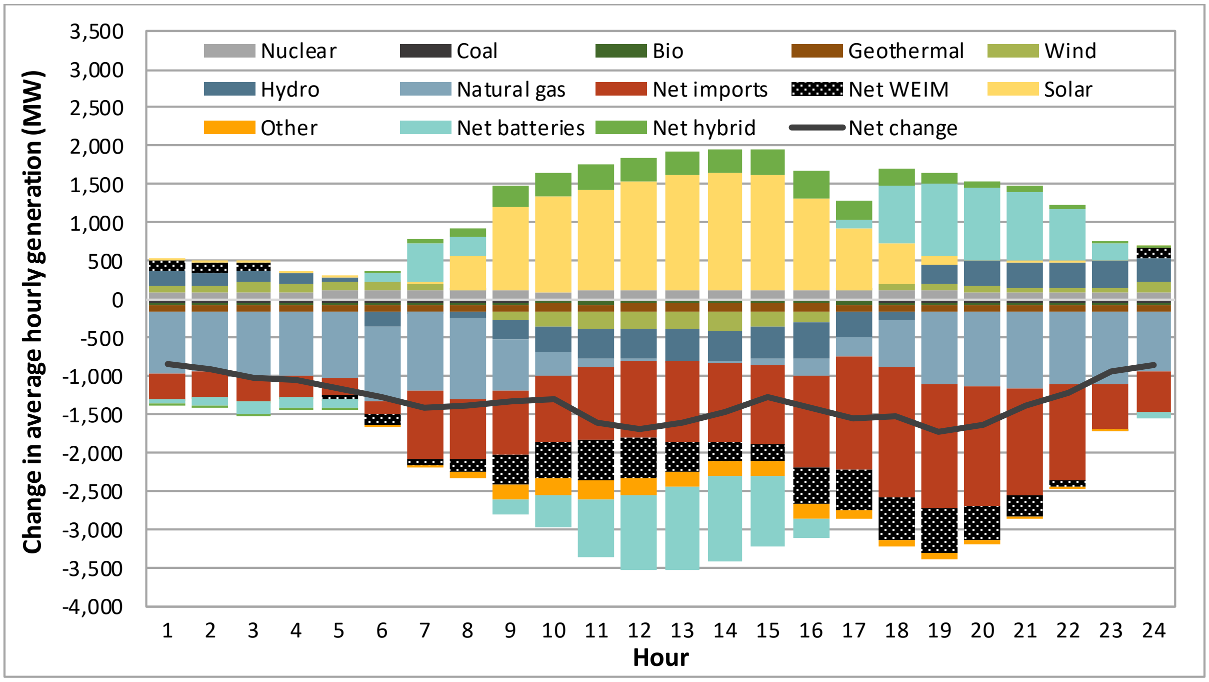
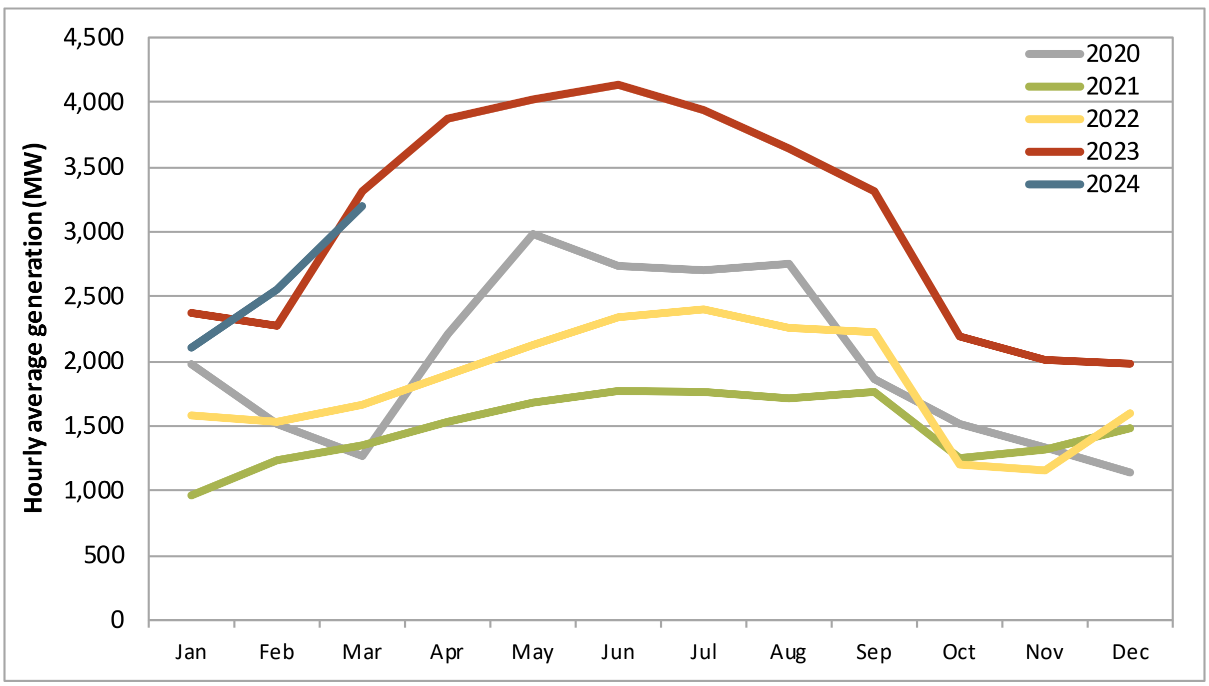


Figure 1.5 Monthly average hydroelectric generation by year



1.1.4 Generation outages

Total generation on outage in the California ISO balancing area averaged about 17,770 MW in the first quarter of 2024. This was an overall increase of 20 percent from the first quarter of 2023, with forced outages increasing by 26 percent and planned outages increasing by ten percent.

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.

Figure 1.6 and Figure 1.7 show the quarterly and monthly averages, respectively, of maximum daily outages during peak hours by type from 2022 through the first quarter of 2024. [13] 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. This trend continued in 2024, with planned maintenance outages increasing by approximately 54 percent from the fourth quarter of 2023 through the first quarter of this year.

During the first quarter of 2024, the average total generation on outage in the California ISO balancing area was 17,770 MW, about 3,000 MW greater than the first quarter of 2023, as shown in Figure 1.6. Forced outages increased by 26 percent when compared to the same quarter last year, while planned outages increased by ten percent.

[13] This is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the California ISO balancing area and do not include outages in the Western Energy Imbalance Market.

Figure 1.6 Quarterly average of maximum daily generation outages by type – peak hours

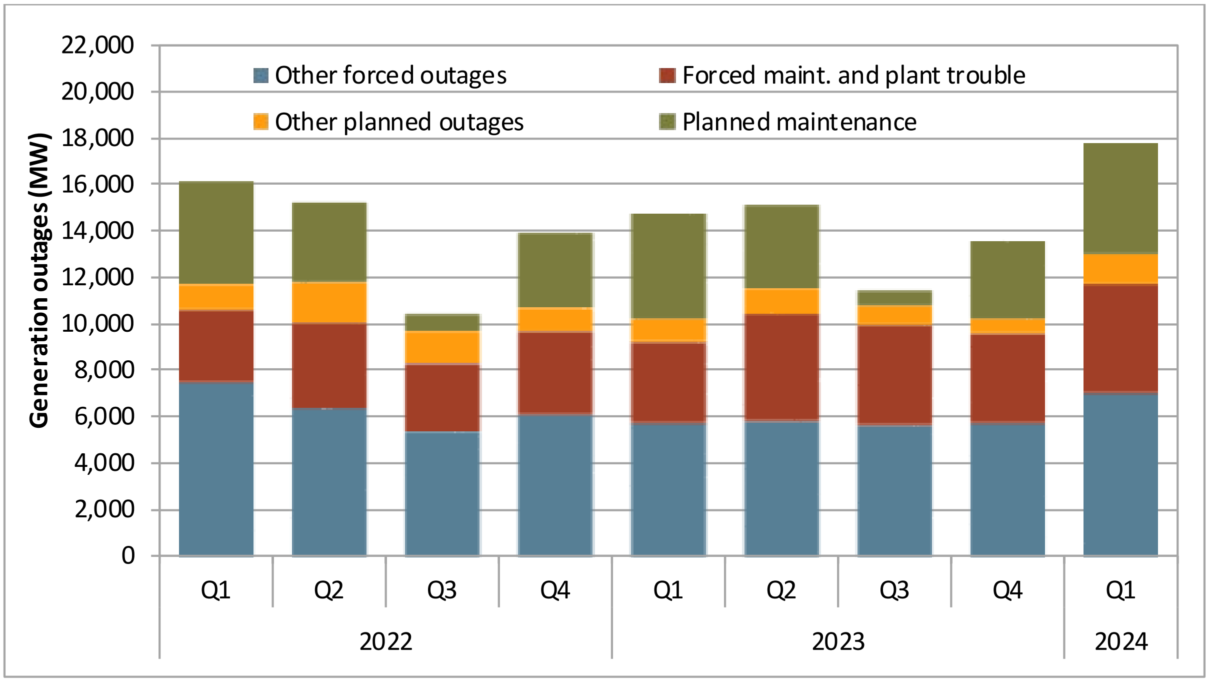
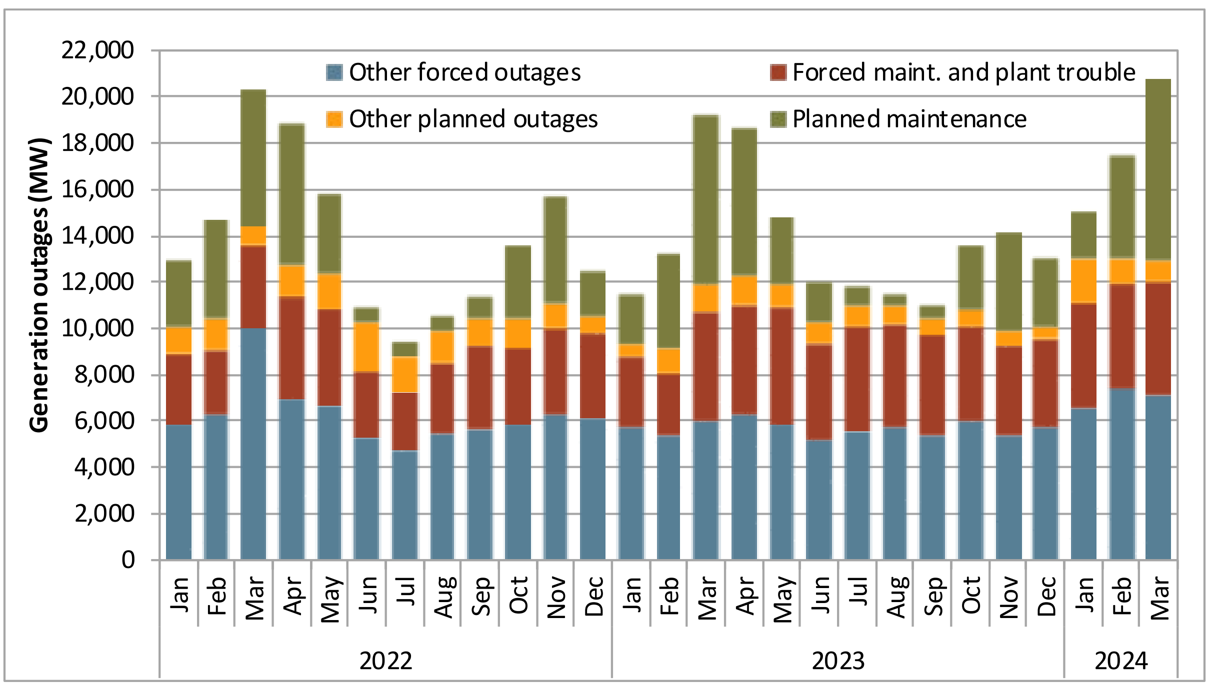


Figure 1.7 Monthly average of maximum daily generation outages by type – peak hours



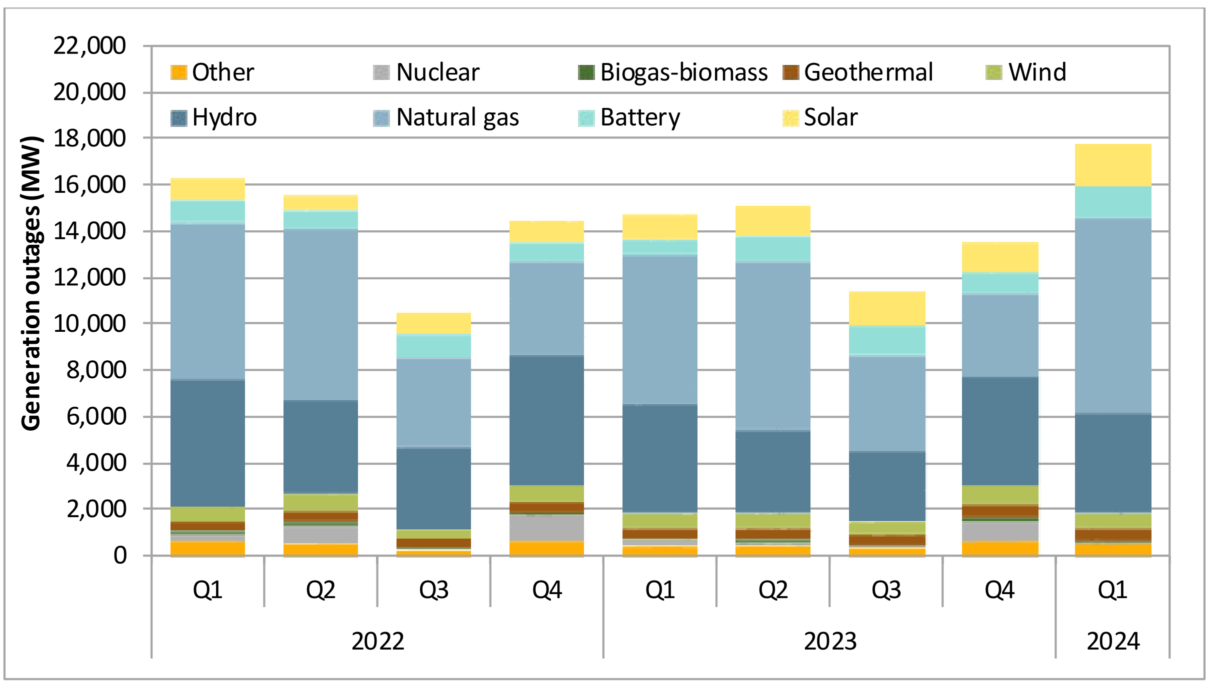
Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged about 8,360 MW and 4,290 MW during the first quarter of 2024, respectively. These two fuel types accounted for a combined 71 percent of the generation outages for the quarter. The amount of natural gas generation outages increased 29 percent relative to the first quarter of 2023.

The quarterly average for battery storage resources increased by 114 percent, with an average of 1,360 MW of capacity on outage in quarter one of 2024 compared to 640 MW in the first quarter of 2023. This increase in the average megawatts on outage was in the context of a significant increase in the total amount of battery storage capacity, from approximately 4,500 MW in January 2023, to 7,700 MW in January 2024. As such, the increase in battery outages is in part explained by a significant increase in the total battery capacity that came on-line in the CAISO footprint.

Figure 1.8 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[14] Hydro, nuclear, and wind outages decreased compared to the first quarter of 2023, while outages for all other resource types increased.

Figure 1.8 Quarterly average of maximum daily generation outages by fuel type – peak hours



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

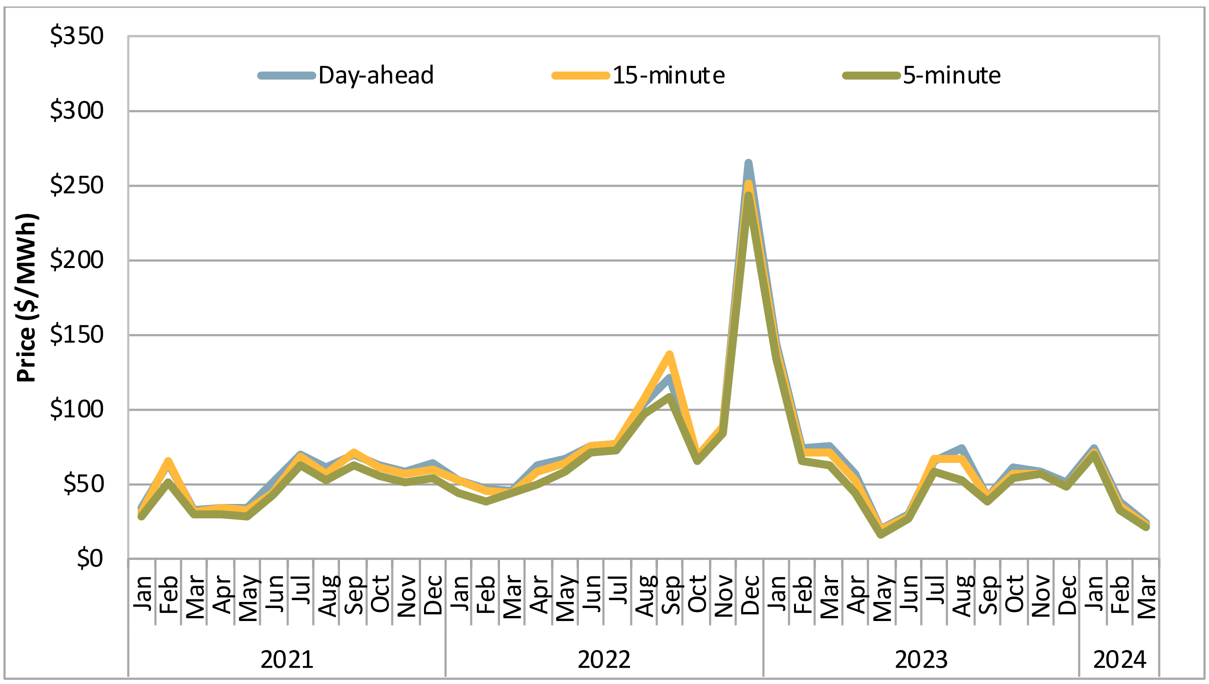
1.2 Energy market performance

1.2.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. In 2024, the first quarter prices in the day-ahead, 15-minute, and 5-minute markets dropped by about 53 percent compared to the first quarter of the previous year. The average price of the three markets this quarter decreased to $43/MWh from $93/MWh in the same quarter of 2023.

Figure 1.9 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from January 2021 to March 2024.

Figure 1.9 Monthly load-weighted average energy prices for California ISO (all hours)



Over the quarter, day-ahead prices averaged $45/MWh, 15-minute prices averaged $43/MWh, and 5-minute prices averaged $42/MWh. Prices across all three markets were about 53 percent less than those in the first quarter of the prior year. January had the highest prices, with an average over the three markets of about $72/MWh.

Low gas prices contributed to the low prices observed this quarter. Figure 1.10 shows monthly average gas prices at SoCal Citygate and load-weighted energy prices from April 2022 to March 2024. The chart shows that the monthly variation of the energy prices is highly correlated with gas prices. The black dashed line shows the monthly average gas price at SoCal Citygate. The colored lines illustrate energy prices. Over the past 24 months, both gas and energy prices exhibited similar fluctuations. The SoCal

City gas price has remained down after declining from its recent peak in December 2022, averaging about $3.23/MMBtu during the first 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.

Figure 1.10 Monthly average SoCal City gas price and load-weighted average electricity prices for California ISO

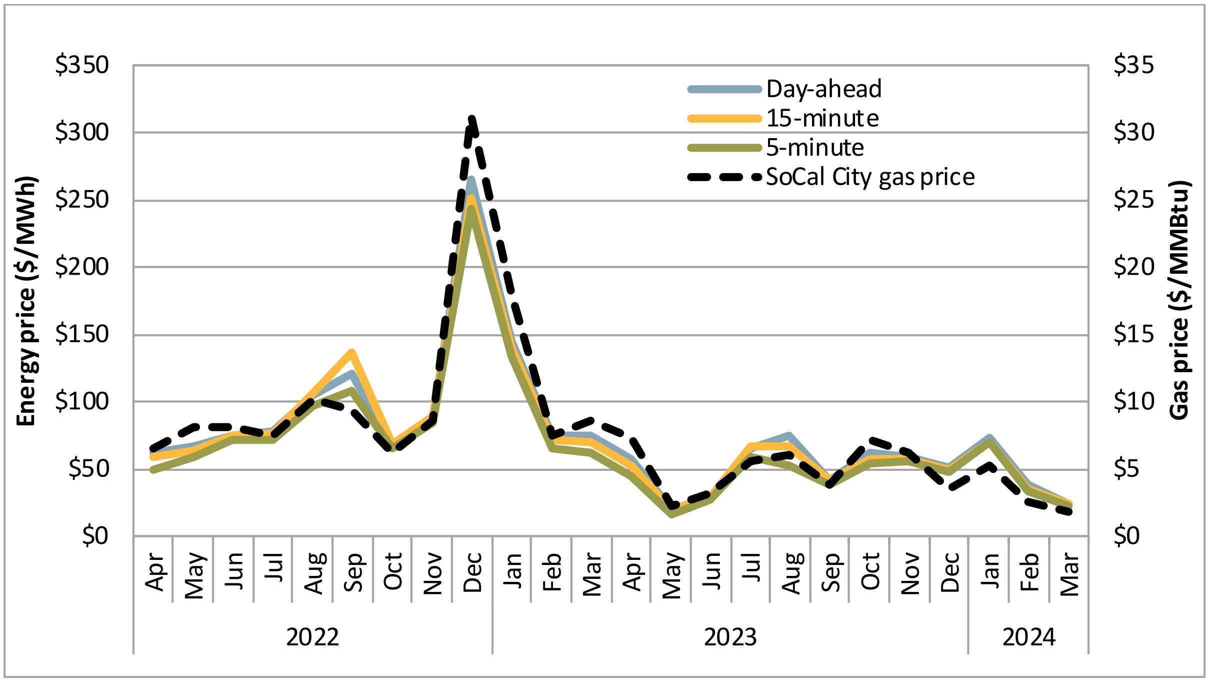


Figure 1.11 illustrates the hourly load-weighted average energy prices for the first quarter compared to the average hourly net load.[15] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) are measured by the left axis, while the average hourly 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, and peaked at hour-ending 20, when demand was still high but solar generation was substantially below its peak. The average net load in this quarter reached 21,706 MW at hour-ending 20.

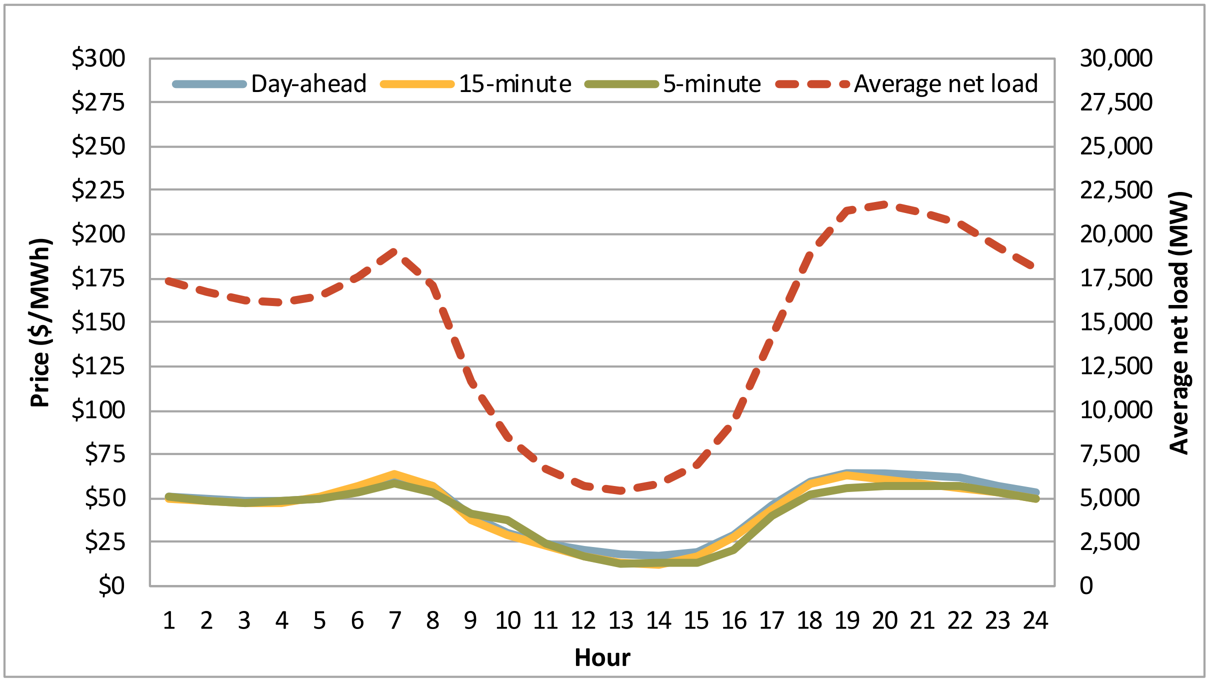
During hour-ending 20, the day-ahead load-weighted average energy price was $64/MWh, the 15-minute price was $61/MWh, and the 5-minute price was $57/MWh. The 5-minute price consistently fell below the day-ahead and 15-minute market prices between hours-ending 15 and 20. The average 5-

[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.

minute price was $5/MWh lower than those of the other two markets during these hours. Day-ahead and 15-minute market prices typically tend to converge on average due to convergence (virtual) bidding.

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

Figure 1.11 Hourly load-weighted average energy prices (January-March)



1.2.2 Bilateral price comparison

Figure 1.12 shows the California ISO 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 the 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. The figure shows prices at the Mid-Columbia hub spiked significantly in mid-January, when temperatures were significantly below average in the Pacific Northwest and Intermountain West regions.[17]

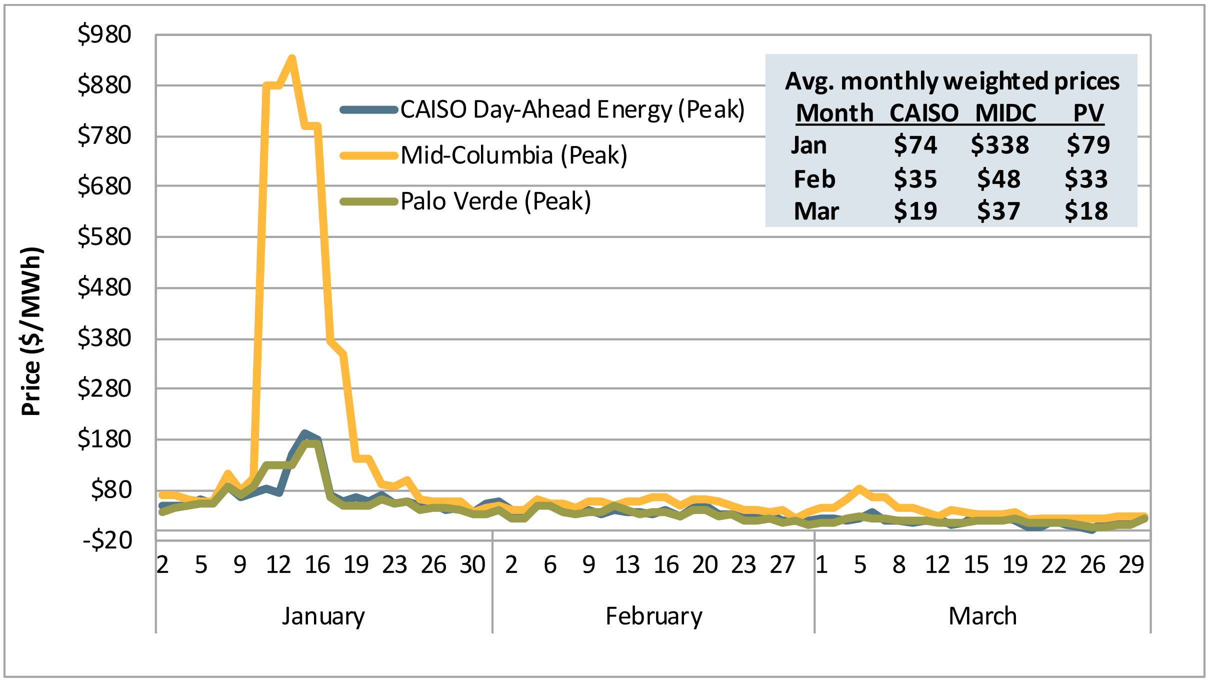
The California ISO FERC Order 831 policy will increase the California ISO energy bid cap to $2,000/MWh if a 16-hour block peak bilateral price, scaled and shaped into hourly prices according to the shape of California ISO hourly prices, exceeds $1,000/MWh. With the 16-hour block bilateral prices reaching

16 Please see Section 1.11 for a detailed discussion on load conformance.

17 National Weather Service – National Oceanic and Atmospheric Administration: https://www.weather.gov/ict/2024_cold

almost $1,000/MWh, the scaled bilateral prices over the peak net load hours significantly exceeded $1,000/MWh. Therefore, the California ISO raised its energy bid cap and penalty prices to $2,000/MWh for many hours in both the day-ahead and real-time markets on four days[18]—January 13 through 16, 2024—during this extreme cold temperature period. Regional differences in prices reflect transmission constraints and greenhouse gas compliance costs.

Figure 1.12 Day-ahead California ISO and bilateral market prices (January–March)



Avg. monthly weighted prices			
Month	CAISO	MIDC	PV
Jan	$74	$338	$79
Feb	$35	$48	$33
Mar	$19	$37	$18

Figure 1.13 compares monthly average bilateral and California ISO day-ahead market prices for 2023 through the first quarter of 2024. Prices in the California ISO balancing area are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). As shown in this figure, average bilateral prices for Mid-Columbia (Peak) significantly exceeded prices at the California ISO DLAPs in January 2024 as a result of a large arctic air mass mid-month,[19] which covered much of the Northwest and Midwest United States. Palo Verde (Peak) prices were sandwiched between California ISO prices in the first quarter.

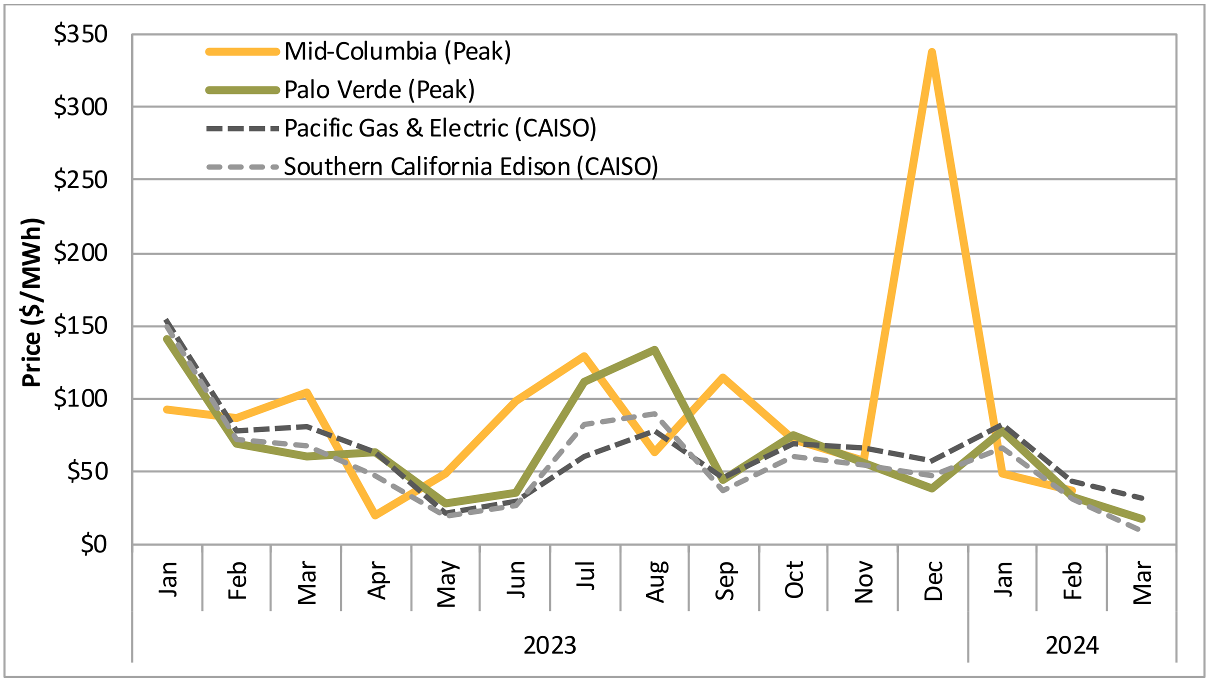
18 Winter Conditions Report for January 2024. California ISO. March 6, 2024. Figure 59: Maximum Import Bid Price and bid ceiling, DAM and RTM Pg. 64. https://www.caiso.com/documents/wintermarketperformancereportforjan2024.pdf

Day-ahead market days and hours: January 14 hour-end 01 to 08 and hour-end 17 to 24. January 15, hour-end 07 and 17 through 22, and January 16 hour-end 07 and 17 to 22.

Real-time market days and hours: January 13 hours-ending 16 to 24. January 14 hours-ending 1 to 8 and 17 to 24. January 14 hours-ending 1 to 8 and 17 to 24. January 15 hours-ending 7, and 17 to 22. January 16 hours-ending 7 to 8 and 17 to 22.

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

Figure 1.13 Monthly average day-ahead and bilateral market prices



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 lower than the average real-time prices at Mid-Columbia and Palo Verde by $45/MWh and $12/MWh, respectively. Average day-ahead prices at Mid-Columbia from ICE were greater than the average real-time Mid-Columbia prices (from Powerdex) by about $16/MWh. Average day-ahead prices at Palo Verde, on the other hand, were about $12/MWh lower than average real-time Palo Verde prices.

1.2.3 Imports and exports

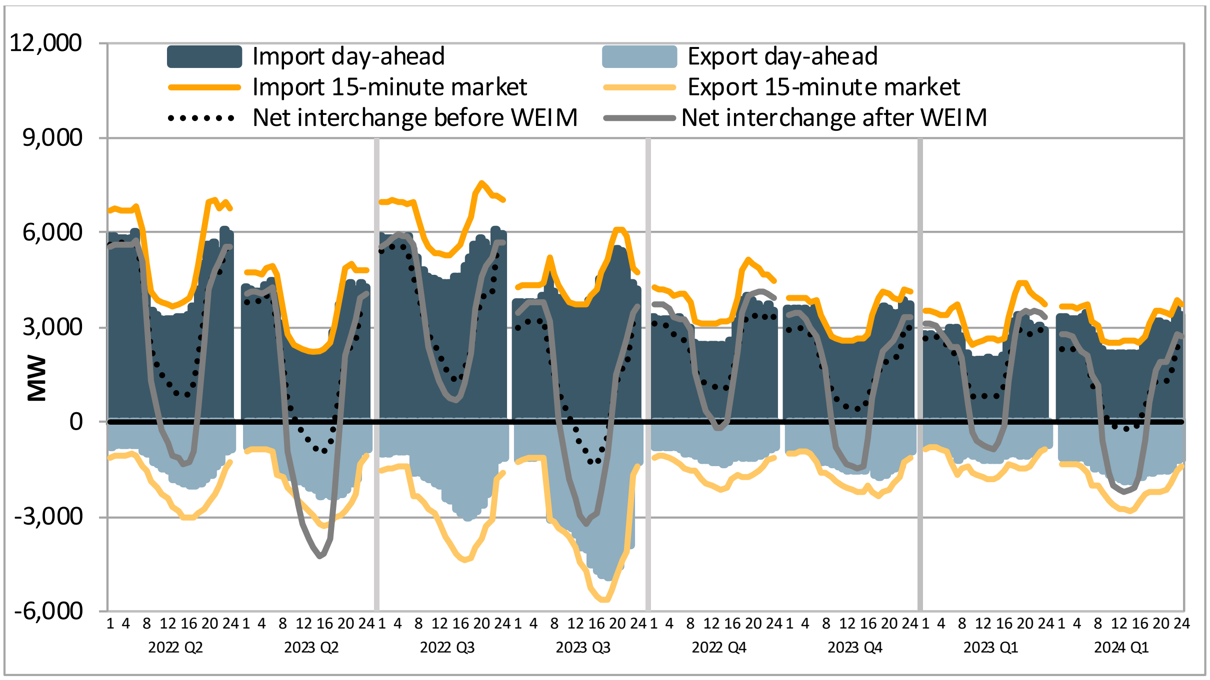
During the first quarter, average imports decreased slightly while exports increased slightly compared to the same quarter in 2023. As shown in Figure 1.14, imports in the day-ahead market (dark blue columns) remained relatively consistent in all hours when compared to the same quarter of 2023, peaking at about 3,500 MW in hour-ending 23. Compared to the first quarter of 2023, 15-minute cleared imports (dark yellow line) decreased the greatest amount in hours-ending 17 to 22, with a maximum average reduction of about 960 MW in hour-ending 18. Exports in both the day-ahead (light blue bars) and 15-minute (pale yellow line) markets increased by about 550 MW and 815 MW, respectively, on average over the hours of 7 to 22, compared to the same quarter of 2023.

Figure 1.14 shows power flowing into the CAISO balancing area as positive and power flowing out of the CAISO area as negative. The dashed black line shows net interchange with the CAISO area before including WEIM transfers into or out of the CAISO area. The dashed black line is the sum of the 15-

minute imports (dark yellow line) and the 15-minute exports (pale yellow line). Compared to the first quarter of 2023, the average net interchange decreased (i.e., moved towards the export direction) in each hour during the first quarter of 2024. Hour-ending 18 had the largest year-over-year decrease, roughly 1,700 MW.

The solid grey line adds WEIM transfers onto the net interchange calculation (dashed black line). When the grey line is below the dashed black line, this indicates WEIM transfers out of the CAISO balancing area. WEIM transfers (solid grey line) were in the export direction on average between hours-ending 9 and 17. Net exports including WEIM transfers peaked at just over 2,200 MW in hour-ending 13. This was almost 1,400 MW more than the largest average net interchange in the export direction in Q1 2023.

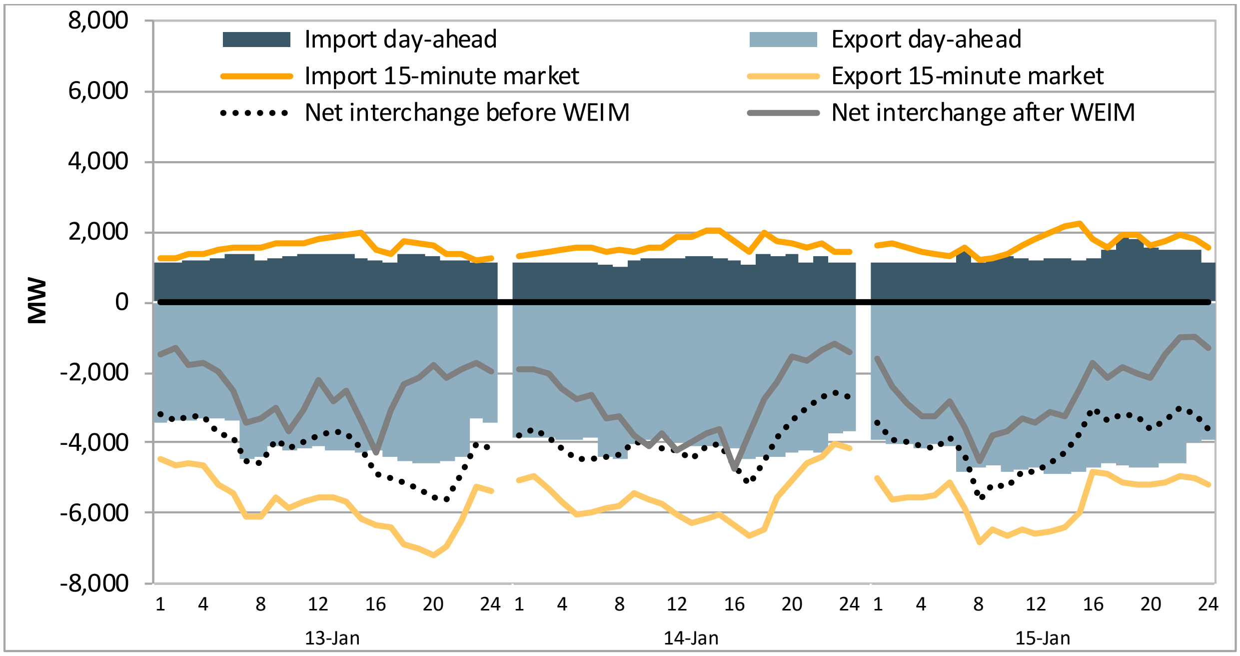
Figure 1.14 Average hourly net interchange by quarter



CAISO balancing area interchange cold weather event January 13–15, 2024

The total CAISO net interchange flow was in the *export* direction for all hours during the cold weather event, January 13–15, 2024. As shown in Figure 1.15, this occurred before and after taking into account net WEIM transfers, as indicated by the dashed black line and solid grey line, respectively. WEIM transfers flowed into the CAISO area during most hours of these days. Over this period, the amount of additional exports clearing the 15-minute market compared to exports clearing the day-ahead market was extremely high, with up to 2,000 MW of additional exports clearing the 15-minute market in some hours.

Figure 1.15 Average hourly net interchange: January 13–15, 2024



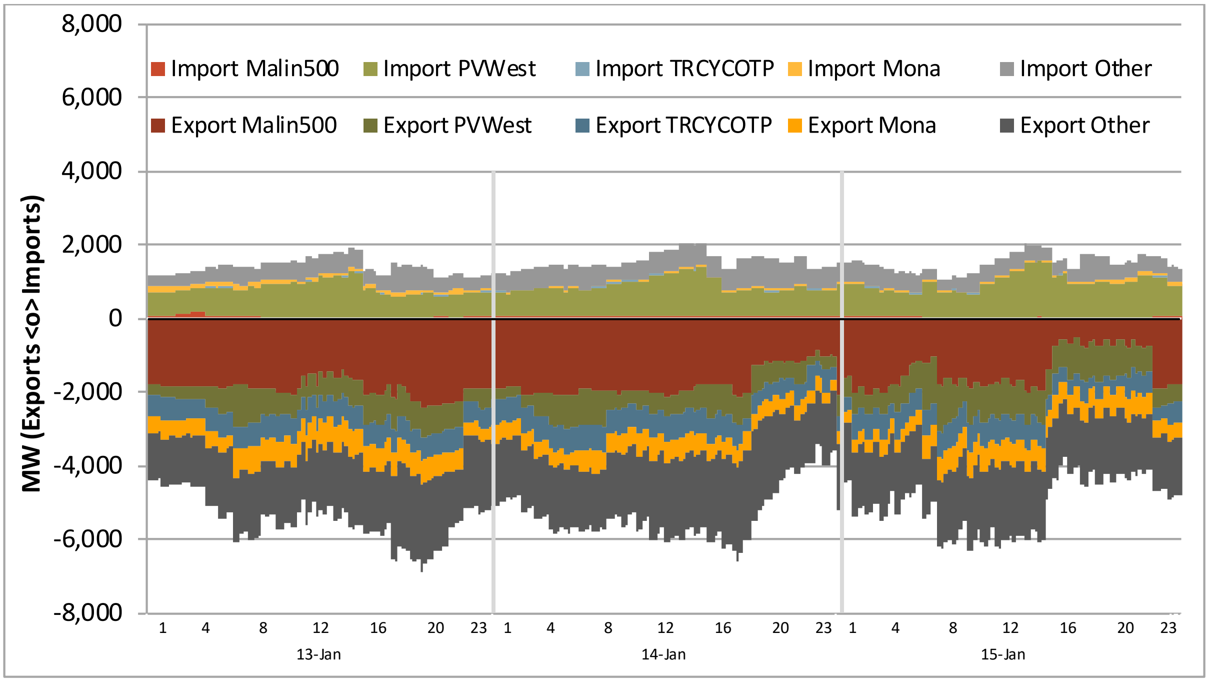
The two major interties[20] connecting the CAISO area to the Pacific Northwest are North-of-Oregon Border (NOB) and Malin. During the cold weather event, the NOB intertie was out-of-service in the export direction due to a combination of scheduled maintenance and a forced outage on an alternate current (AC) transmission element.[21] The Malin intertie also experienced intermittent transmission outages due to the weather in the Pacific Northwest—no forced outages in the CAISO balancing area affected the Malin intertie. These outages on Malin reduced the real-time flow limits, which resulted in congestion on the 6110_COI_S_N nomogram in the CAISO area. For additional congestion detail, refer to Section 1.7.

Figure 1.16 below shows intertie imports and exports in the 15-minute market between January 13 and January 15, 2024. Imports during this period primarily originated from the south on PVWest (light green), as well as from a number of smaller interties. The majority of the exports were on the Malin, PVWest, TRCYCOTP, and Mona (IPP Utah ITC) interties. Export reductions on the Malin intertie on January 14 and 15 were associated with transmission outages identified above.

[20] California ISO POR/POD-Scheduling Path Cross Reference: https://www.caiso.com/documents/2510a.pdf and Intertie Constraint and Branch Group Information Full Network Model Reference Document: https://www.caiso.com/market-operations/network-resource-modeling

[21] Open Access Same-Time Information System (OASIS) API under 'Transmission | Transmission Outages': http://oasis.caiso.com/mrioasis/logon.do

Figure 1.16 15-minute intertie imports and exports: January 13–15, 2024



Import resource adequacy bids

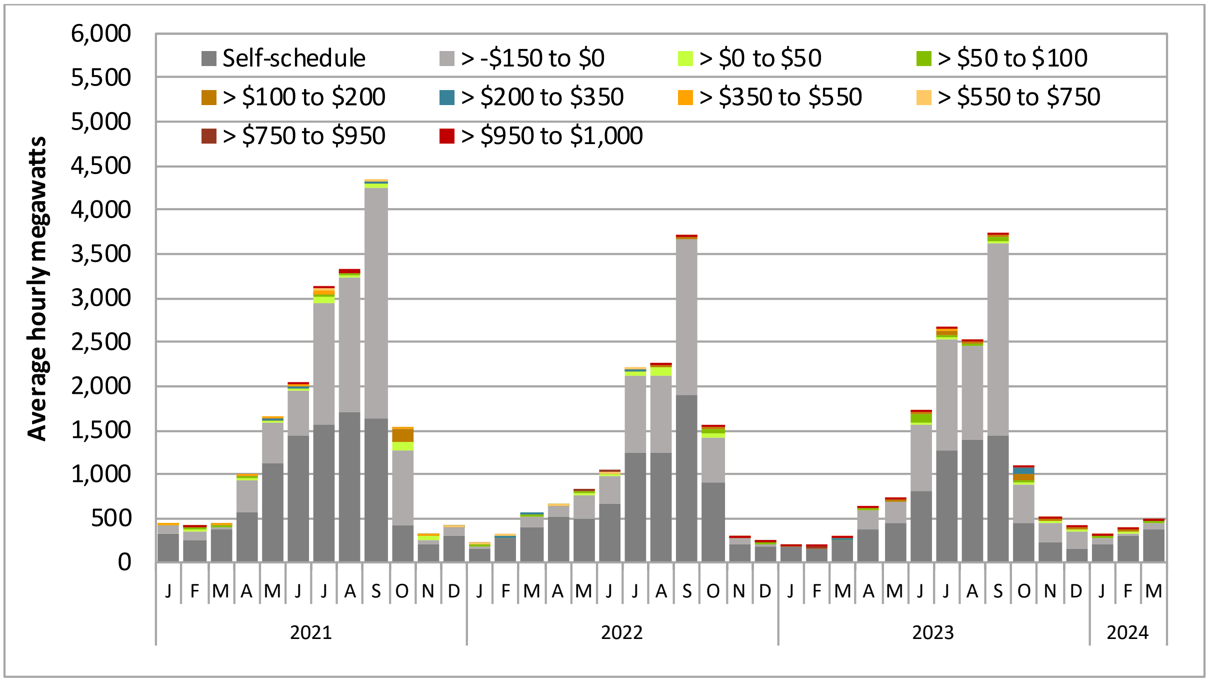
In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the California ISO markets at or below $0/MWh during the availability assessment hours.[22] These rules became effective at the beginning of 2021. They appear 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 1.17 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[23] 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. Levels of resource adequacy imports appear to be reaching a new level of consistency after an initial decline following the June 2020 CPUC decision.

[22] 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.

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

Figure 1.17 Average hourly resource adequacy imports by price bin



1.3 Price variability

In the first quarter of 2024, instances of prices exceeding $250/MWh decreased to 0.24 percent from 0.49 percent in the same quarter of 2023. The proportion of intervals with zero or negative prices increased to 8 percent from 3 percent.

High prices

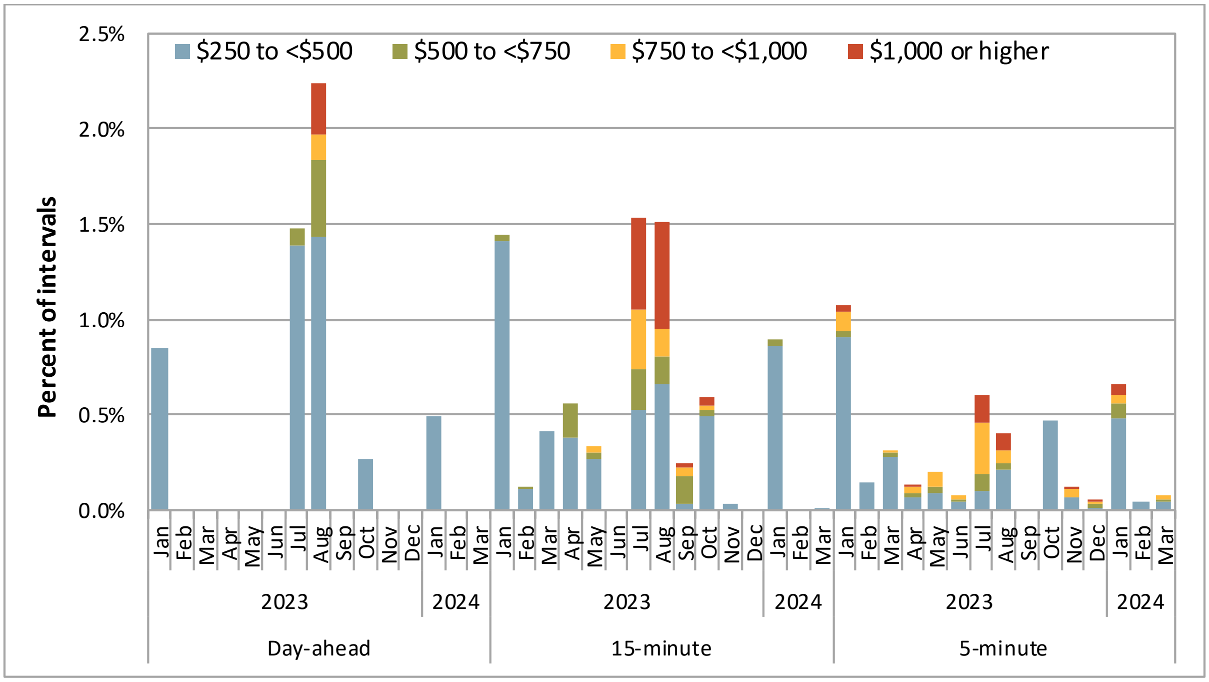
Figure 1.18 shows the frequency of high prices across all three markets for the three largest California ISO balancing area load aggregation points (LAP) by month between January 2023 and March 2024.

In the day-ahead market, the frequency of high prices over $250/MWh decreased compared to the same quarter of 2023. In the first quarter of 2024, the day-ahead market recorded 0.16 percent of intervals with an average price exceeding $250/MWh. In the same quarter of the previous year, 0.28 percent of intervals had prices above $250/MWh.

The 15-minute market also had a lower frequency of price spikes in this quarter compared to the first quarter of 2023. The percentage of intervals with prices above $250/MWh was 0.3 percent, a decrease from 0.66 percent in the same quarter of 2023.

Similarly, the 5-minute market had a reduced frequency of high prices this quarter. The percentage of intervals with prices above $250/MWh decreased to 0.26 percent in the first quarter of 2024 from 0.51 percent in the same quarter of the previous year.

Figure 1.18 Frequency of high prices ($/MWh) by month



The decrease in the frequency of higher prices can be attributed to fewer extreme load conditions for CAISO in the first quarter of 2024 compared to the same quarter in 2023. In both the day-ahead and 5-minute markets, the first quarter of 2024 had fewer intervals of CAISO loads exceeding 25,000 MW and 30,000 MW, which are at the extreme end of the load distribution. This likely contributed to the decreased frequency of high prices.

Negative prices

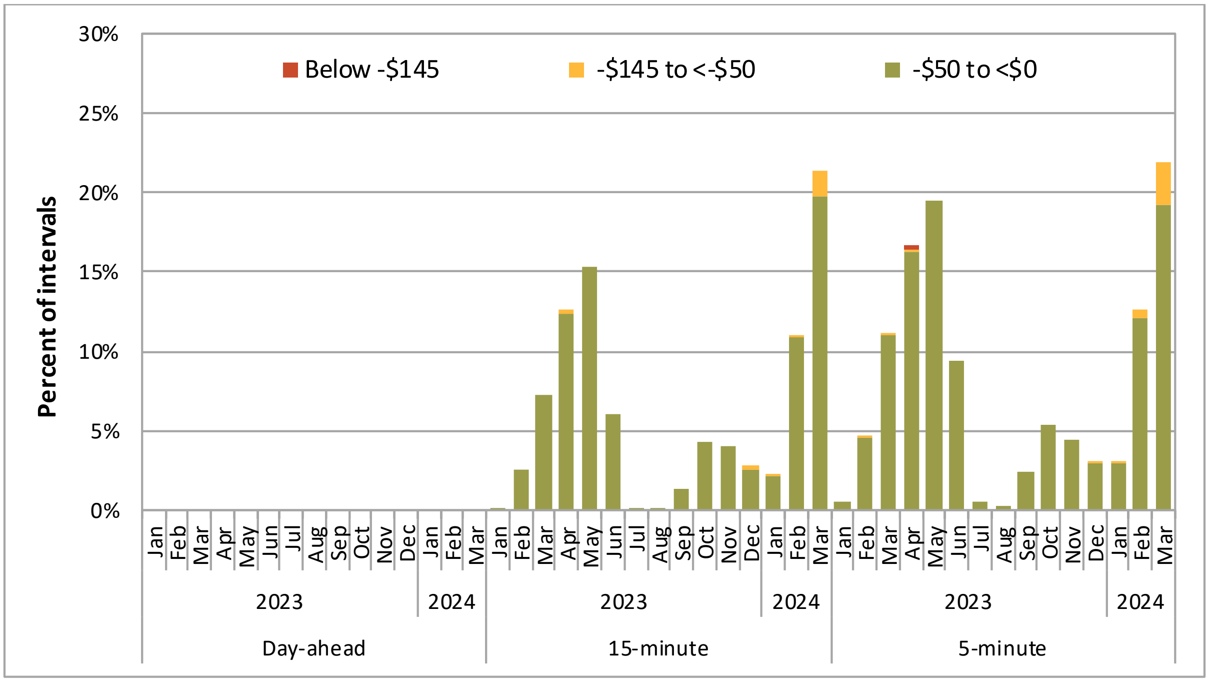
Figure 1.19 shows the frequency of negative prices across all three markets for the three largest load aggregation points (LAPs) by month between January 2023 and March 2024. On average, across the day-ahead, 15-minute, and 5-minute markets, the frequency of negative prices significantly increased from 3 percent to 8 percent in the first quarter of 2024 compared to the same period in 2023.

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.

In the 15-minute market, the frequency of negative prices increased to 11 percent this quarter compared to 3 percent in the first quarter of 2023. In the 5-minute market, negative prices increased to 13 percent this quarter compared to 5 percent in the first quarter of 2023. There were no negative prices in the day-ahead market during the first quarters of 2023 or 2024.

The rise in negative pricing in the first quarter of 2024 compared to the same quarter of 2023 can largely be attributed to lower demand and higher renewable generation around mid-day in 2024.

Figure 1.19 Frequency of negative prices ($/MWh) by month



1.4 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 first quarter, financial entities and marketers were the only convergence bidding participants who profited overall.

1.4.1 Convergence bidding revenues

Net revenues for convergence bidders were about $11.5 million for the first quarter, after inclusion of about $3.3 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply.[24] Figure 1.20 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:

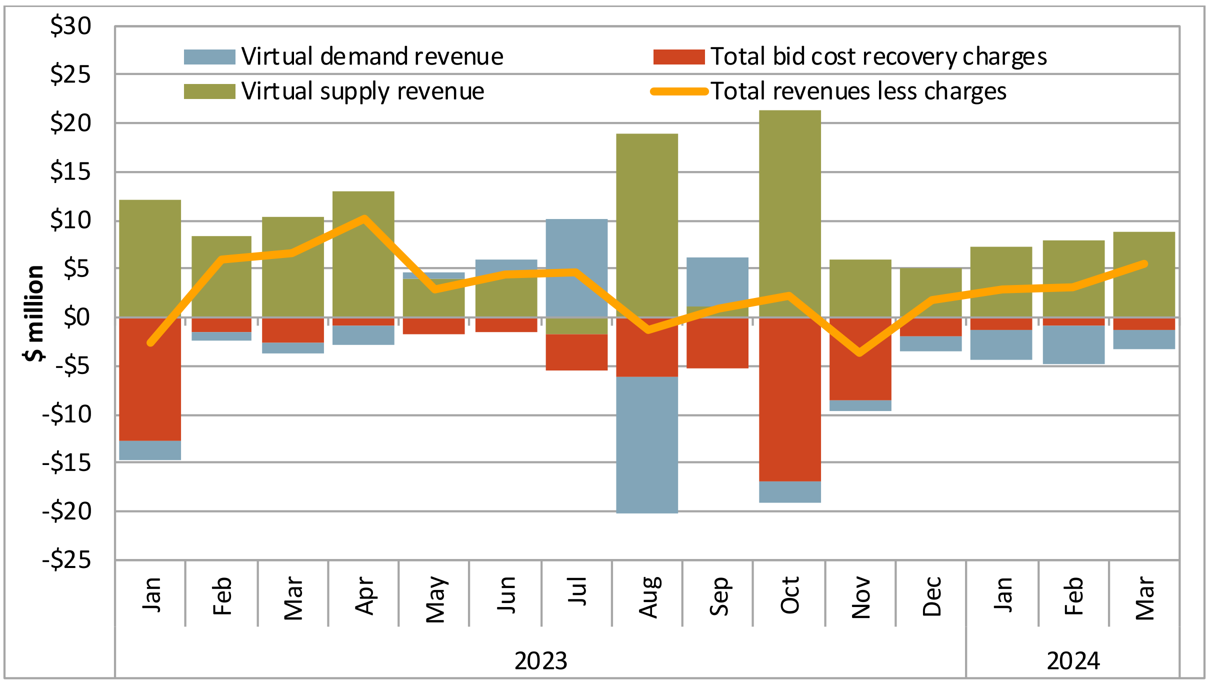
- Total market revenues were positive during all months of the quarter. Net revenues for the quarter overall represent a 15 percent increase compared to the first quarter of 2023.
- Virtual demand revenues were negative in total for all months of the quarter, about -$3.1 million, -$3.9 million, and -$2.1 million for January, February, and March, respectively.

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

- Before accounting for bid cost recovery, virtual supply revenues were about $7.2 million, $7.9 million, and $8.8 million for January, February, and March, respectively.

Bid cost recovery charges allocated to virtual bids were about $1.2 million, $880 thousand, and $1.2 million for January, February, and March, 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.

Figure 1.20 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 1.1 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.[25, 26]

After accounting for bid cost recovery, financial entities and marketers were the only participants who profited from convergence bidding overall. Financial entities and marketers split the net profits at around 89 percent and 11 percent, respectively. Financial entities and marketers accounted for about 79 percent and 18 percent, respectively, of the cleared volume of virtual trades in the first quarter.

Table 1.1 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 Q1								
Financial	2,281	2,395	4,676	-$7.19	$19.66	-$1.70	$17.95	$10.76
Marketer	511	573	1,084	-$1.78	$3.85	-$0.75	$3.10	$1.31
Physical load	6	27	32	-$0.02	$0.15	-$0.35	-$0.21	-$0.23
Physical generation	28	140	167	-$0.13	$0.25	-$0.50	-$0.24	-$0.37
Total	**2,826**	**3,135**	**5,959**	**-$9.12**	**$23.91**	**-$3.30**	**$20.60**	**$11.47**

1.5 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the first quarter of 2024 was 6 percent lower than the same quarter of 2023. Although total volumes were lower, operator adjustments to the RUC procurement target increased by about 35 percent compared to the first quarter of 2023. This was in large part because of a change in the methodology for determining the adjustments in the summer of 2023.[27]

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet real-time load. The residual unit commitment market runs immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of physical

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25 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

26 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.

27 The methodology is based on Imbalance Reserve product proposed as part of the California ISO day-ahead market enhancements initiative (DAME). More information on the results of this change can be found in the California ISO presentation *Market Performance and Planning Forum Q3*, September 27, 2023, slides 210-227: https://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Sep27-2023.pdf

supply cleared in the day-ahead market and the amount of physical supply that may be needed to meet actual real-time demand.

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 1.21 shows the average incremental residual unit commitment requirement by component relative to the day-ahead market.

The green bars reflect the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply gradually increased each month from 100 MW per hour in January to about 480 MW per hour in March.

The blue bar in Figure 1.21 depicts 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 CAISO 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 40 MW per hour in the first quarter of 2024, down from about 280 MW in 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 1.21.

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 1.21 show the average adjustment to the residual unit commitment requirement.

Figure 1.22 shows the hourly distribution of these operator adjustments during the first quarter of 2024. The black line shows the average adjustment quantity in each hour, and the red markers highlight outliers in each hour.

Figure 1.21 Average incremental residual unit commitment requirement by component

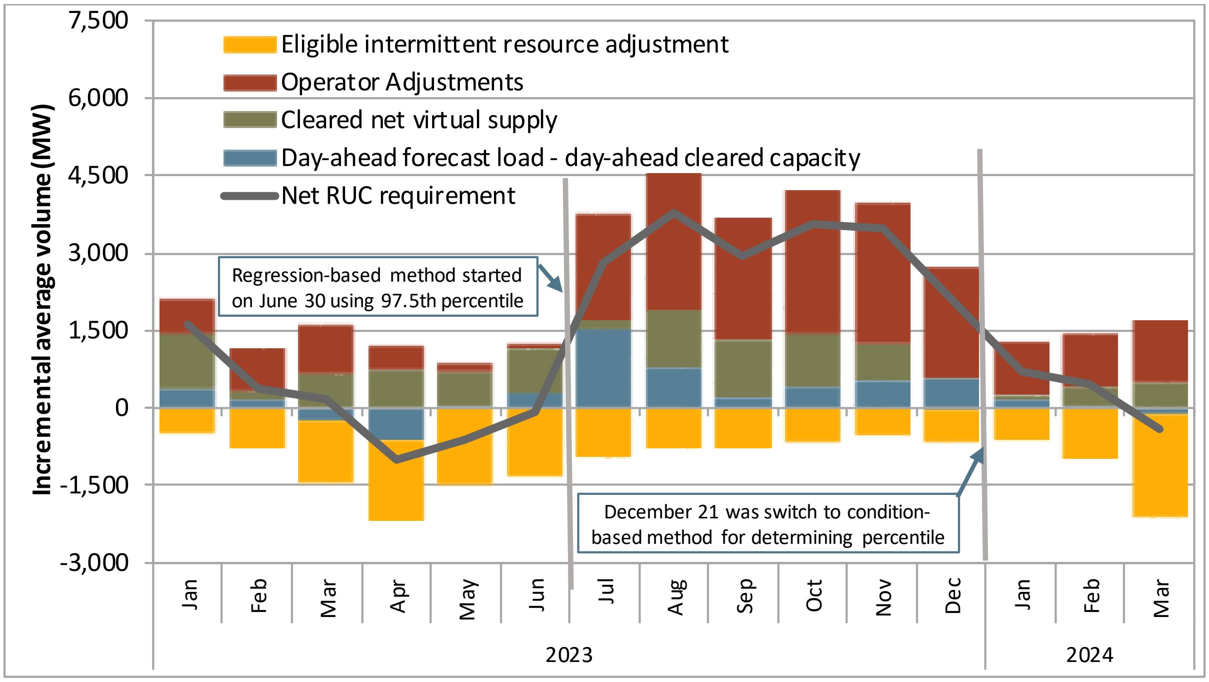
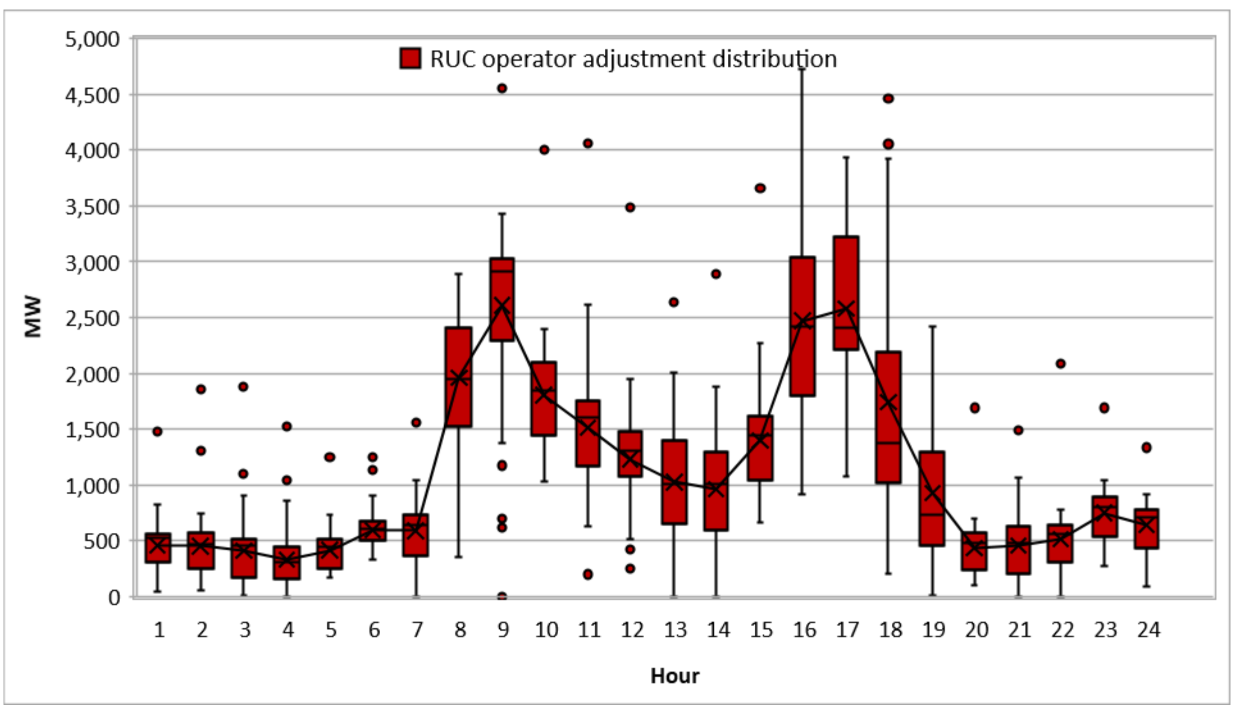


Figure 1.22 Hourly distribution of residual unit commitment operator adjustments (January–March 2024)



Starting on June 30, 2023, the ISO began using the *mosaic quantile regression* method to calculate the RUC adjustments. This calculation is similar to that used to measure flexible ramping product uncertainty, except that it is based on the historical difference between the *day-ahead* and real-time market forecasts for load, solar, and wind uncertainty. This calculation was originally based on the 97.5th percentile of net load uncertainty that might materialize in real-time.

On December 21, the ISO implemented a new operating procedure that modifies the percentile target for calculating the adjustment based on conditions in the system. Under *normal* conditions, the RUC adjustments are calculated based on the 50th percentile of upward net load uncertainty. Operators can adjust the calculation any day to instead be based on the 75th or 97.5th percentile during periods of higher forecast uncertainty or extreme conditions.[28]

Figure 1.23 shows the average RUC adjustment on each day between December 2023 and March 2024. The figure also shows what percentile was used to determine the additional requirements for each day.[29] On January 13th, during the cold-weather event, the 97.5th percentile was used to calculate the RUC adjustments, resulting in an average adjustment for the day of over 2,400 MW. On all other days since the change on December 21, the 50th or 75th percentile targets were used. 69 percent of days between December 21 and March 31 used the 75th percentile, resulting in an adjustment to the residual unit commitment requirement of around 1,200 MW on average across all hours during these days. The 50th percentile was instead used during 30 percent of days during this period, resulting in an adjustment of around 700 MW on average.

On May 7, 2024, the ISO adjusted the operating procedure again for calculating the adjustments used in the residual unit commitment process.[30] The changes limited the adjustments to only the peak morning and peak evening hours as well as added percentile options below the 50th percentile. Under periods with moderate operational uncertainty, the procedure calls for using a RUC adjustment that will only procure enough capacity to cover uncertainty 50 percent of the time (i.e., the 50th percentile of upward uncertainty). During periods with low or very low operational uncertainty, the procedure instead specifies use of either the 25th percentile or no adjustment, respectively. This indicates that there is still

28 See California ISO Operating Procedure 1210, January 1, 2024, pp 12-13: https://www.caiso.com/Documents/1210.pdf

29 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

30 See California ISO Operating Procedure 1210, May 7, 2024, pp 12-13: https://www.caiso.com/Documents/1210.pdf

a substantial degree of judgment and discretion used in setting the RUC adjustment, even when using the mosaic quantile regression method to calculate the uncertainty component.

Given the importance of RUC adjustments in terms of costs and reliability, DMM recommends that the CAISO balancing area continue working on a method for determining the appropriate level of RUC load adjustment.

Figure 1.23 Average residual unit commitment adjustment by day (December 1, 2023 to March 31, 2024)

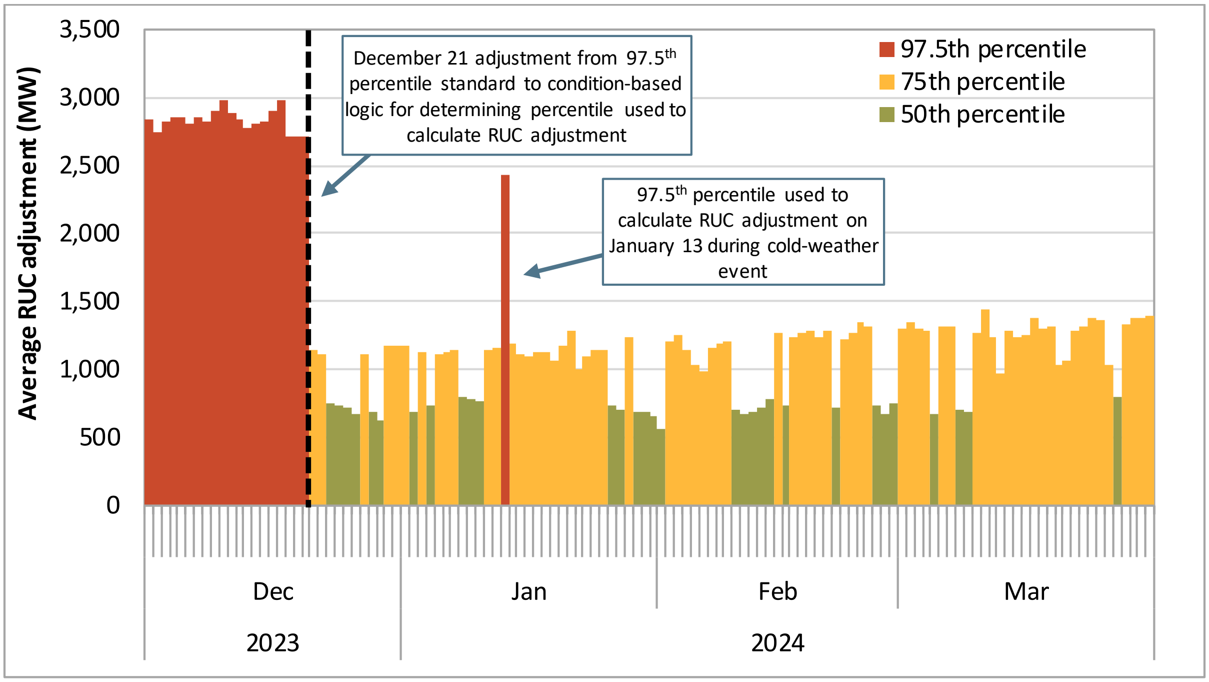
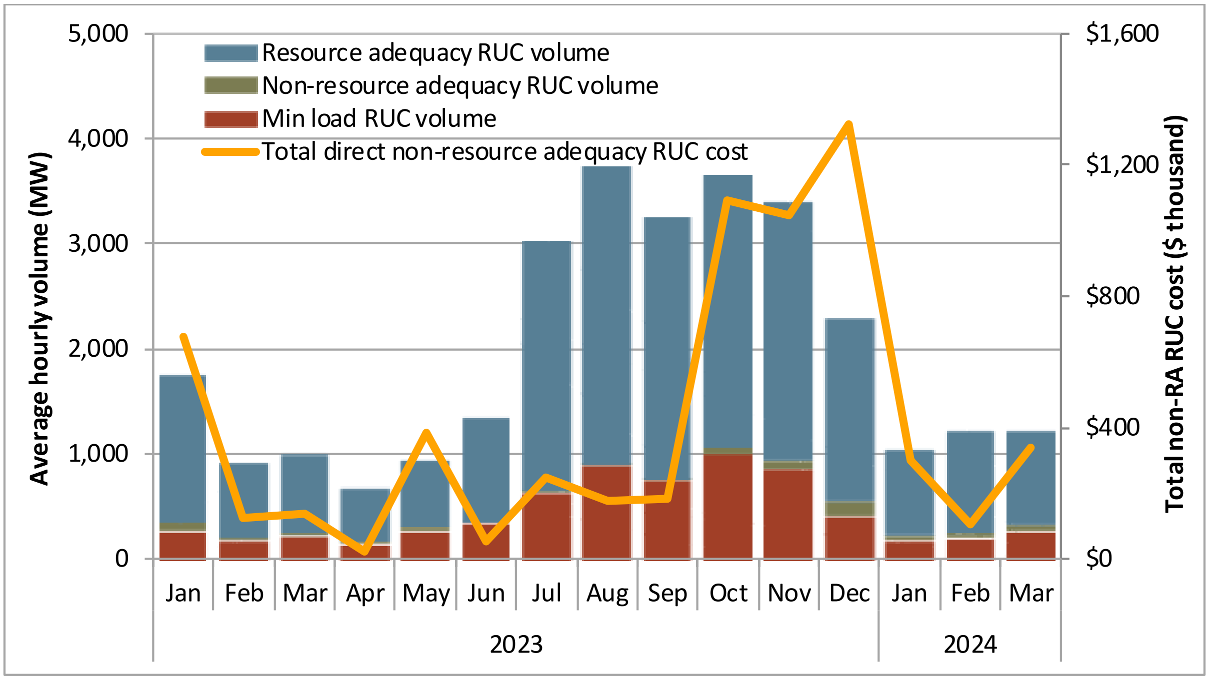


Figure 1.24 shows the monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The average residual unit commitment procurement for the quarter decreased by 6 percent to about 1,150 MW in the first quarter of 2024 from an average of about 1,220 MW in the same quarter of 2023. Of the 1,150 MW capacity, the capacity committed to operate at minimum load averaged 225 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.[31] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.24. In the first quarter of 2024, these costs were about $750,000, about 80 percent of the costs in the same quarter of 2023.

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

Figure 1.24 Residual unit commitment costs and volume



1.6 Ancillary services

Ancillary service payments totaled $20.7 million, a 48 percent decrease from the same quarter last year. Average requirements were higher for regulation down and regulation up, while those for operating reserves remained the same compared to the first quarter of 2023.

1.6.1 Ancillary service requirements

The California ISO procures four ancillary services 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.[32] 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

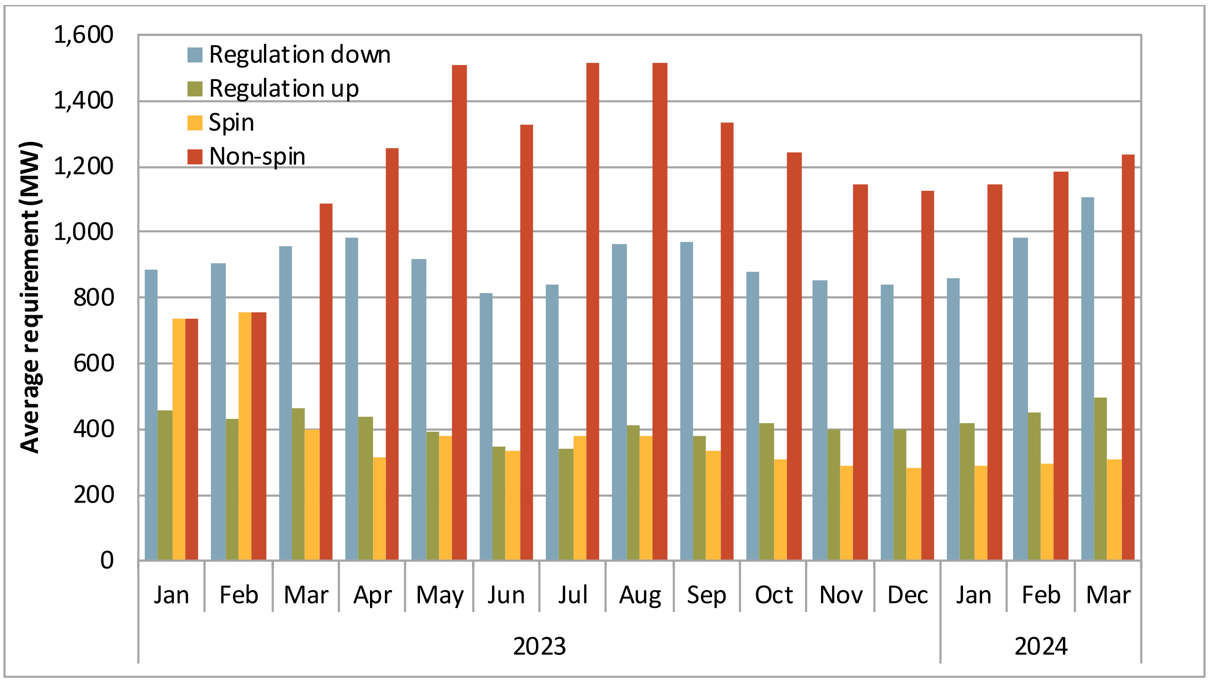
32 More information on ancillary services requirements and procurement for internal and expanded regions is available in: *2020 Annual Report on Market Issues & Performance*, Department of Market Monitoring, August 2021, p 161: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

(3) 10 percent of forecasted solar production.[33] 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. In the first quarter of 2024, CAISO operators procured 20 percent of operating reserves as spinning reserves and the rest as non-spinning reserves.

Figure 1.25 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation down and regulation up requirements increased 7 percent and 1 percent, respectively, compared to the first quarter of 2023. Average requirements for spinning and non-spinning reserves changed drastically, year-over-year, due to CAISO operators' change in procurement targets in the first quarter of 2023. However, average total operating reserve requirements did not change significantly compared to the first quarter of 2023.

Figure 1.25 Average monthly day-ahead ancillary service requirements



1.6.2 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

33 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.

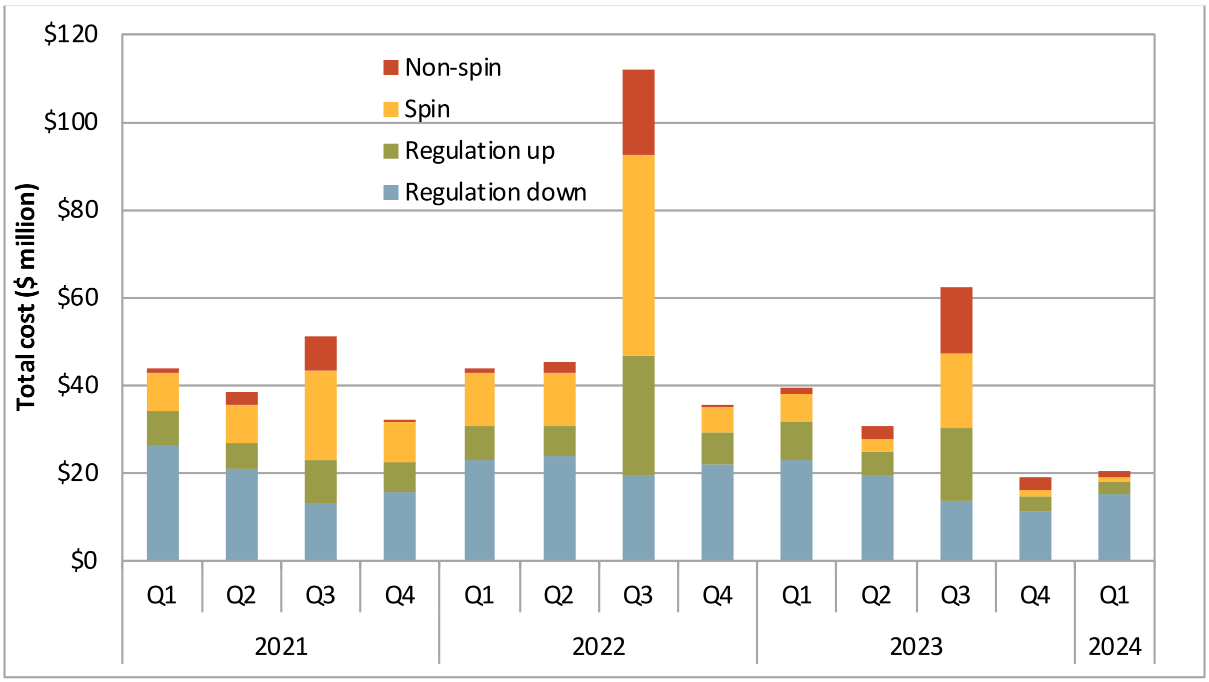
prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger. No scarcity events occurred in the first quarter of 2024.

1.6.3 Ancillary service costs

Ancillary service payments totaled $20.7 million in the first quarter of 2024, around $19 million less than the same quarter of the previous year.

Figure 1.26 shows the total cost of procuring ancillary service products by quarter.[34] Payments for regulation down, regulation up, and spinning reserve decreased 33 percent, 65 percent, and 88 percent, respectively, compared to the first quarter of 2023. Regulation down payments had the largest absolute decrease, at around $7.7 million. Non-spinning reserve payments increased around 5 percent compared to the first quarter of 2023.

Figure 1.26 Ancillary service cost by product



[34] 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.

1.7 Congestion

This section presents analysis of the effect of internal congestion on both day-ahead and real-time markets within the California ISO balancing area.[35] Additionally, it examines the impact of day-ahead congestion on interties. Detailed analysis of WEIM transfer congestion impact is addressed in Section 2.3.

Total congestion rent decreased to $258 million in the first quarter of 2024, down from $280 million in the same quarter of 2023. Although the total congestion rent decreased compared to the first quarter of 2023, intertie congestion rent significantly increased from $14 million to $133 million.

The substantial increase in intertie congestion was due to severe weather and higher demand in the Pacific Northwest during January 2024. This, combined with an outage on the NOB intertie, led to significant congestion rents on the Malin intertie.

In the first quarter of 2024, congestion on internal constraints had a greater impact on local area price separation than in the same quarter of 2023. In the day-ahead market, internal congestion on average increased prices in PG&E and decreased pries in SCE and SDG&E. In the real-time market, congestion decreased prices in balancing authority areas (BAAs) in California and the Desert Southwest,, and increased prices in the Intermountain West and Pacific Northwest. This was heavily influenced by the severe weather conditions and transmission outages in January.

The following sections provide an assessment of the frequency and impact of congestion on prices in the day-ahead, 15-minute, and 5-minute markets. It assesses the impact of congestion on local areas in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric).

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.

The impact of congestion on each pricing node in the California ISO system is calculated as the product of the shadow price of that constraint, and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[36]

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35 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.

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

1.7.1 Congestion in the day-ahead market

Congestion rent and loss surplus

Figure 1.27 shows that in the first quarter of 2024, congestion rent and loss surplus were $258 million and $28 million, respectively. These amounts represent a decrease of 8 percent and 68 percent, respectively, relative to the same quarter of 2023. The significant reduction in the loss component was attributed to lower prices and load in this quarter compared to the same quarter in 2023.

Congestion rent consists of rents from internal constraints and interties. Intertie congestion significantly increased from $14 million in the first quarter of 2023 to $133 million in the first quarter of 2024. Most of this intertie congestion rent came from export congestion from California to the Pacific Northwest. Meanwhile, the internal congestion rent, shown as the blue bar, decreased compared to Q1 2023.

In the day-ahead market, hourly congestion rent collected on a constraint is 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 68 percent decrease in the loss surplus compared to Q1 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.[37]

[37] 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

Figure 1.27 Day-ahead congestion rent and loss surplus by quarter (2022–2024)

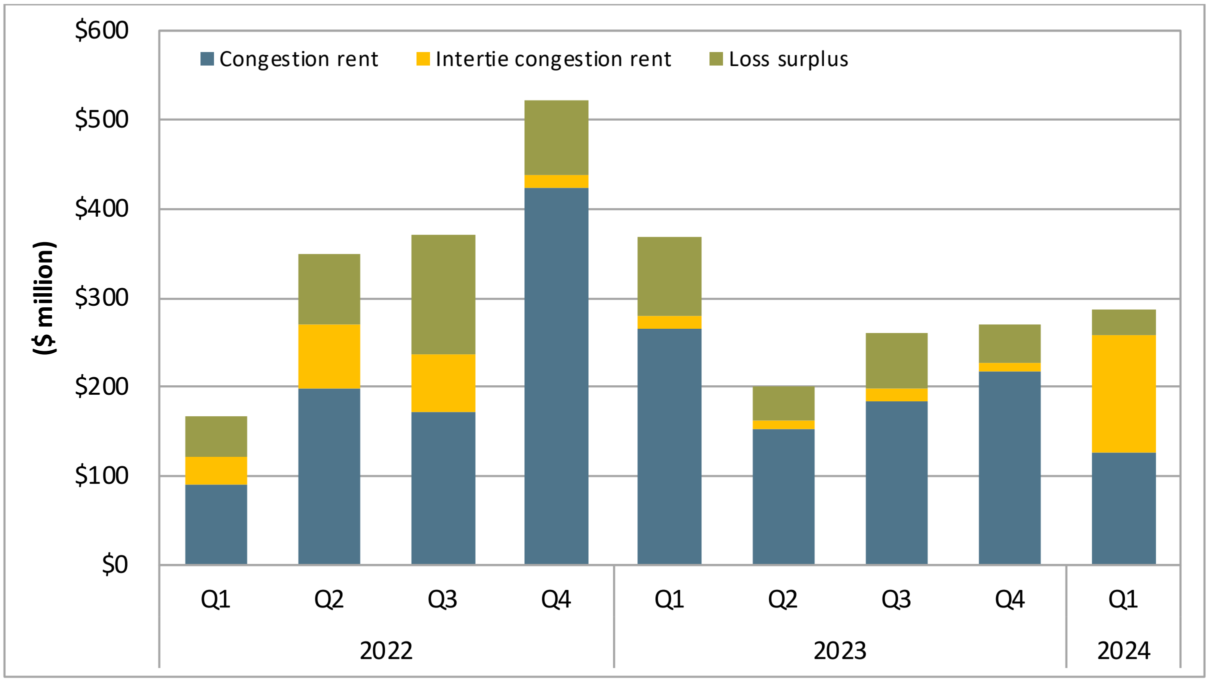


Figure 1.28 shows the overall impact of congestion on day-ahead prices in each load area from 2022 to 2024. Figure 1.29 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in this quarter was higher than during the same quarter of 2023.
- Day-ahead congestion increased quarterly average prices in PG&E by $5.58/MWh, while it decreased average SCE and SDG&E prices by $4.99/MWh and $3.1/MWh, respectively.[38]
- The primary constraints affecting day-ahead market prices were the Tesla-Los Banos #1 500 kV line, Gates-Midway #1 500 kV line, and Moss Landing-Las Aguilas #1 230 kV line.

38 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 1.28 Overall impact of congestion on price separation in the day-ahead market

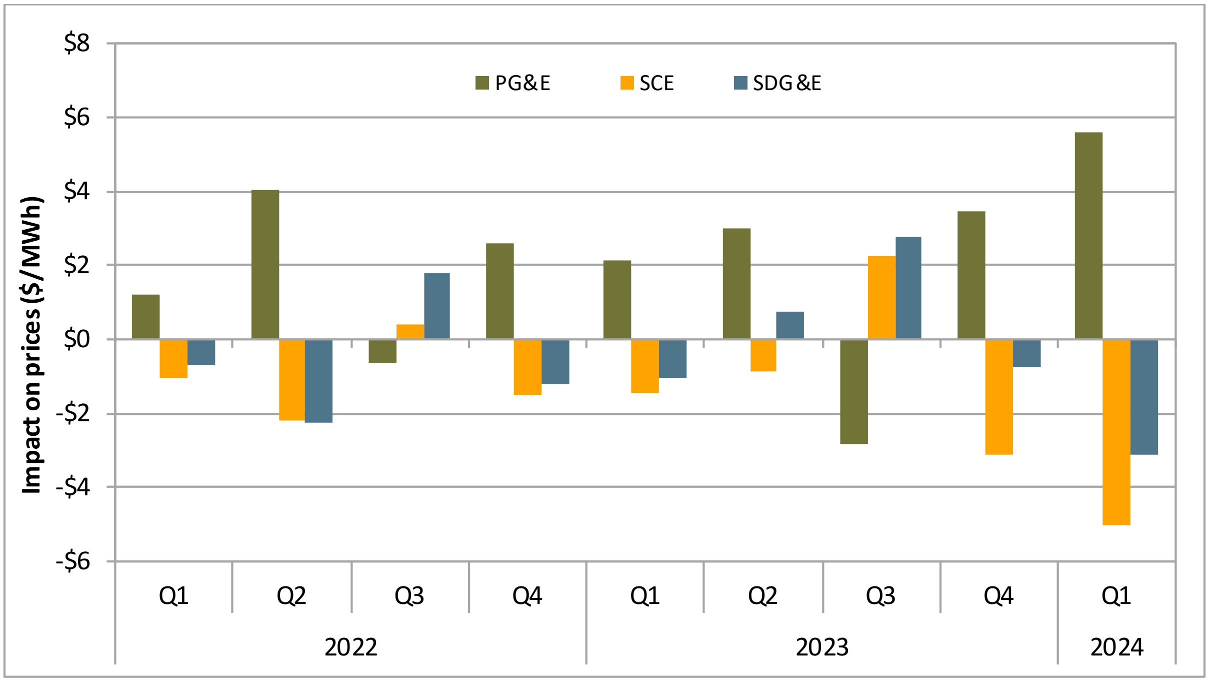
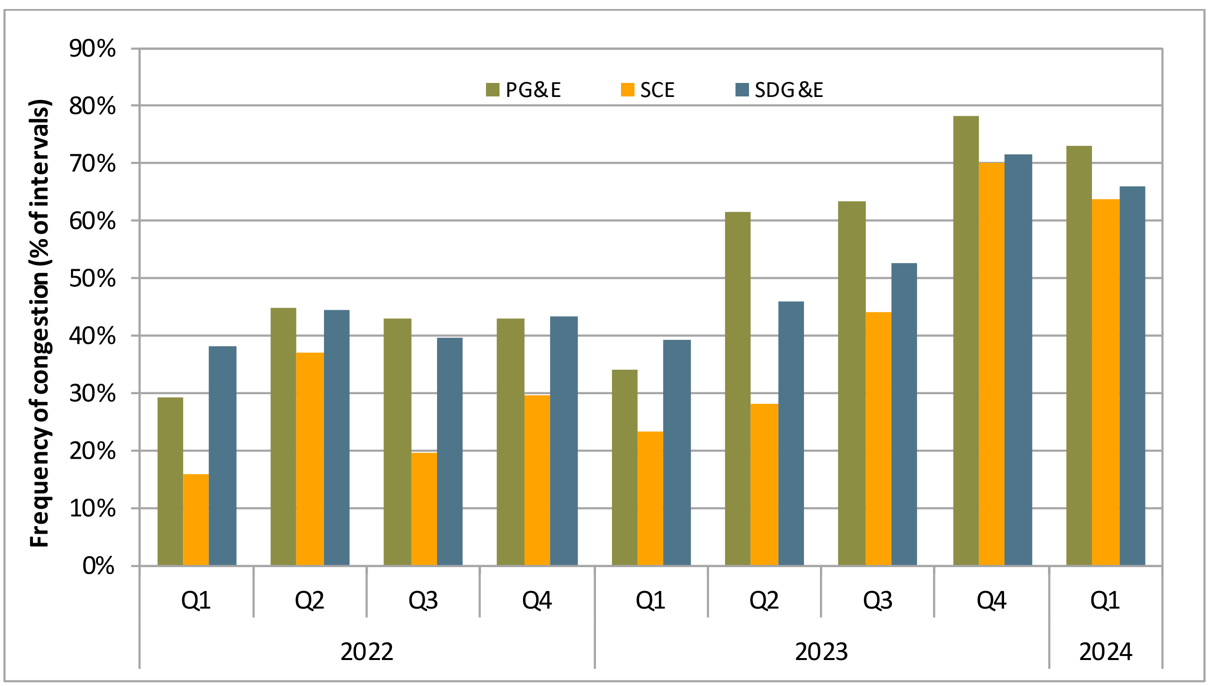


Figure 1.29 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion effect on price separation during the quarter by constraint.[39] 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 Tesla-Los Banos #1 500 kV line, Gates-Midway #1 500 kV line, and Moss Landing-Las Aguilas #1 230 kV line.

Tesla-Los Banos #1 500 kV line

The Tesla-Los Banos #1 500 kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) had the greatest impact on day-ahead prices during the first quarter. The line was congested during 16.8 percent of hours. For the quarter, congestion on the line increased average PG&E prices by $2.03/MWh, and decreased average SCE and SDG&E prices by $1.71/MWh and $1.57/MWh, respectively. This transmission line frequently reached its limits during solar production hours, from hour-ending 9 through hour-ending 16.

Gates-Midway #1 500 kV line

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) bound in 14.2 percent of hours over the quarter. For the quarter, congestion on the constraint increased average PG&E prices by $1.91/MWh and decreased average SCE and SDG&E prices by $1.69/MWh and $1.59/MWh, respectively. This transmission line was generally binding during solar production hours, from hour-ending 9 through hour-ending 15.

Moss Landing-Las Aguilas #1 230 kV line

The Moss Landing-Las Aguilas #1 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in about 17.3 percent of hours. For the quarter, the constraint increased average PG&E prices by about $1.12/MWh, and decreased average SCE and SDG&E prices by $0.9/MWh and $0.85/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 10 through hour-ending 16.

Additionally, it is important to highlight that various constraints contributed to an increase in SDG&E prices. These lines are situated in or linked to the Imperial Valley (IV), a region densely populated with solar power plants, and facilitate the flow of electricity from the Imperial Valley to the metropolitan area within the SDG&E region.

[39] 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 LAPs in the region are grouped in "*Other*".

Table 1.2 Impact of congestion on overall day-ahead prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	16.8%	2.03	-1.71	-1.57
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	14.2%	1.91	-1.69	-1.59
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	17.3%	1.12	-0.90	-0.85
7820_TL50002_IV-NG-OUT_TDM	3.0%	-0.07	-0.03	0.53
30790_PANOCHE_230_30900_GATES_230_BR_2_1	5.7%	0.15	-0.13	-0.12
7820_TL230S_OVERLOAD_NG	4.7%	-0.03	-0.01	0.25
OMS_14830999_IV-SXOutage_NG	0.6%	-0.03	-0.01	0.20
OMS14513059LOSBNS_BUS_OUTAGE	0.5%	0.09	-0.07	-0.07
7820_TL23040_IV_SPS_NG	3.8%	-0.03	-0.01	0.17
OMS_14831000_IV-SXOutage_NG	0.6%	-0.02	-0.01	0.14
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	1.1%	0.06	-0.05	-0.05
24801_DEVERS_500_24804_DEVERS_230_XF_2_P	4.9%	-0.01	0.03	-0.12
30055_GATES1_500_30900_GATES_230_XF_11_P	5.3%	0.04	-0.04	-0.03
35107_DUMBARTN_115_35120_NEWARKD_115_BR_1_1	12.1%	-0.04	0.03	0.03
OMS50004IV-MLOUTAGE_NG	0.6%	-0.01	0.00	0.08
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	0.9%	-0.01	0.00	0.07
OMS_14973100_IV-SXOutage_NG	0.6%	-0.01	0.00	0.07
24801_DEVERS_500_24804_DEVERS_230_XF_1_P	6.6%	-0.01	0.01	-0.05
HUMBOLDT_IMP_NG	38.6%	0.03	-0.02	-0.02
30515_WARNERVL_230_30800_WILSON_230_BR_1_1	1.1%	0.02	-0.02	-0.02
22357_IVPFC1_230_22358_IVPFC_230_PS_1	0.9%	-0.01	0.00	0.05
32056_CORTINA_60.0_30451_CRTNAM_1.0_XF_1	3.7%	0.02	-0.02	-0.02
7820_13810A_RAS_MS-SA_NG	0.5%	0.00	0.01	-0.04
33020_MORAGA_115_32790_STATINX_115_BR_3_1	5.5%	0.01	-0.02	-0.02
OMS15410670TL13810NG	0.5%	0.00	0.01	-0.03
Other	0.6%	0.38	-0.33	-0.10
Total		5.58	-4.99	-3.10

1.7.2 Congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across WEIM.[40] 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 are discussed in greater depth in Section 2.3.

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

Internal congestion in the real-time market followed seasonal trends in solar production and load. Days when there is high load and low solar typically see congestion in the north-to-south direction, while low load and high solar days see congestion in the south-to-north direction.

Figure 1.30 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAP) and EIM load aggregation points (ELAP) in the first quarter of 2024. The blue bars represent the 15-minute price impact, and the yellow bars indicate the 5-minute price impact from internal constraints.

The average impact of congestion in the real-time markets suggested a south-to-north congestion pattern. This results in increased prices in BAAs in the Intermountain West and the Pacific Northwest, while prices of BAAs in California and the Desert Southwest decreased.

This pattern was most affected by severe weather conditions in the Pacific Northwest, along with transmission outages. The Pacific Northwest experienced record-setting cold temperatures, which lead to increased demand in the area. Due to the severe weather, there were various forced outages on transmission lines in Oregon, severely limiting the capacity to transfer electricity from other regions. This led to high congestion.

Figure 1.30 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (January–March 2024)

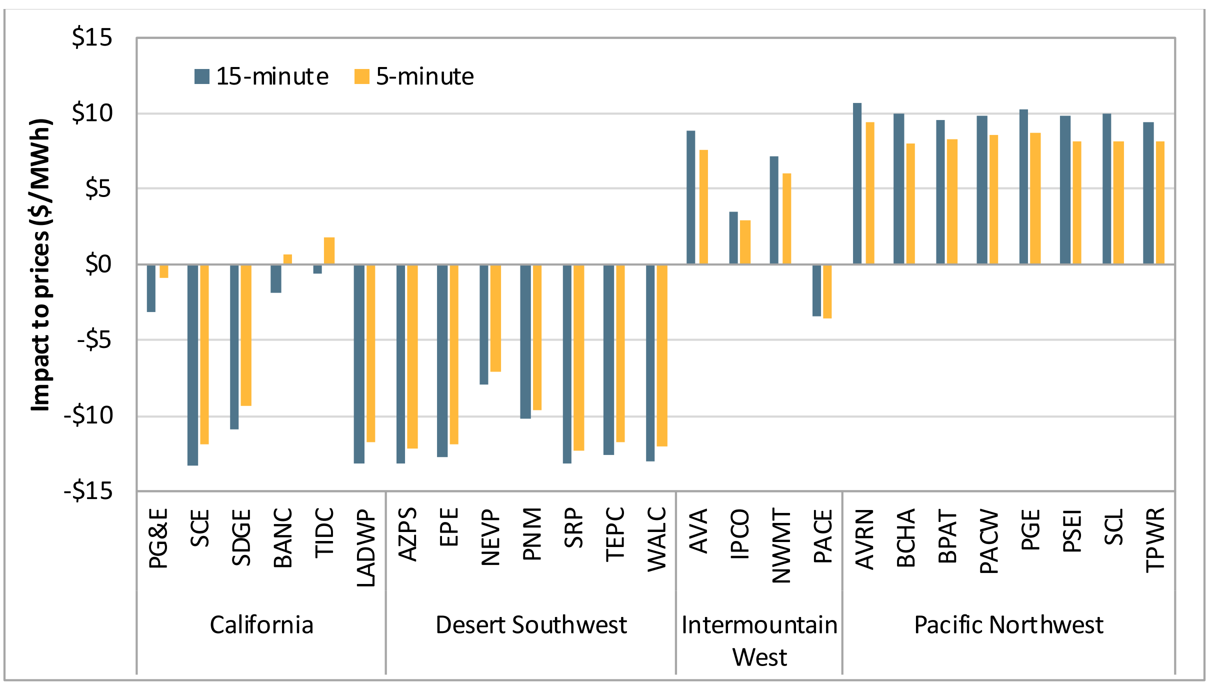


Figure 1.31 displays the average impact of internal congestion on prices in the first quarter of 2023 and 2024. The blue bars represent the impact for 2023, and the red bars show the impact for 2024. This impact was calculated as the average of the 15-minute and 5-minute price impacts of internal constraints for all intervals.

In the first quarter of 2024, the congestion pattern was more straightforward than Q1 2023, with regional-level price increases in the Pacific Northwest and Intermountain West, and decreases in the rest of the WEIM areas. In contrast, the first quarter of 2023 showed more variation within regions. The Desert Southwest consistently had a negative impact due to high solar production, which led to congestion as it traveled to the rest of WEIM.

Figure 1.31 Average impact of internal congestion on real-time market price (2023-2024)

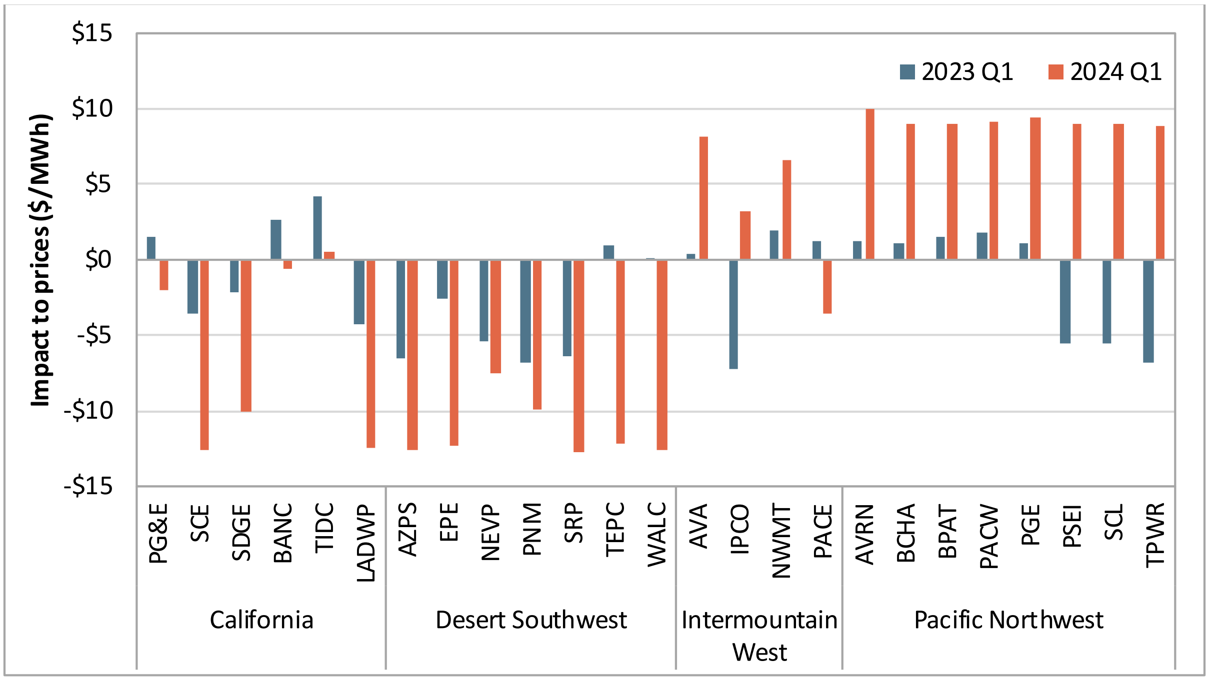


Figure 1.32 and Figure 1.33 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the first quarter of 2024 and 2023, respectively. In the first quarter of 2023, the hourly congestion pattern related to solar production showed price separation from southern areas to northern areas between hours-ending 9 and 17. In the evening, when the sun went down, congestion increased prices in California balancing authority areas.

In the first quarter of 2024, the pattern during solar hours remained similar, but the price impact was much greater. In the post-solar evening hours, congestion continued to increase prices in the Pacific Northwest and Intermountain West, compared to the Desert Southwest and California.

PacifiCorp East was an outlier, as this area experienced a negative impact from internal congestion during most hours. Limited transmission capacity hindered the delivery of less expensive energy out of the region.

Figure 1.32 Overall impact of internal congestion on price separation in the 15-minute market by hour (January–March 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	-0.6	-2.6	-0.6	0.7	0.4	0.3	0.4	2.1	1.0	2.5	-2.7	-4.1	-3.1	-2.7	0.2	-4.6	-11.6	-11.0	-12.1	-10.6	-8.3	-6.8	0.1	-1.7
BANC	-1.2	-3.1	-1.3	0.1	-0.3	0.0	0.1	2.1	2.7	6.6	2.8	0.8	1.2	1.9	5.3	-0.1	-9.7	-11.2	-12.8	-11.0	-8.7	-7.2	-0.3	-2.3
Turlock ID	-1.1	-3.0	-1.3	0.1	-0.3	0.1	0.2	2.4	4.2	9.3	6.3	4.7	5.1	5.6	9.1	2.7	-8.0	-10.1	-12.5	-10.8	-8.5	-7.0	-0.2	-2.2
SCE	-0.7	-2.5	-1.1	0.1	-0.3	0.3	0.2	-3.0	-16.8	-24.7	-33.8	-36.1	-34.3	-33.2	-31.2	-27.8	-22.2	-13.7	-12.7	-11.1	-8.9	-5.7	0.3	-1.6
SDG&E	1.4	-0.8	0.3	1.2	1.3	1.3	0.7	-1.4	-12.2	-20.8	-29.8	-32.8	-30.4	-29.6	-26.3	-23.8	-19.0	-10.9	-11.1	-9.7	-7.7	-3.4	3.1	-0.2
LADWP	0.1	-2.6	-1.3	-0.1	-0.5	0.0	0.0	-3.4	-16.7	-24.1	-33.1	-35.3	-33.6	-32.5	-30.5	-27.3	-21.9	-13.6	-12.4	-11.0	-8.7	-5.8	0.0	-1.7
NV Energy	-0.9	-1.9	-0.9	-0.1	-0.4	0.0	-0.1	-2.5	-10.7	-13.8	-19.0	-20.2	-18.9	-18.4	-16.9	-16.1	-14.0	-9.3	-8.1	-7.6	-6.2	-4.2	-0.2	-1.3
Arizona PS	-1.7	-2.9	-1.7	-0.5	-0.9	-0.1	0.8	-4.8	-18.3	-24.4	-32.7	-34.7	-32.5	-31.8	-30.4	-27.3	-20.7	-13.2	-11.1	-9.7	-7.8	-5.6	-1.0	-1.9
Tucson Electric	-1.6	-2.8	-1.6	-0.7	-1.1	-0.5	-0.7	-4.6	-17.4	-23.4	-31.5	-33.5	-31.4	-30.6	-29.0	-25.8	-19.4	-12.3	-10.6	-9.2	-7.4	-5.3	-0.9	-1.8
Salt River Project	-1.6	-2.9	-1.7	-0.6	-0.9	-0.3	-0.5	-5.0	-18.5	-24.4	-32.8	-34.7	-32.6	-31.9	-30.5	-27.3	-20.7	-13.2	-11.1	-9.9	-7.8	-5.5	-1.0	-1.8
PSC New Mexico	-0.3	-1.8	-0.8	0.0	-0.4	0.1	0.5	-3.5	-14.2	-19.2	-26.3	-28.2	-26.6	-26.1	-24.3	-21.4	-16.1	-10.0	-8.8	-7.1	-5.6	-3.7	0.2	-0.5
WAPA - Desert SW	-1.7	-2.9	-1.7	-0.6	-1.0	-0.3	-0.5	-4.8	-18.0	-24.0	-32.3	-34.2	-32.2	-31.4	-30.0	-26.8	-20.4	-13.0	-11.0	-9.6	-7.7	-5.5	-0.9	-1.9
El Paso Electric	-3.1	-5.0	-4.3	-3.1	-3.4	-2.7	-2.1	-5.3	-17.2	-22.0	-29.5	-31.6	-29.4	-28.6	-27.1	-24.2	-18.2	-11.8	-10.6	-9.6	-8.2	-5.9	-1.7	-2.9
PacifiCorp East	-2.8	-2.8	-2.9	-2.7	-2.4	-2.5	-2.7	-3.0	-4.6	-4.8	-5.5	-5.7	-5.4	-5.3	-4.8	-4.4	-3.1	-2.3	-2.0	-2.1	-2.2	-2.1	-2.3	-2.3
Idaho Power	0.4	1.3	0.5	0.0	0.2	-0.1	-0.1	0.7	3.4	5.0	6.9	6.7	6.1	6.3	6.4	6.8	7.5	6.1	6.2	5.3	4.4	3.1	0.1	0.9
NorthWestern	0.8	2.3	1.0	0.0	0.3	-0.1	-0.1	1.6	8.1	10.9	15.3	15.5	14.3	14.3	14.0	14.4	14.3	10.7	10.6	9.2	7.4	5.2	0.1	1.5
Avista Utilities	1.0	2.7	1.2	0.0	0.3	-0.1	-0.1	2.1	10.0	13.7	19.2	19.5	18.0	18.0	17.4	17.8	17.4	12.8	12.7	11.0	8.9	6.2	0.1	1.7
Avangrid	1.2	3.3	1.5	0.0	0.4	-0.1	-0.1	2.7	12.2	17.4	24.2	22.8	19.5	22.2	21.8	21.6	21.3	15.8	15.4	13.3	10.9	7.5	0.1	2.1
BPA	1.0	2.9	1.3	0.0	0.4	-0.1	-0.1	2.3	11.1	14.9	20.8	21.7	20.2	20.0	19.1	19.6	18.7	13.8	13.6	11.8	9.5	6.6	0.1	1.9
Tacoma Power	1.0	2.9	1.3	0.0	0.4	-0.1	-0.1	2.3	11.0	14.8	20.6	21.2	19.5	19.5	18.8	19.2	18.5	13.7	13.5	11.7	9.5	6.6	0.1	1.9
PacifiCorp West	1.0	3.0	1.3	0.0	0.4	-0.1	-0.1	2.4	10.8	15.5	21.6	21.6	20.0	20.1	19.7	19.7	19.1	14.2	14.0	12.0	9.9	6.8	0.1	1.9
Portland GE	1.0	3.0	1.3	0.0	0.4	-0.1	-0.1	2.4	11.5	15.3	21.3	24.2	23.2	22.4	21.0	22.2	18.9	14.0	13.8	11.9	9.8	6.8	0.1	1.9
Puget Sound Energy	1.0	2.9	1.2	0.0	0.4	-0.1	-0.1	2.3	12.1	15.0	21.0	22.2	20.7	20.4	19.1	20.0	19.1	13.8	13.6	12.0	9.4	6.5	0.1	1.9
Seattle City Light	1.0	2.9	1.2	0.0	0.4	-0.1	-0.1	2.3	13.0	15.1	21.2	22.7	21.0	20.6	19.2	20.5	19.5	14.0	13.7	12.2	9.4	6.5	0.1	1.8
Powerex	1.0	2.8	1.2	0.0	0.4	-0.1	-0.1	2.2	13.6	14.9	21.1	22.9	21.2	20.8	19.1	20.7	19.6	13.9	13.7	12.2	9.3	6.4	0.1	1.8

Hour

Figure 1.33 Overall impact of internal congestion on price separation in the 15-minute market by hour (January–March 2023)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	-0.1	-0.1	-0.1	-0.2	-0.4	-1.9	-3.6	0.9	3.1	4.6	4.8	5.9	5.0	4.1	4.7	3.4	2.8	0.4	1.5	-0.4	-0.9	-1.1	-0.2	-0.2
BANC	-0.1	-0.2	-0.1	-0.2	-0.4	-1.9	-3.4	0.4	3.7	7.6	8.6	9.8	9.5	8.4	8.7	5.6	2.7	0.1	-0.2	-0.6	-0.9	-1.0	-0.4	-0.2
Turlock ID	-0.1	-0.1	-0.1	-0.2	-0.3	-1.9	-3.4	1.3	5.2	11.8	13.6	14.9	14.0	12.8	12.9	8.9	4.5	1.2	1.9	-0.6	-0.6	-1.0	-0.3	-0.1
SCE	0.6	0.5	0.6	0.4	0.6	2.2	4.2	0.1	-3.0	-8.8	-12.1	-15.0	-15.6	-14.5	-14.8	-9.9	-2.5	1.3	1.5	2.1	1.7	2.4	1.3	0.8
SDG&E	1.1	0.9	0.9	0.9	1.2	2.9	4.4	2.0	0.6	-6.8	-8.8	-13.3	-14.4	-13.9	-13.2	-7.4	-0.5	3.6	3.9	4.7	4.0	3.7	2.2	1.3
LADWP	0.0	0.1	-0.1	-0.1	0.3	2.1	3.8	0.0	-2.2	-8.9	-12.2	-15.2	-15.7	-12.1	-13.5	-8.5	-3.1	0.0	-0.4	0.9	1.2	0.7	0.4	0.4
NV Energy	-0.2	0.0	-0.1	-0.2	0.1	1.1	1.9	-1.1	-3.2	-5.0	-5.9	-7.4	-7.6	-7.3	-7.1	-4.8	-2.1	-0.9	-1.3	-0.3	0.5	0.1	0.1	0.2
Arizona PS	-0.4	-0.4	-0.5	-0.3	0.1	1.4	3.0	-3.3	-10.0	-14.6	-17.4	-20.0	-20.8	-20.3	-19.8	-14.0	-7.0	-2.9	-1.9	-0.8	0.1	0.1	-0.3	-0.2
Tucson Electric	-0.4	-0.5	-0.7	-0.3	0.0	1.4	2.9	-3.2	-9.6	-14.2	-17.0	-19.2	-20.0	-19.5	-19.0	-13.6	-6.8	-3.2	-2.2	-1.4	-0.3	-0.4	-0.6	-0.5
Salt River Project	-0.4	-0.4	-0.5	-0.3	0.0	1.4	3.0	-3.5	-10.5	-15.1	-17.8	-20.4	-21.2	-20.8	-20.3	-14.5	-7.3	-3.1	-2.0	-0.9	0.1	0.1	-0.3	-0.2
PSC New Mexico	-0.4	-0.8	-0.5	-0.2	0.0	1.2	2.5	-2.8	-8.0	-11.0	-13.6	-15.5	-16.1	-15.5	-15.2	-11.2	-5.5	-2.9	-2.2	-1.5	-0.5	-0.7	-1.6	-1.3
WAPA - Desert SW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
El Paso Electric	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PacifiCorp East	-6.1	-6.2	-6.2	-6.7	-6.8	-6.8	-7.5	-7.6	-7.3	-7.0	-7.0	-7.1	-7.6	-7.7	-7.9	-8.2	-7.3	-7.8	-8.1	-7.3	-7.0	-6.7	-6.6	-5.9
Idaho Power	-0.1	0.0	0.0	0.0	-0.1	-0.5	-1.0	-0.2	0.2	0.8	1.1	1.1	0.3	-0.3	-0.2	-0.2	0.1	-0.4	-0.7	-0.6	-0.6	-0.5	-0.4	-0.2
NorthWestern	-0.1	0.0	-0.1	0.0	-0.2	-0.9	-1.7	-0.3	0.3	1.4	1.8	2.1	1.9	1.5	1.6	1.0	0.2	-0.6	-0.9	-0.9	-0.9	-0.8	-0.4	-0.2
Avista Utilities	-0.1	0.0	-0.1	0.0	-0.2	-1.1	-2.1	-0.4	0.7	2.3	3.2	4.2	4.2	3.8	3.8	1.9	0.4	-0.5	-0.8	-1.0	-1.0	-0.8	-0.4	-0.2
Avangrid	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA	-0.1	0.0	-0.1	0.0	-0.3	-1.2	-2.3	-0.3	0.9	2.6	3.6	4.7	4.7	4.2	4.3	2.5	0.9	-0.5	-0.8	-1.0	-1.1	-0.9	-0.4	-0.2
Tacoma Power	-0.1	0.0	-0.1	0.0	-0.2	-1.2	-2.2	-0.3	0.9	2.6	3.6	4.6	4.3	3.7	3.7	2.0	0.8	-0.5	-0.8	-1.0	-1.0	-0.9	-0.4	-0.2
PacifiCorp West	-0.1	0.0	-0.1	0.0	-0.3	-1.3	-2.4	-0.2	1.1	3.0	3.8	4.7	4.1	3.5	3.5	2.0	1.0	-0.5	-0.9	-1.0	-1.1	-0.9	-0.4	-0.2
Portland GE	-0.1	0.0	-0.1	0.0	-0.3	-1.2	-2.3	-0.3	1.1	2.7	3.7	4.6	3.8	3.0	3.2	1.5	1.0	-0.5	-0.9	-1.0	-1.1	-0.9	-0.4	-0.2
Puget Sound Energy	-0.1	0.0	-0.1	0.0	-0.2	-1.2	-2.2	-0.3	0.9	2.6	3.6	5.1	6.3	6.5	6.7	4.1	0.8	-0.5	-0.8	-1.0	-1.0	-0.9	-0.4	-0.2
Seattle City Light	-0.1	0.0	-0.1	0.0	-0.2	-1.2	-2.2	-0.3	0.9	2.6	3.5	5.4	7.7	8.4	8.8	5.7	0.8	-0.5	-0.8	-1.0	-1.0	-0.9	-0.4	-0.2
Powerex	-0.1	0.0	-0.1	0.0	-0.2	-1.2	-2.2	-0.3	0.8	2.6	3.5	5.6	8.8	10.0	10.4	6.8	0.7	-0.5	-0.8	-1.0	-1.0	-0.9	-0.4	-0.2

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

Table 1.3 and Table 1.4 show the quarterly impact of congestion from individual constraints on prices in the CAISO and WEIM areas, respectively, for the 15-minute market. The three constraints that had the greatest impact on price separation in the 15-minute market were California-Oregon Intertie (COI) nomogram, Gates-Midway #1 500kV line, and Tesla-Los Banos #1 500kV line.

California-Oregon Intertie (COI) nomogram

California-Oregon Intertie (COI) nomogram (6110_COI_S-N) was a major constraint on the south-to-north flow, leading to increased prices in Pacific Northwest and Intermountain West, and lower prices in California and the Desert Southwest. This nomogram, along with the nomogram named NWACI_SN, was used to manage the flow from California to Oregon. This nomogram was mostly binding in January when the Pacific Northwest experienced severe weather conditions and transmission outages. The average binding limit was 2,300 MW in January and decreased to 800 MW in March.

Gates-Midway #1 500kV line

The Gates-Midway #1 500kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) increased prices in Northern California, the Intermountain West, and the Pacific Northwest, while it decreased prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar hours from hours-ending 9 to 16.

Tesla-Los Banos #1 500kV line

The Tesla-Los Banos #1 500kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) increased prices in Northern California, the Intermountain West, and the Pacific Northwest, while it decreased prices in Southern California and the Desert Southwest. This line experienced congestion during solar hours from hours-ending 10 to 16.

WINDSTAREXPORTTCOR was a major constraint affecting PacifiCorp East (PACE). This line was binding in around 45 percent of intervals in the real-time market, increasing all CAISO default load aggregation point (DLAP) prices and decreasing the PACE price. The line primarily constrained the transfer of wind generation from PACE to the rest of the WEIM.

Table 1.3 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 25 primary congestion constraints (CAISO, January–March 2024)

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
6110_COI_S-N	3.1%	-5.88	-4.57	-4.33
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	14.1%	1.88	-3.06	-2.94
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	14.7%	0.78	-3.21	-3.06
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	14.9%	0.56	-1.47	-1.40
NWACI_SN	0.3%	-0.62	-0.47	-0.45
7820_TL230S_OVERLOAD_NG	4.9%	0.01	0.05	0.76
30005_ROUNDMT_500_30245_ROUNDMT_230_XF_1_P	3.7%	-0.29	-0.19	-0.18
30055_GATES1_500_30057_DIABLO_500_BR_1_1	0.8%	0.11	-0.17	-0.17
7820_TL50002_IV-NG-OUT_TDM	1.0%	0.01	0.03	0.41
INTNEL	0.6%	-0.15	-0.15	-0.15
30790_PANOCHE_230_30900_GATES_230_BR_2_1	3.9%	0.10	-0.16	-0.16
OMS14513059LOSBNS_BUS_OUTAGE	0.3%	0.05	-0.17	-0.16
WINDSTAREXPORTTCOR	47.9%	0.10	0.10	0.10
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	0.6%	0.01	0.02	0.18
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	0.6%	0.03	-0.08	-0.08
OMS14862147_ML_BK81_NG	0.8%	0.01	0.02	0.17
OMS50004IV-MLOUTAGE_NG	0.3%	0.01	0.02	0.16
MCL_PE_SHW_V682	0.3%	-0.06	-0.06	-0.06
99002_MOE-ELD_500_24042_ELDORDO_500_BR_1_2	2.4%	0.06	0.09	0.02
30055_GATES1_500_30060_MIDWAY_500_BR_1_3	0.3%	0.04	-0.06	-0.06
MIGUEL_BKs_MXFLW_NG	0.4%	0.00	0.02	0.13
OMS15244989_TL23054_NG	0.2%	0.01	0.02	0.12
24801_DEVERS_500_24804_DEVERS_230_XF_2_P	3.5%	0.10	0.03	-0.01
30055_GATES1_500_30900_GATES_230_XF_11_P	7.1%	-0.09	-0.02	-0.02
24801_DEVERS_500_24804_DEVERS_230_XF_1_P	4.6%	0.08	0.04	0.01
Other	2.7%	0.00	0.07	0.28
Total		-3.15	-13.35	-10.86

Table 1.4 Impact of internal transmission constraint congestion on 15-minute market prices during all hours (WEIM, January–March 2024)

Constraint location	Constraint	Average quarter impact ($/MWh)																					
		California			Desert Southwest							Intermountain West				Pacific Northwest							
		BANC	TIDC	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	Line_CH-LW_230KV	—	—	—	0.03	-0.06	—	-0.07	—	-0.03	—	—	—	—	—	—	—	—	—	—	—	—	—
	Line_CC-GT_230KV	—	—	—	0.05	0.01	—	0.02	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	NGXFMR1A69KV	—	—	—	—	—	—	—	-0.02	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPAT	NWACI_SN	-0.64	-0.64	-0.46	-0.40	-0.34	-0.34	-0.32	-0.40	-0.38	-0.39	0.51	0.26	0.43	0.03	0.62	0.53	0.54	0.56	0.55	0.54	0.53	0.54
	INTNEL	-0.15	-0.15	-0.15	-0.14	-0.14	-0.14	-0.14	-0.14	-0.14	-0.14	-0.01	-0.13	-0.01	-0.13	-0.16	0.69	0.00	-0.16	-0.17	0.27	0.51	-0.02
CISO	6110_COI_S-N	-6.13	-6.07	-4.46	-3.86	-3.36	-3.27	-3.13	-3.84	-3.67	-3.84	4.45	2.15	3.71	0.03	5.33	4.65	4.77	4.92	4.90	4.73	4.71	4.73
	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	2.35	2.38	-3.13	-2.74	-2.47	-1.71	-2.32	-2.73	-2.64	-2.73	1.76	0.65	1.40	-0.39	2.22	1.86	1.92	2.03	1.98	1.90	1.89	1.90
	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	2.21	2.29	-3.00	-2.65	-2.41	-1.73	-2.28	-2.64	-2.56	-2.64	1.41	0.40	1.08	-0.57	1.81	1.49	1.55	1.65	1.60	1.53	1.52	1.53
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	0.39	1.21	-1.43	-1.25	-0.90	-0.29	-0.66	-1.25	-1.15	-1.25	0.26	—	0.21	—	0.34	0.28	0.29	0.31	0.30	0.29	0.29	0.29
	30005_ROUNDMT_500_30245_ROUNDMT_230_XF_1_P	-0.51	-0.29	-0.18	-0.15	-0.12	-0.08	-0.11	-0.15	-0.14	-0.14	0.25	0.15	0.21	—	0.27	0.26	0.26	0.25	0.26	0.26	0.26	0.26
	24801_DEVERS_500_24804_DEVERS_230_XF_2_P	0.09	0.10	0.10	-0.37	-0.33	-0.07	-0.29	-0.39	-0.35	-0.31	—	—	—	-0.10	0.02	—	—	0.00	—	—	—	—
	30055_GATES1_500_30057_DIABLO_500_BR_1_1	0.14	0.14	-0.17	-0.14	-0.13	-0.08	-0.12	-0.14	-0.14	-0.15	0.08	0.03	0.06	-0.03	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09
	24801_DEVERS_500_24804_DEVERS_230_XF_1_P	0.07	0.07	0.08	-0.27	-0.24	-0.08	-0.21	-0.29	-0.25	-0.23	—	—	—	-0.07	0.03	—	—	—	—	—	—	—
	99002_MOE-ELD_500_24042_ELDORDO_500_BR_1_2	0.06	0.06	0.10	-0.20	-0.32	0.07	-0.38	-0.20	-0.23	-0.15	—	-0.02	—	-0.10	0.01	—	—	0.00	0.00	—	—	—
	OMS14513059LOSBNS_BUS_OUTAGE	0.07	0.08	-0.16	-0.09	-0.08	-0.06	-0.08	-0.09	-0.09	-0.09	0.05	0.01	0.04	-0.02	0.06	0.05	0.06	0.06	0.06	0.05	0.05	0.05
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	0.06	0.06	-0.08	-0.07	-0.06	-0.05	-0.06	-0.07	-0.07	-0.07	0.04	0.02	0.03	-0.01	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	0.09	0.10	-0.15	-0.10	-0.09	-0.02	-0.09	-0.10	-0.10	-0.10	0.00	—	—	—	0.06	0.01	0.02	0.03	0.02	0.02	0.02	0.02
	7820_TL230S_OVERLOAD_NG	—	0.00	0.00	-0.17	-0.13	-0.02	-0.05	-0.16	-0.15	-0.18	—	0.00	—	-0.02	—	—	—	—	—	—	—	—
	30055_GATES1_500_30060_MIDWAY_500_BR_1_3	0.05	0.05	-0.06	-0.05	-0.05	-0.04	-0.05	-0.05	-0.05	-0.05	0.03	0.01	0.03	0.00	0.04	0.03	0.04	0.04	0.04	0.04	0.03	0.04
	6110_COI_N-S	0.04	0.04	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.02	-0.04	-0.02	-0.03	-0.01	-0.05	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
	7820_TL50002_IV-NG-OUT_TDM	—	—	—	-0.09	-0.04	—	0.00	-0.08	-0.08	-0.11	—	—	—	—	—	—	—	—	—	—	—	—
	30055_GATES1_500_30900_GATES_230_XF_11_P	-0.01	-0.01	-0.02	-0.02	-0.02	-0.03	-0.03	-0.02	-0.02	-0.02	0.01	—	0.01	-0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	—	—	—	-0.05	-0.05	-0.01	-0.04	-0.06	-0.05	-0.05	—	—	—	-0.02	—	—	—	—	—	—	—	—
	OMS14862147_ML_BK81_NG	—	—	—	-0.05	-0.04	—	-0.04	-0.05	-0.05	-0.05	—	—	—	—	—	—	—	—	—	—	—	—
	OMS50004IV-MLOUTAGE_NG	—	—	—	-0.05	-0.02	-0.01	-0.02	-0.05	-0.04	-0.05	—	—	—	-0.01	—	—	—	—	—	—	—	—
	OMS15244989_TL23054_NG	—	—	—	-0.04	-0.03	0.00	-0.03	-0.04	-0.04	-0.04	—	—	—	-0.01	—	—	—	—	—	—	—	—
	MIGUEL_BKs_MXFLW_NG	—	—	—	-0.04	-0.03	—	-0.03	-0.04	-0.04	-0.04	—	—	—	—	—	—	—	—	—	—	—	—
	OMS15244988_TL23054_NG	—	—	—	-0.03	-0.03	0.00	-0.02	-0.03	-0.03	-0.03	—	—	—	0.00	—	—	—	—	—	—	—	—
	OMS_14707909_SUNCREST_BK81	—	—	—	-0.02	-0.02	—	-0.02	-0.02	-0.02	-0.02	—	—	—	—	—	—	—	—	—	—	—	—
	OMS_14675470_Suncrest_BK80_NG	—	—	—	-0.02	-0.02	0.00	-0.02	-0.02	-0.02	-0.02	—	—	—	0.00	—	—	—	—	—	—	—	—
	OMS15073046SUNCRESTBK81_NG	—	—	—	-0.02	-0.02	0.00	-0.02	-0.02	-0.02	-0.02	—	—	—	0.00	—	—	—	—	—	—	—	—
	7820_13810A_RAS_MS-SA_NG	—	—	—	-0.02	-0.01	—	-0.01	-0.02	-0.02	-0.02	—	—	—	—	—	—	—	—	—	—	—	—
	32214_RIOOSO_115_32244_BRNSWKT2_115_BR_2_1	—	—	—	—	—	0.03	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
LADWP	Victorville_Los_Angeles	—	—	0.05	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	—	0.00	—	0.00	—	—	—	—	—	—	—	—
PACE	WINDSTAREXPORTTCOR	—	—	—	—	—	—	—	—	—	—	—	—	—	-1.30	—	—	—	—	—	—	—	—
	TOTAL_WYOMING_EXPORT	—	—	—	—	—	—	—	—	—	—	—	—	—	-0.37	—	—	—	—	—	—	—	—
	EAST_WYO_EXP	—	—	—	—	—	—	—	—	—	—	—	—	—	-0.25	—	—	—	—	—	—	—	—
PGE	MCL_PE_SHW_V682	-0.06	-0.06	-0.06	-0.06	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	—	—	—	—	-0.07	—	0.08	—	0.58	0.05	—	0.03
	MRHL_STMW_V11712	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.01	—	0.02	0.01	—	0.01
PNM	115kvLK	—	—	—	—	-0.72	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	115kvMEB_Mi_AL	—	—	—	—	-0.27	—	0.35	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	115kvWE_So_El	—	—	—	—	-0.12	—	0.06	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	115kvMEB_Ca_AL	—	—	—	—	-0.04	—	0.11	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	115kvPicFro	—	—	—	—	-0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	Other	0.00	0.00	-0.01	-0.03	-0.03	-0.01	-0.03	-0.04	-0.04	-0.04	0.00	0.00	0.00	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	Total	-1.90	-0.65	-13.16	-13.11	-12.81	-7.99	-10.17	-13.20	-12.62	-13.02	8.81	3.49	7.16	-3.37	10.70	9.96	9.63	9.80	10.26	9.78	9.93	9.48

1.7.3 Congestion on interties

In the first quarter of 2024, total intertie congestion rent in the day-ahead market substantially increased from $13 million to $133 million compared to the same quarter in 2023. The major driver was increased export congestion from CAISO to the Pacific Northwest during January, which alone amounted to $126 million.

In January, severe weather conditions and high demand in the Pacific Northwest, along with transmission outages, especially on the Nevada-Oregon Border (NOB) intertie, created significant congestion on the Malin intertie.

The total import 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 1.34 shows total intertie congestion charges in the day-ahead market from 2023 to the first quarter of 2024. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 1.35 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 1.5 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 first quarter of 2023, import congestion rent decreased from $13 million to $2 million, whereas export congestion rent surged from $1 million to $130 million.
- The majority of this export congestion rent was from the Malin intertie from January 11th to January 24th due to severe weather conditions in the Pacific Northwest and transmission outages, especially on the Nevada-Oregon Border intertie.
- Compared to the first quarter of 2023, the frequency of congestion on Malin rose from 3 percent to 9 percent of hours in the day-ahead market. There was no congestion on the Nevada-Oregon border since the intertie was on outage during the severe weather period in January. The frequency of congestion on the COTPISO and IPP Utah interties doubled in this quarter compared to the same quarter of 2023.

Figure 1.34 Day-ahead congestion charges on major interties

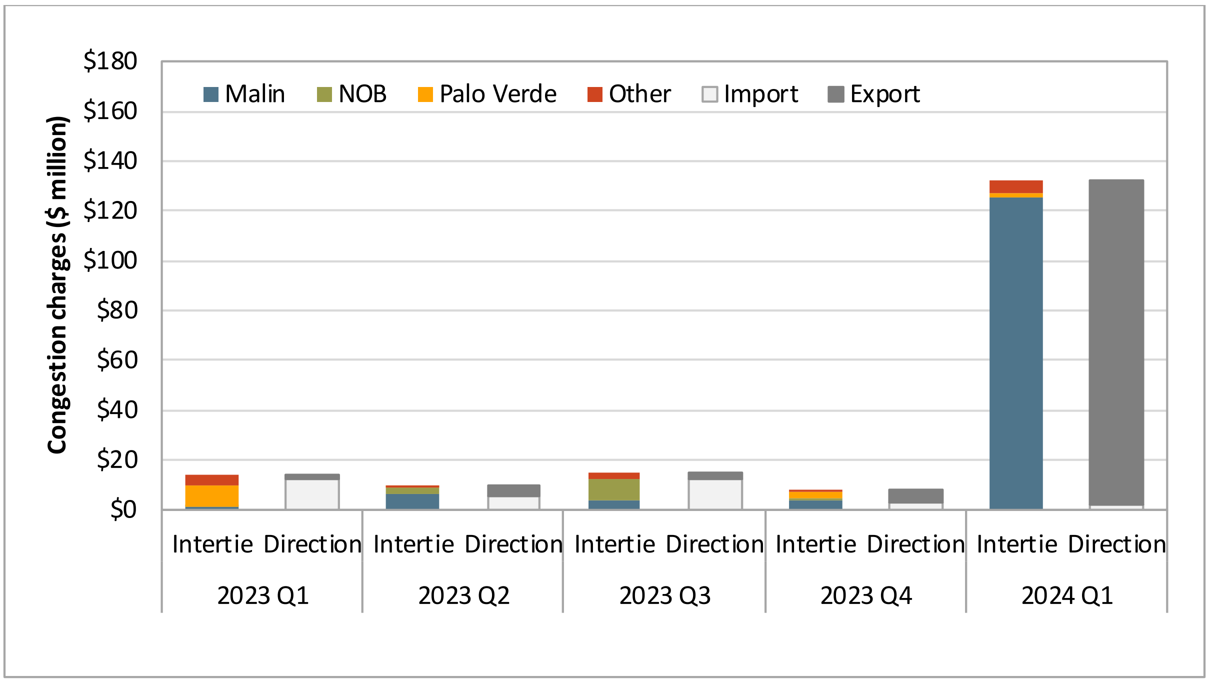


Figure 1.35 Frequency of congestion on major interties in the day-ahead market

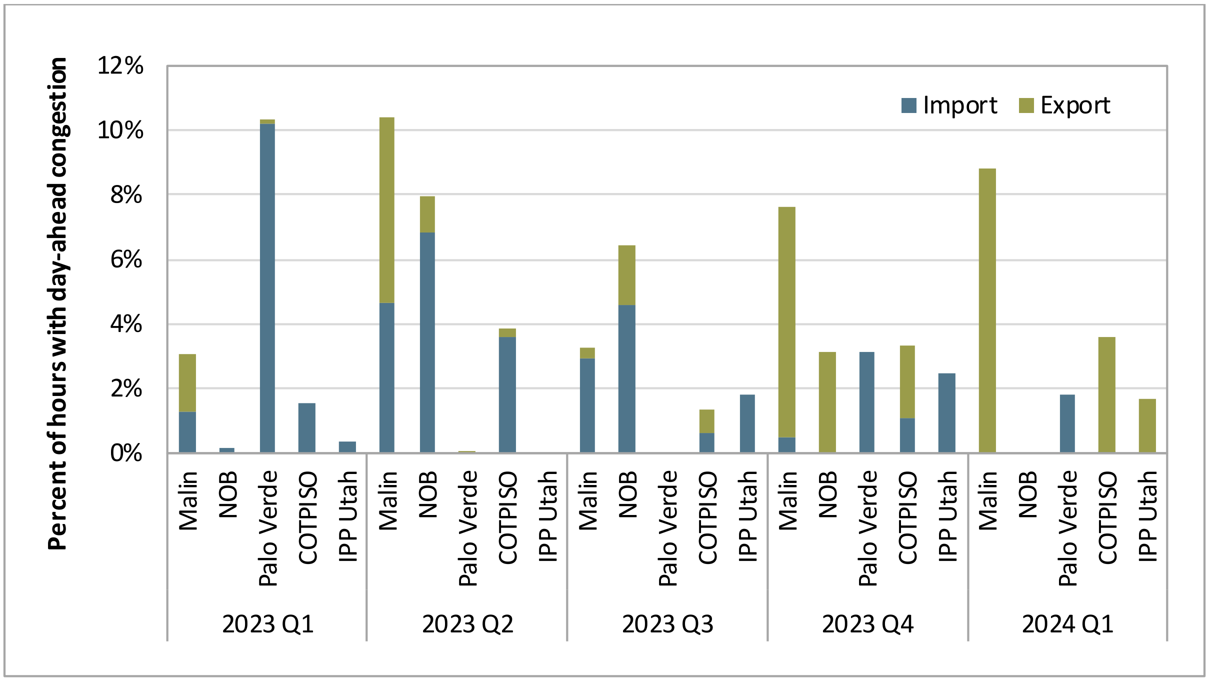


Table 1.5 Summary of intertie congestion in day-ahead market (2023-2024)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1
Northwest											
Malin	I	$381	$2,616	$3,127	$243		1.3%	4.7%	2.9%	0.5%	
	E	$802	$3,650	$339	$3,866	$125,571	1.8%	5.8%	0.3%	7.2%	8.8%
NOB	I	$68	$3,009	$8,755			0.1%	6.9%	4.6%		
	E		$66	$252	$851			1.1%	1.9%	3.1%	
COTPISO	I	$39	$74	$16	$103	$1	1.6%	3.6%	0.6%	1.1%	0.0%
	E		$3	$30	$55	$1,367		0.3%	0.7%	2.2%	3.5%
Cascade	I										
	E		$0			$2,147		0.1%			8.0%
Summit	I	$10		$42	$5		0.2%		1.4%	0.2%	
	E										
Southwest											
Palo Verde	I	$7,988			$2,593	$1,909	10.2%			3.1%	1.8%
	E	$210	$33				0.1%	0.0%			
IPP Utah	I	$18		$59	$186		0.4%		1.8%	2.4%	
	E					$401					1.7%
IPP DC Adelanto	I	$2,996					6.8%				
	E					$1,071					4.0%
Mona	I										
	E			$77	$143	$75			0.4%	0.7%	0.4%
Mead	I	$75				$1	0.3%				0.0%
	E			$2,370					1.5%		
Merchant	I										
	E										
Silver Peak	I										
	E		$13	$2				1.7%	1.0%		
Mercury	I										
	E										
Other	I	$1,164	$91	$21	$81						
	E		$0	$0		$58					
Import total (I)		$12,740	$5,789	$12,021	$3,213	$1,911					
Export total (E)		$1,012	$3,766	$3,071	$4,915	$130,690					
Total		$13,752	$9,555	$15,092	$8,128	$132,601					

* I: import, E: export

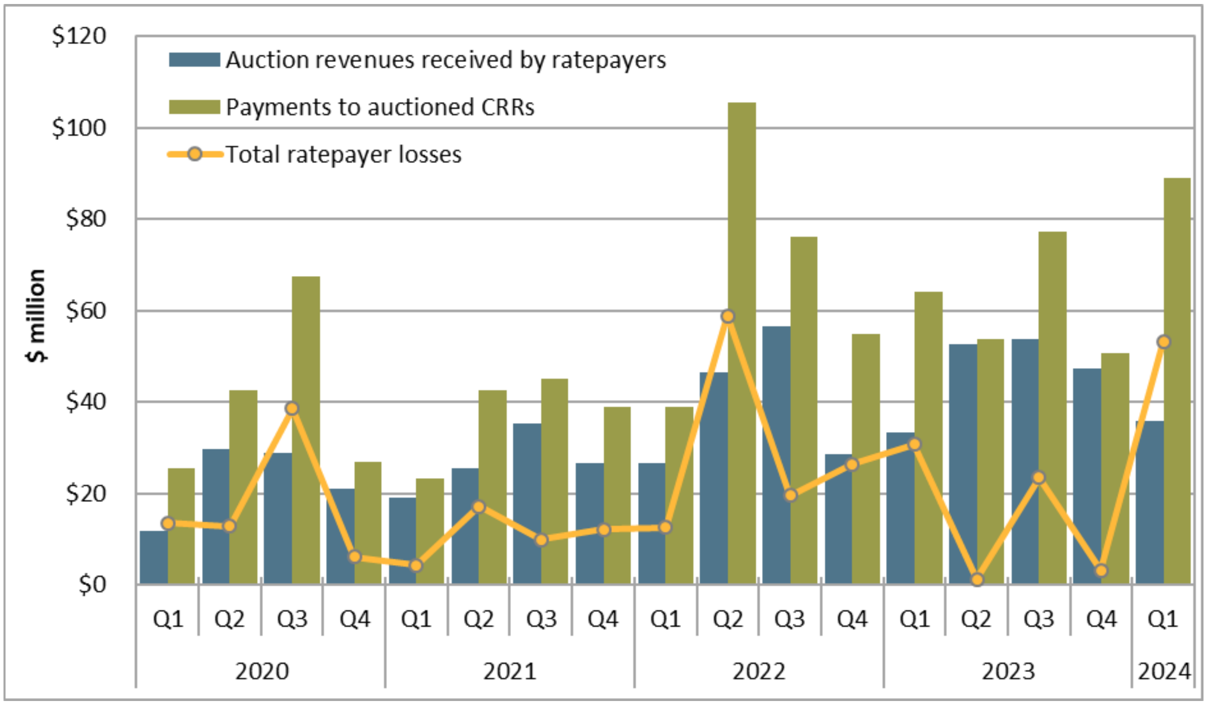
1.8 Congestion revenue rights

Congestion revenue right auction returns

Profits from the congestion revenue right (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 1.36, transmission ratepayers lost about $53 million during the first quarter of 2024, as payments to auctioned congestion revenue rights holders were higher than auction revenues. This was a significant increase from ratepayer losses of about $30 million in the first quarter of 2023. A large portion of the losses occurred during the January cold snap.

Figure 1.36 Auction revenues and payments to non-load serving entities



During the first quarter of 2024:

- Financial entities received profits of over $26 million, up from about $22 million during the same quarter of 2023. Total revenue deficit offsets were about $22 million.[41]
- Marketers made about $10 million from auctioned rights, up from $7 million in 2022. Total revenue deficit offsets were over $8 million.
- Physical generation entities gained over $16 million from auctioned rights, up from $2 million in 2022. Total revenue deficit offsets were about $2 million.

The $53 million in first quarter 2024 auction losses was about 20.6 percent of day-ahead congestion rent. This is significantly up from 1.4 percent in the previous quarter and up from 11 percent in the first quarter of 2023. The losses as a percent of day-ahead congestion rent were well below the average of 28 percent during the three years before the track 1A and 1B changes (2016 through 2018).[42, 43]

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41 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.

42 *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

43 *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, California ISO, June 11, 2018: file://homefiles/home/agirardot/profile/Downloads/draftfinalproposalsecondaddendum-congestionrevenuerightsauctionefficiencytrack1b%20(3).pdf

The impact of track 1A changes, which limit the types of congestion revenue rights that can be sold in the auction, cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under track 1B reduced total payments to non-load serving entities by about $32 million in the first 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, particularly in the first three quarters following their implementation. 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.

1.9 Real-time imbalance offset costs

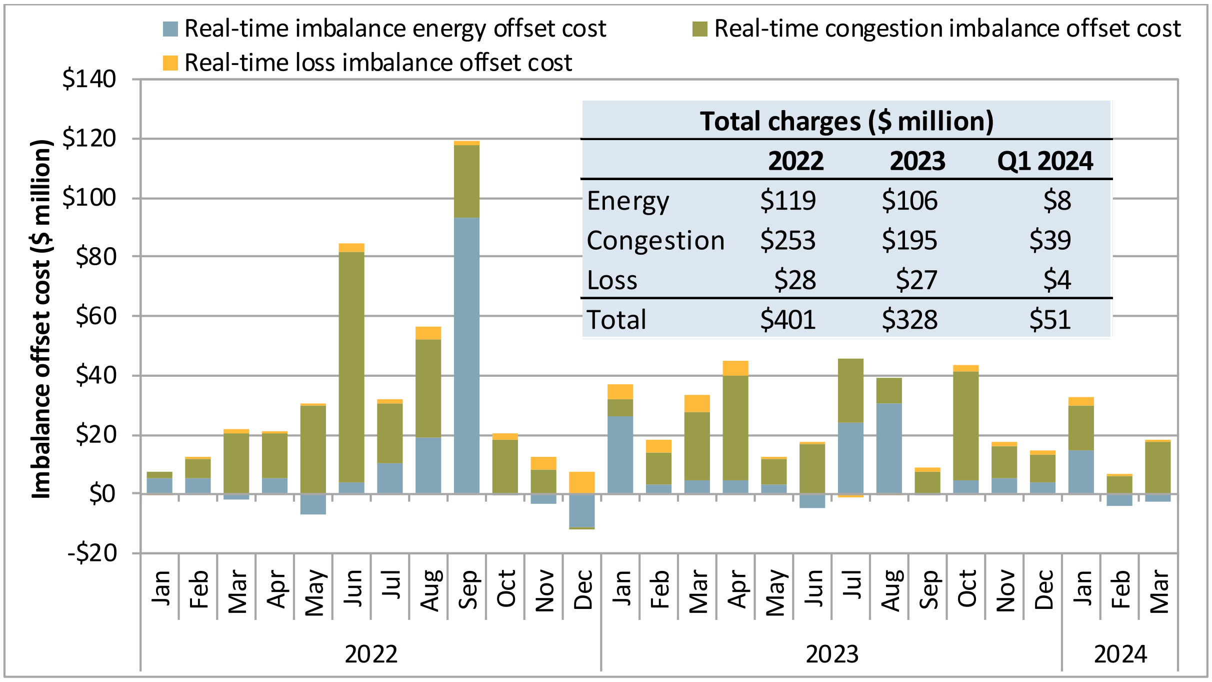
Real-time imbalance offset costs in the California ISO balancing area were $51 million in the first quarter of 2024.[44] This was a decrease from the $90 million of real-time imbalance offset costs in the first quarter of 2023. In the first quarter of 2024, real-time *congestion* imbalance offset costs made up $39 million of these costs while real-time imbalance *energy* offset costs made up $8 million.

The real-time imbalance offset cost is the difference between the total money *paid out* by the California ISO balancing area and the total money *collected* by the California ISO area for energy settled in the real-time energy markets. Within the California ISO balancing area system, the charge is allocated as an uplift to measured demand (physical load plus exports).

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 1.37 shows monthly imbalance offset costs by component since 2022.

[44] 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.

Figure 1.37 Monthly California ISO real-time imbalance offset costs



Real-time imbalance offset costs in the WEIM are also calculated for each balancing area. Any revenue shortfall or revenue surplus is allocated to the WEIM entity scheduling coordinator.[45] Figure 1.38 shows monthly imbalance offset costs for WEIM balancing areas, excluding the CAISO area. 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 1.39 through Figure 1.41 show the monthly real-time energy, congestion, or loss imbalance offset charges for each balancing area in the WEIM. Negative amounts (or credits for revenue surplus) are shown in parentheses. Figure 1.42 shows the *total* real-time imbalance offset charges for each month and balancing area. The final column in each of these figures shows the total amount for each balancing area in the first quarter of 2024.

Of note in the first quarter:

- Imbalance energy offsets for PacifiCorp West were around -$10.3 million (revenue surplus).
- Imbalance energy offsets for Arizona Public Service and NorthWestern Energy were each around $4.7 million (revenue shortfall).
- Congestion imbalance offsets for Powerex were around -$24.5 million (revenue surplus).
- Congestion imbalance offsets for PacifiCorp East were around -$22.3 million (revenue surplus).

45 The ISO allocates real-time congestion imbalance shortfalls and surpluses to the balancing authority area in which the constraints are located. The balancing authority areas then allocate these imbalances based on their tariffs, which can include allocations to third-party customers.

Figure 1.38 Monthly WEIM real-time imbalance offset costs

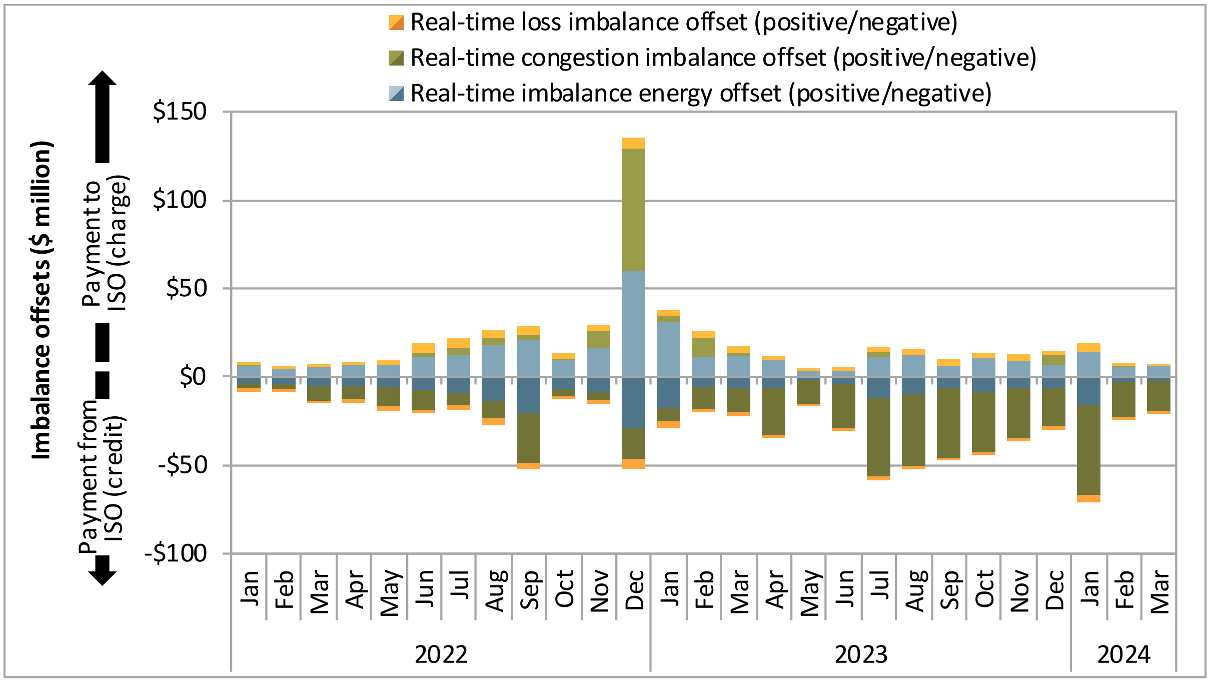


Figure 1.39 Real-time imbalance energy offset charges (credits) by month and balancing area ($ millions)

	2023												2024			Q1 '24
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	*Total*
Arizona Publ. Serv.	8.2	2.4	2.4	1.1	0.2	0.8	1.9	2.0	0.9	1.5	1.4	1.2	2.5	1.4	0.7	4.6
Avangrid				(0.1)	0.0	(0.0)	1.1	1.6	0.2	0.2	(0.2)	0.2	0.2	0.1	3.0	3.3
Avista	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.1	(0.1)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.1
BANC	0.1	(0.0)	(0.0)	(0.0)	0.1	(0.1)	0.1	0.1	(0.2)	(0.3)	0.1	(0.1)	(0.1)	0.2	0.3	0.4
BPA	0.5	0.0	0.7	(0.1)	(0.0)	0.1	0.4	0.3	0.0	0.1	0.2	(0.1)	(1.0)	0.0	0.0	(1.0)
El Paso Electric				(0.4)	(0.1)	(0.2)	(0.4)	0.0	(0.2)	(0.2)	(0.0)	(0.1)	0.1	(0.1)	0.0	0.0
Idaho Power	1.5	0.5	0.4	0.3	1.4	(0.1)	(0.9)	(0.1)	(0.1)	0.9	0.2	(0.5)	2.8	0.1	0.0	2.9
LADWP	(0.5)	0.0	0.0	(0.1)	(0.1)	(0.3)	0.3	0.1	0.0	(0.4)	0.0	0.0	0.1	0.1	(0.0)	0.2
NorthWestern En.	6.3	3.4	2.3	2.3	0.4	0.4	1.8	1.4	0.9	1.6	2.3	2.4	3.0	1.1	0.5	4.7
NV Energy	0.6	0.5	0.6	0.3	0.1	0.1	0.2	0.1	0.1	0.6	0.5	0.7	0.5	0.2	0.2	0.9
PacifiCorp East	7.7	2.1	1.7	1.2	0.3	1.3	2.6	3.4	3.0	4.2	2.1	1.0	1.7	1.1	0.2	3.0
PacifiCorp West	(7.1)	(2.2)	(1.7)	(1.5)	(0.2)	(1.5)	(4.0)	(5.6)	(3.3)	(4.3)	(2.3)	(1.3)	(8.2)	(1.4)	(0.7)	(10.3)
Portland G.E.	0.1	0.0	(0.0)	0.1	0.1	0.0	0.4	0.2	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.1
Powerex	0.7	(0.0)	(0.4)	(0.6)	(0.4)	(0.0)	(0.0)	0.5	0.2	(0.2)	(0.3)	(0.2)	0.7	0.1	(0.1)	0.7
PSC of New Mexico	4.1	2.0	2.9	2.8	0.4	0.6	1.2	1.3	0.7	1.0	1.6	1.0	1.5	1.4	0.8	3.7
Puget Sound En.	(6.2)	(2.9)	(3.0)	(2.0)	(0.6)	(0.9)	(2.2)	(2.3)	(1.2)	(1.8)	(2.2)	(2.0)	(4.4)	(1.4)	(1.0)	(6.8)
Salt River Proj.	(3.9)	(0.9)	(1.5)	(1.3)	(0.8)	(0.8)	(4.4)	(1.7)	(1.1)	(1.2)	(1.4)	(2.0)	(2.4)	(0.1)	(0.5)	(3.0)
Seattle City Light	0.1	0.0	0.2	0.1	(0.0)	(0.1)	(0.1)	0.1	0.0	0.0	0.1	0.1	0.4	(0.0)	0.0	0.4
Tacoma Power	0.0	(0.0)	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tucson Elec. Pow.	0.6	0.4	0.1	0.4	0.1	0.1	0.1	0.2	(0.0)	0.2	0.2	0.3	0.4	0.0	0.0	0.4
Turlock Irrig. Dist.	0.6	0.2	0.3	0.3	0.1	0.2	0.6	0.7	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.3
WAPA DSW				0.4	(0.1)	0.0	0.2	0.1	0.1	(0.5)	(0.0)	(0.0)	(0.1)	0.0	0.0	(0.1)

Figure 1.40 Real-time congestion imbalance offset charges (credits) by month and balancing area ($ millions)

	2023												2024			Q1 '24
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	*Total*
Arizona Publ. Serv.	(0.1)	(0.5)	(1.0)	(0.7)	(0.3)	(1.4)	0.4	0.0	(0.1)	0.0	(0.2)	(0.2)	(0.0)	(0.2)	0.1	(0.1)
Avangrid				(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.0)	(0.0)	(0.1)	(0.0)	(0.6)	(0.1)	(0.3)	(0.9)
Avista	(0.0)	(0.1)	(0.1)	(0.2)	(0.2)	(0.0)	(0.1)	(0.0)	(0.1)	(0.3)	(0.1)	0.0	(1.2)	(0.0)	(0.0)	(1.3)
BANC	(0.0)	0.0	(0.0)	0.1	0.2	0.0	(0.0)	(0.0)	0.0	0.0	0.0	(0.1)	0.0	0.0	(0.0)	0.0
BPA	(0.4)	0.1	(0.4)	(0.4)	(0.9)	(0.1)	(0.5)	(0.4)	(0.4)	(0.6)	(0.2)	(0.1)	(0.8)	0.1	(0.5)	(1.2)
El Paso Electric				(0.1)	(0.4)	(0.3)	(1.1)	(0.3)	(0.2)	(0.9)	(0.0)	(0.0)	(0.1)	(0.2)	(0.0)	(0.3)
Idaho Power	(0.2)	(0.3)	(0.4)	(1.1)	(0.9)	(0.3)	(0.4)	(0.3)	(0.3)	(1.0)	(0.5)	(0.1)	(4.7)	(0.1)	(0.1)	(4.9)
LADWP	(0.2)	(0.1)	(0.4)	(0.4)	(0.4)	(0.4)	(1.9)	(1.2)	(0.8)	(0.5)	(0.3)	(0.3)	(1.4)	(0.3)	(0.5)	(2.3)
NorthWestern En.	(0.2)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	0.1	(0.1)	(0.1)	(0.2)	(0.1)	(0.0)	(1.0)	(0.0)	(0.0)	(1.0)
NV Energy	(0.2)	(0.3)	(0.7)	(0.8)	(0.4)	(0.5)	(0.1)	(0.0)	(0.1)	(0.7)	(0.3)	(0.0)	(1.2)	(0.1)	(0.2)	(1.6)
PacifiCorp East	3.2	10	1.9	(5.3)	(1.0)	(1.1)	(2.9)	(2.9)	(3.4)	(3.6)	(8.8)	(11)	(12)	(6.9)	(3.8)	(22.3)
PacifiCorp West	(0.6)	(0.5)	(0.6)	(1.1)	(1.3)	(0.5)	(1.3)	(1.2)	(0.6)	(1.5)	(0.7)	(0.2)	(8.0)	(0.3)	(0.4)	(8.8)
Portland G.E.	(0.6)	(0.9)	(0.5)	(0.8)	(0.5)	(0.5)	(0.9)	(3.6)	(0.3)	(2.3)	(0.5)	(0.2)	(5.8)	(0.2)	(0.3)	(6.3)
Powerex	(1.5)	(7.3)	(7.1)	(12)	(2.0)	(16)	(29)	(26)	(30)	(17)	(13)	(7.8)	(6.1)	(9.5)	(8.9)	(24.5)
PSC of New Mexico	(0.1)	(0.0)	(0.2)	(1.0)	(0.3)	(0.0)	2.3	(0.1)	(0.2)	(0.1)	(0.7)	5.3	(0.8)	(0.5)	(0.1)	(1.3)
Puget Sound En.	(0.3)	(0.3)	(0.5)	(0.6)	(0.5)	(0.9)	(2.2)	(1.7)	(0.8)	(2.4)	(0.0)	(0.4)	(3.7)	(0.4)	(0.7)	(4.8)
Salt River Proj.	(2.6)	(1.5)	(0.7)	(1.8)	(2.2)	(1.9)	(2.5)	(1.1)	(1.3)	(1.5)	(2.4)	(1.0)	(2.3)	(0.5)	(0.8)	(3.6)
Seattle City Light	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	(0.0)	(0.3)	(0.0)	0.0	(0.3)
Tacoma Power	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)	(0.2)	(0.2)
Tucson Elec. Pow.	(0.4)	(0.3)	(0.3)	(0.8)	(1.4)	(1.3)	(1.4)	(1.1)	(1.0)	(1.3)	(0.1)	(0.2)	(0.9)	(0.6)	(0.6)	(2.0)
Turlock Irrig. Dist.	(0.0)	(0.0)	(0.1)	(0.0)	0.0	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0
WAPA DSW				(0.0)	(0.1)	0.0	(0.0)	(0.2)	(0.0)	(0.0)	(0.0)	(0.0)	0.1	0.0	0.0	0.1

Figure 1.41 Real-time loss imbalance offset charges (credits) by month and balancing area ($ millions)

	2023												2024			Q1 '24
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	*Total*
Arizona Publ. Serv.	(1.3)	(0.7)	(0.8)	(0.3)	(0.1)	(0.1)	(0.7)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.3)	(0.1)	(0.0)	(0.4)
Avangrid				(0.0)	(0.0)	(0.0)	0.0	0.1	0.0	(0.0)	(0.0)	(0.0)	(0.3)	(0.0)	0.0	(0.3)
Avista	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0
BANC	0.2	0.1	(0.1)	0.0	(0.1)	(0.0)	0.0	0.1	0.0	0.0	0.0	0.0	0.1	(0.0)	0.0	0.1
BPA	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	0.1	(0.0)	0.0	0.9	0.0	(0.0)	0.9
El Paso Electric				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.1)
Idaho Power	0.3	0.4	(0.1)	0.1	(0.0)	0.2	0.0	0.7	0.6	0.1	0.3	0.4	(0.3)	(0.1)	(0.0)	(0.4)
LADWP	(0.0)	0.1	(0.1)	(0.1)	0.0	0.0	(0.1)	(0.0)	0.0	0.1	(0.1)	0.1	(0.4)	(0.0)	(0.0)	(0.5)
NorthWestern En.	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	0.1	0.1	0.0	(0.0)	0.1
NV Energy	(0.2)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.3)	(0.0)	(0.1)	(0.4)
PacifiCorp East	(0.5)	0.4	0.8	0.1	0.2	0.0	(0.4)	(0.9)	(0.6)	(0.6)	(0.5)	(1.0)	(1.5)	(0.3)	(0.2)	(1.9)
PacifiCorp West	(0.3)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	(0.2)	(0.2)	0.2	(0.1)	(0.1)	0.0
Portland G.E.	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.1	(0.0)	2.0	(0.0)	(0.0)	1.9
Powerex	1.1	1.7	1.7	1.5	0.0	0.9	2.4	2.6	2.7	2.0	3.1	1.7	1.0	1.4	1.0	3.3
PSC of New Mexico	1.1	0.6	1.0	0.3	0.1	0.4	0.3	0.0	0.0	0.1	0.1	(0.0)	0.1	0.0	(0.0)	0.0
Puget Sound En.	0.1	0.0	(0.1)	(0.0)	(0.0)	0.0	0.1	0.0	0.0	0.1	(0.0)	0.1	0.4	0.1	0.0	0.5
Salt River Proj.	(0.5)	(0.4)	(0.4)	(0.3)	(0.0)	(0.1)	(0.3)	(0.2)	(0.2)	(0.1)	(0.2)	(0.3)	(0.4)	(0.2)	(0.1)	(0.7)
Seattle City Light	0.2	0.1	0.1	0.2	0.0	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.3	0.0	0.0	0.4
Tacoma Power	(0.2)	(0.0)	(0.0)	0.0	(0.0)	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.3)	(0.0)	(0.0)	(0.3)
Tucson Elec. Pow.	(0.2)	(0.0)	(0.1)	(0.1)	0.0	0.1	(0.3)	(0.2)	(0.0)	(0.1)	(0.2)	(0.1)	(0.2)	(0.0)	(0.1)	(0.3)
Turlock Irrig. Dist.	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
WAPA DSW				0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.2)	(0.0)	0.0	(0.2)

Figure 1.42 Total real-time imbalance offset charges (credits) by month and balancing area ($ millions)

	2023												2024			Q1 '24
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	*Total*
Arizona Publ. Serv.	6.8	1.2	0.7	0.2	(0.2)	(0.6)	1.7	1.9	0.6	1.4	1.1	0.9	2.2	1.1	0.8	4.1
Avangrid				(0.3)	(0.1)	(0.1)	1.1	1.5	0.2	0.1	(0.3)	0.2	(0.6)	(0.0)	2.7	2.1
Avista	0.0	(0.0)	(0.0)	(0.2)	(0.2)	(0.0)	0.0	0.1	(0.2)	(0.2)	(0.0)	0.0	(1.2)	(0.0)	0.0	(1.2)
BANC	0.2	0.1	(0.1)	0.0	0.2	(0.1)	0.1	0.1	(0.2)	(0.2)	0.1	(0.1)	0.0	0.1	0.3	0.5
BPA	(0.1)	(0.1)	0.1	(0.6)	(1.0)	(0.1)	(0.2)	(0.2)	(0.4)	(0.3)	(0.1)	(0.2)	(1.0)	0.1	(0.5)	(1.3)
El Paso Electric				(0.5)	(0.5)	(0.5)	(1.5)	(0.4)	(0.4)	(1.1)	(0.0)	(0.1)	(0.1)	(0.3)	(0.0)	(0.4)
Idaho Power	1.6	0.7	(0.2)	(0.7)	0.4	(0.1)	(1.2)	0.2	0.1	0.0	(0.0)	(0.2)	(2.2)	(0.1)	(0.1)	(2.4)
LADWP	(0.7)	0.1	(0.5)	(0.5)	(0.5)	(0.7)	(1.6)	(1.2)	(0.8)	(0.9)	(0.4)	(0.3)	(1.7)	(0.3)	(0.5)	(2.5)
NorthWestern En.	6.1	3.3	2.2	2.2	0.3	0.3	1.9	1.3	0.8	1.4	2.3	2.4	2.1	1.1	0.5	3.7
NV Energy	0.1	0.2	(0.3)	(0.5)	(0.4)	(0.5)	(0.0)	(0.1)	(0.0)	(0.2)	0.2	0.5	(1.0)	0.0	(0.0)	(1.1)
PacifiCorp East	10	13	4.4	(4.0)	(0.5)	0.2	(0.8)	(0.4)	(1.0)	(0.0)	(7.3)	(11)	(11)	(6.1)	(3.8)	(21.3)
PacifiCorp West	(8.0)	(2.8)	(2.4)	(2.7)	(1.5)	(2.0)	(5.3)	(6.9)	(3.9)	(5.8)	(3.2)	(1.7)	(16)	(1.9)	(1.2)	(19.0)
Portland G.E.	(0.3)	(0.7)	(0.4)	(0.6)	(0.4)	(0.4)	(0.4)	(3.3)	(0.2)	(2.1)	(0.4)	(0.2)	(3.8)	(0.2)	(0.3)	(4.3)
Powerex	0.2	(5.6)	(5.8)	(11)	(2.3)	(15)	(27)	(23)	(27)	(15)	(10)	(6.3)	(4.4)	(8.0)	(8.0)	(20.4)
PSC of New Mexico	5.2	2.6	3.7	2.0	0.2	0.9	3.8	1.2	0.5	0.9	1.0	6.3	0.8	0.9	0.7	2.4
Puget Sound En.	(6.4)	(3.2)	(3.6)	(2.6)	(1.1)	(1.7)	(4.4)	(4.0)	(1.9)	(4.1)	(2.2)	(2.3)	(7.8)	(1.7)	(1.6)	(11.1)
Salt River Proj.	(7.0)	(2.7)	(2.6)	(3.4)	(3.0)	(2.8)	(7.1)	(2.9)	(2.7)	(2.9)	(4.0)	(3.3)	(5.1)	(0.7)	(1.4)	(7.3)
Seattle City Light	0.3	0.1	0.2	0.2	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	0.1	0.4	0.0	0.0	0.4
Tacoma Power	(0.2)	(0.1)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.3)	(0.0)	(0.2)	(0.5)
Tucson Elec. Pow.	0.1	0.1	(0.3)	(0.5)	(1.3)	(1.1)	(1.6)	(1.1)	(1.1)	(1.1)	(0.1)	(0.1)	(0.7)	(0.6)	(0.6)	(1.9)
Turlock Irrig. Dist.	0.5	0.2	0.2	0.3	0.1	0.2	0.5	0.7	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.3
WAPA DSW				0.4	(0.2)	0.0	0.2	(0.1)	0.0	(0.5)	(0.1)	(0.0)	(0.2)	0.1	0.1	(0.1)

1.10 Bid cost recovery

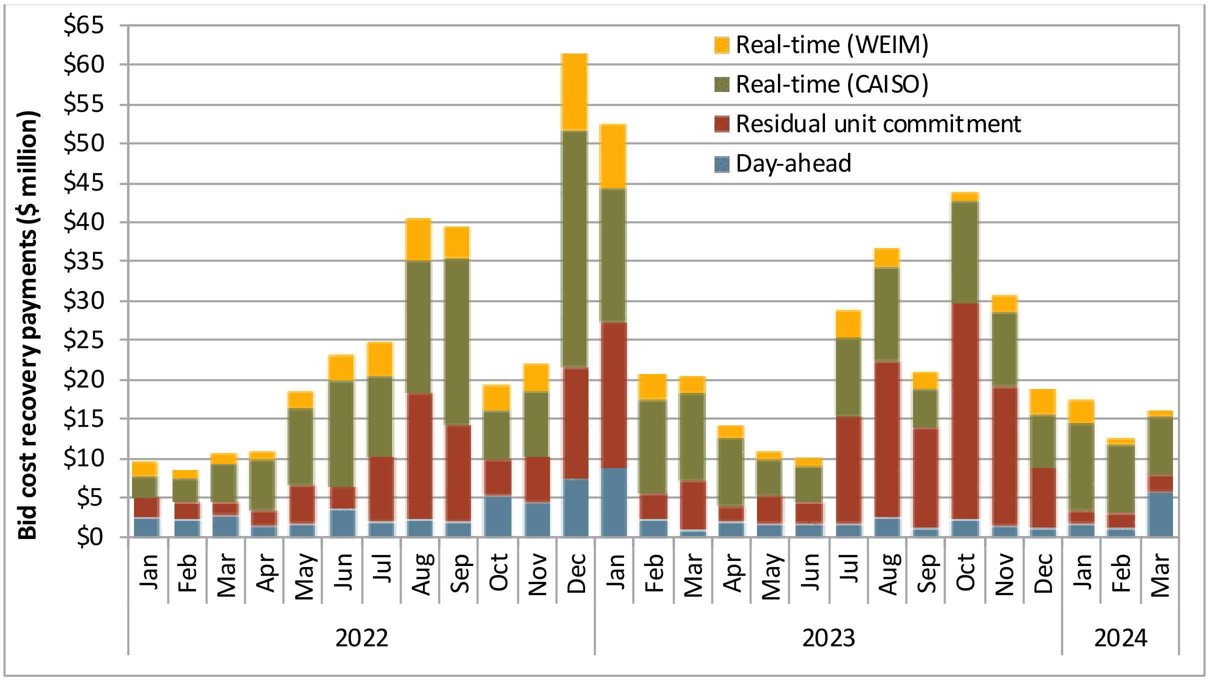
During the first quarter of 2024, estimated bid cost recovery payments for units in the California ISO and Western Energy Imbalance Market (WEIM) balancing areas totaled about $41.5 million and $4.8 million, respectively. These payments were lower than the same quarter of 2023, when payments totaled $80.3 million in the ISO area and $13.1 million in the WEIM area.[46] The overall decrease can be attributed to natural gas price decreases after a spike in in December 2022 that persisted into January 2023. However, in mid-January 2024, severe winter weather affected supply and demand conditions in the California ISO area and the WEIM, including a gas price increase. During this time, there were significant increases in bid cost recovery payments in the ISO, mostly driven by payments to gas resources.

Figure 1.43 shows monthly bid cost recovery payments in the first quarter of 2024. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $8.8 million, which was less than the $12.1 million in the first quarter of 2023. Bid cost recovery payments associated with residual unit commitment during the quarter totaled about $5.7 million, or about $22.3 million lower than the first quarter of 2023. Bid cost recovery attributed to the real-time market totaled about $31.7 million, which is about $4.3 million lower than the payments in the previous quarter and about $21.6 million lower than the same quarter of 2023. Out of the total real-time payments, about $4.8 million was allocated to non-California ISO resources participating in the WEIM.

46 The bid cost recovery payment amounts for 2022 and 2023 in this report are different than what was reported in the Q1 2023 report due to resettlements.

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 first quarter of 2024, about $33.6 million of bid cost recovery payments were made to gas resources, 90 percent of which were paid to units in the California ISO area. About $5.8 million of payments were made to battery energy storage resources, almost entirely going to units in the ISO area. Bid cost recovery payments to solar resources totaled $2.5 million.

Figure 1.43 Monthly bid cost recovery payments



1.11 Imbalance conformance

Operators in the California ISO and the 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.

Frequency and size of imbalance conformance adjustments

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 1.44 shows imbalance conformance adjustments in real-time markets for the first quarter of 2023 and 2024. Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets decreased in the first quarter of 2024 relative to the same quarter of 2023, over both the morning and evening ramp periods. The evening peak highest hourly average of about 1,540 MW decreased by about 800 MW compared to the prior year. During the morning ramp, the highest average hourly adjustments were around 840 MW. This was a decrease of about 60 MW compared to the first quarter of 2023.

The 5-minute market adjustments decreased in the morning and evening ramp hours compared to the first quarter or 2023. Negative adjustments to the load forecast occurred prior to the morning ramp hours and during the mid-day period.

Figure 1.44 Average hourly imbalance conformance adjustment (Q1 2023 and Q1 2024)

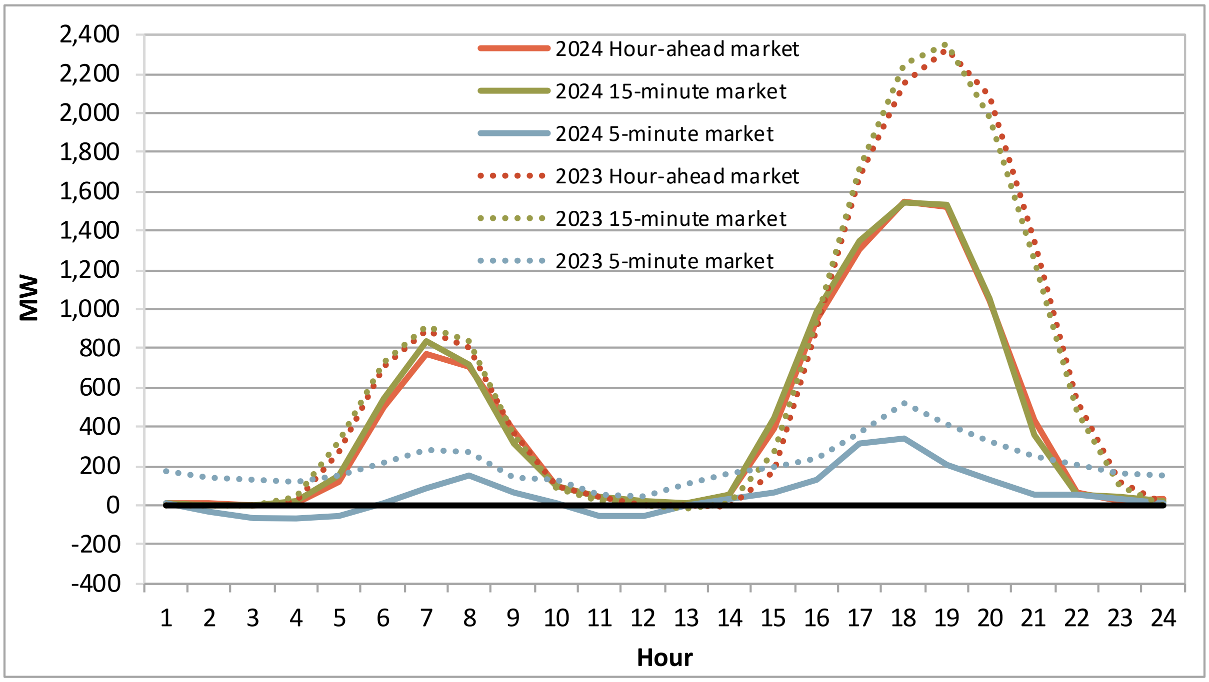
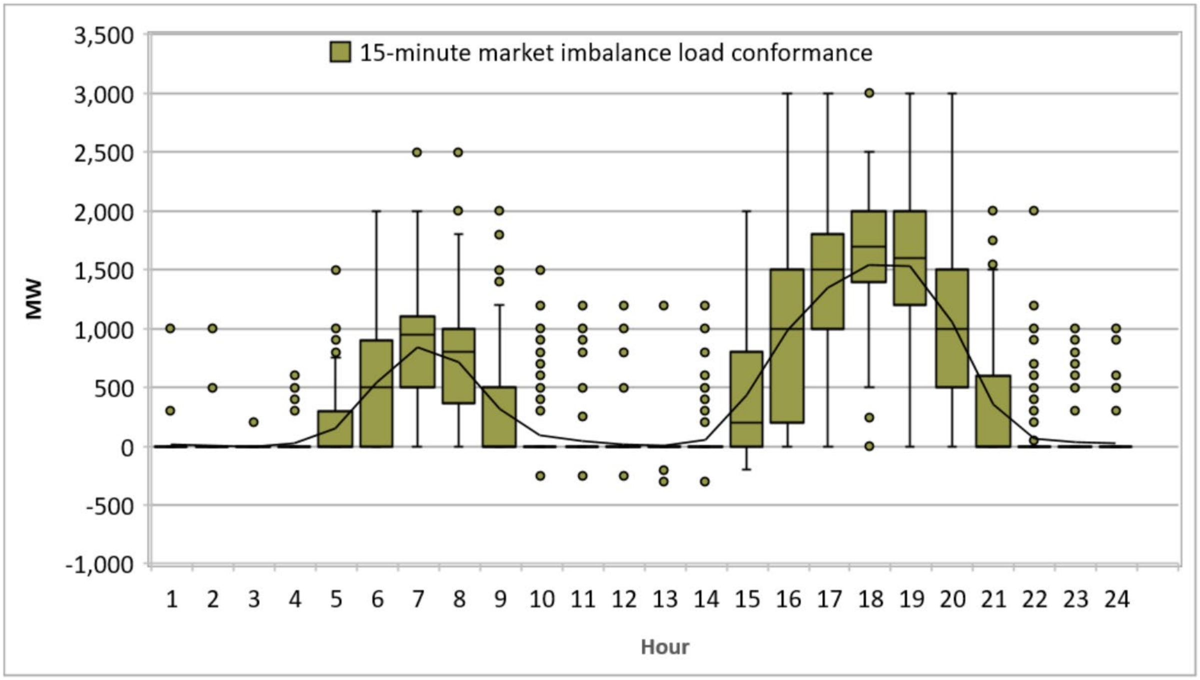


Figure 1.45 shows each hour's distribution of the 15-minute market load adjustments for the first quarter of 2024. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers 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 16 to 19, e.g., 3,000 MW, occurred on February 13 and 18, as well as March 6 associated with rapid solar ramp down.

Figure 1.45 15-minute market hourly distribution of operator load adjustments (Q1 2024)



1.12 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.[47] 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.

1.12.1 Flexible ramping product market outcomes

Flexible ramping product requirement

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

[47] 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.

flexible ramping capacity. This "requirement" for rampable capacity reflects the upper end of uncertainty in each direction that might materialize.[48] 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 evaluation are calculated using a method called *mosaic quantile regression*. This method applies regression techniques on historical data to produce a series of coefficients that define the relationship between forecast information (load, solar, or wind) and the extreme percentile of uncertainty that might materialize (95 percent confidence interval).

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. Here, 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.

Flexible ramping product prices

As part of flexible ramping product enhancements, flexible ramping product prices are now determined locationally at each node. This nodal price can be made up of multiple components.[49] 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.[50] 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.[51] Using the

48 Based on a 95 percent confidence interval.

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

50 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.

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

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.[52] 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.[53] 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 since the enhancements were implemented. When the shadow price on this constraint is zero, this generally reflects that flexible capacity within the wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available.[54] 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 1.46 shows the percent of intervals since implementation of the enhancements in which the shadow price on the pass-group constraint was non-zero. 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.[55] This is compared against the frequency of non-zero prices on the constraint for *system-wide* flexible capacity that was in place prior to the enhancements. The constraint for procuring pass-group flexible capacity was binding very infrequently during the quarter. Prices in the 15-minute market for *upward* flexible capacity on the pass-group constraint were non-zero in around 0.2 percent of intervals. The shadow price on the constraint for procuring *downward* flexible capacity was always zero in the

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

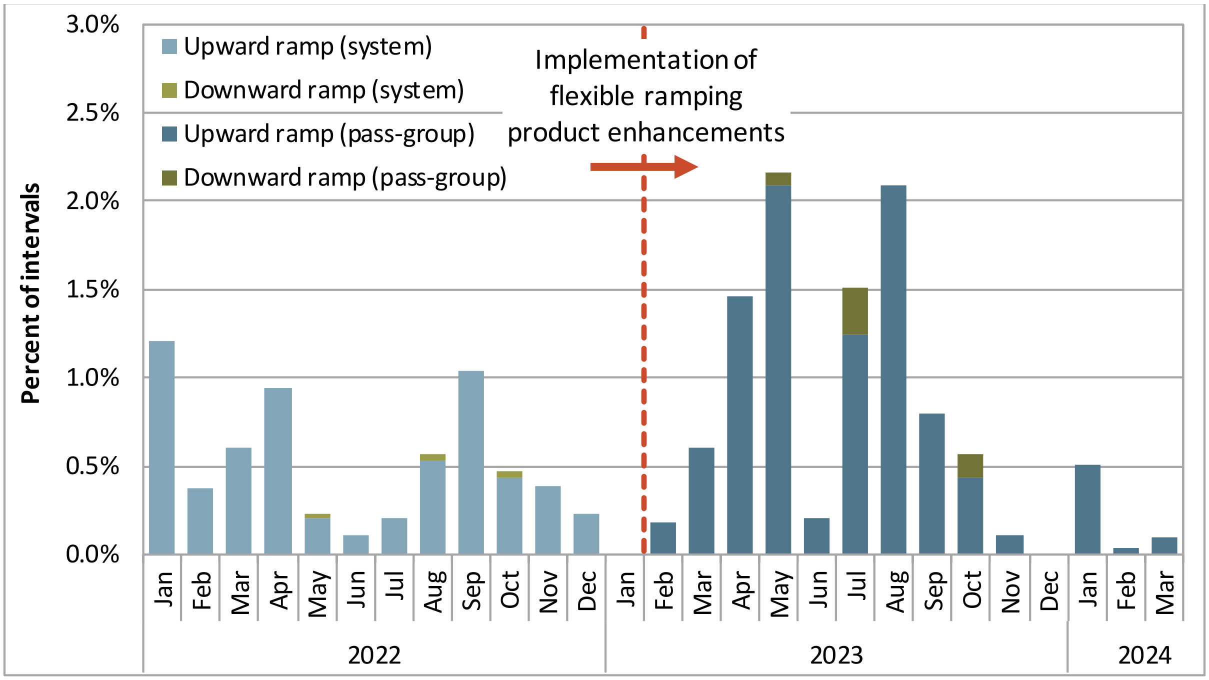
53 For upward flexible capacity, the demand curves are capped at $247/MWh.

54 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.

55 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.

15-minute market during the quarter. In the 5-minute market, the frequency of non-zero prices were similarly infrequent.

Figure 1.46 Frequency of flexible ramping product prices from pass-group constraint (15-minute market)



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

Figure 1.47 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 information shown in Figure 1.46, 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 1.47 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

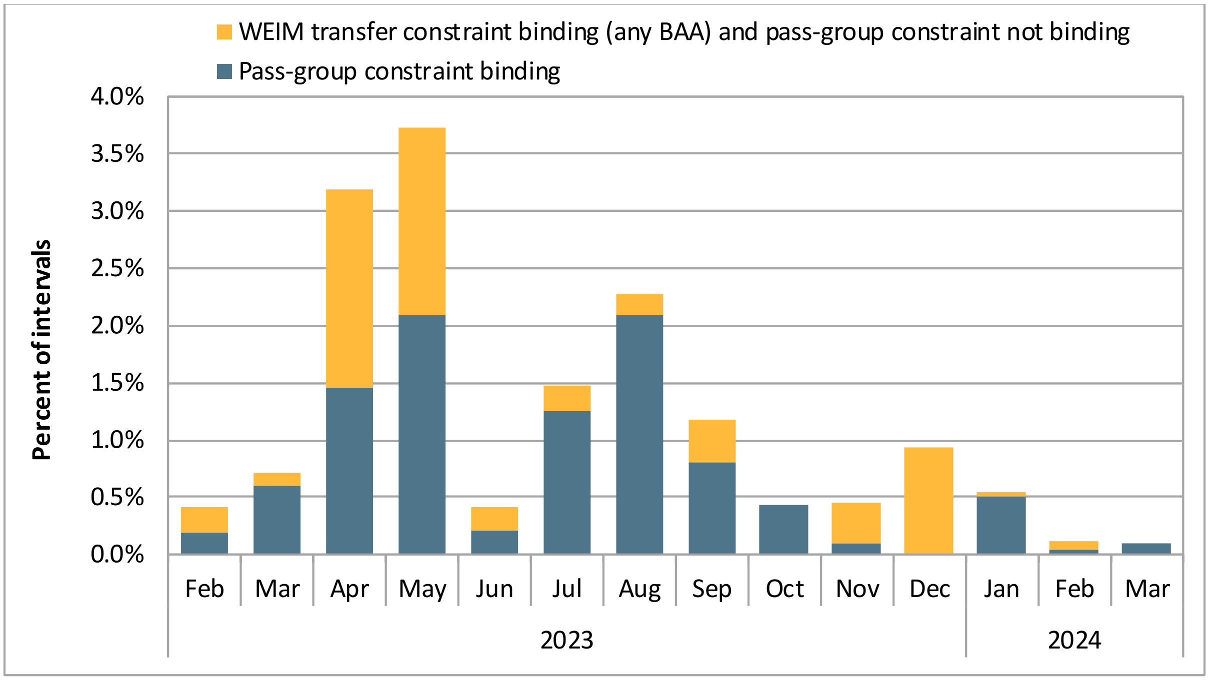


Figure 1.48 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the first quarter. These results are shown separately by the constraint contributing to that price:

- **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 0.2 percent of intervals. In most of these intervals, Powerex

(BHCA) 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 1.48 Frequency of upward flexible ramping product prices by balancing area and constraint (15-minute market, January–March, 2024)

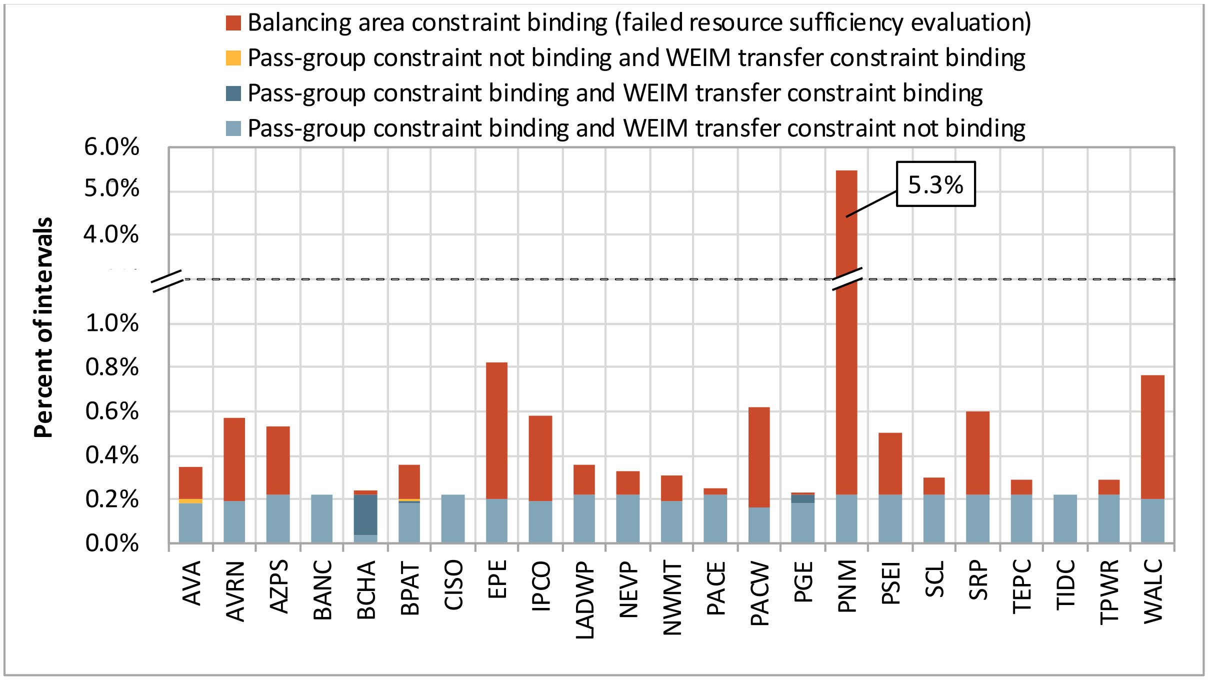


Figure 1.48 also summarizes flexible capacity prices that can exist following a resource sufficiency evaluation failure (red bars). When a balancing area fails the resource sufficiency evaluation, the area will not have access to any diversity benefit of reduced uncertainty over a larger footprint and will instead need to meet its uncertainty needs from flexible capacity within its area only. The Public Service Company of New Mexico (PNM) frequently had prices for flexible capacity in the balancing area following a failure of the resource sufficiency evaluation, during around 5.3 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.

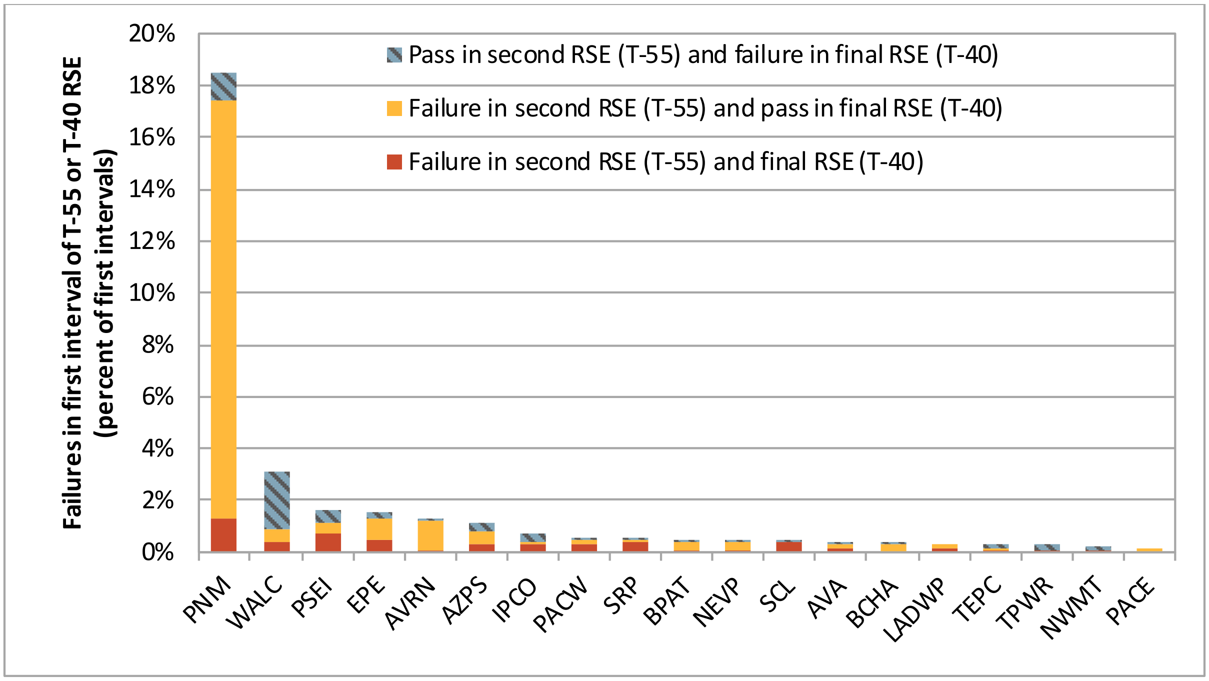
There are three runs of the resource sufficiency evaluation, at 75 minutes (first run), 55 minutes (second run), and 40 minutes (final run) prior to each hour. The first and second runs are sometimes considered the advisory runs, with the final evaluation occurring at 40 minutes prior to the hour. For 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 1.49 summarizes the first interval of each evaluation hour during the quarter with a failure in the second (T-55) or final (T-40) resource sufficiency evaluation run.[56] This reflects failure of either the

[56] Areas that did not fail in the first interval of a resource sufficiency evaluation run at T-55 or T-40 during this period were omitted from these figures.

flexibility or capacity test in the second or final run. The red and yellow bars show instances with a failure in the second evaluation (T-55), and whether the balancing area ultimately failed or passed in that interval based on the final evaluation results at 40 minutes prior to the hour. During the quarter, PNM frequently failed the second resource sufficiency evaluation (T-55) but ultimately passed the test in the final evaluation (T-40). This frequently impacted 15-minute market flexible ramping product prices in the PNM balancing area in the first interval of hours.

Figure 1.49 Upward resource sufficiency evaluation failures in first 15-minute interval of hour (January–March, 2024)



Flexible ramping product procurement

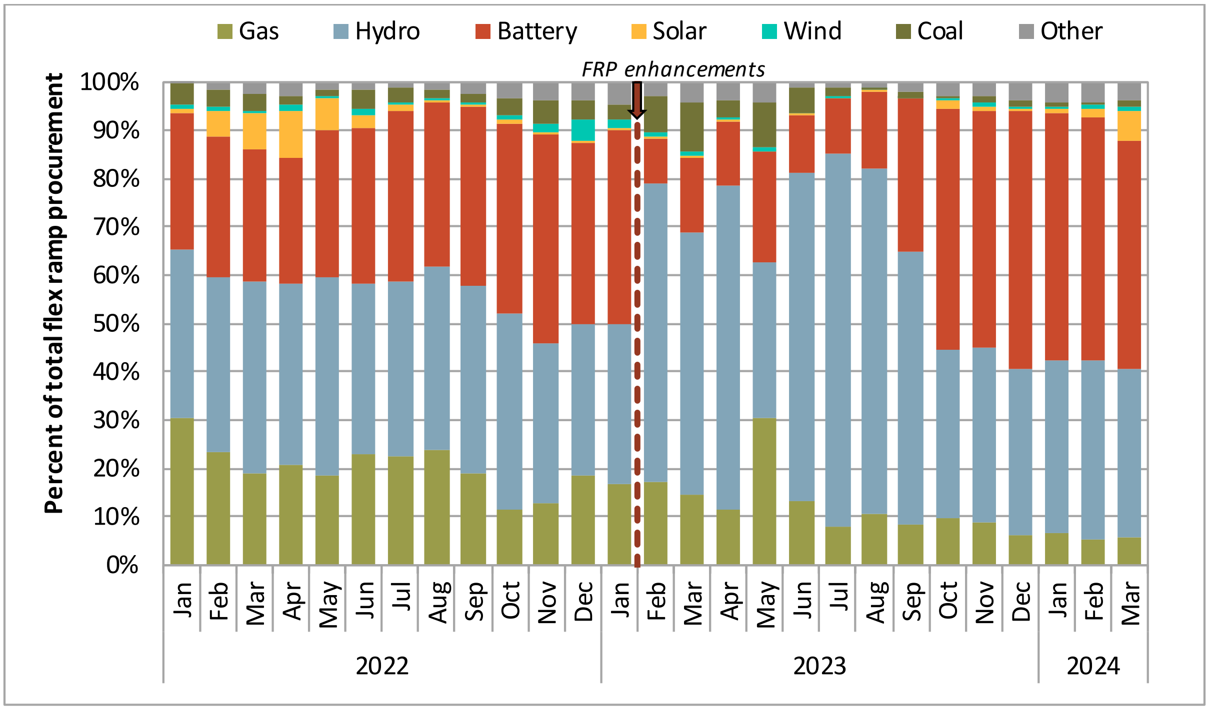
This section summarizes flexible capacity procured to meet the uncertainty needs of the greater WEIM system during the quarter. Figure 1.50 and Figure 1.51 show the percent of upward or downward flexible capacity that was procured from various fuel types, both before and after the enhancements that were implemented at the start of February, 2023. Prior to the enhancements, these amounts reflect the percent of *system-wide* uncertainty. After the enhancements, these amounts instead reflect the percent of *pass-group* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation.

During the quarter, battery resources continued contributing to much of the upward and downward flexible capacity. Battery resources made up almost 50 percent of upward flexible capacity and 28 percent of downward flexible capacity in the first quarter of 2024. Hydro resources continued to supply a large portion of upward flexible capacity (36 percent). Wind and solar resources combined made up around 39 percent of downward flexible capacity.

Figure 1.52 and Figure 1.53 show the percent of upward or downward flexible capacity that was procured in various regions. [57] 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, CAISO continued to make up the majority of upward and downward flexible capacity awards, at around 60 percent for both directions. Balancing areas in the Pacific Northwest made up 31 percent of upward flexible capacity and 17 percent of downward flexible capacity.

Figure 1.50 Percent of upward system or pass-group flexible ramp procurement by fuel type



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

Figure 1.51 Percent of downward system or pass-group flexible ramp procurement by fuel type

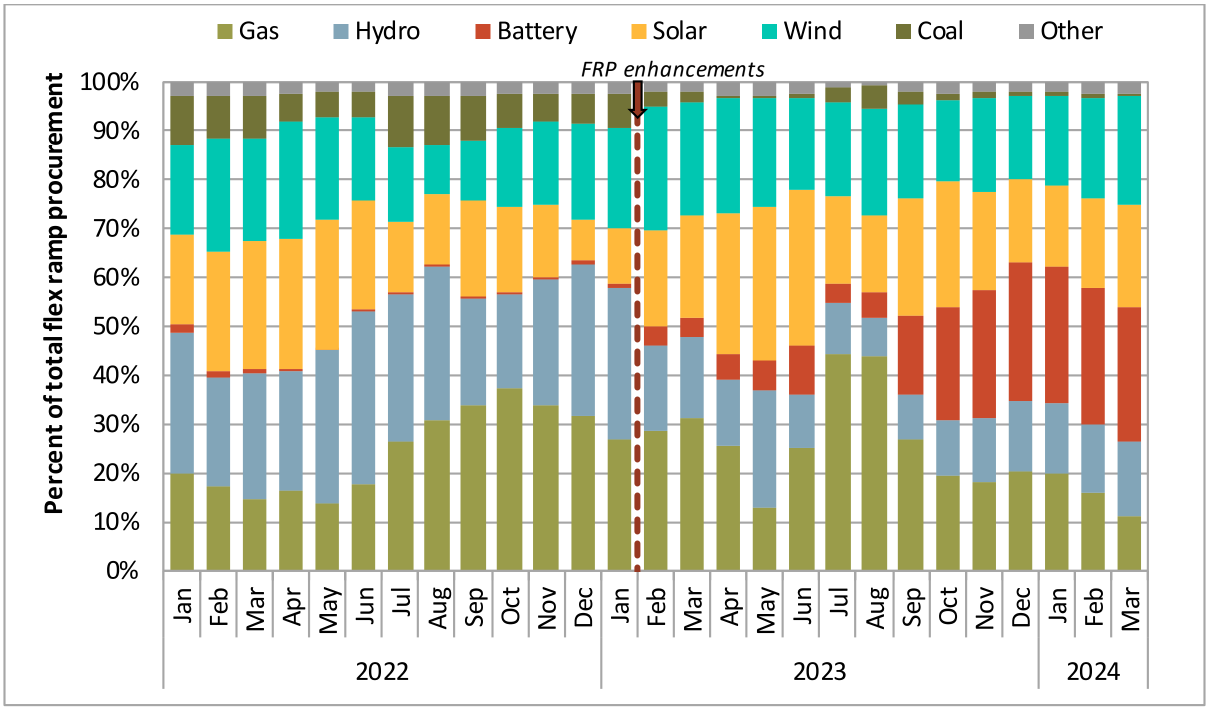


Figure 1.52 Percent of upward system or pass-group flexible ramp procurement by region

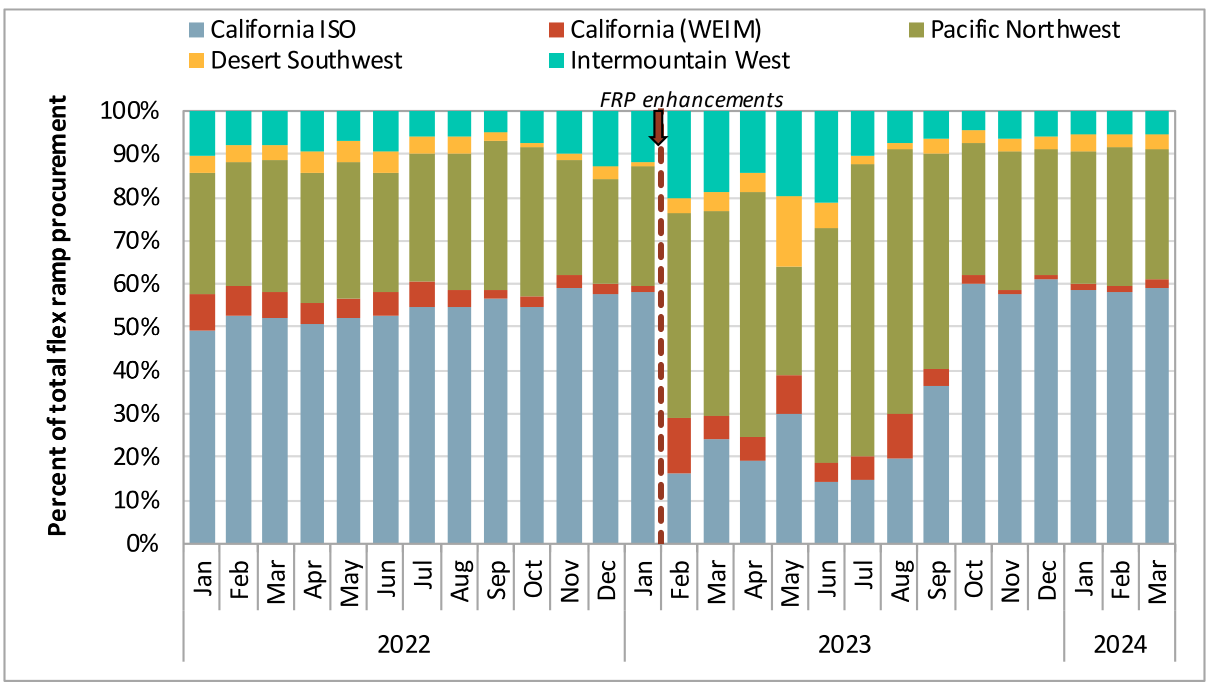
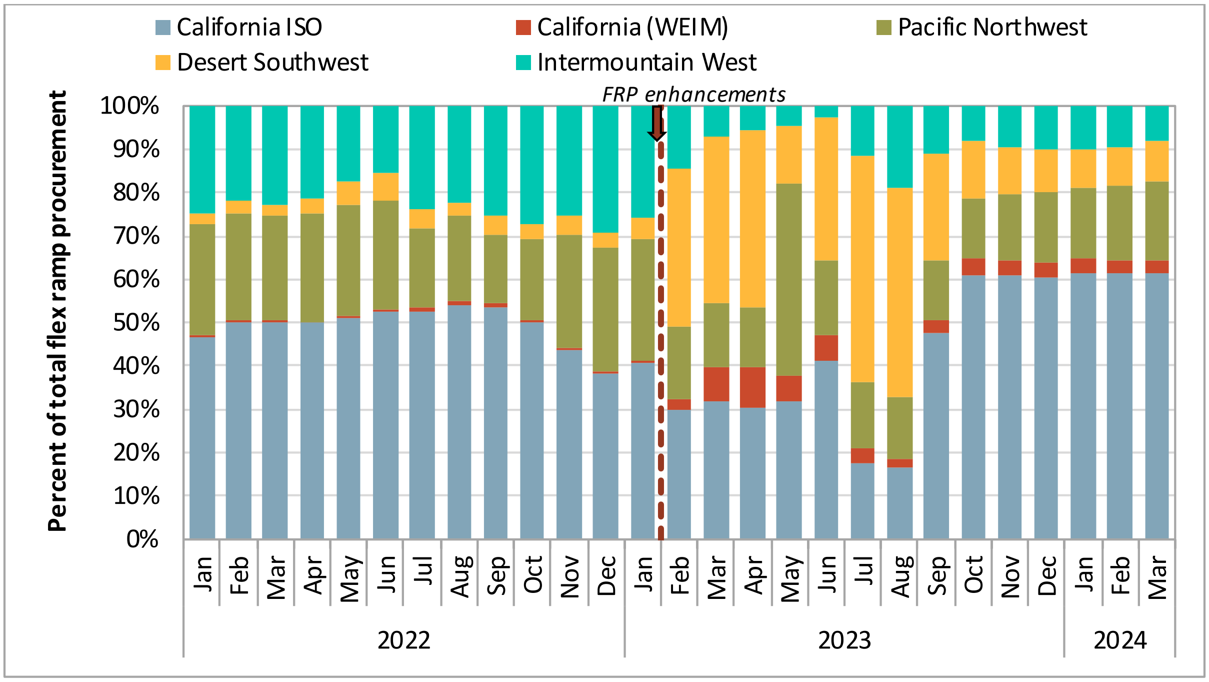


Figure 1.53 Percent of downward system or pass-group flexible ramp procurement by region



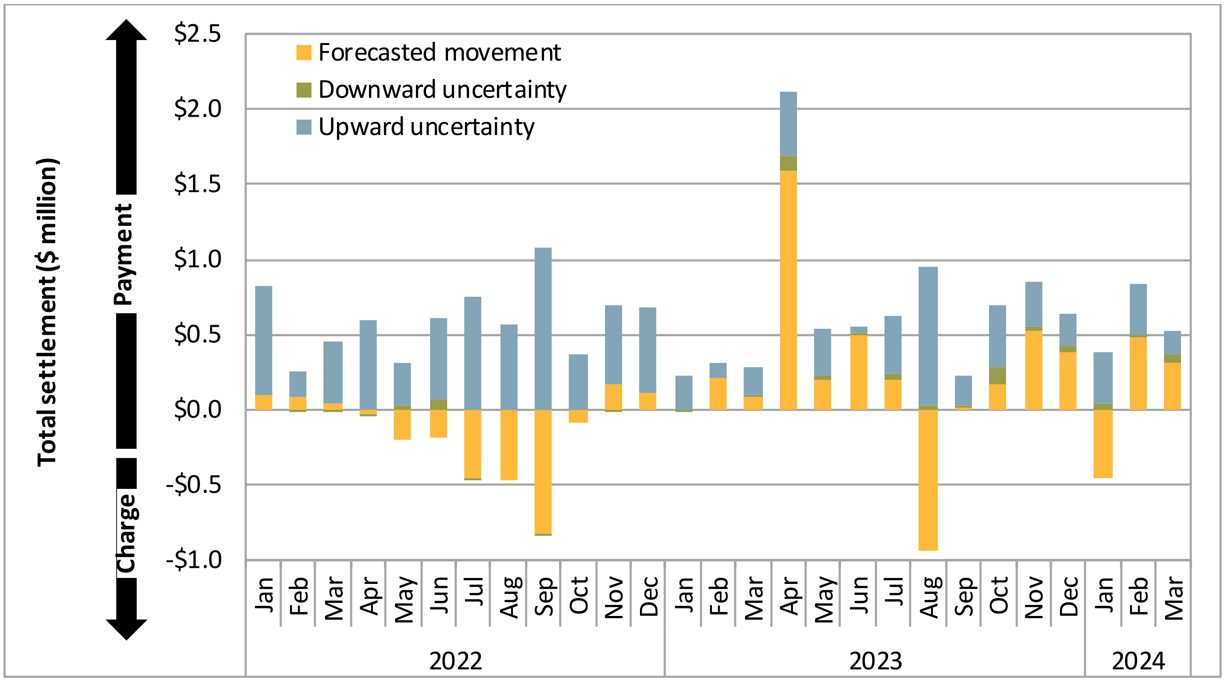
1.12.2 Flexible ramping product settlement

Flexible ramping capacity awards reflect the ability for a resource to ramp above or below their expected schedule in the next interval to address uncertainty that might materialize. Flexible ramping capacity that satisfies the demand for upward or downward flexibility receives payments based on the price for flexible capacity at that node. In addition, the flexible ramping product price is used to pay or charge for *forecasted movements*. Forecasted movement is a resource's expected change in schedule in the next interval. A payment indicates that the resource was given an advisory dispatch by the market in the same direction as the demand for flexibility (e.g., supporting flexibility).[58] A charge indicates that the resource was given an advisory dispatch by the market in the opposite direction as the demand for flexibility (e.g., consuming flexibility).

Figure 1.54 shows the total monthly net payments to resources for flexible ramping capacity to meet upward and downward uncertainty as well as for forecasted movements. Payments for upward and downward uncertainty awards during the first quarter of 2024 were around $1 million, compared to $0.5 million in the first quarter of 2023 and $1.3 million during the first quarter of 2022.

[58] A resource that is given an advisory dispatch by the market to increase output is paid the upward flexible ramping price and charged the downward flexible ramping price. A resource that is given an advisory dispatch by the market to decrease output is paid the downward flexible ramping price and charged the upward flexible ramping price.

Figure 1.54 Monthly flexible ramping product payments (charges) by type

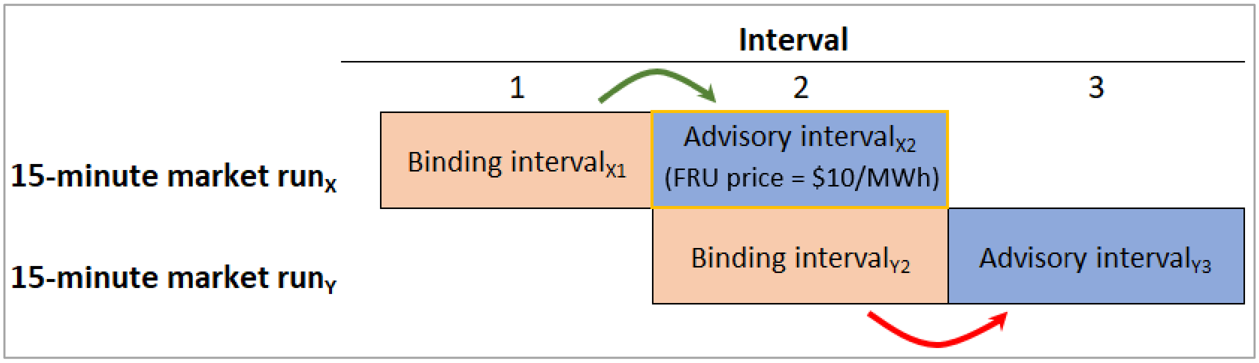


Flexible ramping product error for forecasted movement settlement

The settlement of forecasted movement was incorrect following the implementation of flexible ramping product enhancements on February 1, 2023. The quantity used to settle forecasted movement was incorrectly selected from the following interval in a way that was inconsistent with the price conditions at the time of the movement. The settlement of flexible capacity awards to meet uncertainty was not impacted. The ISO is working on correcting and resettling forecasted movement for the impacted period.

Following the enhancements in February 2023, flexible capacity awards and prices are determined 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. Here, the settled flexible capacity awards and prices exist in the first advisory interval of each market run. The example in Figure 1.55 shows two consecutive 15-minute market runs. The binding intervals are shown in orange and the advisory intervals are shown in blue. Assume there was a price of $10/MWh for upward flexible ramping (FRU) capacity in interval 2 (box with border highlighted yellow). Here, upward *flexible capacity awards* above expected schedules in interval 2 were correctly paid $10/MWh for supporting the demand for flexibility. However, forecasted movement in the following market run—from interval 2 to interval 3—was incorrectly paid or charged $10/MWh based on the direction of the movement (as shown by the red arrow). Forecasted movement from interval 1 to interval 2 (as shown by the green arrow) should have been paid or charged $10/MWh based on the direction of the expected change in schedule. Forecasted movement from interval 2 to interval 3 should have instead been paid the FRU price in the advisory interval Y_3.

Figure 1.55 Example incorrect settlement of forecasted movement



The blue bars in Figure 1.56 show the original settlement of forecasted movement with the error between February 2023 and March 2024 across all balancing areas. The red bars instead show the estimated settlement each month without the error. Payments for forecasted movement in the same direction as the demand for flexibility are shown as positive. Charges for forecasted movement in the opposite direction as the demand for flexibility are shown as negative. During this period, the forecasted movement settlement was around $3.3 million (payment for forecasted movement). Without the error, the settlement for the same period was estimated to be -$2 million (charge for forecasted movement).

Figure 1.57 shows the same information, except by balancing area for the same period. For the Public Service Company of New Mexico (PNM), the forecasted movement settlement with the error was a *payment* of around $0.6 million. Without the error, the settlement was estimated to be a *charge* of around $3 million. For Bonneville Power Administration (BPA), the forecasted movement settlement was around a $0.6 million charge with the error and an estimated $2.6 million charge without the error. For PNM and BPA, the large majority of the difference was associated with failure of the resource sufficiency evaluation in the first 15-minute market interval of the hour. Flexible ramping product procurement and prices in the first interval of each hour is dependent on the second run of the resource sufficiency evaluation at 55 minutes prior to the evaluation hour, based on the latest information available at the time of this market run.[59] In many of these cases, the balancing area failed the second run of the resource sufficiency evaluation such that an area-specific uncertainty requirement was enforced and relaxed at a high price in the first interval of the hour. Here, downward forecasted movement from hourly base-scheduled or intertie resources should have been charged the high interval 1 FRU price for the inter-hour forecasted movement, from interval 4 of the previous hour to interval 1 of the next hour. This inter-hour movement was instead incorrectly charged the interval 4 FRU price. It was the generally smaller intra-hour expected movement from these resources between interval 1 and interval 2 that was incorrectly charged the high interval 1 flexible ramping price.

59 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 hour.

Figure 1.56 Forecasted movement settlement by month

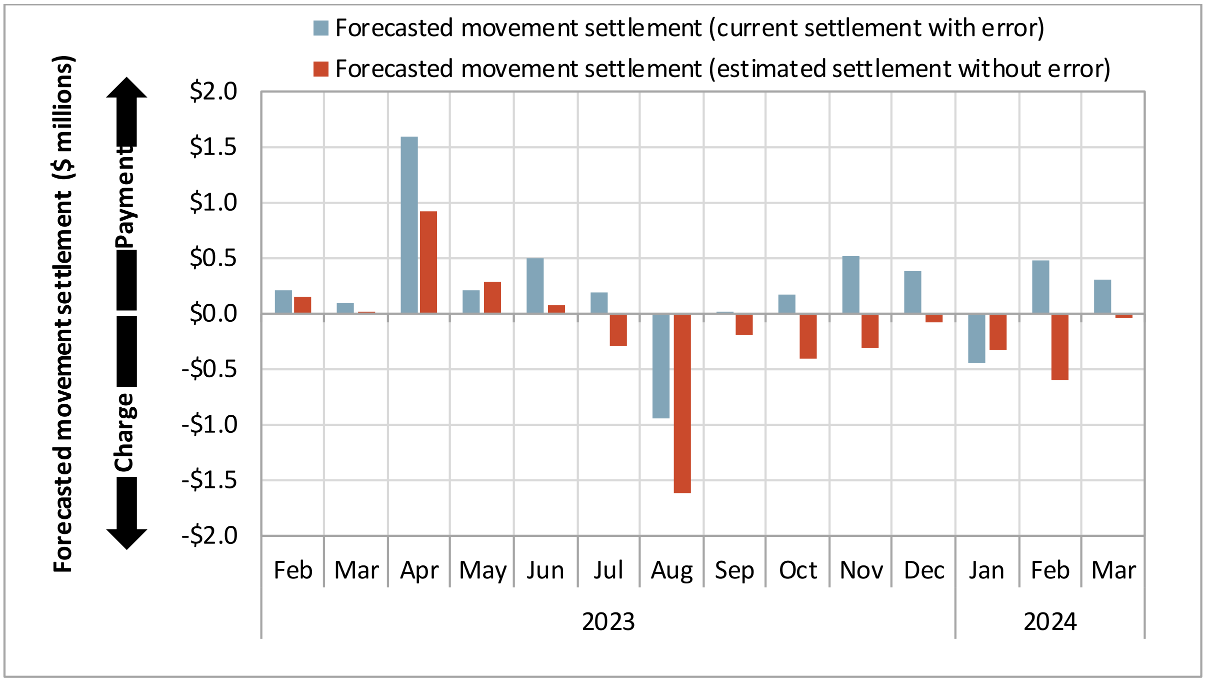
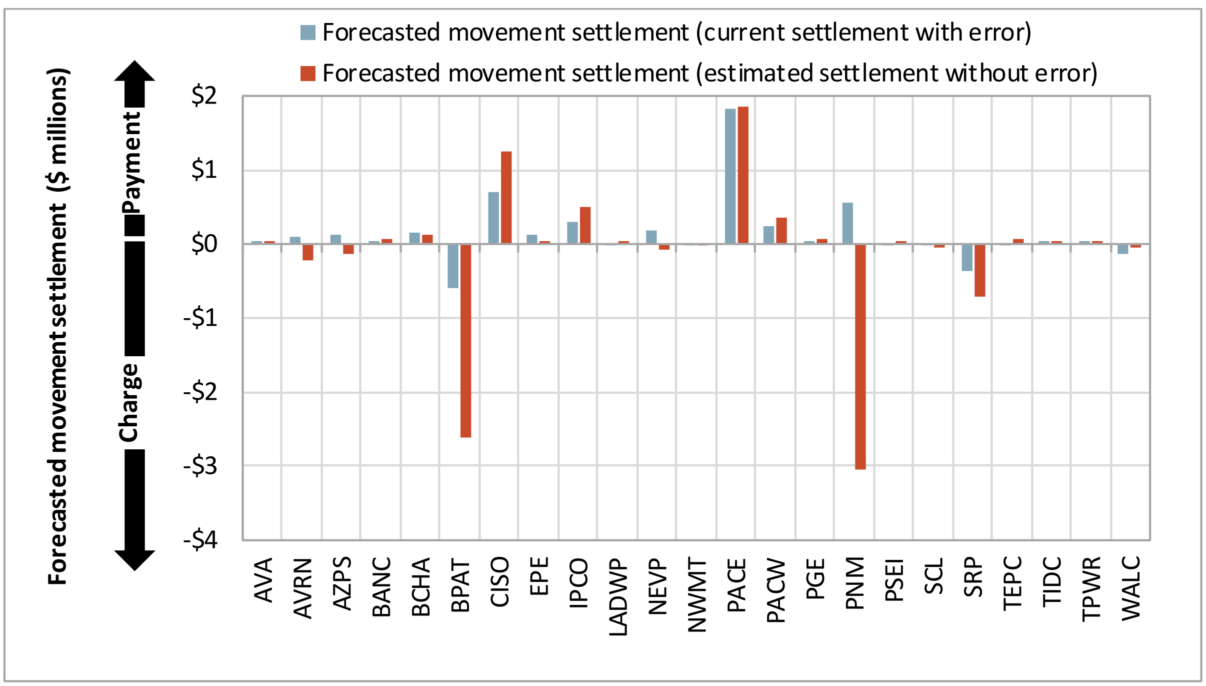


Figure 1.57 Forecasted movement settlement by balancing area (February 2023–March 2024)



1.12.3 Net load uncertainty for the flexible ramping product

The uncertainty requirement is used as part of the flexible ramping product design to capture the extreme ends of net load uncertainty, such that 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. Net load uncertainty is also included in the requirement of the flexible ramp sufficiency test (flexibility test) to capture additional flexibility needs that may be required in the evaluation hour due to variation in either load, solar, or wind forecasts.

The calculation of uncertainty uses 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).[60]

Net load uncertainty for the group of balancing areas that passed the resource sufficiency evaluation

The flexible ramping product uses an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation, which can only be met by flexible capacity within that area. Here, the regressions can be performed in advance and local uncertainty targets can be readily determined based on current forecast information when a balancing area fails the test. However, for the group of balancing areas that pass the resource sufficiency evaluation (known as the pass-group), the uncertainty calculation needs to first know which balancing areas make up this group so that it can perform the regression using historical data accordingly for that group.

To perform the regressions to estimate the pass-group uncertainty, the composition of balancing areas in this group is based on earlier, *advisory* test results for the first and second 15-minute market interval of each hour. In the first interval, the results from the earliest resource sufficiency evaluation (T-75) is used to define the pass-group. In the second interval, the results from the second resource sufficiency evaluation (T-55) is used to define the pass-group. This is based on the latest information available at the time of this process.

However, the current weather information that is ultimately combined with the regression results to calculate uncertainty are instead consistent with the group of balancing areas that are in the pass-group in the *binding* resource sufficiency run for each interval. The binding resource sufficiency run for interval 1 is the second run of the resource sufficiency evaluation (T-55). The binding resource sufficiency run for intervals 2 through 4 is the final resource sufficiency evaluation (T-40). Table 1.6 summarizes this inconsistency by showing which resource sufficiency evaluation run is used for each interval and process.

60 For a detailed explanation of the mosaic quantile regression calculation, see the *Q1 2023 Report on Market Issues and Performance*, Department of Market Monitoring, September 19, 2023, pp 66-70: http://www.caiso.com/Documents/2023-First-Quarter-Report-on-Market-Issues-and-Performance-Sep-19-2023.pdf

Table 1.6 Source of pass-group for determining regression parameters and for calculating uncertainty for flexible ramping capacity

15-minute market interval	Current weather information for calculating uncertainty and flex ramp procurement	Regression inputs and outputs
1	Second run (T-55)	First run (T-75)
2	Final run (T-40)	Second run (T-55)
3	Final run (T-40)	Final run (T-40)
4	Final run (T-40)	Final run (T-40)

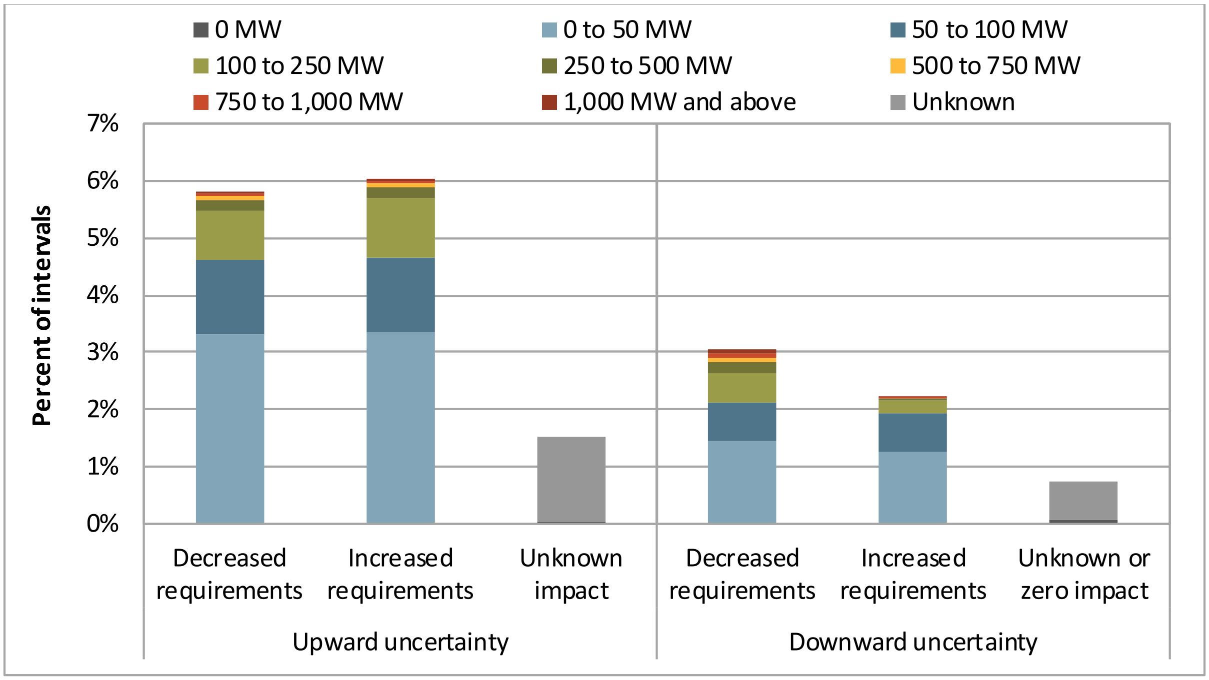
Using one set of balancing areas in the pass-group when determining the regression parameters, and then using a different set of balancing areas in the pass-group when actually calculating uncertainty using those regression parameters, can create significant swings in the calculated uncertainty for the final pass-group. For example, if you have a regression model to predict uncertainty based on forecast information of all but one balancing area passing the test (based on earlier test results), but then combine this with current forecast information of all balancing areas (based on later test results), then the calculated uncertainty can be disconnected from forecasted conditions in the system. DMM has requested that the ISO consider options to resolve inconsistencies in the composition of balancing areas in the pass-group.

During about 18 percent of intervals for the quarter, the composition of balancing areas in the pass-group used for regression information was inconsistent with the composition of balancing areas in the pass-group used for current forecast information. Figure 1.58 summarizes the impact of this inconsistency on pass-group uncertainty requirements in cases when the composition of balancing areas differed between the two sets of data. The figure shows the percent of intervals in which the market uncertainty requirements (with inconsistent balancing areas in the pass-group) were higher or lower than counterfactual uncertainty requirements with a consistent composition of balancing areas in the pass-group.[61] These results are shown separately for the following categories to highlight the impact of this inconsistency on uncertainty requirements.

- **Decreased requirements** indicate that market uncertainty requirements for the pass-group were lower as a result of inconsistent balancing areas in the pass-group.
- **Increased requirements** indicate that market uncertainty requirements for the pass-group were higher as a result of inconsistent balancing areas in the pass-group.
- **No impact** indicates that uncertainty requirements were capped by thresholds in a way that resulted in the same uncertainty requirements.
- **Unknown impact** indicates that there was an inconsistent composition of balancing areas in the pass-group but data was not available to calculate the impact.

61 This analysis accounts for any thresholds that capped, or would have capped, calculated uncertainty requirements.

Figure 1.58 Impact of pass-group inconsistency on uncertainty requirements (January–March 2024)



Threshold for capping uncertainty

Uncertainty calculated from the quantile regressions is capped by the lesser of two ceiling thresholds. The two ceiling thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* ceiling threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from the previous 180 days.[62] The seasonal ceiling 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 is used as the threshold for all hours.[63]

During the quarter, the ceiling thresholds capped *upward* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 11 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 10 percent of intervals in the 15-minute market and 5 percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the seasonal threshold.

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

62 The histogram threshold is updated every day. The distributions are separate for each hour and day type (weekday or weekend/holiday).

63 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.

quantile regression would be negative. During the quarter, downward uncertainty calculated for the group of balancing areas that passed the resource sufficiency evaluation was set near zero by this floor threshold in 0.9 percent of intervals in the 15-minute market, and in 0.2 percent of intervals in the 5-minute market. Upward uncertainty was set near zero by this floor in less than 0.2 percent of intervals in both the 15-minute and 5-minute markets.

Results of mosaic quantile regression uncertainty calculation

Figure 1.59 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation, both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the previous 180 days) 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 month. The dashed red and yellow lines show the average histogram and seasonal ceiling thresholds, respectively, during the period.

Figure 1.60 shows the same information for 5-minute market uncertainty, which reflects the error between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the mosaic quantile regression approach was typically lower or comparable to uncertainty calculated with the histogram approach. In hours-ending 18, 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 uncertainty.

Figure 1.59 15-minute market pass-group uncertainty requirements (weekdays, January–March 2024)

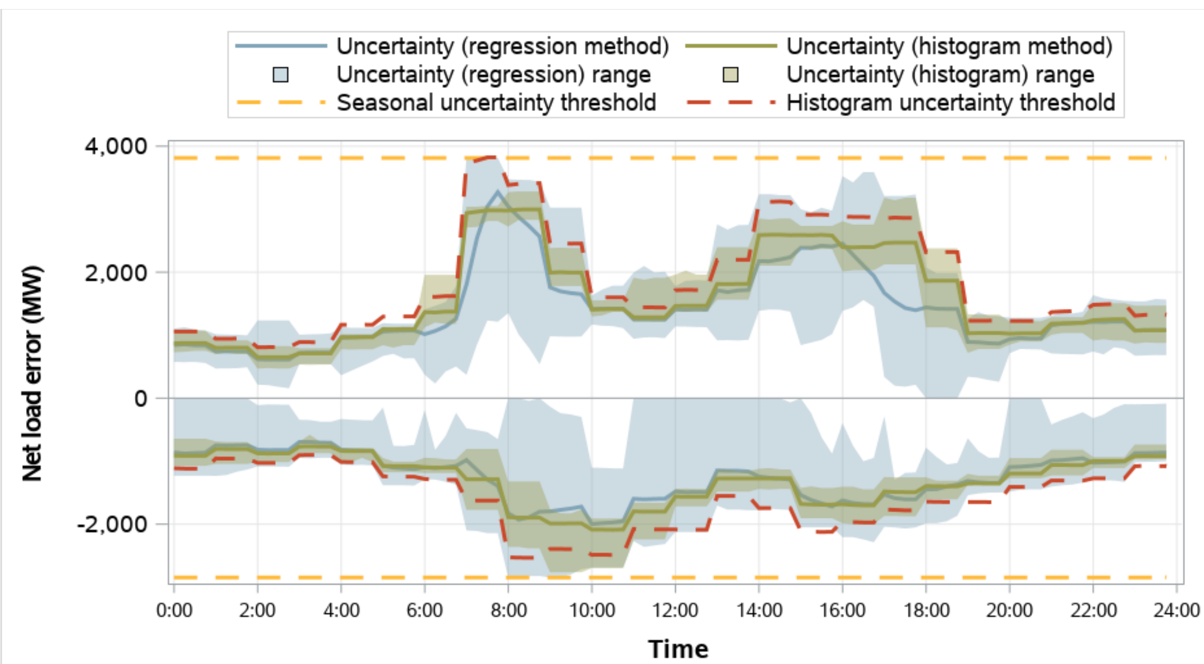


Figure 1.60 5-minute market pass-group uncertainty requirements (weekdays, January–March 2024)

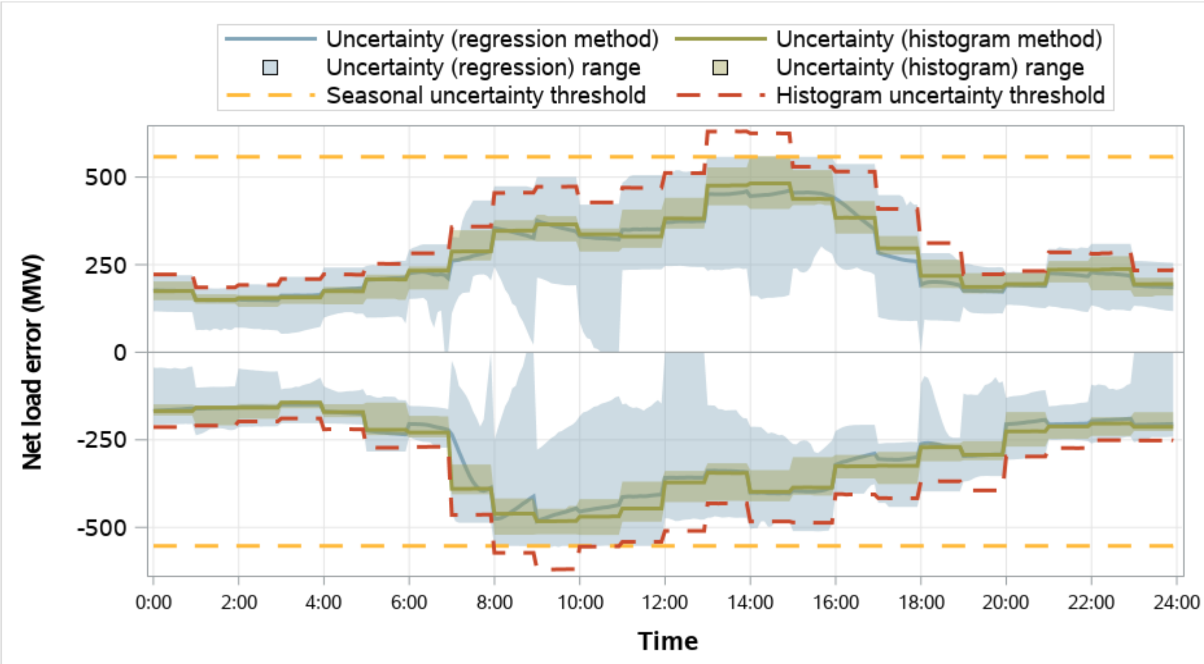


Table 1.7 summarizes the average uncertainty requirement for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. On average across all hours, the 15-minute and 5-minute uncertainty calculated from the regression method was less than the histogram method for both directions.

Table 1.8 summarizes the actual net load error for the pass-group and how that compares to the mosaic regression uncertainty requirements for the same interval.[64] The left side of the table summarizes the closeness of the actual net load error to the pass-group uncertainty requirements when the actual net load error was within (or covered by) the upward or downward requirements. The mosaic regression requirements covered between 94 and 97 percent of actual net load errors across all markets and directions. The right side of the table summarizes when the actual net load error instead exceeded upward or downward uncertainty requirements.

Table 1.9 shows the same information except with requirements calculated from the histogram method. Coverage from the histogram method was more than the mosaic regression method, but by less than 2 percent across all directions and markets.

[64] Actual 15-minute market net load error is measured as the difference between binding 5-minute market net load forecasts and the advisory 15-minute market net load forecast. Actual 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. Both measurements are for the group of balancing areas that passed the resource sufficiency evaluation.

For more information on the calculated uncertainty used in the resource sufficiency evaluation for each balancing area, see DMM's WEIM resource sufficiency evaluation reports.[65]

Table 1.7 Average pass-group uncertainty requirements (January–March 2024)

Market	Uncertainty type	Pass-group uncertainty Histogram	Mosaic	*Difference*
15-minute market	Upward	1,603	1,435	-168
	Downward	1,314	1,250	-64
5-minute market	Upward	274	269	-5
	Downward	291	283	-8

Table 1.8 Actual net load error compared to mosaic regression pass-group uncertainty requirements (January–March 2024)

		Actual net load error falls within calculated uncertainty requirements		*Actual net load error exceeds requirement*	
Market	Uncertainty type	Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	97%	1,489	3%	396
	Downward	94%	1,340	6%	344
5-minute market	Upward	96%	287	4%	89
	Downward	96%	293	4%	97

Table 1.9 Actual net load error compared to histogram pass-group uncertainty requirements (January–March 2024)

		Actual net load error falls within calculated uncertainty requirements		*Actual net load error exceeds requirement*	
Market	Uncertainty type	Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	98%	1,655	2%	416
	Downward	96%	1,381	4%	330
5-minute market	Upward	97%	292	3%	95
	Downward	97%	299	3%	101

65 https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

1.13 Uncertainty calculation assessment

This section reviews the mosaic quantile regression and assesses the regression method for different applications in the market, including the residual unit commitment (RUC) adjustment, flexible ramping product (FRP), and the resource sufficiency evaluation (RSE).

The California ISO introduced a regression method to calculate uncertainty on February 1, 2023.[66] 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.

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. The first 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.[67] 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.

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66 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.

67 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 15-minute market net load forecast.

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 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.[68]

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 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.[69]

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.

68 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/library/market-monitoring-special-reports-presentations-2023

69 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/library/market-monitoring-special-reports-presentations-2023

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 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.[70] 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.

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[70] 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/library/market-monitoring-special-reports-presentations-2023

In the following subsections, this report presents performance metrics for the mosaic quantile regression in the residual unit commitment market adjustment, flexible ramping product uncertainty, and resource sufficiency evaluation uncertainty. Note that these performance metrics are based on the regression coefficients and resulting forecasts from DMM's replication of the ISO's mosaic quantile regression method. The performance metrics are not based on the coefficients and forecasts produced by the ISO.[71]

1.13.1 RUC adjustment

For the residual unit commitment market (RUC) adjustment, uncertainty is defined as the difference between the day-ahead net load forecast and binding 15-minute market forecasts.

Figure 1.61 shows this quarter's distribution of realized uncertainty between the net load forecasts of the day-ahead market and the 15-minute market. The first notable feature is that the uncertainty is symmetric, with values distributed evenly around zero, making zero the most frequently occurring value. The distribution also exhibits a long tail. The area between the red dashed and the black dashed lines highlights the upper 2.5 percent of uncertainty, which ranges from around 2,500 MW to 6,000 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 1.62 shows the daily average RUC adjustment imposed by the CAISO balancing area from December 2023 to March 2024 (blue shaded area). The black dots represent the average realized uncertainty between the RUC and 15-minute market forecasts by day. The chart also shows the results of DMM's replication of the mosaic quantile regression model. These results feature three different percentile quantile regressions. Since the ISO can adjust the percentile value for the RUC adjustment daily, it is challenging to determine the exact percentile used each day in 2024. However, comparing the results of DMM's replication to CAISO's actual RUC adjustments indicates that the majority of the RUC adjustments during this quarter likely used the 75th percentile, with a significant number of days utilizing the 50th percentile. Prior to December 2023, the ISO used the 97.5th percentile to determine the RUC adjustment.

71 This choice is made because there are no statistical significance tests available based on the ISO's estimations. DMM's performance test requires considering statistical significant tests alongside coverage and requirement. Therefore, the requirement and coverage metrics are also based on DMM's replication.

Figure 1.61 Distribution of realized uncertainty between RUC and 15-minute market net load forecasts (January–March, 2024)

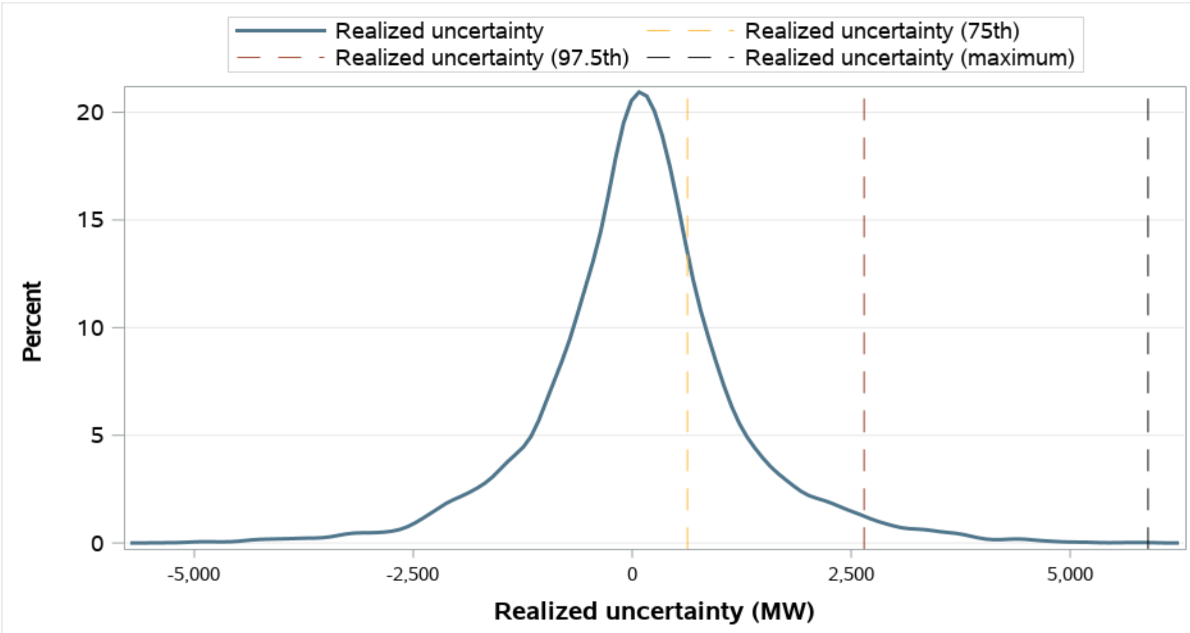


Figure 1.62 Daily average of RUC adjustment replication results

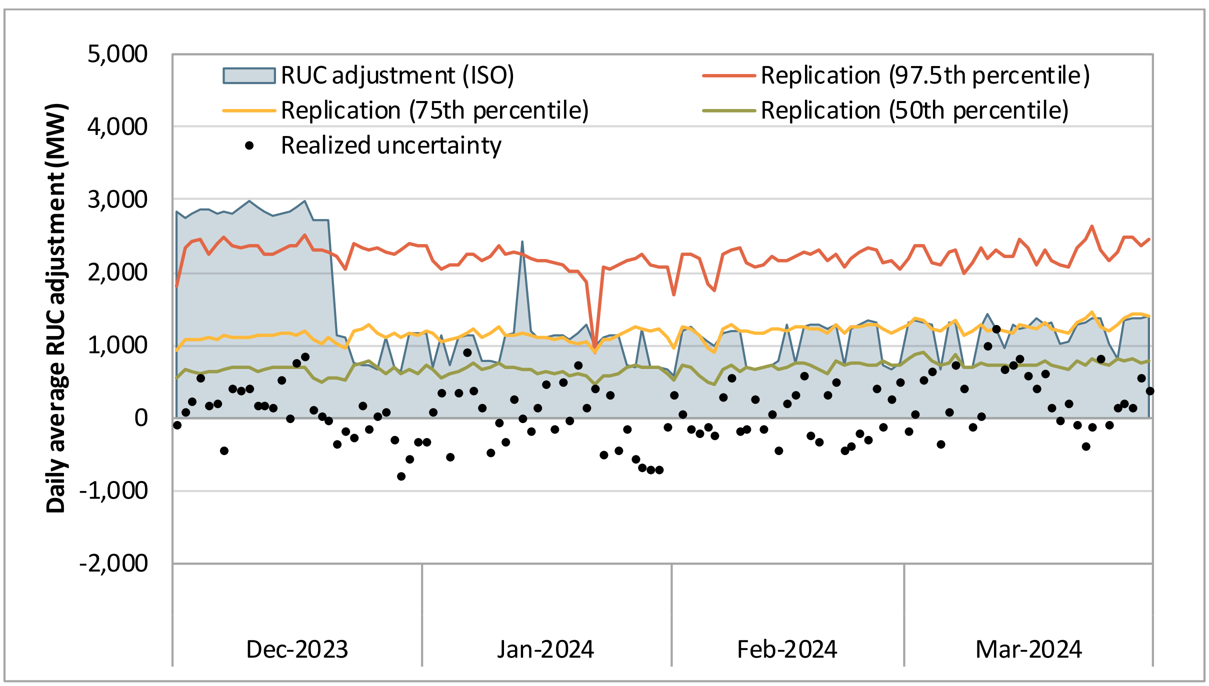


Table 1.10 shows performance metrics for the mosaic quantile regression utilizing DMM's replication of the ISO's mosaic quantile regression model. Each of the first three rows represents the results of DMM's

replication using a different target percentile for upward uncertainty. The last row shows the actual RUC adjustment used by the ISO in the market. The average requirements are divided between all hours and peak hours, with peak hours covering morning and evening ramping periods. In the first quarter, the ISO largely used a combination of the 75th and 50th percentile to calculate the adjustment used in RUC.[72]

The middle section of the table shows the percentage of significant coefficients, indicating how often regression coefficients were statistically different from zero. Notably, the regression targeting the 97.5th percentile shows that only 1 percent of these regressions had significant coefficients. This indicates that 99 percent of the time, the pattern between net load uncertainty and the mosaic variable either did not exist or was unreliable.[73] This low significance is partly due to the 97.5th percentile regression focusing only on 2.5 percent of the sample (about 4-5 data points). The small quantity of data points is insufficient to identify a pattern, leading to non-significant coefficients.

The regression targeting the 50th percentile of uncertainty focuses on all 180 data points. For this regression, still only 26 percent of coefficients were significant during all hours, with this figure rising to 57 percent during peak hours.

The right side of the table shows the coverage rate for DMM's replication of the three regressions and the CAISO area's actual RUC adjustment. As explained above, the coverage rate indicates the percentage of realized uncertainty that falls within the range predicted by the quantile regression. Note that the RUC adjustment is intended to only cover upward uncertainty. Therefore, the coverage rate metric considers all negative realized uncertainty as falling within the regression's prediction range—regardless of how far the 15-minute market load forecast ends up being below the day-ahead market load forecast. The one-sidedness of the prediction range for the RUC uncertainty regression will tend to inflate the coverage rate metric relative to the same regression whose target range was between the 2.5th and 97.5th percentile.

Table 1.10 Mosaic quantile regression performance for RUC adjustment (January–March, 2024)

	Requirement (MW)		Percent of significant coefficients		Coverage	
	All hours	Peak hours(1)	All hours	Peak hours	All hours	Peak hours
Replication (97.5th)	2,187	2,479	1%	3%	99%	99%
Replication (75th)	1,201	1,552	19%	43%	85%	86%
Replication (50th)	700	1,099	26%	57%	67%	72%
ISO	1,094	1,411			82%	81%

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

Figure 1.63 displays a scatterplot of the RUC adjustment used in the market, plotted against the realized uncertainty during the first quarter of 2024. The scatter plot can help to assess if the CAISO balancing

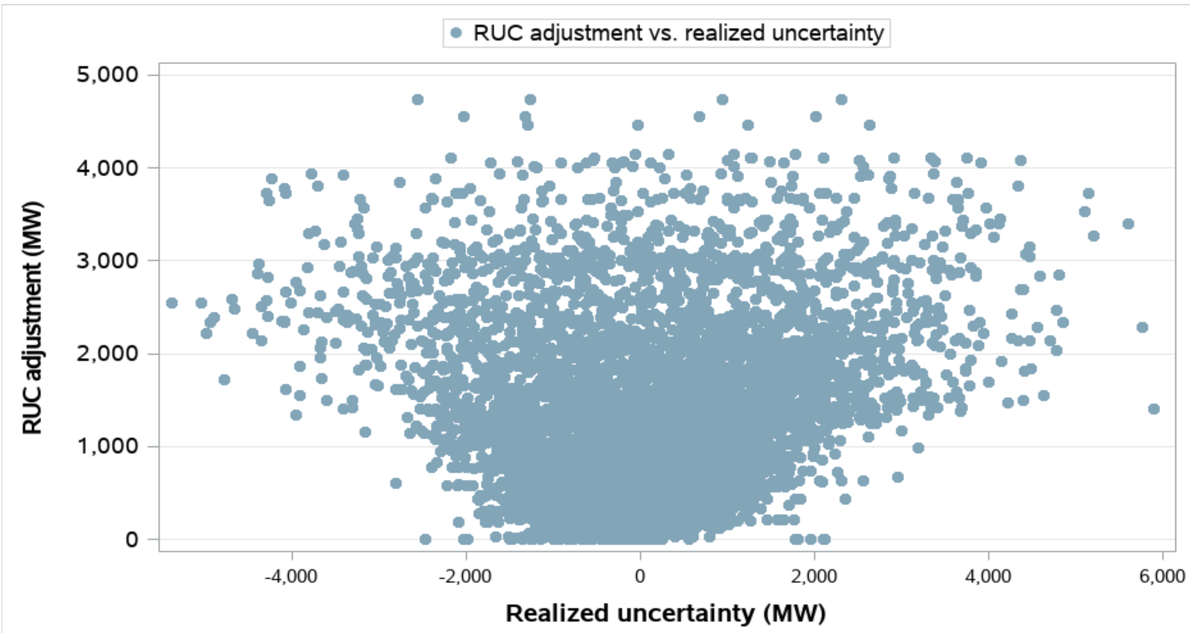
72 The ISO used the 97.5th percentile to calculate the RUC adjustment on January 13 during an extreme cold-weather event.

73 The pattern here refers to the relationship based on percentile values. A 50th percentile regression reflects the overall pattern of all samples, while a 97.5th percentile regression focuses on the extreme cases, representing mostly the upper 2.5 percent of the realized uncertainty and the mosaic variable.

area's overall method for determining the RUC adjustment resulted in setting higher RUC adjustments during periods of greater uncertainty in the day-ahead market net load forecast.

In Q1 2024, there appears to be very little correlation between higher RUC adjustments and higher positive realizations of net load uncertainty. The graph indicates that, regardless of whether the realized uncertainty is high, low, positive, or negative, the RUC adjustment typically varies between 0 MW and 4,000 MW.

Figure 1.63 Comparing RUC adjustments to realized uncertainty (January–March, 2024)



1.13.2 Flexible ramping product

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. Figure 1.64 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 first 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 5,000 MW, reflecting a long tail distribution. These long tails in the distribution could indicate that the uncertainty is influenced by rare, extreme events rather than typical fluctuations.

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

Figure 1.64 Distribution of realized uncertainty in FRP (pass-group, January-March, 2024)

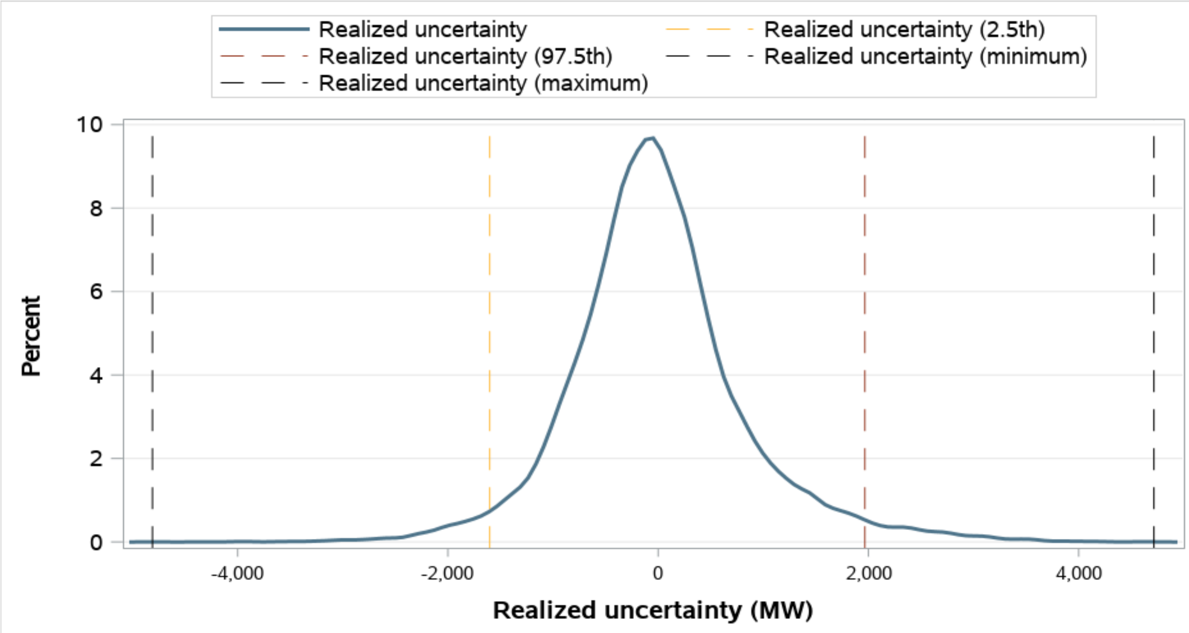


Table 1.11 summarizes performance metrics for the mosaic quantile regression used in the FRP. All metrics in the table are based on DMM's replication, rather than the actual requirements used by the ISO in the market.[74] The table includes the following metrics:

- Percentage of significant coefficients: The table highlights the percentage of significant coefficients across different regressions, including mosaic and three other quantile regressions (load, solar, and wind).[75] The three other quantile regressions contributes to constructing the mosaic variable, and the mosaic regression is used in the final regression to forecast the uncertainty.[76]
- Coverage: This metric compares the coverage rates between the mosaic quantile regression and the histogram method previously used by the ISO, providing insight into how well each method captures the realized uncertainty.
- Requirement: These metric assesses the efficiency of the uncertainty methodologies, comparing the requirements generated by the mosaic quantile regression and the histogram method.

74 The performance of the mosaic regression based on the actual market methodology, which includes some additional thresholds to put ceilings and floors on the mosaic quantile regression outputs, can be found in Section 1.12.3.

75 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.

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/library/market-monitoring-special-reports-presentations-2023

Efficiency metrics are meaningful when paired with the coverage rate. A more efficient method would produces a lower requirement while maintaining the same coverage.

Table 1.11 Mosaic quantile regression performance for FRP (pass-group, January–March, 2024)

Metrics	Type	All hours	Peak hours(1)
Percent of significant coefficient	Mosaic	20%	19%
	Load	14%	16%
	Solar	65%	86%
	Wind	46%	53%
Coverage	Mosaic	94%	95%
	Histogram	93%	93%
Requirement (MW)(2)	Mosaic (M)	1,441	1,532
	Histogram (H)	1,406	1,569
	M/H Ratio(3)	1.03	0.98
	DMM-ISO(4)	166	168

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

(2): The requirement is the average value without the extreme outliers that the regression generates, with the upper and lower 5 percent of extreme requirements removed from this calculation.

(3): The M/H ratio is the requirement of the mosaic quantile regression divided by the histogram requirement.

(4): DMM-ISO indicates the average requirement difference between DMM's replication and the requirement calculated based on ISO's coefficients.

Table 1.11 shows that the coverage and requirements of the mosaic and histogram methods are very similar in the first quarter of 2024. This similarity can be explained by several factors, with a significant factor being the percentage of statistically significant coefficients. The coefficient for the mosaic variable was statistically significant during only 20 percent of intervals.

This means that in 80 percent of cases, the mosaic variable does not show a strong pattern with historical uncertainty.[77] Whether the mosaic variable is high or low, the uncertainty does not consistently respond with similarly high or low levels of uncertainty. Consequently, when looking at future data, even if the mosaic variable is high, it is unclear whether the uncertainty will be high or low.

When the regression relies only on the mosaic variable, which has weak patterns with uncertainty, the outcome becomes very similar to simply analyzing the historical distribution of uncertainty without the mosaic variable—essentially, what the histogram methodology does. The low percentage of significant coefficients is likely to lead to similar requirements and coverage results as the histogram method.

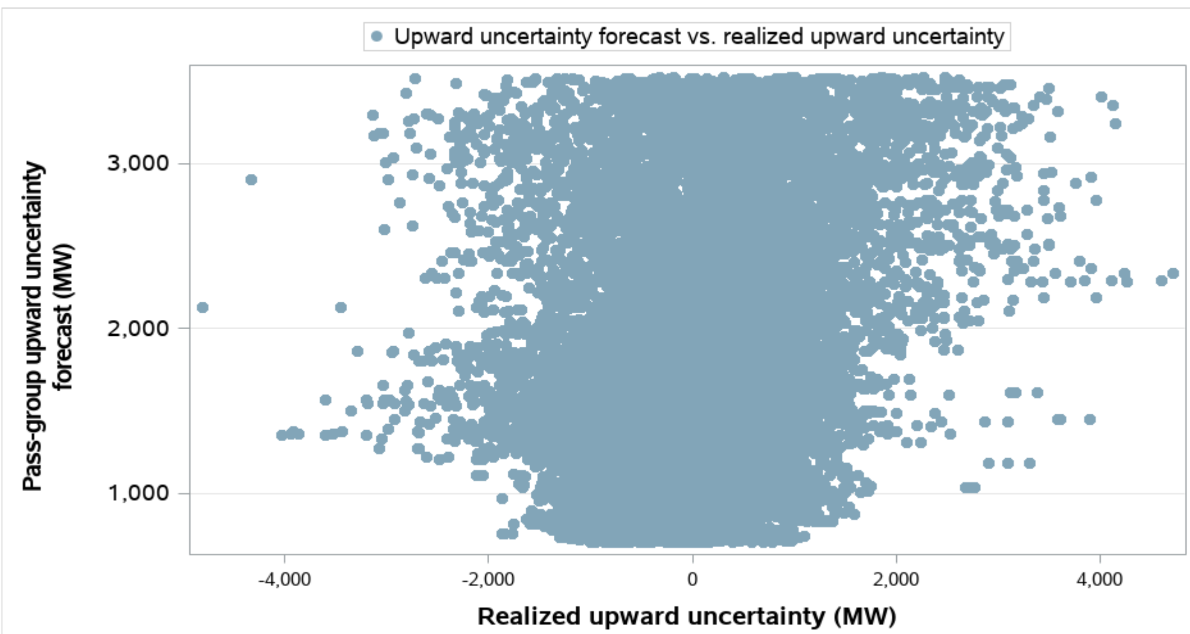
[77] The pattern here corresponds to specific percentile values. When the percentile is set at 97.5th or 2.5th, the pattern reflects the extreme upper and lower 2.5 percent of uncertainty relative to the mosaic variable. If the pattern is strong, it indicates a clear relationship at these extremes. Conversely, a weak pattern suggests that the relationship is less pronounced or not robust.

The mosaic regression shows higher coverage with a similar requirement during peak hours when compared to the histogram. Additionally, this analysis is based on the DMM replication, which tends to produce slightly higher requirements than the ISO calculation. As shown in the last row of Table 1.11, the DMM replication averages around 166 MW higher than the estimates based on the ISO's coefficients.[78]

Figure 1.65 and Figure 1.66 display scatter plots comparing the mosaic regression forecast to the realized uncertainty in both upward and downward scenarios for Q1 2024. As noted above, the DMM replication removes the ceiling and floor thresholds in order to assess the uncertainty forecast produced by the mosaic regression model. However, these plots exclude the top and bottom 5 percent of extreme outliers to focus on the core data.[79]

The analysis explores whether, when realized uncertainty is high, the mosaic method predicts this by setting a higher requirement, and conversely, if realized uncertainty is low, whether the mosaic prediction similarly produces a lower requirement. This pattern is not observed in the scatter plot for Q1 2024. Regardless of whether the realized uncertainty is high, low, or zero, the forecasted values consistently range between 0 and 4,000 MW for upward, and between -500 and -3,000 MW for downward.

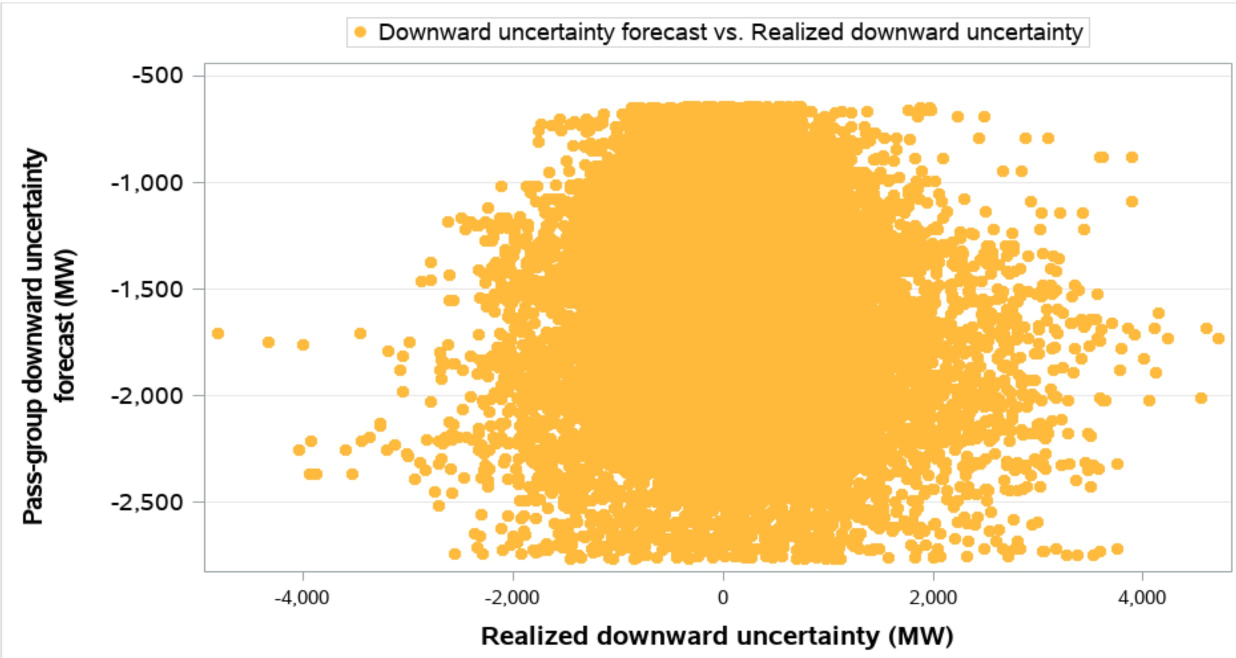
Figure 1.65 Comparing FRP forecast to realized uncertainty (upward pass-group, January–March, 2024)



78 The DMM replication and ISO calculations are based on the same sample and methodology, aside from the DMM replication removing ceiling and floor thresholds. However, the nature of quantile regression requires an algorithm to determine the coefficients. This algorithm can differ from the one used by the ISO. Different algorithms may produce varying coefficients, especially when there is no clear pattern in the data.

79 The decision to remove the outliers stems from the quantile regression producing abnormal requirements, such as a negative 1.3 million MW for flexible ramping down (FRD) this quarter. This issue arises primarily due to the inconsistent composition of the pass-groups and the low percentage of significant coefficients.

Figure 1.66 Comparing FRP forecast to realized uncertainty (downward pass-group, January–March, 2024)



1.13.3 Resource sufficiency evaluation

This section analyzes the performance of the mosaic quantile regression in the resource sufficiency evaluation (RSE). In this section, the realized uncertainty, which the regression should forecast, is the net load forecast difference between the forecasts used in the resource sufficiency evaluation runs and those in the binding 5-minute market runs.

Figure 1.67 shows the distribution of realized uncertainty in the RSE for each balancing authority area (BAA) for the first quarter of 2024. To facilitate comparison across different BAAs, the realized uncertainty has been standardized by its mean and standard deviation. [80] 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.

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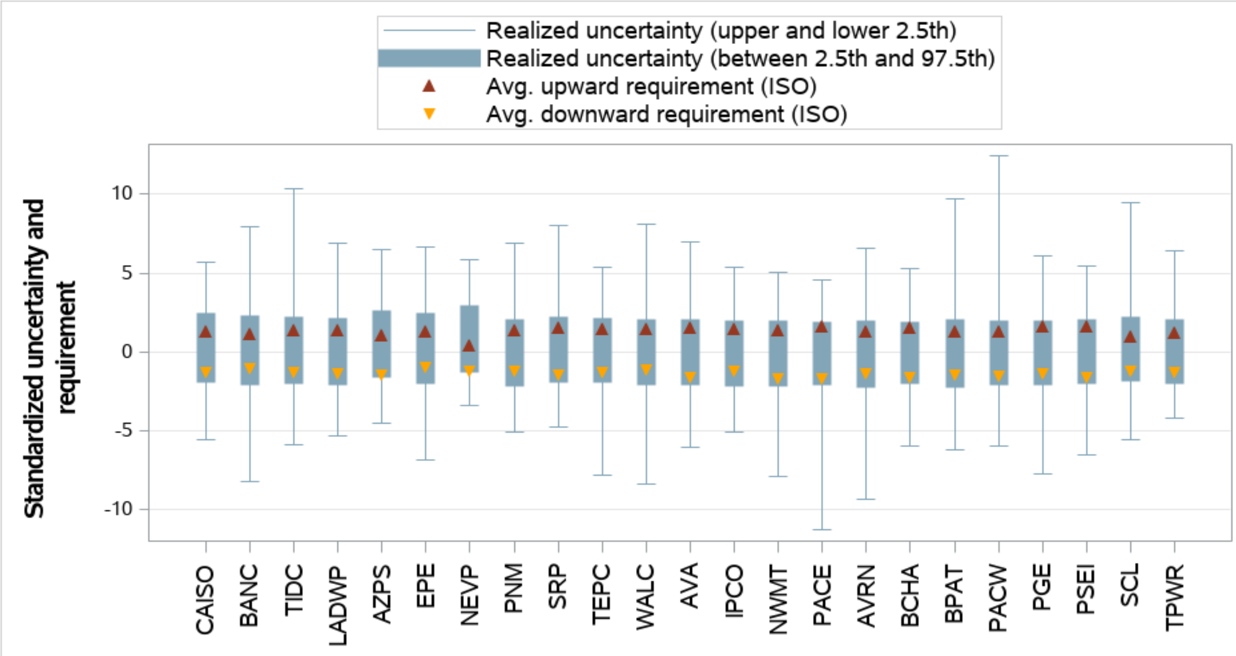
80 Standardizing involves calculating the z-score, which is done by subtracting the mean of uncertainty from each data point and then dividing the result by the standard deviation. This process transforms the data so that it has a mean of zero and a standard deviation of one. This is helpful for comparing 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 1.67 Standardized realized uncertainty and requirement for RSE (January–March, 2024)



This figure 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, while the lines extend to the upper and lower 2.5th percentiles, indicating data extremes. 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, meaning 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 vs. uncertainty**: Generally, the average requirement for each BAA falls within the 2.5th and 97.5th percentiles of realized uncertainty. The 97.5th percentile of realized uncertainty notably exceeded the average upward requirement—or the 2.5th percentile of realized uncertainty was notably lower than the average downward requirement—for NV energy (NEVP), Arizona PS (AZPS), El Paso Electric (EPE), and Seattle City Light (SCL).

Table 1.12 Mosaic quantile regression performance for RSE (January–March, 2024) [81]

BAA	Percent of significant coefficients		Coverage		Requirement (MW)(2)			
	All hours	Peak hours(1)	Mosaic	Histogram	Mosaic (M)	Histogram (H)	M/H Ratio(3)	DMM-ISO(4)
Avangrid	58%	54%	89%	91%	142	184	0.77	4
BPA	28%	29%	86%	88%	200	233	0.86	4
Arizona PS	23%	21%	89%	89%	231	220	1.05	33
Portland GE	23%	23%	88%	87%	124	117	1.05	8
PacifiCorp West	19%	23%	88%	89%	108	111	0.98	9
Avista Utilities	15%	19%	90%	90%	48.5	48.4	1.00	4
NV Energy	13%	20%	82%	83%	174	183	0.95	25
NorthWestern	11%	14%	90%	91%	71.9	73.4	0.98	7
PacifiCorp East	10%	9%	91%	91%	383	372	1.03	26
CAISO	9%	13%	87%	90%	1,074	1,015	1.06	176
Idaho Power	9%	13%	87%	86%	110	109	1.01	7
Powerex	9%	9%	87%	89%	164	151	1.08	17
Seattle City Light	9%	10%	80%	80%	21.0	20.2	1.04	1
El Paso Electric	7%	10%	87%	91%	29.6	32.4	0.91	5
Tucson Electric	7%	10%	85%	88%	76.7	80.9	0.95	3
Salt River Project	7%	11%	89%	91%	102	105	0.97	9
LADWP	6%	10%	89%	88%	150	138	1.08	22
Puget Sound Energy	5%	6%	89%	90%	134	131	1.02	11
BANC	5%	8%	87%	88%	39.5	39.3	1.00	5
Tacoma Power	5%	6%	84%	82%	13.0	11.8	1.10	1
Turlock ID	5%	6%	87%	90%	7.1	7.5	0.95	0
PSC New Mexico	5%	4%	86%	87%	109	108	1.01	12
WAPA - Desert SW	3%	2%	87%	88%	22.6	21.8	1.03	2
Average	**13%**	**14%**	**87%**	**88%**	**154**	**153**	**1.00**	**17**

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

(2): The requirement is the average value without the extreme outliers that the regression generates, with the upper and lower 5 percent of extreme requirements removed from this calculation.

(3): The M/H ratio is the requirement of the mosaic quantile regression divided by the histogram requirement.

(4): DMM-ISO indicates the average requirement difference between DMM's replication and the requirement calculated based on ISO's coefficients.

Table 1.12 summarizes the performance of the mosaic quantile regression for the resource sufficiency evaluation across each BAA, using DMM's replication of the regression. The analysis includes the percentage of significant coefficients during all hours and peak hours, as well as the coverage and requirement comparison between the mosaic and histogram approaches. The BAAs are listed in descending order, starting with those that have the highest percentage of significant coefficients to those with the lowest.

81 The coverage and requirements are calculated based on DMM's replication of the ISO's regression method, without applying the ISO's ceiling and floor thresholds, thus the number may differ from the actual market result. For actual market outcomes, refer to DMM's Western Energy Imbalance Market resource sufficiency evaluation reports: https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

Overall, the coverage rate of the quantile regression forecasts was 87 percent in the first quarter of 2024, far short of the 95 percent target. Seattle City Light and NV Energy had the lowest coverage rates, at 80 percent and 82 percent, respectively. PacifiCorp East had the highest coverage, at 91 percent. This was still below the 95 percent target.

Overall, only 13 percent of regression coefficients were statistically significant in Q1 2024. Additionally, the requirements produced by the regression method were similar to requirements that would have been produced by the histogram method for most BAAs.

As explained in the background section above, a higher percentage of significant coefficients leads to a greater divergence from the histogram method because the regression incorporates the histogram method. When the patterns detected by the regression method are not significant, the regression outcome can closely resemble the histogram, or the forecasts may be irrelevant to the actual uncertainty. The low percentage of statistically significant coefficients suggests that for most BAAs, the advantage of using the mosaic regression over the histogram was minimal in Q1 2024.

Mosaic variable inconsistencies in RSE: regression vs. forecasting

The forecasts used for load, solar, and wind in the resource sufficiency evaluation (RSE) runs are based on data available at the time of each RSE run. These RSE forecasts are typically predicted between 47.5 to 102.5 minutes before the corresponding 5-minute market runs. This uncertainty is what the mosaic quantile regression method should be trying to forecast for the RSE.

However, in determining the coefficients for the regression used to predict RSE uncertainty, the ISO instead uses the difference between the net load forecasts of the first advisory 15-minute market and the corresponding three binding 5-minute markets. The first advisory 15-minute market forecast uses data available when the real-time pre-dispatch (RTPD) run for that interval begins, 45 to 55 minutes before the corresponding 5-minute market runs. This makes the net load prediction used in the first advisory 15-minute market a much shorter-term forecast than the prediction used in the resource sufficiency evaluation runs.

As a result, the determination of the regression coefficients for predicting net load uncertainty for the RSE does not capture the increased net load uncertainty associated with the longer time between RSE net load forecasts and the corresponding 5-minute market runs. Instead, the regression coefficients are built using the shorter-term net load difference between the first advisory 15-minute market and the corresponding 5-minute markets. This is the same data set used to create the regression coefficients for the flexible ramping product. Note that this data set is appropriate to use for creating the regression coefficients for predicting flexible ramping product (FRP) uncertainty, because the net load uncertainty that is being predicted for FRP is the uncertainty between the first advisory 15-minute market and the three corresponding binding 5-minute markets. This is not the case for the uncertainty that the regression should be trying to predict for the resource sufficiency evaluation.

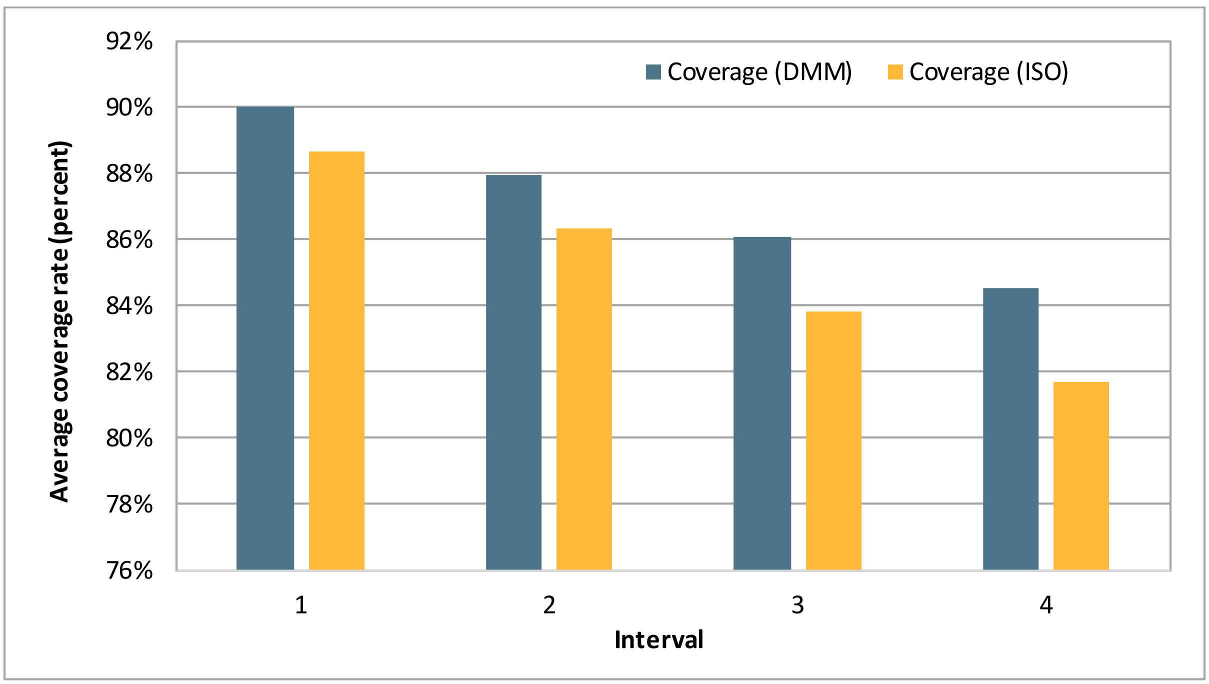
To create the regression coefficients for the resource sufficiency evaluation, the ISO constructs the mosaic variable based on the first advisory 15-minute market forecast rather than the long-term RSE forecast. The regression then identifies patterns between this short-term net load uncertainty and the mosaic variable in past data. For example, past patterns may show that a high mosaic variable correlates with high uncertainty, while a low mosaic variable correlates with low uncertainty.

The mosaic variable that gets multiplied by these regression coefficients to predict uncertainty in the upcoming RSE runs' net load forecast uses the long-term RSE forecast rather than the shorter-term first advisory 15-minute market forecast that was used to create the regression coefficients. This creates an inconsistency in the mosaic variable used to define historical patterns in uncertainty and the mosaic variable used for forecasting.[82] While the long-term and short-term forecast-based mosaic variables are likely correlated, their characteristics can differ due to the longer timeframe involved in the RSE. These two forecasts may have different characteristics in terms of trends and volatility, as seen in the discrepancies between day-ahead, 15-minute, and 5-minute forecasts.

This inconsistency likely results in lower performance in coverage rate for the resource sufficiency evaluation requirements. Figure 1.68 shows the average coverage rate across all BAAs by interval. The blue bar represents the coverage rate based on the DMM replication, while the yellow bar indicates the average coverage rate from the requirements actually used in production by the ISO. The chart shows a clear trend in Q1 2024, where the coverage rate decreases from interval 1 to interval 4.

The decline in coverage rate from interval 1 to interval 4 can be attributed to the inconsistency between the mosaic variable used in regression and forecasting, described above. For interval 1, the RSE forecasting horizon is similar to that of the first advisory 15-minute market forecast. However, intervals 3 and 4 introduce greater discrepancies, with RSE interval 4 having more than double the forecasting horizon of the first advisory 15-minute market forecast.

Figure 1.68 Average coverage rate by intervals in RSE (January–March, 2024)



82 For further information on the mismatch, details can be found in the Western Energy Imbalance Market resource sufficiency evaluation reports: https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

1.14 Exceptional dispatch

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.

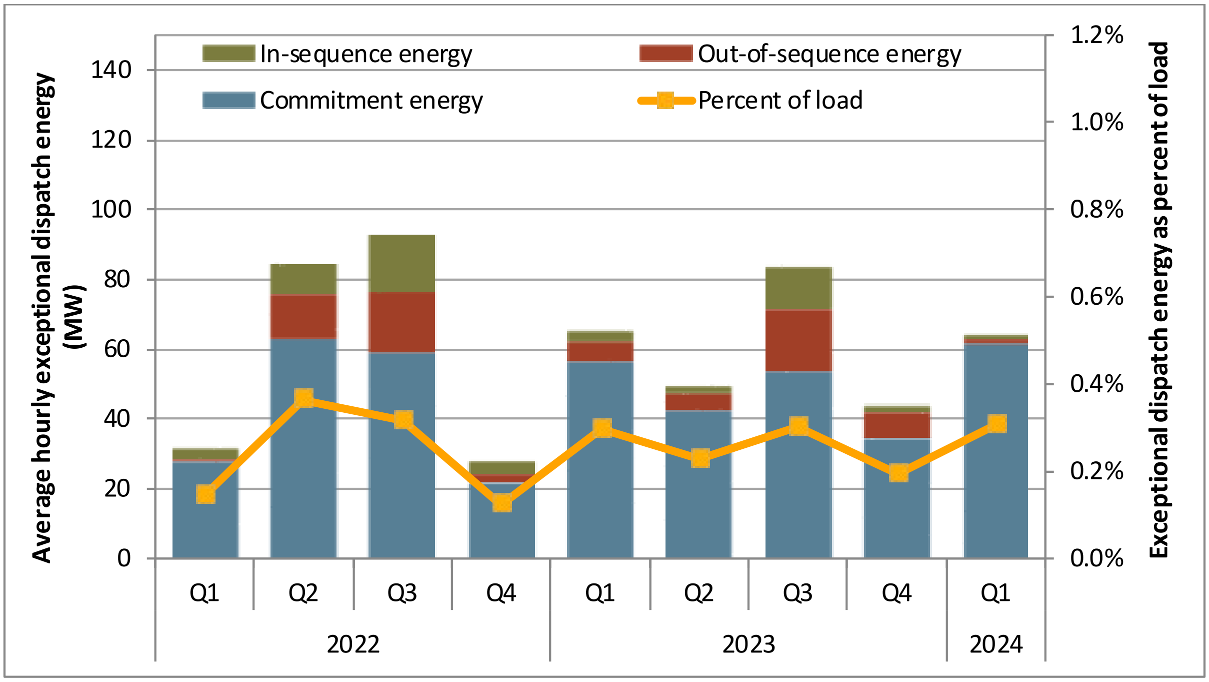
Energy from exceptional dispatch

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 1.69. As shown in Figure 1.69, the average hourly total energy from exceptional dispatches, including minimum load energy from unit commitments, was 64 MW in the first quarter of 2024, which is similar to the 65 MW in the first quarter of 2023.[83]

In the first quarter of 2024, exceptional dispatches for unit commitments (blue) accounted for about 95 percent of all exceptional dispatch energy—about 3 percent was from out-of-sequence energy (red), and the remaining 2 percent was from in-sequence energy (green), as shown in Figure 1.69.

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

Figure 1.69 Average hourly energy from exceptional dispatch



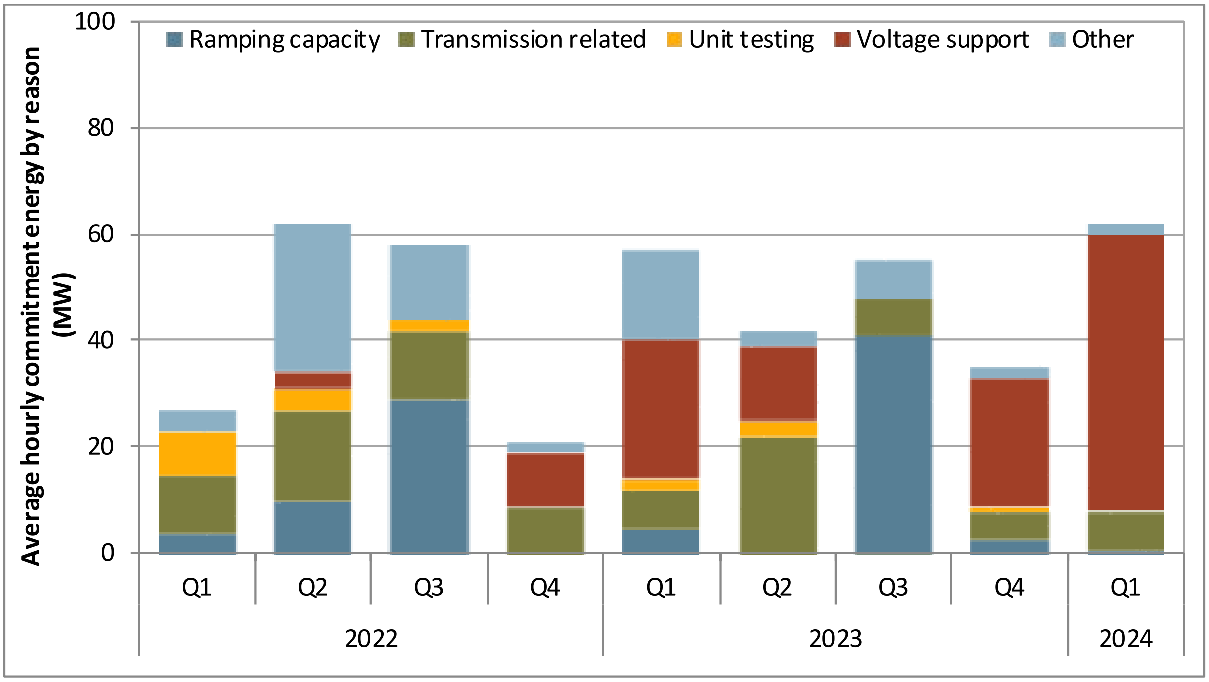
Exceptional dispatches for unit commitment

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 1.70 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 average minimum load energy from unit commitment exceptional dispatches in the first quarter of 2024 was 62 MW which was slightly above the 57 MW of average minimum load energy from unit commitment in the first quarter of 2023.

Commitment energy for voltage support accounted for 84 percent of the average minimum load energy in the first quarter of 2024. This large proportion of exceptional dispatch commitment energy logged as voltage support is likely the result of a set of pumped storage resources that have historically played a pivotal role in voltage support taking outages in February and March. The pumped storage resources' exceptional dispatches for voltage support were frequently into their pumping range, which means that the resource is dispatched to draw energy rather than to generate minimum load. Such exceptional dispatch instructions are not considered commitment energy. An alternative set of thermal resources were committed via exceptional dispatch instructions to provide voltage support in the absence of the pumped storage resources on outage. Those dispatches appear in the market as minimum load energy from exceptional dispatch unit commitments.

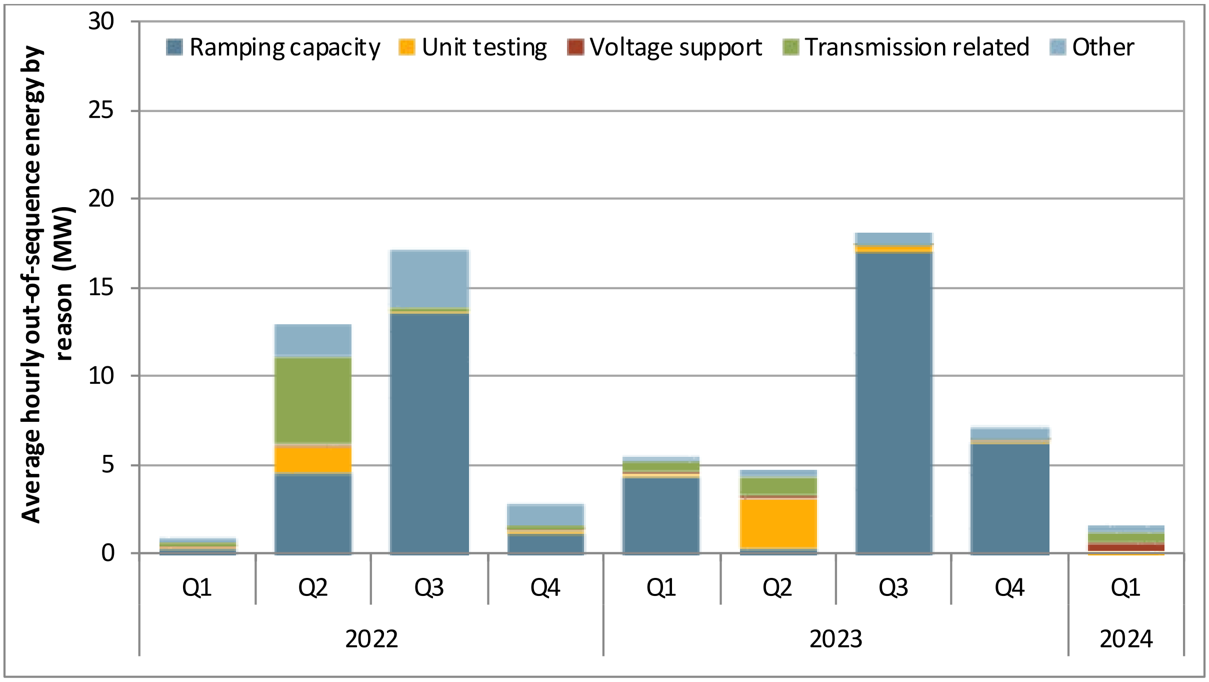
Figure 1.70 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Figure 1.71 shows the average out-of-sequence exceptional dispatch energy by quarter for 2022, 2023, and the first quarter of 2024. The primary reasons logged for out-of-sequence energy in the first quarter of 2024 were transmission related and voltage support. Transmission related exceptional dispatches are issued to mitigate the effects of incomplete or incorrect information on the transmission network or transmission line maintenance. Voltage support exceptional dispatches are issued to ensure that proper voltage is maintained on the grid via the generation or absorption of reactive power by the exceptionally dispatched resources.

Figure 1.71 Out-of-sequence exceptional dispatch energy by reason



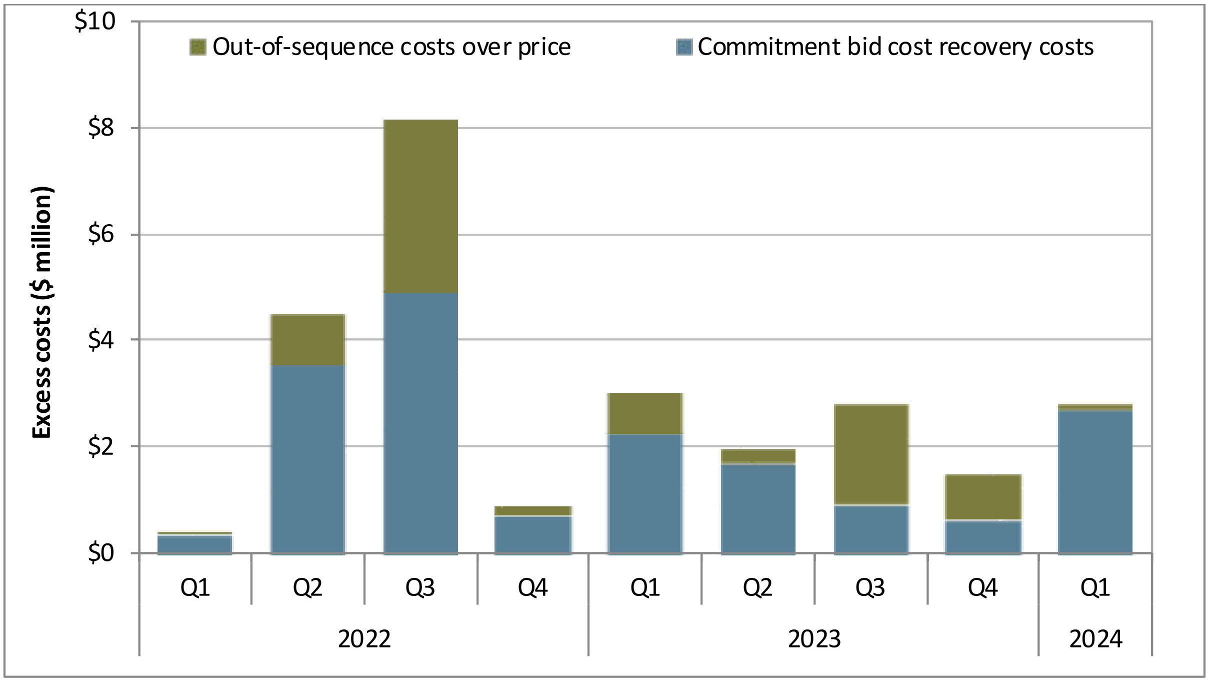
Exceptional dispatch costs

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 1.72 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 first quarter of 2024, out-of-sequence energy costs were $0.14 million, an 81 percent decrease from the first quarter of 2023. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the first quarter of 2024 were $2.7 million, a 20 percent increase from the first quarter of 2023. Overall, the additional costs associated with the exceptional dispatches in the first quarter of 2024 decreased by 7 percent when compared to the first quarter of 2023.

Figure 1.72 Excess exceptional dispatch cost by type



2 Western Energy Imbalance Market

The Western Energy Imbalance Market (WEIM) allows balancing authority areas outside of the California ISO balancing area (CAISO) to voluntarily take part in the ISO real-time market. The WEIM was designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instructions, reducing renewable curtailment, and reducing total requirements for flexible reserves.

The California ISO real-time market software solves a cost minimization problem for dispatch instructions to generation considering all of the resources available to the market, including both the WEIM and CAISO areas. This can allow the market to increase efficiency by optimizing *energy transfers* economically in real-time between WEIM areas—balancing supply and demand across the footprint with lower-cost generation. Energy transfers between balancing areas also help to reduce curtailment of low cost renewables during times of excess generation.

This section covers Western Energy Imbalance Market (WEIM) performance during the first quarter.

2.1 Mid-January cold weather event

Between January 12 and January 16, WEIM balancing areas in the Pacific Northwest and Intermountain West regions experienced an extreme cold weather event.[84] For the balancing areas affected, notably high loads contributed to strained supply conditions, high prices, and an increase in resource sufficiency evaluation failures. This section summarizes loads, prices, and resource sufficiency evaluation failures during this period.

WEIM load during cold weather event

Extreme cold temperatures across the Northwestern United States drove very high loads for many of the balancing areas participating in the WEIM. Figure 2.1 shows the average 5-minute market load for non-CAISO balancing areas in the WEIM for each day by region.[85] On each day between January 12 and January 16, combined load for balancing areas in the Pacific Northwest and Intermountain West regions averaged over 45,000 MW. Load for balancing areas in these regions also peaked over 50,000 MW each day during this period.

Table 2.1 shows the peak 5-minute market load and date for each balancing area during the first quarter. Each balancing area in the Pacific Northwest and Intermountain West regions experienced peak load between January 12 and January 16, 2024.

84 *Winter Conditions Report for January 2024*, California ISO, March 6, 2024: https://www.caiso.com/Documents/WinterMarketPerformanceReportforJan2024.pdf

85 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.

Figure 2.1 Average WEIM load by region (January 2024)

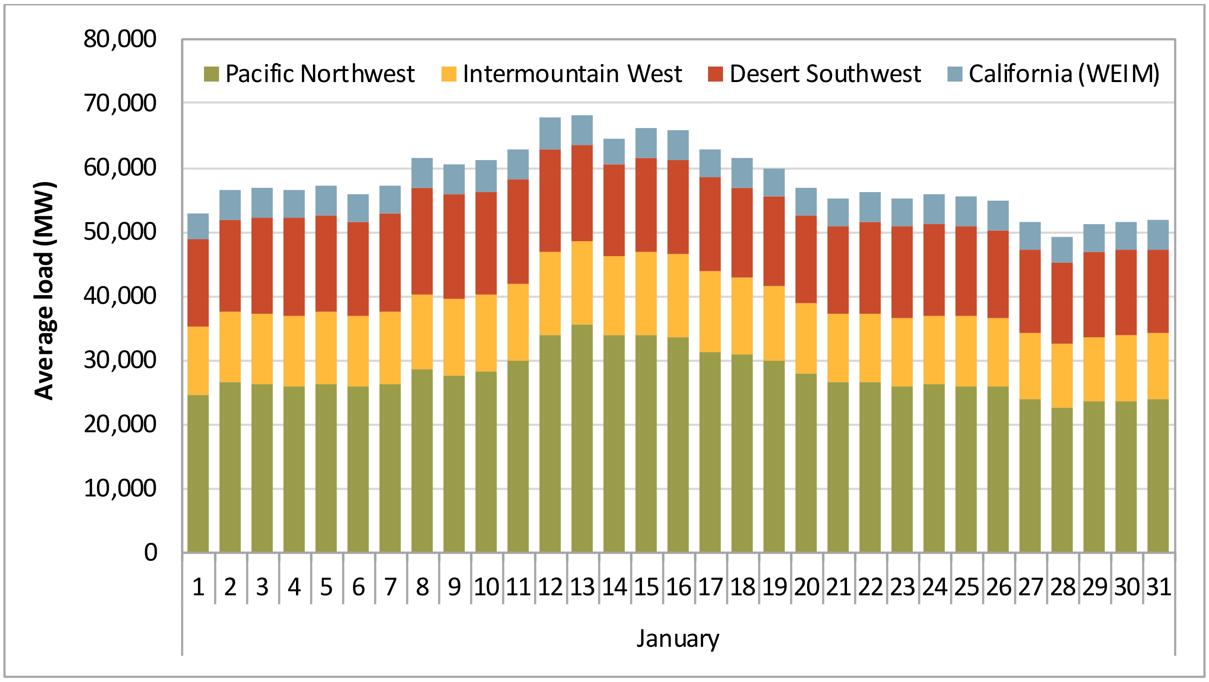


Table 2.1 Peak WEIM load (January–March, 2024)

Region/ balancing area	Peak load (Q1 2024) Date	Load (MW)
California		
California ISO	8-Jan-24	28,511
BANC	9-Jan-24	2,177
LADWP	6-Feb-24	3,274
Turlock Irrig. District	12-Jan-24	350
Desert Southwest		
Arizona Public Service	12-Jan-24	5,182
El Paso Electric	8-Jan-24	1,186
NV Energy	11-Jan-24	4,756
PSC New Mexico	8-Jan-24	2,082
Salt River Project	9-Jan-24	4,676
Tucson Electric	9-Jan-24	1,899
WAPA - Desert SW	20-Mar-24	284
Intermountain West		
Avista Utilities	13-Jan-24	2,345
Idaho Power	16-Jan-24	3,024
NorthWestern Energy	13-Jan-24	2,100
PacifiCorp East	16-Jan-24	7,075
Pacific Northwest		
BPA	13-Jan-24	11,371
PacifiCorp West	16-Jan-24	3,999
Portland General Electric	16-Jan-24	4,053
Powerex	12-Jan-24	12,271
Puget Sound Energy	12-Jan-24	5,344
Seattle City Light	12-Jan-24	1,949
Tacoma Power	12-Jan-24	971

WEIM prices during cold weather event

During the peak of the cold-weather event, balancing areas in the Pacific Northwest and Intermountain West regions were frequently import constrained, with very high prices relative to the rest of the footprint. These prices reflected regional conditions within this group of balancing areas. Figure 2.2 and Figure 2.3 show average 15-minute and 5-minute market prices by component, respectively, for each balancing area between January 13 and January 15. Prices in the 15-minute market for most of the balancing areas in the Pacific Northwest and Intermountain West regions were between $780/MWh and

$940/MWh on average across all hours during this period.[86] Prices in the 5-minute market for the same balancing areas were between $850/MWh and $950/MWh on average across all hours.

The system marginal energy price (SMEC) is the same for all WEIM entities, based on the marginal cost of energy at a reference location in the California ISO balancing area. The congestion on the WEIM transfer constraints (red bars) reflects the price impact because of WEIM transfer congestion that might separate the balancing area from the California ISO (or connected WEIM system).[87]

When transfer capacity limits 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. On average across all hours between January 13 and January 15, prices in most of the Pacific Northwest and Intermountain West regions were significantly higher than the rest of the system because of WEIM transfer congestion.

The yellow and teal bars summarize the price impact from transmission constraints within the California ISO or from balancing areas within the WEIM. Congestion on south-to-north transmission constraints also contributed to the price separation in the Pacific Northwest and Intermountain West regions. The California-Oregon Intertie (COI) nomogram (6110_COI_S-N) in the CAISO area along with the BPA-area constraint, NWACI_SN, were used to manage the flow from California to Oregon. These constraints contributed to higher prices in the Northwest areas and lower prices in the California and Desert Southwest areas.

86 Including NorthWestern Energy, Avista, Avangrid, Portland General Electric, Tacoma Power, Seattle City Light, Puget Sound Energy, PacifiCorp West, and BPA.

87 This accounts for any constraint that can 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). Definitions for the other components are provided in Appendix A.

Figure 2.2 Average 15-minute market prices by component (January 13 to January 15, 2024)

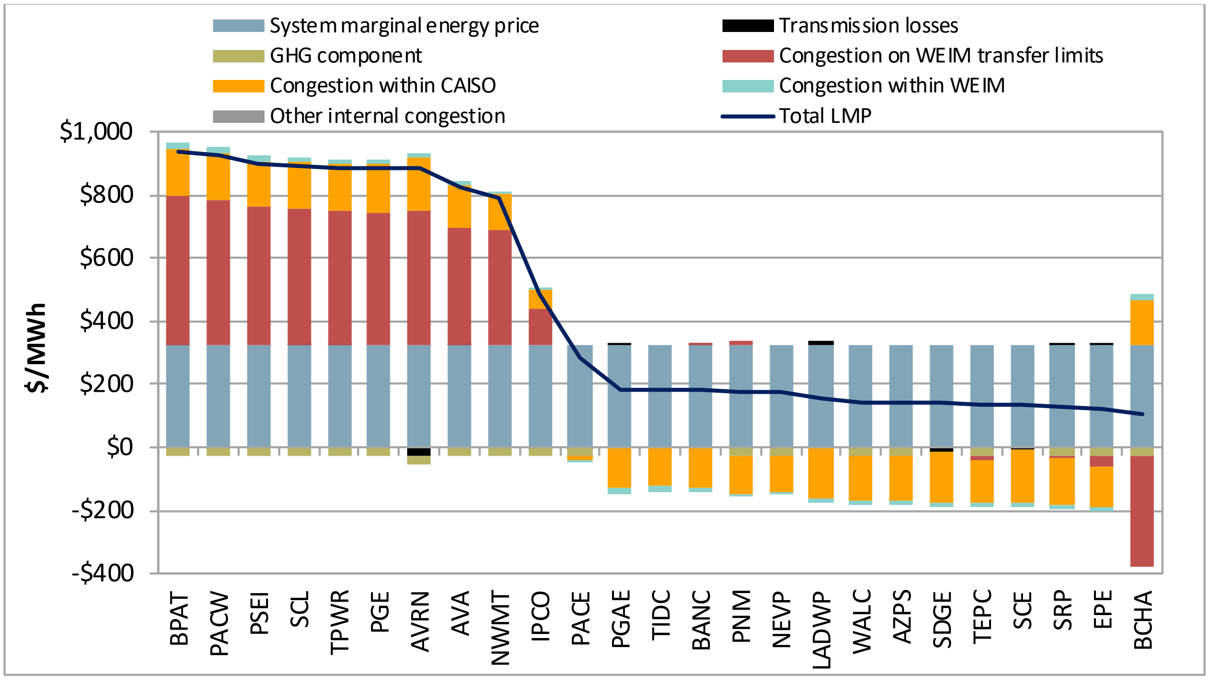


Figure 2.3 Average 5-minute market prices by component (January 13 to January 15, 2024)

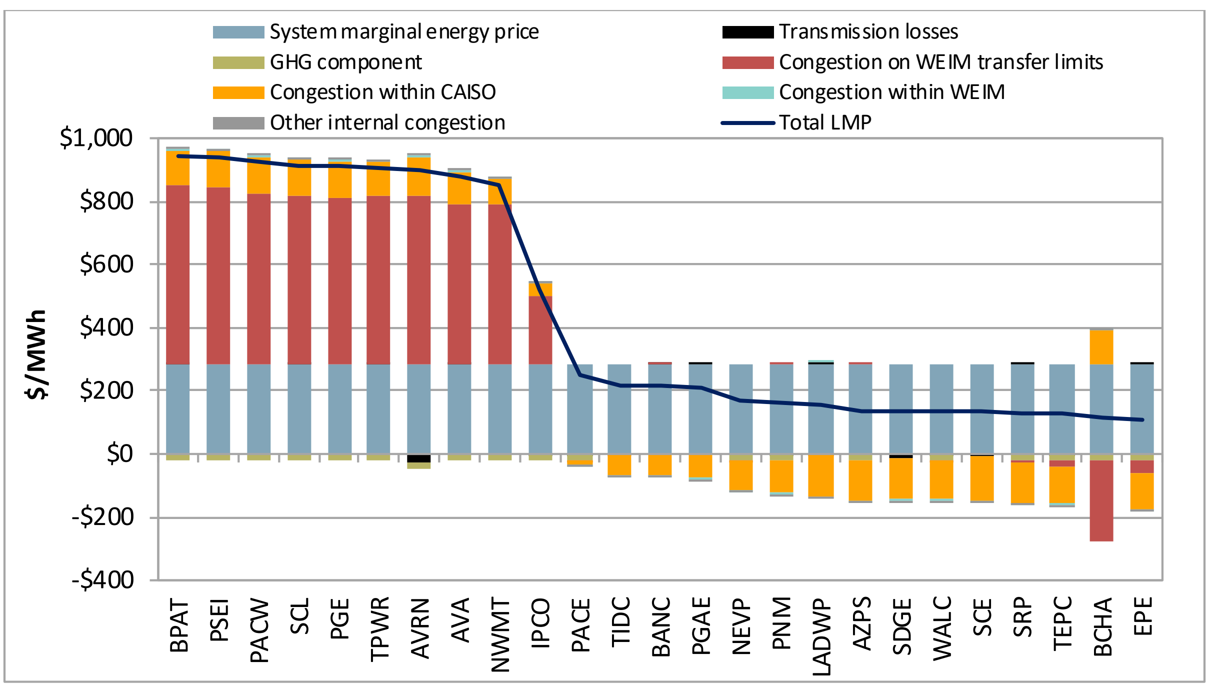


Table 2.2 shows the percent of intervals with WEIM transfer constraint congestion in each balancing area, between January 13 and January 15. *Congested from area* reflects that prices are lower in the balancing area because of limited export capability out of the area or region, relative to the CAISO balancing area. *Congested into area* reflects that prices are higher within an area, because of limited import capability into the area or region.[88]

Balancing areas in the Pacific Northwest and Intermountain West regions were frequently import constrained during the cold-weather event. NorthWestern Energy, Avista, Portland General Electric, Tacoma Power, Seattle City Light, Puget Sound Energy, PacifiCorp West, and BPA were import constrained in around 74 percent of intervals in the 15-minute market and 82 percent of intervals in the 5-minute market. This congestion limited the ability for excess supply in the surrounding WEIM system to address high-load conditions in the Northwest.

Powerex was instead frequently export constrained between January 13 and January 15, during 98 percent of 15-minute intervals and 93 percent of 5-minute intervals. Because of WEIM transfer congestion, prices were lower in Powerex relative to the rest of the balancing areas in the Pacific Northwest.

[88] When prices are higher within an area, this indicates that WEIM transfer congestion limited the ability for outside energy to serve that area's load.

Table 2.2 Frequency of WEIM transfer congestion (January 13–January 15, 2024)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
NV Energy	0%	0%	0%	0%
Arizona Public Service	0%	0%	0%	0%
WAPA – Desert Southwest	0%	0%	0%	0%
PacifiCorp East	1%	0%	0%	0%
Public Service Company of NM	0%	1%	0%	1%
L.A. Dept. of Water and Power	3%	0%	4%	1%
Turlock Irrigation District	2%	0%	5%	0%
Tucson Electric Power	12%	0%	12%	0%
Salt River Project	13%	0%	12%	0%
El Paso Electric Company	42%	0%	44%	0%
Idaho Power	24%	56%	14%	68%
NorthWestern Energy	0%	71%	0%	80%
Avista Utilities	0%	72%	0%	80%
Avangrid Renewables	0%	74%	0%	83%
Portland General Electric	0%	74%	1%	83%
Tacoma Power	0%	74%	0%	83%
Seattle City Light	0%	74%	0%	84%
Puget Sound Energy	0%	74%	0%	83%
PacifiCorp West	0%	76%	0%	83%
Bonneville Power Admin.	1%	75%	1%	83%
Powerex	98%	0%	93%	5%

2.1.1 Resource sufficiency evaluation failures during cold weather event

Figure 2.4 shows the number of upward resource sufficiency evaluation failures by region and day in January.[89] During the peak of the cold weather event (between January 13 and January 15), the frequency of resource sufficiency evaluation failures increased—particularly in the Pacific Northwest and Intermountain West regions. High loads associated with the winter event contributed to the resource sufficiency evaluation failures.

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89 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. 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.

Figure 2.4 Upward resource sufficiency evaluation failures by region (January 2024)

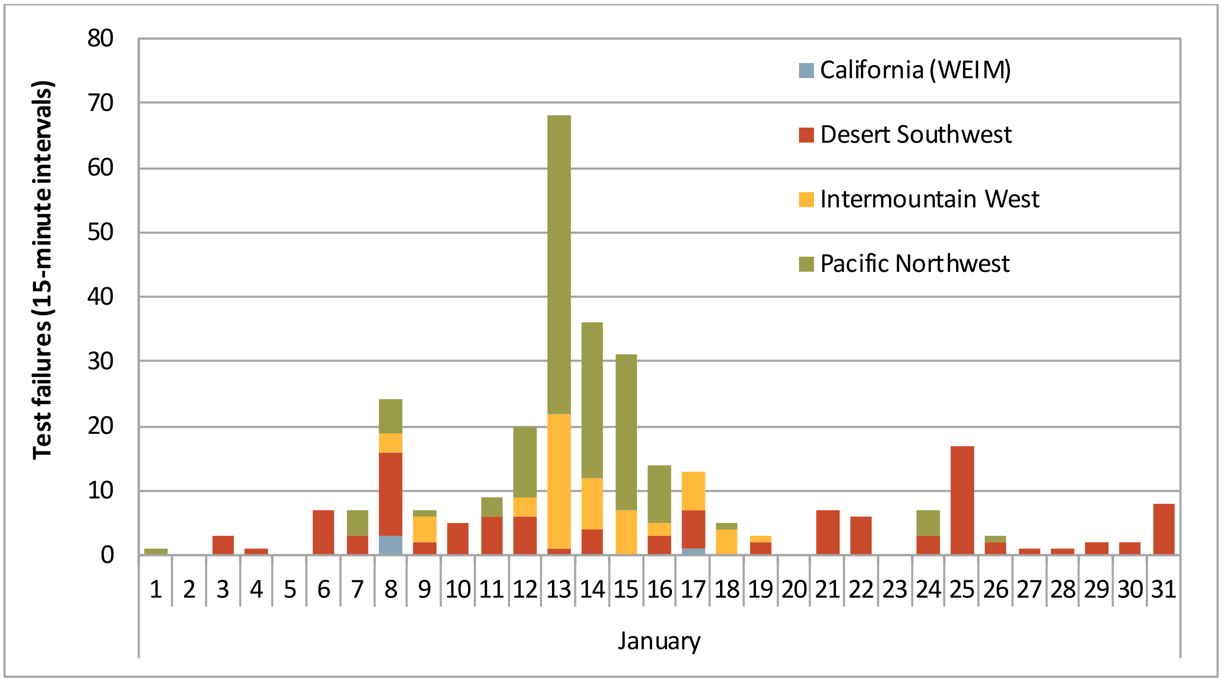
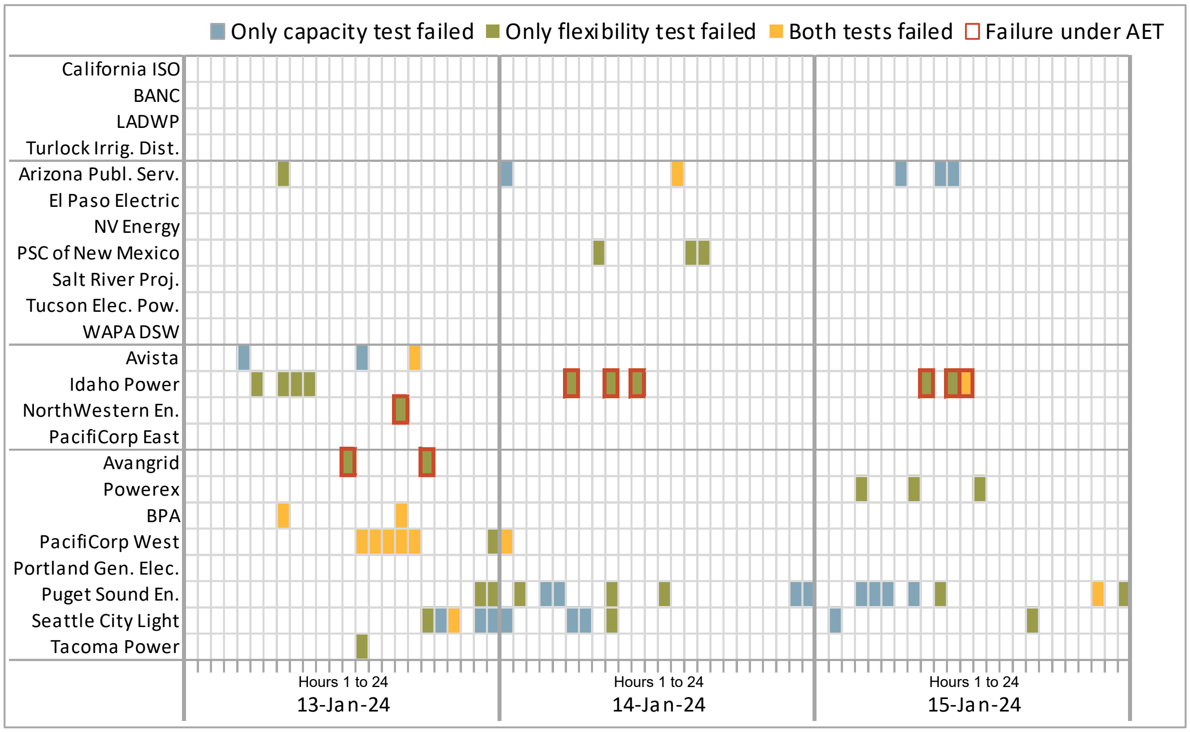


Figure 2.5 shows hours in which each WEIM entity failed the capacity test, flexibility test, or both tests in at least one interval between January 13 and January 15, 2024. During this period, 12 different balancing areas failed the resource sufficiency evaluation with most of the test failures occurring within the Pacific Northwest or Intermountain West regions. Idaho Power, PacifiCorp West, and Puget Sound Energy failed the test most frequently in this period, during roughly 28 intervals each across 7 or more hours. Seattle City Light failed the test during 18 intervals across 11 hours.

The red borders in Figure 2.5 indicate resource sufficiency evaluation failures in which the balancing area had elected to opt in to receiving assistance energy transfers (AET). AET gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure.[90] During this period, six balancing areas were opted in to the program for at least one of the days—Avangrid, Idaho Power, NV Energy, NorthWestern Energy, PacifiCorp East, and PacifiCorp West—with three of these balancing areas experiencing a resource sufficiency evaluation failure while opted in. These three balancing areas were Avangrid, Idaho Power, and NorthWestern Energy. Assistance energy transfers allowed these balancing areas to achieve additional WEIM imports that otherwise would not have occurred following the resource sufficiency evaluation failure. Between January 13 and January 15, Idaho Power achieved as much as 176 MW in additional imports due to AET. NorthWestern Energy achieved as much as 158 MW during the same period.

90 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.

Figure 2.5 Upward resource sufficiency evaluation failures (January 13-15, 2024)



2.2 Prices in the WEIM

This section summarizes prices in the Western energy imbalance market (WEIM) during the first quarter of 2024. Table 2.3 and Table 2.4 show average 15-minute and 5-minute market prices by month. Table 2.5 and Table 2.6 show instead average hourly prices in the 15-minute and 5-minute markets during the fourth quarter. The color gradient highlights deviation from the average system marginal energy price (SMEC), shown in the top row. Here, blue indicates prices below that month's average system price and orange indicates prices above. The CAISO prices in the Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) areas are included as points of comparison.

Congestion on WEIM transfer constraints often drives price separation between areas. When 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. Greenhouse gas compliance costs can also contribute to raising prices in California relative to other areas.

A major change in real-time prices this quarter was high prices in the Pacific Northwest and Intermountain West due to the severe weather even in January. Monthly and hourly prices showed the impact of this event. In January, the Pacific Northwest and Intermountain West had an average price of around $150/MWh. The hourly prices also reflected the impact of these weather events and transmission outages. Typically, prices in the areas are higher during solar hours and lower during evening peak hours. However, this quarter, prices in the areas were higher for all hours due to high congestion caused by transmission outages from the severe weather event.

Table 2.3 Monthly 15-minute market prices

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
	2022									2023												2024		
SMEC	$59	$57	$55	$69	$97	$125	$69	$90	$246	$140	$73	$73	$55	$19	$28	$66	$67	$42	$57	$58	$50	$89	$38	$28
PG&E (CAISO)	$63	$68	$82	$74	$103	$136	$73	$95	$257	$140	$75	$76	$57	$18	$29	$58	$65	$44	$62	$62	$54	$78	$40	$30
SCE (CAISO)	$55	$59	$69	$78	$108	$136	$64	$83	$246	$140	$68	$65	$48	$20	$27	$73	$68	$39	$51	$53	$45	$65	$31	$17
BANC	$65	$68	$68	$72	$105	$131	$75	$95	$252	$142	$75	$76	$59	$19	$30	$56	$54	$42	$59	$62	$53	$77	$41	$31
Turlock ID	$69	$76	$68	$72	$100	$136	$76	$95	$266	$142	$76	$77	$61	$19	$30	$56	$54	$43	$60	$63	$54	$78	$41	$33
LADWP	$55	$57	$63	$77	$108	$135	$67	$87	$256	$142	$73	$68	$49	$20	$27	$67	$50	$36	$45	$52	$46	$68	$32	$18
NV Energy	$49	$53	$56	$69	$93	$117	$58	$79	$243	$131	$66	$66	$50	$17	$23	$59	$40	$33	$38	$48	$42	$65	$30	$19
Arizona PS	$45	$52	$64	$72	$97	$118	$56	$80	$250	$130	$66	$65	$50	$17	$24	$63	$41	$30	$34	$45	$38	$59	$28	$18
Tucson Electric		$54	$64	$72	$96	$111	$57	$77	$222	$129	$63	$60	$47	$21	$26	$58	$38	$30	$33	$45	$39	$59	$27	$15
Salt River Project	$47	$55	$67	$67	$88	$93	$56	$76	$157	$119	$52	$60	$50	$22	$24	$62	$46	$28	$34	$44	$38	$54	$25	$14
PSC New Mexico	$43	$47	$49	$67	$84	$103	$58	$64	$114	$127	$64	$65	$67	$17	$24	$59	$40	$30	$40	$50	$40	$69	$35	$18
WAPA - Desert SW													$57	$20	$24	$62	$41	$30	$34	$45	$40	$60	$29	$14
El Paso Electric													$33	$18	$23	$48	$37	$29	$30	$20	$20	$53	$24	$15
PacifiCorp East	$45	$43	$39	$65	$81	$99	$59	$72	$193	$120	$63	$67	$52	$18	$26	$53	$38	$31	$40	$46	$40	$76	$31	$22
Idaho Power	$57	$47	$32	$69	$81	$92	$63	$84	$237	$132	$71	$73	$59	$16	$27	$52	$39	$33	$56	$53	$45	$112	$35	$27
NorthWestern	$57	$41	$15	$41	$69	$73	$64	$87	$243	$133	$72	$75	$61	$13	$27	$53	$39	$34	$62	$54	$46	$151	$38	$29
Avista Utilities	$57	$41	$12	$36	$67	$73	$65	$86	$246	$133	$72	$74	$64	$12	$27	$49	$39	$34	$63	$55	$46	$155	$38	$30
Avangrid													$61	$7	$28	$49	$40	$37	$63	$56	$48	$164	$38	$31
BPA		$46	$10	$46	$80	$92	$65	$86	$251	$133	$73	$73	$62	$5	$29	$55	$49	$38	$65	$57	$47	$182	$39	$30
Tacoma Power	$59	$44	$13	$39	$74	$80	$64	$85	$248	$134	$72	$73	$62	$6	$29	$50	$43	$37	$64	$55	$47	$165	$39	$31
PacifiCorp West	$59	$42	$13	$42	$76	$89	$64	$85	$244	$132	$71	$72	$61	$6	$28	$48	$39	$35	$64	$55	$47	$170	$38	$30
Portland GE	$59	$43	$15	$43	$77	$92	$65	$87	$244	$132	$71	$72	$62	$9	$29	$50	$43	$37	$65	$55	$47	$165	$38	$32
Puget Sound Energy	$59	$44	$13	$40	$74	$81	$64	$85	$249	$133	$73	$74	$62	$8	$29	$59	$44	$37	$69	$58	$48	$167	$39	$31
Seattle City Light	$60	$45	$12	$40	$74	$80	$64	$85	$249	$133	$75	$72	$61	$6	$28	$50	$45	$37	$64	$55	$47	$167	$40	$30
Powerex	$52	$46	$15	$37	$61	$69	$67	$82	$212	$129	$79	$84	$79	$14	$55	$94	$99	$83	$102	$98	$62	$72	$54	$49

Table 2.4 Monthly 5-minute market prices

	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024	Feb 2024	Mar 2024
SMEC	$50	$51	$45	$62	$88	$97	$66	$86	$241	$135	$68	$66	$47	$16	$27	$58	$53	$39	$53	$57	$49	$85	$35	$26
PG&E (CAISO)	$54	$63	$80	$73	$95	$110	$73	$92	$254	$136	$70	$68	$49	$16	$28	$52	$52	$42	$58	$62	$53	$79	$38	$28
SCE (CAISO)	$45	$54	$63	$72	$98	$107	$60	$77	$234	$133	$63	$58	$41	$16	$26	$62	$53	$35	$48	$52	$44	$63	$29	$16
BANC	$56	$65	$72	$70	$97	$107	$74	$92	$249	$138	$71	$68	$49	$16	$29	$54	$53	$42	$57	$62	$53	$79	$39	$30
Turlock ID	$60	$73	$72	$71	$94	$113	$77	$94	$263	$139	$72	$69	$52	$16	$30	$54	$53	$42	$58	$63	$54	$79	$40	$31
LADWP	$45	$51	$55	$70	$98	$106	$61	$81	$244	$134	$67	$59	$42	$16	$26	$62	$55	$37	$51	$53	$45	$66	$30	$17
NV Energy	$42	$49	$51	$67	$90	$90	$57	$76	$235	$126	$62	$60	$42	$14	$22	$56	$45	$34	$44	$50	$43	$65	$29	$19
Arizona PS	$37	$47	$59	$67	$89	$96	$54	$77	$240	$123	$66	$61	$42	$15	$24	$59	$45	$32	$40	$46	$40	$59	$26	$17
Tucson Electric		$50	$58	$67	$89	$90	$54	$73	$215	$123	$60	$54	$40	$20	$26	$58	$44	$31	$38	$46	$40	$58	$28	$16
Salt River Project	$41	$54	$68	$68	$83	$75	$51	$72	$149	$109	$49	$54	$45	$23	$26	$61	$48	$27	$38	$49	$39	$53	$24	$17
PSC New Mexico	$35	$42	$45	$64	$78	$80	$57	$63	$123	$122	$60	$58	$53	$14	$24	$56	$44	$33	$46	$51	$42	$70	$34	$18
WAPA - Desert SW													$40	$19	$26	$58	$44	$33	$38	$47	$40	$59	$28	$14
El Paso Electric													$28	$16	$23	$47	$40	$30	$33	$23	$23	$52	$24	$15
PacifiCorp East	$39	$39	$29	$59	$74	$76	$57	$70	$192	$116	$59	$62	$45	$14	$25	$52	$43	$34	$44	$47	$40	$73	$30	$21
Idaho Power	$53	$43	$18	$60	$75	$76	$61	$80	$233	$127	$66	$68	$51	$13	$26	$52	$44	$35	$61	$54	$46	$119	$34	$25
NorthWestern	$53	$37	$4	$37	$64	$66	$64	$86	$241	$128	$67	$69	$56	$9	$27	$55	$46	$37	$67	$55	$48	$161	$37	$28
Avista Utilities	$54	$37	-$2	$31	$63	$65	$64	$83	$242	$129	$67	$69	$56	$10	$27	$51	$44	$37	$68	$55	$48	$164	$37	$29
Avangrid													$56	$6	$27	$51	$44	$38	$68	$55	$48	$168	$37	$29
BPA		$37	$2	$34	$68	$78	$63	$83	$247	$130	$68	$68	$57	$4	$28	$53	$48	$37	$69	$56	$47	$184	$37	$28
Tacoma Power	$57	$41	$7	$33	$67	$71	$62	$82	$246	$130	$67	$69	$56	$5	$28	$50	$45	$37	$69	$54	$47	$170	$37	$29
PacifiCorp West	$57	$39	-$2	$37	$68	$69	$63	$83	$239	$129	$66	$68	$56	$6	$26	$50	$42	$37	$68	$54	$47	$171	$37	$28
Portland GE	$57	$38	$0	$37	$68	$72	$63	$84	$239	$129	$66	$68	$56	$9	$27	$50	$45	$37	$69	$54	$47	$169	$37	$29
Puget Sound Energy	$57	$41	$7	$34	$66	$71	$62	$83	$247	$131	$68	$69	$56	$7	$28	$61	$47	$38	$74	$56	$47	$175	$37	$29
Seattle City Light	$58	$41	$5	$33	$67	$70	$62	$82	$247	$130	$69	$68	$56	$5	$27	$50	$46	$37	$68	$55	$47	$171	$37	$28
Powerex	$50	$44	$10	$32	$57	$67	$65	$80	$209	$127	$77	$83	$77	$14	$52	$87	$94	$77	$102	$101	$61	$72	$53	$48

Table 2.5 Hourly 15-minute market prices (January–March)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$50	$50	$48	$47	$50	$57	$64	$58	$46	$42	$43	$39	$34	$32	$33	$45	$60	$70	$75	$72	$66	$62	$52	$51
PG&E (CAISO)	$50	$48	$48	$48	$51	$57	$64	$61	$48	$45	$41	$36	$31	$30	$34	$41	$49	$60	$64	$62	$58	$56	$53	$49
SCE (CAISO)	$49	$47	$47	$47	$50	$57	$63	$54	$28	$16	$8	$2	-$1	-$2	$1	$16	$37	$55	$61	$60	$57	$56	$52	$49
BANC	$49	$47	$47	$47	$50	$57	$64	$60	$49	$48	$46	$40	$35	$34	$38	$45	$50	$59	$62	$61	$58	$55	$52	$48
Turlock ID	$49	$47	$47	$47	$50	$57	$64	$59	$50	$51	$49	$43	$39	$37	$42	$47	$52	$60	$63	$61	$58	$55	$52	$48
LADWP	$51	$48	$47	$48	$50	$57	$64	$58	$31	$18	$11	$5	$1	$0	$4	$17	$39	$57	$63	$61	$58	$57	$53	$49
NV Energy	$43	$42	$42	$43	$47	$52	$56	$47	$32	$26	$22	$17	$13	$12	$14	$25	$40	$52	$56	$54	$50	$47	$46	$43
Arizona PS	$42	$41	$41	$42	$46	$52	$60	$46	$27	$15	$9	$2	-$1	-$2	$8	$17	$35	$54	$53	$62	$56	$46	$48	$42
Tucson Electric	$39	$38	$38	$40	$44	$51	$54	$45	$25	$17	$10	$4	$1	$0	$4	$18	$43	$49	$53	$52	$49	$46	$44	$40
Salt River Project	$38	$38	$38	$42	$45	$50	$51	$40	$21	$15	$9	$8	$1	-$1	$1	$10	$31	$45	$50	$52	$43	$42	$44	$42
PSC New Mexico	$43	$42	$52	$53	$49	$53	$57	$60	$34	$38	$32	$9	$4	$4	$3	$36	$41	$49	$66	$57	$50	$48	$46	$50
WAPA - Desert SW*	$48	$44	$44	$43	$46	$52	$56	$46	$25	$18	$9	$3	-$1	-$1	$1	$14	$35	$52	$60	$54	$52	$47	$45	$42
El Paso Electric*	$34	$33	$33	$35	$40	$48	$56	$43	$23	$15	$9	$5	$4	-$1	$2	$15	$40	$47	$52	$50	$46	$47	$39	$35
PacifiCorp East	$41	$41	$40	$40	$44	$50	$53	$47	$39	$36	$37	$33	$29	$27	$26	$38	$52	$59	$62	$59	$54	$49	$44	$42
Idaho Power	$47	$51	$50	$53	$65	$68	$65	$76	$74	$65	$63	$54	$41	$39	$42	$50	$65	$62	$67	$70	$67	$57	$60	$48
NorthWestern	$55	$59	$63	$63	$72	$79	$73	$87	$77	$75	$76	$75	$66	$73	$65	$65	$80	$87	$87	$86	$86	$78	$69	$64
Avista Utilities	$55	$60	$63	$63	$72	$79	$74	$87	$79	$78	$80	$79	$70	$76	$69	$68	$83	$93	$90	$88	$88	$79	$69	$64
Avangrid*	$63	$65	$69	$72	$77	$79	$71	$83	$79	$80	$87	$82	$72	$76	$84	$80	$84	$92	$92	$89	$87	$79	$72	$70
BPA	$71	$66	$70	$74	$79	$86	$83	$92	$87	$96	$100	$87	$84	$88	$88	$84	$91	$96	$94	$90	$90	$88	$80	$71
Tacoma Power	$64	$66	$70	$73	$78	$79	$72	$84	$80	$89	$86	$83	$73	$75	$83	$79	$82	$90	$91	$88	$87	$79	$75	$71
PacifiCorp West	$67	$66	$70	$73	$78	$85	$72	$84	$79	$80	$86	$83	$74	$80	$89	$79	$92	$93	$91	$89	$87	$80	$72	$71
Portland GE	$63	$66	$70	$73	$78	$81	$72	$84	$80	$80	$86	$84	$75	$78	$85	$82	$82	$91	$89	$89	$87	$79	$73	$71
Puget Sound Energy	$64	$68	$70	$74	$78	$80	$72	$85	$83	$86	$87	$84	$75	$76	$84	$80	$83	$90	$93	$91	$88	$80	$73	$73
Seattle City Light	$64	$67	$70	$73	$78	$79	$73	$84	$82	$92	$87	$84	$75	$76	$84	$81	$84	$90	$91	$89	$88	$82	$73	$75
Powerex	$54	$52	$52	$52	$54	$58	$60	$65	$63	$60	$58	$58	$58	$57	$57	$58	$64	$64	$63	$61	$61	$58	$57	$55

Table 2.6 Hourly 5-minute market prices (January–March)

	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	$51	$50	$50	$49	$50	$53	$59	$58	$51	$51	$39	$34	$28	$30	$29	$30	$49	$55	$59	$65	$64	$62	$55	$53
PG&E (CAISO)	$51	$49	$48	$49	$50	$53	$59	$57	$57	$60	$46	$36	$31	$30	$30	$32	$44	$53	$55	$58	$57	$57	$53	$49
SCE (CAISO)	$50	$48	$47	$48	$49	$53	$58	$49	$27	$19	$6	$1	-$2	-$2	$0	$9	$35	$50	$55	$56	$56	$57	$53	$49
BANC	$50	$48	$47	$48	$49	$53	$59	$56	$58	$64	$52	$42	$35	$35	$36	$36	$45	$53	$55	$57	$56	$56	$53	$48
Turlock ID	$50	$48	$47	$48	$49	$53	$58	$55	$59	$67	$55	$45	$37	$38	$38	$38	$46	$53	$55	$57	$57	$56	$53	$48
LADWP	$53	$49	$47	$48	$50	$53	$59	$54	$30	$22	$9	$3	$0	$0	$4	$11	$39	$51	$56	$57	$57	$58	$54	$50
NV Energy	$44	$43	$43	$45	$47	$50	$54	$46	$34	$32	$20	$19	$11	$11	$11	$16	$38	$49	$52	$53	$51	$50	$48	$45
Arizona PS	$43	$42	$43	$45	$47	$50	$57	$48	$23	$18	$6	$0	-$3	-$4	$7	$9	$32	$54	$51	$61	$50	$48	$49	$44
Tucson Electric	$39	$42	$40	$41	$44	$48	$51	$46	$24	$19	$9	$3	$2	-$1	$4	$16	$45	$55	$50	$51	$50	$48	$46	$41
Salt River Project	$42	$38	$40	$43	$45	$49	$50	$35	$18	$17	$15	$12	-$1	-$2	-$1	$5	$35	$42	$49	$51	$44	$44	$46	$41
PSC New Mexico	$44	$49	$46	$46	$48	$51	$58	$66	$45	$46	$19	$7	$2	$8	$3	$32	$40	$48	$67	$53	$51	$50	$49	$53
WAPA - Desert SW*	$45	$43	$45	$44	$47	$51	$53	$44	$23	$21	$6	$1	-$2	-$3	-$2	$7	$34	$48	$62	$52	$50	$48	$47	$44
El Paso Electric*	$35	$34	$34	$37	$40	$45	$55	$39	$23	$18	$5	$2	-$2	-$2	$1	$9	$37	$46	$48	$49	$47	$47	$40	$36
PacifiCorp East	$41	$41	$42	$43	$45	$48	$51	$49	$43	$43	$32	$27	$22	$24	$23	$24	$44	$49	$51	$56	$54	$51	$47	$45
Idaho Power	$51	$52	$57	$62	$71	$69	$67	$81	$76	$69	$60	$48	$39	$40	$37	$46	$60	$61	$62	$70	$70	$67	$64	$59
NorthWestern	$59	$60	$62	$67	$75	$79	$79	$83	$79	$81	$83	$77	$66	$76	$66	$69	$81	$94	$92	$94	$88	$82	$72	$71
Avista Utilities	$61	$60	$62	$67	$75	$79	$79	$84	$82	$82	$82	$80	$70	$80	$69	$72	$83	$95	$93	$95	$90	$83	$72	$70
Avangrid*	$64	$61	$67	$73	$75	$79	$76	$81	$82	$86	$86	$79	$70	$78	$81	$76	$83	$94	$92	$94	$89	$83	$75	$72
BPA	$71	$62	$68	$74	$79	$85	$85	$85	$84	$98	$96	$90	$87	$85	$80	$76	$88	$96	$97	$90	$91	$95	$86	$72
Tacoma Power	$65	$62	$68	$74	$76	$79	$77	$81	$82	$90	$89	$80	$70	$78	$80	$76	$83	$95	$92	$94	$89	$83	$78	$72
PacifiCorp West	$65	$62	$68	$74	$76	$81	$77	$82	$81	$85	$86	$80	$69	$78	$81	$76	$84	$95	$92	$95	$89	$83	$76	$79
Portland GE	$64	$62	$68	$74	$77	$80	$77	$82	$81	$85	$86	$82	$71	$79	$81	$76	$83	$95	$92	$94	$89	$83	$76	$72
Puget Sound Energy	$65	$62	$68	$74	$77	$80	$77	$84	$90	$89	$88	$83	$70	$77	$80	$76	$83	$95	$92	$97	###	$86	$82	$79
Seattle City Light	$65	$63	$68	$74	$76	$79	$78	$81	$82	$97	$88	$80	$70	$77	$80	$76	$83	$95	$92	$95	$89	$84	$76	$73
Powerex	$54	$52	$51	$55	$54	$58	$59	$60	$59	$59	$59	$58	$58	$57	$57	$58	$61	$63	$60	$65	$60	$58	$58	$54

Hour

2.3 Transfers, limits, and congestion

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.[91] WEIM transfers are constrained by *transfer limits* between the WEIM balancing authority areas, which are discussed in the next section.

Figure 2.6 and Figure 2.7 highlight typical transfer patterns during two key periods that produce a high volume of transfers.[92] 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. Each small tick is 50 MW and each large tick is 250 MW.

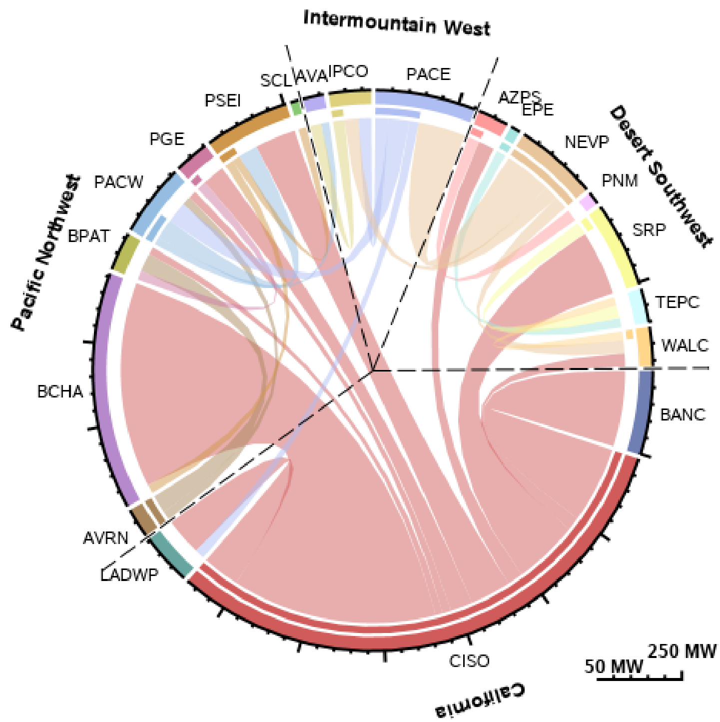
91 See Appendix A for figures on the average hourly transfers by quarter for each WEIM area.

92 In the figures, each small tick is 100 MW, each large tick is 500 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 2.6 shows average dynamic 15-minute market exports out of each area during mid-day hours (between hours 10 and 17) during the quarter.[93] CAISO exported on average over 1,600 MW during these mid-day hours, out to neighboring areas. The mid-day hours typically contain the highest levels of exports out of the CAISO area because of significant solar production.

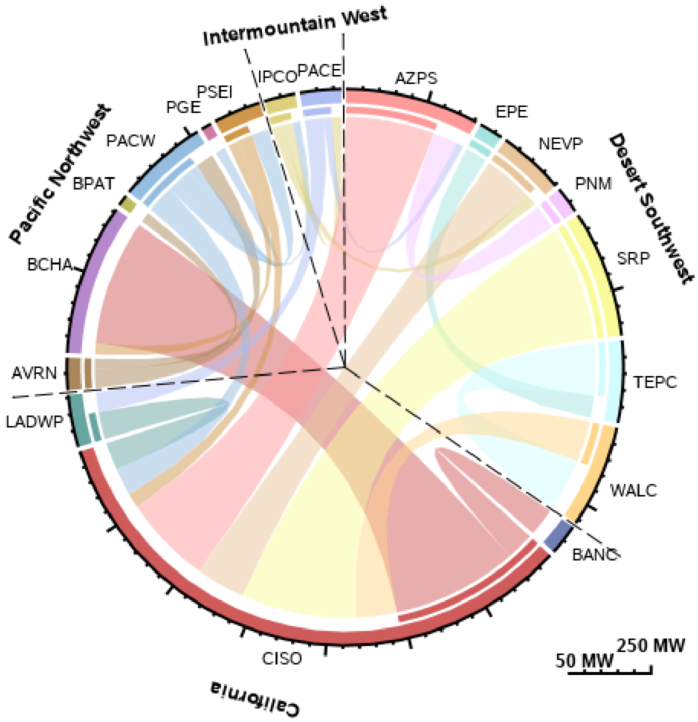
Figure 2.7 shows average dynamic transfers during peak net load hours (between hours 19 and 22) during the quarter. During these hours, imports into the CAISO are often highest. The figure shows an average of over 1,200 MW of exports from LADWP, PacifiCorp West, Puget Sound Energy, Arizona Public Service, NV Energy, Salt River Project, and WAPA Desert Southwest going into the CAISO during these hours (CAISO import).

Figure 2.6 Average 15-minute market WEIM exports (mid-day hours, January–March 2024)



93 These figures exclude the fixed bilateral transactions between WEIM entities (base WEIM transfer schedules) and therefore reflect only *dynamic* market flows optimized in the market.

Figure 2.7 Average 15-minute market WEIM exports (peak load hours, January–March 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 2.7 shows average 15-minute market import and export limits for each balancing area. 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 balancing areas in Table 2.7 are grouped in one of four regions: California, Desert Southwest, Intermountain West, and Pacific Northwest. 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. The last two columns in Table 2.7 shows WEIM transfer limits between these regions (out-of-region import and export limits).

Import and export transfer capacity into or out of the Desert Southwest region was around 34,590 MW and 21,680 MW, respectively. For the Pacific Northwest region, there was an average of around 1,790 MW of import and 840 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 2.7 Average 15-minute market WEIM limits (January–March, 2024)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**21,166**	**33,509**
California ISO	29,862	36,507	18,052	28,784
BANC	4,478	4,136	0	0
LADWP	6,819	12,855	3,114	4,725
Turlock Irrig. District	840	845	0	0
Desert Southwest			**34,586**	**21,677**
Arizona Public Service	33,840	21,082	26,143	14,633
El Paso Electric	642	405	0	0
NV Energy	4,699	3,505	4,037	2,461
PSC New Mexico	954	1,177	0	0
Salt River Project	6,412	6,689	1,534	1,821
Tucson Electric	3,512	4,733	554	702
WAPA - Desert SW	5,610	5,168	2,318	2,061
Intermountain West			**1,688**	**3,208**
Avista Utilities	580	1,128	116	115
Idaho Power	2,242	2,744	485	898
NorthWestern Energy	578	1,022	34	30
PacifiCorp East	2,948	2,974	1,051	2,166
Pacific Northwest			**1,791**	**837**
Avangrid	715	676	18	20
Powerex	695	50	647	0
BPA	709	781	213	204
PacifiCorp West	1,689	1,845	536	523
Portland General Electric	730	693	180	25
Puget Sound Energy	1,348	976	169	37
Seattle City Light	443	446	28	28
Tacoma Power	348	254	0	0

Congestion on WEIM transfer constraints

When limits on constraints impacting WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to prevailing system prices. Figure 2.8 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.[94] 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

94 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.

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.[95]

Powerex was frequently import constrained relative to the CAISO balancing area because of WEIM transfer congestion. Powerex was congested into the area during around 73 and 77 percent of intervals in the 15-minute and 5-minute markets, respectively. On average for the quarter, prices in Powerex were around $16/MWh higher because of WEIM transfer congestion. The rest of the Pacific Northwest region as well as Avista and NorthWestern Energy were also frequently import constrained relative to the rest of the WEIM system, during around 17 percent of 15-minute intervals and 15 percent of 5-minute intervals. 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.[96]

El Paso Electric and Salt River Project were frequently export constrained, during around 12 percent of 15-minute and 5-minute market intervals. This was largely due to intertie constraints that these balancing areas use to manage net WEIM transfers into or out of their system.

Table 2.8 Frequency and impact of transfer congestion in the WEIM (January–March, 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%	$0.04
NV Energy	0.1%	-$0.06	0.0%	$0.00	0.1%	-$0.04	0.0%	$0.25
L.A. Dept. of Water and Power	0.3%	-$0.13	0.2%	$0.18	0.4%	-$0.17	0.4%	$0.46
Arizona Public Service	0.4%	-$0.14	0.4%	$1.84	0.3%	-$0.24	0.3%	$1.74
WAPA – Desert Southwest	0.1%	-$0.07	0.8%	$1.60	0.1%	-$0.08	0.5%	$1.13
Turlock Irrigation District	1%	-$0.20	0.0%	$0.00	1%	-$0.31	0.0%	$0.00
Public Service Company of NM	0.6%	-$0.80	1.1%	$5.30	0.4%	-$0.58	1.0%	$6.26
PacifiCorp East	0.0%	-$0.07	5%	$0.44	0.0%	$0.00	3%	$0.29
Tucson Electric Power	5%	-$0.97	3%	$0.75	4%	-$1.21	4%	$2.19
Idaho Power	0.8%	-$2.95	11%	$11.39	0.5%	-$1.63	9%	$13.75
El Paso Electric Company	12%	-$3.54	1%	$1.11	12%	-$3.82	2%	$1.06
Salt River Project	13%	-$2.86	2%	$1.18	12%	-$2.93	2%	$1.89
NorthWestern Energy	0.0%	-$0.03	18%	$19.78	0.0%	-$0.01	16%	$25.44
Avista Utilities	0.1%	-$0.01	19%	$19.97	0.1%	-$0.01	16%	$25.23
Portland General Electric	3%	-$0.37	16%	$22.75	3%	-$0.44	13%	$26.32
PacifiCorp West	3%	-$0.29	16%	$24.15	3%	-$0.42	13%	$26.79
Avangrid Renewables	3%	-$0.34	16%	$22.85	4%	-$0.54	13%	$26.38
Seattle City Light	3%	-$0.35	17%	$23.95	3%	-$0.52	14%	$27.51
Tacoma Power	3%	-$0.31	17%	$23.49	3%	-$0.46	15%	$27.18
Puget Sound Energy	3%	-$0.27	17%	$23.82	3%	-$0.42	15%	$28.93
Bonneville Power Admin.	5%	-$0.65	20%	$29.39	5%	-$0.87	18%	$31.97
Powerex	6%	-$14.12	73%	$16.11	12%	-$12.00	77%	$16.85

95 When prices are higher within an area, this indicates that WEIM transfer congestion limited the ability for outside energy to serve that area's load.

96 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 LMP will be replaced by the higher of default energy bids and the competitive LMP. The California ISO balancing area is not subject to market power mitigation when WEIM transfer limits into the CAISO area are constrained.

2.4 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.[97] If an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

Frequency of resource sufficiency evaluation failures

Figure 2.8 and Figure 2.9 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.10 and Figure 2.11 provide the same information for the downward direction.[98] The dash indicates the area did not fail the test during the month.

In the first quarter of 2024:

- WAPA Desert Southwest failed the upward flexibility test in around 2.4 percent of intervals.
- Public Service Company of New Mexico (PNM) failed the upward flexibility test in around 1.6 percent of intervals.
- All other balancing areas failed each test type in less than one percent of intervals.

97 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. Assistance energy transfers (AET) give 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.

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

Figure 2.8 Frequency of upward capacity test failures by month and area (percent of intervals)

	2023												2024		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona Publ. Serv.	0.4	0.5	0.7	0.2	0.0	0.1	—	—	—	0.0	—	0.1	—	—	—
Avangrid				0.0	—	—	—	—	0.8	—	—	—	—	—	—
Avista	—	—	—	0.1	0.0	—	—	—	—	0.0	0.1	—	0.3	0.1	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	0.2	—	0.3	0.4	—	0.1	—	—	—	0.3	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric				0.0	0.1	0.3	0.8	0.0	0.1	0.1	—	—	—	—	0.1
Idaho Power	—	—	—	0.0	0.1	—	—	—	—	—	0.1	—	0.0	—	—
LADWP	0.1	—	—	—	—	—	0.1	0.0	—	—	—	0.0	0.1	0.0	—
NorthWestern En.	0.3	0.1	—	—	—	—	0.3	—	—	—	—	—	—	0.1	—
NV Energy	—	—	—	—	0.0	—	0.0	0.0	—	0.0	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	0.0	—	—	—	—	—	—	—	—
PacifiCorp West	0.1	0.1	—	—	—	—	—	0.1	—	—	—	—	0.8	0.0	—
Portland Gen. Elec.	—	0.0	0.0	0.1	0.4	0.1	0.0	—	0.0	0.0	0.6	—	—	—	—
Powerex	—	—	—	—	0.1	—	—	—	0.1	0.0	0.0	—	—	—	—
PSC of New Mexico	—	—	0.7	0.3	0.2	0.0	—	0.0	0.1	0.1	—	0.1	—	—	—
Puget Sound En.	—	0.0	0.2	—	0.1	0.5	1.5	0.5	0.2	0.7	1.0	0.2	0.8	0.1	0.2
Salt River Proj.	1.0	0.4	1.1	0.9	0.2	0.0	2.8	1.2	0.0	0.8	0.2	0.1	0.1	0.1	0.2
Seattle City Light	0.0	0.1	—	—	—	—	0.1	0.9	—	0.1	0.6	—	0.5	—	—
Tacoma Power	0.0	0.1	0.1	—	0.1	—	—	0.1	—	0.1	0.0	—	—	—	0.3
Tucson Elec. Pow.	0.1	0.0	—	—	—	—	0.3	—	—	0.2	—	—	—	—	—
Turlock Irrig. Dist.	—	—	—	0.0	—	—	0.1	—	—	—	—	—	—	—	—
WAPA DSW				2.3	0.8	0.7	1.1	0.6	0.1	0.3	0.4	0.1	—	—	0.1

Figure 2.9 Frequency of upward flexibility test failures by month and area (percent of intervals)

	2023												2024		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona Publ. Serv.	0.9	1.8	2.5	1.1	0.2	0.1	—	0.0	—	—	0.2	0.1	0.2	0.1	0.5
Avangrid				1.0	0.7	0.1	0.2	0.0	0.9	0.1	0.1	0.2	0.2	0.1	0.1
Avista	—	0.0	0.0	0.2	0.2	0.0	—	—	—	0.1	0.1	—	0.1	—	0.1
BANC	—	—	—	—	0.1	—	—	—	—	—	—	—	—	—	—
BPA	—	0.1	0.6	0.2	1.2	0.3	1.3	0.2	0.2	0.1	—	—	0.4	0.0	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric				0.8	0.7	0.3	2.1	0.5	0.6	0.4	0.2	0.1	0.3	0.0	1.0
Idaho Power	0.0	0.1	0.3	0.3	0.5	0.1	—	—	—	0.1	—	—	1.1	—	0.1
LADWP	—	0.3	—	0.1	0.0	0.1	0.0	0.2	0.0	—	—	0.1	0.1	—	0.1
NorthWestern En.	0.3	0.1	0.2	0.8	0.3	0.2	1.0	0.4	0.2	0.2	0.0	0.1	0.5	0.1	0.0
NV Energy	0.1	0.3	0.0	0.1	0.1	0.0	0.1	0.2	0.1	—	0.1	0.0	—	0.1	0.0
PacifiCorp East	0.1	—	0.0	0.1	—	0.0	0.2	—	—	—	—	—	—	—	—
PacifiCorp West	0.1	0.1	—	0.1	0.6	0.0	0.2	—	—	0.0	0.0	0.1	1.0	—	0.1
Portland Gen. Elec.	0.0	0.1	0.0	0.1	1.5	0.7	0.1	—	—	0.6	0.0	—	—	—	0.0
Powerex	—	0.2	—	—	—	—	—	—	—	—	—	—	0.2	—	—
PSC of New Mexico	0.2	—	1.2	5.1	0.9	0.6	0.7	0.5	0.3	1.9	1.9	0.3	2.0	2.3	0.4
Puget Sound En.	—	0.1	0.8	0.2	1.0	0.6	2.6	1.3	0.2	1.3	1.9	0.5	0.8	0.1	0.2
Salt River Proj.	3.5	1.2	1.7	2.0	0.6	0.2	3.7	1.1	0.3	0.6	0.4	0.2	0.2	0.1	0.7
Seattle City Light	—	0.1	—	—	—	—	—	0.5	0.0	0.0	—	—	0.3	—	0.1
Tacoma Power	0.2	0.1	0.2	—	0.1	—	—	—	—	0.2	0.0	—	0.1	0.0	0.4
Tucson Elec. Pow.	0.3	0.3	0.3	0.1	0.1	—	0.2	0.3	—	0.1	0.2	0.1	0.0	0.2	—
Turlock Irrig. Dist.	—	—	—	0.0	—	—	0.1	—	—	—	—	—	—	—	—
WAPA DSW				2.7	0.7	0.8	0.3	0.6	0.2	0.3	0.5	0.1	1.1	2.5	3.5

Figure 2.10 Frequency of downward capacity test failures by month and area (percent of intervals)

Area	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024	Feb 2024	Mar 2024
Arizona Publ. Serv.	—	—	0.6	—	—	—	—	—	—	—	—	0.8	0.1	0.0	0.1
Avangrid				—	—	—	—	—	—	—	0.3	—	—	—	—
Avista	—	—	—	0.0	—	—	—	—	—	—	—	—	—	—	0.1
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	0.1	—	0.2	0.1	—	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric				0.2	0.1	0.3	0.2	0.1	0.2	—	—	—	0.2	—	0.4
Idaho Power	—	—	—	—	—	0.0	—	—	—	—	—	—	—	—	—
LADWP	0.1	—	—	—	—	0.0	—	—	—	—	—	—	—	—	—
NorthWestern En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NV Energy	—	—	—	0.1	0.1	0.6	0.1	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	—	—	—	—	—	0.0	—	—	—	—	—	—	—	—
PSC of New Mexico	—	—	0.1	0.3	—	—	—	—	0.1	—	—	—	—	—	—
Puget Sound En.	—	—	—	—	0.1	—	—	—	—	—	—	—	—	—	—
Salt River Proj.	0.4	1.5	0.2	0.3	0.6	0.4	0.7	—	0.1	0.1	—	—	—	0.1	0.1
Seattle City Light	—	0.1	—	—	—	—	—	0.3	0.1	—	0.1	0.2	0.0	—	—
Tacoma Power	—	0.2	0.1	—	—	—	0.0	—	0.0	—	—	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	0.1	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW				0.2	—	0.8	0.1	0.4	0.5	0.2	0.2	—	—	—	—

Figure 2.11 Frequency of downward flexibility test failures by month and area (percent of intervals)

Area	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024	Feb 2024	Mar 2024
Arizona Publ. Serv.	0.9	0.5	2.1	0.7	1.2	0.1	—	—	—	—	—	0.3	0.1	0.1	0.2
Avangrid				0.1	—	—	—	—	0.1	—	—	—	0.1	—	—
Avista	—	—	0.1	0.1	0.1	—	—	—	—	—	0.1	—	—	0.0	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	0.0	0.1	0.6	5.5	0.0	0.4	—	0.0	0.2	—	—	0.4	0.1	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric				0.2	0.9	1.9	0.5	—	0.3	—	0.2	0.3	0.3	0.2	0.4
Idaho Power	—	—	0.9	0.2	—	—	—	—	0.0	—	0.1	—	—	—	0.0
LADWP	0.1	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NorthWestern En.	—	0.0	—	—	0.2	0.2	—	0.1	0.0	—	—	—	0.2	—	0.1
NV Energy	0.1	0.1	0.1	0.0	0.1	0.4	0.1	0.1	0.0	0.1	0.1	—	—	—	0.1
PacifiCorp East	—	—	—	—	—	—	—	—	0.0	0.1	—	—	—	0.2	0.0
PacifiCorp West	—	—	—	0.0	0.2	0.0	—	—	1.1	—	0.1	—	—	—	0.2
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.1	0.1	—	0.2	—	—	0.0	—	0.2	0.1	—	0.1	—	0.1	0.4
PSC of New Mexico	0.0	—	0.4	1.6	2.1	—	0.1	0.4	1.1	0.4	0.2	0.2	0.9	0.9	0.4
Puget Sound En.	—	—	—	—	0.8	—	—	—	—	—	—	—	—	—	—
Salt River Proj.	1.4	3.3	1.0	0.3	0.1	0.1	0.1	—	—	—	0.1	0.0	0.1	0.1	0.7
Seattle City Light	0.1	0.2	0.0	0.3	0.0	0.3	0.4	1.1	0.2	—	0.8	0.2	0.2	0.1	0.1
Tacoma Power	—	0.2	0.1	—	—	—	0.0	—	0.1	—	0.0	—	—	0.0	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	—	—	—	0.1	—
Turlock Irrig. Dist.	0.1	0.1	0.1	0.1	0.4	—	—	—	—	—	0.1	—	—	0.0	—
WAPA DSW				2.7	0.5	0.7	0.1	0.2	0.6	0.8	0.2	0.1	0.3	0.1	0.0

Assistance energy transfers

Assistance energy transfers (AET) give 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.[99]

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.[100] 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 2.9 shows the days in which a balancing area was opted in to receiving assistance energy transfers during the first quarter. Six 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 and PacifiCorp West.[101] Avangrid, NorthWestern Energy, and NV Energy were opted in to AET during all days of the first quarter.

Table 2.10 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during the first 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

99 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

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

101 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. The CAISO area did not fail the resource sufficiency evaluation during the quarter.

have been available otherwise. Table 2.10 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.

Table 2.9 Assistance energy transfer opt-in designations by balancing area (January–March, 2024)

BAA	Period opted in to assistance energy transfers	Days opted in to AET
Avangrid	Jan. 1 - Mar. 31	91
California ISO	Mar. 4 - Mar. 5, Mar. 18 - Mar. 19, Mar. 25, Mar. 27	6
Idaho Power	Jan. 14 - Jan. 17	4
NorthWestern Energy	Jan. 1 - Mar. 31	91
NV Energy	Jan. 1 - Mar. 31	91
PacifiCorp East	Jan. 15 - Jan. 16	2
PacifiCorp West	Jan. 15 - Jan. 16	2

Table 2.10 Resource sufficiency evaluation failures during assistance energy transfer opt-in (January–March, 2024)

BAA	RSE failures under AET (15-min. intervals)	Failure intervals with additional WEIM imports due to AET (percent)	Average WEIM imports added (MW)	Max WEIM imports added (MW)
Avangrid	12	25%	15	180
California ISO	0	N/A	N/A	N/A
Idaho Power	17	39%	20	176
NorthWestern Energy	21	27%	22	158
NV Energy	3	33%	128	459
PacifiCorp East	0	N/A	N/A	N/A
PacifiCorp West	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.[102] 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.

102 *Western Energy Imbalance Market resource sufficiency evaluation reports*, Department of Market Monitoring: https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

2.5 WEIM imbalance conformance

Frequency and size of imbalance conformance

Table 2.11 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the WEIM and California ISO for the 15-minute and 5-minute markets during the quarter.[103]

The Bonneville Power Administration, El Paso Electric, and Seattle City Light areas used negative imbalance conformance in the 15-minute market most frequently. Other areas had little to no negative conformance in the 15-minute market. Negative imbalance conformance in the 5-minute market was much more frequent in nearly all areas, the exception being Balancing Authority of Northern California (BANC) and the Turlock Irrigation District with no imbalance conformance for the quarter.

The California ISO, Bonneville Power Administration, and El Paso Electric areas had the greatest percent of positive imbalance conformance in the 15-minute market. Other areas had very little or no positive conformance in the 15-minute market. Nearly all areas used positive imbalance conformance in the 5-minute market; however, Seattle City Light, Avista Utilities, Turlock Irrigation District, BANC, Portland Gas Electric Company, PacifiCorp West, and Tacoma Power used positive imbalance in five percent or less of intervals.

103 Powerex is not identified in this table. 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. However, an exceptional event occurred on January 13, 2024 during the cold weather event. In order to maintain load levels due to bad data, the California ISO entered load conformance on behalf of Powerex.

Table 2.11 Average frequency and size of imbalance conformance (January–March)

Balancing area	Market	Positive imbalance conformance: Percent of intervals	Positive imbalance conformance: Average MW	Positive imbalance conformance: Percent of total load	Negative imbalance conformance: Percent of intervals	Negative imbalance conformance: Average MW	Negative imbalance conformance: Percent of total load	Average hourly adjustment MW
California ISO	FMM	37.2%	1,146	5.1%	0.3%	-247	1.4%	426
	RTD	43.0%	292	1.3%	27.5%	-245	1.2%	58
Avangrid Renewables*	FMM	0.1%	50	N/A	0.0%	N/A	N/A	0
	RTD	43.4%	41	N/A	6.1%	-47	N/A	15
BANC	FMM	0.0%	N/A	N/A	0.1%	-120	N/A	0
	RTD	0.1%	33	2.0%	0.1%	-135	8.5%	0
Turlock Irrigation District	FMM	0.1%	35	12.8%	0.0%	N/A	N/A	0
	RTD	0.1%	26	9.7%	0.0%	-20	9.2%	0
LADWP	FMM	0.9%	41	1.5%	1.3%	-43	1.8%	0
	RTD	14.2%	36	1.5%	20.1%	-38	1.6%	-2
NV Energy	FMM	0.0%	100	2.9%	0.0%	-50	1.4%	0
	RTD	54.5%	86	2.3%	11.1%	-138	4.0%	32
Arizona Public Service	FMM	0.4%	50	1.6%	0.0%	N/A	N/A	0
	RTD	61.3%	69	2.2%	20.0%	-65	2.3%	29
Tucson Electric Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	5.6%	46	4.0%	16.7%	-55	5.2%	-7
WAPA - Desert Southwest	FMM	0.0%	N/A	N/A	0.0%	-200	N/A	0
	RTD	17.0%	16	3.3%	46.1%	-18	3.6%	-6
El Paso Electric	FMM	19.9%	15	1.7%	9.2%	-14	1.8%	2
	RTD	23.1%	16	1.9%	12.0%	-17	2.1%	2
Salt River Project	FMM	2.6%	47	1.6%	0.8%	-49	1.7%	1
	RTD	16.7%	52	1.7%	3.5%	-53	1.9%	7
Public Service Co. of New Mexico	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	33.3%	77	5.2%	15.0%	-77	5.6%	14
PacifiCorp East	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	6.3%	78	1.4%	34.5%	-110	2.0%	-33
Idaho Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	9.5%	51	2.5%	19.5%	-60	3.2%	-7
NorthWestern Energy	FMM	1.7%	17	1.1%	0.3%	-21	1.5%	0
	RTD	26.4%	18	1.2%	1.9%	-28	2.1%	4
Avista Utilities	FMM	0.0%	N/A	N/A	3.9%	-41	N/A	-2
	RTD	1.2%	24	1.4%	54.6%	-27	2.0%	-14
Bonneville Power Administration	FMM	31.9%	24	0.3%	67.3%	-34	0.5%	-15
	RTD	32.2%	25	0.3%	67.0%	-34	0.5%	-15
Tacoma Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	3.8%	11	1.6%	3.4%	-9	1.6%	0
PacifiCorp West	FMM	0.0%	N/A	N/A	0.4%	-135	N/A	0
	RTD	3.7%	37	1.4%	11.2%	-43	1.7%	-4
Portland General Electric	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	4.0%	35	1.2%	1.1%	-48	1.8%	1
Puget Sound Energy	FMM	0.0%	N/A	N/A	0.1%	-50	N/A	0
	RTD	12.6%	30	0.9%	13.9%	-33	1.1%	-1
Seattle City Light	FMM	0.6%	13	0.9%	6.7%	-19	1.6%	-1
	RTD	3.8%	20	1.5%	70.8%	-20	1.7%	-14

*Avangrid Renewables is a generation-only entity and therefore load conformance cannot be measured as a percent of load.

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.[104] These figures are included for both the 15-minute and 5-minute markets. Key highlights of the quarter include:

- In this quarter, internal congestion decreased prices in California and the Desert Southwest entities while increasing prices in the Intermountain West and Pacific Northwest. Congestion on WEIM transfer constraints had a significant impact on prices in the Intermountain West and Pacific Northwest by increasing prices.
- Compared to the first quarter of 2023, the overall dynamic WEIM transfer pattern remained similar in this quarter, but there were changes in the Intermountain West region where the transfer volume decreased. Outside of the Intermountain West, PGE and PNM showed a significant reduction in transfer volume in this quarter.

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.

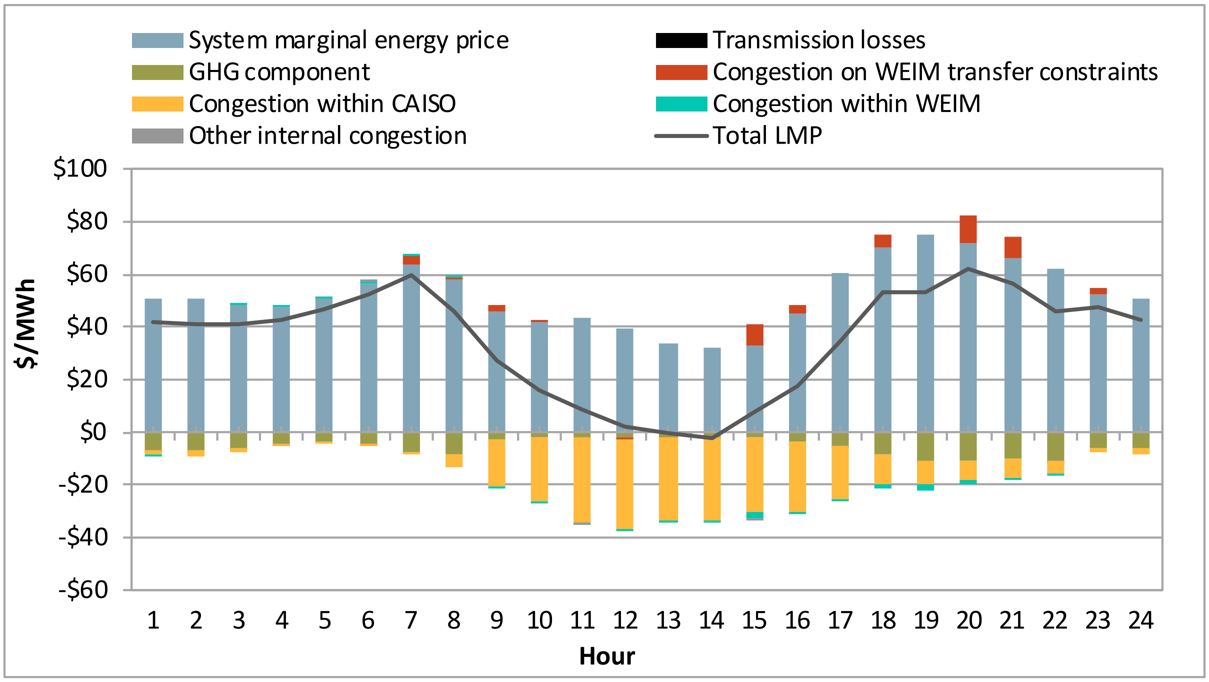
- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location in the California ISO balancing area. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **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 limit WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual

[104] 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.

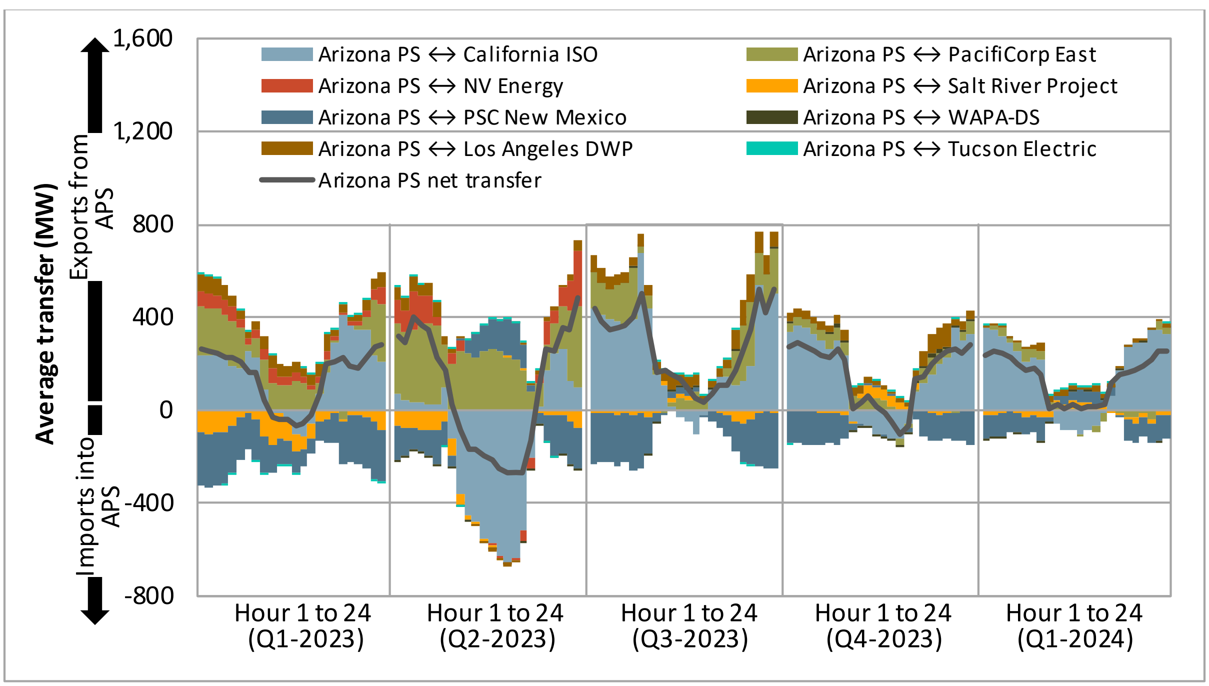
WEIM transfers, (2) total scheduling limits following a resource sufficiency evaluation failure, or (3) intertie constraint (ITC) and intertie scheduling limit (ISL).

A.1 Arizona Public Service

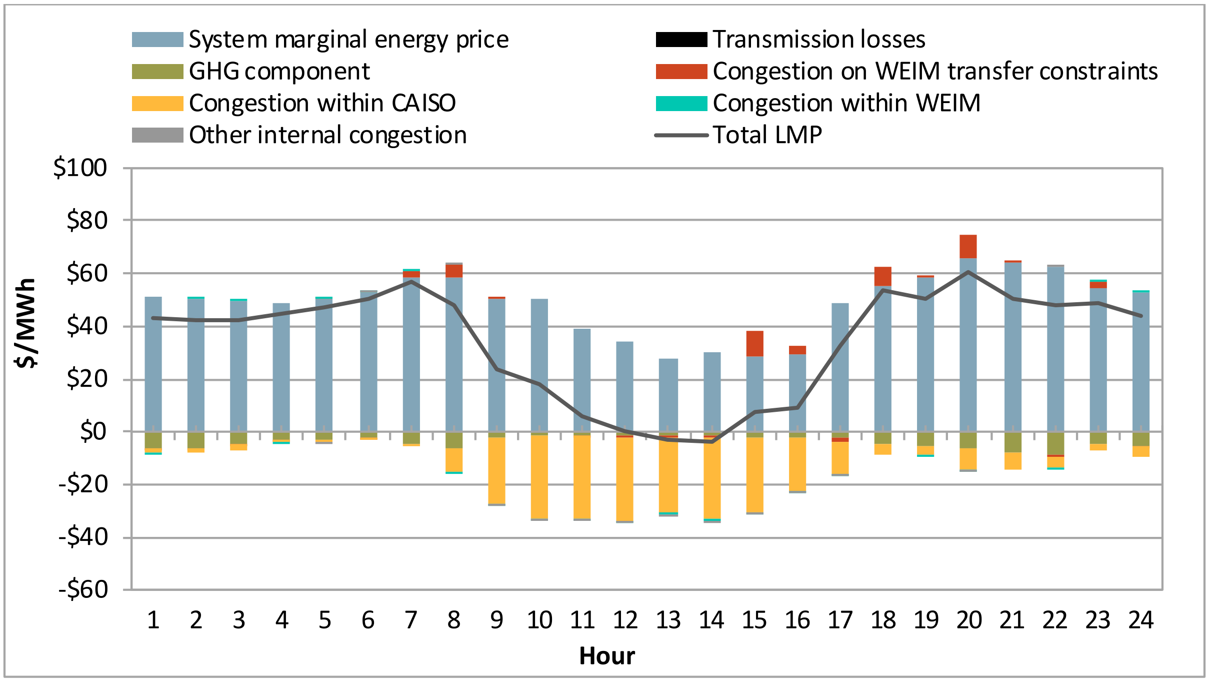
Appendix Figure A.1 Average hourly 15-minute price by component (Q1 2024)



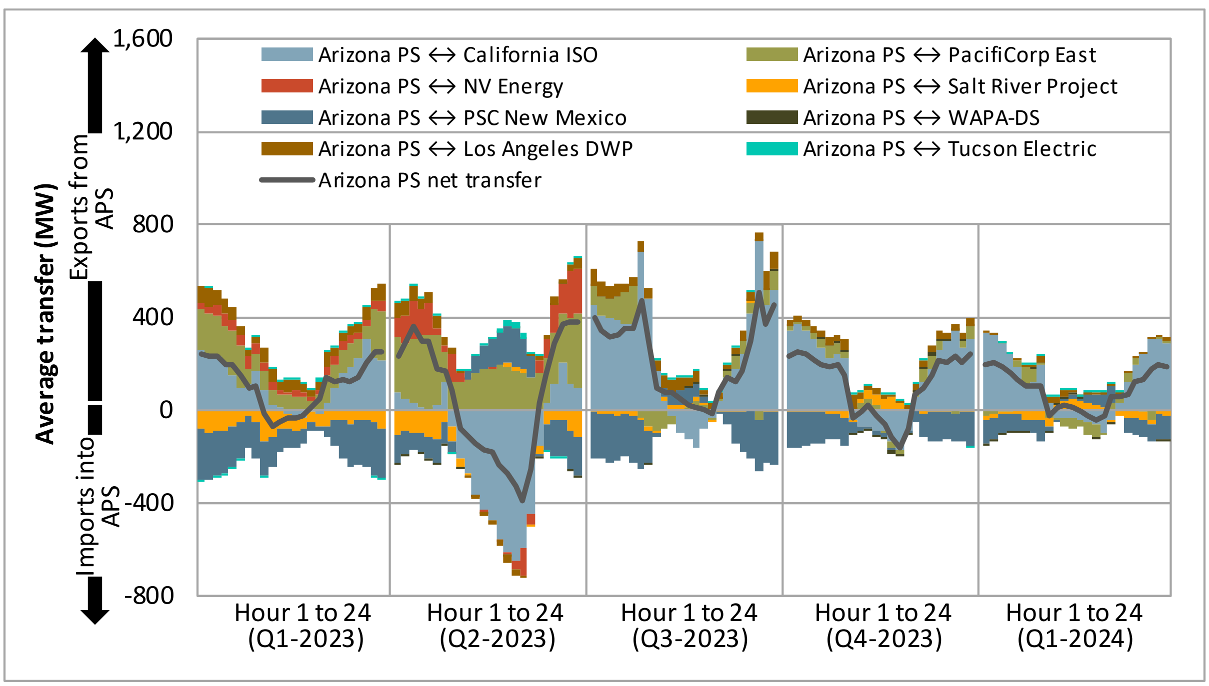
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q1 2024)

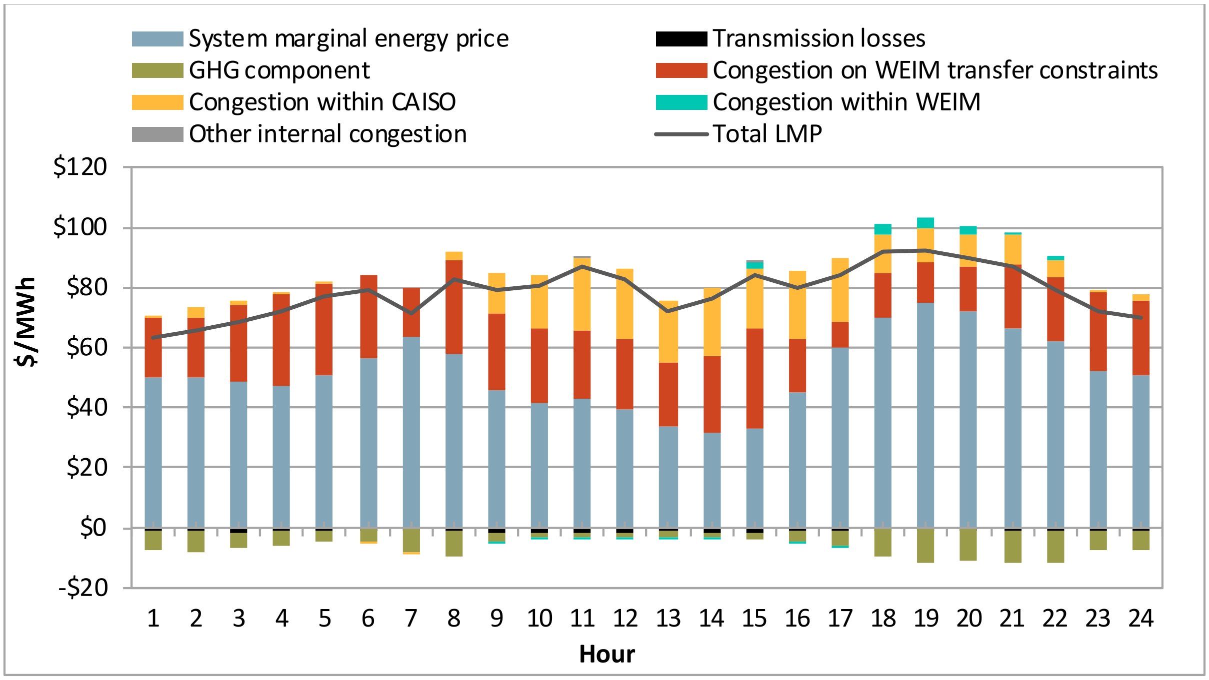


Appendix Figure A.4 Average hourly 5-minute market transfers

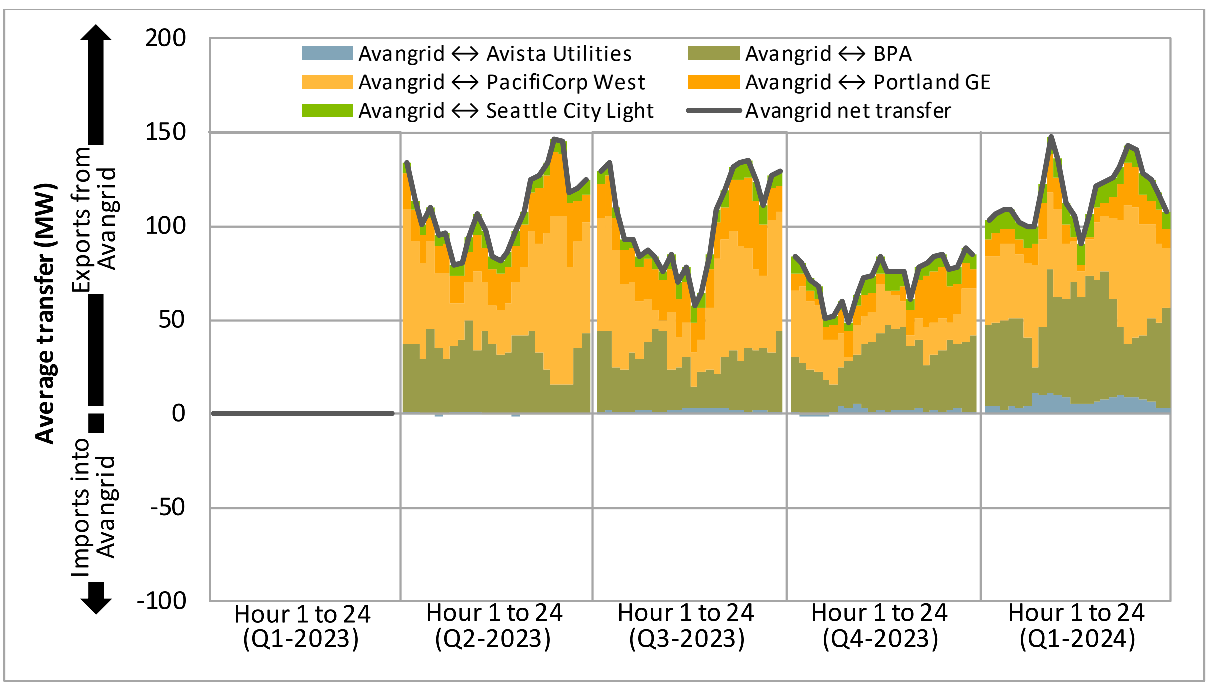


A.2 Avangrid

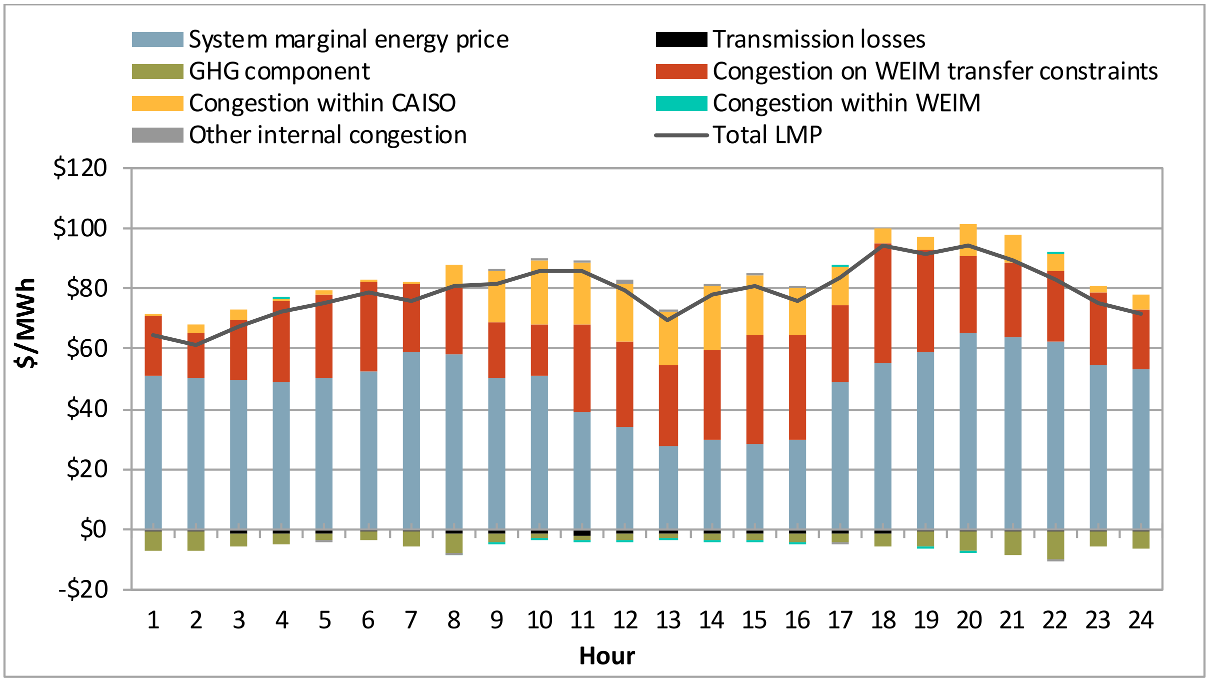
Appendix Figure A.5 Average hourly 15-minute price by component (Q1 2024)



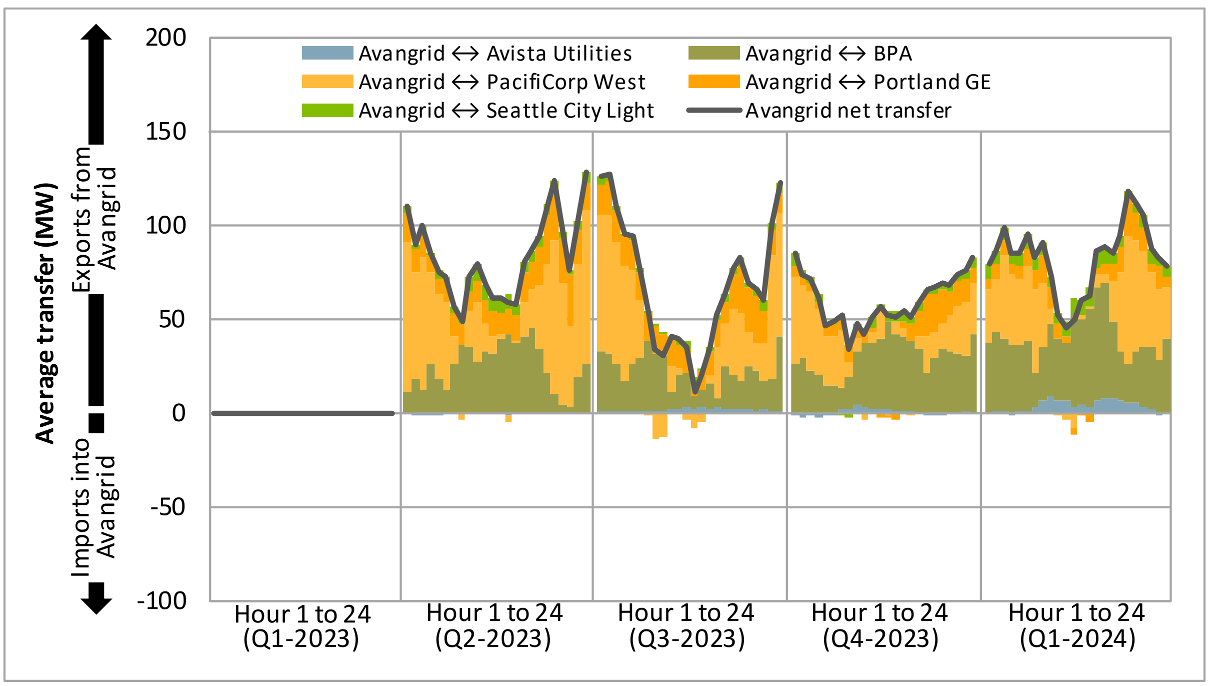
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q1 2024)

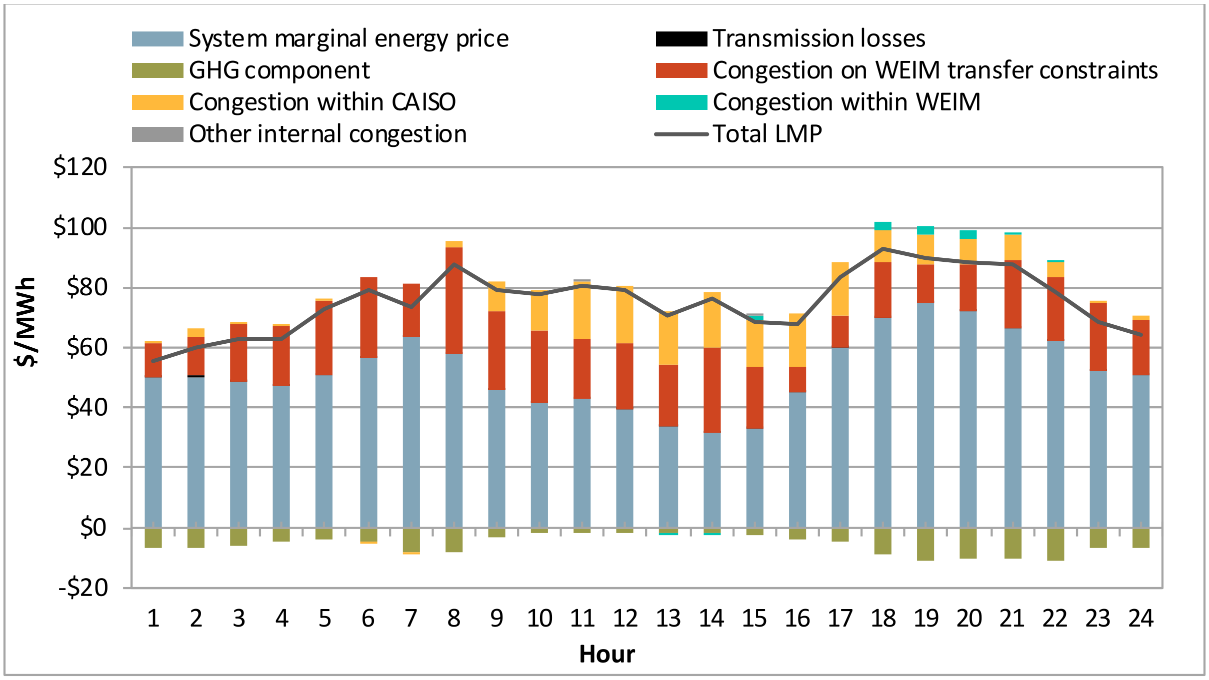


Appendix Figure A.8 Average hourly 5-minute market transfers

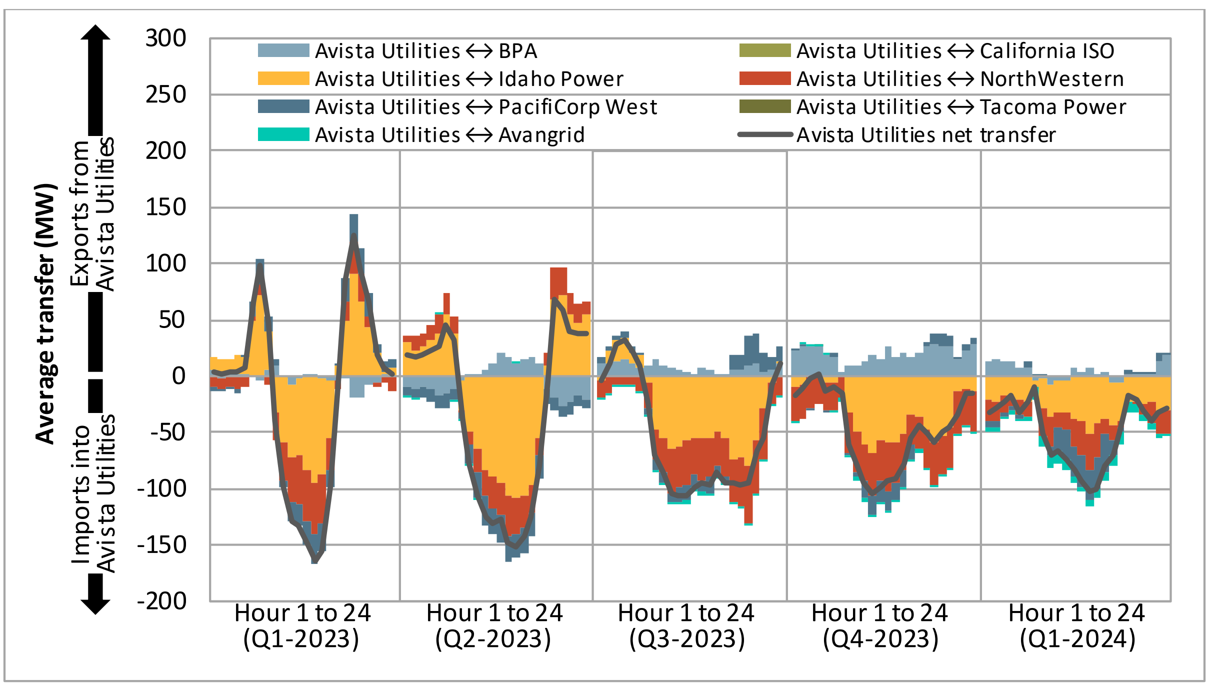


A.3 Avista Utilities

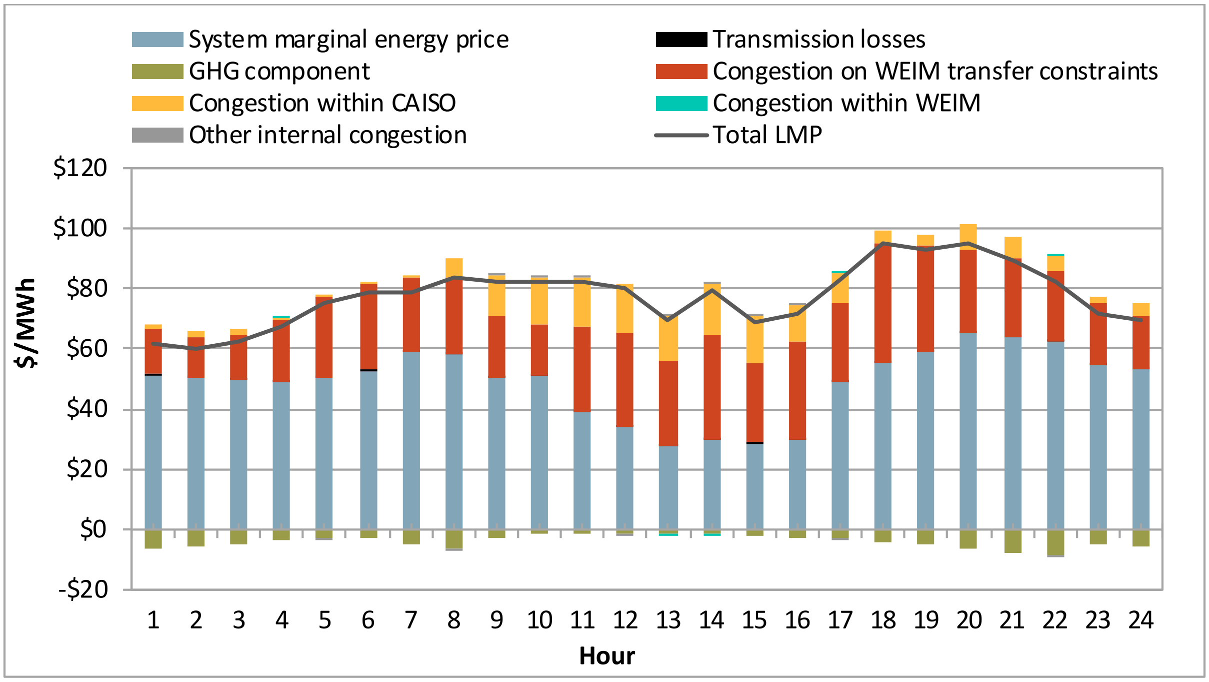
Appendix Figure A.9 Average hourly 15-minute price by component (Q1 2024)



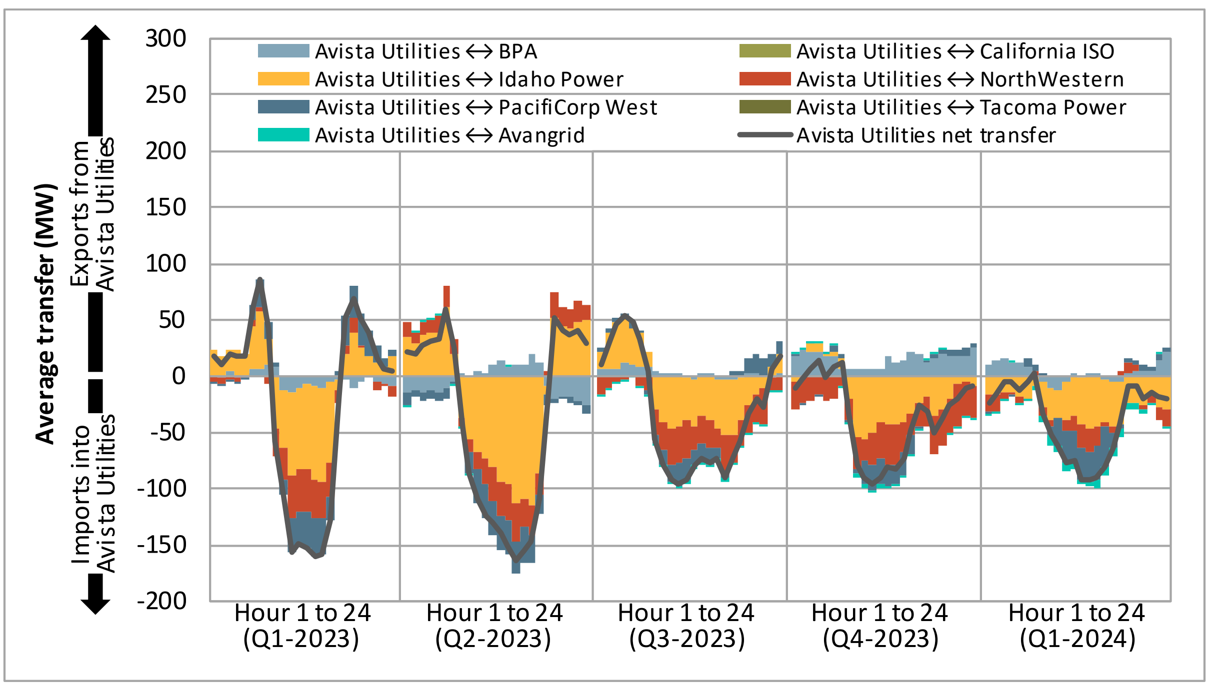
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q1 2024)

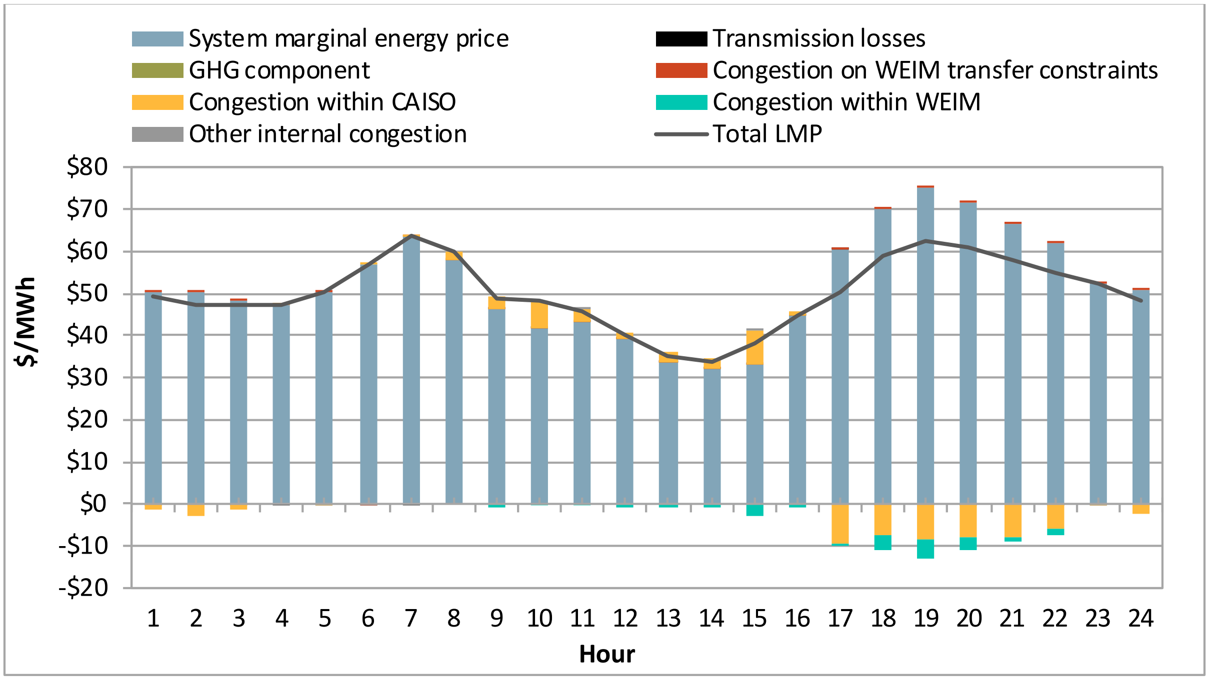


Appendix Figure A.12 Average hourly 5-minute market transfers

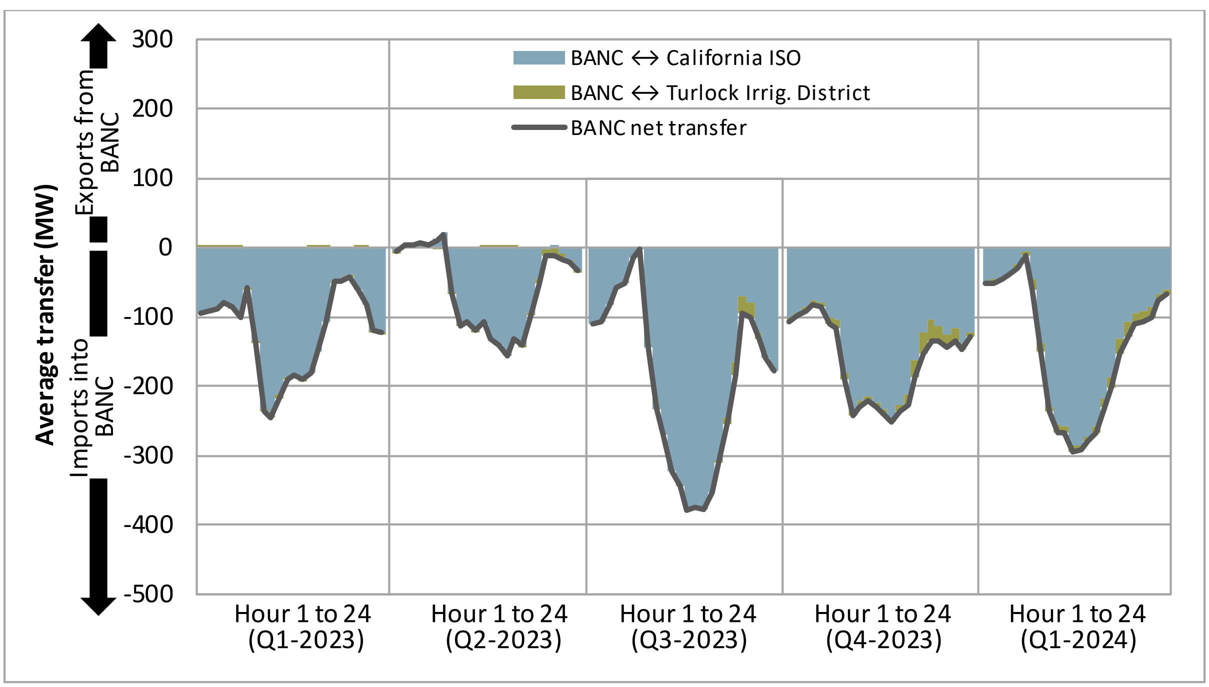


A.4 Balancing Authority of Northern California

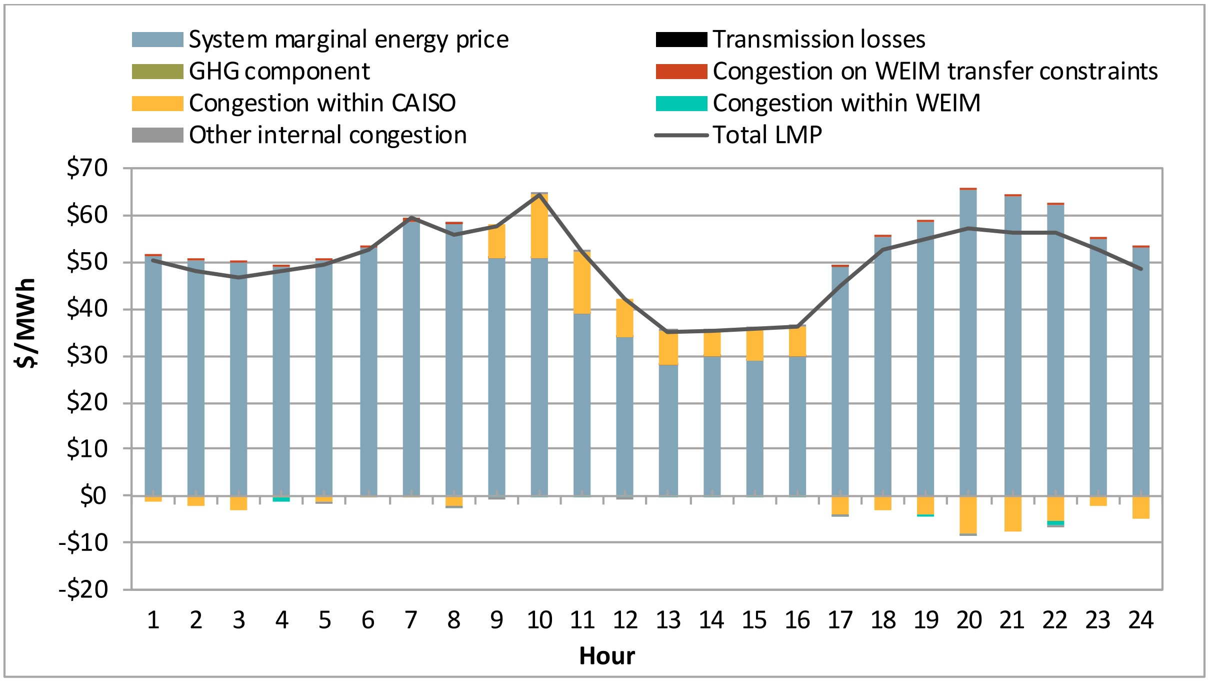
Appendix Figure A.13 Average hourly 15-minute price by component (Q1 2024)



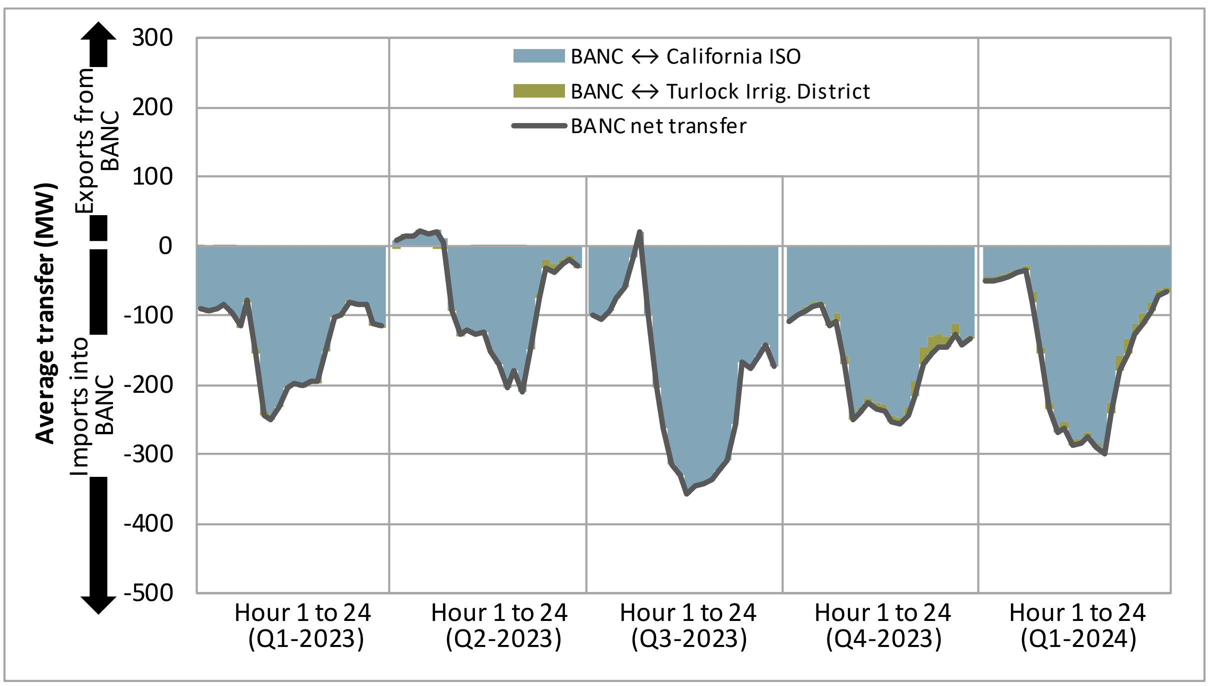
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q1 2024)

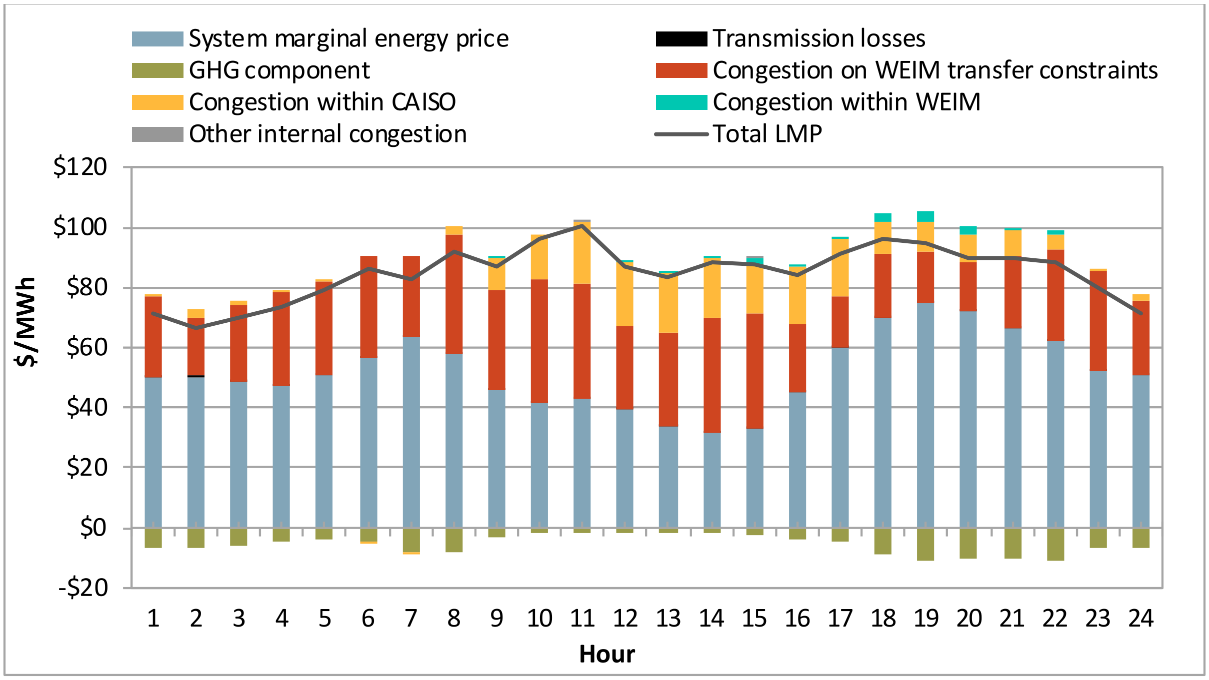


Appendix Figure A.16 Average hourly 5-minute market transfers

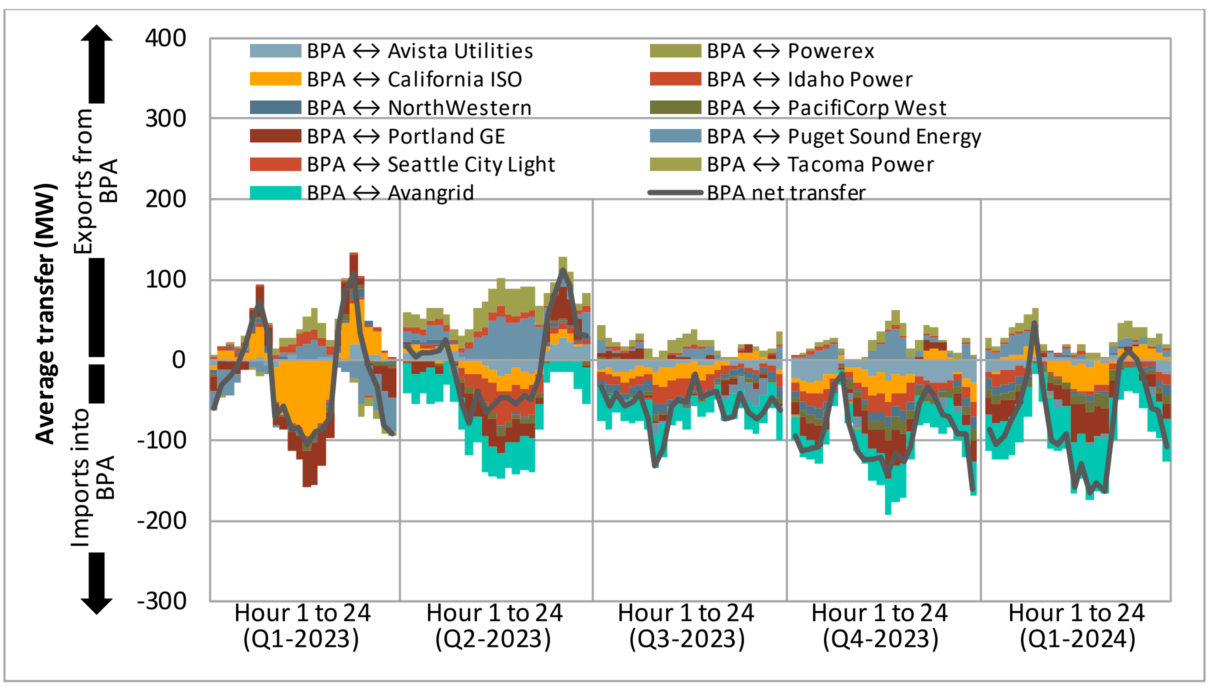


A.5 Bonneville Power Administration

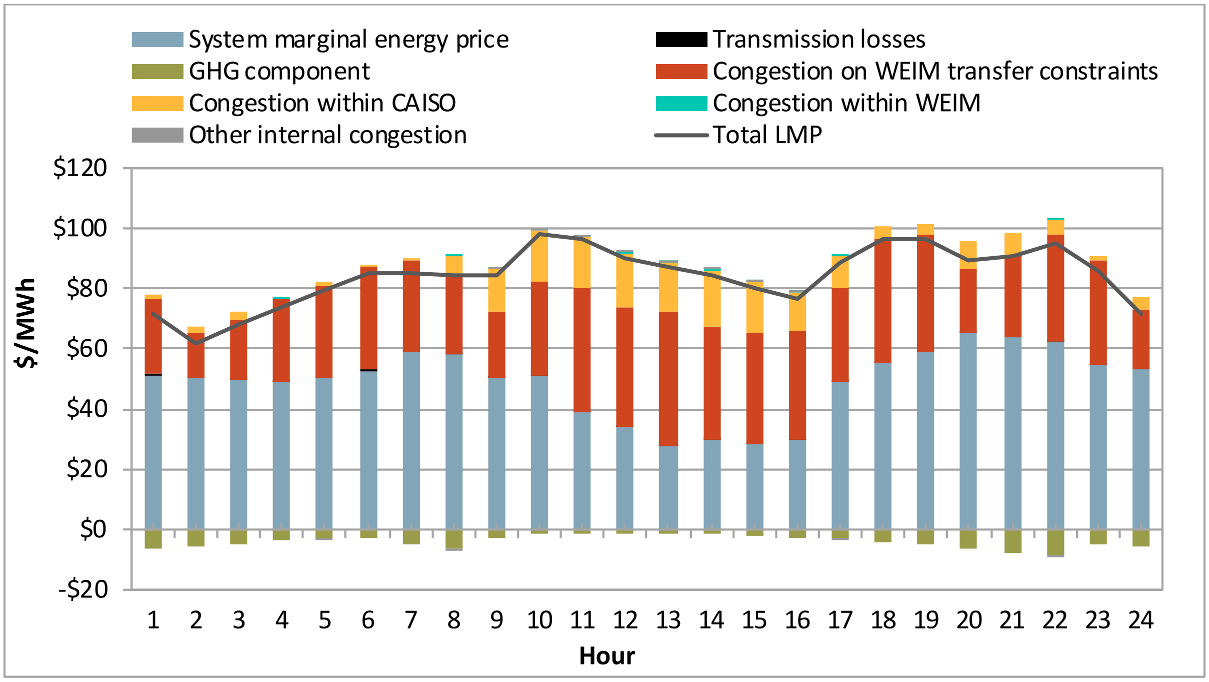
Appendix Figure A.17 Average hourly 15-minute price by component (Q1 2024)



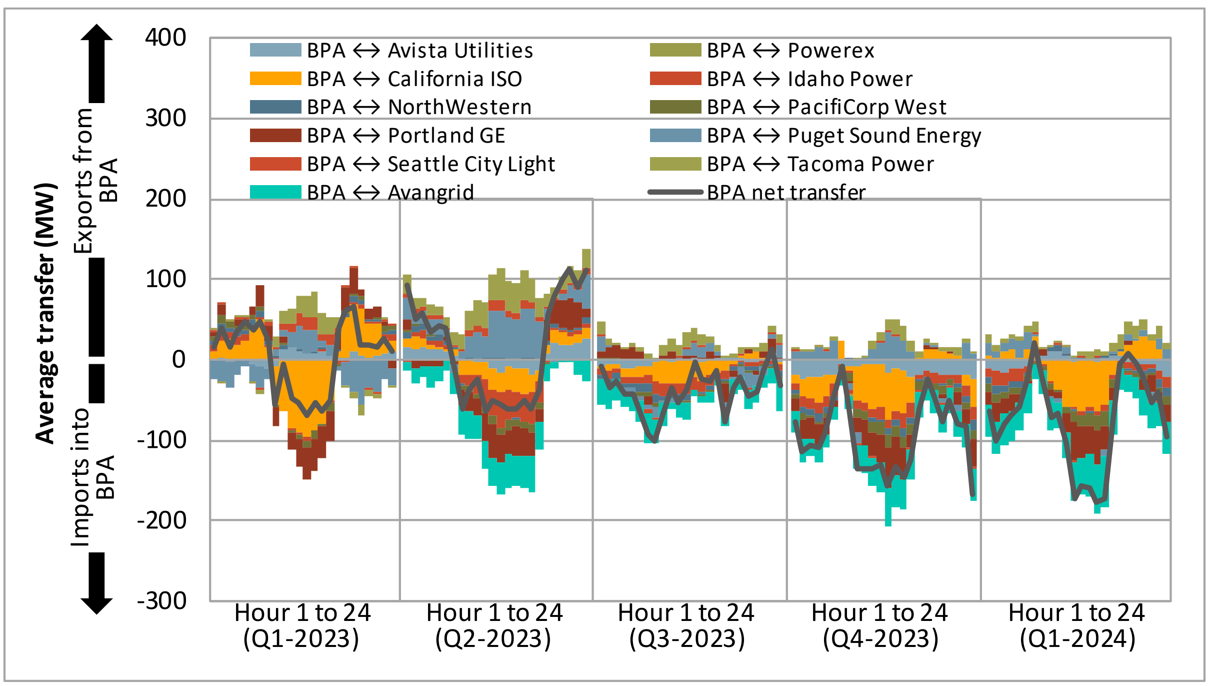
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q1 2024)

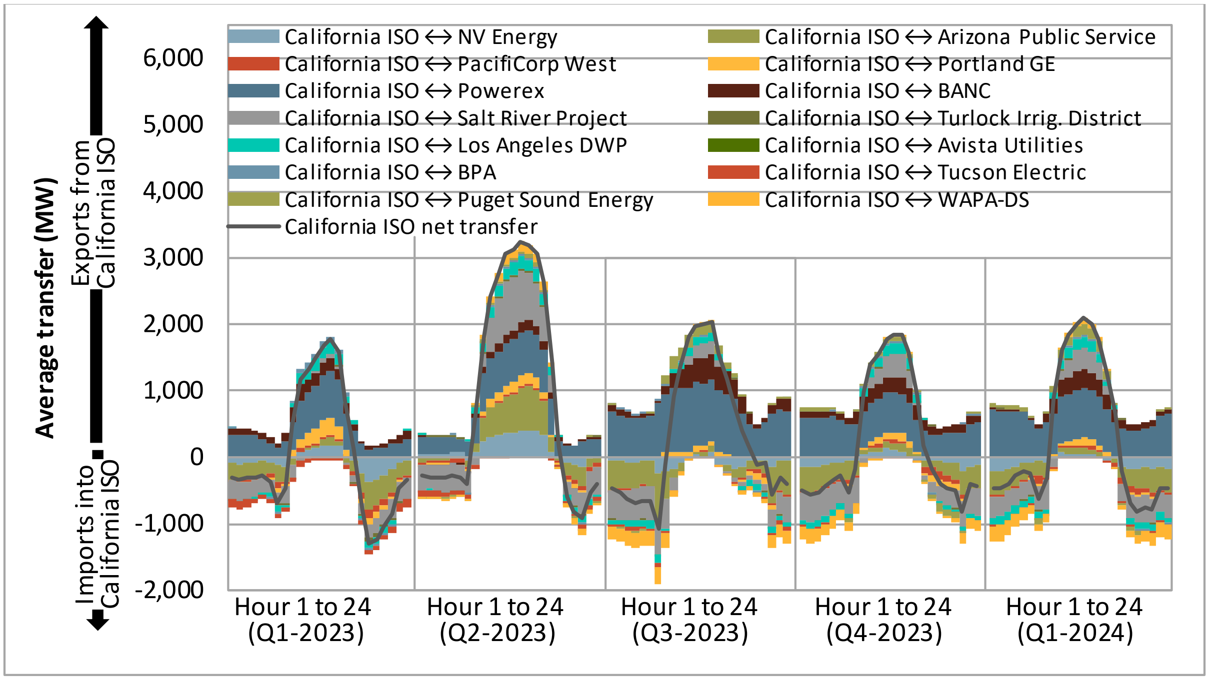


Appendix Figure A.20 Average hourly 5-minute market transfers

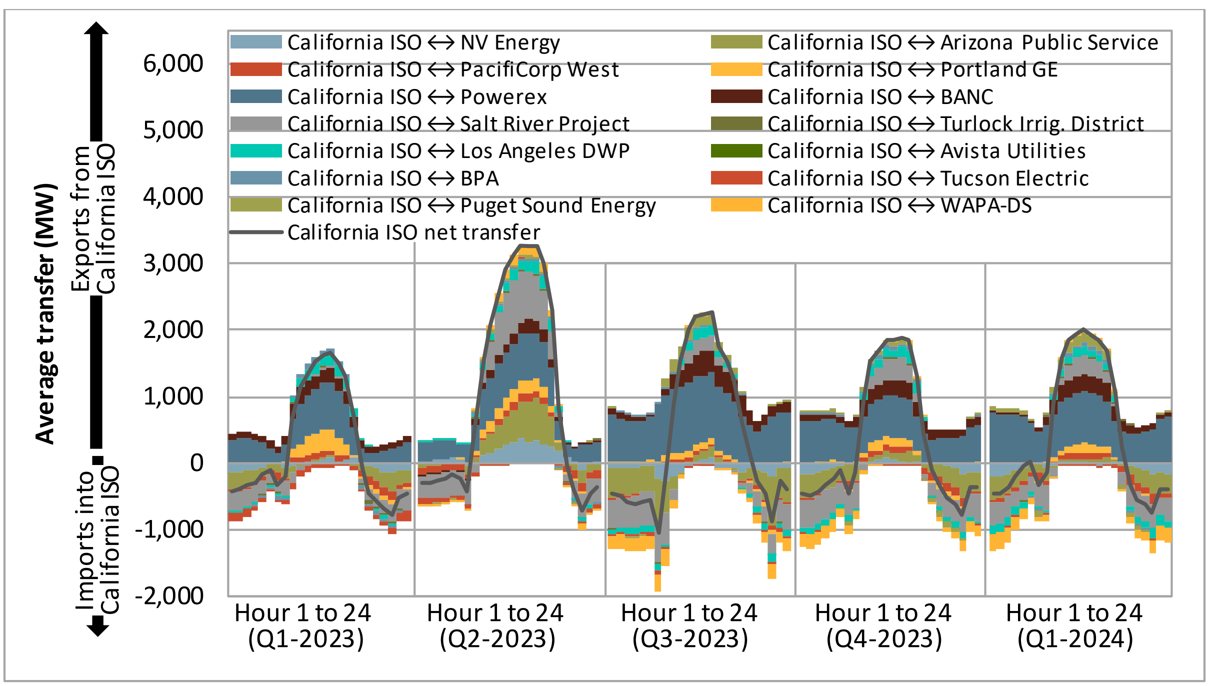


A.6 California ISO

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

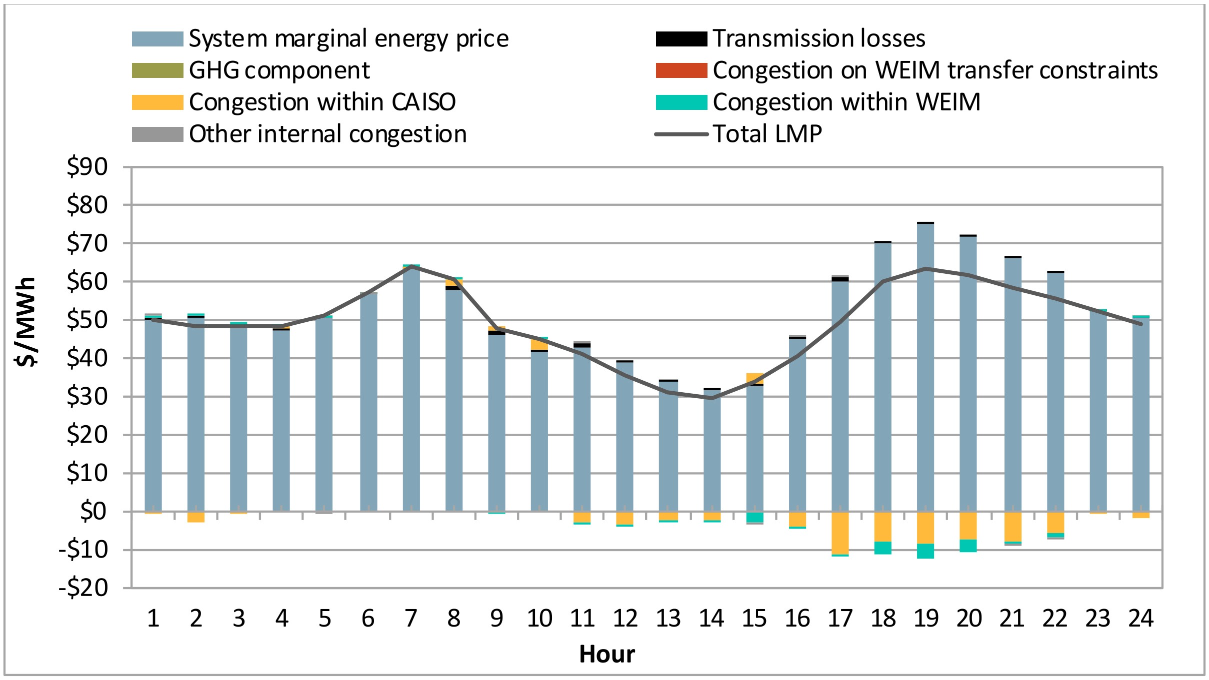


Appendix Figure A.22 Average hourly 5-minute market transfers

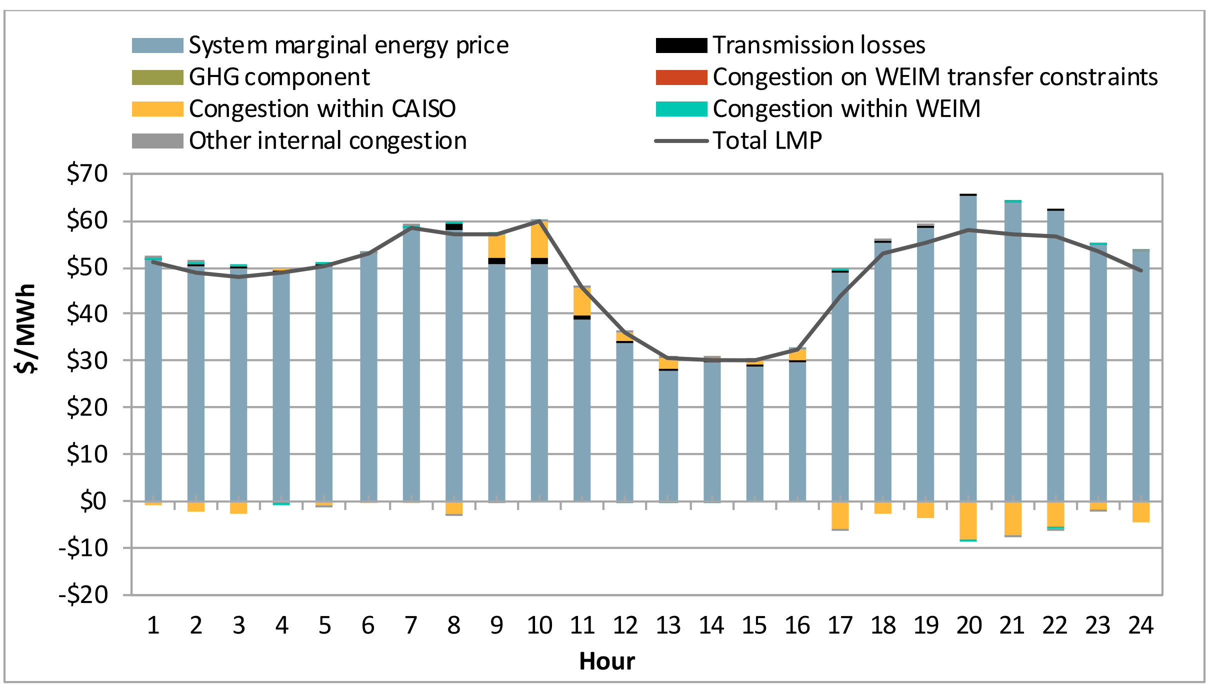


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q1 2024)

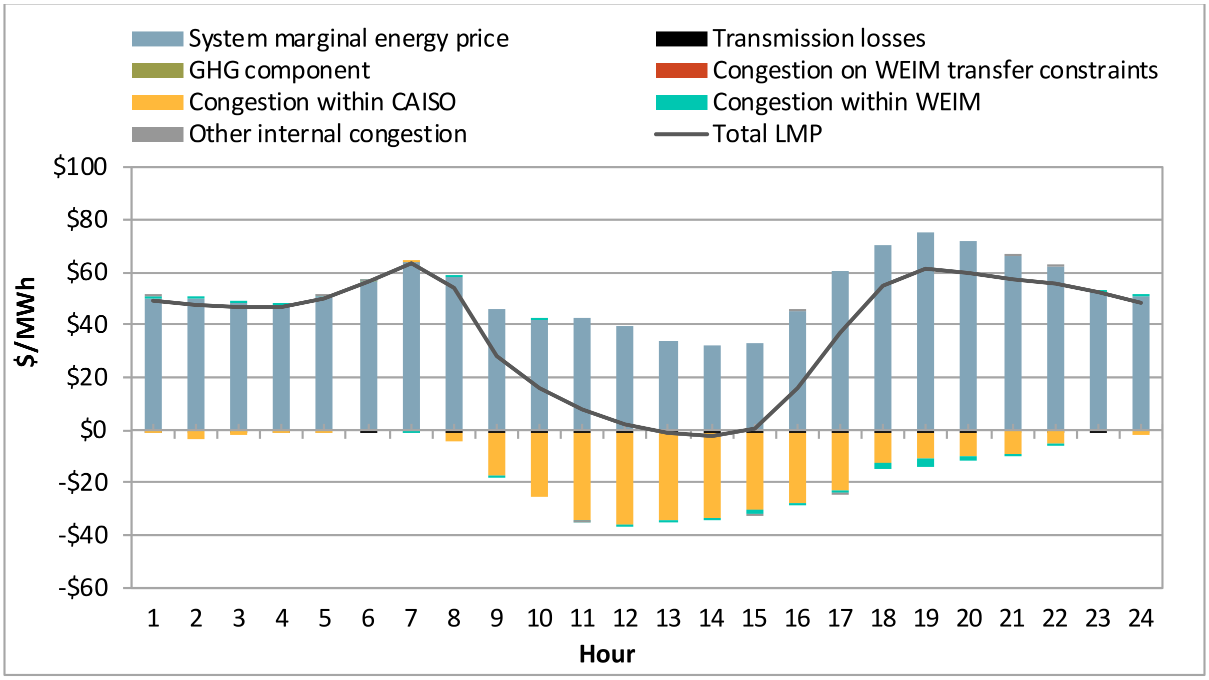


Appendix Figure A.24 Average hourly 5-minute price by component (Q1 2024)

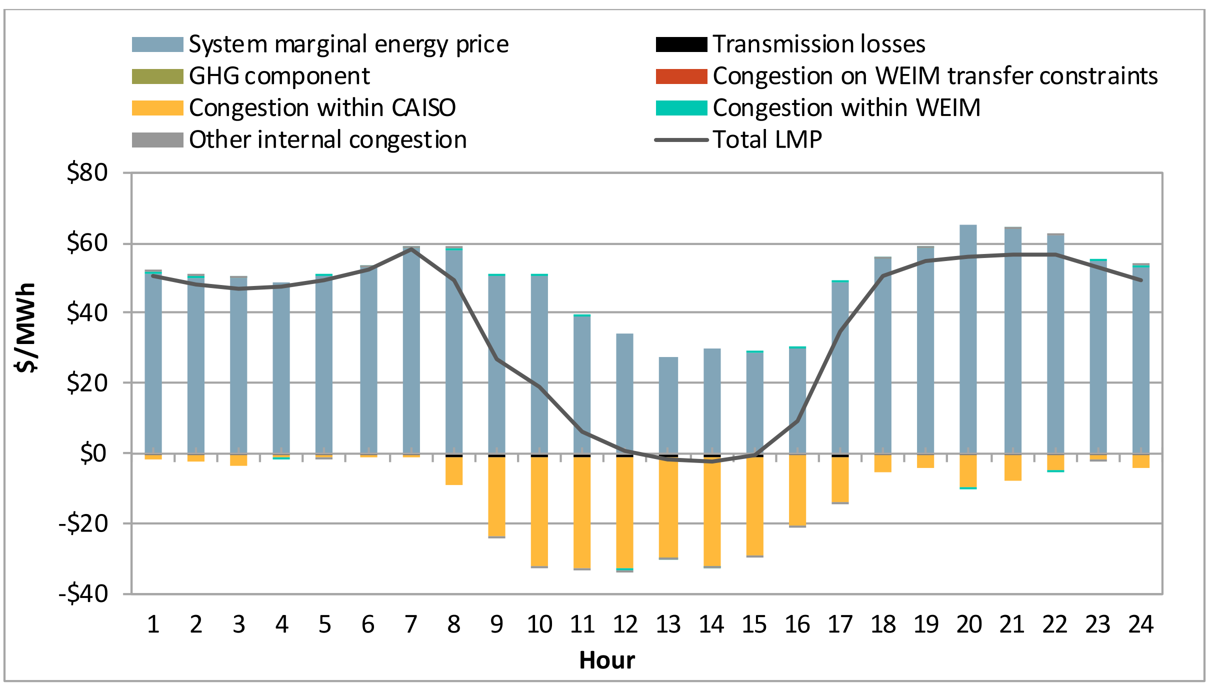


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q1 2024)

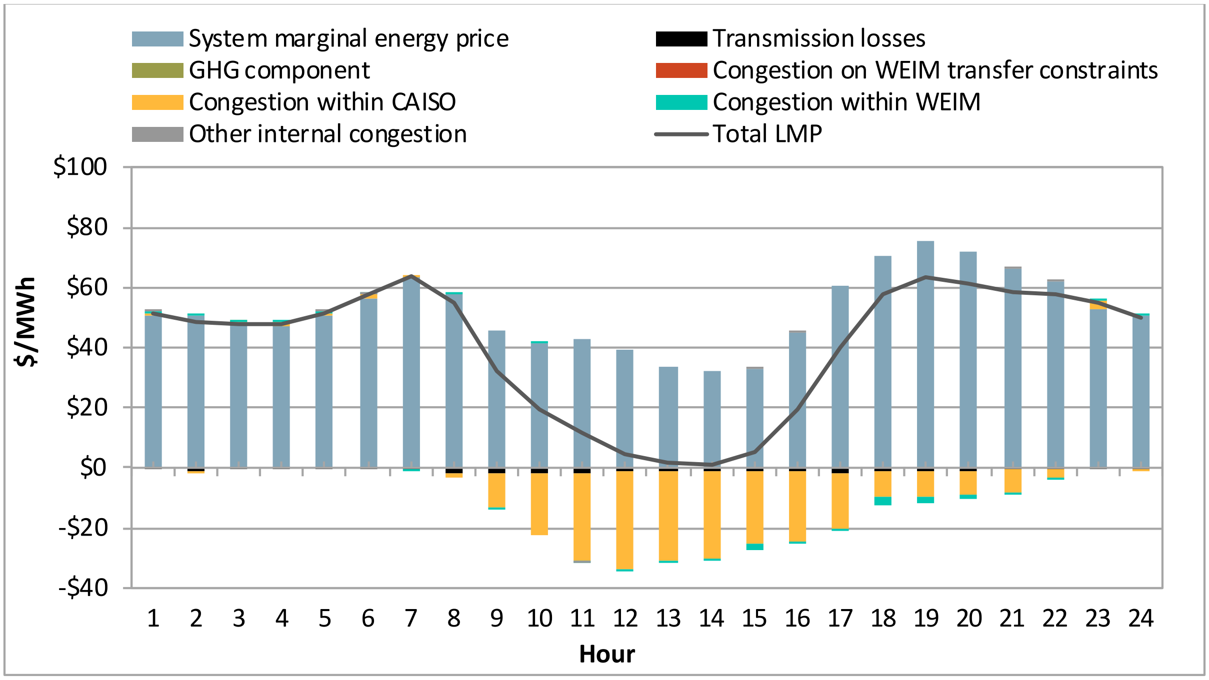


Appendix Figure A.26 Average hourly 5-minute price by component (Q1 2024)

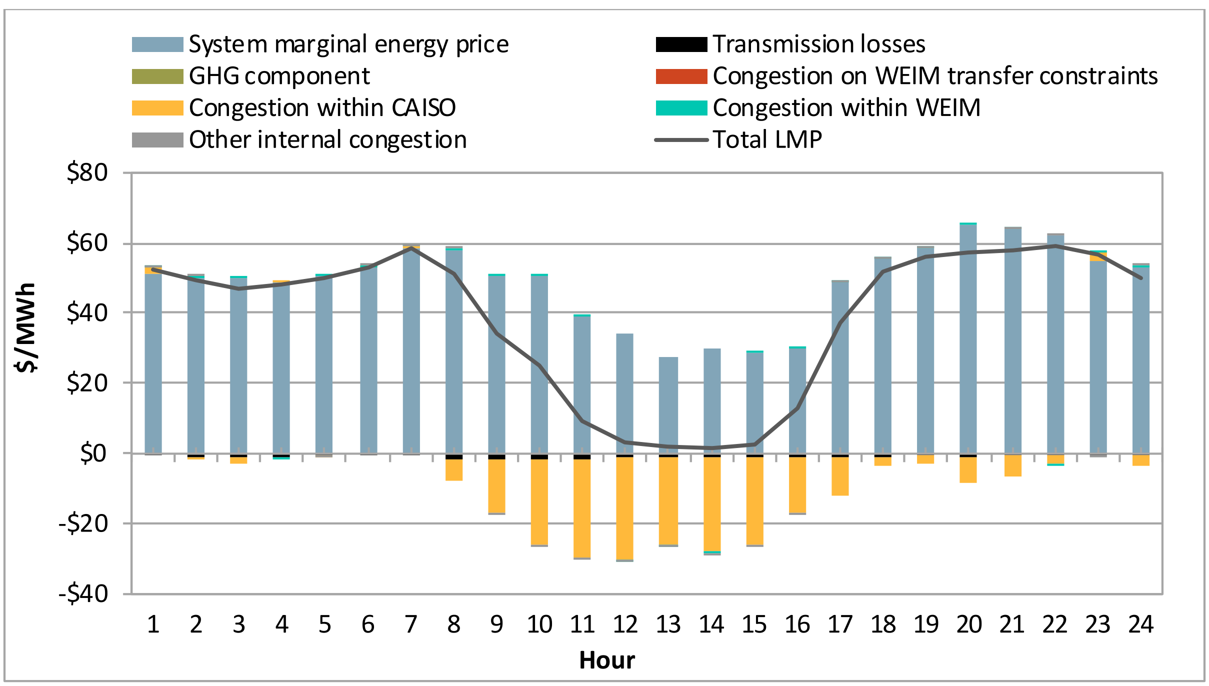


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q1 2024)

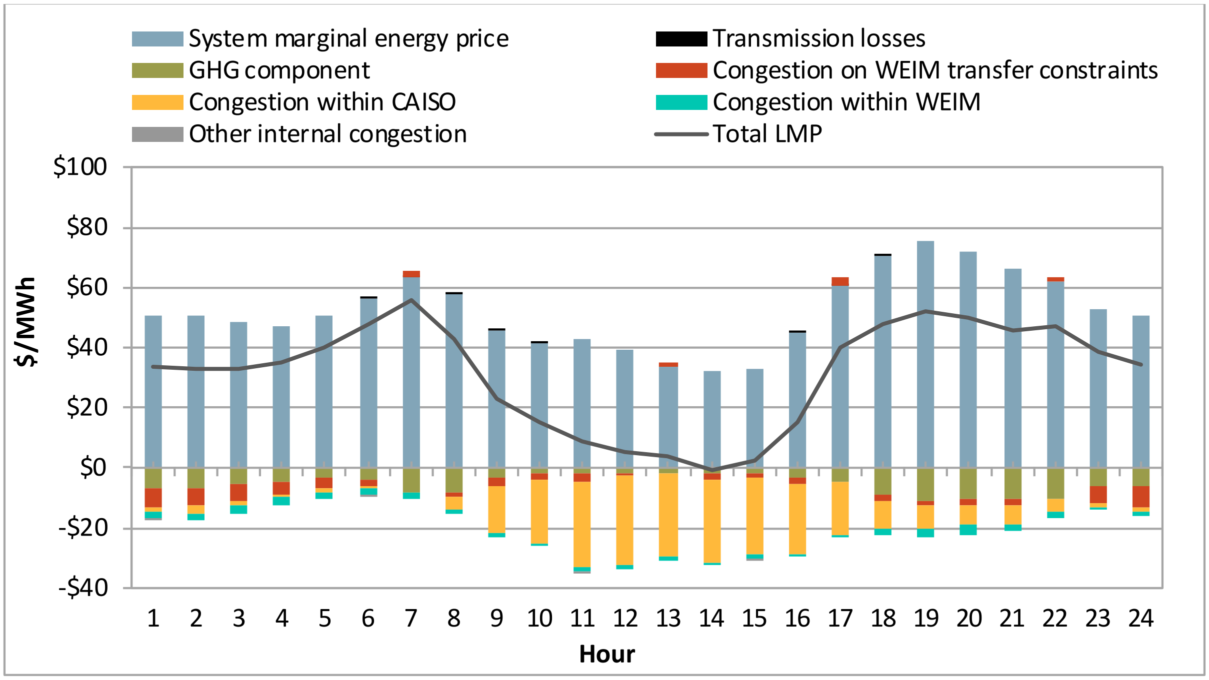


Appendix Figure A.28 Average hourly 5-minute price by component (Q1 2024)

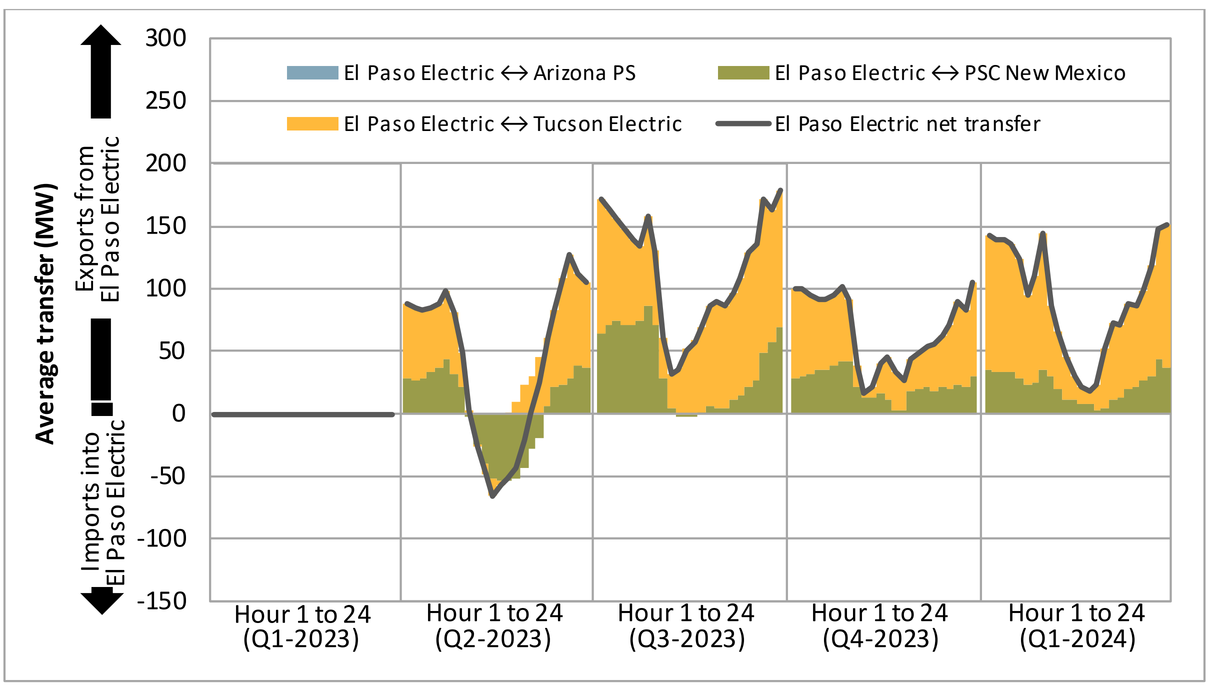


A.7 El Paso Electric

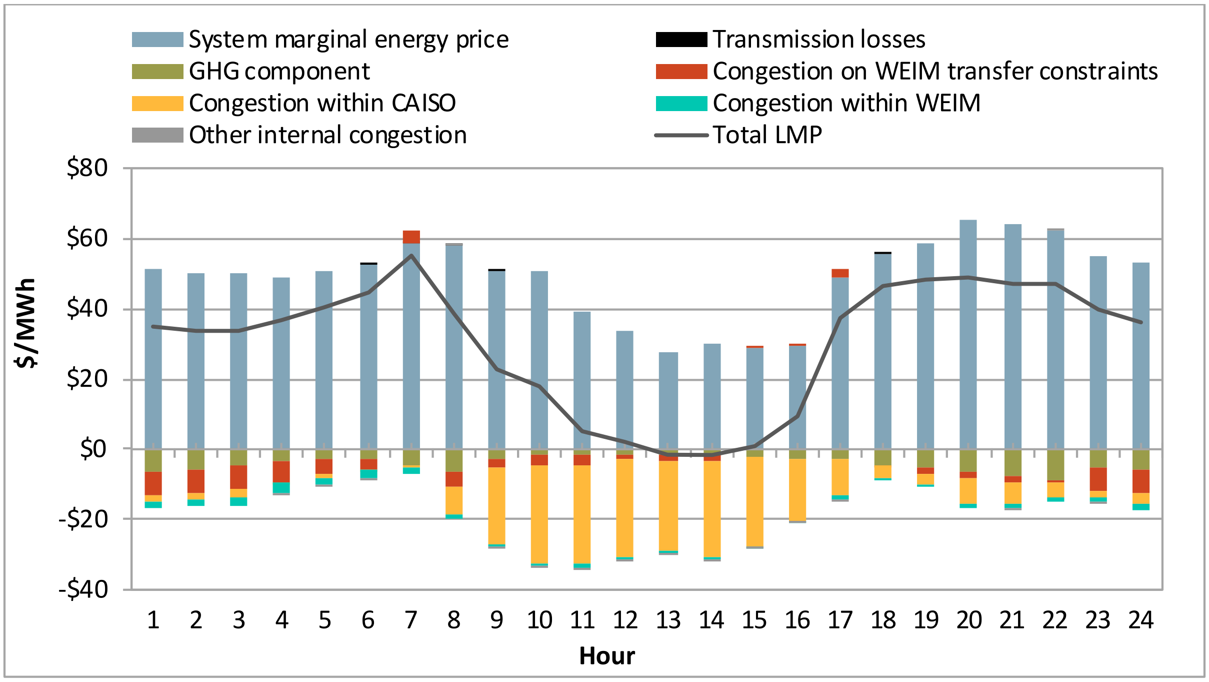
Appendix Figure A.29 Average hourly 15-minute price by component (Q1 2024)



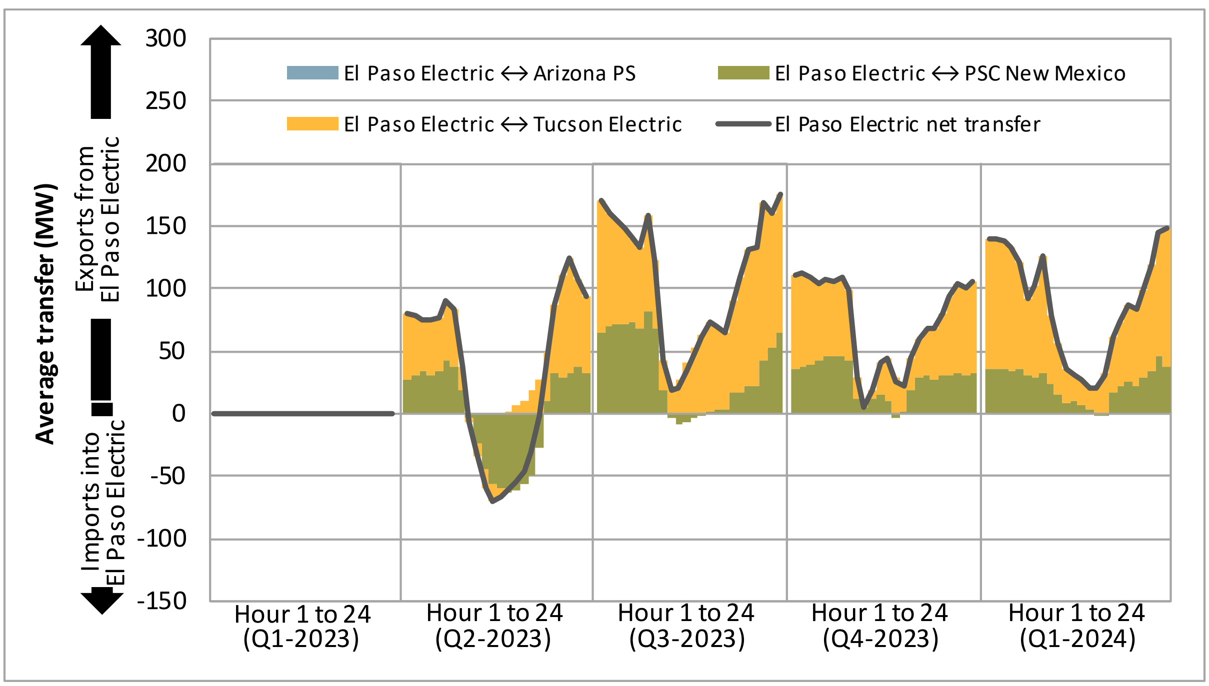
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q1 2024)

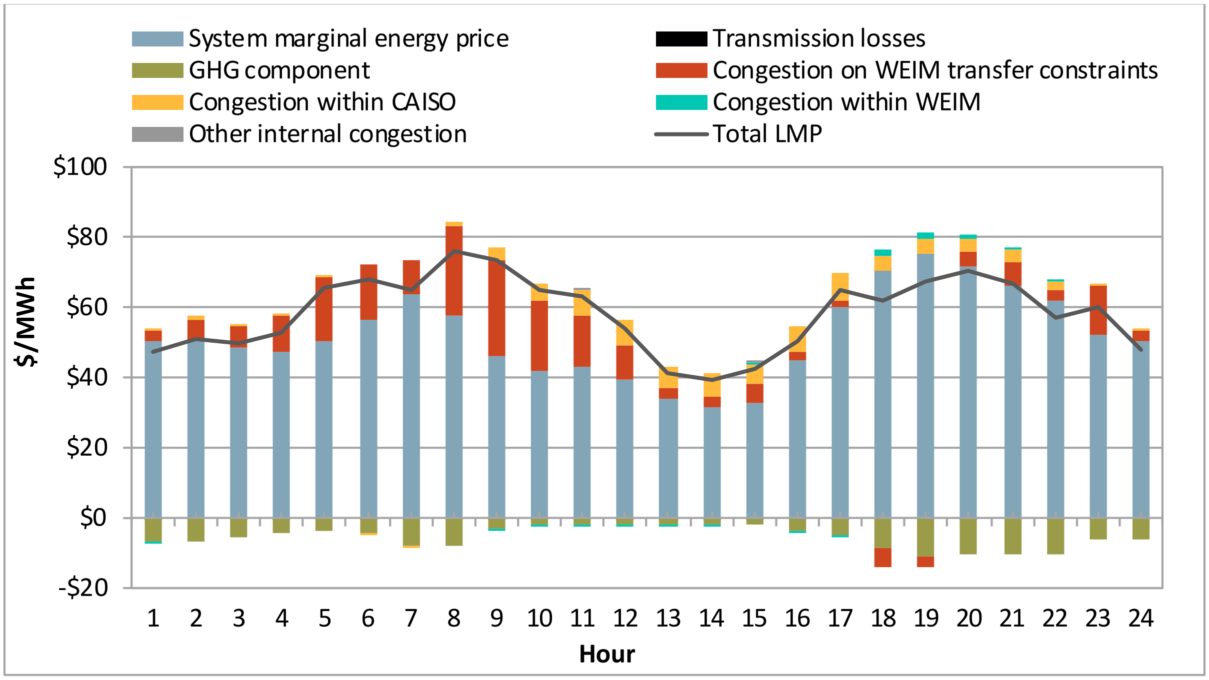


Appendix Figure A.32 Average hourly 5-minute market transfers

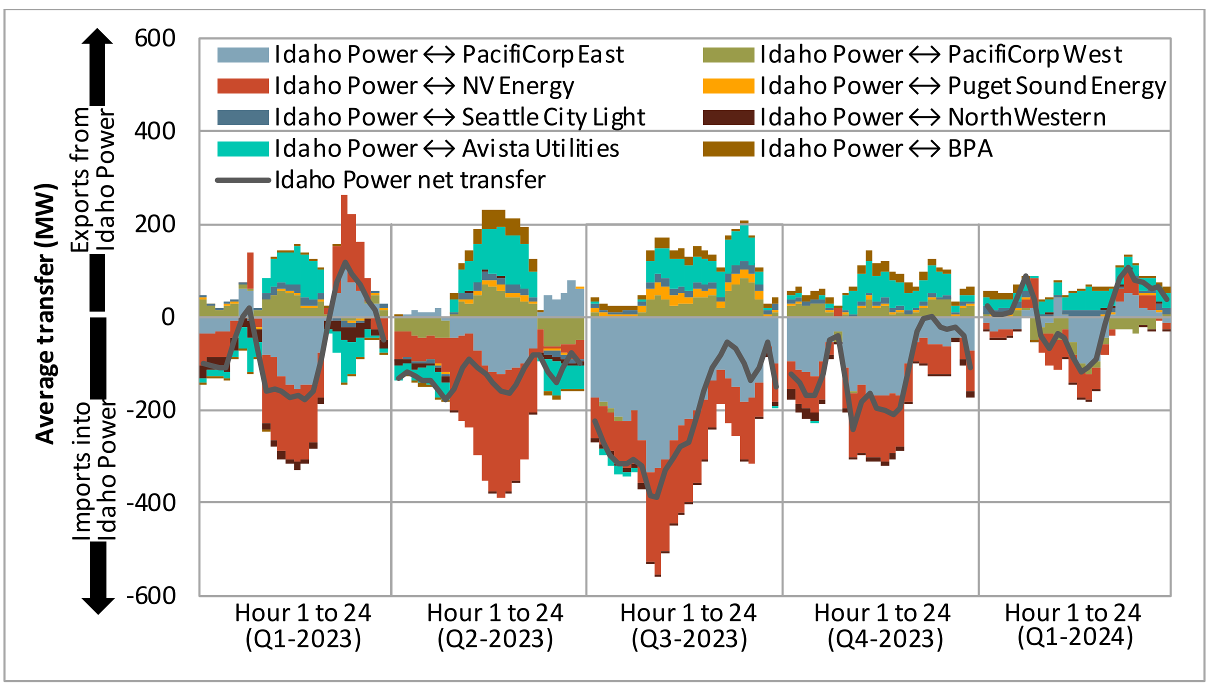


A.8 Idaho Power

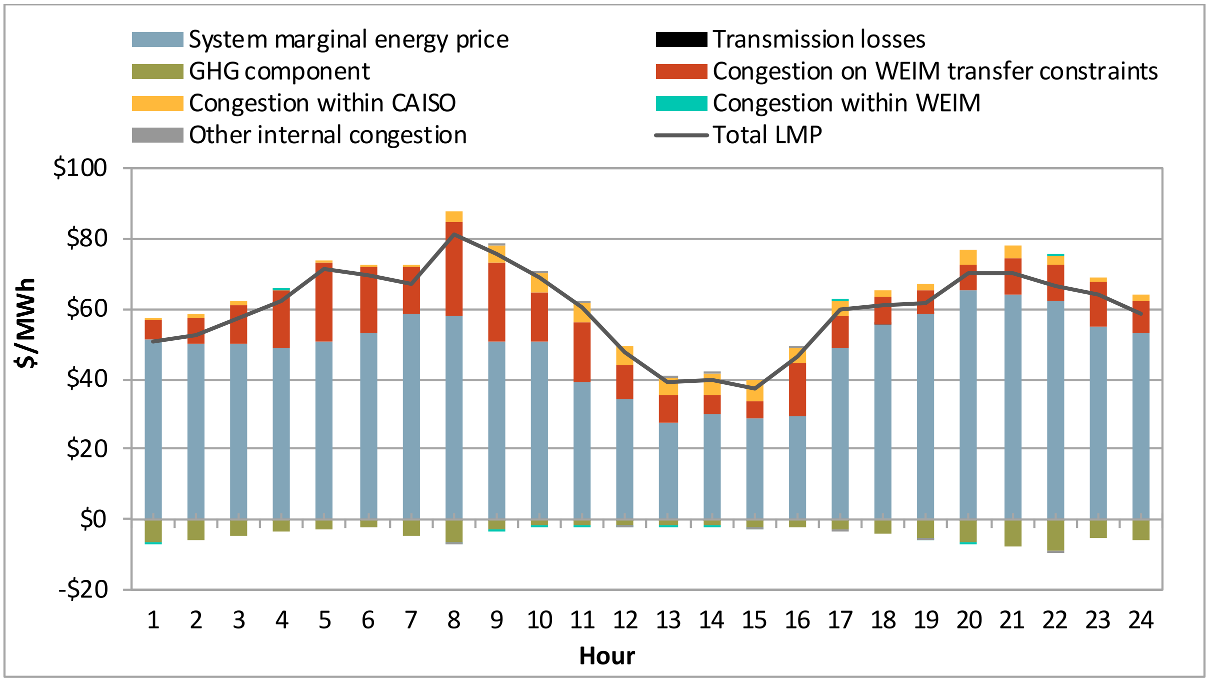
Appendix Figure A.33 Average hourly 15-minute price by component (Q1 2024)



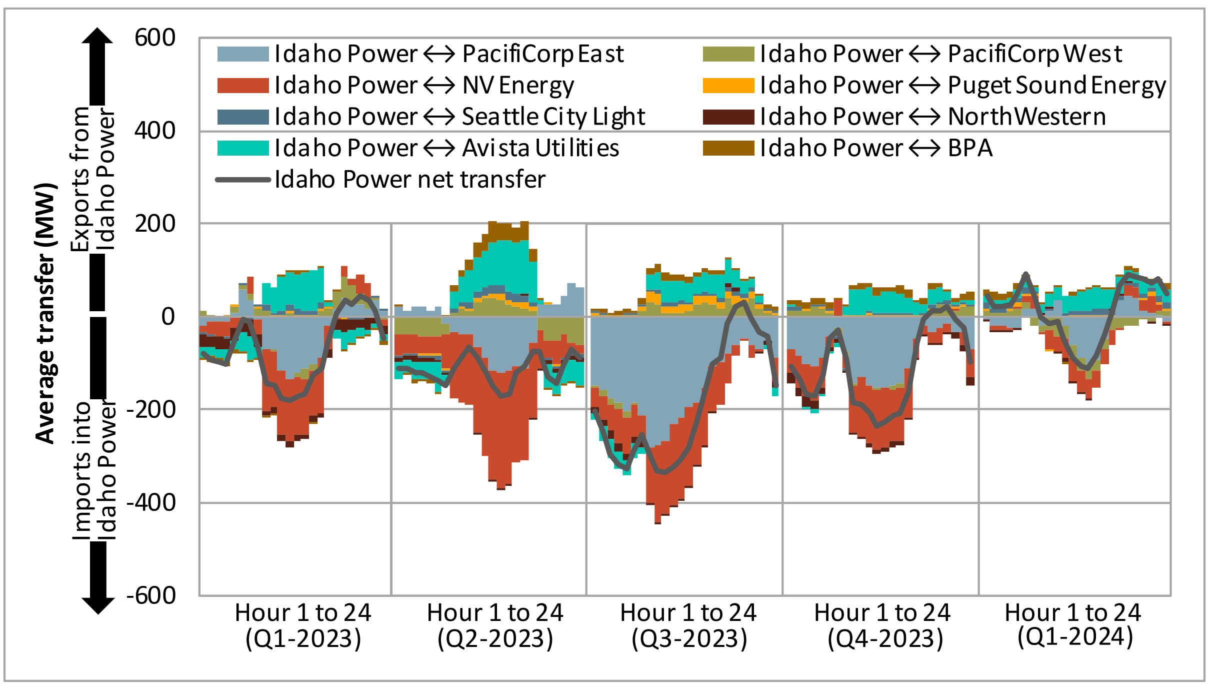
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q1 2024)

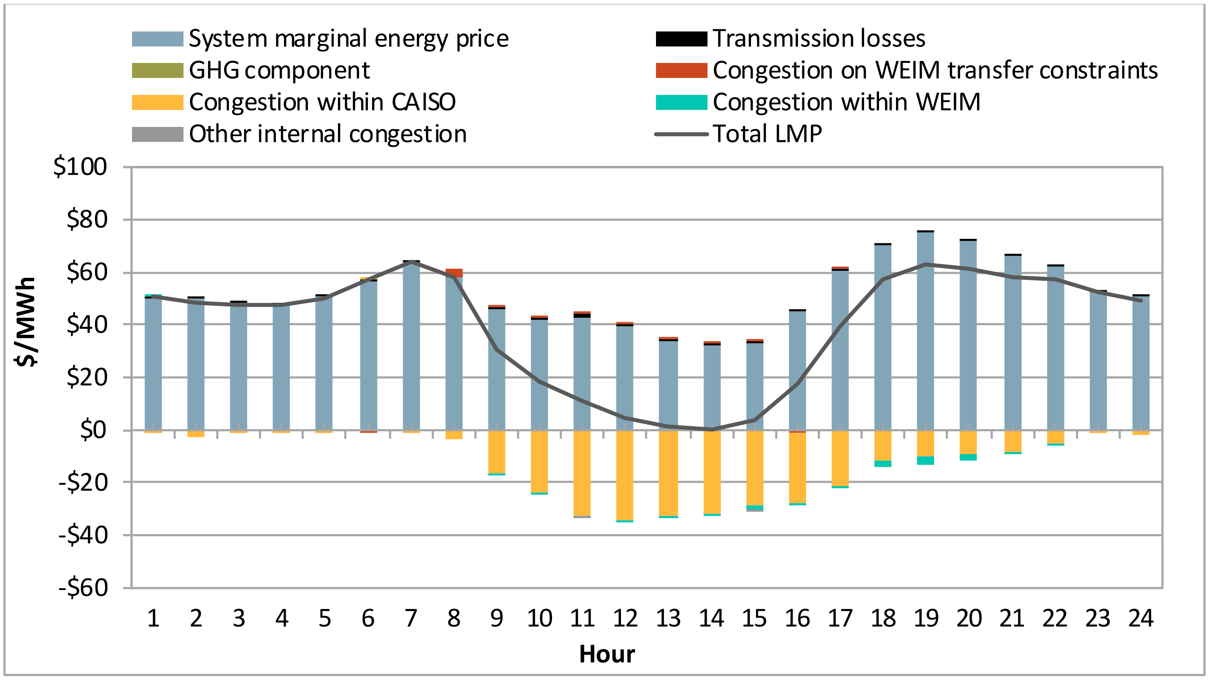


Appendix Figure A.36 Average hourly 5-minute market transfers

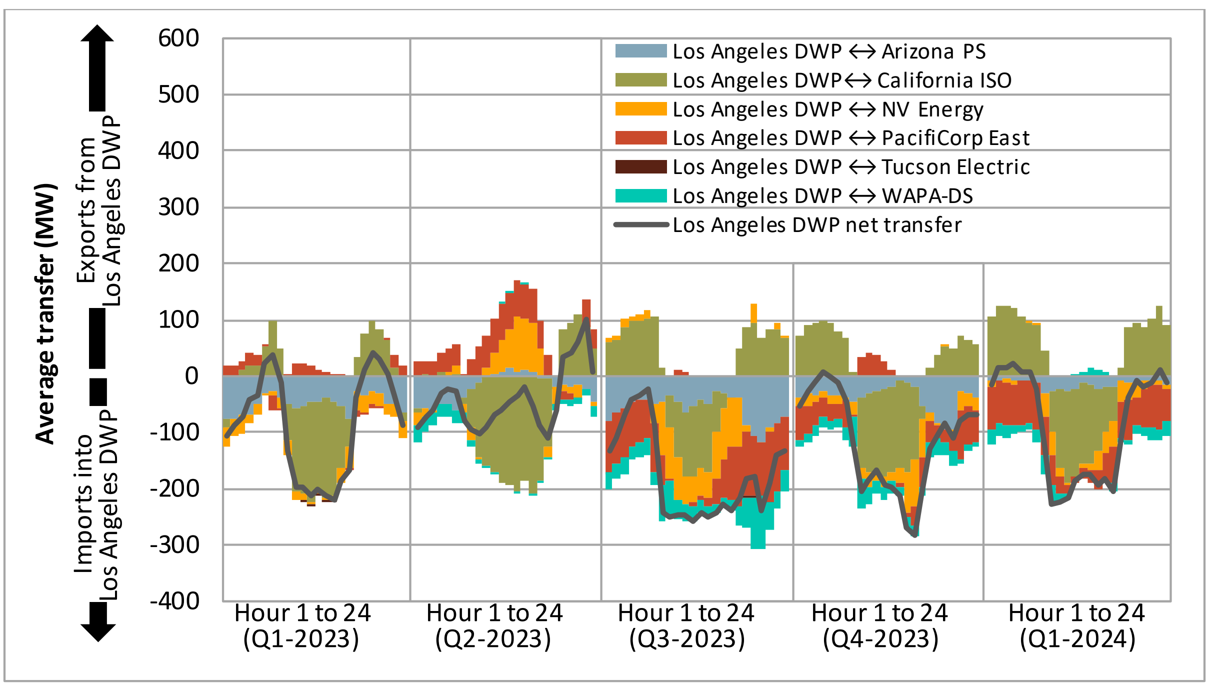


A.9 Los Angeles Department of Water and Power

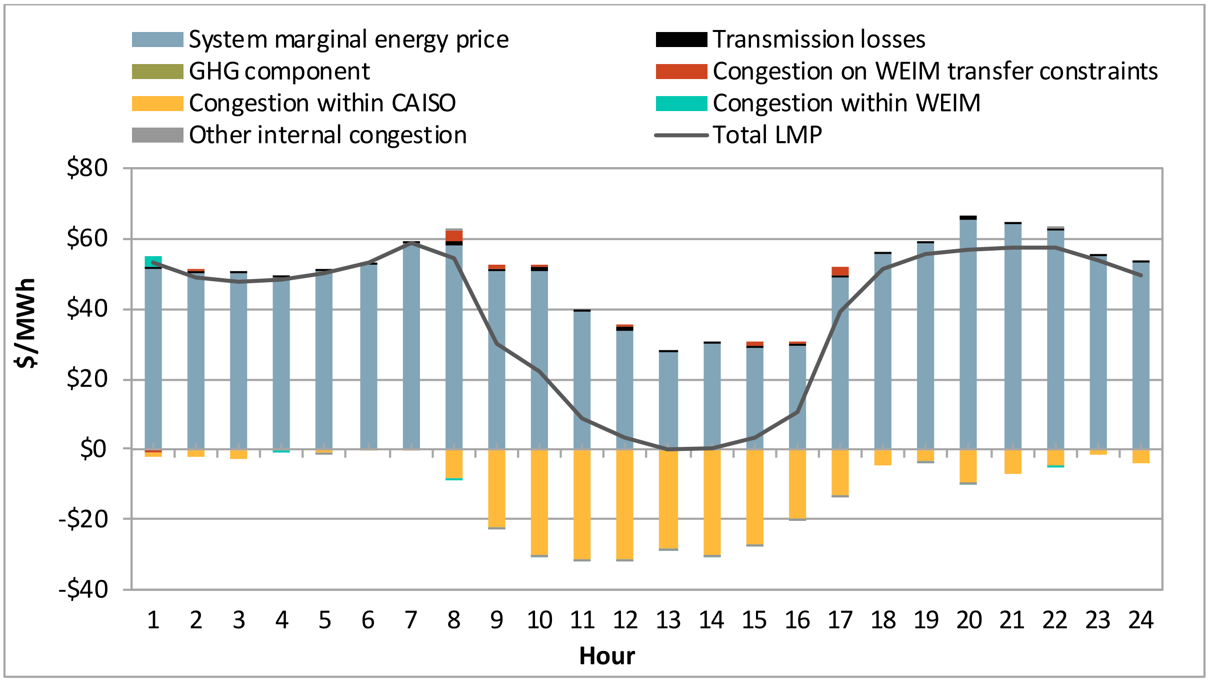
Appendix Figure A.37 Average hourly 15-minute price by component (Q1 2024)



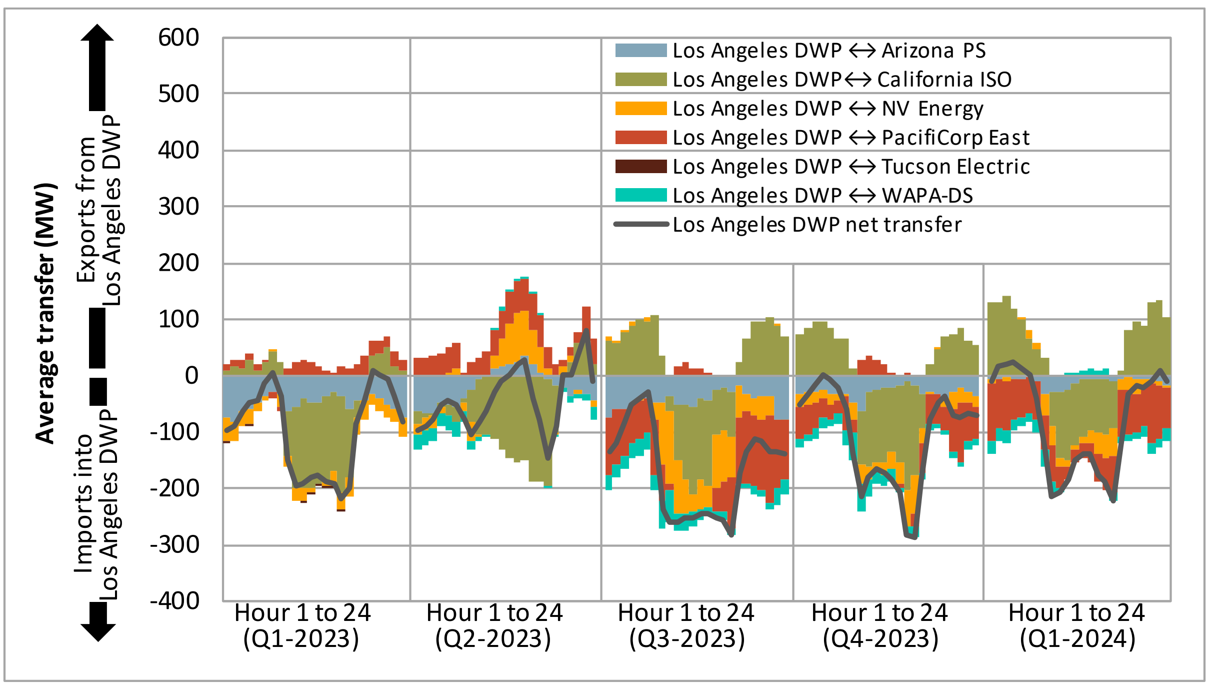
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q1 2024)

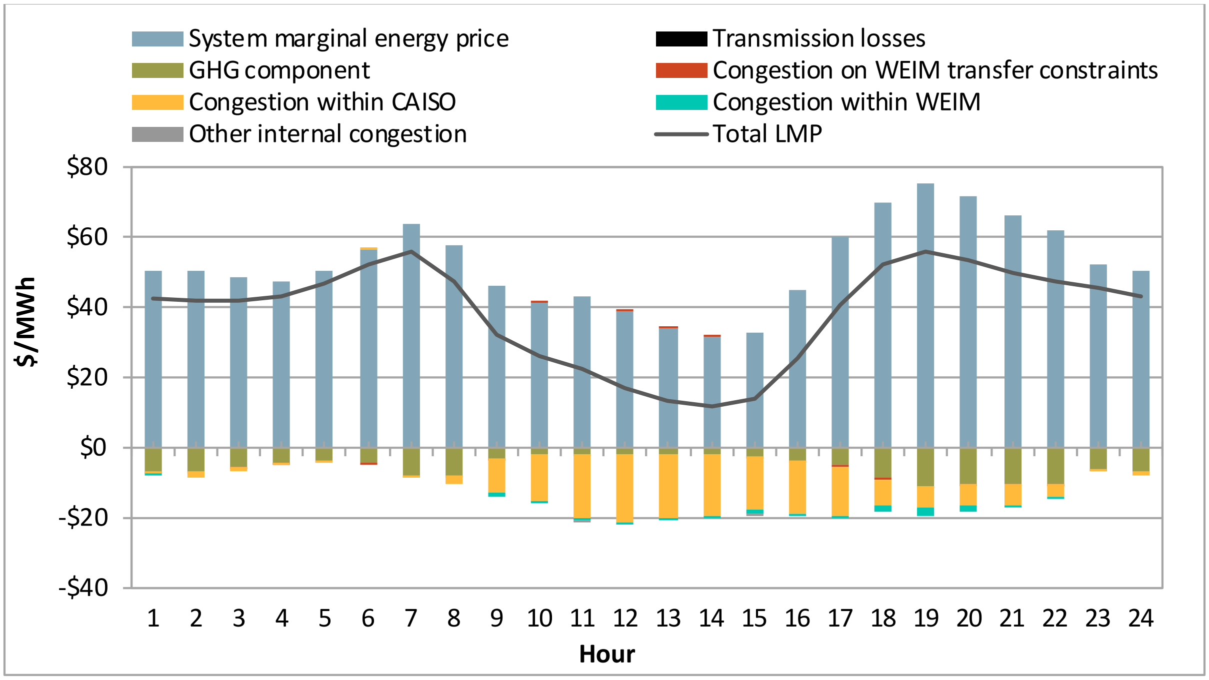


Appendix Figure A.40 Average hourly 5-minute market transfers

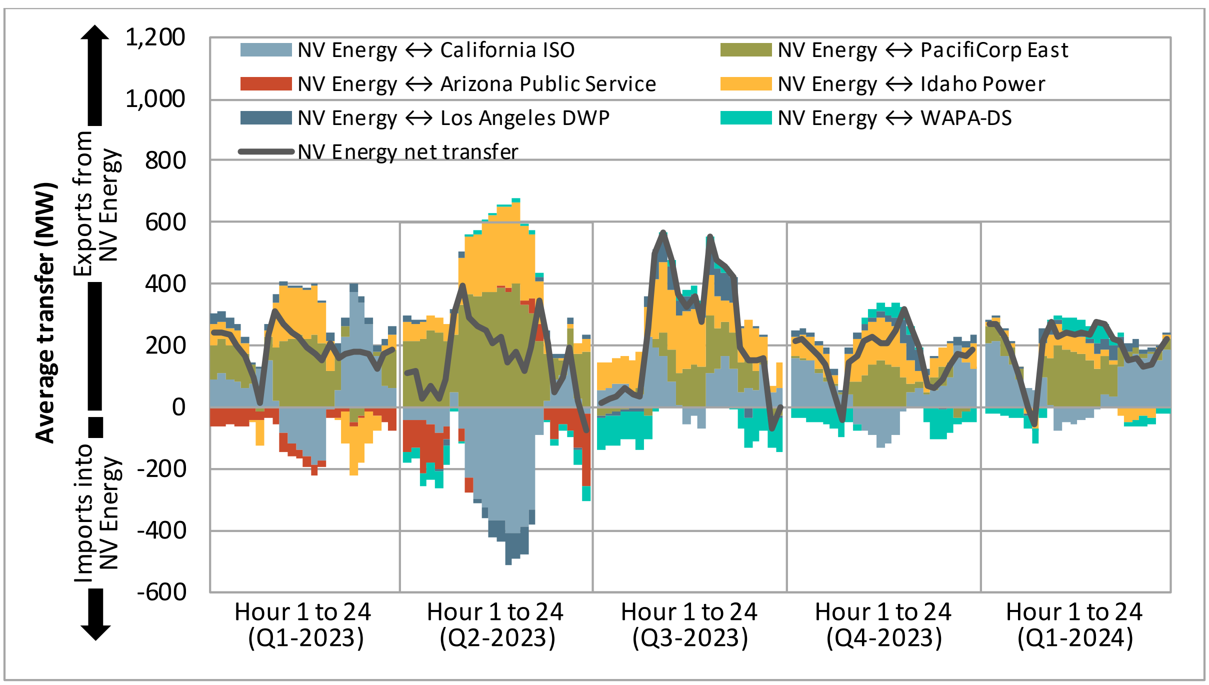


A.10 NV Energy

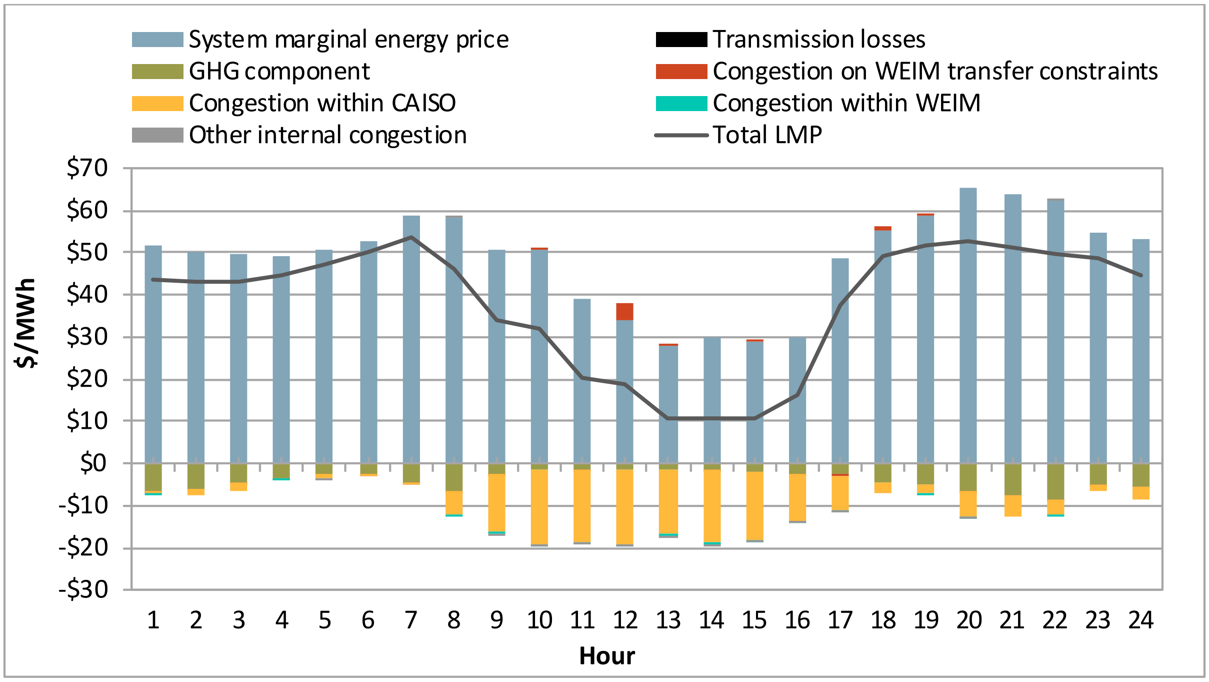
Appendix Figure A.41 Average hourly 15-minute price by component (Q1 2024)



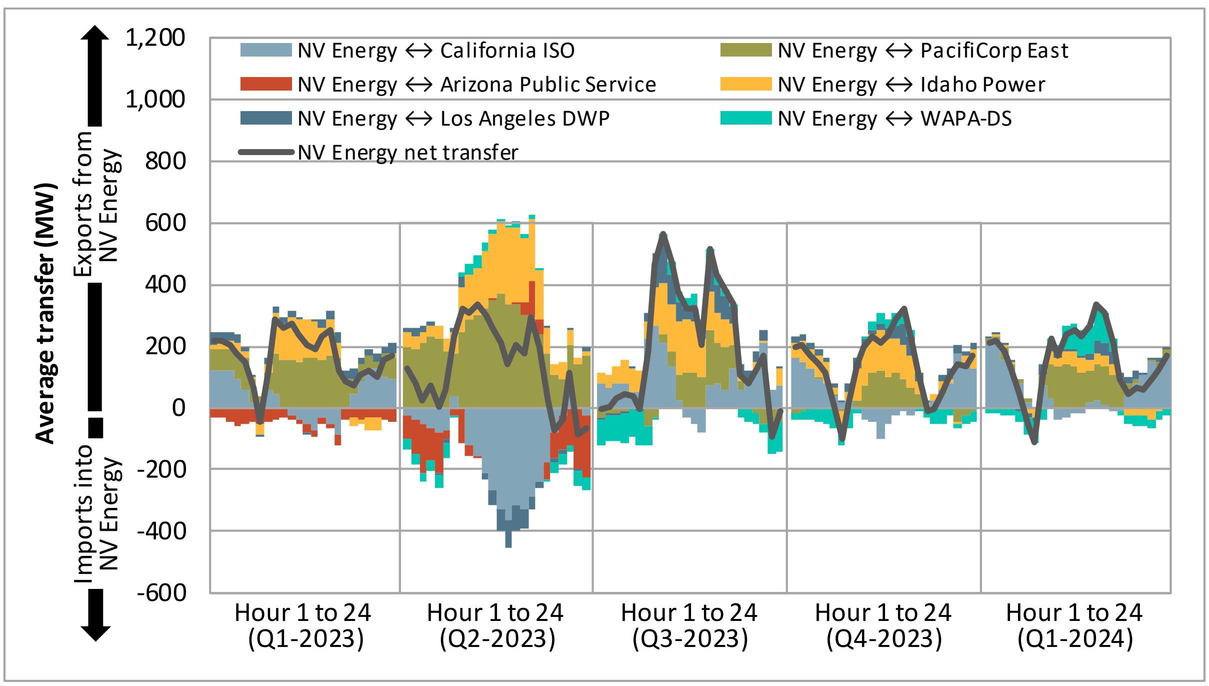
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q1 2024)

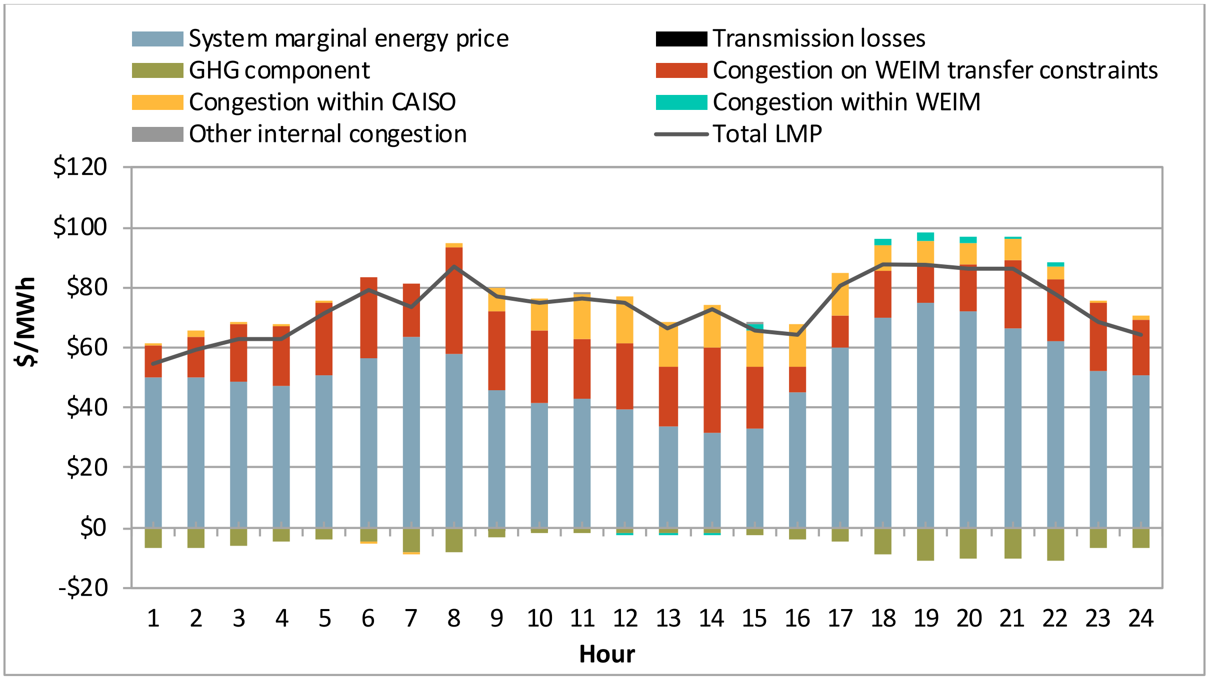


Appendix Figure A.44 Average hourly 5-minute market transfers

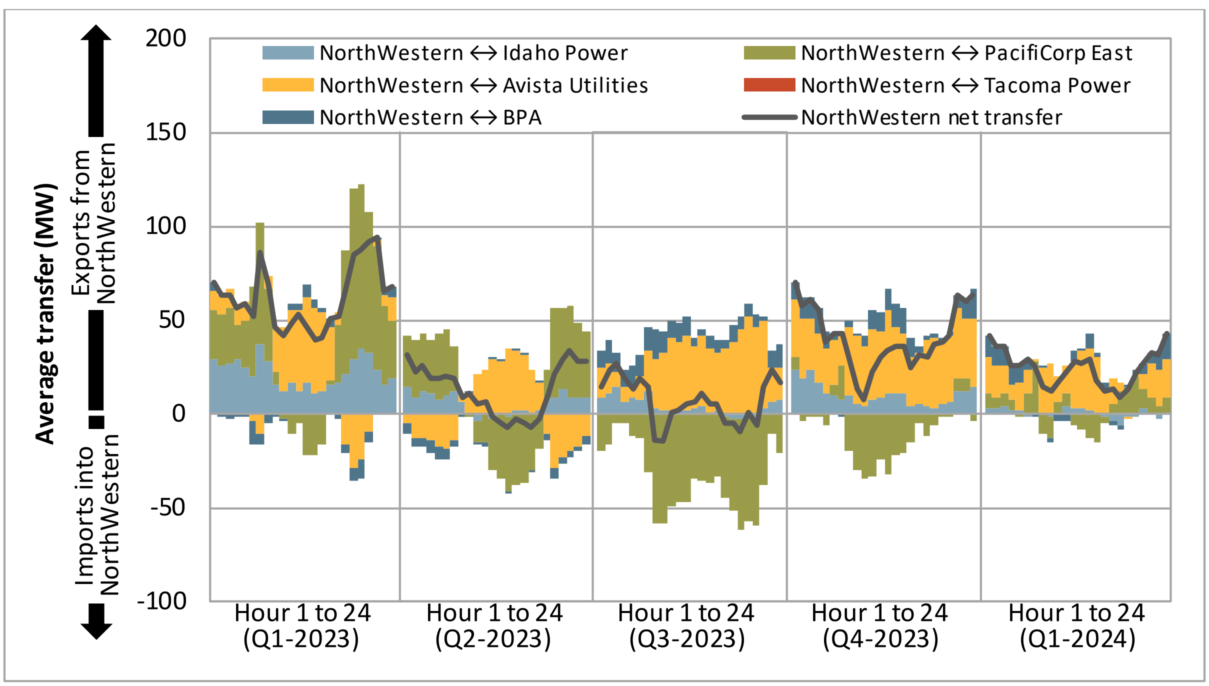


A.11 NorthWestern Energy

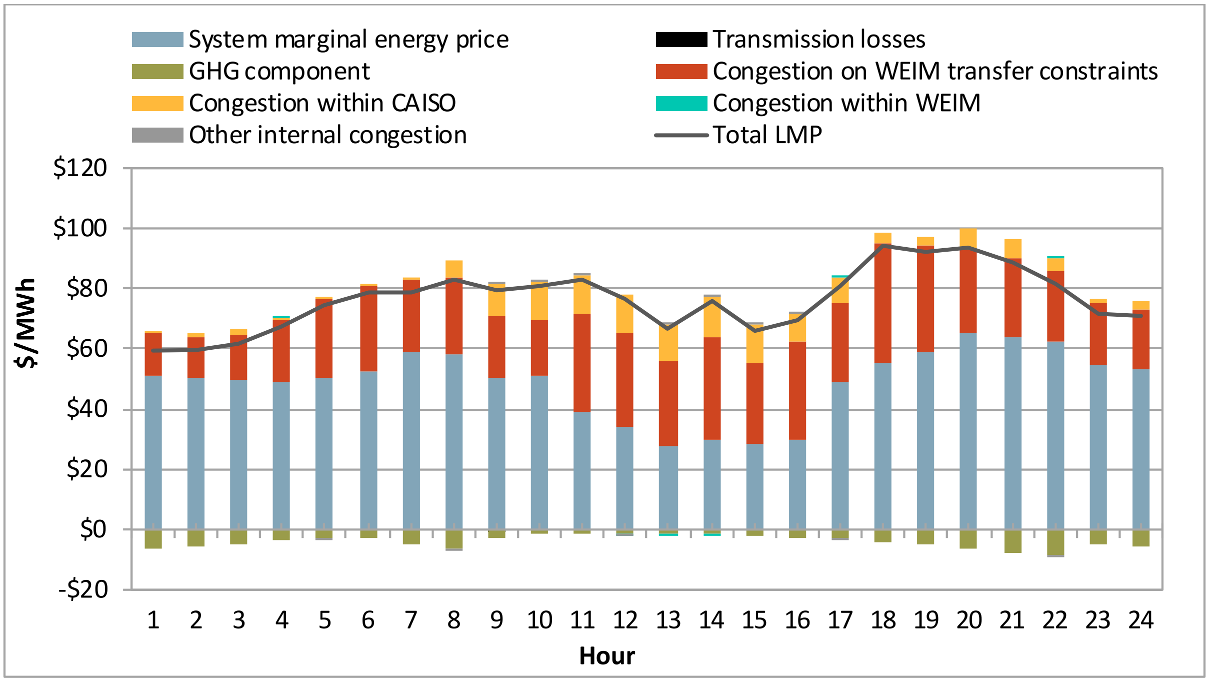
Appendix Figure A.45 Average hourly 15-minute price by component (Q1 2024)



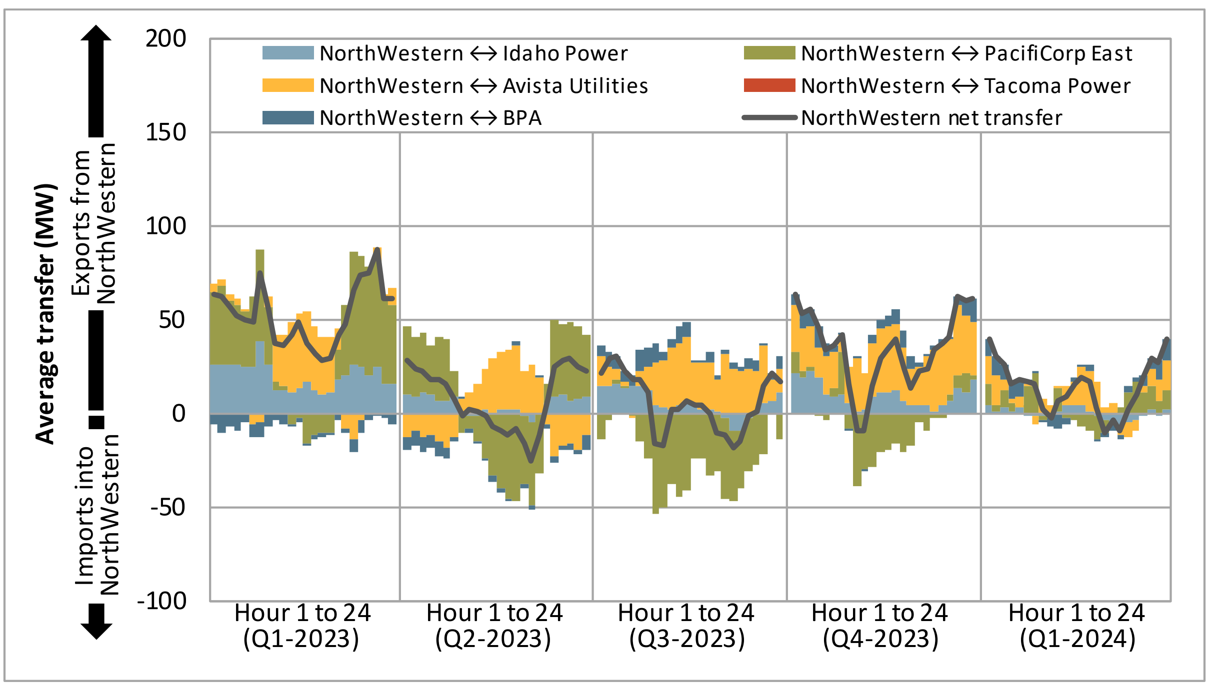
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q1 2024)

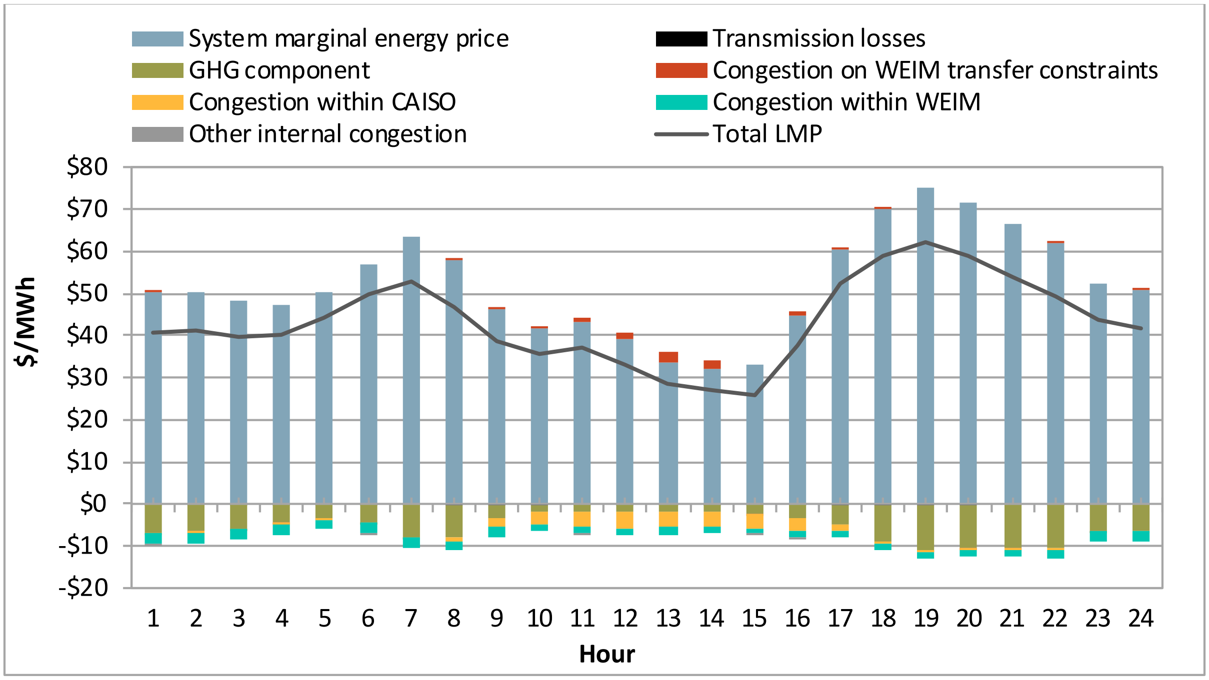


Appendix Figure A.48 Average hourly 5-minute market transfers

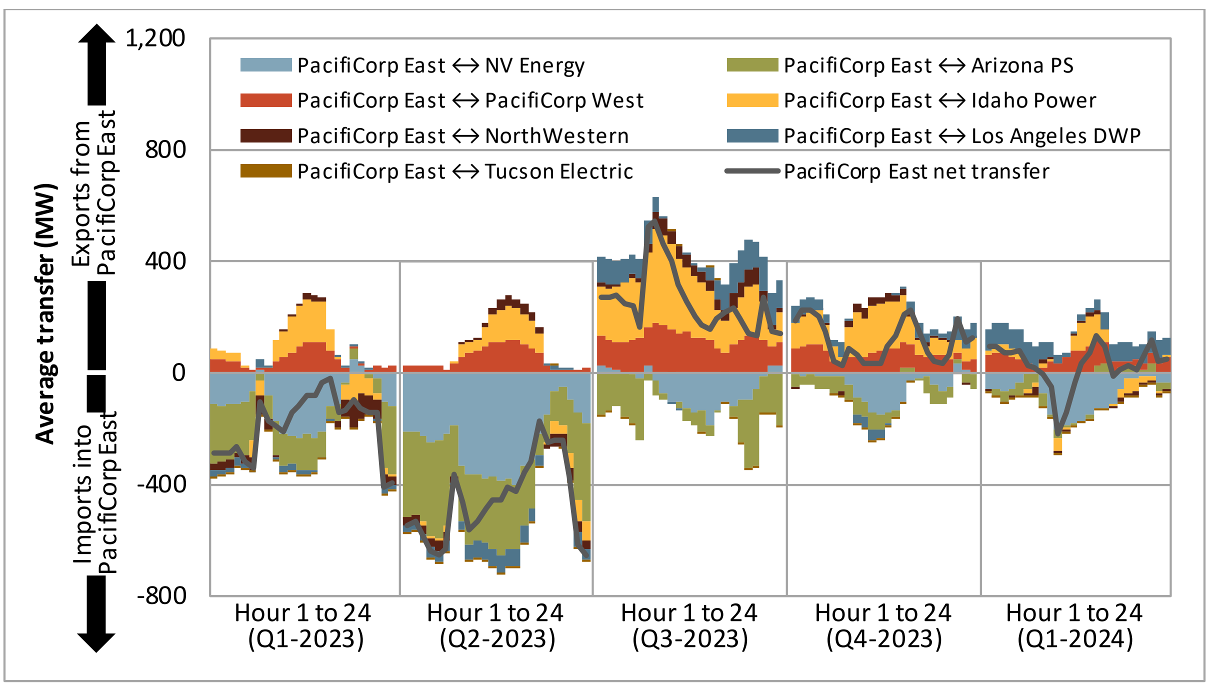


A.12 PacifiCorp East

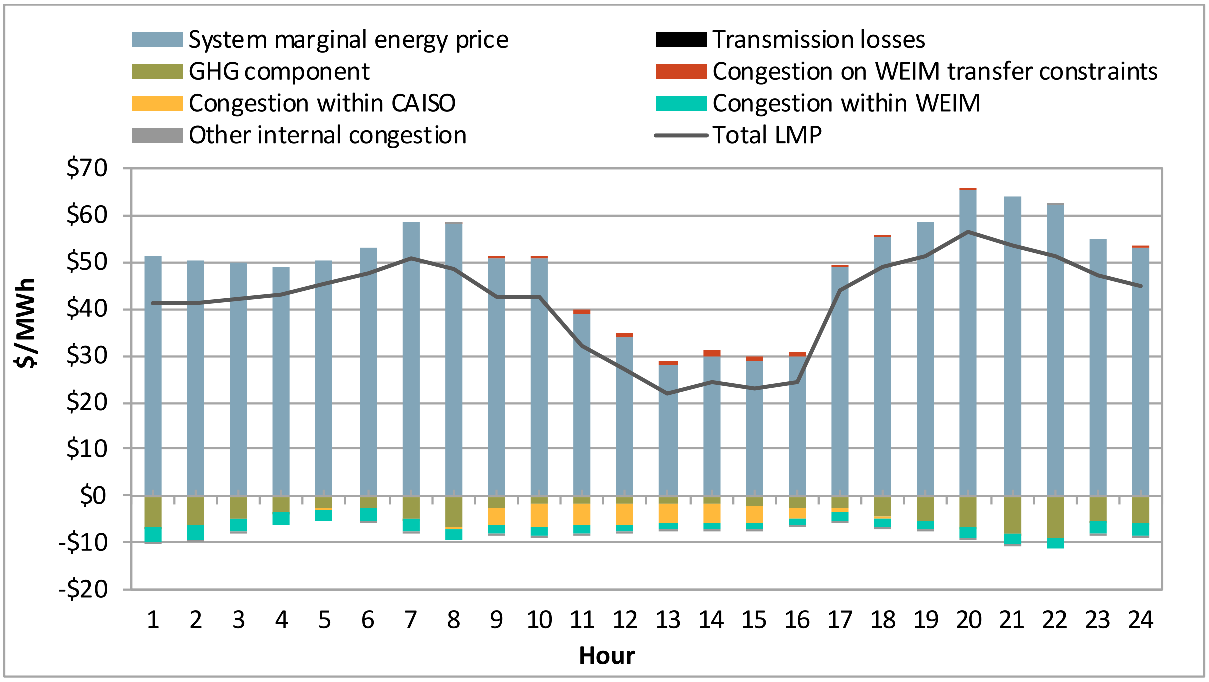
Appendix Figure A.49 Average hourly 15-minute price by component (Q1 2024)



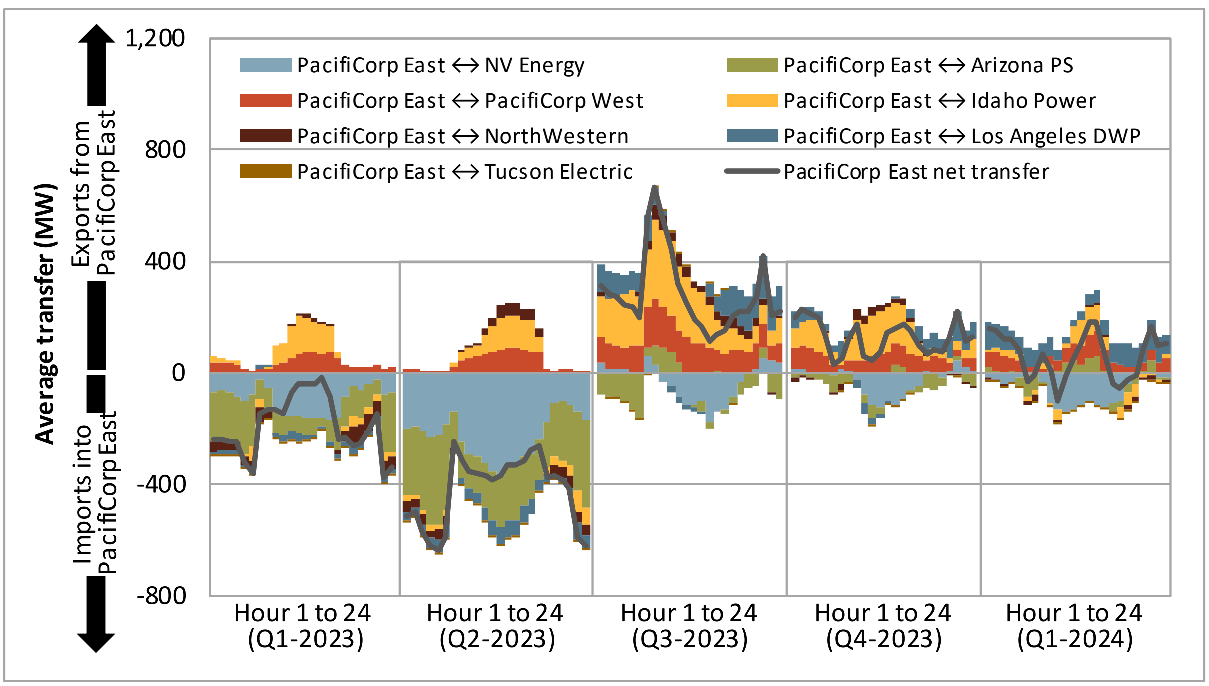
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q1 2024)

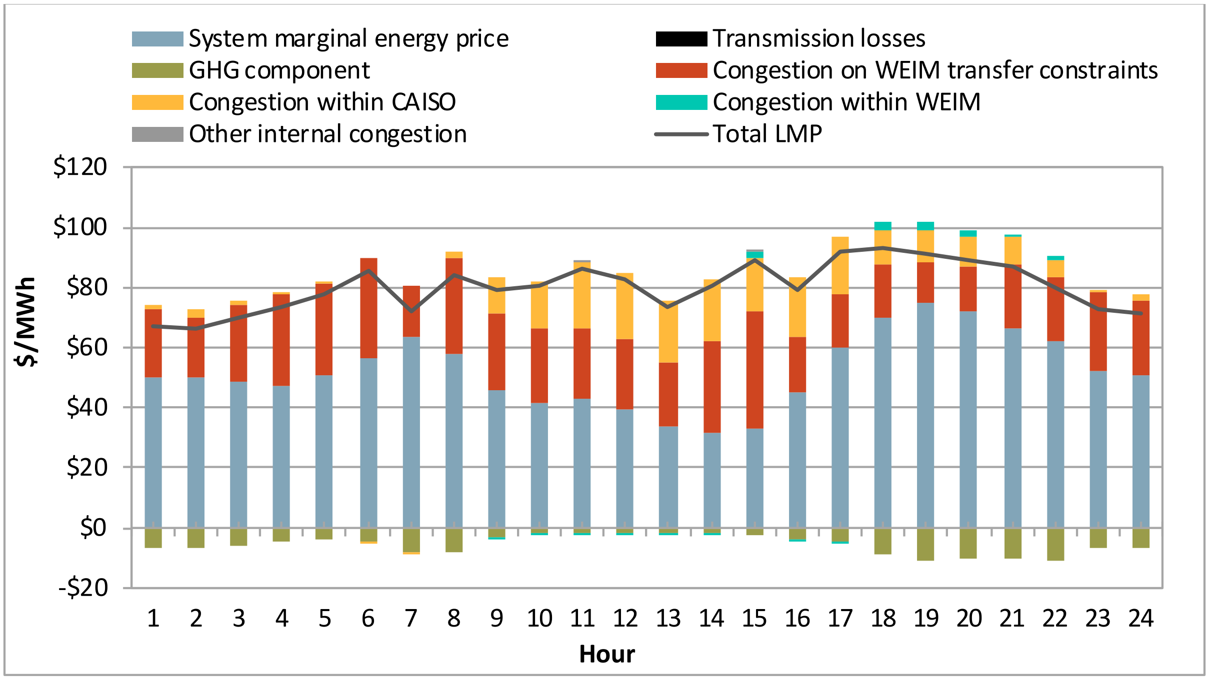


Appendix Figure A.52 Average hourly 5-minute market transfers

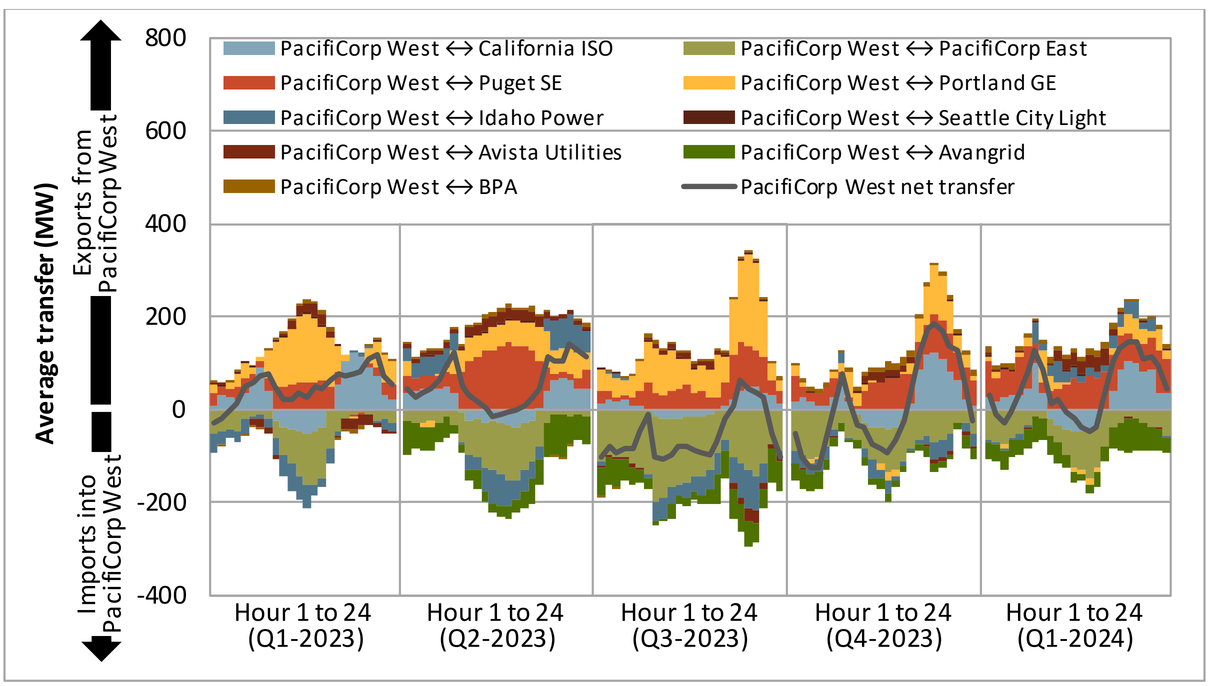


A.13 PacifiCorp West

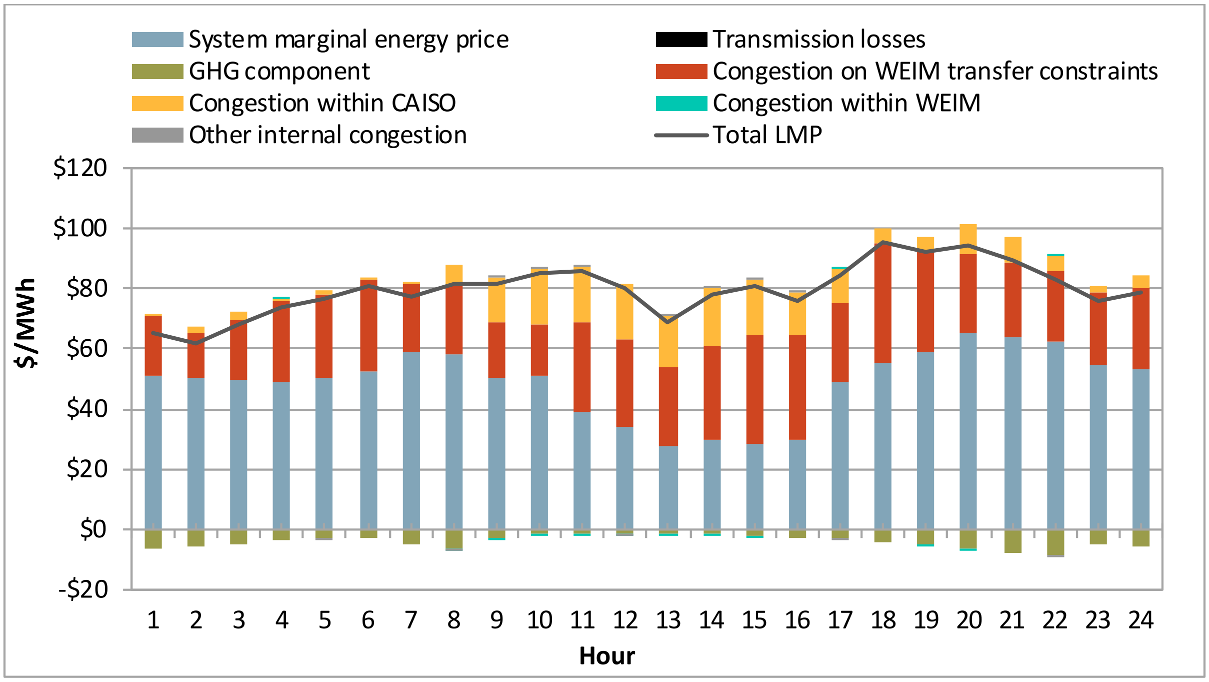
Appendix Figure A.53 Average hourly 15-minute price by component (Q1 2024)



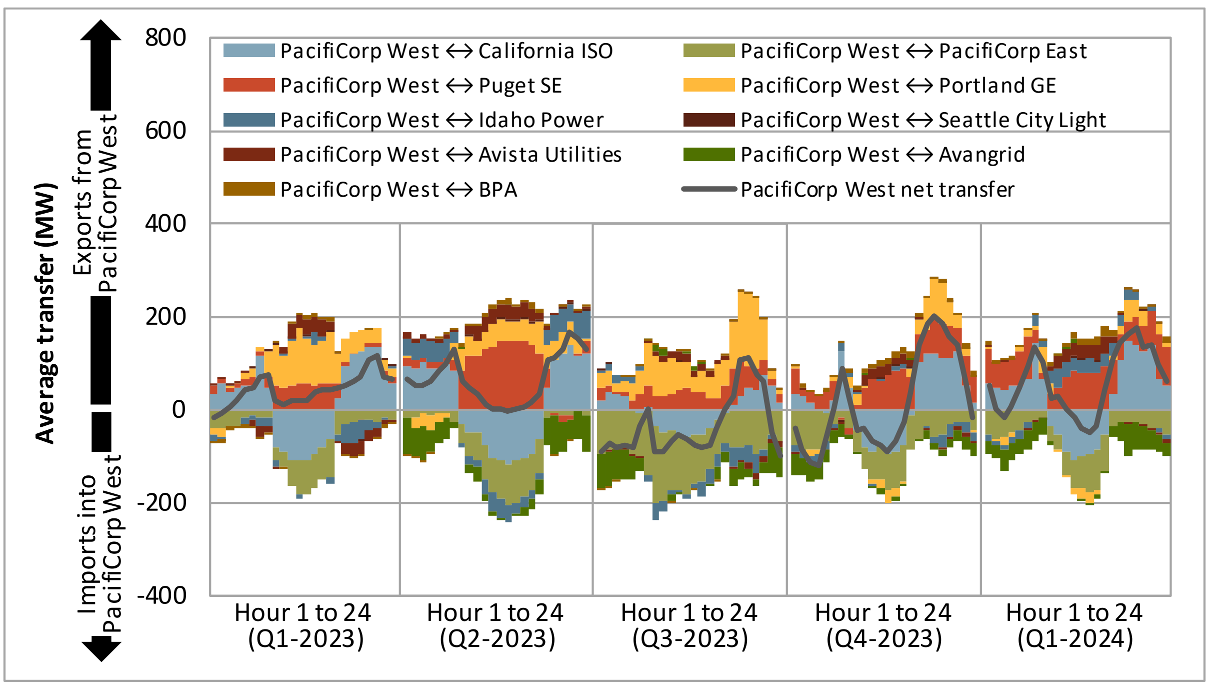
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q1 2024)

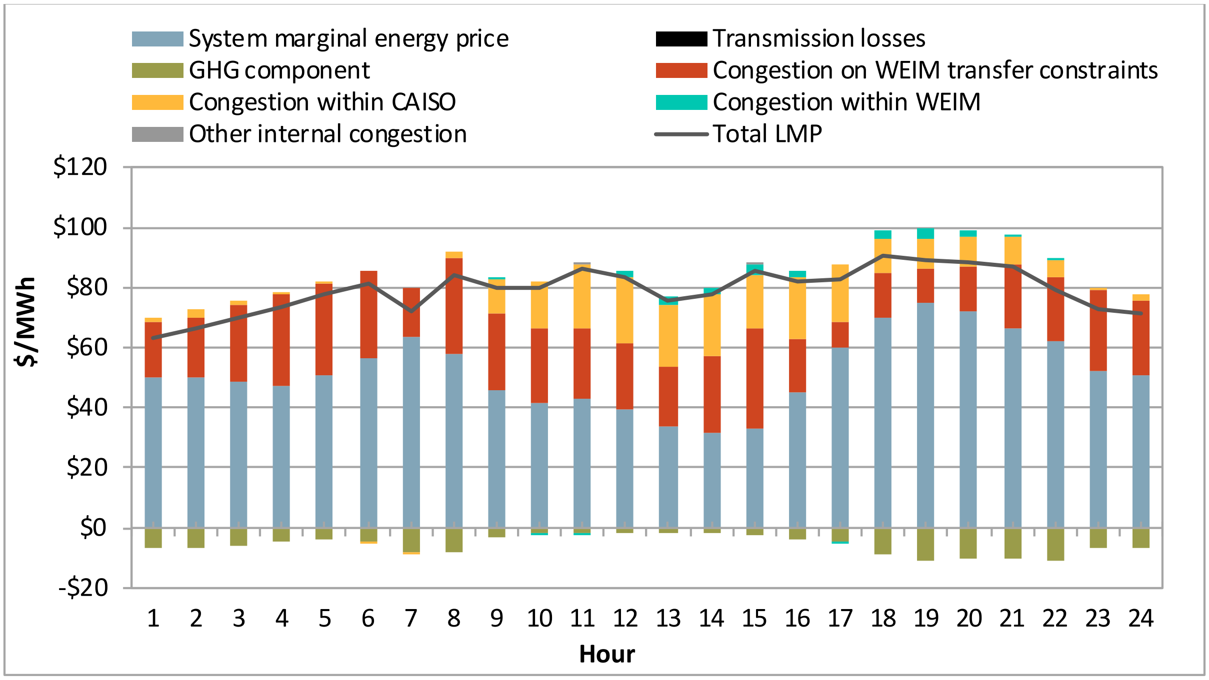


Appendix Figure A.56 Average hourly 5-minute market transfers

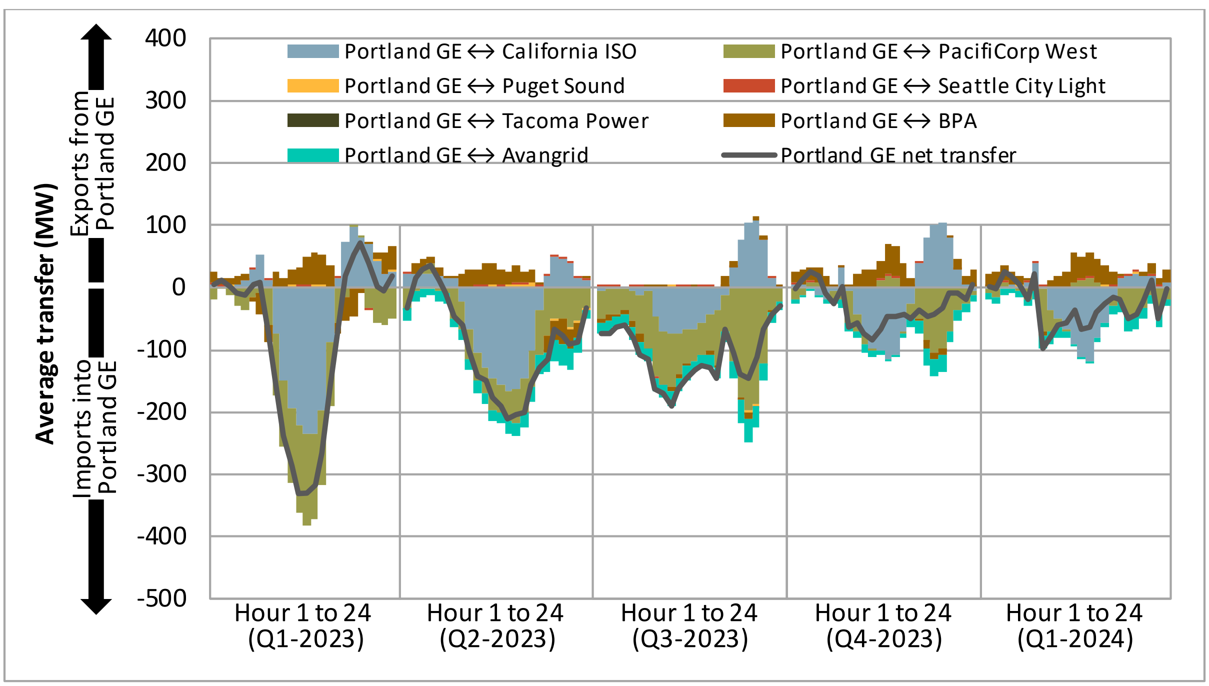


A.14 Portland General Electric

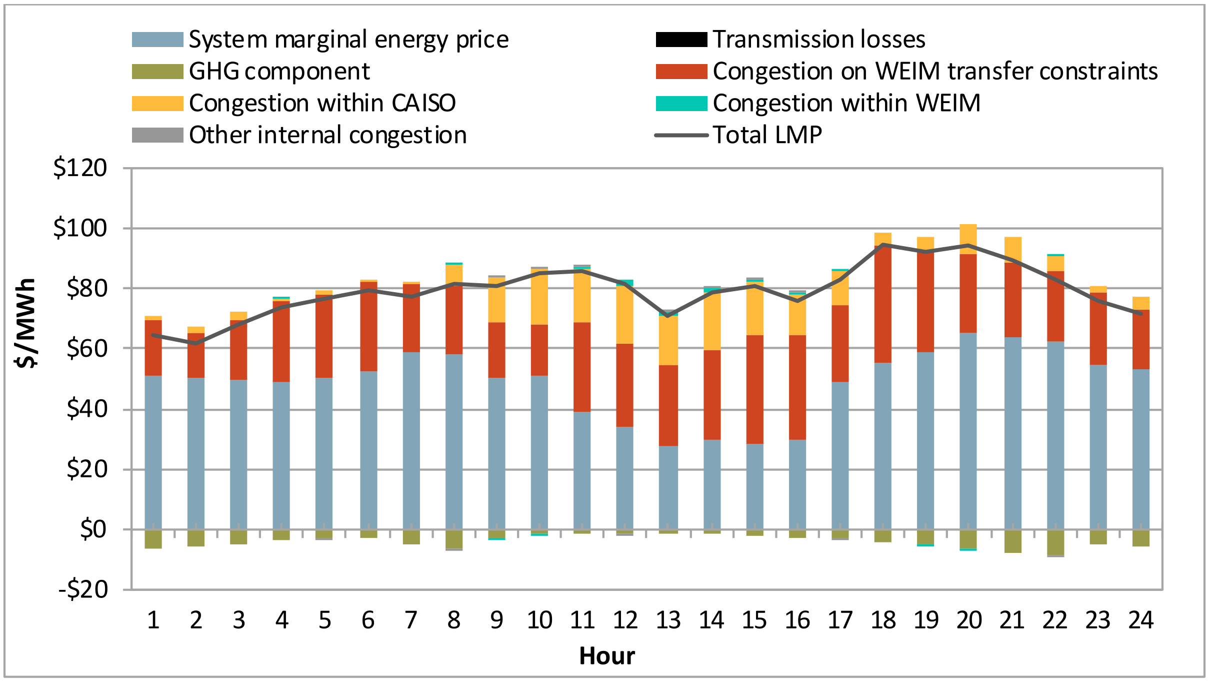
Appendix Figure A.57 Average hourly 15-minute price by component (Q1 2024)



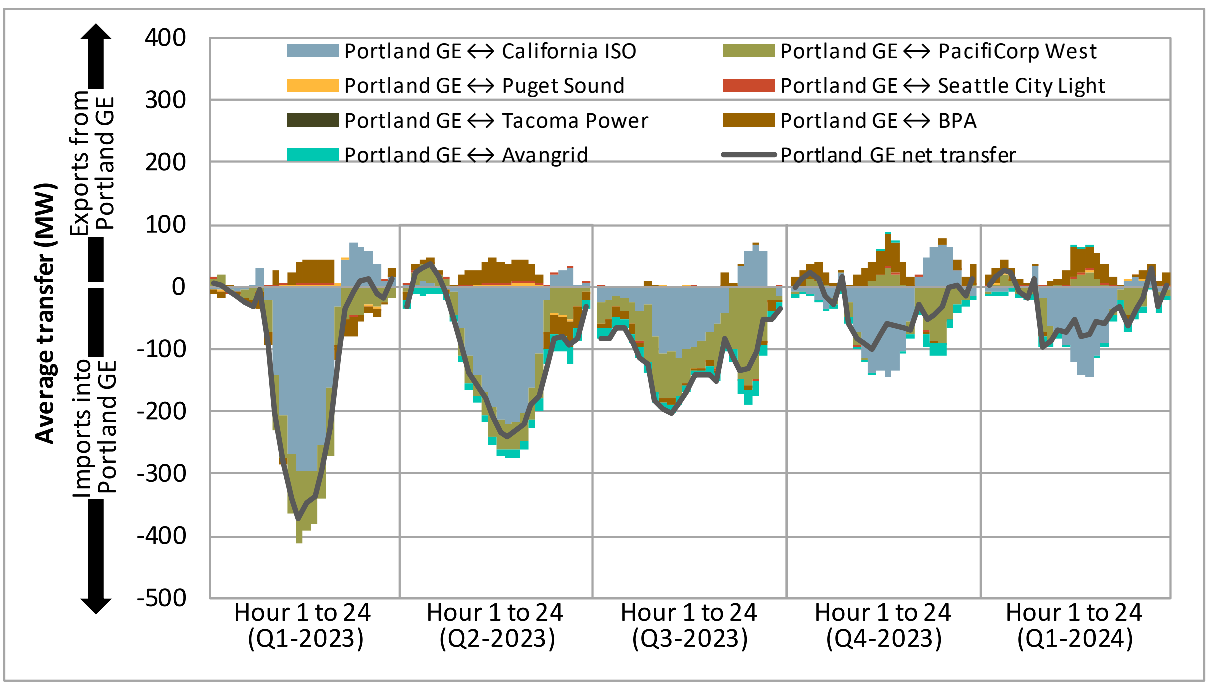
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q1 2024)

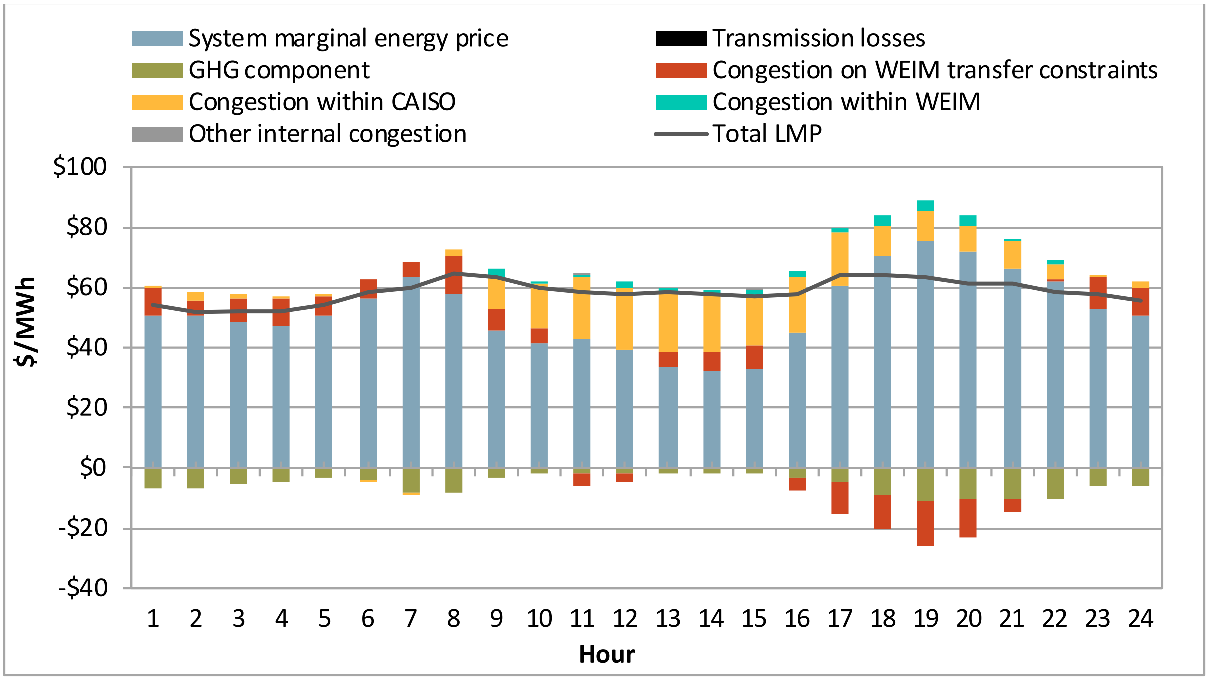


Appendix Figure A.60 Average hourly 5-minute market transfers

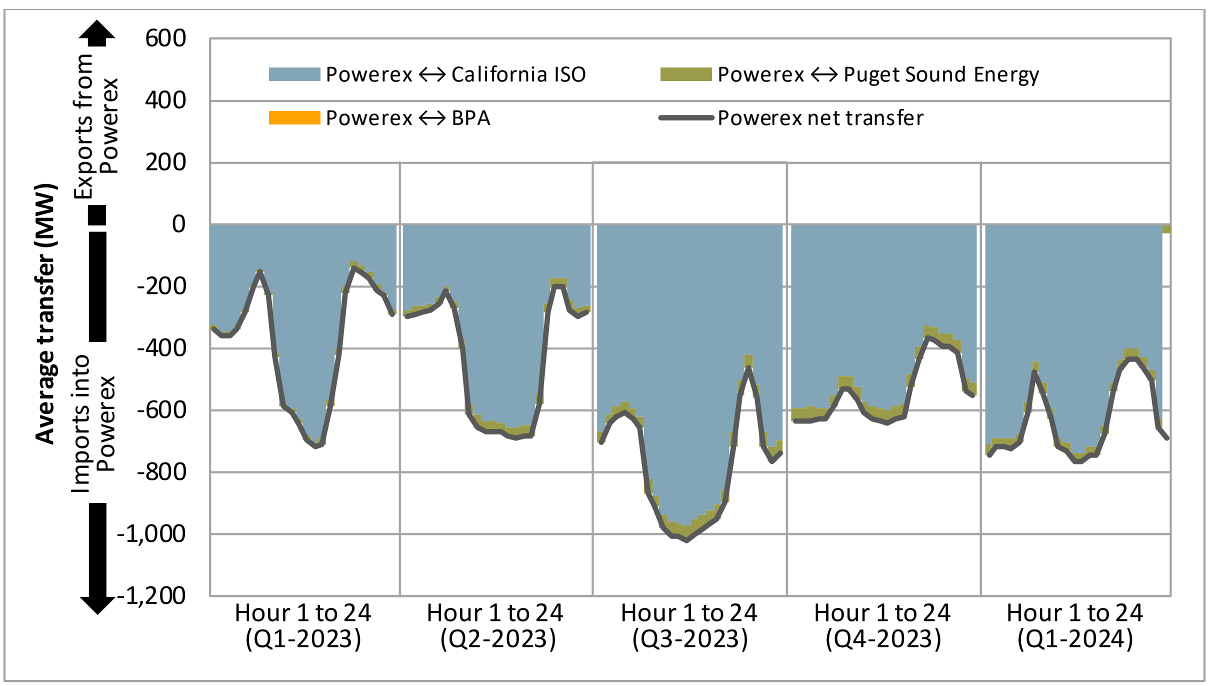


A.15 Powerex

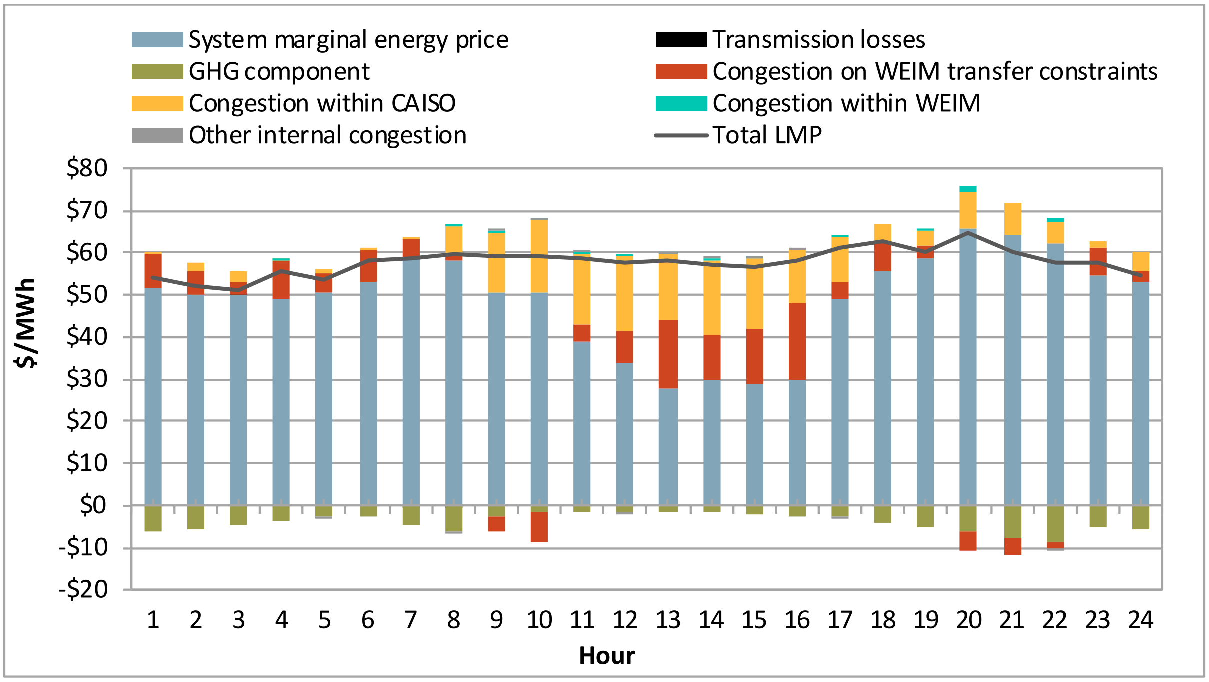
Appendix Figure A.61 Average hourly 15-minute price by component (Q1 2024)



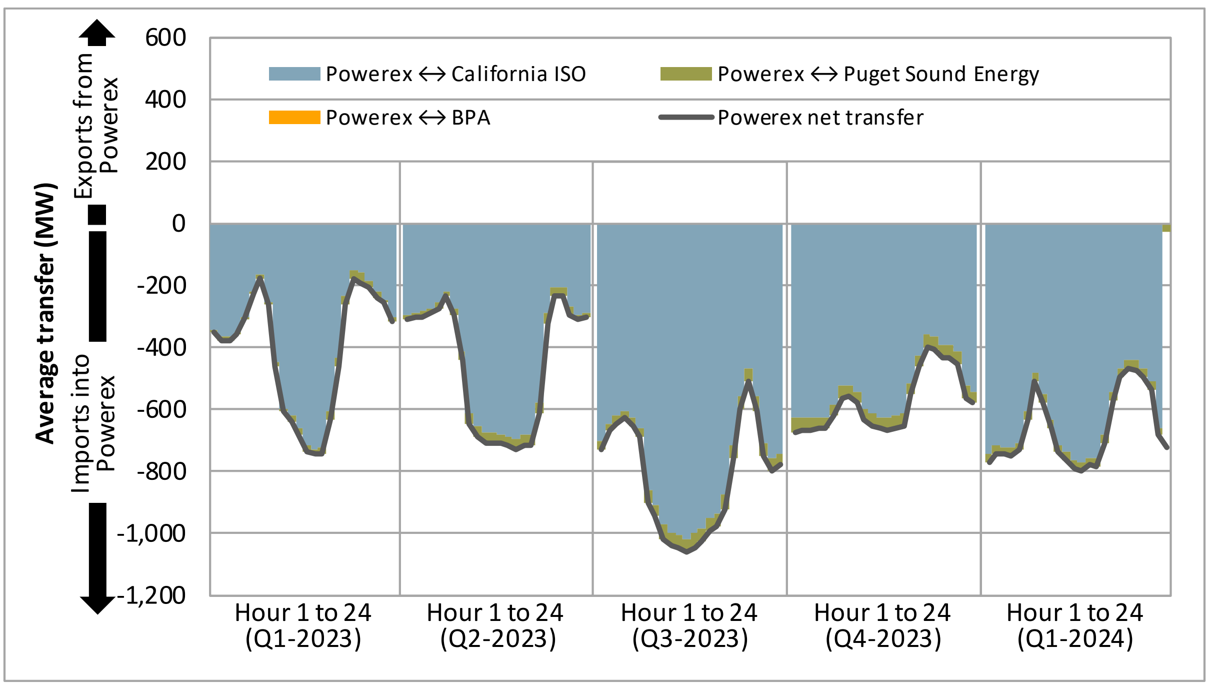
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q1 2024)

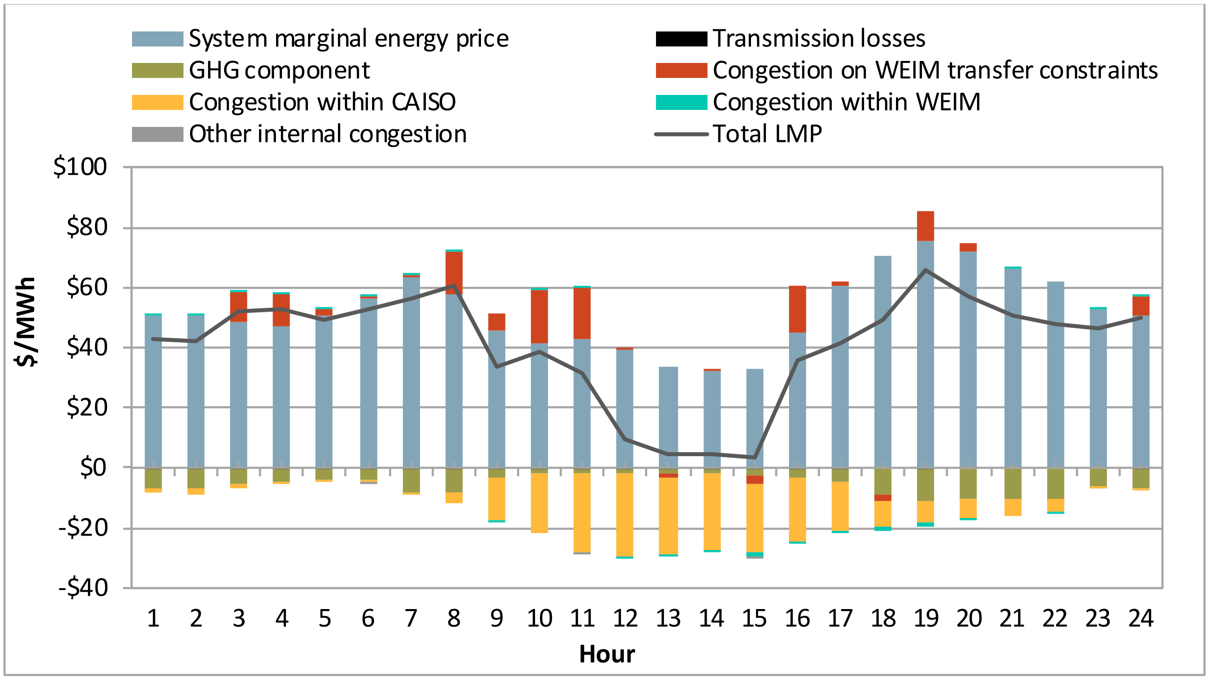


Appendix Figure A.64 Average hourly 5-minute market transfers

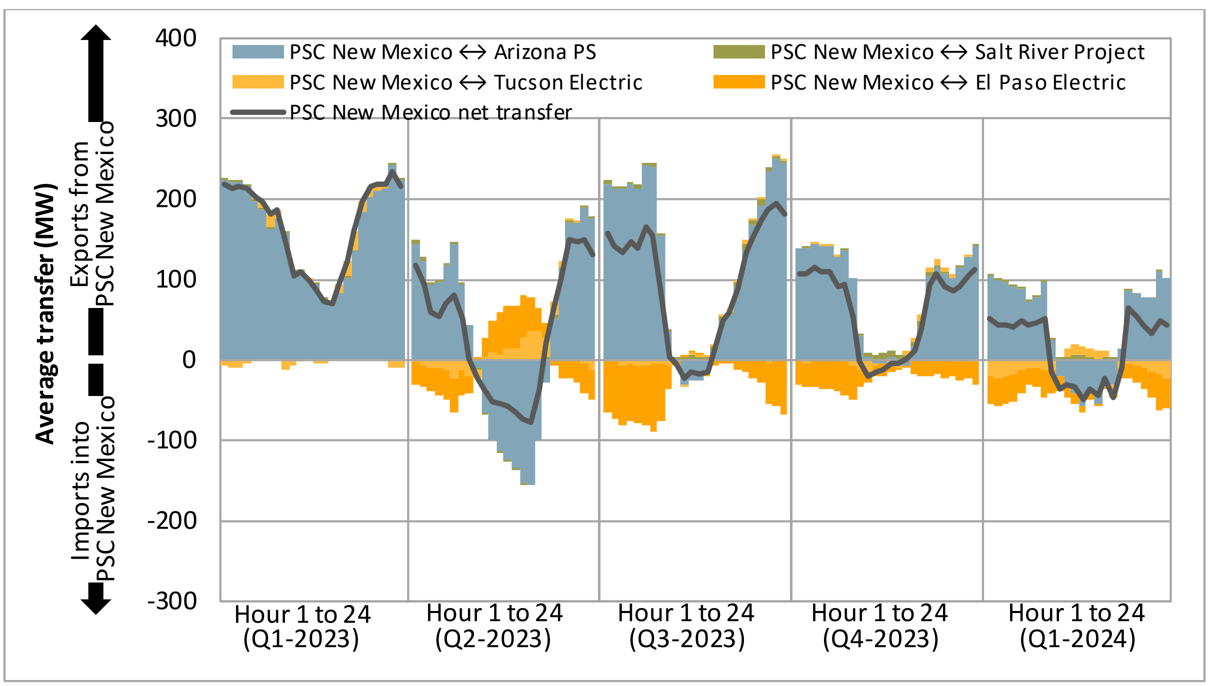


A.16 Public Service Company of New Mexico

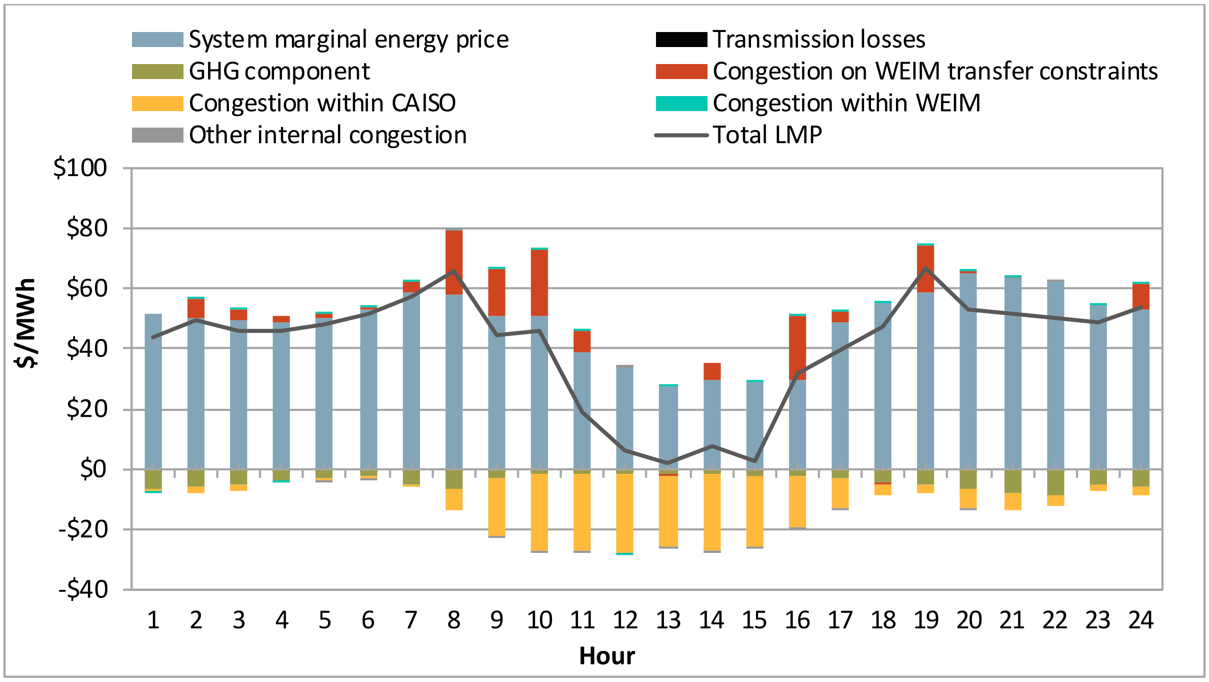
Appendix Figure A.65 Average hourly 15-minute price by component (Q1 2024)



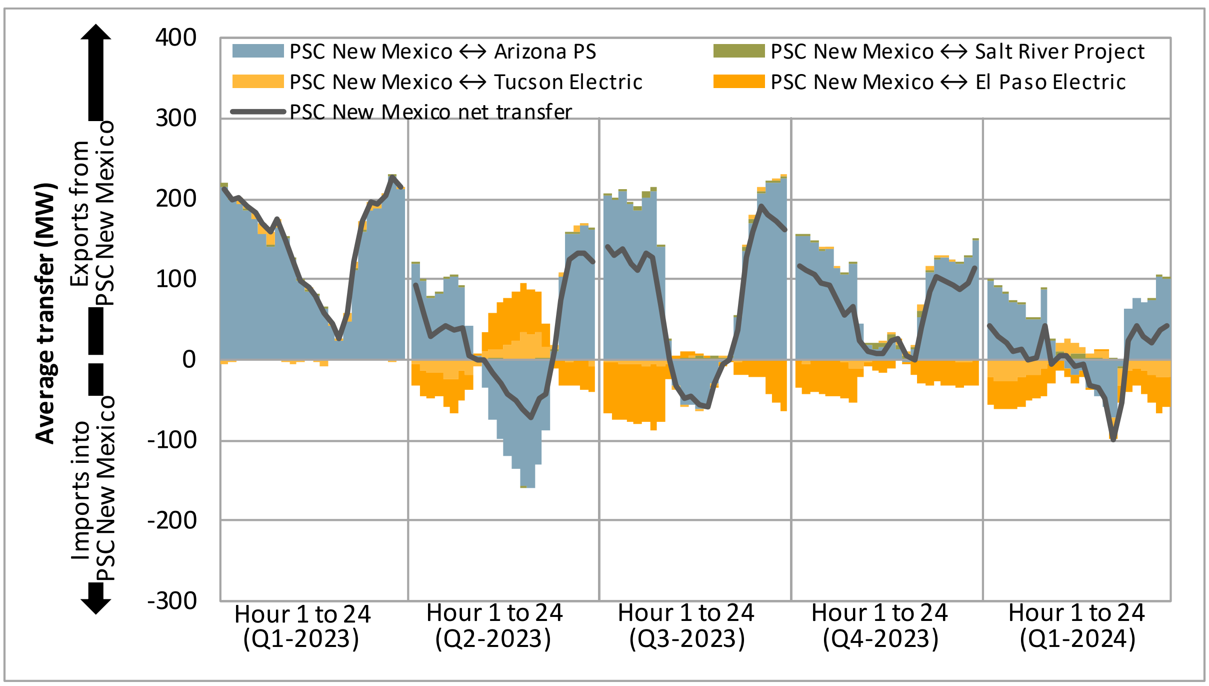
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q1 2024)

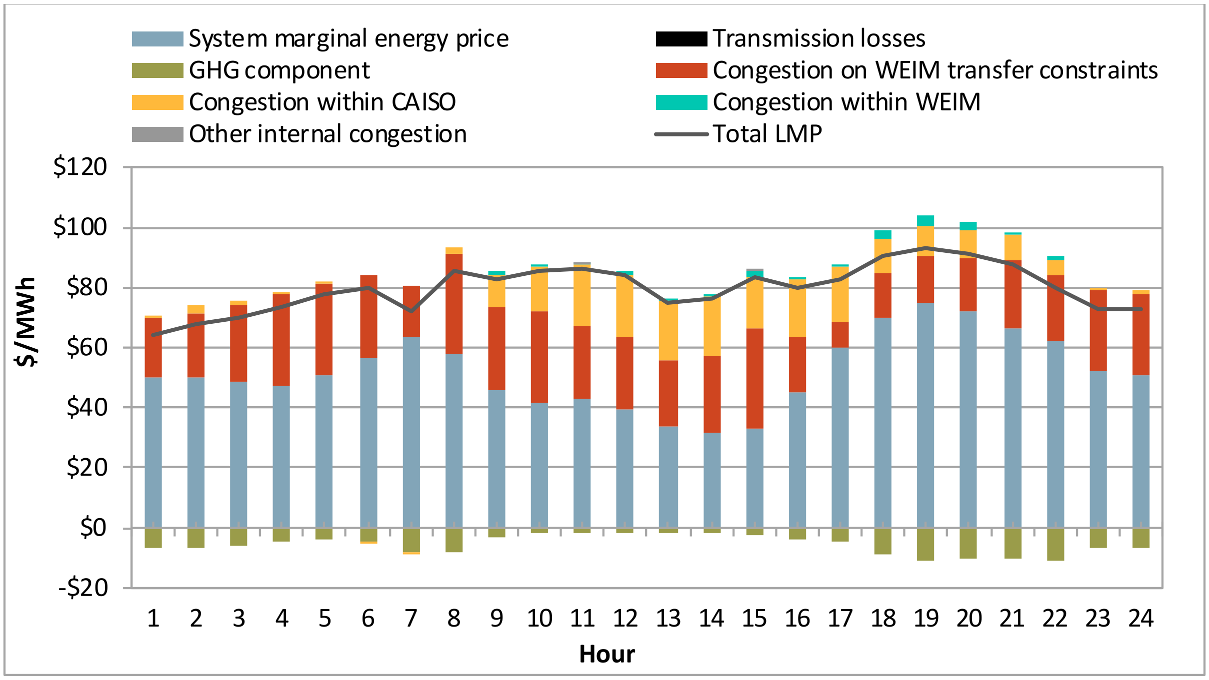


Appendix Figure A.68 Average hourly 5-minute market transfers

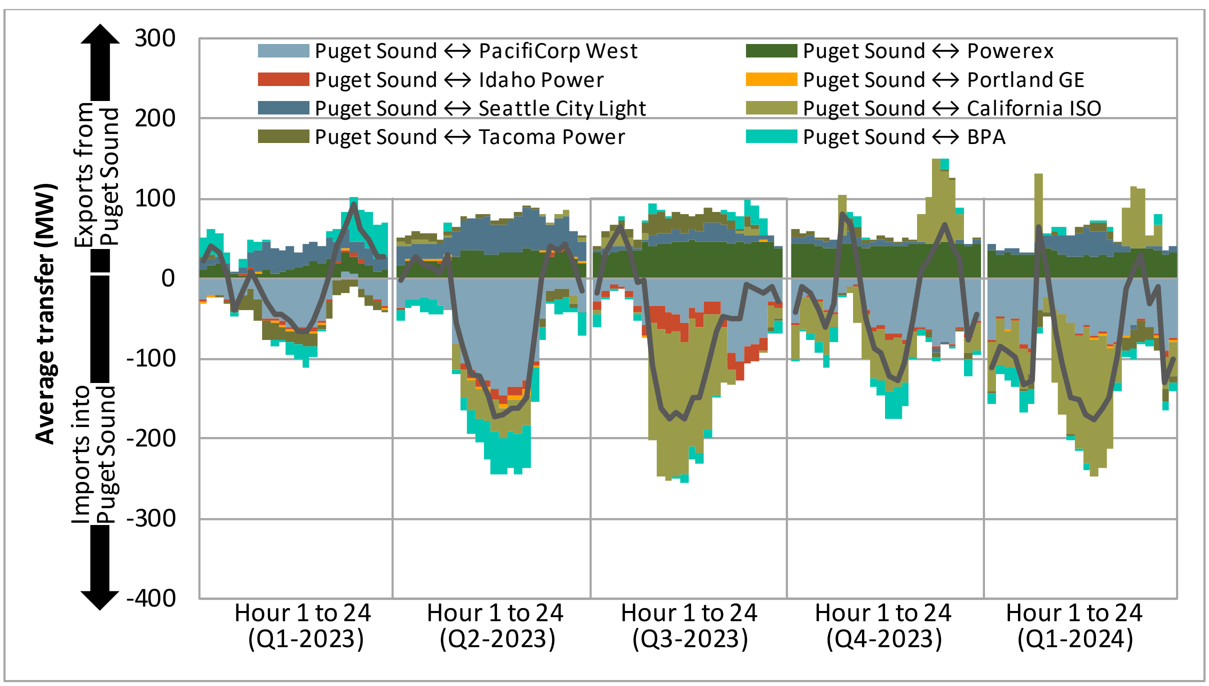


A.17 Puget Sound Energy

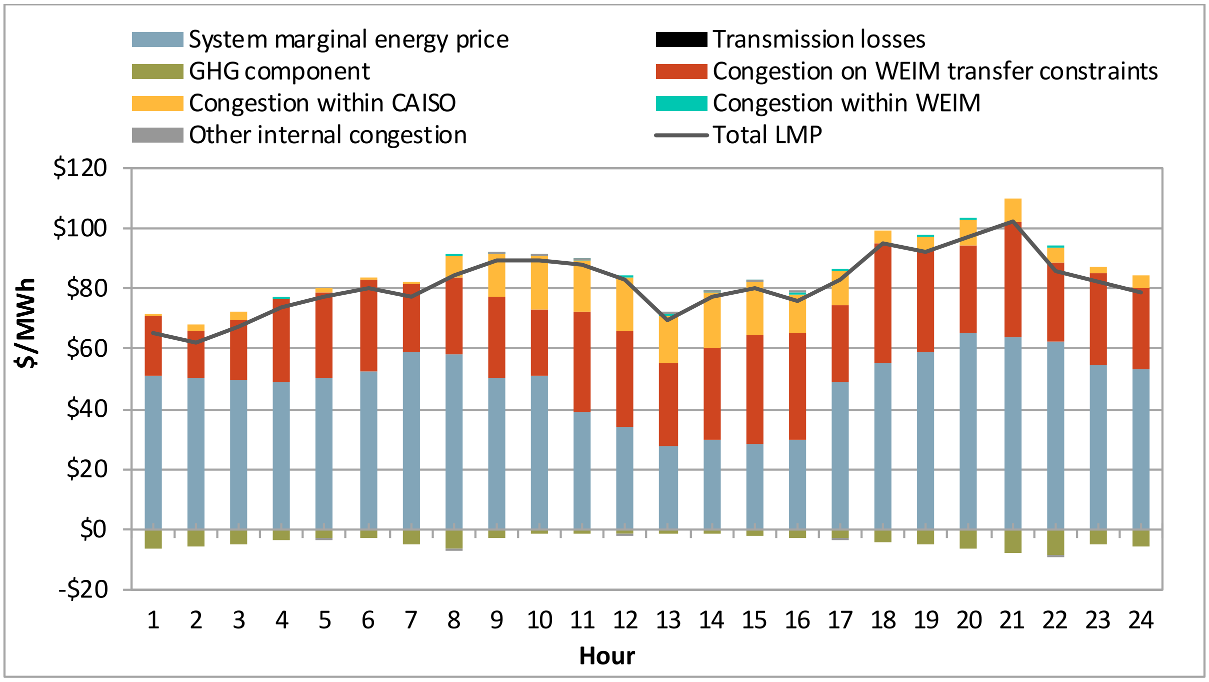
Appendix Figure A.69 Average hourly 15-minute price by component (Q1 2024)



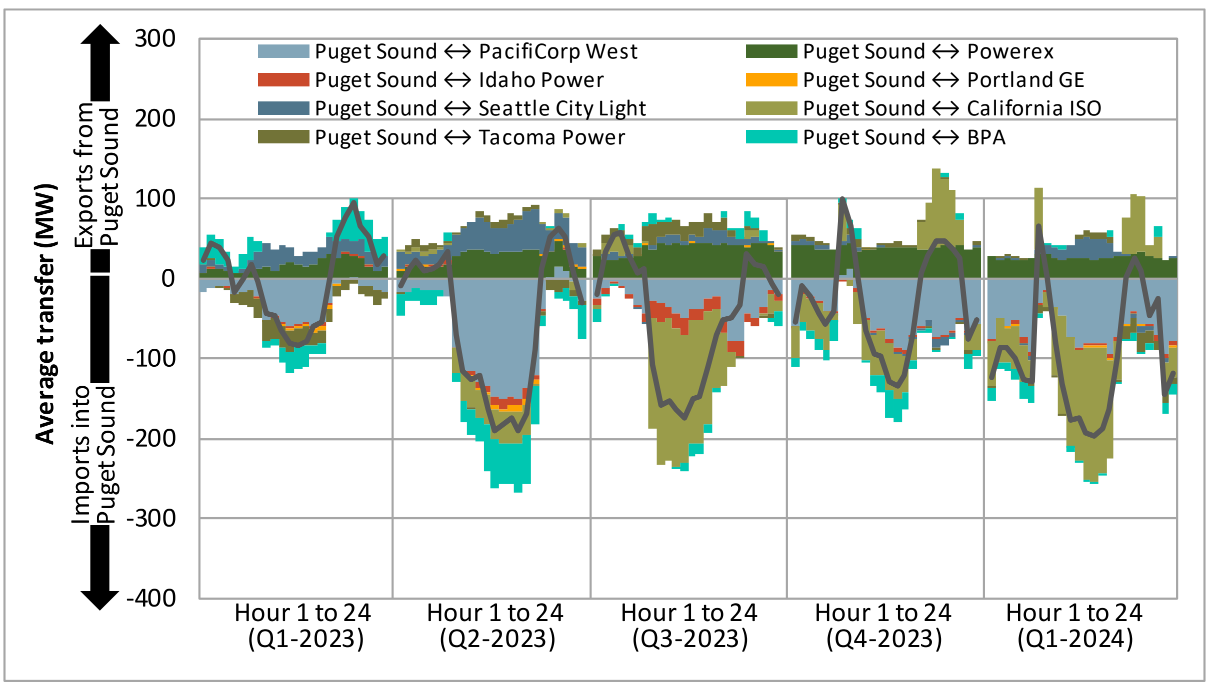
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q1 2024)

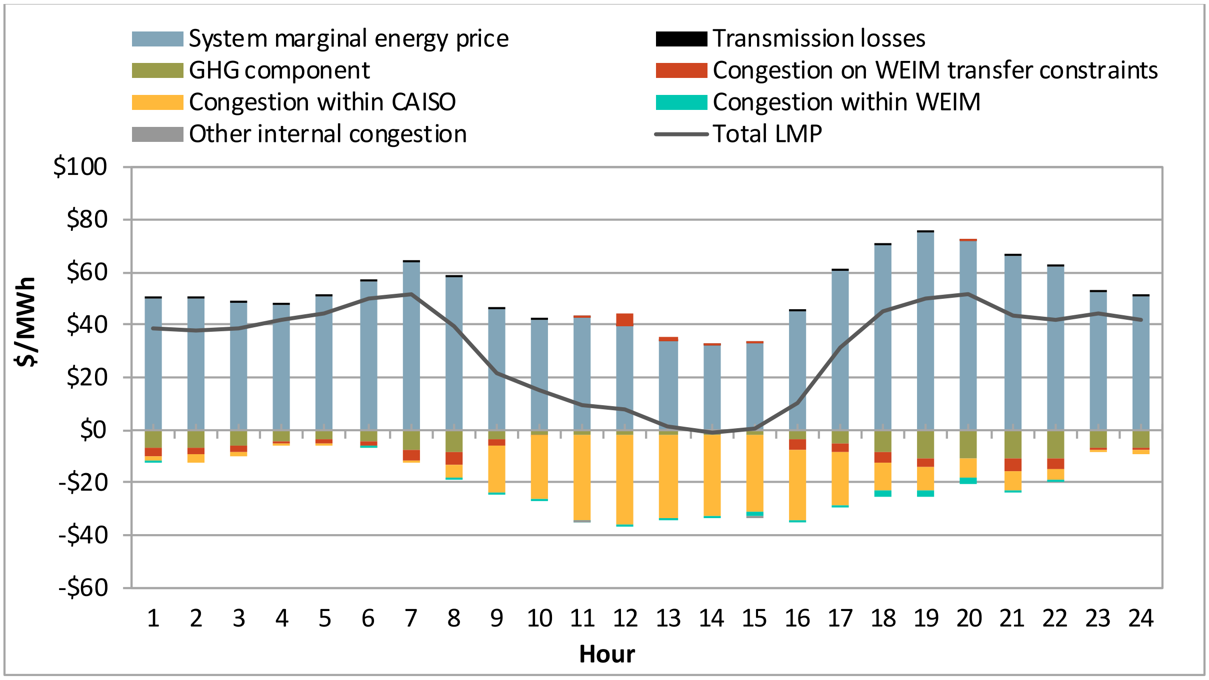


Appendix Figure A.72 Average hourly 5-minute market transfers

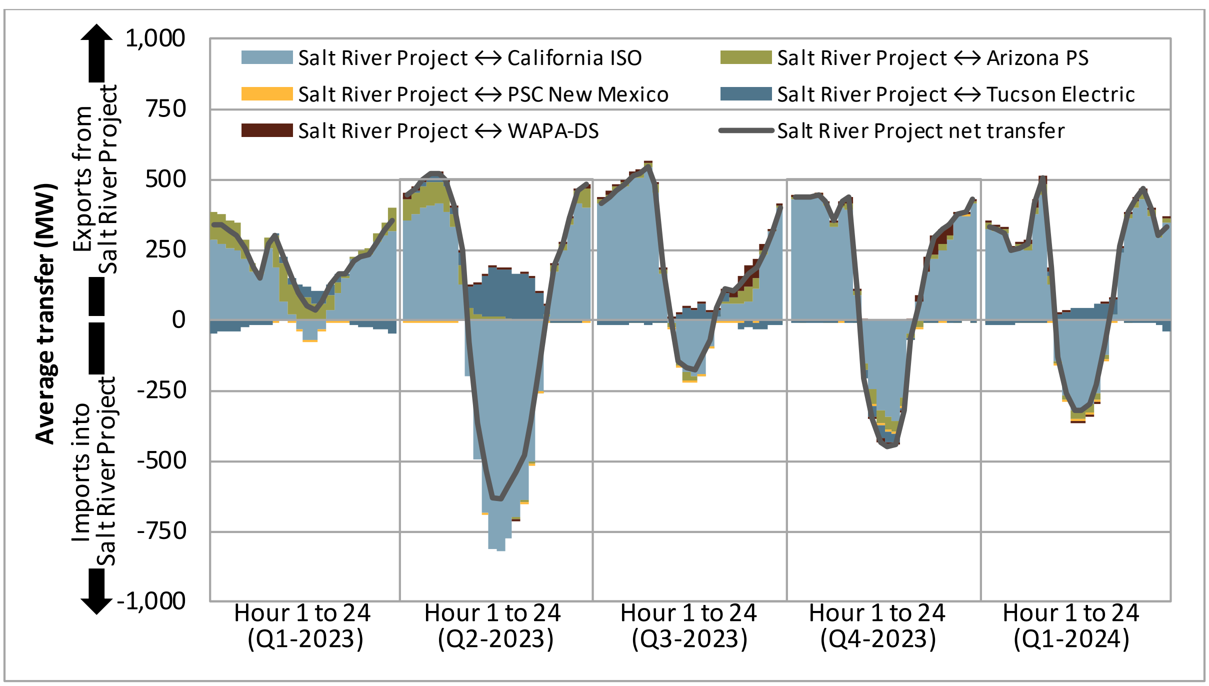


A.18 Salt River Project

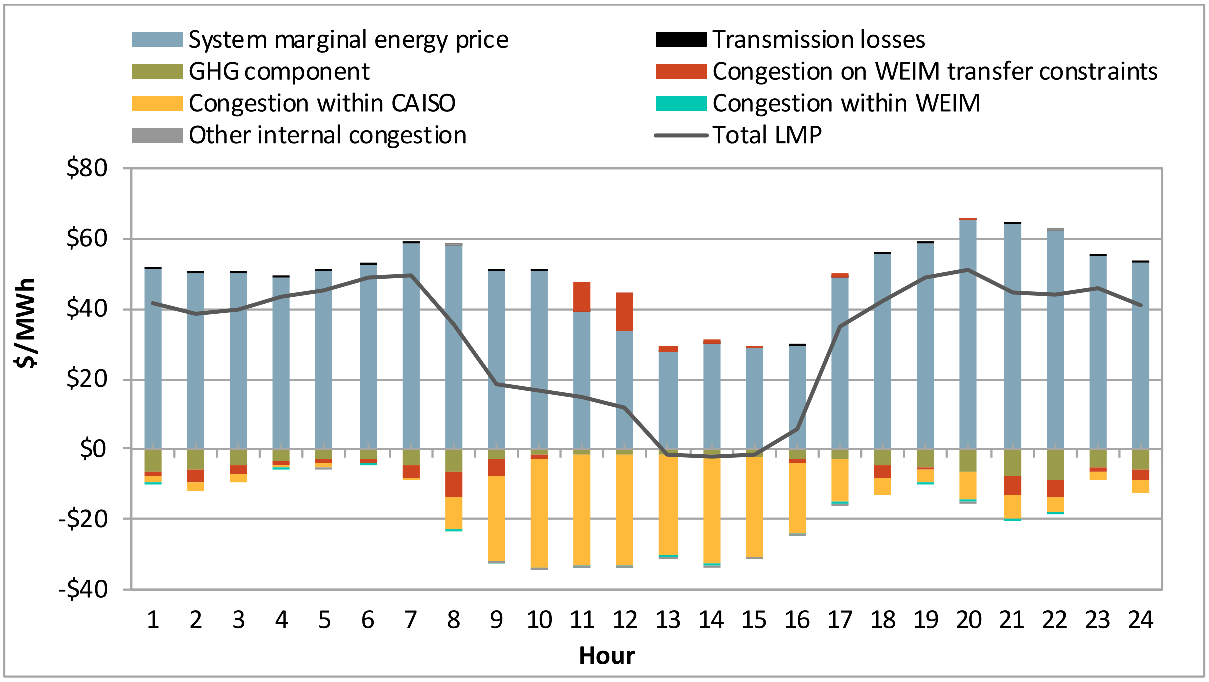
Appendix Figure A.73 Average hourly 15-minute price by component (Q1 2024)



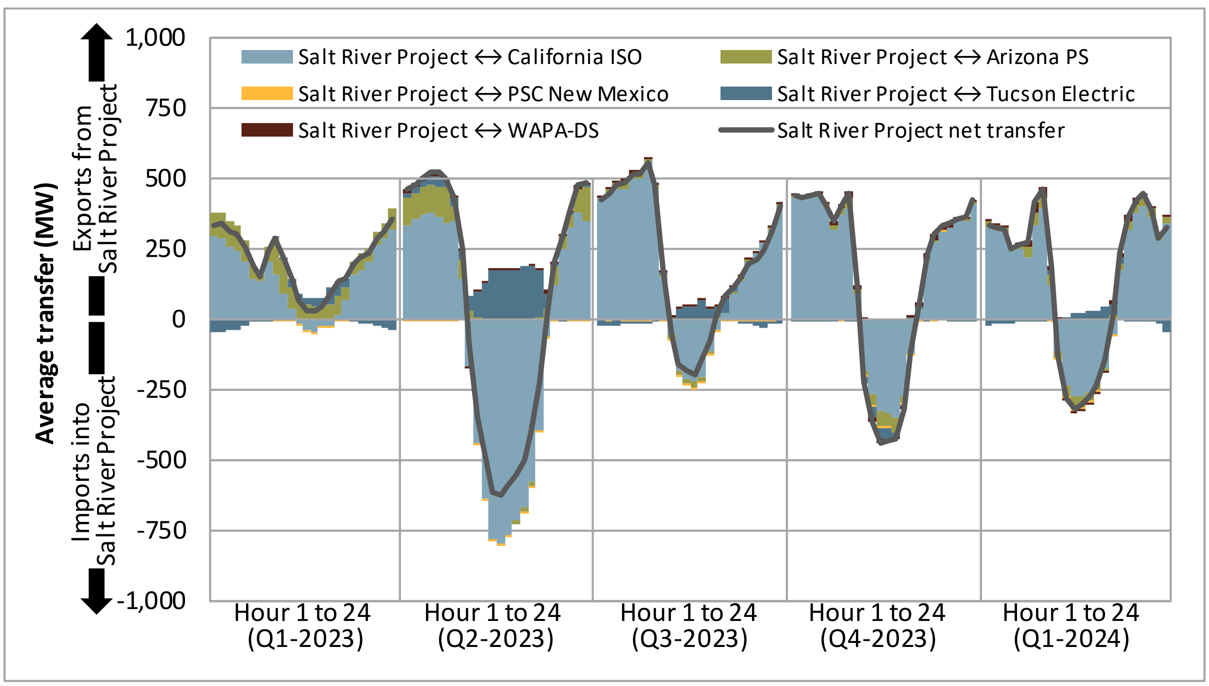
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q1 2024)

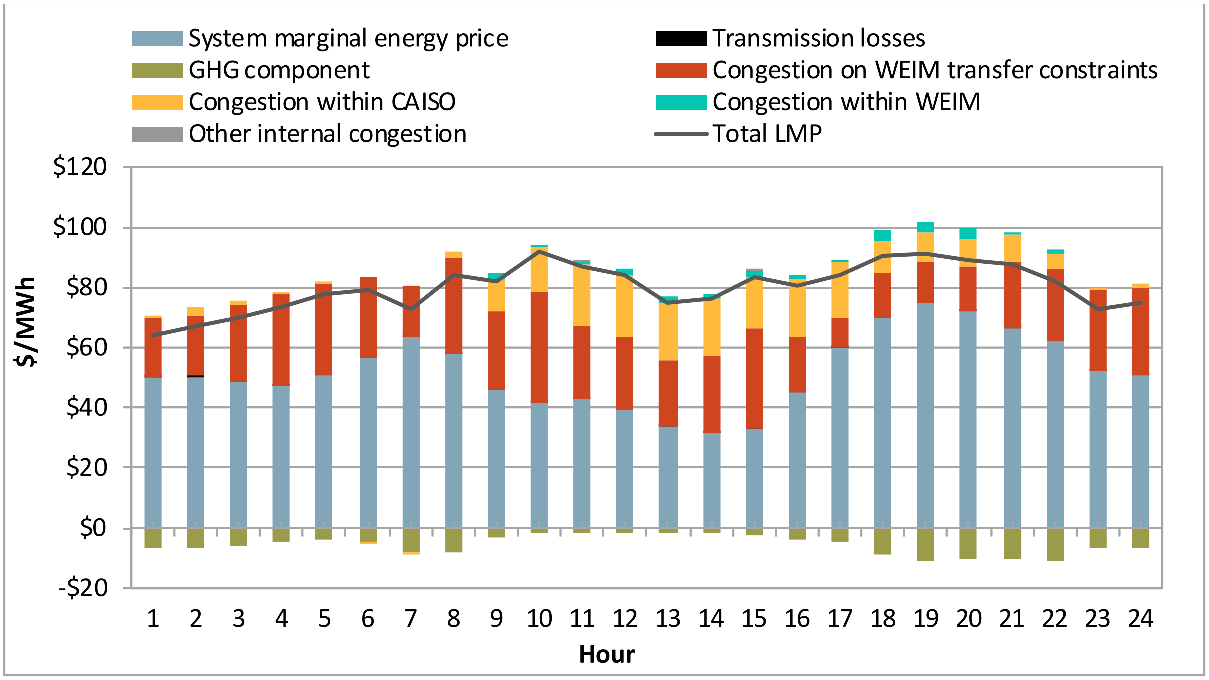


Appendix Figure A.76 Average hourly 5-minute market transfers

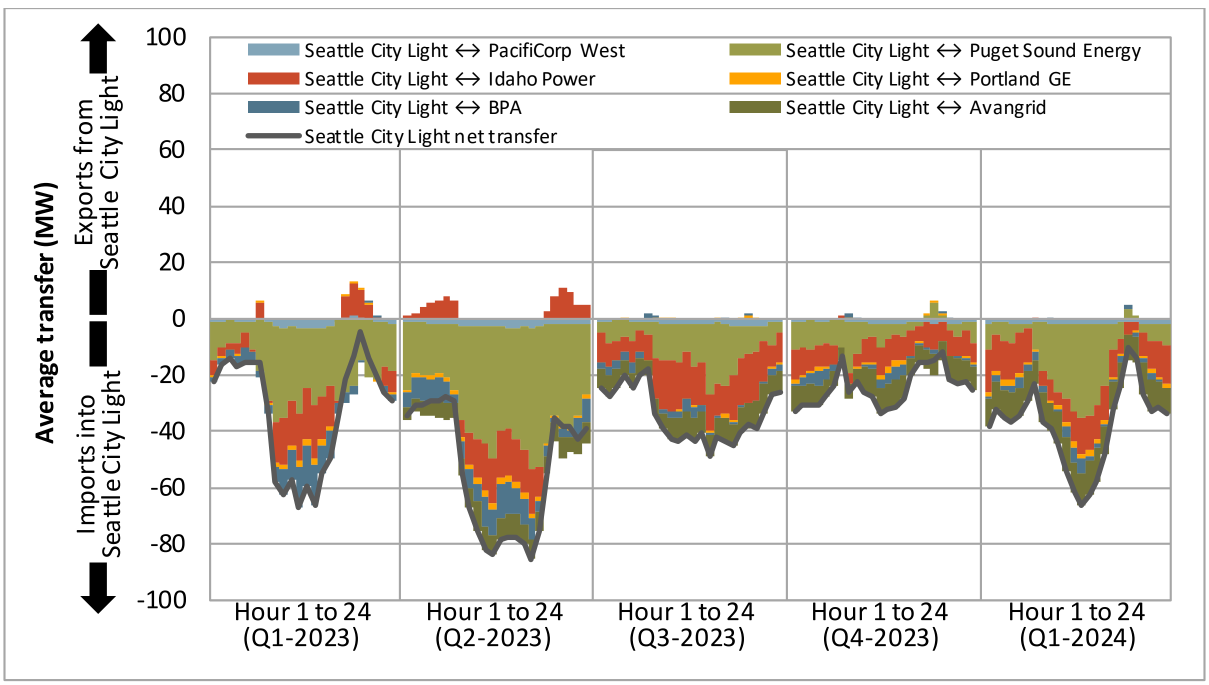


A.19 Seattle City Light

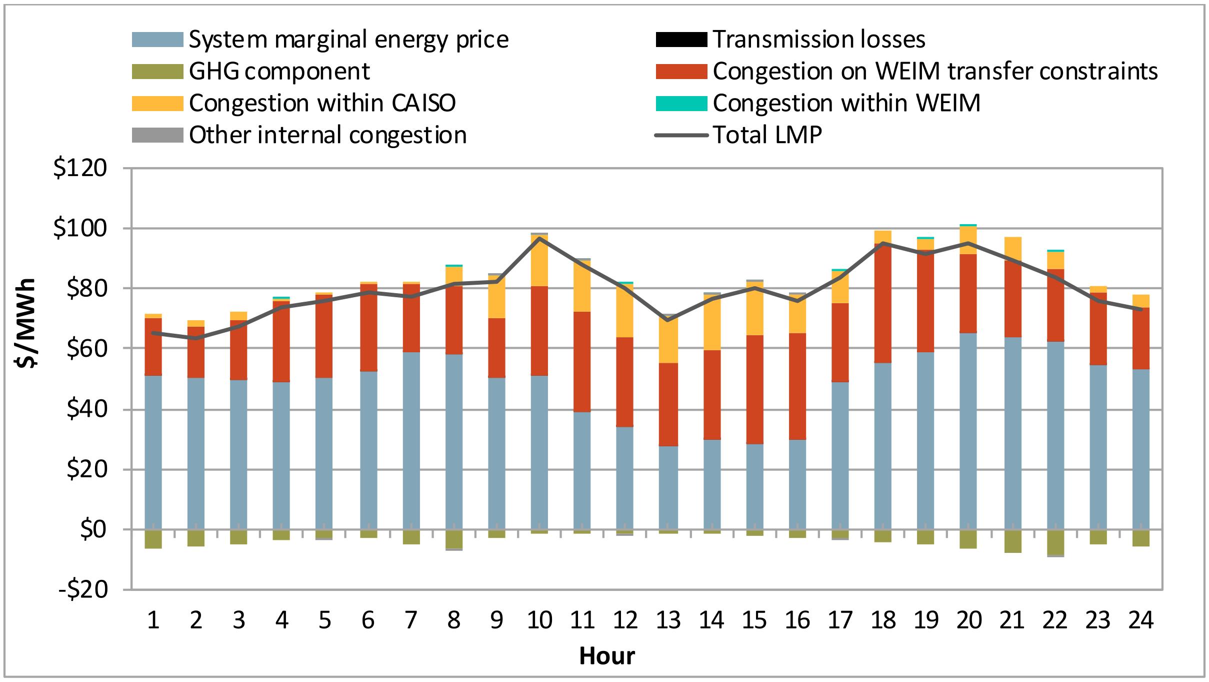
Appendix Figure A.77 Average hourly 15-minute price by component (Q1 2024)



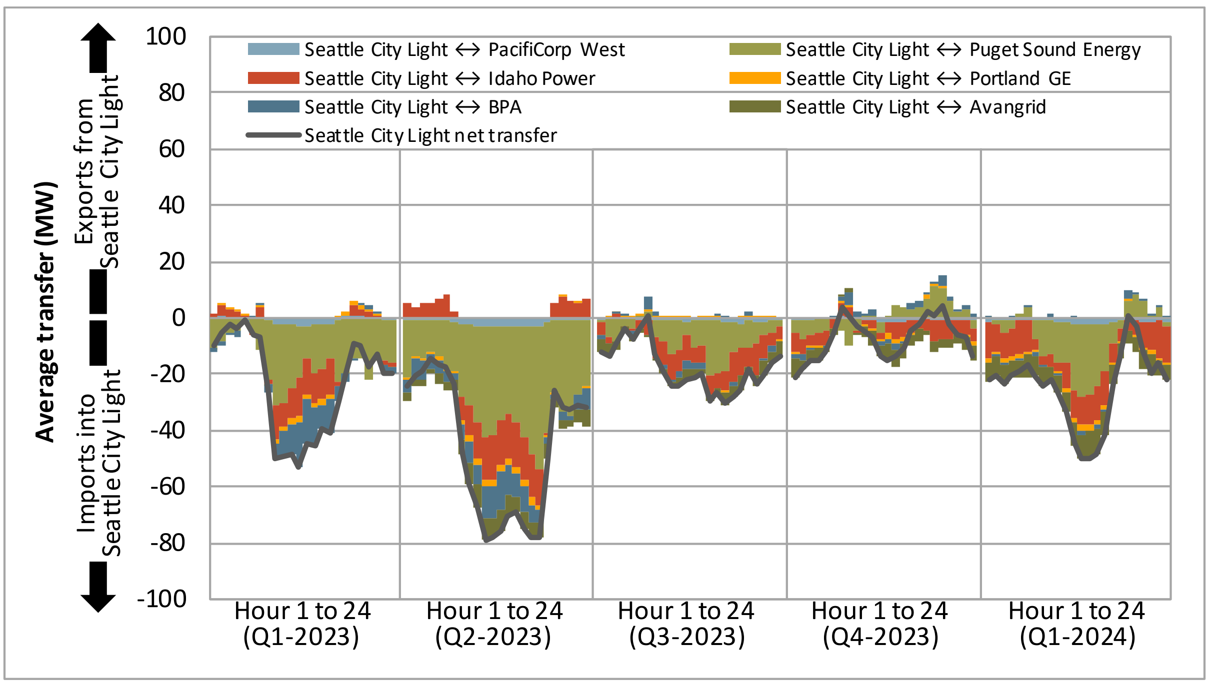
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q1 2024)

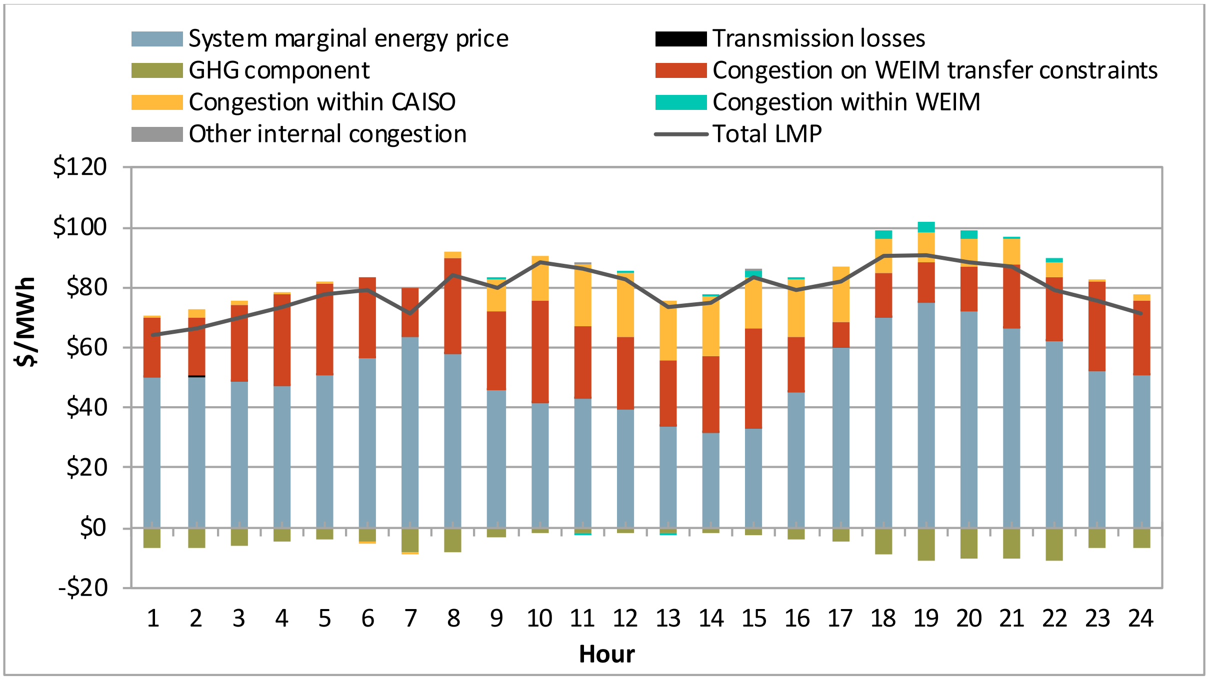


Appendix Figure A.80 Average hourly 5-minute market transfers

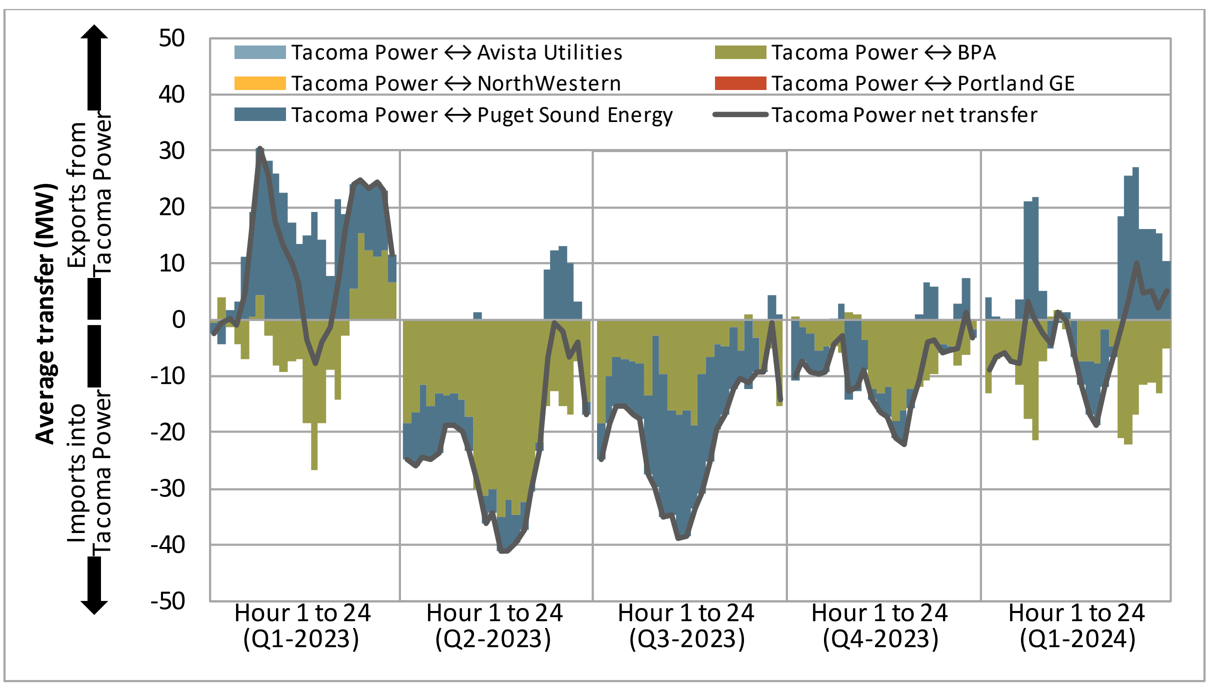


A.20 Tacoma Power

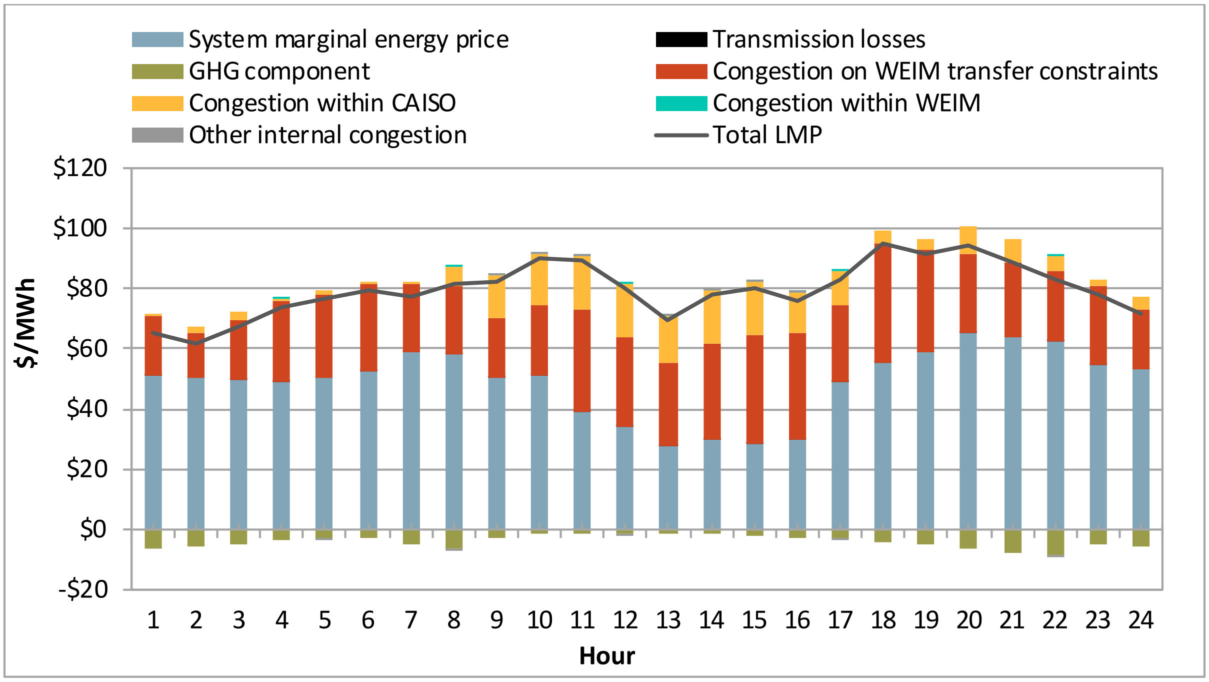
Appendix Figure A.81 Average hourly 15-minute price by component (Q1 2024)



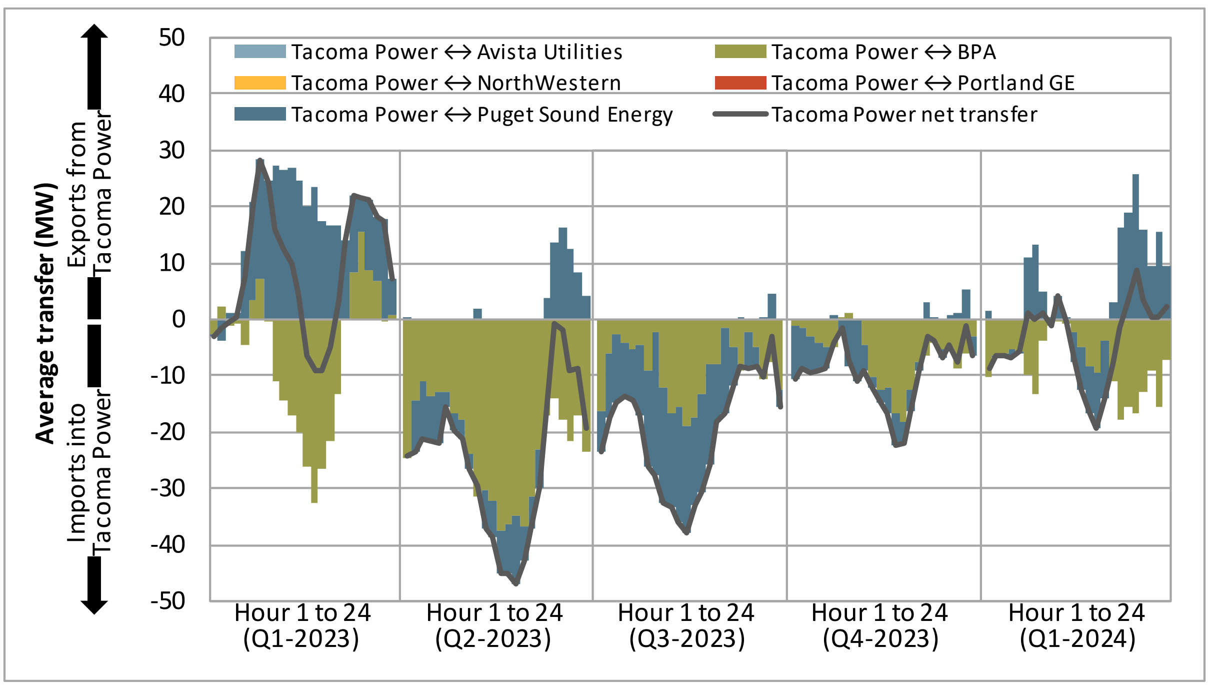
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q1 2024)

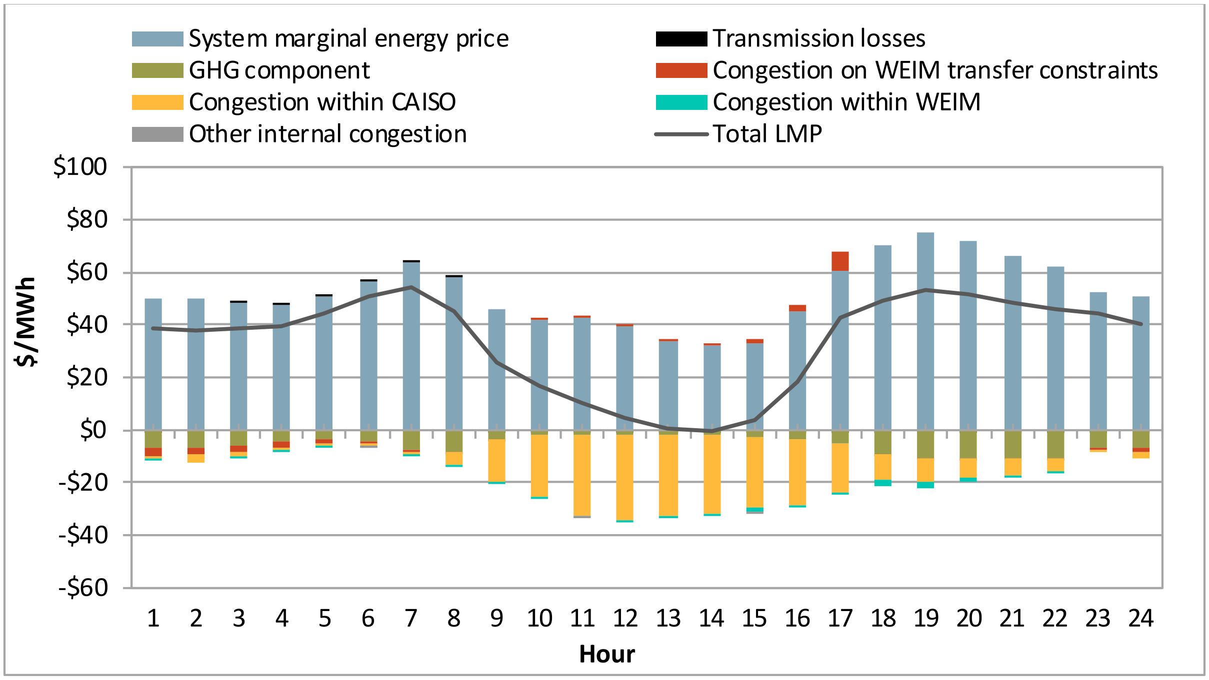


Appendix Figure A.84 Average hourly 5-minute market transfers

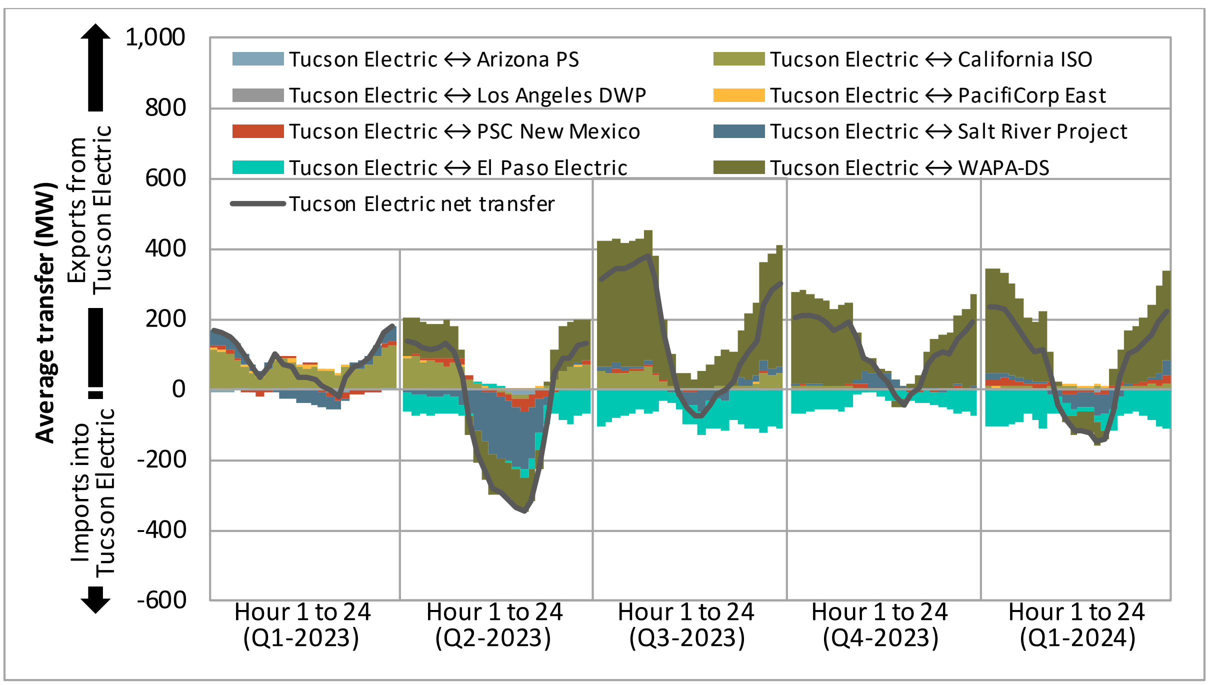


A.21 Tucson Electric Power

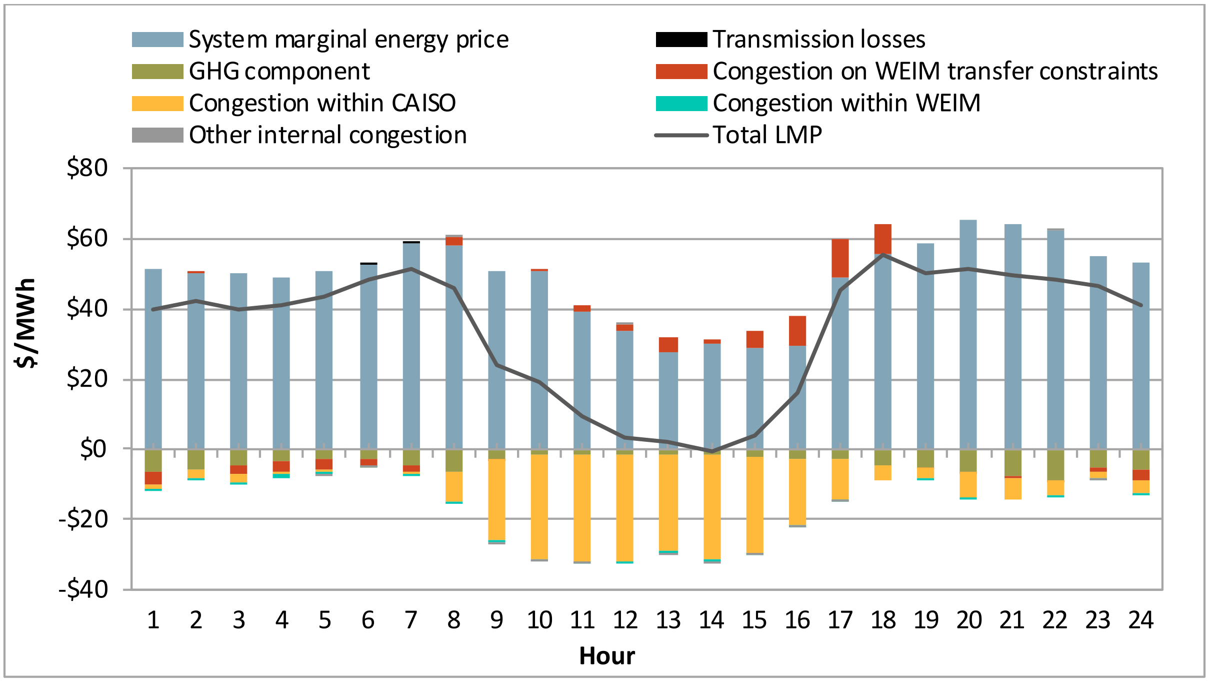
Appendix Figure A.85 Average hourly 15-minute price by component (Q1 2024)



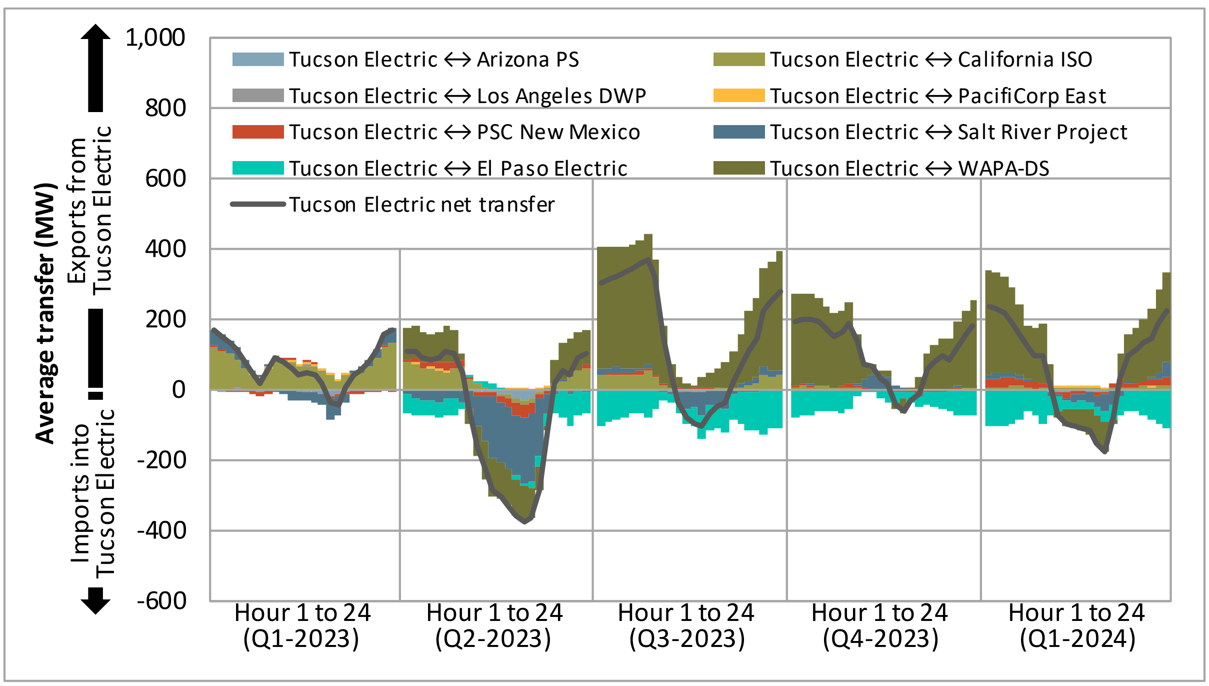
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q1 2024)

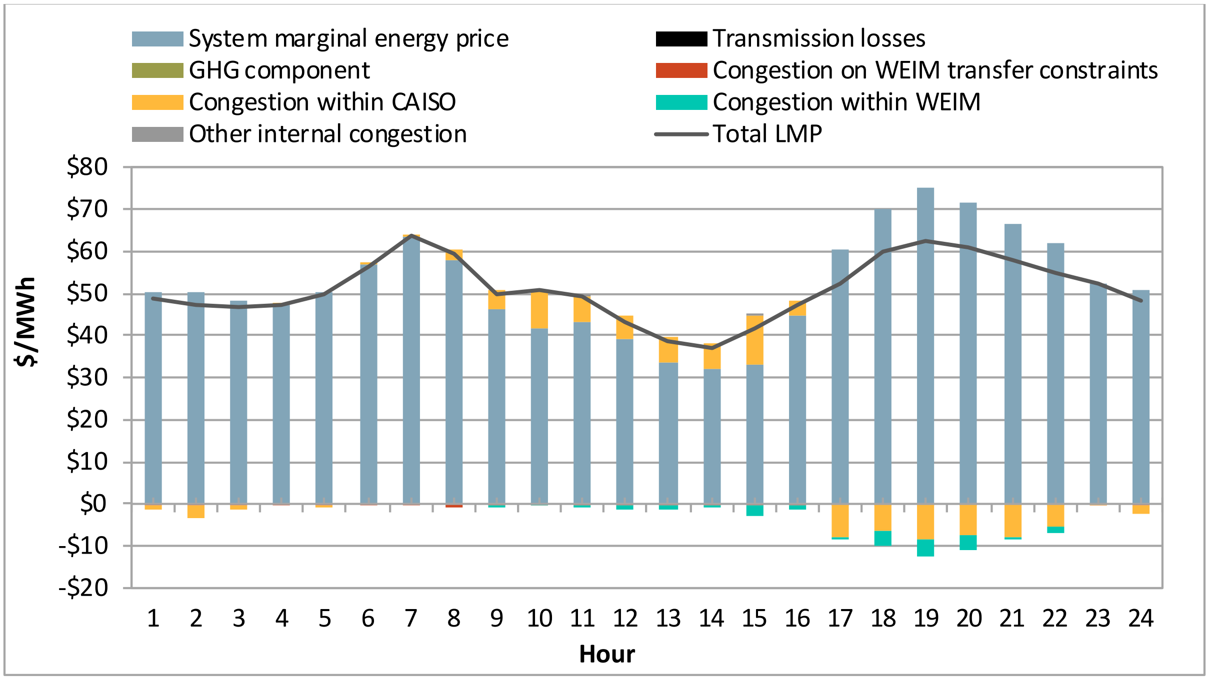


Appendix Figure A.88 Average hourly 5-minute market transfers

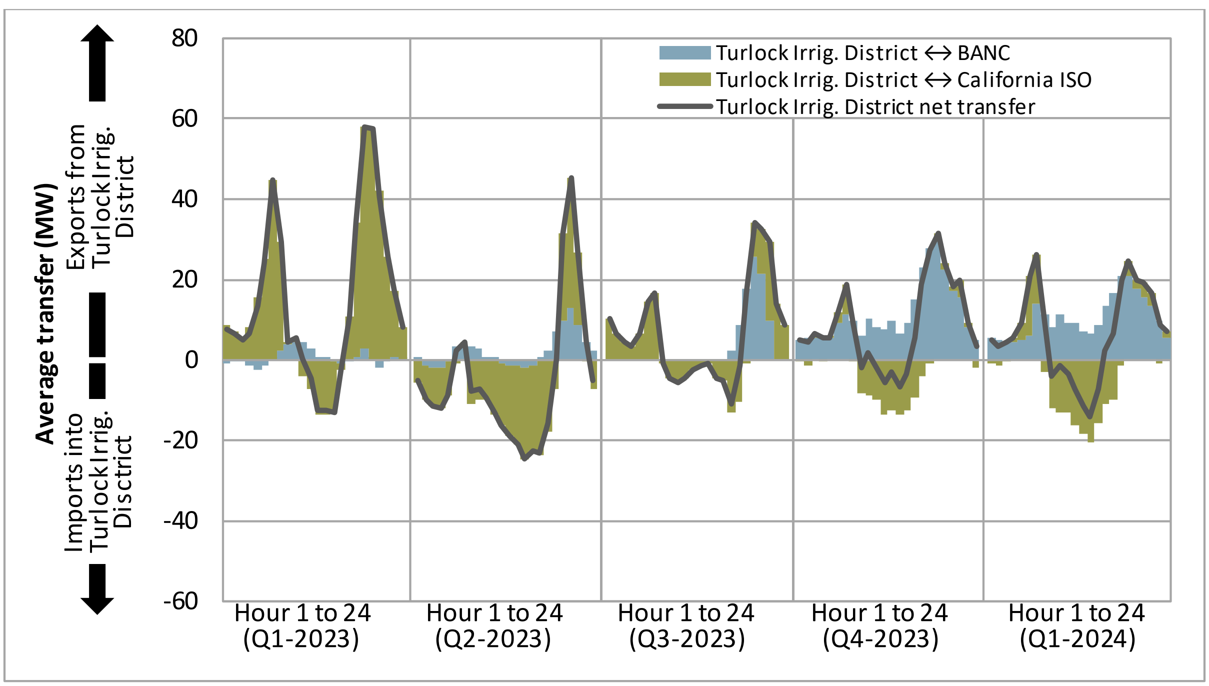


A.22 Turlock Irrigation District

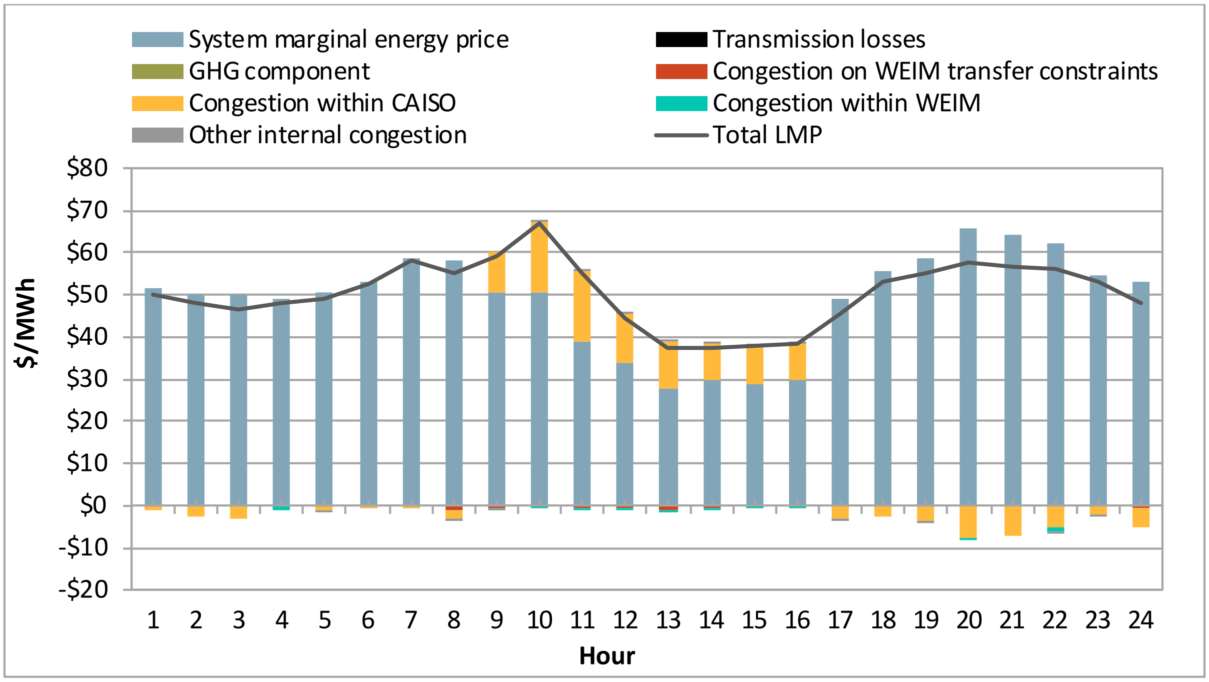
Appendix Figure A.89 Average hourly 15-minute price by component (Q1 2024)



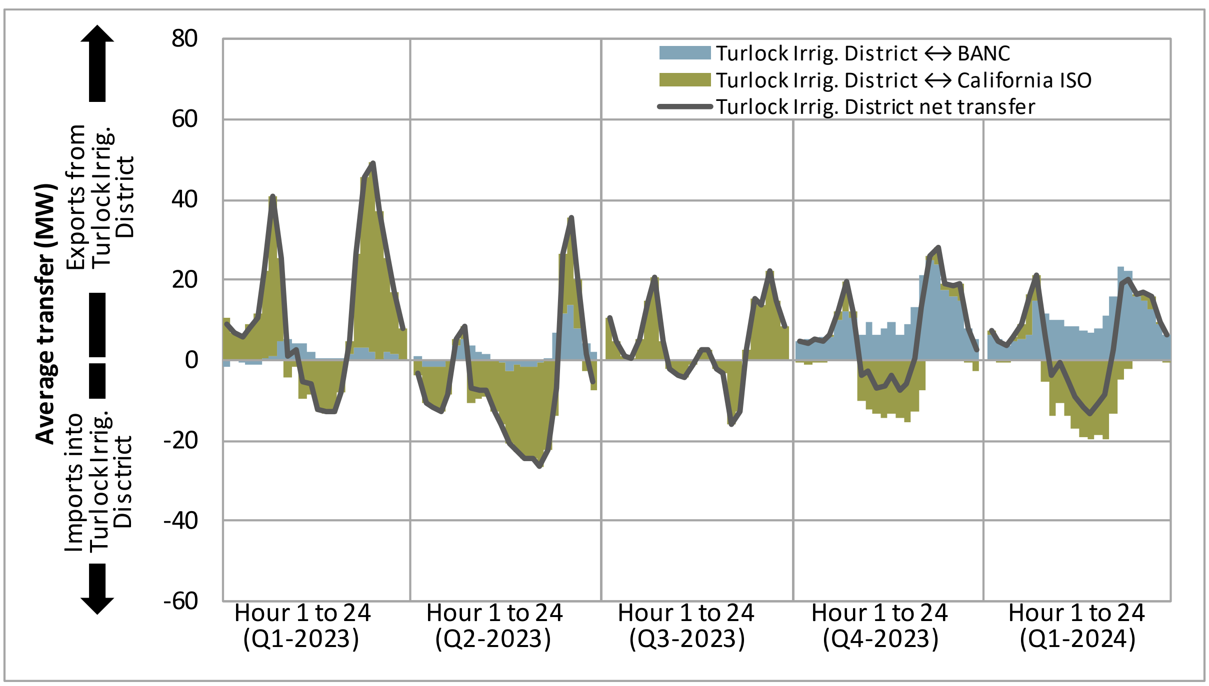
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q1 2024)

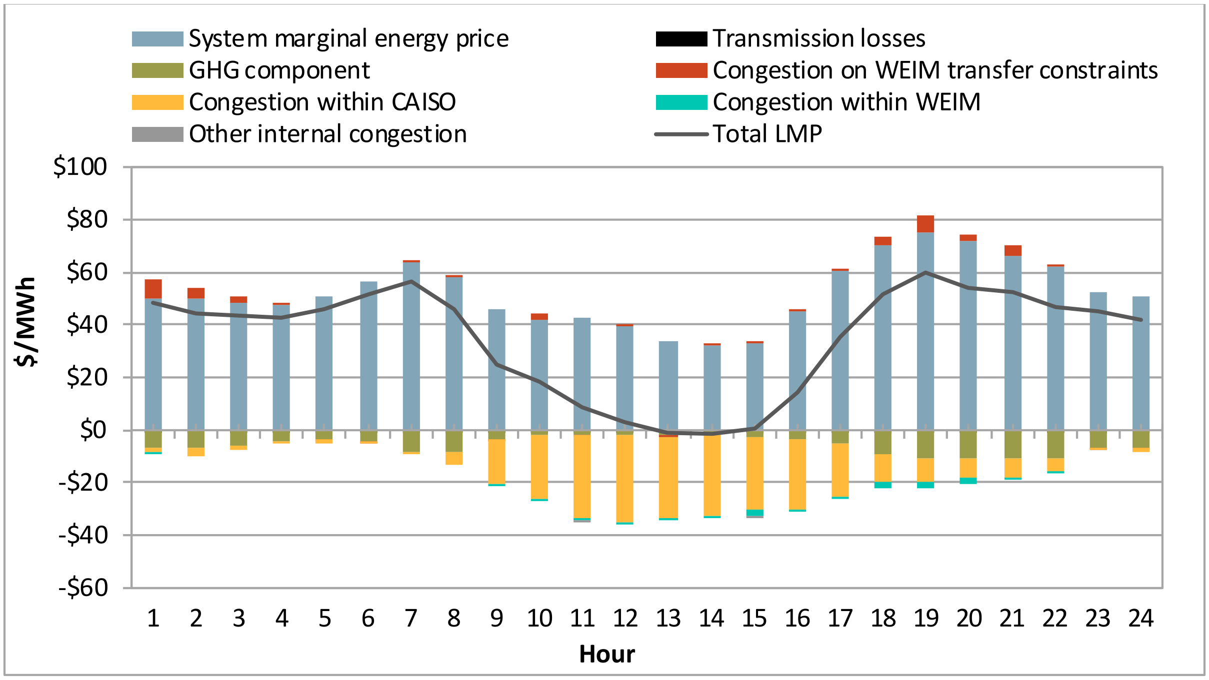


Appendix Figure A.92 Average hourly 5-minute market transfers

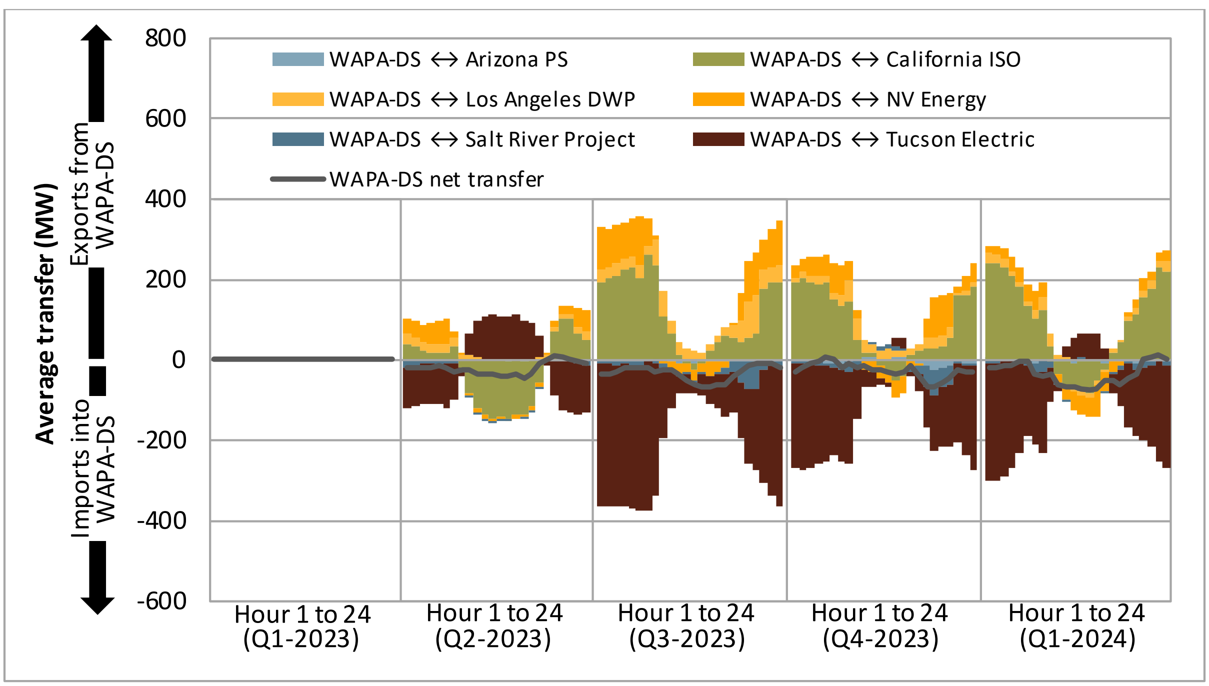


A.23 Western Area Power Administration Desert Southwest

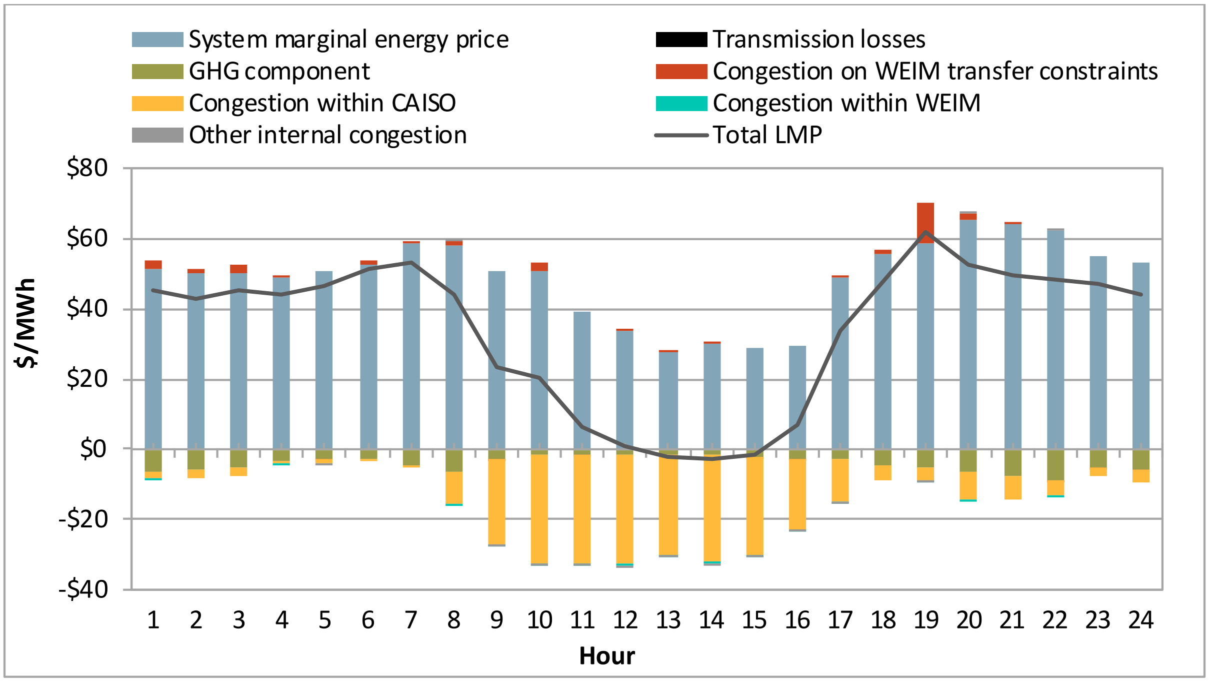
Appendix Figure A.93 Average hourly 15-minute price by component (Q1 2024)



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



Appendix Figure A.95 Average hourly 5-minute price by component (Q1 2024)



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